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Request IR-2:

With respect to the Opinion of Capital Structure and Return on Equity, prepared by Ms. Kathleen C. McShane, please provide:

(a) Microsoft Excel copies of all data, tables, charts, source documents, regression results and statistical tests, and work papers used in the development and preparation of the tables and charts of the testimony and appendices of Ms. McShane; and

(b) An index with files names and/or page or tab numbers associated with the materials provided in (1). For the Microsoft Excel copies of the data, work papers, regressions, and statistical tests, please keep all formulas intact.

Response IR-2:

All of the requested documents have been provided in responses to CA IR-1, CA IR-3 and CA IR-5.

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Request IR-3:

With respect to the Opinion of Capital Structure and Return on Equity, prepared by Ms. Kathleen C. McShane, please provide:

(a) Copies of all data, source documents, and work papers used in the development and preparation of the schedules of Ms. McShane;

(b) Microsoft Excel copies of all schedules of Ms. McShane;

(c) An index with page or tab numbers associated with the materials provided in (1) and (2). For the Microsoft Excel copies of the data, schedules, work papers, regressions, and statistical tests, please keep all formulas intact.

Response IR-3:

Data, source documents, and work papers used in the development and preparation of the schedules of Ms. McShane are provided as attachments as follows:

Used for Schedule #	Attachment	File Name
Schedule 1 Page 1	1	5-31-05 BCUC Order G-52-05.pdf
Schedule 1 Page 1	2	12-16-09 BCUC Order G-158-09.pdf
Schedule 1 Page 1	3	11-06-12 OEB Decision EB-2012-0031.pdf
Schedule 1 Page 1	4	11-2-12 OEB Decision EB-2011-0354.pdf
Schedule 1 Page 1	5	10-25-12 OEB Decision EB-2011-0210.pdf
Schedule 1 Page 1	6	3-10-11 OEB Decision EB-2010-008.pdf

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Used for Schedule #	Attachment	File Name
Schedule 1 Page 1	7	7-12-10 IRAC Order UE-10-03.pdf
Schedule 1 Page 1	8	Dec 2012 PEI Bill 26 Energy Accord Continuation.pdf
Schedule 1 Page 1	9	12-24-09 Newfoundland Order P.U. 46.pdf
Schedule 1 Page 1	10	6-15-12 Newfoundland Order P.U. 17.pdf
Schedule 2	11	S&P Issuer Ranking Oct 22 2012.pdf
Schedule 2	12	VL Sheets Sep and Nov 2012.pdf
Used for Schedule #		**File Name**
Schedule 2	13	VL Summary and Index Nov 30 2012.pdf
Schedule 2	14	wp ROAE Dividend Payout.xlsx
Schedule 2	15	wp Average Earned Returns 07-11.xlsx
Schedule 2	16	wp Capital Structures US.xlsx
Schedule 3	17	wp US Closing Prices Sep-Nov 2012.xlsx
Schedule 3	18	Bloomberg LT Growth Rates Nov 21 2012.pdf
Schedule 3	19	Reuters LT Growth Rates Nov 20 2012.pdf
Schedule 3	20	Zacks LT Growth Rates Dec 11 2012.pdf
Schedule 4	21	Blue Chip Economic Indicators Oct 10 2012.pdf
Schedule 5	22	Consensus Forecasts Oct 8 2012.pdf
Schedule 5	23	BMO Capital Markets Oct 9 2012.pdf
Schedule 5	24	CIBC Oct 31 2012.pdf
Schedule 5	25	Desjardins Oct 31 2012.pdf
Schedule 5	26	National Bank Oct 2012.pdf
Schedule 5	27	RBC Economics Oct 2012.pdf
Schedule 5	28	Scotiabank Sep 27 2012.pdf
Schedule 5	29	TD Economics Oct 11 2012.pdf
Schedule 5	30	wp Summary of Forecasts of Investment Bankers.xlsx
Schedule 5	31	wp Bond Yields.xlsx
Schedule 6	32	wp DCF RP Constant Growth 98-12.xlsx
Schedule 6	33	wp DCF RP Three Stage 98-12.xlsx
Schedule 7	34	wp Moody's A Rated Utility Bond Yields 1997.xlsx
Schedule 7	35	RRA Major Rate Case Decisions 2005-20112.pdf
Schedule 7	36	RRA Major Rate Case Decisions 1999-2004.pdf
Schedule 7	37	RRA Major Rate Case Decisions 1997-1998.pdf
All Schedules	38	McShane Testimony Schedules.xlsx

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The 10-year history of the Bloomberg 30-year A-rated Utility Bond Index used in Schedule 5 is proprietary and under strict-use license, and is therefore not provided.

BRITISH COLUMBIA UTILITIES COMMISSION

ORDER NUMBER G-52-05

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IN THE MATTER OF

the Utilities Commission Act, RSBC 1996, Chapter 473, as amended

and

An Application by FortisBC Inc.
for Approval of 2005 Revenue Requirements,
2005-2024 System Development Plan and 2005 Resource Plan

BEFORE: L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner May 31, 2005

O R D E R

WHEREAS:

A. On November 26, 2004, FortisBC Inc. ("FortisBC") submitted its 2005 Revenue Requirements Application, which also included its Transition Plan and 2005 Capital Plan ("Submission 1"). On the same date, under separate cover, FortisBC also filed its 2005-2024 System Development Plan ("Submission 2"). On December 21, 2004, FortisBC submitted its 2005 Resource Plan ("Submission 3"); and

B. In Submission 1 FortisBC requested approval of a 2005 Revenue Requirement of $184,388,000 and a general rate increase of 4.4 percent; and

C. On December 14, 2004, the Commission issued Order No. G-111-04, establishing a series of Workshops, a Pre-hearing Conference, and approving an interim rate increase of 3.7 percent, effective January 1, 2005, subject to refund with interest calculated at the average prime rate of the principal bank with which FortisBC conducts its business; and

D. A Pre-hearing Conference was held on January 21, 2005 in Kelowna, B.C. to discuss the major issues to be examined, and the steps and timetable for an Oral Public Hearing. Registered Intervenors and FortisBC made their submissions for consideration by the Commission; and

E. Order No. G-14-05 dated January 24, 2005, set out an amended Regulatory Timetable and Issues List and established an Oral Public Hearing to commence on March 21, 2005 in Kelowna, B.C.; and

F. By letter dated January 27, 2005, FortisBC requested a revision to the Regulatory Timetable and process to include a Negotiated Settlement Process ("NSP"). The Commission issued Letter No. L-9-05 dated January 28, 2005, rejecting the request for an NSP because it was concerned that FortisBC and its predecessors have gone for many years without a detailed review of the utility operations in an oral public hearing process; and

G. On March 10, 2005, FortisBC filed a revised 2005 Revenue Requirements Application ("Submission 4") reflecting the impact of updated 2004 actual energy sales and financial results. In Submission 4 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,980,000 and a general rate increase of 4.1 percent, effective January 1, 2005; and

H. On March 18, 2005, FortisBC filed a second revised 2005 Revenue Requirements Application ("Submission 5") primarily reflecting the impact of updates to 2004 power purchase incentive adjustments and 2005 income tax expense. In Submission 5 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,250,000 and a general rate increase of 3.6 percent, effective January 1, 2005; and

I. The Oral Public Hearing proceeded as scheduled in Kelowna, B.C. on March 21 through March 24, 2005. During the Oral Public Hearing, on March 22, 2005, FortisBC filed a third revised 2005 Revenue Requirements Application ("Submission 6") incorporating a correction to the 2004 Actual and 2005 Forecast Mid-Year Rate Base. In Submission 6 FortisBC sought approval for a revised 2005 Revenue Requirement of $179,991,000 and a general rate increase of 4.1 percent, effective January 1, 2005; and

J. Written Final Arguments and Reply Arguments were completed on April 29, 2005; and

K. The Commission Panel has considered Submissions 1 through 6 and all of the related evidence and arguments.

NOW THEREFORE the Commission orders as follows:

1. FortisBC is directed to file complete financial schedules showing:

   (a) The requested 2005 Revenue Requirement of $179,991,000 as per Submission 6;
   (b) All adjustments set out in the Decision issued concurrently with this Order; and
   (c) The final resultant 2005 Revenue Requirement and general rate increase.

   The Commission approves the final resultant 2005 Revenue Requirement and general rate increase consistent with all adjustments set out in the Decision issued concurrently with this Order.

2. If the final general rate increase is less than the 3.7 percent general rate increase granted on an interim refundable basis as per Order No. G-111-04, then refunds should be made to customers as soon as practicable, with interest calculated at the average prime rate of the principal bank with which FortisBC conducts its business. FortisBC is directed to file all relevant refund calculations with the Commission.

…/3

3. If the final general rate increase is greater than the 3.7 percent general rate increase granted on an interim refundable basis as per Order No. G-111-04, the additional monies will be recovered through a rate rider based on forecast consumption for the period July 1, 2005 to December 31, 2005. FortisBC is directed to file all relevant rate rider calculations with the Commission.

4. FortisBC is also directed to comply with all other determinations and instructions set out in the Decision that is issued concurrently with this Order.

DATED at the City of Vancouver, in the Province of British Columbia, this 31st day of May 2005.

BY ORDER

Original signed by:

L.F. Kelsey
Commissioner and Panel Chair

Attachment

BRITISH COLUMBIA UTILITIES COMMISSION

IN THE MATTER OF

FORTISBC INC.

2005 REVENUE REQUIREMENTS APPLICATION
2005-2024 SYSTEM DEVELOPMENT PLAN
2005 RESOURCE PLAN

DECISION

MAY 31, 2005

Before:

L.F. Kelsey, Commissioner and Panel Chair
P.G. Bradley, Commissioner

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1.0 INTRODUCTION

1.1 Background and Historical Context

In 1986 UtiliCorp United and UtiliCorp BC applied to the British Columbia Utilities Commission ("Commission") to acquire a reviewable interest in West Kootenay Power and Light Company Ltd. Following an extensive review, that application was approved by the Commission. The West Kootenay Power and Light Company Ltd. name remained for some time, was subsequently changed several times, eventually to become Aquila Networks Canada (British Columbia) Ltd. ("Aquila(BC)") (the "Utility").

In October 1998, as part of its Preliminary 1999 Revenue Requirements and Incentive Mechanism Review Application, the Utility applied for an Order that a Negotiated Settlement Process ("NSP") be implemented. Commission Order No. G-123-98 approved that application. Following negotiations with Intervenors, wherein a settlement was reached, Commission Order No. G-134-99 approved the November 22, 1999 Settlement Agreement for the period beginning January 1, 2000 and ending December 31, 2002. The terms of the 1999 Settlement Agreement required that the Utility institute an NSP and an Annual Review process to allow the public to examine the filed material, to submit other issues for determination by the Commission and to discuss all issues prior to the final rate application being made.

On November 15, 2002, the Utility requested that the 1999 Settlement Agreement be extended for a period of one year ending December 31, 2003, filing a Preliminary 2003 Revenue Requirements Application in support. Commission Order No. G-83-02 established a 2002 Annual Review and an NSP to determine rates for 2003. The proceedings were held in Penticton B.C. in January 2003. A Public Information Town Hall Meeting was scheduled for those parties not able to participate in the Annual Review. Commission Order No. G-10-03 approved the Negotiated Settlement as issued. This Settlement was a simple extension of the 2000-2002 rate adjustment mechanism approved by the November 22, 1999 Settlement Agreement. The Utility agreed at that time to provide a detailed revenue requirements application for 2004 that would contain a full analysis in support of any proposed rebasing of in the cost categories.

On November 19, 2003, the Utility filed a Preliminary 2004 Revenue Requirements Application with the Commission. Due to the impending sale of the Canadian business of Aquila(BC) to Fortis Inc. and the potential for restructuring, the Utility proposed a one-year extension of the current Settlement Agreement, which was due to expire on December 31, 2003 subject to certain changes as described in the Application. Further, the Utility proposed an NSP to determine the 2004 Revenue Requirements and the parameters of the Incentive Mechanism.

The Utility also requested that the 2003 Annual Review of its performance be scheduled prior to the NSP.

By Order No. G-6-04 the Commission approved an NSP to determine rates for 2004. Following negotiations, Commission Order No. G-38-04 approved the terms of the negotiated settlement agreement.

As contemplated in the Preliminary 2004 Revenue Requirements Application, on December 1, 2003, Fortis Pacific Holdings Inc. ("Fortis Pacific") applied pursuant to Section 54 of the Utilities Commission Act ("UCA") for an Order approving the acquisition of a reviewable interest in Aquila Networks Canada (British Columbia) Ltd. from Aquila Networks British Columbia Ltd. On the same date, Aquila Networks Canada (British Columbia) Ltd applied pursuant to Section 54(5) of the UCA for approval to register a transfer of 100 percent of its Common Shares to Fortis Pacific.

Following a written hearing, the Commission, by Order No. G-39-04 approved the acquisition by Fortis Pacific of a reviewable interest in Aquila Networks Canada (British Columbia) Ltd. The company was renamed FortisBC Inc ("FortisBC").

In response to a Commission information request during the acquisition hearing, FortisBC stated that it anticipated that it would file a general rate application in the fourth quarter of 2004 that would "set out in detail the plans for re-establishing the Utility on a stand-alone basis." FortisBC also stated that the rate application would "provide a basis for full public scrutiny of a more detailed plan including a definitive timetable, a forecast of proposed costs and an assessment of customer benefits, as well as a reasonable record for the Commission's consideration of matters relating to this issue."

1.2 FortisBC Filings and Procedural Summary

On November 26, 2004, FortisBC filed its 2005 Revenue Requirements Application with the Commission ("November Application") (Exhibit B-1). FortisBC applies for an Order, pursuant to the applicable provisions of the UCA including Sections 23, 45, 57, 60, and 61, approving the November Application for the purpose of setting rates and other ancillary matters. Included with this filing, and in compliance with Commission Order No. G-39-04, FortisBC submitted its Transition Plan outlining the steps being taken to move the utility to a stand-alone basis. FortisBC included its 2005 Capital Plan with its November Application and filed under separate cover its 2005-2024 System Development Plan (Exhibit B-2). It filed these plans to address high priority work needed to maintain and expand the electrical system to meet its obligation to provide reliable electricity service to its customers. FortisBC filed its 2005 Resource Plan (Exhibit B-4) in accordance with the Commission's Resource Planning Guidelines and the Commission's directives to utilities in this regard.

FortisBC's November Application requests approval of a general rate increase of 4.4 percent, reflecting principally an increased rate base, an increased cost of financing that rate base and a forecast increase in 2005 expenses, including operating and maintenance expenses and power purchases. The November Application included a request for an interim refundable general rate increase of 4.4 percent, effective January 1, 2005. The increase was based, in part, on a proposal to increase the equity risk premium of FortisBC from 40 to 75 basis points. In response to a Commission staff request, FortisBC determined that the general rate increase would equal 3.7 percent if derived on the basis of its existing equity risk premium of 40 basis points. On December 14, 2004, the Commission issued Order No. G-111-04 approving for FortisBC an interim rate increase of 3.7 percent, effective January 1, 2005, subject to refund with interest calculated for the refund period at the average prime rate of the principal bank with which FortisBC conducts its business. By this Order the Commission also established a series of Application Workshops and a Pre-hearing Conference.

The Commission held the Pre-Hearing Conference in Kelowna, B.C. on January 21, 2005, wherein the Commission Panel considered submissions by participants on finalizing the issues, process steps and regulatory schedule for the proceeding. As part of its consideration of process steps, the Commission Panel heard submissions by parties on whether certain issues would be appropriately reviewed by Technical Committees.

Following the Pre-Hearing Conference, on January 24, 2005 the Commission issued Order No. G-14-05, which set out an amended Regulatory Timetable and Issues. Commission Order No. G-14-05 established an Oral Public Hearing ("Hearing") to commence on March 21, 2005 in Kelowna, and specified that issues associated with the Load Forecast, Demand Side Management ("DSM"), Power Purchases, and Capital Additions would be reviewed by four separate Technical Committees as an adjunct to the Hearing. The Commission directed each Technical Committee to submit a report with recommendations to the Commission by Monday, March 14, 2005, one week prior to the commencement of the Hearing.

By letter dated January 27, 2005, FortisBC requested that the regulatory timetable and process be revised to include an NSP (Exhibit B-8). FortisBC indicated that on the condition that the NSP was successful it would defer its application for an increase to its equity risk premium until the fall of 2005 in anticipation of a Commission process regarding the return on equity adjustment mechanism at that time. FortisBC reported that its proposed revision to the regulatory timetable and process was supported by most Intervenors.

The Commission issued Letter No. L-9-05 on January 28, 2005 rejecting FortisBC's request for an NSP for 2005. The Commission was concerned that FortisBC and its predecessors have gone for many years without a detailed review of the utility operations in an oral public hearing process, while noting that in each of the last two settlements the participants agreed that an oral public hearing was timely and should occur the following year. At the request of FortisBC, and for reasons that are a matter of public record, oral public hearings did not occur. The Commission believed that it was timely to review the finances and revenue requirement of the new B.C.-based utility in an oral public hearing this year. The Commission commented that following such a detailed review and decision, it may then be timely to consider an NSP thereafter. The Commission also noted that successful work by the four Technical Committees would go a considerable distance to streamlining the Hearing.

On March 9, 2005, FortisBC filed the reports of the DSM and Load Forecast Technical Committees (Exhibits B-17 and B-18, respectively). Each Committee recommended that there would be no need to call hearing panels in their respective subject areas. On March 11, 2005, FortisBC filed the reports of the Capital Additions and Power Purchases Technical Committees (Exhibits B-20 and B-21, respectively). The Capital Additions and Power Purchases Technical Committees reported that the meetings were helpful, but recommended that these matters should be addressed at the Hearing.

On March 11, 2005, the Commission wrote to Registered Intervenors requesting that they indicate by March 16, 2005 whether or not they were supportive of the recommendations of the DSM and Load Forecast Committees that there is no need to call hearing panels in their respective subject areas (Exhibit A-14). The Commission indicated in its letter that it would consider no response to indicate support of the Committee recommendations. Out of those intervenors that did not participate in the work of these Committees, the Commission received one letter of support, from the B.C. Old Age Pensioners Association *et al.* ("BCOAPO"), and zero letters of no support. By letter dated March 17, 2005 the Commission accepted the recommendations of the DSM and Load Forecast Committees that there is no need to call hearing panels in the respective subject areas (Exhibit A-16).

On March 10, 2005, FortisBC filed a revised 2005 Revenue Requirements Application (the "Revised Application") (Exhibit B-19). FortisBC indicates that its Revised Application reflects the impact of updates to 2004 actual results on 2005 energy sales and revenue forecasts, and 2004 incentive adjustments. FortisBC reported that its Revised Application includes revisions arising from events subsequent to the November Application, such as FortisBC's Capital Tax appeal and changes to property tax assessment procedures. FortisBC's Revised Application sought approval of a 2005 Revenue Requirement of approximately $180.0 million, and a general rate increase of 4.1 percent, effective January 1, 2005.

On March 18, 2005, FortisBC filed a second revised 2005 Revenue Requirements Application (the “Second Revised Application”) reflecting the impact of updates to 2004 power purchase incentive adjustments and 2005 income tax expense (Exhibit B-25). The Second Revised Application also reflects actual issue costs related to FortisBC’s Series 04-01 Senior Unsecured Debentures equal to $2,091,000, which is less than the forecast of $2,150,000 in the initial Application. The Second Revised Application requests approval to defer and amortize the actual amount. FortisBC’s Second Revised Application seeks approval of a 2005 Revenue Requirement of approximately $179.3 million, and a general rate increase of 3.6 percent, effective January 1, 2005.

The Hearing proceeded as scheduled in Kelowna on March 21 through March 24, 2005.

On March 22, the second day of the Hearing, FortisBC filed a third revised 2005 Revenue Requirements Application (the “Third Revised Application”) (Exhibit B-26). FortisBC indicated that the Third Revised Application incorporates a correction to the 2004 Actual and 2005 Forecast Mid-Year Rate Base; namely that the Mid-Year Rate Base had been understated in the Second Revised Application by approximately $3.0 million in 2004 and $8.3 million in 2005. FortisBC states that the understatement of Rate Base was caused by the incorrect reduction of net additions to plant in service by the amount of new Contributions in Aid of Construction ("CIAC"). FortisBC's Third Revised Application seeks approval of a 2005 Revenue Requirement of approximately $180.0 million, and a general rate increase of 4.1 percent, effective January 1, 2005.

Following the Hearing, written argument was received by FortisBC on April 15, 2005 (“FortisBC Argument”). On April 22, 2005, the Commission received argument from Natural Resources Industries (“NRI”, “NRI Argument”), Interior Municipal Electric Utilities (“IMEU”, “IMEU Argument”), Mr. Alan Wait (“Mr. Wait”, “Wait Argument”), Kootenay-Okanagan Electric Consumers Association (“KOECA”, “KOECA Argument”), and BCOAPO (“BCOAPO Argument”). FortisBC filed its reply argument on April 29, 2005 (“FortisBC Reply Argument”).

FortisBC adopted the convention in its written argument that its November Application, together with its Revised Application, Second Revised Application and Third Revised Application, would be collectively referred to as the “Application”. The Commission uses the same referencing convention in this Decision unless it is necessary to refer to a specific filing, as appropriate.

FortisBC summarizes in its written argument that it seeks an Order of the Commission (FortisBC Argument, pp. 3-5):

- approving a 2005 Revenue Requirement of $179,991,000;
- approving the deferral of the cost of regulatory and related activities and the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000;
- approving the amortization of: the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000 over ten years commencing on January 1, 2005; the costs incurred in FortisBC's 2004 Revenue Requirements negotiated settlement process; and the costs of the 2005-2024 System Development Plan and 2005 Resource Plan, in an aggregate amount of $900,000 over five years commencing on January 1, 2005;
- approving the continuation of the current Demand Side Management and Power Purchase incentive mechanisms for 2005;
- approving the continuation of the flow through to customers of forecast and actual property tax, provincial water fees, and the Power Purchase expense related to the Brilliant contracts for 2005;
- approving the flow-through treatment of the costs of capacity block power purchases forecast for November and December 2005;
- approving an operating and Maintenance expense program with a forecast value of $36,173,000 and a sharing mechanism for expense above or below this amount;
- approving a cost of capital for rate making purposes that reflects a return on equity 75 basis points above that set by the Commission for a benchmark low-risk utility and a common equity ratio of 40 percent of total capitalization;
- acknowledging that the 2005 Capital Plan satisfies the requirements of Section 45 of the Utilities Commission Act and that specified capital projects are in the public interest;
- acknowledging that the 2005 Resource Plan meets the requirements of Section 45 of the Utilities Commission Act, and is in the public interest;
- acknowledging that the 2005 Demand Side Management ("DSM") Expenditures Plan meets the requirements of Section 45 of the Act, and is in the public interest;
- approving a change in the accounting treatment of certain PowerSense costs, such that the costs in the amount of $85,000 are charged to capital rather than operations;
- approving deferral and recovery in 2006 of higher income tax expense that will arise in 2005 if the new Capital Cost Allowance rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005; and
- approving a general rate increase of 4.1 percent effective January 1, 2005.

The following sections of this Decision address, in turn, the issues associated with the 2005 Revenue Requirements Application, the 2005 Capital Plan and 2005-2024 System Development Plan, and the 2005 Resource Plan.

2.0 2005 REVENUE REQUIREMENTS APPLICATION

2.1 Forecasts

2.1.1 Load Forecast

FortisBC describes its service area as experiencing population growth at an increased rate over the last several years. FortisBC observed that in 2004 the growth in energy consumption and the number of customer accounts has been significantly above the long term population growth rate in its service area. To account for these patterns of growth, FortisBC modified its load forecast methodology to decouple population growth from its forecast of energy consumption and customer accounts for the period 2004-2009. FortisBC anticipates that by 2009, energy consumption and customer growth rates will return to the long term rates of population growth. FortisBC normalized all temperature sensitive load data to eliminate the effect of temperature prior to conducting its load forecast and associated statistical analyses. In its November Application, FortisBC forecast a total gross load of 3,368 GWh, subsequently adjusted downward by 78 GWh to 3,290 GWh based on updates to 2004 actual data, and a revised industrial forecast (Exhibit B-1, pp. 4, 9; Exhibit B-19, p. 4). The components of this change are described in greater detail below. The following sections include a summary of the load forecast for each customer class in turn.

Residential

The Residential load forecast is comprised of a forecast of customer accounts and a forecast of use per customer.

FortisBC forecasts the growth rate in its customer accounts based on the long-term linear trend in population growth rates in its service area, augmented by adjustments that reflect actual and expected growth in the short-term. The short-term adjustments encompass the decoupling of the forecast from population growth, as described above. FortisBC forecasts 85,926 Residential customer accounts by 2005 year-end (Exhibit B-1, pp. 4, 10; Exhibit B-12, Q. 38.1, Q. 41.0).

FortisBC forecasts Residential use per customer based on a 19-year average annual decline rate between 1985 and 2003 of 67 kWh/customer. FortisBC indicates that possible explanations for this decline rate are the availability of more efficient electrical appliances and declining dependence on electricity as a primary source of energy for heating and cooling (Exhibit B-1, p. 4; Exhibit B-12, Q. 41.0).

Based on these components, FortisBC initially forecast a Residential load of 1,064 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 10 GWh, to 1,054 GWh, to reflect the impact of actual and normalized 2004 Residential energy consumption that was below forecast despite strong growth in Residential customer accounts (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

General Service

FortisBC's General Service class includes commercial and small industrial customers, as well as schools, hospitals and recreation facilities. FortisBC indicates that it is more difficult to forecast energy consumption in this class because of the diversity in customer size and the lumpiness of load additions.

Applying the same methodology as it uses for the Residential class, FortisBC forecasts 10,306 customer accounts by 2005 year-end. FortisBC forecasts General Service use per customer based on a 25-year average annual incline rate of 26 kWh/customer (Exhibit B-1, pp. 5, 10; Exhibit B-12, Q.42.0). Based on these components, FortisBC initially forecast a General Service load of 570 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 24 GWh, to 546 GWh, to reflect the impact of actual and normalized 2004 General Service energy consumption that was below forecast despite strong growth in General Service customer accounts (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

Industrial

FortisBC forecasts its Industrial load by estimating the annual energy consumption of Celgar, its single largest industrial customer, and adding this amount to a forecast of the remainder of Industrial load determined on the basis of the historical relationship of this portion of Industrial load to overall system load. FortisBC initially estimated Industrial load of 343 GWh, including Celgar load of 65 GWh based on recent Celgar projections, or nearly 20 percent of overall Industrial load. Subsequent to its November Application, FortisBC adjusted this forecast downward by 34 GWh, to 309 GWh, to reflect a new 2005 load forecast projection by Celgar of 31 GWh (Exhibit B-1, pp. 5, 9; Exhibit B-19, p. 4).

Wholesale

FortisBC's Wholesale class is comprised mainly of municipal electric utilities, with a corresponding composition of residential, commercial and industrial customers. Given that this load is largely sensitive to population growth trends, FortisBC forecasts Wholesale consumption based on the relationship between population growth trends and temperature normalized historical consumption in this class (Exhibit B-1, p. 6).

FortisBC initially forecast Wholesale load of 964 GWh. Subsequent to its November Application, FortisBC adjusted this forecast downward by 6 GWh, to 958 GWh, to reflect the impact of actual and normalized 2004 Wholesale energy consumption that was below forecast (Exhibit B-1, p. 9; Exhibit B-19, p. 4).

Irrigation and Lighting

FortisBC forecasts Irrigation load of 47 GWh based on a five-year average load, and assumes that this level will remain constant for the duration of the forecast period. Similarly, forecast Lighting load of 10 GWh is assumed to remain constant for the duration of the forecast period.

System Losses

FortisBC forecasts losses of 369 GWh on the basis that annual losses consistently amount to roughly 12 percent of historical net system load. FortisBC adjusted its forecast losses downward by 3 GWh, to 366 GWh, based on the updates to the load forecast of the respective customer classes described above.

Load Forecast Technical Committee

Commission Order No. G-14-05 specified that issues associated with the Load Forecast would be reviewed by a Technical Committee as an adjunct to the Hearing. The Committee comprised FortisBC and Commission staff as well as Registered Intervenors that expressed an interest to participate. The Commission directed the Load Forecast Technical Committee to submit a report with recommendations to the Commission one-week prior to the commencement of the Hearing (Exhibit A-4).

FortisBC filed the Report of the Load Forecast Technical Committee on March 9, 2005 (Exhibit B-18). The Committee considered several methodological issues in detail over the course of two meetings; most notably a review of the assumptions underlying the regression analyses for the Residential and General Service use per customer forecasts. Further detail of the issues discussed, and the undertakings completed by FortisBC in response, may be referenced in the Report (Exhibit B-18). Committee members concluded that there were no serious methodological concerns with the load forecast. Committee members were provided with the revised forecast, as summarized above, prior to the filing of the report. No concerns were raised about the revised forecast.

The Committee suggested that FortisBC improve upon the communication and transparency of the technical detail and associated calculation spreadsheets for the load forecast. The Committee recommended that there would be no need to call a load forecast panel at the Hearing. After canvassing comment from those Registered

Intervenors that did not participate in the Load Forecast Technical Committee, the Commission accepted this recommendation (Exhibit A-16). A load forecast panel was not called at the Hearing and no load forecast issues were otherwise addressed in the Hearing. No written submissions on the load forecast were received in argument by any party.

Commission Panel Determinations

The Commission Panel has reviewed the FortisBC Load Forecast and the Report of the Load Forecast Technical Committee. **The Commission Panel accepts the revised FortisBC gross load forecast of 3,290 GWh.**

The Commission Panel is mindful of the Technical Committee suggestion that FortisBC improve upon the communication and transparency of the technical detail and associated calculation spreadsheets for the load forecast. Accordingly, the Commission Panel encourages FortisBC to improve its efforts in this regard. The Commission Panel also encourages FortisBC to consult with its Wholesale customers to determine whether any other means exist to obtain a more rigorous and comprehensive load forecast for this customer class. In addition, the Commission Panel has some concern about whether FortisBC's load forecast adequately accounts for diverse regional characteristics that exist across its service area, particularly in light of its reliance on more general population trends in its load forecast methodology. The Commission Panel encourages FortisBC to investigate alternatives to its current load forecast methodology to determine whether any benefit can be gained by segmenting its load forecast by specific regions in its service area, as FortisBC would define them.

2.1.2 Power Purchase and Wheeling Forecast

In its November Application, FortisBC forecast Power Purchase and Wheeling expenses (including water fees) of $74.26 million (Exhibit B-1, Tab 7). Power Purchase expenses alone are forecast to be $62.44 million for 2005, compared to an estimated amount for 2004 of $60.39 million. FortisBC noted that the Power Purchase expense forecast contains uncertainty with respect to load volumes and resource uncertainty. The resource uncertainty is related to market purchases required to supply a small shortfall between its firm resources and forecast loads. In its Revised Application FortisBC reduced the Forecast Power Purchase Expense to $59.45 million as a result of a change in load forecasts. This change reduced total forecast Power supply costs (including wheeling and water fees) to $71.01 million (Exhibit B-19, and Exhibit B-26).

As discussed in the 2005 Resource Plan, FortisBC meets the majority of its needs through its own generation plants and from long-term power purchase agreements, as well as from BC Hydro's Rate Schedule 3808. The remaining amount (mainly for capacity at peak load periods) is acquired through spot market purchases or block purchases from TeckCominco (“Cominco”). In 2004 these purchases were made in advance of need through the purchase of blocks of capacity from Cominco and through the purchase of a call option from Avista Energy (Exhibit B-1, Tab 7, pp. 10-11). The 2005 forecast includes market purchases and Cominco block purchases for January and February (actual) and November and December (estimated). The estimated amount of block purchases from Cominco is for 25MW in November and 100MW in December at estimated prices of $65.20/MW and $65.40/MW, respectively. Spot Market purchases for capacity (with a small amount of energy) are purchased year round depending on whether spot market prices are better than under BC Hydro Rate Schedule 3808. However, in the year 2005 for the months of January and February, and November and December, when FortisBC may be forced to purchase from the market, the forecast prices are 113 mills/KWh (11.3 cents/kWh). These prices are based on the Avista Energy Report and adjusted for the most valuable hours in the block (Exhibit B-1, Tab 7, p. 12). FortisBC provided an example of how this calculation is made in Appendix 1 to Exhibit B-21.

In past years FortisBC forecasted that its shortfall would be made up by market purchases because it does not have a firm contract with Cominco. However, the company typically was able to enter contracts late in the year at below market prices. The resulting difference was shared 50-50 between the company and its customers. This arrangement has been criticized because it appeared that the block purchases, although not firm, were predictable.

For this application FortisBC is proposing that the block purchases for November and December be taken out of the incentive mechanism and be treated as flow-through expense (Exhibit B1, Tab7, p 11).

No intervenor expressed objections to the Power Purchase forecast.

<u>Commission Panel Determinations</u>

The Commission Panel approves the forecast Power Purchases expense of $71,010,000, as revised by Exhibit B-19. Approval of the Power Purchase expense mechanism is addressed in this Decision in Section 2.4: 2005 Incentive Sharing Mechanisms.

2.2 Common Equity Component and Return on Common Equity

FortisBC applies to the Commission for approval of a cost of capital for rate making purposes that reflects a common equity ratio of 40 percent of total capitalization and a return on equity of 75 basis points above that set by the Commission for a benchmark low-risk utility.

In support of this application, FortisBC filed expert evidence titled *Opinion on Capital Structure and Equity Risk Premium for FortisBC*, prepared by Kathleen C. McShane ("Ms. McShane") of Foster Associates Inc., an economic consulting firm (Exhibit B-1, Tab 5). Ms. McShane concluded that a 40 percent common equity ratio, representative of FortisBC's actual capital structure, is reasonable but should be viewed as the minimum necessary to provide adequate financing flexibility. Ms. McShane recommends that FortisBC be allowed an incremental risk premium of 50 to 100 basis points (a mid-point of 75 basis points) relative to that applicable to a low risk benchmark utility.

BCOAPO filed expert evidence titled *Business Risk, Capital Structure and ROE for FortisBC*, prepared by Dr. Laurence D. Booth ("Dr. Booth"), a professor of finance in the Rotman School of Management at the University of Toronto (Exhibit C5-5). Dr. Booth recommends that the current 40 percent common equity ratio be maintained, but that the current FortisBC incremental risk premium of 40 basis points should be reduced to zero rather than increased to 75 basis points.

The following sections summarize the evidence and submissions on these issues, and the Commission's determinations in this regard.

2.2.1 Direct Evidence of Ms. McShane

Ms. McShane's approach to assessing the appropriate capital structure and return on equity ("ROE") for FortisBC was based on: 1) evaluating the reasonableness of the actual capital structure that has been maintained by FortisBC in terms of its compatibility with the business risks of the utility; and 2) accepting the Commission's ROE for a benchmark low risk utility as a point of departure for estimating the equity risk premium for FortisBC at the proposed capital structure (Exhibit B-1, Tab 5, p. 3).

Ms. McShane's evidence is premised on the stand-alone principle and an assessment of the market, supply and regulatory business risks and financial risks faced by of FortisBC. In regard to the stand-alone principle, Ms. McShane comments that there is no reason that FortisBC's capital structure or the fair return on equity should change simply because the identity of the shareholder has changed, but should continue to be premised on the risks faced by FortisBC. Ms. McShane notes that each of the Fortis utilities is financed on a stand-alone basis, so FortisBC's credit will be assessed on its own business risks and ability to generate adequate cash flows (Exhibit B-1, Tab 5, pp. 4-5).

Business Risk

Ms. McShane assesses FortisBC's business risks while noting the following factors:

- FortisBC is a relatively small utility serving a generally rural service area;
- Major industries served by FortisBC include forestry/pulp and paper, agriculture and tourism;
- Population growth in its service area has been strong over the past decade;
- Economic growth in B.C., dependent on the strength of commodity prices and the strength of the US economy, is expected to continue to outpace that of the country as a whole;
- Recent NAFTA rulings in favour of the Canadian forest industry may ultimately be beneficial;
- Increased demand for B.C.'s exports, not just those of the forest products industry, is anticipated from the economies of the Pacific Rim;
- Long-term B.C. economic growth is expected to be at a somewhat lower rate than the country as a whole;
- FortisBC has significant heating load (in competition with natural gas), with approximately one-third of direct residential (and likely wholesale) sales for heating purposes;
- FortisBC has no rate-stabilization mechanism to dampen the effects of weather volatility;
- FortisBC competes to some extent with alternative suppliers of electric power, such as BC Hydro, given the customer choice available to wholesale and large industrial customers;
- Technological change is expected to increasingly create competitive alternatives;
- FortisBC generates 45 percent of its supply from its own hydroelectric plants, obtaining the remainder of its supply through long-term contracts and market purchases; and
- FortisBC has a power purchase incentive mechanism to mitigate its exposure to market price volatility (Exhibit B-1, Tab 5, pp. 7-13).

Ms. McShane assesses three factors associated with the regulatory component of FortisBC business risk: deferral accounts, performance-based regulation ("PBR") and depreciation expense. Ms. McShane states that, in contrast to many Canadian utilities, FortisBC has operated with few deferral accounts: it has no deferral account for short-term interest expense, it has no rate-stabilization mechanism to dampen the effects of weather volatility; and, while it has shared deviations from purchased power costs with customers, it has not operated with a pass-through mechanism for such costs (Exhibit B-1, Tab 5, p. 13).

In her discussion of the impact of FortisBC's PBR from 1996-2004, Ms. McShane notes that the Dominion Bond Rating Service ("DBRS") considers the regulatory environment in B.C. among the more progressive in Canada. In comparison to traditional cost of service ratemaking, Ms. McShane considers that the FortisBC PBR plan, which retains a link to actual costs and includes sharing, exposes the shareholder to a moderately higher level of business risk (Exhibit B-1, Tab 5, pp. 14-15).

Ms. McShane points out that the settlement agreement in the 2000 NSP included a PBR rate stabilization mechanism to limit rate increases to 5 percent or less, with a reduction in annual depreciation expense as necessary to achieve this end. In addition, the same agreement lowered the depreciation rate on transmission assets. Ms. McShane states that both factors have contributed to the free cash flow deficits currently faced by FortisBC (Exhibit B-1, Tab 5, p. 15).

Ms. McShane concludes that FortisBC faces above average business risk relative to its Canadian electric and gas peers, and relative to the low-risk benchmark utility.

Financial Risk

Ms. McShane defines financial risk as the additional risk incurred as a result of assuming debt, which results in the incurrence of additional fixed obligations that must be met before the equity investor is entitled to any of the operating income generated by the utility. Ms. McShane assesses capital structure ratios, interest coverage ratios and debt ratings as points of departure for analyzing the financial risk faced by FortisBC.

Ms. McShane calculates that the actual common equity ratio of FortisBC between 1999 and 2004 has averaged 40.1 percent. While slightly higher than the proposed 40 percent common equity ratio, it is nonetheless consistent with the maintenance of a roughly 60%/40% debt/equity capital structure for at least the last ten years (Exhibit B-1, Tab 5, pp. 16-17). Ms. McShane compares FortisBC's forecast common equity ratio to other Canadian electric utilities and concludes that it is in line with the allowed common equity ratios of other investor-owned electric utilities (Exhibit B-1, Tab 5, pp. 17-20).

Ms. McShane discusses FortisBC's interest coverage ratios as one factor that determines the level of its financial risk. Ms. McShane reports that the pre-tax interest coverage ratio in 2003 equaled 2.1 and that the average pre-tax interest coverage ratio for the five-year period ending 2003 was 2.1. Ms. McShane says that while the 2003 ratio of 2.1 is a material improvement from the ratio of 1.8 in 2002, the five-year average ratio is a deterioration from the previous five-year average ratio of 2.4 calculated over the period 1994-1998. Further, Ms. McShane offers the comparison that the 1999-2003 average ratio of 2.1 is less than the average ratio of 2.4 across other major Canadian electric utilities over the same period. Ms. McShane states that the declining interest coverage ratios of FortisBC reflect, in part, that its allowed returns on equity have generally declined more rapidly than its embedded debt costs (Exhibit B-1, Tab 5, pp. 20-21).

With respect to debt ratings, Ms. McShane reports that DBRS rates FortisBC debt BBB(high) with a "Stable" trend, and has consistently rated it such since 1996. Ms. McShane notes that this is the lowest DBRS rating of the investor-owned electric utilities in Canada. DBRS confirmed its ratings in June 2004 and provided a full evaluation of the company in November 2004. Ms. McShane summarizes the November 2004 DBRS report with the following points:

- The FortisBC financial profile has weakened in recent years due to a variety of factors including free cash flow deficits and low allowed ROEs;
- Relatively large anticipated capital expenditures over the next 4 years will contribute to large free cash flow deficits;
- The rate-stabilization mechanism on depreciation expense may keep cash flows weaker, but the projected free cash flow deficits could be reduced if this mechanism is eliminated;
- A key challenge to the financial profile remains a low interest rate environment; and
- Despite the free cash flow deficits, FortisBC's financial profile is expected to remain acceptable for the ratings.

Ms. McShane reports that the Moody's Investors Service ("Moody's") rated FortisBC Baa3 in November 2004, its first debt rating of the Company. Ms. McShane notes that the rating is premised on low business risk, a significant capital expenditure plan over the next four to five years, the need for rate increase to implement the plan, a low depreciation rate, a tight liquidity position, cash flow deficits and the need for equity infusions from the parent during the period of high capital expenditures. Ms. McShane states that a Baa3 is the lowest investment grade rating, providing little "cushion" should there be any deterioration in the business risk profile or financial parameters (Exhibit B-1, Tab 5, pp. 23-24).

Based on her assessment of FortisBC's business and financial risks, Ms. McShane concludes that a common equity ratio in the range of 40-45 percent is reasonable, compatible with its business risks and adequate to maintain a stand-alone rating of DBRS BBB(high). However, she notes that, given the forecast level of capital expenditures in the near to medium term and expected free cash flow deficits, a 40 percent common equity ratio should be regarded as the floor required to ensure adequate financing flexibility. Ms. McShane concludes that at a 40 percent common equity ratio, "FortisBC would be of higher investment risk than a benchmark Canadian utility, which requires the addition of an incremental equity risk premium to the equity return applicable to the benchmark low-risk utility" (Exhibit B-1, Tab 5, pp. 20-29).

Equity Risk Premium

As noted above, Ms. McShane accepts the Commission's ROE for a benchmark low risk utility as a point of departure for estimating the equity risk premium for FortisBC at the proposed common equity ratio of 40 percent. With this frame of reference, Ms. McShane calculates a range of equity risk premiums for FortisBC relative to a low-risk benchmark utility by estimating the risk differential as between, or as impacted by, PBR versus Cost of Service regulation, utility size, debt costs and relative costs of equity.

To assess the impact of PBR versus Cost of Service regulation, Ms. McShane utilizes a study prepared by the World Bank, which concluded that the difference between the asset (business risk) betas of energy utilities operating under rate of return regulation and price or revenue cap regulation was close to 0.40. Ms. McShane suggests that FortisBC has a risk position in the middle of the two extremes used in the World bank study, or a beta differential of 0.20. Using the Commission's market risk premium of 5.0 percent as reported in its 1999 Decision on Return on Common Equity for a Benchmark Utility, Ms. McShane concludes that the difference between PBR and Cost of Service regulation translates into a difference of 100 basis points (i.e. a 0.20 beta differential multiplied by 5 percent) (Exhibit B-1, Tab 5, p. 15).

To assess the impact of utility size, Ms. McShane utilized a study of historic returns and betas for companies of different sizes to compare the asset betas between a typical publicly-traded Canadian utility, defined by Ms. McShane as a Mid-Cap stock, and FortisBC, defined by Ms. McShane as a Low-Cap stock. Using the differential result of 0.14 and a market risk premium of 5.0 percent, Ms. McShane concludes that the size of FortisBC could justify it receiving an equity risk premium of 70 basis points (Exhibit B-1, Tab 5, p. 31).

To assess the difference between the debt costs of FortisBC and a low-risk benchmark utility, Ms. McShane assumed that a low-risk benchmark utility would be able to achieve a solid A rating on its debt. By comparing the 2002 average spread for a seven-year issue for Canadian utilities rated A(low)/A- or higher (95 basis points) to a FortisBC (Aquila(BC)) 2002 seven-year debt issue at 170 basis points above the benchmark seven-year Canada, Ms. McShane concludes that the difference in debt costs between FortisBC and a low-risk benchmark utility translates into an equity risk premium of 75 basis points (Exhibit B-1, Tab 5, pp. 32-33).

To estimate an equity risk premium for FortisBC using relative costs of equity, Ms. McShane compares the average beta of a group of A rated U.S. utilities, as proxies for the low-risk benchmark utility, to the average beta of a group of BBB rated U.S. utilities, as proxies for FortisBC. Ms. McShane concludes that the differential of 0.10 between the average betas of the two sample groups translates into an equity risk premium of 50 basis points if using a market risk premium of 5.0 percent (Exhibit B-1, Tab 5, pp. 33-35).

In sum, Ms. McShane concludes that a reasonable range for an incremental equity risk premium for FortisBC relative to the low-risk benchmark utility is in the range of 50-100 basis points, with a mid-point of 75 basis points.

2.2.2 Direct Evidence of Dr. Booth

Dr. Booth was asked by BCOAPO to provide an independent assessment of the appropriate common equity ratio and fair return for FortisBC, to assess its business risk and financial flexibility, and to make recommendations to ensure that rates are fair and reasonable. Dr. Booth indicates that his evidence is organized, in part, around: 1) a discussion of the business risk of FortisBC from a capital markets perspective, 2) a discussion of financial market access concerns and questions surrounding "rising" credit standards, and 3) a discussion about coverage ratios and how the capital market reacts to current financial metrics. The following is a brief summary of the evidence of Dr. Booth (Exhibit C5-5).

Dr. Booth considers the business risk of FortisBC to be low. Dr. Booth considers that FortisBC has little "generating" risk given that it is primarily reliant on hydroelectric generation and purchased power. Dr. Booth notes that electricity demand in FortisBC's service area is growing at a slightly higher rate than in B.C. generally, and that compared to electric utilities operating elsewhere in Canada, the regulatory regime in B.C. is stable. Dr. Booth asserts that the main impact of the FortisBC PBR is to provide an incentive to the company to operate more efficiently and earn a higher ROE, not to expose it to material risk. Further, Dr. Booth points to data on actual versus allowed ROE for FortisBC's regulated operations from 1986 through 2004 to conclude that after FortisBC moved to a PBR mechanism in 1996, the actual ROE has been above the allowed ROE (aside from 2002 when the failure to earn the allowed ROE was due to integration expenses and software write-offs). Dr. Booth notes that rather than the DBRS view that FortisBC has a consistent history of earning the regulated ROE, he would define the result rather as "over-earning." Dr. Booth sees "no reason for adding a bonus to the ROE for a system that already effectively enhances the company's ROE and does not increase its risk" (Exhibit C5-5, p. 22).

In association with his discussion of business risk, Dr. Booth provides evidence to show that he usually judges transmission operations as warranting a 30 percent common equity ratio and distribution 35 percent, while more recently, for example, the Alberta Energy and Utilities Board has awarded slightly higher common equity ratios of 33 percent and 37 percent, respectively. In this context, and given his judgment of business risk, Dr. Booth judges the applied-for 40 percent common equity ratio as excessive.

Dr. Booth presents evidence on the degree to which FortisBC is compensated for its risk by utilizing the theoretical relationship between the risk of a firm with financial leverage to a firm without financial leverage plus a financial leverage risk premium. While recognizing that equating the effect of a higher common equity ratio and a higher allowed ROE is largely a matter of judgment, Dr. Booth determines that a higher ROE and common equity ratio awarded FortisBC (then West Kootenay Power) in a 1994 Commission decision is equivalent to 55 basis points above Terasen Gas Inc. ("Terasen Gas") (then BC Gas), the low-risk benchmark utility. Dr. Booth states that one implication of this is that it is important for the Commission to take into account all the ways that it manages the risk of FortisBC and to not double count the same risks in different areas. Dr. Booth judges that FortisBC is marginally riskier than Terasen Gas, but that this risk is more than offset by FortisBC's higher common equity ratio.

Dr. Booth comments on the debt rating implications of FortisBC being a very small electricity company issuing debt in the capital markets under its own name. Dr. Booth states that size is a factor in bond ratings, and it also affects the liquidity of the bond issue. He notes that the result is that smaller issuers tend to issue shorter term debt and have inferior bond ratings than large issuers, all else equal. Dr. Booth comments that the problems associated with the size of FortisBC, in combination with the significant growth in rate base that is anticipated as the utility refurbishes its generation, transmission and distribution plant, may pose capital market access problems. Dr. Booth notes, however, that this access problem could be mitigated with equity infusions from its parent, and ultimately recede as the rate base expansion is completed.

Dr. Booth presents some example calculations of interest coverage ratios to argue that it makes no sense to target a particular interest coverage ratio and allow a higher ROE simply because a company has a high embedded cost of debt. Dr. Booth argues that if the allowed ROE and deemed common equity ratios are considered fair, but the resulting interest coverage is considered too low because of high embedded interest costs and there are capital market access problems, then the solution is to allow or deem some preferred shares, rather than give the equity holder a bonus to the fair ROE or equity ratio.

Dr. Booth assesses the market to book ratio associated with the purchase price of Aquila(BC) by Fortis, as well as the ratios associated with other utility purchases, in comparison to a target ratio of 1.15. He notes his view that values above 1.15 indicate that the rates are too high and that the equity holders are getting a more than fair and reasonable return. Dr. Booth approximates that for the FortisBC purchase the market to book ratio based on total rate base equaled 1.38, while the market to book ratio based on equity (based on assuming debt and valuing it close to book value) equaled 1.96.

In sum, Dr. Booth asserts that the currently approved 40 percent common equity ratio and 40 basis risk premium are excessively generous. Dr. Booth is of the view that there are no grounds for increasing the generosity of these financial metrics, but rather that the elimination of the 40 basis points risk premium would be a conservative roll back.

2.2.3 Submissions

The following sections summarize various arguments and submissions of FortisBC and intervenors with respect to business risk, financial risk, and the equity risk premium.

Business Risk

FortisBC reiterates in its argument that its business risk is greater now than it has been in the past. Using Dr. Booth's frame of reference as a point of departure, FortisBC submits, with reference also to its Resource Plan, that its risk regarding its energy needs is much greater than it was in 1994; it is far more reliant on the market for energy in 2005 than it was in 1994, and the market is more volatile. FortisBC also states that it faces increasing competition from natural gas, its industrial customers have the opportunity to switch to third party supply, and residential use per customer has been steadily declining. FortisBC submits that these factors, combined with its increased reliance on a volatile market, are evidence of its increased business risk (FortisBC Argument, pp. 18-20).

BCOAPO submits that an October 2004 FortisBC presentation to DBRS (Exhibit B-4, Response to BCOAPO IR 88.1) stands in contrast to the conclusion of Ms. McShane that FortisBC faces above average business risk relative to it Canadian electric peers, and relative to the low risk benchmark utility in the B.C. context. BCOAPO submits that FortisBC has told the investment community that it is a low cost, low risk franchise with supportive regulation and no problems in accessing capital, referring in support to the following summary of the FortisBC presentation highlights provided by FortisBC in response to an information request (BCOAPO Argument, pp. 9-10):

- Vertically integrated regulated electric utility,
- Supportive regulation – a low cost, low risk franchise,
- Solid franchise history with strong economic fundamentals,
- Diversified customer base,
- 205MW low cost hydro and long term PPAs in rate base,
- Power purchase costs flow through – limited commodity risk,

- Growing regulated rate base, and
- Strong balance sheet and supportive shareholder.

Further, BCOAPO submits that comparing Ms. McShane's definition of business risk (of exposing the shareholders to the risk of under-recovery of the required return on capital) to the evidence that FortisBC's actual ROE has exceeded its allowed ROE in every year since 1996 (except 2002) would lead it to conclude that there has been no business risk attached to the operations of FortisBC (BCOAPO Argument, p. 11).

BCOAPO submits that FortisBC's industrial load has not had a significant risk impact on the Company. BCOAPO describes that there is little dependence on industrial customers when measured by revenues, and there is minimal bypass risk. Further, there is opportunity for load retention rates should such customers wish to leave the system. BCOPAO points out that no large customers have bypassed the system in the last five years, perhaps explained in part by the possibility of such customers having to reimburse FortisBC for stranded assets should they choose to buy supplies elsewhere (BCOAPO Argument, pp. 12-14). BCOAPO also submits that "what holds in the face of bypass risk also holds in an absolute sense: FortisBC's reliance on low cost hydro makes its generation risk minimal. In practice there is minimal risk of the power not being dispatched or the assets being stranded" (BCOAPO Argument, p. 19).

BCOAPO submits that the risk associated with residential load is limited. In particular, it submits that FortisBC has incremental residential heating load to begin with because its rate are competitive due to its low generating cost. Further, BCOAPO says that the Company has not requested any weather normalizing rate stabilization mechanism in the past ten years. It submits therefore that the company does not consider the impact of weather volatility on residential load to be a material risk (BCOAPO Argument, pp. 12-13).

In regard to the risk associated with market purchases and market volatility, KOECA submits that it is unlikely that higher power purchase costs in the future will result in reduced returns for shareholders given its expectation that the Commission will ensure that this risk will be passed on to customers to keep the Company healthy. Further, KOECA submits that FortisBC does not address how separate risk factors may partially negate themselves, pointing out in example that a decline in residential use per customer, if it leads to a reduction in total residential demand, "would partially compensate for the supposed risk associated with power purchases" (KOECA Argument, pp. 4-5). KOECA submits that if there is uncertainty about the correct methodology to apply to an evaluation of FortisBC's risk, it makes sense to seek "ground truth" by paying attention to the actual experience of the company (KOECA Argument, p. 5).

Financial Risk

FortisBC argues that its financial risk is greater than it has been in the past. Noting again that the financial risk of a utility can be captured in its capital structure ratios, interest coverage ratios and debt ratings, FortisBC reiterates that its 1999-2003 pre-tax interest coverage ratio of 2.1 is significantly less than the previous 5 year average of 2.4 observed between 1994 and 1998. Further, it notes that its debt rating was downgraded by DBRS in 1996 to BBB(high), lower than any other Canadian electric utility in the sample provided by Ms. McShane in her evidence (FortisBC Argument, pp. 21-22), and its Moody's debt rating is Baa3 is lower still, equivalent to a DBRS rating of BBB(low).

FortisBC argues that Dr. Booth's interest coverage ratio calculations, and the conclusions that he draws from them, are flawed and inaccurate. FortisBC submits therefore that this evidence should be rejected (FortisBC Argument, pp. 22-26). FortisBC submits that it was unable to access 30-year bonds in 2004, substantially due to its low interest coverages and being regarded as too high risk (FortisBC Argument, pp. 22, 25-26).

BCOAPO notes that Dr. Booth indicated in cross-examination by FortisBC Counsel that he accepts the interest coverage ratios calculated by FortisBC. However, BCOAPO quotes Dr. Booth as noting that the interest coverage ratios are all temporary timing phenomenon, "basically waiting until the debt costs roll out and wait until its capital expenditure program is completed" (BCOAPO Argument, p. 22).

BCOAPO comments on the cross-examination by Commission Counsel of both Ms. McShane and Dr. Booth as to the impact of an increase in the equity risk premium from 40 to 75 basis points on the five credit challenges identified by Moody's in its November 2004 report. Those five credit challenges are a $450 million capital expenditure plan over next 5-years, rate increases to support the capital expenditure plan, relatively low depreciation rates, a tight liquidity position, and free cash flow deficits requiring equity infusions from its parent. BCOAPO submits that the testimony as to the marginal or non-existent impact of an increase in the equity risk premium on these credit challenges further undermines FortisBC's case for an increase in the equity risk premium (BCOAPO Argument, p. 21).

FortisBC proposes to maintain its current capital structure, with a common equity ratio of 40 percent, noting that the BCOAPO expert also recommends a common equity ratio of 40 percent. Further, FortisBC notes that in their written arguments, intervenors either endorsed this capital structure or had no comment. FortisBC submits that the supporting evidence and the absence of argument against the proposed capital structure strongly support an Order of the Commission approving a capital structure which includes a common equity ratio of 40 percent (FortisBC Argument, p. 17; FortisBC Reply Argument, p. 4).

Equity Risk Premium

BCOAPO presents argument that questions the relevance and justification of Ms. McShane's analysis of the appropriate equity risk premium for FortisBC relative to the low-risk benchmark utility. BCOAPO asserts that Terasen Gas is the BCUC low risk utility given its 33 percent common equity ratio and the fact that it is not granted an equity risk premium above the BCUC automatic ROE. The BCOAPO argues that Ms. McShane refused to accept that Terasen Gas is the BCUC low risk benchmark utility (BCOAPO Argument, p. 16). BCOAPO comments that financial risk compounds business risk and a low common equity ratio indicates low business risk. BCOAPO questions that if Terasen Gas is not the low risk benchmark then it is reasonable to ask what the proposed 75 basis points equity risk premium is over. To illustrate this point, BCOAPO suggests that it may be, for example, that Terasen Gas and FortisBC are now of equivalent risk in which case there would be no reason for a risk premium for FortisBC over the Commission's low risk benchmark (BCOAPO Argument, pp. 16-17).

BCOAPO expands upon its argument in this matter by commenting on the DBRS BBB(high) debt rating of Fortis (which Ms. McShane equates with a Standard & Poors (S&P) rating of BBB) relative to the debt rating of a low-risk benchmark (which Ms. McShane equates with an A rating). BCOAPO submits that Ms. McShane's methodology of assessing the differentials between A and BBB rated utilities is flawed, in part because it does not account for the impact of FortisBC's size on its debt rating (and the related matter that spreads may include liquidity premiums for smaller issues). BCOAPO submits that "if FortisBC were simply a larger firm its bond rating would be higher even if its business risk is unchanged, so basing the analysis on bond ratings in part simply awards FortisBC a higher ROE simply because it is small." BCOAPO submits further that Terasen Gas, with its DBRS A and S&P BBB debt ratings, could fit within the same rating group as FortisBC in Ms. McShane's analysis (BCOAPO Argument, pp. 17-18).

FortisBC submits that FortisBC and Terasen Gas cannot be regarded as having similar debt ratings, as suggested by BCOAPO, in part because: 1) BCOAPO is proceeding on the incorrect premise that Terasen Gas is equivalent to a low risk benchmark utility, when Ms. McShane states that a low risk benchmark utility would be an A rated utility, which Terasen Gas is not; and 2) FortisBC has two ratings in the BBB category and is therefore rated lower than Terasen Gas (FortisBC Reply Argument, pp. 10-11).

With respect to utility size, FortisBC replies that it remains a small utility, unable to diversify its risks to the same extent as larger utilities whose assets, geography and economic bases are less concentrated (FortisBC Reply Argument, p. 12).

In its argument, IMEU submits that FortisBC acquired the utility approximately one-year ago understanding the risks and rewards of its investment. It is of the view that the purchase price that was struck, for a significant premium over book value, was based on this understanding. Therefore, IMEU submits that an increased risk premium is inappropriate and not justified in the short-term, a conclusion it states is also supported by the evidence on FortisBC's risk factors (IMEU Argument, pp. 5-12).

BCOAPO states that with a 40 percent common equity ratio Fortis paid about $734 million to acquire $377 million in equity earning the Commission's automatic ROE plus 40 basis points, which results in a ratio of almost twice book value. BCOAPO submits that this is an excessive, unfair market to book ratio, and that the correct regulatory response should be to reduce the premium, not increase it to 75 basis points (BCOAPO Argument, p. 21).

In response to the issue of the premium over book value, FortisBC submits that the price to regulated book value on its purchase (1.8) reflects also the amount paid for the majority of regulated assets/companies sold in Canada over the last 7 years. Further, it submits that because it is required to engage upon an extensive capital expenditure program over the next several years the premium it paid will effectively be reduced (FortisBC Reply Argument, p. 15).

FortisBC submits that the debt market problem and fair return on equity are not independent from each other because capital structure and ROE (as a function of business risk profile) factor into the willingness of the bond market to lend funds under reasonable rates and terms. FortisBC submits that an increase in the equity risk premium that is fully compensatory with its business and financial risks, along with an increase in the depreciation rate, will address the Company's inability to access the long-term bond markets (FortisBC Reply Argument, p. 14).

2.2.4 Commission Panel Determinations

The Commission Panel has considered the evidence of FortisBC and BCOAPO, and the arguments of all parties. The following discussion highlights the Commission Panel's observations and conclusions in this regard.

With respect to market demand components of business risk, the Commission Panel believes that the prospects for FortisBC residential demand are good given the strong growth prospects in the Okanagan service area, in spite of the penetration of natural gas for heating new residential construction. The Commission Panel is persuaded by the argument that residential heating demand is incremental and not a significant business risk as FortisBC defines it. The Commission Panel notes that because FortisBC is a capacity constrained utility, a reduction to the heating component of demand could actually serve to reduce its business risk. Yet, to the extent the penetration of natural gas for heating could be regarded as a material risk, and to the extent that such risk could have a detrimental impact on FortisBC's credit rating, an increase in the equity risk premium would serve to increase this risk all else equal. The Commission Panel does not agree that a reduction in residential use per customer (as one factor of total demand) is an indication of a net increase in business risk for FortisBC, particularly in light of increasing load growth in the FortisBC service area generally. The Commission Panel also agrees with the evidence that suggests, in general, that population and economic growth will remain strong in the FortisBC service area.

With respect to supply risk factors, the Commission Panel acknowledges that FortisBC does compete to some extent with alternative suppliers of electricity given the customer choice available to wholesale and large industrial customers. The Commission Panel notes, however, that there are strong constraints on the likelihood of municipalities opting for alternative suppliers, and that the industrial component of load is not large and also unlikely to opt for alternative suppliers. The evidence and argument bear this out. Further, the Commission Panel acknowledges that there is risk associated with market purchases and market volatility, but it does not agree that this risk has increased to any measurable extent for FortisBC. FortisBC obtains low-cost supply from its own generating plants and long term contracts, with the remainder of its supply obtained through market purchases. Market purchases, while an increased share, are still limited, and FortisBC has a power purchase incentive mechanism to mitigate its exposure to market price volatility.

The Commission Panel agrees with the evidence that characterizes the regulatory environment in B.C. as progressive, believing it as well to be a positive consideration in respect of the regulatory risk that FortisBC faces. The Commission Panel observes that the progressive regulatory environment in B.C. is noted as a strength in the DBRS credit rating evaluation of FortisBC. The Commission Panel does not agree with the view that the FortisBC's PBR plan is inherently more risky than a traditional cost of service regulatory framework, particularly given the various sharing mechanisms that are components of this plan and the demonstrable evidence that FortisBC's actual ROE has, with one exception, met or exceeded its approved ROE since 1996. The Commission Panel does not consider the evidence of actual ROEs consistently exceeding allowed ROEs to imply, in and of itself, any conclusion about changes in the level of business risk, higher or lower. Even so, the Commission Panel considers the question of whether a utility has been able to meet its revenue requirements as a useful test of the reasonableness of an allowed ROE. In the period since 1994 FortisBC has with one exception met or exceeded its revenue requirements.

FortisBC emphasizes its interest coverage ratios, arguing in part that current low interest coverages are a substantial cause of its inability to access the 30-year bond market in 2004, and in turn that this circumstance is the main driver of its application for an increase in its equity risk premium. FortisBC argues that its interest coverages are significantly lower than in the past by comparing its average interest coverage ratio of 2.1 over the five-year period, 1999-2003, to its average interest coverage of 2.4 over the previous five-year period, 1994-1998. The Commission Panel finds that this comparison is not substantively informative. While Ms. McShane states that the decline reflects, in part, that allowed ROEs have generally declined more rapidly than the embedded debt costs, neither she nor FortisBC have provided any other detailed rationale or context to explain the differences between the two five-year periods. The Commission Panel observes that the consistent DBRS rating of BBB(high)-Stable trend since 1996 largely spans both of the five-year periods used in the averaging calculations. Further, the Commission Panel notes that FortisBC's actual 2004 pre-tax interest coverage ratio is 2.32 and its average pre-tax interest coverage ratio for the period 2000 to 2004 is 2.16, both of which represent increases, respectively, from its 2003 ratio of 2.1 and its 1999-2003 average ratio of 2.1 (Exhibit B-12, Response to BCUC IR 12.5). FortisBC has not explained how these increases should be interpreted in the context of the evidence of decreases that it presents in evidence and in argument. FortisBC notes that the difference between the average interest coverage ratios of the two five-year periods is significant, a difference equal to 0.3. The Commission Panel notes that in FortisBC's initial 2005 application the estimated interest coverage ratio is 2.06, and declined to 2.01 on the basis of assuming a 40 rather than 75 basis points risk premium (Exhibit B-12, Response to BCUC IR 12.7). The difference of 0.05 between these two ratios could be regarded in this context as less than significant and relatively insensitive to changes in the equity risk premium. In addition, the Commission Panel agrees that low interest coverages could be considered a temporary phenomenon in light of FortisBC's planned capital expenditures over the next four years and low depreciation rates currently. The Commission Panel believes that, even to the extent that FortisBC's interest coverages could be regarded as too low, declining, or more than a temporary phenomenon, an increase in the equity risk premium is not the appropriate means to first consider for improving FortisBC's interest coverages. The following discussion elaborates on this.

BCOAPO referred in argument to cross-examination of both Ms. McShane and Dr. Booth by Commission Counsel as to the expected impact of an increase in the equity risk premium on each of the five credit rating challenges identified by Moody's in its November 2004 report. Those credit rating challenges are (Exhibit B-12, Response to BCUC IR 15.0):

- A significant $450 million capital expenditure plan to be implemented over the next 4-5 years;
- The possible need for rate increases in each of the next few years to implement the capital expenditure plan;
- A relatively low depreciation rate for rate-making purposes;

- A liquidity position that is tight for a Baa3 utility company; and
- Free cash flow that is expected to be negative for the next few years, necessitating equity infusions from its parent, as well as additional debt issuance.

The Commission Panel is of the view that both experts' testimony as to the limited or non-existent impact of an increase in the equity risk premium on these credit challenges diminishes the FortisBC argument that an increase in the equity risk premium will materially affect its credit rating and its ability to access the long-term bond market. FortisBC acknowledges in response to a Commission information request that while a change in its equity risk premium from 40 to 75 basis would be a positive consideration, it alone would not likely result in an increase in FortisBC's credit rating. In their November 2004 credit rating reports, both DBRS and Moody's emphasize the issues of FortisBC's free cash flow deficits and low depreciation rates. DBRS notes in one instance that higher depreciation rates could reduce FortisBC free cash flow deficits. The Commission Panel observes that DBRS maintained its FortisBC debt rating of BBB(high)-Stable trend despite its concerns.

The Commission Panel believes that it would be untimely and inappropriate to increase the equity risk premium in response to the credit challenges noted above without measures being taken to more directly address these credit challenges, particularly in light of the Commission Panel's views as to the business risk of FortisBC. To this end, and in alignment with the November 2004 evaluations of both DBRS and Moody's, the Commission Panel has directed FortisBC in this Decision to file its forthcoming study of depreciation rates with its next revenue requirements application, and to have the new rates form part of that application. Also, the Commission Panel notes that the rate stabilization mechanism on depreciation expense is no longer in effect.

The Commission Panel has concerns about the methodology used by Ms. McShane to determine an incremental equity risk premium for FortisBC. For example, the Commission has determined that Terasen Gas is a low risk benchmark utility in B.C., and to ignore this as a reasonable proxy in the analysis calls into question the entire framework, particularly in light of the reliance, in part, on utilities based in the US as proxies for the low-risk benchmark. Further, the Commission Panel agrees with the BCOAPO submission in regard to the impact of size on credit ratings, which calls into question the methodology of comparing the credit ratings across utilities as a means to determine an incremental risk premium, without controlling for the impact of size.

The Commission Panel notes that a fundamental test of the appropriateness of an allowed ROE is whether the utility has been able to attract equity capital. Evidence of this test has been met: the willingness of FortisBC to purchase the equity of Aquila(BC) and to pay a premium in so doing.

The Commission Panel approves the FortisBC application to maintain a common equity ratio of 40 percent and denies the FortisBC application to increase its equity risk premium from 40 to 75 basis points. The Commission Panel denies the BCOAPO recommendation to reduce FortisBC's equity risk premium from 40 basis points to zero on the basis that there is insufficient evidence in support of this recommendation.

2.3 2005 Revenue Requirements

2.3.1 Rate Base

A utility's rate base represents the net investment in assets necessary to provide service. FortisBC's Rate Base, as described in Exhibit B-1 at Tab 6, is comprised principally of Plant in Service, Accumulated Depreciation and Amortization, Deferred Charges and Credits, Allowance for Working Capital, and an Adjustment for Capital Expenditures (FortisBC Argument, p. 29).

FortisBC submits that its forecast mid-year rate base for 2005 of $598,105,000, as provided in Schedule 1 to the Third Revised Application (Exhibit B-26), be approved for purposes of establishing 2005 Revenue Requirements and setting rates to customers effective January 1, 2005 (FortisBC Argument, p. 30).

Rate Base costs include such items as cost of debt, cost of equity, income taxes, property and capital taxes, depreciation and amortization and Allowance for Funds Used During Construction ("AFUDC"). FortisBC seeks approval of forecast total Rate Base costs of $78,569,000 (Exhibit B-26, p.3; FortisBC Argument, pp. 31-38).

Commission Panel Determinations

The Commission Panel accepts the proposed mid-year rate base of $598,105,000 for 2005 subject to directions contained in this Decision that affect the components of rate base. Likewise, FortisBC should update its forecast Rate Base costs according to the relevant Commission Panel determinations elsewhere in this Decision.

2.3.2 Power Supply

The Commission Panel approves FortisBC's forecast Power Supply costs for 2005 of $71,010,000. This is discussed in Section 2.1.2: Power Purchase and Wheeling Forecast.

2.3.3 Operations and Maintenance Expenses and Capitalized Overheads

Forecast 2005 Operations and Maintenance ("O&M") Expenses, before and after capitalized overheads, increased significantly over the 2004 target levels that were part of the 2004 Negotiated Settlement Agreement approved by Order No. G-38-04. The following comparative schedule appears on page 1 of Exhibit B-66 and provides an overview and high level explanations of the major drivers for the increase.

	2004 Targeted O&M	2005 Forecast O&M	Increase/ (Decrease) over Targeted 2004 O&M	Increase due to Transition Plan	Increase due to Inflation	Other Increases
Total before capitalized overheads	$35,645,000	$39,569,000	$3,924,000	$1,158,000	$1,150,000	$1,616,000
Capitalized Overheads	($2,800,000)	($3,396,000)	($596,000)			
Total net of capitalized overheads	$32,845,000	$36,173,000	$3,328,000			

Of the total increase of $3,924,000, the portion caused by the Transition Plan activities, i.e. $1,158,000, is discussed in greater detail in Section 2.6, Transition Plan.

FortisBC states that the inflationary increase of $1,150,000 is the result of normal inflationary pressures on labour, materials and other costs. FortisBC indicates that of this amount, $500,000 is due to increases in benefits costs relating to medical, dental and vacation entitlements, $350,000 is due to wage increases for management and bargaining unit employees, averaging 2.5% to 3%, and $300,000 is the effect of non-labour inflation (i.e. 2%) on the 2005 budget (Exhibit B-66, pp. 1-2).

The amount of $1.6 million, identified as 'Other Increases', arises from additional activities planned in functional areas such as generation, transmission and distribution, and administration and general. The $1.6 million increase actually represents a net amount, which is comprised of various cost increases totaling $2.8 million that are offset by a $1.2 million decrease in insurance and vehicle lease costs. A significant portion (i.e. $1.6 million) of the 2.8 million cost increase is forecast to be spent in the transmission and distribution functional area. Increased activity for substation O&M, and transmission and distribution line maintenance is the major driver for the increase in this functional area and comprises $1.1 million of the $1.6 million. A further $850,000 of the total increase of $2.8 million is due to increased activity in internal audit and corporate governance and environmental, health and safety (Exhibit B-66. pp.2-5).

The increase in the amount of capitalized overheads is a direct function of capital activity, which increased for 2005.

Submissions

BCOAPO states that: “[they] are not in a position to review in detail the OM&A expenditures of the utility” (BCOAPO Argument, p. 25). Mr. Wait argues that the increase in the transmission and distribution expenses for 2005 appears to be excessive (Wait Argument, p.3). IMEU states: “[it] is also concerned that the impact of PBR settlements in past years has resulted in a loading up of costs which are being picked up in the 2005 Revenue Requirements for the Company” (IMEU Argument, p.18). IMEU asks the Commission to review closely the appropriateness of these significant increases through rebasing (IMEU Argument, p. 4).

FortisBC states that the Company has repeatedly expressed its position that base O&M targets have been too low and hence inappropriate on a go forward basis. The Company submits that a material portion of the proposed increase in O&M Expense for 2005 reflects FortisBC’s reassessment of the overall level of O&M expense required to meet service obligations to its customers in the areas of customer service, transmission and distribution, and administration and general costs (FortisBC Argument, pp. 40-41).

Commission Panel Determinations

The Commission Panel has considered all the evidence and arguments and concludes that the proposed increases in forecast 2005 O&M Expenses, before overheads capitalized, over the approved 2004 target levels, appear to be reasonable and required. The Commission Panel fully supports FortisBC’s strategic goals and specific objectives to meet and improve service obligations in various areas and in particular the areas of customer service and transmission and distribution (refer to Section 2.7 for a comprehensive discussion of customer service). The Commission Panel believes that FortisBC should be provided with the resources to allow it to achieve these goals and objectives. The inflationary increases of $1,150,000 are largely uncontrollable by the Company in the short term.

The Commission Panel approves for FortisBC the forecast 2005 O&M expenses, before capitalized overheads, of $39,569,000, subject to adjustments discussed elsewhere in this Decision. It is important to note that specific directives, as set out in Section 2.4.2 on the Operating Expense incentive mechanism, form an integral part of the approval for the above level of expenses. To be clear, the incentive mechanisms are designed to ensure that approved resources are in fact spent on planned programs and activities in 2005.

2.3.4 Pensions

FortisBC has three pension plans: the IBEW Pension Plan, the COPE Pension Plan, and the Fortis Retirement Income Plan ("FRIP"). The IBEW and COPE Pension Plans are defined benefit pension plans. The FRIP consists of a defined benefit provision and a defined contribution provision. Additionally, the Company also has a supplemental pension plan. At the end of 2004 the Pension Plan Funded status was a plan deficit of approximately $23 million (Exhibit B-12, BCUC IR 73.0).

The Company records its annual pension benefits costs on an accrual basis in accordance with the recommendations of CICA Handbook Section 3461 (Exhibit B-12; BCUC IR 73.1.1). The Company estimates the forecast 2005 pension expense to be $3,860,000 and pension funding to be $4,560,000; in 2005 funding will exceed expense by $700,000 (Exhibit B-80, p. 1). In general, the amount of pension expense and the amount of annual funding to the pension plans by the Company will not match in a given year. The difference between these two amounts is recorded as an increase or decrease in the Prepaid Pension Costs account in deferred charges (Exhibit B-12, BCUC IR 34.8). The additional $700,000 in excess of funding for 2005 results in a year end 2005 balance of $5,948,000 for deferred Prepaid Pension Costs account (Exhibit B-80, p. 1).

Commission Counsel questioned Mr. Meyers concerning the different pension costs reported in response to BCUC IR 34.8 and 73.4. Mr. Meyers explained that BCUC IR 73.4 reflected the updated actual year end financial statements for 2004. Also, Mr. Meyers acknowledged that the difference, which impacts 2005, is reflected in the revised applications (T5: 882).

Commission Panel Determinations

The Commission Panel accepts the Company's forecast 2005 pension expense, pension funding amount, and the Prepaid Pension Costs account balance of $5,948,000 at year-end 2005.

2.3.5 Other Post-retirement Benefits

Other post-retirement benefits are benefits to employees for extended health, group MSP, and life insurance. Generally Accepted Accounting Principles ("GAAP") require that all forms of post-retirement benefits be accounted for on an accrual basis as recommended in CICA Handbook Section 3461. The Company records its annual other post-retirement benefits costs on a cash basis, which is not in accordance with CICA Handbook

Section 3461. In the negotiated settlement for the 2000-2002 Revenue Requirements the parties agreed to a variance from GAAP to allow post-retirement benefits to be recorded on a cash basis. The negotiated settlement was approved by Commission Order No. G-134-99 (Exhibit B-12, BCUC IR 73.1-73.2).

For 2005 the Company proposes that the cash basis of accounting for other post-retirement benefits continue (Exhibit B-12, BCUC IR 73.1.2). Mr. Meyers explained in his testimony that the variance from GAAP was appropriate since the Company is required to fund pension expense, but not other post-retirement benefits. Also, the Company does not pay out cash for the other post-retirement benefits like it does for pension expense (T5: 884-886).

The Company estimates an expense of approximately $300,000 using the cash basis. If CICA Handbook Section 3461 were applied, the accrued expense would be $1,380,000. However, if the Company were to adopt the accrual basis prospectively beginning in 2005, the accumulated liability of $4,400,000 would also need to be amortized into expense. Amortization of the accumulated liability of $4,400,000 over approximately 14 years, based on the Expected Average Remaining Service Lifetime of the covered group, results in an additional annual amortization of about $320,000. In total the Company expects the total 2005 other post-retirement expense to be approximately $1,700,000 ($1,380,000 + $320,000) if Section 3461 were adopted. However, if the current variance from GAAP were continued, the Company estimates the accumulated liability to be $5,500,000 at December 31, 2005 (Exhibit B-12, BCUC IR 73.1.3).

<u>Commission Panel Determinations</u>

The Commission Panel notes that the other post-retirement benefits earned each year that were not expensed have already accumulated into a large future liability that continues to increase. However, full compliance and adoption of Section 3461 of the CICA Handbook in 2005 would result in a large rate increase. **The Commission Panel denies the request to continue to record other post-retirement benefits on a cash basis. The Commission Panel orders a variance from GAAP to require that the transition from the cash basis to accrual accounting for other post-retirement benefits be phased-in over a three-year period. For 2005 the Company will include in expense the current cost under the cash basis plus one-third of the accrued expense as if it were in full compliance with Section 3461 and the change were adopted prospectively beginning in 2005. Subsequently for 2006, the Company will include in expense the cost under the cash basis plus one-half of the accrued expense as if it were in full compliance. In the final transition year for 2007, the Company will include the full accrued expense and be in full compliance with Section 3461 of the CICA Handbook. In calculating the Company's 2005 and future revenue requirements, the portion of other post-retirement benefits expense not expected to be paid-out in cash is to be credited to rate base.**

2.3.6 Employee Stock Option Expense

The Company's stated in its response to BCUC IR 74.0 that the Company has not included employee stock option expense in the utility financial schedules in 2005 or in any other year. It also stated that all stock option expenses have been and will be borne by the parent company. However, on March 18, 2005 the Company filed a List of Errata. The Errata indicated that the previous response to BCUC IR 74.0 was in error. The Errata stated that the utility financial schedules contain $25,000 of employee stock option expense in 2004 and $40,000 in 2005 (Exhibit B-24, List of Errata: Item 4).

Commission Counsel questioned Mr. Meyers if the $40,000 in employee stock option expense was still in the application. Mr. Meyers stated that the expense was still in the application and was not aware of previous Commission decisions disallowing employee stock option expense (T5: 889-890). The Commission has disallowed employee stock option expense in the BC Gas Utility Ltd. 2003 Revenue Requirements Decision (p. 15) and in the Pacific Northern Gas Ltd. 2004 Revenue Requirements Decision (p. 47).

Commission Panel Determinations

The Commission Panel directs that the $40,000 employee stock option expense and its related tax effect be removed from the 2005 Revenue Requirements.

2.3.7 2004 Incentive Sharing Adjustments

Commission Order No. G-20-05 approved the 2004 Incentive Adjustments as based on preliminary 2004 financial results, for a total credit of $2,175,000. The Incentive Adjustments comprised a combination of operating, power purchase and DSM incentives. This credit amount is shared between customers and shareholders in accordance with the sharing formulas agreed to in the 2004 Negotiated Settlement Agreement. The customers' share is $1,469,000, which is carried forward and serves to reduce the 2005 Revenue Requirements. The remainder of $706,000 is to the shareholders' account.

FortisBC's Second Revised Application increased the approved customer share of the 2004 Incentive Adjustments from $1,469,000 to $1,791,000. The final total 2004 Incentive Adjustments are based on actual information contained in the audited 2004 financial statements.

Commission Panel Determinations

Further to the approval granted in Commission Order No. G-20-05, the Commission Panel approves the final net 2004 Incentive Adjustments of $1,791,000. This credit balance is to be carried forward and included in the determination of the 2005 Revenue Requirements.

2.4 2005 Incentive Sharing Mechanisms

2.4.1 DSM and Power Purchase Incentives and Flow-through Costs

FortisBC proposes to retain certain aspects of the existing sharing mechanisms for 2005. The Company states: "The Power Purchase Incentive and the Demand Side Management Incentive Mechanisms have been shown to be effective and desirable to customers and the Company. No changes are proposed to either mechanism for 2005." (Exhibit B-1, Tab 8, p. 30)

FortisBC is of the view that the DSM incentive has increased the Company's focus on meeting and exceeding the energy efficiency targets and therefore it proposes to retain the existing DSM incentive for 2005 (FortisBC Argument, p. 48). Further detail and submissions on the DSM Incentive Mechanism are summarized Section 2.5: 2005 Demand Side Management Expenditure Plan.

The Company also proposes to retain the existing power purchase incentive mechanism, under which (a) the full advantage of cost savings either currently embedded in contracts, or which are anticipated, are included in the Power Purchase Forecast, and are therefore to the full benefit of customers, and (b) variances, other than load variances, from the Revenue Requirements forecast are applied 65 percent to customer rates in the subsequent year (75 percent for variances in excess of $1,000,000) (FortisBC Argument, p. 49).

Furthermore, FortisBC proposes the continuation of flow-through treatment (i.e. customers assume 100% of the risk and benefit of variances between approved and actual amounts) for certain other costs over which it has limited or no control. Specifically, these costs are the differences between forecast and actual property taxes, provincial water fees, and the Power Purchase expense related to the Brilliant contracts for 2005. In addition to the continued flow-through treatment for the above items, FortisBC proposes to add a new flow-through item that seeks flow-through treatment for the costs of capacity block power purchases forecast for November and December 2005 (FortisBC Argument, p. 50).

Intervenors did not specifically comment on these Incentive Mechanisms and Flow-Through Costs.

Commission Panel Determinations

The Commission Panel approves the continuation of the existing Power Purchase Incentive and the DSM Incentive Mechanisms for 2005. The Commission Panel also approves for 2005 the continuation of the above proposed flow-through cost items as well as the flow-through for the costs of capacity block power purchases forecast for November and December 2005. In addition, the Commission Panel directs FortisBC to treat income taxes and the expensed portion of Cost of Debt as flow-through cost items in 2005.

2.4.2 Operating Expense Incentive

FortisBC is proposing a temporary asymmetrical sharing mechanism for 2005 with respect to O&M expenses. The Company states that: " Under this proposal, to the extent that 2005 O&M Expense, net of capitalized overheads, are lower than the forecast O&M Expense of $36,173,000 (Exhibit B-26), the variance will be shared equally with customers. Actual O&M Expense in excess of the forecast O&M Expense of $36,173,000 will be entirely to the account of the shareholder." (FortisBC Argument, p.50)

Submissions

NRI was initially concerned that FortisBC was still proposing a modified form of PBR for O&M for 2005. NRI goes on to state however, that: "On further consideration, we don't think that this is a significant issue." (NRI Argument, p. 2).

BCOAPO agrees with the general approach proposed by FortisBC with respect to the 2005 sharing mechanism (BCOAPO Argument, p. 7).

KOECA addressed the issue of PBR and the incentive mechanism extensively, during cross examination and in their Final Argument. KOECA states that it protested the inception of the previous PBR scheme because it believed it had serious flaws. KOECA goes on to point out that: "…there never has been a stated rationale for 50-50 sharing between the utility shareholders and the customers" and it submits that 50-50 sharing for cost savings is so rich for the company that it is compelled to cut services until there is a negative reaction (KOECA Argument, p. 3). KOECA states that: "The incentive system must be constructed so that there is little or no incentive for undesirable activity." (KOECA Argument, p. 3) It asks that the Commission set up a process immediately to determine what sharing ratio should appropriately be set for any incentive mechanism the company is allowed to use, from now on. It goes on to ask that in the meantime the Commission rule that a sharing ratio of 90-10 (in favour of the customers) be instituted (KOECA Argument, p. 4).

FortisBC argues that BCOAPO, IMEU, and KOECA are in effect seeking to re-write the rules of PBR long after the rules were agreed to by customers and the utility, after the results of each year have been finalized, and after the monies have long since been disbursed to the shareholder and customers. FortisBC also states that it is difficult to conceive of how the Commission could, by reducing the monies approved for O&M force FortisBC's shareholders to pay for improvements to customer service. Any forced cuts will only end up hurting customers. FortisBC encourages customers and the Commission to focus on the results of the utility's programs as reflected in objective measures of customer service levels (FortisBC Reply Argument, p. 19).

Commission Panel Determinations

The Commission Panel reviewed and considered the evidence on the proposed asymmetrical operating expense incentive mechanism. While the Commission Panel supports the concept of a sharing mechanism with respect to O &M Expenses in general, it does not agree that sharing should start with the "first dollar". The Commission Panel is of the view that it is management's normal responsibility to try to achieve a reasonable level of saving over budget amounts.

In the current circumstances, it is the Commission Panel's view that it is important to maintain a fair balance in terms of risk sharing between customers and shareholders, and that this generally implies sharing should occur for both positive and negative O&M expense variances.

The Commission Panel is of the strong opinion that only the cost savings from true productivity/efficiency improvements in business processes and procedures should be subject to sharing and that cost savings generated through deferral or cancellation of planned activities are not acceptable for sharing. The Commission Panel is confident that the Company will produce savings from productivity/efficiency improvements inasmuch as Mr. Hughes, President and CEO, testified that FortisBC is very focused on productivity and the management of operations and maintenance costs (T2:77).

Finally, the Commission Panel firmly believes that a very strong link needs to exist between the granting of O&M expense incentives to shareholders and the achievement of objective and measurable performance targets by the Company. **Consequently**, **the Commission Panel directs FortisBC to establish for 2005, an operating expense incentive mechanism with the following parameters:**

(a) The total variance for consideration will be calculated as the difference between the forecast 2005 O&M expenses, net of capitalized overheads, and the actual 2005 O&M expenses, net of capitalized overheads;

(b) Favourable variances, which result from the deferral or cancellation of planned activities/programs and/or reductions to existing service levels, will not be eligible for the sharing mechanism. FortisBC is directed to record these type of favourable variances in a deferral account, whose disposition will be dealt with by the Commission at a future date;

(c) The initial $500,000 of a positive or negative variance [as determined by the conditions set out in (a) and (b)] will be shared on a flow-through basis, i.e. 100% to the customer's account;

(d) Both positive and negative variances in excess of the $500,000 "deadband" in (c) will be subject to sharing. The sharing ratio will be 60:40 to shareholders and customers, respectively;

(e) The sharing of an eligible favourable O&M expense variance in (d) will also be subject to the satisfactory achievement of FortisBC's performance targets (see following paragraph (f) for a detailed discussion). If the Company experiences an unsatisfactory result in any one or more performance targets, the Commission will determine at the 2005 Annual Review whether to disqualify FortisBC from sharing in an eligible favourable operating expense variance in 2005. The Commission will apply a high standard of review, as necessary; and

(f) In reference to (e) above, the Commission Panel further directs that within 60 days of this Decision, FortisBC is to file with the Commission, for review and approval, objective and measurable performance metrics and specific targets to be achieved in 2005. These performance metrics should be appropriate for the measurement of actual performance in the generation, transmission, distribution, and customer service functions of the Company (Commission Panel determinations with respect to Customer Service are set out in Section 2.7). For example, SAIDI, CAIDI could be considered appropriate performance metrics for certain functions.

The following example (assuming a favourable variance) will serve to demonstrate the functioning of the above operating expense incentive mechanism.

Forecast 2005 O&M Expenses, net of capitalized overheads	$36,173,000 [1]	Exhibit B-66, p.1
Assumed actual 2005 O&M Expenses, net of capitalized overheads	35,104,000	
Gross Variance	1,069,000	Favourable
Less: Assumed favourable variance due to deferral of planned activity	200,000	to deferral account
Net Variance	869,000	Favourable
Less: $500,000 "Deadband"- 100% to customers	500,000	
Variance eligible for sharing	369,000	Favourable
Shareholder's share @ 60%	221,400	
Customer's share @ 40 %	147,600	

In the above example calculation, customers would effectively "recapture" $847,600 of the total favourable variance of $1,069,000.

2.4.3 Review of PBR

FortisBC intends to complete a comprehensive review of PBR with a view to engaging in stakeholder consultations by the fourth quarter of 2005. FortisBC says that it will propose implementation in 2006 at the earliest if a fair and workable mechanism can be determined (FortisBC Argument, p. 51).

KOECA argues that a PBR must be reviewed thoroughly, with all necessary evidence brought forward in an oral public hearing to determine whether PBR should be continued at all (KOECA Argument, p. 4). BCOAPO supports FortisBC's proposal for stakeholder consultation, but believes it should be primarily aimed at identifying issues of concern and points of disagreement between all parties involved. BCOAPO submits that this should help establish a more focused and efficient Commission process for review of FortisBC's PBR mechanism (BCOAPO Argument, p. 7).

Commission Panel Determinations

The Commission Panel agrees with FortisBC's intentions and timeline to engage in stakeholder consultations to review its existing PBR mechanism. The Commission Panel directs FortisBC to complete its review of PBR prior to submitting its 2006 Revenue Requirements Application and to propose to the Commission its preferred process for review and implementation of its recommendations. The Commission will determine at that time an appropriate review process going forward.

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[1] Subject to adjustments discussed elsewhere in this Decision.

2.5 2005 Demand Side Management Expenditure Plan

2.5.1 Application

FortisBC filed its planned 2005 DSM expenditures under Tab 10.1 of its Application. The planned expenditures are a one-year extension of FortisBC's 1999-2004 DSM Business Plan. As such, it is a one-year continuation of its existing resource acquisition strategy, programs and incentives. FortisBC proposes to file an updated DSM Potential Study by June 30, 2005 and to file a new DSM Business Plan, covering the period 2005-2014, by October 31, 2005. These latter proposals are a component of FortisBC's Resource Plan – Action Plan.

FortisBC's DSM plan is comprised of expenditures for programs in the Residential, General Service and Industrial sectors, as well as costs for Planning and Evaluation, including salaries, consulting fees for planning reviews, ongoing program monitoring, and periodic evaluation reports and training costs. Both the costs of the DSM Potential Study and the DSM Business Plan are included in the 2005 Planning and Evaluation costs. In sum, FortisBC has set out total 2005 DSM expenditures of approximately $1.8 million for forecast total 2005 savings of 19.1 GWh. At the time that FortisBC filed its Application, these amounts could be compared to 2004 forecast costs and savings of approximately $2.0 million and 21.0 GWh, respectively (for further detail, please refer to Exhibit B-1, Tab 10.1, pp. 5-11; Exhibit B-12, Response to BCUC IR 112.0-117.0; and Exhibit B-17, Report of the DSM Technical Committee).

FortisBC submits that its 2005 DSM Plan, filed in compliance with Section 45 (6.1)(c) of the UCA, is reasonable, prudent, and in the public interest, and therefore requests an Order of the Commission that the 2005 DSM plan meets the requirements of Section 45(6.2)(b) of the UCA and is in the public interest (FortisBC Argument, p. 57).

2.5.2 Demand Side Management Technical Committee

Commission Order No. G-14-05 specified that issues associated with DSM would be reviewed by a Technical Committee as an adjunct to the Hearing. The Committee comprised FortisBC and Commission staff as well as Registered Intervenors that expressed an interest to participate. The Commission directed the DSM Technical Committee to submit a report with recommendations to the Commission one-week prior to the commencement of the Hearing (Exhibit A-4).

FortisBC filed the Report of the DSM Technical Committee on March 9, 2005 (Exhibit B-17). The Committee considered a number of issues and concerns in detail over the course of two meetings. There was particular focus on the methodologies that FortisBC uses to forecast the costs and savings in its DSM Plan and to determine the cost-effectiveness of the component programs. FortisBC provided a detailed explanation, stepping through the calculation spreadsheets where appropriate, to the ultimate satisfaction of Committee members. The Committee agreed that a sensitivity analysis on input variables such as penetration rates would be a useful component of future filings and would improve the assessment of the cost-effectiveness of the various DSM programs. FortisBC intends to include sensitivity analyses in future DSM filings.

The Committee also highlighted a concern that the Terms of Reference for the DSM "2005 Energy Efficiency Potential Assessment", as included in Appendix D to Tab 10.1 of the Application, did not include any focus on capacity savings. In response, FortisBC updated the Terms of Reference for this study to eliminate the concern that capacity savings potential would not be addressed. The update to the Terms of Reference is included in Appendix One of the Report of the DSM Technical Committee (Exhibit B-17). FortisBC indicated that the cost of including a study of capacity savings would be re-allocated from other study components, leaving the total study costs of $24,000 unchanged.

The Committee recommended that the existing DSM Incentive Mechanism and DSM Incentive Committee continue for 2005. The Committee was of the view that there was no basis at present on which to rebase any DSM targets in advance of the comprehensive review of PBR that FortisBC intends to complete by the end of 2005 (refer also to FortisBC Argument, p. 51). The Committee recommended that there would be no need to call a DSM panel at the Hearing. After canvassing comment from those Registered Intervenors that did not participate in the DSM Technical Committee, the Commission accepted this recommendation (Exhibit A-16). No issues with respect to the DSM Plan were raised during the Hearing and no written submissions on the DSM plan were received in argument by any party.

2.5.3 Commission Panel Determinations

The Commission Panel has reviewed the FortisBC DSM Expenditure Plan and the Report of the DSM Technical Committee. **The Commission Panel approves the DSM Expenditure Plan as filed and acknowledges that this Plan meets the requirements of Section 45(6.1) of the UCA.**

The Commission Panel also accepts the recommendation of the DSM Technical Committee that the existing DSM Incentive Mechanism and DSM Incentive Committee continue for 2005. The Commission Panel is satisfied by the response of FortisBC to the other issues of concern raised by the Committee; namely, its intention to file appropriate sensitivity analyses in future filings and to include in its DSM potential study a focus on capacity savings potential. **The Commission Panel directs FortisBC to file its DSM potential study by June 30, 2005 and its 2005-2014 DSM Business Plan by October 31, 2005, the timelines proposed by FortisBC.**

2.6 Transition Plan

2.6.1 Introduction

Commission Order No. G-39-04 approved the acquisition by Fortis Pacific of a reviewable interest in Aquila(BC). The latter company became FortisBC after the acquisition.

Aquila(BC) and Aquila Networks Canada (Alberta) Ltd. ("Aquila Alberta") were affiliates of each other and operated on an integrated basis. The two organizations shared certain functions including, for example, executive management, customer call centre, most of the finance function, human resources, and legal services.

As part of Fortis Pacific's application to acquire a reviewable interest, the company represented that it would unwind certain of the shared functions between the B.C. and Alberta operations and establish and operate FortisBC on a stand-alone basis. Fortis Pacific submitted that establishing the utility on a stand-alone basis would allow it to effectively address customer service quality issues and operational improvements, focus the management's attention on the B.C. service area, and create a more transparent regulatory environment. The stand-alone entity would also have independent financing capacity in capital markets.

Commission Order No. G-39-04 directed Fortis Pacific and, as appropriate, FortisBC to file quarterly reports outlining planning activity, timetables and financial evaluation and impacts of their implementation. By the time the Oral Hearing commenced, the Company had filed two quarterly reports (Exhibit B-12, BCUC IR 123) and a detailed Transition Plan (Exhibit B-1, Tab 10.3). The quarterly reports and the Transition Plan illustrate FortisBC's intentions and progress to date on the changes being made in the areas of customer service and operations, and on setting up a stand-alone organization. FortisBC forecasts that the aforementioned activities will cause 2005 O&M expenses, before capitalized overheads, to increase by $1,158,000 (Exhibit B-66, p. 1). In 2005 FortisBC also expects to incur capital expenditures of $460,000 for the new call center in Trail, B.C. (Exhibit B-12, BCUC IR 124.1). The combined effect of these expenditures requires an increase of approximately $1.2 million in 2005 Revenue Requirements (Exhibit B-1, Tab 10.3, p. 13).

The following sections discuss the significant components of the FortisBC Transition Plan in greater detail.

2.6.2 Customer Service

Customer service is addressed separately in Section 2.7.

2.6.3 Establishment of a Stand-alone utility

During cross-examination, Mr. Hughes, President and CEO of FortisBC explained the advantages of operating a utility on a stand-alone rather than integrated basis. Mr. Hughes testified (T2: 82):

> "We believe that this stand-alone utility based in our B.C. service territory will not only produce improved customer service – why will it do that? Because it will have local knowledge, improved focus and greater responsiveness to trouble calls. But it will also, over time, produce lower costs. Let me give you a couple of examples: Lower employee turn-over, particularly in the call centre; lower building and rental costs; improved responsiveness to customer concerns and requests – for example, customer connection; and last and certainly not least, faster outage restorations."

Commission Counsel asked Mr. Hughes to provide hard evidence that demonstrates that lower costs come from a stand-alone utility (T2:114). Mr. Hughes replied:

> "Well, one of the first things I would point to, and between I think it was about 1992 and 2002 in Newfoundland Power with this model, essentially the O&M was flat. To run a utility over a period of that time with flat O&M obviously proves the value of the model. It's our experience from say Fortis (Ontario), Fortis – we changed that model and we saw a cost improvement. That was more integrated. We've seen it in many. If you go through those things I mentioned, what you will find if you look at the Fortis companies is that our cost performance improves, our customer satisfaction improves by adopting this model pre and post. In the last 15 years, Maritime Electric, you've seen the performance and cost performance." (T2:114-115).

To date, FortisBC has made significant progress toward creating the stand-alone entity. The Head Office has been established in Kelowna and the independent executive management team is mostly in place. FortisBC states that recruitment of staff includes a combination of internal reorganization, outside recruitment and transfers of skilled employees wishing to relocate. The Company also notes that no relocation and severance costs associated with the transfer of positions from Alberta are included in the 2005 Revenue Requirements (Exhibit B-1, Tab 10.3, p. 10).

FortisBC will have its own Board of Directors and it will include members from the service territory. The Board is expected to be in place by the end of 2005.

2.6.4 Field Services

FortisBC states that it intends to pursue two separate initiatives, both of which are aimed at improving customer responsiveness (Exhibit B-1, Tab 10.3, p. 12).

The first initiative is directed at reducing FortisBC's service restoration times. The Company is currently undertaking a comprehensive review with a view to establishing restoration targets applicable to all areas of its service territory. The review will be completed by the second quarter of 2005.

The second initiative is aimed at improving FortisBC's responsiveness to routine customer wait times for services such as new connections. FortisBC states that: "As in the case of restoration times, measurable targets will be established and regularly reviewed to ensure continued timely customer responsiveness on a consistent basis." (Exhibit B-1, Tab 10.3, p.12)

2.6.5 Submissions

BCOAPO opposes the $1.2 million increase in the 2005 Revenue Requirements that result from actions taken under FortisBC's Transition Plan. BCOAPO states that: "…it is not appropriate for it to require ratepayers to pay for the cost for restoring quality of service to levels that existed prior to the move to Calgary." (BCOAPO Argument, p.7) and "…that customers should not be required to bear the cost of improving customer service in the amount of $1.2 million…" (BCOAPO Argument, p. 25) It further argues that to the extent the $1.2 million is reflected in the O&M expenses, these expenses should be reduced accordingly (BCOAPO Argument, p. 25).

KOECA states: "…the Commission should not permit the company to subsequently be rewarded for restoring service levels which should never have been allowed to decline in the first place." (KOECA Argument, p. 2). KOECA argues that a way must be found to determine how much improvement the company must make before it can justify passing on service improvement costs to its customers. It further submits that: "The appropriate approach is to establish what service levels are now being targeted by the company and determine whether they were in fact already at that level in the past. If so, then the company should pay the entire cost of service restoration. If the company intends to provide service levels above those experienced in the past, then in fairness it should be able to recover costs for doing so, but only for the increment above past service levels." (KOECA Argument, p. 2).

IMEU submits is supportive of the efforts of FortisBC to focus on improving customer relations and customer service in the service territory, and to operate the utility in an efficient, safe and reliable manner. It is also pleased to see a locally managed stand-alone operation with a focus on customers and it states that: "…[the IMEU] particularly endorses the statement in FortisBC's argument that it believes that 'it [the stand-alone utility] will also produce the lowest possible costs for our customers over the long term'(Fortis Argument, Page 8)" (IMEU Argument, p. 2). Having made the above statements, IMEU continues to state several concerns, including its concern about the: "…increased costs being passed on to customers as a result of the transition of ownership from Aquila to FortisBC" (IMEU Argument, p.2).

2.6.6 Commission Panel Determinations

The Commission Panel has considered all the evidence and arguments related to this matter. The Commission Panel concurs that the largely one-time cost of moving many of the functions back to B.C. is appropriately an expense for the shareholder. However, it does not agree with Intervenors that the incremental ongoing or recurring costs associated with service improvement activities proposed in the Transition Plan should be borne by shareholders. In Section 2.3.3 the Commission Panel approved the forecast 2005 O&M expenses, before capitalized overheads (i.e. $39,569,000 subject to adjustments), which include the increase of $1,158,000 in O&M expenses related to the Transition Plan. **With respect to the establishment of the Trail Call Center, the Commission Panel also accepts the forecast 2005 capital expenditures of $460,000 and the associated increases in the 2005 Revenue Requirements.**

The targets applicable to service restoration times and customer wait times for services such as new connections should be filed with the Commission as per the Commission Panel's determinations set out in Section 2.4.2, paragraph (f).

FortisBC claims that a stand-alone utility will over time produce lower costs. The Commission Panel directs FortisBC to submit a report one year from this Decision that demonstrates the achievement of cost savings attributable to the stand-alone status of FortisBC. The Commission will determine the need for further reports on a prospective basis.

2.7 Customer Service

In its application to acquire a reviewable interest in Aquila(BC), Fortis Pacific provided evidence that "the conduct of FortisBC's business, including the level of service, either now or in the future, would be maintained or enhanced." (Exhibit B-1, Tab 10.3, p.3). FortisBC further states:

> "In addition to the intentions stated in the Application, multiple stakeholder and public consultations were conducted regarding the Acquisition and transition. During these consultations, the Company also stated its intention to, within a reasonable transition period: 1) improve the overall quality of service to customers; … " (Exhibit B-1, Tab10.3, p. 4)

The Commission, in considering the acquisition application, was mindful of the service level concerns as expressed by customers and the related undertakings of the Applicant. In Order No. G-39-04 approving the acquisition, the Commission made clear its expectations that:

> "… in due course and in a timely manner, steps will be taken to further consider and implement the plans and fulfill the commitments made in the presentations to stakeholders, in the Fortis Application and in the course of this public process." (Order No. G-39-04, Appendix A, p. 11)

With the amount of interest in and attention paid to customer service during the acquisition process, it is not surprising that customer service would be a topic of considerable focus for FortisBC and of much interest to Intervenors in this proceeding.

FortisBC addressed many customer service deficiencies under cross examination. The following is considered by the Commission Panel to be a representative sample of these deficiencies and FortisBC's view of them.

> "What's relevant is that the customer service level and the meter reading was just unacceptable. And we heard this very strongly from the customers." (T2: 103)

> "And another thing we found when we took over this utility and we made fairly good initial efforts to start changing it and we've still got a long way to go, is customer connections. The time from when a customer requested service in B.C. to when they were actually getting it, we felt was far too long." (T2: 116)

> "In principle, we are responding to customers -- what customers have been telling this utility for some time, and that is the level of dissatisfaction that they have with the customer service, the call centre, responsiveness, et cetera." (T2: 169)

> "Newfoundland Power in the early '90s was in a very similar situation as we see here in B.C. today. It was suffering from a very low customer service rating." (T3: 519)

In the course of the proceedings Intervenors were generally positive about to FortisBC's intentions and early progress with respect to improvements in customer service. IMEU's comments on the subject are, in the view of the Commission Panel, generally representative of Intervenor views:

> "The IMEU is supportive of the efforts of FortisBC to focus on improving customer relations and customer service in the service territory and has been generally impressed by the efforts of the new management of the Company to respond to customer concerns" (IMEU Argument, p. 2).

2.7.1 Metrics and Strategies

In Exhibit B-1 at Tab 10.2, FortisBC provides an informative overview of its views on customer service measurement and tracking. The Commission Panel is of the view that customer service may be measured as it occurs, in terms of objective measures of customer service activity, and after the fact, in terms of customer satisfaction response when surveyed. Typically, objective measures are an indication of performance in “real time”, while survey responses measure reaction to performance after the fact and can lag actual performance by a considerable margin depending on the timing of the survey and the degree and nature of the interaction with the (in this case) service provider.

FortisBC indicated its intentions with respect to revising its approach to the measurement of customer service.

> “In general it seems more reasonable to directly measure things that are readily quantifiable, such as reliability, rather than measure them through qualitative questions in the survey. Going forward, it is intended that the customer survey tool be used to more accurately measure the quality and convenience of the customer’s day-to-day interactions with the Company, and employ other metrics for strictly objective facets of customer service.” (Exhibit B-1, Tab 10.2, p27)

FortisBC indicated that in addition to revising the survey questionnaire, it planned to establish metrics and key performance indicators for all departments for the purpose of linking departmental productivity levels in all areas to customer service. Some indicators that FortisBC believes are important to customers are (Exhibit B-1, Tab 10.2, pp 28-29):

- Billing Accuracy;
- Emergency response times;
- First call resolution;
- Commitment to follow-up;
- Tracking completion time for new service requests;
- Meter reading accuracy; and
- Field service complaints.

The following reflects the strategies that FortisBC is currently implementing, or intends to implement, believing that they will result in an improvement in customer service:

> “FortisBC plans to establish its own customer service functionality and is focused on strategies to improve service. These improvements include a more effective call centre, increased meter reading and billing accuracy, enhanced bill format and provision for in-person service. Also, improvements in field service delivery through more effective work processes and resource deployment will decrease wait times for services such as new connections and trouble call response. The Company intends to establish benchmarks to monitor its progress.” (Exhibit B-1, Tab 10.3, p. 17)

FortisBC has identified that the costs of these initiatives, when netted against the forecast reduction in shared services cost from FortisAlberta, form the major part of the approximate $1.2 million increase in revenue requirements discussed in Section 2.6.1 (Exhibit B-1, Tab 10.3, p. 17).

2.7.2 Commission Panel Determinations

The increase in costs to support improvements in customer service has been approved elsewhere in this Decision. In defense of its O&M expense budget, FortisBC encouraged customers and the Commission to focus on the results of the utility's programs as reflected in objective measures of customer service levels (FortisBC Reply Argument, p. 19). The Commission Panel is concerned that although FortisBC indicates that it intends to establish benchmarks to monitor its progress in improving customer service, no specific objective measures have been identified by FortisBC as deliverables resulting from the increase in funding as requested and approved. In the view of the Commission Panel, it would be unreasonable under normal circumstances to approve an increase in funding in the absence of clear targets against which improved performance is expected and may be measured. However, in the circumstances, the Panel supports the need for substantial improvements in service and recognizes the need for urgency in undertaking the initiatives necessary to bring about these improvements.

Therefore, the Commission Panel directs FortisBC to file within 60 days of this Decision a comprehensive set of objective and measurable performance metrics showing respective performance at the beginning of 2005 (estimates where actual is not available) and targets for December 31, 2005 for service areas as follows:

1. **Billing Accuracy**
2. **Emergency response times**
3. **First call resolution**
4. **Commitment to follow-up**
5. **Tracking completion time for new service requests**
6. **Meter reading accuracy**
7. **Field service complaints**
8. **Call center**

Further, FortisBC is directed to report to the Commission by October 31, 2005, actual performance for each of the measures to September 30, 2005, and by January 31, 2006, actual performance for each measure to December 31, 2005.

2.8 Accounting Issues

2.8.1 Depreciation and Amortization Study

FortisBC's last formal depreciation study was undertaken in 1983 and a discussion paper on the service life of transmission and distribution assets was completed in 1999. The Negotiated Settlement Agreement for 2000-2002, approved by Commission Order No. G-134-99, included a reduction of depreciation rates (and therefore depreciation expense) for transmission and distribution assets from 35 years to 50 years, and a further offset to depreciation expense in the form of a Rate Stabilization provision. Neither change was based on an expert-prepared depreciation study examined by the Commission. Since 2000, depreciation rate changes have resulted in a lower annual depreciation expense of about $3.3 million. The Rate Stabilization Adjustment was utilized in 2001, which set-up a $3.1 million adjustment to offset accumulated depreciation (Exhibit B-12, BCUC IR 33.6-33.8; T5: 863-866; FortisBC Argument, pp. 36-38).

The DBRS credit rating report expressed that currently low depreciation rates are a challenge and it observed that the Company's current average depreciation rate appears low in comparison to other utilities (Exhibit B-12, BCUC IR 13.0, p. 2). Similarly, the Moody's credit rating report cites one of the Company's credit challenges to be the relatively low depreciation rate for rate-making purposes (Exhibit B-12, BCUC IR 15.0, p. 1).

Dr. Booth, expert witness for BCOAPO, stated that the depreciation rate should be based on the economic useful life of the assets and it shouldn't be fixed for other purposes (T4: 759). Mr. Meyers from FortisBC indicated that the Company expects to carry out a depreciation study later in 2005 and intends to perform depreciation studies on five-year intervals going forward (T5: 863). Mr. Wait argues that the depreciation rate for vehicles should be increased so that the difference between the vehicle sale value and depreciated value would be minimal (Wait Argument, pp. 3-4).

FortisBC proposes to conduct a depreciation and amortization study by an independent consultant during 2005, for submission with the 2006 Revenue Requirements application (Exhibit B-1, Tab 6, p. 9; Exhibit B-12, BCUC IR 33.6). The Company states that the depreciation study will address issues raised during the proceeding including disposition of the Rate Stabilization Account; different depreciation rates for the generation plants; and depreciation rates for fleet vehicles and computer software. FortisBC argues that it is inappropriate to make any changes to depreciation rates or methodology until a depreciation study is completed (FortisBC Argument, pp. 37-38).

FortisBC states that its policy is to record depreciation expense in the year after the assets are placed in service (Exhibit B-12, BCUC IR 29.1.2).

Commission Panel Determinations

The Commission Panel accepts that the currently approved depreciation rates should not be changed in 2005 until a formal depreciation and amortization study has been completed. The Commission Panel directs FortisBC to file a depreciation and amortization study as part of its next revenue requirements application. The next revenue requirements application will include a rate impact analysis for both with and without any depreciation and amortization rate changes.

2.8.2 Adjustment for Capital Expenditures

The Company calculates the Adjustment for Capital Expenditures on a quarterly weighted average instead of on a 13-month weighted average. The Company states that either method should provide similar results over the long term. The Company argues that should the Commission prefer that the Company move to a 13-month average for calculating the Adjustment for Capital Expenditures in the determination of rate base, the Company suggests that this change be introduced as part of the Company's 2006 Revenue Requirements application (FortisBC Argument, pp. 29-30; Exhibit B-12, BCUC IR 37.0; T5: 867-868).

Commission Panel Determinations

The Commission Panel agrees that the Company should continue to use the quarterly weighted average method to calculate the Adjustment for Capital Expenditures in 2005. The Commission Panel directs the Company to calculate the Adjustment for Capital Expenditures using the 13-month average method, commencing in 2006.

2.8.3 Allowance for Funds Used During Construction

AFUDC represents the cost of capital incurred by the Company while assets are under construction. The Company recognizes that customers should only contribute to assets that are "used and useful". Consequently, the Company deducts AFUDC from revenue requirements and adds it to capital costs, to be recovered through depreciation expense over the life of the asset (Exhibit B-1, Tab 8, p. 26).

The Company has calculated an AFUDC rate of 6.48 percent based on a return on equity of 9.78 percent and weighted average cost of debt of 6.66 percent (Exhibit B-1, Tab 8, p. 26; Exhibit B-12, BCUC IR 80.5 & 85.3).

The Company explained that AFUDC is calculated monthly on a project by project basis for projects with a forecast cost greater than $100,000 and expected to last more than three months duration. The Utility includes Construction Work in Progress ("CWIP") that attracts AFUDC in its rate base. Revenue requirements, including financing costs, are calculated on the mid-year rate base which includes CWIP. Revenue requirements are then reduced by AFUDC, to reflect the cost of financing the CWIP portion of rate base that is not used and useful. The Company stated that Terasen Gas and Pacific Northern Gas Ltd., both regulated by the Commission, do not include AFUDC as a reduction to revenue requirement and exclude CWIP subject to AFUDC from rate base. However the Company states that the net result of using either method should be the same (Exhibit B-12, BCUC IR 85.1-85.10).

The Company provided a reconciliation of the deduction of AFUDC in Schedule 3 to show that the Company has properly deducted AFUDC in calculating income tax expense (Exhibit B-79). Commission Counsel in cross-examination questioned the Company's use of including CWIP that attracts AFUDC in rate base and the practices of other utilities regulated by the Commission. Mr. Lee responded that the Company had no preference between the methodologies (T5: 873).

FortisBC argues that since 1990 it has included CWIP in the calculation of rate base, together with the corresponding deduction of AFUDC in the calculation of revenue requirements. FortisBC does not propose to change its current treatment, and believes that its current treatment better reflects the actual income tax and accounting treatment of AFUDC. If the Commission wishes to change the method of accounting for CWIP and AFUDC, FortisBC argues that the change should be applied prospectively beginning in 2006 as part of the Company's 2006 revenue requirement application (FortisBC Argument, p. 30).

Commission Panel Determinations

The Commission Panel accepts that the Company should continue to calculate CWIP and AFUDC using the current method in 2005. The Commission Panel directs FortisBC in its next revenue requirements application to review its current practice of including CWIP attracting AFUDC into rate base. The review should include a comparison of other electric and gas utilities regulated by the Commission, an analysis of the alternate methods, and a proposal by the Company on whether to continue or change its current AFUDC and CWIP methodology.

The Commission Panel directs the Company to recalculate its AFUDC rate based on the weighted average cost of debt from the Third Revised Application and the return on equity allowed through this Decision. The resulting approved AFUDC rate shall be applied to calculate the AFUDC amounts in 2005.

2.8.4 Capitalization of PowerSense Costs

FortisBC is proposing a change in the accounting treatment of certain PowerSense costs in the amount of $85,000, such that these costs are charged to capital rather than operations (Exhibit B-26, p. 4). The DSM Technical Committee discussed the reasons behind the request with only Mr. Wait expressing concern (Exhibit B-17, p. 3).

Mr. Wait argues that the $85,000 charge for DSM awareness should continue as an operating expense and not be capitalized. He expressed concern for capitalizing costs that do not have physical assets attached and the procedure would cost ratepayers more for ROE and equity (Wait Argument, p. 9). Currently the Company amortizes DSM (deferred energy management) costs over 8 years (Exhibit B-12, BCUC IR 34.1-34.3).

Commission Panel Determinations

The Commission Panel approves the change in accounting treatment of certain PowerSense costs as proposed by the Company. The Commission Panel directs that the upcoming depreciation and amortization study will address the appropriateness of the current amortization period for deferred DSM costs.

2.8.5 Deferred Charges

Net-of-tax Deferral Accounting

Currently, FortisBC treats DSM costs net-of-tax as directed in Commission Order No. G-55-95. All other deferred charges that have been recorded by the Company are on a gross of tax basis. At Transcript Volume 5, page 887, Commission Counsel questioned the appropriateness of recording all deferred charges on a net-of-tax basis. Mr. Meyers responded that, in his opinion, the net-of-tax treatment is appropriate to ensure proper matching of costs and benefits (FortisBC Argument, p. 59).

The Company proposes that deferred amounts related to the proposed 2005 O&M Expense and power purchase sharing mechanisms be recorded net-of-tax so that the associated income tax is correctly matched either to the customers or the shareholder (Exhibit B-12, Response to BCUC IR 34.5). The Company does not propose to extend net-of-tax treatment to other deferral accounts. The Company is of the position that any change in the treatment of deferred charges must apply on a prospective basis only, and should be made only after a full assessment of the impact has been completed (FortisBC Argument, pp. 59-60).

The Commission believes that a consistent treatment of deferral accounts is warranted to ensure proper matching of costs and benefits. **The Commission Panel directs that all deferred charges (excluding preliminary and investigative costs charges transferred to capital projects) be treated using net-of-tax deferral accounting commencing in 2005.**

Tax Rate for Net-of-tax Deferral Accounting

The Company currently books net-of-tax deferrals using the combined federal and provincial statutory tax rate including federal surtax. The 2005 combined statutory tax rate with surtax is 35.62 percent and 34.5 percent without surtax. Mr. Lorimer agreed that the federal surtax was deductible against the large corporation tax. In response to a question by Commission Counsel, Mr. Lorimer rationalized that the 35.62 percent tax rate was appropriate (Exhibit B-12, BCUC IR 34.1; T5 887-888).

In its calculation of the large corporation tax for 2005 the Company has included a federal surtax reduction to compute the net payable large corporation tax (Exhibit B-12, BCUC IR 81.5).

In 2005 the ability to apply the federal surtax to reduce large corporation tax effectively excludes the federal surtax in the combined corporate income tax rate. **The Commission Panel directs that the tax rate to use for net-of-tax deferral accounting is the net effective tax rate to the Company. For 2005 the appropriate tax rate to use for net-of-tax deferral accounting is 34.5 percent without the federal surtax.**

Cost of Regulatory and Related Activities

The Company requests approval for the deferral of the cost of regulatory and related activities. In Table 6.4B, Forecast 2005 Deferred Charges and Credits, the Company proposes to include in 2005 forecast deferral additions of $250,000 for the 2005 Revenue Requirements proceeding, $75,000 for the 2006 Revenue Requirements proceeding, and $150,000 for Other Regulatory proceedings (Exhibit B-1, Tab 6, p. 13).

The Company explained the Other Regulatory proceedings amount is a provision for expected and unexpected regulatory proceedings during the year. The Company anticipates the most significant costs would be for the 2005 Generic Return on Equity hearing plus intervention in proceedings of other utilities such as BC Hydro's Rate Design hearing. The Company states that it is not possible to estimate costs with a reasonable degree of certainty until the scope and process of a proceeding has been determined (Exhibit B-12, BCUC IR 34.7).

The Commission Panel approves gross deferral account additions of $250,000 and $75,000 in 2005 for the 2005 and 2006 Revenue Requirements proceedings, respectively. The Company will file with the Commission upon completion of each of these two proceedings a review of the actual costs, a comparison of the costs from actual to budget, and a demonstration that the costs have been prudently incurred.

The Commission Panel denies the $150,000 provision for Other Regulatory proceedings to be included in rate base. The Commission Panel directs the Company to set-up a non-rate base short-term interest bearing deferral account for each regulatory proceeding that it proposes to seek cost recovery for. The account will collect actual costs incurred for each proceeding. At the conclusion of each proceeding the Company may apply for a prudency review of actual incurred costs for inclusion in rate base as a deferral account.

<u>Series 04-1 Senior Unsecured Debentures Issue Cost and Amortization</u>

FortisBC requests approval for the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000. The Company also requests amortization of the issue cost of the Series 04-1 Senior Unsecured Debentures in the amount of $2,091,000 over ten years commencing on January 1, 2005. The amortization period matches the 10-year term of the bond (Exhibit B-26, p. 3; Exhibit B-1, Tab 8, p. 18; Exhibit B-12, BCUC IR 23.1).

The Commission Panel approves the $2,091,000 issue cost of the Series 04-1 Senior Unsecured Debentures and the amortization over ten years commencing on January 1, 2005.

<u>Amortization of the Costs Incurred for 2004 Revenue Requirement process</u>

The Company requests amortization of the costs incurred in FortisBC's 2004 Revenue Requirements NSP over a one-year period (Exhibit B-26, p. 3; Exhibit B-12, BCUC IR 34.3).

The Commission Panel approves the amortization of costs incurred in FortisBC's 2004 Revenue Requirements NSP for a one-year period in 2005.

<u>Costs and Amortization of the System Development Plan and Resource Plan</u>

The Company requests the amortization of the costs of the 2005-2024 System Development Plan and the 2005 Resource Plan, in an aggregate amount of $900,000, over five years commencing on January 1, 2005 (Exhibit B-26, p. 3). The December 31, 2004 balances are $800,000 for the System Development Plan and $100,000 for the

Resource Plan (Exhibit B-12, BCUC IR 29.0, Table 1-B (2005)). The Company states that these planning activities are carried out at intervals of approximately five years, and are considered to be an ongoing, although intermittent, operating expense. Therefore, the Company proposes to include the amortization of costs in O&M expense (FortisBC Argument, p. 60).

The Commission Panel approves a five-year amortization for each of the System Development Plan and the Resource Plan costs. The Commission Panel determines that net-of-tax deferral accounting is to be used for deferred charges. Consequently, the System Development Plan and Resource Plan costs are not to be amortized to operating expense. Instead these costs are to be amortized to deferred amortization expense.

Capital Cost Allowance Rate Change Deferral

In its Revised Application, FortisBC incorporates changes to the 2005 Revenue Requirements to reflect capital cost allowance ("CCA") rate changes relating to new transmission and distribution assets announced in the February 23, 2005 Federal Budget (Exhibit B-19, p. 6). FortisBC requests approval of a deferral account and recovery in 2006 of higher income tax expense that will arise in 2005 if the new CCA rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005 (Exhibit B-26, p. 5).

The Commission Panel approves a deferral account and recovery in 2006 of higher income tax expense that arises in 2005 if the new CCA rates announced in the February 23, 2005 Federal Budget are not enacted prior to December 31, 2005.

2.8.6 Provision for Income Tax Audits

The Company has included an amount of $100,000 in its 2005 Revenue Requirements as a provision for income tax audits. The Company has been audited by the Canada Revenue Agency ("CRA") for the years up to and including 1998. The Company expects that it will be audited for the years subsequent to 1998 in the near future. The Company believes it is both reasonable and prudent to include this provision in its 2005 income tax expense. The Company indicated that a cumulative provision for income tax audits for the years 1999 to 2004 exists, in the amount of $350,000. FortisBC proposes this provision be retained pending an audit from CRA for these years. Any unused provision upon completion of the audits would be credited to the benefit of customers in calculating the following year's revenue requirement (FortisBC Argument, p. 33; Exhibit B-77, Undertaking U-44).

FortisBC confirmed that the accumulated provisions for tax audits have not been factored into the rate base calculations (Exhibit B-78, Undertaking U-45). IMEU argues that it does not believe that the provision for tax audit should be maintained. Also, IMEU submits that the $350,000 which has been collected from customers should be returned to customers in 2005 (IMEU Argument, 17).

FortisBC in its reply to IMEU believes that the Company's position is a prudent method of providing for the eventual costs of tax audits, and that its proposal to retain the provision and to dispose of any unused amounts upon completion of the audits be approved by the Commission (FortisBC Reply Argument, pp. 29-30).

Commission Panel Determinations

The Commission Panel directs the $100,000 provision for tax audit to be removed from the 2005 Revenue Requirements. The Commission Panel also directs that the cumulative provision of $350,000 for income tax audits already collected be returned to ratepayers in the 2005 test year.

2.8.7 Capital Tax Refund

FortisBC was reassessed for B.C. Capital taxes for the taxation years 1994 through 1998. The primary issues arising from the assessments arose from the netting of CIAC against book value and the netting of certain deferred charge credits against deferred charge debits for purposes of computing the Company's paid-up capital for capital tax purposes. The Company paid the reassessed amounts and appealed the reassessments. In early 2004, the Company, together with Terasen Gas, met with representatives from the B.C. Ministry of Finance to put forth its position on the calculation of the capital taxes. On February 11, 2005 the Company received notice that its appeal has been allowed by the Minister of Finance, and it is awaiting final reassessment (Exhibit B-12, BCUC IR 82.1).

The Company proposes that the capital taxes refund amount, including interest and net of related income taxes, be shared equally between the Company and its customers. The Revised Application includes a provision for one-half of the estimated B.C. Capital Tax refund of $908,000 applied on an after-tax basis, to reduce the 2005 B.C. Capital Tax expense by $292,000 (Exhibit B-19, p. 7). FortisBC argues that since the Company aggressively pursued the appeal, and in view of the fact that PBR is intended to provide incentives to the Company to find ways to reduce cost and to share these cost savings with the customer, it considers it reasonable that the refund be shared on a 50-50 basis (FortisBC Argument, p. 35).

Mr. Meyers agreed that capital tax was a flow-through cost borne by the ratepayers and that the ratepayers paid for the costs of pursuing the appeal. Mr. Meyers stated that the Company aggressively pursued the assessment and that the sharing of the benefit would continue to provide incentives to the Company to continue to appeal similar types of assessments. Upon further questioning from Commission Counsel, Mr. Meyers agreed that as a part of the Company's normal business operation it has an obligation to pursue the tax assessment to keep costs down. Commission Counsel also questioned why the Company was treating the refund on an after-tax basis for the flow-through to customers. Mr. Lorimer replied that the B.C. Capital Taxes, as opposed to the large corporation tax, was a tax deductible item in those years (T5: 843-846).

IMEU does not support the regulatory treatment of B.C. Capital Tax as proposed by the Company. IMEU submits it is completely inappropriate for the Company to be claiming any portion of any refund or positive assessment from the appeals of these tax matters. IMEU considers that, since the customers bore the full cost of the appeals and bore the full cost of the taxes paid during the period, the customers should be entitled to a full refund of the success of the appeals. IMEU notes that if the challenge were unsuccessful, yet prudently undertaken, the cost of the pursuit of the appeal would have been borne by the customers (IMEU Argument, pp. 3, 15-16).

BCOAPO does not support a sharing of the B.C. Capital Tax refund. BCOAPO notes that Mr. Lorimer admitted that FortisBC was not the only utility to appeal the capital tax assessment (T3: 516). BCOAPO argues there is no evidence that the efforts of FortisBC, rather than the efforts of other utilities, were responsible for the capital tax refund (BCOAPO Argument, pp. 25-26).

Commission Panel Determinations

The Commission Panel denies the proposed sharing of the B.C. Capital Tax refund. The Commission Panel directs the Company to include in 2005 the full after-tax refund amount without any sharing to the Company.

3.0 2005 CAPITAL PLAN AND 2005-2024 SYSTEM DEVELOPMENT PLAN

3.1 Introduction

In conjunction with its 2005 Revenue Requirements filing, FortisBC filed its 2005-2024 System Development Plan and its 2005 Capital Plan. FortisBC states that these plans are intended to comply with the requirements of Section 45 of the UCA (Exhibit B-1, Tab 1). Section 45(6) of the UCA states that “A Public Utility must file with the Commission at least once each year a statement in a form prescribed by the Commission of the extensions to its facilities that it plans to construct.” Section 45(6.1) requires that the utility file a capital expenditures plan for a period specified by the Commission in addition to plans for the acquisition of energy and plans for reducing the demands for energy.

In its November Application FortisBC stated that it was seeking an Order that its 2005 System Development Plan meets the requirements of Section 46(6) of the UCA and an Order that its 2005 Capital Expenditure Plan satisfies the requirements of Section 45(6.2)(a) and (b) of the UCA (Exhibit B-1, Tab 9, pp. 5-6). In its Second Revised Application FortisBC no longer sought an Order for the System Development Plan. In clarification, Mr. Macintosh stated that the Orders FortisBC is seeking are contained in the Second Revised Application and did not include an Order for the approval of the System Development Plan, but required an order approving the 2005 Capital Plan (T2: 67). Mr. Debienne stated that although they were not seeking approval, the System Development Plan needs to be considered when evaluating the Capital Plan (T3: 345).

3.2 2005-2024 System Development Plan

The System Development Plan is a long range planning document for capital expenditures on the transmission and distribution system. It considers a 20-year time frame for the transmission system and a 5-year time frame for the distribution system and was preceded by the 1998 Master Plan. Although the time frame for the report is 20 years, the majority of expenditures are anticipated to occur in the next five years. The total transmission and distribution capital forecast for the first five-year period is in excess of $400 million (Exhibit B-1, Tab 9, p. 19).

Inputs to the plan include the forecast growth for the Kootenay and Okanagan regions and assessments of equipment condition and maintenance plans. Each resulting project was assessed against criteria for safety, public impact, restoration time, thermal capacity, system effect of failure, and voltage. Some projects were given a mandatory designation for safety reasons (Exhibit B-2, pp. 2-4).

3.2.1 Bulk Transmission Plan

The following section discuses system deficiencies and/or changes from the 1998 System Plan. Although the most significant deficiencies were addressed by the 230 Kootenay Development project and the South Okanagan Supply reinforcement project, FortisBC has identified several other areas of concern.

One area of concern is the reliability of supply to the City of Kelowna. FortisBC identified that Kelowna will be exposed to a significant load loss from the coincident loss of circuits 72 and 74 or BC Hydro's 2L255 and 2L256 from Vernon. (Exhibit B-2, p. 10). With this occurrence Kelowna could experience a loss of two thirds of its load, with the remainder of load under rotating blackouts. FortisBC testified that the concern with these lines lies with the fact that they share common rights of way and could be subject to outage events such as forest fires or other common mode outages. It was also concerned about the exposure to Kelowna under conditions of maintenance outages. This condition is referred to as an N-1-1 condition. In the previous plan only a loss of one line was considered. However, according to Western Electricity Coordinating Council ("WECC") standards, when it is reasonable to assume a multiple element outage due to one cause a utility must consider the multiple element outage under N-1 contingency standards (T2: 265-267). The solution to this concern is to replace the 161 kV line with a 230 kV transmission line from Vaseux Lake Terminal to the Anderson Terminal in Penticton.

Other changes identified include the supply to the Boundary area and to Osoyoos as well as the need for additional Remedial Action Schemes for Vaseux Lake Terminal and Kelowna to prevent voltage instability in the Penticton/ Oliver and the Kelowna areas (Exhibit B-1, Tab 9, p. 18; Exhibit B-2, pp. 12, 13, 17, 29, 40).

3.2.2 Transmission and Distribution

FortisBC identified a significant number of sub-transmission and distribution projects required for growth and sustaining projects. These are listed in Appendix C of Exhibit B-2 on pages 2 and 3. Distribution projects are listed on page 4 and Telecommunications, Scada, and Protection projects are listed on page 5. All projects have been prioritized according to the criteria described above, and are listed on pages 6 and 7 of Appendix C.

3.2.3 Rate Impacts

FortisBC estimated that the Capital Plan would result in an average increase in rates of 4.8 percent per year for the first five years (Exhibit B-12, BCUC 92.3). As a result of further questions during the Technical Committee meetings FortisBC also estimated that the impact of all other cost components with the Capital Plan included is an average rate increase of 5.2 percent per year (Exhibit B-20, Appendix 1).

However Mr. Debienne stated that the results calculated in response to BCUC 92.3 were misleading because the table contained the Capital Expenditures for the System Development Plan in 2005 and then included the Capital expenditures for the entire company in the remaining years to 2010 (T2: 228). Mr. Debienne also stated that a more accurate representation of the impacts of the System Development Plan can be found in Appendix 1 to Exhibit B-20. While this Exhibit shows the rate impacts for all capital expenditures, the rate impact for the System Development Plan would be approximately two-thirds of that, or a cumulative impact of 20 to 25 percent over six years (T2: 231-232).

3.2.4 Submissions

Arguments from IMEU, BCOAPO, and NRI were generally supportive of the System Development plan and the possible improvements in reliability, but all expressed some concern for the rate impact. IMEU expressed some concerns about the completeness of the System Development Plan, but was encouraged by the Company's commitment to have an open dialogue on the Plan. Mr. Wait had specific comments on the Big White Project and the East Osoyoos Substation, the Boundary reconfiguration, and the lines 30, 32, and 37 (Kaslo, Crawford Bay, Lambert Terminal areas). He also suggested that the 230 kV line from Vaseux Lake to Penticton was not needed and should be delayed. In conclusion he wished to have the System Development Plan address the issues he raised.

FortisBC argued that the System Development Plan and the Capital Plan were developed to ensure that investments in the existing system are sufficient to maintain system integrity and reliability and to optimize the life of the company's assets (FortisBC Argument, p. 9). FortisBC believes the plans are efficient and that it has economized it to the extent possible. However it notes that it is continuing to do analysis to optimize the plan on a year to year basis. (FortisBC Argument, p. 12-13). Regarding the impact on rates, FortisBC acknowledges the impact and notes that for the next 6 to 7 years customers will see a rate bulge as the system is renewed, but in the long term customers will enjoy relatively low rates because of the low cost of generation. In comparison to other utilities, the cost of equipment will be the same, as the company uses the same material and practices as other utilities and that therefore the rates will be comparable to other utilities on that basis (FortisBC Argument, pp. 12-15).

With regard to the need for N-1-1 criteria for the City of Kelowna, FortisBC acknowledges that this is a change from previous criteria but believes it to be necessary because of the possible impacts on Kelowna (FortisBC Argument pp. 14-15).

3.2.5 Commission Panel Determinations

Although the Commission has not been requested to approve the System Development Plan, the Commission Panel has several comments. First, the Commission Panel commends the effort FortisBC has put forward in constructing the System Development Plan. The Commission Panel believes that FortisBC's thorough review of the needs of the system and prioritization of the identified projects will greatly assist future capital expenditures investment decisions. Second, the Commission Panel encourages FortisBC to treat this plan as a living document, to continue to consult with stakeholders, and to keep the inputs to the plan current as the plan evolves. With respect to the rate impacts of the System Development Plan, the Commission Panel is concerned that sustaining a rate increase of approximately 5 percent per year over the next six years may be difficult. Thus, the Commission Panel suggests that for the next capital plan review, and subsequently thereafter, FortisBC should develop alternate scenarios that envision a perhaps less efficient plan but which would involve delaying capital expenditures. The Commission Panel is not suggesting that these scenarios would be preferred, but that their cost impacts need to be known in order to make choices between lower rate increases and higher long term costs. The Commission Panel also notes that customers have enjoyed relatively lower rates than other utilities for a considerable period during the 1980's and 1990's when capital investment levels were much lower.

With respect to the appropriate reliability levels for the City of Kelowna, the Commission Panel notes that the criteria of N-1 is a minimum standard set by the WECC for bulk transmission systems and adopted by most utilities. The Commission Panel acknowledges that there are situations (particularly in large urban centers) where the consequence of a lower probability occurrence of an N-1-1 or N-2 event requires the N-1 standards to be exceeded. Each case is a judgment call and must be evaluated on its own merits. However it is common practice to have N-2 contingency levels for certain load centers in large urban centers (e.g. Vancouver and Victoria). **The Commission Panel accepts that an N-1-1 contingency level for Kelowna is appropriate at this time.**

3.3 2005 Capital Plan

3.3.1 2005 Capital Plan Summary

FortisBC is seeking an order that the 2005 Capital Plan, as setout in Tab 9 of Exhibit B-1, satisfies the requirements of Section 45 (6.2) (a) and (b) of the UCA. The 2005 Capital Plan contains expenditures of $49.4 million (AFUDC and loadings included) for which project approval has been previously received from the Commission. These projects are the Kootenay 230 kV System Development Project, the South Okanagan Supply Reinforcement Project, the Kelowna Area Upgrade and the Upgrade and Life Extension projects involving Unit 5 and Unit 6 at the Upper Bonnington power plant. (Exhibit B-1, Tab 9, p. 4).

As part of the Capital Plan FortisBC proposed that the following four criteria be used to determine if a project should be subject to a CPCN application:

1. the total project cost is $20 million or greater; or
2. the project is likely to generate significant public concerns; or
3. FortisBC believes for any reason that a CPCN application should proceed; or
4. after presentation of a Capital Plan to FortisBC stakeholders, a credible majority of those stakeholders express a desire for a CPCN application.

FortisBC argued that these criteria were consistent with Commission Order No. G-96-04 and directives regarding the British Columbia Transmission Corporation ("BCTC") (Exhibit B-1, Tab 9, p. 6).

FortisBC notes that the Big White Supply Project will be the subject of a Certificate of Public Convenience and Necessity ("CPCN") Application in 2005.

The 2005 Capital plan for Transmission, Stations, Distribution and Telecommunications is based primarily on the System Development Plan, while the 2005 Capital Plan for Generation is based on the Upgrade and Life Extension program as well as other capital sustaining requirements (Exhibit B-1, Tab 9, p. 5).

3.3.2 New Projects

Generation

By a December 8, 2004 letter, FortisBC advised the Commission that in keeping with its proposed CPCN criteria it did not intend to file a CPCN for the Lower Bonnington Upgrade and Life Extension Project. However on May 19, 2005 FortisBC submitted a CPCN application for this project. This project was originally delayed pending the outcome of an agreement with BC Hydro to clarify the entitlement benefits for an upgraded turbine. The subsequent agreement improved the actual benefits of the upgrade.

Transmission and Stations

Although there are numerous small sustaining capital projects, the main projects driving new capital are the Big White Supply project at a total cost of $24.5 million with $3.0 million in 2005; the Ellison Distribution source at a total cost of $8.25 million with $0.25 million in 2005; the Black Mountain distribution source at a total cost of $7.25 million and $0.25 million in 2005; and the new East Osoyoos source at $5.75 million with $0.25 million in 2005; and the Kettle Valley distribution source at a total cost of $7.65 million with $0.15 million in 2005.

Distribution Projects

The Commission Panel notes that the largest expenditure is for new connects ($4.5 million) with the remainder made up of a larger project with respect to the Creston upgrade to the Lambert Terminal project as well as a large number of smaller projects.

Telecom, SCADA, and Protection and Control Projects

The largest project in this category is the Distribution Substation Automation project with total expenditures forecast at $6.2 million dollars with $0.60 million in 2005. The remainder consists of a number of modest sustaining projects totaling $1.4 million.

CPCN Requirements

As discussed above, FortisBC has proposed that a number of criteria be used to guide FortisBC when applying for CPCN's. No intervenors commented on the CPCN criteria.

3.3.3 Commission Panel Determinations

The Commission Panel confirms that the 2005 Capital Plan satisfies the requirements of Section 45(6.2)(a) and (b) of the UCA.

With regard to the CPCN Criteria, the Commission Panel is in general agreement with FortisBC's assessment of the appropriate criteria to guide the Company and the Commission when applying for CPCN's. However FortisBC has missed an important distinction with respect to the BCTC application. BCTC has acknowledged that the Commission has the authority to designate any projects it deems necessary for a CPCN application, regardless of the criteria. **In exercising this prerogative the Commission will be guided by the suggested criteria. However, in practice the Commission intends to review each year's capital filings and will determine with reasons which projects will require CPCNs.**

The Commission approves all capital projects listed in Tab 9 of Exhibit B-1, except for the following projects, for which the Commission Panel directs FortisBC to submit CPCN applications.

1. **Big White Supply:** As FortisBC suggests, this project is required because its total cost will exceed $20 million and because of public concerns with respect to routing and capital cost recovery.

2. **East Osoyoos Source:** This is required because of uncertainty with respect to the timing of this project and alternative solution. In addition, there seems to be some uncertainty regarding the supply from Bentley substation.
3. **Kettle Valley Distribution Source:** As with (2) above, there appears to be some uncertainty with regard to the best solution for the Boundary area. The Commission Panel is of the view that allowing public comment on the proposed solution would be of value.
4. **Distribution Substation Automation:** This is required because it is not clear to the Commission Panel what the possible risks and benefits are associated with the project, what precedent it may set for future projects, and if FortisBC is selecting the appropriate technology.

The Commission Panel invites FortisBC to withdraw its May 19, 2005 CPCN application for the Lower Bonnington Upgrade and Life Extension Project.

4.0 2005 RESOURCE PLAN

4.1 Background

The Commission's mandate to direct and evaluate the resource plans of energy utilities is intended to facilitate the cost-effective delivery of secure and reliable energy services. The Commission's Resource Planning Guidelines (the "Guidelines") outline a comprehensive process to assist utilities in the development of such plans. The Commission requires that any resource plans filed under Section 45(6.1) of the UCA be prepared in accordance with its Guidelines.

The Commission requires consideration of all known resources for meeting the demand for a utility's product, including those which focus on traditional and alternative supply sources, and those which focus on conservation of energy and DSM. Resource planning is intended to facilitate the selection of cost-effective resources that yield the best overall outcome of expected impacts and risks for ratepayers over the long run. The process aids in defining and assessing market-based costs and benefits, while also entailing the assessment of tradeoffs between other expected impacts that may vary across alternative resource portfolios. Such impacts may be associated with objectives such as reliability, security of supply, rate stability and risk mitigation, or specific social or environmental impacts. In sum, a resource planning process that assesses multiple objectives and the tradeoffs between alternative resource portfolios is key to the development of a cost-effective resource plan for meeting demand for a utility's service (Guidelines, pp. 1-2).

On December 21, 2004 FortisBC filed its Resource Plan as Volume 3 of its 2005 Revenue Requirements Application. FortisBC prepared and filed its Resource Plan in response to the Commission's directive to utilities to file such plans as contemplated by Section 45(6.1) of the UCA. FortisBC states that its Resource Plan is consistent with the Guidelines.

4.2 2005 Resource Plan Summary

FortisBC's 2005 Resource Plan is a study of its load and resource Requirements over the period 2005-2024. It summarizes its Resource Plan objectives as to reliably meet customer load requirements, in agreement with stakeholder expectations, with existing and new resources if needed, with minimum rate and environmental impacts and with the guidance of the B.C. Energy Plan.

FortisBC's long-term firm requirements and its current planning in this regard establish the initial frame of reference for its Resource Plan. FortisBC's hydroelectric generation plants are expected to supply approximately 214MW of firm capacity and 1,569GWh of energy in 2005, or roughly 30 percent and 50 percent of its capacity and energy requirements, respectively. FortisBC has long-term purchase agreements for additional firm resources with the Columbia Power Corporation/CBT Power Corporation ("CPC/CBT"), for 149MW of capacity and 984GWh of energy through 2056, and with BC Hydro under the PPA, for 200MW of capacity and associated energy through 2013. The total of its long-term firm resources currently supply about 98 percent of its energy needs and about 76 percent of its capacity requirements (Exhibit B-4, pp. 5, 19). FortisBC assessed its load and resource balance through 2024 with its existing and planned resources. Its planned resource additions include its Upgrade and Life-Extension program, Upper Bonnington Re-Powering, and purchase options from local existing and planned resources such as Cominco and the CPC/CBT Brilliant Expansion. The results of its study indicate that with existing owned resources and supply contracts, FortisBC will be able to meet almost all of its energy requirements until 2013 when the 200MW BC Hydro PPA potentially expires. FortisBC notes that there will continue to be a small capacity-related energy shortfall during peak winter periods, growing only slightly to 2013 given that the energy take under the BC Hydro PPA can increase as load grows.

FortisBC's current strategy for acquiring additional resources includes the purchase of capacity-related energy from the market with a combination of short-term advance purchases of capacity and/or energy blocks as well as purchases from the spot market. FortisBC states that it favours capacity purchases because they allow peaking energy to be supplied from BC Hydro under the PPA and because they do not involve any surpluses. FortisBC has regarded this as a more cost-effective strategy than securing long-term firm resources to meet peak demands because it minimizes over-purchases of energy, with the consequent risk that the sell-back of un-needed energy will be at a lower price. Further, FortisBC is constrained from exporting when taking energy from BC Hydro under the PPA. FortisBC acknowledges that while it views its current strategy as cost-effective, it faces the risk of fluctuating power purchase expenses given the exposure to market volatility, as well as reliability risk associated with the market's ability to supply its peaking needs (Exhibit B-4, pp. 19-20). FortisBC's resource planning allowed it to review this strategy in view of expected load growth over the planning horizon. It also allowed FortisBC to investigate the impact if the BC Hydro PPA is not be renewed after 2013, given the significant annual shortfalls in capacity and energy that would occur under this scenario.

FortisBC's Resource Plan presents a comprehensive set of Case Scenarios to assess various strategies to maintain its Load and Resource balance over the 2005-2024 planning horizon. FortisBC models one set of three cases under which it pursues its existing market strategy, while considering separate scenarios wherein the BC Hydro PPA continues until 2024 with no new firm resources added (Case A-1), the BC Hydro PPA ends in 2013 and no new firm resources are added (Case A-2), and the BC Hydro PPA ends in 2013 and is replaced with a new firm resource (Case A-3). FortisBC models a second set of three cases under which it pursues a new market strategy and assumes the BC Hydro PPA continues, while considering separate scenarios wherein no new firm resources are added (Case B-1), a 75MW Peaking Plant is added in 2008 (Case B-2), and a BC Clean Resource (Biomass Plant) is added in 2010 (Case B-3). And finally, FortisBC models a third set of three cases under which it pursues a new market strategy and assumes the PPA ends in 2013, while considering separate scenarios wherein the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-1), a 75MW Peaking Plant is added in 2008 and the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-2), and a BC Clean Resource (Biomass Plant) is added in 2010 and the BC Hydro PPA is replaced with a new 250MW firm resource (Case C-3).

There are a number of assumptions common to the analysis of each Case, including common discount rates (nominal 8, 10, and 12 percent values), common Load and DSM forecasts and, where relevant, common forecast market prices for electricity based on a forecast of Mid-C index values for the 2005-2024 period. FortisBC's Resource Plan considers Load and DSM forecasts consistent with the forecasts provided in support of its 2005 Revenue Requirements Application. While it assumes a constant DSM forecast over the time period of its Resource Plan, FortisBC addresses uncertainty in the factors underlying its load forecast, such as economic and population growth rates, by incorporating a High and Low load forecast. The High forecast assumes a 25 percent increase in the annual load growth rate, while the Low forecast incorporates a 20 percent reduction in the annual load growth rate (Exhibit B-4, pp. 22-30, 59).

In contrast to the existing market strategy modeled in the A-Cases, under which the shortfall between firm resources and requirements is met with short-term monthly or one-year ahead purchases (aside from roughly 75MW of purchases in the spot market), the new market strategy pursued under the B Cases is characterized by meeting the shortfall with medium-term three to five year energy block purchases (again, with roughly 75 MW of spot market purchases). FortisBC modeled the new market strategy as a test of the protection it affords against market volatility risk and reliability risk under the expectation, in part, that this strategy is less susceptible to price shock risk. Medium-term block purchases are considered an effective hedge against price shock because if prices rise the sell-back price of surpluses rises accordingly, offsetting increased costs.

In sum, the modeling of each Case allows FortisBC to assess the incremental cost and rate impacts associated with moving to a new market strategy, losing the BC Hydro PPA, building a peaking plant resource, or building a BC Clean energy resource. FortisBC assessed the sensitivity of its modeling results to changes in discount rates, variations in market prices and the degree of exposure to market price volatility, as well as changes to the assumptions regarding the relative amounts of energy purchased in the spot market in the relevant Cases.

FortisBC concludes, in part, that:

- The existing market strategy under the expected load forecast is the lowest-cost portfolio under the scenario that the BC Hydro PPA continues until 2024 (Case A-1);
- The existing market strategy would continue to be the lowest-cost portfolio if it is not possible to renew the PPA (Case A-2), but the exposure to the market under this scenario would likely be unacceptable, notwithstanding the uncertainty about the viability of the market at that time, and would require the addition of a new long-term firm resource;
- If the PPA is replaced by a new long-term firm resource, the impact on power purchase costs are expected to be significant, an estimated five percent levelized rate impact;
- The new market strategy, while more costly, could be justified with an extreme rise in market prices of approximately six times, but only marginally justified with a moderate rise of about three times, considering also the possibility of price decreases and the benefits of improved reliability;
- A more detailed study of the new market strategy would be required in order to more fully assess the trade-off between increased cost and offsetting risk, and to optimize the new strategy in this regard;
- Adding a BC Clean resource would entail significant cost increases and may not be desired, while other options, such as purchasing "green tags", could be economic and will be investigated;
- The peaking plant resource, as an alternative to short-term market purchases, is not recommended due to its increased cost; and
- These conclusions are supported under reasonable variations in load forecast, discount rates and market prices.

All told, on the basis of its Resource Plan FortisBC concludes that additional long-term firm resources are not needed until when and if the BC Hydro PPA expires, potentially in 2013. Further, FortisBC states that it should consider reducing its exposure to short-term market purchases (FortisBC Argument, p. 53).

FortisBC proposes the following Action Plan based on its conclusions (Ex. B-4, p. 74; FortisBC Argument, p. 53-54):

1. The Company will begin discussions with BC Hydro, with a view to gaining certainty regarding the status of the PPA beyond 2013.

2. The Company will conduct a more detailed study of a much shorter time frame than was assessed in this Resource Plan study, approximately five years, to optimize a new market strategy that provides more protection from market volatility and improved reliability. FortisBC comments that modeling the market is a complex undertaking and involves a variety of possible strategies and products that could be purchased. It contemplates that it may be possible that some combination of medium term purchases from Cominco and peaking purchase from others can provide a similar level of protection from market volatility and improved reliability at lower cost than the energy block purchases that were simulated in this Resource Plan.

3. The Company will update and file its DSM Potential Study and complete a new DSM plan covering the period 2005-2014, investigating whether a more aggressive program is more cost-effective.

4. The Company proposes to update its Resource Plan on a bi-annual basis. FortisBC states that it is essential that with the dependence on the market to meet some of its requirements, the Company needs to detect shifts in load growth and market trends as soon as possible in order to make the necessary adjustments to its resource plan.

5. The Company will investigate options other than addition of a new long-term firm clean resource for complying with the B.C. Energy Plan.

4.3 Submissions

FortisBC refers in argument to the following two issues raised in respect to its Resource Plan (FortisBC Argument, p. 54):

- Finalizing the PPA with BC Hydro for long term firm resources; and
- The proposed strategy to reduce exposure to market prices.

FortisBC is of the view that while there is risk associated with finalizing an agreement with BC Hydro, successful negotiations can be concluded prior to 2013 when the PPA is due to expire, FortisBC is optimistic that it won't be a protracted negotiation given its prior experiences of working with BC Hydro (FortisBC Argument, p. 55).

FortisBC refers to its extensive analysis of the new market strategy to conclude that there is a reasonable likelihood of financial benefits to the customer by moving to a strategy that lessens exposure to the spot market. Because it recognizes that such a strategy is very sensitive to market factors, FortisBC proposes to conduct a more detailed study over a shorter time frame than was necessitated in its Resource Plan in order to optimize a strategy that provides more protection from market volatility and improved reliability (FortisBC Argument, pp. 55-56).

FortisBC submits that its Resource Plan is reasonable and prudent, meets the requirements of Section 45(6.2)(b) of the UCA, and is in the public interest (FortisBC Argument, p. 56; FortisBC Reply Argument, p. 28).

4.4 Commission Panel Determinations

The Commission Panel has reviewed the FortisBC Resource Plan, and all of the associated evidence adduced over the course of the hearing. **The Commission Panel accepts the Resource Plan, and component Action Plan,**

determining that it is reasonable and prudent, and that it meets the requirements of Section 45(6.2)(b) of the UCA and is in the public interest.

The Commission Panel has some concerns about the methodological framework that underpins the Resource Plan to the degree that the approach to explicitly account for uncertainty is not especially sophisticated. In one example, the Commission Panel determined that the conclusions of the Resource Plan are not robust to the impact on the new market strategy from changes to the sell back price of surplus energy. The Commission Panel appreciates that FortisBC recognizes that its Resource Plan could be improved in general with greater attention to sensitivity analysis, and in particular with a detailed study of a new market strategy over a shorter time horizon. The Commission Panel encourages FortisBC, both in the next iteration of its resource planning study and in the forthcoming study of a new market strategy, to provide a more comprehensive treatment of the uncertainty in its planning parameters. Besides expanding upon its sensitivity analyses, FortisBC could explore the potential of a simulation analysis, with the use of distributions around key input variables where possible, as a means to improve its accounting of uncertainty in its resource planning study.

With reference to FortisBC's proposed Action Plan, the Commission Panel supports the initiative to begin discussions with BC Hydro, with a view to gaining certainty regarding the status of the PPA beyond 2013. The Commission Panel recognizes that the results of the Resource Plan indicate that a sufficient window of time exists over which FortisBC can gain certainty on the status of the PPA before needing to consider other resource options. The Commission Panel requests that FortisBC file a status update on the progress of negotiations with BC Hydro at the same time as it files its next revenue requirements application, or sooner as applicable. The Commission Panel also requests that FortisBC file at that time a status update on the progress of its detailed study of a new market strategy, including preliminary results as relevant. As noted earlier in this Decision, the Commission Panel directs FortisBC to file its DSM potential study by June 30, 2005 and its 2005-2014 DSM Business Plan by October 31, 2005, the timelines proposed by FortisBC.

FortisBC proposes to update its Resource Plan on a bi-annual basis. In light of the results of the 2005 Resource Plan, the Commission Panel accepts this timeline for the next iteration of the Resource Plan, anticipating then that FortisBC will file an updated plan at the same time it files a 2007 Revenue Requirements application. However, the Commission Panel does not approve FortisBC's proposed timeline as a matter of policy in this instance. The Commission Panel will determine the timeline for any resource planning updates on a prospective basis with its review of future Resource Plans.

DATED at the City of Vancouver, in the Province of British Columbia, this 31st day of May 2005.

Original signed by:

L.F. Kelsey
Panel Chair and Commissioner

Original signed by:

P.G. Bradley
Commissioner

APPEARANCES

P. MILLER	Commission Counsel
G.K. MACINTOSH, Q.C. K. CAIRNS D. O'LEARY	FortisBC Inc.
C. WEAFER	Interior Municipal Electrical Utilities
R. GATHERCOLE P. MACDONALD	The BC Old Age Pensioners Organization Council of Senior Citizens Organizations of BC Federated Anti-Poverty Groups of BC Senior Citizen's Association of Canada End Legislated Poverty
D. SCARLETT	Kootenay-Okanagan Electric Consumers' Association
R. TARNOFF	Natural Resources Industries
A. WAIT	Himself

R. GORTER W. KRAMPL R.W. RERIE D. CHONG	Commission Staff
R. STUBBINGS	Commission Consultant
ALLWEST REPORTING LTD.	Court Reporters

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

FortisBC Inc.
2005 Revenue Requirements,
2005-2024 System Development Plan and 2005 Resource Plan

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated December 14, 2004 and Order No. G-111-04 approving an interim rate increase effective January 1, 2005 and establishing the Regulatory Timetable for the review process
A-2	Letter dated December 18, 2005 providing information for the FortisBC Workshops and Pre-hearing Conference proceedings
A-3	Letter dated December 20, 2005 advising Participants that issues to be included on the Issues List will be discussed at the Pre-hearing Conference
A-4	Letter dated January 24, 2005 releasing Order No. G-14-05, the Issues List and the Amended Regulatory Timetable
A-5	Letter dated January 19, 2005 responding to Mr. Karow’s January 9, 2005 submission (Exhibit C2-4)
A-6	Letter No. L-9-05 dated January 28, 2005 denying FortisBC’s request for a Negotiated Settlement Process
A-7	Letter and Commission Information Request No. 1 dated January 28, 2005
A-8	Letter dated February 2, 2005 regarding Helmut Wartenberg’s Information Request (Exhibit No. C8-3) to the Commission
A-9	Letter dated February 2, 2005 declining Mr. Karow’s January 24, 2005 request to postpone the regulatory timetable and to post the Curriculum Vitae of Commission Board members and staff on the web (Exhibit No. C2-5)
A-10	Letter dated February 17, 2005 responding to Mr. Scarlett's letter of January 26, 2005 commenting on FortisBC’s eligibility for the 2004 Incentive Payment
A-11	Letter and Order No. G-20-05 dated February 22, 2005 regarding the 2004 Incentive Adjustments

Exhibit No.	Description
A-12	Letter dated February 24, 2005 regarding the Oral Public Hearing location and start time
A-13	Letter and Commission Information Request No. 1 to the BC Old Age Pensioners Organization *et* al dated March 3, 2005
A-14	Letter to Registered Intervenors dated March 11, 2005 regarding whether they are supportive of the FortisBC Demand Side Management Technical Committee and the Load Forecast Technical Committee recommendations (Exhibit B-17 and B-18) with request to respond by March 16, 2005
A-15	Public Hearing Procedural Letter dated March 16, 2005
A-16	Letter dated March 17, 2005 accepting the recommendations of the Demand Side Management and Load Forecast Committees that there is no need to call hearing panels in the respective subject areas
A-17	Letter dated March 17, 2005 responding to Mr. Karow’s e-mail of March 17, 2005 regarding Information Request’s
A-18	Chart from FortisBC 2005 Revenue Requirements – Operations and Maintenance Costs (before Overheads capitalized)

APPLICANT DOCUMENTS

B-1	**FORTISBC INC.** 2005 Revenue Requirements Application dated November 26, 2004
B-2	FortisBC 2005-2024 System Development Plan submitted November 26, 2004
B-3	Notice of Counsel retainment dated December 16, 2004 from Dean O’Leary Farris, Vaughn, Wills & Murphy
B-4	Letter dated December 21, 2004 filing the 2005 Resource Plan (including Appendix D)
B-5	January 20, 2005 Workshop Presentation - 2005 Resource Plan
B-6	January 18 and 20, 2005 Workshop Presentation – System Development Plan (SDP) 2005-2024
B-7	January 21, 2005 Workshop Presentation – 2005 Revenue Requirements

Exhibit No.	Description
B-8	Letter dated January 27, 2005 requesting a revision to the Timetable and process for disposing of the Application
B-9	Letter dated January 31, 2005 replying to comments regarding the 2004 Incentive Program
B-10	Letter dated February 8, 2005 regarding Technical Committees
B-11	2004 Annual Review Powerpoint presentation dated January 20, 2005
B-12	Response dated February 18, 2005 to Commission Information Request No. 1 - (Note: Question 104 response includes attachment with original confidential report from PowerNex *Associates* Inc. for which FortisBC Inc. has provided authorization to now release as non-confidential)
B-12A	Excel spreadsheet files from Exhibit B-12 (CD)
B-13	Response dated February 18, 2005 to The BC Old Age Pensioners Organization *et al.* Information Request No. 1
B-14	Responses dated February 18, 2005 to Information Request No. 1 from the following: IMEU Han Karow Kootenay-Okanagan Electric Consumers Association Natural Resource Industries Alan Wait Helmut Wartenberg
B-15	Letter dated February 24, 2005 requesting that FortisBC Inc. be exempted from the requirement of filing the March 1, 2005 report on transition activities
B-16	Letter and Information Request No. 1 dated March 4, 2005 to the BC Old Age Pensioners Organization
B-17	Letter dated March 9, 2005 and Report of the Demand Side Management Technical Committee
B-18	Letter dated March 9, 2005 and Report of the Load Forecast Technical Committee
B-19	Letter dated March 10, 2005 and revisions to 2005 Revenue Requirements Application
B-20	Letter dated March 11, 2005 and Report of the Capital Additions Technical Committee

Exhibit No.	Description
B-21	Letter dated March 11, 2005 and Report of the Power Purchase Technical Committee
B-22	Letter and Witness Panels dated March 16, 2005
B-23	Letter dated March 15, 2005 and the FortisBC Semi-Annual Demand Side Management Report in response to Commission Information Request 111
B-24	Letter dated March 18, 2005 filing Errata to FortisBC's Information Responses filed February 18, 2005 (Exhibit B-14)
B-24A	Final Errata Page – Response to Karow Information Request No. 1
B-25	Letter dated March 18, 2005 filing a Revised 2005 Revenue Requirements Application ("Second Revised Application")
B-26	Letter dated March 22, 2005 filing a Revised 2005 Revenue Requirements Application ("Third Revised Application")
B-27	Undertaking: Panel 2 – Transcript Page 134, lines 22-26
B-28	Undertaking: Panel 2 – Transcript Page 152, lines 20-26
B-29	Undertaking: Panel 2 – Transcript Page 168, lines 6-8
B-30	Undertaking: Panel 2 – Transcript Page 182, lines 12-15
B-31	Undertaking: Panel 2 – Transcript Page 183, lines 4-5
B-32	Undertaking: Panel 2 – Transcript Page 187, lines 9-21
B-33	Undertaking: Panel 3 – Transcript Page 205, line 5 to Page 206, line 24
B-34	Undertaking: Panel 3 – Transcript Page 208, lines 1-22
B-35	Undertaking: Panel 3 –Transcript Page 218, lines 8-26 and Page 219, lines 1-25

Exhibit No.	Description
B-36	Undertaking: Panel 3 – Transcript Page 219, lines 16 and 17
B-37	Corrected version of Exhibit C5-9
B-38	Undertaking: Panel 3 – Transcript Page 306, lines 25-26, and Page 307, lines 1-3
B-39	Undertaking: Panel 3 – Transcript Page 309, lines 13-15
B-40	Undertaking: Panel 3 – Transcript Page 312, lines 13-16
B-41	Undertaking: Panel 3 – Transcript Page 313, lines 12-14 and lines 17-18
B-42	Undertaking: Panel 3 – Transcript Page 318, lines 1-3
B-43	Undertaking: Panel 3 – Transcript Page 322, lines 22-25
B-44	Undertaking: Panel 3 – Transcript Page 325, lines 25-26
B-45	Undertaking: Panel 3 – Transcript Page 327, lines 3-4
B-46	Undertaking: Panel 3 – Transcript Page 374, lines 15-22
B-47	Undertaking: Panel 3 – Transcript Page 376, lines 13-26, and Page 377, lines 1-5
B-48	Undertaking: Panel – Transcript Page 385, lines 24-26, and Page 386, lines 1-2
B-49	Undertaking: Panel 3 – Transcript Page 393, lines 10-14
B-50	Undertaking: Panel 4 – Transcript Page 437, lines 24-26
B-51	Undertaking: Panel 4 – Transcript Page 445, lines 1-7

Exhibit No.	Description
B-52	Undertaking: Panel 4 – Transcript Page 493, line 26, and Page 494, lines 1-3
B-53	Undertaking: Panel 6 – Transcript Page 512, lines 23-26, and Page 513, lines 1-8
B-54	FortisBC Management Discussion and Analysis dated February 3, 2005 regarding Three Months and Twelve Months Ended December 31, 2004 compared to Three Months and Twelve Months Ended December 31, 2003
B-55	Booth Evidence – Recalculation of Interest Coverage Ratios (Summary)
B-56	Evidence, dated June 1996, of Laurence D. Booth and Michael K. Berkowitz on Capital Structure and Fair Return before the Alberta Energy and Utilities Board in the Alberta Electric Utilities 1996 Tariff Applications
B-57	Excerpt, dated April 13, 1994, from Volume 7, Page 1183 of the BC Gas Utility Ltd., West Kootenay Power Ltd., and Pacific Northern Gas hearing process on the Rates of Return on Common Equity
B-58	Excerpt from FortisAlberta & FortisBC – British Columbia – Your Bill (Bill Insert)
B-59	Undertaking: Panel 4 – Transcript Page 493, line 26, and Page 494, lines 1-3, and Page 495, lines 8-10
B-60	Undertaking: Panel 5 – Transcript Page 668, lines 20-23
B-61	Undertaking: Panel 5 – Transcript Page 673, lines 14-15
B-62	Undertaking 29: Panel 6 - Transcript Page 819, lines 16-20
B-63	Undertaking 30: Panel 6 - Transcript Page 820, lines 14-18
B-64	Undertaking 31: Panel 6 - Transcript Page 821, lines 25-26, and Page 822, line 1
B-65	Undertaking 32: Panel 6 - Transcript Page 826, lines 17-26, and Page 827, lines 1-21
B-66	Undertaking 33: Panel 6 - Transcript Page 828, lines 20-26, and Page 829, lines 1-8

Exhibit No.	Description
B-67	Undertaking 34: Panel 6 - Transcript Page 829, lines 14-26, and Page 830 lines 1-19
B-68	Undertaking 35: Panel 6 - Transcript Page 831, lines 1-26, and Page 832 lines 1-4
B-69	Undertaking 36: Panel 6 - Transcript Page 833, lines 12-14
B-70	Undertaking 37: Panel 6 - Transcript Page 833, lines 23-26, and Page 834, lines 1-3
B-71	Undertaking 38: Panel 6 - Transcript Page 834, lines 10-12
B-72	Undertaking 39: Panel 6 - Transcript Page 835, lines 10-13
B-73	Undertaking 40: Panel 6 - Transcript Page 847, lines 12-14
B-74	Undertaking 41: Panel 6 - Transcript Page 850, lines 6-10
B-75	Undertaking 42: Panel 6 - Transcript Page 851, lines 26, and Page 852, line 3
B-75A	Letter dated April 13, 2005 regarding correction to Undertaking (Exhibit B-75)
B-76	Undertaking 43: Panel 6 - Transcript Page 854, lines 25-26, Page 855, 1-15
B-77	Undertaking 44: Panel 6 - Transcript Page 860, lines 8-21
B-78	Undertaking 45: Panel 6 - Transcript Page 861, lines 12-13
B-79	Undertaking 46: Panel 6 - Transcript Page 874, lines 3-7
B-80	Undertaking 47: Panel 6 - Transcript Page 878, lines 20-26 and Page 879, lines 3-4
B-81	Undertaking 48: Panel 6 - Transcript Page 883, lines 14-26 from March 24, 2005

Exhibit No.	Description
INTERVENOR DOCUMENTS	
C1-1	**KOOTENAY-OKANAGAN ELECTRIC CONSUMERS ASSOCIATION** – Notice of Intervention dated November 30, 2004 from Donald Scarlett
C1-2	Letter dated January 26, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C1-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C1-4	Table – Actual and Allowed ROE
C2-1	**KAROW, HANS** – Notice of Intervention dated December 2, 2004
C2-2	Letter dated December 27, 2004 regarding Mr. Karow's interim submission
C2-3	Letter dated January 3, 2005 filing Mr. Karow's follow-up submission
C2-4	E-mail dated January 9, 2005 – Follow-up submission with respect to his January 3, 2005 and December 27, 2004 filings
C2-5	Email dated January 24, 2005 enclosing a further follow-up to the January 3, 2005 and December 27, 2004 submission and information request
C2-6	Information Request dated February 2, 2005 to FortisBC Inc.
C2-7	E-mail dated March 17, 2005 regarding general information request
C3-1	**WAIT, ALAN** – Notice of Intervention dated December 7, 2004
C3-2	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C3-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C3-4	Excerpt from Waneta HydroElectric Expansion Project Report
C3-5	2004 Revenue Requirements - Appendix A to Order No. G-38-04 – Page 11 of 27 dated March 3, 2004

Exhibit No.	**Description**
C4-1	**NATURAL RESOURCE INDUSTRIES** – Notice of Intervention dated December 7, 2004 from Richard Tarnoff
C4-2	E-mailed dated January 28, 2005 regarding whether FortisBC Inc. should receive an incentive for 2004
C4-3	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C4-4	Letter dated February 3, 2005 advising that Richard Tarnoff will also be representing Hedley Improvement District
C5-1	**THE BC OLD AGE PENSIONERS ORGANIZATION *ET AL*.** – Notice of Intervention dated December 16, 2004 from Richard Gathercole
C5-2	Letter dated January 24, 2005 confirming availability of BCOAPO's witness, Mr. Lawrence Booth
C5-3	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C5-4	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C5-5	Evidence of Laurence Booth filed February 25, 2005
C5-6	Letters and responses dated March 11, 2005 to Commission Information Request No. 1 and FortisBC Inc. Information Request No. 1
C5-6A	Detailed information regarding Information Request responses to Exhibit C5-6 (CD)
C5-7	Letter dated March 14, 2005 responding to Commission letter of March 11, 2005 regarding support of FortisBC Inc.'s Technical Committees recommendations (Exhibit A-14)
C5-8	Witness aid, headed "Background", with chart
C5-9	Table – Percentage deviation of actuals from forecast loads for each group and the average over the period 1995-2003
C6-1	**COLUMBIA POWER CORPORATION** – Notice of Intervention dated December 23, 2004

Exhibit No.	Description
C7-1	**SLACK, BURYL** – Notice of Intervention dated December 30, 2004
C8-1	**WARTENBERG, HELMUT** – Notice of Intervention dated January 4, 2005
C8-2	Letter dated January 18, 2005 citing concerns and summary requests
C8-3	Information Request No. 1 dated January 27, 2005 to the British Columbia Utilities Commission
C8-4	Information Request No. 1 dated February 1, 2005 to FortisBC
C9-1	**TERASEN GAS INC.** – Notice of Intervention dated January 5, 2005 from Scott Thomson
C10-1	**INTERIOR MUNICIPAL ELECTRICAL UTILITIES (IMEU)** – Notice of Intervention dated January 5, 2005 from R.E. Carle
C10-2	Letter dated January 12, 2005 from Christopher P Weafer, Owen·Bird advising that he has been retained as counsel for the IMEU
C10-3	Letter dated January 27, 2005 commenting on FortisBC's eligibility for the 2004 Incentive Payment
C10-4	Information Request No. 1 dated February 2, 2005 to FortisBC Inc.
C10-5	E-mail dated March 17, 2005 in response to H. Karow e-mail of March 17, 2005 (Exhibit C2-7)
C11-1	**POWERHOUSE DEVELOPMENTS INC.** – Notice of Intervention dated January 5, 2005 from W.P. Harland
C12-1	**GLACIER POWER BC LTD.** - Notice of Intervention dated February 7, 2005 from Neil Murphy

Exhibit No.	Description
INTERESTED PARTY DOCUMENTS	
D-1	Renninger, Bud – Web registration received January 6, 2005
D-2	Web registration dated February 7, 2005 from Neil Murphy, Glacier Power BC Ltd. requesting Interested Party status – **WITHDRAWN** – Changed to Intervenor Status
LETTERS OF COMMENT	
E-1	Letter of Comment dated December 14, 2004 from Robb Mayes
E-2	Letter of Comment dated December 14, 2004 from David Egli
E-3	Letter of Comment received December 15, 2004 from Elkink Ranch Ltd.
E-4	Letter of Comment dated December 15, 2004 from Ron Planiden
E-5	Letter of Comment dated December 31, 2004 from Ken Hoffman and Lori Robertson
E-6	Letter of Comment dated December 31, 2004 from Derrick M. May, P.Eng.
E-7	Letter of Comment dated January 3, 2004 from R.C. Cassan
E-8	Letter of Comment dated December 25, 2004 from James Johnston
E-9	Letter to the Editor, Castlegar News dated January 6, 2005 from Marilyn Idle
E-10	Letter of Comment received January 7, 2005 from Tom Stanley
E-11	Letter to the Editor dated January 4, 2005 from Ed Chenail
E-12	Letter of Comment dated January 13, 2005 from Van Quaia
E-13	Letter of Comment dated January 19, 2005 from John Slater, Mayor, Town of Osoyoos
E-14	E-mail from Robert Hobbs, Chair, BCUC providing clarification on two points contained in Ms. Idle's Letter to the Editor of the Castlegar News (Exhibit E-9)
E-15	Letter of Comment dated February 3, 2005 from David Pehota

Exhibit No.	Description
E-16	Letter of Comment dated February 9, 2005 from Elizabeth Strong
E-17	Letter of Comment dated February 21, 2005 from Helen Kennedy
E-18	Letter of Comment dated February 24, 2005 from Donna Krane

IN THE MATTER OF

TERASEN GAS INC.
TERASEN GAS (VANCOUVER ISLAND) INC.
TERASEN GAS (WHISTLER) INC.

AND

RETURN ON EQUITY AND CAPITAL STRUCTURE

DECISION

December 16, 2009

BEFORE:

Anthony J. Pullman, Commissioner/Panel Chair
D.A. Cote, Commissioner
M.R. Harle, Commissioner

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EXECUTIVE SUMMARY

In this Decision the Commission considers an application by Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and Terasen Gas (Whistler) Inc. ("TGW") (collectively, "Terasen") regarding Return on Equity and Capital Structure.

TGI requested a change in the common equity component of its capital structure from 35.01 percent to 40 percent and that the increased common equity component be included in the setting of its rates effective January 1, 2010.

The Commission considered, among other matters, its jurisdiction, the fair return standard, evidence on TGI's business risks, and credit ratings and metrics and concluded that TGI's business risk had increased since 2005 and that the appropriate equity ratio for TGI was 40 percent effective January 1, 2010.

TGI also requested an increased in its return on equity ("ROE") from the existing 8.47 percent to 11 percent for rate setting purposes, and that the new ROE for TGI be used in establishing the ROE for TGVI and TGW for rate setting at a premium of 70 basis points and 50 basis points respectively over TGI's ROE, and that the revised ROE for TGI, TGVI and TGW be effective July 1, 2009.

The Commission considered the various approaches used to determine ROE and the expert evidence called on behalf of Terasen and of the Intervenors on ROE. It concluded that primary weight should be accorded to the Discounted Cash Flow approach, lesser weight to the Equity Risk Premium approach (including the Capital Asset Pricing Model) and minimal weight to the Comparable Earnings approach. The Commission concluded that the appropriate ROE for TGI is 9.50 percent. Noting that the Intervenors did not oppose the request that the ROE be effective July 1, 2009 the Commission granted that request.

The July 1, 2009 effective date results in the ROE for TGI for 2009 being 8.47 percent for six months and 9.50 percent for six months, or an average annual ROE of 8.98 percent. The ROEs for TGVI and TGW become on average respectively 60 and 50 basis points higher as a result of the Commission's conclusion on their level of business risk compared to that of TGI.

The Commission considered evidence on whether the existing automatic adjustment mechanism used in the determination of the ROE of TGI, TGVI and TGW still met the fair return standard and determined that it did not. The automatic adjustment mechanism would only have produced an ROE of 8.43 percent for TGI in 2010 compared to the 9.50 percent determined by the Commission. The Commission has accordingly directed that the automatic adjustment mechanism be eliminated. However, it has also directed TGI to complete its study of alternative formulae and report to the Commission by December 31, 2010.

The Commission declined to continue to allow TGVI a premium of 70 basis points over TGI's ROE. It determined the premium should be reduced to 50 basis points as a result of a reduction in TGVI's risk since 2005. TGW was allowed a risk premium of 50 basis points over TGI's ROE.

The Commission has also determined that the ROE for TGI will continue to serve as the Benchmark ROE for FortisBC and any other utility in BC that uses the Benchmark ROE to set rates.

1.0 INTRODUCTION

On May 15, 2009 Terasen Gas Inc. (“TGI”), Terasen Gas (Vancouver Island) Inc. (“TGVI”), and Terasen Gas Whistler Inc. (“TGW”) filed an application under sections 59 and 60 of the *Utilities Commission Act* with the British Columbia Utilities Commission (the “Application”). In this Decision the three utilities are collectively referred to as “Terasen”; the *Utilities Commission Act* as the “*Act*” or “*UCA*”; and the British Columbia Utilities Commission as the “Commission” or “BCUC.”

The Application seeks the following relief:

- that the Commission determine an increased return of 11 percent on common equity (“ROE”) for TGI for rate-setting purposes, that the so determined ROE for TGI be used in establishing the ROE of TGVI and TGW used for rate-setting, and that the revised ROE for TGI, TGVI and TGW be effective July 1, 2009;
- that the Commission eliminate the use of an ROE automatic adjustment mechanism (“AAM”) in the determination of the ROE to be used by Terasen for rate-setting;
- that, in replacement of the use of an AAM in the determination of their ROE, the ROE determined in the proceeding to be appropriate for TGI be used as the benchmark or generic ROE (“Benchmark ROE”) for the determination of the ROE of TGVI and TGW. TGVI and TGW request that the Commission continue to set their respective allowed returns on equity with reference to the Benchmark ROE established in the proceeding by adding a utility specific risk premium of 70 basis points in the case of TGVI and 50 basis points in the case of TGW to the Benchmark ROE;
- that the Commission alter and increase the common equity component of TGI’s capital structure for rate-setting purposes from 35.01 percent to 40 percent and that the increased common equity component be included in the setting of TGI’s rates effective January 1, 2010;
- that the Commission set the current rates of TGI and TGW as interim, effective July 1, 2009, until such time as permanent rates are established which give effect to the relief requested; and
- that, pursuant to the provisions of the Special Direction [issued to the Commission under section 7 of the *Vancouver Island Natural Gas Pipeline Act*], the increase in TGVI’s allowed ROE resulting from the Commission’s determinations in this proceeding be treated as an increase to TGVI’s cost of service, effective July 1, 2009, which will result in an adjustment

to the 2009 Revenue Deficiency or Revenue Surplus and will be reflected in the Revenue Deficiency Deferral Account ("RDDA") balance.

The process the Commission followed to hear the Application is described in greater detail in Appendix A to this Decision.

The allowable return on a utility's invested capital is a combination of two factors when determining a fair return:

1) the percent of its invested capital that is held as equity relative to the percent held as debt, that is, its capital structure; and
2) the rate of return allowed on the equity portion of the capital structure.

Kathleen C. McShane provided expert evidence on behalf of Terasen on capital structure and fair return on equity. Her testimony is found at Exhibit B-1, Tab 3. Ms. McShane refers to this combination when she states that, "varying both capital structures and ROEs is used by the BCUC" and is one approach to determining a fair return (Exhibit B-1, Tab 3, p. 21). She also states that, "the capital structure and the return on equity are inextricably linked." (Exhibit B-1, Tab 3, p. 3)

The capital structure and ROE for Terasen are established by the Commission for use in the calculation of rates. The actual achieved ROE and return on invested capital for a given year may differ from the ROE established by the Commission for that year because of such factors as variances between actual and forecast revenues or costs of service.

Since 1994 the Commission has annually set the ROE for utilities in British Columbia based on the Benchmark ROE for TGI using a formula that ties the utilities' rates of return on equity to the forecast yield on long-term Canada (30 year) bonds for the forthcoming year. This formula has commonly been referred to as the AAM. The capital structure of utilities has been reviewed less frequently, generally when there has been an application to the Commission for such a review. The background of ROE awards in BC, Canada, and the US since 1994, including the use of a formula to establish ROE is set out in Appendix B to this Decision.

Terasen submits that:

- The fair return standard is not being met;
- The formula that produces the ROE is "broken";
- The recent turbulence in credit markets has further highlighted the formula's flaws; and
- TGI's business risks are increasing.

Combined, in Terasen's view, these four realities mean that the results of the current formulaic approach to ROE are inadequate, and the current equity component in the capital structure of TGI should be increased. Terasen urges the Commission to update both the Benchmark ROE and TGI's capital structure and make the required determination to enable utilities in BC to operate from a healthy and sustainable foundation and continue to appropriately serve the public interest.
(Exhibit B-1, pp. 9, 10)

The Joint Industry Electricity Steering Committee ("JIESC") submits that the fair return standard is being met, that TGI's business risks have not increased, and the AAM has demonstrated remarkable strength in the face of the largest disruption to financial markets in the last 70 years. This is in part evidenced by the $900 million premium (1.7 times the net book value of the equity) paid by Fortis Inc. for Terasen Inc. ("TI") (the parent company of the three Terasen utilities) in the spring of 2007 and by TGI's ability to issue $100 million in debt in February 2009. (JIESC Argument, p. 4)

In order to assess the reasonableness of the relief sought by Terasen, it is necessary to consider the legal and regulatory bases for determining an appropriate capital structure and ROE, and the issues flowing therefrom. These considerations are made in the context of the recent economic situation, including the challenges in financial markets in 2008-2009, as well as recent relevant regulatory developments, particularly the 2009 National Energy

Board ("NEB") Trans Quebec & Maritimes Pipeline Decision RH-1-2008 ("TQM Decision"), the NEB's Reasons for Decision-review of the Multi-Pipeline Cost of Capital Decision (RH-2-94) dated October 8, 2009 ("NEB Letter Decision"), in which it determined that the RH-2-94 Decision will not continue in effect, that is, the return on equity for the pipelines regulated by the NEB will not be determined by an automatic adjustment mechanism, and the Alberta Utilities Commission ("AUC") 2009 Generic Cost of Capital Decision, Decision 2009-216 ("AUC Decision 2009-216") issued on November 12, 2009.

This Decision is divided into the following Sections which address the issues that the Commission Panel needs to determine:

<u>Section 2.0 - Jurisdiction and the Fair Return Standard</u>

This Section discusses the following issues: What are the interests of the parties and the Commission's obligations under the *Utilities Commission Act?* What is the fair return standard and how does the Commission Panel determine whether it is currently being met? Are US data relevant in this determination? If the fair return standard is not being met for TGI, how should the Commission Panel proceed to ensure that it is met?

<u>Section 3.0 - Risks and Capital Structure</u>

This Section discusses the following issues: Have TGI's risks increased since 2005 and if so how should this be reflected in TGI's capital structure? What is TGI's appropriate capital structure?

<u>Section 4.0 - The Appropriate Return on Equity for TGI</u>

This Section discusses the following issues: Given TGI's capital structure what is the appropriate ROE for TGI and what approaches to its determination should the Commission Panel give weight?

<u>Section 5.0 - The Automatic Adjustment Mechanism</u>

This Section discusses the following issues: Given TGI's appropriate ROE, does the Commission's AAM produce an ROE that meets the fair return standard? If not, should the Commission retain, amend, or eliminate its AAM?

Section 6.0 - The Appropriate Return on Equity for TGVI and TGW

This Section discusses the following issue: Given TGI's appropriate capital structure and ROE what are the appropriate ROEs for TGVI and TGW?

Section 7.0 - TGI as the Benchmark Utility

This Section discusses the following issue: What impact should the Commission Panel's determination have on the remaining utilities in BC that might be affected, namely, FortisBC Inc. ("FortisBC") and Pacific Northern Gas Ltd. ("PNG")?

2.0 JURISDICTION AND THE FAIR RETURN STANDARD

In this Section the following issues are addressed:

- What are the interests of the parties and the Commission's obligations under the *Act*?
- What is the fair return standard and how does the Commission Panel determine whether it is currently being met?
- Are US data relevant in this determination?
- If the fair return standard is not being met for TGI, how should the Commission Panel proceed to ensure that it is met?

2.1 The Interests of the Parties and the Commission's Obligations under the *Act*

Terasen states that the impact of its Application is to increase TGI's revenue requirements by $44.9 million, an increase of approximately 3.6 percent ($38 per year) to the annual bill of a TGI residential customer in the Lower Mainland. Further, Terasen states that the impact can be broken down as follows:

Company	Impact of 1% Equity Increase ($000)	Impact of .25% ROE Increase ($000)
TGI	$2,400	$3,100
TGVI	N/A	$800(1)

(1) Terasen notes that the revenue requirement increase for TGVI may not necessarily translate to a customer rate impact because of the soft cap mechanism.

(Source: Exhibit B-3, BCUC 3.5, 3.6)

The Intervenors take exception to the timing and amount of the increases being sought. Counsel for JIESC characterizes them as "worse than unreasonable, they are blatantly opportunistic and must be denied" (T2:23). The British Columbia Old Age Pensioners Organization *et al.* ("BCOAPO") submits that, "these increases would occur despite the Applicant…providing the exact same service quality and reliability as it currently does. In other words, it represents money for nothing." (BCOAPO Argument, para 1)

It is clear that Terasen has a significant interest in receiving the relief sought in the Application and the Intervenors have a significant stake in minimizing it.

Terasen has made the Application pursuant to sections 59 and 60 of the *Act*. Those sections are quoted in their entirety in Appendix C to this Decision.

Under section 60(1)(b) of the *Act*, when setting a rate the Commission must have due regard to the setting of a rate that:

(i) is not unjust or unreasonable within the meaning of section 59;

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands; and

(iii) encourages public utilities to increase efficiency, reduce costs, and enhance performance.

Under section 59(5) of the *Act* a rate is "unjust" or "unreasonable" if it is:

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility;

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property; and

(c) unjust and unreasonable for any other reason.

The Industrial Customer Group ("ICG") submits that the *Act* requires the Commission to balance the interests of the parties and set a just and reasonable rate that provides the utility with a fair return on the rate base. ICG submits that section 59 of the *Act* explicitly requires the Commission to consider the rates from the customer perspective, specifically whether the proposed rate is fair and reasonable for the nature and quality of the service. Part of that consideration must include the economic impact of the rate for the service on customers. The Commission's primary responsibility is to regulate rates as a surrogate for competition and to keep rates within the reasonableness one would expect in a properly functioning market. Considering the customer perspective is one-half of the balance equation in a regulated environment. When acting as the surrogate for competition, the Commission cannot and must not protect Terasen from all competitive risk by raising the ROE at the expense of customers. Doing so would ignore the interest of the customers who are captive to the monopoly. (ICG Argument, p. 5)

Terasen submits that the following quotation from page eight of the Commission's 2006 Decision on Terasen's ROE, Capital Structure and the AAM ("2006 ROE Decision") correctly sets out that the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital:

> "The Commission Panel does not accept that the reference by Martland J. to a "balancing of interests" to mean that the exercise of determining a fair return is an exercise of balancing the customers' interests in low rates, assuming no detrimental effects on the quality of service, with the shareholders' interest in a fair return. In coming to a conclusion of a fair return, the Commission does not consider the rate impacts of the revenue required to yield the fair return. Once the decision is made as to what is a fair return, the Commission has a duty to approve rates that will provide a reasonable opportunity to earn a fair return on invested capital." (Terasen Reply, para 6)

2.2 The Fair Return Standard

Terasen cites the TQM Decision, which summarizes the fair return standard at page 6:

> "The Fair Return Standard requires that a fair or reasonable overall return on capital should:
>
> - be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement);
> - enable the financial integrity of the regulated enterprise to be maintained (financial integrity requirement); and

- permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (capital attraction requirement)." (Terasen Argument, para 12)

Terasen and the Intervenors address the fair return standard from the perspectives of the return on invested capital of the utility, the return on the equity, the level of financial risk, the creditworthiness and financial integrity of the utility, and, on the premium paid over book value for TI by Fortis Inc. in 2007.

In her evidence, Ms. McShane states: "The capital structure and the return on equity are inextricably linked; the fair return on equity cannot be established without reference to the level of financial risk inherent in the capital structure adopted for regulatory purposes." (Exhibit B-1, Tab 3, p. 3)

Ms. McShane addresses the maintenance of the creditworthiness and financial integrity of the utility and opines that the capital structure of TGI, in conjunction with the returns allowed on its sources of capital, should provide the basis for a stand-alone investment grade debt ratings in the A category. Debt ratings in the A category assure that Terasen should be able to access the capital markets on reasonable terms and conditions during both robust and difficult, or weak, capital market conditions. (Exhibit B-1, Tab 3, p.26; Terasen Argument, para 101)

The Intervenors do not disagree with the A rating but observe that Terasen has enjoyed an A rating for many years. (JIESC Argument, p. 12)

JIESC points out that:

- in 2007, Fortis Inc. "purchased the TGI equity (sic) paying a premium of $900 million for it. A premium over book value upon which Terasen is not permitted to allow either a debt or equity return. This amounts to 1.7 times the equity value";
- in February 2009, a time when "debt markets were still recovering from the 2008 financial turmoil" TGI was able to issue $100 million debt; and

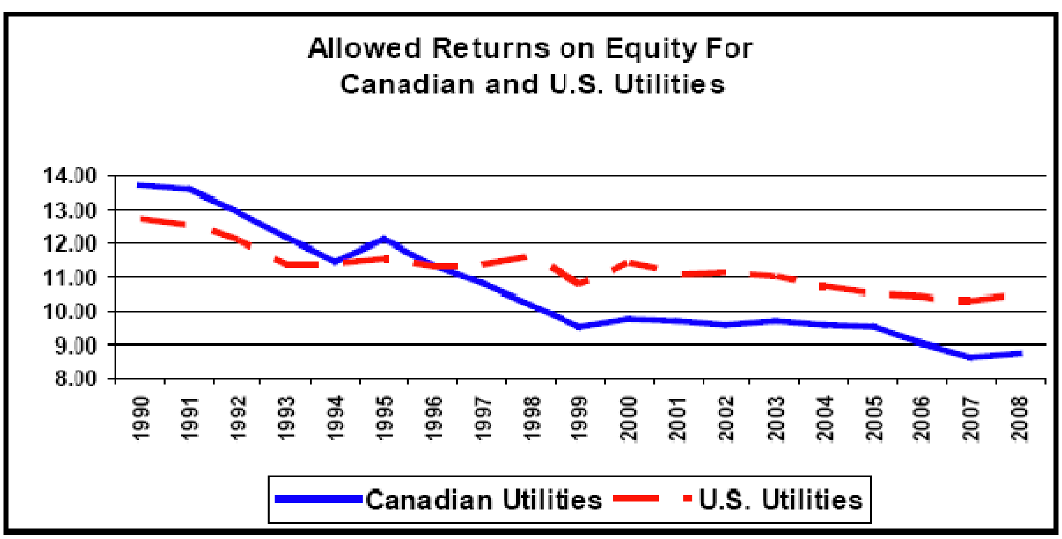
- in May 2009 TGI's bond rating was confirmed at "A" by both DBRS Limited ("DBRS") and Moody's Investors Services ("Moody's"). (JIESC Argument, p. 13)

Terasen points out that TGI's Moody's rating actually is A3 and submits that the rating is "only one notch above BBB+, which is a level at which even Dr. Booth believes TGI should not be." (Terasen Reply, para 82)

Terasen also addresses the issue of acquisition premia and refers the Commission to its 2006 ROE Decision where the Commission addressed the acquisition of TI by Kinder Morgan Inc. ("KMI") and stated at page 13: "There is no evidence before the Commission that any of the premium paid by KMI will be included in either of the Companies' rate bases and recovered from their customers. The Commission's role is to determine a suitable capital structure for the Applicants and return on equity for a benchmark low-risk utility and the KMI/TI transaction is not relevant to the Commission's determination." (Terasen Reply, para 94)

2.3 The Applicability of US Data in Determining the Fair Return Standard

Terasen provides the following chart to compare the differences between ROEs allowed to electric and natural gas utilities by state regulatory agencies in the US with the ROEs allowed by Canadian regulatory agencies:



(Exhibit B-1, p. 14)

Terasen includes two reports as appendices to the Application:

i) a report sponsored by the Ontario Energy Board ("OEB") entitled "A Comparative Analysis of Return on Equity of Natural Gas Utilities" dated June 14, 2007 and authored by Concentric Energy Advisors ("CEA") (the "CEA Report"); and

ii) a report sponsored by the Canadian Gas Association ("CGA") entitled "Allowed Return on Equity in Canada and the United States: An Economic, Financial and Institutional Analysis" authored by National Economic Research Associates, Inc ("NERA") dated February 2008 (the "NERA Report").

The CEA Report made ten conclusions, of which three are germane:

1. "(6) On the whole, there are no evident fundamental differences in the business and operating risks facing Ontario utilities as compared to those facing US companies or other provinces' utilities that would explain the difference in ROEs";

2. "(7) Other market related distinctions and resulting financial risk differences, particularly between Canada and the US, do exist. These factors, including differences in market structure, investor bases, regulatory environments, and other economic factors may have an impact on investors' return requirements for Canadian versus US utility investments. However, through analysis and interviews with key market participants, representatives of customer groups, and other individuals with past involvement in ROE proceedings in Canada and the US, these differences are determined to be negligible"; and

3. "(9) As a result of the interplay between the Canadian and US markets, Canadian utilities compete for capital essentially on the same basis as utilities in the US." (Exhibit B-1, Appendix 3)

The NERA Report concludes, in part:

> "We find that the regulatory institutions and customs for setting regulated prices for investor owned Canadian and US utilities are very alike. That is, in accounting, administrative procedures, regulatory legislation, and basic constitutional protections of private property, little or nothing separates the average Canadian from the average US regulatory jurisdictions…"

> "We examine the definition of risk to investors of placing their capital at the use of the public, for which the ROE provides compensatory payment. We look at how those risks could be different in Canada versus the US. What we find is that the basic sources of risk—regulatory, business and financial—are comparable with respect to both jurisdictions. Objective and disinterested analyses of the relative risks between Canadian and US utilities are rare, but what we have found points to no smaller risks in Canada. As such, we conclude that there is no objective evidence showing that business or regulatory risks are sufficiently lower in Canada to account for the divergences in Figure 1 [A Figure showing the Allowed Return Differential (Canada - US) for Gas Distribution Utilities in the period 1992-2007]." (Exhibit B-1, Appendix 4, Executive Summary)

Terasen filed the evidence of Mr. Donald A. Carmichael, a financial consultant and advisor, as Tab 2 to the Application. His opinion evidence addresses the integration of markets and competition for capital. Mr Carmichael states that the globalization of Canadian capital markets and the removal of various personal and institutional restrictions on foreign investment have caused the Canadian and international capital markets to become substantially more integrated than in the past, and points to the fact that:

- many of Canada's largest institutional investors have become major players on international stock markets and non-Canadian private equity situations;
- the market in Canada for the new issuance of foreign bonds and debentures has grown rapidly reflecting Canadian lenders' desire to diversify their portfolios with new issuers and to achieve higher returns than those available from domestic issuers; and
- the funding requirements for announced infrastructure projects in Canada will be significant and will directly compete with debt and equity financing for utilities. (Exhibit B-1, Tab 2, pp. 32-35)

Terasen submits that restrictions on foreign investments by Canadians have been removed and that competition for capital is not constrained by provincial or national borders. Canadian and international capital markets have become more integrated than in the past. Large amounts of capital are required for infrastructure projects in Canada and around the world. Terasen submits that TGI's capital structure and return on equity must be comparable to other companies of similar risk to allow it to successfully compete for capital. (Terasen Argument, para 19)

The NEB addressed the issue in the TQM Decision where it stated:

> "In the Board's view, global financial markets have evolved significantly since 1994. Canada has witnessed increased flows of capital and implemented tax policy changes that facilitate these flows. As a result, the Board is of the view that Canadian firms are increasingly competing for capital on a global basis.
>
> A fair return on capital should, among other things, be comparable to the return available from the application of the invested capital to other enterprises of like risk and permit incremental capital to be attracted to the regulated company on reasonable terms and conditions. TQM needs to compete for capital in the global market place. The Board has to ensure that TQM is allowed a return that enables TQM to do so. …As a result, the Board is of the view that pipeline companies operating in the U.S. have the potential to act as a useful proxy for the investment opportunities available in the global market place." (TQM Decision, pp. 66-67)

In addition, the AUC stated that it would, "review the market based return data available on the record in respect of the sample US utility proxy groups and employ this data in its CAPM [Capital Asset Pricing Model] and DCF [Discounted Cash Flow] determinations." (AUC Decision 2009-216, para 205)

Terasen submits that global competition for capital means that TGI's capital structure must be comparable to its North American peers. In Terasen's view, the TQM Decision recognizes this capital requirement, which should also be recognized by the Commission. (Terasen Argument, para 95)

In the 2006 ROE Decision the Commission addressed what it saw as the two issues of relying on US data to establish appropriate capital structures and ROEs for utilities. On the first issue (i.e. that there are opportunities for Canadian investors to commit capital globally) the Commission noted that Canadian investors faced a considerable foreign exchange risk when investing and was not convinced that the Federal Government's relaxation of foreign content rules in retirement portfolios should be a reason to increase the equity return of a benchmark low-risk utility.

On the second issue (i.e. that in measuring the risk premium it is necessary to look beyond Canadian data) the Commission stated that it was prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when those data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data give unreliable results; based on the fact that the US and Canadian economy and capital markets were closely integrated. (2006 ROE Decision, p. 50)

BCOAPO submits that "select US utilities...are not useful in determining comparable returns and comparable risk." (BCOAPO Argument, para 7)

Dr. Laurence Booth provided a written opinion of the fair return for TGI on behalf of the Intervenors. In his evidence, Dr. Booth states: "The message from these….disasters of US regulatory policy [i.e. the bankruptcy of Pacific Gas and Electric; the Enron and WorldCom frauds; the failure of US entities such as Lehman Brothers; and 'stock market disasters represented by pipelines like Duke Energy'] is that the US is not Canada, no matter what American witnesses before the Canadian regulatory tribunals seem to think. Regulation in the US has followed a different path to that in Canada, as is patently obvious to anyone who looks at its results. Drawing any insights from how investors perceive US utilities (or banks) given this different regulatory approach in my judgment is of very little value. I would strongly advise Canadian regulatory tribunals to ignore the advice of experts, who have US experience in mind when they from (sic) their judgments. Instead, they should focus on Canadian solutions that have worked rather than US solutions that have resulted in disaster." (Exhibit C11-5, p. 103)

Terasen submits that the evidence demonstrates that Dr. Booth's attempt to use Enron and WorldCom as examples of light-handed US utility regulation fails; neither Enron nor WorldCom were US utilities or utility holding companies, and Dr. Booth's citation of Enron, WorldCom, or Duke Energy fails to support the argument that the Commission should not consider US utilities in its determination of a fair return on equity. (Terasen Argument, para 352-53)

Commission Determination

In view of the fact that no party took issue with the articulation of the fair return standard by the NEB in the TQM Decision, the Commission Panel endorses it. It also agrees with Terasen that the combination of the equity ratio and the allowed return thereon should be adequate to attract capital on reasonable terms and conditions and allow TGI to maintain the A3 rating on its debt and unsecured debt from Moody's.

As for the Intervenors' submissions that this is not the time for a rate increase, and ICG's submission that the Commission must balance the requirements of customers with those of Terasen, the Commission Panel adopts the Commission's statement in the 2006 ROE Decision where it made it clear that its obligation was and is to set rates that are fair and reasonable, and to allow a utility the opportunity to earn a fair rate of return.

The Commission Panel has considered the premium paid by Fortis Inc. to acquire the equity capital of TI in 2007. As was the case with respect to the premium paid by KMI for the shares of TI discussed in the 2006 ROE Decision there is no evidence before the Commission that any of the premium paid by Fortis Inc. will be included in any of the Companies' rate bases and recovered from their customers. Further, as was the case with the KMI acquisition, the Commission imposed "ring-fencing" conditions upon Fortis Inc. The Commission Panel considers that the Commission's role is to determine an appropriate capital structure and return on equity for Terasen and that the acquisition of TI by Fortis Inc. is not relevant to the Commission Panel's determination in this regard.

As for the US data, the Commission Panel agrees with the NEB and AUC that utilities in Canada need to compete for capital in the global market place, and regulatory agencies in Canada have to ensure that utilities subject to their jurisdiction are allowed a return that enables them to do so.

In addition, the Commission Panel continues to be prepared to accept the use of historical and forecast data of US utilities when applied: as a check to Canadian data, as a substitute for Canadian data when Canadian data do not exist in significant quantity or quality, or as a supplement to Canadian data when Canadian data gives unreliable results. Given the paucity of relevant Canadian data, the Commission Panel considers that natural gas distribution companies operating in the US have the potential to act as a useful proxy in determining TGI's capital structure, ROE, and credit metrics.

Having determined what the fair return comprises and that US data may be relevant in its determination, the Commission Panel considers that there are enough data before it to bring into question whether the fair return standard is being met in TGI's case. Accordingly, in the following sections the Commission Panel examines the evidence and determines whether an increase in TGI's equity ratio is justified, following which it determines the approaches to which it will give weight in its determination of TGI's allowed ROE. The Commission Panel examines the result of these determinations to ensure that the fair return standard is met for TGI.

3.0 RISKS AND CAPITAL STRUCTURE

This Section defines risk in the utility regulatory environment, considers TGI's business risk and determines a suitable capital structure for TGI for regulatory purposes. The following issues are addressed:

- Have the business, regulatory and financial risks of TGI increased since 2005 and, if so, how should they be reflected in TGI's capital structure?
- What is TGI's appropriate capital structure?

Terasen sets out the following reasons why TGI's common equity ratio should be increased from 35.01 percent to 40 percent:

1) TGI's level of business risk has increased;
2) there have been material increases in the allowed common equity ratios of some of TGI's Canadian utility peers;
3) its credit metrics are weak for its credit ratings, and in isolation fall below investment grade guidelines;
4) its equity ratio of 35 percent, together with lower allowed ROEs and lower corporate income tax rates have caused its interest coverage ratios to be the lowest in Canada and to continue to fall;
5) rating agencies continue to view a common equity ratio of 35.01 percent as weak. At 40 percent TGI would still lie at the lower end of Moody's guideline range for an investment grade rating on this credit metric;
6) the further global integration of the Canadian capital markets warrants a strengthening of TGI's financial parameters; and
7) the forecast North American and global investment requirements for infrastructure point to significant competition for capital going forward. TGI should be positioned so that it can compete successfully. At the existing capital structure, TGI's credit metrics compare unfavourably to those of its US peers. (Exhibit B-1, Tab 3, pp. 39-40)

The assessment of risks has significant bearing on the application of the fair return standard and the determination of an appropriate common equity ratio for regulatory purposes.

3.1 The Definition of Risk in the Utility Regulatory Environment

In discussing business risk in its Argument, Terasen refers to page 17 of the 2006 ROE Decision. At that reference, the Commission defined risk as follows:

> "The Applicant and Intervenors broadly agree on the definition of risk to a benchmark low-risk utility. Investment risk comprises the sum of business risk, financial risk and regulatory risk."
>
> "Business risk is the risk that the utility will not be able to earn a return on its capital or of its capital. Dr. Booth summarized those elements that constitute business risk as:
>
>> '…stemming from uncertainty in the demand for the firm's product resulting, for example, from changes in the economy, the actions of competitors, and the possibility of product obsolescence. This demand uncertainty is compounded by the method used by the firm and the uncertainty in the firms' cost structure, caused, for example, by uncertain input costs, like those for labour or critical raw or semi-manufactured materials.' "
>
> "Financial risk is measured through the debt equity ratio of a utility."
>
> "Regulatory risks are those that might arise from regulatory lag, from disallowed operating or capital costs or from punitive awards." (2006 ROE Decision, p. 17 [references omitted]; Terasen Argument, para 23)

Terasen discusses the business risk of TGI and states that it is useful to consider short-term and long-term risks. In the short-term the focus is generally on TGI's ability to earn a fair return on its investments from year to year. In the longer term the risk relates to whether or not the utility will be able to recover the cost of its investments over their useful lives and earn a fair return on such investment over the long run. (Exhibit B-3, BCUC 14.1)

Terasen notes that business risk has both short-term and long-term aspects and that since a local distribution company's ("LDC") investments have a useful life that extends over a long period of time, it is the longer-term fundamental business risks that must be given primary consideration when evaluating the business risk of a gas distribution utility.

Ms. McShane observes that regulatory agencies in Canada have followed two separate approaches to addressing utility risk. The NEB and the AUC have adopted one approach whereby each utility subject to their jurisdiction has an individual equity ratio which is determined by its respective long and short-term business risks, to which is applied a uniform ROE. The other approach, followed by the Commission, the OEB and the *Regie de l'Energie*, is to establish the capital structure and ROE for a benchmark utility and to set capital structures and ROEs for all other utilities in their jurisdiction with reference to the benchmark. (Exhibit B-1, Tab 3, p. 21)

Commission Determination

The Commission Panel notes that no party took issue with the Commission's characterization of risk in its 2006 ROE Decision and accordingly accepts the definition for the purposes of this proceeding.

The Commission Panel accepts Terasen's characterization of its business risk as having long-term and short-term aspects and it will consider them separately in Sections 3.2 and 3.3 of this Decision.

In its 2006 ROE Decision the Commission stated: "The Commission Panel concludes that the appropriate capital structure range for consideration of TGI is in the range of 35 percent to 38 percent and that given the effect of deferral accounts in reducing the risk of TGI, the appropriate equity component for TGI is 35 percent. Given the preferred shares in the capital structure of all other Canadian gas distribution utilities, the equity component of TGI will remain the lowest in Canada for gas distribution utilities." (2006 ROE Decision, p. 36)

In this Decision, however, the Commission Panel considers the effect of deferral accounts in reducing the risk of TGI as reducing the short-term, and not the long-term, business risk of TGI, and will accordingly adjust TGI's ROE rather than its capital structure.

3.2 TGI's Long-Term Business Risk

In Tab 1 of its Application, Terasen sets out key factors that have affected TGI's business risks in recent years:

1) Provincial climate change and energy policies have increased the risk inherent to TGI's core natural gas business;
2) the effect of aboriginal rights issues on utilities in BC;
3) the competitive position of natural gas relative to electricity has been weakened;
4) TGI is capturing a smaller percentage of new construction;
5) electricity is increasingly the choice of high-density housing;
6) alternative energy sources further weaken TGI's competitive position;
7) fuel switching has also diminished demand for natural gas; and
8) the use of natural gas per (customer) account continues to decline. (Exhibit B-1, p. 24 and Tab 1)

Terasen states that the first two factors are new in that they have emerged since its last ROE application in 2005, and that the remaining key factors were identified by it as factors affecting its business risk in 2005. These risk factors are addressed below.

3.2.1 Provincial Climate Change Policies

Terasen states that the Throne Speech delivered on February 13, 2007 outlined the province's Greenhouse Gas ("GHG") reduction target. A second announcement on February 19, 2008 introduced a carbon tax in BC. These two policies and their subsequent implementation into law have increased TGI's business risk since 2005. Since the publication of, "The BC Energy Plan: A Vision for Clean Energy Leadership" ("2007 Energy Plan") in February 2007, the provincial government has taken a leadership role in the fight against climate change/global warming and, in the spring 2008 Legislative Session, introduced the following bills:

- Bill 15 – *Utilities Commission Amendment Act*;

- Bill 16 – *Greenhouse Gas Reduction (Renewable and Low Carbon Fuel Requirements) Act*;
- Bill 18 – *Greenhouse Gas Reduction (Cap and Trade) Act*;
- Bill 31 – *Greenhouse Gas Reduction (Emission Standards) Statutes Amendment Act*;
- Bill 27 – *Local Government (Green Communities) Statutes Amendment Act, 2008*; and
- Bill 37 – *Carbon Tax Act*.

Under the *Greenhouse Gas Reduction Target Act* (passed in 2007), and under Ministerial Order dated November 25, 2008, BC's GHG emission targets levels have been established as:

- 2012 6 percent below 2007 levels;
- 2016 18 percent below 2007 levels;
- 2020 33 percent below 2007 levels;
- 2050 80percent below 2007 levels. (Exhibit B-1, Tab 1, pp. 3, 5)

Terasen states that as of March 31, 2009, pursuant to a climate action charter between the Province and the Union of BC Municipalities establishing, among other things, a commitment to a goal of becoming carbon neutral by 2012, 174 local governments had become signatories. In addition the Province has set emission targets for universities, schools and hospitals.

Terasen states that TGI's risk profile has increased substantially due to the climate change challenge, the provincial GHG reduction targets, and how these targets have shaped customers' views of natural gas. In its view, there can be no doubt that these actions will have an impact on the use of natural gas, TGI's opportunities, and TGI's ability to recover its investment over the long term.

Terasen states that the BC Carbon Tax, implemented effective July 1, 2008, to help the Province reach its GHG reduction targets, reduces the competiveness of natural gas relative to alternative energy sources that are not subject to the carbon tax, and provides a direct pricing signal to customers in relation to GHG emissions. The tax started at $10/tonne of GHG and will increase by $5/tonne each year to $30/tonne by 2012. Terasen cites the BC Climate Action Team's recommendation that: "After 2012, if required to achieve the emissions targets, increase the British Columbia carbon tax in a manner that aligns with the policies of other jurisdictions and key economic facts." (Exhibit B-1, Tab 1, pp. 10-11).

A Terasen witness testified that "and there are calls...from certain academics and others that say in order for the government to get the consumption of GHGs down, it's going to have to move to $300. So, that's $15 a GJ [gigajoule], not $1.50, on top of the commodity and the delivery rates" (T2:155). $300 per tonne is also the carbon tax assumed by 2026 in the Nyboer Report discussed later in this Section (Exhibit B-11, Panel 1.1).

Terasen submits that the carbon tax reduces natural gas' competiveness relative to alternative energy sources that are not subject to the carbon tax and will help to sensitize customers to the level of GHG emissions they generate by sending them price signals. The provincial carbon tax increases the business risks of TGI. (Terasen Argument, para 52)

Terasen states that government policy that discourages consumers from using natural gas will have the effect of reducing throughput volumes on the TGI system and reducing the attachment of new customers. The recovery of fixed costs from a smaller customer base, and on lower throughput, leads to rate pressure for the remaining customers. Left unmitigated and unchecked, these effects can lead to loss of existing natural gas customers and a potential "downward spiral" in which the risk of non-recovery of invested capital increases and assets potentially become stranded.
(Exhibit B-11, Panel 1.1)

Terasen filed a report entitled, "A Technology Roadmap to Low Greenhouse Gas Emissions in the Canadian Economy: A sectoral and regional analysis," dated August 22, 2008, and prepared for the National Round Table on the Environment and the Economy by J & C Nyboer and Associates, Inc, (the "Nyboer Report") which describes itself as a "technology roadmap derived from the *Getting to 2050* deep emissions reductions pathways that simulates a 20 percent reduction in Canada's GHG emissions from 2006 levels by 2020 and a 65 percent reduction in emissions by 2050." The Nyboer Report's findings are that by 2050 virtually all residential and commercial space and water heating in BC will have migrated from natural gas to electricity. (Exhibit B-11, Panel 1.1, and Attachment 1.0)

TGI's President agreed that under this scenario TGI would be out of business by 2050, but testified "We think it's one of many (possible scenarios). Our concern is what degree of influence it seems to be having in certain circles amongst policy makers." (T3:279-80)

Terasen stated that:

> "Reports of this type to policy makers, with access by consumers, can and does shape the long-term view of policy makers and the broader community respecting a product (in this case, natural gas) and may well be influential in formulating public policy that has long-term negative impacts on the demand for that product (i.e. natural gas). The outcome identified in the Report would reduce throughput on the Terasen natural gas delivery systems, which all else equal, will increase the unit costs to the remaining natural gas customers. In the extreme, the Company could have stranded assets if the roadmap that is outlined in the Report materializes." (Exhibit B-11, Panel 1.1, p. 2)

TGI's President summed up his testimony as follows:

> "We believe that natural gas is a foundational fuel, not a transitional fuel, but we're not sure that all the necessary parties are in alignment with that. We have an absence of a continental carbon policy, we have an absence of a national one, and we've got a lot of vulcanization [balkanization] going on that ultimately needs to be and I think will be resolved. I'm just not sure how all the crumbs are going to fall from that. We're not sitting before this Panel saying the sky is falling. Let us be clear on that. Chicken Little is not in the hearing room...we're not here saying that this company is going out of business." (T3:227-28)

The Commercial Energy Consumers Association of British Columbia ("CEC") submits that the overall result of its evaluation of TGI's risk in 2009 versus 2005 is that significant new positive reductions of risk are now in sight, whereas in 2005 these did not exist. Offsetting this are the new provincial GHG reduction policies which would potentially limit any throughput growth for the utility.

CEC considers the net balance of these overall results to be the key focus of determining if the business risk has changed sufficiently enough to warrant a change to either the allowed ROE or the equity ratio. CEC's assessment of the evidence is: i) that TGI's business risk has not increased appreciably enough to warrant a change to allowed ROE or its equity ratio, and ii) that the Province's GHG policies are so new, and Terasen's analysis and mitigation response are so limited at this time, that Terasen has not established a persuasive case for increased business risk.

CEC submits that it would be premature for the Commission to make assumptions that the business risk surrounding TGI's inability to recover its investment capital has increased until the Commission has one or more scenario projections in evidence which lay out how the targeted reductions might unfold for Terasen and its customers. (CEC Argument, p. 15)

ICG submits that Provincial climate change and energy policies do not necessarily increase TGI's business risks as Provincial energy conservation measures affect throughput, but Terasen's profits are not dependent on volume. ICG characterizes Terasen's concerns about carbon tax impacts after 2012 as "purely speculative," and submits that: "[i]t is premature for Terasen to assume the worst, and seek to impose additional economic burden on its customers that cannot be supported by the current circumstances." (ICG Argument, p. 8)

JIESC submits that "these alleged "risks" (i.e. climate change and First Nations) must be considered in the context of their likely impact on Terasen's capability to earn a return on and a return of, its capital." To the extent there are increased risks arising out of GHGs or First Nation issues, JIESC submits that these risks are "more than offset by the improvements in the competitive position of natural gas in comparison to electricity." (JIESC Argument, p. 20)

Terasen submits that such submissions "should be seen for what they are, and that is an attempt to distract the Commission from addressing the evidence before it," and that the evidence establishes, as even CEC acknowledges, that government policies and legislation have created uncertainty and will have long-term impacts on Terasen's natural gas distribution business. (Terasen Reply, para 28)

3.2.2 First Nations

Terasen submits that the lack of certainty of the nature and extent of aboriginal rights and title in BC together with the lack of treaties combine to create operational and regulatory complexity, and a risk of litigation, that: i) are greater than those faced by similar businesses in other jurisdictions, and ii) contribute to TGI facing a higher degree of risk than utility operations in other provinces. (Exhibit B-1, p. 14)

The Intervenors characterize First Nations' risk to Terasen as "minimal" (JIESC Argument, p. 26) and of "little impact." (BCOAPO Argument, para 29)

In Reply, Terasen submits that the primary issue in respect of First Nations risks is the increase in these risks since 2005, and none of the Intervenors suggested that there has been no increase in this risk in the past five years. (Terasen Reply, para 76)

3.2.3 Other Key Factors

As for the other key factors, Terasen submits that natural gas' competitive position relative to electricity has been weakened, that TGI is capturing a smaller percentage of new construction; electricity is increasingly the choice of high-density housing; alternative energy sources further weaken TGI's competitive position; that fuel switching has also diminished demand for natural gas; and that the use of gas per account continues to decline. Terasen states that many factors have been exacerbated by the uncertainty created by the provincial climate change initiatives and the introduction of the carbon tax.

BCOAPO rejects Terasen's claim that TGI's competitive position relative to electricity in BC has decreased since 2005 and submits that the exact opposite is true, citing the introduction by BC Hydro of the Residential Inclining Block rate as having actually made natural gas more competitive relative to electricity, especially for single family dwellings. BCOAPO submits that "the alleged threat" faced by Terasen due to government policies taken as a whole is not 'profound' and has not materially increased Terasen's business risk such that their common equity ratio should be changed. (BCOAPO Argument, para 19, 20)

ICG submits that the competitive position of natural gas relative to electricity has not been weakened, and that "at the very least, Terasen is currently maintaining its competitive position with BC Hydro." (ICG Argument, p. 8)

Terasen submits that future electricity prices are uncertain due to the extent of, and cost of, resource additions and other factors, but "what is known is that BC Hydro does have major, historic low-cost, hydro-electric resources...and due to the size of those resources, relatively low electric prices will continue long into the future. On the other side of the cost comparison between the cost of natural gas and electricity to consumers is the commodity price of natural gas. It appears to be common ground between the Terasen Utilities and Intervenors that natural gas commodity prices are volatile." (Terasen Reply, para 48-49)

Terasen also submits that the submissions of the Intervenors would have the Commission believe that if the annual cost of natural gas to the consumer is less than the annual cost of electricity then TGI does not have an increase in business risk from 2005. Terasen further submits that by focusing on cost comparisons the Intervenors' submissions fail to take into account the uncertainty and business risks associated with non-cost factors such as public perception and changes in behaviour that are required by government regulation. According to Terasen: "There can be no doubt that the mantras of provincial government energy policy are the promotion of 'clean' forms of energy, such as 'clean electricity,' and the reduction in GHG emissions." (Terasen Reply, para 57)

3.3 TGI's Short-Term Business Risk

Terasen provides a comparison of TGI's earned ROE with its allowed ROE for the years 1992-2008. In the 15 years since the introduction of the AAM in 1994 the comparison shows that it has earned more than its allowed ROE in 13 years and earned less in two years. TGI's allowed and achieved

ROEs for the years 2004-2009 are set out in the table below. In these years, TGI has been operating under a performance based regulation regime under which it shares any over-achievements with its customers. (Exhibit B-6, BCUC 91.1)

Year	Allowed ROE (%)	Achieved ROE (%) Pre-sharing	Achieved ROE (%) Post-sharing	Incentives Earned ($000)
2004	9.15	9.344	9.247	1,179
2005	9.03	10.784	9.907	6,969
2006	8.80	10.472	9.636	7,147
2007	8.37	10.729	9.550	10,018
2008	8.62	10.637	9.628	8,726

(Source: Exhibit B-6, BCUC 91.1)

Terasen states that in July 2003 TGI received Commission approval of a negotiated settlement for a 2004-2007 Performance Based Review ("PBR") which established a process for determining its delivery charges and incentive mechanisms for improved operating efficiencies and included incentives for it to operate more efficiently through the sharing of the benefits between it and its customers.

The PBR Settlement included ten service quality measures designed to ensure TGI maintained adequate service levels and set out the requirements for an annual review process between TGI and interested parties regarding its current performance and future activities. The PBR Settlement provided for a 50/50 sharing mechanism of earnings above or below the allowed return on equity beginning in 2004.

Terasen states that in 2007 TGI applied to extend the 2004-2007 PBR Settlement agreement to 2008-2009, which the Commission approved (Exhibit B-3, Attachment 39.1), and that with the expiry of PBR and related incentive earnings, it becomes more important that the Commission ensure that TGI's investors are afforded a fair return. (Exhibit B-3, BCUC 39.2)

TGI's short-term business risk and its ability to earn a return on its capital in the short-term is affected by the Commission's approval of a number of deferral accounts which permit TGI to defer variances relating to gas commodity costs, the effect of weather, variations in residential and commercial customer usage and certain expense categories such as property taxes and short-term interest rates.

TGI provided the following table showing the dollar value and percentage of its 2009 total revenue requirement and its 2009 delivery margin revenue requirement covered by deferral accounts:

	Revenue Requirement		Revenue Requirement Covered by Deferred Charges			Revenue Requirement Not Covered by Deferred Charges	
Revenue Requirement Item	$000's	% of Total	% Covered by Deferred Charges	($000's)	% of Total Revenue Requirement	($000's)	% of Total Revenue Requirement
Cost of Gas	$ 1,187,999	70.3%	100.0%	$ 1,187,999	70.3%	$ -	0.0%
Operation & Maintenance Expenses	174,942	10.4%	4.9%	8,570	0.5%	166,372	9.9%
Property and Sundry Taxes	47,593	2.8%	100.0%	47,593	2.8%	-	0.0%
Depreciation and Amortization	89,685	5.3%	0.0%	-	0.0%	89,685	5.3%
Other Operating Revenue	(23,444)	-1.4%	4.3%	(1,000)	-0.1%	(22,444)	-1.3%
Income Taxes *	26,331	1.6%	0.0%	-	0.0%	26,331	1.6%
Interest	110,953	6.6%	94.4%	104,691	6.2%	6,262	0.4%
Equity Earned Return	75,360	4.5%	0.0%	-	0.0%	75,360	4.5%
Total Revenue Requirement	**1,689,419**	**100.0%**		**1,347,853**	**79.8%**	**341,566**	**20.2%**
Total Delivery Margin Revenue Requirement	**501,420**	**100.0%**		**159,854**	**31.9%**	**341,566**	**68.1%**

* Since deferral accounts are maintained on a net-of-tax basis, to the extent any amounts were charged to or credited to deferral accounts, there would be an offsetting income tax impact

(Exhibit B-3, BCUC 88.2)

Terasen submits that TGI's deferral accounts have changed little since 2005, and points to the Commission's finding relating to TGI's gas commodity costs deferral accounts at page 25 of the 2006 ROE Decision that, "the vast majority of gas distribution companies in North America have some form of commodity deferral account, and that this protects both the utility from commodity risk and the customers from imprudent purchasing and from the utilities profiting from the purchase, transportation and storage of gas."

In the 2006 ROE Decision, the Commission also observed that for many of the other costs that have deferral account treatment, "that TGI is not penalized for underestimating or rewarded for overestimating a cost over which it has little or no control." Terasen submits that this observation of the Commission remains valid.

Terasen also cites the Commission's discussion of TGI's Revenue Stabilization Adjustment Mechanism ("RSAM") deferral account in the 2006 ROE Decision, where it referred to two facets of the account, the first as a weather normalization account, and the second to enable TGI to defer margin variances arising from residential and commercial customers consuming more or less gas than forecast. As for weather normalization, the Commission was of the view that TGI was similar to a number of utilities in North America that can defer the effects of temperature on usage. Since weather is a symmetrical risk, with equal odds of over and underachieving, the Commission determined that it should not be taken into account when establishing return on equity.

The Commission considered the second facet of the RSAM to be a short-term business risk mitigant, which was not available to TGI's comparators.

Terasen points out that the RSAM does not mitigate the risk associated with TGI's forecast customer additions, as it only relates to use per account, and submits that with regard to the statement that margin variance accounts are not available to other utilities, that an increasing number of other utilities both in Canada and the US now have decoupling protection, which is required to ensure that a utility is not deterred from or economically disadvantaged by undertaking energy conservation programs. In those instances where per customer usage varies from forecast because incorrect values were accepted by the regulator, Terasen submits that the values would have been accepted with no symmetrical bias. Accordingly Terasen submits that neither facet of the RSAM should be taken into account when determining return on equity, and that the RSAM should not be taken into account in considering the long-term business risks of TGI. (Terasen Argument, para 46)

3.4 Capital Structure

All three of Terasen's expert witnesses commented on the equity ratio of TGI and compared it with major natural gas LDCs in Canada, utilities in Ontario, and US utilities.

Terasen sets out the equity ratios of the other major natural gas LDCs in Canada as follows:

Company	**Equity Ratio (%)**
TGI	35.01
ATCO Gas[1]	38.00
Union Gas	36.00
Enbridge Gas (“EGDI”)	36.00
Gaz Metro	38.50

(1)ATCO Gas’ equity ratio was increased to 39 percent by AUC Decision 2009-216.

(Source: Exhibit B-1, p. 13)

Ms. McShane also observes that ATCO Gas, Union Gas and EGDI all have preferred shares in their capital structures, whereas TGI does not, and that since 2005, the NEB has approved increases in the equity ratios of a number of gas pipelines it regulates. (Exhibit B-1, Tab 3, pp. 32-33)

Ms. McShane testified that TransCanada’s increase of equity ratio to 40 percent was a result of a negotiated settlement and that she was not aware of what was traded off in return for the increase. She acknowledged that she was not aware of any regulatory agency putting weight on the equity ratios that come out of negotiated settlements. (T4:475-77)

Mr. Carmichael recommends that the Commission increase TGI’s deemed equity base to at least 40 percent to achieve an appropriate stand alone financing structure. According to Mr. Carmichael, such an increase would be consistent with decisions in other Canadian regulatory jurisdictions, and primarily in Ontario, which has chosen to increase the common equity bases of i) natural gas LDCs to 36 percent for Union Gas and EGDI (in addition to their preferred shares) and ii) electric LDCs to 40 percent for Toronto Hydro and other major LDCs. The increase would also recognize that TGI must compete for debt and equity funds against thicker equity capitalized gas distribution companies from the US. (Exhibit B-1, Tab 2, p. 50)

Dr. James H. Vander Weide was retained by Terasen to: i) assess the validity of the AAM, ii) conduct an analysis of the cost of equity for TGI, and iii) recommend an appropriately fair ROE and deemed equity ratio for TGI. In his filed evidence he states that during the period 2006-08 the average approved equity ratio for US electric utilities, and for US natural gas utilities, was 48 percent and 49 percent, respectively, and that these were significantly higher than the approved equity ratio for TGI. (Exhibit B-1, Tab 4, p. 35)

JIESC submits that the only relevant changes in common equity ratios are the changes for Union Gas and EGDI, whose common equity ratios have both increased from 35 percent to 36 percent since 2005 (with the increase in Union Gas's common equity ratio being, "the result of a negotiated settlement under which presumably the interveners received value"). Since it considers TGI to be less risky than these utilities, it submits that TGI should continue to have a lower equity ratio. (JIESC Argument, p. 29)

In Reply, Terasen submits that Union Gas and EGDI have less business risk in that electric prices in the service areas of Union Gas and EGDI are higher than BC Hydro prices, and in that neither Union Gas nor EGDI are subject to government policies and legislation similar to the energy-related policies of the BC provincial government. Terasen submits that the risks of TGI are greater than those of both Union Gas and EGDI. (Terasen Reply, para 84)

3.5 Credit Ratings and Metrics

Terasen states that TGI's debt is currently rated by all three major debt rating agencies, Moody's, DBRS, and Standard & Poor's (on an unsolicited basis only), and that Moody's debt rating of A3 for TGI's senior unsecured debentures is the lowest rating of the three agencies and is only one level above the Baa rating category. Since it believes that bond investors are more likely to focus on the lowest rating, TGI focuses on Moody's ratings and guidelines. (Exhibit B-1, Tab 3, p. 33)

Terasen filed a Moody's report entitled *"Rating Methodology: North American Regulated Gas Distribution Industry (Local Distribution Companies),"* dated October 2006 which covers 30 gas utilities in North America (Canada and the United States). (Exhibit B-6, BCUC Attachment 111.1, p. 1)

Moody's states that the focus of its rating methodology is on the "pure" gas LDCs in North America and is concerned principally with operating utilities regulated by their local jurisdictions and not with gas utilities owned by parent holding companies that have other non-regulated businesses. TGI is the only Canadian utility included in the report, which focuses on the following core rating factors:

- sustainable profitability;
- regulatory support;
- ring fencing; and
- financial strength and flexibility.

In addition, the report analyzes factors that are common across all industries such as liquidity, corporate governance, event risk, and legal structure.

The report describes the methodology used to rate a gas utility company which focuses on the following factors and gives them the following weights:

- Sustainable Profitability
  - Return on Equity (15 percent)
  - EBIT [Earnings before Income Taxes] to Customer Base (5 percent)
- Regulatory Support
  - Regulatory Support and Relationship (10 percent)
- Ring Fencing
  - Ring Fencing (10 percent)

- Financial Strength and Flexibility
  EBIT/Interest (15 percent)
  Retained Cash Flow/Debt (15 percent)
  Debt to Book Capitalization (excluding goodwill) (15 percent)
  Free Cash Flow/Funds from Operations (15 percent).

The following table sets out TGI's ratings by Moody's and where on the "factor mapping" the ratings place TGI:

Category	**Metric/Comment**	**Indicated Rating**
Return on Equity	9%-14%	A
EBIT to Customer Base	>$350/customer	Aaa
Regulatory Support and Relationship	"Very good, proactive support"	Aa
Ring Fencing	"Very good provisions"	Aa
EBIT/Interest	1 – 2x	Ba
Retained Cash Flow/Debt	5 – 10%	Ba
Debt to Book Capitalization	65 – 85%	Ba
Free Cash Flow/Funds from Operations	(15%) – (30%)	A

The report notes with respect to TGI that: "Notwithstanding TGI's relatively low risk business profile, its financial profile is considered weak at the A3, senior unsecured rating level. Accordingly, further sustained weakening of TGI's financial metrics, for instance ROE below 8 percent, EBIT/Interest below 2x, RCF [Retained Cash Flow]/Debt below 5 percent and/or Debt/Book Capitalization (excluding goodwill) above 65 percent, would likely lead to a downgrade of TGI's rating." The report concludes that TGI's model rating would be a Baa1.

In its May 2009 report affirming TGI's A3 rating, Moody's cautions:

> "However, in the context of the current low interest rate environment and weaker economy, Moody's is becoming concerned that TGI's credit metrics could deteriorate to levels that, despite the relative supportiveness of TGI's regulatory environment, are not commensurate with the company's existing A3 senior unsecured rating and therefore could lead to a negative rating action...Moody's will be following the progress of TGI's cost of capital application and its pending application for 2010 rates to determine their impact on TGI's financial profile." (Exhibit B-3, BCUC 1.86.2)

Terasen states that a credit rating downgrade below the A rating category could lead to TGI being required to post letters of credit with its counterparties, which would incur a direct cost in the form of letter of credit fees. In addition, and of more concern, would be the potential restriction this could place on TGI's commodity hedging activities, which can extend out three years, and where given the volatility in gas prices, the mark to market exposure on a derivative can vary significantly. When TGI enters into financial hedges, it restricts its activities to A or higher rated counterparties, and, with a B rating, could face similar restrictions and be constrained in pursuing its hedging activity, to the potential detriment of its customers. (Exhibit B-1, p. 37)

The impact of a downgrade by Moody's is also considered by Ms. McShane who opines that a downgrade increases the cost of the new debt, but also affects outstanding debt. An increase in the cost of debt to a utility increases the required yield on the outstanding debt and reduces the value of that debt. Since existing holders are the most likely purchasers of future issues, a debt rating downgrade, with resulting negative impact on the value of their existing holdings, would likely make them less willing to purchase future issues.
(Exhibit B-1, Tab 3, p. 27)

JIESC submits that TGI's consistent "A" bond ratings are due to the regulatory regime and the constancy of TGI's earnings and do not appear to be in jeopardy. The JIESC submits that if the Commission does conclude that TGI's "A" rating is in jeopardy, it should "pick a low cost alternative to protect it, like the issuance of preferred shares rather than increase the equity ratio." JIESC also points out that while TGI may appear to have weak credit metrics in comparison to US utilities, it has a higher bond rating than most US utilities and submits that the credit rating which looks at utilities' total risk profile is more important than credit metrics, which represent one item assessed in determining the bond rating. (JIESC Argument, pp. 29-30)

In Reply, Terasen submits that preferred shares are inefficient, and not the appropriate means of addressing credit rating metrics, since: i) Moody's views such preferred shares more as debt instruments, and therefore the issuance of preferred shares would not address concerns with credit rating metrics, and ii) the dividends on preferred shares are not tax deductible, on a debt equivalent basis, the debt component is an expensive form of debt. (Terasen Reply, para 83)

3.6 Interest Coverage Ratios

Terasen states that TGI currently has one of the weaker credit metrics of the sample Canadian utilities, and is lower than the group average. Terasen compares TGI's interest coverage ratio with those of its Canadian peers as follows:

Utility	**2005**	**2006**	**2007**	**2008**
EGDI	2.29	1.80	2.24	2.27
Gaz Metro	2.65	2.45	2.30	2.21
Union	2.09	1.91	2.24	2.28
TGI	1.94	2.00	1.95	1.96

(Source: Exhibit B-1, Table 7.4, p. 40)

Terasen states that TGI's trust indenture provides that TGI will not issue debentures or other debt instruments other than Purchase Money Mortgages ("PMM") maturing 18 months or more after date of issue unless consolidated available net earnings are at least two times the annual interest requirements on all additional obligations (including the additional debt to be issued).

Terasen states that TGI has outstanding PMMs totalling approximately $275 million, which fall due in 2015/16 and that, while a determination has not been made, it is currently of the view that it may not be able to reissue the PMM's on maturity with the result that they will be refinanced with unsecured debentures. Since the PMM's are not subject to the issuance coverage test, while the unsecured debentures that refinance them would be, Terasen states that the refinancing of its PMM's on their maturity will lead to further constraints on the issuance coverage test.

Terasen provides Exhibit B-28, which discusses the coverage test and attaches a table which demonstrates that at 35 percent equity and an 8.43 percent ROE it would have difficulty in issuing $100 million of unsecured debt in 2009. (Exhibit B-28)

Commission Determination

Based on the Commission's assessment of TGI's long-term business risk in its 2006 ROE Decision, the fact that TGI has no preferred shares in its capital structure, and a comparison with the other major natural gas LDCs in Canada, the Commission Panel considers that the equity ratio of TGI, remains in the range of 35 percent to 38 percent before considering the impact of any change in TGI's long-term business risk that has occurred since 2005.

The Commission Panel agrees with the Intervenors that all risks cited by Terasen existed in 2005 with the exception of the climate change related risks and those related to First Nations.

As for the existing risks, the Commission Panel does not see how TGI's ability to earn a return on or of its capital has been adversely affected since 2005. Although all Intervenors identify the competitive position of natural gas compared with electricity as one risk which has diminished since 2005, the Commission Panel considers that natural gas' competitive edge over electricity is dependent on too many significant variables, such as the level of the carbon tax, the volatility of natural gas prices and the impact of government policy on BC Hydro's rates, to be considered permanent.

As for concerns about the risks posed by First Nations, the Commission Panel agrees with Terasen that the risks did not exist in 2005, to the extent they are currently perceived, and that they constitute an increase in risk over natural gas LDCs operating in other provinces. The Commission Panel does not consider that the risks presently cast doubt over TGI's ability to earn a return on or of its capital.

The Commission Panel agrees with Terasen that the introduction of climate change legislation by the provincial government has created a level of uncertainty that did not exist in 2005 and that the change in government policy will quite probably cause potential customers not to opt for natural gas and persuade potential retrofitters to opt for electricity. In addition, the Commission Panel considers that the Nyboer Report presents a scenario that did not exist in 2005 under which the three Terasen utilities might not earn a return of their capital. The scenario that now exists is described in a publication of a reputable consulting group which appears to have the attention of policymakers.

As for the evidence that US natural gas LDCs have thicker equity ratios than their Canadian counterparts, the Commission Panel notes that no reasons for the difference were entered into evidence. The Commission Panel concludes that the difference between US and Canadian natural gas LDCs' equity ratios is not of itself determinative.

The Commission Panel considers that TGI's business risk has increased since 2005. In the Commission Panel's opinion the additional risk suggests an equity ratio for TGI of 40 percent. **Accordingly, the Commission Panel determines that the appropriate equity ratio for TGI is 40 percent effective January 1, 2010.**

As it did in its 2006 ROE Decision, the Commission Panel requires TGI to file within 30 days of this Decision a document setting out how and when it will implement this change to its capital structure in compliance with the ring-fencing conditions approved by the Commission in its Order G-49-07.

4.0 THE APPROPRIATE RETURN ON EQUITY FOR TGI

The issue that is addressed in this Section is: Given TGI's capital structure, what is the appropriate ROE for TGI and what approaches to its determination should the Commission Panel give weight?

There are several approaches used to determine ROE, none of which is universally preferred. Therefore, in order to determine the appropriate ROE for TGI, the Commission Panel must first review the main approaches for determining an appropriate ROE and decide how much weight to accord the results from each.

The approaches are reviewed in Section 4.1, below. Once they have been reviewed and the Commission Panel has determined how much weight to give to each, it then reviews, in Section 4.2, the results from each of the approaches as calculated by the various experts, to determine the appropriate ROE for TGI.

4.1 The Approaches used to Determine ROE

Terasen identifies three approaches used to determine ROE:

1) Discounted cash flow ("DCF");
2) Equity risk premium ("ERP");and
3) Comparable earnings ("CE").

Ms. Mc Shane states that: "Each of the tests is based on different premises and brings a different perspective to the fair return on equity. None of the individual tests is, on its own, a sufficient means of estimating the fair return; each of the tests has its own strengths and weaknesses. Individually, each of the tests can be characterized as a relatively inexact instrument; no single test can pinpoint the fair return." (Exhibit B-1, Tab 3, p. 42)

4.1.1 Discounted cash flow approach

Terasen submits that the discounted cash flow approach for the determination of the return on equity of regulated utilities is an approach that has been widely accepted, and widely used for many years, even though in recent years the use of the DCF approach by Canadian regulatory agencies has been limited. Terasen cites an article by Dr. Makholm from ***Public Utilities Fortnightly*** dated May 15, 2003 entitled, "In Defence of the Gold Standard," where Dr. Makholm stated that, "the DCF method has endured [in the US] for most of the past two decades for three basic reasons:

- It rests on a solid, straightforward theoretical base;
- It capitalizes on the depth of U.S. capital markets-meaning analysis can use "proxy groups" of publicly traded companies in the same industry to manage the variability of individual company DCF calculations; and
- It makes use of company growth projections from disinterested industry analysts-a key attribute for a method to gauge the opportunity cost of capital in the mind of investors." (Exhibit B-20)

Dr. Booth states that, "…the DCF estimate is particularly appropriate for use in determining the fair rate of return for a regulated utility." (Exhibit C11-5, Appendix C, p. 4)

JIESC submits that, "By comparison [with the Capital Asset Pricing Model ("CAPM")] DCF and comparable earnings are black boxes with numerous judgements and are much less constrained by the facts." (JIESC Argument, p. 2)

JIESC points out that the DCF approach has not been accepted by a Canadian regulator in the last 10 years. In addition it points out that Ms. McShane's discounted cash flow test uses a sample of US gas and electricity utilities and relies on *Value Line* and Thomson Reuters I/B/E/S ("I/B/E/S") forecasts for estimating earnings growth. The JIESC submits that "this [reliance] still suffers from the strong possibility of upward bias and should be subject to considerable caution before being used." (JIESC Argument, p. 39)

Terasen replies that there is no suggestion that *Value Line* forecasts suffer from upward bias, and that Dr. Vander Weide testified that studies that have purported to show upward bias have statistical errors.

Terasen takes issue with the characterization of the DCF and CE tests by JIESC as "black boxes" and submits that the criteria used by Ms. McShane in selecting companies of comparable risk are objective and explicit, and focus on characteristics to ensure comparability. The way the returns are measured in both the DCF and comparable earnings approaches are transparent, and the tests, in contrast to the CAPM, are compatible with meeting the comparable returns requirement. (Terasen Reply, para 104)

4.1.2 Equity Risk Premium Approach

Terasen submits that the equity risk premium test is derived from the concept that there is a direct relationship between the level of risk assumed and the return required. Since an investor in common equity takes greater risk than an investor in bonds the equity investor requires a premium above bond yields in compensation for the greater risk.

Terasen states that the Capital Asset Pricing Model ("CAPM") is one of the equity risk premium models, and is the most common, but not the only one. CAPM is based on a portfolio investment theory and relies on the premise that an investor requires compensation for non-diversifiable risks only. Non-diversifiable risks are those risks that are related to overall market factors (e.g., interest rate changes, economic growth), while company-specific risks, according to CAPM, can be diversified away by investing in a portfolio of securities; therefore, the investor requires no compensation to bear those risks. (Terasen Argument, para 296)

Under the CAPM approach, ROE is calculated using the following formula:

ROE = Risk-Free Rate + {Relative Risk Adjustment x Market Risk Premium}

In CAPM, risk is measured using the relative risk adjustment, known as beta. Theoretically, the beta is a forward looking estimate of the contribution of a particular stock to the overall risk of a portfolio. In practice, the beta is a calculation of the historical correlation between the overall equity market returns, as proxied in Canada by the returns on S&P/TSX Composite Index, and the returns on individual stocks or portfolios of stocks. (Exhibit B-1, Tab 3, p. 45)

Ms. McShane states that the "raw" betas for publicly-traded Canadian regulated gas and electric companies, the TSE Gas/Electric Index, and the S&P/TSX Utilities Sector declined significantly in the periods between 1993 and 1998 and between 1999 and 2005, and that following an increase in 2007 to 0.50, the utility betas again declined in 2008 to approximately 0.25. These "raw" betas of approximately 0.25 for Canadian utilities provide virtually no explanatory power in terms of capturing utility investors' return expectations. While that is clear, the more difficult task is to determine if and how the "raw" beta values can be translated into a relative risk adjustment that does provide an indication of the return requirements of utility investors. In order to arrive at a reasonable relative risk adjustment, the normative ("what should happen") CAPM needs to be integrated with what has been empirically observed ("what does or has happened").

Ms. McShane states that the practice of adjusting betas toward the equity market beta of 1.0, rather than the calculated "raw" betas, takes account of the observed tendency of stocks with low betas to achieve higher returns than predicted by the simple CAPM and vice-versa. Adjusted betas are a standard means of estimating betas, and are widely disseminated to investors by investment research firms, including Bloomberg, *Value Line* and Merrill Lynch. All three of these firms use a similar methodology to adjust "raw" betas toward the equity market beta of 1.0 and give approximately 2/3 weight to the calculated "raw" beta and 1/3 weight to the equity market beta of 1.0. (Exhibit B-1, Tab 3, p. 56)

Terasen contends that if beta is to be considered a reasonable measure of risk, then the use of the traditional estimate of beta in the CAPM should produce a reasonable estimate of a utility's cost of equity. It calculates that applying conventionally estimated betas for Canadian utilities using the last five years of data in the range 0.25 to 0.30 to a 5-6 percent risk premium on the Canadian market index yields a utility risk premium of 1.5 percent to 1.8 percent. Adding this utility risk premium to the May 2009 forecast yield on long Canada bonds of 3.69 percent produces a cost of equity in the range 5.19 percent to 5.49 percent. Since this result is “absurdly low” in comparison to current yields on utility bonds, Terasen concludes either that: (1) betas as traditionally measured do not correctly measure the risk of utility stocks; or (2) the CAPM does not apply to the Canadian marketplace. (Exhibit B-3, BCUC 14.5.1)

Ms. McShane calculates the “raw” beta for PNG Ltd. (“PNG”) to be 0.26 for 2008 (Exhibit B-1, Tab 3, Schedule 11). Dr. Booth testified that PNG was “the riskiest Canadian utility” (T5:603).

JIESC addresses adjustment to beta, noting that Dr. Booth concluded that it is unreasonable to just use the statistical estimate without recognising the underlying events that caused it, and then to make the appropriate adjustments. JIESC submits that Ms. McShane confirmed that no regulatory agency in Canada has accepted adjusted betas and that in the TQM Decision the NEB specifically rejected adjusted betas. (JIESC Argument, p. 37)

Terasen submits that an ROE based on CAPM fails to meet the Commission’s obligation to provide Terasen with the opportunity to earn a fair return on its investment in utility assets in that the CAPM methodology does not, and is not intended to, relate to the business risk associated with an investment in utility assets. Rather, it relates to how the investment in one asset (usually a security) affects the overall riskiness of a basket (or portfolio) of investments. CAPM assumes that an investor has a diversified portfolio of investments and that risk is measured only by reference to the impact that a specific investment has on the overall diversified portfolio; CAPM is not attempting to measure the business risk of a utility or other company. (Terasen Argument, para 146)

The May 2003 article from *Public Utilities Fortnightly* cited above states that:

> “CAPM, by comparison, is abstruse as a piece of theory. Further, because most of the components of the calculation are common to all companies (i.e., the risk-free rate and the market risk premium), the CAPM cannot make use of the law of large

> numbers. That is to say, the problems associated with which risk-free rate to pick, or which market risk premium to adopt, hinder the result, no matter how many companies the calculation are performed upon. Finally, the CAPM has no tie to disinterested company analysts that not only reflect, but also shape, the opinions of investors. It is thus no surprise that the CAPM is vastly less popular among US regulatory commissions as a rate of return method." (Exhibit B-20)

JIESC points to page 35 of Dr. Booth's evidence where he states that CAPM is, "overwhelmingly the most important model used by a company in estimating their cost of equity capital," and cites a 2001 survey of 392 US chief financial officers ("CFOs") in the Journal of Financial Economics. Dr. Booth points out that 70 percent of the US CFOs use CAPM and a further 30 percent use a multi-beta approach similar to his two factor model to measure their own cost of equity. (JIESC Argument, pp. 33, 34)

4.1.3 Comparable Earnings Approach

Terasen states that the comparable earnings approach calculates the achieved earnings returns of a sample of low-risk competitive unregulated Canadian firms over a business cycle.

The comparable earnings test is the only test that explicitly recognizes that, in the North American regulatory framework, the return is applied to an original cost (book value) rate base. The concept that regulation is a surrogate for competition means that the combination of an original cost rate base and a fair return should result in a value to investors commensurate with that of competitive ventures of similar risk.

JIESC cites six basic reasons why Dr. Booth does not use a comparable earned rate of return or comparable earnings approach:

- it is an average not a marginal rate of return;
- it is an accounting rate of return not an economic rate of return;
- it may include the impact of market power;
- it is based on non-inflation adjusted numbers;

- it is earned on historic accounting book equity that does not reflect what can be earned on investments today; and
- it varies with the firms selected in the "comparable earnings" sample.

In addition, the JIESC submits that no regulatory board or commission in Canada has given support to the comparable earnings approach in recent years and that the Alberta Energy and Utilities Board ("AEUB") very explicitly rejected its use in its 2004 Generic Cost of Capital Decision (2004-052). (JIESC Argument, pp. 40-41)

At the Oral Phase of Argument, JIESC noted that the AUC had confirmed the AEUB's 2004 finding about CE at paragraph 281 of AUC Decision 2009-216. (T6:774)

Terasen points out that in his evidence, Dr. Booth, as he had in 2005, agreed in that some of his problems with the CE test also appear in the process of setting rates under regulation, notably that both use an accounting rate of return; it is an average, not a marginal, return; it is based on historic book equity; and based on non inflation-adjusted numbers. (Terasen Argument, para 330)

Terasen submits that the *Act* requires the Commission, "to provide a fair return to the utility and what the utility invests in its infrastructure. It's a fair return to the utility. The *Act* doesn't say it has to be a fair return to the investors in the utility" and notes that the Alberta board rejected CE, "because they said it didn't deal with returns available to investors," which is not the case in BC. (T6:807)

Commission Determination

The Commission Panel has considered the three approaches to determining ROE for a regulated utility and agrees with Terasen that it should take all three into account when establishing an ROE. The Commission Panel agrees that the DCF and ERP are the most common approaches used by regulatory agencies in the US and that CAPM has been widely used in Canada in the period since 1994. The Commission Panel has seen no evidence that suggests: i) it should ignore the fact that the Commission gave the DCF approach weight in the 2006 ROE Decision, or ii) that would persuade it to depart from the Commission's finding in that decision that the CE methodology had not outlived its usefulness when it commented: "However, the Commission Panel is not convinced that the CE methodology has outlived its usefulness, and believes that it may yet play a role in future ROE hearings."

As for the two most commonly used approaches, the Commission Panel finds that the DCF approach has the more appeal in that it is based on a sound theoretical base, it is forward looking and can be utility specific. The Commission Panel has considered the submission of the JIESC concerning "upward bias" of analysts' estimates and considers that no allegations of upward bias have been levelled against utility analysts and that *Value Line* estimates will be free from any suggestion of upward bias. Accordingly the Commission Panel will not give any weight to suggestions of analyst bias.

The Commission Panel notes that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor or beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment.

The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently absurd.

Accordingly the Commission Panel determines that in determining a suitable ROE for TGI, it will give most weight to the DCF approach, some lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.

4.2 The Evidence Concerning ROE

This part of Section 4 examines the approaches used by the witnesses to develop their recommended ROEs and the results of the tests they applied.

4.2.1 Discounted Cash Flow

The DCF approach was used by both Ms. McShane and Dr. Vander Weide.

Ms. McShane states that there are multiple versions of the DCF model available to estimate the investor's required return. An analyst can employ a constant growth model or a multiple period model to estimate the cost of equity. The constant growth model rests on the assumption that investors expect cash flows to grow at a constant rate throughout the life of the stock. Similarly, a multiple period model rests on the assumption that growth rates will change over the life of the stock.

Ms. McShane states that to estimate the DCF cost of equity she used both models and applied the discounted cash flow test to a sample of low risk US "pure-play" electric and gas distributors that were intended to serve as a proxy for TGI. In applying the DCF test, she states she relied solely on published forecast growth rates that were readily available to investors. In applying the constant growth model, she relied primarily on the consensus (mean) of analysts' earnings growth rate forecasts as the proxy for investors' long-term growth expectations.

To estimate the ROE, Ms. McShane selected a sample of low risk US electric and natural gas distribution utilities, which met the following criteria: were classified by *Value Line* as a gas distributor or an electric utility; had a *Value Line* Safety Rank of "2" or better; had a Standard & Poor's business risk profile of "Excellent" and a debt rating of A- or higher; was not presently being acquired; and had a consistent history of analysts' forecasts.

Thirteen utilities met these criteria of which four (Dominion Resources, Duke Energy, FPL, and Southern Co.) were electric utilities with significant regulated generating assets. (Exhibit B-1, Tab 3, pp. 64-66 and Appendix C)

Ms. McShane agreed that, with the possible exception of Southern Co., such utilities would have to raise considerable amounts of capital replacing their generating assets. (T4:570)

Dr. Vander Weide applied the DCF model to the *Value Line* electric and natural gas utilities which he selected from all the utilities in *Value Line*'s electric and natural gas industry groups that had paid dividends during every quarter and did not decrease dividends during any quarter of the past two years, had at least three analysts included in the I/B/E/S mean growth forecast, were not in the process of being acquired, had a *Value Line* Safety Rank of 1, 2, or 3, and had investment grade S&P bond ratings.

Dr. Vander Weide's selection criteria captured ten natural gas LDCs (a number of which were also featured in Moody's report attached to Exhibit B-6, BCUC 111.1) and 24 *Value Line* electric utilities. The latter included some of the largest generating utilities in the US as well as a number of combination gas and electric utilities. (Exhibit B-1, Tab 4, pp. 33, 60, 61)

Ms. McShane states that her constant growth models indicate a cost of equity of approximately 11 percent. Her two-stage model is based on the premise that investors expect the growth rate for the utilities to be equal to the analysts' forecasts (which are five year projections) for the first five years, but, in the longer-term (from year six onward) to migrate to the expected nominal long-run growth rate of 5 percent per annum in the economy, and indicates a cost of equity of approximately 10.4 percent (Exhibit B-1, Tab 3, p. 66 and Schedule 18). Ms. McShane updated her constant growth model in Exhibit B-3, BCUC 65.3 and found the result of 11 percent to be "virtually identical."

Dr. Vander Weide concludes that the cost of equity using a constant growth approach is 12.4 percent for the 24 *Value Line* electric utilities in his study and 11.5 percent for the ten *Value Line* natural gas utilities. In response to an Information Request ("IR"), he updated these percentages as of July 2009 to 11.5 percent and 11.9 percent respectively. (Exhibit B-6, BCUC 107.1)

Dr. Vander Weide testified that he did not seek to eliminate utilities which were not "pure-play" natural gas distribution utilities from his study, and that had he done so he might have eliminated Equitable Resources and Questar Corp from his *Value Line* LDCs on the grounds that both companies have significant upstream operations. This would have reduced the cost of equity for his remaining eight "pure-play" *Value Line* LDCs to "something like" 10.5 percent. (T3:388)

JIESC submits that since dividend yields for the period of January 2009 to March 2009 are "biased upwards because stock market prices were at all time lows," the utilization of these yields together with long term I/B/E/S growth forecasts by Ms. McShane will substantially overstate investors' required returns.

Terasen replies that in the response to IR in Exhibit B-3, BCUC 65.3.1, Ms. McShane had updated her results and concluded that the estimated "bare-bones" ROE derived from the constant growth DCF model was virtually identical to the 11.0 percent she had estimated at the time her evidence was filed. (Terasen Reply, para 113)

Terasen discusses the regulatory treatment of US LDCs and of TGI in its Argument. It cites the CEA report for the CGA which states in its Executive Summary: "There are of course differences in regulatory treatment from province to province and from state to state. But we find generally that there is no persistent difference in regulatory legislation or rule making between Canada and the US."

Terasen submits that the rate setting methodologies of the *Value Line* US LDCs and TGI are quite similar. Both the *Value Line* US LDCs and TGI are subject to rate of return regulations which are designed to provide the companies an opportunity to recover prudently incurred costs and earn a fair rate of return on their investments. In addition, the US LDCs and TGI both benefit from the availability of cost recovery mechanisms that are designed to reduce regulatory lag. (Terasen Argument, para 346-347)

Terasen states that most US gas utilities have automatic rate adjustment mechanisms for purchased gas costs and weather normalization, and that many US gas utilities have decoupling mechanisms that seek to stabilize revenues by “decoupling” gas rates from gas volumes. Decoupling occurs either through a rate design that allows recovery of fixed costs from fixed monthly charges, or through a revenue normalization adjustment mechanism that increases rates or refunds rates to customers for the difference between actual revenues and authorized revenues. (Exhibit B-3, BCUC 74.3)

Terasen identifies another difference in regulatory treatment in that Canadian regulatory agencies do not allow natural gas LDCs to recover deferred income taxes in the rates they charge their customers while US state regulators in the most part do (Exhibit B-11, Panel 1.1). Terasen testified that, at December 2008, TGI had $261 million of income taxes it had not collected from its customers (T3:286).

Dr. Booth states that in 1978 many US utilities faced, “significant regulatory lag that exposed utilities to inflation risk...Subsequently, two factors have largely removed this risk: the decline in inflation and the adoption of forward test years.” (Exhibit C11-5, Appendix C, p. 9)

Dr. Vander Weide testified that it was no longer a “rule of thumb” that US regulatory bodies used historic test years to set rates, that there are now many that have forward-looking test years, and that those without forward-looking test periods are able to adjust their historical test periods for known and measurable changes such as commissioning a new plant or a negotiated pay increase settlement. (T3: 391)

Terasen filed the actual earned ROEs of the *Value Line* LDCs which demonstrate that of the eight "pure-play" LDCs (that is ignoring Equitable and Questar), three consistently earned less than their allowed returns and the remaining five earned at or around their allowed ROEs. By excluding Equitable and Questar, the average ROE earned by the 8 remaining *Value Line* LDCs ranged from 10.1 percent to 11.3 percent in the period 2004-2008. (Exhibit B-28)

In its Argument, JIESC quotes Dr. Booth's evidence that:

> "The regulation of US utilities suffers from the same philosophical and cultural factors in the US and there is no reason to believe that the results are any different. Without examining US regulatory practise in detail, since much of it is the result of individual state regulation, Canadian utilities seem to be regulated on a much more pro-active basis with very little regulatory lag. In contrast, it appears that US utilities sometimes go several years between rate hearings. Canadian utilities also seem to make more use of deferral accounts. As a result, there is little to be gained from looking at US utilities without making significant risk adjustments which is rarely done. However, since the underlying operations are similar and there is increasing uncontested evidence presented on behalf of the utilities, I have started to examine them". (Exhibit C11-5, Appendix G, p. 2 cited at JIESC Argument, p. 46)

Commission Determination

The Commission Panel agrees that Canadian data do not lend themselves to the DCF approach due to the very limited universe of stand-alone utilities in Canada and the lack of sufficient analysts' forecasts. However, the Commission Panel has also found that US data can act as a proxy for Canadian data where adequate Canadian data do not exist. Accordingly, the Commission Panel determines that the four DCF tests before it are relevant.

The Commission Panel places no weight to Dr. Vander Weide's US *Value Line* electric utilities test, since it included a large number of very large US vertically integrated utilities with significant amounts of generation assets. Not only did the inclusion of these very large US vertically integrated utilities tend to skew the results upwards, but they were not in the Commission Panel's view suitable comparators for a "pure-play" natural gas LDC like TGI.

The Commission Panel gives the most weight to Dr. Vander Weide's *Value Line* natural gas LDC DCF test and to both Ms. McShane's DCF tests. The Commission Panel eliminates the two *Value Line* gas utilities which had significant non-utility operations (Equitable and Questar) from Dr. Vander Weide's test and the four large vertically integrated electric utilities from Ms. McShane's two-stage DCF test. The Commission Panel considers a return in the range of 10.0 percent to 10.5 percent to be a starting point for determining TGI's ROE using the DCF approach.

The Commission Panel agrees with Dr Booth that "significant risk adjustments" to US utility data are required in this instance to recognize the fact that TGI possesses a full array of deferral mechanisms which give it more certainty that it will, in the short-term, earn its allowed return than the *Value Line* US natural gas LDCs enjoy. The Commission Panel notes Dr. Booth's suggestion that the risk premium required by US utilities is between 90 and 100 basis points more than utilities in Canada require may set an upper limit on the necessary adjustment. Accordingly, the Commission Panel will reduce its DCF estimate by between 50 and 100 basis points to a range of 9.0 percent to 10.0 percent, before any allowance for financing flexibility.

The Commission Panel's determination on the allowance for financing flexibility appears later in this Section.

4.2.3 Equity Risk Premium

Ms. McShane performs three ERP tests: i) a risk-adjusted equity market risk premium test; ii) a DCF-based equity risk premium test; and iii) a historic utility equity risk premium test. (Exhibit B-1, Tab 3, pp. 43-63)

Dr. Vander Weide performs two ERP tests, an *ex post* risk premium and an *ex ante* risk premium test. His *ex post* risk premium test measures the required risk premium on an equity investment in TGI from historical data on the returns experienced by investors in Canadian utility stocks compared to investors in long-term Canada bonds. His *ex ante* risk premium test is based on studies of the expected return on comparable groups of utilities in each month of the study period compared to the interest rate on long-term government bonds. (Exhibit B-1, Tab 4, pp. 30 and 32)

Dr. Booth relies on what he terms a 'classic' CAPM risk premium model and a two-factor model. The 'classic' CAPM estimate is based on an historic average market risk premium "adjusted" for the changing risk profile of the long Canada bond, while his two-factor model takes into account the interest rate sensitivity of utility stocks. As a check to his results he uses a DCF based utility risk premium test. (Exhibit C11-5, p. 56)

The table below summarizes the results of the tests performed:

Witness	**Test**	**Indicated ROE**	**FFA**	**Total ROE**
Ms. McShane	Risk-Adjusted Equity Market Risk Premium Test	8.75%	0.50%	9.25%
	DCF-Based Equity Risk Premium Test	10.00%[1]	0.50%	10.50%
	Historic Utility Equity Risk Premium Test	10.50%	0.50%	11.00%
Dr. Vander Weide	*Ex post* Risk Premium	9.20%	0.50%	9.70%
	Ex ante Risk Premium	11.40%	N/A	11.40%
Dr. Booth	"Classic" CAPM	7.00%	0.75%	7.75%
	Two-stage CAPM	7.00%	0.75%	7.75%

([1]) Revised by Ms. McShane to 9.5 percent. (T4:452)
(Source: Exhibits B-1, Tab 3, p. 63; B-1, Tab 4, p. 35; and C11-5, p. 56)

A comparison of Ms. McShane's risk-adjusted equity market risk premium test and Dr. Booth's "classic" CAPM tests show the following assumptions and results:

	Ms. McShane	Dr. Booth
Long-term Canada bond yield	4.25%	4.50%
Equity risk premium	6.75%	5.00%
Relative risk adjustment	0.65-0.70	0.50
Indicated ROE	8.75%	7.00%
Allowance for financial flexibility	0.50%	0.75%
Total	9.25%	7.75%

Prior to the Oral Phase of Argument, the Commission circulated a letter dated November 18, 2009. The letter had, as an attachment, a document similar to that which Commission staff has prepared each November in accordance with the Commission's Order G-25-94, as amended by Orders G-80-99, G-109-01, and G-14-06 for the purpose of determining the allowed return on common equity for a benchmark low-risk utility for the ensuing year. The document shows that the forecast yield on long-term Canada bonds for 2010 is 4.302 percent. (Exhibit A-12)

4.2.3.1 Ms. McShane's Results

(a) Risk-Adjusted Equity Market Risk Premium Test

For her risk-adjusted equity market risk premium test, Ms. Mc Shane uses a long-term Canada bond yield of 4.25 percent, an equity risk premium of 6.75 percent and a relative risk adjustment of 0.65-0.70 (the relative risk adjustment or beta was described in Section 4.1.2). To derive her equity risk premium of 6.75 percent she used an expected value of the future equity market return in a range of 11.0 percent-12.0 percent, based on both the Canadian and US equity market returns, from which she deducted both the near-term (2010) and the longer-term forecasts for long-term Canada bond yields of 4.25 percent and 5.25 percent respectively. (Exhibit B-1, Tab 3, p. 51)

Terasen submits that because equity risk premium tests are forward-looking, historic risk premium data need to be evaluated in light of prevailing economic and capital market conditions. If available, direct estimates of the forward-looking risk premium should supplement estimates of the risk premium made using historic data. (Terasen Argument, para 202)

Ms. McShane states that the "raw" calculated betas for the five-year period ending March 2009 of her sample of fifteen US utilities averaged 0.41, while the average reported *Value Line* beta for the sample (and the beta more likely to be relied upon by analysts and investors) was 0.66. (Exhibit B-1, Tab 3, Schedule 15)

Based on her analysis of standard deviations of market returns and betas, Ms. McShane adopts a relative risk adjustment in the range of 0.65-0.70. (Exhibit B-1, Tab 3, p. 57)

JIESC cites Dr. Booth's evidence in response to Ms. McShane's evidence: "I don't believe you can subtract the current LTC [long-term Canada bond] yield from a long run average equity return since it mismatches the underlying inflationary environments…so her procedures may over estimate the market risk premium by at least 1.0%." (JIESC Argument, p. 36)

JIESC describes Ms. McShane's adjustment to beta as" unreasonable" and submits that no regulatory agency in Canada has accepted adjusted betas and that in the TQM Decision, the NEB specifically rejected adjusted betas. (JIESC Argument, p. 37)

Terasen replies that Ms. McShane's relative risk adjustment of 0.65-0.70 is not based on the premise that the utility risk will rise to that of an average risk firm, but rather is based on the following:

- relative standard deviations of utility returns compared to the returns of other sectors of the market composite;
- the empirical evidence generally that the actual returns of low beta stocks have been higher than the theoretical CAPM would predict;

- the empirical evidence specific to Canadian utilities that the actual returns have historically been higher than the "raw" regression betas would predict; and
- the published betas, which incorporate the adjustment toward the market mean of 1.0, and which investors and analysts are likely to rely on when forming their return expectations. (Terasen Reply, para 121)

(b) DCF-Based Equity Risk Premium Test

Ms. McShane performed her DCF-based equity risk premium test by constructing monthly cost of equity estimates for a sample of low risk US gas and electric utilities as a proxy for TGI for the period 1991-March 2009 using the DCF model. Using a single variable and a two variable approach Ms. McShane concludes that the indicated cost for utility equity before any allowance for financing flexibility lay in the 9.7 percent to 10.25 percent range. (Exhibit B-1, Tab 3, pp. 59-61)

In her written evidence, Ms. McShane noted that as of the end of March 2009 the spread between A rated Canadian utility bonds and 30-year Canada bonds was approximately 345 basis points. When preparing her evidence Ms. McShane forecast that spread to decrease to approximately 225 to 250 basis points. In her direct examination at page 452 of the transcript Ms. McShane noted that the spreads had declined more than she had anticipated to a level of approximately 165 to 175 basis points. Using the spread of 170 basis points, she testified that the indicated utility cost of equity before any adjustment for financing flexibility was 9.5 percent (T4:452).

(c) Historic Utility Equity Risk Premium Test

Ms. McShane's historic utility premium test involves comparing the returns of utilities in Canada for the period 1956-2008 and electric utilities and natural gas utilities in the US for the period 1947-2008, on the grounds that, "Reliance on achieved equity risk premiums for utilities as an indicator of what investors expect for the future is based on the proposition that over the longer term, investors' expectations and experience converge. The more stable an industry, the more likely it is that this convergence will occur." An analysis of the underlying data indicates there has been no upward or downward trend in the utility equity returns and that the utility returns in both the US and Canada have, "clustered in the range of 11.0-12.0%, with a mid-point of approximately 11.5%."

Ms. McShane adopts a long-run forecast of 5.25 percent for long-term Canada bond yields, and deducts that long-run forecast from the mid-point of utility returns (11.5 percent) to derive a utility risk premium of 6.25 percent. To that utility risk premium she adds the 4.25 percent long Canada forecast for 2010 to derive an ROE of 10.5 percent for TGI for 2010. (Exhibit B-1, Tab 3, pp. 62-63)

JIESC submits that Ms. McShane's return recommendation is "excessive and unreasonable." (JIESC Argument, p. 3)

4.2.3.2 Dr. Vander Weide's Results

(a) *Ex post* Risk Premium

Dr. Vander Weide measures the return experienced by investors in Canadian utility stocks from historical data on returns earned by investors in: (1) the S&P/TSX utilities stock index for the period 1956 -2008; and (2) a basket of Canadian utility stocks created by the BMO Capital Markets ("BMO CM") for the period 1963-2008, which suggests that the former had an equity risk premium of 4.3 percent and the latter 6.6 percent, which Dr. Vander Weide averages and adds the current long bond rate of 3.69 percent to derive an *ex post* risk premium ROE calculation of 9.7 percent.

Dr. Vander Weide states that the BMO CM basket contains Canadian companies that receive a higher percentage of revenues from traditional utility operations than the companies currently in the S&P/TSX utilities stock index, and includes Enbridge Inc. and TransCanada Corporation. (Exhibit B-1, Tab 4, pp. 31-32)

(b) *Ex ante* Risk Premium

Dr. Vander Weide's *ex ante* risk premium test is based on studies of the expected return on comparable groups of utilities in each month of his study period (September 1999 to February

2009) compared to the interest rate on long-term government bonds. The electric utility group yields an *ex ante* risk premium estimate of 8.0 percent, and the natural gas comparable group an *ex ante* risk premium estimate of 7.5 percent. To these percentages he adds the current long-Canada bond yield of 3.69 percent for an average indicated ROE of 11.4 percent. (Exhibit B-1, Tab 4, pp. 32-33)

JIESC submits that the methodology used by Dr. Vander Weide was selective in the period studied and used bond returns rather than bond yields in a period of falling interest rates and thus over estimates utility returns by roughly 3.4 percent. (JIESC Argument, p. 44)

4.2.3.3 Dr. Booth's Results

(a) "Classic" CAPM

Dr. Booth estimates the market risk premium to be 5.0 percent and a uses a beta of 0.50 to develop a utility risk premium of 2.50 percent, to add to his long Canada yield forecast of 4.5 percent to arrive at a required rate of return of 7.0 percent. Adding in 0.50 percent for issue cost and 0.25 percent as a margin for error, he recommends a 7.75 percent fair ROE.

In his written evidence, Dr. Booth states that at the height of the financial crisis, Professor Fernandez surveyed finance professors around the world to find out what they used for the market risk premium. Dr. Booth presented the results of this survey which show that the median in the US is 6.0 percent and in Canada is 5.1 percent. Furthermore, Dr. Booth concluded that "the survey of Fernandez indicated that the 5.8 percent used by the BCUC is within the range of common values used by Canadian Professors of Finance of 5.0% and 6.0 %." (Exhibit C11-5, pp. 50-2)

Terasen submits that the Commission should put no weight on the results of the classic CAPM model of Dr. Booth. (Terasen Argument, para 299)

(b) Two Factor Model CAPM

Dr. Booth estimated a two factor model for utilities where their returns were driven by the common market factor, the TSX Composite return, as well as the return on the long-term Canada bond.

Given the measurement error involved in any statistical estimation and the sensitivity of the estimates to economic conditions, Dr. Booth regards the two models "as being the same." Terasen submits that Dr. Booth's application of the two-factor model understates the utility equity return requirement, because it uses a market risk premium which is even lower than that used by Dr. Booth in his classic CAPM approach (5.0 percent vs. 5.5 percent), and ignores other factors which have generated utility returns. This understates the actual utility market returns by close to 20 percent.

Terasen submits that the Commission should put no weight on the results of Dr. Booth's two-factor model. (Terasen Argument, para 301-305)

(c) DCF Based Utility Risk Premium

As a check for his CAPM results, Dr. Booth uses data for the US electric and gas utilities followed by Standard and Poors to estimate a DCF required rate of return from which he subtracts the ten-year US government bond yield to estimate the utility risk premium for these US utilities at 2.21 percent to 2.68 percent, which he increases to 2.96 percent. He states that if the risk premiums are valid for Canada, they would imply a fair return of 7.50 percent (long Canada yield forecast of 4.50 percent plus the 2.96 percent risk premium) to which the 0.50 percent flotation cost would be added. Although this is slightly higher than his direct estimates from the CAPM and two factor models, he states that it "needs adjusting for the yield gap between ten and 30 year debt yields but indicates that the estimates are in the right ball-park." (Exhibit C11-5, p. 77)

Terasen points out that Dr. Booth's calculations show: i) negative growth expectations in some instances, and ii) negative calculated utility risk premiums in a significant number of instances. Terasen submits that Dr. Booth's growth rate and resulting utility risk premiums do not reflect investors' expectations. Terasen further submits that the results of Dr. Booth's DCF check, and the utility risk premiums that he estimates using the DCF approach, should be rejected by the Commission. (Terasen Argument, para 311)

Commission Determination

For the ERP approach, the Commission Panel has considered the four "non-CAPM" tests applied by Ms. McShane and Dr. Vander Weide. The Commission Panel considers that both Ms. McShane's DCF-based equity risk premium test and Dr. Vander Weide's *ex ante* risk premium test cover too short a period to be determinative. In addition Ms. McShane computes the risk premium by deducting the current, rather than the experienced, long-term Canada bond forecast from the derived returns. In the Commission Panel's view these two tests can at best be considered checks for the witnesses' DCF tests and the Commission Panel accords them no weight.

The Commission Panel notes that Dr. Vander Weide's *ex post* risk premium test gave 50 percent weight to a BMO CM basket of companies which, in the Commission Panel's view, covered too short a period, contained too few utilities, and included energy holding companies with significant non-regulated operations. Accordingly, the Commission Panel places no weight on this basket.

The Commission Panel considers that the results of Ms. McShane's historic equity risk premium test and Dr. Vander Weide's *ex post* risk premium test yield comparable results on historic Canadian utility data. The Commission Panel finds the Canadian data adequate and, for the reasons set out in its Determination in Section 2 above, gives weight to the Canadian data and no weight to the results of US utility data contained in Ms. McShane's historic equity risk premium test. The Canadian utility data can be summarized as follows:

	Utility Equity Return (%)	Bond Return (%)	Utility Risk Premium (%)
Ms. McShane	12.00	7.80	4.20
Dr. Vander Weide	11.84	7.54	4.30
Average	11.92	7.67	4.25

The Commission Panel considers that the Canadian utility premium of 4.25 percent should be adjusted to reflect the fact that it was calculated over a period when long-term Canada bonds averaged 7.67 percent and that there is not a one-for-one relationship between the increase or decrease in long-term Canada bond yields and the utility equity risk premium. The Commission Panel accepts the evidence of Dr. Vander Weide in this proceeding described in Section 5.0 below that this relationship may range between 0.50 and 0.75 and, using the 2010 forecast long-term Canada bond yield of 4.30 percent in Exhibit A-12, establishes a range of 9.25 percent to 10.25 percent for the ERP approach, before an allowance for financing flexibility.

For the CAPM approach, the Commission Panel has considered Ms. McShane's risk-adjusted equity market risk premium test and Dr. Booth's "classic" CAPM test. The Commission Panel notes that Dr. Booth's two-factor model CAPM test is essentially the same as his "classic" CAPM test and accords it no extra weight. As Dr. Booth's DCF based utility risk premium test was used by him as a check the Commission Panel finds that it need not accord it any additional weight.

The Commission Panel establishes a CAPM estimate by using the Consensus estimate of 4.30 percent for the risk free rate, establishing an equity market premium in the range of the consensus estimate of Canadian professors of finance of 5 percent to 6 percent, and using an adjusted beta in the range of 0.60 to 0.66. This produces a "bare-bones" CAPM estimate in the range of 7.30 percent to 8.30 percent before an allowance for financing flexibility.

4.2.4 Comparable Earnings

Ms. McShane states that her selection of Canadian unregulated companies was limited to industries that are characterized by relatively stable demand characteristics, as well as consistent dividend payments and relatively low earnings and share price volatility. The initial universe consisted of 490 firms on the TSX in Global Industry Classification Standard sectors 20-30, being Industrials, Consumer Discretionary and Consumer Staples and comprising thirteen major industries.

The initial selection was narrowed down to 27 companies by eliminating companies which:

- had 2007 equity less than $100 million;
- had missing or negative common equity during 1991-2007;
- were income trusts;
- had less than five years of market data;
- paid no dividends in any year 2004-2008;
- traded fewer than 5 percent of their outstanding shares in 2007;
- had stock ranked “higher risk” or “speculative by the Canadian Business Service;
- had debt rated non-investment grade, i.e., BB+ or below by either DBRS or Standard & Poor’s, or for which none of the agencies report a rating; or
- had average five-year “raw” betas ending December 2007 and December 2008 in excess of 1.0.

Ms. McShane states that since unregulated companies’ returns on equity tend to be cyclical, the appropriate period for measuring unregulated company returns should encompass an entire business cycle, covering years of both expansion and decline. The cycle should be representative of a future normal cycle, e.g., relatively similar in terms of inflation and real economic growth. The period 1991-2007 constitutes a full business cycle including the recession of 1991-1992.

Ms. McShane estimates that the average level of returns for low risk Canadian unregulated companies over a normal business cycle is in the approximate range of 12.5-12.75 percent. The comparative risk data indicate, on balance, that Canadian unregulated companies are somewhat riskier than utilities. The somewhat higher risk of the unregulated companies relative to the typical Canadian utility requires a modest downward adjustment. A downward adjustment of 75-100 basis points (based on the typical spread between Moody's BBB rated long-term industrial bond yields and long-term A rated utility bond yields and the relative betas of the unregulated companies and the Canadian and US utility samples) reduces the ROE to a range of 11.5-11.75 percent.

Ms. McShane states that although she considers that the arguments that a downward adjustment to the comparable earnings test results for market/book ratios are without merit, the data indicate that the market/book ratio for the overall Canadian equity market averaged approximately 2.0 times from 1991-2007, the period over which the comparable earnings test was conducted, while the market/book ratio for the sample of comparable Canadian unregulated companies averaged 2.1 times. In her view, the similarity of the lower average market/book ratio of the low risk unregulated Canadian companies relative to the Canadian equity market composites permits the inference that the sample average returns are not characterized by market power. Thus, she submits the comparable earnings results do not warrant an adjustment for market/book ratios.

Ms. McShane also does a comparable earnings test on a larger sample of US unregulated companies which suggests a higher return on equity. (Exhibit B-1, Tab 3, pp. 67-72)

Commission Determination

As for the CE approach, the Commission Panel has reviewed Ms. Mc Shane's selection process, the period of the study, and the results. The companies display conservative stock and debt ratings, an average market to book ratio of 2.1, and an average adjusted beta of 0.71. The Commission Panel considers that the initial results of 12.5 percent which Ms. McShane reduced to 11.5 percent suggest that an estimate of what unregulated Canadian companies of low business risk are earning on the book values of their equity may lie in the range of 10.5 percent to 11.5 percent.

4.2.5 Allowance for Financing Flexibility

Ms. McShane states that a financing flexibility allowance is an integral part of the cost of capital as well as a required element of the concept of a fair return. It is intended to cover three distinct aspects:

- flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity;
- a margin, or cushion, for unanticipated capital market conditions; and
- recognition of the “fairness” principle.

Ms. McShane contends that, at a minimum, the financing flexibility allowance should be adequate to allow a utility to maintain its market value, notionally, at a slight premium to book value, i.e., in the range of 1.05-1.10, where a utility would be able to recover actual financing costs, as well as be in a position to raise new equity (under most market conditions) without impairing its financial integrity. A financing flexibility allowance adequate to maintain a market/book in the range of 1.05-1.10 is approximately 50 basis points. As this financing flexibility adjustment is minimal, it does not fully address the comparable returns standard. (Exhibit B-1, Tab 3, pp. 66-67)

Terasen states that the application of a return estimated on the basis of market values and applied to book values implies a market value just equal to book value, and drew the Commission’s attention to the conclusion drawn by Alberta’s Independent Assessment Team in its review of the cost of capital for the Power Purchase Arrangements in 1999, where it stated: “This is sometimes associated with flotation costs but is more properly regarded as providing a financial cushion which is particularly applicable given the use of historic cost book values in traditional rate of return regulation in Canada.” TGI states that the adjustment to the market derived cost for financing flexibility rate provides a minimal increment to preserve financial integrity (i.e. market price slightly in excess of book value). (Exhibit B-3, BCUC 64.1)

Both Ms. McShane and Dr. Vander Weide propose the addition of an allowance for financing flexibility of 50 basis points to what they term the return on equity estimates derived from their DCF and equity risk premium tests, although Dr. Vander Weide does not propose to add it to his *ex ante* risk premium test.

Dr. Vander Weide testified that in the DCF model an issue discount of 2-3 percent on a utility's stock price coupled with issue costs of 5 percent "would amount to approximately 25 basis points." (T3:393)

Similarly Dr. Booth adds an allowance for issue costs of 50 basis points and 25 basis points as a "margin of error." Dr. Booth states: "However, I normally add 50 basis points as a cushion to the direct estimates in line with this practice of many regulators. This is mainly to ensure that there is no dilution and stock prices are more variable than a 10 percent floatation cost allowance would indicate." (Exhibit C11-5, p. 60)

The AUC adjusts CAPM results by adding 50 basis points to CAPM estimates on the grounds that "CAPM results likely underestimate the required market equity return by at least 50 basis points." (AUC Decision 2009-216, para 326)

Commission Determination

The Commission Panel finds no evidence before it to suggest that utilities in Canada trade in the market/book range of 1.05 to 1.10 that prompts Ms. McShane's recommended 50 basis point allowance for flotation costs. The Commission Panel agrees with Dr. Vander Weide that under normal circumstances flotation costs, comprising financing and market pressure costs arising at the time of the sale of new equity, require a 25 basis point addition to a ROE estimate.

The Commission Panel notes that the margin, or cushion, for unanticipated capital market conditions was used in Alberta in a situation where a formula for 20 year Power Purchase Arrangements was being established. It does not find the reference relevant in this proceeding.

As for the fairness principle, the Commission Panel agrees with the practice of the AUC of adding 50 basis points to CAPM estimates and adopts it in this proceeding.

Accordingly the Commission Panel determines that for DCF, ERP and CAPM estimates it will add a 25 basis point allowance to recognize the cost of issuing additional equity. The Commission Panel will add an additional 50 basis point fairness allowance to CAPM estimates. The Commission Panel will make no allowance for CE estimates.

4.2.6 Fair Return on Equity

Having determined that it will accord weight to each of the three approaches and determined the appropriate ROE ranges that the approaches yielded, the Commission Panel can determine TGI's ROE.

Commission Determination

Earlier in this Decision the Commission Panel found that the suitable equity ratio for TGI is in the 40 percent range, and that it would consider the effect of its short-term business risk mitigators (such as RSAM and deferral accounts) in the determination of TGI's ROE.

The Commission Panel also determined that it would give most weight to the DCF approach, lesser weight to the ERP and CAPM approaches and a very small amount of weight to the CE approach.

The following table sets out the Commission Panel's determined ranges for each approach:

Approach	Range (%)	Allowance (%)	Total (%)
DCF	9.00-10.00	0.25	9.25-10.25
ERP	9.25-10.00	0.25	9.50-10.25
CAPM	7.30-8.30	0.75	8.05-9.05
CE	10.5-11.5	0.0	10.5-11.5

Accordingly, after attaching the weight that it considers appropriate to each of the three approaches the Commission Panel determines that the ROE for TGI is 9.50 percent.

4.3 Interim Rates and the Effective Date of the ROE Increase

Terasen requests that any increase in the ROE of the three utilities should be reflected in their rates effective from July 1, 2009. Prior to the commencement of the Oral Hearing, the Commission Panel considered an application by Terasen pursuant to section 89 of the *Act*, that the rates of the three utilities be made interim effective July 1, 2009. Section 89 of the *Act* is included in Appendix C to the Decision.

All Intervenors opposed Terasen's request at that time. The CEC submitted that all parties had agreement on the equity ratio and the ROE in the Commission approved settlement documents that can be found in Commission Order G-33-07. CEC acknowledged that while the 2008/2009 Negotiated Settlement Agreement ("NSA") did not preclude Terasen from applying to the Commission for a variation in its equity ratio or ROE, it submitted that it was inequitable that Terasen would seek and receive an adjustment for a period of six months of the 2008/2009 settlement period on what it termed a retroactive basis. (Exhibit C3-2)

Terasen's Reply pointed out that its request was in no way retroactive and that it was perfectly within the terms of the NSA. (Exhibit B-2)

In Order G-78-09 dated June 24, 2009, the Commission Panel agreed with Terasen Utilities that an Order approving the requested relief that their current rates be made interim would be on a 'without prejudice' basis, and that "all Parties will have the opportunity to fully participate in the hearing process and no final order will be made until all evidence has been heard and considered." (Exhibit A-4)

In its Reply, Terasen notes that no Intervenor disputed that the change to the ROE of Terasen should be effective July 1, 2009 (Terasen Reply, para 1). During the Oral Argument Phase counsel for JIESC, CEC ICG and BCOAPO all stated that they took no position on the issue (T6:837).

Commission Determination

The Commission Panel notes that the Intervenors take no position on this issue and grants the relief requested by Terasen. The effect of this determination will result in the ROE for TGI for 2009 being 8.47 percent for 6 months and 9.50 percent for six months or an average annual ROE of 8.98 percent, with that of TGVI being on average 60 basis points higher for 2009 (in accordance with the Commission Panel's determination at Section 6.1 below) and that of TGW 50 basis points higher for 2009.

4.4 The Impact of the Determinations on the Fair Return Standard

Having established an equity ratio of 40 percent, and a ROE of 9.5 percent , the Commission Panel revisits the fair return standard to ensure that TGI's overall return will be comparable to the return available from the application of the invested capital to other enterprises of like risk (comparable investment requirement), enable TGI's financial integrity to be maintained (financial integrity requirement), and permit TGI to attract incremental capital on reasonable terms and conditions (capital attraction requirement).

In this regard it has considered Moody's credit metrics and its rating of TGI.

The Commission Panel notes that the ROE of 9.5 percent should enable TGI, following the end of its PBR regime, to maintain its earnings in the 9.0 to 14.0 percent range and maintain this metric at its present level in Moody's A range.

The Commission Panel considers that the combination of a 40 percent equity level and a ROE of 9.5 percent will improve the financial metrics such as EBIT/Interest, Retained Cash Flow/Debt, Debt to Book Capitalization and Free Cash Flow/Funds from Operations.

The Commission Panel observes that a 40 percent equity level would move TGI from a Ba to Baa under Moody's factor mapping and that this metric alone is worth 15 percent of a Moody's rating. Similarly the combination of a 40 percent equity level and a ROE of 9.5 percent will result in an increase in EBIT/Interest from between 1-2 to between 2-3 and would move TGI from Ba to Baa, under Moody's factor mapping and that this metric is worth another 15 percent of a Moody's rating.

These improvements in metrics should, in the Commission Panel's opinion, enable TGI both to maintain its A3 rating with a margin of comfort and to attract the capital it requires on reasonable terms and conditions.

In addition, the Commission Panel considers that the combination of a 40 percent equity level and a ROE of 9.5 percent will increase TGI's times interest covered ratio and will thus enable it to raise comfortably more than the $100 million of unsecured debentures its current equity level and ROE allow.

As a result the Commission Panel considers that its decision meets the fair return standard for TGI.

5.0 THE AUTOMATIC ADJUSTMENT MECHANISM

This Section addresses the issues:

- Given TGI's appropriate ROE, does the Commission's adjustment mechanism produce an ROE that meets the fair return standard?
- If not, should the Commission retain, amend, or eliminate the adjustment mechanism?

Terasen requests that the adjustment mechanism be eliminated, with all three of its expert witnesses urging the Commission to abandon the formula.

Ms. McShane states that reliance on a formula which tracks changes in the long-term Canada bond yield, rather than the composite of factors that bear on equity return requirements, has resulted in allowed ROEs falling below levels commensurate with a fair return and that the extent to which this has happened since 1994 can be assessed by the table which compares the allowed ROEs of Canadian and US utilities set out in Section 2.3 of this Decision.

Terasen submits that the adoption of adjustment mechanism in Canada in the mid-1990s coincided with the almost exclusive use of equity risk premium and CAPM approaches for the determination of allowed ROE for utilities in Canada.

Ms. McShane testified that the crossover between Canadian and US utility returns started when regulatory commissions in Canada started to place almost all the weight on the CAPM and equity risk premium tests. (T4:565)

Terasen states that since the adjustment mechanisms were first adopted in the mid 1990s, yields on long-term Canada bonds have steadily decreased and returns on equity allowed for Canadian utilities have decreased to unprecedented low levels.

In addition the turbulence in the capital markets experienced in the last three years has led to a "flight to quality" which has created an abnormal demand for long-term Canada bonds that were already in short supply. This flight to quality has driven down the yield on the long-term Canada bonds, and consequently driven down the formulaic ROE that uses the long-term Canada bonds as a benchmark. Yet even as the allowed ROE has declined, the cost of capital for utilities has risen dramatically, as investors have demanded higher premiums for risk.

Terasen contends that if it cannot offer a return to equity to investors similar to returns available to comparable risk investments, it will be disadvantaged in competing for capital in the future, even if the capital markets return to historical norms. (Exhibit B-1, p. 23)

Mr. Carmichael points to credit rating agencies which have recently highlighted their concerns regarding the weak state of credit metrics achieved by utilities such as TGI that are regulated with an ROE formula, and which have compared such utility's lower metrics with those of US utilities that the rating agencies believe to be comparable.

Mr. Carmichael states that the financial performance of utilities in Canada lags the performance of US based utilities. This has prompted an equity analyst to suggest that ROE formulae in use by regulators in Canada are "confiscatory and fail to meet the fair return standard," while other analysts suggest that the formulae are now "broken." According to the latter group of analysts, under current financial market circumstances such formulas result in lower rates of return on common equity, while all evidence indicates that capital markets require higher returns on corporate securities reflecting the re-pricing of risk which has taken place. Debt analysts have opined that ROE results produced by the formulas "have not reflected the real world increase in the cost of capital" and "the annual ROE adjustment is not even yielding the right direction of change in the cost of capital." (Exhibit B-1, Tab 2, p. 7)

Dr. Vander Weide performs a number of tests to determine the validity of the adjustment mechanism ROE formula, the most significant of which were to examine evidence on the sensitivity of the forward looking, or *ex ante*, required equity risk premium on utility stocks to changes in interest rates in Canada and the US. He states that while the ROE adjustment formula implies that the cost of equity for TGI declines by 75 basis points for every 100-basis-point decline in the yield to maturity on long-Canada bonds, his findings support the conclusions that i) the cost of equity declines by less than 50 basis points for every 100-basis-point decline in the yield to maturity on long-Canada bonds, and ii) US regulators typically reduce the allowed ROE by less than 50 basis points when the yield to maturity on long-term government bonds declines by 100 basis points. (Exhibit B-1, Tab 4, p. 9)

According to Terasen the process of designing an automatic adjustment formula should involve a balance among the following criteria:

- it should be relatively simple to understand and apply;
- it should be based on changes in one or more reasonably available and verifiable variables;
- it should exclude changes in variables due to abnormal market events;
- it should incorporate variables which vary in a quantifiable way with the utility cost of equity; and
- it should incorporate variables which are not vulnerable to changes caused by company-specific circumstances which may not impact on the cost of equity for the utilities to which the formula applies. (Exhibit B-1, pp. 31-32)

Terasen stated that it was working on the design of such a formula, but had nothing to show for its efforts so far. (T2:87-88)

FortisBC supports Terasen's Application, including the elimination of the AAM. (FortisBC Argument, para 2)

PNG submits that, "the evidence in this proceeding demonstrates overwhelmingly that the automatic adjustment formula does not produce a fair return on common equity for BC utilities and should therefore be eliminated, at least until a more appropriate automatic adjustment mechanism can be determined." (PNG Argument, para 4)

On the other hand, Dr. Booth states that, "…I would recommend that the BCUC maintain their ROE formula indefinitely since like most such formulae in Canada it has done a remarkably good job of awarding ROEs that are within a zone of reasonableness, while minimising repetitive testimony. It is also broadly consistent with awarding allowed ROEs consistent with adjustment formulae used elsewhere in Canada." (Exhibit C11-5, pp. 3, 4)

JIESC submits that Terasen's analysis comparing US with Canadians ROEs is "oversimplified and incorrect. All of the data shows that risk premiums generally, not just for utilities, for Canada are lower that (sic) in the US. ...Canadian and US Utility and market risk premiums departed company, not when the AAM came into place, but when Canada got its financial house in order in 1997 and the US failed to do so. Up until last year Canada generally had financial surpluses and the US has faced increasing deficits." (JIESC Argument, p. 45)

Terasen observes that while in 1995 the NEB adopted an AAM similar to that adopted in BC in 1994, that in the NEB Letter Decision, the NEB determined that the RH-2-94 Decision will not continue in effect. As a result, the return on equity for the pipelines regulated by the NEB will not be determined by an automatic adjustment mechanism (Terasen Argument, para 4).

At the Oral Phase of Argument, counsel for FortisBC pointed out that the AUC had "moved away from" its automatic adjustment formula in AUC Decision 2009-216. (T6:743)

Commission Determination

A key consideration in the determination of whether to retain, amend or eliminate the AAM is whether the ROE produced by application of the formula for 2010 is reasonably comparable to the ROE determined by the Commission Panel from the evidence before it. The Commission's calculation of the ROE for 2010, as derived from the adjustment mechanism, is 8.43 percent, compared to the Commission Panel's determination that the appropriate ROE for TGI in 2010 is 9.50 percent. The Commission Panel determines that, in its present configuration, the AAM will not provide an ROE for TGI for 2010 that meets the fair return standard.

The Commission Panel agrees that a single variable is unlikely to capture the many causes of changes in ROE and that in particular the recent flight to quality has driven down the yield on long-term Canada bonds, while the cost of risk has been priced upwards.

In the Commission Panel's opinion, reliance on CAPM by Canadian regulatory agencies has also contributed to the divergence between Canadian and US allowed ROEs. In light of the limited weight given by the Commission Panel to CAPM in determining the ROE for TGI for 2010, it would seem inconsistent to retain the adjustment mechanism.

Accordingly the Commission Panel directs that the AAM be eliminated. TGI is directed to complete its study of alternative formulae and report to the Commission by December 31, 2010.

6.0 THE APPROPRIATE RETURN ON EQUITY FOR TGVI AND TGW

This Section looks at TGVI and TGW. The business risks of each are considered and a suitable capital structure and ROE for each are determined. It addresses the issue: Given TGI's appropriate capital structure and ROE what are the appropriate ROEs for TGVI and TGW?

TGVI and TGW request that the Commission continue to set their respective allowed returns on equity with reference to the Benchmark ROE established in this proceeding for TGI by adding a utility specific premium of 70 basis points for TGVI and 50 basis points for TGW to the Benchmark ROE.

Terasen submits that the business risks relating to TGI also relate to TGVI and TGW. All three companies are in the natural gas distribution business in British Columbia, and all three are subject to the provincial policies and legislation, and other factors that have increased the risk of TGI.

6.1 TGVI

TGVI requests that the Commission continue to set it's allowed ROE with reference to TGI's ROE established in the proceeding by adding a utility specific risk premium of 70 basis points to TGI's ROE.

In addition to TGI's business risk Terasen cites additional sources of business risk faced by TGVI:

- TGVI is a relatively immature LDC seeking to build a new market on Vancouver Island where it is at a competitive disadvantage caused by the differences in gas versus electric rate design methodologies;
- TGVI is burdened with the recovery of an accumulated deficit that peaked at approximately $88 million in 2002;
- TGVI faces the elimination of Provincial royalty revenues in 2012 that have ranged from $35 to $40 million in recent years and cover approximately 20 percent of the current cost of service;

- TGVI is highly dependent on industrial load related to the Vancouver Island Pulp Mill Joint Venture which is taking transportation service at its minimum allowed levels and whose contracts expire at the end of 2012, and the Island Cogeneration Project ("ICP") contract with BC Hydro whose future has been made less certain by the current climate change legislation and policy;
- TGVI faces a greater security of supply risk due the fact that all gas to the Island flows from a single source on the mainland and is also dependent on the use of undersea high pressure transmission facilities; and
- TGVI will become liable to repay $75 million of non-interest-bearing senior government debt, currently sitting as a credit to rate base, which when repaid will contribute to higher cost of service and impact the competitive position of the utility.

Terasen cites Ms. McShane's testimony in the 2005 ROE hearing as follows:

> "In my opinion, to equate TGVI to the benchmark low risk utility, an allowed common equity ratio of no less than 45-50% would be required (compared to the range of 35-40% for Terasen Gas). Terasen Gas is proposing a 40% common equity ratio for TGVI. I view the proposal as reasonable; however, the difference between the proposed 40% and the indicated range of 45-50% (mid-point of 47.5%) requires an incremental equity risk premium relative to the benchmark low risk utility return." (Exhibit B-11, Panel 1.6)

In the 2006 ROE Decision, the Commission found: "that the uncertainty surrounding the contract with BC Hydro beyond 2007 creates a significant incremental change to TGVI's business risk together with uncertainty as to the ultimate recovery of the balance on the RDDA. In addition, the uncertainty regarding the cessation of royalty payments from the Provincial Government and the need to repay the interest free loans from senior levels of government demonstrate that TGVI is exposed to considerably greater business risk than a benchmark low-risk utility. It is evident to the Commission Panel that in TGVI's case the probability of not earning a return on and of capital is considerably higher than is the case with the five "mature" gas distribution companies in Canada" (2006 ROE Decision, page 30). Based on these findings the Commission approved an equity ratio of 40 percent for TGVI and ROE 70 basis points higher than TGI.

6.2 TGW

TGW requests that the Commission continue to set its respective allowed ROE with reference to TGI's ROE established in the proceeding by adding a utility specific risk premium of 50 basis points to TGI's ROE.

Terasen submits that the relative risk of TGW as compared to TGI since the proceeding that led to the Commission's Order G-35-09 in April 2009, which found that a premium of 50 basis points over the Benchmark ROE was appropriate, has not changed. (TGI Argument, para 364)

Commission Determination

The Commission has in the past awarded both increased equity ratios and ROEs for both TGVI and TGW over those awarded TGI. The Commission Panel considers that TGVI's risk has declined since 2005 because of i) the resolution of the contract with BC Hydro at ICP and ii) greater certainty around the recovery of its RDDA balance.

Accordingly the Commission Panel determines that TGVI's premium over TGI's ROE should be reduced from 70 basis points to 50 basis points. The Commission Panel determines that TGW's premium over TGI's ROE should remain at 50 basis points for the reasons set out in the Commission Order G-35-09.

The Commission Panel notes that in determining TGI's equity ratio and ROE in this proceeding it has sought to determine an equity ratio for TGI that reflects its long-term business risks, while adjusting its ROE to reflect its short-term business risks. It also notes that the evidence suggests that both TGVI and TGW have greater long-term business risk than TGI while possessing similar deferral mechanisms to enable them to earn their allowed ROEs in the short-term. The Commission Panel further notes Ms. McShane's testimony that both utilities require greater equity thickness than 40 percent.

Accordingly, the Commission directs TGVI and TGW to file with their next revenue requirement applications evidence as to what equity component best reflects their respective long-term business risks.

7.0 TGI AS THE BENCHMARK UTILITY

This Section discusses the concept of the benchmark utility and what effect the Commission Panel's determination should have on other utilities in BC primarily FortisBC and PNG. It addresses the issue: What impact should the Commission Panel's determination have on the remaining utilities in BC that may be affected, namely FortisBC and PNG.

Ms. McShane observes that, "it is important to recognize that, while it may be administratively efficient to designate one utility as the "benchmark," it does not necessarily follow that (1) the designated benchmark is the lowest risk utility, or (2) that the risk of the designated benchmark utility does not change over time relative to its peers." (Exhibit B-1, Tab 3, p. 24)

In response to an Information Request as to whether TGI still considered itself a "benchmark low-risk utility" for the purposes of setting allowed ROEs, TGI replies that it has been designated "a benchmark low-risk utility" by the Commission, and points out that BC Hydro and BC Transmission Corporation have their ROE set with reference to the most comparable investor owned utility, which by virtue of size and geography has defaulted to TGI.

TGI accepts that it is has been, and will be, the benchmark utility in respect of being the "benchmark" or "standard" used to set the ROE of other utilities in BC, but does not consider itself to be "a benchmark low-risk utility" now, if it ever was. Any utility could act as the benchmark and TGI due to its size has been selected as the benchmark by the Commission in the past. (Exhibit B-3, BCUC 2.1)

PNG submits that if the Commission determines that the AAM no longer produces a fair return for the Terasen, it follows that the formula no longer produces a fair return for the other utilities subject to the formula, including PNG.

PNG states that it will assess whether any adjustment to its utility specific risk premiums are required as a result of the Commission's decision and, if adjustments are required, that it will file an update to its 2010 Capital Structure and Equity Risk Premium Application. (PNG Argument, para 3)

FortisBC seeks an order of the Commission maintaining the current regulatory framework in British Columbia whereby TGI's ROE is established as the Benchmark ROE for utilities in British Columbia, including FortisBC, as previously ordered by the Commission in Order G-14-06.

FortisBC submits that the Commission determined in 1994 that the use of a benchmark was in the public interest, and that there is no evidence in the record of this proceeding to suggest that the benchmark concept should be abandoned in British Columbia. FortisBC identifies a number of advantages that flow from a Benchmark ROE for utilities including:

- cost savings to the Commission and to Intervenors in avoiding additional, unnecessary hearings; the evidence related to economic outlook and capital market conditions need not be presented nor heard more than once;
- a consistent approach to economic outlook and capital market conditions, considered with reference to expert evidence gathered at a single point in time; and
- greater consistency with respect to ROE determinations for individual utilities from a common base.

FortisBC submits that the NSA approved by the Commission in Order G-193-08 is a performance based regulation settlement and contemplates the application of the TGI's ROE as the Benchmark ROE for FortisBC through to, at a minimum, 2011. The NSA provides for FortisBC to receive the "allowed return on equity" which is calculated by reference to the Benchmark ROE with adjustments and sharing as contemplated in the approved NSA.

Commission Determination

The Commission Panel notes that PNG seeks no relief in this proceeding and that it proposes to consider this Decision and to determine if any amendments to its 2010 Capital Structure and Equity Risk Premium Application are merited.

The Commission Panel agrees with FortisBC that there is no evidence on the record in this proceeding suggesting that the use of a Benchmark ROE is not in the public interest. **Accordingly the Commission Panel determines that the ROE for TGI it has determined in this proceeding should continue to serve as the Benchmark ROE for FortisBC and any other utility in BC that uses the Benchmark ROE to set rates.**

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of December 2009.

Original signed by:
A.J. (TONY) PULLMAN
PANEL CHAIR/COMMISSIONER

Original signed by:
DENNIS A. COTE
COMMISSIONER

Original signed by:
MICHAEL R. HARLE
COMMISSIONER

BRITISH COLUMBIA
UTILITIES COMMISSION

ORDER
NUMBER G-158-09

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IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

An Application by
Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI") and
Terasen Gas (Whistler) Inc. ("TGW") (collectively the "Terasen Utilities")
for Return on Equity and Capital Structure

BEFORE: A.J. Pullman, Panel Chair
D.A. Cote, Commissioner
M.R. Harle, Commissioner

December 16, 2009

O R D E R

WHEREAS:

A. By letter dated May 15, 2009, the Terasen Utilities filed with the British Columbia Utilities Commission (the "Commission") pursuant to sections 59 and 60 of the *Utilities Commission Act* (the "*Act*"), an application for Return on Equity and Capital Structure (the "Application"); and

B. TGI applied for an increased Return on Equity ("ROE") for rate-setting purposes, and that the so determined ROE for TGI be used in establishing the ROE of TGVI and TGW used for rate-setting. The Application requests that the revised ROE be effective from July 1, 2009. In addition TGI applied for an increase of the equity ratio in its Capital Structure to 40 percent effective January 1, 2010. Terasen Utilities further requested that the Commission set their current rates as interim, effective July 1, 2009, until such time as permanent rates were established; and

C. By Order G-53-09 dated May 21, 2009, the Commission established a Procedural Conference to take place on June 9, 2009 to hear submissions regarding the regulatory process for the review of the Application; and

D. Further to the Procedural Conference, the Commission issued Order G-70-09 dated June 9, 2009 which established a Regulatory Timetable for an Oral Hearing Process as well as a schedule for written argument to hear submissions from the Parties on the subject of the request for interim rates; and

E. By Order G-78-09 dated June 24, 2009, the Commission ordered, with Reasons for Decision attached as Appendix A to the Order, that the current rates of TGI and TGW be set as interim effective July 1, 2009 and that the changes to the allowed ROE from this proceeding be treated as changes to TGVI's cost of service, effective July 1, 2009; and

F. The Oral Hearing took place from September 28, 2009 to October 1, 2009. The following Intervenors took an active role in the proceedings, filed written argument or took part in the Oral Phase of Argument; the British Columbia Old Age Pensioners' Organization *et al.* ("BCOAPO"), the Commercial Energy Consumers of British Columbia ("CEC"), FortisBC Inc. ("FortisBC"), Pacific Natural Gas Ltd. ("PNG"), the Joint Industry Electricity Steering Committee ("JIESC") and the Industrial Customer Group ("ICG"); and

G. The schedule of written Argument provided for Final Submissions to be filed as follows: i) Terasen Utilities, FortisBC and PNG on or before October 20, 2009; ii) Intervenors on or before November 6, 2009; and iii) Reply from Terasen Utilities, FortisBC and PNG on or before November 13, 2009; and

H. An Oral Phase of Argument was held on November 24, 2009; and

I. The Commission Panel has considered the Application, the evidence, and the submissions of the Parties all as set forth in the Decision issued concurrently with this Order.

NOW THEREFORE the Commission orders as follows:

1. The appropriate equity ratio for TGI is 40 percent effective January 1, 2010.

2. TGI is to file within 30 days a document setting out how and when it will implement the change to its capital structure in compliance with the ring-fencing conditions approved by Commission Order G-49-07.

3. A return on equity for TGI of 9.50 percent for rate-setting purposes is approved effective July 1, 2009.

4. The TGI ROE approved in paragraph 3 of this Order is to be used as the Benchmark ROE in establishing the return on equity of TGVI and TGW used for rate-setting purposes and the allowed return on equity for TGVI and TGW is effective July 1, 2009.

5. TGVI's request to continue to set its allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 70 basis points is denied. TGVI is allowed a utility specific risk premium of 50 basis points above the Benchmark ROE.

6. TGW's request to continue to set its allowed return on equity with reference to the Benchmark ROE by adding a utility specific risk premium of 50 basis points is approved.

7. TGVI and TGW are to file in their respective next revenue requirement applications evidence on the equity component that best reflects their respective long-term business risks.

8. The TGI ROE approved in paragraph 3 of this Order can continue to serve as the Benchmark ROE for FortisBC and any other utility in British Columbia that uses a Benchmark ROE to set rates.

9. The automatic adjustment mechanism is eliminated.

10. TGI is to complete its study of alternative formulae to an automatic adjustment mechanism and report to the Commission on the study results by December 31, 2010.

DATED at the City of Vancouver, in the Province of British Columbia, this 16th day of December, 2009

BY ORDER

Original signed by:

A.J. Pullman
Panel Chair and Commissioner

THE APPLICATION

On May 15, 2009 Terasen Gas Inc. ("TGI"), Terasen Gas (Vancouver Island) Inc. ("TGVI"), and Terasen Gas Whistler Inc. ("TGW") filed a return on equity and capital structure application under sections 59 and 60 of the *Utilities Commission Act* with the British Columbia Utilities Commission ("Application").

The following Intervenors took an active role in the proceedings, filed written argument or took part in the Oral Argument Phase of the proceedings:

- Joint Industry Electricity Steering Committee ("JIESC")
- Commercial Energy Consumers of BC ("CEC")
- British Columbia Old Age Pensioners Organization

  Active Support Against Poverty
  B.C. Coalition of People with Disabilities
  Council of Seniors' Organizations of B.C.
  End Legislated Poverty
  Federated Anti-Poverty Groups of B.C., and
  Tenants' Rights Action Coalition (collectively "BCOAPO")

- Industrial Customer Group, comprising:

  Certainteed Gypsum Canada Inc.
  Domtar Pulp and Paper Products Inc.
  Federated Co-operatives Ltd.
  Teck Metals Ltd., Weyerhaeuser Company Ltd. and
  Zellstoff Celgar Limited Partnership (collectively"ICG")

- FortisBC Inc.
- Pacific Northern Gas Ltd.

Following receipt of the Application, the Commission issued Order G-53-09 dated May 21, 2009 establishing a Preliminary Regulatory Timetable, including a notice of procedural conference to be held on June 9, 2009.

By Order G-70-09 dated June 9, 2009 following the procedural conference, the Commission published the final Regulatory Timetable which set dates for two rounds of Information Requests and an Oral Hearing to commence on September 28, 2009.

Order G-70-09 also established a schedule for written argument on the subject of Terasen's request pursuant to section 89 of the *Act* for interim rates. Intervenor submissions were due on June 15, 2009 and Terasen reply by June 22nd, 2009.

By Order G-78-09 and Reasons for Decision dated June 24, 2009, the Commission approved, pursuant to section 89 of the *Act*, of the request of TGI and TGW that their respective current rates be set as interim, effective July 1, 2009. In addition, pursuant to the provisions of the Special Direction made under section 7 of the Vancouver Island Natural Gas Pipeline Act, the Commission ordered that changes to the allowed ROE from the proceeding were to be treated as changes to TGVI's cost of service, effective July 1, 2009.

The Commission Panel accepted Terasen's submission that the application for interim relief should be reviewed pursuant to section 89 of the *Act* which does not refer to special circumstances. It further agreed with Terasen that a Commission Order approving the requested relief that the current rates be made interim was on a 'without prejudice' basis, that all parties would have the opportunity to fully participate in the hearing process and that no final order would be made until all evidence had been heard and considered. (Exhibit A-4)

The Oral Hearing commenced on September 28, 2009 and concluded on October 1, 2009. Argument was received from the Terasen, PNG and FortisBC on October 20, 2009. Argument was filed by the following Intervenors on November 6, 2009: JIESC, BCOAPO, CEC and ICG. Reply was filed by Terasen on November 13, 2009.

The Oral Phase of Argument was scheduled to take place on November 24, 2009. Parties were originally asked to address the following issues:

- Whether the Commission Panel can take into account the Alberta Utilities Commission 2009 Generic Cost of Capital Decision, Decision 2009-216, dated November 12, 2009 (Decision 2009-216) in arriving at its decision?
- Whether the Commission Panel should take into account Decision 2009-216 in arriving at its decision?
- If the Commission Panel were to eliminate the automatic adjustment mechanism (“adjustment mechanism”) as requested by the Terasen Utilities, upon what evidentiary basis can the Commission Panel conclude that the return on common equity (“ROE”) that it determines for TGI in this proceeding should be used as the benchmark or generic ROE for FortisBC and Pacific Northern Gas?
- If the Commission Panel were to eliminate the adjustment mechanism as requested by the Terasen Utilities and conclude that the ROE that it determines for TGI in this proceeding should not be used as the benchmark or generic ROE for FortisBC and Pacific Northern Gas, what are the consequences for FortisBC and Pacific Northern Gas?

By letter dated November 18, 2009 the Commission added two additional issues to the Agenda and requested that parties address a document prepared by Commission staff in accordance with the Commission’s Order G-25-94, as amended by Orders G-80-99, G-109-01, and G-14-06 for the purpose of determining the allowed return on common equity for a benchmark low-risk utility for the ensuing year, which showed that the current formula resulted in an allowed return on common equity of 8.43 percent for a low-risk benchmark utility in 2010. The two further issues to be addressed were:

- Whether any party objects to the Commission Panel relying upon the staff document in arriving at its decision; and
- If there is no objection, now that the formula has produced an allowed return on common equity for 2010 of 8.43 percent, does it follow that, for the purposes of the JIESC Final Argument, the Panel no longer needs to consider the JIESC alternative position to set the return on equity on the basis of Dr. Booth’s recommendation of 7.75 percent?

The Oral Phase of Argument took place on November 24, 2009 as scheduled.

THE HISTORY OF ROE AWARDS IN BC, CANADA AND THE US SINCE 1994, AND THE USE OF A FORMULA TO ESTABLISH ROE

Prior to 1994 the ROE and capital structures of utilities in North America for rate setting purposes were established as part of the periodic revenue requirement applications the utilities would file with their regulators. In 1994, the BCUC held a public hearing into the appropriate rates of return on common equity and capital structure for BC Gas (now TGI), West Kootenay Power (now FortisBC) and PNG. In addition, the Commission heard evidence on processes or mechanisms that might be employed to improve the determination of ROE and capital structures in future years. In its decision dated June 10, 1994 attached to Order G-35-94, the Commission, for the purpose of setting the 1995 rate of return on common equity for utilities subject to its jurisdiction, accepted an automatic adjustment mechanism, based on long-term Canada bond yields. The formula has remained in place since that time and was adjusted by Orders G-80-99 and G-109-01. Following the 2005 ROE hearing the Commission issued Order G-14-06 and its 2006 ROE Decision on March 2, 2006, amending the formula.

As a result of Order G-14-06 the benchmark ROE now rises or falls by 75 basis points for each 100 basis point increase or decrease in the forecast long-Canada bond yield, as follows: ROEt = 9.145% - [0.75 x (5.25% - YLDt)], where YLDt equals the forecast long-term Government of Canada bond.

By Letter L-55-08 dated November 20, 2008, the Commission determined that the current ROE automatic adjustment mechanism resulted in an allowed return on common equity of 8.47 percent for a low-risk benchmark utility in 2009. This was calculated by averaging the November 2008 Consensus Forecasts of the 10-year Canada bond yield at the end of [both?] February and of November, 2009, and adding the average yield spread between 10-year and 30-year bonds of 0.50 percent reported by the Bank of Canada for all trading days in October, 2008 to arrive at the forecast yield on long-term Canada bonds for 2009 of 4.35 percent.

Commission Order G-14-06 set the approved benchmark return on equity (ROE) at 9.145 percent assuming a 30-year long Canada bond yield of 5.25 percent, and directed that where the forecast yield was greater or less than 5.25 percent, a sliding scale adjustment would raise or lower the benchmark ROE by 75 percent of the change in the forecast yield on long-term Canada bonds which would be rounded to the nearest 2 decimal places as follows:

$$9.145 – (0.75 * (5.25 – 4.35)) = 8.470\%$$

Based on L-55-08 the following ROEs were approved for 2009 for the following utilities in BC on their capital structures: Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc., Fortis BC Inc. and Pacific Northern Gas Ltd.

Section 4(d) of Special Direction No. HC2 obliges the Commission to set rates for BC Hydro that enable it to achieve an annual rate of return on equity equal to the pre-income tax annual rate of return allowed by the commission to the most comparable investor-owned energy utility regulated under the *Act.*

Similarly, section 3(c) of Special Direction No. 9 obliges the Commission to set rates for BCTC that generate for the transmission corporation an annual rate of return on deemed equity that is equal to the annual rate of return that is allowed by the commission on the authority's equity as that term is defined in Special Direction HC2.

In Canada an adjustment mechanism was employed by a number of regulatory bodies including the NEB (1995), the OEB (1997) and the AEUB (2004).

In the US an attempt to develop an adjustment mechanism was made by only two regulatory agencies – the Federal Energy Regulatory Commission (“FERC”) and the New York Public Service Commission (“NYPSC”). The FERC generally dropped its pursuit of a generic formula by about 1992 over legal concerns that a company-specific record must support the finding of a fair return. The FERC since has not departed from a case-by-case examination of the cost of equity. The NYPSC formula was created after an extensive process but was never adopted formally by the NYPSC.

Both FERC and NYSPC focused on a formula for deriving the cost of equity, rather than the long bond rates plus a pre-determined spread (Exhibit B-1, Appendix x, p.17).

In its Letter Decision, the NEB determined that the RH-2-94 Decision would not continue in effect and that the return on equity for the pipelines it regulates will no longer be determined by an adjustment mechanism.

In its Decision 2009-216, the AUC, following a generic hearing, determined that it would not employ an adjustment formula for 2010, but would initiate a process in 2011 "in order to allow the capital markets some time to return to traditional relationships or show evidence of what the new relationships may be." (AUC Decision, para 423-24)

The OEB is undertaking a consultative process on the cost of capital for the utilities it regulates, while proceedings are ongoing in Newfoundland and Québec.

EXCERPTS FROM UTILITIES COMMISSION ACT

Discrimination in rates

59 (1) A public utility must not make, demand or receive

(a) an unjust, unreasonable, unduly discriminatory or unduly preferential rate for a service provided by it in British Columbia, or

(b) a rate that otherwise contravenes this Act, the regulations, orders of the commission or any other law.

(2) A public utility must not

(a) as to rate or service, subject any person or locality, or a particular description of traffic, to an undue prejudice or disadvantage, or

(b) extend to any person a form of agreement, a rule or a facility or privilege, unless the agreement, rule, facility or privilege is regularly and uniformly extended to all persons under substantially similar circumstances and conditions for service of the same description.

(3) The commission may, by regulation, declare the circumstances and conditions that are substantially similar for the purpose of subsection (2) (b).

(4) It is a question of fact, of which the commission is the sole judge,

(a) whether a rate is unjust or unreasonable,

(b) whether, in any case, there is undue discrimination, preference, prejudice or disadvantage in respect of a rate or service, or

(c) whether a service is offered or provided under substantially similar circumstances and conditions.

(5) In this section, a rate is "unjust" or "unreasonable" if the rate is

(a) more than a fair and reasonable charge for service of the nature and quality provided by the utility,

(b) insufficient to yield a fair and reasonable compensation for the service provided by the utility, or a fair and reasonable return on the appraised value of its property, or

(c) unjust and unreasonable for any other reason.

Setting of rates

60 (1) In setting a rate under this Act

(a) the commission must consider all matters that it considers proper and relevant affecting the rate,

(b) the commission must have due regard to the setting of a rate that

(i) is not unjust or unreasonable within the meaning of section 59,

(ii) provides to the public utility for which the rate is set a fair and reasonable return on any expenditure made by it to reduce energy demands, and

(iii) encourages public utilities to increase efficiency, reduce costs and enhance performance,

(b.1) the commission may use any mechanism, formula or other method of setting the rate that it considers advisable, and may order that the rate derived from such a mechanism, formula or other method is to remain in effect for a specified period, and

(c) if the public utility provides more than one class of service, the commission must

(i) segregate the various kinds of service into distinct classes of service,

(ii) in setting a rate to be charged for the particular service provided, consider each distinct class of service as a self contained unit, and

(iii) set a rate for each unit that it considers to be just and reasonable for that unit, without regard to the rates fixed for any other unit.

(2) In setting a rate under this Act, the commission may take into account a distinct or special area served by a public utility with a view to ensuring, so far as the commission considers it advisable, that the rate applicable in each area is adequate to yield a fair and reasonable return on the appraised value of the plant or system of the public utility used, or prudently and reasonably acquired, for the purpose of providing the service in that special area.

(3) If the commission takes a special area into account under subsection (2), it must have regard to the special considerations applicable to an area that is sparsely settled or has other distinctive characteristics.

(4) For this section, the commission must exclude from the appraised value of the property of the public utility any franchise, licence, permit or concession obtained or held by the utility from a municipal or other public authority beyond the money, if any, paid to the municipality or public authority as consideration for that franchise, licence, permit or concession, together with necessary and reasonable expenses in procuring the franchise, licence, permit or concession.

Partial relief

89 On an application under this Act, the commission may make an order granting the whole or part of the relief applied for or may grant further or other relief, as the commission considers advisable.

LIST OF APPEARANCES

G.A. FULTON, Q.C.	Commission Counsel
C.B.JOHNSON, Q.C. T. AHMED	Terasen Gas Inc. Terasen Gas (Vancouver Island) Inc. Terasen Gas (Whistler) Inc.
R.B. WALLACE	Joint Industry Electricity Steering Committee
C. WEAFER	Commercial Energy Consumers of BC
E. KUNG L. WORTH	British Columbia Old Age Pensioners Organization (“BCOAPO”) Active Support Against Poverty B.C. Coalition of People with Disabilities Council of Seniors' Organizations of B.C. End Legislated Poverty Federated Anti-Poverty Groups of B.C. Tenants' Rights Action Coalition
D. BURSEY	Industrial Customer Group, comprising Certainteed Gypsum Canada Inc., Domtar Pulp and Paper Products Inc., Federated Co-operatives Ltd., Teck Metals Ltd., Weyerhaeuser Company Ltd. and Zellstoff Celgar Limited Partnership
R.J. McDONELL	FortisBC Inc.
C. DONOHUE	Pacific Northern Gas Ltd.

E. Cheng F.Metcalfe	Commission Staff Contract Staff
Court Reporters	Allwest Reporting Ltd.

LIST OF PANELS

Terasen Gas Inc., Terasen Gas (Vancouver Island) Inc., Terasen Gas (Whistler) Inc

PANEL 1 – Company and Policy Panel

RANDY JESPERSEN	President and Chief Executive Officer
SCOTT THOMPSON	Vice President, Regulatory Affairs
ROGER DALL'ANTONIA	Vice President, Treasurer

PANEL 2 - Expert Opinion on a Benchmark Fair Return

JAMES H. VANDER WEIDE, PhD	Duke University

PANEL 3 - Expert Opinion on Capital Markets with Company View

DONALD A. CARMICHAEL, MBA	Financial Consultant
ROGER DALL'ANTONIA	Vice President, Treasurer

PANEL 4 - Expert Opinion on a Benchmark Fair Return

KATHLEEN C. MCSHANE, MBA, CFA	President, Foster Associates Inc.

The Joint Industry Electricity Steering Committee, the Commercial Energy Consumers Association of British Columbia and the British Columbia Old Age Pensioners Organization

LAURENCE G. BOOTH, DBA	University of Toronto

IN THE MATTER OF
the Utilities Commission Act, R.S.B.C. 1996, Chapter 473

and

Terasen Gas Inc.
Terasen Gas (Vancouver Island) Inc. and
Terasen Gas (Whistler) Inc.
collectively the "Terasen Utilities"
Return on Equity and Capital Structure Application

EXHIBIT LIST

Exhibit No.	Description
COMMISSION DOCUMENTS	
A-1	Letter dated May 21, 2009 appointing the Commission Panel for the review of the Terasen Utilities Application for a Return on Equity and Capital Structure Application
A-2	Letter dated May 21, 2009 Preliminary Regulatory Timetable, Notice of Procedural Conference and Written Public Hearing.
A-2-1	Submitted at hearing September 28, 2009 Monthly Price Report - Canadian Natural Gas Focus dated September 2009
A-2-2	Submitted at hearing September 28, 2009 Newspaper article in the Vancouver Sun from September 2nd
A-2-3	Submitted at hearing September 29, 2009 Recalculated ROE without any adjustments
A-2-4	Submitted at hearing September 30, 2009 NATIONAL BANK FINANCIAL, SEPTEMBER 14, 2009 Corporate Indicative Issuance Spreads based on Government of Canada Yield Curve
A-2-5	Submitted at hearing October 1, 2009 Article entitled "How did economists get it so wrong" by Paul Krugman from the New York Times September 6, 2009
A-3	Letter dated June 9, 2009 Regulatory Timetable

APPENDIX F
to Order G-158-09
Page 2 of 7

Exhibit No.	Description
A-4	Letter dated June 24, 2009 – Reasons for Decision for Interim rate Relief
A-5	Letter dated June 29, 2009 BCUC IR No. 1 to Terasen Utilities
A-6	Letter dated July 31, 2009 BCUC IR No. 2 to Terasen Utilities
A-7	Letter dated September 2, 2009 Commission Panel Information Request No. 1 to Terasen Utilities
A-8	Letter dated September 3, 2009 Information Request No. 1 on the Evidence of Dr. Laurence Booth
A-9	Letter dated September 21, 2009 – Opening Statement
A-10	Letter dated October 27, 2009 – Oral Phase of Argument
A-11	Letter dated November 16, 2009 – Oral Phase of Argument
A-12	Letter dated November 18, 2009 - Oral Phase of Argument

APPLICANT DOCUMENTS TERASEN UTILITIES

B-1	Letter dated May 15, 2009 Terasen Utilities application for Return on Equity and Capital Structure.
B-2	Letter dated June 18, 2009 Terasen Utilities Reply Comments on Interim Relief
B-3	Letter dated July 20, 2009 Response to BCUC IR No. 1
B-3-1	Response to BCUC IR No. 1 Attachments Parts 1of 5
B-3-2	Response to BCUC IR No. 1 Attachments Parts 2 of 5
B-3-3	Response to BCUC IR No. 1 Attachments Parts 3 of 5
B-3-4	Response to BCUC IR No. 1 Attachments Parts 4 of 5
B-3-5	Response to BCUC IR No. 1 Attachments Parts 5 of 5
B-4	Letter dated July 20, 2009 Terasen Utilities Response to CEC IR No. 1

Exhibit No.	Description
B-5	Letter dated July 20, 2009 Terasen Utilities Response to JIESC-BCOAPO-CEC IR No. 1
B-6	Letter dated August 13, 2009 Terasen Utilities Response to BCUC IR No. 2
B-7	Letter dated August 13, 2009 Terasen Utilities Response to JIESC-BCOAPO-CEC IR No. 2
B-8	Letter dated August 13, 2009 Terasen Utilities Response to CEC IR No. 2
B-9	Letter dated September 3, 2009 Terasen Utilities IRs on the Evidence of Dr. L. Booth
B-10	Letter dated September 21, 2009 Erratum Response to IR No. 1.24.2 - page 80 of Exhibit B-3 correcting the table and highlighting the affected cells.
B-11	Letter dated September 21, 2009 Response to Commission Panel IR No. 1
B-12	Letter dated September 21, 2009 Terasen Utilities Witness Panels and Direct Testimony
B-12-1	Letter dated September 21, 2009 REPLACEMENT with corrections - Terasen Utilities Witness Panels and Direct Testimony
B-13	Letter dated September 24, 2009 Opening Statement of R.L. (Randy) Jespersen, CEO on Behalf of the Terasen Utilities
B-14	Submitted at hearing September 28, 2009 Speech from the Throne August 25, 2009
B-15	Submitted at hearing September 28, 2009 Response from the Terasen Gas Inc. revenue requirement application to a Commission Staff Request 2.31.2
B-16	Submitted at hearing September 28, 2009 Full BC Hydro Service Plan, the August, 2009 update
B-17	Submitted at hearing September 29, 2009 Moody's A-rated and Baa-rated Utility Bond Yields
B-18	Submitted at hearing September 29, 2009 common equity component of Fortis
B-19	Submitted at hearing September 30, 2009 Consumer Prices Consensus Economics, Consensus Forecasts, Long-Term Forecasts
B-20	Submitted at hearing October 1, 2009 TGI 2005 ROE Exhibit B-3, Response to BCUC IR 74.1, Appendix 74.1

Exhibit No.	**Description**
B-21	Submitted at hearing October 1, 2009 (PAGES 193 AND 194 FROM FINANCIAL THEORY AND CORPORATE POLICY BY COPELAND AND WESTON WITH ATTACHED TRANSCRIPT PAGES 795 AND 796 FROM 2005
B-22	Submitted at hearing October 1, 2009 PAPER BY DR. BOOTH ENTITLED "CAPITAL MARKET DEVELOPMENTS IN THE POST-OCTOBER 1987 PERIOD: A CANADIAN PERSPECTIVE
B-23	Submitted at hearing October 1, 2009 COLOURED GRAPH, WITH PAGES 790 TO 804 FROM TGI-TGVI ROE HEARING, NOVEMBER 17, 2005, VOLUME 5
B-24	Submitted at hearing October 1, 2009 TAB 2, APPENDIX A, RISK-ADJUSTED EQUITY MARKET RISK PREMIUM TEST
B-25	Submitted at hearing October 1, 2009 TWO TABLES, BOTH HEADED "EXHIBIT, COMPARISON OF DR. BOOTH'S COST OF EQUITY RESULTS TO THE YIELDS ON MOODY'S A-RATED AND BAA-RATED UTILITY BONDS”
B-26	Submitted at hearing October 1, 2009 SCHEDULE 12, SPREADS SINCE 1990, WITH ATTACHED PAGE 15
B-27	Submitted at hearing October 1, 2009 70 REFERENCE: APPENDIX B, PAGE 1, LINES 18-25", PAGE 78
B-28	Letter dated October 20, 2009 Submission of Outstanding Undertakings

INTERVENOR DOCUMENTS

C1	**BRITISH COLUMBIA OLD AGE PENSIONERS' ORGANIZATION (BCOAPO) -** Letter dated May 29, 2009 filing request by Leigha Worth for Intervenor Status
C1-2	Letter dated June 15, 2009 via Email BCOAPO submissions on interim relief
C2-1	Changed to Interested Party
C3-1	**COMMERCIAL ENERGY CONSUMERS ASSOCIATION OF BRITISH COLUMBIA (CEC) VIA EMAIL -** dated June 4, 2009, 2009 filing request by Christopher Weafer for Intervenor Status
C3-2	Letter dated June 12, 2009 CEC submissions on interim relief

Exhibit No.	Description
C3-3	Letter dated July 07, 2009 CEC information Request No. 1
C3-4	Letter dated July 31, 2009 CEC information Request No. 2
C4-1	**LOUELLA VINCENT VIA EMAIL -** dated May 31, 2009, 2009 filing request for Intervenor Status
C5-1	**BC HYDRO (BCH) ONLINE REGISTRATION -** dated June 5, 2009, filing request for Intervenor Status
C6-1	**FORTIS BC (FBC) ONLINE REGISTRATION -** dated June 5, 2009, filing request by Dennis Swanson for Intervenor Status
C6-2	Removed exhibit: under Arguments
C7-1	**MINISTRY OF ENERGY, MINES AND PETROLEUM RESOURCES (MEMPR)** letter dated June 8, 2009, filing request by Duane Chapman for Intervenor Status
C8-1	**VANCOUVER ISLAND GAS JOINT VENTURE (VIGJV)** letter dated June 5, 2009, filing request by Karl Gustafson for Intervenor Status
C9-1	**ZELLSTOFF CELGAR (ZC)** letter dated June 8, 2009, filing request by Brian Merwin for Intervenor Status
C9-2	Letter dated June 8, 2009 Via Email ZC submissions on interim relief
C10-1	**PACIFIC NORTHERN GAS (PNG) - VIA EMAIL** letter dated June 8, 2009 filing request by Craig Donohue for Intervenor Status
C11-1	**JOINT INDUSTRY ELECTRICITY STEERING COMMITTEE (JIESC)** letter dated June 8, 2009 filing request by Brian Wallace for Intervenor Status
C11-1-1	Submitted at hearing September 30, 2009 EXHIBIT C11-11, AMENDED Page 5 CIA-Canadian Institute of Actuaries data Exhibits of Dr.Vander Weide taken from CIA
C11-2	Letter dated June 8, 2009 JIESC submissions on interim relief
C11-3	Letter dated July 6, 2009 **- VIA EMAIL** Joint Information Request on behalf of JIESC, BCOAPO and CEC
C11-4	Letter dated July 30, 2009 **- VIA EMAIL** Joint Information Request 2 on behalf of JIESC, BCOAPO and CEC
C11-5	Letter dated August 2009 JIESC submission Evidence of Laurence D. Booth

APPENDIX F
to Order G-158-09
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Exhibit No.	**Description**
C11-6	Letter dated September 15, 2009 Response of Dr. Booth to BCUC IR No. 1
C11-7	Letter dated September 15, 2009 Dr. Booth responses to TGI IR No.1
C11-8	Submitted at hearing September 28, 2009 Excerpt from BC Hydro Service Plan 2009/10 - 2011/12
C11-9	Submitted at hearing September 28, 2009 Excerpt from BC Hydro Service Plan 2009/10 - 2011/12 August 2009 Update
C11-10	Submitted at hearing September 29, 2009 Alberta EUB Decision Generic Cost of Capital
C11-11	Submitted at hearing September 29, 2009 JIESC materials for cross-examination of Terasen panel number two
C11-12	Submitted at hearing September 30, 2009 Scotia Bank Group Global Economic Research Weekly Trends from September 25, 2009
C11-13	Submitted at hearing September 30, 2009 Scotia Bank Group Global Economic Research – Global Forecast Update September 3, 2009
C11-14	Submitted at hearing September 30, 2009 Excerpt of Direct Testimony of James M Coyne on Behalf of ATCO Utilities ET AL November 20, 2008 in Alberta Utilities Commission 2009 Generic Cost of Capital Proceeding
C11-15	Submitted at hearing September 30, 2009 Bank of Montreal Capital Markets report on Fortis Dated June 11, 2009
C11-16	Submitted at hearing October 1, 2009 ARTICLE FROM *THE JOURNAL OF FINANCE*, VOL. XLVI, NO. 4, SEPTEMBER 1991 ENTITLED "LIQUIDITY, MATURITY AND THE YIELDS ON U.S. TREASURY SECURITIES BY Y. AMIHUD AND H. MENDELSON
C11-17	Letter received October 14, 2009 JIESC/CEC/BCOAPO joint submission Dr. Booth's Responses to Undertakings
C12-1	**TECK COAL LTD (TC) – VIA EMAIL** Letter Dated July 06, 2009 filing by J. David Newlands to register as Intervenor

Exhibit No.	Description
C13-1	**INDUSTRIAL CUSTOMER GROUP (ICG) – VIA EMAIL** Letter Dated July 24, 2009 filing by and for David Bursey, Katie Seymour and Harold Todd to register as Intervenor (Certainteed Gypsum Canada Inc., Domtar Pulp and Paper Products Inc., Federated Co-operatives Ltd., Teck Metals Ltd., Weyerhaeuser Company Ltd., Zellstoff Celgar Limited Partnership)

INTERESTED PARTY DOCUMENTS

D-1	**CENTRAL HEAT DISTRIBUTION (CHD)** Letter Dated May 22, 2009 John Barnes filing to register as Interested Party
D-2	**COPE 378 (COPE) ONLINE REGISTRATION -** dated June 5, 2009, filing request by Kevin Smyth to register as Interested Party
D-3	**BP CANADA ENERGY COMPANY ONLINE REGISTRATION-** dated June 3, 2009, filing request by Cheryl Worthy to register as Interested Party
D-4	**BRITISH COLUMBIA TRANSMISSION CORPORATION (BCTC) ONLINE REGISTRATION -** dated June18, 2009, filing request by Gordon Doyle to register as Interested Party
D-5	**ACCESS GAS SERVICES INC. – ONLINE REGISTRATION** dated July 20, 2009 filing request by Tom Dixon for Interested party status

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Susan Frank
Vice President and Chief Regulatory Officer
Regulatory Affairs

BY COURIER

November 6, 2012

Ms. Kirsten Walli
Secretary
Ontario Energy Board
Suite 2700, 2300 Yonge Street
Toronto, ON.
M4P 1E4

Dear Ms. Walli:

EB-2012-0031 – Hydro One Networks' 2013 and 2014 Transmission Revenue Requirement Application – Hydro One Update to Settlement Agreement

Further to Ms. Varjacic's letter of November 2, 2012, attached please find the updated Settlement Agreement which provides more detailed evidentiary references.

An electronic copy of the Agreement have been filed using the Board's Regulatory Electronic Submission System.

Sincerely,

ORIGINAL SIGNED BY SUSAN FRANK

Susan Frank

Attach.

EB-2012-0031

SETTLEMENT AGREEMENT

Hydro One Networks Inc.
Test year 2013 and 2014 Transmission Rates

November 6, 2012

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Hydro One Networks Inc.
Test Year 2013 and 2014 Transmission Rates
EB-2012-0031

SETTLEMENT AGREEMENT

PREAMBLE:

This Settlement Agreement is filed with the Ontario Energy Board ("the Board") in connection with the application by Hydro One Networks Inc. ("Hydro One") for an Order or Orders approving the revenue requirement and customer rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

Further to the Board's Procedural Order No. 3 dated and issued October 1, 2012, a Settlement Conference was held on October 23, 24, 25 and 26, 2012 in accordance with the *Ontario Energy Board Rules of Practice and Procedure* ("Rules") and the Board's Settlement Conference Guidelines ("Guidelines").

Hydro One and the following intervenors ("the parties") participated in the settlement conference:

Association of Major Power Consumers in Ontario ("AMPCO")
Association of Power Producers of Ontario ("APPrO")
Building Owners and Managers Association Toronto ("BOMA")
Canadian Manufacturers & Exporters ("CME")
Consumers Council of Canada ("CCC")
Energy Probe Research Foundation ("EP")
Goldcorp
London Property Management Association ("LPMA")
Pollution Probe ("PP") – participation subsequently withdrawn from proceeding
Power Workers' Union ("PWU")
School Energy Coalition ("SEC")
Vulnerable Energy Consumers Coalition ("VECC")

Ontario Energy Board staff also participated in the settlement conference, but are not a party to this settlement agreement.

Outlined below are the positions of the parties following the settlement conference. The settlement agreement follows the format of the Approved Issues List for ease of reference. The issues are characterized as follows:

Settled: If the settlement agreement is accepted by the Board, the parties will not adduce any evidence or argument during the oral hearing as the Applicant and those intervenors who take any position on the issue agree to the proposed settlement;

Partially Settled: If the settlement agreement is accepted by the Board, the parties will only adduce evidence and argument during the hearing on portions of the issues as the Applicant and those intervenors who take any position on the issue were able to agree on some, but not all, aspects of the particular issue; and

Not Settled: The Applicant and those intervenors who take a position on the issue will adduce evidence and argument at the hearing on the issue as the parties were unable to reach agreement.

For ease of reference, the following outlines the status of the issues as outlined in the Settlement Agreement:

Settled: Issue completely resolved. Parties will not adduce evidence or argument at the hearing.	**Partially Settled:** Issue partially resolved. Parties will adduce evidence and argument at hearing on certain portions of the issue.	**Not Settled:** Issue not resolved. Evidence to be adduced and argument presented on entirety of issue.
# issues settled: 23	# issues partially settled: 1	# issues not settled: 1

The positions taken by the various parties on each of the settled issues are identified throughout the Settlement Agreement. A party who is noted as taking no position on an issue may or may not have participated in the discussion on that particular issue and takes no position on the settlement reached or on the sufficiency of the evidence filed to date.

The Settlement Agreement provides a brief description of each of the settled issues, together with references to the evidence filed. The supporting parties to each settled issue agree that the evidence in respect of that settled issue, as supplemented in some instances by additional information recorded in the proposal, supports the proposed settlement. In addition, the supporting parties agree that the evidence filed in support of each settled issue and the additional information as recorded herein contains sufficient detail, rationale and quality of information to allow the Board to make findings in keeping with the settlement reached. The Intervenors are relying on the accuracy and completeness of the Appendices in entering into this Agreement.

The Board's Settlement Conference Guidelines (p.3) require the parties to consider whether a settlement agreement should include an adjustment mechanism for any settled issue that may be affected by external factors. Hydro One and the other parties who participated in the Settlement Conference consider that no settled issues require such an adjustment mechanism other than those expressly set forth in this settlement agreement.

None of the parties can withdraw from the Settlement Agreement except in accordance with Rule 32 of the Ontario Energy Board's *Rules of Practice and Procedure*. Finally, unless stated otherwise, the settlement of any particular issue in this proceeding and the positions of the parties in this Proposal are without prejudice to the rights of parties to raise the same issue and/or to take any position thereon in any other proceedings, unless explicitly stated otherwise.

The parties agree that the remaining unsettled issue will be dealt with during the oral phase of this proceeding, subject to further direction from the Board. The outstanding issue relating to rate base is regarding the net book value (NBV) of Red Lake TS. Goldcorp is the only intervenor with concerns. Hydro One proposes that this issue be dealt with as directed by the Board.

The parties agree that all positions, negotiations and discussion of any kind whatsoever that took place during the Settlement Conference and all documents exchanged during the conference that were prepared to facilitate settlement discussions are strictly confidential and without prejudice, and inadmissible unless relevant to the resolution of any ambiguity that subsequently arises with respect to the interpretation of any provision of this Settlement Agreement.

It is fundamental to the agreement of the parties that none of the provisions of this Settlement Agreement are severable. If the Board does not, prior to the commencement of the hearing of the evidence in this proceeding, accept the provisions of the Settlement Agreement in their entirety there is no Settlement Agreement unless the parties agree to the contrary.

For the Board's ease of reference, a List of Approvals Sought is attached as Appendix A.

OVERVIEW:

The parties were able to reach agreement on most issues, including Operations, Maintenance & Administration (OM&A) costs, Capital Expenditures and Rate Base, and all other Revenue Requirement related issues. The parties were unable to reach agreement on the appropriate Export Transmission rate for 2013 and 2014 and have therefore agreed that this issue should proceed to the oral hearing, subject to further direction from the Board

Overall rate impacts were a guiding principle that led to the Settlement Agreement. Hydro One filed a rate application seeking a 0.6% increase in 2013 transmission rates and a 9.1% increase in 2014 transmission rates. The parties efforts were focused on determining an appropriate Revenue Requirement and resulting rate levels for 2013 and 2014, while balancing Hydro One's need to continue to safely and reliably operate and to fund its expanding work program.

The overall financial impact of the Settlement Agreement is to reduce the revenue requirement from $1,464.5M to $1,445.7M in 2013 and $1,557.7M to $1,537.2M in 2014 or by $18.7M and $20.5M respectively. The resulting overall rate impact is a 0% rate increase in 2013 and 7.1% rate increase in 2014, down from 0.6% and 9.1% rate increases in the Application. The financial rate impact calculation is attached to this Settlement Agreement as Appendix B.

As noted above, all parties agree that the Settlement Agreement is a broad package proposal. Thus, individual components of the Settlement Agreement ought not be considered or reviewed in isolation. All parties agree the overall package of the Settlement Agreement represents a fair and reasonable agreement that balances the interests of all stakeholders including the ratepayers, the intervenors, concerns previously noted by the Board and Hydro One's needs in order to run a safe and reliable transmission system.

Only one issue remains outstanding – the Export Transmission Service (ETS) rate to be charged. Several parties have filed evidence regarding the appropriate ETS rate including the IESO, APPrO and Hydro-Québec Energy Marketing Inc. (HQ). Hydro One is neutral regarding this issue.

The particulars of the Settlement Agreement are detailed below by issue as set out in the Issues List.

GENERAL

1. Has Hydro One responded appropriately to all relevant Board directions from previous proceedings?

   Settled. For the purposes of reaching a settlement, the parties accept that the Applicant has appropriately responded to all directives from prior proceedings. Particulars, where relevant, are discussed below in the context of other issues.

   Evidence: The evidence in relation to this issue includes the following:

A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model

A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
A-19-1	Summary of Board Directives and Undertakings from Previous Proceedings
C1-3-3	Development OM&A
C1-3-3 Attachment 1	Smart Grid Development Report
C1-5-2	Compensation, Wages, Benefits
C1-5-2 Attachment 1	Mercer Compensation Cost Benchmarking Study
C1-5-2 Attachment 2	Payroll Table 2009 to 2012
C1-7-2	Overhead Capitalization Rate
C1-7-2 Attachment 1	Review of Overhead Capitalization Rates (Transmission) - 2013/2014
C1-7-2 Attachment 2	Review of Overhead Capitalization Policy
D1-3-3	Development Capital
D1-3-3 Appendix A	Summary of Development Capital Projects in Excess of $3 Million
D1-3-3 Appendix B	OPA Supporting Material for Oshawa TS
D1-3-3 Appendix C	OPA Document on Southwestern Ontario Reactive Compensation Milton SVC dated March 2012
D1-3-3 Appendix D	Letter from OPA dated June 30, 2011
D1-3-3 Appendix E	Letter from OPA dated March 8, 2012
D1-3-3 Appendix F	Letter from OPA dated August 7, 2012
D2-2-3	Investment Summary for Programs/Projects in excess of $3M
F1-1-1	Regulatory Accounts
H1-5-1	Rates for Export Transmission Service
I-1-1.01 Staff 1	OEB Interrogatory #1

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

2. Is the overall increase in 2013 and 2014 revenue requirement reasonable?

Settled. For the purposes of reaching a settlement, the parties agree that the settled revenue requirement before adjustment of $1,445.7M in 2013 and $1,537.2M in 2014 is reasonable. The parties are further in agreement that after adjusting for External Revenues, the Export Revenue Credit, transmission riders and low voltage switch gear items, the Rates Revenue Requirement resulting from this settlement agreement of $1,390.3M in 2013 and $1457.0M in 2014 is reasonable. This represents a decrease of $8.2M in 2013 and a decrease of $36.2M in 2014 from the application as originally filed. The resulting rate increase will be 0.0% in 2013 and 7.1% in 2014 versus 0.6% and 9.1% as proposed in the application.

The parties agree that the revenue requirement will be adjusted to reflect the Board's latest cost of capital parameters for the 2013 and 2014 test years in the final rate order as described in Exhibit B1, Tab 1, Schedule 1.

As of December 31, 2012, there will be a regulatory asset balance of ($30.3M). Hydro One initially proposed refunding that asset balance equally over each of the test years. In an effort to strive for a 0% increase in transmission rates for 2013, the parties agreed to utilize the regulatory asset balance as a balancing item to ensure that the increase in 2013 remains at 0.0% after other adjustments are made (such as for the latest cost of capital parameters). Any remaining balance will be refunded to customers in 2014. The precise amount to be refunded in the test years will be reflected in the final rate order.

The table below summarizes the proposal:

Hydro One Transmission Revenue Requirement Settlement Agreement

	2012	2013	2014
OM&A		440.3	449.7
Depreciation		345.0	371.5
Income tax		46.2	55.7
Cost of capital		614.2	660.4
Revenue requirement	**1,418.4**	**1,445.7**	**1,537.2**
	5.4%	1.9%	6.3%
Less: External revenues		-31.6	-36.6
Less: Export revenue credit		-31.0	-30.1
Less: "Tx Riders"		-4.5	-25.7
Add: LVSG		11.7	12.2
Rates Revenue Requirement	**1,385.1**	**1,390.3**	**1,457.0**
		0.4%	4.8%
Estimated impact of load reduction		0.4%	-2.3%
Assumed Rate Impact		**0.0%**	**7.1%**

Hydro One's application as filed assumes that the ETS rate would remain at $2/MWh. A number of alternative rates are being proposed. Should the Board approve a change in the ETS rate, the parties agree that the full impact of the change will be tracked in the existing Board approved Excess Export Services Revenue Account for disposition in a future rate application.

Evidence: The evidence in relation to this issue includes the following:

E1-1-1	Revenue Requirement
E2-1-1	Calculation of Revenue Requirement
I-2-1.01 Staff 2	OEB Interrogatory #2
I-2-1.02 Staff 3	OEB Interrogatory #3

I-2-1.03 Staff 4	OEB Interrogatory #4
I-2-1.04 Staff 5	OEB Interrogatory #5
I-2-1.05 Staff 6	OEB Interrogatory #6
I-2-1.06 Staff 7	OEB Interrogatory #7
I-2-1.07 Staff 8	OEB Interrogatory #8
I-2-1.08 Staff 9	OEB Interrogatory #9
I-2-1.09 Staff 10	OEB Interrogatory #10
I-2-1.10 Staff 11	OEB Interrogatory #11
I-2-1.11 Staff 12	OEB Interrogatory #12
I-2-1.12 Staff 13	OEB Interrogatory #13
I-2-1.13 Staff 14	OEB Interrogatory #14
I-2-1.14 Staff 15	OEB Interrogatory #15
I-2-2.01 LPMA 1	LPMA Interrogatory #1
I-2-3.01 EP 1	Energy Probe Interrogatory #1
I-2-3.02 EP 2	Energy Probe Interrogatory #2
I-2-3.03 EP 3	Energy Probe Interrogatory #3
I-2-3.04 EP 4	Energy Probe Interrogatory #4
I-2-3.05 EP 5	Energy Probe Interrogatory #5
I-2-3.06 EP 6	Energy Probe Interrogatory #6
I-2-3.07 EP 7	Energy Probe Interrogatory #7
I-2-5.01 VECC 1	VECC Interrogatory #1
I-2-5.02 VECC 2	VECC Interrogatory #2
I-2-5.03 VECC 3	VECC Interrogatory #3
I-2-5.04 VECC 4	VECC Interrogatory #4
I-2-5.05 VECC 5	VECC Interrogatory #5
I-2-5.06 VECC 6	VECC Interrogatory #6
I-2-5.07 VECC 7	VECC Interrogatory #7
I-2-5.08 VECC 8	VECC Interrogatory #8
I-2-5.09 VECC 9	VECC Interrogatory #9
I-2-5.10 VECC 10	VECC Interrogatory #10
I-2-5.11 VECC 11	VECC Interrogatory #11
I-2-5.12 VECC 12	VECC Interrogatory #12
I-2-5.13 VECC 13	VECC Interrogatory #13
I-2-5.14 VECC 14	VECC Interrogatory #14
I-2-8.01 PWU 1	PWU Interrogatory #1
I-2-9.01 SEC 1	SEC Interrogatory #1
I-2-9.02 SEC 2	SEC Interrogatory #2
I-2-9.04 SEC 4	SEC Interrogatory #4
I-2-9.05 SEC 5	SEC Interrogatory #5
I-2-9.06 SEC 6	SEC Interrogatory #6
I-2-10.01 CCC 1	CCC Interrogatory #1
I-2-10.02 CCC 2	CCC Interrogatory #2

I-2-10.03 CCC 3	CCC Interrogatory #3
I-2-10.04 CCC 4	CCC Interrogatory #4
I-2-10.05 CCC 5	CCC Interrogatory #5
I-2-14.01 CME 1	CME Interrogatory #1
JT1.1 TCR Staff 4	OEB Technical Conference Response #4
KT1.12	Undertaking Response #12

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

LOAD FORECAST AND REVENUE FORECAST

3. Is the load forecast and methodology appropriate and have the impacts of Conservation and Demand Management initiatives been suitably reflected?

   Settled. For the purposes of reaching a settlement, all parties accept Hydro One's load forecast as set out in Exhibit A, Tab 15, Schedule 2. Hydro One continues to apply the same forecasting methodology previously approved by the Board in EB-2010-0002 which the parties agree remains appropriate.

   The impacts of CDM and Demand Response and how they are reflected in the load forecast were the primary areas of concern for some intervenors. The Board had some concern in this area as well in prior proceedings. In EB-2010-0002, Hydro One's last Transmission Rates Application, the Board directed Hydro One to work with the OPA to devise a means of effectively and accurately measuring CDM impacts. Hydro One has done so and has relied upon the latest CDM and Demand Response forecasts in its load forecast for the test years.

   There remains some concern on the part of certain intervenors about the accuracy and reliability of the CDM and Demand Response forecasts prepared by the OPA. In order to address those concerns, Hydro One has agreed to establish a new variance account to track the impact of actual CDM and Demand Response results on the Load Forecast and the resulting impact on revenue requirement.

   Hydro One agrees to set up a variance account to track the difference between the forecast of 755MW for 2013 and 1158MWfor 2014 and the actual CDM savings related to the OPA-funded, LDC-delivered programs. Hydro One will use the annual results reported by the OPA in September of each year for the verified results of the previous year in accordance with the CDM Guidelines issued by the Board in EB-2012-0003. Time-of-use savings will not be included in this variance account because they are currently not included in the annual province-wide CDM program results reported by the OPA.

Hydro One also agreed to track the actual Demand Response results against the forecast as set out in Exhibit A, Tab 15, Schedule 2, Attachment 1, Appendix A, Table 8 of 836MW in 2013 and 880MW2014 (net of 317MW and 410MW respectfully for 2013 and 2014 already included in CDM program results delivered by LDCs) in this variance account. Hydro One will use annual Demand Response results provided by the OPA each September for results of the previous year in a similar format as the province-wide CDM results delivered by the LDCs.

The disposition of the balance in the LDC CDM and Demand Response Variance Account will be part of a future Rate Application.

Evidence: The evidence in relation to this issue includes the following:

A-6-1	Compliance with OEB Filing Requirements for Electricity Transmitters
A-15-1	Economic Indicators
A-15-2	Business Load Forecast and Methodology
A-15-2 Appendix A	Monthly Econometric Model
A-15-2 Appendix B	Annual Econometric Model
A-15-2 Appendix C	End-Use Model
A-15-2 Appendix D	Historical Ontario Demand and Charge Determinant Data
A-15-2 Appendix E	Consensus Forecast for Ontario GDP and Housing Starts
A-15-2 Appendix F	Forecast Accuracy
A-15-2 Attachment 1	Incorporating Conservation and Demand Management Impacts in the Load Forecast
I-3-1.01 Staff 16	OEB Interrogatory #16
I-3-1.02 Staff 17	OEB Interrogatory #17
I-3-1.03 Staff 18	OEB Interrogatory #18
I-3-1.04 Staff 19	OEB Interrogatory #19
I-3-1.05 Staff 20	OEB Interrogatory #20
I-3-1.06 Staff 21	OEB Interrogatory #21
I-3-1.07 Staff 22	OEB Interrogatory #22
I-3-2.01 LPMA 2	LPMA Interrogatory #2
I-3-2.02 LPMA 3	LPMA Interrogatory #3
I-3-2.03 LPMA 4	LPMA Interrogatory #4
I-3-2.04 LPMA 5	LPMA Interrogatory #5
I-3-3.01 EP 8	Energy Probe Interrogatory #8
I-3-3.02 EP 9	Energy Probe Interrogatory #9
I-3-3.03 EP 10	Energy Probe Interrogatory #10
I-3-5.01 VECC 15	VECC Interrogatory #15
I-3-5.02 VECC 16	VECC Interrogatory #16
I-3-5.03 VECC 17	VECC Interrogatory #17
I-3-5.04 VECC 18	VECC Interrogatory #18
I-3-5.05 VECC 19	VECC Interrogatory #19

I-3-5.06 VECC 20	VECC Interrogatory #20
I-3-5.07 VECC 21	VECC Interrogatory #21
I-3-5.08 VECC 22	VECC Interrogatory #22
I-3-5.09 VECC 23	VECC Interrogatory #23
I-3-5.10 VECC 24	VECC Interrogatory #24
I-3-5.11 VECC 25	VECC Interrogatory #25
I-3-13.01 AMPCO 1	AMPCO Interrogatory #1
I-3-13.02 AMPCO 2	AMPCO Interrogatory #2
I-3-13.03 AMPCO 3	AMPCO Interrogatory #3
JT1.2 TCR EP1	Energy Probe Technical Conference Response #1
KT1.6	Undertaking Response #6
KT1.7	Undertaking Response #7
KT1.8	Undertaking Response #8

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

4. Are Other Revenue (including export revenue) forecasts appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the 2013 external revenue forecast of $31.6M is appropriate. Some intervenors were concerned that the forecast for external revenues in 2014 was too low based on historical average actual external revenues. Accordingly, as part of the settlement, Hydro One agreed to increase the forecast for external revenues in 2014 by $4.8M to $36.6M from $31.8M in order to reflect the historical average of actual revenues in the previous three years. The table below summarizes the proposed change:

External Revenue ($M)	***2013***	***2014***
Filed Evidence	31.6	31.8
Settlement Agreement	31.6	36.6
Change Proposed	-	4.8

Three of the four inputs (Secondary Land Use, Station Maintenance and Engineering and Project Delivery) into the overall external revenue forecasts are currently tracked in symmetrical variance accounts. The parties agreed that all inputs into the external revenues should be tracked in a variance account. Thus, Hydro One agreed to create a new symmetrical variance account to track any differences in Other External Revenue.

As noted above, the parties have also agreed, that Hydro One will track any changes in ETS Revenue in the Excess Export Services Revenue Account should the Board approve a change to the current ETS rate of $2.00/MWh.

Evidence: The evidence in relation to this issue includes the following:

E1-2-1	External Revenues
I-4-2.01 LPMA 6	LPMA Interrogatory #6
I-4-2.02 LPMA 7	LPMA Interrogatory #7
I-4-2.03 LPMA 8	LPMA Interrogatory #8
I-4-2.04 LPMA 9	LPMA Interrogatory #9
I-4-2.05 LPMA 10	LPMA Interrogatory #10
I-4-2.06 LPMA 11	LPMA Interrogatory #11
I-4-5.01 VECC 26	VECC Interrogatory #26
I-4-5.02 VECC 27	VECC Interrogatory #27
I-4-5.03 VECC 28	VECC Interrogatory #28
I-4-5.04 VECC 29	VECC Interrogatory #29
I-4-9.01 SEC 7	SEC Interrogatory #7
I-4-10.01 CCC 6	CCC Interrogatory #6
I-4-10.02 CCC 7	CCC Interrogatory #7
KT1.23	Undertaking Response #23

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

OPERATIONS, MAINTENANCE AND ADMINISTRATION COSTS

Overall OM&A Settlement and its Rationale

All issues relating to Operations, Maintenance and Administration costs have been settled. The parties focused on overall spending levels for OM&A expenditures rather than focusing on any one particular aspect of those costs. The rationale for the settlement of Issues 5, 6 and 7 is outlined below.

Hydro One's application forecast OM&A expenditures of $453.3M and $459.7M in 2013 and 2014 respectively.

In order to address the concerns expressed by intervenors, balanced against Hydro One's needs to effectively operate the transmission business, combined with ongoing productivity initiatives being undertaken, Hydro One agreed to reduce 2013 spending levels by $13.0M from $453.3M to $440.3M. OM&A spending for 2014 will be reduced by $10M from $459.7M to $449.7M. The parties agree that these reduced proposed spending levels are appropriate.

The table below summarizes the proposed changes:

OM&A ($M)	***2013***	***2014***
Filed Evidence	453	460
Settlement Agreement	440	450
Change Proposed	-13	-10

5. Are the proposed spending levels for Sustaining, Development and Operations OM&A in 2013 and 2014 appropriate, including consideration of factors such as system reliability and asset condition?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

A-15-6	Work Execution Strategy
C1-1-1	Cost of Service Summary
C1-2-1	Sustaining Investment Structure
C1-2-2	Transmission Assets and Sustaining Investment Overview
C1-2-2 Appendix A	Hydro One Transmission Asset Descriptions
C1-3-1	Summary of OM&A Expenditures
C1-3-2	Sustaining OM&A
C1-3-3	Development OM&A
C1-3-3 Attachment 1	Smart Grid Development Report
C1-3-4	Operations OM&A
C1-3-5	Customer Care OM&A
C1-4-1	Summary of Shared Services – OM&A
C1-4-2	Common Corporate Functions & Services and Other OM&A
C1-4-3	Shared Services OM&A – Asset Management
C1-4-4	Shared Services OM&A – Information Technology
C1-4-4 Attachment 1	H1 Telecom Inc. Services Review and Benchmarking
C1-4-5	Shared Services OM&A – Cornerstone
C1-4-6	Shared Services OM&A – Cost of Sales - External Work
C1-4-7	Property Taxes
C2-1-1	Cost of Service

C2-2-1	Comparison of OM&A Expense by Major Category
I-5-1.01 Staff 23	OEB Interrogatory #23
I-5-1.02 Staff 24	OEB Interrogatory #24
I-5-1.03 Staff 25	OEB Interrogatory #25
I-5-1.04 Staff 26	OEB Interrogatory #26
I-5-1.05 Staff 27	OEB Interrogatory #27
I-5-1.06 Staff 28	OEB Interrogatory #28
I-5-1.07 Staff 29	OEB Interrogatory #29
I-5-1.08 Staff 30	OEB Interrogatory #30
I-5-1.09 Staff 31	OEB Interrogatory #31
I-5-1.10 Staff 32	OEB Interrogatory #32
I-5-1.11 Staff 33	OEB Interrogatory #33
I-5-1.12 Staff 34	OEB Interrogatory #34
I-5-1.13 Staff 35	OEB Interrogatory #35
I-5-2.01 LPMA 12	LPMA Interrogatory #12
I-5-3.01 EP 11	Energy Probe Interrogatory #11
I-5-3.02 EP 12	Energy Probe Interrogatory #12
I-5-3.03 EP 13	Energy Probe Interrogatory #13
I-5-3.04 EP 14	Energy Probe Interrogatory #14
I-5-3.05 EP 15	Energy Probe Interrogatory #15
I-5-3.06 EP 16	Energy Probe Interrogatory #16
I-5-3.07 EP 17	Energy Probe Interrogatory #17
I-5-3.08 EP 18	Energy Probe Interrogatory #18
I-5-3.09 EP 19	Energy Probe Interrogatory #19
I-5-3.10 EP 20	Energy Probe Interrogatory #20
I-5-3.11 EP 21	Energy Probe Interrogatory #21
I-5-8.01 PWU 2	PWU Interrogatory #2
I-5-8.02 PWU 3	PWU Interrogatory #3
I-5-8.03 PWU 4	PWU Interrogatory #4
I-5-8.04 PWU 5	PWU Interrogatory #5
I-5-8.05 PWU 6	PWU Interrogatory #6
I-5-8.06 PWU 7	PWU Interrogatory #7
I-5-8.07 PWU 8	PWU Interrogatory #8
I-5-8.08 PWU 9	PWU Interrogatory #9
I-5-8.09 PWU 10	PWU Interrogatory #10
I-5-8.10 PWU 11	PWU Interrogatory #11
I-5-8.11 PWU 12	PWU Interrogatory #12
I-5-8.12 PWU 13	PWU Interrogatory #13
I-5-8.13 PWU 14	PWU Interrogatory #14
I-5-8.14 PWU 15	PWU Interrogatory #15
I-5-8.15 PWU 16	PWU Interrogatory #16

I-5-9.01 SEC 8	SEC Interrogatory #8
I-5-9.02 SEC 9	SEC Interrogatory #9
I-5-9.03 SEC 10	SEC Interrogatory #10
I-5-9.04 SEC 11	SEC Interrogatory #11
I-5-9.05 SEC 12	SEC Interrogatory #12
I-5-9.06 SEC 13	SEC Interrogatory #13
I-5-9.07 SEC 14	SEC Interrogatory #14
I-5-9.08 SEC 15	SEC Interrogatory #15
I-5-9.09 SEC 16	SEC Interrogatory #16
I-5-9.10 SEC 17	SEC Interrogatory #17
I-5-10.01 CCC 8	CCC Interrogatory #8
I-5-10.02 CCC 9	CCC Interrogatory #9
I-5-10.03 CCC 10	CCC Interrogatory #10
I-5-10.04 CCC 11	CCC Interrogatory #11
I-5-10.05 CCC 12	CCC Interrogatory #12
I-5-10.06 CCC 13	CCC Interrogatory #13
I-5-10.07 CCC 14	CCC Interrogatory #14
I-5-10.08 CCC 15	CCC Interrogatory #15
I-5-12.01 THESL 1	THESL Interrogatory #1
JT1.1 TCR PWU 5	PWU Technical Conference Response #5
JTI.1 TCR Staff 8	OEB Technical Conference Response #8
JT1.1 TCR Staff 10	OEB Technical Conference Response #10
KT1.13	Undertaking Response #13
KT1.14	Undertaking Response #14
KT1.15	Undertaking Response #15
KT1.24	Undertaking Response #24
KT1.26	Undertaking Response #26
KT1.36	Undertaking Response #36

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

6. Are the proposed spending levels for Shared Services and Other O & M in 2013 and 2014 appropriate?

Settled. See rationale above.

Evidence: The evidence in relation to this issue includes the following:

C1-3-5	Customer Care OM&A
C1-4-1	Summary of Shared Services – OM&A

C1-4-2	Shared Services – Common Corporate Functions & Services and Other OM&A
C1-4-3	Shared Services OM&A– Asset Management
C1-4-4	Shared Services OM&A – Information Technology
C1-4-4 Attachment 1	H1 Telecom Inc. Services Review and Benchmarking
C1-4-5	Shared Services OM&A – Cornerstone
C1-4-6	Shared Services OM&A – Cost of Sales - External Work
C1-4-7	Property Taxes
I-6-1.01 Staff 36	OEB Interrogatory #36
I-6-1.02 Staff 37	OEB Interrogatory #37
I-6-1.03 Staff 38	OEB Interrogatory #38
I-6-3.01 EP 22	Energy Probe Interrogatory #22
I-6-3.02 EP 23	Energy Probe Interrogatory #23
I-6-3.03 EP 24	Energy Probe Interrogatory #24
I-6-3.04 EP 25	Energy Probe Interrogatory #25
I-6-3.05 EP 26	Energy Probe Interrogatory #26
I-6-5.01 VECC 30	VECC Interrogatory #30
I-6-5.02 VECC 31	VECC Interrogatory #31
I-6-9.01 SEC 19	SEC Interrogatory #19
I-6-10.01 CCC 16	CCC Interrogatory #16
I-6-10.02 CCC 17	CCC Interrogatory #17
I-6-10.03 CCC 18	CCC Interrogatory #18
I-6-10.04 CCC 19	CCC Interrogatory #19
I-6-10.05 CCC 20	CCC Interrogatory #20
I-6-10.06 CCC 21	CCC Interrogatory #21
I-6-10.07 CCC 22	CCC Interrogatory #22

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

7. Are the 2013/14 Human Resources related costs (wages, salaries, benefits, incentive payments, labour productivity and pension costs) including employee levels appropriate? Has Hydro One demonstrated improvements in efficiency and value for dollar associated with its compensation costs?

   Settled. See rationale above.

   Evidence: The evidence in relation to this issue includes the following:

A-17-1	Cost Efficiencies/Productivity
A-17-2	Productivity Metrics

A-17-2 Attachment 1	Measuring Productivity at Hydro One
A-17-2 Attachment 2	OEB Expert Evidence Requirements
C1-5-1	Corporate Staffing
C1-5-2	Compensation, Wages, Benefits
C1-5-2 Attachment 1	Mercer Compensation Cost Benchmarking Study
C1-5-2 Attachment 2	Payroll Table 2009 to 2012
C1-5-3	Pension Costs
C2-3-1	Comparison of Wages and Salaries
I-7-1.01 Staff 39	OEB Interrogatory #39
I-7-1.02 Staff 40	OEB Interrogatory #40
I-7-1.03 Staff 41	OEB Interrogatory #41
I-7-1.04 Staff 42	OEB Interrogatory #42
I-7-1.05 Staff 43	OEB Interrogatory #43
I-7-1.06 Staff 44	OEB Interrogatory #44
I-7-1.07 Staff 45	OEB Interrogatory #45
I-7-1.08 Staff 46	OEB Interrogatory #46
I-7-2.01 LPMA 13	LPMA Interrogatory #13
I-7-2.02 LPMA 14	LPMA Interrogatory #14
I-7-3.01 EP 27	Energy Probe Interrogatory #27
I-7-3.02 EP 28	Energy Probe Interrogatory #28
I-7-3.03 EP 29	Energy Probe Interrogatory #29
I-7-3.04 EP 30	Energy Probe Interrogatory #30
I-7-3.05 EP 31	Energy Probe Interrogatory #31
I-7-3.06 EP 32	Energy Probe Interrogatory #32
I-7-3.07 EP 33	Energy Probe Interrogatory #33
I-7-3.09 EP 35	Energy Probe Interrogatory #35
I-7-3.10 EP 36	Energy Probe Interrogatory #36
I-7-3.11 EP 37	Energy Probe Interrogatory #37
I-7-3.13 EP 39	Energy Probe Interrogatory #39
I-7-3.14 EP 40	Energy Probe Interrogatory #40
I-7-3.15 EP 41	Energy Probe Interrogatory #41
I-7-3.16 EP 42	Energy Probe Interrogatory #42
I-7-3.17 EP 43	Energy Probe Interrogatory #43
I-7-3.18 EP 44	Energy Probe Interrogatory #44
I-7-3.19 EP 45	Energy Probe Interrogatory #45
I-7-3.20 EP 46	Energy Probe Interrogatory #46
I-7-3.21 EP 47	Energy Probe Interrogatory #47
I-7-3.22 EP 48	Energy Probe Interrogatory #48
I-7-3.23 EP 49	Energy Probe Interrogatory #49
I-7-5.01 VECC 32	VECC Interrogatory #32
I-7-8.01 PWU 17	PWU Interrogatory #17

I-7-9.01 SEC 20	SEC Interrogatory #20
I-7-9.02 SEC 21	SEC Interrogatory #21
I-7-9.03 SEC 22	SEC Interrogatory #22
I-7-10.01 CCC 23	CCC Interrogatory #23
I-7-10.02 CCC 24	CCC Interrogatory #24
I-7-10.03 CCC 25	CCC Interrogatory #25
I-7-10.04 CCC 26	CCC Interrogatory #26
I-7-13.01 AMPCO 4	AMPCO Interrogatory #4
I-7-13.02 AMPCO 5	AMPCO Interrogatory #5
I-7-13.03 AMPCO 6	AMPCO Interrogatory #6
I-7-13.04 AMPCO 7	AMPCO Interrogatory #7
JT1.1 TCR Staff 12	OEB Technical Conference Response #12
JT1.1 TCR Staff 13	OEB Technical Conference Response #13
JT1.1 TCR Staff 14	OEB Technical Conference Response #14
JT1.1 TCR Staff 15	OEB Technical Conference Response #15
JT1.1 TCR Staff 16	OEB Technical Conference Response #16
JT1.2 TCR EP3	Energy Probe Technical Conference Response #3
KT1.9	Undertaking Response #9
KT1.10	Undertaking Response #10
KT1.11	Undertaking Response #11
KT1.16	Undertaking Response #16
KT1.27	Undertaking Response #27
KT1.28	Undertaking Response #28
KT1.31	Undertaking Response #31
KT1.32	Undertaking Response #32
KT1.33	Undertaking Response #33
KT1.34	Undertaking Response #34

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

8. Are the methodologies used to allocate Shared Services and Other O & M costs to the transmission business and to determine the transmission overhead capitalization rate for 2013/14 appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that Hydro One has used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Network Transmission and Distribution Rate Applications. Similarly, Hydro One has followed the overhead capitalization rate methodology previously accepted by the Board. Both of these have been updated for the current filing. The parties thus agree that the methodologies used to allocate Shared Services and Other O&M costs to the transmission overhead capitalization rate for 2013 and 2014 are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-1	Common Corporate Costs, Cost Allocation Methodology
C1-7-1 Attachment 1	Review of Shared Services Cost Allocation (Transmisison) – 2012
C1-7-2	Overhead Capitalization Rate
C1-7-2 Attachment 1	Review of Overhead Capitalization Rates (Transmission) – 2013-2014
C1-7-2 Attachment 2	Review of Overhead Capitalization Policy
I-8-3.01 EP 50	Energy Probe Interrogatory #50
I-8-3.02 EP 51	Energy Probe Interrogatory #51
I-8-9.01 SEC 23	SEC Interrogatory #23
I-8-10.01 CCC 27	CCC Interrogatory #27
JT1.2 TCR EP5	Energy Probe Technical Conference Response #5
JT1.2 TCR EP6	Energy Probe Technical Conference Response #6

Supporting Parties: PWU, AMPCO, SEC, CCC, CME

Parties taking no position: EP, VECC, LPMA, BOMA, Goldcorp, APPrO

9. Are the amounts proposed to be included in the 2013 and 2014 revenue requirements for income and other taxes appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the amounts proposed to be included in the 2013 and 2014 revenue requirement for income and other taxes are appropriate, subject to an increase in the Apprenticeship Tax Credit by $1.3M in 2013 and $1.0M in 2014 (resulting in corresponding decreases in tax expenses included in rates).

Evidence: The evidence in relation to this issue includes the following:

C1-9-1	Payments in Lieu of Corporate Income Taxes
C2-5-1	Calculation of Utility Income Taxes
C2-5-1 Attachment 1	Calculation of Utility Income Taxes Test Years (2013, 2014)
C2-5-1 Attachment 2	Calculation of Capital Cost Allowance Test Years (2013, 2014)
C2-5-1 Attachment 3	Calculation of Utility Income Taxes Historic Years (2009, 2010)

C2-5-1 Attachment 4	Calculation of Capital Cost Allowance Historic Years (2009, 2010) and Forecast Years (2011, 2012)
C2-5-1 Attachment 5	Calculation of Apprenticeship and Education Tax Credit Test Years (2013, 2014)
C2-5-1 Attachment 6	Calculation of Apprenticeship and Education Tax Credit Historic Years (2009, 2010)
C2-5-2	2010 Hydro One Networks Income Tax Return
C2-5-2 Attachment 1	Federal and Ontario Income Tax Return
C2-5-2 Attachment 2	Calculation of Utility Income Taxes (Transmission and Distribution)
C2-5-2 Attachment 3	Calculation of Capital Cost Allowance (Transmission and Distribution)
C2-5-3	2011 Hydro One Networks Income Tax Return
C2-5-3 Attachment 1	Federal and Ontario Income Tax Return
C2-5-3 Attachment 2	Calculation of Utility Income Taxes (Transmission and Distribution)
C2-5-3 Attachment 3	Calculation of Capital Cost Allowance (Transmission and Distribution)
I-9-1.01 Staff 47	OEB Interrogatory #47
I-9-1.02 Staff 48	OEB Interrogatory #48
I-9-1.03 Staff 49	OEB Interrogatory #49
I-9-2.01 LPMA 15	LPMA Interrogatory #15
I-9-2.02 LPMA 16	LPMA Interrogatory #16
I-9-2.03 LPMA 17	LPMA Interrogatory #17
I-9-2.04 LPMA 18	LPMA Interrogatory #18
I-9-2.05 LPMA 19	LPMA Interrogatory #19
I-9-2.06 LPMA 20	LPMA Interrogatory #20
I-9-2.07 LPMA 21	LPMA Interrogatory #21
JT1.1 TCR Staff 17	OEB Technical Conference Response #17

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

10. Is Hydro One Networks' proposed depreciation expense for 2013 and 2014 appropriate?

Settled. For the purposes of reaching a settlement, the parties agree that the proposed depreciation expense for 2013 and 2014 which reflects the 2011

Depreciation Rate Review filed at Exhibit C1, Tab 8, Schedule 1, Attachment 1 is appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-8-1	Depreciation and Amortization Expenses
C1-8-1 Attachment 1	2011 Depreciation Rate Review
C2-4-1	Depreciation and Amortization Expenses
I-10-2.01 LPMA 22	LPMA Interrogatory #22

Supporting Parties: EP, LPMA, SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

CAPITAL EXPENDITURES AND RATE BASE

11. Are the amounts proposed for rate base in 2013 and 2014 appropriate?

Partially Settled. The Applicant has proposed a rate base of $9,413.5M and $10,050.9M in the test years.

For the purposes of reaching a settlement, Hydro One has agreed to reduce its planned capital expenditures in 2013 as outlined below in Issue 12. This will result in reduced in-service additions in 2013, which has an associated reduction in rate base for both 2013 and 2014.

Taking into account those reductions, the parties other than Goldcorp agree that a rate base of $9,353.4M in 2013 and a rate base of $9,933.8M in 2014 are appropriate. This represents a reduction in rate base of $60.1M in 2013 and $117.1M in 2014 compared to that initially proposed, after reflecting depreciation.

Detailed calculations are provided in the table below.

Capital Expenditures ($M)	***2012***	***2013***	***2014***
Filed Evidence	850.0	1,102.4	1,121.5
Settlement Agreement	850.0	982.4	1,121.5
Change Proposed	-	- 120.0	-
In-Service ($M)			

Filed Evidence	1,294.7	904.1	1,023.0
Settlement Agreement	1,295.0	784.1	1,023.0
Change Proposed	-	- 120.0	-
Gross In-Service Impact on Rate Base ($M)			
Filed Evidence	8,628.5	9,413.5	10,050.9
Settlement Agreement	8,628.5	9,353.5	9,930.9
Change Proposed	-	- 60.0	- 120.0
Net Rate Base after Accumulated Depreciation ($M)			
Filed Evidence	8,628.5	9,413.5	10,050.9
Settlement Agreement	8,628.5	9,353.4	9,933.8
Change Proposed		- 60.1	- 117.1

The only aspect of this issue which remains unsettled is the net book value of Red Lake TS. Goldcorp is the only intervenor with concerns in this regard. Hydro One and Goldcorp have written separately to the Board regarding this issue.

Evidence: The evidence in relation to this issue includes the following:

D1-1-1	Rate Base
D1-1-2	In-Service Capital Additions
D1-2-1	Allowance for Funds Used During Construction
D1-5-1	Materials and Supplies Inventory
D2-1-1	Statement of Utility Rate Base
D2-3-1	Continuity of Property, Plant and Equipment
D2-3-2	Continuity of Accumulated Depreciation
D2-3-3	Continuity of Property, Plant and Equipment - Construction Work In Progress
I-11-1.01 Staff 50	OEB Interrogatory #50
I-11-1.02 Staff 51	OEB Interrogatory #51
I-11-1.03 Staff 52	OEB Interrogatory #52
I-11-1.04 Staff 53	OEB Interrogatory #53
I-11-2.01 LPMA 23	LPMA Interrogatory #23
I-11-2.02 LPMA 24	LPMA Interrogatory #24
I-11-2.03 LPMA 25	LPMA Interrogatory #25
I-11-4.01 PP 1	Pollution Probe Interrogatory #1
I-11-4.02 PP 2	Pollution Probe Interrogatory #2
I-11-4.03 PP 3	Pollution Probe Interrogatory #3
I-11-4.04 PP 4	Pollution Probe Interrogatory #4
I-11-4.05 PP 5	Pollution Probe Interrogatory #5
I-11-4.06 PP 6	Pollution Probe Interrogatory #6
I-11-4.07 PP7	Pollution Probe Interrogatory #7
I-11-4.08 PP 8	Pollution Probe Interrogatory #8

I-11-4.09 PP 9	Pollution Probe Interrogatory #9
I-11-4.10 PP 10	Pollution Probe Interrogatory #10
I-11-4.11 PP 11	Pollution Probe Interrogatory #11
I-11-4.12 PP 12	Pollution Probe Interrogatory #12
I-11-4.13 PP 13	Pollution Probe Interrogatory #13
I-11-4.14 PP 14	Pollution Probe Interrogatory #14
I-11-4.15 PP 15	Pollution Probe Interrogatory #15
I-11-4.16 PP 16	Pollution Probe Interrogatory #16
I-11-4.17 PP 17	Pollution Probe Interrogatory #17
I-11-4.18 PP 18	Pollution Probe Interrogatory #18
I-11-4.19 PP 19	Pollution Probe Interrogatory #19
I-11-4.20 PP 20	Pollution Probe Interrogatory #20
I-11-4.21 PP 21	Pollution Probe Interrogatory #21
I-11-4.22 PP 22	Pollution Probe Interrogatory #22
I-11-4.23 PP 23	Pollution Probe Interrogatory #23
I-11-4.24 PP 24	Pollution Probe Interrogatory #24
I-11-4.25 PP 25	Pollution Probe Interrogatory #25
I-11-4.26 PP 26	Pollution Probe Interrogatory #26
I-11-4.27 PP 27	Pollution Probe Interrogatory #27
I-11-4.28 PP 28	Pollution Probe Interrogatory #28
I-11-4.29 PP 29	Pollution Probe Interrogatory #29
I-11-5.01 VECC 33	VECC Interrogatory #33
I-11-7.01 Gold 1	Goldcorp Interrogatory #1
I-11-7.02 Gold 2	Goldcorp Interrogatory #2
I-11-7.03 Gold 3	Goldcorp Interrogatory #3
I-11-7.04 Gold 4	Goldcorp Interrogatory #4
I-11-7.05 Gold 5	Goldcorp Interrogatory #5
I-11-7.06 Gold 6	Goldcorp Interrogatory #6
I-11-9.01 SEC 24	SEC Interrogatory #24
I-11-12.01 THESL 2	THESL Interrogatory #2
I-11-12.02 THESL 3	THESL Interrogatory #3
I-11-12.03 THESL 4	THESL Interrogatory #4
I-11-12.04 THESL 5	THESL Interrogatory #5
I-11-13.01 AMPCO 8	AMPCO Interrogatory #8
I-11-13.02 AMPCO 9	AMPCO Interrogatory #9
JT1.1 TCR PP1	Pollution Probe Technical Conference Response #1
JT1.1 TCR PP2	Pollution Probe Technical Conference Response #2
JT1.1 TCR PP3	Pollution Probe Technical Conference Response #3
JT1.1 TCR PP4	Pollution Probe Technical Conference Response #4
KT1.5	Undertaking Response #5

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, APPrO

12. Are the proposed 2013 and 2014 Sustaining and Development and Operations capital expenditures appropriate, including consideration of factors such as system reliability and asset condition?

Settled.

For the purposes of reaching a settlement, the parties agreed to reduce 2013 capital expenditures and in service additions by $120.0 M from $1,102.4M to $982.4M. The reductions will be recognized through the re-prioritization of investments based on Hydro One's Investment Planning and Prioritization process to ensure the impact to risks and business values are minimized while reducing the overall rate impacts on customers. For the purposes of reaching a settlement, the parties agree that capital expenditures , for 2013 and 2014 are appropriate, with the agreed upon reduction in 2013.

The table below summarizes the proposed changes:

Capital Expenditures ($M)	***2012***	***2013***	***2014***
Filed Evidence	850	1102	1122
Settlement Agreement	850	982	1122
Change Proposed		-120	0

Evidence: The evidence in relation to this issue includes the following:

D1-3-1	Summary of Capital Expenditures
D1-3-2	Sustaining Capital
D1-3-3	Development Capital
D1-3-3 Appendix A	Summary of Development Capital Projects in Excess of $3 Million
D1-3-3 Appendix B	OPA Supporting Material for Oshawa TS
D1-3-3 Appendix C	OPA Document on Southwestern Ontario Reactive Compensation Milton SVC dated March 2012
D1-3-3 Appendix D	Letter from OPA dated June 30, 2011
D1-3-3 Appendix E	Letter from OPA dated March 8, 2012
D1-3-3 Appendix F	Letter from OPA dated August 7, 2012
D1-3-4	Operations Capital
D2-2-1	Comparison of Net Capital Expenditures by Major Category – Historic, Bridge Year and Test Year
D2-2-2	List of Capital Expenditure Programs or Projects Requiring in Excess of $3 Million in Test Year 2013 or 2014

D2-2-3	Investment Summary for Programs/Projects in Excess of $3 Million
I-12-1.01 Staff 54	OEB Interrogatory #54
I-12-1.02 Staff 55	OEB Interrogatory #55
I-12-1.03 Staff 56	OEB Interrogatory #56
I-12-1.04 Staff 57	OEB Interrogatory #57
I-12-1.05 Staff 58	OEB Interrogatory #58
I-12-1.06 Staff 59	OEB Interrogatory #59
I-12-1.07 Staff 60	OEB Interrogatory #60
I-12-1.08 Staff 61	OEB Interrogatory #61
I-12-1.09 Staff 62	OEB Interrogatory #62
I-12-1.10 Staff 63	OEB Interrogatory #63
I-12-1.11 Staff 64	OEB Interrogatory #64
I-12-1.12 Staff 65	OEB Interrogatory #65
I-12-1.13 Staff 66	OEB Interrogatory #66
I-12-1.14 Staff 67	OEB Interrogatory #67
I-12-1.15 Staff 68	OEB Interrogatory #68
I-12-1.16 Staff 69	OEB Interrogatory #69
I-12-1.17 Staff 70	OEB Interrogatory #70
I-12-1.18 Staff 71	OEB Interrogatory #71
I-12-1.19 Staff 72	OEB Interrogatory #72
I-12-3.01 EP 52	Energy Probe Interrogatory #52
I-12-3.02 EP 53	Energy Probe Interrogatory #53
I-12-3.03 EP 54	Energy Probe Interrogatory #54
I-12-3.04 EP 55	Energy Probe Interrogatory #55
I-12-9.01 SEC 25	SEC Interrogatory #25
I-12-9.02 SEC 26	SEC Interrogatory #26
I-12-9.03 SEC 27	SEC Interrogatory #27
I-12-9.04 SEC 28	SEC Interrogatory #28
I-12-9.05 SEC 29	SEC Interrogatory #29
I-12-9.06 SEC 30	SEC Interrogatory #30
I-12-9.07 SEC 31	SEC Interrogatory #31
I-12-9.08 SEC 32	SEC Interrogatory #32
I-12-9.09 SEC 33	SEC Interrogatory #33
I-12-9.10 SEC 34	SEC Interrogatory #34
I-12-10.01 CCC 28	CCC Interrogatory #28
I-12-10.02 CCC 29	CCC Interrogatory #29
I-12-10.03 CCC 30	CCC Interrogatory #30
I-12-10.04 CCC 31	CCC Interrogatory #31
I-12-10.05 CCC 32	CCC Interrogatory #32
I-12-12.01 THESL 6	THESL Interrogatory #6

I-12-12.02 THESL 7	THESL Interrogatory #7
I-12-12.03 THESL 8	THESL Interrogatory #8
I-12-12.04 THESL 9	THESL Interrogatory #9
I-12-12.05 THESL 10	THESL Interrogatory #10
I-12-13.01 AMPCO 10	AMPCO Interrogatory #10
JT1.1 TCR Staff 23	OEB Technical Conference Response #23
JT1.2 TCR EP8	Energy Probe Technical Conference Response #8
KT1.29	Undertaking Response #29
KT1.30	Undertaking Response #30

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO

Parties taking no position: PWU, Goldcorp, APPrO

13. Are the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures appropriate?

Settled. Please see rationale for issue 12 above. For the purposes of reaching a settlement, the parties agree that the proposed 2013 and 2014 levels of Shared Services and Other Capital expenditures are appropriate.

Evidence: The evidence in relation to this issue includes the following:

D1-4-1	Summary of Shared Services Capital
D1-4-2	Shared Services Capital – Information Technology
D1-4-3	Shared Services Capital – Cornerstone
D1-4-4	Shared Services Capital – Facilities & Real Estate
D1-4-5	Shared Services Capital – Transport, Work and Service Equipment
D2-2-1	Comparison of Net Capital Expenditures by Major Category – Historic, Bridge Year and Test Year
D2-2-2	List of Capital Expenditure Programs or Projects Requiring in Excess of $3 Million in Test Year 2013 or 2014
D2-2-3	Investment Summary for Programs/Projects in Excess of $3 Million
I-13-9.01 SEC 35	SEC Interrogatory #35
I-13-10.01 CCC 33	CCC Interrogatory #33
I-13-10.02 CCC 34	CCC Interrogatory #34
I-13-10.03 CCC 35	CCC Interrogatory #35

Supporting Parties: AMPCO, SEC, CCC, CME

Parties taking no position: EP, VECC, LPMA, BOMA, PWU, Goldcorp, APPrO

14. Are the methodologies used to allocate shared services and other capital expenditures to the transmission business appropriate?

Settled. Hydro One has used the Corporate Cost Allocation Methodology previously accepted by the Board in prior Hydro One Network Transmission and Distribution Rate Applications. For the purposes of reaching a settlement, the parties accept that the methodologies used to allocate Shared Services and other capital costs to the transmission business are appropriate.

Evidence: The evidence in relation to this issue includes the following:

C1-7-3	Common Asset Allocation
C1-7-3 Attachment 1	Review of Shared Assets Allocation (Transmission) - 2012

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position. EP, LPMA, Goldcorp, APPrO

15. Are the inputs used to determine the working capital component of the rate base and the methodology used appropriate?

Settled. For the purposes of reaching a settlement the parties agree that the inputs and methodology used by the Applicant to determine the working capital component of the rate base are appropriate.

Evidence: The evidence in relation to this issue includes the following:

D1-1-3	Working Capital
D1-1-3 Attachment 1	A Determination of the Working Capital Requirements of Hydro One Networks' Transmission Business
D2-4-1	Statement of Working Capital
I-15-2.01 LPMA 26	LPMA Interrogatory #26
I-15-2.02 LPMA 27	LPMA Interrogatory #27
I-15-3.01 EP 56	Energy Probe Interrogatory #56

Supporting Parties: EP, VECC, LPMA, SEC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

16. Does Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets and support the O&MA and Capital expenditures for 2013/14.

Settled. For the purposes of reaching a settlement**,** the parties accept that Hydro One's Asset Condition Assessment information and Investment Planning Process adequately address the condition of the transmission system assets in support of the OM&A and Capital expenditures for 2013 and 2014.

Evidence: The evidence in relation to this issue includes the following:

A-13-1	Planning Process
A-13-1 Appendix A	2012 Business Plan Assumptions
A-13-2	Transmission 10 Year Outlook
A-15-3	Investment Plan Development
A-15-4	Investment Prioritization Process
A-15-5	Project and Program Approval & Control
C1-2-1	Sustaining Investment Structure
C1-2-2	Transmission Assets and Sustaining Investment Overview
C1-2-2 Appendix A	Hydro One Transmission Asset Descriptions
I-16-1.01 Staff 73	OEB Interrogatory #73
I-16-1.02 Staff 74	OEB Interrogatory #74
I-16-1.03 Staff 75	OEB Interrogatory #75
I-16-1.04 Staff 76	OEB Interrogatory #76

Supporting Parties: SEC, VECC, LPMA, EP, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

COST OF CAPITAL/CAPITAL STRUCTURE

17. Is the proposed timing and methodology for determining the return on equity and short-term debt prior to the effective date of rates appropriate?

Settled. For the purposes of reaching a settlement the parties agree that the proposed timing and methodology as outlined in Exhibit B1, Tab 1, Schedule 1 is appropriate for determining the return on equity and short-term debt prior to the effective date of the rates as reflected in the Board approved rate order for the test years.

The table below summarizes the revenue requirement impact of the proposed changes to the 2013 and 2014 rate base based on the applied for Cost of Capital parameters.

Cost of Capital ($M)*	***2013***	***2014***
Filed Evidence	618.1	668.1
Settlement Agreement*	614.2	660.4
Change Proposed	(3.9)	(7.7)

*Includes return on equity and cost of short and long term debt.

Evidence: The evidence in relation to this issue includes the following:

B1-1-1	Cost of Capital
B2-1-1	Debt and Equity Summary
I-17-2.01 LPMA 28	LPMA Interrogatory #28
I-17-3.01 EP 57	Energy Probe Interrogatory #57
I-17-10.01 CCC 36	CCC Interrogatory #36
I-17-13.01 AMPCO 11	AMPCO Interrogatory #11

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

18. Is the forecast of long term debt for 2012-2014 appropriate?

Settled. For the purposes of reaching a settlement the parties agree the forecast of long term debt rates following the methodology outlined in Exhibit B1, Tab 2, Schedule 1 is appropriate. Please see the table above under Issue 17.

Evidence: The evidence in relation to this issue includes the following:

B1-2-1	Cost of Third Party Long-Term Debt
B2-1-2	Cost of Long-Term Debt Capital
I-18-2.01 LPMA 29	LPMA Interrogatory #29
I-18-2.02 LPMA 30	LPMA Interrogatory #30
I-18-2.03 LPMA 31	LPMA Interrogatory #31
I-18-3.01 EP 58	Energy Probe Interrogatory #58
I-18-3.02 EP 59	Energy Probe Interrogatory #59
I-18-3.03 EP 60	Energy Probe Interrogatory #60
I-18-9.01 SEC 36	SEC Interrogatory #36
I-18-9.02 SEC 37	SEC Interrogatory #37

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

DEFERRAL/VARIANCE ACCOUNTS

19. Are the proposed amounts, disposition and continuance of Hydro One's existing Deferral and Variance accounts appropriate?

Settled. For the purposes of reaching a settlement, the parties accept Hydro One's account balances.

As noted in Issue 2 above, the parties agree that the amounts refunded to rate payers in 2013 associated with the ($30.3) million regulatory asset balance will be used as a balancing item to ensure a 0.0% increase for 2013. Any remaining balance will be refunded to customers in 2014. The precise amount to be refunded in each year will be reflected in the final rate order once the cost of capital has been established.

In addition, as noted above, the parties agreed that should the Board approve a change in the Export Transmission Services rate, the full impact of the approved rate will be tracked in the Board approved Excess Export Services Revenue Account for disposition in a future rate application.

As of December 31, 2012, both the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs had zero balances. For the purposes of reaching a settlement, Hydro One agreed to discontinue those two accounts. This is reflected in Appendix A.

Evidence: The evidence in relation to this issue includes the following:

F1-1-1	Regulatory Accounts
F1-1-3	Planned Disposition of Regulatory Accounts
F2-1-1	Regulatory Accounts for Approval
F2-1-2	Schedule of Annual Recoveries
F2-1-3	Continuity Schedules – Regulatory Accounts
I-19-1.01 Staff 77	OEB Interrogatory #77
I-19-1.02 Staff 78	OEB Interrogatory #78
I-19-1.03 Staff 79	OEB Interrogatory #79
I-19-1.04 Staff 80	OEB Interrogatory #80
I-19-3.01 EP 61	Energy Probe Interrogatory #61
I-19-9.01 SEC 38	SEC Interrogatory #38
I-19-9.02 SEC 39	SEC Interrogatory #39
I-19-10.01 CCC 37	CCC Interrogatory #37
I-19-10.02 CCC 38	CCC Interrogatory #38
I-19-10.03 CCC 39	CCC Interrogatory #39

JT1.1 TCR Staff 25	OEB Technical Conference Response #25
JT1.2 TCR EP9	Energy Probe Technical Conference Response #9
KT1.35	Undertaking Response #35

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: EP, LPMA, Goldcorp, APPrO

20. Are the proposed new Deferral and Variance Accounts appropriate?

Settled.

For the purposes of reaching a settlement and as previously described Hydro One has agreed to create two new variance accounts to track variances in

a) other external revenues and

b) the differences between the forecast and actual CDM savings related to the OPA funded LDC delivered programs and the actual Demand Response results against forecast. The CDM variance account is more fully described above in the context of Issue 3.

For the Other External Revenues Variance Account, Hydro One will establish a new variance account to record the differences between Other External Revenues embedded in rates and Actual Revenues.

These new proposed accounts have also been reflected in Appendix A.

Evidence: The evidence in relation to this issue includes the following:

F1-1-2	Regulatory Accounts Requested
I-20-1.01 Staff 81	OEB Interrogatory #81
I-20-10.01 CCC 40	CCC Interrogatory #40
I-20-10.02 CCC 41	CCC Interrogatory #41
JT1.1 TCR Staff 26	OEB Technical Conference Response #26

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

COST ALLOCATION

21. Is the cost allocation proposed by Hydro One appropriate?

Settled. Hydro One is proposing to continue to use the cost allocation methodology previously approved by the Board. For the purposes of reaching a settlement, the parties agree that the cost allocation proposed by Hydro One is appropriate.

Attached at Appendix C is an updated Draft Summary Uniform Transmission Rates and Revenue Disbursements Factors for 2013 and 2014.

Evidence: The evidence in relation to this issue includes the following:

G1-1-1	Cost Allocation and Charge Determinants
G1-2-1	Description of Cost Allocation Methodology
G1-3-1	Network and Line Connection Pools
G1-4-1	Transformation Connection Pool
G1-5-1	Wholesale Meter Pool
G1-6-1	Low Voltage Switchgear Compensation
G2-1-1	List of Transmission Lines by Functional Category
G2-1-2	List of Transmission Stations by Functional Category
G2-2-1	Allocation Factors for Dual Function Lines
G2-3-1	Allocation Factors for Generator Line Connections
G2-3-2	Allocation Factors For Generator Station Connections
G2-4-1	Asset Value by Functional Category
G2-4-2	Depreciation by Functional Category
G2-4-3	Return on Capital and Income Taxes by Functional Category
G2-4-4	OM&A Costs by Functional Category
G2-5-1	Detailed Revenue Requirement by Rate Pool
H1-1-1	Overview of Uniform Transmission Rates
H1-2-1	Transmission Customers Load Forecast
H1-3-1	Charge Determinants
H1-4-1	Rates for Wholesale Meter Service
H2-1-1	Current Ontario Transmission Rate Schedules
H2-1-1 Attachment 1	Ontario Transmission Rates Schedules EB-2011-0268
H2-1-1 Attachment 2	Uniform Transmission Rates and Revenue Disbursement Allocators
H2-2-1	Current Wholesale Meter Service and Exit Fee Schedule
H2-2-2	Proposed Wholesale Meter Service and Exit Fee Schedule
I-21-5.01 VECC 34	VECC Interrogatory #34
I-21-5.02 VECC 35	VECC Interrogatory #35
I-21-5.03 VECC 36	VECC Interrogatory #36
I-21-5.04 VECC 37	VECC Interrogatory #37
I-21-5.05 VECC 38	VECC Interrogatory #38
I-21-5.06 VECC 39	VECC Interrogatory #39

I-21-5.07 VECC 40	VECC Interrogatory #40

Supporting Parties: EP, SEC, VECC, LPMA, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: Goldcorp, APPrO

GREEN ENERGY PLAN

22. Are the OM&A and capital amounts in the Green Energy Plan (GEP) appropriate and based on appropriate planning criteria?

Settled. For the purposes of reaching a settlement, the parties accept the filed GEP as appropriate for 2013 and 2014.

Hydro One clarified that the approvals for OM&A and capital sought in the GEP are the same projects included in the overall proposals for OM&A and capital. Given agreement regarding OM&A and capital, there is agreement for the GEP. Hydro One confirmed that it is not seeking Board approval of elements of the plan that go beyond the test years.

The 2013 and 2014 elements of Hydro One's GEP are covered by the settlement of Issues 2 to 18 inclusive. Intervenors have no questions in this proceeding on the elements of Hydro One's GEP that lie outside the ambit of the 2013 and 2014 test years.

Evidence: The evidence in relation to this issue includes the following:

A-14-1	Transmission Green Energy Plan
A-14-1 Appendix A	Letter from Ministry of Energy and Infrastructure – dated September 21, 2009
A-14-1 Appendix B	Letters from Ministry of Energy and Infrastructure – dated May 5, 2010 and May 7, 2010
A-14-1 Appendix C	Letter from Ontario Power Authority – dated April 7, 2011
A-14-1 Appendix D	Letter from Hydro One – dated December 29, 2009
I-22-1.01 Staff 82	OEB Interrogatory #82
I-22-1.02 Staff 83	OEB Interrogatory #83
I-22-3.01 EP 62	Energy Probe Interrogatory #62
I-22-3.02 EP 63	Energy Probe Interrogatory #63
I-22-3.03 EP 64	Energy Probe Interrogatory #64
I-22-3.04 EP 65	Energy Probe Interrogatory #65
I-22-3.05 EP 66	Energy Probe Interrogatory #66

I-22-9.01 SEC 40	SEC Interrogatory #40
I-22-13.01 AMPCO 12	AMPCO Interrogatory #12
I-22-13.02 AMPCO 13	AMPCO Interrogatory #13
I-22-13.03 AMPCO 14	AMPCO Interrogatory #14
I-22-13.04 AMPCO 15	AMPCO Interrogatory #15
I-22-13.05 AMPCO 16	AMPCO Interrogatory #16
I-22-13.06 AMPCO 17	AMPCO Interrogatory #17
I-22-13.07 AMPCO 18	AMPCO Interrogatory #18
I-22-13.08 AMPCO 19	AMPCO Interrogatory #19

Supporting Parties: SEC, VECC, BOMA, CCC, CME, PWU, AMPCO

Parties taking no position: EP, LPMA, Goldcorp, APPrO

EXPORT TRANSMISSION SERVICE RATES

23. What is the appropriate level for Export Transmission Rates in Ontario?

Not Settled. The parties agree that this issue should be determined in an oral hearing before the Board.

Evidence: The evidence in relation to this issue includes the following:

H1-5-1	Rates for Export Transmission Service
H1-5-2	IESO Export Transmission Service Study
H2-1-2	Proposed Uniform Transmission Rates
I-23-1.01 Staff 84	OEB Interrogatory #84
I-23-1.02 Staff 85	OEB Interrogatory #85
I-23-1.03 Staff 86	OEB Interrogatory #86
I-23-1.04 Staff 87	OEB Interrogatory #87
I-23-1.05 Staff 88	OEB Interrogatory #88
I-23-1.06 Staff 89	OEB Interrogatory #89
I-23-1.07 Staff 90	OEB Interrogatory #90
I-23-1.08 Staff 91	OEB Interrogatory #91
I-23-1.09 Staff 92	OEB Interrogatory #92
I-23-5.01 VECC 41	VECC Interrogatory #41
I-23-5.02 VECC 42	VECC Interrogatory #42
I-23-5.03 VECC 43	VECC Interrogatory #43
I-23-5.04 VECC 44	VECC Interrogatory #44
I-23-5.05 VECC 45	VECC Interrogatory #45
I-23-5.06 VECC 46	VECC Interrogatory #46

I-23-5.07 VECC 47	VECC Interrogatory #47
I-23-5.08 VECC 48	VECC Interrogatory #48
I-23-5.09 VECC 49	VECC Interrogatory #49
I-23-5.10 VECC 50	VECC Interrogatory #50
I-23-5.11 VECC 51	VECC Interrogatory #51
I-23-5.12 VECC 52	VECC Interrogatory #52
I-23-5.13 VECC 53	VECC Interrogatory #53
I-23-5.14 VECC 54	VECC Interrogatory #54
I-23-6.01 HQ 1	HQ Interrogatory #1
I-23-6.02 HQ 2	HQ Interrogatory #2
I-23-6.03 HQ 3	HQ Interrogatory #3
I-23-6.04 HQ 4	HQ Interrogatory #4
I-23-6.05 HQ 5	HQ Interrogatory #5
I-23-6.06 HQ 6	HQ Interrogatory #6
I-23-6.07 HQ 7	HQ Interrogatory #7
I-23-6.08 HQ 8	HQ Interrogatory #8
I-23-6.09 HQ 9	HQ Interrogatory #9
I-23-6.10 HQ 10	HQ Interrogatory #10
I-23-6.11 HQ 11	HQ Interrogatory #11
I-23-6.12 HQ 12	HQ Interrogatory #12
I-23-6.13 HQ 13	HQ Interrogatory #13
I-23-6.14 HQ 14	HQ Interrogatory #14
I-23-6.15 HQ 15	HQ Interrogatory #15
I-23-6.16 HQ 16	HQ Interrogatory #16
I-23-8.01 PWU 18	PWU Interrogatory #18
I-23-9.01 SEC 41	SEC Interrogatory #41
I-23-9.02 SEC 42	SEC Interrogatory #42
I-23-9.03 SEC 43	SEC Interrogatory #43
I-23-10.01 CCC 42	CCC Interrogatory #42
I-23-11.01 APPrO 1	APPrO Interrogatory #1
I-23-11.02 APPrO 2	APPrO Interrogatory #2
I-23-11.03 APPrO 3	APPrO Interrogatory #3
I-23-11.04 APPrO 4	APPrO Interrogatory #4
I-23-11.05 APPrO 5	APPrO Interrogatory #5
I-23-11.06 APPrO 6	APPrO Interrogatory #6
I-23-11.07 APPrO 7	APPrO Interrogatory #7
I-23-11.08 APPrO 8	APPrO Interrogatory #8
I-23-11.09 APPrO 9	APPrO Interrogatory #9
I-23-11.10 APPrO 10	APPrO Interrogatory #10
I-23-11.11 APPrO 11	APPrO Interrogatory #11
I-23-11.12 APPrO 12	APPrO Interrogatory #12

KT1.1	Undertaking Response #1
KT1.2	Undertaking Response #2
KT1.3	Undertaking Response #3
KT1.4	Undertaking Response #4

Supporting Parties: NOT REQUIRED

Parties taking no position:

CONNECTION PROCEDURES

24. Are the proposed modifications to the Hydro One connection procedures appropriate?

Settled. Hydro One proposed some modifications to the connection procedures currently in use. The modifications were intended to reflect the overall timelines required for load connections and generation connections based on Hydro One's experience over the last few years. The current Board approved Transmission Connection Procedures for Hydro One included timeframes which are ambitious given the current realities of the electricity market.

AMPCO had some concerns with the proposed modifications. Hydro One clarified that the changes were intended to simply reflect the true timeframes required to connect a load or generation customer based on Hydro One's experience. In addition, the changes are more transparent as they reflect the overall timeframes for each phase of the connection process rather than simply timelines for Hydro One to complete those items for which it is responsible within each phase. The proposed changes provide customers better information. With that clarification, AMPCO's concerns were addressed.

In Exhibit I, Tab 24, Schedule 1.03 Staff 95, Hydro One proposed two further revisions to the proposed new connection procedures in parts f) and j) of the response. Hydro One agreed to include the proposed revised connection procedures as part of the draft rate order, which will include the two changes outlined in the interrogatory response.

Accordingly, the parties are in agreement that the proposed changes to the connection procedures for Hydro One are appropriate.

Evidence: The evidence in relation to this issue includes the following:

A-12-1	Key Governing Legislation, Standards and Codes
I-24-1.01 Staff 93	OEB Interrogatory #93
I-24-1.02 Staff 94	OEB Interrogatory #94
I-24-1.03 Staff 95	OEB Interrogatory #95

I-24-1.04 Staff 96	OEB Interrogatory #96
I-24-1.05 Staff 97	OEB Interrogatory #97
I-24-3.01 EP 67	Energy Probe Interrogatory #67
I-24-10.01 CCC 43	CCC Interrogatory #43
I-24-13.01 AMPCO 20	AMPCO Interrogatory #20
I-24-13.02 AMPCO 21	AMPCO Interrogatory #21
I-24-13.03 AMPCO 22	AMPCO Interrogatory #22
I-24-13.04 AMPCO 23	AMPCO Interrogatory #23
I-24-13.05 AMPCO 24	AMPCO Interrogatory #24

Supporting Parties: PWU, AMPCO

Parties taking no position: EP, SEC, VECC, LPMA, BOMA, CCC, CME, APPrO

ACCOUNTING STANDARDS

25. Have all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP been identified and reflected in the appropriate manner in the Application, the revenue requirement for the Test Years and the proposed rates.

Settled. For the purposes of reaching a settlement the parties agree that all impacts of the conversion of regulatory and financial accounting from CGAAP to USGAAP have been identified and reflected in the appropriate manner in the Application, the revenue requirement for the test years and the proposed rates.

Evidence: The evidence in relation to this issue includes the following:

A-12-2	Summary of Hydro One Transmission Policies
I-25-1.01 Staff 98	OEB Interrogatory #98

Supporting Parties: SEC, VECC, LPMA, BOMA, CCC, CME, AMPCO, PWU

Parties taking no position: EP, APPrO

APPENDIX A

LIST OF APPROVALS SOUGHT

1. An Order pursuant to Section 78 of the *Ontario Energy Board Act* approving 2013 and 2014 Revenue Requirement and rates for the transmission of electricity to be implemented January 1, 2013 and January 1, 2014.

2. As a result of the Settlement Proposal, Hydro One Networks seeks approval of a revenue requirement of $1,446 million and $1,537 million for the test years 2013 and 2014, respectively. This results in an increase in Hydro One Transmission's Rates Revenue Requirement of 0% and 7.1%, respectively, reflecting an estimated increase on the average customer's total bill of 0.0% in 2013 and 0.6% in 2014. The estimate of the impact on a customer's total bill assumes commodity costs of 7.2¢/kWh and that transmission represents 7.9% of an average distribution connected customer's total bill.

3. Hydro One Networks seeks approval of regulatory assets totaling ($30.3) million as at December 31, 2012. Hydro One seeks approval to refund this balance over a two year period and to reduce the annual revenue requirement accordingly. Hydro One proposes to refund an amount that will ensure the overall rate increase in 2013 will be 0.0% and to refund any remaining balance to customers in 2014.

4. Hydro One Networks seeks approval to continue the following deferral accounts including, the Excess Export Service Revenue Account, the External Secondary Land Use Revenue Variance Account, the External Station Maintenance and E&CS Revenue Variance Account, the Tax Rate Changes Account, the Rights Payments Variance Account, the Pension Cost Differential Account, and the East-West Tie account.

5. For 2013 and 2014, Hydro One Transmission is requesting that the Board approve the establishment of four new deferral accounts, the External Revenue – Partnership Transmission Projects Account, the Long-Term Transmission Future Corridor

Acquisition and Development Account, the Other External Revenues Variance Account, the LDC CDM Demand Response Variance Account.

6. Hydro One Transmission is also requesting the discontinuance effective January 1, 2013 of the Deferred Export Service Credit Revenue Account, the Long Term Project Development Costs Account, the Impact for Changes in USGAAP Account and the USGAAP Incremental Transition Costs Account.

7. Hydro One Networks also requests the Board approve several proposed modifications to the current Transmission Connection Procedures, which were approved by the Board in EB-2006-0189 to reflect the current electricity market conditions with respect to the connection of renewable generation. The proposed changes relate to a number of sections in Hydro One Transmission's Connection Procedures including: 1) the Customer Connection Process, 2) Security Deposit Procedure, 3) Customer Impact Assessment Procedure, 4) Schedule of Charges and Fees, and 5) Connection Process Timelines. Hydro One will also incorporate further revisions to the proposed connection procedures as outlined in parts f) and j) of the interrogatory response to in Exhibit I, Tab 24, Schedule 1.03, Staff 95.

8. Approval of Hydro One's Green Energy Plan.

APPENDIX B

	Filing (Blue Page)			Reduce 2013 capex/in-service by $120M; decrease OM&A by $13M & $10M; increase 2014 ext. revenue by $4.8M; increase tax credit by $1.3M & $1M; adjust rider refund timing; updated LVSG			Variance	
Draft Rate Increases	ROE	ROE	ROE	ROE	ROE	ROE		
October 29, 2012	9.42%	9.16%	9.44%	9.42%	9.16%	9.44%		
	2012	2013	2014	2012	2013	2014		
Revenue requirement								
OM&A		453.3	459.7		440.3	449.7	(13.0)	(10.0)
Depreciation on fixed assets		346.7	374.7		345.0	371.5	(1.7)	(3.3)
Return on debt		268.3	283.8		266.5	280.5	(1.7)	(3.3)
Return on equity		344.9	379.5		342.7	375.1	(2.2)	(4.4)
Income tax		46.4	55.2		46.2	55.7	(0.2)	0.5
AFUDC		4.9	4.8		4.9	4.8	0.0	0.0
Revenue requirement	1,418.4	1,464.5	1,557.7	1,418.4	1,445.7	1,537.2	(18.7)	(20.5)
	5.4%	3.2%	6.4%	5.4%	1.9%	6.3%		
Less: Non-rate revenues	(28.7)	(31.6)	(31.8)	(28.7)	(31.6)	(36.6)	-	(4.8)
	1,389.7	1,432.8	1,525.9	1,389.7	1,414.1	1,500.6	(18.7)	(25.3)
	5.9%	3.1%	6.5%	5.9%	1.8%	6.1%		
Less: Export revenue credit	(16.0)	(31.0)	(30.1)	(16.0)	(31.0)	(30.1)		
	1,373.6	1,401.8	1,495.8	1,373.6	1,383.1	1,470.5		
	6.0%	2.1%	6.7%	6.0%	0.7%	6.3%		
Less: "Tx Riders"	-	(15.1)	(15.1)	-	(4.5)	(25.7)	10.6	(10.6)
	1,373.6	1,386.7	1,480.7	1,373.6	1,378.6	1,444.8	(8.1)	(35.9)
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%		
Add: LVSG	11.5	11.7	12.5	11.5	11.7	12.2	(0.1)	(0.3)
Rates Revenue Requirement	1,385.1	1,398.5	1,493.1	1,385.1	1,390.3	1,457.0	(8.2)	(36.2)
	6.6%	1.0%	6.8%	6.6%	0.4%	4.8%		
Estimated impact of load reduction	-1.2%	0.4%	**-2.3%**	-1.2%	0.4%	**-2.3%**		
Assumed Rate Impact	**7.8%**	**0.6%**	**9.1%**	**7.8%**	**0.0%**	**7.1%**		
Rate Base		9413.5	10050.9		9353.4	9933.8		

APPENDIX C

DRAFT

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2013

Transmitter	Revenue Requirement ($)			
	Network	**Line Connection**	**Transformation Connection**	**Total**
FNEI (Note 3)	$3,897,095	$779,431	$1,650,564	$6,327,089
CNPI (Note 4)	$2,840,979	$568,204	$1,203,260	$4,612,443
GLPT (Note 5)	$21,710,466	$4,342,158	$9,195,184	$35,247,808
H1N (Note 1)	$855,746,155	$171,151,779	$362,440,102	$1,389,338,036
All Transmitters	$884,194,694	$176,841,572	$374,489,109	$1,435,525,376

Transmitter	Total Annual Charge Determinants (MW)			
	Network	**Line Connection**	**Transformation Connection**	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	4,019.8	2,939.4	1,057.6	
H1N (Note 2)	240,274.0	232,874.3	201,107.9	
All Transmitters	245,064.3	236,695.8	202,910.3	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	**Line Connection**	**Transformation Connection**	
Uniform Transmission Rates ($/kW-Month)	**3.61**	**0.75**	**1.85**	
FNEI Allocation Factor	**0.00441**	**0.00441**	**0.00441**	
CNPI Allocation Factor	**0.00321**	**0.00321**	**0.00321**	
GLPT Allocation Factor	**0.02455**	**0.02455**	**0.02455**	
H1N Alocation Factor	**0.96783**	**0.96783**	**0.96783**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2013 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2013 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
Note 5: GLPT Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2010-0291 dated on December 19, 2011.
Note 6: Calculated data in shaded cells.

APPENDIX C

DRAFT

Summary Uniform Transmission Rates and Revenue Disbursement Factors
for Rates Effective January 1, 2014

Transmitter	Revenue Requirement ($)			
	Network	Line Connection	Transformation Connection	Total
FNEI (Note 3)	$3,870,865	$799,421	$1,656,804	$6,327,089
CNPI (Note 4)	$2,821,857	$582,777	$1,207,808	$4,612,443
GLPT (Note 5)	$21,564,340	$4,453,521	$9,229,946	$35,247,808
H1N (Note 1)	$890,953,721	$184,001,982	$381,345,079	$1,456,300,783
All Transmitters	$919,210,784	$189,837,701	$393,439,638	$1,502,488,123

Transmitter	Total Annual Charge Determinants (MW)			
	Network	Line Connection	Transformation Connection	
FNEI (Note 3)	187.1	213.5	76.2	
CNPI (Note 4)	583.4	668.6	668.6	
GLPT (Note 5)	4,019.8	2,939.4	1,057.6	
H1N (Note 2)	234,635.3	227,880.9	196,795.3	
All Transmitters	239,425.6	231,702.4	198,597.7	

Transmitter	Uniform Rates and Revenue Allocators			
	Network	Line Connection	Transformation Connection	
Uniform Transmission Rates ($/kW-Month)	**3.84**	**0.82**	**1.98**	
FNEI Allocation Factor	**0.00421**	**0.00421**	**0.00421**	
CNPI Allocation Factor	**0.00307**	**0.00307**	**0.00307**	
GLPT Allocation Factor	**0.02346**	**0.02346**	**0.02346**	
H1N Alocation Factor	**0.96926**	**0.96926**	**0.96926**	
Total of Allocation Factors	1.00000	1.00000	1.00000	

Note 1: Proposed Hydro One Networks (H1N) 2014 Revenue Requirement
Note 2: Proposed Hydro One Networks (H1N) 2014 Charge Determinants
Note 3: FNEI Rates Revenue Requirement and Charge Determinants per Board Decision and Order on EB-2009-0387 dated December 9, 2010.
Note 4: CNPI Rates Revenue Requirement and Charge Determinants per Board Decision on RP-2001-0034 dated December 11, 2001.
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Note 6: Calculated data in shaded cells.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2011-0210

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Marika Hare
Presiding Member

Karen Taylor
Board Member

DECISION AND ORDER

Union Gas Limited ("Union") filed an application on November 10, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013 (the "Application"). The Board assigned file number EB-2011-0210 to the Application and issued a Notice of Application on December 1, 2011. This is the first cost-of-service application for setting rates since 2007. From 2008 to 2012 rates were set under an Incentive Regulation Mechanism ("IRM") which adjusted rates through a mechanistic formula.

The Board issued its Procedural Order No. 1 on January 11, 2012, which established the approved list of intervenors for this proceeding. The list included:

- Association of Power Producers of Ontario (“APPrO”)
- Building Owners and Managers Association Toronto (“BOMA”)
- Canadian Manufacturers and Exporters (“CME”)
- City of Kitchener (“Kitchener”)
- Consumers Council of Canada (“CCC”)
- Enbridge Gas Distribution Inc. (“Enbridge”)
- Energy Probe Research Foundation (“Energy Probe”)
- Federation of Rental-housing Providers of Ontario (“FRPO”)
- Industrial Gas Users Association (“IGUA”)
- Jason F. Stacey
- Just Energy Ontario LP (“Just Energy”)
- London Property Management Association (“LPMA”)
- Ontario Association of Physical Plant Administrators (“OAPPA”)
- Ontario Power Generation (“OPG”)
- School Energy Coalition (“SEC”)
- Six Nations Natural Gas Company Limited (“SNNG”)
- Shell Energy North America (Canada) Inc. (“Shell Energy”)
- TransAlta Generation Partnership (“TransAlta Generation”)
- TransAlta Cogeneration LP (“TransAlta Cogeneration”)
- TransCanada Pipelines Limited (“TCPL”)
- TransCanada Energy Limited (“TCE”)
- Vulnerable Energy Consumers Coalition (“VECC”).

The Board also determined that APPrO, BOMA, CME, CCC, Energy Probe, FRPO, IGUA, LPMA, OAPPA, SEC, and VECC are eligible to apply for an award of costs under the Board’s *Practice Direction on Cost Awards*.

Union filed its Application on the basis of US Generally Accepted Accounting Principles (“USGAAP”). At the same time, Union sought approval to move to USGAAP from Canadian GAAP as part of this Application. The Board decided to first deal with Union’s request for the adoption of USGAAP for regulatory purposes (the “Preliminary Issue”) prior to processing the Application in accordance with the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (the “Addendum Report”).

In Procedural Order No. 1 the Board established a timeline for interrogatories, interrogatory responses, submissions, and reply submissions related to the Preliminary Issue in advance of further procedural steps. In addition, the Board adopted the evidence related to the USGAAP issue from Union's 2012 IRM Proceeding EB-2011-0025 (the "Adopted Evidence").

Submissions were received from the LPMA, CCC, SEC, CME, APPrO and Board staff. LPMA, CCC, SEC and Board staff supported the request by Union for the adoption of USGAAP for regulatory purposes. CME and APPrO were also supportive of Union's request but provided some proposed conditions of approval.

The Board issued its Decision on the Preliminary Issue and Procedural Order No. 2 on March 1, 2012. The Board granted Union approval to use USGAAP for regulatory purposes. The Board also set out the timelines for the Issues Conference, Issues Day Hearing, filing of interrogatories and responses to interrogatories by Union in this Procedural Order.

Procedural Orders No. 3 and No. 4 set timelines for the next procedural steps, including setting dates for the Technical Conference and the Settlement Conference.

The Board revised some of the timelines for interrogatories and filing intervenor evidence in Procedural Order No. 5 after considering a letter filed by TCPL that requested revised dates to accommodate timelines related to the hearing of its application before the National Energy Board.

TCPL filed a Notice of Motion on May 17, 2012. The Motion requested the following:

1) An Order requiring Union to provide proper answers to the Interrogatories identified in Appendix "A" to the Notice of Motion, or such other information as the Board considers appropriate.

2) An Order requiring Union to file with the Board unredacted copies of pages in Interrogatory Responses that were filed in redacted form as part of Union's Interrogatory Responses to TCPL, so that the Board could assess the reasonableness of the claims for confidentiality and make such order as it considers appropriate in that regard.

The Board in Procedural Order No. 6, issued on May 18, 2012, decided that it would not hear the second request as part of the TCPL Motion as there were other exhibits, not mentioned in TCPL's Motion, which were filed under confidential cover. The Board in Procedural Order No. 6 established a separate process for reviewing Union's claims for confidentiality.

The Board heard the Motion filed by TCPL by way of written hearing. Procedural Order No. 6 made provision for all parties to the proceeding to file submissions on the merits of TCPL's motion and for TCPL to file reply submissions. This process was completed on June 8, 2012.

TCPL, BOMA and Union filed submissions on TCPL's motion. The interrogatory information sought by TCPL related primarily to Union's Parkway West project which purports to provide for loss of critical unit protection at Parkway.

With respect to the Parkway West project questions, TCPL's position was that the information that it was seeking was necessary for the Board to evaluate the reasonableness of Union's proposed capital expenditures. Union submitted that the information requested by TCPL was not relevant to Union's Application as the Parkway West project would not come into rate base until 2014 and did not impact 2013 rates. Union's position was that providing such further information could have no bearing on deciding the issues before the Board in this Application.

BOMA's submissions largely supported TCPL's request for Union to provide answers to the TCPL Parkway West interrogatories.

The Board in its Decision dated June 15, 2012, granted the Motion and required Union to provide responses to the interrogatories.

With respect to the relevance of the Parkway West interrogatories, the Board indicated that a review of the forecast capital spending plan was a conventional aspect of a cost of service rebasing process. The Board recognized that the specific projects that were the focus of the interrogatories at issue were not expected to close to rate base within the test year, and that the Board was not conducting a review of the projects for approval. However, the Board has commonly reviewed capital spending forecasts as part of a cost of service review, and determined that it would do so in this case.

The Board noted that the proposed projects may have important implications for Union's operations during the following year, in particular if Union is again entering into an incentive regulation regime for rate-setting. The Board indicated that it would be remiss in considering this cost-of-service application if it did not ensure that it had as clear a picture as possible of the significant developments likely to arise within the next regulatory rate-setting period.

On the issue of confidentiality, the Board determined that, except for the benchmarking studies, the information that Union proposed to redact was not confidential, and that the full and unredacted versions should form part of the public record. With respect to the benchmarking studies, the Board agreed with Union that the specific rankings of the studies' participants (other than Union) should not be on the public record, and therefore allowed the redactions. However, the Board required that the list of the participants to the studies be made public where it was included in the study. The Board noted that in assessing the relevance of a benchmarking study, it was important that the "comparators" be known.

As per Procedural Order No. 4, a Settlement Conference was held from June 6 to June 18, 2012 between Union and intervenors to settle some or all issues. In broad terms, the parties reached an agreement with respect to rate base and cost of service for the test year, being the issues under headings Exhibit B – Rate Base and Exhibit D – Cost of Service, respectively, with the exception of matters pertaining to Gas Supply Planning (Issue 3.14) and capital expenditures relating to Parkway West (Issue 1.1). The parties also reached agreement on several other issues, each of which were separately identified as settled in the Settlement Agreement. As a result of the Settlement Agreement, the updated revenue deficiency proposed by Union was reduced to $54.524 million from $71.4 million. The Board considered and accepted the Settlement Agreement as reasonable.

The Board addresses below the issues that remained unresolved.

UNSETTLED ISSUES

The following issues were considered by the Board:

- Weather Methodology
- Normalized Average Consumption ("NAC")

- Operating Revenue
- Other Revenues
- Ex-franchise Revenue
- Optimization and Gas Supply Plan
- Cost of Capital
- Cost Allocation
- Rate Design
- Deferral and Variance Accounts
- Parkway West
- Other Issues

WEATHER METHODOLOGY

Union has proposed to use a 20-year declining trend to derive the total Heating Degree Days ("HDD") estimates for 2012 and 2013. The 2013 weather normal forecast is based on the 20-year declining trend weather normal methodology. In RP-2003-0063, the Board approved a 70:30 weighting of the 30-year average forecast and the 20-year declining trend. The Board directed Union to change the weighting by 5% annually, until the methodology reached a 50:50 weighting. However, based on the Settlement Agreement approved by the Board in EB-2005-0520, Union's current methodology in rates reflects a 55:45 weighting of the 30-year average and the 20-year declining trend methodology. The 50:50 weighting approved by the Board was not achieved as a result of that Settlement Agreement.

Intervenors and Board staff argued that Union had not adequately justified the use of a 20-year declining trend. They submitted that Union had not presented other methodologies to demonstrate that the 20-year declining trend is superior to other methodologies. LPMA submitted that Union had merely compared the proposed 20-year declining trend with the current approach approved in rates. LPMA further submitted that Enbridge in the EB-2006-0034 proceeding had presented an exhaustive analysis of 9 different forecasting methodologies that were ranked based on a number of statistical measures over a number of different periods[1], and that Union did not do such an extensive analysis in this case. Board staff submitted that Union had not provided sufficient evidence for the Board to make an informed decision. Board staff further

[1] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p.31.

argued that the Board had no basis for determining if the 20-year declining trend is the most appropriate and accurate forecasting methodology for Union.

Similarly, VECC submitted that Union presented more models in the 2004 proceeding (RP-2003-0063) where it presented six different methodologies in addition to the 20-year declining trend.

In its reply submission, Union submitted that intervenors had several opportunities to test other models and they could have asked Union for additional evidence during the discovery process, but did not do so. Union submitted that the Board should not reject the 20-year declining trend on the basis that there is some other methodology which may provide better results. Union submitted that the Board should make a decision on the basis of what is filed in evidence and that is a choice between the 20-year declining trend, the existing method and the 30-year average.

LPMA submitted that Union only considered a trend methodology based on a 20-year time horizon with no other explanatory variables other than the trend used to explain the fluctuation in heating degree days. Further, Union did not consider adding any other variables to the trend model to see if it could find a better equation that might improve the forecast.[2]

Some intervenors (LPMA, VECC and Energy Probe) specifically argued that there is a significant flaw in the equations used to forecast degree days for the Test Year. They submitted that the equations are not statistically significant even at an 85% level of confidence. In reply, Union submitted that the 20-year declining trend was statistically superior to the blended and the 30-year average methodology. While the results of the 30-year average are significant at the 30-45% confidence level, the existing methodology is significant at the 70% confidence level. Union submitted that intervenors were critical of the 20-year declining trend but were overlooking the weakness and bias that exist in the existing methodology and the 30-year average.

Energy Probe also submitted that Union had not investigated zone based Heating Degree Days forecast methodologies as was done by Enbridge. Board staff made a similar submission that Union should have considered the possibility of different

[2] Oral Hearing Transcripts, EB-2011-0210, Volume1 at pp. 44-46.

forecasting approaches across the different regions. Energy Probe submitted that Union was using Pearson Airport Data for weather which was not a fair representation of Union's franchise area. In reply, Union submitted that there was no evidence to support Energy Probe's position and the evidence indicates that the weather in Union's franchise area in the North and the South is highly correlated to Pearson, at a correlation of over 90%.

Board staff and VECC further submitted that Union had not performed some of the tests that would validate its regression model. This includes testing for heteroskedasticity.[3] The presence of heteroskedasticity can invalidate statistical tests of significance that assume that the modelling errors are uncorrelated and normally distributed and that their variances do not vary with the effects being modelled. VECC submitted that testing for heteroskedasticity was not a major exercise and therefore should have been undertaken.

SEC and Board staff submitted that the 20-year trend possibly results in a steep downward sloping curve even though it may be slicing the middle of the data denoting better symmetry. Board staff noted that this results in far lower Normalized Average Consumption numbers for 2012 and 2013. SEC noted that the 20 years is the period of trend that produces the steepest downward sloping curve. In reply, Union submitted that Board staff was focusing on the volatility of NAC which was an indirect argument since weather is one of the components in the NAC calculation.

Many intervenors and Board staff submitted that based on the evidence, the Board should approve a 50:50 blend of the 30-year average and the 20-year declining trend for 2013. BOMA, however, recommended that the Board should approve the current approach in rates which is the 55:45 blend.

LPMA submitted that the 20-year trend component of the blended methodology should not be Union's 20-year declining trend forecast as included in the evidence. First, the 20-year trend forecast as filed by Union should be updated to reflect actual 2011data, as should the 30-year moving average. Second, the 20-year declining trend equations modified for a structural shift that is shown in Attachments 1 of 3 of Exhibit J1.3 should be used in place of the equations shown in Attachments 2 and 4.

[3] Heteroskedasticity occurs when the standard deviations of a variable monitored over a specific amount of time, are not constant.

LPMA submitted that for the Southern service area the equation that includes the structural shift variable with an overall fit confidence interval of more than 99% should be used. The test year forecast from this equation from a statistical point of view is 3,816 HDD which should be used in the weighting for the 2013 forecast.

In the North, LPMA submitted that the two equations were both a good fit with an overall confidence level of more than 99%. However, the equation with the structural shift variable explains a higher proportion (56%) of the variability in the data as compared to the equation without it. The test year forecast from the better fitting equation from a statistical point of view is 4,844 HDD. LPMA submitted that this should be used in the weighting for the 2013 forecast.

Lastly, Board staff and LPMA requested the Board to direct Union to present better evidence at the next cost of service proceeding. LPMA submitted that the Board should direct Union to conduct a comprehensive review of at least the same forecasting methodologies as reviewed by Enbridge in both their EB-2006-0034 and the current EB-2011-0354 rates proceedings and provide that analysis at the next rebasing proceeding.

In reply, Union submitted that the introduction of a dummy variable in 1998 by LPMA is highly subjective. Union indicated that by introducing a dummy variable, LPMA was suggesting that the weather had changed in 1998 and became colder going forward. Union submitted that this was subjective and introducing a dummy variable could lead to arguments in future proceedings with respect to when a dummy variable should be introduced. Union submitted that the 20-year declining trend ranks above the LPMA dummy variable methodology, considering that the dummy variable methodology shows large mean percent and root mean square errors.

Union submitted that the Board should focus on the evidence presented and the evidence shows that the 20-year declining trend is superior to the existing and the 30-year average methodologies. Consequently, the Board should approve Union's proposal.

Board Findings

In the RP-2003-0063 proceeding, Union sought to use a 20-year declining trend methodology. In that Decision, the Board approved an initial 70:30 weighting of the 30-year average forecast and the 20-year declining trend. The Board directed Union to change the weighting by 5% annually, until the methodology reached a 50:50 weighting.

In this proceeding, intervenors and Board staff have submitted that Union failed to bring forward or discuss other methodologies. Union, in its reply argument, submitted that intervenors did not raise concerns or provide additional evidence during the discovery process. The Board believes that it is the responsibility of the applicant to provide the evidentiary basis to support its position. Union failed to review other scenarios and provide the Board with the information and statistical support necessary for the Board to determine that the 20-year declining trend is the most appropriate methodology. Even the 50:50 blended methodology that was approved in RP-2003-0063 was not discussed by Union in its Application, but was only reviewed through interrogatories and evidence that emerged during the proceeding.

Union submitted that Board staff erred when it focussed on the volatility of NAC while discussing weather. However, the Board considers that it is clear that the weather is becoming more volatile, and that it is desirable to adopt a methodology that smooths this volatility. In the RP-2003-0063 Decision, the Board noted that both the 30-year average and the 20-year declining trend have advantages. The 20-year trend may track through the middle of the data as Union claims and would respond more quickly to changes in short-term trends but would also be more volatile. On the other hand, the 30-year average will respond more slowly to changes but would be less volatile.[4] During this proceeding Union has agreed that the weather is becoming more volatile.

Union, in reply argument, stated on page 85:

> And the evidence is, while it may be getting warmer as a trend, weather is still – and getting more so – volatile and that the experience in the weather charts we looked at shows that there are wide swings in the weather year to year, and frankly, within a year.

[4]Decision with Reasons, RP-2003-0063, March 18, 2004 at p. 22.

The Board finds that since the 20-year declining trend reflects a shorter time period, it would be more likely to be affected by large variations in weather between one year and another. In other words, it would not perform as well as the blended methodology to smooth the effects of a particular year that is warmer or colder. The Board believes that use of the 20-year declining trend methodology could expose ratepayers to wider variations in costs from year to year since the methodology may not produce stable results and is susceptible to volatile weather patterns.

The Board directs that a 50:50 blended approach of the 20-year declining trend and the 30-year average methodology be adopted. Union is further directed to make the required adjustments to incorporate 2011 actual data, thus using the most recent and available data.

The Board does not agree with LPMA that a dummy variable should be introduced. The Board believes that this is a subjective adjustment to the methodology. The Board finds that a dummy variable is not necessarily required to account for the upward move between 1998 and 2000.

The Board directs Union to reflect the appropriate adjustments in the Draft Rate Order.

Union has submitted that its weather data for its Northern and Southern franchise areas is highly correlated. The Board does not agree that a high level of correlation necessarily implies that it is appropriate to use the same forecasting methodology in each of the North and South franchise areas. Union should consider analyzing each of the weather stations it utilizes to arrive at a weighting of its Southern and Northern degree days. A uniform approach may not be suitable for Union’s service areas that exhibit wide weather variations between the North and South.

The Board does not see the need to provide direction to Union with respect to future filings in the event that Union chooses again to apply to change the degree day methodology. As stated earlier in this Decision, it is the applicant’s responsibility to present sufficient evidence to demonstrate why a change in methodology or approach is appropriate.

NORMALIZED AVERAGE CONSUMPTION ("NAC")

Union's forecast estimates of NAC are prepared for the residential customers by individual rate class. Commercial NAC estimates are first prepared for the total commercial service class, then converted to regional estimates and finally allocated to the individual rate classes on the basis of historical volumetric shares. The industrial market demand is determined by a total volume equation and average consumption estimates are then subsequently derived. The NAC forecast for residential and commercial customers incorporates assumptions related to several demand variables: weather normal, energy efficiency, total bill amounts, fall seasonal weather and structural trend variables.

Residential NAC estimates are prepared separately for Union South and North customers. The residential econometric forecasting follows the methodology used in EB-2005-0520. The NAC estimates are the product of two regression equations: an average use per customer equation and a total volume equation. The average of the two econometric demand estimates is then adjusted for the forecast demand side management program NAC impact. The commercial NAC forecast estimates are obtained from regression analysis of commercial consumption data from all general service rate classes.

Intervenors and Board staff submitted that the NAC forecast for the residential and commercial markets are significantly lower than the historic trend. Board staff submitted that Union has forecasted a decline of 5.1% from 2011 to 2013 in the M2 residential market, which is significantly higher than an average annual reduction of approximately 1.5% from 1992 to 2011. LPMA submitted that Union was forecasting that the percentage decline in non-weather related average residential use will double in the bridge and test years.

Similarly, with respect to Rate 01, LPMA submitted that the residential average annual use fell by 0.2% in 2006 to 2011, 1.3% in 2001 to 2011, and 1.4% in 1991 to 2011. However, for the bridge and test years, Union has forecasted a decline of 2.4% per year for the bridge and test years reflecting an increase in the rate of decline by one full percentage point compared to historical rates. LPMA and VECC submitted that Union has not provided any evidence to support this accelerated decline in average use. LPMA noted that the rate of decline due to furnace efficiency improvements has not accelerated, and neither has the reduction due to Demand Side Management ("DSM") initiatives.

LPMA, VECC, CCC and Energy Probe submitted that the Board should approve a forecast for the two residential classes that reflects a decline in average use in the bridge and test years that is consistent with the historical data. CCC and LPMA submitted that a reduction of 1.4% per year for both classes is reasonable and consistent with the long term trend. This would reduce the M2 average use from 2,264 m^3 in 2011 to 2,201m^3 in 2013 and the 01 average use from 2,269 m^3 to 2,206m^3 over the same period. VECC submitted that the NAC forecast for M1 and Rate 01 should be increased by 1.1% for 2012 and 2013. Energy Probe further submitted that the Board should continue the Average Use True Up Variance Account (the "Average Use Account", No. 179-118) in 2013.

LPMA and Board staff expressed similar concerns with respect to the decrease in average use forecast for the old rate M2 and Rate 01. While the annual percentage decline between 1991 and 2011 is only 0.4%, Union has forecasted a reduction in commercial old rate M2 by 3.4% on an annualized basis for 2011 to 2013. LPMA submitted that over the last 5 and 10 year periods, the average use for these customers had actually increased. Union supported the forecasted decrease by stating that the increase in average use in this category in 2011 was an outlier.

LPMA further submitted that the commercial use per customer equation used by Union did not include any explanatory variables related to the economy or the relative price of natural gas versus other energy sources, such as electricity. LPMA submitted that the increase in 2011 could be explained by the fact that the economy in 2011 was back to near pre-recession levels and natural gas prices have been at record lows while electricity prices have continued to rise.

With respect to commercial Rate 10 volumes, LPMA submitted that the forecasted decline of 1.7% per year is not reasonable considering that the average use in this category is higher in 2011 than it was in any previous year. Moreover, the general trend has been higher over the last decade. LPMA submitted that the Board should approve a forecast for the three commercial classes that reflects a decline in average use in the bridge and test years that is consistent with the historical data. LPMA submitted that a reduction of 0.4% per year for commercial M2, and 1.0% for commercial 01 is reasonable and consistent with the long term trend.

None of the intervenors made a submission on the industrial average use forecasts. LPMA submitted that the forecasted average uses for the Rate 10 and M2 category were plausible.

In reply, Union submitted that the NAC calculations for the various residential, commercial and industrial components of the general service market are checked for specification every year and where appropriate have been re-specified. Union further noted that the results are statistically significant at the 95% level of confidence.

Union submitted that the intervenors had not challenged the statistical validity of the results of the NAC methodology but rather argued that the results could not be correct. Union submitted that the Board should reject the arguments forwarded by intervenors and approve the NAC forecast methodology as it has done in the past.

Union further submitted that should the Board have any concerns with respect to the NAC forecast, it could continue maintaining the Average Use Account that was in place during the incentive regulation period.   Although Union did not prefer this approach, it indicated that continuing the deferral account would resolve the dispute around the NAC forecast. Under that option, Union submitted that the Board could include Union's NAC forecast in rates and apply the Average Use Account to track any changes.

Board Findings

The Board notes that Union's proposed NAC calculations forecast a much larger decrease than historic rates of decline. However, the Board believes that an arbitrary increase in the NAC numbers is not appropriate, given that Union's NAC numbers have been derived using econometric models that were previously approved by the Board. Moreover, moving to the 50:50 blended weather methodology will likely result in changes to Union's NAC calculations.

The Board therefore accepts the NAC forecast in rates as proposed (subject to an update for the approved weather methodology) by Union but finds that the continued operation and use of the Average Use Account for the 2013 test year is appropriate and is fair to both Union and ratepayers. The Board directs Union to revise the NAC calculations based on the Board approved weather methodology and is directed to incorporate the revised numbers in the Draft Rate Order.

OPERATING REVENUE

Customer Attachments

Union has forecasted modest increases in customer attachments over the 2011 to 2013 period. In its Application, Union forecasted customer attachments of 19,510, 20,380 and 22,491 in 2011, 2012 and 2013 respectively.

Board staff submitted that Union had not included customer attachments related to the Red Lake project. At the hearing, Union confirmed that it expected to add approximately 800 customers in the community of Red Lake by 2013. Board staff submitted that although Union included the costs of the project in rate base, the revenues had not been accounted for in the current Application. Board staff submitted that as a matter of principle Union should include conversions related to Red Lake in its Application including the distribution revenues that are attributed to these attachments.

LPMA submitted that Union had under forecasted customer attachments in three of the past four years. The average under forecast number in 2008, 2010 and 2011 was 6,455, while in 2009, when the impact of the recession hit the housing market, Union over forecasted by 2,354 additions.[5] LPMA submitted that the average variance over the four years was 4,253. LPMA therefore submitted that the Board should increase the general service customer forecast by 4,250 in both the bridge and test years.

In reply, Union submitted that year-to-date, it was tracking lower than its forecast of total billed customers. The actual total number of billed customers as of June 2012 was 1,366,306 which represented a deficit of 399 customers as compared to the forecast.[6] Union therefore submitted that there was no reason to increase Union's customer attachment forecast for 2012 or 2013. With respect to the addition of Red Lake customers, Union submitted that revenues attributed to Red Lake were not material and this would not reach the materiality threshold as defined by the Board.

[5] Exhibit J.C-1-1-5.
[6] Oral Hearing Transcripts, EB-2011-0210, Volume 1 at p. 59.

Board Findings

The evidence indicates that Union is tracking marginally behind its total customer billed forecast for 2012. The Board sees no reason for increasing the forecast by 4,250 customers. Although LPMA refers to previous under forecasted numbers in 2008, 2010 and 2011, there is no evidence that such a trend will necessarily be continued. The Board finds that Union's forecast is reasonable, with one exception as noted below.

The Board believes that the 800 customers that Union has forecasted to attach in Red Lake must be included. Although this increase may be immaterial, it is based on an undisputed planning input. Union has included the capital costs of this project in rate base and the Board sees no reason for not including the revenues from these additions in the 2013 operating revenues. Accordingly, the Board directs Union to increase the customer forecast by 800 customers for 2013.

Contract Customer Demand Forecast

Union segments the contract customer market into different sectors. They include gas fired power generation, steel, refinery and petrochemical, greenhouse, wholesale and broad-based commercial and industrials ("LCI/Key"). The volume and revenue forecasts for contract customers are developed using two methodologies. An econometric forecast is developed for the majority of the customers and a detailed bottom-up forecast is developed for the large T1 and Rate 100 customers.

For the small to mid-size contract markets represented by the LCI and Greenhouse market sectors, Union uses econometric analysis to forecast consumption requirements. For the remainder of the contract market, Union uses a bottom-up approach given its extensive understanding of these accounts through ongoing interactions between the customer and the account manager.

APPrO in its submission proposed an overall increase of $3.09 million to the revenue forecast with respect to the contract market. This includes a power revenue commodity increase of $1.0 million, incremental fuel associated with the commodity revenue of $0.14 million, a T1 billing contract demand overrun revenue of $0.75 million and other contract overrun revenue of $1.2 million.

APPrO in its submission noted that, in accordance with provincial policy, coal-fired generation is in the process of being phased out. APPrO submitted that gas-fired generation has replaced much of the coal-fired generation capacity and provides back-up for renewable generation. APPrO submitted that reduced coal-fired generation will increase the runtime for gas-fired power generation.

APPrO submitted that Union's methodology to forecast power commodity revenue was fundamentally flawed since it used dated information. APPrO noted that Union included 2009, 2010 and part of 2011 data as the basis for the forecast and submitted that this was not appropriate as it did not take into account the impact of coal-fired generation closures. APPrO further maintained that Union did not incorporate the Independent System Electricity Operator ("IESO") forecast of a higher provincial power demand in 2013. The IESO 18-month outlook indicates that the 2013 aggregate energy consumption is expected to be 1.1% higher in 2013 than in 2011. In reply, Union submitted that customers were in the best position to provide relevant information. Union argued that customers ultimately have to contract for the services and it was in their best interest to provide reliable estimates.

APPrO submitted that commodity revenues for power customers for 2013 should be increased by $1.0 million which would be similar to the $4.9 million revenue collected from this group in 2011. This adjustment would also impact the customer supplied fuel which is treated as a revenue item by Union. APPrO submitted that customer supplied fuel should be increased by the same proportion as the commodity revenues which was 11% in this case. An 11% increase to customer supplied fuel results in an increase of $0.14 million to the $1.3 million included in rates.

With respect to overrun revenues, APPrO, LPMA, Energy Probe and Board staff submitted that Union had understated overrun revenues for 2013.Intervenors and Board staff submitted that Union had not forecasted any overrun charges in the power market for 2012 and 2013. This is despite the fact that the Halton Hills power plant had already incurred $300,000 in overrun charges up to the end of June 2012. Board staff suggested an increase of $300,000 to the overrun charges while LPMA submitted that the overrun revenue forecast for the power market should be adjusted to the same level as in 2011 which was $600,000. SEC and FRPO adopted LPMA's submission in this regard. Energy Probe submitted that the overrun revenues for the power market should be increased to about $500,000. APPrO submitted that the closure of the coal plants and the low efficiency Lennox plant is driving additional volumes at Halton Hills and other gas-fired generation plans. APPrO therefore argued that 2012 overrun revenues could exceed 2011 revenues. APPrO proposed that the 2013 overrun revenue should be increased to $750,000 for 2013.

With respect to the non-power markets, LPMA expressed a concern about unsupported reductions in the overrun forecast. Union forecasted $600,000 in overrun revenues for the Test Year. LPMA noted that average overrun revenues for the non-power markets from 2007 through to 2011 were $1.7 million a year and have been stable over this period. LPMA submitted that $1.7 million was a reasonable forecast for 2013. Board staff, SEC and FRPO agreed with LPMA. APPrO noted that the three-year average overrun revenues in the non-power market which included 2007, 2010 and 2011 but excluded the financial crisis years of 2008 and 2009 was $1.8 million. APPrO accordingly submitted that the overrun revenues should be increased by $1.2 million which was $100,000 more than what the other intervenors had suggested.

In reply, Union submitted that it had forecast overrun revenues for 2013. Union noted that an amount of $600,000 related to overrun revenues had been included in 2013 rates.

Board Findings

The Board does not accept the contract customer demand forecast to be reasonable. As outlined below, Union’s forecasts do not reflect known changes in the market and environment, and have been demonstrated through evidence to be understated. The Board finds that the following three adjustments to Union’s contract customer demand forecast should be made.

First, with respect to commodity revenues, in preparing its forecast, Union considered only a narrow range of inputs, namely, its own forecast and estimates provided by each customer. In addition, the data is dated and does not take into account recent events or changes in the market. The Board agrees with APPrO that market conditions have changed significantly over the past couple of years because coal-fired generation is on the decline and is being replaced by gas-fired generation. Accordingly the Board directs Union to increase forecast 2013 commodity revenues by $1.0 million and directs that a corresponding increase of $0.14 million in the fuel commodity revenue should also be made.

Second, the Board directs Union to increase forecast 2013 overrun revenues by $0.5 million. The Board notes that the evidence in the proceeding shows that actual power plant overruns in 2012 were already $0.3 million by mid-2012. There is no evidence to suggest that there would not be a continuation of such revenues in 2013.

Third, the Board directs Union to increase non-power market overrun revenue by $1.1 million from $600,000 to a total of $1.7 million in 2013, which is about the average revenue in this category from 2007 to 2011, exclusive of 2008 and 2009, the years of the financial downturn.

Storage & Transportation Revenue

Union's storage and transportation ("S&T") revenue forecast for 2012 and 2013 is organized under the following headings:

- Long-term transportation revenue forecast;
- Short-term transportation and exchanges revenue forecast; and
- Short-term storage and balancing revenue forecast.

Long-Term Transportation Revenue Forecast

Union's forecast for long-term transportation revenue is $148.5 million in 2012 and $141.9 million in 2013. The forecast is made up of three components: M12 Long-term Transportation, Other Long-Term Transportation, and Other Storage and Transportation Services.

<u>M12 Long-term Transportation</u>

The revenue for M12 Long-term Transportation represents long-term firm transportation on Union's Dawn-Parkway transmission system. It includes M12, M12X and F24-T transportation services which transport gas supplies easterly, westerly or bi-directionally on the system. Table 1 provides the actual and forecast revenues for M12 Long-term Transportation.

Table 1
M12 Long-term Transportation Revenue

Revenue (Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
M12 Transportation	$141.9	$138.3	$134.0	$121.1
M12 Transportation Overrun	$0.5	$0.0	$0.0	$0.0
M12X Transportation	$0.0	$1.5	$5.9	$13.5
Total	$142.4	$139.8	$139.9	$134.6

LPMA in its submission observed that as per Exhibit J.C-4-5-2, revenues for M12 long-term transportation revenues have been steadily increasing since 2007. LPMA noted that revenues for 2011 and the forecast for 2012 were just under $140 million, with a reduction of $5.3 million forecast for 2013 relative to 2012. LPMA further noted that as per Exhibit J6.3, the year-to-date actual revenues were tracking close to the forecast in 2012.

LPMA accepted Union's explanation of a reduction in 2013 which attributed the reduction to turnback of M12 capacity that began in 2011 and is forecast to continue in 2012 and 2013. LPMA noted that in a response provided in Exhibit J8.10, Union indicated that there was an increase of $280,000 based on changes to M12, M12-X and C1 long-term firm contracts since the forecast was completed. LPMA submitted that this increase should be reflected in the forecast.

LPMA submitted that an acceptance of the forecast did not imply that the capacity that was not currently contracted for had no value. LPMA submitted that Union had significant excess capacity on the Dawn to Parkway system and it was possible that the unused capacity may be contracted for in 2013. LPMA therefore submitted that any variance from the Long-term Transportation revenue forecast, both up and down, should be captured in a variance account and shared 90% to ratepayers and 10% to the shareholder. FRPO and APPrO adopted LPMA's recommendations on this matter. CME accepted LPMA's recommendation of a variance account but submitted that the actual amount in 2013 rates should be $139.8 million as compared to $134.6 million. CME submitted that there was significant revenue potential considering that the gas had to get to Dawn regardless of where the gas was coming from.

In reply, Union rejected CME's proposal to adjust the M12 Long-term Transportation revenues. Union reiterated that it had experienced significant turnback on the Dawn-Parkway and Dawn-Kirkwall systems and this has resulted in a lower forecast in 2013 as compared to 2011 and 2012. Union also rejected LPMA's position that a deferral account should be established to capture the variance related to the Long-term Transportation revenue forecast. Union submitted that it has always been at risk for the Long-term Transportation revenues and that the same regulatory treatment should be continued.

<u>Other Long-term Transportation</u>

There are three components that comprise the Other Long-term Transportation revenue forecast: C1 Long-term Transportation, M13 (Local Production) and M16 (Storage-Transportation Service). The actual and forecast revenues for these services are shown in Table 2.

Table 2
Other Long-term Transportation Revenue

Revenue (Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
C1 Long-term Transportation	$6.3	$7.6	$6.6	$5.2
M13 Transportation	$0.4	$0.3	$0.4	$0.4
M16 Transportation	$0.6	$0.6	$0.6	$0.6
Total	$7.3	$8.5	$7.6	$6.2

Union attributed the decline in C1 Long-term Transportation revenue since 2011 to changes in market dynamics and gas flows affecting the Dawn-Parkway and Ojibway systems.

LPMA in its submission accepted the decline in C1 Long-term transportation revenues but noted that actual year-to-date 2012 revenues were up by 7% as compared to the forecast. Accordingly, LPMA submitted that the 2013 forecast should be adjusted by the same proportion resulting in an increase of $400,000.

In reply, Union rejected LPMA’s submission to make an upward revision of $400,000 to the C1 Long-term Transportation revenue forecast. Union provided the clarification that revenues for 2012 which were categorized as C1 short-term were actually sold as C1 long-term. Consequently, there was an increase in the C1 Long-term Transportation forecast and a decrease in the C1 short-term transportation forecast. Union further submitted that this was an example of a selective adjustment where LPMA proposed adjustments for positive variances but excluded adjustments when they showed a negative variance.

Union submitted that the overall forecasts were reasonable even though there may be some negative or positive variances in the different categories. With respect to C1 Long-term Transportation, Union indicated that Dawn to Parkway revenues were offset by the negative variance in the M12 account. Union submitted that it had essentially forecast more capacity to be sold as short-term firm rather than C1 long-term.

Other S&T Revenue

This category is comprised of revenue earned from name changes, Ontario Producers and other miscellaneous services. The revenue for these services have been constant at $1.1 million in 2010 and 2011 and forecasted to be the same for 2012 and 2013. LPMA accepted Union’s forecast for these services. APPrO and FRPO adopted LPMA’s submission with respect to Long-term Storage and Transportation Revenue.

Board Findings

The Board accepts Union’s forecast of 2013 M12 Long-Term Transportation Revenue, Other Long-Term Transportation Revenue, and Other S&T Revenue as reasonable. The Board will not require Union to adjust estimated revenues as was suggested by some parties, as the Board concurs with Union that the adjustments are selective in nature. The Board rejects LPMA’s request to establish a variance account related to Long-term Transportation Revenue, as the Board believes that Union should continue to bear this forecast risk, consistent with the current treatment.

Short-term Transportation and Exchanges Revenue Forecast

The short-term transportation and exchanges revenue forecast is $32.2 million for 2012, and $20.2 million for 2013.

Short-term Transportation

The transportation component of the transactional forecast is comprised of short-term firm and interruptible transportation on Union's Dawn-Parkway systems, the Ojibway system and St. Clair/Bluewater system. Union forecasted $11.1 million in revenues in 2012 and again in 2013, down from $12.5 million in 2011. Union attributes the decline to insufficient takeaway capacity on TCPL downstream of Parkway. LPMA in its submission accepted the forecasted declines. LPMA also argued that the same variance account treatment that it proposed for Long-term Transportation Revenues should be applied to Short-term Transportation Revenues.

Board Findings

The Board accepts Union's forecast of 2013 Short-term Transportation Revenue as reasonable. The Board rejects LPMA's request to establish a variance account related to Short-term Transportation Revenue, as the Board believes that Union should continue to bear this forecast risk, consistent with the current treatment.

Short-term Storage & Balancing

Union's forecast for short-term storage and balancing is $9.1 million in 2012 and $11.5 million in 2013. This forecast is comprised of two components: peak short-term storage, and off-peak storage, balancing and loans. Union has forecasted an increase in 2013 related to short-term peak storage revenues. The primary reason for this increase is the increase in the forecast price of storage, from $0.55 per GJ in 2012 to $0.85 per GJ in 2013.

LPMA noted that based on data provided in Exhibit J6.3, the June year-to-date revenues for off-peak storage/balancing/loan services were tracking close to the forecast. LPMA accepted Union's forecast for 2013 since 2012 revenues were on track to meet the forecast and the forecast of $2.5 million for 2013 was similar to 2012.

However, LPMA noted that according to Exhibit J6.3, the year-to-date revenues for short-term storage services were over the forecast by $2.7 million, i.e. 87%. Moreover, the June 2012 actual revenues of $5.8 million were only slightly under the annual forecast of $6.6 million. LPMA submitted that using the same methodology as for base exchanges, the projected 2012 forecast based on how revenues were currently tracking was $12.3 million.

LPMA submitted that the 2013 forecast should be increased to the projected 2012 level of $12.3 million from the current forecast of $8.988 million. LPMA noted that the forecast of $12.3 million was still below the levels recorded in 2007 through 2010, despite more excess utility space projected to be available in 2013 than in previous years. FRPO and CME agreed with LPMA on these issues.

In reply, Union submitted that the 2012 forecast was initially prepared at an average price of $0.55 per GJ. However, the actual price was $0.84 per GJ and this was the cause of the positive variance. Union provided clarification that the forecast for 2013 was based on actual 2012 prices, which were at $0.60 per GJ and not $0.85 per GJ. Union submitted that there was no evidentiary basis to increase the 2013 forecast.

Board Findings

The Board accepts Union's forecast for 2013 Short-Term Storage & Balancing revenue as reasonable. Given the uncertainty relating to the forecast, the Board approves the continued operation and use of the Short-Term Storage & Balancing variance account to capture any variance of Short-Term Storage & Balancing net revenue from forecast, both up and down during the 2013 test year, consistent with the current practice. The Board notes that 90% of the net revenue forecast related to short-term storage and balancing is to be built into rates for 2013. The balance in the variance account is to be shared 90% to ratepayers and 10% to the shareholder.

OPTIMIZATION AND GAS SUPPLY PLAN

Exchanges

Exchange revenue is comprised of activity using Union's upstream transportation capacity to provide exchange services to third parties. It also includes net revenue generated from pipe releases or revenue from TCPL's Firm Transportation Risk Alleviation Mechanism ("FT-RAM") program. Union did not include any amount for the FT-RAM program in its Application due to the uncertainty surrounding the continuation of the program. TCPL has proposed to end the program in its current application before the National Energy Board.

Union included base exchange related revenues of $9.1 million in 2013. This compares to $8.6 million in 2010, $9.7 million in 2011 and a forecasted amount of $6.9 million in 2012.

LPMA and Energy Probe submitted that the forecast for base exchange revenues were significantly understated. LPMA referred to Exhibit J6.3 which shows that the actual base exchange revenue for year-to-date as at the end of June was 66% higher than the forecast for the same period. LPMA proposed that the Board should increase the 2013 forecast of $9.1 to reflect the under forecast in 2012. Union forecasted achieving $4.0 million or 58% of its revenues as of June 2012. LPMA proposed using the same ratio but applying it to the actual revenues of $6.6 million as of June which would result in an annual number of $11.4 million for 2012. LPMA submitted that Union had provided no evidence that base exchange revenues would decline in 2013 and the Board should therefore increase Union's revenues from $9.1 to $11.4 million in 2013, essentially maintaining the same level as that projected for 2012. CME supported LPMA's submission in this matter.

Union, in its reply argument, submitted that the Board should include $9.1 million in rates for base exchanges with any variance subject to sharing 75:25 in favour of ratepayers, consistent with the treatment prior to IRM.

Firm Transportation Risk Alleviation Mechanism ("FT-RAM")

FT-RAM or Firm Transportation Risk Alleviation Mechanism is a service to TransCanada's long-haul firm transportation ("FT") shippers. The FT-RAM program allows long-haul FT shippers to apply unutilized FT demand charges against their cost of interruptible transportation ("IT") service. TCPL introduced the FT-RAM program to promote the renewal of incremental contracting for long-haul FT service.

In its Argument-in-Chief, Union proposed to include $11.6 million in rates and establish a variance account to capture any additional revenues or any revenue shortfall. Union submitted that it should have 100% downside protection below $11.6 million and any revenue above $11.6 million should be shared 75:25 in favour of ratepayers.

Energy Probe submitted that Union's forecast of $11.6 million should be accepted only if the Board categorizes these revenues as transportation related. Energy Probe submitted that FT-RAM revenues should be classified as gas costs and 100% of the revenues should go to ratepayers through the Purchased Gas Variance Account.

Board staff submitted that Union had used the capacity that is excess to its gas supply plan to generate a significant amount of revenue over the years. In cases where the transportation capacity was assigned to a third-party, Union earned revenue by selling this capacity. Revenues generated through assignments flowed to ratepayers through the Unabsorbed Demand Charges ("UDC") deferral account. However, when Union needed the supply and it was being delivered through an alternate route, revenue generated as a result of such assignment flowed to Union's utility earnings. If the empty pipeline was TCPL capacity, then Union generated RAM credits through TCPL's FT-RAM program. Board staff submitted that under the FT-RAM program Union was monetizing RAM credits and it was then delivering gas through alternate and cheaper routes. In other words, Union was selling transportation capacity paid for by ratepayers and repurchasing the same service at a lower cost while keeping the margins. Board staff along with a number of intervenors submitted that Union had generated significant revenues using the FT-RAM program during the IRM period, the majority of which flowed through to Union's shareholder.

Board staff submitted that almost all revenues generated as a result of using pipeline capacity that customers have paid for in gas supply costs should go back to offset gas costs. Board staff submitted that customers have paid for this capacity and they should therefore derive any benefit as a result of optimization. However, Board staff did recognize that Union needs some incentive to optimize and proposed that 90% of the revenues generated through optimization activities related to transportation capacity that in-franchise customers have paid for should go to offset gas costs while the remaining amount should flow to utility earnings.

Although most intervenors agreed with the general argument of Board staff, they rejected the sharing formula. Intervenors such as LPMA, BOMA, Energy Probe, CME and FRPO submitted that all revenues generated through optimization activities related to transportation capacity paid for by ratepayers should go to offset gas costs. LPMA submitted that Union should not receive any incentive to get the best cost for the gas it supplies to its system gas customers. LPMA noted that Union does not make a profit on the cost of gas; it is a flow through cost to system gas customers. LPMA submitted that the cost of gas includes the cost of getting the gas to the Union system. LPMA stressed that the actual cost of gas, including the actual cost of getting it to Union is what system gas customers should be paying for. APPrO adopted LPMA's submission with respect to exchange related revenues.

FRPO in its submission attempted to provide some distinction between revenues that should offset gas costs and revenues that represent true optimization. FRPO submitted that FT-RAM credits associated with long haul contracts should be classified as gas costs while optimization of transportation within Union's franchise area or optimization of Storage Transportation Service ("STS") contracts could be classified as optimization that would be captured in the historical storage and transportation exchange services deferral account.

CME in its submission addressed the larger issue of revenue deficiency noting that cumulative overearnings during the IRM years averaged around $40 million a year. CME submitted that it could not understand why ratepayers were facing a revenue deficiency as opposed to a sufficiency. CME attributed the overearnings during the IRM years to revenue increases rather than cost reductions. An important contributor to the revenue increases was FT-RAM revenues.

CME noted that the Board and intervenors rely on Union to adhere to the concepts and principles embedded in the Board's regulation of gas utilities. CME submitted that one of the fundamental concepts was that for ratemaking purposes, gas commodity costs and upstream transportation costs are to be treated as pass-through items. CME maintained that the utility should neither profit nor lose as a result of the actual commodity or upstream transportation costs. CME was of the opinion that the utility holds the amounts in trust that it receives from ratepayers on account of gas commodity or upstream transportation costs. If actual costs are less than the actual amounts collected, then ratepayers are to receive a credit and if actual costs are higher, then ratepayers have to pay the difference. CME submitted that the excess funds could not be converted to profits without the prior explicit consent of ratepayers or the utility regulator.

CME submitted that Union had not presented all the relevant facts for the intervenors and the Board to determine the validity of its actions. CME maintained that Union's argument that it has undertaken optimization activities before is irrelevant since it had never explicitly presented the facts to the Board. CME asserted that Union could not unilaterally take action to enrich its shareholder at the expense of ratepayers.

In its Argument-in-Chief, Union indicated that there was a deferral account relating to upstream optimization and exchange activity going back to 1993 and perhaps even earlier. Union submitted that the exchange activities Union has undertaken since 2003 as it related to FT-RAM were similar to optimization activities that it undertook before and would undertake in 2013. Union referred to an interrogatory response that states that Union was able to extract value from new services introduced by upstream transportation providers in excess of what was achieved historically.[7] The new service referred to was TCPL's FT-RAM.

CME, in its submission, rejected Union's argument that FT-RAM refers to activities that are covered by the existing deferral accounts related to upstream transportation and exchange activities. CME stressed that the deferral accounts referred to only that component of upstream transportation that was periodically freed up as a result of weather or declines in demand. The rationale for sharing the incentive between the utility and ratepayers was to facilitate the use of idle capacity.   CME submitted that this account did not cover optimization of upstream transportation surpluses self-created by the utility on a planned basis.

[7] CME Final Argument at Tab 28,

CME in its submission noted that there were two means through which Union monetized FT contracts. One was through capacity assignments and the other one was through leaving its FT capacity unutilized and using a cheaper alternative route to transport the required gas. CME submitted that both of these activities were nothing but upstream gas cost reductions. They could not be classified as exchange transactions or a transactional service. CME maintained that these were planned decisions and not related to capacity temporarily rendered surplus due to conditions beyond Union's control, such as weather or demand. CME submitted that revenues generated as a result of such activities must be classified as gas costs and should be cleared through the current regime of gas supply deferral accounts.

LPMA submitted that should the Board determine that FT-RAM revenues should not flow to system gas customers, but should flow through S&T revenues, then the amount included in the forecast for 2013, and how it is allocated to rate classes needed to be addressed.

LPMA noted that Union had proposed to include $11.6 million in rates, with a variance account to provide protection. LPMA referred to Exhibit J7.11 that estimated FT-RAM revenues of $37.8 million should the program continue for all of 2012. LPMA also noted that Union had received FT-RAM credits of $19.9 million on a year-to-date basis.

LPMA submitted that the Board should not approve the inclusion of any amounts in rates for 2013. In this way, customers would receive some credit in 2013 and would not be faced with a claw back if the program was eliminated. LPMA further noted that such an approach would eliminate the need to determine how to allocate the credits to the various rate classes. The allocation could be dealt with in a later proceeding when the credits came up for disposition. IGUA recommended a similar approach because it did not support including FT-RAM revenues as a rate mitigation option considering that it may not be available in 2013 and beyond. However, IGUA did not take any position on the treatment of FT-RAM revenues.

In reply, Union disagreed with the categorization proposed by intervenors. Union noted that intervenors were attempting to make a distinction between RAM-related exchanges and base exchanges with their argument being that RAM-related revenues should offset gas costs while base exchange revenues should be treated as traditional S&T revenues. Union argued that an exchange was an exchange and that there was no distinction to be made. Union saw no reason to depart from the well-established regulatory treatment of exchanges that treats them as regulated revenues pursuant to the C1 rate schedule.

Union also observed that exchange revenues were not unregulated. The only difference was that during the IRM period they were not subject to deferral treatment. However, they continued to be part of the utility earnings calculation and were subject to earnings sharing.

Union reiterated the definition of an “exchange” that had been clarified several times during the proceeding. Union stated that:

> An exchange is a contractual agreement where party ‘A’ agrees to give physical gas to party ‘B’ at one location and party ‘B’ agrees to give physical gas to party ‘A’ at another location. Either party ‘A’ or party ‘B’ may agree to pay the other party for this service. An exchange can only happen between a point on Union’s system and a point off of Union’s system. The exchange must also happen on the same day at the same time.

Union also rejected the argument of intervenors that the exchange activities were planned and a feature of the gas supply plan. Although Union forecasted a certain level of activity, Union submitted that it was consequential to the service made available by other parties, specifically TCPL.

Union, in reply, noted that the gas supply deferral accounts and the S&T deferral accounts have existed in parallel for years and the treatments for these deferral accounts have been different. While the gas supply deferral accounts have been treated as pass through items, exchanges and other S&T related activities have been treated as forecast revenues subject to deferral treatment.

Union also rejected CME’s assertion that the Board had no knowledge of Union’s FT-RAM related activities prior to this proceeding. Union submitted that in the EB-2009-0101 proceeding, Union explicitly informed parties that it had taken advantage of the FT-RAM service offered by TCPL. During this proceeding, Union reported significant over-earnings in relation to its S&T forecast. Union stated that in response to the over earnings, intervenors revised the 2007-0606 IRM settlement agreement and changed the earnings sharing mechanism from 50:50 to 90:10 in favour of ratepayers to be triggered if the actual ROE exceeded the Board approved ROE threshold by 300 basis points.

Union stressed the fact that intervenors had the opportunity to review whether IRM should continue or not in the EB-2009-0101 proceeding when Union crossed the 300 basis points threshold, but they chose not to. Union pointed to the fact that it was evident that a large contributor to the over earnings was Union's S&T activity that contributed $37 million to earnings of which Union's use of FT-RAM was a significant component.

Union also referred to the 2009 rates proceeding (EB-2008-0220), wherein the Board rendered a decision on a new service introduced by TCPL, Dawn Overrun Service – Must Nominate ("DOS MN"). In this proceeding, CME argued that DOS MN related revenues should be treated as gas supply costs. The Board did not agree with CME and determined that DOS MN revenues should be treated as S&T revenues. Union submitted that although DOS MN and FT-RAM were different services, the treatment was the same.

Union argued that it needs to sell an exchange into the market under the C1 rate schedule and this results in revenue being generated. Union therefore submitted that these revenues cannot be categorised as gas costs because they do not fit in either the gas commodity reductions or toll variances categories.

Union rejected intervenors' position and submitted that intervenors are attempting to classify revenues between gas costs and traditional S&T activity. Union argued that CME's definition did not take into account the market and it was not feasible to monitor the weather or demand on a daily basis. With respect to FRPO's definition, Union indicated that it was limited to particular services and would not be applicable if Union's portfolio were to change from long-haul to short-haul services or if it were to earn revenues on the Dawn-Parkway system.

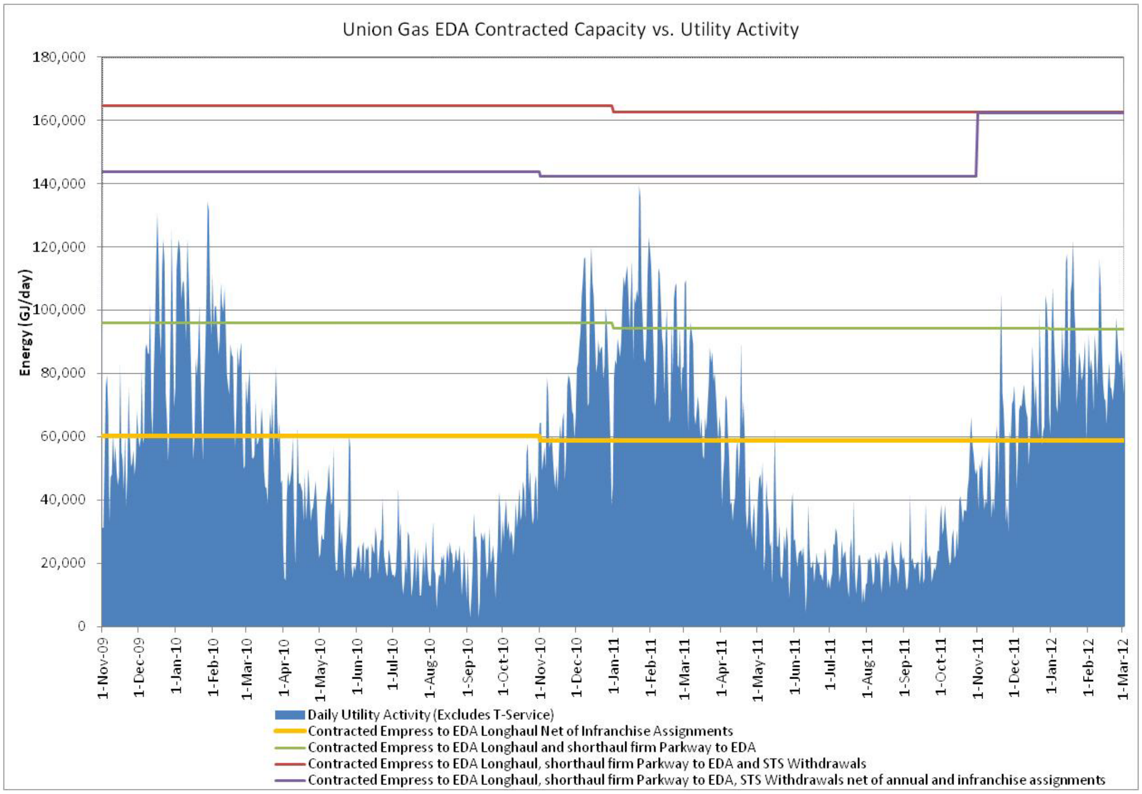
Union submitted that the best approach would be to establish an exchange-related account that is subject to sharing. This would avoid the problem of trying to differentiate the revenues generated and would be a principle based approach that would simplify implementation on a going forward basis. Union indicated that it had estimated FT RAM related revenues of $11.6 million in 2013. However, its preferred approach was to embed no amount in rates and have a deferral account that is subject to a 75:25 sharing in favour of ratepayers.

<u>Gas Supply Plan</u>

Union's gas supply planning process is guided by a set of principles that are intended to ensure that customers receive secure, diverse gas supply at a prudently incurred cost. Intervenors and Board staff submitted that Union is over contracting for FT Service to the Northern/Eastern Delivery Areas and this has resulted in customers incurring UDC for upstream transportation that is left empty or does not flow to full capacity to meet customers' annual firm demands. Board staff and Energy Probe submitted that ratepayers have incurred approximately $5.7 million in UDC costs from 2007 to 2011. Intervenors and Board staff further submitted that Union had arbitraged the excess firm capacity generating transportation revenues for the utility. Union, in reply submitted that all parties referred to the excess in a general manner and no party specifically identified the excess quantity or the specific contracts that Union should not have entered into.

Intervenors and Board staff referred to the graphical representation below of firm contracts in the Eastern Delivery Area ("EDA") that shows how the excess capacity of 20,000 GJ per day was assigned on a long-term basis. VECC, in its submission, noted that a portion of annual transportation contracts was assigned in its entirety on an annual basis, such that, from an operational perspective, it was as if Union had never entered into these contracts.[8]

[8] VECC Final Argument atp.20.



Referring to the same chart, Union, in reply, submitted that it did not over contract and the contracted capacity shown in the chart was appropriate in order to meet a design day. Union further noted that during the valley periods, Union injects gas into storage in order to meet average utility consumption throughout the year. If Union did not inject gas into storage then it would need to contract for even more gas and thus more capacity, during the winter. Union submitted that intervenors did not provide any support for their argument that Union had excess upstream capacity apart from the fact that Union earned S&T revenues during that period. Union submitted that ultimately the gas was required to meet in-franchise customer needs as presumed in the gas supply plan.

Board staff argued that Union's reliance on a design day[9]that is based on the coldest day within the past 50 years is flawed and this results in a far larger cushion than required. In its reply submission, Union argued that Union's design day of minus 29 degrees Celsius was not extremely cold for some of Union's service areas such as Fort Francis and North Bay. Union further noted that although Union's franchise area last experienced the design day in 1981, it has had several days of extreme weather where

[9] Oral Hearing Transcripts, EB-2011-0210, Volume 7 at pp. 161-162. (Design Day is a 47 degree day in the North and a 44 degree day in the South).

the temperature has been within two heating degree days of the design day. Union submitted that the importance of design day is critical in utility planning because the consequences of not having gas on a design day could be significant.[10]

Board staff and VECC noted that Union confirmed at the hearing that if the actual degree day requirements had exceeded the capacity of the firm assets that remained after optimization, Union would have been able to meet its gas supply requirements in several ways. Consequently, Board staff and VECC argued that Union did not require the capacity that it had contracted for. Union in its reply argument noted that its transportation portfolio had been adjusted substantially downwards since 2000. Union submitted that between 2002 and 2011, Union had reduced its long-term firm transportation portfolio of Empress to the Northern Delivery Area by 47%, from 358,643 GJs per day to 191,177 GJs per day.

CME submitted that a gas supply plan that was premised to profit from using upstream transportation capacity paid for by ratepayers was incompatible with the principle that a utility cannot profit from amounts received for upstream transportation.

FRPO, in its submission, argued that Union's gas supply plan relies on long-term firm service contracts that have been avoided or turned back by all customers, including prudent utilities in Canada and the United States within the last few years. FRPO indicated that declining firm contracts on the TCPL mainline is common knowledge. However, Union has continued to hold annual FT contracts even though utilities like Enbridge have moved to shorter-term arrangements such as winter Short-Term Firm Transportation ("STFT"). FRPO referred to Union's response at the hearing that expressed the possibility that Union may not be able to recontract if it were to move to winter STFT. However, FRPO argued that firm contracting on the TCPL main line has diminished significantly, resulting in spare capacity that cannot be sold.

In its reply argument, Union submitted that it had turned back substantial quantities of long haul FT Service during the past few years. Union noted that unlike Enbridge, Union does not require winter peaking service and therefore the reference by FRPO to Enbridge's winter STFT service was not relevant. Union also disputed FRPO's claim that STFT service has always been available and with the exception of service to

[10] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p.85.

Montreal, STFT has been available for decades. Union submitted that it had indicated at the hearing that STFT was not available in 2011 in the Sault Ste. Marie Delivery Area. In addition, if Union were to use STFT service to get gas in the Sault Ste. Marie Delivery Area, it would have to ensure that STFT was available on all three segments, Dawn to St. Clair, the international crossing and from St. Clair to Sault Ste. Marie. For these reasons, Union submitted that it did not contract for STFT.

CME expressed concerns related to the forecast of 10.4 PJs of UDC which was significantly higher than the current forecast of 4.4 PJs. CME's concern was related to the fact that the UDC for Union was increasing while the market as a whole was taking steps to minimize expected UDC through a combination of FT and STFT. CME submitted that Union was not taking any steps to minimize UDC.

CME submitted that Union should be directed to mitigate the level of UDC to the maximum extent possible with the condition that the Board would review the UDC amount in a future process. CME did not suggest making any changes to the forecast UDC.

VECC, FRPO, CME and LPMA submitted that the Board should require a consultation that includes Union and interested parties to review and recommend changes to the gas supply plan that better responds to the needs of ratepayers. However, many intervenors agreed with Board staff that the gas supply plan for 2013 should be accepted. IGUA did not take any position on the gas supply issue.

Union, in reply, submitted that the gas supply plan was prudent and should be approved as filed. The principles were reasonable and the Board has on previous occasions approved Union's gas supply plan with no changes. Although Union did not feel that a consultation was required, it did indicate that should the Board decide to consider this approach, Union would prefer an independent review as compared to a consultation with intervenors.

Board Findings

Although the issues of optimization and natural gas supply planning are listed separately on the Issues List, it is evident to the Board from this proceeding that the issues are, in fact, inter-related.

Union defines optimization as a market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise, bundled customers. Union asserts that exchanges are nothing more than a type of optimization activity. Union has defined an exchange as a contractual agreement where party A agrees to give physical gas to party B at one location, and party B agrees to give physical gas to party A at another location. Either party A or party B may agree to pay the other party for this service. An exchange can only happen between a point on Union's system and a point off Union's system.

It is clear to the Board that the nature of Union's optimization activities has evolved since the NGEIR proceeding[11] and the commencement of Union's incentive regulation regime. Union has submitted in past proceedings that in the context of a balanced gas supply portfolio, few if any, firm assets are available to support transactional services on a future planned basis[12]. Union has asserted that firm assets are made available as a result of weather and market variances.

The Board finds that the record in this proceeding is clear that firm assets are being made available for transactional services on a planned basis, with releases occurring prior to the commencement of the heating season and with capacity being assigned for up to a full year. The revenues or margins arising from these services are not being returned to customers as an offset to gas supply costs.

The Board observes Union's statements that the purpose of the gas supply plan is to ensure secure and reliable gas supply to bundled customers from a diverse supply range, all at a prudently incurred cost. However, the record in this proceeding suggests that Union's optimization activities have, in their own right, become a driver of the gas supply plan, and are no longer solely a consequence of it.

The Board finds that Union's ability to "manufacture" optimization opportunities undermines the credibility of Union's gas supply planning process, the planning methodology, and the resulting gas supply plan.

[11] The Board initiated the Natural Gas Electricity Interface Review ("NGEIR") in 2005 to examine the regulatory treatment of natural gas infrastructure and services, specifically storage regulation (EB-2005-0551).
[12] RP-2003-0063/EB-2003-0087, Exhibit C1, Tab 3, Page 6 of 16.

As submitted by various parties to this proceeding and Board staff, Union has had an incentive to contract excessive upstream gas transportation services to the detriment of the ratepayer. Union has not filed convincing evidence that the amount and type of upstream gas transportation contracts procured on behalf of ratepayers reflects the objective application of its gas supply planning principles.

For example, the Board is of the view that the schedule filed by Union[13] showing decontracting on the TCPL system is not helpful. The schedule does not inform the Board's overall assessment of whether the gas supply plan is prudent, as the schedule does not speak to whether too much or too little TCPL capacity has been released. Further, the schedule does not inform the Board as to whether the increase in tolls on the remaining long-term FT capacity with TCPL arising from decontracting has been more than offset by reductions in tolls on alternative transportation routes, including those pipeline companies in which Union's parent company has, or will have, an economic interest.

Union provided evidence that it did not consider this type of cost-benefit analysis in its gas supply planning function and that the gas supply personnel look only at current tolls when making a purchasing decision.[14] Moreover, Union testified that its gas supply planning personnel may not have an understanding of the basis upon which the rates or tolls paid for upstream transportation are calculated.[15]

The Board does not accept this approach. The Board is of the view that the principles used by Union's gas supply planning group are at a very high level and thus provide little guidance with respect to how the costs that Union incurs are calculated, and whether such costs would, in fact, be prudently incurred.

Union's evidence on its optimization activities has not been clear and Union's approach with respect to optimization in general has not been helpful. The Board notes that absent the TCPL application filed with the NEB on September 1, 2011, little information describing the nature of these activities (notably FT-RAM) would have been available.

In RP-1999-0001, the Board, quoting from E.B.R.O. 452 (paragraph 6.5 of that decision) stated that:

[13] Union Gas Reply Argument Compendium, Gas Supply Tab 4. Union Gas – TransCanada Long-haul and STS Summary 2000 – 2011.
[14] Oral Hearing Transcripts, EB-2011-0210, Volume 3 at pp. 103-104.
[15] Ibid. at pp. 153-155.

> Regulation is intended to be a surrogate for competition in the marketplace and the legislation intended that the Company has an opportunity to recover its costs and to earn a fair rate of return on its shareholders' equity…The system requires the regulator to act on faith with the utility, bearing in mind the prospective nature of the evidence. The regulator expects the utility, in return, to provide the best possible forecast data that can be made available, on a timely basis.

The Board also said in paragraph 4.2 of RP-1999-0001:

> The Board appreciates that business plans are not carved in stone and the utility must have flexibility to meet ongoing demands of the marketplace; however, this flexibility must be balanced against the utility's obligations as a regulated entity. This is particularly true when the Company is not responding to exogenous events, beyond the Company's control, but is implementing its own initiatives.

Union stated that there have been at last 20 separate proceedings before the Board relating to QRAMs, deferral accounts, and rebasing and argued that the Board's discovery-related powers are tools that the Board has at its disposal which go well beyond what even a court of law has in a civil context. The implication of these arguments is that these issues should have been identified by intervenors and Board staff via interrogatories, document production, and technical conferences.[16]

The Board disagrees with Union's assertion that it is the responsibility of intervenors and Board staff to undertake adequate discovery to ensure that the record is complete. Union is a rate regulated entity, and the information asymmetry in evidence in this proceeding is illustrative of the need for the Board to reiterate Union's affirmative disclosure obligations.

At paragraph 4.5 in RP-1999-0001 the Board clearly sets out a utility's affirmative obligation to disclose by stating:

> The Company has an affirmative obligation to provide the Board with the best possible evidence and it is not incumbent on the intervenors to ensure, through cross examination of the Company's witnesses, that the record is adequate and complete. The Company cannot shirk its

[16] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 3.

> responsibilities as a regulated entity by submitting evidence that is vague and incomplete.

Union has not met this affirmative obligation.

Optimization

Consistent with the long-standing principle that a gas utility should not profit from the procurement of gas supply for its in-franchise customers, and to eliminate the creation of inappropriate incentives during the test year, the Board finds that the optimization activities, as defined below, are to be considered part of gas supply, not part of transactional services.

The Board reiterates that gas supply costs refer to both the upstream gas cost, including fuel gas, and the cost (rate multiplied by contract volume) of upstream transportation that is required to deliver gas supply to Union's in-franchise customers in the North and South Delivery Areas.

Consistent with the description provided by Union, the Board will define optimization as any market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise bundled customers, including, but not limited to, all FT-RAM activities and exchanges.

The Board finds that 90% of all optimization net revenues shall accrue to ratepayers and 10% shall accrue to Union as an incentive to continue to undertake these activities on behalf of ratepayers. Although Union has undertaken optimization activities for a lengthy period of time, it has indicated that absent an incentive, these types of activities may not occur. The Board has not considered the issue of whether optimization is an integral part of prudent utility practice that should be undertaken by Union without the payment of an incentive. Absent consideration of this issue by the Board in the context of this proceeding, the Board is of the view that it is appropriate for an incentive to be continued, at a 10% rate. This level of incentive is consistent with that associated with short-term storage and balancing.

The Board orders the establishment of a new gas supply variance account in which 90% of all optimization margins not otherwise reflected in the revenue requirement are to be captured for the benefit of ratepayers. This variance account is symmetrical. The balance of this gas supply variance account will be disposed of on an annual basis.

The Board finds that at the time an application to clear this new gas supply variance account is filed with the Board, Union must also file a proposal to allocate the balance of the new gas supply variance account to in-franchise customers, including direct purchase customers in the North. This proposal must be based on regulatory principles.

Consistent with these findings, 90% of Union's 2013 forecast of base exchanges of $9.1 million is to be reflected in the 2013 test year revenue requirement. Union's 2013 forecast of FT-RAM related revenue is $11.6 million. Given the uncertainty relating to whether the FT-RAM program will be continued by TCPL through the 2013 test year and subject to the Board's finding that a 10% incentive for optimization activities is to accrue to Union, the Board finds that only half (50%) of Union's FT-RAM forecast for 2013 should be reflected in the 2013 revenue requirement. To be clear, 90% of one half of Union's estimate of FT-RAM related revenue in 2013 is to be reflected in Union's 2013 Board-approved rates, i.e. $5.22 million.

Gas Supply Plan

The Board approves Union's 2013 Natural Gas Supply Plan, as filed. However, the Board has concerns with Union's gas supply planning process, its planning methodology, and the resulting supply plan in light of Union's actions over the incentive regulation period. The Board believes that confidence in the gas supply plan is essential. The Board is therefore of the view that a further, more detailed review of Union's gas supply planning functions would be beneficial.

The Board is of the view that an expert, independent review rather than a consultation is a better way to proceed, given the highly specialized nature of the review to be undertaken. Accordingly, the Board orders Union, prior to its next rates proceeding (cost of service or incentive regulation), to file with the Board an expert, independent review of its gas supply plan, its gas supply planning process, and gas supply planning methodology.

This review is to be conducted by an independent third party with gas supply planning expertise. The Board directs Union to establish a deferral account to capture the cost of the expert, independent review, for disposition in Union's next rates proceeding.

As suggested by Union, intervenors and Board staff are to be provided an opportunity to review the Request for Proposals ("RFP") associated with this review prior to issuance. The scope or purpose of the review will be subject to the comments of intervenors and Board staff. In addition to comments that may be provided by parties, the Board finds that the purpose of the review should include, but not be limited to, the following:

1. Verify that Union's gas supply planning process, methodology, and plan reflects appropriate planning principles, including a reference to cost.
2. Determine whether planning principles are objectively applied and result in a gas supply plan that is "right sized".
3. Determine whether Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches.
4. Recommend whether the two approaches should be aligned.
5. Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.
6. Determine whether the peak day in the North and South Delivery Areas are appropriately/consistently reflected in the gas supply plan, and if not, recommend remedial action.
7. Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with decontracting a particular gas transportation route and recontracting on an alternative route, and recommend remedial action, if required.
8. Determine whether Union is using the transportation portion of the gas supply portfolio to favour the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action, if required.
9. Examine the cost allocation and rate design used by Union to allocate the cost of gas supply to in-franchise customers in the North and South to ensure that it is appropriate and reflects regulatory principles.
10. Examine the structure of the current natural gas supply deferral and variance accounts, with a view to simplifying and standardizing these accounts in the North and South Delivery Areas.
11. Determine whether the structure and text of the various natural gas supply deferral and variance accounts is consistent with the principles of the Decisions and Orders that provided the authorization for these accounts and consistent with the findings of the Board in this proceeding, and recommend remedial action, if required.

The results of the review are to be subject to a stakeholder information process and then be submitted in conjunction with Union's next rates proceeding (cost of service or incentive regulation regime).

COST OF CAPITAL

Union's investment in rate base is financed by a combination of short-term and long-term debt, preferred shares and common equity. The current Board approved capital structure is based on a 36% common equity component. The remaining 64% is financed by a mix of short-term debt, long-term debt and preferred shares.

Union has proposed a capital structure which includes a common equity ratio of 40% for 2013 as compared to the 36% currently included in rates. The 36% equity ratio was set as a result of a Settlement Agreement in the 2007 Cost of Service Proceeding (EB-2005-0520).

Union has proposed a long-term debt ratio of 60.17% and a debt rate of 6.53%. The short-term debt ratio is -2.92% with a rate of 1.31%. The average embedded cost of preferred share capital for 2013 is 3.05%. This is a decrease from the 2007 Board approved cost of 4.74%.

Common Equity Ratio

Most intervenors and Board staff submitted that Union's proposal to raise the common equity ratio from 36% to 40% should be rejected. IGUA did not take any position on this issue.

In support of its proposal, Union retained two experts: Mr. Steven M. Fetter and Dr. Vander Weide. In response, intervenors presented the expert evidence of Dr. Lawrence D. Booth.

Intervenors and Board staff cited the Report of the Board on Cost of Capital for Ontario's Regulated Utilities[17] that provided guidelines with respect to a gas utility's capital structure. The report on page 50 states:

[17] Report of the Board on Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084),pp. 49, 51.

> For electricity transmitters, generators and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.

Intervenors and Board staff submitted that Union had made no attempt to comply with the guideline in requesting a change in the equity thickness and Union's evidence indicated that it had not analyzed its financial and business risk as part of this proceeding. Board staff and intervenors further noted that Union's argument was that its current equity structure is not commensurate with its risk. However, Union agreed that its business or financial risk had not changed materially since 2006. In fact, Union witnesses confirmed several times during the oral hearing that there had been no material increase to its business or financial risk.[18] Union agreed in reply that its risk profile had not changed but it noted that in the 2007 rates case, Dr. Carpenter and the Brattle Group stated that Union's business risk warranted an equity ratio between 40 and 56%, depending on the allowed rate of return.[19] Union therefore believed that an equity ratio of 40% was appropriate based on its current risk profile.

Mr. Fetter was of the opinion that an equity thickness of 40%-42% would improve Union Gas' financial profile benefitting its customers through Union's enhanced ability to attract capital from investors when needed and upon reasonable terms. Mr. Fetter, in his report, also indicated that equity ratios of utilities were rarely set below 40% in the United States. Mr. Fetter further noted that a review of other Canadian gas utilities showed that the deemed equity ratios were in the range of 39% to 43%. In its Argument-in-Chief, Union submitted that it had to compete for capital with other utilities across the United States and Canada and a 36% equity ratio puts Union at a disadvantage.[20]

In reply, Union submitted that none of the intervenors had challenged Union's position that other comparable utilities had higher equity ratios than 36% and that Union was lower relative to its peers. Union further submitted that no party challenged the comparability of Union to ATCO Gas or Terasen. Union disputed intervenors' argument that comparability has no value and noted that Dr. Booth, the expert consultant of the

[18] Oral Hearing Transcripts, EB-2011-0210, Volume 4 at p. 128 and Volume 5 at pp. 15 and 31.
[19] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 105.
[20] Oral Hearing Transcripts, EB-2011-0210, Volume 13 at p. 53.

intervenors, in his testimony confirmed that the regulator should give weight to the deemed equity ratios of comparable utilities.[21]

CCC submitted that the Board consistent with its own policy must examine the individual circumstances of Union and in particular, the business and financial risk faced by Union to determine whether a change in capital structure is required. CCC further submitted that the use of comparators may supplement, but cannot replace that analysis. CCC also disputed Mr. Fetter's opinion that a higher equity ratio would allow Union to withstand future unforeseen events. CCC argued that Mr. Fetter's opinion was hypothetical.

Intervenors and Board staff submitted that Union had provided no evidence that it has not been able to compete for capital on favourable terms with other utilities. Intervenors and Board staff submitted that throughout the IRM period which coincided with a severe global financial crisis, Union had maintained a high credit rating. Union has been able to attract capital on reasonable terms under its current capital structure. Intervenors and Board staff referred to an interrogatory response[22] where Union confirmed that an equity ratio of 40% would not lead to a higher credit rating or a lower cost of debt. This view was also stated in the Standard and Poor's report which notes that Union would not get a higher rating than Spectra, its parent. In Reply, Union submitted that DBRS in its report noted that Union had requested a 40% deemed equity ratio. Union submitted that in that report DBRS expected Union to manage its balance sheet in line with the new regulatory capital structure and maintain greater financial flexibility commensurate with the current rating category. Union argued that this meant that Union would fit more appropriately with the current rating if it had a 40% common equity.[23]

Dr. Booth in his testimony expressed the view that one major aspect of risk was whether a utility was able to earn its allowed return on equity. Dr. Booth noted that since 2000, Union's average over-earning was about 2%. Intervenors and Board staff in their submission noted that Union had over-earned by approximately $278.7 million from 2007 to 2012. Intervenors and Board staff submitted that Union had provided no evidence to demonstrate a change in its risk profile. In reply, Union submitted that there

[21] Oral Hearing Transcripts, EB-2011-0210, Volume 6 at p. 61.
[22]Exhibit J.E-1-1-2.
[23] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 102.

is a surplus of supply east of Union's Dawn to Parkway system and that posed a significant risk to Union. Union noted that there was further risk of turnback and this was reflected in lower revenues on Dawn to Kirkwall and M12.[24]

BOMA, in its submission, submitted that Union's interest coverage ratio was 2.74 which was higher than the 2% minimum interest coverage ratio set out in Union's trust indenture. This was higher than the ratios in 2008, 2009 and 2010 when it was 2.4%and 2.24% in 2007. However, the interest coverage ratio was lower than the threshold when the unregulated business was excluded from the calculation. BOMA further submitted that with respect to the interest coverage ratio, the common practice was to look at the entire company and not just the regulated portion of the business.[25] Union, in reply, disagreed with BOMA and submitted that this view was at odds with the general focus of intervenors that pursue to ensure that there is no cross-subsidy of the unregulated business by the regulated business. Union submitted that the intervenors wanted the Board to agree that it was appropriate to cross-subsidize the regulated business in order to meet the interest coverage ratio.

CCC in its argument cited the Ontario Court of Appeal in its decision (Toronto Hydro-Electric System Limited v. Ontario Energy Board, 2010) where the court stated that regulated utilities must balance the needs of shareholders and ratepayers. CCC submitted that if the proposed change in capital structure is approved, Union's shareholders will benefit by approximately $17 million while there would be no corresponding benefit within the test year to Union's ratepayers. CCC submitted that the Board should conclude that Union had not balanced the interests of its ratepayers and shareholders and accordingly disallow the change in the common equity ratio.

LPMA submitted that if the Board does approve Union's proposal or approves an equity ratio greater than the current 36%, then in that case, the Board would have to deal with how to treat preferred shares in the deemed capital structure. LPMA submitted that according to USGAAP, Union's preference shares were classified as equity by their auditors. LPMA submitted that there was no reason for the Board to deviate from the USGAAP treatment. SEC disagreed with LPMA and submitted that when the Board reviewed Union's capital structure in 2004, it did not consider preference shares to be equity and the Board should therefore refrain from doing so in this case. SEC submitted

[24] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 107.
[25] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at p. 88.

that the preference shares should be treated as long-term debt. Union agreed with SEC and noted that the Board had never considered Union's preference shares in any assessment of Union's common equity ratio. In addition, Union noted that they were not even considered relevant by Dr. Booth in his analysis.

SEC, in its submission, agreed with Union that the Board's Report on Cost of Capital is a guideline. However, it noted that the Board had thoroughly reviewed the business risk of Union in 2004 and unless there was a change in the business risk, there was no need for a utility to come before the Board with a different proposal. SEC submitted that Union was merely rearguing the 2004 case and there was no new evidence to show a change in risk.

SEC further submitted that Union had not articulated any benefits to ratepayers such as better access to market or lower borrowing costs, which Union already enjoys. In reply, Union submitted that the expectation that a higher equity ratio must be accompanied by lower borrowing costs or a ratings upgrade is unrealistic. Union therefore submitted that the Board should reject the submissions of intervenors.

Unlike other intervenors, LPMA and SEC submitted that Union's common equity ratio should be reduced from 36% to 35% consistent with what the Board had determined when it last reviewed the business risk and equity thickness of the company in 2004.

Cost of Debt

None of the intervenors raised any issues with the rates for short-term and long-term debt or preferred shares. LPMA however made a submission on the mix of short-term and long-term debt.

LPMA submitted that Union's proposal of a long-term debt ratio of 60.17% and a short-term debt ratio of -2.92% meant that ratepayers were being asked to pay a long-term debt rate on $108.5 million of borrowings and receive a credit at the short-term debt rate. LPMA submitted that this was not appropriate and was an indication that Union was over capitalized for rate base purposes.

LPMA noted that Union attributed the negative short-term debt to items outside of rate base that the utility has to invest in, such as construction work-in-progress and the contribution in excess of expenses for pension.

Union's average short-term borrowing for 2013 is predicted by LPMA to be $136 million[26] which represents approximately 3.66% of Union's rate base.

LPMA and SEC submitted that Union has more long-term debt than needed to finance rate base. This is under the scenario of a 36% and a 40% common equity ratio. At the same time, these scenarios have not included any short-term debt according to LPMA.

LPMA and SEC submitted that the Board should direct Union to include $136 million in short-term debt in the cost of capital calculation. Both parties further submitted that the balancing figure would be the long-term debt component. LPMA considered this to be an appropriate approach since in its view it was obvious that some of the long-term debt is being used to finance items outside of rate base.

In reply, Union noted that its cash position varied significantly due to the seasonal nature of its business. It further stated that long-term debt changes do not occur quickly and that the cash position would slowly return to short-term debt as the long-term debt level adjusted through maturities and reduced issues. Union submitted that issuing debt in small amounts was administratively burdensome and lumpy. Union indicated that it obtains long-term financing when prudent and tries to take advantage of favourable market conditions.

Union further submitted that having a negative short-term balance was not a new issue and the Board had addressed this before in the RP-2003-0063 proceeding. In the RP-2003-0063 Decision with Reasons dated March 18, 2004, the Board, on page112, determined that Union was in compliance with its deemed capital structure even though its long-term debt had marginally exceeded the 65% debt component of its approved capital structure. This excess was offset by a negative short-term debt balance.

Union emphasized that in the RP-2003-0063 Decision, the Board had used the word "marginal" to describe the level of excess in the long-term debt component. The actual

[26] Oral Hearing Transcripts, EB-2011-0210,Volume 5 at p. 40.

unfunded short-term debt was approximately $130 million in 2004 which is higher than the current unfunded short-term debt component of $115 million. Union submitted that the Board should reach a similar conclusion in this proceeding and not make any adjustments to the short-term or long-term debt component.

Board Findings

Deemed Common Equity Thickness

The Board finds that a deemed common equity ratio of 36% is appropriate for the 2013 test year, consistent with the deemed common equity ratio that was in place over the 2007 to 2012 period, inclusively.

The 2009 Cost of Capital Policy of the Board at page 43 sets out that for natural gas distributors such as Union, deemed capital structure is determined on a case-by-case basis and that reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risks.

Union filed no evidence in this proceeding that demonstrates its business and/or financial risks have changed over the period that the IRM Settlement Agreement was in place. In fact, Union stated many times during the proceeding that its business and financial risks have not changed and that it accepts that its overall risk profile has not materially changed since 2006.

Union put forth two arguments to support its application for a 40% deemed common equity ratio. The first is that the current deemed common equity ratio of 36% is too low and has never appropriately reflected its business and financial risk. Second, that the deemed common equity ratio should be increased solely on the basis of comparability; i.e., because other Canadian utilities now have higher deemed common equity ratios, the Board should also approve a higher deemed common equity ratio for Union.

The Board will address each of these two arguments in turn.

The Board does not accept the proposition that the deemed common equity thickness of 35% as determined by the Board in 2004 and subsequently increased to 36% as a result of a Settlement Agreement was incorrect and that it did not adequately reflect Union's financial and business risk profile. Union has filed no evidence to support this position that the deemed equity ratio was not correct and the Board therefore gives this argument little or no weight.

The Fair Return Standard ("FRS") requires that a fair or reasonable return on capital should:

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

Union's second argument focuses on the first part of the comparable investment standard – that the return on invested capital must be comparable. However, Union's argument fails to address the second part of the comparable investment standard, that being the issue of "enterprises of like risk". Union would have the Board increase (and potentially reduce) its deemed common equity ratio in lock-step with the decisions of other regulators, without an analysis of whether the utilities to which it is compared are enterprises of like risk.

The Board acknowledges that there was a general consensus on the Canadian utilities that intervenors and Union asserted were comparable. The Board notes, however, that neither Union nor the intervenors filed analytical evidence that demonstrated that these utilities are of like risk to Union. Rather, what evidence was presented was anecdotal, ad hoc, and incomplete.

The Board is aware that since the 2008 financial crisis, the deemed common equity ratios of certain Canadian rate regulated entities have been increased. However, no evidence was filed in this proceeding that set out the risks that resulted in findings supporting higher deemed common equity for these utilities and no evidence was filed that demonstrates Union faces similar risks.

Union reiterated throughout the proceeding that its business and/or financial risks have not changed since 2006.

Accordingly, there is no reasonable basis for the Board to increase Union's deemed common equity ratio above the 36% level presently reflected in rates.

The Board does not agree with the submission of SEC that a higher deemed equity ratio must be supported by benefits to ratepayers. The Board's obligation to determine the quantum of common equity (at issue in this proceeding) and the cost of that equity (subject to the Settlement Agreement) is governed by the FRS, which is a non-optional, legal standard.

The Board also does not agree with the submission of CCC that the Board must balance the interests of ratepayers and shareholders in determining the deemed common equity ratio. Consistent with the jurisprudence discussed in the 2009 Cost of Capital Policy, the Board remains of the view that it is not in the determination of the cost of capital that investor and consumer interests are balanced. This balance is achieved in the setting of rates.

Finally, the Board is of the view that there is no evidentiary basis to support a reduction in deemed common equity from the existing 36% to 35%.

Cost of Debt and Preferred Shares

The Board approves the cost of short-term, long-term debt, and preferred shares as per Appendix B, Schedule 3 of the Settlement Agreement. The Board notes that no issues were raised by intervenors or Board staff regarding the appropriateness of these costs during the proceeding.

Debt and Preferred Share Capitalization

The Board approves the amount of long-term debt, short-term debt, and preferred share equity as set out by Union in Exhibit J5.4, page 2, lines 7 through 12, which reflects the Settlement Agreement relating to this proceeding and deemed common equity of 36%.

The Board's findings on the amount of short-term and long-term debt are consistent with previous decisions of the Board and are consistent with Union's evidence that items outside of rate base are funded by short-term debt.

The Board has not undertaken a comprehensive review of whether it is appropriate for a gas utility to have preferred shares in its capital structure. The Board is generally aware that preferred shares are often referred to as "mezzanine capital", having characteristics of both debt and equity. There was no assessment of the characteristics of Union's issued and outstanding preferred shares in this proceeding. Similarly, there was no assessment of whether Union's issued and outstanding preferred shares should be considered to be common equity or debt for the purpose of determining Union's capital structure in order to set utility rates.

The Board will thus continue its current practice of approving the amount and cost of Union's preferred shares as a separate part of total utility capitalization. The Board notes, however, that the presence of preferred shares has the effect of reducing the amount of total debt capitalization in Union's capital structure.

COST ALLOCATION

General Cost Allocation Issues

Union provided a summary description of the methodology used to complete the cost allocation study, which supports the 2013 rate proposals. Union submitted that subject to the removal of the unregulated storage operations and certain proposals in Exhibit G1, Tab 1 (which are discussed below), the cost allocation study is consistent with the studies that were approved by the Board and used in the past, including in EB-2005-0520.

Union noted that the objective of the cost allocation study is to allocate the utility test year cost of service to customer rate classes for the purpose of acting as a guide to the rate design process. To allocate costs, the test year cost of service is analyzed to determine the appropriate functionalization and classification of costs. Union noted that the allocation of costs to individual rate classes is based upon these determinations.[27]

Union stated that the cost allocation study consists of three steps. These steps are:

Functionalization of costs to utility service functions: The first step of the cost allocation process is to associate asset and operating costs with the various utility service functions. There are four functions generally accepted as necessary to obtain and move gas to market: purchase and production of gas, storage, transmission, and distribution.

Classification of costs to cost incurrence (demand, commodity, customer): The second step categorizes functionalized asset and operating costs into classifications according to cost incurrence. The three main classifications are demand-related, commodity-related, and customer-related. Demand-related costs, also known as capacity-related costs are costs that vary with peak day usage of the system. Commodity-related costs are costs that are typically variable in nature and vary with the

[27] Exhibit G3, Tab 1, Schedule 1 at p. 1 (Updated).

level of gas consumed. Customer-related costs are costs that are incurred by virtue of a customer taking service and do not vary with either peak day demand or consumption.

Allocation of costs to rate classes: The final step in the cost allocation process attributes the three types of costs classified above. Allocation factors that reflect the underlying cause of cost incurrence are used in the allocation process. For example, demand-related costs are allocated using the peak day demands of each rate class. Commodity-related costs are allocated based on rate class consumption. Customer-related costs are allocated based on the number of customers in a rate class.[28]

Union noted that once these steps have been completed, costs allocated to each rate class can be totaled and compared to the revenue achieved.

Union noted that judgment is required in apportioning costs to the various functions and their sub-classifications. Union stated that this judgment is based on the specific knowledge of how its system is operated. As a result, a fully distributed cost of service study is used to provide an indication of cost responsibility by rate class at a specific point in time, but cannot and should not be viewed as a precise measurement of the actual cost to serve a particular rate class, much less a particular customer.[29]

Union noted that the cost allocation study for the current test year no longer includes costs associated with Union's unregulated storage business. Only utility costs relating to a maximum 100 PJ of storage space are included in the cost allocation study and used to allocate the cost of service to the utility rate classes.

Union noted that it allocated storage-related costs based on forecast in-franchise demand and system integrity requirements. All remaining storage-related costs, beyond the 100 PJ of regulated storage space, are allocated to the "Excess Utility Storage Space" category. Union charges its unregulated storage business the costs allocated to the Excess Utility Storage Space category for its use of the regulated storage space that is not required to meet in-franchise requirements. The total revenue requirement in this category, less compressor fuel, unaccounted-for-gas ("UFG") and non-utility system integrity costs, represents the cross charge to the non-utility. Accordingly, the allocators associated with regulated storage reflect only regulated activity.[30]

[28] Exhibit G1, Tab 1 at pp. 2-3 (Updated).
[29] Exhibit G3, Tab 1, Schedule 1 at p.2.
[30] Exhibit G1, Tab 1 at pp. 1-2. (Updated).

Union submitted that in conducting its analysis and preparing its cost allocation evidence, it used the Board's previously approved cost allocation methodologies, subject to the removal of the unregulated business and specific proposals which are discussed later in this Decision.

Board Findings

The Board generally accepts Union's cost allocation study and the resulting allocation of costs for the 2013 rate year. However, the Board has made findings on Union's specific cost allocation proposals below, which do impact, in some cases, the allocation of costs for certain groups of assets.

The Board notes that the allocation of costs, subject to the Board's findings on specific cost allocation proposals below, is approved only for 2013. The Board has some concerns with Union's 2014 rate redesign proposals (Rates 01 / 10 and Rates M1 / M2). Accordingly, the Board has directed Union, later in this Decision, to file an updated cost allocation study as part of its 2014 rates filing. The reasons associated with the Board's direction to file an updated cost allocation study are discussed in the section of this Decision that addresses Union's Rate 01 / 10 and Rate M1 / M2 rate redesign proposal.

System Integrity

Union noted that the 100 PJ of storage space reserved for in-franchise demands includes the space reserved for system integrity. System integrity space costs are included in the cost allocation study and allocated to utility rate classes and the Excess Utility Storage Space category. The Excess Utility Storage category includes the system integrity space costs for short-term storage and non-utility storage operations. Union submitted that it used the Board-approved methodology to allocate system integrity costs, except for its proposal related to storage pool hysteresis.

Consistent with the Board-approved methodology, Union proposed that the filled space costs continue to be allocated on the basis of storage space requirements. For purposes of determining storage pool hysteresis requirements, Union calculated a revised storage space requirement which includes total working storage capacity less non-utility third party storage space and system integrity space reserved for the Hagar LNG facility and storage hysteresis. Union noted that it requires empty system integrity space on November 1to manage late season injection demands. The space is specifically held in reserve to manage the difference between in-franchise supplies and demands. Empty system integrity space is not required for short-term and long-term non-utility storage contracts as these contracts have little to no firm injection rights during October and November. Accordingly, Union proposed to allocate the empty system integrity space costs reserved for hysteresis based on the revised storage space excluding short-term and long-term non-utility storage space.[31]

The issue of system integrity space was partially settled as part of the settlement process. The Settlement Agreement states:

> For the purpose of settlement, the parties accept Union's proposed system integrity space value and its allocation for 2013. Acceptance is without prejudice to the examination at the hearing of matters pertaining to the actual use of utility storage space, including system integrity space, provided that the determination of this issue by the Board will not result in any change to the test year revenue requirement related to issues described under heading Exhibit B – Rate Base and heading Exhibit D – Cost of Service.[32]

Issue 6.4 is as follows: "Is the cost allocation study methodology to allocate the cost of system integrity appropriate?" The Settlement Agreement states that there is no settlement of this issue.[33]

Therefore, the issues relating to system integrity space that remain unsettled are whether the cost allocation study methodology for allocating the costs of system integrity space is appropriate and whether Union could use its fall integrity space as part of its winter integrity space.

No parties argued that the methodology used by Union to allocate the costs of system integrity space is not appropriate.

FRPO noted that Union has proposed that it would have two sets of contingency storage space - fall contingency space of 3.5 PJs and winter contingency space of 6 PJs. FRPO stated that the fall contingency space would be used in the event of a warmer than average weather and in providing extra space for continued storage

[31] Ibid at pp. 3-5.
[32] Updated Settlement Agreement, July 18, 2012 at pp. 15-16.
[33] Ibid at p. 19.

operations. The winter contingency space would be used to keep Union's storage operating during the critical periods of cold weather in the winter months.

FRPO postulated that the 3.5 PJs of fall contingency space could also be used as part of the 6 PJs of winter contingency space. Basically, FRPO asked Union to consider that if the 3.5 PJs of fall space were not filled, then that space could be subsequently used as part of the 6 PJs of space reserved for the winter. In that scenario, Union would make available an additional 3.5 PJs of storage space that could be used to sell short-term storage services (as it is now part of Union's Excess Utility Space classification). Union responded that it would be too expensive to fill that space in December and would result in a negative overall impact for ratepayers.[34]

FRPO argued that the price to fill that space is not necessarily more expensive in the winter (December fill) than for the fall (July fill).[35][36] As such, FRPO submitted that Union should consider using the 3.5 PJs of fall contingency space as a contributor to the 6 PJs of winter space. This would make available an additional 3.5 PJs of storage space and could provide a $3.0 million benefit to ratepayers as the storage contingency space would be better optimized.[37]

LPMA supported FRPO on this issue. LPMA submitted that the Board should direct Union to conduct an independent third-party analysis of the potential benefit of increased storage revenue (related to the availability of an additional 3.5 PJs of storage space) versus the potential cost additions for purchasing gas in the winter and selling that gas the following summer.[38] No other parties made submissions on this issue.

Union submitted that as no parties raised concerns regarding its methodology for allocating system integrity space, its proposal should be accepted by the Board.

With respect to FRPO's and LPMA's submissions on the use of its fall integrity space as part of its winter integrity space, Union submitted that there is considerable risk around this proposal and it is likely that any gas purchased after November would be at a higher cost. Union noted that it has never optimized its system integrity space. Union noted that the benefit that FRPO believes to be present is dependent on a number of

[34] Technical Conference Transcripts, EB-2011-0210, Volume 1 at pp. 73-75.
[35] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at pp. 144.
[36] Exhibit K14.5 at p. 32.
[37] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 145.
[38] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 74.

factors which are out of Union's control, namely, fall weather, winter weather, summer / winter price differentials. Union submitted that what FRPO is proposing essentially amounts to gambling with the system integrity space. In Union's submission, as system operator, it is not prudent to do so.

In response to LPMA's suggestion that there could be a third-party study of the issue, Union submitted that there is no merit to that proposal as the outcome of the study would depend, in any particular year, on the summer / winter price differential and the fall weather / winter weather. For those reasons, Union submitted that FRPO's and LPMA's submissions should be rejected.[39]

Board Findings

The Board finds that Union's methodology for allocating system integrity space is appropriate. The Board notes that no parties raised concerns regarding this proposal.

The Board finds that the proposal made by FRPO and LPMA that the fall integrity space should be used as part of the winter integrity space is not adequately supported by the evidence in this proceeding. The Board notes that the increased revenue potential of $3.0 million cited by FRPO is hypothetical and in fact, the proposal could be detrimental to ratepayers depending on certain factors that are outside of Union's control (i.e. weather, price differentials, etc.). The Board notes that Union has stated that it has never optimized its system integrity space. The Board is of the view that the evidence in this proceeding does not support a change in approach.

The Board also rejects LPMA's suggestion that the Board direct Union to conduct an independent third-party analysis on this issue. The Board agrees with Union that the outcome of the study is likely to depend, in any particular year, on the summer / winter price differential and the fall weather / winter weather. Therefore, the results of the study may not be reliable for more than a year.

Tecumseh Metering Assets

Union noted that in its Board-approved 2007 cost allocation study, certain Tecumseh metering assets at the Dawn facility were reflected as transmission assets in its plant accounting records. These metering assets were directly assigned to the Dawn Station

[39] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 135-136.

transmission function and the Dawn Station Customer classification. The costs were then allocated to the M12 rate class based on Tecumseh metering demands.

Union noted that based on a review of the Tecumseh metering assets, it updated the plant accounting records to move the assets from transmission to underground storage. However, as the Tecumseh metering assets continue to provide transmission service, Union directly assigned the Tecumseh metering assets to the Dawn Station transmission function. Similar to other underground storage assets functionalized to the Dawn Station, Union proposed to classify the costs to the demand classification and allocate the costs to rate classes based on the design day demand of Dawn compression. Union also proposed to eliminate the Dawn Station Customer classification, as the Tecumseh metering costs were the only costs previously allocated to this functional classification.[40]

LPMA supported this proposed change in the cost allocation methodology. LPMA noted that these assets provide transmission service to both ex-franchise and in-franchise customers, and the updated methodology is consistent with the allocation of costs of other interconnects in the Dawn Station. LPMA also stated that the impact of this proposal is not significant.[41]No other parties made submissions on this issue.

Union submitted that as no parties raised concerns with Union's proposal, it should be accepted by the Board.[42]

Board Findings

The Board approves Union's proposal as it relates to the Tecumseh Metering Assets. The Board finds that Union's updated cost allocation methodology for this group of assets is reasonable and is consistent with the allocation of other similar assets.

Oil Springs East Assets

Union proposed to change the functionalization, classification and allocation of costs associated with Oil Springs East assets for 2013. In Union's Board-approved 2007 cost allocation study, Union directly assigned the structure and improvements and

[40] Exhibit G1, Tab 1 at pp. 6-7.
[41] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 73.
[42] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 133.

measuring and regulating equipment plant costs associated with the Oil Springs East storage pool to the Dawn Trafalgar Easterly transmission function. This re-classification from underground storage to transmission was based on the use of the assets, which previously served Union North transmission needs. Union also classified the costs to the Dawn Trafalgar Easterly Oil Springs East Metering classification, and allocated costs to rate classes based on design day demand on the Dawn Parkway transmission system.

Union noted that its review of Oil Springs East storage pool assets determined that these assets now provide both storage and transmission services to customers. Accordingly, Union proposed to eliminate the direct assignment of Oil Springs East assets to the Dawn Trafalgar Easterly transmission function and functionalize these assets between storage and transmission. Union noted that this approach is consistent with the treatment of other underground storage assets at the Dawn facility that provide both storage and transmission services. Given Union's proposal to eliminate the direct assignment of Oil Springs East assets, Union also proposed to eliminate the transmission classification of Dawn Trafalgar Easterly Transmission for Oil Springs East metering.[43]

LPMA submitted that the changes to the allocation of the Oil Spring East Asset costs are appropriate. LPMA noted that Union's review has determined these assets provide both storage and transmission services to customers. As a result, Union proposed to functionalize these assets between storage and transmission, rather than continue the direct assignment of these assets to the Dawn-Trafalgar easterly transmission function.[44] No other parties commented on this issue.

Union submitted that as no parties have concerns with Union's proposal, it should be accepted by the Board.[45]

Board Findings

The Board approves Union's proposal as it relates to the Oil Springs East Assets. The Board finds that Union's updated allocation methodology for this group of assets is appropriate and notes that it is consistent with the treatment of other underground

[43] Exhibit G1, Tab 1 at pp. 7-8.
[44] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 72-73.
[45] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 132.

storage assets at the Dawn facility that provide both storage and transmissions services.

New Ex-Franchise Services

Union noted that since Union's Board-approved 2007 cost allocation study was completed, several new ex-franchise transportation services have been developed by Union and approved by the Board. Specifically, Union has developed the C1 Dawn to Dawn-TCPL and C1 Dawn to Dawn-Vector firm transportation services, as well as the M12 firm all day (F24-T) transportation service.

Union proposed to include the costs associated with these new transportation services in its 2013 cost allocation study. A description of the cost allocation methodology proposed for each of the new transportation services is provided below.[46]

Dawn to Dawn-TCPL

Union noted that the C1 Dawn to Dawn-TCPL firm transportation service was developed to meet TCPL's need for a firm transportation service within the Dawn yard from Dawn to the Dawn-TCPL interconnect. Union's transmission system had the ability to accommodate requests for transportation on this path on an interruptible basis but required new facilities to offer the transportation service on a firm basis. This service was approved in EB-2010-0207.

Union noted that the costs of the Dawn to Dawn-TCPL firm transportation service include measuring and regulating assets, compressor fuel and UFG. Union proposed to directly assign the measuring and regulating gross plant, accumulated depreciation, and depreciation expense to the Dawn Station Demand classification and then to the C1 rate class. Similarly, the compressor fuel and UFG costs associated with the Dawn to Dawn-TCPL firm transportation service are also directly assigned to the C1 rate class.

Union stated that this cost allocation approach is designed to ensure that the costs associated with the provision of the Dawn to Dawn-TCPL firm transportation service are assigned to the C1 rate class and recovered in rates from customers utilizing the Dawn to Dawn-TCPL firm transportation service.[47]

[46] Exhibit G1, Tab 1 at p. 8.
[47] Ibid at p. 9.

No parties commented on this issue.

Dawn to Dawn-Vector

Union noted that the C1 Dawn to Dawn-Vector firm transportation service was developed to meet Greenfield Energy Centre LP's need for a firm transportation service within the Dawn yard from Dawn to the Dawn-Vector interconnect. This service was approved in EB-2007-0613.

Union noted that the costs of the Dawn to Dawn-Vector firm transportation service include the costs associated with compressor fuel and UFG. Consistent with Union's proposal for the Dawn to Dawn-TCPL transportation service, Union proposed to directly assign the compressor fuel and UFG costs to the C1 rate class.

Union stated that this cost allocation approach is designed to ensure that the costs associated with the provision of the Dawn to Dawn-Vector firm transportation service are assigned to the C1 rate class and recovered in rates from customers utilizing the Dawn to Dawn-Vector firm transportation service.[48]

No parties commented on this issue.

M12 Firm / All Day (F24-T)

Union noted that, as part of the NGEIR proceeding (EB-2005-0551), it developed an enhanced M12 F24-T transportation service that provides additional nomination windows and firm all day transportation capacity to power generators and other customers.

Union noted that the costs for the M12 F24-T transportation service include employee salaries and benefits and compressor maintenance costs. Union proposed to directly assign the employee salaries and benefits and compressor maintenance costs to the Dawn Trafalgar Easterly Transmission function and then to the M12 rate class.

Union stated that this cost allocation approach ensures that the costs associated with the provision of the M12 F24-T transportation service are assigned to the M12 rate

[48] Ibid at p. 10.

class and recovered in rates from customers utilizing the M12 F24-T transportation service.[49]

APPrO stated that it is opposed to Union’s M12 F24-T allocation methodology. APPrO argued that Union should include the cost of the additional nomination windows in the overall O&M cost of the Dawn-Trafalgar system, just as it does for the remainder of M12 capacity, where Union provides eight nomination windows for those shippers also contracting for TransCanada's STS service. APPrO argued that F24-T customers should not be paying a separate charge for extra nomination windows.

APPrO noted that F24-T is an add-on service to Union's M12 and C1 service. F24-T has nine additional nomination windows. F24-T is used by generators, as well as other customers that require additional nomination windows. The service is used in conjunction with non-utility storage so that these customers can access intra-day balancing services. Shippers using F24-T contract for TransCanada capacity downstream of Parkway.

APPrO noted that, under the Settlement Agreement, Union agreed to reduce the O&M budget by $0.5 million. Half of this amount is related to the reduction in provision for wages and salaries, and the other half is related to amounts attributable to non-utility services. APPrO stated that the net amount after these reductions is $0.65 million.

APPrO noted that Union provides a similar service for other M12 customers and for customers that contract for TransCanada's STS service. APPrO stated that STS and F24-T share the four standard NAESB nomination windows, as well as the four STS windows. As such, F24-T only has five incremental windows above the eight windows that are shared.

APPrO noted that Union does not charge STS customers a separate and distinct fee associated with providing the four extra STS nomination windows. APPrO noted that Union stated that it did not know if there were extra costs associated with providing these four extra nomination windows, but stated that if there are extra costs related to receiving and processing these nominations then these costs are embedded in the M12 rate, and not charged separately.

[49] Ibid at p. 11.

APPrO stated that F24-T shippers pay the same underlying M12 rate as a STS shipper which includes the cost for the eight nomination windows, and they also pay a separate charge for the extra nomination windows.

APPrO noted that Union has 1,250,000 GJs / day of M12 service that feeds into TransCanada's STS service. APPrO stated that this amount is significantly larger than the volume of F24-T shippers and has no extra nomination charge associated with it. APPrO proposed that the $0.65 million of annual O&M cost related to the F24-T service be included and recovered as part of the overall M12 costs and no specific charge apply to the F-24T customers.

APPrO submitted that this cost allocation would be done in the same manner as done for those M12 shippers contracting for STS service. To ensure that not all M12 shippers have access to the additional nomination windows, APPrO proposed that access be conditional upon the customer holding downstream FTSN capacity with TransCanada.

In the event that the Board determines that Union should charge a separate rate for F24-T, APPrO submitted that the costs allocated directly to F24-T should only reflect the increase in the five nomination windows (as opposed to the nine nomination windows as proposed by Union). This means that approx. $359,000 of the $645,000 would be allocated to F24-T, with the balance being recovered within the overall M12 service. In addition, APPrO submitted that Union should be required to use the billing determinants as shown in Exhibit J.G-9-13-1 of 442,154 GJs / day to calculate the F24-T charge.[50] No other parties commented on this issue.

Union stated that the premise of APPrO's argument is that Union accommodates STS windows within its overall O&M and does not separately charge for access to the STS windows as it does for F24-T. Union submitted that what APPrO's argument fails to recognize is that F24-T was specifically developed and agreed to as part of the NGEIR settlement to meet the needs of power generators.

The Settlement Agreement in the EB-2005-0551 proceeding speaks to this issue directly. Union noted that the Settlement Agreement states at page 14,

[50] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at pp. 139-142.

> "IT capital costs and the costs associated with the additional staffing required to implement F24-T, F24-S, UPBS and DPBS will be recovered from customers who elect the new services."

Union noted that the Settlement Agreement recognized that there would be incremental costs associated with providing F24-T service. As a result of the Settlement Agreement, F24-T service was added to the M12 rate schedule. Union argued that based on the above noted Settlement Agreement, the F24-T service should have a specific charge applied to reflect the incremental nomination windows available to those shippers.

In regard to APPrO's argument that the Board should direct Union to base the rate for the F24-T charge on the updated F24-T demands of 442,154 GJs / day, Union submitted that this change is immaterial and therefore it should not have to update the calculation for the charge.[51]

Board Findings

The Board approves Union's proposals as they relate to the Dawn to Dawn-TCPL service and the Dawn to Dawn-Vector service. The Board believes that these proposals adequately reflect cost allocation principles and are appropriate.

The Board accepts Union's M12 F24-T cost allocation methodology as filed, as it is consistent with the principle of cost causality.

Consistent with the Settlement Agreement in EB-2005-0551, the Board approves a supplemental service charge for F24-T customers. However, the Board agrees with the submission of APPrO that the charge should be calculated based on the costs associated with the 5 incremental nomination windows and be based on the updated F24-T demand, as set out in Exhibit J.G-9-13-1.

Other Cost Allocation Proposals

Union North Distribution Customer Stations Plant

Union currently allocates Union North customer station costs to its North in-franchise rate classes in proportion to average number of customers, excluding the small volume general service Rate 01 rate class. Union noted that the customer stations, however,

[51] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 141-143.

are constructed for customers that have hourly consumption in excess of 320 m^3. Assuming a typical industrial customer load factor of 40 percent and 20 hours of flow per day, the annual consumption for customers with a customer station would be a minimum of 934,400 m^3. Union noted that based on 2010 actual volumes, no Rate 01 customers and only a small percentage of Rate 10 customers consume 934,400 m^3 or more per year.

Union noted that all other medium and large volume customers require a total maximum daily requirement of 14,000 m^3 or more to be eligible for the respective firm contract rate classes (Rate 20 and Rate 100). Based on peak hourly flow equal to $1/20^{th}$ of the maximum daily quantity of 14,000 m^3 or more, the approximate hourly consumption for the firm contract rate classes is 700 m^3. Accordingly, Rate 20 and Rate 100 customers exceed the hourly customer station requirement of 320 m^3.

Union proposed to allocate customer station costs based on the average number of customers, excluding the Rate 01 rate class and Rate 10 customers that do not meet the annual consumption threshold of 934,400 m^3.[52]

APPrO submitted that the change to the allocation of North Distribution Customer Station Plant is not appropriate. APPrO noted that Union's proposed change in allocation methodology has the effect of reallocating approximately $2.17M of revenue requirement from Rate 10 to Rates 20, 25 and 100.

APPrO noted that Union's proposed methodology is underpinned by the assumption that North customer station costs are only applicable to those customers that have an annual consumption greater than 934,400 m^3. APPrO submitted that the design criterion to size and install meters and regulators is the peak hourly load and pressure considerations. APPrO argued that annual consumption is not a design criterion. APPrO also noted that capital costs are driven by design criteria and not annual consumption.

APPrO submitted that Union's reallocation of North customer station plant costs is flawed because capital costs are dependent on the design criteria of peak hourly flow, not annual consumption. APPrO proposed that no change be made to the current allocation. In the alternative, to the extent that any changes are made, they should be consistent with the corrected Exhibit J.G-5-13-1, Attachment 1. Or in other words, on

[52] Exhibit G1, Tab 1 at pp. 12-13.

the average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3 / hour.

APPrO also noted that for those customers that take both firm and interruptible service, there is only one meter. Under Union's proposal, customers taking service under Rate 10, 20 or 100 are first allocated costs of the meter station for the firm load, and then they receive a second allocation of costs related to the customer station for the interruptible load. Therefore, APPrO submitted that there is a double allocation of costs caused by Union's proposal.[53] No other parties commented on this issue.

Union stated that APPrO advances two arguments in support of their position. The first is that the 934,000 m^3annual consumption figure is arbitrary, and the second is that because there may be overlap in the Rate 20 and Rate 100 with the Rate 25, the number of customers used in the allocation is overstated and results in double recovery.

As to the first argument, Union stated that the annual figure is not arbitrary. Union noted that 320 m^3/ hour, 20 hours a day, 365 days a year, aggregates to 934,400 m^3 / year.

As to the second argument, Union submitted that there is no double count of the allocation of costs. The costs of distribution customer stations are allocated and recovered from all contract rate classes, including interruptible classes, and customers taking a firm service in combination with an interruptible service pay for only a portion of the station costs in each of their rates. Union submitted that there is no over-recovery of North Distribution Customer Station Costs.[54]

Board Findings

The Board will not approve Union's proposal to reallocate the North Distribution Customer Station Costs. The Board agrees with the submissions of APPrO that since capital costs are dependent on the design criteria related to peak hourly flow, the reallocation of costs based on annual consumption is not appropriate.

The Board is of the view that since capital costs are dependent on the design criteria related to peak hourly flow, the allocation methodology should reflect the design criteria of peak hourly flow and not annual consumption. Therefore, the Board finds that the

[53] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 132-135.
[54] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 137-138.

North Distribution Customer Station Plant costs should be allocated on the basis ofthe average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3 / hour. The Board believes that this allocation methodology better reflects cost allocation principles. The Board directs Union to file this update as part of the Draft Rate Order process.

Distribution Maintenance – Meter and Regulator Repairs

Union noted that it currently classifies Union South distribution maintenance costs for meter and regulator repair to Distribution Customers and allocates the costs to the M2 rate class. For Union North, distribution maintenance costs for meter and regulator repair are classified to Distribution Demand and allocated to rate classes in proportion to the allocation of distribution meter and regulator gross plant.

Based on a review of its operating practices, Union determined that there are minimal maintenance costs associated with residential meters because it is more economical to replace small residential meters than perform repairs. To reflect Union's operating practices and harmonize cost allocation between Union North and Union South, Union proposed to align the Union North and Union South distribution maintenance meter and regulator repair cost methodology.

Union proposed to classify and allocate both Union North and Union South distribution maintenance costs for meter and regulator repair in proportion to the distribution meter and regulator gross plant cost allocation, excluding Rates M1 and 01.[55]

LPMA supported the proposal made by Union. LPMA agreed with Union that its proposal would harmonize the cost allocation between the North and the South and would better reflect its operating practices.

LPMA noted that Union's current M1 and Rate 01 rate classes include customers that have an annual consumption of up to 50,000 m^3 / year. Union proposed to change this effective January 1st, 2014 and reduce the number of customers in these classes by reducing the threshold to 5,000 m^3 / year. LPMA stated that it is not clear if Union's proposal would shift more costs associated with the maintenance costs from meter and regulator repairs into the M2 and Rate 10 classes as more customers are moved into those classes. LPMA stated that these additional customers will have their associated

[55] Exhibit G1, Tab 1 at pp. 13-14.

distribution meter and regulator gross plant costs moved with them, resulting in a greater proportion of the meter and regulator costs in these rate classes than the current split.

LPMA noted that at Union's next rebasing, where cost allocation will again be reviewed, the customers that use between 5,000 m^3/ year and 50,000 m^3 / year would now be in a class that attract the repair costs, even though Union's evidence in this proceeding is that the customers currently in Rates M1 and 01, which include these customers, would not attract repair costs. LPMA argued that this is most likely to be the case in the future, at least for the smaller volume customers that are proposed to be moved from Rates M1 and 01 to Rates M2 and 10, respectively. LPMA submitted that the Board should direct Union to address this potential issue in its next cost allocation study if the Board approves Union's proposal for the change in the split between the rate classes from 50,000 m^3 to 5,000 m^3.[56]No other parties commented on this issue.

Union submitted that no parties raised any concerns with the proposed allocation for 2013 and therefore the proposal should be approved by the Board. Union submitted that LPMA’s concerns related to the 2014 Rate M1 / M2 and Rate 01 / 10 rate redesign do not withstand any rigorous scrutiny and should be dismissed.[57]

Board Findings

The Board accepts Union’s proposal to classify and allocate both Union North and Union South distribution maintenance costs for meter and regulator repair in proportion to the distribution meter and regulator gross plant cost allocation, excluding the M1 and Rate 01 rate classes. The Board accepts Union’s submission that the harmonization of the cost allocation methodology between Union’s North and South operation areas better reflects Union’s operating practices and cost allocation principles.

Distribution Maintenance – Equipment on Customer Premises

Union currently allocates South distribution maintenance costs for equipment on customer premises to M1 and M2 customers based on service call time, and allocates North distribution maintenance costs for equipment on customer premises are allocated to rate classes based on a historic allocator.

[56] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at pp. 75-77.
[57] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 139.

Union stated that the costs for maintenance of equipment on customer premises are primarily related to customer station maintenance. In order to more accurately reflect costs and to harmonize the allocation approach between Union North and Union South, Union proposed to allocate both the Union North and Union South Distribution Maintenance – Equipment on Customer Premises to rate classes in proportion to the allocation of customer station gross plant.[58]

LPMA supported Union's proposal regarding the allocation of Distribution Maintenance - Equipment on Customer Premises costs. LPMA submitted that Union's proposal would harmonize the approach in Union South and Union North, and more accurately reflect cost causation. LPMA also submitted this proposal is consistent with the proposal to allocate the distribution maintenance costs associated with the meter and regulator repairs.[59]

APPrO submitted that Union's proposal for allocating Distribution Maintenance - Equipment on Customer Premises costs is not appropriate. APPrO submitted that the effect of the proposal is to move $1.5 million in costs from Rate 01 to Rates 10, 20, 100 and 25. APPrO submitted that there is nothing on the record as to what the subject of this maintenance category is.

APPrO argued that the effect of the proposal in the South is to reallocate $0.32 million from the small volume rate class to larger volume rate classes. APPrO submitted that it has concerns with this proposal as these costs have been historically allocated to small volume customers, and now without regard for a full and complete understanding of the equipment involved, Union proposed to allocate these costs to the large volume rate classes. APPrO noted that the current methodology (in the North), as approved by the Board in EB-2005-0520, is to allocate costs in proportion to Appliance Rentals. APPrO stated that the reference to Appliance Rentals could be to equipment on customer premises, which have nothing to do with customer stations.

APPrO submitted that Union provided no evidence on what has changed between EB-2005-0520 and how that would result in this change in allocation methodology.

[58] Exhibit G1, Tab 1 at p. 14.
[59] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 77.

APPrO submitted that Union's proposal should be rejected in its entirety. APPrO submitted that a definition for customer station plant needs to be determined before an allocation methodology for these assets can be properly understood by parties and directed by the Board.[60] No other parties commented on this issue.

Union submitted that its proposal reflects the principle of cost causality harmonizes the North and South allocation methods and replaces the current Board-approved cost allocation methods that have outlived their purpose with a methodology that is up-to-date. As such, Union argued that its proposal should be accepted as filed.[61]

Board Findings

The Board will not approve Union's proposal to allocate both the Union North and Union South equipment on customer premises distribution maintenance costs to rate classes in proportion to the allocation of customer station gross plant. The Board agrees with the submission of APPrO that there is no evidence in this proceeding as to what the subject of this maintenance category is. Accordingly, the Board directs Union to file, in conjunction with the 2014 cost allocation study ordered elsewhere in this Decision, sufficient evidence to support this potential change in cost allocation, including a definition for this maintenance category and a delineation of what has changed since EB-2005-0520 that would result in a change to the allocation methodology.

Purchase Production General Plant

Union noted that it currently functionalizes general plant costs in proportion to the functionalization of rate base and O&M costs. However, general plant costs are functionalized to the Purchase Production function based on O&M costs only since there are no other plants costs functionalized to Purchase Production. The Purchase Production general plant costs are classified to Purchase Production Other and allocated to Union South in-franchise customers in proportion to delivery volumes, excluding the T1 and T3 rate classes.

Union proposed to classify general plant costs to both the Purchase Production System and Purchase Production Other classifications in proportion to the components of Purchase Production System and Other O&M. Union also proposed to allocate general plant costs to rate classes in proportion to the components of Purchase Production

[60] Oral Hearing Transcripts,EB-2011-0210, Volume 15 at pp. 135-139.
[61] Oral Hearing Transcripts,EB-2011-0210, Volume 16 at pp. 139-140.

System and Other O&M. Union noted that this methodology change ensures general plant costs that are functionalized to purchase production are classified and allocated to rate classes on the same basis.[62]

LPMA supported this proposal and no other parties commented on this issue.[63] Union submitted that no parties raised any concerns in regards to this proposal and therefore it should be approved as filed.[64]

Board Findings

The Board approves Union's proposal to update the allocation of purchase production general plant costs. The Board accepts Union's submission that this methodology better reflects cost allocation principles than the existing methodology.

Parkway Station Costs

Mr. Rosenkranz, an expert witness for CME, CCC, City of Kitchener and FRPO, described the manner in which the costs of transporting gas on the Dawn-Parkway transmission system are divided and allocated. Mr. Rosenkranz noted that these costs are divided into two distinct categories: the cost of the compressors needed to move gas from the Dawn Hub into the Dawn-Parkway system (Dawn Station costs); and all remaining costs (Dawn-Trafalgar Easterly costs). Mr. Rosenkranz noted that the Dawn-Trafalgar Easterly costs include Union's transmission pipelines, the compressors at Lobo, Bright, and Parkway, and the metering facilities at Kirkwall and Parkway. Dawn-Trafalgar Easterly costs are allocated using a distance-based commodity-kilometre methodology while Dawn Station costs are allocated on the basis of design-day demand.[65]

Mr. Rosenkranz noted that Union delivers and receives gas at Parkway and that the predominant direction of physical flow at Parkway is from Union to TCPL and Enbridge.[66][67] Mr. Rosenkranz noted that the metering and compression facilities at

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[62] Exhibit G1, Tab 1 at pp. 14-15 (Updated).
[63] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 77.
[64] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 140.
[65] Exhibit K10.7 at p. 2.
[66] Ibid at p. 3.
[67] Exhibit B1, Tab 9, Schedule 2 shows that the flows through Parkway are predominately export based.

Parkway Station are designed to meet Union's design day requirements to export gas from Union to TCPL and Enbridge.

Mr. Rosenkranz noted that metering costs are a function of design day demand and that compression horsepower at Parkway is determined by Union's peak day requirement to deliver gas to TCPL and Enbridge. In addition, Mr. Rosenkranz stated that Union's metering and compression assets at Parkway are not used to transport or deliver gas to any of Union's upstream in-franchise markets connected to the Dawn-Parkway transmission system. Therefore, Mr. Rosenkranz recommended that the Parkway station costs be separated from the overall Dawn-Trafalgar Easterly Transmission costs and allocated to rate classes on the basis of design day requirements.[68]

Mr. Rosenkranz noted that once the Parkway Station costs have been separated in the cost allocation, the costs should be recovered from those services that use the Parkway facilities. In addition, Mr. Rosenkranz recommended the establishment of a non-export M12 service that can be used by in-franchise customers to meet an obligated delivery requirement at Parkway. The non-export M12 service would allow shippers to deliver gas to Union but would not give shippers the right to deliver gas to TCPL or Enbridge. Mr. Rosenkranz recommended that the costs for this service should be allocated on the same basis as the Dawn-Trafalgar Easterly costs (exclusive of the Parkway Station Costs).[69]

Board staff[70], LPMA[71], BOMA[72], FRPO[73], Kitchener[74] and others supported the recommendations of Mr. Rosenkranz, as discussed above. LPMA submitted that the Parkway Station is not used to transport or deliver natural gas to any of the upstream in-franchise markets that are connected to the Dawn-Trafalgar transmission system. LPMA submitted that it is clear that the Parkway station metering and compression do not provide any benefits to in-franchise customers. As a result, these customers should not pay any of the associated costs.[75]

[68] Exhibit K10.7 at p. 3.
[69] Ibid at pp. 3-4.
[70] Board staff Argument, August 17, 2012, at pp. 19-20.
[71] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 77-82.
[72] BOMA Factum for Argument at p. 54.
[73] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 158.
[74] City of Kitchener Argument, August 17, 2012, at p. 1.
[75] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 79.

Energy Probe supported Union's existing allocation of Parkway Station Costs[76]for four reasons. First, the peak design day criterion has not been challenged by parties. Second, if the proposal were to be accepted by the Board, more Parkway Station Costs would be borne by ex-franchise customers, exacerbating decontracting and lowering revenue which would need to be offset by higher rates to in-franchise customers. Third, costs would increase for customers of Enbridge. Finally, as per the Settlement Agreement relating to this application, the agreement to re-examine the Parkway delivery obligation could also result in changes to the treatment of the cost allocation for Parkway Station Costs.

Union noted that the treatment of Parkway station costs was last reviewed by the Board in EBRO 493/494. Union noted that with the exception of Energy Probe, which continues to support the current allocation, intervenors support Mr. Rosenkranz's proposal reflected in his evidence at Exhibit K10.7.

Union stated that the submission and recommendations of Mr. Rosenkranz are based on the premise that in-franchise customers receive little or no benefit from the Parkway Station and, therefore, in-franchise customers should not be responsible for Parkway Station costs. Union submitted that this premise is unfounded, and was determined to be so by the Board in EBRO 493/494. The Parkway Station provides benefits to in-franchise ratepayers in a number of ways. First, obligated deliveries received on the discharge side of Parkway provide a direct benefit to in-franchise shippers by reducing the size of the Dawn-Trafalgar facilities servicing in-franchise rate classes. Absent the Parkway obligation, in-franchise rates would be higher. Therefore, Union submitted that in-franchise ratepayers receive a substantial benefit from the existence of the Parkway Station.

Union also noted that its North in-franchise customers receive a benefit from being connected to Parkway because, without it, they could not access Dawn storage.

Union noted that in EBRO 486, it was directed by the Board to prepare an M12 cost allocation study to ensure that there was no cross-subsidiary among rate classes using the Dawn-Trafalgar transmission system. That study was filed with the Board in EBRO 493/494. The Board's decision addresses the allocation of the Dawn Station and Dawn-Trafalgar costs, including the Parkway Station.

[76] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at pp. 65-66.

Union submitted that nothing has changed as it relates to the design of the Dawn-Trafalgar system and the Parkway Station, and how it was used at the time of the EBRO 493/493 decision and how it is used now. On this basis, Union submitted that the proposal to change the allocation methodology should be rejected.[77]

Board Findings

The Board agrees with Union that in-franchise customers benefit from the Parkway Station. The Board also notes, as highlighted by Energy Probe, that there may be a number of unintended consequences associated with Mr. Rosenkranz's proposal, the consequences of which have not been considered in the context of this application. The Board will therefore not approve the separation of the Parkway Station costs from overall Dawn-Trafalgar Easterly Transmission costs, as proposed by Mr. Rosenkranz at this time. The Board will revisit this issue as part of Union's 2014 rates proceeding, after the Board receives Union's report on the outcome of the Parkway Obligation Working Group[78].

Kirkwall Station Costs

In its application, Union did not propose any changes to the allocation of the Kirkwall Station costs. LPMA noted that Mr. Rosenkranz also did not address the issue of Kirkwall metering costs in his evidence. LPMA submitted that the use of the Kirkwall Station has changed over the years and may change further in the future (given the changing flow of natural gas in the northeast area of North America which includes Ontario). LPMA stated these changing dynamics demonstrate the need to review the allocation of the Kirkwall Station costs. The changing flow of natural gas in the northeast has been highlighted by Union in this proceeding through the level of turn-back of M12 capacity that has already occurred and is forecast to occur in the future.

LPMA noted that the Parkway-to-Maple bottleneck has been raised in this proceeding. The dramatic increase in TCPL tolls, especially along the northern Ontario route relative to other routes to the Greater Toronto Area, has illustrated the potential need for the Parkway West project. LPMA stated that all of these issues highlight the fact that there has been considerable change that has taken place with respect to the flows of gas around the Parkway Station, since Union last reviewed the cost allocation and rate

[77] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 143-145.
[78] Union Settlement Agreement, June 28, 2012, Section 3.17, p.16

design for services offered on the Dawn-Trafalgar system in 1995, and that the Board last approved in Union's 1997 rate case, which was EBRO 493/494. LMPA submitted that the Board should direct Union to review the allocation of Kirkwall metering costs.[79] No other parties commented on this issue and Union did not respond to LPMA's submission in reply.

Board Findings

The Board agrees with the submissions of LPMA. The use of the Kirkwall Station has changed substantially over the years and there is a clear need to review the allocation of Kirkwall Station costs. The Board directs Union to undertake a review of the allocation of Kirkwall metering costs as part of its updated cost allocation study which the Board has directed Union, later in this Decision, to file in its 2014 rates filing.

Dawn-Trafalgar Easterly Costs

Union's Dawn-Trafalgar Easterly costs include Union's transmission pipelines, the compressors at Lobo, Bright, and Parkway, and the metering facilities at Kirkwall and Parkway. Dawn-Trafalgar Easterly costs are allocated using a distance-based commodity-kilometre methodology.

LPMA submitted that, with the removal of the Parkway station metering and compression costs discussed above and subject to the review of the Kirkwall metering costs also noted above, the allocation of the remaining Dawn-Trafalgar Easterly costs should continue to be based on the distance-based commodity-kilometre methodology. LPMA argued that there has been no evidence presented in this proceeding to suggest that this allocation methodology is not appropriate for these remaining costs, nor has any evidence been presented in support of another methodology.[80] No other parties commented on this issue.

Board Findings

The Board approves Union's proposed allocation of the Dawn-Trafalgar Easterly costs. The Board finds that the distance-based commodity-kilometre methodology used to

[79] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 80.
[80] Ibid. at p. 81.

allocate the Dawn-Trafalgar Easterly costs is appropriate and reflective of cost allocation principles.

Utility / Non-Utility Storage Cost Allocation

Board staff noted that Union's methodology for separating its utility and non-utility storage businesses was originally approved by the Board in EB-2005-0551 and confirmed by the Board in EB-2011-0038. In the EB-2011-0038 Decision and Order, the Board stated:

> The Board finds that the intent of the NGEIR Decision was to effect the one-time separation of plant assets between Union's utility and non-utility businesses. Therefore, there is no need for a subsequent separation (or the filing of another cost study).[81]
>
> The Board finds that Union has appropriately applied its 2007 Cost Allocation Study for the one-time separation of plant.[82]

Union, in this proceeding, provided a description of its methodology for allocating costs related to storage additions. Union provided the following table:

Description	Allocation Methodology
New Storage Asset – increase in capacity or deliverability	100% Allocation to unregulated
New Storage Asset – no increase in capacity or deliverability	Allocated regulated versus unregulated based on the historic allocation of assets at that location
Replacement Asset – no increase in capacity or deliverability	Allocated regulated versus unregulated based on the historic allocation of assets being replaced.
Replacement Asset – increase in capacity or deliverability	Cost of replacing the existing asset like for like is allocated regulated versus unregulated based on the historic allocation of assets being replaced. The cost of providing the incremental capacity or deliverability is allocated 100% to the unregulated operation. This results in a new blended rate for this asset.

With respect to the allocation of O&M costs related to non-utility storage, Union stated that:

[81] Decision and Order, EB-2011-0038,January 20, 2012 at pp. 6-7.
[82] Decision and Order, EB-2011-0038,January 20, 2012 at p. 11.

a) Actual O&M related to the operation of the storage facilities was allocated to the non-utility storage operation using the same allocators applied to the assets for that facility.

b) Administrative and general expenses and benefits in support of non-utility storage operations were allocated in proportion to storage O&M.

c) O&M costs related to the development of new storage assets are assigned based on an estimate of time spent annually on the development of non-utility projects.

d) O&M costs related to the Regulatory Department for development of new storage assets, are assigned based on an estimate of time spent annually on the development of non-utility projects.[83]

Board staff supported the methodologies for allocating capital and O&M costs to non-utility storage as described above.

Board staff also noted that as a result of Union's review of its allocation factors in early 2012[84], which sought to confirm that the methodology set out above was applied correctly, Union identified updates that were required to10 of its storage pools. Union noted that after the allocation factors were updated, it compared the updates against its 2013 rate evidence. Union determined that the use of the revised allocation factors for storage capital additions would have decreased the utility storage assets by approximately $25,000 in 2013. Union also noted that the allocation factor update results in a decrease to utility O&M of $100,000.[85]

Board staff submitted that although these amounts are quite small, the Board should require Union to update its allocation factors as part of its evidence in this proceeding and reassign the noted amounts from utility to non-utility ($100,000 in O&M and the revenue requirement related to the $25,000 in decreased utility storage capital costs).

Board staff also submitted that the above noted methodology for allocating costs between utility and non-utility storage related to storage additions should continue going

[83] Exhibit A2, Tab 2, p.8.
[84] This review occurred as a result of recommendations in the Black & Veatch report filed in EB-2011-0038.
[85] Union - Supplemental Question Responses, FRPO Supplemental Question #2.

forward and that the allocation of utility / non-utility storage costs should be updated in every rebasing and be reflected in the pre-filed evidence. [86] BOMA supported Board staff's submission on this issue.[87]

FRPO submitted that Union has under-allocated storage plant additions to the non-utility storage operation by continuing to use the same plant allocation factors that were developed for the one-time separation of plant. FRPO noted that Union refers to these as original or historic allocation factors. FRPO submitted that Union needs to update these factors each year to reflect the changes in the relative amounts of utility and non-utility storage. FRPO noted that Union provided updated allocation factor for each storage asset. FRPO noted that Union has stated that if it had used the revised updated factors to allocate plant additions for maintenance capital projects, the estimated allocation of plant to non-utility storage would have been $50,000 higher in 2012 and $25,000 higher in 2013. FRPO noted that, however, Union did not provide actual information for the years 2007 through 2011, even though the impact of Union's failure to update the cost allocation factor on 2013 rates depends on the cumulative misallocation of plant additions since 2007, not just the allocations during the bridge year. FRPO noted that Union does not propose to make any adjustment in 2013 to correct this error. FRPO argued that the allocation of plant to non-utility storage should be increased by $25,000 for 2013 and that Union should provide evidence (continuity schedules) supporting this allocation change prior to its 2014 rates proceeding.

FRPO noted that Union's failure to update the plant allocation factors also means that O&M was under-allocated to non-utility storage operation for 2013. FRPO noted that according to Union, the utility O&M costs should be reduced by approximately $100,000 based on its update to storage allocation factors. FRPO submitted that the 2013 utility O&M amount should be reduced by $100,000 and that the O&M amount for non-utility storage should be updated annually.

FRPO also raised a concern regarding the allocation of general plant to non-utility storage. FRPO submitted that Union has under-allocated general plant additions to non-utility storage plant by failing to update the other general plant allocation factor.

FRPO noted that the one-time separation of storage plant included an allocation of general plant. Two separate allocation factors were used, one factor for vehicles and a

[86] Board Staff Submission, August 17, 2012, at pp. 21-24.
[87] BOMA Factum for Argument at p. 54.

second factor for general plant. FRPO noted that the other general plant allocation factor that was used for the one-time separation was 2.92%. FRPO noted that this factor is the arithmetic average of the ratio of non-utility storage plant to total plant, 3.2%, and the share of non-utility support costs in the total O&M, which at the time of separation was 2.52%. FRPO stated that Union has not updated the other plant allocation since the one-time separation of plant.

Based on plant and O&M shares for year-end 2010, FRPO estimated the other plant allocation factor should be raised from 2.92% to at least 4%. Using the 4% other plant allocation factor, FRPO estimated the under-allocation to Union's non-utility storage business related to the allocation of general plant costs.[88]

FRPO noted that the application of the 4% other plant allocation factor across 2010, 2011, 2012 and 2013 shows an increasing under-allocation of non-utility, which peaks at $306,000 for 2013. FRPO requested that Union be directed to make the changes to the other general plant allocation factor using the most up-to-date information available prior to the implementation of 2013 rates.[89]

FPRO also requested that the Board direct Union to file plant continuity schedules related to Union's non-utility business as part of its 2014 rates filing.[90] FRPO and Energy Probe also submitted that the Board should direct Union to have Black and Veatch update the report that was filed in EB-2011-0038 as part of its 2014 rates filing.[91]

Union submitted that the updates to the storage related O&M and capital costs that parties are suggesting be made are immaterial. Union stated that the total amount of this update is approx. $50,000. In Union's submission, the quantum of the change does not warrant the treatment that parties are proposing. Union stated that it has a robust methodology to manage plant additions and plant replacements.

Union also submitted that there is no reason for Black & Veatch to revisit this issue again. It was first considered in the EB-2010-0039 case, and again in EB-2011-0038 and the report contains up-to-date information.[92]

[88] FRPO Argument Compendium at p. 22.
[89] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at pp. 134-142.
[90] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at p. 140.
[91] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at pp. 63-64.
[92] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 146-147.

Board Findings

The Board finds that Union's allocation methodologies for capital additions and O&M costs related to its utility and non-utility storage operations are appropriate. The Board is of the view that these allocation methodologies reasonably reflect cost allocation principles.

The Board notes that, based on a review that Union undertook in early 2012 regarding its utility and non-utility storage allocations, Union identified certain allocation factor updates that are required to a number of its storage pools. The Board directs Union to implement the storage allocation factor update as part of this proceeding. The Board notes that there seems to be a misunderstanding among parties as to the dollar amount that is the outcome of the allocation factor update. The Board notes that Board staff stated that the allocation factor update results in an approximate decrease in utility storage assets of $25,000 and a decrease in utility O&M of $100,000 for 2013. However, Union stated that the total amount related to this update is $50,000. The Board directs Union to explain which amount is the correct amount that needs to be updated to reflect the change in allocation factors. The Board directs Union to implement this change as part of the Draft Rate Order process.

With respect to FRPO's argument that an update is also required to the general plant allocation, the Board finds that it does not have sufficient evidence on this issue to make this finding. While the Board is of the view that there may or may not be an under-allocation of general plant to Union's non-utility storage operation, the quantum of that under-allocation, if any, is not clear from the evidence in this proceeding. Therefore, the Board will not direct Union to make an update to the general plant allocation for the purpose of setting 2013 rates.

However, the Board finds that in order for parties, and the Board, to confirm that the allocation of storage costs between Union's utility and non-utility storage operations is correct, the Board requires up-to-date continuity schedules related to Union's non-utility storage business. The Board directs Union to file, as part of its 2014 rates filing, these continuity schedules.

Also, the Board directs Union to hire an independent consultant to update the report that was filed in the EB-2011-0038 proceeding and file that report as part of its 2014 rates proceeding.

The Board believes that it should have a robust evidentiary record in Union's 2014 rates proceeding on all issues related to the allocation of storage costs between utility and non-utility storage. The Board notes that, as part of Union's 2014 rates filing, it will revisit the allocation of all storage related costs between Union's utility and non-utility storage operations. At that time, the Board may also order further updates to the allocation factors (including the general plant allocation factor).

RATE DESIGN

General Rate Design Issues

Union noted that when designing its 2013 proposed rates for Union North and Union South, the following factors were taken into consideration:

- The revenue deficiency for the company as a whole;
- The relative rate changes of other rate classes;
- The allocated cost of service;
- The level of current rates and the magnitude of the proposed change;
- The potential impact on customers;
- The level of contribution to fixed cost recovery;
- Customer expectations with respect to rate stability and predictability; and
- Equivalency of comparable service options.

Union stated that the revenue-to-cost ratios reflect Union's application of accepted rate design principles and are underpinned by the cost allocation study. Union also submitted that the 2013 proposed revenue-to-cost ratios are within an acceptable range and are generally consistent with those approved by the Board in EB-2005-0520.[93]

In an interrogatory response, Union noted that revenue-to-cost ratios are the outcome, not an input, of the application of Union's rate design considerations described above. Union submitted that acceptable revenue-to-cost ratios must:

[93] Exhibit H1, Tab 1, p. 12 (Updated).

- Satisfy rate design principles discussed above, and
- Bear a reasonable relationship to previously approved revenue-to-cost ratios.

Union stated that acceptable revenue-to-cost ratios guidelines include:

1. Firm in-franchise general services (Rate 01, Rate 10, Rate M1 & Rate M2) close to unity.
2. Large firm in-franchise contract services (Rate T1, Rate T3 and Rate 100) close to unity.
3. Other in-franchise firm services between (1) and (2) above will vary due to firm rate continuum considerations. A revenue-to-cost ratio approximating 80% or more is generally realized.
4. Rate M12 firm transportation service close to unity.
5. Interruptible in-franchise service pricing is set in relative relationship to firm services, with the resulting revenue-to-cost ratios showing greater deviation from unity.[94]

Board staff submitted that Union's rate design considerations (and revenue-to-cost ratio guidelines), discussed above, are appropriate. However, Board staff raised a number of concerns regarding how these rate design considerations were followed.

Board staff stated that a general principle is that approved revenue-to-cost ratios, for in-franchise customers, should not move away from a unity position. In a number of in-franchise rate classes, the EB-2005-0520 Board-approved revenue-to-cost ratios were closer to unity than proposed in this case. These rate classes are: Rate 01 (from 0.976 to 0.975), Rate 25 (from 0.467 to 0.446), Rate M2 (from 0.972 to 0.940), Rate M5A (from 0.824 to 0.746), and Rate M10 (from 0.131 to 0.073).[95]

Union provided the following rationale for these changes. Union stated that the proposed rate is designed to manage the relationship between the firm and interruptible service, maintain the rate continuum across all of the firm rate classes and the interruptible rate class, and to manage the level of rate increases to the rate classes.[96] Board staff noted that these may be reasonable reasons to breach the general principle

[94]Ex. J.H-1-5-2.
[95]Ibid.
[96] Oral Hearing Transcripts, EB-2011-0210, Volume 12 at p. 8.

of not moving away from unity.

In response to Union's proposal to increase rates in Rate M1 to slightly beyond unity (1.003) and over-recover from that rate class by an amount of $1.14 million, Board staff submitted that this over-recovery (which results in cross-subsidization) is not appropriate.[97] Rate M1 (Union's small volume general service class in the South) should not have to pay more costs than are allocated to that class (on the basis of the cost allocation study). Board staff noted that Rate M1 is Union's only in-franchise rate class with a revenue-to-cost ratio higher than 1.0. Board staff noted that Union is attempting to balance the rate continuum and help offset larger rate increases in other rate classes by over-recovering in Rate M1. In Board staff's view this proposal is unfair to Union's M1 customers. Board staff submitted that Rate M1's rate design should not result in a revenue-to-cost ratio higher than 1.0.

Board staff noted that Union is materially under-recovering from Rate M7 ($1.2 million) and Rate M12 ($2.6 million) and that these rate classes have delivery rate impacts of less than 2%.[98] Board staff noted that for rate continuum purposes further rate increases for Rate M7 are not feasible. However, Board staff stated that Rate M12 does not have the same rate continuum constraints as does M7. Board staff submitted that Union should increase its rates in Rate M12 to result in a revenue-to-cost ratio of 1.0.

Board staff also commented on Union's allocation of S&T margins to the rate classes. Board staff noted that the overall revenue deficiency (after the proposed rate increases have been applied) for Union's Northern in-franchise rate classes is $13.125 million and the overall revenue deficiency (after the proposed rate increases have been applied) for Union's Southern in-franchise rate classes is $10.778 million. The overall revenue deficiency for in-franchise rate classes (after the proposed rate increases have been applied) is $23.903 million.[99] These amounts are offset by the S&T margins of $23.903 million that are built into rates. Board staff noted that approximately 55% of S&T margins are being allocated to the North and approximately45% are being allocated to the South. Union noted that the methodology for the split in the S&T margin allocation between operation areas is that the same proportion of the total revenue deficiency (before proposed revenue increases are applied) should be recovered by S&T margin allocations in both operation areas.[100] This methodology results in approximately 30%

[97] Exhibit H3, Tab 1, Schedule 1.
[98] Ibid.
[99] Ibid.
[100] Oral Hearing Transcripts, EB-2011-0210,Volume 11 at pp.146-148.

of the total revenue deficiency in each operation area being recovered through the allocation of S&T margins.[101]

Board staff submitted that although the methodology used by Union as discussed above results in an equitable allocation of S&T margins between operating areas (from the perspective of offsetting the revenue deficiency) it has no correlation to the manner in which the revenues are derived and is different from the last allocation of S&T margins in 2007 (EB-2005-0520).

Board staff noted that Union has acknowledged that it is using the S&T margins as a rate design tool to manage rate impacts, rate continuity and revenue-to-cost ratios in 2013.[102] In its Argument-in-Chief, Union submitted that using these margins as a rate design tool has been done in the past and is appropriate.[103]

Board staff noted that the Board, in this proceeding, needs to determine whether the allocation of S&T margins should be properly considered a rate design tool. Board staff is of the view that the allocation of S&T margins should not be used as a rate design tool. Board staff submitted that there are more appropriate ways to allocate these revenues which have more direct linkages to the manner in which the S&T margins are generated. BOMA supported the submissions of Board staff.[104]

LPMA supported Board staff's submissions that the M1 revenue-to-cost ratio should be no higher than 1.0 and that the M12 revenue-to-cost ratio should be increased to 1.0.[105]

VECC supported Board staff's submission that the M1 revenue-to-cost ratio should be no higher than 1.0. VECC also submitted that it has some concerns regarding Union's allocation of S&T margins. VECC stated that Union has allocated the S&T margins to rate classes for the purpose of managing rate impacts, with no regard for the causal connection between the generation of S&T revenues and the classes that pay for the assets that generate the S&T revenues. VECC stated that allocation of these revenues should be based on some equitable distribution across all distribution ratepayers.[106]

[101] Exhibit H3, Tab 1, Schedule 1.
[102] Oral Hearing Transcripts, EB-2011-0210, Volume 12 at pp. 121-122.
[103] Oral Hearing Transcripts, EB-2011-0210, Volume 13 at p.81.
[104] BOMA Factum for Argument at p. 54.
[105] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p.89.
[106] VECC Argument, August 21, 2012 at p. 24-25.

Union submitted that the revenue-to-cost ratios are reasonable as filed. Union noted that the revenue-to-cost ratios are the outcome of the rate design process and reflect the application of the rate design principles described in Exhibit H1, Tab 1 (and cited above). Union noted that there has never been a requirement that revenue-to-cost ratios be limited to 1.0. Union noted that, in 2007, the Board approved rates for Rate 10 that resulted in a revenue-to-cost ratio of 1.058.

Union submitted that the principal submission made by most intervenors on this topic is that the revenue-to-cost ratio for Rate M1 should be adjusted from the proposed level of 1.003 down to 1.0. A number of parties have suggested that this adjustment could be funded by increasing the M12 revenue-to-cost ratio from 0.984 to unity. Union submitted that the revenue-to-cost ratio of 1.003 is not materially different from 1.0 and is not inconsistent with resulting revenue-to-cost ratios approved by the Board in the past.

With respect to M12, Union submitted that the revenue-to-cost ratio of 0.984 is consistent with the cost-based Board-approved rate design for M12 services. Union noted that the M12 revenue-to-cost ratio is less than 1.0 because Dawn-Trafalgar westerly service revenues earned under C1 rate schedule reduce M12 rates. Increasing the M12 revenue-to-cost ratio to 1.0 would result in over-recovery of Dawn-Parkway costs presently allocated to ex-franchise services.

Union also made submissions on the issue raised by Board staff and VECC on the use of S&T margins as a rate-making tool. Union stated that it does not agree with the position of Board staff and VECC. Union noted that the use of S&T margin for rate design purposes has been a long standing and necessary feature of Union's rate design process. Absent the ability to use S&T margin for rate design, Union would need to deal with rate impacts and rate continuity issues by adjusting revenue-to-cost ratios alone. As part of the rate design process, Union has allocated approximately $13.1 million of S&T margins to the North and approximately $10.8 million of the S&T margins to the South. Union stated that this is a greater proportion than has ever been allocated to the North. Union noted that it is seeking to recover proportionally the same level of revenue deficiency between Union North and South because it reasonably balances the need to manage rate impacts in the North and the need to address rate continuum concerns in the South. Union submitted that using S&T margin to smooth rate continuum impacts and to manage rate design considerations is a longstanding feature of Union's rate design, and it should be continued by the Board in this proceeding.

Board Findings

The Board finds that Union's rate design considerations and revenue-to-cost ratio guidelines are generally appropriate. However, the Board has concerns with some of Union's rate design proposals, as discussed below.

The Board agrees with Board staff, that in general, applied-for revenue-to-cost ratios for in-franchise customers should not move farther away from 1.0 than the revenue-to-cost ratios that are presently approved and reflected in rates. The Board notes that for a number of in-franchise rate classes, the EB-2005-0520 Board-approved revenue-to-cost ratios were closer to unity than the revenue-to-cost ratios proposed in this proceeding. These rate classes are: Rate 01 (from 0.976 to 0.975), Rate 25 (from 0.467 to 0.446), Rate M2 (from 0.972 to 0.940), Rate M5A (from 0.824 to 0.746), and Rate M10 (from 0.131 to 0.073). As a result, the Board finds that the proposed revenue to cost ratios are not appropriate.

The Board notes that some parties made the argument that the revenue-to-cost ratio should be no greater than 1.0 for the M1 rate class. The Board agrees with this submission and is of the view that no compelling rationale was provided by Union to support a revenue-to-cost ratio for the M1 rate class greater than 1.0. Therefore, the Board finds no in-franchise rate class should have a revenue-to-cost ratio greater than 1.0.

The Board finds that Union's use of the S&T margins as a rate design tool to manage rate impacts, rate continuity and revenue-to-cost ratios in 2013 is not appropriate. The Board believes that S&T margins should be allocated to rate classes on the basis of sound regulatory principles. The Board does not agree that these margins should be used arbitrarily to manage rate impacts.

The Board notes that elsewhere in this Decision, the Board has found that certain optimization activities are to be considered part of gas supply, removing these activities from what Union has previously defined as transactional services and included in its S&T margin forecast. In this Decision, the Board has defined optimization as any market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise bundled customers, including, but not limited to, all FT-RAM activities and exchanges. The net revenues related to these optimization activities are no longer to be included in the S&T margin forecast.

The Board finds that optimization related net revenues should be allocated to those customers that pay the costs of facilitating Union's gas supply plan. Therefore, the Board directs Union to file a proposed allocation methodology, as part of the Draft Rate Order process, which allocates the optimization margins to those customers. The Board notes that this proposal must be based on regulatory principles.

With respect to the remaining S&T margins, the Board notes that this Decision sets out sub-categories for these margins including: Long-Term Transportation related S&T margins, Short-Term Transportation related S&T margins, and Storage and Other Balancing Services related S&T margins. The Board directs Union to file allocation methodologies for the above noted sub-categories, as part of the Draft Rate Order process, which reflect regulatory principles.

The Board directs Union to use its proposed methodologies to allocate the S&T margins to its rate classes as part of the Draft Rate Order process. The Board also notes that the methodologies for allocating S&T margins that are ultimately accepted by the Board are to be used in Union's next rates proceeding (cost of service or IRM).

The Board expects, as part of the Draft Rate Order process, that Union will file revised rates that reflect all of the findings in this Decision and that reflect the rate design principles ordered by the Board above.

Rate 01 / 10 and Rate M1 / M2 – Volume Breakpoint and Rate Block Harmonization Proposal for 2014

Union proposed to lower the annual volume breakpoint between the Rate 01 and Rate 10 rate classes in Union North and the Rate M1 and Rate M2 rate classes in Union South from 50,000 m^3 to 5,000 m^3. Union also proposed to harmonize the rate block structures in the small volume general service rate classes (Rate 01 and Rate M1) and in the large volume general service rate classes (Rate 10 and Rate M2). Union proposed to utilize the current Board-approved rate block structures for Rate M1 and Rate M2 in Union South for Rate 01 and Rate 10 in Union North respectively. Union proposed to implement the annual volume breakpoint and rate block structure changes on a revenue neutral basis effective January 1, 2014.[107]

[107] Exhibit H1, Tab 1 at p. 14 (Updated).

Union noted that its proposal to lower the annual volume breakpoint between small volume general service rate classes (Rate 01 and Rate M1) and large volume general service rate classes (Rate 10 and Rate M2) to 5,000 m^3 from 50,000 m^3 will improve the rate class composition of Rate 01 and M1 and achieve more homogeneous rate classes. Also, Union noted that the proposal will improve the rate class size in Rate 10 and Rate M2, which will ensure viable large volume general service rate classes and improve rate stability.[108]

All parties agreed with Union's proposition that the volume breakpoint between the Rate 01 / Rate 10 and Rate M1 / M2 should be reduced for the reasons cited above and that the rate blocking structure should be harmonized. However, no party agreed with the methodology used by Union to give effect to its proposal. Board staff[109], LPMA[110], SEC[111] and other parties explicitly raised concerns regarding Union's methodology for allocating costs between the noted rate classes.

LPMA noted that with respect to the customer-related costs, Union has used a customer-weighting factor to determine the amount of customer-related costs that are associated with the customers that will be moving rate classes. LPMA noted that the weights used are 1.0 for residential, 1.5 for commercial, and 2.0 for industrial. LPMA noted that when asked if Union had any empirical evidence to support the relative differences in the weights used, Union replied that the empirical evidence that they have in this is similar to the evidence that they used when they did the 2007 rate split, which used the same weightings. LPMA noted that Union filed a report in support of the 2007 split prepared by Navigant Consulting Inc. that simply stated that the weights currently used by Union were 1.0 for residential, 1.5 for commercial, and 2.0 for industrial. The Navigant report went on to say that it understood that Union was currently reviewing the appropriateness of those weights. In the undertaking response, Union indicated that it could not find any other 2007 source files related to the weightings. LPMA noted that there was no evidence concerning Union's review anywhere on the record in this proceeding.

LPMA stated that there is no evidence that customer-related costs for commercial customers are 50% higher than they are for residential customers. LPMA noted that customer-related costs include such items as billing and meter-reading costs,

[108] Exhibit H1, Tab 1 at pp. 14-16 (Updated).
[109] Board Staff Submission, August 17, 2012 at pp. 30-34.
[110] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 82.
[111] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp.214-217.

depreciation and the return on meters, regulators and service lines. LPMA submitted that Union has provided no evidence to suggest that the commercial customers that would change rate classes under Union's proposal are any different from residential customers when it comes to billing costs or meter reading costs.

LPMA also raised concerns regarding how Union allocated the delivery-related costs for the group of customers that would be changing rate classes under Union's proposal. LPMA noted that these costs include demand-related costs and commodity-related costs. LPMA stated that, in the South, the vast majority of the other delivery-related costs are demand-related costs for both Rates M1 and M2, with a small component of commodity-related costs. In the North, all of the other delivery-related costs are demand-related costs. However, LPMA noted that Union estimated the costs for the customers that are moving rate classes on the basis of commodity volumes. LPMA submitted that a more appropriate methodology would be to use a design-day weighting allocator which is developed based on a full cost allocation study. LPMA noted that Union generally allocates demand-related costs based on peak day demand. However, LPMA noted that Union indicated that based on forecast data it did not have all of the detailed material that is needed to do a detailed cost study.[112]

Parties made differing arguments regarding how to deal with Union's proposal. Many parties argued that Union should be directed to file more comprehensive evidence (including a cost allocation study) supporting its proposal to reduce the volume breakpoint (and specifically supporting the methodology used to allocate costs) in the noted rate classes prior to the Board approving Union's proposal.

Board staff stated that it supports Union's goal to achieve more homogenous general service rate classes and to increase the size of its larger volume general service rate classes. However, Board staff also submitted that Union should file better supporting evidence for the manner in which costs will be allocated between the rate classes that are the subject of Union's proposal.[113]

LPMA and SEC offered other submissions for the Board to consider in adjudicating this issue.

[112] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 85-88.
[113] Board Staff Submission, August 17, 2012, at p. 34.

LPMA submitted that the Board should approve Union's proposal with a modification to the customer weighting, a change to the monthly customer charge, and the direction to file a cost allocation study as soon as possible which confirms that the costs have been allocated appropriately.

LPMA submitted that a more appropriate weighting scheme for the customer-related costs, in the absence of empirical evidence, is to use the same weight for commercial customers as for residential customers. The impact on the customer-related costs that would be moved to Rate M2 is significant. LPMA noted that this change results in a substantial reduction in the costs moved to Rates 10 and M2. The reduction to Rate 10 is $2.4 million and $4.4 million to Rate M2.

With respect to the monthly customer charge for the Rate 10 and M2, LPMA made the following submissions. LPMA noted that Union proposed a $35 monthly customer charge for both rate classes. Union arrived at this monthly charge by taking the midpoint of the monthly customer charges required to recover all customer-related costs for these two rate classes. LPMA stated that this methodology was used to achieve Union’s goal of maintaining the same monthly fixed charge for the noted rate classes. LPMA submitted that Union’s proposal is inappropriate. LPMA noted that there is a clear difference in the monthly customer charge based on the allocated customer charges between Rates 10 and M2. In particular, the cost-based Rate 10 monthly charge would be $41, while the Rate M2 monthly charge would be $30. LPMA stated that Union is effectively under-recovering, based on its proposed $35 monthly charge, from those in Rate 10 and over-recovering from those in Rate M2.

LPMA submitted that the Rate M2 monthly customer charge should be set at $30 and the Rate 10 monthly customer charge should be set at $40. LPMA stated that these recommended monthly charges are cost-based charges.

LPMA submitted that the Board should direct Union to prepare a proper cost allocation study as soon as possible so ratepayers can be satisfied the costs are being allocated appropriately. LPMA stated that the cost allocation study should be filed with the Board and intervenors as soon as possible so the parties have the opportunity to determine if adjustments to rates are required to more properly and equitably recover the properly allocated costs.

LPMA also noted it would be preferable to implement Union's proposal, with its proposed revisions, effective January 1, 2013, rather than waiting until 2014. LPMA noted that Union has indicated that it is not practical to implement the changes by January 1, 2013, as Union requires Board approval in time to update administrative systems and billing systems. LPMA noted that there were no other reasons provided as to why the change could not be implemented on January 1, 2013. LPMA stated that it understands that time may be required to change the blocking structure in Union North to match that of Union South. However, LPMA submitted that there is no reason to delay the change in the break point in Union South. There are no changes proposed in the block structure for Rates M1 and M2. The change in the break point simply requires Union to identify the customers that will move from rate M1 to rate M2, and then move them. As a result, LPMA stated that there is no obstacle to moving a small percentage of the overall customers from Rate M1 to M2 on January 1, 2013. LPMA submitted that the Board should direct Union to implement the remaining change as early as is practical in 2013.[114]

In response to LPMA's argument, Union made the following submissions.

Union noted that the logic of LPMA's position is that there is unlikely to be a significant difference in the customer-related costs to serve residential and commercial customers and as such, these two types of customers should be applied an equal weighting. Union submitted that that logic applies equally to all aspects of the general service, small volume rate class including: residential, commercial and industrial. Therefore, given LPMA's rationale, Union submitted that all residential, commercial and industrial customers should be weighted equally.

With respect to LPMA's argument on the demand-related costs, Union submitted that the methodology used to split the remaining costs is the same as it used to split the costs between the current M1 and M2 rate classes.

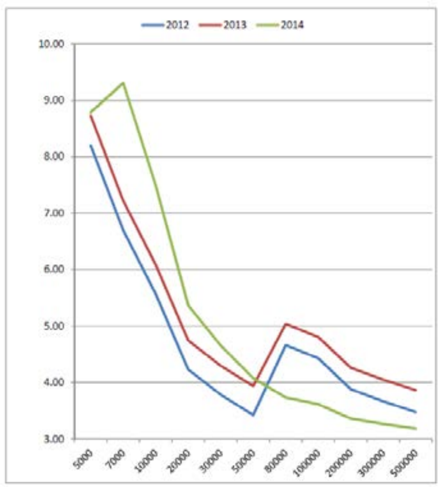
Union submitted that it accepts LPMA's submissions on revising the monthly customer charge to $30 for Rate M2 and $40 for Rate 10.

Union noted that LPMA suggested that the implementation of its proposal occur at the beginning of 2013 for Rates M1 and M2 and that the implementation for Rates 01 and 10 could occur later. Union submitted that this is not possible. Union stated that it needs

[114] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 85-88 and 90-93.

eight months to change its systems. Therefore, Union stated that it will implement its breakpoint proposal for Rates 01, 10, M1 and M2 in the first QRAM after its systems have been updated to reflect this change.

SEC noted that rate continuity requires that when you go from one rate class to another you would still be recording your economies of scale. SEC noted that in Union North, the rates designed for 2013 and 2014 are relatively continuous and SEC does not have major concerns with rate continuity. However, for Union South, SEC submitted that there are significant discontinuities between rates M1 and M2. SEC provided the following chart which highlights the issues it has raised regarding Union's small volume general service classes.[115]



SEC provided the following analysis of the above chart. SEC noted that the chart reflects the unit costs for customers. SEC noted that when you analyze current 2012 rates and the proposed 2013 rates, at and around the breakpoint there is a large increase in the per unit cost for customers.

SEC noted that there are economies of scale in place as you increase volumes and therefore there should not be any increase at (or around) the breakpoint. SEC stated that the reason for the increased per unit cost around the breakpoint between the M1 and M2 rate classes can only be caused by the fact that there is an over-allocation of costs to the M2 rate class.

[115] SEC Argument Compendium at p. 45.

SEC submitted that the 2014 rate proposal reflects a smoother rate continuum. However, SEC noted that the 2014 proposal still does not address the over-allocation of costs to Rate M2. SEC cited the following table to highlight the over-allocation of costs to Rate M2 and to also comment on its view concerning the over-allocation of costs to Rate 10 in Union North.[116]

	a	b	c	d	e	f	g	h	i	j
	North	*Delivery - related costs*	*Volumes*	*Delivery costs per unit*	*Pre-Move Costs*	*Pre-Move Volumes*	*Pre-Move Unit Costs*	*Post-Move Costs*	*Post-Move Volumes*	*Post-Move Unit Costs*
1	Up to 5,000 (01)	$35,211	609,371,320	$0.057783	$47,065	837,395,959	$0.056204	$35,211	609,371,320	$0.057783
2	5,000 to 50,000 (01-10)	$11,854	228,024,639	$0.051986						
3	Over 50,000 (10)	$15,476	244,955,407	$0.063179	$15,476	244,955,407	$0.063179	$27,330	472,980,046	$0.057783
4	Totals - North	$62,541	1,082,351,366	$0.057783	$62,541	1,082,351,366	$0.057783	$62,541	1,082,351,366	$0.057783
	South	*Delivery - related costs*	*Volumes*	*Delivery costs per unit*	*Pre-Move Costs*	*Pre-Move Volumes*	*Pre-Move Unit Costs*	*Post-Move Costs*	*Post-Move Volumes*	*Post-Move Unit Costs*
5	Up to 5,000 (M1)	$75,911	2,043,883,921	$0.037141	$99,137	2,679,558,627	$0.036998	$75,911	2,043,883,921	$0.037141
6	5,000 to 50,000 (M1-M2)	$23,226	635,674,706	$0.036538						
7	Over 50,000 (M2)	$36,461	971,362,682	$0.037536	$36,461	971,362,682	$0.037536	$59,687	1,607,037,388	$0.037141
8	Totals - South	$135,598	3,650,921,309	$0.037141	$135,598	3,650,921,309	$0.037141	$135,598	3,650,921,309	$0.037141

SEC noted that the above table deals only with delivery costs as the delivery-related costs highlight the issue of the over-allocation of costs to Rates 10 and M2 for 2013.

SEC noted that Line 1 reflects Rate 01, and Line 5 reflects M1. Line 3 and Line 7 reflect Rate 10 and M2 respectively. SEC noted that the delivery costs (on a per unit basis and prior to the implementation of Union's 2014 breakpoint reduction proposal) for a Rate 01 customer are 5.62 cents / m^3 and 6.32 cents / m^3 for a Rate 10 customer. SEC submitted that this cannot be correct.

Similarly, for M1 and M2, SEC noted that the delivery costs (on a per unit basis and prior to the implementation of Union's 2014 breakpoint reduction proposal) for a Rate M1 customer are 3.699 cents / m^3 and 3.753 cents / m^3 for a Rate M2 customer. SEC submitted that this also cannot be correct.

SEC noted that what Union did, in order to adjust for this over-allocation of costs for 2014, is move less costs over for 2014 to achieve a situation where M1 and M2 and 01 and 10, respectively, have the same unit costs for delivery. SEC submitted that this is also likely not correct.

[116]Ibid at p. 61.

SEC stated that because the pre-move costs show higher costs in Rates 10 and M2 that there has been an over-allocation of costs to those rate classes. Therefore, the 2013 costs for the small volume general service classes have been allocated incorrectly. SEC stated that it does not know the quantum of the over-allocation. SEC also noted that the existing over-allocation has only been disclosed because Union has provided evidence regarding the movement of costs in the small volume general service rate classes to give effect to its 2014 breakpoint reduction proposal and it has created some anomalous results.

SEC submitted that considering Union has not done a proper cost allocation study to reflect the new proposed breakpoint, the Board has no way of knowing what the right costs are for 2013. SEC submitted that all that is known, based on Union's evidence, is that the results of Union's allocation are anomalous.

Overall, SEC submitted that the Board does not have the jurisdiction to set new rates for Rates 01, 10, M1 and M2 in 2013, because there is no strong evidence before the Board upon which those rates can be set. SEC submitted that the Board should not change the rates in 2013 for Rates 01, 10, M1 and M2 and should direct Union to file a cost allocation study as soon as possible. SEC stated that the cost allocation study should be filed as part of an application seeking to establish new rates for the above noted rate classes. SEC submitted that any foregone revenues that are caused by not increasing the rates for the above noted rate classes in 2013 should be borne by Union's shareholder as it is Union's responsibility to file sufficient evidence to support changes in rates.[117]

Union argued that there is no legal support for SEC's proposition that the Board has no jurisdiction to approve the rate design changes proposed by Union. Union noted that the Board has the power to set what it determines to be just and reasonable rates.

Union stated that SEC's argument is largely one of rate continuity, which SEC believes to be demonstrative of some inherent problem with Union's allocation of costs.

Union stated that the rate continuity problem raised by SEC has an explanation. Union stated that what has happened during the period of IRM is that the monthly customer charge for rates M1 and 01 were increased from $16 in 2007 to $21 in 2010, and those customer charge increases were offset by reductions in the volumetric rates for these

[117]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 211-229.

rate classes. Overall, the rate changes were revenue neutral. Union noted that there were no similar increases in monthly charges or corresponding reductions in volumetric rates of the large volume general service classes (Rates 10 and M2). Therefore, Union stated that the rate continuum that existed in 2007 was gradually eroded because of a cross-subsidy that was occurring in the general service rate classes where the larger volume, but still below 50,000 / m^3 customers, receiving the benefit of the reduction in volumetric rates (and not being impacted substantially by the monthly charge increase).

Union submitted that the problem cited by SEC is not a problem with cost allocation. Instead, it shows what can happen with rate design over time and why it is important to monitor these issues. Union submitted that its 2014 breakpoint reduction proposal addresses the concerns raised by SEC regarding rate continuity. Union submitted that SEC's arguments should be rejected and the volumetric breakpoint should be reduced as proposed by Union.[118]

Board Findings

The Board is of the view that Union's proposal to reduce the volume breakpoint between the Rate 01 / Rate 10 and Rate M1 / M2 classes and harmonize the blocking structure has merit. The Board believes that Union's proposal does improve the rate class composition of Rate 01 and M1 and achieves more homogeneous rate classes. The Board believes that the proposal will improve the rate class size in Rate 10 and Rate M2, which will ensure viable large volume general service rate classes and improve rate stability.

However, the Board agrees with the submissions of Board staff and Intervenors that the methodology used by Union to allocate costs between the rate classes and give effect to its proposal is flawed. The Board believes that Union's allocation methodology results in an inequitable allocation of costs as between Rates 01 and 10 and between Rates M1 and M2. As such, the Board will not approve the proposed change in volume breakpoint, effective January 1, 2014.

The Board directs Union to undertake a comprehensive cost allocation study which includes the volume breakpoint reduction proposal. The Board is not satisfied that the allocation has been done correctly at this time and therefore the Board will not accept Union's proposal. The Board is also not willing to accept LPMA's proposals to change

[118]Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp.152-155.

the allocation methodology as there is no evidence on the record that would support a finding that LPMA's allocation methodology is superior to the method put forth by Union.

SEC argued that, if the Board found problems with Union's proposed allocation methodology, it should not change the existing rates at all for 2013. SEC argued that the Board is only empowered to set rates that are just and reasonable, and given that, in SEC's view, Union's allocation of costs as between Rates 01 / 10 and Rates M1 / M2 is flawed for 2013 (even without applying the breakpoint proposal), the Board cannot make any changes to the existing rates (including, a "true-up" to reflect the new Board approved revenue requirement). SEC argued that the onus is on Union to justify any changes to rates, and if its proposals are not adequately supported then the Board should make no changes at all.

The Board does not agree with this position. The Board has an obligation to set rates for Rate 01, Rate 10, Rate M1 and Rate M2 for 2013. Whether the breakpoints remain the same or whether they change, the Board will still set rates for these classes. The Board notes that there was significant criticism of Union's proposed methodology, which may have merit, but the Board will not be changing the breakpoints in this decision. However, this does not lead to a conclusion that the rates in question must be frozen at existing levels. Even if the Board were to keep the rates at existing levels, this would still amount to the setting of rates. To fail to pass along the allocated portion of the revenue deficiency to the 01/10 and M1 / M2 rate classes would result in an unrecovered deficiency for Union. In the Board's view, this outcome would not equate to the Board setting just and reasonable rates.

In setting just and reasonable rates, the Board must make the best determination it can based on the evidence available. Although the Board will not adjust the breakpoints in this proceeding, it will require Union to update the 01/10 and M1 / M2 rates based on the approved revenue deficiency and the other relevant findings in this Decision.

The Board therefore directs Union to file a comprehensive cost allocation study which includes the allocation of costs for its volume breakpoint proposal no later than its 2014 rates filing. The Board directs Union to include in that study analysis of the issue raised by LPMA regarding the allocation of costs for Distribution Maintenance – Meter and Regulator Repairs related to the customers that would be moving rate classes. The Board also directs Union to include an analysis of the Distribution Maintenance – Equipment on Customer Premises cost allocation methodology and an analysis of the

Kirkwall Metering Station cost allocation methodology in this cost allocation study, consistent with the Board's findings elsewhere in this Decision.

Rate M4, Rate M5A and Rate M7 - Eligibility Criteria Proposals for 2014

Union proposed to lower the eligibility criteria for the mid-market bundled contract rate classes (Rate M4 or Rate M5A) and the large market bundled contract rate class (Rate M7) in Union South. Union proposed to implement the bundled contract rate class eligibility changes effective January 1, 2014.

Union noted that it is proposing changes to the mid-market and large market contract rate eligibility for the following reasons:

i. Continuity of service: Lowering the eligibility ensures that existing mid-market contract rate customers will continue to take service in a contract rate class even if they undertake conservation and efficiency initiatives and/or are already at the rate class eligibility threshold.

ii. Sufficient class size: Lowering the eligibility criteria ensures sufficient rate class size for both the mid-market and large market rate classes. Union noted that Rate M7 customers that have already migrated to Rate M4 or Rate M5A as a result of demand reductions will again be eligible for service under Rate M7. The lower eligibility criteria also make a contract rate option available to large non-contract Rate M2 customers.[119]

The proposed eligibility changes for the mid-market and large market bundled contract rate classes are described below.

<u>Rate M4 and Rate M5A – Eligibility Criteria</u>

Union noted that to qualify for service in the current mid-market Rate M4 and Rate M5A rate classes, a customer must have a daily contracted demand between 4,800 m^3 and 140,870 m^3 and a minimum annual volume of 700,000 m^3. In addition, the annual volume commitment for Rate M4 customers must equal 146 days use of firm daily contracted demand (i.e. a 40% load factor).

[119] Exhibit H1, Tab 1 at pp. 28-29 (Updated).

Union proposed to lower the eligibility criteria for Rate M4 and Rate M5A in Union South to a daily contracted demand of 2,400 m^3. The maximum daily contracted demand would be reduced to 60,000 m^3. The minimum annual volume requirement would be reduced to 350,000 m^3. Rate M4 will continue to require 146 days use of firm daily contracted demand.

Union stated that the proposed changes to lower the eligibility criteria for Rate M4 reflect the significant changes in the Union South mid-market. For Rate M4, the number of customers has declined from 194 in the Board-approved 2007 forecast to 121 in Union's 2013 forecast. Union estimated that lowering the Rate M4 eligibility requirements makes a firm contract service potentially available to a further 595 customers with annual volumes exceeding 350,000 m^3 currently taking service under Rate M2.

Union also noted that a large number of customers currently taking service in Rate M4 are at or near the daily contracted demand and annual volume eligibility threshold. Of the 121 Rate M4 customers in the 2013 forecast, there are 31 customers (26%) with daily contracted demand of 4,800 m^3 and 69 customers (57%) whose firm daily contracted demand falls entirely within the first firm demand block of 8,450 m^3 / day.

Union stated that lowering the Rate M4 daily contracted demand threshold to 2,400 m^3 shifts these customers closer to the mid-point of the first demand block, which will allow for more meaningful average pricing and rate stability in this rate class.

Union proposed to lower the Rate M5A eligibility to a daily contracted demand of 2,400 m^3 and a minimum annual volume requirement of 350,000 m^3 to maintain consistent eligibility with Rate M4.[120]

Rate M7 – Eligibility Criteria

Union noted that the current eligibility criteria to qualify for Rate M7 consists of a combined firm, interruptible and seasonal daily contracted demand of 140,870 m^3 and a minimum annual volume of 28,327,840 m^3. Union proposed to lower the Rate M7 eligibility to a daily contracted demand of 60,000 m^3. This minimum daily contracted demand aligns with the maximum daily contracted demand for Rate M4 and Rate M5A.

[120] Ibid. at pp. 29-31

Union proposed to eliminate the minimum annual volume requirement as a condition of qualifying for Rate M7.

Union noted that there are four customers forecast as Rate M7 in 2013. Lowering the Rate M7 eligibility criteria will result in five customers currently forecast in Rate M4 and 17 customers currently forecast in Rate M5A to be eligible for Rate M7. Union stated that at 26 customers, Rate M7 has sufficient rate class size to ensure meaningful average rate class pricing.[121]

LPMA supported Union's M4 / M5A eligibility criteria reduction proposal. LPMA noted that this will offer more M2 customers the option of moving to Rate M4.

However, LPMA noted that it is concerned with the communication that large M2 customers may receive about the movement from Rate M2 to Rate M4.

LPMA noted that the impact on the large M2 customer can be positive or negative, depending on their load factor. Customers with a low load factor could end up paying more under Rate M4 than they did under Rate M2.

Given the uncertainty as to the cost impacts of moving to Rate M4, LPMA submitted that there should be clear and concise communication with customers. LPMA submitted that the Board should direct Union to do a comparison of the annual costs for each of the customers that have the ability to move rate classes, calculating their annual costs based on both Rates M2 and M4. Union should then be required to contact the customer directly and provide them with the information they need to make an informed decision.[122] No other parties commented on this issue.

Union noted that no parties opposed its M4, M5A and M7 eligibility criteria reduction proposal and that it is willing to undertake LPMA's communication proposal. Union stated that it would make sure that the customers know that they will become eligible for contract rate classes at the lower threshold. Union noted that there are about 600 customers that this issue relates to and Union will send a direct mailing to them.[123]

[121] Ibid. at p. 31.
[122] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 93-95.
[123] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 157-158.

Board Findings

The Board approves Union's proposal to change the eligibility criteria for the mid-market bundled contract rate classes (Rate M4 or Rate M5A) and the large market bundled contract rate class (Rate M7) in Union South. The Board accepts Union's submissions that the proposed changes ensure sufficient class size and the continuity of service in the noted rate classes.

The Board directs Union to communicate these proposals to the relevant customers as agreed to by Union in its reply argument.

Rate T1 Redesign and Rate T3 Customer Charge

Union proposed to split the current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service. Union proposed to implement the new rate classes, eligibility changes and rate structures, on a revenue neutral basis, effective January 1, 2013.

Union noted that it made its proposal to split current Rate T1 into two rate classes in order to better align cost incurrence and cost recovery by recognizing the differences in distribution demand and distribution customer-related costs between small Rate T1 and large Rate T1 customers. Union noted that the proposed split also addresses the significant diversity in daily contracted demand and firm annual consumption that exists between small and large customers within the current Rate T1 rate class.[124]

Union also proposed to increase the monthly charge for Rate T3 from $17,657 to approximately $21,661. Kitchener Utilities (the only customer in this rate class) made arguments on this issue, which are discussed below.

<u>Proposed Rate T1 / Rate T2 Eligibility</u>

Union noted that to qualify for the current Rate T1 service, a customer must have combined firm and interruptible annual consumption of 5,000,000 m^3 or more. For the new Rate T1 mid-market service, Union proposed a minimum annual volume of 2,500,000 m^3. Further, Union proposed that the daily firm contracted demand for the new Rate T1 not exceed 140,870 m^3.

[124] Exhibit H1, Tab 1 at pp. 32 and 35 (Updated).

Union noted that the new Rate T2 large market service will be available to customers with a minimum firm daily contracted demand of 140,870 m^3. Union did not propose any minimum annual volume requirement as a condition for qualifying for the new Rate T2.

Union stated that its proposal to split the current Rate T1 into two rate classes will result in improved rate class composition in both Rate T1 and Rate T2. Specifically, both proposed Rate T1 and Rate T2 will be comprised of more homogeneous customers in terms of firm contracted demands and firm annual consumption. The proposed split of current Rate T1 will also recognize cost differences within the current Rate T1 rate class associated with the allocation of distribution demand-related and distribution customer-related costs.[125]

Rate T1 Rate Design and Pricing

Union proposed that the rate structure for the new Rate T1 consist of a monthly customer charge, a two block monthly demand charge and a single block commodity charge. The table below provides a comparison of Rate T1 before rate redesign and proposed new Rate T1 rate structures and proposed rates.

Comparison of 2013 Proposed Rate T1 with no Redesign
and 2013 Proposed Rate T1 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T1 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$2,001.29
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 28,150 m^3 Next 112,720 m^3	31.5395 23.2744
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0715
Fuel Ratio	Transportation	0.237%	Transportation	0.256%

Union noted that the proposed monthly customer charge of $2,001.29 is cost-based and fully recovers all of the customer-related costs applicable to the new Rate T1. The two block demand charge recovers approximately 82% of new Rate T1 demand-related

[125] Ibid at p. 38.

transportation costs. The remainder of new Rate T1 demand-related transportation costs are recovered through the Rate T1 storage related sufficiency. The single commodity charge recovers all the variable transportation costs.

Union noted that the two block demand and single block commodity rate structure for firm service in new Rate T1 is based on the comparable Rate M4 firm service, which also has a daily contracted demand breakpoint of 28,150 m^3. This approach results in consistency between mid-market bundled and mid-market semi-unbundled service offerings.

Union noted that it is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. However, given that Union is proposing a maximum firm daily contracted demand of 140,870 m^3 in the new Rate T1, the new Rate T1 rate schedule will exclude the storage space, storage injection/withdrawal rights and transportation service provisions that are only applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day.[126]

New Rate T2 Rate Design and Pricing

Union proposed that the rate structure for the new Rate T2 consist of a monthly customer charge, two block monthly demand charge and a single block commodity charge. The table below provides a comparison of Rate T1 before rate redesign and proposed new Rate T2 rate structures and proposed rates.

Comparison of 2013 Proposed Rate T1 with no Redesign
and 2013 Proposed Rate T2 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T2 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$6,000.00
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 140,870 m^3 All Over 140,870 m^3	21.7032 11.3232
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0081
Fuel Ratio	Transportation	0.237%	Transportation	0.234%

[126] Ibid at pp.41-43.

Union noted that the proposed monthly customer charge for the new Rate T2 rate class has been set at $6,000. At this level, the proposed monthly customer charge recovers approximately 50% of the customer-related costs attributable to the new Rate T2. Union proposed to set the monthly customer charge at $6,000 in order to ensure a smooth rate continuum between Rate T1 and Rate T2 at the daily contracted demand breakpoint of 140,870 m^3. Union noted that the balance of the customer-related costs not recovered in the Rate T2 monthly customer charge are recovered in the first block demand charge, which is common to all Rate T2 customers. The revenue-to-cost ratio for new Rate T2 is consistent with the revenue to cost ratio for Rate T1 before rate redesign.

Union noted that the two block demand rate structure for the new Rate T2 is based on a daily contracted demand breakpoint of 140,870 m^3. This is the same daily contracted demand as the current Rate T1 structure. The two block demand charge also recovers all the demand-related transportation costs. The single commodity charge recovers all the variable transportation costs.

Union noted that it is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. The proposed 2013 Rate T2 rate schedule will include all the current Board approved storage space and storage injection/withdrawal rights per the current approved Rate T1 rate schedule. Union also noted that the transportation service provisions that are applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3 / day are included in the proposed T2 rate schedule.[127]

APPrO[128] and IGUA[129] supported Union's proposal to split current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service.

Kitchener submitted that the proposed monthly charge under Rate T3 is not just and reasonable, relative to the proposed monthly charges for existing Rate T1 (without redesign) and Rates T1 and T2 (with redesign), given the comparability in customer size and load characteristics between large Rate T2 customers and Kitchener.

[127]Ibid at pp. 44-45.
[128]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 142-143.
[129] IGUA Argument, August 22, 2012, at p. 1.

Kitchener submitted that its bears a disproportionate share of customer-related costs under its existing Rate T3 service which are unreasonably (and fully) reflected in the current monthly charge of $17,567 and even more unfairly reflected in the proposed monthly charge of $21,661. Kitchener submitted that these charges are excessive, both in absolute terms and when compared to similarly sized customers in the existing Rate T1 class and proposed new Rate T2 class that, like Kitchener, are directly served from transmission main and do not have multiple redelivery points.

Kitchener noted that while it does not object, in principle, to Union's proposal to split the existing Rate T1 class into a new Rate T1 mid-market service and a new Rate T2 large market service, Kitchener does object to the proposed differential rate treatment for customer-related costs to be recovered under the monthly charge for rates T1, T2 and T3.

Kitchener submitted that the monthly charge under Rate T3 should not exceed the comparable charge for Rate T2 if the Board allows the proposed redesign to proceed. Kitchener submitted that, in the alternative, if the Board does not approve the Rate T1 redesign, then the monthly charge for Rate T3 should not exceed the comparable charge approved by the Board for existing Rate T1.[130]

Union noted that no parties objected to its proposal and therefore it should be accepted. In response to Kitchener's argument regarding the Rate T3 monthly charge, Union submitted that Kitchener had not led any evidence challenging the customer-related costs and the cost allocations in the 2013 cost study, which identified the customer-related costs and those specifically attributable to Kitchener.

Union noted that the proposed T3 rates are increasing by only 2% and the T3 rates have been relatively flat since 2007. Union submitted that this is a reasonable rate increase.

Union stated that Kitchener is requesting that other rate classes pay a portion of Kitchener's customer-related costs. Union noted that it could align the T3 monthly customer charge with either T1 or T2. However, Union would recover the remaining customer-related costs from Kitchener in its demand charge. Union stated that the result

[130] Kitchener Argument, August 17, 2012, at pp. 1-6.

would be that Kitchener's total transportation bill would remain the same. Union submitted that Kitchener's submission should be rejected.[131]

Board Findings

The Board approves Union's proposal to split the current Rate T1 into two rate classes; a new Rate T1 mid-market service and a new Rate T2 large market service effective January 1, 2013. The Board accepts Union's submission that splitting the current Rate T1 into two rate classes better aligns cost incurrence and cost recovery by recognizing the differences in distribution demand and distribution customer-related costs between small Rate T1 and large Rate T1 customers.

The Board finds that the monthly charge proposed by Union for Kitchener, under Rate T3, is appropriate as filed. The Board finds that the proposed monthly customer charge applicable to Kitchener reasonably recovers the customer-related costs incurred to serve Kitchener. In addition, the Board agrees with Union that Kitchener has not challenged the customer-related costs and the cost allocations in the 2013 cost study, which identified the customer-related costs and those specifically attributable to Kitchener. As such, the Board does not have a reasonable basis upon which it could direct Union to revise the T3 customer charge.

Supplemental Service Charge – Group Meters for Commercial / Industrial Customers in Rate M1 and Rate M2

Union proposed to update the additional service charge applicable to "Supplemental Service to Commercial and Industrial Customers under Group Meters" in Rate M1 and Rate M2. Union noted that the supplemental service allows for the combination of readings from several meters, where the meters are located on contiguous pieces of property of the same owner and are not divided by a public right-of-way.

Union proposed to increase the additional service charge on the Rate M1 rate schedule from the current approved $15 per month to $21 per month. On the Rate M2 rate schedule, Union proposed to increase the additional service charge from the current approved $15 per month to $70 per month ($35 per month in 2014 – for consistency with its 2014 M1 / M2 rate design proposal). Union stated that it is proposing to increase the additional service charge to ensure that customers who combine readings from

[131] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 158-159.

several meters do not receive an unintended benefit in comparison to customers who cannot combine meter readings. This change will result in all Rate M1 and Rate M2 customers paying the same monthly customer charge for all meter readings.[132]

Union noted, in cross-examination, that the benefit received by customers that have the ability to combine meter readings is that those customers have the opportunity to combine volumes. Combining volumes allows customers to have more of their volumes charged at lower rates (in the higher volume blocks of the delivery rates).[133]

VECC supported Union's proposal as filed.[134]Board staff also supported Union's proposal and noted that that the same supplemental charge should be applied in the North. Board staff noted that Union offers an equivalent meter combination service in its Northern service area. However, there is no equivalent supplemental charge.

Board staff submitted that Union's Northern customers that have the ability to combine meters are receiving the same unintended benefit as those Southern customers that have the same ability. Accordingly, a supplemental charge equal to the monthly customer charge should be applied to Union's Northern customers (Rate 01 and Rate 10) that combine meter readings to ensure equitable treatment among the customers in those rate classes.[135]

LPMA submitted that the Board should direct Union to extend its existing policy in the North to the South and eliminate this supplemental service charge.[136]

Union submitted that the longstanding policy in the North of allowing customers to combine meter readings without a supplemental charge should be maintained. However, Union stated that should the Board be inclined to harmonize the supplemental service charge in the North and South, Union supported the introduction of a service charge in the North over the elimination of the South supplemental charge. Union made this argument primarily on the basis that there should not be an unintended benefit for South customers.[137]

[132] Exhibit H1, Tab 1 at p. 56 (Updated).
[133] Oral Hearing Transcripts, EB-2011-0210, Volume 12 at p. 13.
[134] VECC Argument, August 21, 2012, at p. 28.
[135] Board Staff Submission, August 17, 2012 at pp. 29-30.
[136] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at pp. 96-97.
[137] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 159-160.

Board Findings

The Board finds that the supplemental charge for the combination of meter readings (where the meters are located on contiguous pieces of property of the same owner and are not divided by a public right-of-way) should be harmonized as between North and South. The Board finds that the longstanding policy of allowing customers to combine meter readings without a supplemental service charge should be maintained in the North and should be extended to the South. As such, the Board directs Union to eliminate this supplemental charge in its Southern service area. Accordingly, in the Draft Rate Order process, Union is directed to update its revenue forecast to reflect the above finding.

Rate Mitigation

Union argued that the proposals included in its 2013 rates filing result in total bill impacts of less than 10% and based on the Board's guidelines on electricity, no mitigation is necessary.[138] Union did, however, provide a number of potential rate mitigation measures that could be invoked if the Board deems it necessary. Those rate mitigation measures were provided at Exhibit J11.10.

A number of parties made submissions on the issue ofrate mitigation. Board staff submitted that rate mitigation should only be applied when rate impacts are greater than 10% on the total bill. Board staff noted that 10% rate impacts on the total bill has been used in the past by the Board as a benchmark for what magnitude of rate impacts should trigger rate mitigation for the purpose of setting electricity transmission and distribution rates. Board staff therefore submitted that the same 10% benchmark is appropriate in this case.

If the Board's findings in this proceeding, when taken as a whole, result in rate impacts greater than 10% on the total bill, Board staff submitted that the Board should consider any and all rate mitigation measures it deems appropriate.[139] BOMA supported Board staff's submission on the issue of rate mitigation.[140]

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[138] Oral Hearing Transcripts, EB-2011-0210,Volume 13 at p. 81.
[139] Board Staff Submission, August 17, 2012, at p. 34.
[140] BOMA Factum for Argument at p. 54.

Energy Probe submitted that depending on the overall level of rate increases remaining after the Board makes it Decision in this proceeding, rate mitigation measures may or may not be necessary.[141]

LPMA submitted that depending on the Board's findings with respect to Union's M1 / M2 and Rate 01 / Rate 10 volume breakpoint reduction proposal, rate mitigation measures may or may not be necessary. LPMA essentially argued that if the rate impacts for any customer are higher than 10% on the total bill, then rate mitigation should occur.[142]

APPrO submitted that rate mitigation measures should be implemented when the rate impacts are greater than 10% on the delivery portion of the bill, as opposed to total bill impacts.[143] IGUA supported APPrO's position on this issue.[144]

Board Findings

The Board notes that it has made a number of findings in this decision that reduce the revenue requirement and impact the distribution of the approved revenue requirement between customer classes. As a result, it is not clear to the Board at this juncture that rate mitigation will be necessary. The Board will therefore review the rate impacts after the findings set out in this Decision have been implemented in the Draft Rate Order stage of the proceeding. At that time, the Board will determine whether any rate mitigation measures will be required.

Other Rate Design Issues

Board Findings

The Board notes that parties either generally supported Union's evidence or made no comments on the rate design issues listed below.

Issue H2 – Is Union's response to the Board directive to review the M12 and C1 ratemaking methodology appropriate?

[141] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 70.
[142] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 98.
[143] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 147.
[144] IGUA Argument, August 22, 2012, at p. 2.

Issue H6 – Is the introduction of M4 interruptible service offering effective January 1, 2014 appropriate?

Issue H9 – Is recovering UFG on transportation activity in the winter months for the Dawn to Dawn-Vector transportation service appropriate?

Issue H11 – Is the proposal to modify the M12, M13, M16 and C1 rate schedules including Schedule A, Schedule A-2013 and Schedule C appropriate?

Issue H12 – Is the proposal to change the Distribution Consolidated Billing fee to $0.57 per month per customer appropriate?

Issue H13 – Are the proposed changes to the Gas Supply Administration Fee appropriate?

Issue H15 – Is the proposal to change the rate design for services originating at Kirkwall to eliminate Kirkwall measuring and regulating costs appropriate?

The Board approves Union's proposals with respect to each of the above-noted rate design issues.

The Board notes that it has included a summary of its findings related to cost allocation and rate design in Appendix "A" of this Decision.

DEFERRAL ACCOUNTS

Average Use Per Customer Deferral Account (Account No. 179-118)

Union noted that the Average Use Account was established in EB-2007-0606 to record the margin variance resulting from the difference between the actual rate of decline in use-per-customer and the forecast rate of decline in use-per-customer included in Union's Board-approved rates.

Union proposed to continue tracking the average use per customer in the existing deferral account. Union also proposed to change the description of Average Use Account in the accounting order to remove the limitation that makes it applicable only to the current incentive regulation plan, 2008 through 2012. Union noted that the proposed accounting order for the Average Use Account would allow it to be in effect until it is changed or eliminated.[145]

Union initially noted that the Average Use Account will not record differences from forecast for 2013 because 2013 is a cost of service year. The earliest that the Average Use Account would be used is in relation to 2014, assuming that there is an incentive regulation framework in place at that time and that the average use true-up is a feature of that framework.[146]

Energy Probe argued that the average use deferral account should be in operation for 2013 as part of an accommodation for shareholder and ratepayer interests around the 2013 NAC and volume forecasts as discussed in the NAC section of this Decision.[147]

LPMA submitted that it does not accept Union's proposal with respect to the Average Use Account. LPMA noted that this account was established in EB-2007-0606 as part of a true-up mechanism that was utilized under IRM, and the current wording of the account makes it applicable only to the current incentive regulation plan years, 2008 through 2012.

LPMA submitted that this account should not be used for the 2013 test year. LPMA noted that part of the risk for which Union earns its return on equity in a cost-of-service test year is its forecast risk. Use of the Average Use Account would reduce the risk, with no corresponding benefit to customers. LPMA noted that the use of the Average Use Account during the IRM term was to reflect that the average use was expected to decline over the term of the IRM plan, and that both Union and ratepayers would benefit from the implementation of such an account over the IRM, by ensuring that neither party benefited at the expense of the other.

LPMA noted that Union originally indicated that it does not need to keep the account open and that it could be eliminated for 2013 and reintroduced as a part of the next IRM application. In light of the admission, LPMA submitted that there is no reason to keep the account open other than it might be used in 2014. LPMA submitted that the Board should eliminate this account for 2013. LPMA stated that the Board should not approve

[145] Exhibit H1, Tab 4 at p. 3 (Updated).
[146] Exhibit J.DV-4-3-1.
[147] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 51.

the continuation of an account that it knows will not be used for the test year and may or may not be used in the future beyond the test year.[148]

As discussed previously, Union submitted that should the Board have any concerns with respect to the NAC forecast, it could continue to maintain the operation and use of the Average Use Account that was in place during the incentive regulation period. Although Union noted that it does not prefer this approach, it indicated that continuing the Average Use Account would resolve the dispute around the NAC forecast.[149]

Board Findings

As set out earlier in this Decision, the Board accepts Union's NAC forecast as filed, but orders Union to continue the operation and use of the Average Use Account for the 2013 rate year to ensure fairness among Union and ratepayers. The Board therefore directs that the Average Use Account will be open and in operation for the 2013 test year. The Board directs Union to file a Draft Accounting Order for the Average Use Account that reflects the Board's findings in this Decision.

Inventory Revaluation Deferral Account (No. 179-109)

Union proposed to remove the Transmission Line Pack Gas account in the accounting order for the Inventory Revaluation Deferral Account in order to be consistent with accounting changes and for administrative simplicity. Union noted that it has reclassified line pack gas from gas in inventory to property, plant and equipment, and therefore it has proposed that line pack gas should not be revalued quarterly as part of inventory.[150]

LPMA supported Union's proposal and no other parties commented on this issue.[151] Accordingly, Union requested that its proposed change related to the Inventory Revaluation Deferral Account be approved by the Board.

[148] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 104-106.
[149] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 25-26.
[150] Exhibit H1, Tab 4, p. 2 (Updated).
[151] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 104.

Board Findings

The Board accepts Union's proposal to remove the Transmission Line Pack Gas account in the accounting order for the Inventory Revaluation Deferral Account for the reasons cited by Union.

Short-term Storage and Other Balancing Services Deferral Account (No. 179-70)

Union noted that following the NGEIR Decision (EB-2005-0551), Union's practice has been to sell its non-utility storage space on a long-term basis and to sell the excess utility space on a short-term basis (less than 2 years). Union stated that, despite this practice, it is authorized by the Board to sell non-utility storage space under short-term contracts and retain 100% of the revenues.

Union noted that if it sells short-term peak storage services using non-utility storage space, the total margins received from the sale of all peak short-term storage should be allocated to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage sold each calendar year. Union stated that this methodology is transparent to all participants and will yield the same proportionate return on all short-term transactions for the ratepayers and the shareholders.

Union stated that considering the seasonal volatility and variability of market-priced storage, it cannot predict what period of time will yield the highest or lowest prices for short-term peak storage services. Union noted that the use of a proportionate share of calendar year margins ensures that neither party is impacted by the timing of storage sale, or fluctuations to storage values throughout the year.

Union noted that it is able to give effect to its proposal by its ability to track what storage assets are being used for each type of storage transaction.

Union stated that, going forward, it will continue to sell all excess annual utility storage as short-term peak storage and 90% of all margins from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, and C1 Firm Short-Term Deliverability will accrue to ratepayers.[152]

[152] Exhibit C1, Tab 7.

Union noted that it proposed to change the description of the Short-term Storage and Other Balancing Services Deferral Account (the “Short-Term Storage Account”) in the accounting order to update the list of revenues included in the account and the proposed short-term storage margin sharing methodology.[153]

Union proposed the following description for the Short-Term Storage Account:

> To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for Short-term Storage and Other Balancing Services including; Peak Short-Term Storage underpinned by excess utility storage assets, Off-Peak Short-Term Storage, Gas Loans and Supplemental Balancing Services and the net revenue forecast for these services as approved by the Board for ratemaking purposes.[154]

Board staff supported Union’s proposal with a few qualifications. Board staff submitted that Union should sell only short-term storage services using the excess utility space and that the revenues should be allocated between the utility and non-utility storage operations as proposed by Union. With regard to how Union goes about selling short-term services, Board staff submitted that Union should give priority to the sale of short-term storage services that rely on the excess utility storage space. This will help to ensure that ratepayers are not being adversely harmed by Union’s non-utility business selling the same services as its utility business.

In addition, Board staff submitted that the Short-Term Storage Account should capture payments related to storage encroachment. In its January 20, 2012 Decision and Order in EB-2011-0038, the Board stated the following:

> However, the Board does note that, in the past, Union has encroached on its utility space. The Board is of the view that the existence of Union’s utility assets creates a situation where those assets effectively becomean “insurance policy” in relation to Union’s resource optimization activities on the non-utility side of its storage operations. Union’s utility assets can act as a backstop on the rare occasions when Union oversells its non-utility storage space. The evidence suggests that the occurrence of this has been rare and it would be difficult to determine retrospectively to what degree, if any, Union relied on the existence of the utility assets in the conduct of its non-utility storage business to set contract terms and pricing.

[153] Exhibit H1, Tab 4.
[154] Exhibit H1, Tab 4, Appendix C.

> The Board is of the view that there should be an ongoing monitoring of this potential encroachment so as to inform the Board as to the need to revisit this issue at a future date. The Board therefore finds that Union shall be required to monitor for and maintain records of all future encroachments and provide such information in its rebasing application.[155]

It was Board staff's position that the Board, in EB-2011-0038, was concerned about the occurrence of storage encroachment. The Board decided not to address this issue at that time because the occurrence had been rare (only one instance recorded in evidence).

Board staff noted that, in this proceeding, Union provided a schedule highlighting that for a brief period in 2011, Union again encroached on its utility storage position.[156] Board staff noted that this second recorded encroachment requires the Board to address the situation now.

Board staff submitted that Union should be required by the Board to pay fair market value for the use of its utility storage space in the rare situations that Union's non-utility storage operation encroaches on its utility storage space. Board staff noted that in cross-examination Union stated that the cost to rectify its encroachment issue in October 2011 was $1.1 million. This was the cost incurred by Union to move 2 PJs off its system.[157]

Board staff submitted that the 10% incentive payment to Union's shareholder, which applies to the other net revenues in the Short-Term Storage Account, should not apply to storage encroachment payment amounts. Union should not be granted a 10% incentive payment for encroaching on its utility storage space.

Energy Probe supported Board staff's submission and also argued that the account should be broadened to include short-term storage revenues obtained from optimizing utility storage space that is not classified as excess utility storage space.[158]

LPMA noted that there are two issues that need to be addressed related to the Short-Term Storage Account. The first issue is the proposed change in the

[155] Decision and Order, EB-2011-0038, January 20, 2012, at p. 16.
[156] Exhibit C1, Tab 6.
[157] Oral Hearing Transcripts, EB-2011-0210, Volume 7 at p. 173.
[158] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 61.

wording and what is actually to be captured by the account. The second issue is how the amounts that are to be recorded in the account should be calculated.

On the first issue, LPMA submitted that any revenue generated through the use of the regulated utility storage space up to the 100 PJ cap, both planned and the excess over planned, should be recorded in the account for sharing with ratepayers. LPMA stated that to do otherwise would be to deny ratepayers a share of the revenues generated by assets, the costs of which are already built into their rates. The planned use of utility storage assets includes contingency space, some of which is filled on a planned basis and some of which is left empty on a planned basis. The use of the contingency space can be altered during the year depending on the circumstances that exist. Similarly, a colder than expected fall season could result in increased storage capacity being available. LPMA submitted that the wording of the deferral account should reflect the inclusion of all revenues generated from the regulated utility storage assets of 100 PJs.

On the second issue, LPMA submitted that the Board should direct Union to tie all individual transactions to the utility assets first and when all of these assets have been contracted for, only then would any additional transactions be tied to non-utility assets. LPMA noted that Union's proposal essentially mirrors this, because it is only when the amount of peak short-term storage services contracted for exceeds the excess utility space that the sharing would begin. LPMA noted that the difference between the two proposals is that, under LPMA's proposal, the prices for the individual transactions would be tied to the utility and non-utility assets, and this methodology should mitigate concerns about Union's potential to capture revenue from utility storage if the value of storage falls during the year.[159]

With respect to Board staff's argument that the Short-Term Storage Account should capture amounts related to storage encroachment, Union submitted that there is no proper basis for an account to capture amounts related to this issue. Union noted that the last encroachment happened for a very brief period of time and that Union took steps immediately to rectify that situation and incurred a cost of $1.1 million, which was borne in its entirety by Union's shareholder.[160]

[159]Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 109-113.
[160]Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 130-131.

Board Findings

The Board believes that there are two issues that need to be addressed with respect to the Short-Term Storage Account. The first issue is the proposed change in the wording in the Accounting Order and what should be captured by the account. The second issue is how the amounts that are to be recorded in the account should be calculated.

First, the Board does not accept Union's proposed wording for the Short-term Storage Account. The Board is in agreement with LPMA that all revenues generated through the use of the regulated utility storage space up to the 100 PJ cap, both planned and the excess over planned, should be recorded in the account for sharing with ratepayers. The Board notes that the revenues that are to be recorded in the Short-Term Storage account relate to the sale of short-term storage, which is defined as all storage transactions that are for a duration of 2 years or less.

The Board also finds that the account should capture storage encroachment and that the 10% incentive payment to Union's shareholder should not apply to storage encroachment payment amounts. The Board believes that there are two issues related to storage encroachment that need to be addressed by the Board in this proceeding.

The first storage encroachment issue relates to the costs arising from actions undertaken to rectify the encroachment, i.e., the cost incurred by Union that is associated with moving gas out of its utility storage space. The Board notes that Union has agreed that its shareholder will pay any costs related to rectifying encroachment situations. The Board believes that this is the appropriate treatment.

The second storage encroachment issue is whether there should be a charge to Union's non-utility storage business to reflect the opportunity cost of the utility storage space that is not available for sale due to encroachment by Union's non-utility storage business. The Board finds that a charge of this nature is appropriate in order to minimize the opportunity for unintended incentives.

The Board notes that pursuant to EB-2011-0038, Union must disclose to the Board when storage encroachment has occurred.[161] That decision, however, only requires Union to file this information in conjunction with its rebasing applications.

The Board therefore directs Union, at the time that the Short-Term Storage Account is to be disposed, to file a report similar to that ordered by the Board in EB-2011-0038. If a storage encroachment has occurred, Union is further directed to file a calculation for the payment by Union's non-utility business to its utility business for storage encroachment. The Board believes that this payment should reflect the market value for the utility space that was subject to the encroachment. The Board notes that this finding only relates to any storage encroachment that occurs after the date of this Decision and will not apply retroactively to previous storage encroachments.

The Board directs Union to revise the wording in the Accounting Order for the Short-Term Storage Account to reflect the above noted findings. The wording in the account must reflect the Board's finding that the account will capture all revenues generated by utility storage assets, i.e., all assets up to 100PJs, and that it will also capture storage encroachment. The Board notes that the Accounting Order shall also be worded broadly enough to ensure that it captures all short-term storage transactions. The Board directs Union to file a revised Accounting Order for the Short-Term Storage Account as part of the Draft Rate Order process.

On the second issue relating to the Short-Term Storage Account, how the amounts that are to be recorded in the account are to be calculated, the Board accepts Union's proposal. The Board believes that Union's proposal to allocate the total margins received from the sale of all peak short-term storage to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage sold each calendar year is appropriate. Given the uncertainty inherent in the pricing of market-based storage, the Board believes that Union's proposal best ensures that ratepayers and shareholders receive the same proportionate return on all short-term transactions.

However, to minimize the opportunity for unintended incentives, the Board directs Union to prioritize the sale of its utility storage capacity ahead of the sale of short-

[161] Decision and Order, EB-2011-0038, January 20, 2012, at p. 16.

term storage services from its non-utility storage operation. The Board finds that whenever utility capacity is available for sale, that capacity is to be used to facilitate short-term storage transactions on a priority basis. Only when utility storage capacity is fully sold can Union sell non-utility storage capacity on a short-term basis.

Finally, the Board directs Union to file sufficient evidence, at the time the balance in the Short-Term Storage Account is to be disposed, to allow the Board to confirm that Union has appropriately prioritized the sale of its utility storage space and calculated the balance in the account in accordance with this Decision.

Gas Supply Optimization Variance Account

Board Findings

In accordance with the Board's findings set out earlier in this Decision, the Board directs Union to establish a symmetrical variance account to capture the variance in the actual net revenues related to gas supply optimization activities and the amount built into rates. As ordered previously, the amount built into rates related to gas supply optimization is 90% of Union's 2013 forecast of base exchanges and 90% of half of Union's FT-RAM 2013 forecast. The balance in the account will be shared 90% to ratepayers and 10% to the shareholder. The Board finds that the balance in this account will be disposed of on an annual basis. The Board also finds that the disposition amounts will be allocated in the same manner as the gas supply optimization related margin amounts will be reflected in rates.

The Board directs Union to file a draft accounting order as part of the Draft Rate Order process which reflects the Board's findings related to the establishment of the Gas Supply Optimization Variance Account.

Gas Supply Plan Review – Consultant Cost Deferral Account

Board Findings

In accordance with the Board's findings set out earlier in this Decision, the Board directs Union to establish a deferral account to capture the costs of hiring a consultant to undertake a review of Union's gas supply plan.

The Board directs Union to file a draft accounting order as part of the Draft Rate Order process which reflects the Board's findings related to the establishment of the Gas Supply Plan Review - Consultant Cost Deferral Account.

Preparation of Audited Financial Statement Deferral Account

Board Findings

In accordance with the Board's findings set out later in this Decision, the Board directs Union to establish a deferral account to capture the costs of preparing audited financial statements.

The Board directs Union to file a draft accounting order as part of the Draft Rate Order process which reflects the Board's findings related to the establishment of the Preparation of Audited Financial Statements Deferral Account.

Elimination of Late Payment Penalty Litigation Deferral Account (Account No. 179-113) and Harmonized Sales Tax Deferral Account (Account No. 179-124)

<u>Late Payment Penalty Litigation (Deferral Account No.179-113)</u>

Union stated that the Late Payment Penalty Litigation deferral account was established in 2004 to record the costs incurred by Union in connection with the late payment penalty litigation. This includes its legal costs, costs of actuarial advice, costs of analyzing historic billing records and the cost of any judgment against Union. Union noted that the litigation in connection to late payment is now complete. Union proposed to close this account effective January 1, 2013.

<u>Harmonized Sales Tax ("HST") (Deferral Account No. 179-124)</u>

Union stated that this account was established to record the amount of Provincial Sales Tax previously paid and collected in approved rates that is now subject to HST tax credits (i.e. the savings to Union). The account was also used to record the amount of HST paid on taxable items for which no tax credits are received (i.e. the additional costs to Union). Union has shared the net impact 50/50 between the ratepayers and its shareholder. Union does not see a need to continue with this deferral account as

Union's budget includes the impact of HST. Upon settlement of the balance in the account, Union proposed to close this account effective January 1, 2013.[162]

No parties raised any concerns arising from the closure of the above noted accounts. Union requested that the accounts be closed.[163]

Board Findings

The Board finds that above noted accounts can be closed as requested by Union. The Board agrees that both of these accounts have served their purpose and are not needed for 2013.

PARKWAY WEST PROJECT

Union's Dawn to Parkway system begins at Union's Dawn Compressor Station and extends 228 km northeast to Parkway, near Oakville, Ontario. The existing Parkway Compressor Station is currently served by a single valve site and header system. The Dawn-Parkway system at this location consists of three parallel pipelines of varying sizes/diameters (26", 34" and 48"). Union connects to the Enbridge system on the suction side of the compressor in the existing Parkway Compression Station. Union owns and operates custody transfer measurement at this interconnection, which is known as Parkway (Consumers).

Union also connects to the TCPL system on the discharge side of the Station in the existing Parkway Compression Station. Union owns and operates check measurement at this interconnection, which is known as Parkway (TCPL). The Lisgar Station is approximately 2 km east of the Parkway Compressor Station. Gas is delivered to Enbridge at the Lisgar Station through 26" and 34" pipelines that extend past the Parkway Compressor Station.

Union has indicated that a significant amount of gas supply intended for delivery into the Greater Toronto Area ("GTA") and other parts of Ontario is either delivered at or passes through Parkway. Based on Enbridge design day system demand of approximately 3.7

[162] Exhibit H1, Tab 4, pp. 4-5 (Updated).
[163] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 131.

PJ/day, Union delivers approximately 57% of that supply to Enbridge at Parkway or through the Parkway compression.

Union has stated that a loss of delivery at Parkway and/or Lisgar would have significant and immediate impact on the Enbridge system. Union indicated that an outage at Parkway (Consumers) would result in a delivery loss of 0.8 to 1.4 PJ/day while an outage at Lisgar would result in a delivery loss of 0.2 to 0.8 PJ/day into the Enbridge system during peak demand. A combined outage of both facilities could result in an immediate delivery loss of 1.6 PJ/day for Enbridge.

Union has indicated that an outage at Parkway (Consumers) and Lisgar during peak demand would impact regional gas flows to points east of Parkway in eastern Ontario, Quebec and the U.S. Northeast as the GTA consumes available supply. In addition, natural gas-fired power generation facilities in the GTA would likely be impacted by low pressure or system outages.

In order to ensure security of supply to its Ontario customers, Union proposes to install a second metering and a header system connected to the Dawn to Parkway system which would allow continued supply to Enbridge in the event of an outage of the existing Dawn to Parkway system interconnection at Parkway.

Union's proposed Parkway West Project is comprised of three components that are to be undertaken over a three year period.

1. Parkway West Land Purchase – 2012: $15.0 million.
2. Parkway West Metering and Headers – 2013: $80.0 million.
3. Parkway West Loss of Critical Unit Protection – 2014: $120.0 million.

The facilities, if ultimately approved, will allow Union to meet export demand on a design day to Parkway (TCPL) and Parkway (Consumers) under an outage of the major components of the existing Parkway compression station.

Union has indicated that the volumes delivered to TCPL through Parkway compression are not fully covered by Loss of Critical Unit ("LCU") protection. According to Union, as volumes grow and throughput through Parkway compression reaches 3.0 PJ/day, there would be no LCU protection. Union has indicated that an outage of one of the Parkway compressors in the future could significantly impact gas flows during peak demand into Ontario markets, such as the GTA and Northern and Eastern Ontario. Union has stated that failure to deliver during peak day conditions at Parkway could impact the reliability of the Union delivery system and could lead shippers to de-contract on the Dawn-Parkway path. Consequently, Union is of the opinion that LCU protection at Parkway is appropriate and the proposed facilities are the best option.

Union has estimated the cost of the Parkway West Project to be approximately $217 million. Union confirmed at the hearing that none of the facilities would be completed and placed into service during the Test Year. Therefore, the proposed facilities would not impact 2013 rates, and Union stated that it was not seeking any approvals from the Board with respect to the Parkway West Project in the current application.

Board staff submitted that since the project has no impact on 2013 rates, it was not certain what determination the Board could make in relation to this project. Board staff noted that the cost, need, prudence and impact on the environment will all be reviewed in the Leave to Construct application that Union is expected to file before the end of 2012.

Board staff submitted that Union should be directed to file comprehensive information in the Leave to Construct application. This would include detailed information on possible alternatives and the opportunities that the project could provide for the non-utility portion of Union's operations.

Energy Probe submitted that Union had rejected all the alternatives to the project provided by TCPL in its evidence. Energy Probe argued that the Parkway West Project was not just about LCU protection and improving reliability but one of the collateral benefits of this project was that it would increase transactional services at the Dawn Hub. Energy Probe referred to a presentation Union made to Spectra executives that forecasts revenue attributable to the project of $23 million in 2014.

Energy Probe submitted that the Board should conduct a comprehensive review of options for LCU, Parkway extension, Enbridge reinforcements and/or long term transportation arrangements before Union's proposed projects are approved.

BOMA in its submission indicated that apart from the Parkway West Project, Enbridge was planning to construct a 24 km transmission line from the new Albion city gate on its distribution system to Union's proposed Parkway West station. Union and Enbridge initially explored the possibility of joint ownership of the Parkway West to Albion pipeline but Enbridge then decided to construct the pipeline itself.

BOMA submitted that the two distinct projects proposed by Enbridge and Union will likely cost ratepayers more as compared to a joint effort. BOMA was of the opinion that the LCU compression at Parkway was unnecessary at this time and there was no evidence that the new compressor was required to deliver gas to Enbridge or other customers.

BOMA also rejected Union's claim that the LCU compressor was required in the event of a failure of one of the compressors currently in use. BOMA submitted that the likelihood of a serious compression failure was minimal and this was confirmed by Union's evidence on the record.[164]

BOMA noted that Union's evidence of further increases of deliveries through Parkway were not reliable and the market was not ready for such a service at this point in time. BOMA therefore submitted that the Board should forewarn Union about the risk of approval of such expenditures considering that they were not required at this point in time.

BOMA submitted that the Board should examine both the Union and Enbridge expansion plans before it makes a decision to approve either of the projects in and around Parkway. BOMA added that the Board should consider these expansion projects in an Ontario-wide context.

BOMA urged the Board to require TCPL, Union and Enbridge to discuss alternatives and negotiate a solution that minimizes overall capital costs while maintaining reliability and access to markets. BOMA submitted that such discussions should take place prior to Enbridge and Union filing their respective Leave to Construct applications.

[164] Exhibit J.B-1-7-8, Attachment 9, Slide 7.

LPMA in its submission indicated that Union's Leave to Construct application should include a wider perspective: that the needs of Enbridge and the potential options to serve those needs not only by Union, but also by TCPL be considered. LPMA submitted that the Board should consider a proceeding that encompasses Union's Parkway West project, Enbridge's GTA reinforcement project, TCPL options, any Parkway to Maple expansion by any of the companies involved, and any other projects related to this issue. LPMA submitted that the Board's process should include an integrated planning exercise that involves all parties that may be affected, along with all those parties that can provide cost-effective solutions.

APPrO in its submission noted that its members were major shippers on both the TCPL and Union system. APPrO noted that its members were quite sensitive to additional infrastructure considering that TCPL tolls have increased significantly over the last few years.

APPrO maintained that Union should first ensure that there is a genuine problem to resolve and if so, ratepayers deserve the most cost-effective solution and not merely the facility solution that Union has proposed. APPrO submitted that Union should conduct due diligence on potential alternatives to the proposed Parkway West build. This could include not only alternatives proposed by TCPL, but other commercial solutions as well. APPrO recommended that Union conduct broad consultations with all stakeholders including M12 shippers and in-franchise users of the Dawn-Trafalgar system that would be impacted by this major project.

TCPL in its submission maintained that the Parkway West project was at best premature and at worst, a redundant piece of infrastructure that would impose significant costs on Ontario consumers. TCPL submitted that in certain cases, there could be justification for duplicate or redundant infrastructure such as supply diversity and competition. The Board in such cases should weigh the benefits of duplication with the costs that Ontario consumers would bear.

TCPL's opinion was that Union did not require LCU protection at Parkway at this time. TCPL specifically noted that failure of compression at Parkway was an extremely improbable event and that Union's compression has a 99.9% reliability rate. TCPL further noted that two-thirds of the Enbridge GTA peak day load was directly supplied to

Enbridge at Parkway with existing LCU protection and Enbridge was not likely to receive any additional benefit from the proposed LCU.

If Union required LCU protection for TCPL deliveries, TCPL indicated that it could acquire non-facility LCU protection for a fraction of the cost of the $180 million associated with the proposed LCU protection.

TCPL submitted that it had identified at least four alternatives to the proposed LCU which included using existing infrastructure, existing TCPL infrastructure in conjunction with Union infrastructure or adding small and efficient capacity increases on the TCPL system. These alternatives would provide lower ownership and operating costs and would be scalable according to TCPL.

TCPL submitted that Union had not seriously explored all options and had not entered into a dialogue or consultation with TCPL on this matter. TCPL submitted that the project was essentially a way to bypass the TCPL system and had no bearing on providing greater reliability to TCPL or Enbridge at Parkway. TCPL submitted that if the issue is reliability then Union should consult with Enbridge and TCPL to ensure system reliability, both from an operational and economical perspective.

Enbridge in its submission urged the Board to not make any determinations in this proceeding with respect to the Parkway West project including any decisions related to process and timing. Enbridge submitted that any determination would amount to prejudging the Leave to Construct applications that still have to be filed by Union and Enbridge. Union in its reply argument agreed with Enbridge.

Furthermore, Union rejected the alternative proposals put forth by TCPL. Union argued that the alternatives would be more costly if carefully examined and appear largely designed to address competitive concerns that TCPL may have with respect to its own volumes. Union submitted that the proposals put forth by TCPL would either cost more than the Parkway West project or were similar to what Union had proposed. Union submitted that if one of the proposals was simply to install a used compressor, Union could do the same provided TCPL would sell a used compressor to Union. Union noted that in terms of preparedness it was further ahead since it had already entered into an option to purchase the required land in an area where land is difficult to obtain.

Union submitted that Parkway West was essentially a reliability project consisting of two components: LCU protection and a second feed for Enbridge at Parkway (Consumers) and the Lisgar feed backup. Union noted that intervenors were confused about the Parkway West project and were improperly relating it to Enbridge's system reliability project and the expansion of the line from Parkway or Albion to Maple.

Union indicated that TCPL's claim of the Parkway West project being a pre-build for an expansion of Union's transportation corridor was incorrect. Union submitted that the Parkway to Maple congestion was a different issue and Union's position that there is a bottleneck at Maple was well known. Union referred to the presentation that it had given at the stakeholder conference in the Natural Gas Market Review held in October 2010 where it expressed concern about the bottleneck from Parkway to Maple limiting supplies into and from Ontario. In that proceeding, Union had indicated that a Parkway to Maple expansion was a natural project for TCPL to undertake. TCPL in that proceeding disagreed with Union's position and indicated that there was no bottleneck between Parkway and Maple.

Consequently, Union initiated its own open season as a result of which TCPL also held an open season to gauge interest from shippers. In its reply submission, Union confirmed that it bid into TCPL's open season and also indicated that there was insufficient demand for two competing Parkway to Maple projects. Union submitted that there was no evidence that Union was looking to bypass TCPL in this specific corridor.

Union also disagreed with TCPL's claim that it had not consulted with TCPL on the Parkway West project. Union submitted that there was no communication from TCPL and Union learned of TCPL's concern and the different alternatives to the Parkway West project through the evidence filed by TCPL in this proceeding.

Lastly, Union submitted that it is committed to filing complete information in its Leave to Construct application including information about compressors. Union also acknowledged that it assumes the complete risk of expenses incurred on the Parkway West project until it obtains approval for the project from the Board.

Board Findings

In the context of this application, no approvals of the Board are required for the facilities that comprise the Parkway West project. The Board notes that Union plans to file a subsequent Leave to Construct application in the latter part of 2012 for those portions of the Parkway West project that it believes require Leave to Construct approval by the Board. As such, the Board is not making any determination in this Decision relating to the need or any other issue that will be considered in this subsequent proceeding. The Board acknowledges that Union has recognized that any facility expenditures remain the responsibility of Union and its shareholder until, when and if, Board approval is obtained and amounts are closed to rate base.

The record in this proceeding makes it clear to the Board that the relationships between the three large natural gas pipeline companies that serve Ontario customers - Union, Enbridge and TCPL, are complex. The Board notes that not only do these companies compete to construct new facilities and utilize existing facilities; they are also each customers of the other. They are bound, however, by the fact that the operation of each of its respective natural gas system is integrated in the province of Ontario, and that Ontario customers pay a significant portion of, if not all of, the cost of installed natural gas facilities, and that each entity has an incentive to maximize rate base.

The Board is concerned with the apparent lack of cooperation and consultation between Union, Enbridge and TCPL that came to light in this proceeding. The Board is concerned that this may have adverse consequences for Ontario ratepayers – result in higher rates and costs than would otherwise be the case, contribute to the uneconomic bypass of existing natural gas infrastructure, create asset stranding, encourage the proliferation of natural gas infrastructure, and lead to the underutilization of existing natural gas infrastructure.

The Board agrees that the consideration of the Parkway West facilities requires a wider perspective. The Board therefore encourages Union to engage TCPL, Enbridge and shippers in a consultative process, the purpose of which is to jointly consider the need for the Parkway West project, explore reasonable alternatives (including the repurposing of existing facilities) in order to maximize the benefit to Ontario ratepayers. The result of this process would then be filed with Union's Leave to Construct application for the Parkway West facilities.

The Board does not concur with Union's submission that this consultation should occur after it has filed its Leave to Construct application for the Parkway West project. The Board believes that full consideration of alternatives should occur in advance and that to do otherwise would be an inappropriate use of the Board's and other parties' time and resources.

OTHER ISSUES

Financial Statements

Board staff argued that Union should be required to file separate audited financial statements for the rate regulated portion of the company. Currently Union files audited financial statements for the entire company, which includes that portion of its business that is not subject to rate regulation. Board staff submitted that section 2.1.6 of the natural gas Reporting and Record Keeping Requirements ("RRRs") requires Union to file separate financial statements for the rate regulated portion of the utility, and that Ontario Power Generation was required by the Board to file separate audited financial statements for the regulated portion of its business. Board staff further submitted that, irrespective of any requirements in the RRRs, audited financial statements for the rate regulated portion of the business would allow the Board to better assess the revenue requirement and earnings sharing in rate applications.

Board staff's submission was supported by some intervenors. CME noted that separate financial statements for the regulated business would assist parties in determining the proper allocations between the rate regulated and non-rate regulated storagebusinesses.

In reply, Union stated that preparing separate audited financial statements for the regulated side of the business would be an expensive undertaking. It further submitted that no party had identified any particular piece of information that was not disclosed in the proceeding that would have been provided in separate audited financial statements. Union stated that preparing separate audited financial statements would provide little or no value.

Board Findings

The Board directs Union to prepare and file separate audited financial statements for that portion of its business that is subject to rate regulation. For the utility business regulated by the Board, the Board directs Union to provide annually a full set of audited financial statements, with all related notes to these financial statements, prepared under the applicable generally accepted accounting principles used to report to financial regulators in Canada and in the USA. These audited financial statements will be filed with the Board as soon as possible after Union releases its financial results to the public, but no later than June 30th each year. The Board believes that this information will assist in both assessing the revenue requirement in future cost of service proceedings, and in monitoring during the course of the IRM term.

The costs of preparing these financial statements shall be collected in a new deferral account (described in more detail elsewhere in this Decision).The Board will establish a Preparation of Audited Financial Statement Deferral Account, which will be reviewed and disposed of with Union's other deferral and variance accounts.

THE BOARD ORDERS THAT:

1. Union shall file with the Board, and shall also forward to all intervenors a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 42 days of the date of this Decision. The Draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. The Draft Rate Order shall also include draft accounting orders related to the deferral accounts set up or approved by the Board in this Decision.

3. The intervenors shall file any comments on the Draft Rate Order with the Board and forward to Union within 14 days of the filing of the Draft Rate Order.

4. Union shall file with the Board and forward to the intervenors responses to any comments on its Draft Rate Order within 14 days of the receipt of any submissions.

5. The intervenors shall file with the Board and forward to Union, their respective cost claims within 14days from the date of the Final Rate Order.

6. Union shall file with the Board and forward to the intervenors any objections to the claimed costs within 21 days from the date of the Final Rate Order.

7. The intervenors shall file with the Board and forward to Union any responses to any objections for cost claims within 28 days of the date of the Final Rate Order.

8. Union shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, October 25, 2012
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

EB-2011-0210
Union Gas Limited
Decision and Order

For convenience, the Board's determinations on cost allocation and rate design that have been set out in this Decision and Order are briefly summarized in the table below. However, this summary should not be interpreted as augmenting or superseding any part of this Decision and Order.

Cost Allocation and Rate Design – Summary of Board Findings

Issue	**Board Findings**
COST ALLOCATION	
General Cost Allocation	Accepted Union's Cost Allocation Study .
System Integrity	Accepted Union's cost allocation proposal.
Tecumseh Metering Assets	Accepted Union's cost allocation proposal.
Oil Springs East Assets	Accepted Union's cost allocation proposal.
New Ex-Franchise Services	Accepted Union's cost allocation proposals related to the Dawn to Dawn-TCPL and Dawn to Dawn-Vector services. Accepted Union's cost allocation proposal for the M12 F24-T service with some required changes.
Union North Distribution Customer Stations Plant	Directed Union to allocate costs related to North Distribution Customer Station Plant on the basis of average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3 / hour.
Distribution Maintenance – Meter and Regulator Repairs	Accepted Union's cost allocation proposal.
Distribution Maintenance – Equipment on Customer Premises	Denied Union's cost allocation proposal. Directed Union to file, as part of its 2014 cost allocation study, analysis of this cost allocation issue.
Purchase Production General Plant	Accepted Union's cost allocation proposal.
Parkway Station Costs	Ordered no change to the allocation of Parkway Station costs. Noted that the Board will revisit after Union files the report on the outcome of the Parkway Obligation Working Group.
Kirkwall Station Costs	Directed Union to review its allocation of Kirkwall Station costs as part of its 2014 cost allocation

	study.
Dawn-Trafalgar Easterly Costs	Accepted Union's cost allocation proposal.
Utility / Non-Utility Storage Allocation	Accepted Union's cost allocation methodology. Directed Union to revise allocation for 2012 allocation factor update. Directed Union to file, as part of its 2014 rates filing, continuity schedules related to Union's non-utility storage operation and an update to the Black and Veatch report.
RATE DESIGN	
General Rate Design	Generally accepted Union's rate design considerations and revenue-to-cost ratio guidelines. Ordered Union to not move any in-franchise rate classes' revenue-to-cost ratio further from 1.0 than previously approved. Ordered Union to not have a revenue-to-cost ratio higher than 1.0 for any in-franchise rate class. Ordered Union to file, as part of the Draft Rate Order process, a proposed methodology for allocating optimization related margins to customers that pay the costs of Union's gas supply plan. Ordered Union to file, as part of the Draft Rate Order process, a proposed methodology for allocating S&T related margins which reflects regulatory principles. Ordered Union to update its proposed rates to reflect all of the related findings in the Decision.
Rate 01 / 10 and Rate M1 / M2 – Volume Breakpoint and Rate Block Harmonization Proposal for 2014	Denied Union's rate design proposal at this time. Directed Union to file, as part of its 2014 rates filing, a cost allocation study which includes an analysis of: the allocation of costs for its volume breakpoint proposal, the issue raised by LPMA regarding the allocation of costs for Distribution Maintenance – Meter and Regulator repairs for those customers that move rate classes under Union's volume breakpoint proposal, the allocation of costs for Distribution Maintenance – Equipment on Customers Premises and the allocation of Kirkwall Station costs.

Rate M4, M5A and Rate M7 – Eligibility Criteria Proposals for 2014	Accepted Union’s rate design proposals.
Rate T1 Redesign	Accepted Union’s rate design proposal.
Supplemental Service Charge – Group Meters for Commercial / Industrial Customers in Rate M1 and Rate M2	Denied Union’s proposal. Directed Union to eliminate this supplemental service charge in its Southern Service area.
Rate Mitigation	Noted that it is not clear, at this time, whether rate mitigation will be necessary. Will determine whether rate mitigation measures will be implemented after the Draft Rate Order has been reviewed by the Board.
Response to directive to review M12 and C1 ratemaking methodology	Accepted Union’s response.
Rate M4 Interruptible Service Offering for 2014	Accepted Union’s rate design proposal.
UFG Recovery on transportation activity, in the winter months, for the Dawn to Dawn-Vector transportation service	Accepted Union’s proposal.
Rate M12, M13, M16, and C1 – Rate Schedule Modification	Accepted Union’s proposals.
Distribution Consolidated Billing Fee	Accepted Union’s proposal.
Gas Supply Administration Fee	Accepted Union’s proposal.
Kirkwall to Dawn Transportation Service Rate Design – Kirkwall Metering Costs	Accepted Union’s proposal.

Ontario Energy Board

Commission de l'Énergie de l'Ontario

Ontario

EB-2011-0210

IN THE MATTER OF the *Ontario Energy Board Act 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an Application by Union Gas Limited for an Order or Orders approving or fixing just and reasonable rates and other charges for the sale, distribution, transmission and storage of gas commencing January 1, 2013.

BEFORE: Marika Hare
Presiding Member

Karen Taylor
Board Member

DECISION AND ORDER

Union Gas Limited ("Union") filed an application on November 10, 2011 with the Ontario Energy Board (the "Board") under section 36 of the *Ontario Energy Board Act, 1998* for an order of the Board approving or fixing rates for the distribution, transmission and storage of natural gas, effective January 1, 2013 (the "Application"). The Board assigned file number EB-2011-0210 to the Application and issued a Notice of Application on December 1, 2011. This is the first cost-of-service application for setting rates since 2007. From 2008 to 2012 rates were set under an Incentive Regulation Mechanism ("IRM") which adjusted rates through a mechanistic formula.

The Board issued its Procedural Order No. 1 on January 11, 2012, which established the approved list of intervenors for this proceeding. The list included:

- Association of Power Producers of Ontario (“APPrO”)
- Building Owners and Managers Association Toronto (“BOMA”)
- Canadian Manufacturers and Exporters (“CME”)
- City of Kitchener (“Kitchener”)
- Consumers Council of Canada (“CCC”)
- Enbridge Gas Distribution Inc. (“Enbridge”)
- Energy Probe Research Foundation (“Energy Probe”)
- Federation of Rental-housing Providers of Ontario (“FRPO”)
- Industrial Gas Users Association (“IGUA”)
- Jason F. Stacey
- Just Energy Ontario LP (“Just Energy”)
- London Property Management Association (“LPMA”)
- Ontario Association of Physical Plant Administrators (“OAPPA”)
- Ontario Power Generation (“OPG”)
- School Energy Coalition (“SEC”)
- Six Nations Natural Gas Company Limited (“SNNG”)
- Shell Energy North America (Canada) Inc. (“Shell Energy”)
- TransAlta Generation Partnership (“TransAlta Generation”)
- TransAlta Cogeneration LP (“TransAlta Cogeneration”)
- TransCanada Pipelines Limited (“TCPL”)
- TransCanada Energy Limited (“TCE”)
- Vulnerable Energy Consumers Coalition (“VECC”).

The Board also determined that APPrO, BOMA, CME, CCC, Energy Probe, FRPO, IGUA, LPMA, OAPPA, SEC, and VECC are eligible to apply for an award of costs under the Board’s *Practice Direction on Cost Awards*.

Union filed its Application on the basis of US Generally Accepted Accounting Principles (“USGAAP”). At the same time, Union sought approval to move to USGAAP from Canadian GAAP as part of this Application. The Board decided to first deal with Union’s request for the adoption of USGAAP for regulatory purposes (the “Preliminary Issue”) prior to processing the Application in accordance with the Addendum to Report of the Board: Implementing International Financial Reporting Standards in an Incentive Rate Mechanism Environment (the “Addendum Report”).

In Procedural Order No. 1 the Board established a timeline for interrogatories, interrogatory responses, submissions, and reply submissions related to the Preliminary Issue in advance of further procedural steps. In addition, the Board adopted the evidence related to the USGAAP issue from Union's 2012 IRM Proceeding EB-2011-0025 (the "Adopted Evidence").

Submissions were received from the LPMA, CCC, SEC, CME, APPrO and Board staff. LPMA, CCC, SEC and Board staff supported the request by Union for the adoption of USGAAP for regulatory purposes. CME and APPrO were also supportive of Union's request but provided some proposed conditions of approval.

The Board issued its Decision on the Preliminary Issue and Procedural Order No. 2 on March 1, 2012. The Board granted Union approval to use USGAAP for regulatory purposes. The Board also set out the timelines for the Issues Conference, Issues Day Hearing, filing of interrogatories and responses to interrogatories by Union in this Procedural Order.

Procedural Orders No. 3 and No. 4 set timelines for the next procedural steps, including setting dates for the Technical Conference and the Settlement Conference.

The Board revised some of the timelines for interrogatories and filing intervenor evidence in Procedural Order No. 5 after considering a letter filed by TCPL that requested revised dates to accommodate timelines related to the hearing of its application before the National Energy Board.

TCPL filed a Notice of Motion on May 17, 2012. The Motion requested the following:

1) An Order requiring Union to provide proper answers to the Interrogatories identified in Appendix "A" to the Notice of Motion, or such other information as the Board considers appropriate.

2) An Order requiring Union to file with the Board unredacted copies of pages in Interrogatory Responses that were filed in redacted form as part of Union's Interrogatory Responses to TCPL, so that the Board could assess the reasonableness of the claims for confidentiality and make such order as it considers appropriate in that regard.

The Board in Procedural Order No. 6, issued on May 18, 2012, decided that it would not hear the second request as part of the TCPL Motion as there were other exhibits, not mentioned in TCPL's Motion, which were filed under confidential cover. The Board in Procedural Order No. 6 established a separate process for reviewing Union's claims for confidentiality.

The Board heard the Motion filed by TCPL by way of written hearing. Procedural Order No. 6 made provision for all parties to the proceeding to file submissions on the merits of TCPL's motion and for TCPL to file reply submissions. This process was completed on June 8, 2012.

TCPL, BOMA and Union filed submissions on TCPL's motion. The interrogatory information sought by TCPL related primarily to Union's Parkway West project which purports to provide for loss of critical unit protection at Parkway.

With respect to the Parkway West project questions, TCPL's position was that the information that it was seeking was necessary for the Board to evaluate the reasonableness of Union's proposed capital expenditures. Union submitted that the information requested by TCPL was not relevant to Union's Application as the Parkway West project would not come into rate base until 2014 and did not impact 2013 rates. Union's position was that providing such further information could have no bearing on deciding the issues before the Board in this Application.

BOMA's submissions largely supported TCPL's request for Union to provide answers to the TCPL Parkway West interrogatories.

The Board in its Decision dated June 15, 2012, granted the Motion and required Union to provide responses to the interrogatories.

With respect to the relevance of the Parkway West interrogatories, the Board indicated that a review of the forecast capital spending plan was a conventional aspect of a cost of service rebasing process. The Board recognized that the specific projects that were the focus of the interrogatories at issue were not expected to close to rate base within the test year, and that the Board was not conducting a review of the projects for approval. However, the Board has commonly reviewed capital spending forecasts as part of a cost of service review, and determined that it would do so in this case.

The Board noted that the proposed projects may have important implications for Union's operations during the following year, in particular if Union is again entering into an incentive regulation regime for rate-setting. The Board indicated that it would be remiss in considering this cost-of-service application if it did not ensure that it had as clear a picture as possible of the significant developments likely to arise within the next regulatory rate-setting period.

On the issue of confidentiality, the Board determined that, except for the benchmarking studies, the information that Union proposed to redact was not confidential, and that the full and unredacted versions should form part of the public record. With respect to the benchmarking studies, the Board agreed with Union that the specific rankings of the studies' participants (other than Union) should not be on the public record, and therefore allowed the redactions. However, the Board required that the list of the participants to the studies be made public where it was included in the study. The Board noted that in assessing the relevance of a benchmarking study, it was important that the "comparators" be known.

As per Procedural Order No. 4, a Settlement Conference was held from June 6 to June 18, 2012 between Union and intervenors to settle some or all issues. In broad terms, the parties reached an agreement with respect to rate base and cost of service for the test year, being the issues under headings Exhibit B – Rate Base and Exhibit D – Cost of Service, respectively, with the exception of matters pertaining to Gas Supply Planning (Issue 3.14) and capital expenditures relating to Parkway West (Issue 1.1). The parties also reached agreement on several other issues, each of which were separately identified as settled in the Settlement Agreement. As a result of the Settlement Agreement, the updated revenue deficiency proposed by Union was reduced to $54.524 million from $71.4 million. The Board considered and accepted the Settlement Agreement as reasonable.

The Board addresses below the issues that remained unresolved.

UNSETTLED ISSUES

The following issues were considered by the Board:

- Weather Methodology
- Normalized Average Consumption ("NAC")

- Operating Revenue
- Other Revenues
- Ex-franchise Revenue
- Optimization and Gas Supply Plan
- Cost of Capital
- Cost Allocation
- Rate Design
- Deferral and Variance Accounts
- Parkway West
- Other Issues

WEATHER METHODOLOGY

Union has proposed to use a 20-year declining trend to derive the total Heating Degree Days ("HDD") estimates for 2012 and 2013. The 2013 weather normal forecast is based on the 20-year declining trend weather normal methodology. In RP-2003-0063, the Board approved a 70:30 weighting of the 30-year average forecast and the 20-year declining trend. The Board directed Union to change the weighting by 5% annually, until the methodology reached a 50:50 weighting. However, based on the Settlement Agreement approved by the Board in EB-2005-0520, Union's current methodology in rates reflects a 55:45 weighting of the 30-year average and the 20-year declining trend methodology. The 50:50 weighting approved by the Board was not achieved as a result of that Settlement Agreement.

Intervenors and Board staff argued that Union had not adequately justified the use of a 20-year declining trend. They submitted that Union had not presented other methodologies to demonstrate that the 20-year declining trend is superior to other methodologies. LPMA submitted that Union had merely compared the proposed 20-year declining trend with the current approach approved in rates. LPMA further submitted that Enbridge in the EB-2006-0034 proceeding had presented an exhaustive analysis of 9 different forecasting methodologies that were ranked based on a number of statistical measures over a number of different periods[1], and that Union did not do such an extensive analysis in this case. Board staff submitted that Union had not provided sufficient evidence for the Board to make an informed decision. Board staff further

[1]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p.31.

argued that the Board had no basis for determining if the 20-year declining trend is the most appropriate and accurate forecasting methodology for Union.

Similarly, VECC submitted that Union presented more models in the 2004 proceeding (RP-2003-0063) where it presented six different methodologies in addition to the 20-year declining trend.

In its reply submission, Union submitted that intervenors had several opportunities to test other models and they could have asked Union for additional evidence during the discovery process, but did not do so. Union submitted that the Board should not reject the 20-year declining trend on the basis that there is some other methodology which may provide better results. Union submitted that the Board should make a decision on the basis of what is filed in evidence and that is a choice between the 20-year declining trend, the existing method and the 30-year average.

LPMA submitted that Union only considered a trend methodology based on a 20-year time horizon with no other explanatory variables other than the trend used to explain the fluctuation in heating degree days. Further, Union did not consider adding any other variables to the trend model to see if it could find a better equation that might improve the forecast.[2]

Some intervenors (LPMA, VECC and Energy Probe) specifically argued that there is a significant flaw in the equations used to forecast degree days for the Test Year. They submitted that the equations are not statistically significant even at an 85% level of confidence. In reply, Union submitted that the 20-year declining trend was statistically superior to the blended and the 30-year average methodology. While the results of the 30-year average are significant at the 30-45% confidence level, the existing methodology is significant at the 70% confidence level. Union submitted that intervenors were critical of the 20-year declining trend but were overlooking the weakness and bias that exist in the existing methodology and the 30-year average.

Energy Probe also submitted that Union had not investigated zone based Heating Degree Days forecast methodologies as was done by Enbridge. Board staff made a similar submission that Union should have considered the possibility of different

[2] Oral Hearing Transcripts, EB-2011-0210, Volume1 at pp. 44-46.

forecasting approaches across the different regions. Energy Probe submitted that Union was using Pearson Airport Data for weather which was not a fair representation of Union's franchise area. In reply, Union submitted that there was no evidence to support Energy Probe's position and the evidence indicates that the weather in Union's franchise area in the North and the South is highly correlated to Pearson, at a correlation of over 90%.

Board staff and VECC further submitted that Union had not performed some of the tests that would validate its regression model. This includes testing for heteroskedasticity.[3] The presence of heteroskedasticity can invalidate statistical tests of significance that assume that the modelling errors are uncorrelated and normally distributed and that their variances do not vary with the effects being modelled. VECC submitted that testing for heteroskedasticity was not a major exercise and therefore should have been undertaken.

SEC and Board staff submitted that the 20-year trend possibly results in a steep downward sloping curve even though it may be slicing the middle of the data denoting better symmetry. Board staff noted that this results in far lower Normalized Average Consumption numbers for 2012 and 2013. SEC noted that the 20 years is the period of trend that produces the steepest downward sloping curve. In reply, Union submitted that Board staff was focusing on the volatility of NAC which was an indirect argument since weather is one of the components in the NAC calculation.

Many intervenors and Board staff submitted that based on the evidence, the Board should approve a 50:50 blend of the 30-year average and the 20-year declining trend for 2013. BOMA, however, recommended that the Board should approve the current approach in rates which is the 55:45 blend.

LPMA submitted that the 20-year trend component of the blended methodology should not be Union's 20-year declining trend forecast as included in the evidence. First, the 20-year trend forecast as filed by Union should be updated to reflect actual 2011data, as should the 30-year moving average. Second, the 20-year declining trend equations modified for a structural shift that is shown in Attachments 1 of 3 of Exhibit J1.3 should be used in place of the equations shown in Attachments 2 and 4.

[3]Heteroskedasticity occurs when the standard deviations of a variable monitored over a specific amount of time, are not constant.

LPMA submitted that for the Southern service area the equation that includes the structural shift variable with an overall fit confidence interval of more than 99% should be used. The test year forecast from this equation from a statistical point of view is 3,816 HDD which should be used in the weighting for the 2013 forecast.

In the North, LPMA submitted that the two equations were both a good fit with an overall confidence level of more than 99%. However, the equation with the structural shift variable explains a higher proportion (56%) of the variability in the data as compared to the equation without it. The test year forecast from the better fitting equation from a statistical point of view is 4,844 HDD. LPMA submitted that this should be used in the weighting for the 2013 forecast.

Lastly, Board staff and LPMA requested the Board to direct Union to present better evidence at the next cost of service proceeding. LPMA submitted that the Board should direct Union to conduct a comprehensive review of at least the same forecasting methodologies as reviewed by Enbridge in both their EB-2006-0034 and the current EB-2011-0354 rates proceedings and provide that analysis at the next rebasing proceeding.

In reply, Union submitted that the introduction of a dummy variable in 1998 by LPMA is highly subjective. Union indicated that by introducing a dummy variable, LPMA was suggesting that the weather had changed in 1998 and became colder going forward. Union submitted that this was subjective and introducing a dummy variable could lead to arguments in future proceedings with respect to when a dummy variable should be introduced. Union submitted that the 20-year declining trend ranks above the LPMA dummy variable methodology, considering that the dummy variable methodology shows large mean percent and root mean square errors.

Union submitted that the Board should focus on the evidence presented and the evidence shows that the 20-year declining trend is superior to the existing and the 30-year average methodologies. Consequently, the Board should approve Union’s proposal.

Board Findings

In the RP-2003-0063 proceeding, Union sought to use a 20-year declining trend methodology. In that Decision, the Board approved an initial 70:30 weighting of the 30-year average forecast and the 20-year declining trend. The Board directed Union to change the weighting by 5% annually, until the methodology reached a 50:50 weighting.

In this proceeding, intervenors and Board staff have submitted that Union failed to bring forward or discuss other methodologies. Union, in its reply argument, submitted that intervenors did not raise concerns or provide additional evidence during the discovery process. The Board believes that it is the responsibility of the applicant to provide the evidentiary basis to support its position. Union failed to review other scenarios and provide the Board with the information and statistical support necessary for the Board to determine that the 20-year declining trend is the most appropriate methodology. Even the 50:50 blended methodology that was approved in RP-2003-0063 was not discussed by Union in its Application, but was only reviewed through interrogatories and evidence that emerged during the proceeding.

Union submitted that Board staff erred when it focussed on the volatility of NAC while discussing weather. However, the Board considers that it is clear that the weather is becoming more volatile, and that it is desirable to adopt a methodology that smooths this volatility. In the RP-2003-0063 Decision, the Board noted that both the 30-year average and the 20-year declining trend have advantages. The 20-year trend may track through the middle of the data as Union claims and would respond more quickly to changes in short-term trends but would also be more volatile. On the other hand, the 30-year average will respond more slowly to changes but would be less volatile.[4] During this proceeding Union has agreed that the weather is becoming more volatile.

Union, in reply argument, stated on page 85:

> And the evidence is, while it may be getting warmer as a trend, weather is still – and getting more so – volatile and that the experience in the weather charts we looked at shows that there are wide swings in the weather year to year, and frankly, within a year.

[4]Decision with Reasons, RP-2003-0063, March 18, 2004 at p. 22.

The Board finds that since the 20-year declining trend reflects a shorter time period, it would be more likely to be affected by large variations in weather between one year and another. In other words, it would not perform as well as the blended methodology to smooth the effects of a particular year that is warmer or colder. The Board believes that use of the 20-year declining trend methodology could expose ratepayers to wider variations in costs from year to year since the methodology may not produce stable results and is susceptible to volatile weather patterns.

The Board directs that a 50:50 blended approach of the 20-year declining trend and the 30-year average methodology be adopted. Union is further directed to make the required adjustments to incorporate 2011 actual data, thus using the most recent and available data.

The Board does not agree with LPMA that a dummy variable should be introduced. The Board believes that this is a subjective adjustment to the methodology. The Board finds that a dummy variable is not necessarily required to account for the upward move between 1998 and 2000.

The Board directs Union to reflect the appropriate adjustments in the Draft Rate Order.

Union has submitted that its weather data for its Northern and Southern franchise areas is highly correlated. The Board does not agree that a high level of correlation necessarily implies that it is appropriate to use the same forecasting methodology in each of the North and South franchise areas. Union should consider analyzing each of the weather stations it utilizes to arrive at a weighting of its Southern and Northern degree days. A uniform approach may not be suitable for Union’s service areas that exhibit wide weather variations between the North and South.

The Board does not see the need to provide direction to Union with respect to future filings in the event that Union chooses again to apply to change the degree day methodology. As stated earlier in this Decision, it is the applicant’s responsibility to present sufficient evidence to demonstrate why a change in methodology or approach is appropriate.

NORMALIZED AVERAGE CONSUMPTION (“NAC”)

Union’s forecast estimates of NAC are prepared for the residential customers by individual rate class. Commercial NAC estimates are first prepared for the total commercial service class, then converted to regional estimates and finally allocated to the individual rate classes on the basis of historical volumetric shares. The industrial market demand is determined by a total volume equation and average consumption estimates are then subsequently derived. The NAC forecast for residential and commercial customers incorporates assumptions related to several demand variables: weather normal, energy efficiency, total bill amounts, fall seasonal weather and structural trend variables.

Residential NAC estimates are prepared separately for Union South and North customers. The residential econometric forecasting follows the methodology used in EB-2005-0520. The NAC estimates are the product of two regression equations: an average use per customer equation and a total volume equation. The average of the two econometric demand estimates is then adjusted for the forecast demand side management program NAC impact. The commercial NAC forecast estimates are obtained from regression analysis of commercial consumption data from all general service rate classes.

Intervenors and Board staff submitted that the NAC forecast for the residential and commercial markets are significantly lower than the historic trend. Board staff submitted that Union has forecasted a decline of 5.1% from 2011 to 2013 in the M2 residential market, which is significantly higher than an average annual reduction of approximately 1.5% from 1992 to 2011. LPMA submitted that Union was forecasting that the percentage decline in non-weather related average residential use will double in the bridge and test years.

Similarly, with respect to Rate 01, LPMA submitted that the residential average annual use fell by 0.2% in 2006 to 2011, 1.3% in 2001 to 2011, and 1.4% in 1991 to 2011. However, for the bridge and test years, Union has forecasted a decline of 2.4% per year for the bridge and test years reflecting an increase in the rate of decline by one full percentage point compared to historical rates. LPMA and VECC submitted that Union has not provided any evidence to support this accelerated decline in average use. LPMA noted that the rate of decline due to furnace efficiency improvements has not accelerated, and neither has the reduction due to Demand Side Management ("DSM") initiatives.

LPMA, VECC, CCC and Energy Probe submitted that the Board should approve a forecast for the two residential classes that reflects a decline in average use in the bridge and test years that is consistent with the historical data. CCC and LPMA submitted that a reduction of 1.4% per year for both classes is reasonable and consistent with the long term trend. This would reduce the M2 average use from 2,264 m^3 in 2011 to 2,201m^3 in 2013 and the 01 average use from 2,269 m^3 to 2,206m^3 over the same period. VECC submitted that the NAC forecast for M1 and Rate 01 should be increased by 1.1% for 2012 and 2013. Energy Probe further submitted that the Board should continue the Average Use True Up Variance Account (the "Average Use Account", No. 179-118) in 2013.

LPMA and Board staff expressed similar concerns with respect to the decrease in average use forecast for the old rate M2 and Rate 01. While the annual percentage decline between 1991 and 2011 is only 0.4%, Union has forecasted a reduction in commercial old rate M2 by 3.4% on an annualized basis for 2011 to 2013. LPMA submitted that over the last 5 and 10 year periods, the average use for these customers had actually increased. Union supported the forecasted decrease by stating that the increase in average use in this category in 2011 was an outlier.

LPMA further submitted that the commercial use per customer equation used by Union did not include any explanatory variables related to the economy or the relative price of natural gas versus other energy sources, such as electricity. LPMA submitted that the increase in 2011 could be explained by the fact that the economy in 2011 was back to near pre-recession levels and natural gas prices have been at record lows while electricity prices have continued to rise.

With respect to commercial Rate 10 volumes, LPMA submitted that the forecasted decline of 1.7% per year is not reasonable considering that the average use in this category is higher in 2011 than it was in any previous year. Moreover, the general trend has been higher over the last decade. LPMA submitted that the Board should approve a forecast for the three commercial classes that reflects a decline in average use in the bridge and test years that is consistent with the historical data. LPMA submitted that a reduction of 0.4% per year for commercial M2, and 1.0% for commercial 01 is reasonable and consistent with the long term trend.

None of the intervenors made a submission on the industrial average use forecasts. LPMA submitted that the forecasted average uses for the Rate 10 and M2 category were plausible.

In reply, Union submitted that the NAC calculations for the various residential, commercial and industrial components of the general service market are checked for specification every year and where appropriate have been re-specified. Union further noted that the results are statistically significant at the 95% level of confidence.

Union submitted that the intervenors had not challenged the statistical validity of the results of the NAC methodology but rather argued that the results could not be correct. Union submitted that the Board should reject the arguments forwarded by intervenors and approve the NAC forecast methodology as it has done in the past.

Union further submitted that should the Board have any concerns with respect to the NAC forecast, it could continue maintaining the Average Use Account that was in place during the incentive regulation period. Although Union did not prefer this approach, it indicated that continuing the deferral account would resolve the dispute around the NAC forecast. Under that option, Union submitted that the Board could include Union's NAC forecast in rates and apply the Average Use Account to track any changes.

Board Findings

The Board notes that Union's proposed NAC calculations forecast a much larger decrease than historic rates of decline. However, the Board believes that an arbitrary increase in the NAC numbers is not appropriate, given that Union's NAC numbers have been derived using econometric models that were previously approved by the Board. Moreover, moving to the 50:50 blended weather methodology will likely result in changes to Union's NAC calculations.

The Board therefore accepts the NAC forecast in rates as proposed (subject to an update for the approved weather methodology) by Union but finds that the continued operation and use of the Average Use Account for the 2013 test year is appropriate and is fair to both Union and ratepayers. The Board directs Union to revise the NAC calculations based on the Board approved weather methodology and is directed to incorporate the revised numbers in the Draft Rate Order.

OPERATING REVENUE

Customer Attachments

Union has forecasted modest increases in customer attachments over the 2011 to 2013 period. In its Application, Union forecasted customer attachments of 19,510, 20,380 and 22,491 in 2011, 2012 and 2013 respectively.

Board staff submitted that Union had not included customer attachments related to the Red Lake project. At the hearing, Union confirmed that it expected to add approximately 800 customers in the community of Red Lake by 2013. Board staff submitted that although Union included the costs of the project in rate base, the revenues had not been accounted for in the current Application. Board staff submitted that as a matter of principle Union should include conversions related to Red Lake in its Application including the distribution revenues that are attributed to these attachments.

LPMA submitted that Union had under forecasted customer attachments in three of the past four years. The average under forecast number in 2008, 2010 and 2011 was 6,455, while in 2009, when the impact of the recession hit the housing market, Union over forecasted by 2,354 additions.[5] LPMA submitted that the average variance over the four years was 4,253. LPMA therefore submitted that the Board should increase the general service customer forecast by 4,250 in both the bridge and test years.

In reply, Union submitted that year-to-date, it was tracking lower than its forecast of total billed customers. The actual total number of billed customers as of June 2012 was 1,366,306 which represented a deficit of 399 customers as compared to the forecast.[6] Union therefore submitted that there was no reason to increase Union's customer attachment forecast for 2012 or 2013. With respect to the addition of Red Lake customers, Union submitted that revenues attributed to Red Lake were not material and this would not reach the materiality threshold as defined by the Board.

[5]Exhibit J.C-1-1-5.
[6] Oral Hearing Transcripts, EB-2011-0210, Volume 1 at p. 59.

Board Findings

The evidence indicates that Union is tracking marginally behind its total customer billed forecast for 2012. The Board sees no reason for increasing the forecast by 4,250 customers. Although LPMA refers to previous under forecasted numbers in 2008, 2010 and 2011, there is no evidence that such a trend will necessarily be continued. The Board finds that Union's forecast is reasonable, with one exception as noted below.

The Board believes that the 800 customers that Union has forecasted to attach in Red Lake must be included. Although this increase may be immaterial, it is based on an undisputed planning input. Union has included the capital costs of this project in rate base and the Board sees no reason for not including the revenues from these additions in the 2013 operating revenues. Accordingly, the Board directs Union to increase the customer forecast by 800 customers for 2013.

Contract Customer Demand Forecast

Union segments the contract customer market into different sectors. They include gas fired power generation, steel, refinery and petrochemical, greenhouse, wholesale and broad-based commercial and industrials ("LCI/Key"). The volume and revenue forecasts for contract customers are developed using two methodologies. An econometric forecast is developed for the majority of the customers and a detailed bottom-up forecast is developed for the large T1 and Rate 100 customers.

For the small to mid-size contract markets represented by the LCI and Greenhouse market sectors, Union uses econometric analysis to forecast consumption requirements. For the remainder of the contract market, Union uses a bottom-up approach given its extensive understanding of these accounts through ongoing interactions between the customer and the account manager.

APPrO in its submission proposed an overall increase of $3.09 million to the revenue forecast with respect to the contract market. This includes a power revenue commodity increase of $1.0 million, incremental fuel associated with the commodity revenue of $0.14 million, a T1 billing contract demand overrun revenue of $0.75 million and other contract overrun revenue of $1.2 million.

APPrO in its submission noted that, in accordance with provincial policy, coal-fired generation is in the process of being phased out. APPrO submitted that gas-fired generation has replaced much of the coal-fired generation capacity and provides back-up for renewable generation. APPrO submitted that reduced coal-fired generation will increase the runtime for gas-fired power generation.

APPrO submitted that Union's methodology to forecast power commodity revenue was fundamentally flawed since it used dated information. APPrO noted that Union included 2009, 2010 and part of 2011 data as the basis for the forecast and submitted that this was not appropriate as it did not take into account the impact of coal-fired generation closures. APPrO further maintained that Union did not incorporate the Independent System Electricity Operator ("IESO") forecast of a higher provincial power demand in 2013. The IESO 18-month outlook indicates that the 2013 aggregate energy consumption is expected to be 1.1% higher in 2013 than in 2011. In reply, Union submitted that customers were in the best position to provide relevant information. Union argued that customers ultimately have to contract for the services and it was in their best interest to provide reliable estimates.

APPrO submitted that commodity revenues for power customers for 2013 should be increased by $1.0 million which would be similar to the $4.9 million revenue collected from this group in 2011. This adjustment would also impact the customer supplied fuel which is treated as a revenue item by Union. APPrO submitted that customer supplied fuel should be increased by the same proportion as the commodity revenues which was 11% in this case. An 11% increase to customer supplied fuel results in an increase of $0.14 million to the $1.3 million included in rates.

With respect to overrun revenues, APPrO, LPMA, Energy Probe and Board staff submitted that Union had understated overrun revenues for 2013.Intervenors and Board staff submitted that Union had not forecasted any overrun charges in the power market for 2012 and 2013. This is despite the fact that the Halton Hills power plant had already incurred $300,000 in overrun charges up to the end of June 2012. Board staff suggested an increase of $300,000 to the overrun charges while LPMA submitted that the overrun revenue forecast for the power market should be adjusted to the same level as in 2011 which was $600,000. SEC and FRPO adopted LPMA's submission in this regard. Energy Probe submitted that the overrun revenues for the power market should be increased to about $500,000. APPrO submitted that the closure of the coal plants and the low efficiency Lennox plant is driving additional volumes at Halton Hills and other gas-fired generation plans. APPrO therefore argued that 2012 overrun revenues could exceed 2011 revenues. APPrO proposed that the 2013 overrun revenue should be increased to $750,000 for 2013.

With respect to the non-power markets, LPMA expressed a concern about unsupported reductions in the overrun forecast. Union forecasted $600,000 in overrun revenues for the Test Year. LPMA noted that average overrun revenues for the non-power markets from 2007 through to 2011 were $1.7 million a year and have been stable over this period. LPMA submitted that $1.7 million was a reasonable forecast for 2013. Board staff, SEC and FRPO agreed with LPMA. APPrO noted that the three-year average overrun revenues in the non-power market which included 2007, 2010 and 2011 but excluded the financial crisis years of 2008 and 2009 was $1.8 million. APPrO accordingly submitted that the overrun revenues should be increased by $1.2 million which was $100,000 more than what the other intervenors had suggested.

In reply, Union submitted that it had forecast overrun revenues for 2013. Union noted that an amount of $600,000 related to overrun revenues had been included in 2013 rates.

Board Findings

The Board does not accept the contract customer demand forecast to be reasonable. As outlined below, Union's forecasts do not reflect known changes in the market and environment, and have been demonstrated through evidence to be understated. The Board finds that the following three adjustments to Union's contract customer demand forecast should be made.

First, with respect to commodity revenues, in preparing its forecast, Union considered only a narrow range of inputs, namely, its own forecast and estimates provided by each customer. In addition, the data is dated and does not take into account recent events or changes in the market. The Board agrees with APPrO that market conditions have changed significantly over the past couple of years because coal-fired generation is on the decline and is being replaced by gas-fired generation. Accordingly the Board directs Union to increase forecast 2013 commodity revenues by $1.0 million and directs that a corresponding increase of $0.14 million in the fuel commodity revenue should also be made.

Second, the Board directs Union to increase forecast 2013 overrun revenues by $0.5 million. The Board notes that the evidence in the proceeding shows that actual power plant overruns in 2012 were already $0.3 million by mid-2012. There is no evidence to suggest that there would not be a continuation of such revenues in 2013.

Third, the Board directs Union to increase non-power market overrun revenue by $1.1 million from $600,000 to a total of $1.7 million in 2013, which is about the average revenue in this category from 2007 to 2011, exclusive of 2008 and 2009, the years of the financial downturn.

Storage & Transportation Revenue

Union's storage and transportation ("S&T") revenue forecast for 2012 and 2013 is organized under the following headings:

- Long-term transportation revenue forecast;
- Short-term transportation and exchanges revenue forecast; and
- Short-term storage and balancing revenue forecast.

Long-Term Transportation Revenue Forecast

Union's forecast for long-term transportation revenue is $148.5 million in 2012 and $141.9 million in 2013. The forecast is made up of three components: M12 Long-term Transportation, Other Long-Term Transportation, and Other Storage and Transportation Services.

M12 Long-term Transportation

The revenue for M12 Long-term Transportation represents long-term firm transportation on Union's Dawn-Parkway transmission system. It includes M12, M12X and F24-T transportation services which transport gas supplies easterly, westerly or bi-directionally on the system. Table 1 provides the actual and forecast revenues for M12 Long-term Transportation.

Table 1
M12 Long-term Transportation Revenue

Revenue (Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
M12 Transportation	$141.9	$138.3	$134.0	$121.1
M12 Transportation Overrun	$0.5	$0.0	$0.0	$0.0
M12X Transportation	$0.0	$1.5	$5.9	$13.5
Total	$142.4	$139.8	$139.9	$134.6

LPMA in its submission observed that as per Exhibit J.C-4-5-2, revenues for M12 long-term transportation revenues have been steadily increasing since 2007. LPMA noted that revenues for 2011 and the forecast for 2012 were just under $140 million, with a reduction of $5.3 million forecast for 2013 relative to 2012. LPMA further noted that as per Exhibit J6.3, the year-to-date actual revenues were tracking close to the forecast in 2012.

LPMA accepted Union's explanation of a reduction in 2013 which attributed the reduction to turnback of M12 capacity that began in 2011 and is forecast to continue in 2012 and 2013. LPMA noted that in a response provided in Exhibit J8.10, Union indicated that there was an increase of $280,000 based on changes to M12, M12-X and C1 long-term firm contracts since the forecast was completed. LPMA submitted that this increase should be reflected in the forecast.

LPMA submitted that an acceptance of the forecast did not imply that the capacity that was not currently contracted for had no value. LPMA submitted that Union had significant excess capacity on the Dawn to Parkway system and it was possible that the unused capacity may be contracted for in 2013. LPMA therefore submitted that any variance from the Long-term Transportation revenue forecast, both up and down, should be captured in a variance account and shared 90% to ratepayers and 10% to the shareholder. FRPO and APPrO adopted LPMA's recommendations on this matter. CME accepted LPMA's recommendation of a variance account but submitted that the actual amount in 2013 rates should be $139.8 million as compared to $134.6 million. CME submitted that there was significant revenue potential considering that the gas had to get to Dawn regardless of where the gas was coming from.

In reply, Union rejected CME's proposal to adjust the M12 Long-term Transportation revenues. Union reiterated that it had experienced significant turnback on the Dawn-Parkway and Dawn-Kirkwall systems and this has resulted in a lower forecast in 2013 as compared to 2011 and 2012. Union also rejected LPMA's position that a deferral account should be established to capture the variance related to the Long-term Transportation revenue forecast. Union submitted that it has always been at risk for the Long-term Transportation revenues and that the same regulatory treatment should be continued.

<u>Other Long-term Transportation</u>

There are three components that comprise the Other Long-term Transportation revenue forecast: C1 Long-term Transportation, M13 (Local Production) and M16 (Storage-Transportation Service). The actual and forecast revenues for these services are shown in Table 2.

Table 2
Other Long-term Transportation Revenue

Revenue (Millions)	2010 Actual	2011 Actual	2012 Forecast	2013 Forecast
C1 Long-term Transportation	$6.3	$7.6	$6.6	$5.2
M13 Transportation	$0.4	$0.3	$0.4	$0.4
M16 Transportation	$0.6	$0.6	$0.6	$0.6
Total	$7.3	$8.5	$7.6	$6.2

Union attributed the decline in C1 Long-term Transportation revenue since 2011 to changes in market dynamics and gas flows affecting the Dawn-Parkway and Ojibway systems.

LPMA in its submission accepted the decline in C1 Long-term transportation revenues but noted that actual year-to-date 2012 revenues were up by 7% as compared to the forecast. Accordingly, LPMA submitted that the 2013 forecast should be adjusted by the same proportion resulting in an increase of $400,000.

In reply, Union rejected LPMA's submission to make an upward revision of $400,000 to the C1 Long-term Transportation revenue forecast. Union provided the clarification that revenues for 2012 which were categorized as C1 short-term were actually sold as C1 long-term. Consequently, there was an increase in the C1 Long-term Transportation forecast and a decrease in the C1 short-term transportation forecast. Union further submitted that this was an example of a selective adjustment where LPMA proposed adjustments for positive variances but excluded adjustments when they showed a negative variance.

Union submitted that the overall forecasts were reasonable even though there may be some negative or positive variances in the different categories. With respect to C1 Long-term Transportation, Union indicated that Dawn to Parkway revenues were offset by the negative variance in the M12 account. Union submitted that it had essentially forecast more capacity to be sold as short-term firm rather than C1 long-term.

Other S&T Revenue

This category is comprised of revenue earned from name changes, Ontario Producers and other miscellaneous services. The revenue for these services have been constant at $1.1 million in 2010 and 2011 and forecasted to be the same for 2012 and 2013. LPMA accepted Union's forecast for these services. APPrO and FRPO adopted LPMA's submission with respect to Long-term Storage and Transportation Revenue.

Board Findings

The Board accepts Union's forecast of 2013 M12 Long-Term Transportation Revenue, Other Long-Term Transportation Revenue, and Other S&T Revenue as reasonable. The Board will not require Union to adjust estimated revenues as was suggested by some parties, as the Board concurs with Union that the adjustments are selective in nature. The Board rejects LPMA's request to establish a variance account related to Long-term Transportation Revenue, as the Board believes that Union should continue to bear this forecast risk, consistent with the current treatment.

Short-term Transportation and Exchanges Revenue Forecast

The short-term transportation and exchanges revenue forecast is $32.2 million for 2012, and $20.2 million for 2013.

Short-term Transportation

The transportation component of the transactional forecast is comprised of short-term firm and interruptible transportation on Union's Dawn-Parkway systems, the Ojibway system and St. Clair/Bluewater system. Union forecasted $11.1 million in revenues in 2012 and again in 2013, down from $12.5 million in 2011. Union attributes the decline to insufficient takeaway capacity on TCPL downstream of Parkway. LPMA in its submission accepted the forecasted declines. LPMA also argued that the same variance account treatment that it proposed for Long-term Transportation Revenues should be applied to Short-term Transportation Revenues.

Board Findings

The Board accepts Union's forecast of 2013 Short-term Transportation Revenue as reasonable. The Board rejects LPMA's request to establish a variance account related to Short-term Transportation Revenue, as the Board believes that Union should continue to bear this forecast risk, consistent with the current treatment.

Short-term Storage & Balancing

Union's forecast for short-term storage and balancing is $9.1 million in 2012 and $11.5 million in 2013. This forecast is comprised of two components: peak short-term storage, and off-peak storage, balancing and loans. Union has forecasted an increase in 2013 related to short-term peak storage revenues. The primary reason for this increase is the increase in the forecast price of storage, from $0.55 per GJ in 2012 to $0.85 per GJ in 2013.

LPMA noted that based on data provided in Exhibit J6.3, the June year-to-date revenues for off-peak storage/balancing/loan services were tracking close to the forecast. LPMA accepted Union's forecast for 2013 since 2012 revenues were on track to meet the forecast and the forecast of $2.5 million for 2013 was similar to 2012.

However, LPMA noted that according to Exhibit J6.3, the year-to-date revenues for short-term storage services were over the forecast by $2.7 million, i.e. 87%. Moreover, the June 2012 actual revenues of $5.8 million were only slightly under the annual forecast of $6.6 million. LPMA submitted that using the same methodology as for base exchanges, the projected 2012 forecast based on how revenues were currently tracking was $12.3 million.

LPMA submitted that the 2013 forecast should be increased to the projected 2012 level of $12.3 million from the current forecast of $8.988 million. LPMA noted that the forecast of $12.3 million was still below the levels recorded in 2007 through 2010, despite more excess utility space projected to be available in 2013 than in previous years. FRPO and CME agreed with LPMA on these issues.

In reply, Union submitted that the 2012 forecast was initially prepared at an average price of $0.55 per GJ. However, the actual price was $0.84 per GJ and this was the cause of the positive variance. Union provided clarification that the forecast for 2013 was based on actual 2012 prices, which were at $0.60 per GJ and not $0.85 per GJ. Union submitted that there was no evidentiary basis to increase the 2013 forecast.

Board Findings

The Board accepts Union's forecast for 2013 Short-Term Storage & Balancing revenue as reasonable. Given the uncertainty relating to the forecast, the Board approves the continued operation and use of the Short-Term Storage & Balancing variance account to capture any variance of Short-Term Storage & Balancing net revenue from forecast, both up and down during the 2013 test year, consistent with the current practice. The Board notes that 90% of the net revenue forecast related to short-term storage and balancing is to be built into rates for 2013. The balance in the variance account is to be shared 90% to ratepayers and 10% to the shareholder.

OPTIMIZATION AND GAS SUPPLY PLAN

Exchanges

Exchange revenue is comprised of activity using Union's upstream transportation capacity to provide exchange services to third parties. It also includes net revenue generated from pipe releases or revenue from TCPL's Firm Transportation Risk Alleviation Mechanism ("FT-RAM") program. Union did not include any amount for the FT-RAM program in its Application due to the uncertainty surrounding the continuation of the program. TCPL has proposed to end the program in its current application before the National Energy Board.

Union included base exchange related revenues of $9.1 million in 2013. This compares to $8.6 million in 2010, $9.7 million in 2011 and a forecasted amount of $6.9 million in 2012.

LPMA and Energy Probe submitted that the forecast for base exchange revenues were significantly understated. LPMA referred to Exhibit J6.3 which shows that the actual base exchange revenue for year-to-date as at the end of June was 66% higher than the forecast for the same period. LPMA proposed that the Board should increase the 2013 forecast of $9.1 to reflect the under forecast in 2012. Union forecasted achieving $4.0 million or 58% of its revenues as of June 2012. LPMA proposed using the same ratio but applying it to the actual revenues of $6.6 million as of June which would result in an annual number of $11.4 million for 2012. LPMA submitted that Union had provided no evidence that base exchange revenues would decline in 2013 and the Board should therefore increase Union's revenues from $9.1 to $11.4 million in 2013, essentially maintaining the same level as that projected for 2012. CME supported LPMA's submission in this matter.

Union, in its reply argument, submitted that the Board should include $9.1 million in rates for base exchanges with any variance subject to sharing 75:25 in favour of ratepayers, consistent with the treatment prior to IRM.

Firm Transportation Risk Alleviation Mechanism ("FT-RAM")

FT-RAM or Firm Transportation Risk Alleviation Mechanism is a service to TransCanada's long-haul firm transportation ("FT") shippers. The FT-RAM program allows long-haul FT shippers to apply unutilized FT demand charges against their cost of interruptible transportation ("IT") service. TCPL introduced the FT-RAM program to promote the renewal of incremental contracting for long-haul FT service.

In its Argument-in-Chief, Union proposed to include $11.6 million in rates and establish a variance account to capture any additional revenues or any revenue shortfall. Union submitted that it should have 100% downside protection below $11.6 million and any revenue above $11.6 million should be shared 75:25 in favour of ratepayers.

Energy Probe submitted that Union's forecast of $11.6 million should be accepted only if the Board categorizes these revenues as transportation related. Energy Probe submitted that FT-RAM revenues should be classified as gas costs and 100% of the revenues should go to ratepayers through the Purchased Gas Variance Account.

Board staff submitted that Union had used the capacity that is excess to its gas supply plan to generate a significant amount of revenue over the years. In cases where the transportation capacity was assigned to a third-party, Union earned revenue by selling this capacity. Revenues generated through assignments flowed to ratepayers through the Unabsorbed Demand Charges ("UDC") deferral account. However, when Union needed the supply and it was being delivered through an alternate route, revenue generated as a result of such assignment flowed to Union's utility earnings. If the empty pipeline was TCPL capacity, then Union generated RAM credits through TCPL's FT-RAM program. Board staff submitted that under the FT-RAM program Union was monetizing RAM credits and it was then delivering gas through alternate and cheaper routes. In other words, Union was selling transportation capacity paid for by ratepayers and repurchasing the same service at a lower cost while keeping the margins. Board staff along with a number of intervenors submitted that Union had generated significant revenues using the FT-RAM program during the IRM period, the majority of which flowed through to Union's shareholder.

Board staff submitted that almost all revenues generated as a result of using pipeline capacity that customers have paid for in gas supply costs should go back to offset gas costs. Board staff submitted that customers have paid for this capacity and they should therefore derive any benefit as a result of optimization. However, Board staff did recognize that Union needs some incentive to optimize and proposed that 90% of the revenues generated through optimization activities related to transportation capacity that in-franchise customers have paid for should go to offset gas costs while the remaining amount should flow to utility earnings.

Although most intervenors agreed with the general argument of Board staff, they rejected the sharing formula. Intervenors such as LPMA, BOMA, Energy Probe, CME and FRPO submitted that all revenues generated through optimization activities related to transportation capacity paid for by ratepayers should go to offset gas costs. LPMA submitted that Union should not receive any incentive to get the best cost for the gas it supplies to its system gas customers. LPMA noted that Union does not make a profit on the cost of gas; it is a flow through cost to system gas customers. LPMA submitted that the cost of gas includes the cost of getting the gas to the Union system. LPMA stressed that the actual cost of gas, including the actual cost of getting it to Union is what system gas customers should be paying for. APPrO adopted LPMA's submission with respect to exchange related revenues.

FRPO in its submission attempted to provide some distinction between revenues that should offset gas costs and revenues that represent true optimization. FRPO submitted that FT-RAM credits associated with long haul contracts should be classified as gas costs while optimization of transportation within Union's franchise area or optimization of Storage Transportation Service ("STS") contracts could be classified as optimization that would be captured in the historical storage and transportation exchange services deferral account.

CME in its submission addressed the larger issue of revenue deficiency noting that cumulative overearnings during the IRM years averaged around $40 million a year. CME submitted that it could not understand why ratepayers were facing a revenue deficiency as opposed to a sufficiency. CME attributed the overearnings during the IRM years to revenue increases rather than cost reductions. An important contributor to the revenue increases was FT-RAM revenues.

CME noted that the Board and intervenors rely on Union to adhere to the concepts and principles embedded in the Board's regulation of gas utilities. CME submitted that one of the fundamental concepts was that for ratemaking purposes, gas commodity costs and upstream transportation costs are to be treated as pass-through items. CME maintained that the utility should neither profit nor lose as a result of the actual commodity or upstream transportation costs. CME was of the opinion that the utility holds the amounts in trust that it receives from ratepayers on account of gas commodity or upstream transportation costs. If actual costs are less than the actual amounts collected, then ratepayers are to receive a credit and if actual costs are higher, then ratepayers have to pay the difference. CME submitted that the excess funds could not be converted to profits without the prior explicit consent of ratepayers or the utility regulator.

CME submitted that Union had not presented all the relevant facts for the intervenors and the Board to determine the validity of its actions. CME maintained that Union's argument that it has undertaken optimization activities before is irrelevant since it had never explicitly presented the facts to the Board. CME asserted that Union could not unilaterally take action to enrich its shareholder at the expense of ratepayers.

In its Argument-in-Chief, Union indicated that there was a deferral account relating to upstream optimization and exchange activity going back to 1993 and perhaps even earlier. Union submitted that the exchange activities Union has undertaken since 2003 as it related to FT-RAM were similar to optimization activities that it undertook before and would undertake in 2013. Union referred to an interrogatory response that states that Union was able to extract value from new services introduced by upstream transportation providers in excess of what was achieved historically.[7] The new service referred to was TCPL's FT-RAM.

CME, in its submission, rejected Union's argument that FT-RAM refers to activities that are covered by the existing deferral accounts related to upstream transportation and exchange activities. CME stressed that the deferral accounts referred to only that component of upstream transportation that was periodically freed up as a result of weather or declines in demand. The rationale for sharing the incentive between the utility and ratepayers was to facilitate the use of idle capacity. CME submitted that this account did not cover optimization of upstream transportation surpluses self-created by the utility on a planned basis.

[7]CME Final Argument at Tab 28,

CME in its submission noted that there were two means through which Union monetized FT contracts. One was through capacity assignments and the other one was through leaving its FT capacity unutilized and using a cheaper alternative route to transport the required gas. CME submitted that both of these activities were nothing but upstream gas cost reductions. They could not be classified as exchange transactions or a transactional service. CME maintained that these were planned decisions and not related to capacity temporarily rendered surplus due to conditions beyond Union's control, such as weather or demand. CME submitted that revenues generated as a result of such activities must be classified as gas costs and should be cleared through the current regime of gas supply deferral accounts.

LPMA submitted that should the Board determine that FT-RAM revenues should not flow to system gas customers, but should flow through S&T revenues, then the amount included in the forecast for 2013, and how it is allocated to rate classes needed to be addressed.

LPMA noted that Union had proposed to include $11.6 million in rates, with a variance account to provide protection. LPMA referred to Exhibit J7.11 that estimated FT-RAM revenues of $37.8 million should the program continue for all of 2012. LPMA also noted that Union had received FT-RAM credits of $19.9 million on a year-to-date basis.

LPMA submitted that the Board should not approve the inclusion of any amounts in rates for 2013. In this way, customers would receive some credit in 2013 and would not be faced with a claw back if the program was eliminated. LPMA further noted that such an approach would eliminate the need to determine how to allocate the credits to the various rate classes. The allocation could be dealt with in a later proceeding when the credits came up for disposition. IGUA recommended a similar approach because it did not support including FT-RAM revenues as a rate mitigation option considering that it may not be available in 2013 and beyond. However, IGUA did not take any position on the treatment of FT-RAM revenues.

In reply, Union disagreed with the categorization proposed by intervenors. Union noted that intervenors were attempting to make a distinction between RAM-related exchanges and base exchanges with their argument being that RAM-related revenues should offset gas costs while base exchange revenues should be treated as traditional S&T revenues. Union argued that an exchange was an exchange and that there was no distinction to be made. Union saw no reason to depart from the well-established regulatory treatment of exchanges that treats them as regulated revenues pursuant to the C1 rate schedule.

Union also observed that exchange revenues were not unregulated. The only difference was that during the IRM period they were not subject to deferral treatment. However, they continued to be part of the utility earnings calculation and were subject to earnings sharing.

Union reiterated the definition of an "exchange" that had been clarified several times during the proceeding. Union stated that:

> An exchange is a contractual agreement where party 'A' agrees to give physical gas to party 'B' at one location and party 'B' agrees to give physical gas to party 'A' at another location. Either party 'A' or party 'B' may agree to pay the other party for this service. An exchange can only happen between a point on Union's system and a point off of Union's system. The exchange must also happen on the same day at the same time.

Union also rejected the argument of intervenors that the exchange activities were planned and a feature of the gas supply plan. Although Union forecasted a certain level of activity, Union submitted that it was consequential to the service made available by other parties, specifically TCPL.

Union, in reply, noted that the gas supply deferral accounts and the S&T deferral accounts have existed in parallel for years and the treatments for these deferral accounts have been different. While the gas supply deferral accounts have been treated as pass through items, exchanges and other S&T related activities have been treated as forecast revenues subject to deferral treatment.

Union also rejected CME's assertion that the Board had no knowledge of Union's FT-RAM related activities prior to this proceeding. Union submitted that in the EB-2009-0101 proceeding, Union explicitly informed parties that it had taken advantage of the FT-RAM service offered by TCPL. During this proceeding, Union reported significant over-earnings in relation to its S&T forecast. Union stated that in response to the over earnings, intervenors revised the 2007-0606 IRM settlement agreement and changed the earnings sharing mechanism from 50:50 to 90:10 in favour of ratepayers to be triggered if the actual ROE exceeded the Board approved ROE threshold by 300 basis points.

Union stressed the fact that intervenors had the opportunity to review whether IRM should continue or not in the EB-2009-0101 proceeding when Union crossed the 300 basis points threshold, but they chose not to. Union pointed to the fact that it was evident that a large contributor to the over earnings was Union's S&T activity that contributed $37 million to earnings of which Union's use of FT-RAM was a significant component.

Union also referred to the 2009 rates proceeding (EB-2008-0220), wherein the Board rendered a decision on a new service introduced by TCPL, Dawn Overrun Service – Must Nominate ("DOS MN"). In this proceeding, CME argued that DOS MN related revenues should be treated as gas supply costs. The Board did not agree with CME and determined that DOS MN revenues should be treated as S&T revenues. Union submitted that although DOS MN and FT-RAM were different services, the treatment was the same.

Union argued that it needs to sell an exchange into the market under the C1 rate schedule and this results in revenue being generated. Union therefore submitted that these revenues cannot be categorised as gas costs because they do not fit in either the gas commodity reductions or toll variances categories.

Union rejected intervenors' position and submitted that intervenors are attempting to classify revenues between gas costs and traditional S&T activity. Union argued that CME's definition did not take into account the market and it was not feasible to monitor the weather or demand on a daily basis. With respect to FRPO's definition, Union indicated that it was limited to particular services and would not be applicable if Union's portfolio were to change from long-haul to short-haul services or if it were to earn revenues on the Dawn-Parkway system.

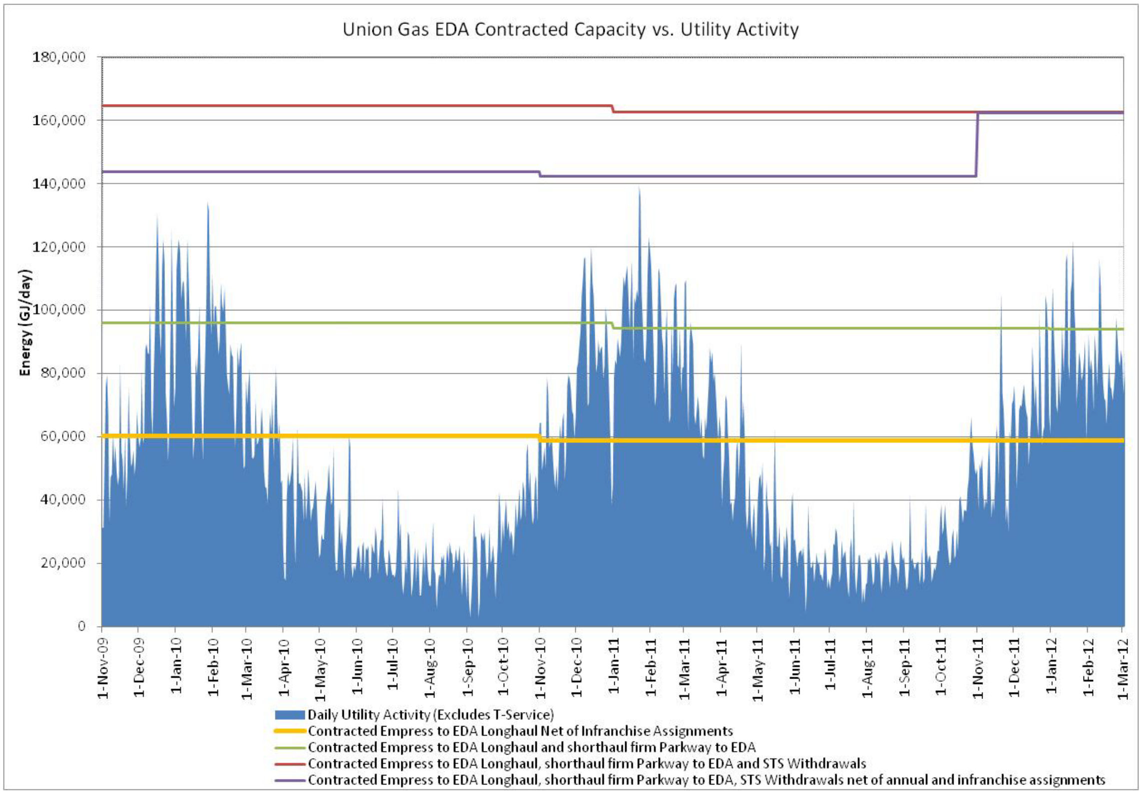
Union submitted that the best approach would be to establish an exchange-related account that is subject to sharing. This would avoid the problem of trying to differentiate the revenues generated and would be a principle based approach that would simplify implementation on a going forward basis. Union indicated that it had estimated FT RAM related revenues of $11.6 million in 2013. However, its preferred approach was to embed no amount in rates and have a deferral account that is subject to a 75:25 sharing in favour of ratepayers.

Gas Supply Plan

Union's gas supply planning process is guided by a set of principles that are intended to ensure that customers receive secure, diverse gas supply at a prudently incurred cost. Intervenors and Board staff submitted that Union is over contracting for FT Service to the Northern/Eastern Delivery Areas and this has resulted in customers incurring UDC for upstream transportation that is left empty or does not flow to full capacity to meet customers' annual firm demands. Board staff and Energy Probe submitted that ratepayers have incurred approximately $5.7 million in UDC costs from 2007 to 2011. Intervenors and Board staff further submitted that Union had arbitraged the excess firm capacity generating transportation revenues for the utility. Union, in reply submitted that all parties referred to the excess in a general manner and no party specifically identified the excess quantity or the specific contracts that Union should not have entered into.

Intervenors and Board staff referred to the graphical representation below of firm contracts in the Eastern Delivery Area ("EDA") that shows how the excess capacity of 20,000 GJ per day was assigned on a long-term basis. VECC, in its submission, noted that a portion of annual transportation contracts was assigned in its entirety on an annual basis, such that, from an operational perspective, it was as if Union had never entered into these contracts.[8]

[8] VECC Final Argument atp.20.



Referring to the same chart, Union, in reply, submitted that it did not over contract and the contracted capacity shown in the chart was appropriate in order to meet a design day. Union further noted that during the valley periods, Union injects gas into storage in order to meet average utility consumption throughout the year. If Union did not inject gas into storage then it would need to contract for even more gas and thus more capacity, during the winter. Union submitted that intervenors did not provide any support for their argument that Union had excess upstream capacity apart from the fact that Union earned S&T revenues during that period. Union submitted that ultimately the gas was required to meet in-franchise customer needs as presumed in the gas supply plan.

Board staff argued that Union's reliance on a design day[9]that is based on the coldest day within the past 50 years is flawed and this results in a far larger cushion than required. In its reply submission, Union argued that Union's design day of minus 29 degrees Celsius was not extremely cold for some of Union's service areas such as Fort Francis and North Bay. Union further noted that although Union's franchise area last experienced the design day in 1981, it has had several days of extreme weather where

[9] Oral Hearing Transcripts, EB-2011-0210, Volume 7 at pp. 161-162. (Design Day is a 47 degree day in the North and a 44 degree day in the South).

the temperature has been within two heating degree days of the design day. Union submitted that the importance of design day is critical in utility planning because the consequences of not having gas on a design day could be significant.[10]

Board staff and VECC noted that Union confirmed at the hearing that if the actual degree day requirements had exceeded the capacity of the firm assets that remained after optimization, Union would have been able to meet its gas supply requirements in several ways. Consequently, Board staff and VECC argued that Union did not require the capacity that it had contracted for. Union in its reply argument noted that its transportation portfolio had been adjusted substantially downwards since 2000. Union submitted that between 2002 and 2011, Union had reduced its long-term firm transportation portfolio of Empress to the Northern Delivery Area by 47%, from 358,643 GJs per day to 191,177 GJs per day.

CME submitted that a gas supply plan that was premised to profit from using upstream transportation capacity paid for by ratepayers was incompatible with the principle that a utility cannot profit from amounts received for upstream transportation.

FRPO, in its submission, argued that Union's gas supply plan relies on long-term firm service contracts that have been avoided or turned back by all customers, including prudent utilities in Canada and the United States within the last few years. FRPO indicated that declining firm contracts on the TCPL mainline is common knowledge. However, Union has continued to hold annual FT contracts even though utilities like Enbridge have moved to shorter-term arrangements such as winter Short-Term Firm Transportation ("STFT"). FRPO referred to Union's response at the hearing that expressed the possibility that Union may not be able to recontract if it were to move to winter STFT. However, FRPO argued that firm contracting on the TCPL main line has diminished significantly, resulting in spare capacity that cannot be sold.

In its reply argument, Union submitted that it had turned back substantial quantities of long haul FT Service during the past few years. Union noted that unlike Enbridge, Union does not require winter peaking service and therefore the reference by FRPO to Enbridge's winter STFT service was not relevant. Union also disputed FRPO's claim that STFT service has always been available and with the exception of service to

[10]Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p.85.

Montreal, STFT has been available for decades. Union submitted that it had indicated at the hearing that STFT was not available in 2011 in the Sault Ste. Marie Delivery Area. In addition, if Union were to use STFT service to get gas in the Sault Ste. Marie Delivery Area, it would have to ensure that STFT was available on all three segments, Dawn to St. Clair, the international crossing and from St. Clair to Sault Ste. Marie. For these reasons, Union submitted that it did not contract for STFT.

CME expressed concerns related to the forecast of 10.4 PJs of UDC which was significantly higher than the current forecast of 4.4 PJs. CME's concern was related to the fact that the UDC for Union was increasing while the market as a whole was taking steps to minimize expected UDC through a combination of FT and STFT. CME submitted that Union was not taking any steps to minimize UDC.

CME submitted that Union should be directed to mitigate the level of UDC to the maximum extent possible with the condition that the Board would review the UDC amount in a future process. CME did not suggest making any changes to the forecast UDC.

VECC, FRPO, CME and LPMA submitted that the Board should require a consultation that includes Union and interested parties to review and recommend changes to the gas supply plan that better responds to the needs of ratepayers. However, many intervenors agreed with Board staff that the gas supply plan for 2013 should be accepted. IGUA did not take any position on the gas supply issue.

Union, in reply, submitted that the gas supply plan was prudent and should be approved as filed. The principles were reasonable and the Board has on previous occasions approved Union's gas supply plan with no changes. Although Union did not feel that a consultation was required, it did indicate that should the Board decide to consider this approach, Union would prefer an independent review as compared to a consultation with intervenors.

Board Findings

Although the issues of optimization and natural gas supply planning are listed separately on the Issues List, it is evident to the Board from this proceeding that the issues are, in fact, inter-related.

Union defines optimization as a market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise, bundled customers. Union asserts that exchanges are nothing more than a type of optimization activity. Union has defined an exchange as a contractual agreement where party A agrees to give physical gas to party B at one location, and party B agrees to give physical gas to party A at another location. Either party A or party B may agree to pay the other party for this service. An exchange can only happen between a point on Union's system and a point off Union's system.

It is clear to the Board that the nature of Union's optimization activities has evolved since the NGEIR proceeding[11] and the commencement of Union's incentive regulation regime. Union has submitted in past proceedings that in the context of a balanced gas supply portfolio, few if any, firm assets are available to support transactional services on a future planned basis[12]. Union has asserted that firm assets are made available as a result of weather and market variances.

The Board finds that the record in this proceeding is clear that firm assets are being made available for transactional services on a planned basis, with releases occurring prior to the commencement of the heating season and with capacity being assigned for up to a full year. The revenues or margins arising from these services are not being returned to customers as an offset to gas supply costs.

The Board observes Union's statements that the purpose of the gas supply plan is to ensure secure and reliable gas supply to bundled customers from a diverse supply range, all at a prudently incurred cost. However, the record in this proceeding suggests that Union's optimization activities have, in their own right, become a driver of the gas supply plan, and are no longer solely a consequence of it.

The Board finds that Union's ability to "manufacture" optimization opportunities undermines the credibility of Union's gas supply planning process, the planning methodology, and the resulting gas supply plan.

[11] The Board initiated the Natural Gas Electricity Interface Review ("NGEIR") in 2005 to examine the regulatory treatment of natural gas infrastructure and services, specifically storage regulation (EB-2005-0551).
[12] RP-2003-0063/EB-2003-0087, Exhibit C1, Tab 3, Page 6 of 16.

As submitted by various parties to this proceeding and Board staff, Union has had an incentive to contract excessive upstream gas transportation services to the detriment of the ratepayer. Union has not filed convincing evidence that the amount and type of upstream gas transportation contracts procured on behalf of ratepayers reflects the objective application of its gas supply planning principles.

For example, the Board is of the view that the schedule filed by Union[13] showing decontracting on the TCPL system is not helpful. The schedule does not inform the Board's overall assessment of whether the gas supply plan is prudent, as the schedule does not speak to whether too much or too little TCPL capacity has been released. Further, the schedule does not inform the Board as to whether the increase in tolls on the remaining long-term FT capacity with TCPL arising from decontracting has been more than offset by reductions in tolls on alternative transportation routes, including those pipeline companies in which Union's parent company has, or will have, an economic interest.

Union provided evidence that it did not consider this type of cost-benefit analysis in its gas supply planning function and that the gas supply personnel look only at current tolls when making a purchasing decision.[14] Moreover, Union testified that its gas supply planning personnel may not have an understanding of the basis upon which the rates or tolls paid for upstream transportation are calculated.[15]

The Board does not accept this approach. The Board is of the view that the principles used by Union's gas supply planning group are at a very high level and thus provide little guidance with respect to how the costs that Union incurs are calculated, and whether such costs would, in fact, be prudently incurred.

Union's evidence on its optimization activities has not been clear and Union's approach with respect to optimization in general has not been helpful. The Board notes that absent the TCPL application filed with the NEB on September 1, 2011, little information describing the nature of these activities (notably FT-RAM) would have been available.

In RP-1999-0001, the Board, quoting from E.B.R.O. 452 (paragraph 6.5 of that decision) stated that:

[13] Union Gas Reply Argument Compendium, Gas Supply Tab 4. Union Gas – TransCanada Long-haul and STS Summary 2000 – 2011.
[14] Oral Hearing Transcripts, EB-2011-0210, Volume 3 at pp. 103-104.
[15] Ibid. at pp. 153-155.

> Regulation is intended to be a surrogate for competition in the marketplace and the legislation intended that the Company has an opportunity to recover its costs and to earn a fair rate of return on its shareholders' equity…The system requires the regulator to act on faith with the utility, bearing in mind the prospective nature of the evidence. The regulator expects the utility, in return, to provide the best possible forecast data that can be made available, on a timely basis.

The Board also said in paragraph 4.2 of RP-1999-0001:

> The Board appreciates that business plans are not carved in stone and the utility must have flexibility to meet ongoing demands of the marketplace; however, this flexibility must be balanced against the utility's obligations as a regulated entity. This is particularly true when the Company is not responding to exogenous events, beyond the Company's control, but is implementing its own initiatives.

Union stated that there have been at last 20 separate proceedings before the Board relating to QRAMs, deferral accounts, and rebasing and argued that the Board's discovery-related powers are tools that the Board has at its disposal which go well beyond what even a court of law has in a civil context. The implication of these arguments is that these issues should have been identified by intervenors and Board staff via interrogatories, document production, and technical conferences.[16]

The Board disagrees with Union's assertion that it is the responsibility of intervenors and Board staff to undertake adequate discovery to ensure that the record is complete. Union is a rate regulated entity, and the information asymmetry in evidence in this proceeding is illustrative of the need for the Board to reiterate Union's affirmative disclosure obligations.

At paragraph 4.5 in RP-1999-0001 the Board clearly sets out a utility's affirmative obligation to disclose by stating:

> The Company has an affirmative obligation to provide the Board with the best possible evidence and it is not incumbent on the intervenors to ensure, through cross examination of the Company's witnesses, that the record is adequate and complete. The Company cannot shirk its

[16] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 3.

> responsibilities as a regulated entity by submitting evidence that is vague and incomplete.

Union has not met this affirmative obligation.

<u>Optimization</u>

Consistent with the long-standing principle that a gas utility should not profit from the procurement of gas supply for its in-franchise customers, and to eliminate the creation of inappropriate incentives during the test year, the Board finds that the optimization activities, as defined below, are to be considered part of gas supply, not part of transactional services.

The Board reiterates that gas supply costs refer to both the upstream gas cost, including fuel gas, and the cost (rate multiplied by contract volume) of upstream transportation that is required to deliver gas supply to Union's in-franchise customers in the North and South Delivery Areas.

Consistent with the description provided by Union, the Board will define optimization as any market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise bundled customers, including, but not limited to, all FT-RAM activities and exchanges.

The Board finds that 90% of all optimization net revenues shall accrue to ratepayers and 10% shall accrue to Union as an incentive to continue to undertake these activities on behalf of ratepayers. Although Union has undertaken optimization activities for a lengthy period of time, it has indicated that absent an incentive, these types of activities may not occur. The Board has not considered the issue of whether optimization is an integral part of prudent utility practice that should be undertaken by Union without the payment of an incentive. Absent consideration of this issue by the Board in the context of this proceeding, the Board is of the view that it is appropriate for an incentive to be continued, at a 10% rate. This level of incentive is consistent with that associated with short-term storage and balancing.

The Board orders the establishment of a new gas supply variance account in which 90% of all optimization margins not otherwise reflected in the revenue requirement are to be captured for the benefit of ratepayers. This variance account is symmetrical. The balance of this gas supply variance account will be disposed of on an annual basis.

The Board finds that at the time an application to clear this new gas supply variance account is filed with the Board, Union must also file a proposal to allocate the balance of the new gas supply variance account to in-franchise customers, including direct purchase customers in the North. This proposal must be based on regulatory principles.

Consistent with these findings, 90% of Union's 2013 forecast of base exchanges of $9.1 million is to be reflected in the 2013 test year revenue requirement. Union's 2013 forecast of FT-RAM related revenue is $11.6 million. Given the uncertainty relating to whether the FT-RAM program will be continued by TCPL through the 2013 test year and subject to the Board's finding that a 10% incentive for optimization activities is to accrue to Union, the Board finds that only half (50%) of Union's FT-RAM forecast for 2013 should be reflected in the 2013 revenue requirement. To be clear, 90% of one half of Union's estimate of FT-RAM related revenue in 2013 is to be reflected in Union's 2013 Board-approved rates, i.e. $5.22 million.

Gas Supply Plan

The Board approves Union's 2013 Natural Gas Supply Plan, as filed. However, the Board has concerns with Union's gas supply planning process, its planning methodology, and the resulting supply plan in light of Union's actions over the incentive regulation period. The Board believes that confidence in the gas supply plan is essential. The Board is therefore of the view that a further, more detailed review of Union's gas supply planning functions would be beneficial.

The Board is of the view that an expert, independent review rather than a consultation is a better way to proceed, given the highly specialized nature of the review to be undertaken. Accordingly, the Board orders Union, prior to its next rates proceeding (cost of service or incentive regulation), to file with the Board an expert, independent review of its gas supply plan, its gas supply planning process, and gas supply planning methodology.

This review is to be conducted by an independent third party with gas supply planning expertise. The Board directs Union to establish a deferral account to capture the cost of the expert, independent review, for disposition in Union's next rates proceeding.

As suggested by Union, intervenors and Board staff are to be provided an opportunity to review the Request for Proposals ("RFP") associated with this review prior to issuance. The scope or purpose of the review will be subject to the comments of intervenors and Board staff. In addition to comments that may be provided by parties, the Board finds that the purpose of the review should include, but not be limited to, the following:

1. Verify that Union's gas supply planning process, methodology, and plan reflects appropriate planning principles, including a reference to cost.
2. Determine whether planning principles are objectively applied and result in a gas supply plan that is "right sized".
3. Determine whether Union's differing peak-day methodologies in the North and South Delivery Areas are appropriate, and if not, recommend alternative approaches.
4. Recommend whether the two approaches should be aligned.
5. Compare the methodology of determining the peak design day, based on the coldest day in the last 50 years, with other heat-sensitive distributors in North America.
6. Determine whether the peak day in the North and South Delivery Areas are appropriately/consistently reflected in the gas supply plan, and if not, recommend remedial action.
7. Determine whether Union is conducting sufficient due diligence with respect to the cost benefit analysis associated with decontracting a particular gas transportation route and recontracting on an alternative route, and recommend remedial action, if required.
8. Determine whether Union is using the transportation portion of the gas supply portfolio to favour the transportation paths of entities in which Union or its parent has (or will have in the future) an economic interest, and recommend remedial action, if required.
9. Examine the cost allocation and rate design used by Union to allocate the cost of gas supply to in-franchise customers in the North and South to ensure that it is appropriate and reflects regulatory principles.
10. Examine the structure of the current natural gas supply deferral and variance accounts, with a view to simplifying and standardizing these accounts in the North and South Delivery Areas.
11. Determine whether the structure and text of the various natural gas supply deferral and variance accounts is consistent with the principles of the Decisions and Orders that provided the authorization for these accounts and consistent with the findings of the Board in this proceeding, and recommend remedial action, if required.

The results of the review are to be subject to a stakeholder information process and then be submitted in conjunction with Union's next rates proceeding (cost of service or incentive regulation regime).

COST OF CAPITAL

Union's investment in rate base is financed by a combination of short-term and long-term debt, preferred shares and common equity. The current Board approved capital structure is based on a 36% common equity component. The remaining 64% is financed by a mix of short-term debt, long-term debt and preferred shares.

Union has proposed a capital structure which includes a common equity ratio of 40% for 2013 as compared to the 36% currently included in rates. The 36% equity ratio was set as a result of a Settlement Agreement in the 2007 Cost of Service Proceeding (EB-2005-0520).

Union has proposed a long-term debt ratio of 60.17% and a debt rate of 6.53%. The short-term debt ratio is -2.92% with a rate of 1.31%. The average embedded cost of preferred share capital for 2013 is 3.05%. This is a decrease from the 2007 Board approved cost of 4.74%.

<u>Common Equity Ratio</u>

Most intervenors and Board staff submitted that Union's proposal to raise the common equity ratio from 36% to 40% should be rejected. IGUA did not take any position on this issue.

In support of its proposal, Union retained two experts: Mr. Steven M. Fetter and Dr. Vander Weide. In response, intervenors presented the expert evidence of Dr. Lawrence D. Booth.

Intervenors and Board staff cited the Report of the Board on Cost of Capital for Ontario's Regulated Utilities[17] that provided guidelines with respect to a gas utility's capital structure. The report on page 50 states:

[17] Report of the Board on Cost of Capital for Ontario's Regulated Utilities, dated December 11, 2009 (EB-2009-0084),pp. 49, 51.

> For electricity transmitters, generators and gas utilities, the deemed capital structure is determined on a case-by-case basis. The Board's draft guidelines assume that the base capital structure will remain relatively constant over time and that a full reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risk.

Intervenors and Board staff submitted that Union had made no attempt to comply with the guideline in requesting a change in the equity thickness and Union's evidence indicated that it had not analyzed its financial and business risk as part of this proceeding. Board staff and intervenors further noted that Union's argument was that its current equity structure is not commensurate with its risk. However, Union agreed that its business or financial risk had not changed materially since 2006. In fact, Union witnesses confirmed several times during the oral hearing that there had been no material increase to its business or financial risk.[18] Union agreed in reply that its risk profile had not changed but it noted that in the 2007 rates case, Dr. Carpenter and the Brattle Group stated that Union's business risk warranted an equity ratio between 40 and 56%, depending on the allowed rate of return.[19] Union therefore believed that an equity ratio of 40% was appropriate based on its current risk profile.

Mr. Fetter was of the opinion that an equity thickness of 40%-42% would improve Union Gas' financial profile benefitting its customers through Union's enhanced ability to attract capital from investors when needed and upon reasonable terms. Mr. Fetter, in his report, also indicated that equity ratios of utilities were rarely set below 40% in the United States. Mr. Fetter further noted that a review of other Canadian gas utilities showed that the deemed equity ratios were in the range of 39% to 43%. In its Argument-in-Chief, Union submitted that it had to compete for capital with other utilities across the United States and Canada and a 36% equity ratio puts Union at a disadvantage.[20]

In reply, Union submitted that none of the intervenors had challenged Union's position that other comparable utilities had higher equity ratios than 36% and that Union was lower relative to its peers. Union further submitted that no party challenged the comparability of Union to ATCO Gas or Terasen. Union disputed intervenors' argument that comparability has no value and noted that Dr. Booth, the expert consultant of the

[18]Oral Hearing Transcripts, EB-2011-0210, Volume 4 at p. 128 and Volume 5 at pp. 15 and 31.
[19] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 105.
[20] Oral Hearing Transcripts, EB-2011-0210, Volume 13 at p. 53.

intervenors, in his testimony confirmed that the regulator should give weight to the deemed equity ratios of comparable utilities.[21]

CCC submitted that the Board consistent with its own policy must examine the individual circumstances of Union and in particular, the business and financial risk faced by Union to determine whether a change in capital structure is required. CCC further submitted that the use of comparators may supplement, but cannot replace that analysis. CCC also disputed Mr. Fetter's opinion that a higher equity ratio would allow Union to withstand future unforeseen events. CCC argued that Mr. Fetter's opinion was hypothetical.

Intervenors and Board staff submitted that Union had provided no evidence that it has not been able to compete for capital on favourable terms with other utilities. Intervenors and Board staff submitted that throughout the IRM period which coincided with a severe global financial crisis, Union had maintained a high credit rating. Union has been able to attract capital on reasonable terms under its current capital structure. Intervenors and Board staff referred to an interrogatory response[22] where Union confirmed that an equity ratio of 40% would not lead to a higher credit rating or a lower cost of debt. This view was also stated in the Standard and Poor's report which notes that Union would not get a higher rating than Spectra, its parent. In Reply, Union submitted that DBRS in its report noted that Union had requested a 40% deemed equity ratio. Union submitted that in that report DBRS expected Union to manage its balance sheet in line with the new regulatory capital structure and maintain greater financial flexibility commensurate with the current rating category. Union argued that this meant that Union would fit more appropriately with the current rating if it had a 40% common equity.[23]

Dr. Booth in his testimony expressed the view that one major aspect of risk was whether a utility was able to earn its allowed return on equity. Dr. Booth noted that since 2000, Union's average over-earning was about 2%. Intervenors and Board staff in their submission noted that Union had over-earned by approximately $278.7 million from 2007 to 2012. Intervenors and Board staff submitted that Union had provided no evidence to demonstrate a change in its risk profile. In reply, Union submitted that there

[21] Oral Hearing Transcripts, EB-2011-0210, Volume 6 at p. 61.
[22]Exhibit J.E-1-1-2.
[23] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 102.

is a surplus of supply east of Union's Dawn to Parkway system and that posed a significant risk to Union. Union noted that there was further risk of turnback and this was reflected in lower revenues on Dawn to Kirkwall and M12.[24]

BOMA, in its submission, submitted that Union's interest coverage ratio was 2.74 which was higher than the 2% minimum interest coverage ratio set out in Union's trust indenture. This was higher than the ratios in 2008, 2009 and 2010 when it was 2.4%and 2.24% in 2007. However, the interest coverage ratio was lower than the threshold when the unregulated business was excluded from the calculation. BOMA further submitted that with respect to the interest coverage ratio, the common practice was to look at the entire company and not just the regulated portion of the business.[25] Union, in reply, disagreed with BOMA and submitted that this view was at odds with the general focus of intervenors that pursue to ensure that there is no cross-subsidy of the unregulated business by the regulated business. Union submitted that the intervenors wanted the Board to agree that it was appropriate to cross-subsidize the regulated business in order to meet the interest coverage ratio.

CCC in its argument cited the Ontario Court of Appeal in its decision (Toronto Hydro-Electric System Limited v. Ontario Energy Board, 2010) where the court stated that regulated utilities must balance the needs of shareholders and ratepayers. CCC submitted that if the proposed change in capital structure is approved, Union's shareholders will benefit by approximately $17 million while there would be no corresponding benefit within the test year to Union's ratepayers. CCC submitted that the Board should conclude that Union had not balanced the interests of its ratepayers and shareholders and accordingly disallow the change in the common equity ratio.

LPMA submitted that if the Board does approve Union's proposal or approves an equity ratio greater than the current 36%, then in that case, the Board would have to deal with how to treat preferred shares in the deemed capital structure. LPMA submitted that according to USGAAP, Union's preference shares were classified as equity by their auditors. LPMA submitted that there was no reason for the Board to deviate from the USGAAP treatment. SEC disagreed with LPMA and submitted that when the Board reviewed Union's capital structure in 2004, it did not consider preference shares to be equity and the Board should therefore refrain from doing so in this case. SEC submitted

[24] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 107.
[25] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at p. 88.

that the preference shares should be treated as long-term debt. Union agreed with SEC and noted that the Board had never considered Union's preference shares in any assessment of Union's common equity ratio. In addition, Union noted that they were not even considered relevant by Dr. Booth in his analysis.

SEC, in its submission, agreed with Union that the Board's Report on Cost of Capital is a guideline. However, it noted that the Board had thoroughly reviewed the business risk of Union in 2004 and unless there was a change in the business risk, there was no need for a utility to come before the Board with a different proposal. SEC submitted that Union was merely rearguing the 2004 case and there was no new evidence to show a change in risk.

SEC further submitted that Union had not articulated any benefits to ratepayers such as better access to market or lower borrowing costs, which Union already enjoys. In reply, Union submitted that the expectation that a higher equity ratio must be accompanied by lower borrowing costs or a ratings upgrade is unrealistic. Union therefore submitted that the Board should reject the submissions of intervenors.

Unlike other intervenors, LPMA and SEC submitted that Union's common equity ratio should be reduced from 36% to 35% consistent with what the Board had determined when it last reviewed the business risk and equity thickness of the company in 2004.

Cost of Debt

None of the intervenors raised any issues with the rates for short-term and long-term debt or preferred shares. LPMA however made a submission on the mix of short-term and long-term debt.

LPMA submitted that Union's proposal of a long-term debt ratio of 60.17% and a short-term debt ratio of -2.92% meant that ratepayers were being asked to pay a long-term debt rate on $108.5 million of borrowings and receive a credit at the short-term debt rate. LPMA submitted that this was not appropriate and was an indication that Union was over capitalized for rate base purposes.

LPMA noted that Union attributed the negative short-term debt to items outside of rate base that the utility has to invest in, such as construction work-in-progress and the contribution in excess of expenses for pension.

Union's average short-term borrowing for 2013 is predicted by LPMA to be $136 million[26] which represents approximately 3.66% of Union's rate base.

LPMA and SEC submitted that Union has more long-term debt than needed to finance rate base. This is under the scenario of a 36% and a 40% common equity ratio. At the same time, these scenarios have not included any short-term debt according to LPMA.

LPMA and SEC submitted that the Board should direct Union to include $136 million in short-term debt in the cost of capital calculation. Both parties further submitted that the balancing figure would be the long-term debt component. LPMA considered this to be an appropriate approach since in its view it was obvious that some of the long-term debt is being used to finance items outside of rate base.

In reply, Union noted that its cash position varied significantly due to the seasonal nature of its business. It further stated that long-term debt changes do not occur quickly and that the cash position would slowly return to short-term debt as the long-term debt level adjusted through maturities and reduced issues. Union submitted that issuing debt in small amounts was administratively burdensome and lumpy. Union indicated that it obtains long-term financing when prudent and tries to take advantage of favourable market conditions.

Union further submitted that having a negative short-term balance was not a new issue and the Board had addressed this before in the RP-2003-0063 proceeding. In the RP-2003-0063 Decision with Reasons dated March 18, 2004, the Board, on page112, determined that Union was in compliance with its deemed capital structure even though its long-term debt had marginally exceeded the 65% debt component of its approved capital structure. This excess was offset by a negative short-term debt balance.

Union emphasized that in the RP-2003-0063 Decision, the Board had used the word "marginal" to describe the level of excess in the long-term debt component. The actual

[26] Oral Hearing Transcripts, EB-2011-0210,Volume 5 at p. 40.

unfunded short-term debt was approximately $130 million in 2004 which is higher than the current unfunded short-term debt component of $115 million. Union submitted that the Board should reach a similar conclusion in this proceeding and not make any adjustments to the short-term or long-term debt component.

Board Findings

Deemed Common Equity Thickness

The Board finds that a deemed common equity ratio of 36% is appropriate for the 2013 test year, consistent with the deemed common equity ratio that was in place over the 2007 to 2012 period, inclusively.

The 2009 Cost of Capital Policy of the Board at page 43 sets out that for natural gas distributors such as Union, deemed capital structure is determined on a case-by-case basis and that reassessment of a gas utility's capital structure will only be undertaken in the event of significant changes in the company's business and/or financial risks.

Union filed no evidence in this proceeding that demonstrates its business and/or financial risks have changed over the period that the IRM Settlement Agreement was in place. In fact, Union stated many times during the proceeding that its business and financial risks have not changed and that it accepts that its overall risk profile has not materially changed since 2006.

Union put forth two arguments to support its application for a 40% deemed common equity ratio. The first is that the current deemed common equity ratio of 36% is too low and has never appropriately reflected its business and financial risk. Second, that the deemed common equity ratio should be increased solely on the basis of comparability; i.e., because other Canadian utilities now have higher deemed common equity ratios, the Board should also approve a higher deemed common equity ratio for Union.

The Board will address each of these two arguments in turn.

The Board does not accept the proposition that the deemed common equity thickness of 35% as determined by the Board in 2004 and subsequently increased to 36% as a result of a Settlement Agreement was incorrect and that it did not adequately reflect Union's financial and business risk profile. Union has filed no evidence to support this position that the deemed equity ratio was not correct and the Board therefore gives this argument little or no weight.

The Fair Return Standard ("FRS") requires that a fair or reasonable return on capital should:

- Be comparable to the return available from the application of invested capital to other enterprises of like risk (the comparable investment standard);
- Enable the financial integrity of the regulated enterprise to be maintained (the financial integrity standard); and
- Permit incremental capital to be attracted to the enterprise on reasonable terms and conditions (the capital attraction standard).

Union's second argument focuses on the first part of the comparable investment standard – that the return on invested capital must be comparable. However, Union's argument fails to address the second part of the comparable investment standard, that being the issue of "enterprises of like risk". Union would have the Board increase (and potentially reduce) its deemed common equity ratio in lock-step with the decisions of other regulators, without an analysis of whether the utilities to which it is compared are enterprises of like risk.

The Board acknowledges that there was a general consensus on the Canadian utilities that intervenors and Union asserted were comparable. The Board notes, however, that neither Union nor the intervenors filed analytical evidence that demonstrated that these utilities are of like risk to Union. Rather, what evidence was presented was anecdotal, ad hoc, and incomplete.

The Board is aware that since the 2008 financial crisis, the deemed common equity ratios of certain Canadian rate regulated entities have been increased. However, no evidence was filed in this proceeding that set out the risks that resulted in findings supporting higher deemed common equity for these utilities and no evidence was filed that demonstrates Union faces similar risks.

Union reiterated throughout the proceeding that its business and/or financial risks have not changed since 2006.

Accordingly, there is no reasonable basis for the Board to increase Union's deemed common equity ratio above the 36% level presently reflected in rates.

The Board does not agree with the submission of SEC that a higher deemed equity ratio must be supported by benefits to ratepayers. The Board's obligation to determine the quantum of common equity (at issue in this proceeding) and the cost of that equity (subject to the Settlement Agreement) is governed by the FRS, which is a non-optional, legal standard.

The Board also does not agree with the submission of CCC that the Board must balance the interests of ratepayers and shareholders in determining the deemed common equity ratio. Consistent with the jurisprudence discussed in the 2009 Cost of Capital Policy, the Board remains of the view that it is not in the determination of the cost of capital that investor and consumer interests are balanced. This balance is achieved in the setting of rates.

Finally, the Board is of the view that there is no evidentiary basis to support a reduction in deemed common equity from the existing 36% to 35%.

Cost of Debt and Preferred Shares

The Board approves the cost of short-term, long-term debt, and preferred shares as per Appendix B, Schedule 3 of the Settlement Agreement. The Board notes that no issues were raised by intervenors or Board staff regarding the appropriateness of these costs during the proceeding.

Debt and Preferred Share Capitalization

The Board approves the amount of long-term debt, short-term debt, and preferred share equity as set out by Union in Exhibit J5.4, page 2, lines 7 through 12, which reflects the Settlement Agreement relating to this proceeding and deemed common equity of 36%.

The Board's findings on the amount of short-term and long-term debt are consistent with previous decisions of the Board and are consistent with Union's evidence that items outside of rate base are funded by short-term debt.

The Board has not undertaken a comprehensive review of whether it is appropriate for a gas utility to have preferred shares in its capital structure. The Board is generally aware that preferred shares are often referred to as "mezzanine capital", having characteristics of both debt and equity. There was no assessment of the characteristics of Union's issued and outstanding preferred shares in this proceeding. Similarly, there was no assessment of whether Union's issued and outstanding preferred shares should be considered to be common equity or debt for the purpose of determining Union's capital structure in order to set utility rates.

The Board will thus continue its current practice of approving the amount and cost of Union's preferred shares as a separate part of total utility capitalization. The Board notes, however, that the presence of preferred shares has the effect of reducing the amount of total debt capitalization in Union's capital structure.

COST ALLOCATION

General Cost Allocation Issues

Union provided a summary description of the methodology used to complete the cost allocation study, which supports the 2013 rate proposals. Union submitted that subject to the removal of the unregulated storage operations and certain proposals in Exhibit G1, Tab 1 (which are discussed below), the cost allocation study is consistent with the studies that were approved by the Board and used in the past, including in EB-2005-0520.

Union noted that the objective of the cost allocation study is to allocate the utility test year cost of service to customer rate classes for the purpose of acting as a guide to the rate design process. To allocate costs, the test year cost of service is analyzed to determine the appropriate functionalization and classification of costs. Union noted that the allocation of costs to individual rate classes is based upon these determinations.[27]

Union stated that the cost allocation study consists of three steps. These steps are:

Functionalization of costs to utility service functions: The first step of the cost allocation process is to associate asset and operating costs with the various utility service functions. There are four functions generally accepted as necessary to obtain and move gas to market: purchase and production of gas, storage, transmission, and distribution.

Classification of costs to cost incurrence (demand, commodity, customer): The second step categorizes functionalized asset and operating costs into classifications according to cost incurrence. The three main classifications are demand-related, commodity-related, and customer-related. Demand-related costs, also known as capacity-related costs are costs that vary with peak day usage of the system. Commodity-related costs are costs that are typically variable in nature and vary with the

[27] Exhibit G3, Tab 1, Schedule 1 at p. 1 (Updated).

level of gas consumed. Customer-related costs are costs that are incurred by virtue of a customer taking service and do not vary with either peak day demand or consumption.

Allocation of costs to rate classes: The final step in the cost allocation process attributes the three types of costs classified above. Allocation factors that reflect the underlying cause of cost incurrence are used in the allocation process. For example, demand-related costs are allocated using the peak day demands of each rate class. Commodity-related costs are allocated based on rate class consumption. Customer-related costs are allocated based on the number of customers in a rate class.[28]

Union noted that once these steps have been completed, costs allocated to each rate class can be totaled and compared to the revenue achieved.

Union noted that judgment is required in apportioning costs to the various functions and their sub-classifications. Union stated that this judgment is based on the specific knowledge of how its system is operated. As a result, a fully distributed cost of service study is used to provide an indication of cost responsibility by rate class at a specific point in time, but cannot and should not be viewed as a precise measurement of the actual cost to serve a particular rate class, much less a particular customer.[29]

Union noted that the cost allocation study for the current test year no longer includes costs associated with Union's unregulated storage business. Only utility costs relating to a maximum 100 PJ of storage space are included in the cost allocation study and used to allocate the cost of service to the utility rate classes.

Union noted that it allocated storage-related costs based on forecast in-franchise demand and system integrity requirements. All remaining storage-related costs, beyond the 100 PJ of regulated storage space, are allocated to the "Excess Utility Storage Space" category. Union charges its unregulated storage business the costs allocated to the Excess Utility Storage Space category for its use of the regulated storage space that is not required to meet in-franchise requirements. The total revenue requirement in this category, less compressor fuel, unaccounted-for-gas ("UFG") and non-utility system integrity costs, represents the cross charge to the non-utility. Accordingly, the allocators associated with regulated storage reflect only regulated activity.[30]

[28] Exhibit G1, Tab 1 at pp. 2-3 (Updated).
[29] Exhibit G3, Tab 1, Schedule 1 at p.2.
[30] Exhibit G1, Tab 1 at pp. 1-2. (Updated).

Union submitted that in conducting its analysis and preparing its cost allocation evidence, it used the Board's previously approved cost allocation methodologies, subject to the removal of the unregulated business and specific proposals which are discussed later in this Decision.

Board Findings

The Board generally accepts Union's cost allocation study and the resulting allocation of costs for the 2013 rate year. However, the Board has made findings on Union's specific cost allocation proposals below, which do impact, in some cases, the allocation of costs for certain groups of assets.

The Board notes that the allocation of costs, subject to the Board's findings on specific cost allocation proposals below, is approved only for 2013. The Board has some concerns with Union's 2014 rate redesign proposals (Rates 01 / 10 and Rates M1 / M2). Accordingly, the Board has directed Union, later in this Decision, to file an updated cost allocation study as part of its 2014 rates filing. The reasons associated with the Board's direction to file an updated cost allocation study are discussed in the section of this Decision that addresses Union's Rate 01 / 10 and Rate M1 / M2 rate redesign proposal.

System Integrity

Union noted that the 100 PJ of storage space reserved for in-franchise demands includes the space reserved for system integrity. System integrity space costs are included in the cost allocation study and allocated to utility rate classes and the Excess Utility Storage Space category. The Excess Utility Storage category includes the system integrity space costs for short-term storage and non-utility storage operations. Union submitted that it used the Board-approved methodology to allocate system integrity costs, except for its proposal related to storage pool hysteresis.

Consistent with the Board-approved methodology, Union proposed that the filled space costs continue to be allocated on the basis of storage space requirements. For purposes of determining storage pool hysteresis requirements, Union calculated a revised storage space requirement which includes total working storage capacity less non-utility third party storage space and system integrity space reserved for the Hagar LNG facility and storage hysteresis. Union noted that it requires empty system integrity space on November 1to manage late season injection demands. The space is specifically held in reserve to manage the difference between in-franchise supplies and demands. Empty system integrity space is not required for short-term and long-term non-utility storage contracts as these contracts have little to no firm injection rights during October and November. Accordingly, Union proposed to allocate the empty system integrity space costs reserved for hysteresis based on the revised storage space excluding short-term and long-term non-utility storage space.[31]

The issue of system integrity space was partially settled as part of the settlement process. The Settlement Agreement states:

> For the purpose of settlement, the parties accept Union's proposed system integrity space value and its allocation for 2013. Acceptance is without prejudice to the examination at the hearing of matters pertaining to the actual use of utility storage space, including system integrity space, provided that the determination of this issue by the Board will not result in any change to the test year revenue requirement related to issues described under heading Exhibit B – Rate Base and heading Exhibit D – Cost of Service.[32]

Issue 6.4 is as follows: "Is the cost allocation study methodology to allocate the cost of system integrity appropriate?" The Settlement Agreement states that there is no settlement of this issue.[33]

Therefore, the issues relating to system integrity space that remain unsettled are whether the cost allocation study methodology for allocating the costs of system integrity space is appropriate and whether Union could use its fall integrity space as part of its winter integrity space.

No parties argued that the methodology used by Union to allocate the costs of system integrity space is not appropriate.

FRPO noted that Union has proposed that it would have two sets of contingency storage space - fall contingency space of 3.5 PJs and winter contingency space of 6 PJs. FRPO stated that the fall contingency space would be used in the event of a warmer than average weather and in providing extra space for continued storage

[31]Ibid at pp. 3-5.
[32]Updated Settlement Agreement, July 18, 2012 at pp. 15-16.
[33]Ibid at p. 19.

operations. The winter contingency space would be used to keep Union's storage operating during the critical periods of cold weather in the winter months.

FRPO postulated that the 3.5 PJs of fall contingency space could also be used as part of the 6 PJs of winter contingency space. Basically, FRPO asked Union to consider that if the 3.5 PJs of fall space were not filled, then that space could be subsequently used as part of the 6 PJs of space reserved for the winter. In that scenario, Union would make available an additional 3.5 PJs of storage space that could be used to sell short-term storage services (as it is now part of Union's Excess Utility Space classification). Union responded that it would be too expensive to fill that space in December and would result in a negative overall impact for ratepayers.[34]

FRPO argued that the price to fill that space is not necessarily more expensive in the winter (December fill) than for the fall (July fill).[35][36] As such, FRPO submitted that Union should consider using the 3.5 PJs of fall contingency space as a contributor to the 6 PJs of winter space. This would make available an additional 3.5 PJs of storage space and could provide a $3.0 million benefit to ratepayers as the storage contingency space would be better optimized.[37]

LPMA supported FRPO on this issue. LPMA submitted that the Board should direct Union to conduct an independent third-party analysis of the potential benefit of increased storage revenue (related to the availability of an additional 3.5 PJs of storage space) versus the potential cost additions for purchasing gas in the winter and selling that gas the following summer.[38] No other parties made submissions on this issue.

Union submitted that as no parties raised concerns regarding its methodology for allocating system integrity space, its proposal should be accepted by the Board.

With respect to FRPO's and LPMA's submissions on the use of its fall integrity space as part of its winter integrity space, Union submitted that there is considerable risk around this proposal and it is likely that any gas purchased after November would be at a higher cost. Union noted that it has never optimized its system integrity space. Union noted that the benefit that FRPO believes to be present is dependent on a number of

[34] Technical Conference Transcripts, EB-2011-0210, Volume 1 at pp. 73-75.
[35] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at pp. 144.
[36] Exhibit K14.5 at p. 32.
[37] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 145.
[38] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 74.

factors which are out of Union's control, namely, fall weather, winter weather, summer / winter price differentials. Union submitted that what FRPO is proposing essentially amounts to gambling with the system integrity space. In Union's submission, as system operator, it is not prudent to do so.

In response to LPMA's suggestion that there could be a third-party study of the issue, Union submitted that there is no merit to that proposal as the outcome of the study would depend, in any particular year, on the summer / winter price differential and the fall weather / winter weather. For those reasons, Union submitted that FRPO's and LPMA's submissions should be rejected.[39]

Board Findings

The Board finds that Union's methodology for allocating system integrity space is appropriate. The Board notes that no parties raised concerns regarding this proposal.

The Board finds that the proposal made by FRPO and LPMA that the fall integrity space should be used as part of the winter integrity space is not adequately supported by the evidence in this proceeding. The Board notes that the increased revenue potential of $3.0 million cited by FRPO is hypothetical and in fact, the proposal could be detrimental to ratepayers depending on certain factors that are outside of Union's control (i.e. weather, price differentials, etc.). The Board notes that Union has stated that it has never optimized its system integrity space. The Board is of the view that the evidence in this proceeding does not support a change in approach.

The Board also rejects LPMA's suggestion that the Board direct Union to conduct an independent third-party analysis on this issue. The Board agrees with Union that the outcome of the study is likely to depend, in any particular year, on the summer / winter price differential and the fall weather / winter weather. Therefore, the results of the study may not be reliable for more than a year.

Tecumseh Metering Assets

Union noted that in its Board-approved 2007 cost allocation study, certain Tecumseh metering assets at the Dawn facility were reflected as transmission assets in its plant accounting records. These metering assets were directly assigned to the Dawn Station

[39] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 135-136.

transmission function and the Dawn Station Customer classification. The costs were then allocated to the M12 rate class based on Tecumseh metering demands.

Union noted that based on a review of the Tecumseh metering assets, it updated the plant accounting records to move the assets from transmission to underground storage. However, as the Tecumseh metering assets continue to provide transmission service, Union directly assigned the Tecumseh metering assets to the Dawn Station transmission function. Similar to other underground storage assets functionalized to the Dawn Station, Union proposed to classify the costs to the demand classification and allocate the costs to rate classes based on the design day demand of Dawn compression. Union also proposed to eliminate the Dawn Station Customer classification, as the Tecumseh metering costs were the only costs previously allocated to this functional classification.[40]

LPMA supported this proposed change in the cost allocation methodology. LPMA noted that these assets provide transmission service to both ex-franchise and in-franchise customers, and the updated methodology is consistent with the allocation of costs of other interconnects in the Dawn Station. LPMA also stated that the impact of this proposal is not significant.[41]No other parties made submissions on this issue.

Union submitted that as no parties raised concerns with Union's proposal, it should be accepted by the Board.[42]

Board Findings

The Board approves Union's proposal as it relates to the Tecumseh Metering Assets. The Board finds that Union's updated cost allocation methodology for this group of assets is reasonable and is consistent with the allocation of other similar assets.

Oil Springs East Assets

Union proposed to change the functionalization, classification and allocation of costs associated with Oil Springs East assets for 2013. In Union's Board-approved 2007 cost allocation study, Union directly assigned the structure and improvements and

[40] Exhibit G1, Tab 1 at pp. 6-7.
[41] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 73.
[42] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 133.

measuring and regulating equipment plant costs associated with the Oil Springs East storage pool to the Dawn Trafalgar Easterly transmission function. This re-classification from underground storage to transmission was based on the use of the assets, which previously served Union North transmission needs. Union also classified the costs to the Dawn Trafalgar Easterly Oil Springs East Metering classification, and allocated costs to rate classes based on design day demand on the Dawn Parkway transmission system.

Union noted that its review of Oil Springs East storage pool assets determined that these assets now provide both storage and transmission services to customers. Accordingly, Union proposed to eliminate the direct assignment of Oil Springs East assets to the Dawn Trafalgar Easterly transmission function and functionalize these assets between storage and transmission. Union noted that this approach is consistent with the treatment of other underground storage assets at the Dawn facility that provide both storage and transmission services. Given Union's proposal to eliminate the direct assignment of Oil Springs East assets, Union also proposed to eliminate the transmission classification of Dawn Trafalgar Easterly Transmission for Oil Springs East metering.[43]

LPMA submitted that the changes to the allocation of the Oil Spring East Asset costs are appropriate. LPMA noted that Union's review has determined these assets provide both storage and transmission services to customers. As a result, Union proposed to functionalize these assets between storage and transmission, rather than continue the direct assignment of these assets to the Dawn-Trafalgar easterly transmission function.[44] No other parties commented on this issue.

Union submitted that as no parties have concerns with Union's proposal, it should be accepted by the Board.[45]

Board Findings

The Board approves Union's proposal as it relates to the Oil Springs East Assets. The Board finds that Union's updated allocation methodology for this group of assets is appropriate and notes that it is consistent with the treatment of other underground

[43] Exhibit G1, Tab 1 at pp. 7-8.
[44] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 72-73.
[45] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 132.

storage assets at the Dawn facility that provide both storage and transmissions services.

New Ex-Franchise Services

Union noted that since Union's Board-approved 2007 cost allocation study was completed, several new ex-franchise transportation services have been developed by Union and approved by the Board. Specifically, Union has developed the C1 Dawn to Dawn-TCPL and C1 Dawn to Dawn-Vector firm transportation services, as well as the M12 firm all day (F24-T) transportation service.

Union proposed to include the costs associated with these new transportation services in its 2013 cost allocation study. A description of the cost allocation methodology proposed for each of the new transportation services is provided below.[46]

Dawn to Dawn-TCPL

Union noted that the C1 Dawn to Dawn-TCPL firm transportation service was developed to meet TCPL's need for a firm transportation service within the Dawn yard from Dawn to the Dawn-TCPL interconnect. Union's transmission system had the ability to accommodate requests for transportation on this path on an interruptible basis but required new facilities to offer the transportation service on a firm basis. This service was approved in EB-2010-0207.

Union noted that the costs of the Dawn to Dawn-TCPL firm transportation service include measuring and regulating assets, compressor fuel and UFG. Union proposed to directly assign the measuring and regulating gross plant, accumulated depreciation, and depreciation expense to the Dawn Station Demand classification and then to the C1 rate class. Similarly, the compressor fuel and UFG costs associated with the Dawn to Dawn-TCPL firm transportation service are also directly assigned to the C1 rate class.

Union stated that this cost allocation approach is designed to ensure that the costs associated with the provision of the Dawn to Dawn-TCPL firm transportation service are assigned to the C1 rate class and recovered in rates from customers utilizing the Dawn to Dawn-TCPL firm transportation service.[47]

[46] Exhibit G1, Tab 1 at p. 8.
[47] Ibid at p. 9.

No parties commented on this issue.

Dawn to Dawn-Vector

Union noted that the C1 Dawn to Dawn-Vector firm transportation service was developed to meet Greenfield Energy Centre LP's need for a firm transportation service within the Dawn yard from Dawn to the Dawn-Vector interconnect. This service was approved in EB-2007-0613.

Union noted that the costs of the Dawn to Dawn-Vector firm transportation service include the costs associated with compressor fuel and UFG. Consistent with Union's proposal for the Dawn to Dawn-TCPL transportation service, Union proposed to directly assign the compressor fuel and UFG costs to the C1 rate class.

Union stated that this cost allocation approach is designed to ensure that the costs associated with the provision of the Dawn to Dawn-Vector firm transportation service are assigned to the C1 rate class and recovered in rates from customers utilizing the Dawn to Dawn-Vector firm transportation service.[48]

No parties commented on this issue.

M12 Firm / All Day (F24-T)

Union noted that, as part of the NGEIR proceeding (EB-2005-0551), it developed an enhanced M12 F24-T transportation service that provides additional nomination windows and firm all day transportation capacity to power generators and other customers.

Union noted that the costs for the M12 F24-T transportation service include employee salaries and benefits and compressor maintenance costs. Union proposed to directly assign the employee salaries and benefits and compressor maintenance costs to the Dawn Trafalgar Easterly Transmission function and then to the M12 rate class.

Union stated that this cost allocation approach ensures that the costs associated with the provision of the M12 F24-T transportation service are assigned to the M12 rate

[48]Ibid at p. 10.

class and recovered in rates from customers utilizing the M12 F24-T transportation service.[49]

APPrO stated that it is opposed to Union's M12 F24-T allocation methodology. APPrO argued that Union should include the cost of the additional nomination windows in the overall O&M cost of the Dawn-Trafalgar system, just as it does for the remainder of M12 capacity, where Union provides eight nomination windows for those shippers also contracting for TransCanada's STS service. APPrO argued that F24-T customers should not be paying a separate charge for extra nomination windows.

APPrO noted that F24-T is an add-on service to Union's M12 and C1 service. F24-T has nine additional nomination windows. F24-T is used by generators, as well as other customers that require additional nomination windows. The service is used in conjunction with non-utility storage so that these customers can access intra-day balancing services. Shippers using F24-T contract for TransCanada capacity downstream of Parkway.

APPrO noted that, under the Settlement Agreement, Union agreed to reduce the O&M budget by $0.5 million. Half of this amount is related to the reduction in provision for wages and salaries, and the other half is related to amounts attributable to non-utility services. APPrO stated that the net amount after these reductions is $0.65 million.

APPrO noted that Union provides a similar service for other M12 customers and for customers that contract for TransCanada's STS service. APPrO stated that STS and F24-T share the four standard NAESB nomination windows, as well as the four STS windows. As such, F24-T only has five incremental windows above the eight windows that are shared.

APPrO noted that Union does not charge STS customers a separate and distinct fee associated with providing the four extra STS nomination windows. APPrO noted that Union stated that it did not know if there were extra costs associated with providing these four extra nomination windows, but stated that if there are extra costs related to receiving and processing these nominations then these costs are embedded in the M12 rate, and not charged separately.

[49]Ibid at p. 11.

APPrO stated that F24-T shippers pay the same underlying M12 rate as a STS shipper which includes the cost for the eight nomination windows, and they also pay a separate charge for the extra nomination windows.

APPrO noted that Union has 1,250,000 GJs / day of M12 service that feeds into TransCanada's STS service. APPrO stated that this amount is significantly larger than the volume of F24-T shippers and has no extra nomination charge associated with it. APPrO proposed that the $0.65 million of annual O&M cost related to the F24-T service be included and recovered as part of the overall M12 costs and no specific charge apply to the F-24T customers.

APPrO submitted that this cost allocation would be done in the same manner as done for those M12 shippers contracting for STS service. To ensure that not all M12 shippers have access to the additional nomination windows, APPrO proposed that access be conditional upon the customer holding downstream FTSN capacity with TransCanada.

In the event that the Board determines that Union should charge a separate rate for F24-T, APPrO submitted that the costs allocated directly to F24-T should only reflect the increase in the five nomination windows (as opposed to the nine nomination windows as proposed by Union). This means that approx. $359,000 of the $645,000 would be allocated to F24-T, with the balance being recovered within the overall M12 service. In addition, APPrO submitted that Union should be required to use the billing determinants as shown in Exhibit J.G-9-13-1 of 442,154 GJs / day to calculate the F24-T charge.[50] No other parties commented on this issue.

Union stated that the premise of APPrO's argument is that Union accommodates STS windows within its overall O&M and does not separately charge for access to the STS windows as it does for F24-T. Union submitted that what APPrO’s argument fails to recognize is that F24-T was specifically developed and agreed to as part of the NGEIR settlement to meet the needs of power generators.

The Settlement Agreement in the EB-2005-0551 proceeding speaks to this issue directly. Union noted that the Settlement Agreement states at page 14,

[50] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at pp. 139-142.

> "IT capital costs and the costs associated with the additional staffing required to implement F24-T, F24-S, UPBS and DPBS will be recovered from customers who elect the new services."

Union noted that the Settlement Agreement recognized that there would be incremental costs associated with providing F24-T service. As a result of the Settlement Agreement, F24-T service was added to the M12 rate schedule. Union argued that based on the above noted Settlement Agreement, the F24-T service should have a specific charge applied to reflect the incremental nomination windows available to those shippers.

In regard to APPrO's argument that the Board should direct Union to base the rate for the F24-T charge on the updated F24-T demands of 442,154 GJs / day, Union submitted that this change is immaterial and therefore it should not have to update the calculation for the charge.[51]

Board Findings

The Board approves Union's proposals as they relate to the Dawn to Dawn-TCPL service and the Dawn to Dawn-Vector service. The Board believes that these proposals adequately reflect cost allocation principles and are appropriate.

The Board accepts Union's M12 F24-T cost allocation methodology as filed, as it is consistent with the principle of cost causality.

Consistent with the Settlement Agreement in EB-2005-0551, the Board approves a supplemental service charge for F24-T customers. However, the Board agrees with the submission of APPrO that the charge should be calculated based on the costs associated with the 5 incremental nomination windows and be based on the updated F24-T demand, as set out in Exhibit J.G-9-13-1.

Other Cost Allocation Proposals

Union North Distribution Customer Stations Plant

Union currently allocates Union North customer station costs to its North in-franchise rate classes in proportion to average number of customers, excluding the small volume general service Rate 01 rate class. Union noted that the customer stations, however,

[51] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 141-143.

are constructed for customers that have hourly consumption in excess of 320 m^3. Assuming a typical industrial customer load factor of 40 percent and 20 hours of flow per day, the annual consumption for customers with a customer station would be a minimum of 934,400 m^3. Union noted that based on 2010 actual volumes, no Rate 01 customers and only a small percentage of Rate 10 customers consume 934,400 m^3 or more per year.

Union noted that all other medium and large volume customers require a total maximum daily requirement of 14,000 m^3 or more to be eligible for the respective firm contract rate classes (Rate 20 and Rate 100). Based on peak hourly flow equal to $1/20^{th}$ of the maximum daily quantity of 14,000 m^3 or more, the approximate hourly consumption for the firm contract rate classes is 700 m^3. Accordingly, Rate 20 and Rate 100 customers exceed the hourly customer station requirement of 320 m^3.

Union proposed to allocate customer station costs based on the average number of customers, excluding the Rate 01 rate class and Rate 10 customers that do not meet the annual consumption threshold of 934,400 m^3.[52]

APPrO submitted that the change to the allocation of North Distribution Customer Station Plant is not appropriate. APPrO noted that Union's proposed change in allocation methodology has the effect of reallocating approximately $2.17M of revenue requirement from Rate 10 to Rates 20, 25 and 100.

APPrO noted that Union's proposed methodology is underpinned by the assumption that North customer station costs are only applicable to those customers that have an annual consumption greater than 934,400 m^3. APPrO submitted that the design criterion to size and install meters and regulators is the peak hourly load and pressure considerations. APPrO argued that annual consumption is not a design criterion. APPrO also noted that capital costs are driven by design criteria and not annual consumption.

APPrO submitted that Union's reallocation of North customer station plant costs is flawed because capital costs are dependent on the design criteria of peak hourly flow, not annual consumption. APPrO proposed that no change be made to the current allocation. In the alternative, to the extent that any changes are made, they should be consistent with the corrected Exhibit J.G-5-13-1, Attachment 1. Or in other words, on

[52] Exhibit G1, Tab 1 at pp. 12-13.

the average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3 / hour.

APPrO also noted that for those customers that take both firm and interruptible service, there is only one meter. Under Union's proposal, customers taking service under Rate 10, 20 or 100 are first allocated costs of the meter station for the firm load, and then they receive a second allocation of costs related to the customer station for the interruptible load. Therefore, APPrO submitted that there is a double allocation of costs caused by Union's proposal.[53] No other parties commented on this issue.

Union stated that APPrO advances two arguments in support of their position. The first is that the 934,000 m^3annual consumption figure is arbitrary, and the second is that because there may be overlap in the Rate 20 and Rate 100 with the Rate 25, the number of customers used in the allocation is overstated and results in double recovery.

As to the first argument, Union stated that the annual figure is not arbitrary. Union noted that 320 m^3/ hour, 20 hours a day, 365 days a year, aggregates to 934,400 m^3 / year.

As to the second argument, Union submitted that there is no double count of the allocation of costs. The costs of distribution customer stations are allocated and recovered from all contract rate classes, including interruptible classes, and customers taking a firm service in combination with an interruptible service pay for only a portion of the station costs in each of their rates. Union submitted that there is no over-recovery of North Distribution Customer Station Costs.[54]

Board Findings

The Board will not approve Union's proposal to reallocate the North Distribution Customer Station Costs. The Board agrees with the submissions of APPrO that since capital costs are dependent on the design criteria related to peak hourly flow, the reallocation of costs based on annual consumption is not appropriate.

The Board is of the view that since capital costs are dependent on the design criteria related to peak hourly flow, the allocation methodology should reflect the design criteria of peak hourly flow and not annual consumption. Therefore, the Board finds that the

[53] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 132-135.
[54] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 137-138.

North Distribution Customer Station Plant costs should be allocated on the basis ofthe average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3 / hour. The Board believes that this allocation methodology better reflects cost allocation principles. The Board directs Union to file this update as part of the Draft Rate Order process.

Distribution Maintenance – Meter and Regulator Repairs

Union noted that it currently classifies Union South distribution maintenance costs for meter and regulator repair to Distribution Customers and allocates the costs to the M2 rate class. For Union North, distribution maintenance costs for meter and regulator repair are classified to Distribution Demand and allocated to rate classes in proportion to the allocation of distribution meter and regulator gross plant.

Based on a review of its operating practices, Union determined that there are minimal maintenance costs associated with residential meters because it is more economical to replace small residential meters than perform repairs. To reflect Union's operating practices and harmonize cost allocation between Union North and Union South, Union proposed to align the Union North and Union South distribution maintenance meter and regulator repair cost methodology.

Union proposed to classify and allocate both Union North and Union South distribution maintenance costs for meter and regulator repair in proportion to the distribution meter and regulator gross plant cost allocation, excluding Rates M1 and 01.[55]

LPMA supported the proposal made by Union. LPMA agreed with Union that its proposal would harmonize the cost allocation between the North and the South and would better reflect its operating practices.

LPMA noted that Union's current M1 and Rate 01 rate classes include customers that have an annual consumption of up to 50,000 m^3 / year. Union proposed to change this effective January 1st, 2014 and reduce the number of customers in these classes by reducing the threshold to 5,000 m^3 / year. LPMA stated that it is not clear if Union's proposal would shift more costs associated with the maintenance costs from meter and regulator repairs into the M2 and Rate 10 classes as more customers are moved into those classes. LPMA stated that these additional customers will have their associated

[55] Exhibit G1, Tab 1 at pp. 13-14.

distribution meter and regulator gross plant costs moved with them, resulting in a greater proportion of the meter and regulator costs in these rate classes than the current split.

LPMA noted that at Union's next rebasing, where cost allocation will again be reviewed, the customers that use between 5,000 m^3/ year and 50,000 m^3 / year would now be in a class that attract the repair costs, even though Union's evidence in this proceeding is that the customers currently in Rates M1 and 01, which include these customers, would not attract repair costs. LPMA argued that this is most likely to be the case in the future, at least for the smaller volume customers that are proposed to be moved from Rates M1 and 01 to Rates M2 and 10, respectively. LPMA submitted that the Board should direct Union to address this potential issue in its next cost allocation study if the Board approves Union's proposal for the change in the split between the rate classes from 50,000 m^3 to 5,000 m^3.[56]No other parties commented on this issue.

Union submitted that no parties raised any concerns with the proposed allocation for 2013 and therefore the proposal should be approved by the Board. Union submitted that LPMA's concerns related to the 2014 Rate M1 / M2 and Rate 01 / 10 rate redesign do not withstand any rigorous scrutiny and should be dismissed.[57]

Board Findings

The Board accepts Union's proposal to classify and allocate both Union North and Union South distribution maintenance costs for meter and regulator repair in proportion to the distribution meter and regulator gross plant cost allocation, excluding the M1 and Rate 01 rate classes. The Board accepts Union's submission that the harmonization of the cost allocation methodology between Union's North and South operation areas better reflects Union's operating practices and cost allocation principles.

Distribution Maintenance – Equipment on Customer Premises

Union currently allocates South distribution maintenance costs for equipment on customer premises to M1 and M2 customers based on service call time, and allocates North distribution maintenance costs for equipment on customer premises are allocated to rate classes based on a historic allocator.

[56] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at pp. 75-77.
[57] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 139.

Union stated that the costs for maintenance of equipment on customer premises are primarily related to customer station maintenance. In order to more accurately reflect costs and to harmonize the allocation approach between Union North and Union South, Union proposed to allocate both the Union North and Union South Distribution Maintenance – Equipment on Customer Premises to rate classes in proportion to the allocation of customer station gross plant.[58]

LPMA supported Union's proposal regarding the allocation of Distribution Maintenance - Equipment on Customer Premises costs. LPMA submitted that Union's proposal would harmonize the approach in Union South and Union North, and more accurately reflect cost causation. LPMA also submitted this proposal is consistent with the proposal to allocate the distribution maintenance costs associated with the meter and regulator repairs.[59]

APPrO submitted that Union's proposal for allocating Distribution Maintenance - Equipment on Customer Premises costs is not appropriate. APPrO submitted that the effect of the proposal is to move $1.5 million in costs from Rate 01 to Rates 10, 20, 100 and 25. APPrO submitted that there is nothing on the record as to what the subject of this maintenance category is.

APPrO argued that the effect of the proposal in the South is to reallocate $0.32 million from the small volume rate class to larger volume rate classes. APPrO submitted that it has concerns with this proposal as these costs have been historically allocated to small volume customers, and now without regard for a full and complete understanding of the equipment involved, Union proposed to allocate these costs to the large volume rate classes. APPrO noted that the current methodology (in the North), as approved by the Board in EB-2005-0520, is to allocate costs in proportion to Appliance Rentals. APPrO stated that the reference to Appliance Rentals could be to equipment on customer premises, which have nothing to do with customer stations.

APPrO submitted that Union provided no evidence on what has changed between EB-2005-0520 and how that would result in this change in allocation methodology.

[58] Exhibit G1, Tab 1 at p. 14.
[59] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 77.

APPrO submitted that Union's proposal should be rejected in its entirety. APPrO submitted that a definition for customer station plant needs to be determined before an allocation methodology for these assets can be properly understood by parties and directed by the Board.[60] No other parties commented on this issue.

Union submitted that its proposal reflects the principle of cost causality harmonizes the North and South allocation methods and replaces the current Board-approved cost allocation methods that have outlived their purpose with a methodology that is up-to-date. As such, Union argued that its proposal should be accepted as filed.[61]

Board Findings

The Board will not approve Union's proposal to allocate both the Union North and Union South equipment on customer premises distribution maintenance costs to rate classes in proportion to the allocation of customer station gross plant. The Board agrees with the submission of APPrO that there is no evidence in this proceeding as to what the subject of this maintenance category is. Accordingly, the Board directs Union to file, in conjunction with the 2014 cost allocation study ordered elsewhere in this Decision, sufficient evidence to support this potential change in cost allocation, including a definition for this maintenance category and a delineation of what has changed since EB-2005-0520 that would result in a change to the allocation methodology.

Purchase Production General Plant

Union noted that it currently functionalizes general plant costs in proportion to the functionalization of rate base and O&M costs. However, general plant costs are functionalized to the Purchase Production function based on O&M costs only since there are no other plants costs functionalized to Purchase Production. The Purchase Production general plant costs are classified to Purchase Production Other and allocated to Union South in-franchise customers in proportion to delivery volumes, excluding the T1 and T3 rate classes.

Union proposed to classify general plant costs to both the Purchase Production System and Purchase Production Other classifications in proportion to the components of Purchase Production System and Other O&M. Union also proposed to allocate general plant costs to rate classes in proportion to the components of Purchase Production

[60] Oral Hearing Transcripts,EB-2011-0210, Volume 15 at pp. 135-139.
[61] Oral Hearing Transcripts,EB-2011-0210, Volume 16 at pp. 139-140.

System and Other O&M. Union noted that this methodology change ensures general plant costs that are functionalized to purchase production are classified and allocated to rate classes on the same basis.[62]

LPMA supported this proposal and no other parties commented on this issue.[63] Union submitted that no parties raised any concerns in regards to this proposal and therefore it should be approved as filed.[64]

Board Findings

The Board approves Union's proposal to update the allocation of purchase production general plant costs. The Board accepts Union's submission that this methodology better reflects cost allocation principles than the existing methodology.

Parkway Station Costs

Mr. Rosenkranz, an expert witness for CME, CCC, City of Kitchener and FRPO, described the manner in which the costs of transporting gas on the Dawn-Parkway transmission system are divided and allocated. Mr. Rosenkranz noted that these costs are divided into two distinct categories: the cost of the compressors needed to move gas from the Dawn Hub into the Dawn-Parkway system (Dawn Station costs); and all remaining costs (Dawn-Trafalgar Easterly costs). Mr. Rosenkranz noted that the Dawn-Trafalgar Easterly costs include Union's transmission pipelines, the compressors at Lobo, Bright, and Parkway, and the metering facilities at Kirkwall and Parkway. Dawn-Trafalgar Easterly costs are allocated using a distance-based commodity-kilometre methodology while Dawn Station costs are allocated on the basis of design-day demand.[65]

Mr. Rosenkranz noted that Union delivers and receives gas at Parkway and that the predominant direction of physical flow at Parkway is from Union to TCPL and Enbridge.[66][67] Mr. Rosenkranz noted that the metering and compression facilities at

[62] Exhibit G1, Tab 1 at pp. 14-15 (Updated).
[63] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 77.
[64] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 140.
[65] Exhibit K10.7 at p. 2.
[66] Ibid at p. 3.
[67] Exhibit B1, Tab 9, Schedule 2 shows that the flows through Parkway are predominately export based.

Parkway Station are designed to meet Union's design day requirements to export gas from Union to TCPL and Enbridge.

Mr. Rosenkranz noted that metering costs are a function of design day demand and that compression horsepower at Parkway is determined by Union's peak day requirement to deliver gas to TCPL and Enbridge. In addition, Mr. Rosenkranz stated that Union's metering and compression assets at Parkway are not used to transport or deliver gas to any of Union's upstream in-franchise markets connected to the Dawn-Parkway transmission system. Therefore, Mr. Rosenkranz recommended that the Parkway station costs be separated from the overall Dawn-Trafalgar Easterly Transmission costs and allocated to rate classes on the basis of design day requirements.[68]

Mr. Rosenkranz noted that once the Parkway Station costs have been separated in the cost allocation, the costs should be recovered from those services that use the Parkway facilities. In addition, Mr. Rosenkranz recommended the establishment of a non-export M12 service that can be used by in-franchise customers to meet an obligated delivery requirement at Parkway. The non-export M12 service would allow shippers to deliver gas to Union but would not give shippers the right to deliver gas to TCPL or Enbridge. Mr. Rosenkranz recommended that the costs for this service should be allocated on the same basis as the Dawn-Trafalgar Easterly costs (exclusive of the Parkway Station Costs).[69]

Board staff[70], LPMA[71], BOMA[72], FRPO[73], Kitchener[74] and others supported the recommendations of Mr. Rosenkranz, as discussed above. LPMA submitted that the Parkway Station is not used to transport or deliver natural gas to any of the upstream in-franchise markets that are connected to the Dawn-Trafalgar transmission system. LPMA submitted that it is clear that the Parkway station metering and compression do not provide any benefits to in-franchise customers. As a result, these customers should not pay any of the associated costs.[75]

[68] Exhibit K10.7 at p. 3.
[69]Ibid at pp. 3-4.
[70] Board staff Argument, August 17, 2012, at pp. 19-20.
[71] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 77-82.
[72] BOMA Factum for Argument at p. 54.
[73] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 158.
[74] City of Kitchener Argument, August 17, 2012, at p. 1.
[75] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 79.

Energy Probe supported Union's existing allocation of Parkway Station Costs[76]for four reasons. First, the peak design day criterion has not been challenged by parties. Second, if the proposal were to be accepted by the Board, more Parkway Station Costs would be borne by ex-franchise customers, exacerbating decontracting and lowering revenue which would need to be offset by higher rates to in-franchise customers. Third, costs would increase for customers of Enbridge. Finally, as per the Settlement Agreement relating to this application, the agreement to re-examine the Parkway delivery obligation could also result in changes to the treatment of the cost allocation for Parkway Station Costs.

Union noted that the treatment of Parkway station costs was last reviewed by the Board in EBRO 493/494. Union noted that with the exception of Energy Probe, which continues to support the current allocation, intervenors support Mr. Rosenkranz's proposal reflected in his evidence at Exhibit K10.7.

Union stated that the submission and recommendations of Mr. Rosenkranz are based on the premise that in-franchise customers receive little or no benefit from the Parkway Station and, therefore, in-franchise customers should not be responsible for Parkway Station costs. Union submitted that this premise is unfounded, and was determined to be so by the Board in EBRO 493/494. The Parkway Station provides benefits to in-franchise ratepayers in a number of ways. First, obligated deliveries received on the discharge side of Parkway provide a direct benefit to in-franchise shippers by reducing the size of the Dawn-Trafalgar facilities servicing in-franchise rate classes. Absent the Parkway obligation, in-franchise rates would be higher. Therefore, Union submitted that in-franchise ratepayers receive a substantial benefit from the existence of the Parkway Station.

Union also noted that its North in-franchise customers receive a benefit from being connected to Parkway because, without it, they could not access Dawn storage.

Union noted that in EBRO 486, it was directed by the Board to prepare an M12 cost allocation study to ensure that there was no cross-subsidiary among rate classes using the Dawn-Trafalgar transmission system. That study was filed with the Board in EBRO 493/494. The Board's decision addresses the allocation of the Dawn Station and Dawn-Trafalgar costs, including the Parkway Station.

[76] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at pp. 65-66.

Union submitted that nothing has changed as it relates to the design of the Dawn-Trafalgar system and the Parkway Station, and how it was used at the time of the EBRO 493/493 decision and how it is used now. On this basis, Union submitted that the proposal to change the allocation methodology should be rejected.[77]

Board Findings

The Board agrees with Union that in-franchise customers benefit from the Parkway Station. The Board also notes, as highlighted by Energy Probe, that there may be a number of unintended consequences associated with Mr. Rosenkranz's proposal, the consequences of which have not been considered in the context of this application. The Board will therefore not approve the separation of the Parkway Station costs from overall Dawn-Trafalgar Easterly Transmission costs, as proposed by Mr. Rosenkranz at this time. The Board will revisit this issue as part of Union's 2014 rates proceeding, after the Board receives Union's report on the outcome of the Parkway Obligation Working Group[78].

Kirkwall Station Costs

In its application, Union did not propose any changes to the allocation of the Kirkwall Station costs. LPMA noted that Mr. Rosenkranz also did not address the issue of Kirkwall metering costs in his evidence. LPMA submitted that the use of the Kirkwall Station has changed over the years and may change further in the future (given the changing flow of natural gas in the northeast area of North America which includes Ontario). LPMA stated these changing dynamics demonstrate the need to review the allocation of the Kirkwall Station costs. The changing flow of natural gas in the northeast has been highlighted by Union in this proceeding through the level of turn-back of M12 capacity that has already occurred and is forecast to occur in the future.

LPMA noted that the Parkway-to-Maple bottleneck has been raised in this proceeding. The dramatic increase in TCPL tolls, especially along the northern Ontario route relative to other routes to the Greater Toronto Area, has illustrated the potential need for the Parkway West project. LPMA stated that all of these issues highlight the fact that there has been considerable change that has taken place with respect to the flows of gas around the Parkway Station, since Union last reviewed the cost allocation and rate

[77] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 143-145.
[78] Union Settlement Agreement, June 28, 2012, Section 3.17, p.16

design for services offered on the Dawn-Trafalgar system in 1995, and that the Board last approved in Union's 1997 rate case, which was EBRO 493/494. LMPA submitted that the Board should direct Union to review the allocation of Kirkwall metering costs.[79] No other parties commented on this issue and Union did not respond to LPMA's submission in reply.

Board Findings

The Board agrees with the submissions of LPMA. The use of the Kirkwall Station has changed substantially over the years and there is a clear need to review the allocation of Kirkwall Station costs. The Board directs Union to undertake a review of the allocation of Kirkwall metering costs as part of its updated cost allocation study which the Board has directed Union, later in this Decision, to file in its 2014 rates filing.

Dawn-Trafalgar Easterly Costs

Union's Dawn-Trafalgar Easterly costs include Union's transmission pipelines, the compressors at Lobo, Bright, and Parkway, and the metering facilities at Kirkwall and Parkway. Dawn-Trafalgar Easterly costs are allocated using a distance-based commodity-kilometre methodology.

LPMA submitted that, with the removal of the Parkway station metering and compression costs discussed above and subject to the review of the Kirkwall metering costs also noted above, the allocation of the remaining Dawn-Trafalgar Easterly costs should continue to be based on the distance-based commodity-kilometre methodology. LPMA argued that there has been no evidence presented in this proceeding to suggest that this allocation methodology is not appropriate for these remaining costs, nor has any evidence been presented in support of another methodology.[80] No other parties commented on this issue.

Board Findings

The Board approves Union's proposed allocation of the Dawn-Trafalgar Easterly costs. The Board finds that the distance-based commodity-kilometre methodology used to

[79] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 80.
[80] Ibid. at p. 81.

allocate the Dawn-Trafalgar Easterly costs is appropriate and reflective of cost allocation principles.

Utility / Non-Utility Storage Cost Allocation

Board staff noted that Union's methodology for separating its utility and non-utility storage businesses was originally approved by the Board in EB-2005-0551 and confirmed by the Board in EB-2011-0038. In the EB-2011-0038 Decision and Order, the Board stated:

> The Board finds that the intent of the NGEIR Decision was to effect the one-time separation of plant assets between Union's utility and non-utility businesses. Therefore, there is no need for a subsequent separation (or the filing of another cost study).[81]
>
> The Board finds that Union has appropriately applied its 2007 Cost Allocation Study for the one-time separation of plant.[82]

Union, in this proceeding, provided a description of its methodology for allocating costs related to storage additions. Union provided the following table:

Description	Allocation Methodology
New Storage Asset – increase in capacity or deliverability	100% Allocation to unregulated
New Storage Asset – no increase in capacity or deliverability	Allocated regulated versus unregulated based on the historic allocation of assets at that location
Replacement Asset – no increase in capacity or deliverability	Allocated regulated versus unregulated based on the historic allocation of assets being replaced.
Replacement Asset – increase in capacity or deliverability	Cost of replacing the existing asset like for like is allocated regulated versus unregulated based on the historic allocation of assets being replaced. The cost of providing the incremental capacity or deliverability is allocated 100% to the unregulated operation. This results in a new blended rate for this asset.

With respect to the allocation of O&M costs related to non-utility storage, Union stated that:

[81] Decision and Order, EB-2011-0038,January 20, 2012 at pp. 6-7.
[82] Decision and Order, EB-2011-0038,January 20, 2012 at p. 11.

a) Actual O&M related to the operation of the storage facilities was allocated to the non-utility storage operation using the same allocators applied to the assets for that facility.

b) Administrative and general expenses and benefits in support of non-utility storage operations were allocated in proportion to storage O&M.

c) O&M costs related to the development of new storage assets are assigned based on an estimate of time spent annually on the development of non-utility projects.

d) O&M costs related to the Regulatory Department for development of new storage assets, are assigned based on an estimate of time spent annually on the development of non-utility projects.[83]

Board staff supported the methodologies for allocating capital and O&M costs to non-utility storage as described above.

Board staff also noted that as a result of Union's review of its allocation factors in early 2012[84], which sought to confirm that the methodology set out above was applied correctly, Union identified updates that were required to10 of its storage pools. Union noted that after the allocation factors were updated, it compared the updates against its 2013 rate evidence. Union determined that the use of the revised allocation factors for storage capital additions would have decreased the utility storage assets by approximately $25,000 in 2013. Union also noted that the allocation factor update results in a decrease to utility O&M of $100,000.[85]

Board staff submitted that although these amounts are quite small, the Board should require Union to update its allocation factors as part of its evidence in this proceeding and reassign the noted amounts from utility to non-utility ($100,000 in O&M and the revenue requirement related to the $25,000 in decreased utility storage capital costs).

Board staff also submitted that the above noted methodology for allocating costs between utility and non-utility storage related to storage additions should continue going

[83] Exhibit A2, Tab 2, p.8.
[84] This review occurred as a result of recommendations in the Black & Veatch report filed in EB-2011-0038.
[85] Union - Supplemental Question Responses, FRPO Supplemental Question #2.

forward and that the allocation of utility / non-utility storage costs should be updated in every rebasing and be reflected in the pre-filed evidence. [86] BOMA supported Board staff's submission on this issue.[87]

FRPO submitted that Union has under-allocated storage plant additions to the non-utility storage operation by continuing to use the same plant allocation factors that were developed for the one-time separation of plant. FRPO noted that Union refers to these as original or historic allocation factors. FRPO submitted that Union needs to update these factors each year to reflect the changes in the relative amounts of utility and non-utility storage. FRPO noted that Union provided updated allocation factor for each storage asset. FRPO noted that Union has stated that if it had used the revised updated factors to allocate plant additions for maintenance capital projects, the estimated allocation of plant to non-utility storage would have been $50,000 higher in 2012 and $25,000 higher in 2013. FRPO noted that, however, Union did not provide actual information for the years 2007 through 2011, even though the impact of Union's failure to update the cost allocation factor on 2013 rates depends on the cumulative misallocation of plant additions since 2007, not just the allocations during the bridge year. FRPO noted that Union does not propose to make any adjustment in 2013 to correct this error. FRPO argued that the allocation of plant to non-utility storage should be increased by $25,000 for 2013 and that Union should provide evidence (continuity schedules) supporting this allocation change prior to its 2014 rates proceeding.

FRPO noted that Union's failure to update the plant allocation factors also means that O&M was under-allocated to non-utility storage operation for 2013. FRPO noted that according to Union, the utility O&M costs should be reduced by approximately $100,000 based on its update to storage allocation factors. FRPO submitted that the 2013 utility O&M amount should be reduced by $100,000 and that the O&M amount for non-utility storage should be updated annually.

FRPO also raised a concern regarding the allocation of general plant to non-utility storage. FRPO submitted that Union has under-allocated general plant additions to non-utility storage plant by failing to update the other general plant allocation factor.

FRPO noted that the one-time separation of storage plant included an allocation of general plant. Two separate allocation factors were used, one factor for vehicles and a

[86] Board Staff Submission, August 17, 2012, at pp. 21-24.
[87] BOMA Factum for Argument at p. 54.

second factor for general plant. FRPO noted that the other general plant allocation factor that was used for the one-time separation was 2.92%. FRPO noted that this factor is the arithmetic average of the ratio of non-utility storage plant to total plant, 3.2%, and the share of non-utility support costs in the total O&M, which at the time of separation was 2.52%. FRPO stated that Union has not updated the other plant allocation since the one-time separation of plant.

Based on plant and O&M shares for year-end 2010, FRPO estimated the other plant allocation factor should be raised from 2.92% to at least 4%. Using the 4% other plant allocation factor, FRPO estimated the under-allocation to Union's non-utility storage business related to the allocation of general plant costs.[88]

FRPO noted that the application of the 4% other plant allocation factor across 2010, 2011, 2012 and 2013 shows an increasing under-allocation of non-utility, which peaks at $306,000 for 2013. FRPO requested that Union be directed to make the changes to the other general plant allocation factor using the most up-to-date information available prior to the implementation of 2013 rates.[89]

FPRO also requested that the Board direct Union to file plant continuity schedules related to Union's non-utility business as part of its 2014 rates filing.[90] FRPO and Energy Probe also submitted that the Board should direct Union to have Black and Veatch update the report that was filed in EB-2011-0038 as part of its 2014 rates filing.[91]

Union submitted that the updates to the storage related O&M and capital costs that parties are suggesting be made are immaterial. Union stated that the total amount of this update is approx. $50,000. In Union's submission, the quantum of the change does not warrant the treatment that parties are proposing. Union stated that it has a robust methodology to manage plant additions and plant replacements.

Union also submitted that there is no reason for Black & Veatch to revisit this issue again. It was first considered in the EB-2010-0039 case, and again in EB-2011-0038 and the report contains up-to-date information.[92]

[88] FRPO Argument Compendium at p. 22.
[89] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at pp. 134-142.
[90] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at p. 140.
[91] Oral Hearing Transcripts, EB-2011-0210,Volume 14 at pp. 63-64.
[92] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 146-147.

Board Findings

The Board finds that Union's allocation methodologies for capital additions and O&M costs related to its utility and non-utility storage operations are appropriate. The Board is of the view that these allocation methodologies reasonably reflect cost allocation principles.

The Board notes that, based on a review that Union undertook in early 2012 regarding its utility and non-utility storage allocations, Union identified certain allocation factor updates that are required to a number of its storage pools. The Board directs Union to implement the storage allocation factor update as part of this proceeding. The Board notes that there seems to be a misunderstanding among parties as to the dollar amount that is the outcome of the allocation factor update. The Board notes that Board staff stated that the allocation factor update results in an approximate decrease in utility storage assets of $25,000 and a decrease in utility O&M of $100,000 for 2013. However, Union stated that the total amount related to this update is $50,000. The Board directs Union to explain which amount is the correct amount that needs to be updated to reflect the change in allocation factors. The Board directs Union to implement this change as part of the Draft Rate Order process.

With respect to FRPO's argument that an update is also required to the general plant allocation, the Board finds that it does not have sufficient evidence on this issue to make this finding. While the Board is of the view that there may or may not be an under-allocation of general plant to Union's non-utility storage operation, the quantum of that under-allocation, if any, is not clear from the evidence in this proceeding. Therefore, the Board will not direct Union to make an update to the general plant allocation for the purpose of setting 2013 rates.

However, the Board finds that in order for parties, and the Board, to confirm that the allocation of storage costs between Union's utility and non-utility storage operations is correct, the Board requires up-to-date continuity schedules related to Union's non-utility storage business. The Board directs Union to file, as part of its 2014 rates filing, these continuity schedules.

Also, the Board directs Union to hire an independent consultant to update the report that was filed in the EB-2011-0038 proceeding and file that report as part of its 2014 rates proceeding.

The Board believes that it should have a robust evidentiary record in Union's 2014 rates proceeding on all issues related to the allocation of storage costs between utility and non-utility storage. The Board notes that, as part of Union's 2014 rates filing, it will revisit the allocation of all storage related costs between Union's utility and non-utility storage operations. At that time, the Board may also order further updates to the allocation factors (including the general plant allocation factor).

RATE DESIGN

General Rate Design Issues

Union noted that when designing its 2013 proposed rates for Union North and Union South, the following factors were taken into consideration:

- The revenue deficiency for the company as a whole;
- The relative rate changes of other rate classes;
- The allocated cost of service;
- The level of current rates and the magnitude of the proposed change;
- The potential impact on customers;
- The level of contribution to fixed cost recovery;
- Customer expectations with respect to rate stability and predictability; and
- Equivalency of comparable service options.

Union stated that the revenue-to-cost ratios reflect Union's application of accepted rate design principles and are underpinned by the cost allocation study. Union also submitted that the 2013 proposed revenue-to-cost ratios are within an acceptable range and are generally consistent with those approved by the Board in EB-2005-0520.[93]

In an interrogatory response, Union noted that revenue-to-cost ratios are the outcome, not an input, of the application of Union's rate design considerations described above. Union submitted that acceptable revenue-to-cost ratios must:

[93] Exhibit H1, Tab 1, p. 12 (Updated).

- Satisfy rate design principles discussed above, and
- Bear a reasonable relationship to previously approved revenue-to-cost ratios.

Union stated that acceptable revenue-to-cost ratios guidelines include:

1. Firm in-franchise general services (Rate 01, Rate 10, Rate M1 & Rate M2) close to unity.
2. Large firm in-franchise contract services (Rate T1, Rate T3 and Rate 100) close to unity.
3. Other in-franchise firm services between (1) and (2) above will vary due to firm rate continuum considerations. A revenue-to-cost ratio approximating 80% or more is generally realized.
4. Rate M12 firm transportation service close to unity.
5. Interruptible in-franchise service pricing is set in relative relationship to firm services, with the resulting revenue-to-cost ratios showing greater deviation from unity.[94]

Board staff submitted that Union's rate design considerations (and revenue-to-cost ratio guidelines), discussed above, are appropriate. However, Board staff raised a number of concerns regarding how these rate design considerations were followed.

Board staff stated that a general principle is that approved revenue-to-cost ratios, for in-franchise customers, should not move away from a unity position. In a number of in-franchise rate classes, the EB-2005-0520 Board-approved revenue-to-cost ratios were closer to unity than proposed in this case. These rate classes are: Rate 01 (from 0.976 to 0.975), Rate 25 (from 0.467 to 0.446), Rate M2 (from 0.972 to 0.940), Rate M5A (from 0.824 to 0.746), and Rate M10 (from 0.131 to 0.073).[95]

Union provided the following rationale for these changes. Union stated that the proposed rate is designed to manage the relationship between the firm and interruptible service, maintain the rate continuum across all of the firm rate classes and the interruptible rate class, and to manage the level of rate increases to the rate classes.[96] Board staff noted that these may be reasonable reasons to breach the general principle

[94] Ex. J.H-1-5-2.
[95] Ibid.
[96] Oral Hearing Transcripts, EB-2011-0210, Volume 12 at p. 8.

of not moving away from unity.

In response to Union's proposal to increase rates in Rate M1 to slightly beyond unity (1.003) and over-recover from that rate class by an amount of $1.14 million, Board staff submitted that this over-recovery (which results in cross-subsidization) is not appropriate.[97] Rate M1 (Union's small volume general service class in the South) should not have to pay more costs than are allocated to that class (on the basis of the cost allocation study). Board staff noted that Rate M1 is Union's only in-franchise rate class with a revenue-to-cost ratio higher than 1.0. Board staff noted that Union is attempting to balance the rate continuum and help offset larger rate increases in other rate classes by over-recovering in Rate M1. In Board staff's view this proposal is unfair to Union's M1 customers. Board staff submitted that Rate M1's rate design should not result in a revenue-to-cost ratio higher than 1.0.

Board staff noted that Union is materially under-recovering from Rate M7 ($1.2 million) and Rate M12 ($2.6 million) and that these rate classes have delivery rate impacts of less than 2%.[98] Board staff noted that for rate continuum purposes further rate increases for Rate M7 are not feasible. However, Board staff stated that Rate M12 does not have the same rate continuum constraints as does M7. Board staff submitted that Union should increase its rates in Rate M12 to result in a revenue-to-cost ratio of 1.0.

Board staff also commented on Union's allocation of S&T margins to the rate classes. Board staff noted that the overall revenue deficiency (after the proposed rate increases have been applied) for Union's Northern in-franchise rate classes is $13.125 million and the overall revenue deficiency (after the proposed rate increases have been applied) for Union's Southern in-franchise rate classes is $10.778 million. The overall revenue deficiency for in-franchise rate classes (after the proposed rate increases have been applied) is $23.903 million.[99] These amounts are offset by the S&T margins of $23.903 million that are built into rates. Board staff noted that approximately 55% of S&T margins are being allocated to the North and approximately45% are being allocated to the South. Union noted that the methodology for the split in the S&T margin allocation between operation areas is that the same proportion of the total revenue deficiency (before proposed revenue increases are applied) should be recovered by S&T margin allocations in both operation areas.[100] This methodology results in approximately 30%

[97] Exhibit H3, Tab 1, Schedule 1.
[98] Ibid.
[99] Ibid.
[100] Oral Hearing Transcripts, EB-2011-0210,Volume 11 at pp.146-148.

of the total revenue deficiency in each operation area being recovered through the allocation of S&T margins.[101]

Board staff submitted that although the methodology used by Union as discussed above results in an equitable allocation of S&T margins between operating areas (from the perspective of offsetting the revenue deficiency) it has no correlation to the manner in which the revenues are derived and is different from the last allocation of S&T margins in 2007 (EB-2005-0520).

Board staff noted that Union has acknowledged that it is using the S&T margins as a rate design tool to manage rate impacts, rate continuity and revenue-to-cost ratios in 2013.[102] In its Argument-in-Chief, Union submitted that using these margins as a rate design tool has been done in the past and is appropriate.[103]

Board staff noted that the Board, in this proceeding, needs to determine whether the allocation of S&T margins should be properly considered a rate design tool. Board staff is of the view that the allocation of S&T margins should not be used as a rate design tool. Board staff submitted that there are more appropriate ways to allocate these revenues which have more direct linkages to the manner in which the S&T margins are generated. BOMA supported the submissions of Board staff.[104]

LPMA supported Board staff's submissions that the M1 revenue-to-cost ratio should be no higher than 1.0 and that the M12 revenue-to-cost ratio should be increased to 1.0.[105]

VECC supported Board staff's submission that the M1 revenue-to-cost ratio should be no higher than 1.0. VECC also submitted that it has some concerns regarding Union's allocation of S&T margins. VECC stated that Union has allocated the S&T margins to rate classes for the purpose of managing rate impacts, with no regard for the causal connection between the generation of S&T revenues and the classes that pay for the assets that generate the S&T revenues. VECC stated that allocation of these revenues should be based on some equitable distribution across all distribution ratepayers.[106]

[101] Exhibit H3, Tab 1, Schedule 1.
[102] Oral Hearing Transcripts, EB-2011-0210, Volume 12 at pp. 121-122.
[103] Oral Hearing Transcripts, EB-2011-0210, Volume 13 at p.81.
[104] BOMA Factum for Argument at p. 54.
[105]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p.89.
[106] VECC Argument, August 21, 2012 at p. 24-25.

Union submitted that the revenue-to-cost ratios are reasonable as filed. Union noted that the revenue-to-cost ratios are the outcome of the rate design process and reflect the application of the rate design principles described in Exhibit H1, Tab 1 (and cited above). Union noted that there has never been a requirement that revenue-to-cost ratios be limited to 1.0. Union noted that, in 2007, the Board approved rates for Rate 10 that resulted in a revenue-to-cost ratio of 1.058.

Union submitted that the principal submission made by most intervenors on this topic is that the revenue-to-cost ratio for Rate M1 should be adjusted from the proposed level of 1.003 down to 1.0. A number of parties have suggested that this adjustment could be funded by increasing the M12 revenue-to-cost ratio from 0.984 to unity. Union submitted that the revenue-to-cost ratio of 1.003 is not materially different from 1.0 and is not inconsistent with resulting revenue-to-cost ratios approved by the Board in the past.

With respect to M12, Union submitted that the revenue-to-cost ratio of 0.984 is consistent with the cost-based Board-approved rate design for M12 services. Union noted that the M12 revenue-to-cost ratio is less than 1.0 because Dawn-Trafalgar westerly service revenues earned under C1 rate schedule reduce M12 rates. Increasing the M12 revenue-to-cost ratio to 1.0 would result in over-recovery of Dawn-Parkway costs presently allocated to ex-franchise services.

Union also made submissions on the issue raised by Board staff and VECC on the use of S&T margins as a rate-making tool. Union stated that it does not agree with the position of Board staff and VECC. Union noted that the use of S&T margin for rate design purposes has been a long standing and necessary feature of Union's rate design process. Absent the ability to use S&T margin for rate design, Union would need to deal with rate impacts and rate continuity issues by adjusting revenue-to-cost ratios alone. As part of the rate design process, Union has allocated approximately $13.1 million of S&T margins to the North and approximately $10.8 million of the S&T margins to the South. Union stated that this is a greater proportion than has ever been allocated to the North. Union noted that it is seeking to recover proportionally the same level of revenue deficiency between Union North and South because it reasonably balances the need to manage rate impacts in the North and the need to address rate continuum concerns in the South. Union submitted that using S&T margin to smooth rate continuum impacts and to manage rate design considerations is a longstanding feature of Union's rate design, and it should be continued by the Board in this proceeding.

Board Findings

The Board finds that Union's rate design considerations and revenue-to-cost ratio guidelines are generally appropriate. However, the Board has concerns with some of Union's rate design proposals, as discussed below.

The Board agrees with Board staff, that in general, applied-for revenue-to-cost ratios for in-franchise customers should not move farther away from 1.0 than the revenue-to-cost ratios that are presently approved and reflected in rates. The Board notes that for a number of in-franchise rate classes, the EB-2005-0520 Board-approved revenue-to-cost ratios were closer to unity than the revenue-to-cost ratios proposed in this proceeding. These rate classes are: Rate 01 (from 0.976 to 0.975), Rate 25 (from 0.467 to 0.446), Rate M2 (from 0.972 to 0.940), Rate M5A (from 0.824 to 0.746), and Rate M10 (from 0.131 to 0.073). As a result, the Board finds that the proposed revenue to cost ratios are not appropriate.

The Board notes that some parties made the argument that the revenue-to-cost ratio should be no greater than 1.0 for the M1 rate class. The Board agrees with this submission and is of the view that no compelling rationale was provided by Union to support a revenue-to-cost ratio for the M1 rate class greater than 1.0. Therefore, the Board finds no in-franchise rate class should have a revenue-to-cost ratio greater than 1.0.

The Board finds that Union's use of the S&T margins as a rate design tool to manage rate impacts, rate continuity and revenue-to-cost ratios in 2013 is not appropriate. The Board believes that S&T margins should be allocated to rate classes on the basis of sound regulatory principles. The Board does not agree that these margins should be used arbitrarily to manage rate impacts.

The Board notes that elsewhere in this Decision, the Board has found that certain optimization activities are to be considered part of gas supply, removing these activities from what Union has previously defined as transactional services and included in its S&T margin forecast. In this Decision, the Board has defined optimization as any market-based opportunity to extract value from the upstream supply portfolio held by Union to serve in-franchise bundled customers, including, but not limited to, all FT-RAM activities and exchanges. The net revenues related to these optimization activities are no longer to be included in the S&T margin forecast.

The Board finds that optimization related net revenues should be allocated to those customers that pay the costs of facilitating Union's gas supply plan. Therefore, the Board directs Union to file a proposed allocation methodology, as part of the Draft Rate Order process, which allocates the optimization margins to those customers. The Board notes that this proposal must be based on regulatory principles.

With respect to the remaining S&T margins, the Board notes that this Decision sets out sub-categories for these margins including: Long-Term Transportation related S&T margins, Short-Term Transportation related S&T margins, and Storage and Other Balancing Services related S&T margins. The Board directs Union to file allocation methodologies for the above noted sub-categories, as part of the Draft Rate Order process, which reflect regulatory principles.

The Board directs Union to use its proposed methodologies to allocate the S&T margins to its rate classes as part of the Draft Rate Order process. The Board also notes that the methodologies for allocating S&T margins that are ultimately accepted by the Board are to be used in Union's next rates proceeding (cost of service or IRM).

The Board expects, as part of the Draft Rate Order process, that Union will file revised rates that reflect all of the findings in this Decision and that reflect the rate design principles ordered by the Board above.

Rate 01 / 10 and Rate M1 / M2 – Volume Breakpoint and Rate Block Harmonization Proposal for 2014

Union proposed to lower the annual volume breakpoint between the Rate 01 and Rate 10 rate classes in Union North and the Rate M1 and Rate M2 rate classes in Union South from 50,000 m^3 to 5,000 m^3. Union also proposed to harmonize the rate block structures in the small volume general service rate classes (Rate 01 and Rate M1) and in the large volume general service rate classes (Rate 10 and Rate M2). Union proposed to utilize the current Board-approved rate block structures for Rate M1 and Rate M2 in Union South for Rate 01 and Rate 10 in Union North respectively. Union proposed to implement the annual volume breakpoint and rate block structure changes on a revenue neutral basis effective January 1, 2014.[107]

[107] Exhibit H1, Tab 1 at p. 14 (Updated).

Union noted that its proposal to lower the annual volume breakpoint between small volume general service rate classes (Rate 01 and Rate M1) and large volume general service rate classes (Rate 10 and Rate M2) to 5,000 m^3 from 50,000 m^3 will improve the rate class composition of Rate 01 and M1 and achieve more homogeneous rate classes. Also, Union noted that the proposal will improve the rate class size in Rate 10 and Rate M2, which will ensure viable large volume general service rate classes and improve rate stability.[108]

All parties agreed with Union's proposition that the volume breakpoint between the Rate 01 / Rate 10 and Rate M1 / M2 should be reduced for the reasons cited above and that the rate blocking structure should be harmonized. However, no party agreed with the methodology used by Union to give effect to its proposal. Board staff[109], LPMA[110], SEC[111] and other parties explicitly raised concerns regarding Union's methodology for allocating costs between the noted rate classes.

LPMA noted that with respect to the customer-related costs, Union has used a customer-weighting factor to determine the amount of customer-related costs that are associated with the customers that will be moving rate classes. LPMA noted that the weights used are 1.0 for residential, 1.5 for commercial, and 2.0 for industrial. LPMA noted that when asked if Union had any empirical evidence to support the relative differences in the weights used, Union replied that the empirical evidence that they have in this is similar to the evidence that they used when they did the 2007 rate split, which used the same weightings. LPMA noted that Union filed a report in support of the 2007 split prepared by Navigant Consulting Inc. that simply stated that the weights currently used by Union were 1.0 for residential, 1.5 for commercial, and 2.0 for industrial. The Navigant report went on to say that it understood that Union was currently reviewing the appropriateness of those weights. In the undertaking response, Union indicated that it could not find any other 2007 source files related to the weightings. LPMA noted that there was no evidence concerning Union's review anywhere on the record in this proceeding.

LPMA stated that there is no evidence that customer-related costs for commercial customers are 50% higher than they are for residential customers. LPMA noted that customer-related costs include such items as billing and meter-reading costs,

[108] Exhibit H1, Tab 1 at pp. 14-16 (Updated).
[109] Board Staff Submission, August 17, 2012 at pp. 30-34.
[110] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 82.
[111] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp.214-217.

depreciation and the return on meters, regulators and service lines. LPMA submitted that Union has provided no evidence to suggest that the commercial customers that would change rate classes under Union's proposal are any different from residential customers when it comes to billing costs or meter reading costs.

LPMA also raised concerns regarding how Union allocated the delivery-related costs for the group of customers that would be changing rate classes under Union's proposal. LPMA noted that these costs include demand-related costs and commodity-related costs. LPMA stated that, in the South, the vast majority of the other delivery-related costs are demand-related costs for both Rates M1 and M2, with a small component of commodity-related costs. In the North, all of the other delivery-related costs are demand-related costs. However, LPMA noted that Union estimated the costs for the customers that are moving rate classes on the basis of commodity volumes. LPMA submitted that a more appropriate methodology would be to use a design-day weighting allocator which is developed based on a full cost allocation study. LPMA noted that Union generally allocates demand-related costs based on peak day demand. However, LPMA noted that Union indicated that based on forecast data it did not have all of the detailed material that is needed to do a detailed cost study.[112]

Parties made differing arguments regarding how to deal with Union's proposal. Many parties argued that Union should be directed to file more comprehensive evidence (including a cost allocation study) supporting its proposal to reduce the volume breakpoint (and specifically supporting the methodology used to allocate costs) in the noted rate classes prior to the Board approving Union's proposal.

Board staff stated that it supports Union's goal to achieve more homogenous general service rate classes and to increase the size of its larger volume general service rate classes. However, Board staff also submitted that Union should file better supporting evidence for the manner in which costs will be allocated between the rate classes that are the subject of Union's proposal.[113]

LPMA and SEC offered other submissions for the Board to consider in adjudicating this issue.

[112]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 85-88.
[113] Board Staff Submission, August 17, 2012, at p. 34.

LPMA submitted that the Board should approve Union's proposal with a modification to the customer weighting, a change to the monthly customer charge, and the direction to file a cost allocation study as soon as possible which confirms that the costs have been allocated appropriately.

LPMA submitted that a more appropriate weighting scheme for the customer-related costs, in the absence of empirical evidence, is to use the same weight for commercial customers as for residential customers. The impact on the customer-related costs that would be moved to Rate M2 is significant. LPMA noted that this change results in a substantial reduction in the costs moved to Rates 10 and M2. The reduction to Rate 10 is $2.4 million and $4.4 million to Rate M2.

With respect to the monthly customer charge for the Rate 10 and M2, LPMA made the following submissions. LPMA noted that Union proposed a $35 monthly customer charge for both rate classes. Union arrived at this monthly charge by taking the midpoint of the monthly customer charges required to recover all customer-related costs for these two rate classes. LPMA stated that this methodology was used to achieve Union's goal of maintaining the same monthly fixed charge for the noted rate classes. LPMA submitted that Union's proposal is inappropriate. LPMA noted that there is a clear difference in the monthly customer charge based on the allocated customer charges between Rates 10 and M2. In particular, the cost-based Rate 10 monthly charge would be $41, while the Rate M2 monthly charge would be $30. LPMA stated that Union is effectively under-recovering, based on its proposed $35 monthly charge, from those in Rate 10 and over-recovering from those in Rate M2.

LPMA submitted that the Rate M2 monthly customer charge should be set at $30 and the Rate 10 monthly customer charge should be set at $40. LPMA stated that these recommended monthly charges are cost-based charges.

LPMA submitted that the Board should direct Union to prepare a proper cost allocation study as soon as possible so ratepayers can be satisfied the costs are being allocated appropriately. LPMA stated that the cost allocation study should be filed with the Board and intervenors as soon as possible so the parties have the opportunity to determine if adjustments to rates are required to more properly and equitably recover the properly allocated costs.

LPMA also noted it would be preferable to implement Union's proposal, with its proposed revisions, effective January 1, 2013, rather than waiting until 2014. LPMA noted that Union has indicated that it is not practical to implement the changes by January 1, 2013, as Union requires Board approval in time to update administrative systems and billing systems. LPMA noted that there were no other reasons provided as to why the change could not be implemented on January 1, 2013. LPMA stated that it understands that time may be required to change the blocking structure in Union North to match that of Union South. However, LPMA submitted that there is no reason to delay the change in the break point in Union South. There are no changes proposed in the block structure for Rates M1 and M2. The change in the break point simply requires Union to identify the customers that will move from rate M1 to rate M2, and then move them. As a result, LPMA stated that there is no obstacle to moving a small percentage of the overall customers from Rate M1 to M2 on January 1, 2013. LPMA submitted that the Board should direct Union to implement the remaining change as early as is practical in 2013.[114]

In response to LPMA's argument, Union made the following submissions.

Union noted that the logic of LPMA's position is that there is unlikely to be a significant difference in the customer-related costs to serve residential and commercial customers and as such, these two types of customers should be applied an equal weighting. Union submitted that that logic applies equally to all aspects of the general service, small volume rate class including: residential, commercial and industrial. Therefore, given LPMA's rationale, Union submitted that all residential, commercial and industrial customers should be weighted equally.

With respect to LPMA's argument on the demand-related costs, Union submitted that the methodology used to split the remaining costs is the same as it used to split the costs between the current M1 and M2 rate classes.

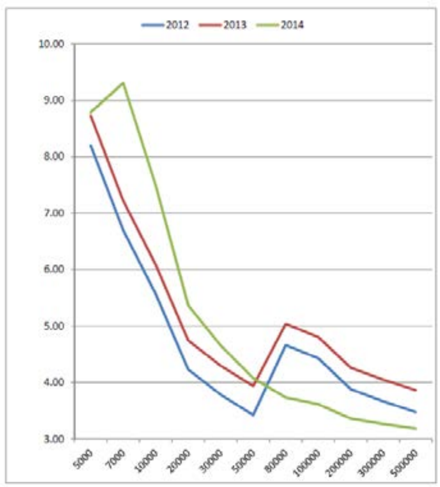
Union submitted that it accepts LPMA's submissions on revising the monthly customer charge to $30 for Rate M2 and $40 for Rate 10.

Union noted that LPMA suggested that the implementation of its proposal occur at the beginning of 2013 for Rates M1 and M2 and that the implementation for Rates 01 and 10 could occur later. Union submitted that this is not possible. Union stated that it needs

[114] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 85-88 and 90-93.

eight months to change its systems. Therefore, Union stated that it will implement its breakpoint proposal for Rates 01, 10, M1 and M2 in the first QRAM after its systems have been updated to reflect this change.

SEC noted that rate continuity requires that when you go from one rate class to another you would still be recording your economies of scale. SEC noted that in Union North, the rates designed for 2013 and 2014 are relatively continuous and SEC does not have major concerns with rate continuity. However, for Union South, SEC submitted that there are significant discontinuities between rates M1 and M2. SEC provided the following chart which highlights the issues it has raised regarding Union's small volume general service classes.[115]



SEC provided the following analysis of the above chart. SEC noted that the chart reflects the unit costs for customers. SEC noted that when you analyze current 2012 rates and the proposed 2013 rates, at and around the breakpoint there is a large increase in the per unit cost for customers.

SEC noted that there are economies of scale in place as you increase volumes and therefore there should not be any increase at (or around) the breakpoint. SEC stated that the reason for the increased per unit cost around the breakpoint between the M1 and M2 rate classes can only be caused by the fact that there is an over-allocation of costs to the M2 rate class.

[115] SEC Argument Compendium at p. 45.

SEC submitted that the 2014 rate proposal reflects a smoother rate continuum. However, SEC noted that the 2014 proposal still does not address the over-allocation of costs to Rate M2. SEC cited the following table to highlight the over-allocation of costs to Rate M2 and to also comment on its view concerning the over-allocation of costs to Rate 10 in Union North.[116]

	a	b	c	d	e	f	g	h	i	j
	North	*Delivery - related costs*	*Volumes*	*Delivery costs per unit*	*Pre-Move Costs*	*Pre-Move Volumes*	*Pre-Move Unit Costs*	*Post-Move Costs*	*Post-Move Volumes*	*Post-Move Unit Costs*
1	Up to 5,000 (01)	$35,211	609,371,320	$0.057783	$47,065	837,395,959	$0.056204	$35,211	609,371,320	$0.057783
2	5,000 to 50,000 (01-10)	$11,854	228,024,639	$0.051986						
3	Over 50,000 (10)	$15,476	244,955,407	$0.063179	$15,476	244,955,407	$0.063179	$27,330	472,980,046	$0.057783
4	Totals - North	$62,541	1,082,351,366	$0.057783	$62,541	1,082,351,366	$0.057783	$62,541	1,082,351,366	$0.057783
	South	*Delivery - related costs*	*Volumes*	*Delivery costs per unit*	*Pre-Move Costs*	*Pre-Move Volumes*	*Pre-Move Unit Costs*	*Post-Move Costs*	*Post-Move Volumes*	*Post-Move Unit Costs*
5	Up to 5,000 (M1)	$75,911	2,043,883,921	$0.037141	$99,137	2,679,558,627	$0.036998	$75,911	2,043,883,921	$0.037141
6	5,000 to 50,000 (M1-M2)	$23,226	635,674,706	$0.036538						
7	Over 50,000 (M2)	$36,461	971,362,682	$0.037536	$36,461	971,362,682	$0.037536	$59,687	1,607,037,388	$0.037141
8	Totals - South	$135,598	3,650,921,309	$0.037141	$135,598	3,650,921,309	$0.037141	$135,598	3,650,921,309	$0.037141

SEC noted that the above table deals only with delivery costs as the delivery-related costs highlight the issue of the over-allocation of costs to Rates 10 and M2 for 2013.

SEC noted that Line 1 reflects Rate 01, and Line 5 reflects M1. Line 3 and Line 7 reflect Rate 10 and M2 respectively. SEC noted that the delivery costs (on a per unit basis and prior to the implementation of Union's 2014 breakpoint reduction proposal) for a Rate 01 customer are 5.62 cents / m^3 and 6.32 cents / m^3 for a Rate 10 customer. SEC submitted that this cannot be correct.

Similarly, for M1 and M2, SEC noted that the delivery costs (on a per unit basis and prior to the implementation of Union's 2014 breakpoint reduction proposal) for a Rate M1 customer are 3.699 cents / m^3 and 3.753 cents / m^3 for a Rate M2 customer. SEC submitted that this also cannot be correct.

SEC noted that what Union did, in order to adjust for this over-allocation of costs for 2014, is move less costs over for 2014 to achieve a situation where M1 and M2 and 01 and 10, respectively, have the same unit costs for delivery. SEC submitted that this is also likely not correct.

[116]Ibid at p. 61.

SEC stated that because the pre-move costs show higher costs in Rates 10 and M2 that there has been an over-allocation of costs to those rate classes. Therefore, the 2013 costs for the small volume general service classes have been allocated incorrectly. SEC stated that it does not know the quantum of the over-allocation. SEC also noted that the existing over-allocation has only been disclosed because Union has provided evidence regarding the movement of costs in the small volume general service rate classes to give effect to its 2014 breakpoint reduction proposal and it has created some anomalous results.

SEC submitted that considering Union has not done a proper cost allocation study to reflect the new proposed breakpoint, the Board has no way of knowing what the right costs are for 2013. SEC submitted that all that is known, based on Union's evidence, is that the results of Union's allocation are anomalous.

Overall, SEC submitted that the Board does not have the jurisdiction to set new rates for Rates 01, 10, M1 and M2 in 2013, because there is no strong evidence before the Board upon which those rates can be set. SEC submitted that the Board should not change the rates in 2013 for Rates 01, 10, M1 and M2 and should direct Union to file a cost allocation study as soon as possible. SEC stated that the cost allocation study should be filed as part of an application seeking to establish new rates for the above noted rate classes. SEC submitted that any foregone revenues that are caused by not increasing the rates for the above noted rate classes in 2013 should be borne by Union's shareholder as it is Union's responsibility to file sufficient evidence to support changes in rates.[117]

Union argued that there is no legal support for SEC's proposition that the Board has no jurisdiction to approve the rate design changes proposed by Union. Union noted that the Board has the power to set what it determines to be just and reasonable rates.

Union stated that SEC's argument is largely one of rate continuity, which SEC believes to be demonstrative of some inherent problem with Union's allocation of costs.

Union stated that the rate continuity problem raised by SEC has an explanation. Union stated that what has happened during the period of IRM is that the monthly customer charge for rates M1 and 01 were increased from $16 in 2007 to $21 in 2010, and those customer charge increases were offset by reductions in the volumetric rates for these

[117] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 211-229.

rate classes. Overall, the rate changes were revenue neutral. Union noted that there were no similar increases in monthly charges or corresponding reductions in volumetric rates of the large volume general service classes (Rates 10 and M2). Therefore, Union stated that the rate continuum that existed in 2007 was gradually eroded because of a cross-subsidy that was occurring in the general service rate classes where the larger volume, but still below 50,000 / m^3 customers, receiving the benefit of the reduction in volumetric rates (and not being impacted substantially by the monthly charge increase).

Union submitted that the problem cited by SEC is not a problem with cost allocation. Instead, it shows what can happen with rate design over time and why it is important to monitor these issues. Union submitted that its 2014 breakpoint reduction proposal addresses the concerns raised by SEC regarding rate continuity. Union submitted that SEC's arguments should be rejected and the volumetric breakpoint should be reduced as proposed by Union.[118]

Board Findings

The Board is of the view that Union's proposal to reduce the volume breakpoint between the Rate 01 / Rate 10 and Rate M1 / M2 classes and harmonize the blocking structure has merit. The Board believes that Union's proposal does improve the rate class composition of Rate 01 and M1 and achieves more homogeneous rate classes. The Board believes that the proposal will improve the rate class size in Rate 10 and Rate M2, which will ensure viable large volume general service rate classes and improve rate stability.

However, the Board agrees with the submissions of Board staff and Intervenors that the methodology used by Union to allocate costs between the rate classes and give effect to its proposal is flawed. The Board believes that Union's allocation methodology results in an inequitable allocation of costs as between Rates 01 and 10 and between Rates M1 and M2. As such, the Board will not approve the proposed change in volume breakpoint, effective January 1, 2014.

The Board directs Union to undertake a comprehensive cost allocation study which includes the volume breakpoint reduction proposal. The Board is not satisfied that the allocation has been done correctly at this time and therefore the Board will not accept Union's proposal. The Board is also not willing to accept LPMA's proposals to change

[118]Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp.152-155.

the allocation methodology as there is no evidence on the record that would support a finding that LPMA's allocation methodology is superior to the method put forth by Union.

SEC argued that, if the Board found problems with Union's proposed allocation methodology, it should not change the existing rates at all for 2013. SEC argued that the Board is only empowered to set rates that are just and reasonable, and given that, in SEC's view, Union's allocation of costs as between Rates 01 / 10 and Rates M1 / M2 is flawed for 2013 (even without applying the breakpoint proposal), the Board cannot make any changes to the existing rates (including, a "true-up" to reflect the new Board approved revenue requirement). SEC argued that the onus is on Union to justify any changes to rates, and if its proposals are not adequately supported then the Board should make no changes at all.

The Board does not agree with this position. The Board has an obligation to set rates for Rate 01, Rate 10, Rate M1 and Rate M2 for 2013. Whether the breakpoints remain the same or whether they change, the Board will still set rates for these classes. The Board notes that there was significant criticism of Union's proposed methodology, which may have merit, but the Board will not be changing the breakpoints in this decision. However, this does not lead to a conclusion that the rates in question must be frozen at existing levels. Even if the Board were to keep the rates at existing levels, this would still amount to the setting of rates. To fail to pass along the allocated portion of the revenue deficiency to the 01/10 and M1 / M2 rate classes would result in an unrecovered deficiency for Union. In the Board's view, this outcome would not equate to the Board setting just and reasonable rates.

In setting just and reasonable rates, the Board must make the best determination it can based on the evidence available. Although the Board will not adjust the breakpoints in this proceeding, it will require Union to update the 01/10 and M1 / M2 rates based on the approved revenue deficiency and the other relevant findings in this Decision.

The Board therefore directs Union to file a comprehensive cost allocation study which includes the allocation of costs for its volume breakpoint proposal no later than its 2014 rates filing. The Board directs Union to include in that study analysis of the issue raised by LPMA regarding the allocation of costs for Distribution Maintenance – Meter and Regulator Repairs related to the customers that would be moving rate classes. The Board also directs Union to include an analysis of the Distribution Maintenance – Equipment on Customer Premises cost allocation methodology and an analysis of the

Kirkwall Metering Station cost allocation methodology in this cost allocation study, consistent with the Board's findings elsewhere in this Decision.

Rate M4, Rate M5A and Rate M7 - Eligibility Criteria Proposals for 2014

Union proposed to lower the eligibility criteria for the mid-market bundled contract rate classes (Rate M4 or Rate M5A) and the large market bundled contract rate class (Rate M7) in Union South. Union proposed to implement the bundled contract rate class eligibility changes effective January 1, 2014.

Union noted that it is proposing changes to the mid-market and large market contract rate eligibility for the following reasons:

i. Continuity of service: Lowering the eligibility ensures that existing mid-market contract rate customers will continue to take service in a contract rate class even if they undertake conservation and efficiency initiatives and/or are already at the rate class eligibility threshold.

ii. Sufficient class size: Lowering the eligibility criteria ensures sufficient rate class size for both the mid-market and large market rate classes. Union noted that Rate M7 customers that have already migrated to Rate M4 or Rate M5A as a result of demand reductions will again be eligible for service under Rate M7. The lower eligibility criteria also make a contract rate option available to large non-contract Rate M2 customers.[119]

The proposed eligibility changes for the mid-market and large market bundled contract rate classes are described below.

<u>Rate M4 and Rate M5A – Eligibility Criteria</u>

Union noted that to qualify for service in the current mid-market Rate M4 and Rate M5A rate classes, a customer must have a daily contracted demand between 4,800 m^3 and 140,870 m^3 and a minimum annual volume of 700,000 m^3. In addition, the annual volume commitment for Rate M4 customers must equal 146 days use of firm daily contracted demand (i.e. a 40% load factor).

[119] Exhibit H1, Tab 1 at pp. 28-29 (Updated).

Union proposed to lower the eligibility criteria for Rate M4 and Rate M5A in Union South to a daily contracted demand of 2,400 m^3. The maximum daily contracted demand would be reduced to 60,000 m^3. The minimum annual volume requirement would be reduced to 350,000 m^3. Rate M4 will continue to require 146 days use of firm daily contracted demand.

Union stated that the proposed changes to lower the eligibility criteria for Rate M4 reflect the significant changes in the Union South mid-market. For Rate M4, the number of customers has declined from 194 in the Board-approved 2007 forecast to 121 in Union’s 2013 forecast. Union estimated that lowering the Rate M4 eligibility requirements makes a firm contract service potentially available to a further 595 customers with annual volumes exceeding 350,000 m^3 currently taking service under Rate M2.

Union also noted that a large number of customers currently taking service in Rate M4 are at or near the daily contracted demand and annual volume eligibility threshold. Of the 121 Rate M4 customers in the 2013 forecast, there are 31 customers (26%) with daily contracted demand of 4,800 m^3 and 69 customers (57%) whose firm daily contracted demand falls entirely within the first firm demand block of 8,450 m^3 / day.

Union stated that lowering the Rate M4 daily contracted demand threshold to 2,400 m^3 shifts these customers closer to the mid-point of the first demand block, which will allow for more meaningful average pricing and rate stability in this rate class.

Union proposed to lower the Rate M5A eligibility to a daily contracted demand of 2,400 m^3 and a minimum annual volume requirement of 350,000 m^3 to maintain consistent eligibility with Rate M4.[120]

Rate M7 – Eligibility Criteria

Union noted that the current eligibility criteria to qualify for Rate M7 consists of a combined firm, interruptible and seasonal daily contracted demand of 140,870 m^3 and a minimum annual volume of 28,327,840 m^3. Union proposed to lower the Rate M7 eligibility to a daily contracted demand of 60,000 m^3. This minimum daily contracted demand aligns with the maximum daily contracted demand for Rate M4 and Rate M5A.

[120] Ibid. at pp. 29-31

Union proposed to eliminate the minimum annual volume requirement as a condition of qualifying for Rate M7.

Union noted that there are four customers forecast as Rate M7 in 2013. Lowering the Rate M7 eligibility criteria will result in five customers currently forecast in Rate M4 and 17 customers currently forecast in Rate M5A to be eligible for Rate M7. Union stated that at 26 customers, Rate M7 has sufficient rate class size to ensure meaningful average rate class pricing.[121]

LPMA supported Union's M4 / M5A eligibility criteria reduction proposal. LPMA noted that this will offer more M2 customers the option of moving to Rate M4.

However, LPMA noted that it is concerned with the communication that large M2 customers may receive about the movement from Rate M2 to Rate M4.

LPMA noted that the impact on the large M2 customer can be positive or negative, depending on their load factor. Customers with a low load factor could end up paying more under Rate M4 than they did under Rate M2.

Given the uncertainty as to the cost impacts of moving to Rate M4, LPMA submitted that there should be clear and concise communication with customers. LPMA submitted that the Board should direct Union to do a comparison of the annual costs for each of the customers that have the ability to move rate classes, calculating their annual costs based on both Rates M2 and M4. Union should then be required to contact the customer directly and provide them with the information they need to make an informed decision.[122] No other parties commented on this issue.

Union noted that no parties opposed its M4, M5A and M7 eligibility criteria reduction proposal and that it is willing to undertake LPMA's communication proposal. Union stated that it would make sure that the customers know that they will become eligible for contract rate classes at the lower threshold. Union noted that there are about 600 customers that this issue relates to and Union will send a direct mailing to them.[123]

[121] Ibid. at p. 31.
[122] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 93-95.
[123] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 157-158.

Board Findings

The Board approves Union's proposal to change the eligibility criteria for the mid-market bundled contract rate classes (Rate M4 or Rate M5A) and the large market bundled contract rate class (Rate M7) in Union South. The Board accepts Union's submissions that the proposed changes ensure sufficient class size and the continuity of service in the noted rate classes.

The Board directs Union to communicate these proposals to the relevant customers as agreed to by Union in its reply argument.

Rate T1 Redesign and Rate T3 Customer Charge

Union proposed to split the current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service. Union proposed to implement the new rate classes, eligibility changes and rate structures, on a revenue neutral basis, effective January 1, 2013.

Union noted that it made its proposal to split current Rate T1 into two rate classes in order to better align cost incurrence and cost recovery by recognizing the differences in distribution demand and distribution customer-related costs between small Rate T1 and large Rate T1 customers. Union noted that the proposed split also addresses the significant diversity in daily contracted demand and firm annual consumption that exists between small and large customers within the current Rate T1 rate class.[124]

Union also proposed to increase the monthly charge for Rate T3 from $17,657 to approximately $21,661. Kitchener Utilities (the only customer in this rate class) made arguments on this issue, which are discussed below.

Proposed Rate T1 / Rate T2 Eligibility

Union noted that to qualify for the current Rate T1 service, a customer must have combined firm and interruptible annual consumption of 5,000,000 m^3 or more. For the new Rate T1 mid-market service, Union proposed a minimum annual volume of 2,500,000 m^3. Further, Union proposed that the daily firm contracted demand for the new Rate T1 not exceed 140,870 m^3.

[124] Exhibit H1, Tab 1 at pp. 32 and 35 (Updated).

Union noted that the new Rate T2 large market service will be available to customers with a minimum firm daily contracted demand of 140,870 m^3. Union did not propose any minimum annual volume requirement as a condition for qualifying for the new Rate T2.

Union stated that its proposal to split the current Rate T1 into two rate classes will result in improved rate class composition in both Rate T1 and Rate T2. Specifically, both proposed Rate T1 and Rate T2 will be comprised of more homogeneous customers in terms of firm contracted demands and firm annual consumption. The proposed split of current Rate T1 will also recognize cost differences within the current Rate T1 rate class associated with the allocation of distribution demand-related and distribution customer-related costs.[125]

Rate T1 Rate Design and Pricing

Union proposed that the rate structure for the new Rate T1 consist of a monthly customer charge, a two block monthly demand charge and a single block commodity charge. The table below provides a comparison of Rate T1 before rate redesign and proposed new Rate T1 rate structures and proposed rates.

Comparison of 2013 Proposed Rate T1 with no Redesign
and 2013 Proposed Rate T1 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T1 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	\$6,600.83	Charge per Re-delivery point	\$2,001.29
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 28,150 m^3 Next 112,720 m^3	31.5395 23.2744
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0715
Fuel Ratio	Transportation	0.237%	Transportation	0.256%

Union noted that the proposed monthly customer charge of \$2,001.29 is cost-based and fully recovers all of the customer-related costs applicable to the new Rate T1. The two block demand charge recovers approximately 82% of new Rate T1 demand-related

[125] Ibid at p. 38.

transportation costs. The remainder of new Rate T1 demand-related transportation costs are recovered through the Rate T1 storage related sufficiency. The single commodity charge recovers all the variable transportation costs.

Union noted that the two block demand and single block commodity rate structure for firm service in new Rate T1 is based on the comparable Rate M4 firm service, which also has a daily contracted demand breakpoint of 28,150 m^3. This approach results in consistency between mid-market bundled and mid-market semi-unbundled service offerings.

Union noted that it is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. However, given that Union is proposing a maximum firm daily contracted demand of 140,870 m^3 in the new Rate T1, the new Rate T1 rate schedule will exclude the storage space, storage injection/withdrawal rights and transportation service provisions that are only applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3/day.[126]

New Rate T2 Rate Design and Pricing

Union proposed that the rate structure for the new Rate T2 consist of a monthly customer charge, two block monthly demand charge and a single block commodity charge. The table below provides a comparison of Rate T1 before rate redesign and proposed new Rate T2 rate structures and proposed rates.

Comparison of 2013 Proposed Rate T1 with no Redesign
and 2013 Proposed Rate T2 with Redesign

	2013 Proposed Rate T1 Firm Transportation Rate with no Redesign		2013 Proposed Rate T2 Firm Transportation Rate With Rate Design Changes	
Monthly Customer Charge	Charge per Re-delivery point	$6,600.83	Charge per Re-delivery point	$6,000.00
Monthly Demand Charge (cents/m^3)	First 140,870 m^3 All Over 140,870 m^3	17.8705 12.2113	First 140,870 m^3 All Over 140,870 m^3	21.7032 11.3232
Monthly Commodity Charge (cents/m^3)	First 2,360,653 m^3 All Over 2,360,653 m^3	0.0232 0.0116	All Volumes	0.0081
Fuel Ratio	Transportation	0.237%	Transportation	0.234%

[126]Ibid at pp.41-43.

Union noted that the proposed monthly customer charge for the new Rate T2 rate class has been set at $6,000. At this level, the proposed monthly customer charge recovers approximately 50% of the customer-related costs attributable to the new Rate T2. Union proposed to set the monthly customer charge at $6,000 in order to ensure a smooth rate continuum between Rate T1 and Rate T2 at the daily contracted demand breakpoint of 140,870 m^3. Union noted that the balance of the customer-related costs not recovered in the Rate T2 monthly customer charge are recovered in the first block demand charge, which is common to all Rate T2 customers. The revenue-to-cost ratio for new Rate T2 is consistent with the revenue to cost ratio for Rate T1 before rate redesign.

Union noted that the two block demand rate structure for the new Rate T2 is based on a daily contracted demand breakpoint of 140,870 m^3. This is the same daily contracted demand as the current Rate T1 structure. The two block demand charge also recovers all the demand-related transportation costs. The single commodity charge recovers all the variable transportation costs.

Union noted that it is not proposing any changes to the storage services currently available under the current Rate T1 rate schedule. The proposed 2013 Rate T2 rate schedule will include all the current Board approved storage space and storage injection/withdrawal rights per the current approved Rate T1 rate schedule. Union also noted that the transportation service provisions that are applicable to new and existing customers with incremental daily firm demand requirements in excess of 1,200,000 m^3 / day are included in the proposed T2 rate schedule.[127]

APPrO[128] and IGUA[129] supported Union's proposal to split current Rate T1 into two rate classes with distinct rate structures; a new Rate T1 mid-market service and a new Rate T2 large market service.

Kitchener submitted that the proposed monthly charge under Rate T3 is not just and reasonable, relative to the proposed monthly charges for existing Rate T1 (without redesign) and Rates T1 and T2 (with redesign), given the comparability in customer size and load characteristics between large Rate T2 customers and Kitchener.

[127]Ibid at pp. 44-45.
[128]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 142-143.
[129] IGUA Argument, August 22, 2012, at p. 1.

Kitchener submitted that its bears a disproportionate share of customer-related costs under its existing Rate T3 service which are unreasonably (and fully) reflected in the current monthly charge of $17,567 and even more unfairly reflected in the proposed monthly charge of $21,661. Kitchener submitted that these charges are excessive, both in absolute terms and when compared to similarly sized customers in the existing Rate T1 class and proposed new Rate T2 class that, like Kitchener, are directly served from transmission main and do not have multiple redelivery points.

Kitchener noted that while it does not object, in principle, to Union's proposal to split the existing Rate T1 class into a new Rate T1 mid-market service and a new Rate T2 large market service, Kitchener does object to the proposed differential rate treatment for customer-related costs to be recovered under the monthly charge for rates T1, T2 and T3.

Kitchener submitted that the monthly charge under Rate T3 should not exceed the comparable charge for Rate T2 if the Board allows the proposed redesign to proceed. Kitchener submitted that, in the alternative, if the Board does not approve the Rate T1 redesign, then the monthly charge for Rate T3 should not exceed the comparable charge approved by the Board for existing Rate T1.[130]

Union noted that no parties objected to its proposal and therefore it should be accepted. In response to Kitchener's argument regarding the Rate T3 monthly charge, Union submitted that Kitchener had not led any evidence challenging the customer-related costs and the cost allocations in the 2013 cost study, which identified the customer-related costs and those specifically attributable to Kitchener.

Union noted that the proposed T3 rates are increasing by only 2% and the T3 rates have been relatively flat since 2007. Union submitted that this is a reasonable rate increase.

Union stated that Kitchener is requesting that other rate classes pay a portion of Kitchener's customer-related costs. Union noted that it could align the T3 monthly customer charge with either T1 or T2. However, Union would recover the remaining customer-related costs from Kitchener in its demand charge. Union stated that the result

[130] Kitchener Argument, August 17, 2012, at pp. 1-6.

would be that Kitchener's total transportation bill would remain the same. Union submitted that Kitchener's submission should be rejected.[131]

Board Findings

The Board approves Union's proposal to split the current Rate T1 into two rate classes; a new Rate T1 mid-market service and a new Rate T2 large market service effective January 1, 2013. The Board accepts Union's submission that splitting the current Rate T1 into two rate classes better aligns cost incurrence and cost recovery by recognizing the differences in distribution demand and distribution customer-related costs between small Rate T1 and large Rate T1 customers.

The Board finds that the monthly charge proposed by Union for Kitchener, under Rate T3, is appropriate as filed. The Board finds that the proposed monthly customer charge applicable to Kitchener reasonably recovers the customer-related costs incurred to serve Kitchener. In addition, the Board agrees with Union that Kitchener has not challenged the customer-related costs and the cost allocations in the 2013 cost study, which identified the customer-related costs and those specifically attributable to Kitchener. As such, the Board does not have a reasonable basis upon which it could direct Union to revise the T3 customer charge.

Supplemental Service Charge – Group Meters for Commercial / Industrial Customers in Rate M1 and Rate M2

Union proposed to update the additional service charge applicable to "Supplemental Service to Commercial and Industrial Customers under Group Meters" in Rate M1 and Rate M2. Union noted that the supplemental service allows for the combination of readings from several meters, where the meters are located on contiguous pieces of property of the same owner and are not divided by a public right-of-way.

Union proposed to increase the additional service charge on the Rate M1 rate schedule from the current approved $15 per month to $21 per month. On the Rate M2 rate schedule, Union proposed to increase the additional service charge from the current approved $15 per month to $70 per month ($35 per month in 2014 – for consistency with its 2014 M1 / M2 rate design proposal). Union stated that it is proposing to increase the additional service charge to ensure that customers who combine readings from

[131] Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 158-159.

several meters do not receive an unintended benefit in comparison to customers who cannot combine meter readings. This change will result in all Rate M1 and Rate M2 customers paying the same monthly customer charge for all meter readings.[132]

Union noted, in cross-examination, that the benefit received by customers that have the ability to combine meter readings is that those customers have the opportunity to combine volumes. Combining volumes allows customers to have more of their volumes charged at lower rates (in the higher volume blocks of the delivery rates).[133]

VECC supported Union's proposal as filed.[134]Board staff also supported Union's proposal and noted that that the same supplemental charge should be applied in the North. Board staff noted that Union offers an equivalent meter combination service in its Northern service area. However, there is no equivalent supplemental charge.

Board staff submitted that Union's Northern customers that have the ability to combine meters are receiving the same unintended benefit as those Southern customers that have the same ability. Accordingly, a supplemental charge equal to the monthly customer charge should be applied to Union's Northern customers (Rate 01 and Rate 10) that combine meter readings to ensure equitable treatment among the customers in those rate classes.[135]

LPMA submitted that the Board should direct Union to extend its existing policy in the North to the South and eliminate this supplemental service charge.[136]

Union submitted that the longstanding policy in the North of allowing customers to combine meter readings without a supplemental charge should be maintained. However, Union stated that should the Board be inclined to harmonize the supplemental service charge in the North and South, Union supported the introduction of a service charge in the North over the elimination of the South supplemental charge. Union made this argument primarily on the basis that there should not be an unintended benefit for South customers.[137]

[132] Exhibit H1, Tab 1 at p. 56 (Updated).
[133] Oral Hearing Transcripts, EB-2011-0210, Volume 12 at p. 13.
[134] VECC Argument, August 21, 2012, at p. 28.
[135] Board Staff Submission, August 17, 2012 at pp. 29-30.
[136] Oral Hearing Transcripts, EB-2011-0210,Volume 15 at pp. 96-97.
[137] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at pp. 159-160.

Board Findings

The Board finds that the supplemental charge for the combination of meter readings (where the meters are located on contiguous pieces of property of the same owner and are not divided by a public right-of-way) should be harmonized as between North and South. The Board finds that the longstanding policy of allowing customers to combine meter readings without a supplemental service charge should be maintained in the North and should be extended to the South. As such, the Board directs Union to eliminate this supplemental charge in its Southern service area. Accordingly, in the Draft Rate Order process, Union is directed to update its revenue forecast to reflect the above finding.

Rate Mitigation

Union argued that the proposals included in its 2013 rates filing result in total bill impacts of less than 10% and based on the Board's guidelines on electricity, no mitigation is necessary.[138] Union did, however, provide a number of potential rate mitigation measures that could be invoked if the Board deems it necessary. Those rate mitigation measures were provided at Exhibit J11.10.

A number of parties made submissions on the issue ofrate mitigation. Board staff submitted that rate mitigation should only be applied when rate impacts are greater than 10% on the total bill. Board staff noted that 10% rate impacts on the total bill has been used in the past by the Board as a benchmark for what magnitude of rate impacts should trigger rate mitigation for the purpose of setting electricity transmission and distribution rates. Board staff therefore submitted that the same 10% benchmark is appropriate in this case.

If the Board's findings in this proceeding, when taken as a whole, result in rate impacts greater than 10% on the total bill, Board staff submitted that the Board should consider any and all rate mitigation measures it deems appropriate.[139] BOMA supported Board staff's submission on the issue of rate mitigation.[140]

[138] Oral Hearing Transcripts, EB-2011-0210,Volume 13 at p. 81.
[139] Board Staff Submission, August 17, 2012, at p. 34.
[140] BOMA Factum for Argument at p. 54.

Energy Probe submitted that depending on the overall level of rate increases remaining after the Board makes it Decision in this proceeding, rate mitigation measures may or may not be necessary.[141]

LPMA submitted that depending on the Board's findings with respect to Union's M1 / M2 and Rate 01 / Rate 10 volume breakpoint reduction proposal, rate mitigation measures may or may not be necessary. LPMA essentially argued that if the rate impacts for any customer are higher than 10% on the total bill, then rate mitigation should occur.[142]

APPrO submitted that rate mitigation measures should be implemented when the rate impacts are greater than 10% on the delivery portion of the bill, as opposed to total bill impacts.[143] IGUA supported APPrO's position on this issue.[144]

Board Findings

The Board notes that it has made a number of findings in this decision that reduce the revenue requirement and impact the distribution of the approved revenue requirement between customer classes. As a result, it is not clear to the Board at this juncture that rate mitigation will be necessary. The Board will therefore review the rate impacts after the findings set out in this Decision have been implemented in the Draft Rate Order stage of the proceeding. At that time, the Board will determine whether any rate mitigation measures will be required.

Other Rate Design Issues

Board Findings

The Board notes that parties either generally supported Union's evidence or made no comments on the rate design issues listed below.

Issue H2 – Is Union's response to the Board directive to review the M12 and C1 ratemaking methodology appropriate?

[141] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 70.
[142] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 98.
[143] Oral Hearing Transcripts, EB-2011-0210, Volume 15 at p. 147.
[144] IGUA Argument, August 22, 2012, at p. 2.

Issue H6 – Is the introduction of M4 interruptible service offering effective January 1, 2014 appropriate?

Issue H9 – Is recovering UFG on transportation activity in the winter months for the Dawn to Dawn-Vector transportation service appropriate?

Issue H11 – Is the proposal to modify the M12, M13, M16 and C1 rate schedules including Schedule A, Schedule A-2013 and Schedule C appropriate?

Issue H12 – Is the proposal to change the Distribution Consolidated Billing fee to $0.57 per month per customer appropriate?

Issue H13 – Are the proposed changes to the Gas Supply Administration Fee appropriate?

Issue H15 – Is the proposal to change the rate design for services originating at Kirkwall to eliminate Kirkwall measuring and regulating costs appropriate?

The Board approves Union's proposals with respect to each of the above-noted rate design issues.

The Board notes that it has included a summary of its findings related to cost allocation and rate design in Appendix "A" of this Decision.

DEFERRAL ACCOUNTS

Average Use Per Customer Deferral Account (Account No. 179-118)

Union noted that the Average Use Account was established in EB-2007-0606 to record the margin variance resulting from the difference between the actual rate of decline in use-per-customer and the forecast rate of decline in use-per-customer included in Union's Board-approved rates.

Union proposed to continue tracking the average use per customer in the existing deferral account. Union also proposed to change the description of Average Use Account in the accounting order to remove the limitation that makes it applicable only to the current incentive regulation plan, 2008 through 2012. Union noted that the proposed accounting order for the Average Use Account would allow it to be in effect until it is changed or eliminated.[145]

Union initially noted that the Average Use Account will not record differences from forecast for 2013 because 2013 is a cost of service year. The earliest that the Average Use Account would be used is in relation to 2014, assuming that there is an incentive regulation framework in place at that time and that the average use true-up is a feature of that framework.[146]

Energy Probe argued that the average use deferral account should be in operation for 2013 as part of an accommodation for shareholder and ratepayer interests around the 2013 NAC and volume forecasts as discussed in the NAC section of this Decision.[147]

LPMA submitted that it does not accept Union's proposal with respect to the Average Use Account. LPMA noted that this account was established in EB-2007-0606 as part of a true-up mechanism that was utilized under IRM, and the current wording of the account makes it applicable only to the current incentive regulation plan years, 2008 through 2012.

LPMA submitted that this account should not be used for the 2013 test year. LPMA noted that part of the risk for which Union earns its return on equity in a cost-of-service test year is its forecast risk. Use of the Average Use Account would reduce the risk, with no corresponding benefit to customers. LPMA noted that the use of the Average Use Account during the IRM term was to reflect that the average use was expected to decline over the term of the IRM plan, and that both Union and ratepayers would benefit from the implementation of such an account over the IRM, by ensuring that neither party benefited at the expense of the other.

LPMA noted that Union originally indicated that it does not need to keep the account open and that it could be eliminated for 2013 and reintroduced as a part of the next IRM application. In light of the admission, LPMA submitted that there is no reason to keep the account open other than it might be used in 2014. LPMA submitted that the Board should eliminate this account for 2013. LPMA stated that the Board should not approve

[145] Exhibit H1, Tab 4 at p. 3 (Updated).
[146] Exhibit J.DV-4-3-1.
[147] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 51.

the continuation of an account that it knows will not be used for the test year and may or may not be used in the future beyond the test year.[148]

As discussed previously, Union submitted that should the Board have any concerns with respect to the NAC forecast, it could continue to maintain the operation and use of the Average Use Account that was in place during the incentive regulation period. Although Union noted that it does not prefer this approach, it indicated that continuing the Average Use Account would resolve the dispute around the NAC forecast.[149]

Board Findings

As set out earlier in this Decision, the Board accepts Union's NAC forecast as filed, but orders Union to continue the operation and use of the Average Use Account for the 2013 rate year to ensure fairness among Union and ratepayers. The Board therefore directs that the Average Use Account will be open and in operation for the 2013 test year. The Board directs Union to file a Draft Accounting Order for the Average Use Account that reflects the Board's findings in this Decision.

Inventory Revaluation Deferral Account (No. 179-109)

Union proposed to remove the Transmission Line Pack Gas account in the accounting order for the Inventory Revaluation Deferral Account in order to be consistent with accounting changes and for administrative simplicity. Union noted that it has reclassified line pack gas from gas in inventory to property, plant and equipment, and therefore it has proposed that line pack gas should not be revalued quarterly as part of inventory.[150]

LPMA supported Union's proposal and no other parties commented on this issue.[151] Accordingly, Union requested that its proposed change related to the Inventory Revaluation Deferral Account be approved by the Board.

[148]Oral Hearing Transcripts, EB-2011-0210, Volume 15 at pp. 104-106.
[149]Oral Hearing Transcripts, EB-2011-0210,Volume 16 at pp. 25-26.
[150] Exhibit H1, Tab 4, p. 2 (Updated).
[151]Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 104.

Board Findings

The Board accepts Union's proposal to remove the Transmission Line Pack Gas account in the accounting order for the Inventory Revaluation Deferral Account for the reasons cited by Union.

Short-term Storage and Other Balancing Services Deferral Account (No. 179-70)

Union noted that following the NGEIR Decision (EB-2005-0551), Union's practice has been to sell its non-utility storage space on a long-term basis and to sell the excess utility space on a short-term basis (less than 2 years). Union stated that, despite this practice, it is authorized by the Board to sell non-utility storage space under short-term contracts and retain 100% of the revenues.

Union noted that if it sells short-term peak storage services using non-utility storage space, the total margins received from the sale of all peak short-term storage should be allocated to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage sold each calendar year. Union stated that this methodology is transparent to all participants and will yield the same proportionate return on all short-term transactions for the ratepayers and the shareholders.

Union stated that considering the seasonal volatility and variability of market-priced storage, it cannot predict what period of time will yield the highest or lowest prices for short-term peak storage services. Union noted that the use of a proportionate share of calendar year margins ensures that neither party is impacted by the timing of storage sale, or fluctuations to storage values throughout the year.

Union noted that it is able to give effect to its proposal by its ability to track what storage assets are being used for each type of storage transaction.

Union stated that, going forward, it will continue to sell all excess annual utility storage as short-term peak storage and 90% of all margins from C1 Off-Peak Storage, Gas Loans, Enbridge LBA, Supplemental Balancing Services, and C1 Firm Short-Term Deliverability will accrue to ratepayers.[152]

[152] Exhibit C1, Tab 7.

Union noted that it proposed to change the description of the Short-term Storage and Other Balancing Services Deferral Account (the “Short-Term Storage Account”) in the accounting order to update the list of revenues included in the account and the proposed short-term storage margin sharing methodology.[153]

Union proposed the following description for the Short-Term Storage Account:

> To record, as a debit (credit) in Deferral Account No. 179-70 the difference between actual net revenues for Short-term Storage and Other Balancing Services including; Peak Short-Term Storage underpinned by excess utility storage assets, Off-Peak Short-Term Storage, Gas Loans and Supplemental Balancing Services and the net revenue forecast for these services as approved by the Board for ratemaking purposes.[154]

Board staff supported Union’s proposal with a few qualifications. Board staff submitted that Union should sell only short-term storage services using the excess utility space and that the revenues should be allocated between the utility and non-utility storage operations as proposed by Union. With regard to how Union goes about selling short-term services, Board staff submitted that Union should give priority to the sale of short-term storage services that rely on the excess utility storage space. This will help to ensure that ratepayers are not being adversely harmed by Union’s non-utility business selling the same services as its utility business.

In addition, Board staff submitted that the Short-Term Storage Account should capture payments related to storage encroachment. In its January 20, 2012 Decision and Order in EB-2011-0038, the Board stated the following:

> However, the Board does note that, in the past, Union has encroached on its utility space. The Board is of the view that the existence of Union’s utility assets creates a situation where those assets effectively becomean “insurance policy” in relation to Union’s resource optimization activities on the non-utility side of its storage operations. Union’s utility assets can act as a backstop on the rare occasions when Union oversells its non-utility storage space. The evidence suggests that the occurrence of this has been rare and it would be difficult to determine retrospectively to what degree, if any, Union relied on the existence of the utility assets in the conduct of its non-utility storage business to set contract terms and pricing.

[153] Exhibit H1, Tab 4.
[154] Exhibit H1, Tab 4, Appendix C.

> The Board is of the view that there should be an ongoing monitoring of this potential encroachment so as to inform the Board as to the need to revisit this issue at a future date. The Board therefore finds that Union shall be required to monitor for and maintain records of all future encroachments and provide such information in its rebasing application.[155]

It was Board staff's position that the Board, in EB-2011-0038, was concerned about the occurrence of storage encroachment. The Board decided not to address this issue at that time because the occurrence had been rare (only one instance recorded in evidence).

Board staff noted that, in this proceeding, Union provided a schedule highlighting that for a brief period in 2011, Union again encroached on its utility storage position.[156] Board staff noted that this second recorded encroachment requires the Board to address the situation now.

Board staff submitted that Union should be required by the Board to pay fair market value for the use of its utility storage space in the rare situations that Union's non-utility storage operation encroaches on its utility storage space. Board staff noted that in cross-examination Union stated that the cost to rectify its encroachment issue in October 2011 was $1.1 million. This was the cost incurred by Union to move 2 PJs off its system.[157]

Board staff submitted that the 10% incentive payment to Union's shareholder, which applies to the other net revenues in the Short-Term Storage Account, should not apply to storage encroachment payment amounts. Union should not be granted a 10% incentive payment for encroaching on its utility storage space.

Energy Probe supported Board staff's submission and also argued that the account should be broadened to include short-term storage revenues obtained from optimizing utility storage space that is not classified as excess utility storage space.[158]

LPMA noted that there are two issues that need to be addressed related to the Short-Term Storage Account. The first issue is the proposed change in the

[155] Decision and Order, EB-2011-0038, January 20, 2012, at p. 16.
[156] Exhibit C1, Tab 6.
[157] Oral Hearing Transcripts, EB-2011-0210, Volume 7 at p. 173.
[158] Oral Hearing Transcripts, EB-2011-0210, Volume 14 at p. 61.

wording and what is actually to be captured by the account. The second issue is how the amounts that are to be recorded in the account should be calculated.

On the first issue, LPMA submitted that any revenue generated through the use of the regulated utility storage space up to the 100 PJ cap, both planned and the excess over planned, should be recorded in the account for sharing with ratepayers. LPMA stated that to do otherwise would be to deny ratepayers a share of the revenues generated by assets, the costs of which are already built into their rates. The planned use of utility storage assets includes contingency space, some of which is filled on a planned basis and some of which is left empty on a planned basis. The use of the contingency space can be altered during the year depending on the circumstances that exist. Similarly, a colder than expected fall season could result in increased storage capacity being available. LPMA submitted that the wording of the deferral account should reflect the inclusion of all revenues generated from the regulated utility storage assets of 100 PJs.

On the second issue, LPMA submitted that the Board should direct Union to tie all individual transactions to the utility assets first and when all of these assets have been contracted for, only then would any additional transactions be tied to non-utility assets. LPMA noted that Union's proposal essentially mirrors this, because it is only when the amount of peak short-term storage services contracted for exceeds the excess utility space that the sharing would begin. LPMA noted that the difference between the two proposals is that, under LPMA's proposal, the prices for the individual transactions would be tied to the utility and non-utility assets, and this methodology should mitigate concerns about Union's potential to capture revenue from utility storage if the value of storage falls during the year.[159]

With respect to Board staff's argument that the Short-Term Storage Account should capture amounts related to storage encroachment, Union submitted that there is no proper basis for an account to capture amounts related to this issue. Union noted that the last encroachment happened for a very brief period of time and that Union took steps immediately to rectify that situation and incurred a cost of $1.1 million, which was borne in its entirety by Union's shareholder.[160]

[159]Oral Hearing Transcripts, EB-2011-0210,Volume 15 at p. 109-113.
[160]Oral Hearing Transcripts, EB-2011-0210,Volume 16 at p. 130-131.

Board Findings

The Board believes that there are two issues that need to be addressed with respect to the Short-Term Storage Account. The first issue is the proposed change in the wording in the Accounting Order and what should be captured by the account. The second issue is how the amounts that are to be recorded in the account should be calculated.

First, the Board does not accept Union's proposed wording for the Short-term Storage Account. The Board is in agreement with LPMA that all revenues generated through the use of the regulated utility storage space up to the 100 PJ cap, both planned and the excess over planned, should be recorded in the account for sharing with ratepayers. The Board notes that the revenues that are to be recorded in the Short-Term Storage account relate to the sale of short-term storage, which is defined as all storage transactions that are for a duration of 2 years or less.

The Board also finds that the account should capture storage encroachment and that the 10% incentive payment to Union's shareholder should not apply to storage encroachment payment amounts. The Board believes that there are two issues related to storage encroachment that need to be addressed by the Board in this proceeding.

The first storage encroachment issue relates to the costs arising from actions undertaken to rectify the encroachment, i.e., the cost incurred by Union that is associated with moving gas out of its utility storage space. The Board notes that Union has agreed that its shareholder will pay any costs related to rectifying encroachment situations. The Board believes that this is the appropriate treatment.

The second storage encroachment issue is whether there should be a charge to Union's non-utility storage business to reflect the opportunity cost of the utility storage space that is not available for sale due to encroachment by Union's non-utility storage business. The Board finds that a charge of this nature is appropriate in order to minimize the opportunity for unintended incentives.

The Board notes that pursuant to EB-2011-0038, Union must disclose to the Board when storage encroachment has occurred.[161] That decision, however, only requires Union to file this information in conjunction with its rebasing applications.

The Board therefore directs Union, at the time that the Short-Term Storage Account is to be disposed, to file a report similar to that ordered by the Board in EB-2011-0038. If a storage encroachment has occurred, Union is further directed to file a calculation for the payment by Union's non-utility business to its utility business for storage encroachment. The Board believes that this payment should reflect the market value for the utility space that was subject to the encroachment. The Board notes that this finding only relates to any storage encroachment that occurs after the date of this Decision and will not apply retroactively to previous storage encroachments.

The Board directs Union to revise the wording in the Accounting Order for the Short-Term Storage Account to reflect the above noted findings. The wording in the account must reflect the Board's finding that the account will capture all revenues generated by utility storage assets, i.e., all assets up to 100PJs, and that it will also capture storage encroachment. The Board notes that the Accounting Order shall also be worded broadly enough to ensure that it captures all short-term storage transactions. The Board directs Union to file a revised Accounting Order for the Short-Term Storage Account as part of the Draft Rate Order process.

On the second issue relating to the Short-Term Storage Account, how the amounts that are to be recorded in the account are to be calculated, the Board accepts Union's proposal. The Board believes that Union's proposal to allocate the total margins received from the sale of all peak short-term storage to ratepayers and shareholders based on the utility and non-utility share of the total quantity of peak short-term storage sold each calendar year is appropriate. Given the uncertainty inherent in the pricing of market-based storage, the Board believes that Union's proposal best ensures that ratepayers and shareholders receive the same proportionate return on all short-term transactions.

However, to minimize the opportunity for unintended incentives, the Board directs Union to prioritize the sale of its utility storage capacity ahead of the sale of short-

[161] Decision and Order, EB-2011-0038, January 20, 2012, at p. 16.

term storage services from its non-utility storage operation.   The Board finds that whenever utility capacity is available for sale, that capacity is to be used to facilitate short-term storage transactions on a priority basis. Only when utility storage capacity is fully sold can Union sell non-utility storage capacity on a short-term basis.

Finally, the Board directs Union to file sufficient evidence, at the time the balance in the Short-Term Storage Account is to be disposed, to allow the Board to confirm that Union has appropriately prioritized the sale of its utility storage space and calculated the balance in the account in accordance with this Decision.

Gas Supply Optimization Variance Account

Board Findings

In accordance with the Board's findings set out earlier in this Decision, the Board directs Union to establish a symmetrical variance account to capture the variance in the actual net revenues related to gas supply optimization activities and the amount built into rates. As ordered previously, the amount built into rates related to gas supply optimization is 90% of Union's 2013 forecast of base exchanges and 90% of half of Union's FT-RAM 2013 forecast. The balance in the account will be shared 90% to ratepayers and 10% to the shareholder. The Board finds that the balance in this account will be disposed of on an annual basis. The Board also finds that the disposition amounts will be allocated in the same manner as the gas supply optimization related margin amounts will be reflected in rates.

The Board directs Union to file a draft accounting order as part of the Draft Rate Order process which reflects the Board's findings related to the establishment of the Gas Supply Optimization Variance Account.

Gas Supply Plan Review – Consultant Cost Deferral Account

Board Findings

In accordance with the Board's findings set out earlier in this Decision, the Board directs Union to establish a deferral account to capture the costs of hiring a consultant to undertake a review of Union's gas supply plan.

The Board directs Union to file a draft accounting order as part of the Draft Rate Order process which reflects the Board's findings related to the establishment of the Gas Supply Plan Review - Consultant Cost Deferral Account.

Preparation of Audited Financial Statement Deferral Account

Board Findings

In accordance with the Board's findings set out later in this Decision, the Board directs Union to establish a deferral account to capture the costs of preparing audited financial statements.

The Board directs Union to file a draft accounting order as part of the Draft Rate Order process which reflects the Board's findings related to the establishment of the Preparation of Audited Financial Statements Deferral Account.

Elimination of Late Payment Penalty Litigation Deferral Account (Account No. 179-113) and Harmonized Sales Tax Deferral Account (Account No. 179-124)

Late Payment Penalty Litigation (Deferral Account No.179-113)

Union stated that the Late Payment Penalty Litigation deferral account was established in 2004 to record the costs incurred by Union in connection with the late payment penalty litigation. This includes its legal costs, costs of actuarial advice, costs of analyzing historic billing records and the cost of any judgment against Union. Union noted that the litigation in connection to late payment is now complete. Union proposed to close this account effective January 1, 2013.

Harmonized Sales Tax ("HST") (Deferral Account No. 179-124)

Union stated that this account was established to record the amount of Provincial Sales Tax previously paid and collected in approved rates that is now subject to HST tax credits (i.e. the savings to Union). The account was also used to record the amount of HST paid on taxable items for which no tax credits are received (i.e. the additional costs to Union). Union has shared the net impact 50/50 between the ratepayers and its shareholder. Union does not see a need to continue with this deferral account as

Union's budget includes the impact of HST. Upon settlement of the balance in the account, Union proposed to close this account effective January 1, 2013.[162]

No parties raised any concerns arising from the closure of the above noted accounts. Union requested that the accounts be closed.[163]

Board Findings

The Board finds that above noted accounts can be closed as requested by Union. The Board agrees that both of these accounts have served their purpose and are not needed for 2013.

PARKWAY WEST PROJECT

Union's Dawn to Parkway system begins at Union's Dawn Compressor Station and extends 228 km northeast to Parkway, near Oakville, Ontario. The existing Parkway Compressor Station is currently served by a single valve site and header system. The Dawn-Parkway system at this location consists of three parallel pipelines of varying sizes/diameters (26", 34" and 48"). Union connects to the Enbridge system on the suction side of the compressor in the existing Parkway Compression Station. Union owns and operates custody transfer measurement at this interconnection, which is known as Parkway (Consumers).

Union also connects to the TCPL system on the discharge side of the Station in the existing Parkway Compression Station. Union owns and operates check measurement at this interconnection, which is known as Parkway (TCPL). The Lisgar Station is approximately 2 km east of the Parkway Compressor Station. Gas is delivered to Enbridge at the Lisgar Station through 26" and 34" pipelines that extend past the Parkway Compressor Station.

Union has indicated that a significant amount of gas supply intended for delivery into the Greater Toronto Area ("GTA") and other parts of Ontario is either delivered at or passes through Parkway. Based on Enbridge design day system demand of approximately 3.7

[162] Exhibit H1, Tab 4, pp. 4-5 (Updated).
[163] Oral Hearing Transcripts, EB-2011-0210, Volume 16 at p. 131.

PJ/day, Union delivers approximately 57% of that supply to Enbridge at Parkway or through the Parkway compression.

Union has stated that a loss of delivery at Parkway and/or Lisgar would have significant and immediate impact on the Enbridge system. Union indicated that an outage at Parkway (Consumers) would result in a delivery loss of 0.8 to 1.4 PJ/day while an outage at Lisgar would result in a delivery loss of 0.2 to 0.8 PJ/day into the Enbridge system during peak demand. A combined outage of both facilities could result in an immediate delivery loss of 1.6 PJ/day for Enbridge.

Union has indicated that an outage at Parkway (Consumers) and Lisgar during peak demand would impact regional gas flows to points east of Parkway in eastern Ontario, Quebec and the U.S. Northeast as the GTA consumes available supply. In addition, natural gas-fired power generation facilities in the GTA would likely be impacted by low pressure or system outages.

In order to ensure security of supply to its Ontario customers, Union proposes to install a second metering and a header system connected to the Dawn to Parkway system which would allow continued supply to Enbridge in the event of an outage of the existing Dawn to Parkway system interconnection at Parkway.

Union's proposed Parkway West Project is comprised of three components that are to be undertaken over a three year period.

1. Parkway West Land Purchase – 2012: $15.0 million.
2. Parkway West Metering and Headers – 2013: $80.0 million.
3. Parkway West Loss of Critical Unit Protection – 2014: $120.0 million.

The facilities, if ultimately approved, will allow Union to meet export demand on a design day to Parkway (TCPL) and Parkway (Consumers) under an outage of the major components of the existing Parkway compression station.

Union has indicated that the volumes delivered to TCPL through Parkway compression are not fully covered by Loss of Critical Unit ("LCU") protection. According to Union, as volumes grow and throughput through Parkway compression reaches 3.0 PJ/day, there would be no LCU protection. Union has indicated that an outage of one of the Parkway compressors in the future could significantly impact gas flows during peak demand into Ontario markets, such as the GTA and Northern and Eastern Ontario. Union has stated that failure to deliver during peak day conditions at Parkway could impact the reliability of the Union delivery system and could lead shippers to de-contract on the Dawn-Parkway path. Consequently, Union is of the opinion that LCU protection at Parkway is appropriate and the proposed facilities are the best option.

Union has estimated the cost of the Parkway West Project to be approximately $217 million. Union confirmed at the hearing that none of the facilities would be completed and placed into service during the Test Year. Therefore, the proposed facilities would not impact 2013 rates, and Union stated that it was not seeking any approvals from the Board with respect to the Parkway West Project in the current application.

Board staff submitted that since the project has no impact on 2013 rates, it was not certain what determination the Board could make in relation to this project. Board staff noted that the cost, need, prudence and impact on the environment will all be reviewed in the Leave to Construct application that Union is expected to file before the end of 2012.

Board staff submitted that Union should be directed to file comprehensive information in the Leave to Construct application. This would include detailed information on possible alternatives and the opportunities that the project could provide for the non-utility portion of Union's operations.

Energy Probe submitted that Union had rejected all the alternatives to the project provided by TCPL in its evidence. Energy Probe argued that the Parkway West Project was not just about LCU protection and improving reliability but one of the collateral benefits of this project was that it would increase transactional services at the Dawn Hub. Energy Probe referred to a presentation Union made to Spectra executives that forecasts revenue attributable to the project of $23 million in 2014.

Energy Probe submitted that the Board should conduct a comprehensive review of options for LCU, Parkway extension, Enbridge reinforcements and/or long term transportation arrangements before Union's proposed projects are approved.

BOMA in its submission indicated that apart from the Parkway West Project, Enbridge was planning to construct a 24 km transmission line from the new Albion city gate on its distribution system to Union's proposed Parkway West station. Union and Enbridge initially explored the possibility of joint ownership of the Parkway West to Albion pipeline but Enbridge then decided to construct the pipeline itself.

BOMA submitted that the two distinct projects proposed by Enbridge and Union will likely cost ratepayers more as compared to a joint effort. BOMA was of the opinion that the LCU compression at Parkway was unnecessary at this time and there was no evidence that the new compressor was required to deliver gas to Enbridge or other customers.

BOMA also rejected Union's claim that the LCU compressor was required in the event of a failure of one of the compressors currently in use. BOMA submitted that the likelihood of a serious compression failure was minimal and this was confirmed by Union's evidence on the record.[164]

BOMA noted that Union's evidence of further increases of deliveries through Parkway were not reliable and the market was not ready for such a service at this point in time. BOMA therefore submitted that the Board should forewarn Union about the risk of approval of such expenditures considering that they were not required at this point in time.

BOMA submitted that the Board should examine both the Union and Enbridge expansion plans before it makes a decision to approve either of the projects in and around Parkway. BOMA added that the Board should consider these expansion projects in an Ontario-wide context.

BOMA urged the Board to require TCPL, Union and Enbridge to discuss alternatives and negotiate a solution that minimizes overall capital costs while maintaining reliability and access to markets. BOMA submitted that such discussions should take place prior to Enbridge and Union filing their respective Leave to Construct applications.

[164] Exhibit J.B-1-7-8, Attachment 9, Slide 7.

LPMA in its submission indicated that Union's Leave to Construct application should include a wider perspective: that the needs of Enbridge and the potential options to serve those needs not only by Union, but also by TCPL be considered. LPMA submitted that the Board should consider a proceeding that encompasses Union's Parkway West project, Enbridge's GTA reinforcement project, TCPL options, any Parkway to Maple expansion by any of the companies involved, and any other projects related to this issue. LPMA submitted that the Board's process should include an integrated planning exercise that involves all parties that may be affected, along with all those parties that can provide cost-effective solutions.

APPrO in its submission noted that its members were major shippers on both the TCPL and Union system. APPrO noted that its members were quite sensitive to additional infrastructure considering that TCPL tolls have increased significantly over the last few years.

APPrO maintained that Union should first ensure that there is a genuine problem to resolve and if so, ratepayers deserve the most cost-effective solution and not merely the facility solution that Union has proposed. APPrO submitted that Union should conduct due diligence on potential alternatives to the proposed Parkway West build. This could include not only alternatives proposed by TCPL, but other commercial solutions as well. APPrO recommended that Union conduct broad consultations with all stakeholders including M12 shippers and in-franchise users of the Dawn-Trafalgar system that would be impacted by this major project.

TCPL in its submission maintained that the Parkway West project was at best premature and at worst, a redundant piece of infrastructure that would impose significant costs on Ontario consumers. TCPL submitted that in certain cases, there could be justification for duplicate or redundant infrastructure such as supply diversity and competition. The Board in such cases should weigh the benefits of duplication with the costs that Ontario consumers would bear.

TCPL's opinion was that Union did not require LCU protection at Parkway at this time. TCPL specifically noted that failure of compression at Parkway was an extremely improbable event and that Union's compression has a 99.9% reliability rate. TCPL further noted that two-thirds of the Enbridge GTA peak day load was directly supplied to

Enbridge at Parkway with existing LCU protection and Enbridge was not likely to receive any additional benefit from the proposed LCU.

If Union required LCU protection for TCPL deliveries, TCPL indicated that it could acquire non-facility LCU protection for a fraction of the cost of the $180 million associated with the proposed LCU protection.

TCPL submitted that it had identified at least four alternatives to the proposed LCU which included using existing infrastructure, existing TCPL infrastructure in conjunction with Union infrastructure or adding small and efficient capacity increases on the TCPL system. These alternatives would provide lower ownership and operating costs and would be scalable according to TCPL.

TCPL submitted that Union had not seriously explored all options and had not entered into a dialogue or consultation with TCPL on this matter. TCPL submitted that the project was essentially a way to bypass the TCPL system and had no bearing on providing greater reliability to TCPL or Enbridge at Parkway. TCPL submitted that if the issue is reliability then Union should consult with Enbridge and TCPL to ensure system reliability, both from an operational and economical perspective.

Enbridge in its submission urged the Board to not make any determinations in this proceeding with respect to the Parkway West project including any decisions related to process and timing. Enbridge submitted that any determination would amount to prejudging the Leave to Construct applications that still have to be filed by Union and Enbridge. Union in its reply argument agreed with Enbridge.

Furthermore, Union rejected the alternative proposals put forth by TCPL. Union argued that the alternatives would be more costly if carefully examined and appear largely designed to address competitive concerns that TCPL may have with respect to its own volumes. Union submitted that the proposals put forth by TCPL would either cost more than the Parkway West project or were similar to what Union had proposed. Union submitted that if one of the proposals was simply to install a used compressor, Union could do the same provided TCPL would sell a used compressor to Union. Union noted that in terms of preparedness it was further ahead since it had already entered into an option to purchase the required land in an area where land is difficult to obtain.

Union submitted that Parkway West was essentially a reliability project consisting of two components: LCU protection and a second feed for Enbridge at Parkway (Consumers) and the Lisgar feed backup. Union noted that intervenors were confused about the Parkway West project and were improperly relating it to Enbridge's system reliability project and the expansion of the line from Parkway or Albion to Maple.

Union indicated that TCPL's claim of the Parkway West project being a pre-build for an expansion of Union's transportation corridor was incorrect. Union submitted that the Parkway to Maple congestion was a different issue and Union's position that there is a bottleneck at Maple was well known. Union referred to the presentation that it had given at the stakeholder conference in the Natural Gas Market Review held in October 2010 where it expressed concern about the bottleneck from Parkway to Maple limiting supplies into and from Ontario. In that proceeding, Union had indicated that a Parkway to Maple expansion was a natural project for TCPL to undertake. TCPL in that proceeding disagreed with Union's position and indicated that there was no bottleneck between Parkway and Maple.

Consequently, Union initiated its own open season as a result of which TCPL also held an open season to gauge interest from shippers. In its reply submission, Union confirmed that it bid into TCPL's open season and also indicated that there was insufficient demand for two competing Parkway to Maple projects. Union submitted that there was no evidence that Union was looking to bypass TCPL in this specific corridor.

Union also disagreed with TCPL's claim that it had not consulted with TCPL on the Parkway West project. Union submitted that there was no communication from TCPL and Union learned of TCPL's concern and the different alternatives to the Parkway West project through the evidence filed by TCPL in this proceeding.

Lastly, Union submitted that it is committed to filing complete information in its Leave to Construct application including information about compressors. Union also acknowledged that it assumes the complete risk of expenses incurred on the Parkway West project until it obtains approval for the project from the Board.

Board Findings

In the context of this application, no approvals of the Board are required for the facilities that comprise the Parkway West project. The Board notes that Union plans to file a subsequent Leave to Construct application in the latter part of 2012 for those portions of the Parkway West project that it believes require Leave to Construct approval by the Board. As such, the Board is not making any determination in this Decision relating to the need or any other issue that will be considered in this subsequent proceeding. The Board acknowledges that Union has recognized that any facility expenditures remain the responsibility of Union and its shareholder until, when and if, Board approval is obtained and amounts are closed to rate base.

The record in this proceeding makes it clear to the Board that the relationships between the three large natural gas pipeline companies that serve Ontario customers - Union, Enbridge and TCPL, are complex. The Board notes that not only do these companies compete to construct new facilities and utilize existing facilities; they are also each customers of the other. They are bound, however, by the fact that the operation of each of its respective natural gas system is integrated in the province of Ontario, and that Ontario customers pay a significant portion of, if not all of, the cost of installed natural gas facilities, and that each entity has an incentive to maximize rate base.

The Board is concerned with the apparent lack of cooperation and consultation between Union, Enbridge and TCPL that came to light in this proceeding. The Board is concerned that this may have adverse consequences for Ontario ratepayers – result in higher rates and costs than would otherwise be the case, contribute to the uneconomic bypass of existing natural gas infrastructure, create asset stranding, encourage the proliferation of natural gas infrastructure, and lead to the underutilization of existing natural gas infrastructure.

The Board agrees that the consideration of the Parkway West facilities requires a wider perspective. The Board therefore encourages Union to engage TCPL, Enbridge and shippers in a consultative process, the purpose of which is to jointly consider the need for the Parkway West project, explore reasonable alternatives (including the repurposing of existing facilities) in order to maximize the benefit to Ontario ratepayers. The result of this process would then be filed with Union's Leave to Construct application for the Parkway West facilities.

The Board does not concur with Union's submission that this consultation should occur after it has filed its Leave to Construct application for the Parkway West project. The Board believes that full consideration of alternatives should occur in advance and that to do otherwise would be an inappropriate use of the Board's and other parties' time and resources.

OTHER ISSUES

Financial Statements

Board staff argued that Union should be required to file separate audited financial statements for the rate regulated portion of the company. Currently Union files audited financial statements for the entire company, which includes that portion of its business that is not subject to rate regulation. Board staff submitted that section 2.1.6 of the natural gas Reporting and Record Keeping Requirements ("RRRs") requires Union to file separate financial statements for the rate regulated portion of the utility, and that Ontario Power Generation was required by the Board to file separate audited financial statements for the regulated portion of its business. Board staff further submitted that, irrespective of any requirements in the RRRs, audited financial statements for the rate regulated portion of the business would allow the Board to better assess the revenue requirement and earnings sharing in rate applications.

Board staff's submission was supported by some intervenors. CME noted that separate financial statements for the regulated business would assist parties in determining the proper allocations between the rate regulated and non-rate regulated storagebusinesses.

In reply, Union stated that preparing separate audited financial statements for the regulated side of the business would be an expensive undertaking. It further submitted that no party had identified any particular piece of information that was not disclosed in the proceeding that would have been provided in separate audited financial statements. Union stated that preparing separate audited financial statements would provide little or no value.

Board Findings

The Board directs Union to prepare and file separate audited financial statements for that portion of its business that is subject to rate regulation. For the utility business regulated by the Board, the Board directs Union to provide annually a full set of audited financial statements, with all related notes to these financial statements, prepared under the applicable generally accepted accounting principles used to report to financial regulators in Canada and in the USA. These audited financial statements will be filed with the Board as soon as possible after Union releases its financial results to the public, but no later than June 30th each year. The Board believes that this information will assist in both assessing the revenue requirement in future cost of service proceedings, and in monitoring during the course of the IRM term.

The costs of preparing these financial statements shall be collected in a new deferral account (described in more detail elsewhere in this Decision).The Board will establish a Preparation of Audited Financial Statement Deferral Account, which will be reviewed and disposed of with Union's other deferral and variance accounts.

THE BOARD ORDERS THAT:

1. Union shall file with the Board, and shall also forward to all intervenors a Draft Rate Order attaching a proposed Tariff of Rates and Charges reflecting the Board's findings in this Decision, within 42 days of the date of this Decision. The Draft Rate Order shall also include customer rate impacts and detailed supporting information showing the calculation of the final rates.

2. The Draft Rate Order shall also include draft accounting orders related to the deferral accounts set up or approved by the Board in this Decision.

3. The intervenors shall file any comments on the Draft Rate Order with the Board and forward to Union within 14 days of the filing of the Draft Rate Order.

4. Union shall file with the Board and forward to the intervenors responses to any comments on its Draft Rate Order within 14 days of the receipt of any submissions.

5. The intervenors shall file with the Board and forward to Union, their respective cost claims within 14days from the date of the Final Rate Order.

6. Union shall file with the Board and forward to the intervenors any objections to the claimed costs within 21 days from the date of the Final Rate Order.

7. The intervenors shall file with the Board and forward to Union any responses to any objections for cost claims within 28 days of the date of the Final Rate Order.

8. Union shall pay the Board's costs incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, October 25, 2012
ONTARIO ENERGY BOARD

Original signed by

Kirsten Walli
Board Secretary

Appendix A

EB-2011-0210
Union Gas Limited
Decision and Order

For convenience, the Board's determinations on cost allocation and rate design that have been set out in this Decision and Order are briefly summarized in the table below. However, this summary should not be interpreted as augmenting or superseding any part of this Decision and Order.

Cost Allocation and Rate Design – Summary of Board Findings

Issue	Board Findings
COST ALLOCATION	
General Cost Allocation	Accepted Union's Cost Allocation Study .
System Integrity	Accepted Union's cost allocation proposal.
Tecumseh Metering Assets	Accepted Union's cost allocation proposal.
Oil Springs East Assets	Accepted Union's cost allocation proposal.
New Ex-Franchise Services	Accepted Union's cost allocation proposals related to the Dawn to Dawn-TCPL and Dawn to Dawn-Vector services. Accepted Union's cost allocation proposal for the M12 F24-T service with some required changes.
Union North Distribution Customer Stations Plant	Directed Union to allocate costs related to North Distribution Customer Station Plant on the basis of average number of customers, excluding Rate 01 and the Rate 10 customers that do not meet the hourly consumption threshold of 320 m^3 / hour.
Distribution Maintenance – Meter and Regulator Repairs	Accepted Union's cost allocation proposal.
Distribution Maintenance – Equipment on Customer Premises	Denied Union's cost allocation proposal. Directed Union to file, as part of its 2014 cost allocation study, analysis of this cost allocation issue.
Purchase Production General Plant	Accepted Union's cost allocation proposal.
Parkway Station Costs	Ordered no change to the allocation of Parkway Station costs. Noted that the Board will revisit after Union files the report on the outcome of the Parkway Obligation Working Group.
Kirkwall Station Costs	Directed Union to review its allocation of Kirkwall Station costs as part of its 2014 cost allocation

	study.
Dawn-Trafalgar Easterly Costs	Accepted Union's cost allocation proposal.
Utility / Non-Utility Storage Allocation	Accepted Union's cost allocation methodology. Directed Union to revise allocation for 2012 allocation factor update. Directed Union to file, as part of its 2014 rates filing, continuity schedules related to Union's non-utility storage operation and an update to the Black and Veatch report.
RATE DESIGN	
General Rate Design	Generally accepted Union's rate design considerations and revenue-to-cost ratio guidelines. Ordered Union to not move any in-franchise rate classes' revenue-to-cost ratio further from 1.0 than previously approved. Ordered Union to not have a revenue-to-cost ratio higher than 1.0 for any in-franchise rate class. Ordered Union to file, as part of the Draft Rate Order process, a proposed methodology for allocating optimization related margins to customers that pay the costs of Union's gas supply plan. Ordered Union to file, as part of the Draft Rate Order process, a proposed methodology for allocating S&T related margins which reflects regulatory principles. Ordered Union to update its proposed rates to reflect all of the related findings in the Decision.
Rate 01 / 10 and Rate M1 / M2 – Volume Breakpoint and Rate Block Harmonization Proposal for 2014	Denied Union's rate design proposal at this time. Directed Union to file, as part of its 2014 rates filing, a cost allocation study which includes an analysis of: the allocation of costs for its volume breakpoint proposal, the issue raised by LPMA regarding the allocation of costs for Distribution Maintenance – Meter and Regulator repairs for those customers that move rate classes under Union's volume breakpoint proposal, the allocation of costs for Distribution Maintenance – Equipment on Customers Premises and the allocation of Kirkwall Station costs.

Rate M4, M5A and Rate M7 – Eligibility Criteria Proposals for 2014	Accepted Union's rate design proposals.
Rate T1 Redesign	Accepted Union's rate design proposal.
Supplemental Service Charge – Group Meters for Commercial / Industrial Customers in Rate M1 and Rate M2	Denied Union's proposal. Directed Union to eliminate this supplemental service charge in its Southern Service area.
Rate Mitigation	Noted that it is not clear, at this time, whether rate mitigation will be necessary. Will determine whether rate mitigation measures will be implemented after the Draft Rate Order has been reviewed by the Board.
Response to directive to review M12 and C1 ratemaking methodology	Accepted Union's response.
Rate M4 Interruptible Service Offering for 2014	Accepted Union's rate design proposal.
UFG Recovery on transportation activity, in the winter months, for the Dawn to Dawn-Vector transportation service	Accepted Union's proposal.
Rate M12, M13, M16, and C1 – Rate Schedule Modification	Accepted Union's proposals.
Distribution Consolidated Billing Fee	Accepted Union's proposal.
Gas Supply Administration Fee	Accepted Union's proposal.
Kirkwall to Dawn Transportation Service Rate Design – Kirkwall Metering Costs	Accepted Union's proposal.

Ontario Energy Board **Commission de l'énergie de l'Ontario**

Ontario

EB-2010-0008

IN THE MATTER OF AN APPLICATION BY

ONTARIO POWER GENERATION INC.

PAYMENT AMOUNTS FOR PRESCRIBED FACILITIES FOR 2011 AND 2012

DECISION WITH REASONS

March 10, 2011

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EB-2010-0008

IN THE MATTER OF the *Ontario Energy Board Act, 1998*, S.O.1998, c.15, (Schedule B);

AND IN THE MATTER OF an application by Ontario Power Generation Inc. pursuant to section 78.1 of the *Ontario Energy Board Act, 1998* for an Order or Orders determining payment amounts for the output of certain of its generating facilities.

BEFORE: Cynthia Chaplin
Presiding Member & Chair

Marika Hare
Member

Cathy Spoel
Member

DECISION WITH REASONS

MARCH 10, 2011

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Table of Contents

Appendices:

1 INTRODUCTION

Ontario Power Generation Inc. ("OPG") filed an application with the Ontario Energy Board (the "Board") on May 26, 2010. The application was filed under section 78.1 of the *Ontario Energy Board Act, 1998*, S.O 1998, c. 15 (Schedule B) (the "Act"), seeking approval for payment amounts for OPG's prescribed generation facilities for the test period January 1, 2011 through December 31, 2012, to be effective March 1, 2011. The Board assigned the application file number EB-2010-0008.

OPG also requested that the Board issue an order declaring the current payment amounts interim if the new payment amounts are not implemented by March 1, 2011. By order dated February 17, 2011, the Board declared the current payment amounts interim effective March 1, 2011.

1.1 Legislative Requirements

Section 78.1(1) of the Act establishes the Board's authority to set the payment amounts for the prescribed generation facilities. Section 78.1 can be found at Appendix D of this Decision. Section 78.1(4) states:

> The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment.

Section 78.1(5) states:

> The Board may fix such other payment amounts as it finds to be just and reasonable,
> (a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or
> (b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable.

Ontario Regulation 53/05, *Payments Under Section 78.1 of the Act,* ("O. Reg. 53/05") provides that the Board may establish the form, methodology, assumptions and calculations used in making an order that sets the payment amounts. O. Reg. 53/05 also includes detailed requirements that govern the determination of some components of the payment amounts.

O. Reg. 53/05 affects the setting of payment amounts for the prescribed generation facilities in three principal ways:

1. requiring that OPG establish certain variance and deferral accounts and that the Board ensure recovery of the balance in those accounts subject to certain conditions being met;
2. requiring that the Board ensure that certain costs, financial commitments or revenue requirement impacts be recovered by OPG; and
3. setting certain financial values that must be accepted by the Board when it makes its first order under section 78.1 of the Act.

The last item was addressed in the first payment amounts proceeding, EB-2007-0905.

O. Reg. 53/05 can be found at Appendix E.

1.2 The Prescribed Generation Facilities

OPG owns and operates both regulated and unregulated generation facilities. As set out in section 2 of O. Reg. 53/05, the regulated, or prescribed, facilities consist of three nuclear generating stations and six hydroelectric generating stations. These facilities produce approximately 48% of Ontario's electricity.

Table 1: Prescribed Generation Facilities

Hydroelectric		Nuclear	
Station	Capacity[1]	Station	Capacity[1]
Sir Adam Beck I	417 MW	Pickering A NGS	1,030 MW
Sir Adam Beck II	1,499 MW	Pickering B NGS	2,064 MW
Sir Adam Beck Pump Generating Station	174 MW	Darlington NGS	3,512 MW
DeCew Falls I	23 MW		
DeCew Falls II	144 MW		
R.H Saunders	1,045 MW		
Total	**3,302 MW**		**6,606 MW**

Note 1: Net in-service capacity
Source: Exh. A1-4-2, Chart 1 and Exh. A1-4-3, Chart 1

OPG also owns the Bruce A and B nuclear generating stations. These stations are leased on a long term basis to Bruce Power L.P. Under section 6(2)9 of O. Reg. 53/05, the Board must ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations. Under section 6(2)10 of O. Reg. 53/05, the revenues from the lease, net of costs, are to be used to reduce the payment amounts for the prescribed nuclear generating stations.

OPG has entered into a Memorandum of Agreement ("MOA") with its shareholder. This MOA sets out the shared expectations of the shareholder and the company regarding mandate, governance, performance and communications. Included in its provisions related to the nuclear mandate are expectations related to continuous improvement, benchmarking, and improved operations. The MOA is reproduced in Appendix G.

1.3 Previous Proceedings

The current application is OPG's second cost of service application. The first cost of service application, EB-2007-0905, was filed on November 30, 2007. The Board's decision on the 21 month test period, April 1, 2008 to December 31, 2009, was issued on November 3, 2008.

OPG filed two notices of motion for review and variance seeking to vary the portion of the EB-2007-0905 decision dealing with the treatment of tax losses. The first motion, EB-2008-0380, filed on November 24, 2008, was dismissed. The second motion, EB-2009-0380 was filed on January 28, 2009 and a decision granting the motion was issued on May 11, 2009. This decision is discussed further in Chapter 10.

On June 9, 2009, OPG filed an application for an accounting order regarding deferral and variance accounts approved in EB-2007-0905. As part of the application, OPG informed the Board that it had deferred the filing of its payment amounts application by one year. The decision, under file number EB-2009-0174, which addressed the treatment of deferral and variance accounts for the period after December 31, 2009, was issued on October 6, 2009.

The Board initiated a consultation on the filing guidelines for the current payment amounts application on September 24, 2009. The filing guidelines were issued under file number EB-2009-0331 on November 27, 2009.

1.4 The Application

In advance of its application, OPG held stakeholder information sessions on March 29, 2010 and April 1, 2010. At those sessions, OPG indicated that it would file the 2011-2012 payment amounts application in mid-April. However, on April 15, 2010, OPG advised that the application would be delayed to late May and that OPG was reviewing the application to identify ways to further lessen the impact of its request on ratepayers.

The application was filed on a Canadian GAAP basis on May 26, 2010. The proposed revenue requirement and recovery of deferral and variance accounts, as filed on May 26, 2010, is summarized in the following table.

Table 2: Proposed Revenue Requirement

$ million	Regulated Hydroelectric			Nuclear			Test Period Total
	2011	2012	Test Period	2011	2012	Test Period	
Expenses							
OM&A	$128.2	$125.9	$254.1	$2,021.2	$2,067.9	$4,089.1	$4,343.2
Gross Revenue Charge/Nuclear Fuel	257.1	252.2	509.3	235.6	261.7	497.3	1,006.6
Depreciation and Amortization	65.6	65.0	130.6	235.4	256.4	491.8	622.4
Property and Capital Taxes	-	-	-	16.0	16.6	32.6	32.6
Income Taxes	30.6	27.4	58.0	53.9	75.9	129.8	187.8
Cost of Capital							
Short-term Debt	4.6	6.1	10.7	3.0	4.3	7.3	18.0
Long-term Debt	106.9	105.8	212.7	70.8	74.4	145.2	357.9
Return on Equity	176.1	175.3	351.4	116.6	123.2	239.8	591.2
Adjustment for Lesser of UNL or ARC	-	-	-	85.0	83.1	168.1	168.1
Other Revenue							
Ancillary and Other	44.9	46.2	91.1	32.0	24.0	56.0	147.1
Bruce Revenue Net of Costs	-	-	-	128.1	143.0	271.1	271.1
Revenue Requirement	**$724.2**	**$711.5**	**$1,435.7**	**$2,677.4**	**$2,796.5**	**$5,473.9**	**$6,909.6**
Deferral and Variance Account Recovery	**(39.5)**	**(47.3)**	**(86.8)**	**227.1**	**232.8**	**459.9**	**373.1**

Source: Exh. I1-1-1, Table 1

With some exceptions, OPG proposed that the 2010 year end balances in the deferral and variance accounts be amortized over a 22 month period from March 1, 2011 to December 31, 2012. The major exception to that proposal is the tax loss variance account, which OPG proposed be amortized over a 46 month period, from March 1, 2011 to December 31, 2014, in order to lessen ratepayer impact. To achieve the revenue requirement and disposition of balances in the deferral and variance accounts, OPG requested the payment amounts and riders shown in the following table, which also provides the current payment amounts and riders.

Table 3: Payment Amounts and Rate Riders

($ per MWh)	Hydroelectric	Nuclear
Current		
Payment Amount	36.66	52.98
Rate Rider	—	2.00
Total	36.66	54.98
Proposed		
Payment Amount	37.38	55.34
Rate Rider	(2.46)	5.09
Total	34.92	60.43

Source: Exh. A1-2-2 (as filed May 26, 2010)

OPG estimated that if the application was approved as filed, the combined effect of the proposed payment amounts and rate riders would be an increase of 6.2% over the current payment amounts. This would be a 1.7% or $1.86 increase on the monthly total bill for a typical residential consumer consuming 800 kWh per month.

A summary of the approvals that OPG is seeking in the current application is found at Appendix B.

1.5 The Proceeding

Details of the procedural aspects of the proceeding are provided in Appendix A.

The Board issued Procedural Order No. 3 on July 21, 2010, establishing the final issues list for the proceeding. That list is found at Appendix F.

The Board received five letters of comment in response to the notice of application. The Board has reviewed each of these letters. The letters raise a variety of issues, many of which are dealt with in this Decision and others which are beyond the scope of this proceeding. Although the Board will not address each letter specifically, these comments have been taken into account in the Board's deliberations.

Two parties applied for, and were granted, observer status. Thirteen parties applied for and were granted intervenor status. The following intervenors took an active role in the proceeding: The Association of Major Power Consumers in Ontario (“AMPCO”), Canadian Manufacturers & Exporters (“CME”), Consumers Council of Canada (“CCC”), Energy Probe Research Foundation (“Energy Probe”), Green Energy Coalition (“GEC”), Pollution Probe Foundation (“Pollution Probe”), Power Workers’ Union (“PWU”), School Energy Coalition (“SEC”), Society of Energy Professionals (“Society”) and Vulnerable Energy Consumers Coalition (“VECC”).

CME and CCC brought motions seeking production of certain materials. The Board denied the motions in an oral decision on October 4, 2010. A copy of the decision on the motions can be found at Appendix C.

During the proceeding, confidential treatment was granted for a large number of documents. These documents are filed at the Board’s offices.

1.6 Board Observations

This Decision addresses a large number of issues. Most of these issues were material in nature; a number were not. Quite a number of very material issues were explored somewhat late in the process; in some cases the arguments themselves contained what could be characterized as evidence. The regulation of OPG is complex. It is imperative that the high priority issues be identified early and explored thoroughly and effectively during the proceeding.

The Board understands that many of the issues pursued by the parties were sizeable in the absolute sense, often involving millions of dollars. However, issues must be prioritized to ensure that the most significant issues, in terms of dollars and/or in terms of principle, are adequately investigated to ensure an appropriate outcome. The Board and the process are best served by the thorough investigation of the highest priority issues.

It is the Board’s conclusion that a number of issues which parties pursued vigorously in cross-examination and argument were not of sufficiently high priority in terms of the dollars or the principle involved. The Board’s concern is that an inordinate focus on lower priority issues diminishes the time and resources available to pursue the more substantive, higher priority issues. This is not intended as a criticism of any of the parties; nor is it an indication that there was insufficient evidence for the Board to render its decision. Rather, these comments are intended to guide the parties as to the Board's expectations for the next proceeding based on our observations of this proceeding.

The Board will explore with OPG and stakeholders how best to identify issues in the next proceeding to ensure that the highest priority issues are identified early.

The Board would also observe that at times the analysis was complicated by the fact that data was presented in ways which was not always comparable. The Board expects OPG to present data on a consistent basis so that comparisons are accurate.

1.7 Summary of Board Findings

The Board has adjusted OPG's requested revenue requirement in some areas and has increased the forecast of revenues in some areas. The following list summarizes those adjustments; the details of the findings are contained in the subsequent chapters of this Decision:

- An increase in forecast hydroelectric production, including a provision for increased Gross Revenue Charge and a variance account to capture the effects of Surplus Baseload Generation;
- An increase in forecast revenue from water transactions;
- An increase in forecast nuclear production, including a provision for increased nuclear fuel costs;
- A sharing of the revenues generated from sales of heavy water;
- A provision for increases in Canadian Nuclear Safety Commission costs;
- The removal of CWIP from rate base;
- A reduction in nuclear compensation costs in 2011 and 2012;
- An update for the return on equity, in accordance with the Board's policy; and
- An adjustment to the Hydroelectric Incentive Mechanism.

The following list identifies the studies and reports that the Board has directed OPG to complete in this Decision:

- Benchmarking of Nuclear Performance;
- Nuclear Staffing Benchmark Analysis;

- Review of Nuclear Fuel Procurement Program ;
- Compensation Benchmarking Study; and
- Depreciation Study.

OPG applied for a total revenue requirement of $6,909.6 million and deferral and variance account recovery of $373.1 million for the two-year test period, resulting in an average payment increase of 6.2%. The Board does not yet have all of the data necessary to establish the final revenue requirement because certain calculations remain to be completed by OPG. Based on the data the Board does have, the Board anticipates a small upward adjustment in the payment amounts that is in the range of less than 1%.

2 BUSINESS PLANNING AND BILL IMPACTS

2.1 Business Planning

The application is based on OPG's 2010-2014 business plan. OPG's business planning process is an annual decentralized process, although planning instructions originate from the finance department. The individual business units develop specific strategic and performance objectives and plan work to achieve the objectives. For the nuclear business, the 2010-2014 business plan incorporates "gap-based" and "top-down" business planning approaches. The gap-based business planning approach was introduced as part of the Phase 2 nuclear benchmarking initiative. There is further discussion of this approach later in this Decision.

In response to the financial and economic environment, OPG's business planning guidelines for 2010 required an $85 million reduction in OM&A compared with previously planned levels for that year. The 2010-2014 business plan was approved by the OPG Board of Directors in November 2009 and received shareholder concurrence.

At stakeholder information sessions held in late March and early April 2010, OPG indicated that it would file its application in mid-April. On April 15, 2010, OPG communicated to stakeholders that the timing for the application had been adjusted to late May and that OPG was reviewing its application to identify ways to further lessen the impact of its request on ratepayers. In May 2010, OPG decided to delay the requested implementation date for new payment amounts to March 1, 2011 and extended the proposed recovery period for the tax loss variance account. These changes were reviewed and approved by the OPG Board of Directors.

The PWU submitted that the assumptions in the 2010-2014 business plan are an appropriate basis on which to set payment amounts. The PWU is concerned, however, with the top-down business planning process used for the nuclear business, and the introduction of the gap-based approach using benchmarking results. The PWU stated that the benchmarking comparators were not peers and further stated that the top-down business planning approach is not appropriate given the capital intensive nature of the business, the technical complexity of the CANDU generators and the strict regulatory requirements of the nuclear business.

CME took issue with OPG's statements regarding the $85 million reduction, referring to the OPG press release dated March 29, 2010:

> We deferred our rate application once but we must go to the OEB this year to make a request for an increase in our regulated rates. We continue to look for internal savings on top of the $85 million we've saved to date.

CME argued that OPG did not reduce OM&A as suggested, but rather only reduced the original increase in OPG's 2009-2013 business plan by $85 million. CME described this and other examples (e.g. $260 million work-drive cost savings discussed later in this Decision at Chapter 4) as misleading characterizations of cost increases as cost reductions.

CME submitted that OPG's business planning process is deficient because it fails to consider total electricity price increases and other economic circumstances facing consumers in deriving the budgets and estimates that form the basis of the application. CME observed that, based on a plain reading of OPG's business planning instructions, the Board could conclude that OPG considers economic turmoil and the hardship consumers are facing in its planning process. CME submitted that, based on the testimony of OPG witnesses, one could conclude that OPG was of the view that the Board can only consider budgets, cost estimates and work programs when determining just and reasonable rates and that the economic hardship facing consumers merely set the context for OPG's planning.

CME submitted that the Board would be ignoring the statutory objectives set out in section 1(1)1 of the Act if it accepts OPG's business planning approach. The objective states:

> 1(1) The Board, in carrying out its responsibilities under this or any other Act in relation to electricity, shall be guided by the following objectives:
> 1. To protect the interests of consumers with respect to prices and the adequacy, reliability and quality of electricity service.

Further, CME referred to the Minister of Energy and Infrastructure's letter of May 5, 2010, to OPG regarding the impact of the recent recession:

> Bearing that in mind, I would request OPG carefully reassess the contents of its rate application prior to filing with the Ontario Energy Board. I would

> like OPG to demonstrate concerted efforts to identify cost saving opportunities and focus your forthcoming rate application on those items that are essential to the safe and reliable operation of your existing assets and projects already under development.

CME submitted that the evidence in the case reveals that neither the hydroelectric business nor the nuclear business was asked to reassess the contents of their respective business plans, or to identify ways to lessen costs. Based on the testimony of OPG witnesses, CME observed that the Business Planning group concluded that the business plan already addressed the Minister's concerns. CME submitted that OPG's response to the requests of the Minister should be of concern to the Board.

CCC observed that the "Renewed Regulatory Framework for Electricity" announced by the Board on October 27, 2010 is specifically tied to green energy investments. CCC submitted that neither the Board's policy initiative nor the Ontario Clean Energy Benefit, which provides residential consumers with a 10% rebate, absolve OPG from taking total bill impacts into consideration in its planning.

With respect to the obligation of utilities, CCC referred to the Ontario Court of Appeal decision in the Toronto Hydro-Electric System Ltd. ("Toronto Hydro") case. CCC submitted that the principles of the decision apply for all intents and purposes to OPG:

> The principles that govern a regulated utility that operates as a monopoly differ from those that apply to private sector companies, which operate in a competitive market. The directors and officers of unregulated companies have a fiduciary duty to act in the best interests of the company (which is often interpreted to mean in the best interests of the shareholders) while a regulated utility must operate in a manner that balances the interests of the utility shareholders against those of its ratepayers. If a utility fails to operate in this way, it is incumbent on the OEB to intervene in order to strike this balance and protect the interests of the ratepayers.[1]

Both CME and CCC submitted that OPG failed to respond appropriately to the Minister's letter of May 5, 2010. CCC submitted that OPG has added to the burden on ratepayers by unnecessarily requesting construction work in progress treatment for the Darlington Refurbishment Project and by not considering a reduction of its return on equity ("ROE"). CME argued that an unregulated market participant would likely make efforts to "hold the line on electricity price increases" in difficult economic

[1] *Toronto Hydro-Electric System Ltd. v. Ontario Energy Board*, [2010] ONCA 284, para. 50 (Leave to Appeal to Supreme Court of Canada denied).

circumstances. CME submitted that the Board could approve a revenue requirement for OPG that reflects a lower ROE, arguing that a temporary reduction in ROE poses no threat to system safety or reliability. CME referred to the period prior to 2008 when the shareholder acknowledged that it did not need a full equity return to cover its actual costs of capital. At the time, the shareholder used a 5% return on equity to establish the revenue requirement for OPG.

OPG replied that the criticisms of the company's business planning process related to issues that, in OPG's view, have nothing to do with the company. OPG disagreed that it is obliged to consider costs over which it has no control.

With respect to the parties' reference to the Toronto Hydro case, OPG stated that the Board's decision, which was upheld by the Court, was related to concern about under-investment in physical plant and was hence a matter of prudence.

With respect to the Minister's letter of May 5, 2010, OPG replied that senior management had decided to delay the application to consider whether the application could be adjusted well before receiving the letter. OPG admitted that it did not change work plans or budgets in the 2010-2014 business plan, but maintained that this was not necessary "given the care OPG took in containing costs over which it has control during business planning."[2]

Board Findings

OPG has adopted a new planning process in the nuclear business, with an emphasis on top-down planning and a gap-based approach designed to drive significant improvement in OPG's operations. The Board does not share the concerns expressed by PWU in this area. The business planning process used by the nuclear division ("gap-based" and "top-down") has the potential to result in an important paradigm shift in how OPG operates. This shift is important if OPG is to improve operating and cost performance in its nuclear business. The Board sees no evidence to suggest that this change will bring about a reduction in safety or reliability. For reasons explained more fully in the benchmarking section of this Decision, the Board does not agree with PWU that OPG's business is not suitable for benchmarking. The Board notes that OPG's shareholder has called for benchmarking in its Memorandum of Agreement. As noted in several places in this Decision, the Board will assess the results of this change in the planning process and the emphasis on continual improvement in future applications.

[2] Reply Argument, p. 13.

With respect to the Minister's letter of May 5, 2010, the evidence is that OPG had already decided, before the letter was received, to forgo any rate increase for January and February 2011 and to delay the recovery of the tax loss variance account. The first adjustment represents a reduction in impact on ratepayers, but not necessarily a reduction in costs: OPG may choose to absorb the forgone revenues without reducing expenditures; it may defer costs to a later period; and for some of the largest projects (Niagara Tunnel, Pickering B Continued Operations and Darlington Refurbishment) the costs are captured through variance accounts in any event. The second adjustment is no reduction at all, merely a delay. OPG took no further or direct action in response to the Minister's May 5, 2010 letter. The business units were not even requested to consider the matter. The Board finds this response surprising. At a minimum, the Minister's letter indicates that the shareholder believed additional savings were possible. The Board would therefore have expected the company to look for further genuine savings. OPG has described what in its view are substantial reductions already included in the application, for example the plan over plan reduction of $85 million. The Board concludes that while this reduction does represent a genuine step towards cost control, it is an exaggeration to call it "savings". Most consumers would reasonably expect "savings" to mean a reduction over what is currently being paid. This is what the Minister requested and this is what OPG has largely failed to deliver.

The Board agrees that OPG has an obligation to consider the economic climate, including trends in electricity costs and consumers' ability to pay, in its business planning activities. A consideration of all aspects of the business climate is part of appropriate business planning. The Board does not agree, however, that OPG has an *obligation* to adjust its plan in response to the external environment. OPG is correct that it cannot control other aspects of consumers' electricity bills. This larger context is for the Board to consider in setting just and reasonable rates, and in particular, in considering whether OPG's forecast costs are reasonable. (This is discussed further below.) While OPG could certainly have proposed cost reductions in light of the economic climate (for example, a reduced return on equity), its *obligation* is to plan taking account of the requirements of its business and to propose payment amounts which represent recovery of an efficient and reasonable level of costs.

2.2 Bill Impacts

OPG estimated that the proposed payment amounts and riders result in an average increase of 6.2% from current payment amounts and riders. The increase represents an increase of approximately 1.7% or $1.86 on the typical residential customer's bill. OPG noted that the current payment amounts have been in place for almost three years by the time new payment amounts come into effect on March 1, 2011, and accordingly the increase OPG is seeking amounts to approximately 2% per year.

OPG argued, "To the extent other forces impact this bill, it would be both unfair and a legal error to reduce OPG's just and reasonable payment amounts to account for those external affects."[3] OPG further argued that it was entitled to recover all prudently incurred costs, which it described in the following way:

> Expenditures are deemed to be prudent in the absence of reasonable grounds to suggest the contrary. Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged.[4]

OPG concluded that total bill impacts should be considered by the Board through the integrated policy framework announced on October 27, 2010 (the Renewed Regulatory Framework).

PWU supported OPG's position. PWU agreed that the Board's statutory objective is to protect the interests of consumers, but pointed out that the Board must also respect the adequacy, reliability and quality of electricity services, as noted in the second statutory objective:

> 2. To promote the economic efficiency and cost effectiveness in the generation, transmission, distribution, sale and demand management of electricity and to facilitate the maintenance of a financially viable electricity industry.

PWU submitted that the Board has no authority to consider factors beyond OPG's control, if it finds OPG's costs are just and reasonable. PWU argued that it is inappropriate to consider costs over which the Board has no jurisdiction, such as the Global Adjustment Mechanism and the Harmonized Sales Tax.

PWU also asserted that the cost of generation from the prescribed facilities is among the lowest cost generation available to Ontario consumers. PWU submitted that

[3] Argument in Chief, p. 5.
[4] Reply Argument, p. 9.

maximizing the value of OPG's prescribed facilities will help to mitigate bill increases related to higher priced supply that would replace production from the prescribed facilities. PWU also submitted that the Board needs to consider intergenerational equity and that there is an impact on future ratepayers if work is deferred to mitigate bill impacts for today's ratepayers.

SEC argued that the 6.2% increase masks the true extent of the increases OPG proposed. SEC submitted that the revenue requirement reductions related to the Darlington Refurbishment Project should not be implemented and that additional costs related to pension and other post employment benefits should not be deferred. When these factors and the impact of the tax loss variance account balance are taken into account, SEC concluded that the increase over current payment amounts is 13.1%, a decrease of 4.7% for hydroelectric and an increase of 23.0% for nuclear. OPG responded that SEC's analysis is not an "apples to apples" comparison and noted that even SEC admitted that not all the amounts are directly comparable. OPG argued that SEC had understated the current payment amounts by not accounting for the EB-2008-0038 decision (related to the tax loss variance account), and that SEC overstated the test period payment amounts by including post test period amounts.

CCC and CME submitted that the Board should consider total bill impact in its determination of payment amounts. CCC noted that the government's "2010 Ontario Economic Fiscal Review" stated that electricity prices are expected to rise by 46% over the next five years. CME referred to the evidence that it filed in the proceeding, an analysis by Aegent Energy Advisors, which concluded that total costs for non-residential customers would rise by 47% to 64% over the next five years and that the increase for residential customers would be 38% to 47%.

CME submitted that the Board's statutory objective in section 1(1)1 of the Act demands that total bill impact evidence be considered. CCC argued similarly that the Board is legally obligated to take total bill impact into consideration when determining the payment amounts. CCC referred to the decision of the Supreme Court of Canada in the Northwestern Utilities Ltd. case in which the court stated:

> The duty of the Board was to fix fair and reasonable rates; rates which, under the circumstances, would be fair to the consumer, on the one hand

> and which, on the other hand, would secure to the company a fair return for the capital invested.[5]

Both CCC and CME noted that the Board recognized the need to consider total bill impact when setting rates in the Board's decision in the Hydro One Networks Inc. ("Hydro One") distribution rates case, EB-2009-0096:

> …the Board must take into account the overall increase and prospect of further increases in the commodity portion of the bill. While these charges are outside of the control of the applicant, they are no less real for customers. In giving effect to the Board's objective to protect the interests of consumers the Board cannot ignore the overall impacts on customers.[6]

CCC submitted that it does not take issue with allowing OPG a fair return on its capital, but stated that the Board must first determine the prudent and acceptable level of investment and then allow OPG a fair return.

CCC argued that the Board's policy initiative (Renewed Regulatory Framework) and the Ontario Clean Energy Benefit rebate do not relieve the Board of its obligation to consider total bill impact in its determination of payment amounts. Similarly, CME stated that the policy initiative does not relieve the Board from considering CME's evidence on bill impacts. CME reported that the majority of its members are either too large to quality for the Ontario Clean Energy Benefit or too small to qualify for benefits available to large consumers. CME stated that if care is not taken in managing increases in electricity prices, these manufacturers are likely to leave Ontario.

OPG responded that parties seeking reductions to OPG's application are doing so on the basis that aspects of the electricity bill over which OPG has no control are rising. OPG argued that the parties overstate the jurisdiction of the Board and that the arguments are really more in the nature of complaints relating to legislative and policy choices made by the Province.

OPG argued that the decision of the Supreme Court of Canada in the Northwestern Utilities case provided for a fair return to the company for the capital invested. OPG also noted that the Board's objectives include not only the protection of consumer interests but also facilitating a financially viable electricity industry. OPG argued that fair

[5] *Northwestern Utilities Ltd. v. Edmonton (City)*, [1929] S.C.R. 186 at pp. 192-193. ("Northwestern Utilities")
[6] Decision with Reasons, EB-2009-0096, April 9, 2010, p. 13.

return to a utility is comprised of two legal entitlements: the right to recover all prudently incurred costs and the right to a fair return on invested capital.

With respect to prudently incurred costs, in OPG's view, only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses may be excluded. OPG referred to the prudence standard in the Enbridge Gas Distribution Inc. decision, RP-2001-0032:

- Decisions made by the utility's management should generally be presumed to be prudent unless challenged on reasonable grounds.
- To be prudent, a decision must have been reasonable under the circumstances that were known or ought to have been known to the utility at the time the decision was made.
- Hindsight should not be used in determining prudence, although consideration of the outcome of the decision may legitimately be used to overcome the presumption of prudence.
- Prudence must be determined in a retrospective factual inquiry, in that the evidence must be concerned with the time the decision was made and must be based on facts about the elements that could or did enter into the decision at the time.[7]

OPG referred to the Board's decision on Hydro One transmission rates, EB-2008-0272, which was made near the bottom of the economic downturn, and noted that the Board stated that it would be inappropriate to "arbitrarily reduce spending in direct response to the economic downturn."[8]

With respect to the fair return standard, OPG referred to the decision of the Supreme Court of Canada in the Northwestern Utilities case:

> By a fair return is meant that the company will be allowed as a large return on the capital invested in its enterprise (which will be net to the company) as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise.[9]

[7] Decision with Reasons, RP-2001-0032, December 13, 2002, p. 63.
[8] Decision with Reasons, EB-2008-0272, May 28, p. 4.
[9] *Northwestern Utilities*, pp. 192-193.

OPG also cited the Federal Court of Appeal's decision in *TransCanada Pipelines v. National Energy Board*, in which the court agreed that the approved rates will enable the company to earn a fair return and is not influenced by any resulting rate impact on customers.[10] OPG also noted that the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities*, EB-2009-0084, states that meeting the fair return standard is a legal requirement.

Board Findings

Throughout this Decision the Board has rendered findings on the reasonableness of OPG's forecast costs and revenues, and in some cases on the prudence of expenditures which were in excess of prior forecasts. The Board has made adjustments to OPG's proposals in a number of areas. The overall effect of this Decision is a reduction in the revenue requirement from that originally requested by OPG and lower payment amounts than requested and a reduced bill increase for customers. The detailed calculation of the payment amounts will be done by OPG as part of the process of completing the Payment Amounts Order, but the Board estimates that the increase will be in the order of 1%.

The Board has broad discretion to adopt the mechanisms it judges appropriate in setting just and reasonable rates. This is clearly established in O. Reg. 53/05 and the Act. O. Reg. 53/05 states "the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act" subject to certain rules which are specified in O. Reg. 53/05. Section 78.1 states "the Board may fix such other payment amounts as it finds to be just and reasonable, (a) on application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable…" With these authorities, the Board may take account of a broad suite of factors that affect the company and factors that affect consumers. Both considerations are relevant in determining just and reasonable payment amounts. For example, the Board may consider evidence on economic conditions and factors influencing other aspects of electricity rates. These sorts of factors may well be relevant in terms of deciding the appropriate pacing or level of expenditures. The Board must be satisfied that the rates are just and reasonable and it must consider all evidence that it finds relevant for that purpose. For the current proceeding, the Board finds that evidence regarding the economic situation and the trend in overall electricity costs is a relevant consideration,

[10] (2004), 319 N.R. 172 (FCA).

along with a variety of other factors (such as inflation rates, interest rates, legislation, business needs, benchmarking results).

OPG and PWU would have the Board constrain its consideration of the various spending proposals to a very narrow examination based on the presumption that all proposed expenditures are reasonable unless proved otherwise. In the words of OPG, "Only costs that are found to be dishonestly incurred, or which are negligent or wasteful losses, may be excluded from the legitimate operating costs of the utility in determining the rates that may be charged." The Board disagrees. When considering forecast costs, the onus is on the company to make its case and to support its claim that the forecast expenditures are reasonable. The company provides a wide spectrum of such evidence, including business cases, trend analysis, benchmarking data, etc. The test is not dishonesty, negligence, or wasteful loss; the test is reasonableness. And in assessing reasonableness, the Board is not constrained to consider only factors pertaining to OPG. The Board has the discretion to find forecast costs unreasonable based on the evidence – and that evidence may be related to the cost/benefit analysis, the impact on ratepayers, comparisons with other entities, or other considerations.

The benefit of a forward test period is that the company has the benefit of the Board's decision in advance regarding the recovery of forecast costs. To the extent costs are disallowed, for example, a forward test period provides the company with the opportunity to adjust its plans accordingly. In other words, there is not necessarily any cost borne by shareholders (unless the company decides to continue to spend at the higher level in any event). Somewhat different considerations will come into play when undertaking an after-the-fact prudence review. In the case of an after-the-fact prudence review, if the Board disallows a cost, it is necessarily borne by the shareholder. There is no opportunity for the company to take action to reduce the cost at that point. For this reason, the Board concludes there is a difference between the two types of examination, with the after-the-fact review being a prudence review conducted in the manner which includes a presumption of prudence.

The Board has considered the overall impact of the various adjustments it has made to the requested amounts and concludes that the resulting new payment amounts are just and reasonable in light of all relevant circumstances. The overall increase is approximately 1%.

3 REGULATED HYDROELECTRIC FACILITIES

3.1 Production Forecast

OPG's historic hydroelectric production and test period hydroelectric production forecast are summarized in the following table.

Table 4: Hydroelectric Production

TWh	2007	2008	2009	2010	2011	2012
Forecast	17.5	17.4	18.5	19.3	19.4	19.0
Actual	18.2	19.0	19.4			
Variance	0.7	1.6	0.9			
SBG in Forecast				(0.2)	(0.5)	(0.8)

Source: Exh. E1-1-2, Table 1

OPG uses computer models to derive water flow and production forecasts for the regulated hydroelectric facilities. OPG states that the models have proven to be 90% accurate and that statistical analysis indicates no bias. The hydroelectric water conditions variance account captures the revenue and cost impact of the difference between forecast and actual water conditions.

Surplus baseload generation ("SBG") occurs when electricity production from baseload facilities exceeds Ontario demand. This situation is in many cases alleviated by spilling water at the Niagara plants. OPG stated that in 2009 SBG was more prevalent than it has been historically and, as a result, OPG forecast significant SBG in the test period whereas in the past no specific provision was made for this factor. SBG was negligible in 2008, and for 2009 it was estimated at 0.6 TWh, of which 0.19 TWh was attributable to the regulated hydroelectric facilities.[11]

The SBG forecast for 2010, 2011 and 2012 is 0.2 TWh, 0.5 TWh, and 0.8 TWh, respectively. OPG's SBG forecast is based on publicly available information related to other market participants and its own market intelligence. Relevant factors include potential curtailment from other generators, exports, expected river flows, timing for re-commissioning of Bruce Nuclear facilities, etc. OPG identified expanded wind

[11] Exh. L-2-19.

generation as the primary driver for this forecast in the test period. The test period SBG forecast has a revenue requirement impact of $32.5 million.[12]

OPG explained that the IESO is responsible for mitigating SBG, but when SBG is anticipated OPG establishes offer prices so that any output reductions are based on market economics and a variety of operational constraints. OPG stated that historically it has used all available hydroelectric storage prior to spilling water, but also noted that its use of the Pump Generating Station ("PGS") is always based on the comparative economics of the pump/generate cycle in terms of the associated market prices.

SBG was the only aspect of the hydroelectric production forecast on which parties provided submissions. The PWU supported the inclusion of SBG in the production forecast. Board staff, AMPCO, CME, CCC, SEC and VECC submitted that SBG should not be included in the production forecast, but proposed that a variance account be used. The primary reason cited was the difficulty in forecasting SBG, and most parties noted that the expected 2010 SBG will be considerably lower than originally forecast. The forecast for 2010 was originally 0.2 TWh, but the year-to-date level (as of October 3, 2010) was only 0.0204 TWh. OPG maintained that this situation was due to lower than normal water flows during periods when SBG had been expected and cautioned that higher SBG was still expected before the end of the year.

OPG acknowledged in its Argument in Chief that a variance account for this factor might be appropriate. Board staff submitted that variations in production due to SBG should be treated in a manner similar to variations in water conditions and that OPG should record SBG production losses (ordered by IESO or of its own initiative) in a deferral account. Other intervenors supported the use of a variance account, including VECC, SEC, AMPCO, CCC, CME and PWU. SEC, supported by AMPCO, submitted that only SBG directed by the IESO should be charged to the account.

CME supported use of the account for tracking purposes but cautioned that it might challenge any amount in the account on the basis that "it is questionable as to whether an utility owner that causes adverse impacts on its own utility [through procurement decisions] can recover the costs of those adverse impacts in regulated rates."[13]

[12] Exh. L-5-24.
[13] CME Argument, para. 174.

In reply, OPG argued that it would be inappropriate to exclude SBG from the forecast as this would be inconsistent with the treatment of other factors which are included in the forecast. OPG went on to argue that if the Board is not prepared to accept OPG's original test period forecast of 1.3 TWh, it should at least accept a forecast of 0.4 TWh, which corresponds to the level in 2009 and the forecast for 2010.

OPG indicated its support for a variance account, but emphasized that it should measure variances from the best forecast of SBG. OPG further submitted that the basis for the account should be a modified version of that proposed by Board staff. OPG proposed that the reconciliation be based on:

> …any IESO order or instructions (if applicable), general market conditions (e.g. total demand, total baseload, total supply) and actual production reports from the SGB-affected generation units that show deviations from production that are contemporaneous with SBG conditions.[14]

OPG maintained that SEC and AMPCO's proposal was unworkable because SBG is not normally managed through IESO directives. OPG also argued that CME's approach would inappropriately penalize those resources within the market that help to mitigate the condition.

Board Findings

The only issue the Board needs to address is the inclusion of SBG in the production forecast and whether a variance account is appropriate.

The evidence is clear that SBG was a significant factor in 2009 and is likely to be so again in 2011 and 2012 with the expected increase in wind generation and the expected return to service of refurbished Bruce Nuclear facilities. The Board, however, does not find that the evidence supports a forecast of 1.3 TWh. This is a significant increase over the 2009 actual and even the 2010 forecast. Added to this is the fact that 2010 is now expected to have much lower SBG. The Board accepts that this is in large part due to lower water levels, but the Board finds that there is insufficient evidence to support a forecast of 1.3 TWh for 2011 and 2012. The Board concludes that rather than setting a forecast, a better approach will be to capture the impacts of all SBG through a variance account, with no allowance built into the forecast. This approach will bring transparency to the level of SBG and will assist in assessing whether OPG has taken adequate steps to mitigate the impact of SBG (which is discussed further below).

[14] Reply Argument, p. 27.

The Board will establish a variance account for SBG, with SBG to be measured on the basis proposed by OPG. The Board will not adopt the proposal of SEC and AMPCO that SBG be limited to instances where the IESO directs OPG to take action. The Board accepts OPG's position and evidence that SBG is currently addressed through market mechanisms as well as IESO orders or instructions. The Board has no evidence regarding the implications of requiring OPG to act only on the basis of IESO directives, but the Board is concerned that such an approach would not allow an adequate consideration of the other factors involved (safety, environmental, water level, economics) which the evidence shows are taken into account in responding to SBG conditions.

The evidence indicates that OPG uses the PGS to mitigate the impact of SBG if the market price spreads are large enough to incent OPG to deploy the PGS. The Board will review the use of PGS for this purpose when reviewing the amounts in the account. This is addressed further in Chapter 11 in the section on the Hydroelectric Incentive Mechanism.

The Board does not need to address at this time the issue raised by CME in relation to considerations which may arise at a future disposition of the account. The Board will review the account balance for prudence prior to determining disposition, as is the Board's normal practice.

3.2 Operating Costs

Historic and test period operating costs for the regulated hydroelectric facilities are summarized in the following table.

Table 5: Operating Costs Summary – Regulated Hydroelectric ($ million)

Cost Item	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
OM&A:						
Base OM&A	$78.6	$53.9	$61.5	$61.8	$68.7	$62.2
Project OM&A	7.0	14.6	9.1	5.3	9.7	10.0
Allocation of Corporate Costs	21.9	26.3	24.9	25.1	24.8	26.3
Allocation of Centrally Held Costs	16.1	14.6	17.4	20.3	22.9	25.5
Asset Service Fee	2.3	2.5	2.6	2.0	2.1	2.0
Total OM&A	$125.9	$111.8	$115.5	$114.4	$128.2	$125.9
Gross Revenue Charge	$241.8	$253.5	$259.6	$257.2	$257.1	$252.2

Source: Exh. F1-1-1

Base OM&A and project OM&A costs have been stable historically, and the test period forecast represents a small increase over prior years actual spending. Allocated costs are rising; these costs are addressed in Chapter 6.

Gross Revenue Charges ("GRC") are payments made by OPG to the province. These payments are made by owners of hydroelectric facilities under section 92.1 of the *Electricity Act, 1998*. The GRC consists of a property tax component and a water rental component. The latter is determined by O. Reg. 124/02 under the *Electricity Act, 1998* and is a function of energy produced and the rate set by the Provincial Government.

The hydroelectric business uses three main sources for benchmarking: EUCG Inc., Canadian Electrical Association ("CEA") and Navigant Consulting. OPG maintained that the individual stations and the regulated facilities in aggregate perform generally better than EUCG and CEA benchmarks in the areas of availability and reliability. OPG's evidence is that the OM&A unit energy cost benchmarking demonstrates that the regulated hydroelectric facilities are cost competitive. OPG provided the results of the EUCG and Navigant benchmarking in support of its position. While there are differences between stations, the aggregate plant result for OM&A cost for 2008 was in the first quartile in both the EUCG and Navigant benchmarking studies. OPG's expectation is that the rankings will be similar for the test period.

There were no submissions objecting to hydroelectric operating costs except for the OM&A related to the Saunders Visitor Centre. This matter is addressed in the next section. There were no submissions on the regulated hydroelectric benchmarking results presented in the evidence. OPG submitted that the test period OM&A budget is reasonable and should be approved, subject to the Board's findings on compensation and the Visitor Centre.

Board Findings

The Board finds the test period costs to be reasonable. The largest component of the hydroelectric costs is the Gross Revenue Charge, and the Board has no authority with respect to this rate. Given the Board's finding that the production forecast will not be reduced for SBG, the Board will increase the provision for the Gross Revenue Charge by $6.6 million in 2011 and $11.5 million in 2010.[15]

[15] Exh. L-5-24.

The Board further finds that the benchmarking methodology and results are reasonable and notes that they have been accepted without challenge by all parties. This evidence supports the conclusion that the hydroelectric business has achieved an acceptable level of efficiency and that the OM&A costs are reasonable. The OM&A costs are also reasonable in light of the trend in actual spending.

3.3 Capital Expenditures and Rate Base

OPG's forecasted capital expenditures for the regulated hydroelectric facilities total $327.9 million and $235.7 million in 2011 and 2012, respectively. A break-out by major grouping, including historical planned and actual amounts, is set out in the following table.

Table 6: Hydroelectric Capital Expenditures

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Niagara Plant Group	$9.9	$33.6	$24.8	$42.2	$25.6	$36.2	$30.7	$30.9
Niagara Tunnel	63.9	170.6	131.3	346.8	213.5	241.8	288.0	199.0
Saunders GS	10.5	4.6	4.0	6.6	11.9	17.3	9.2	5.8
TOTAL	**$84.3**	**$208.8**	**$160.1**	**$395.6**	**$251.0**	**$295.3**	**$327.9**	**$235.7**

Source: Exh. D1-1-1, Table 1

OPG is seeking approval of regulated hydroelectric in-service additions to rate base of $60.9 million, $42.9 million and $51.5 million for 2010, 2011 and 2012, respectively. OPG submits that its capital spending has been prudent and the in-service additions to rate base should be approved. OPG's historical and proposed rate base for the test period is set out in the following table.

Table 7: Hydroelectric Rate Base

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Total Gross Plant	$4,396.5	$4,433.2	$4,416.8	$4,480.6	$4,438.6	$4,485.0	$4,538.0	$4,585.5
Total Accum. Dep.	507.8	570.2	569.5	633.1	631.2	693.6	756.7	820.2
Total Net Plant	3,888.7	3,857.8	3,847.3	3,847.5	3,807.4	3,791.4	3,781.3	3,765.3
Cash Working Capital	21.8	21.8	23.6	21.8	26.0	23.6	21.5	21.5
Materials & Supplies	0.6	0.6	0.6	0.6	0.6	0.7	0.6	0.6
Rate Base	**$3,911.1**	**$3,880.2**	**$3,871.5**	**$3,869.9**	**$3,834.0**	**$3,815.7**	**$3,803.4**	**$3,787.4**

Source: Exh. L-1-2, Exh. B2-1-1 Table 1, Exh. B2-2-1 Table 1 and Exh. B2-5-1 Table 1

Intervenors and Board staff made submissions on three specific projects: the Niagara Tunnel Project, the Sir Adam Beck 1 G9 Rehabilitation and the St. Lawrence Power Development Visitor Centre.

PWU submitted that OPG is under investing in hydroelectric assets.

Board Findings

The Board finds that the hydroelectric capital budget for projects coming into service during the test period is reasonable in that it is supported by the business cases. No party objected to this portion of the capital budget.

The Board is providing no explicit approval in this Decision for the capital budget associated with multi-year hydroelectric projects which do not come into service during the test period. Some issues were raised related to the Niagara Tunnel Project and the adequacy of OPG's budget, and those are addressed below.

The Board has also determined that no adjustments to the hydroelectric rate base are warranted. Intervenors raised objections to two specific projects, and those are addressed below.

3.3.1 Niagara Tunnel Project

The OPG Board of Directors approved the Niagara Tunnel Project in 2005. The cost was forecast at $985 million and the in-service date was late 2009. In May 2009, the OPG Board approved a revised cost of $1,600 million and a revised in-service date of December 2013. OPG provided a Business Case Summary for the project, dated May 2009 with its application. OPG plans to spend $288.0 million and $199.0 million on the project in 2011 and 2012, respectively. However, as the project will not come into service until 2013, no expenditures related to this project are included in the rate base proposed for the test period. OPG noted that the expenditures related to the Niagara Tunnel Project will be subject to section 6(2)4 of O. Reg. 53/05, and will be addressed at the time the expenditures are proposed for recovery through a payment amounts application.

The Board determined in Procedural Order No. 3 that it would only make prudence determinations with respect to projects or costs that close to rate base in the test period.[16] As a result, intervenor submissions largely focused on the filing of ongoing reports concerning the Niagara Tunnel Project.

AMPCO submitted that the Board should order OPG to produce an annual monitoring report on the tunnel project that is comparable to the report OPG will produce for the Darlington Refurbishment Project. CCC submitted that the Board should require OPG to provide the Project Execution Plan reports (similar to what was filed in the undertaking response JX2.4) until the project is brought forward for approval. In CCC's view, these reports would assist the Board in the final assessment of the project. CCC noted that OPG intends to regularly review and update the project execution plan, and that this reporting will be provided to the OPG Board of Directors and the shareholder.

SEC observed that there will likely be internal OPG reporting on the tunnel project more frequently than once a year. On this basis, SEC submitted that it would be reasonable for the Board to require a tunnel project status report in June 2011 and June 2012. SEC suggested that if the reports indicated a significant cost overrun the Board could call OPG in for review if it was apparent at the time that OPG would not be filing a payment amounts application in 2013. SEC saw further value in the proposed reporting since the Board, if it were aware of cost over-runs in 2011, could hold a "mini-hearing" on the matter in 2011.

OPG responded that the reporting suggested by the parties would be of limited value because the tunnel is expected to be in service in 2013. OPG further argued that the proposed reporting would add unnecessary regulatory burden and cost. OPG noted that it will make a comprehensive filing on the project in the first quarter of 2012 as part of its next payment amounts application and argued that there is too short a time frame for interim reporting.

OPG also objected to filing updated copies of the Project Execution Plan because the Board does not have the same role as the OPG Board in overseeing and managing the project. OPG submitted that reporting to the Board should be focused on the specific

[16] Procedural Order No. 3, dated July 21, 2010, p. 11 "The Board will retain the current statement of issue 4.2 including the term "appropriate" and the reference to business cases. The Board will only make prudence determinations with respect to projects or costs that close to rate base in the test period. While the Board agrees that it would be appropriate to review other aspects of the capital budgets, the Board expects that this review will be more in the form of a status update. The Board does not intend to make any form of quantitative or qualitative finding with respect to projects and costs which close to rate base in the period after the test period."

information required to efficiently monitor and regulate OPG's prescribed facilities and should not be required just because it is provided to OPG's Board of Directors.

OPG also objected to mid-year reporting for the purposes of allowing the Board to hold a mini-hearing. OPG submitted that there is no legal basis for the Board to assume a quasi-project management role during the course of a major project; nor is it a proper role for the Board. OPG also suggested it would create a conflict with the Board's later duty to determine the prudence of the expenditures.

Board Findings

The Board will not require additional reporting on the status of the Niagara Tunnel Project prior to OPG's next payments case. The Board does not intend to manage the project, nor will it to conduct any sort of intermediate review, or "mini-hearing". The appropriate course of action is for the Board to conduct a thorough prudence review at the time that OPG proposes to add the project to rate base. The Board will expect OPG to file Project Execution Plans, as well as any other progress reports completed over the duration of the project, at the time of the prudence review.

3.3.2 Investment in Hydroelectric Assets

PWU submitted that OPG's proposed hydroelectric capital and OM&A budgets are appropriate but minimally so. PWU suggested that its own analysis indicates that the test years are in a period when hydroelectric reinvestment levels should be on the rise given the age of the assets, however investment and rate base levels are declining from 2010 levels. PWU submitted that OPG should be directed to file information on the demographics of the regulated hydroelectric assets. OPG replied that this proposal should be rejected because it would require complex analysis and the value of the analysis has not been demonstrated.

Board Findings

The Board will not direct OPG to perform the asset demographics analysis proposed by PWU. PWU asserted that spending should be increasing based on the age of the assets. Spending, however, is primarily related to the condition of the assets, and while age is a contributing factor to asset condition, it is by no means the only one. However, it is up to OPG to provide the relevant evidence to support its proposed expenditures and to demonstrate that it is making adequate investments to maintain an appropriate level of reliability. The Board notes that there is no evidence that reliability has been compromised by the level of expenditures for the test period.

3.3.3 Sir Adam Beck I G9 Rehabilitation

The G9 rehabilitation project includes replacement of the generator, rehabilitation and upgrade of the turbine, and a new transformer. The evidence indicated that OPG expected to complete the project in December 2010 at a cost of $32.1 million.

AMPCO pointed out that in the previous proceeding, EB-2007-0905, the projected cost was $30 million with an in-service date of 2009. AMPCO submitted that the increase has not been adequately justified and that the rate base addition should be reduced by $1 million.

OPG responded that the project is on schedule and within the budget presented in the business case summary filed in the current application and that AMPCO did not demonstrate that the costs associated with the project were imprudent. OPG pointed out that the information that AMPCO quoted was at the concept stage, and was later updated at the business case summary stage.

Board Findings

The Board finds that AMPCO's proposal to remove $1 million from rate base is unwarranted. The cost overrun is $2 million, or about 7% in relation to the original project budget. The Board finds that the magnitude of this overrun is not sufficient to suggest mismanagement or imprudence.

3.3.4 St. Lawrence Power Development Visitor Centre

The St. Lawrence Power Development Visitor Centre, which opened in August 2010, is adjacent to the R.H. Saunders Generating Station located in the city of Cornwall. OPG's Board approved the project with a budget of $12.6 million in March 2009. OPG described the purpose of the Visitor Centre as providing an important venue for OPG to deliver its hydroelectric communications (e.g., water safety) while improving community and aboriginal support for continued operation of OPG's second largest hydroelectric generating station.

Energy Probe, Board staff, CCC, CME, AMPCO and VECC opposed the inclusion of about $12 million in hydroelectric rate base and about $0.5 million OM&A for the Visitor Centre, for the following reasons:

- It is inappropriate for electricity ratepayers to pay for expenditures and investments whose purpose is to promote OPG's brand and whose main focus appears to be regional tourism and local municipal relations;
- Water safety messaging is a minor element of the centre and the unregulated hydroelectric segments of OPG benefit from the centre but no costs are recovered from these segments;
- There are more effective ways to promote the Waterways Public Safety campaign;
- Although the project is characterized by OPG as sustaining, there is no direct contribution to the production of electricity at the R.H. Saunders Generating Station; and
- OPG's mandate is to provide electricity and not educational and cultural opportunities.

SEC supported the inclusion of the Visitor Centre in OPG's hydroelectric rate base. SEC believes that the wrong question has been asked to assess the appropriateness of the proposed rate base treatment. In SEC's view, the question that should be asked is whether the project is a normal and usual part of the business of generating electricity from the Saunders facility and just good corporate citizenship, not whether the Visitor Centre will produce more electricity at the facility. SEC also stated that the Visitor Centre is virtually entirely about the Saunders facility and therefore any benefit to the unregulated business is incidental.

OPG argued that the parties opposing the inclusion of the Visitor Centre in rate base had too narrow a view of the purpose of the centre and that the views of parties were not reflective of the realities of operating a major power plant in the modern world. OPG likened the Visitor Centre to administration buildings, storage facilities and parking lots, which are accepted as necessary infrastructure even though they do not directly generate electricity. OPG also noted that the aboriginal relations function is included in base OM&A expense and that the Visitor Centre will strengthen the relationship with the Mohawks of Akwesasne. OPG also argued that its position is consistent with the Memorandum of Agreement with its shareholder requiring OPG to operate in accordance with the highest corporate standards in the areas of social responsibility and corporate citizenship. OPG also objected to having some of the cost allocated to its unregulated hydroelectric business as the Visitor Centre focuses on themes local to the Saunders station.

Board Findings

The Board agrees with OPG and SEC that it is reasonable to include the capital cost of the Visitor Centre in rate base for the regulated hydroelectric facilities. The Saunders generating station is a major corporate facility in the Cornwall area, and it is reasonable for the operation of the facility to promote good relations with the surrounding community. The Board also notes that the Visitor Centre was built, in part, to replace the one that OPG was required to close for security reasons. The Board agrees that it would be inappropriate to allocate any of the costs to the non-regulated facilities as the focus is mainly on local issues and the local facility. As the Board is making no reduction to rate base for this item, there will also be no reduction to the associated OM&A costs.

3.4 Other Revenues

OPG earns revenue from a number of sources other than through the regulated payment amounts for hydroelectric generation. These sources of other revenue include ancillary services, segregated mode of operations and water transactions.

The IESO purchases the following ancillary services from OPG: black start capability, reactive support/voltage control service, automatic generation control and operating reserve. A forecast of the revenues from ancillary services is applied as an offset to the hydroelectric revenue requirement. Differences between the forecast and actual revenues are recorded in the Ancillary Service Net Revenue Variance Account – Hydroelectric.

Segregated mode of operation (“SMO”) transactions occur at the Saunders GS. Units at Saunders can be segregated, when pre-arranged, to serve the Hydro Quebec control area. A high voltage DC intertie between Ontario and Quebec began commercial service in 2009 and, as a consequence, SMO revenues have declined. The SMO forecast in the previous case was based on a 3 year historical average. The test period SMO forecast is based on SMO results for the second half of 2009.

Water transactions (“WT”) between OPG and the New York Power Authority allow the two parties to use a portion of the other’s share of water for electricity generation. In 2009, low electricity market prices reduced WT revenues. As in the case of SMO, the WT forecast in the previous case was based on a three-year historical average. OPG has proposed a test period forecast based on the actual net revenues in 2009.

The following table summarizes historic and test period hydroelectric other revenue.

Table 8: Other Revenues – Regulated Hydroelectric ($ million)

Revenue Source	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget (1)	2011 Plan	2012 Plan
Ancillary Services	$35.6	$32.4	$41.2	$33.1	$42.5	$39.1	$38.3	$39.5
Segregated Mode of Operation	4.4	5.0	13.7	6.6	3.6	6.6	1.5	1.6
Water Transactions	4.3	5.2	8.8	6.9	4.9	6.9	5.1	5.2
Total	**$44.3**	**$42.6**	**$63.7**	**$46.6**	**$51.0**	**$52.6**	**$44.9**	**$46.2**

Note 1: The figures for Segregated Mode of Operations and Water Transactions for 2010 are the amounts imputed by the Board for 2009 (EB-2007-0905). They do not reflect the revenues OPG expects to earn in 2010.

Source: Exh. G1-1-2, Table 1

Both CME and VECC submitted that OPG's test year forecasts for SMO and WT should be adjusted. VECC argued that the current Board approved methodology incorporates actual performance over time and provides OPG with an incentive to increase revenues. VECC also noted that in 2008, OPG earned $12.8 million in excess of the forecast amount for SMO and WT. VECC submitted that applying the current Board approved methodology for forecasting SMO and WT would increase other revenue by $13 million. CME also supported retaining the existing forecast methodology. In the alternative, CME submitted that the Board should establish a revenue sharing mechanism that credits 75% of the net revenue to ratepayers, citing similarities to sharing mechanisms in the gas industry.

In reply, OPG noted that it had a net loss for SMO of almost $1 million for the 12 months up to August 2010, and that neither CME nor VECC challenged the impact of the DC intertie or depressed market prices. OPG agreed that a three-year rolling average will eventually reflect OPG's net revenues, but that in the interim OPG will have returned to ratepayers millions of dollars more than it has earned on SMO and WT.

With respect to VECC's observation about 2008 revenue being higher than forecast, OPG replied that a bad forecast is not a justification for using a methodology which OPG considers wrong. OPG stated that there is no evidentiary basis for the revenue sharing mechanism suggested by CME.

OPG concluded that its proposed methodology should be accepted, but that beginning in 2013, it would have no objection to returning to the three-year average methodology.

Board Findings

The Board finds that the forecast test period revenue for ancillary services is appropriate. No party objected to this forecast, and O. Reg. 53/05 requires the use of a variance account to capture the actual results in any event.

In the last proceeding the Board approved a rolling three-year average for the purposes of forecasting SMO and WT, with the variance borne by OPG. The Board finds that this approach provides reasonable results over time as periods of under-performance will be balanced by periods of over-performance. The Board also agrees with VECC that the strength of this approach is that it embeds actual performance while at the same time providing the company with an incentive to increase revenue. For the structure to be effective, however, it must be retained over time. For this reason, the Board is inclined to retain this approach. The exception to this would be in the case where there has been a fundamental or structural change in circumstances which would render a forecast based on historical performance unreasonable. In the current case, the Board concludes that a rolling three-year forecast remains appropriate for WT, but is not appropriate for SMO.

For SMO, the Board concludes that the operation of the DC intertie with Quebec represents a structural change that renders past experience unreliable for purposes of forecasting future performance. For this reason, the Board will accept OPG's forecast for 2011 and 2012. The Board will revisit this issue in the next proceeding, with the expectation that a return to a rolling average forecast will again become appropriate. The Board notes OPG's acceptance of this approach.

For WT the Board finds that the revenue forecast should be based on the three-year average for 2007, 2008 and 2009. This results in a revenue forecast of $6 million per year, or an increase of $1.7 million over the proposed level for the test period. OPG argues that this forecast does not adequately reflect the lower market prices of 2009 compared to 2008. The Board disagrees. The nature of a rolling forecast is that it takes into account all recent experience. Further, the Board finds that a year of lower market prices does not represent a structural change; market prices are by their nature variable. The Board concludes that there is no evidence to support a change to the forecasting methodology for WT.

The Board will not adopt the revenue sharing mechanism proposed by CME. The Board concludes that the best balance of benefits to ratepayers and incentives for OPG is under a structure where the revenue requirement includes a forecast based on historical experience and any variance is borne by OPG. This is the approach adopted by the Board in the last proceeding and it remains appropriate.

4 NUCLEAR FACILITIES

4.1 Production Forecast

Historic nuclear production and test period nuclear production forecasts are summarized in the following table.

Table 9: Nuclear Production (TWh)

	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Darlington NGS	27.2	28.9	26.0	27.8	28.9	29.0
Pickering A NGS	3.6	6.4	5.7	6.6	7.4	7.7
Pickering B NGS	13.4	12.9	15.1	13.7	14.6	15.3
Forecast for Major Unforeseen Events	0.0	0.0	0.0	(2.0)	(2.0)	(2.0)
Total	**44.2**	**48.2**	**46.8**	**46.2**	**48.9**	**50.0**

Source: Exh. E2-1-1, Table 1

The production forecast of 48.9 TWh for 2011 and 50.0 TWh for 2012 was part of the 2010-2014 business plan approved by OPG's Board of Directors. This represents a total increase of 3.9 TWh over actual production in 2008 and 2009.

OPG establishes annual production forecasts for the individual nuclear units and an aggregated forecast for each station leading to an overall nuclear production forecast. The annual forecast is equal to the sum of the units' capacity multiplied by the number of hours in the year, less the number of hours for planned outages and forced production loses. The forecasts include allowances for uncertainty at the station level and the fleet level to recognize events which may not be predictable. OPG has forecast improved production performance across its fleet through reduced planned outage days and improvements in the forced loss rate ("FLR"). The FLR is an indicator of performance reliability. It is a measure of the percentage of energy generation during non-planned outage periods that a plant is not capable of supplying to the electrical grid because of forced production losses such as forced outages.

The forecast also includes 2.0 TWh in reduced production in each year for what OPG calls "major unforeseen events" ("MUE"). From 2005 to 2008, OPG's actual annual nuclear production forecast was less than the business plan level by approximately 3.5

TWh on average. OPG explained that the difference was largely due to forced outages and forced extensions to planned outages due to MUE. OPG's analysis indicated that on average more than 2.0 TWh was associated with MUE, and this experience formed the basis of OPG's test period forecast. The revenue requirement impact of the 2.0 TWh of MUE is $200 million in the test period.[17] Although the business plan includes the provision for MUE, OPG has established performance "stretch" targets for the nuclear business which are 2.0 TWh higher.

Most intervenors recommended that the Board deny the 2.0 TWh adjustment related to MUE. Board staff noted that OPG's nuclear division "stretch" target does not include the MUE adjustment. Several parties expressed concern that incentive payments for OPG management would be based on these "stretch" targets, while payment levels would be based on the lower production forecast.

CCC argued that the MUE adjustment had not been justified and noted that OPG's own witness stated, "we expect to get 50.9 [TWh] in 2011 and 52 [TWh] in 2012".[18] CME made similar arguments and took the view that OPG's evidence in support of the adjustment was extremely limited given the magnitude of the financial impact.

AMPCO noted that the 2011-2012 forecast, while higher than 2008-2009 actual, is lower than the 2008-2009 forecast in the prior proceeding. AMPCO submitted that it would be reasonable to expect that forecast production should improve following the vacuum building outages and the investment in performance improvements, including accounting for some additional outage related to the Pickering B Continued Operations project. AMPCO concluded:

> Having invested heavily in performance improvement, with the Board's approval in past 3 years, consumers have a reasonable expectation that forecasted production should improve, not decline relative to the forecast presented in the previous case, as OPG has suggested.[19]

CME also submitted that witness testimony suggests that OPG does not actually expect to suffer the loss for which it is seeking compensation. In CME's view:

[17] Exh. L-5-25.
[18] Tr. Vol. 6, p. 82.
[19] AMPCO Argument, para. 152.

> OPG cannot have it both ways. They cannot say on the one hand that it is more accurate to say that they will hit 48.9 TWh and 50.0 TWh, but then on the other say that they *expect* to actually hit 50.9 TWh and 52 TWh.[20]

In SEC's view, OPG has not presented evidence that past experience is a good predictor of the future. SEC submitted that, on the contrary, OPG has presented a great deal of evidence about programs and initiatives designed to improve future performance and evidence that for other aspects of the forecast the past is not a good predictor of the future.

PWU did not support the exclusion of the 2.0 TWh for MUE because in its view the result would be an unrealistically high production forecast.

OPG replied that no party questioned or contradicted that MUEs have occurred and are likely to occur in the future; nor did any party introduce evidence that OPG had overestimated the impact of MUEs. OPG noted that the MUE adjustment was less than the historical variance between forecast and actual production. OPG further argued that its approach was consistent with the position put forward by Board staff in the previous proceeding.

SEC also submitted that there should be an adjustment to reflect a change in the Darlington FLR from 1.5% to 1.0%. The historical FLR for Darlington is provided in the following table:

Table 11: Darlington Forced Loss Rate

Year	FLR (%)
2005	1.3
2006	3.2
2007	1.1
2008	0.7
2009	1.6
2010[1]	3.5
5 Year Average (2005-2009)	**1.6**

Note 1: Projection based on 8 months of data, Undertaking J6.5
Source: Exh. L12-30

[20] CME Argument, para. 187.

In SEC's view, an FLR of 1.0% is more reasonable because it is the four year average but removes the anomalous FLR of 3.2% in 2006. SEC estimated this would add between $7 million and $10 million to test period revenues. Board staff submitted that the Darlington FLR should be reduced to 1.1% for much the same reasons. OPG responded that the Darlington FLR was not based on historical average, but was based on recent performance and plant material condition, past and future investment to improve reliability and other performance initiatives.

Board Findings

The evidence is clear that the business plan approved by OPG's Board of Directors and upon which the application is based includes the 2.0 TWh adjustment for MUE. It is also clear that the nuclear business plan does not contain this adjustment – a difference which OPG characterizes as a "stretch goal" to go beyond the business plan.

In the words of one OPG witness:

> We are trying to drive our stations towards higher performance in producing generation for the company, as well as for the Province of Ontario. But because we always have these big one-time events that seem to be occurring, it would be inappropriate and inaccurate to submit a forecast without something like this in it.
>
> So that is why we are trying to drive our nuclear organization to better performance, but at the same time want to create a realistic and reliable forecast that the rest of the company and the IESO and everyone can rely upon.[21]

OPG also argued that "it is in the interest of the people of Ontario that OPG provide incentives to its employees [to] maximize production from the nuclear assets owned by the Province".[22] This benefit to the people of Ontario is presumably through greater quantities of available generation and higher revenues to the company if actual production exceeds forecast. However, this benefit is at the direct expense of ratepayers because the forecast (and therefore the payment level) ensures that the company is protected in the event the incentives are completely unsuccessful. Ratepayers would benefit directly from this incentive structure if all or some of the stretch goal was incorporated into the production forecast used for payment setting purposes. And as OPG acknowledges, the stretch goals have to be achievable to be

[21] Tr. Vol. 6, p. 83.
[22] Reply Argument, pp. 76-77.

effective. The testimony establishes that OPG does expect to achieve the higher forecast. The Board concludes a lower level of MUE should be adopted into the forecast because the evidence demonstrates that the target production levels are viewed as achievable and OPG expects to achieve them.

OPG's MUE forecast rests on the premise that because these unforeseen events have happened in the past they will happen again. OPG claims that no reduction in the level of these events can be expected as a result of the various performance improvement initiatives which have been implemented. The Board does not find this position to be substantiated by the evidence. There may well be events which are unforeseen, but the nuclear business plan, the benchmarking efforts, and forecast expenditures are all aligned with enhancing the reliability and *performance* of the nuclear units. While the Board accepts that there may continue to be significant events which have the effect of reducing production, the Board cannot accept the position that the level of these events will be unaffected by the full spectrum of performance improvements established by OPG. The Board further notes that the Memorandum of Agreement between OPG and its shareholder states that, "OPG's top operational priority will be to improve the operation of its existing nuclear fleet." The Board concludes that it is reasonable for ratepayers to be the beneficiaries of improved performance being driven internally and by the shareholder.

The Board concludes that a forecast of 50.4 TWh for 2011 and 51.5 TWh for 2012 should be used for determining the revenue requirement. This incorporates an MUE adjustment of 0.5 TWh per year. The Board finds that this provides adequate recognition of past historic variances due to MUE and the possibility of future similar events, but also incorporates the impact of overall performance improvements, recognizes the expectations of the nuclear business and sets an incentive structure that provides benefits to ratepayers while still providing upside potential for OPG.

Finally, the Board accepts OPG's evidence that the Darlington FLR forecast is not an average of past performance, and finds that, even if an average were an appropriate method, it would not be appropriate to remove the results of 2006 given the similarly high year-to-date FLR for 2010. No adjustment will be made to the Darlington FLR. This issue is also discussed in the next section.

4.2 Nuclear Benchmarking

In the previous proceeding, the Board directed OPG to produce further benchmarking studies in its next application. In response to the Board's direction, OPG retained ScottMadden Inc. to undertake a nuclear benchmarking initiative in conjunction with the development of the 2010-2014 nuclear business plan.

ScottMadden prepared two reports. The Phase 1 report summarized the results of benchmarking OPG's nuclear operational and financial performance against external peers using 19 industry performance metrics. The Phase 2 report established performance improvement targets with the intent of driving OPG's nuclear business closer to top quartile performance. The following table summarizes plant level performance against the 19 industry performance metrics.

Table 10: Plant Level Performance Summary

Metric	Best Quartile*	Median*	Pickering A	Pickering B	Darlington
Safety					
All Injury Rate			0.73 ⇧	0.96 ⇧	1.04 ⇧
2-Year Industrial Safety Accident Rate	0.05	0.09	0.14 ⇩	0.07 ⇧	0.04 ⇧
2-Year Collective Radiation Exposure (man-rem per unit)	62.15	81.84	44.2 ⇧	95.81 ⇧	72.83 ⇧
Airborne Tritium (TBq) Emissions per Unit	48.0	101.0	101.0 ⇧	50.7 ⇧	40.0 ⇩
Fuel Reliability (microcuries per gram)	0.000001	0.000165	0.00059 ⇧	0.00159 ⇩	0.00025 ⇧
2-Year Reactor Trip Rate (# per 7,000 hrs)	0.00	0.33	1.22 ⇩	0.26 ⇔	0.00 ⇔
3-Year Auxiliary Feedwater System Unavailability	0.0014	0.0020	0.0119 ⇧	0.0040 ⇧	0.0017 ⇧
3-Year Emergency AC Power Unavailability	0.0024	0.0076	0.0081 ⇩	0.0091 ⇧	0.0020 ⇔
3-Year High Pressure Safety Injection Unavailability	0.0001	0.0037	0.0012 ⇧	0.0001 ⇧	0.0001 ⇧
Reliability					
WANO NPI (Index)	96.19	62.46	60.84 ⇧	60.93 ⇔	95.67 ⇔
2-Year Forced Loss Rate (%)	0.68	3.79	37.90 ⇩	18.19 ⇩	0.93 ⇧
2-Year Unit Capability Factor (%)	90.97	84.31	56.6 ⇩	73.17 ⇔	91.99 ⇔
2-Year Chemistry Performance Indicator (Index)	1.00	1.01	1.13 ⇧	1.25 ⇩	1.00 ⇔
1-Year Online Elective Maintenance (work orders/unit)	218	278	425 ⇧	695 ⇧	311 ⇧
1-Year Online Corrective Maintenance (work orders/unit)	4	7	14 ⇧	28 ⇧	11 ⇧
Value for Money					
3-Year Total Generating Costs per MWh ($/Net MWh)	28.66	32.31	92.27 ⇧	58.68 ⇔	30.08 ⇔
3-Year Non-Fuel Operating Costs per MWh ($/Net MWh)	18.06	21.28	82.62 ⇧	50.95 ⇔	25.10 ⇔
3-Year Fuel Costs per MWh ($/Net MWh)	5.02	5.37	2.64 ⇔	2.68 ⇔	2.62 ⇔
3-Year Capital Costs per MW DER	32.79	46.22	32.07 ⇩	32.44 ⇧	18.79 ⇔

*Panel used for WANO quartile and median data was All COG CANDU

⇧ = overall upward trend during reporting period

⇩ = overall declining trend during reporting period

⇔ = consistent performance during the reporting period

Green = best quartile performance/max NPI points achieved if applicable
White = 2nd quartile performance
Yellow = 3rd quartile performance
Red = lowest quartile performance

Source: Exh. F5-1-1, Table 2

The ScottMadden Phase 1 report identified three key metrics (of the 19 benchmarked) and OPG's rank with respect to the comparators:

- World Association of Nuclear Operators Nuclear Performance Index: OPG ranks 17th out of 20
- Unit Capability Factor: OPG ranks 18th out of 20
- Total Generating Cost per MWh: OPG ranks 16th out of 16

The evidence and the testimony of OPG witnesses and Mr. John Sequeira of ScottMadden Inc., addressed the implementation of a gap-based business planning process to drive improvements. OPG has developed initiatives to close performance gaps between it and its industry peers. OPG has implemented a top-down approach to set operational and financial performance targets and generation targets. Under the top-down approach, performance gaps are identified relative to comparators; targets are set by management and communicated down to the business units which are requested to define ways to close the gap. In contrast, under the bottom-up approach, business units develop their business plans which are rolled up to the company level. OPG stated that the top-down business planning is a new commitment that establishes limits on cost and sets expectations for production that directly impact the nuclear payment amounts.

OPG submitted that the benchmarking methodology employed by ScottMadden is reasonable and should be accepted by the Board. In addition, OPG is of the view that the benchmarking results and the targets chosen are appropriate and by adopting the recommendations of ScottMadden in the Phase 2 Report, including top-down gap-based business planning, OPG has responded fully to the Benchmarking Reports and the Board's direction in EB-2007-0905.

OPG further submitted that the combination of the site and support unit initiatives, along with the fleet-wide initiatives, ensured that the 2010 - 2014 business plan operational and financial targets established during the ScottMadden Phase 2 target setting were maintained and/or exceeded.

Board staff, AMPCO, CME, PWU, SEC and VECC filed submissions on the benchmarking initiative and addressed the following areas in some detail:

- Comparators;
- Forced Loss Rate;

- Continuous Improvement
- Radiation Protection Pilot; and
- Staff Level Benchmarking.

<u>Comparators</u>

OPG identified that in selecting all North American nuclear plants as peers, including those using pressurized water reactor ("PWR") and boiling water reactor ("BWR") technology, the benchmarking peer group was expanded beyond that used in the benchmarking study that was filed in EB-2007-0905. OPG also believes that there are a number of key drivers such as unit size, single unit versus multi-unit stations, age of reactors and technology differences that assist in explaining relative performance. In regard to technology differences, OPG stated that CANDU technology may result in specific cost disadvantages related to the engineering, operating and maintenance costs as compared to PWR and BWR. Whether the disadvantages exceeded the advantages was a matter of dispute.

PWU submitted that the comparator group chosen by ScottMadden is not comparable to OPG due to the unique technological differences of CANDU and therefore it is inappropriate to employ top-down planning based on a flawed external benchmarking exercise. PWU further argued that benchmarking must focus on cost factors that are within the control of management and, in regard to the ScottMadden report, a deliberate decision was made to not attempt to isolate these costs.

Board staff argued that there is no evidence in this case that the disadvantages of CANDU technology exceed the advantages and therefore the CANDU technology should not be a significant consideration in assessing OPG performance against U.S. reactors. SEC stated that it was logically inconsistent for OPG to argue that its CANDU facilities are inherently more costly to operate while also stating that it is not possible to identify and quantify these costs. SEC submitted that OPG should improve benchmarking by undertaking a study of the major cost differences between CANDU and PWR/BWR facilities.

OPG responded that Board staff understated the difference between CANDU and PWR/BWR reactors. While there are advantages to CANDU including lower fuel cost and online fuelling, there are also disadvantages such as extended outage times and higher costs to address maintenance and inspections associated with fuel handling.

Board staff submitted that it would be useful to supplement the benchmarking by assessing targets for each plant against historical performance to assist the Board with its decision making. SEC submitted that the next phase of benchmarking should remove outliers and include analysis of unit size, age and refurbishment status. CME supported SEC's submission. OPG maintained that it has to balance a number of factors and cost is only one of them.

Forced Loss Rate

The Phase 1 report identified that Darlington's two year FLR average was 0.93%. OPG's target for Darlington FLR is 1.5%. SEC and Board staff submitted that OPG's target, which is based on historical data, should be adjusted to exclude the outlier of 3.2% in 2006. Board staff submitted that the FLR target should be 1.1% while SEC submitted that the FLR should be 1.0%. Board staff further submitted that an FLR exceeding 1.1% does not represent "continuous improvement" and that the Board may wish to consider removing $14 million from the revenue requirement.

In reply, OPG stated that the targets were not based on historical averages, but based on recent performance and plant material condition. OPG also stated neither Board staff nor SEC offered any reason why the actual results for 2006 should be ignored. While 2006 is higher than other recent years, 2008 was considerably lower, and the purpose of averaging is to smooth the impacts of both high and low years. OPG further submitted that Board staff and SEC did not take into account the most recent 2010 forecast of 3.5% (based on eight months of actual data) and, in light of this result, 3.2% cannot be considered an outlier. OPG stated that 1.5% does represent a substantial improvement. The Board decision on FLR is also addressed in the production forecast section in this Decision at section 4.1.

Continuous Improvement

Whether the targets represented continuous improvement was an issue because the Memorandum of Agreement that OPG has with its shareholder, and which is found at Appendix G, states:

> OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against nuclear plants worldwide as well as against the top quartile of private and publicly-owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

The Board staff submission questioned whether the Darlington FLR and Total Generating Cost targets represented continuous improvement as referred to in the ScottMadden Phase 2 report and OPG's Memorandum of Agreement, particularly given OPG's ranking in the industry of 16th out of 16 for Total Generating Cost.

OPG replied that Board staff's focus was too narrow. OPG stated that Board staff focused on value for money metrics while there are nineteen benchmarking measures.

Radiation Protection Pilot

In order to demonstrate how detailed top-down staffing analysis can be used to identify and drive staffing reduction, ScottMadden piloted an analysis using OPG's Radiation Protection Function. This involved: (a) identifying initial top-down benchmark targets based upon Electric Utility Cost Group ("EUCG") data and Bruce Power staff levels, (b) defining current OPG activities by position, (c) identifying the FTEs associated with each activity, (d) benchmarking these activities against peer companies, and (e) developing estimates of potential OPG future staff levels. Based on the analysis, ScottMadden recommended a potential reduction of 48 FTEs, comprised of 35 being reassigned and 13 eliminated altogether. OPG responded by reassigning 35 staff and eliminating one FTE.

Board staff submitted that ratepayers should not bear the cost of OPG's choice to retain employee positions that the expert consultant identified were not necessary. CME supported this position. OPG replied that the $2.2 million per year reduction advocated by Board staff fails to recognize that one of the 13 positions was eliminated. OPG also stated that the recommendation was held in abeyance pending further study of Pickering A and B consolidation as well as incremental work associated with the alpha contamination industry issue which arose in the last 6 to 8 months.

Staff Level Benchmarking

Board staff quoted from the Phase 2 report at page 26 in the staff submission,

> The results of both the EUCG and the Bruce Power functional comparison showed that overall OPGN staff levels per unit exceed both the industry median and Bruce Power levels… For the most part, however, OPGN staff levels are generally higher than the comparison panels.

Staff also referred to the Navigant report filed in the previous proceeding which found OPG's 2006 staffing levels to be 12% higher than benchmark. Staff submitted that an updated benchmarking report should be filed with the next application and that the Board should direct OPG to file a similar staffing analysis undertaken by ScottMadden

(Appendix G of the Phase 2 Report). OPG stated it considers Total Generating Cost to be the key metric and that staffing and remuneration are factors that drive cost. OPG argued that it was the company's responsibility to decide what evidence to produce to support its application, and in its view Board staff had not shown why filing the staffing analysis should be directed by the Board.

Board Findings

The Board accepts the benchmarking methodology and finds that the ScottMadden reports were conducted objectively and based on considerable expertise and experience in these types of studies. The evidence demonstrates that benchmarking can be conducted for an entity such as OPG. While there are differences between OPG's circumstances and those of its comparators, the entities can be compared and appropriate conclusions can be drawn. OPG's own shareholder expects such comparisons (as identified in the Memorandum of Agreement), and the Board identified the importance of this type of analysis in the prior payment amounts decision. Benchmarking analysis can assist the Board in assessing the reasonableness of OPG's expenditure proposals.

While suggestions were put forward for improvements in the benchmarking parameters and comparators, there was no clear consensus on whether these changes would improve the quality of the methodology or the study. The Board directs OPG to continue undertaking the benchmarking work and to produce a report to be filed with the next cost of service application. By keeping the methodology and report format consistent, the Board will be able to identify the progress OPG has made in improving its performance relative to the peer group.

The Board will not direct that OPG conduct a study on the differences between CANDU and PWR/BWR technologies, but as OPG itself acknowledges, it is the company's responsibility to decide what evidence to produce to support its application. OPG may wish to consider whether a study of the major cost differences between CANDU and PWR/BWR would facilitate the review of its application on the issue of cost differences between the various technologies.

The actual results of the benchmarking study show that OPG's performance falls far short of what ratepayers should reasonably expect. On all three key metrics in the Phase 1 report OPG ranked last or very close to last. The Board acknowledges OPG's enthusiasm in adopting the top-down approach to budgeting and the commitment to continual improvement in performance. However, the evidence to date has shown limited results. The Radiation Protection Pilot, the cost consequences of which have been captured in Section 6.1, Compensation, is a case in point. An opportunity for increased efficiency was identified but was not fully implemented. This may be a function of timing in terms of how long it takes to implement changes but is nonetheless evidence that only limited progress has been achieved despite OPG's stated commitment to continual improvement. The Board will direct OPG to conduct an examination of staffing levels as part of its next benchmarking study. As OPG works towards improving its overall cost performance the Board wishes to monitor developments in the area of staffing, as well as compensation and operational performance.

With respect to the targets, the Board has already decided (in the context of the production forecast) not to adjust the Forced Loss Rate forecast. Although the Board accepts the forecast target, there is considerable room for improvement as demonstrated by OPG's historical FLR in the Phase 1 report, and the Board expects to review in the next application the initiatives OPG has taken and intends to take to improve the FLR.

The Board will make no adjustments to the OM&A forecasts directly as a result of this benchmarking work. However, the Board's findings with respect to compensation are based in part on the benchmarking evidence. This is discussed more fully in Chapter 6.

4.3 Nuclear OM&A

The test period OM&A forecast is summarized in the following table.

Table 12: OM&A Summary – Nuclear

$ million	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Base OM&A	$1,204.9	$1,252.4	$1,216.5	$1,187.0	$1,192.3	$1,219.8
Project OM&A	111.6	136.5	143.7	143.8	135.9	132.2
Outage OM&A	215.6	196.1	254.8	284.6	214.8	201.1
Generation Development OM&A	11.8	34.1	79.5	40.5	5.9	4.5
Allocation of Corporate Costs	240.7	237.6	234.5	247.0	249.2	252.3
Allocation of Centrally Held Costs	210.2	132.2	58.8	171.0	199.0	234.3
Asset Service Fee	33.2	28.8	27.2	24.6	24.1	23.7
Total OM&A	$2,027.9	$2,017.7	$2,015.0	$2,098.6	$2,021.2	$2,067.9
Fuel	$113.0	$149.9	$172.6	$201.9	$235.6	$261.7

Source: Exh. F2-1-1 Table 1

Base OM&A is the main cost component for operations and maintenance of the nuclear facilities. Base OM&A also includes labour costs for planned outages and the cost of all forced outages. OPG stated that base OM&A has been reduced significantly noting a decline of $32 million between 2008 actual and 2012 forecast. OPG also stated it has made significant operational and cost improvements which have been demonstrated since the previous application, with cumulative work-driven cost savings of $260 million for the 2010 - 2012 period. In addition, 2012 regular staff levels are forecast to be below 2008 levels by 689, while non-regular staff FTEs will be reduced by 559. OPG noted that these reductions are due to the seven key initiatives that form part of the 2010 - 2014 nuclear business plan and other cost control measures.

Project OM&A includes the costs related to portfolio projects and non-portfolio projects such as Pickering B Continued Operations. OPG stated that there have been significant reductions in portfolio OM&A due to an increased focus on cost control and reprioritization of project work.

Outage OM&A levels depend on the number of specific outages in a given year. The test period outage OM&A is significantly lower than the levels spent in 2009 and 2010, when vacuum building outages were undertaken at Darlington and Pickering.

Board staff and intervenors focused on three issues: Base OM&A, Pickering B Continued Operations and nuclear fuel. These are addressed below.

4.3.1 Base, Project and Outage OM&A

Board staff questioned OPG's assertion that 2012 base OM&A costs are forecast to be below 2008 with cumulative work driven cost savings of $260 million for the 2010-2012 period. Staff noted that OPG only identified adjustments that were in its favour in arriving at the $260 million figure, as only cost increases were included to normalize the results. Board staff also observed that there was OM&A underspending (compared with approved levels) in 2008 and 2009 of $67 million.

Board staff also submitted that it was unable to confirm OPG's FTE reductions evidence, suggesting to Board staff that the reductions were overstated. One of the contributors to this difficulty in confirming FTE reductions is OPG's practice of using headcount for historical periods and FTE for the future test period. Board staff also questioned the appropriateness of using 2008 as a comparator year given the costs and staff vacancies that were deferred from 2007 to 2008 which contributed to a base OM&A increase of $47.5 million from 2007 to 2008.

CME agreed with Board staff that OPG does not appear to have achieved work-driven savings of $260 million and noted that the Board should be particularly concerned by the historical trend of OPG's Base OM&A decreasing in 2009 and 2010, followed by material increases in the test years.

OPG replied that its evidence clearly shows a downward trend from 2008 to 2012 on a normalized basis. OPG maintained that when the 2010-2012 data are properly adjusted, there is a $260 million savings when compared with 2008. OPG replied that it chose 2008 as a comparator year because it was the first year of regulation, and 2008 was not chosen to make the test period forecast appear more favourable.

In reply, OPG presented data from three sources and concluded that the FTE reductions from 2008 to 2012 are 643 and not 443 as stated in the staff submission. OPG noted that the restated FTE reduction of 643 is not much lower than the 689 provided in the application.

SEC submitted that the Darlington OM&A budget should be reduced to meet a non-fuel operating cost of $25.10/MWh, stating there is room to manage staffing. SEC submitted that this would reduce the revenue requirement by $40 million. OPG replied that the interrogatory responses that SEC was relying on were not all presented on the same basis and that other post employment benefits were not included consistently.

SEC submitted that base OM&A should also be reduced by $10 million, or 1% of labour costs, to reflect the difference between the standardized labour rates used for calculating the budget and the actual labour costs. OPG responded that the submission is not consistent with the evidence. OPG referred to testimony to the effect that there will always be a variance with respect to the standard labour costing process.

SEC also submitted that OPG should develop a plan to achieve a non-fuel cost target of $40.00/MWh for Pickering A and B, but did not suggest a specific OM&A reduction for Pickering. AMPCO submitted that the 10% base OM&A disallowance for Pickering A from the previous case did not impair OPG’s ability to operate Pickering A safely and that the costs related to the operation of Pickering A continue to be excessive. AMPCO therefore submitted there should be a further 10% reduction in base OM&A for the test period for Pickering A. OPG replied that AMPCO’s submission has no basis in the evidence and is arbitrary. OPG further argued that it has implemented a more aggressive business planning process, including aggressive targets for Pickering A operation and maintenance costs.

Board Findings

Despite the disagreements amongst the parties as to the extent of OPG's claimed savings to date, the Board concludes that OPG has made progress in controlling costs and the growth of costs, but the benchmarking evidence and compensation evidence demonstrate that further progress is warranted. Rather than selecting specific cost per MWh targets for each of the stations, the Board has focused its attention on compensation costs. Compensation costs are one of the key drivers of OM&A expenditures and hence overall cost performance. That issue is addressed in Chapter 6. The Pickering B Continued Operations project is addressed separately below.

The Board will make no additional adjustments to the forecast Base, Project or Outage OM&A levels, with one exception. In its Impact Statement filed on September 30, 2010, OPG identified a $13 million increase over the test period for Canadian Nuclear Safety Commission ("CNSC") fees. OPG did not request recognition of this increase because it is largely offset by a freeze on management salaries. However, the Board is adjusting the provision for compensation costs in Chapter 6 and is including the impact of the management wage freeze in that adjustment. The Board will therefore allow the increased cost associated with CNSC costs as well.

4.3.2 Pickering B Continued Operations

OPG has proposed a continued operations program to extend the life of the four units at Pickering B from 2014-2016 to 2018-2020. OPG noted the program must be undertaken in the test period or the units will start to close and the potential benefits will be lost. There is also the consideration that OPG does not plan to operate the two units at Pickering A with Pickering B shut down due to significant technical and economic challenges. Therefore extending the service life at Pickering B until 2020 will allow the two Pickering A units to operate until at least 2020.

OPG stated that the project is covered by O. Reg. 53/05 section 6(2)4 as the program will increase output, and OPG has requested variance account treatment. The program includes maintenance to improve plant condition, inspections, some feeder replacement and the fuel channel life cycle management project.

In the project business case, OPG estimated that the project will cost $190.2 million, all of which is OM&A. The test period costs are $92.9 million. However, OPG acknowledged that it had double counted the cost of the fuel channel life management project ($8.8 million), and therefore the forecast is actually $84.1 million. The business case analysis indicated that the project has a net present value of $1.1 billion ($2010). OPG has assigned a medium level of confidence to achieving the expected four years of additional life. Accordingly, OPG's Depreciation Review Committee has not proceeded with approval to extend life for depreciation purposes. PWU and the Society supported OPG's position.

CCC submitted that it would be premature for the Board to approve the project at this time and suggested that the need and economics should be considered within the context of the Ontario Power Authority's ("OPA") long term supply plan which will come before the Board for approval. Energy Probe submitted that it had low confidence in the success and good performance of the project and stated its preference to have the project funded by a private shareholder. In reply, OPG repeated that the work must be undertaken in the test period as otherwise the units will start to close in 2014.

Board staff questioned the costing of the Pickering B Continued Operations project. Outside of the admitted double counting for the fuel channel life management project, staff questioned the range of cost estimates in the public domain of $190.2 million in the application and $300 million in other OPG documents as well as the lack of contingency in the $190.2 million figure. OPG dismissed Board staff's concerns in Reply Argument, stating that, "For some reason Board staff is unable to distinguish between numbers that appear in press releases and sustainability reports and the testimony of the senior OPG executive that is actually accountable for the project." [23] OPG asserted that the cost of $190.2 million is OPG's best estimate.

Board staff also questioned the estimated benefits associated with the project and recommended that OPG provide an independent analysis of the project to support future cost recovery. For example, staff submitted the use of a price of approximately $50/MWh is inappropriate in assessing Pickering relative to replacement generation and that the appropriate figure to use is Total Generating Cost. Staff also questioned the assumed unit capability factors since they were much higher than the actual unit capability factors at the Pickering stations. SEC agreed with Board staff that the

[23] Reply Argument, p. 201.

benefits of the project appear to be over stated. SEC submitted that OPG should curtail further spending until an independent analysis of the benefits is carried out.

OPG argued that no parties provided competing analyses of the benefits. In OPG's view, references to the assumptions used in its analysis were selective and it is clear that the OPA supports the test period expenditures. OPG further submitted that using Total Generating Cost for the benefits analysis should be rejected since it includes costs that will exist notwithstanding the shutdown of Pickering. With respect to unit capability factors, OPG noted that it had performed a sensitivity analysis with varying levels of unit capability factors and the net present value is significantly positive even for the lower end of the range.

Board staff argued that, given the confidence expressed by OPG's witnesses that the project will come in on budget and that no contingency is required, there should be no need to use the capacity refurbishment variance account. If the Board has discretion, staff recommended that the Board restrict the use of the account to those costs that are not routine OM&A activities (i.e., the fuel channel life cycle management project). Staff also noted its concerns that OPG stated it is counting on the variance account to the extent a contingency is required. AMPCO supported the approach proposed by Board staff. OPG maintained that the entire project is clearly within the scope of the account. OPG noted that even work for which there is high confidence can have a variance. Further, if the project comes in under budget, excluding it from the variance account would mean that ratepayers would be denied a credit.

Board Findings

The Board approves $84.1 million in costs for Pickering B Continued Operations in this test period.

In this proceeding, the Board is of the view that its role is limited to determining the following:

- whether the planned spending on the Pickering B Continued Operations in 2011 and 2012 is reasonable based on the business case; and
- whether OPG's decision not to extend the end of life for Pickering B for accounting purposes is reasonable. This issue is addressed in Chapter 8.

The Board will consider spending for years beyond the current test period in OPG's next application, at which time there will be examination of the progress to date and an assessment of project economics and the company's confidence level on the basis of that experience and more current information.

With respect to the planned spending during the test period, the Board has determined that the proposed O&M budget is reasonable, except for the double counting of the fuel channel life cycle management project which will be corrected. The Board is satisfied that the business case substantiates the reasonableness of test period expenditures. However, the Board does have concerns with respect to the analysis. Parties have raised a number of other issues regarding the specifics of the benefits analysis, including the unit capability factors, the price used for comparative purposes and the absence of a contingency component in the cost estimate. The Board expects OPG to address these issues more fully in its next application when the Board considers the next segment of spending, as well as any variance in the account. In seeking to provide the best evidence, OPG should consider seeking an independent assessment by the OPA to be filed with its next application.

With respect to the operation of the variance account, the Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to Pickering B Continued Operations as the project is designed to increase output of a generating facility to which O. Reg. 53/05 applies.

Although this project is to be funded entirely through operating expenditures, it has many similarities with a capital project because O. Reg. 53/05 requires the tracking of any variances through the operation of the capacity refurbishment variance account. In the normal course, for projects funded through operating expenditures, the company would bear the risk of budget variances and would therefore need to manage the costs within its overall revenue envelope. For this project, however, any variances will be captured in the variance account for later prudence determination by the Board. The Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the prudence of any incremental expenditure (over the approved level for the test period) the Board will consider whether OPG might prudently have offset the cost increases through cost reductions or cost deferrals elsewhere in its operations.

4.3.3 Nuclear Fuel

The nuclear fuel cost forecast is $235.6 million for 2011 and $261.7 million for 2012. OPG's current contract mix is 25% indexed contracts (base price plus escalation at time of delivery) and 75% market related contracts (based on market price at time of delivery). OPG's supply contracts are summarized in the following table.

Table 13: Summary of Existing Fuel Contracts (as of Dec 31, 2009)

Contract	Contract Negotiation	Date of First Delivery	Delivery Period	Total Quantity (000 kgU)	Pricing: MR = Market Related COMB = Combination of MR & Indexed
A	2006 1st half	2007	7 Years	1,462	MR
B	2006 1st half	2010	6 Years	1,154	COMB
C	2006 1st half	2011	5 Years	385	COMB
D	2007 2nd half	2009	9 Years	1,154	COMB

Source: Exh. F2-5-1, Chart 3

OPG asserted that its procurement process balances security of supply with quality and price. Submissions were filed on procurement practices and the nuclear fuel variance account.

Board staff submitted that OPG's fuel procurement strategy needs to be better balanced, with greater emphasis on minimizing cost. Staff pointed to the 30% decline in the market price in uranium in the last two years and noted that OPG's costs have increased 35% in the same period. Staff questioned the prudence of contracting for three to four years of supply within about one year, when OPG stated that only two years of supply is required. Staff also argued that it appears the lack of emphasis on regularly entering the market and minimizing fuel costs contributes to the "disconnect" between uranium prices and OPG's fuel costs discussed in the application. CCC and CME, SEC and VECC made similar or supporting submissions. CCC and VECC also proposed that there be a third party assessment of OPG's procurement strategy.

OPG responded that the benchmarking results demonstrated that OPG's fuel costs per MWh are lower than any other nuclear operator in the comparator group and that the absolute increase in fuel cost is due to a higher forecast production. OPG further noted that although uranium prices have declined from their peak, they remain substantially above levels seen prior to 2005.

OPG noted that the procurement strategy was reviewed by an external party in 2007 and the report was filed as an undertaking response. OPG maintained that the strategy was approved by the Board in the last proceeding and the only difference now is that parties are using hindsight to suggest that other strategies are appropriate. OPG did express its willingness to undertake another external review of nuclear fuel procurement as long as the funding is maintained in the regulatory affairs budget.

Board staff argued that the current structure of the nuclear fuel variance account does not provide appropriate incentives to minimize nuclear fuel costs and instead provides an incentive for OPG to over-forecast fuel costs. Board staff also noted that when this variance account was established, staff's understanding was that it was to ensure that both consumers and OPG would be held harmless to the extent actual fuel costs differed from the OPG forecast. Nuclear fuel inventory is reflected in rate base as part of working capital. Board staff submitted that OPG would over earn if the Board approves a larger amount for nuclear fuel in working capital than OPG actually uses in the test period. Staff noted that OPG's nuclear fuel inventory was overstated by $27 million during the previous test period and that therefore OPG benefitted financially.

Board staff submitted that the nuclear fuel variance account should be restructured to capture changes in nuclear fuel inventory and to establish a sharing mechanism that is favourable to ratepayers. CCC, CME and SEC supported these recommendations. VECC submitted that the asymmetrical sharing mechanism proposed by Board staff required further analysis. As an alternative to restructuring the existing variance account, VECC proposed that the Board approve a sub-account or separate account for the variance related to fuel inventory in working capital. AMPCO submitted that the account balances should be recalculated since the beginning of the Board's oversight of OPG.

OPG replied that parties provided no evidence to support their claims that the nuclear fuel variance account is a disincentive to cost control. OPG argued that the main driver of the variance was actual production being lower than forecast. OPG maintained that the increase in fuel cost in the test period is related to increases in the price of uranium, processing and higher nuclear production.

OPG argued that Board staff's proposal for a sharing mechanism presents a significant business risk to OPG and is contrary to the creation of just and reasonable rates. OPG also argued that using the existing variance account or creating a new one to address the perceived over-recovery due to nuclear fuel inventory in rate base is too complex to do accurately.

Board Findings

The Board accepts the forecast of fuel costs for 2011 and 2012, and will increase the forecast by $9 million in recognition of the increased production forecast the Board has set.[24]

The Board has determined that a variance account for nuclear fuel costs is not an appropriate way to incent OPG to look for the most efficient portfolio of contracts for nuclear fuel procurement. Nuclear fuel is one of the inputs which OPG must manage, and other than the fact that the Board approved a variance account in the last proceeding, there is no particular reason why this type of cost should be treated as a pass through. The Board has determined that it is more appropriate for the company to bear the risk that the forecast is inaccurate, than for ratepayers to do so.

In the next proceeding, the Board will examine OPG's procurement program to determine whether the company is optimizing its contracting in order to minimize costs to ratepayers. The Board will therefore direct OPG to file an external review as part of its next application.

4.4 Nuclear Capital Expenditures and Rate Base

OPG's forecasted capital expenditures for the nuclear facilities, including the Darlington Refurbishment Project ("DRP"), are $296.9 million in 2011 and $447.4 million in 2012. A break-out, including historical planned amounts and actual expenditures, is set out in the following table.

Table 14: Nuclear Capital Expenditures

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Project Portfolio	$186.4	$172.0	$163.5	$172.0	$159.4	$171.9	$172.0	$172.1
P2/3 Isolation	9.3	17.0	5.7	10.0	14.1	8.8	0.0	0.0
Minor Fixed Assets	11.5	17.8	14.2	16.8	17.0	20.2	19.7	19.5
Pickering B Refurbishment	0.0	0.0	0.0	148.8	0.0	0.0	0.0	0.0
Total Operations	**207.2**	**206.8**	**183.4**	**347.6**	**190.5**	**200.9**	**191.7**	**191.6**
Generation Development*	**0.0**	**0.0**	**0.0**	**0.0**	**1.0**	**72.9**	**105.2**	**255.8**
TOTAL NUCLEAR	**$207.2**	**$206.8**	**$183.4**	**$347.6**	**$191.5**	**$273.8**	**$296.9**	**$447.4**
Note: * Darlington Refurbishment Project								

Source: Exh. D2-1-1, Tables 1 and 2, Exh. D2-1-1, Tables 4a-c

[24] Exh. L-5-25

OPG stated that total project portfolio, including both capital (shown in the table above) and OM&A expenditures, in the test period is $280.3 million in 2011 and $283.2 million in 2012, and that these amounts are consistent with OPG's target annual reinvestment levels of $25 million to $30 million per nuclear unit. The generation development capital reflects the expenditures related to the definition phase of the DRP and the Darlington Campus Master Plan.

In response to the Board's direction in the prior decision, OPG provided a more detailed explanation of the treatment of the Pickering 2/3 Isolation project costs. There were no submissions from parties on this matter.

OPG is seeking approval of a rate base for its nuclear facilities of $4,041.3 million for 2011 and $4,150.8 million for 2012. The proposed amounts reflect $175.5 million and $186.6 million of in-service additions in 2011 and 2012, respectively. OPG's historical and proposed rate base is set out in the following table.

Table 15: Nuclear Rate Base

($ million)	2007 Actual	2008 Approved	2008 Actual	2009 Approved	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Gross Plant at Cost	$4,321.1	$4,525.5	$4,499.0	$4,733.2	$4,679.5	$5,355.3	$5,672.7	$6,047.7
Accumulated Depreciation	1,446.1	1,737.8	1,733.1	2,037.1	2,023.7	2,278.8	2,500.5	2,745.4
Total Net Plant	**2,875.0**	**2,787.7**	**2,765.9**	**2,696.1**	**2,655.8**	**3,076.5**	**3,172.2**	**3,302.3**
Working Capital	16.0	16.0	15.9	16.0	14.3	9.2	4.0	4.0
Fuel	208.7	281.1	266.9	330.1	316.9	357.4	379.8	360.8
Materials & Supplies	400.4	424.4	415.5	441.7	434.4	468.9	485.3	483.7
Total WC/Fuel/M&S	**625.1**	**721.5**	**698.3**	**787.8**	**765.6**	**835.5**	**869.1**	**848.5**
TOTAL NUCLEAR RATE BASE	**$3,500.1**	**$3,509.2**	**$3,464.2**	**$3,483.9**	**$3,421.4**	**$3,912.0**	**$4,041.3**	**$4,150.8**

Source: Exh. B3-3-1 Tables 1 and 2, Exh. B3-4-1 Tables 1 and 2, Exh. L-1-2

OPG's proposed rate base for 2011 and 2012 also includes $125.5 million and $306.0 million respectively for Construction Work in Progress ("CWIP") related to the DRP. The issue of CWIP is addressed in Chapter 5.

The test period revenue requirement does not include any capital or non-capital costs related to new nuclear development. According to OPG, any costs it incurs related to the planning and preparation for new nuclear will be recovered from a new funding mechanism determined by the Province. If no such funding mechanism has been created, then OPG will seek to recover any costs incurred through the Nuclear Development Variance account pursuant to the provisions of O. Reg. 53/05.

No parties objected to any of the proposed capital expenditures except the DRP. This project is discussed in Chapter 5. Parties did raise objections with respect to the level of test year rate base.

Board staff argued that nuclear rate base should be reduced by a total of $128 million in 2011 and $161 million in 2012 for the following four adjustments:

- $100 million should be removed in each of 2011 and 2012 because OPG has not made any changes to prevent a recurrence of the over forecasting of rate base in 2008 and 2009. The historical overstatement of forecast rate base resulted in overearnings of $5.4 million in 2008 and $7.3 million in 2009, not including effects on taxes and depreciation;
- $6 million should be removed in 2011 and $12 million in 2012 to reflect 2010 actual rate base additions being under budget by approximately 10% or $12 million;
- $22 million should be removed in 2011 and $44 million in 2012 because the evidence is that the weld overlay project at Darlington will not proceed until after the test period; and
- $5 million for the partial deferral of the Maintenance Facility at Darlington.

CME, SEC and VECC agreed with Board Staff.

OPG's position was that the $100 million historical overstatement is based on a portion of rate base that ignores un-amortized asset retirement costs ("ARC"), which comprises more than one third of the proposed nuclear rate base. OPG argued that the positive variance in unamortized ARC would offset most of this. OPG also suggested that it had under-recovered depreciation expense in the prior years which would also serve to offset some of the rate base overstatement.

OPG submitted that the Board should apply the same reasoning as found in the Board's Hydro One 2009-2010 transmission rates decision. In that decision, the Board reasoned on the matter of revenue over-collection due to capital underspending that:

> On the other hand, there will be some level of revenue over-collection if the shortfall pertains to projects with in-service dates in the test period. However, the Board accepts that any potential over-collection is short-term in nature because rate base will be corrected in Hydro One's next application. The Board will rely on its usual manner of testing and setting rate base at the next cost of service proceeding and will not order that expenditures be tracked in a variance account.[25]

With respect to projects deferred beyond the test period, OPG's position was that these projects would be replaced with other high priority projects. Board staff questioned the prioritization process and whether this approach was appropriate in times of rising rates. OPG argued that it has a robust process for evaluating proposed capital spending and that Board staff's project-by-project focus is inconsistent with the Board's longstanding approach to reviewing levels of capital spending rather than specific projects. OPG maintained that the level of project spending has been benchmarked and is consistent with other nuclear operators. OPG also pointed out that its project spending has been constant in the period 2007 to 2012 despite increases in material and labour costs. OPG referred to the Board's decision in EB-2005-0001 which stated that it was not the Board's role to micro-manage Enbridge Gas Distribution Inc.'s capital spending plans. OPG also suggested that it is not uncommon for external factors to impact on a utility's ability to undertake a specific project. In these situations, OPG suggested that utilities will advance work from a future year.

AMPCO argued that rate base should be reduced as a result of two projects, the Darlington Change Room project, which was over budget, and the Pickering Cafeteria which was over budget and considerably late. AMPCO argued that the Board should disallow the cost overruns and that additions to rate base should be reduced.

OPG responded that AMPCO had failed to establish that OPG had acted imprudently. OPG also argued that the Post Implementation Report for the Pickering Cafeteria Project, which was relied upon by AMPCO, should not be used as the basis for a finding of imprudence because it is a retrospective review conducted with the benefit of hindsight and not information that could have been known at the time of project execution. With respect to the Darlington Change Room project, OPG pointed out that the final costs were compared with partial release amounts and that only 40% of the engineering had been completed at that stage. OPG argued that a range of +60% to -

[25] Decision with Reasons, EB-2008-0272, May 28, 2009, p. 37.

40% around a project's estimated cost is reasonable, citing the Project Management Institute in support of this proposition.

Board Findings

The Board finds that the proposed capital budget for projects entering service in the test period is reasonable. With the exception of the DRP, the Board is making no finding on the appropriateness of the capital budget for projects entering rate base after the test year. DRP is addressed in Chapter 5.

The Board will not adjust rate base going forward in response to past overstatement of rate base. Looking at total rate base, there is no established trend of over-forecasting. There may be a history of overestimating the level of new plant entering service, but no clear pattern can be discerned at this time which would warrant an adjustment going forward.

The Board notes that while financial accounting requires that ARC be included in gross plant and accumulated depreciation, it would be beneficial and would improve transparency for regulatory purposes if gross plant and accumulated depreciation for ARC were separately identified in the rate base evidence. The Board expects this approach to be taken in the next application.

Several parties argued that there should be an adjustment to capture the impact of the deferral of the weld overlay project and the maintenance facility. As a general proposition, the Board agrees that it should not be reviewing every item in OPG's portfolio, but should be focusing on the larger items, the overall level of capital spending, and whether the budget is reasonable for projects entering rate base in the test period. The Board accepts OPG's evidence that when one project is deferred, there are other projects that can be brought forward. The Board agrees that this is a reasonable approach as much of the work is undertaken by full time staff and contractors which are specifically authorized to work in the nuclear facilities. The Board accepts that OPG cannot easily ramp up or down the overall pace of work on these projects. Although some overall slippage beyond the test period may result, the Board has determined that an adjustment for the deferral of these projects is not warranted given the small amounts involved. In the next proceeding, the Board will re-examine the issue of rate base additions and the accuracy of OPG's forecasts in this area. The separate presentation of data related to ARC will assist in this regard.

The Board understands AMPCO's concerns about the overspending on the Pickering cafeteria and on the Darlington change room. However, these projects are very small compared to the overall nuclear division, and the Board is not persuaded that rate base should be reduced as a result of the cost overruns. The Board accepts OPG's evidence that there were unique attributes to these projects being built at a nuclear plant.

The Board is, however, concerned about OPG's argument that a range of +60% to -40% around a capital project's estimated cost is reasonable. This may be acceptable for relatively small projects which do not warrant a large investment in upfront detailed costing or where the variations on a portfolio basis are smaller. However, the Board does not consider the range acceptable for larger projects because it suggests a lack of adequate cost control. The Board notes that OPG is confident that the DRP (the largest current project) will have a range of $6 billion to $10 billion, a range of +25% to -25% around the midpoint of $8 billion. The Board expects OPG to do just as well on any other projects of substance. In addition to the need for rigorous cost control, the Board is also concerned that projects be assessed on an accurate analysis of the costs and benefits. A project which is reasonable on the basis of a particular cost estimate might well be unreasonable if the costs were 60% higher.

4.5 Other Revenues

OPG receives revenue from non-energy businesses and that revenue is applied as an offset to the nuclear revenue requirement. These businesses are heavy water services, isotope sales and inspection and maintenance services. The nuclear facilities also provide ancillary services as described in the Other Revenue – Hydroelectric section. The variance between forecast and actual ancillary services revenue are recorded in the Ancillary Service Net Revenue Variance Account – Nuclear.

The table below sets out the actual and forecast levels for other revenue.

Table 16: Other Revenues – Nuclear ($ million)

Revenue Source	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
NGD- Related Revenues:						
Heavy Water Sales & Processing	$30.3	$28.5	$25.5	$23.1	$17.3	$15.6
Isotope Sales (Cobalt 60 + Tritium)	7.0	10.2	7.2	9.3	9.6	11.0
Inspection & Maintenance Services	90.6	63.1	43.7	44.5	19.7	0.0
Total NGD-Related Revenues	127.9	101.7	76.4	77.0	46.6	26.6
NGD-Related Direct Costs	63.8	45.1	35.7	31.9	17.5	5.6
NGD-Related Contribution Margin	64.1	56.6	40.7	45.0	29.0	20.9
Ancillary Services	2.8	3.4	2.4	2.9	2.9	3.0
Other	1.7	0.3	0.8	0.1	0.1	0.1
Total	**$68.6**	**$60.3**	**$43.9**	**$48.0**	**$32.0**	**$24.0**

Source: Exh. G2-1-1, Table 1

The decrease in other revenues in the test period is largely the result of the reduced revenue from Inspection & Maintenance Services. The primary external customer for these services is Bruce Power. OPG and Bruce Power have agreed to terminate the service agreement effective June 2011. Parties focused their submissions on heavy water sales.

OPG proposed that effective March 1, 2011, all revenues and costs associated with the sale of surplus heavy water be excluded as an offset to the payment amounts. SEC, supported by VECC, submitted that net revenues from any sales of surplus heavy water should offset test period revenue requirement. While the surplus heavy water is fully depreciated and therefore not in rate base, SEC stated that it is still an asset on the books of the nuclear operations. In SEC's view, ratepayers paid for this heavy water – albeit prior to the Board's regulation of OPG - and are entitled to the benefits of any sales.

OPG replied that the surplus status of the surplus heavy water is an important factor to be considered. The heavy water is not required to support operations and the costs of storing and maintaining the assets are excluded from the revenue requirement. While acknowledging ratepayers had paid for the surplus heavy water, OPG referred to the

2006 ATCO decision of the Supreme Court of Canada, which stated "The payment does not incorporate acquiring ownership or control of the utility's assets."[26]

Board Findings

With the exception of revenues from heavy water sales, discussed below, the Board accepts OPG's forecast of other revenues from nuclear operations.

With respect to heavy water sales, the Board is guided by three decisions in addition to the Supreme Court's decision in ATCO, namely the decision in EB-2005-0211 (the "Cushion Gas decision")[27] and EB-2005-0211/EB-2006-0081 ("the Review Decision)[28] and the Divisional Court decision in *Toronto Hydro-Electric Systems Ltd. v. Ontario Energy Board*.[29]

First, the Board notes that the ATCO decision was not made in the context of rate-setting, a fact acknowledged by the Court itself, and in that respect is not strictly analogous to the current case. The Board's decision in EB-2005-0211, the "Cushion Gas Decision" is also relevant, but more analogous to the current case. In that case Union Gas was selling an asset that was surplus to utility requirements and would not need to be replaced. The Board determined that it did have the jurisdiction to order a splitting of proceeds. The Board further determined that a splitting of proceeds did not constitute "confiscation" (a term used in the ATCO decision) but rather was an exercise in ratemaking which could be designed to incentivize utility behaviour and protect ratepayers. The Board subsequently decided to review this decision on its own motion and ultimately confirmed the decision that the Board has jurisdiction to allocate proceeds to ratepayers for ratemaking purposes.

The Divisional Court's decision in *Toronto Hydro-Electric Systems Ltd. v. Ontario Energy Board* found that the Board's ratemaking powers gave it the authority to allocate the proceeds to ratepayers from the sale of certain properties (albeit ones that were being replaced by different properties), and noted that the Board had done so in order to mitigate the impact on ratepayers.

Revenue from the sale of heavy water is in many ways akin to any other revenue offset; in fact, that is how OPG proposed to treat it in the last proceeding and the Board

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[26] *ATCO Gas and Pipelines Ltd. v. Alberta (Energy and Utilities Board)*, 2006 SCC 4, para. 68.
[27] Decision with Reasons, June 28, 2006.
[28] Decision and Order, January 30, 2007.
[29] [2009] O.J. No. 1872.

approved it. When the heavy water was purchased and/or produced, it went into OPG's rate base. Over the years, ratepayers at least notionally paid all of the costs associated with these assets both through depreciation expenses and through the cost of capital on the amounts in rate base. In other words, rates were based on the total recovery of the capital costs, often explained as both a return of capital and a return on capital. As the assets were fully depreciated by the time OPG applied for its first payments order, the Board did not set or approve the payment amounts related to these assets. However, they would have formed part of the payments that OPG recovered from ratepayers prior to OPG's regulation by the Board.

OPG observes in its reply argument that any heavy water that is sold will be surplus, and not required to support the regulated operations. Although this is true, that does not differentiate it from other types of revenue offsets, for example, isotope sales. Isotopes produced by OPG and sold to a third party are not used to support regulated operations. Almost by definition, anything sold (whether a good or a service) and used as a revenue offset is surplus to utility operations. And yet it is the long standing practice of this Board, both for OPG and for the many gas and electricity distribution and transmission companies it regulates, to use its ratemaking (or payment making) powers to apply these revenues as an offset to the utility's revenue requirement. In some cases these offsets can have a material impact on rates. The rationale is not based on any ownership claim; rather it is based on the regulatory principle that only reasonable costs are eligible for recovery and that a reasonable level of cost is the level of cost associated with the efficient operation of the system. Therefore, if costs can be reduced by selling products or services to third parties, then ratepayers should only be required to pay the efficient level of costs, which reflects the revenue offsets from the efficient use of the assets. It may also be appropriate to provide utilities with incentives to run operations as efficiently as possible. For this reason, the revenue offsets are sometimes shared between the company and the ratepayer as a means of encouraging the company to maximize those revenue offsets – for its benefit and also the benefit of the ratepayer.

Disputes surrounding the Board's jurisdiction to use these revenues as offsets tend to focus on revenues from sales of capital assets: for example heavy water, cushion gas, or real property. From a ratemaking perspective, however, there is little to distinguish the ratepayer contribution toward capital assets from the ratepayer contribution to services sold by a utility. Although the accounting treatment is different (the costs of capital assets are recovered through rates/payments over a number of years through depreciation and a return on rate base, whereas O&M costs are expensed and recovered through rates/payments in the year they occur), the underlying costs for both the provision of services to third parties and surplus assets are borne by ratepayers. For example, OPG is only able to make isotope sales because ratepayers pay the costs associated with OPG's capacity to provide these services. In that light, no party argued that using these revenues as a revenue offset is inappropriate. However, OPG is able to provide these services because it has "surplus" resources.

The Board is therefore not convinced that there is a fundamental difference between revenues a utility earns through the sale of capital assets and those it earns through the sale of services. By using the revenue from heavy water sales as revenue offsets for the purpose of setting rates or payments, the Board is no more confiscating the capital assets of a utility than it is confiscating the labour of utility's employees when it uses revenues from isotope sales as revenue offsets. Indeed, as noted in the cushion gas decision, the suggestion that such offsets amount to confiscation or some type of ratepayer ownership of utility assets is miscast. The Board's power to set payment amounts (or rates) is a broad one. The Board must have regard to all of a utility's costs, but must also consider the utility's revenues.

The Board concludes that the same approach is appropriate with respect to heavy water sales. Namely, is there a good reason to split proceeds from heavy water sales? The Board concludes there is, both to protect ratepayers and to provide an appropriate incentive to OPG. The proceeds of the sale are an appropriate offset to the costs that have otherwise been borne by ratepayers. This offset is appropriate as it recognizes the efficient utilization of the assets and hence the efficient level of costs which are reasonably borne by ratepayers. It is also appropriate to share the proceeds with OPG in order to provide the company with an incentive to maximize the revenues. The Board orders the forecast proceeds for 2011 and 2012, as identified by OPG, to be split 50/50 between ratepayers and customers. As these amounts were provided in confidence, the Board will not disclose them in this decision. However, OPG will be required to incorporate these amounts in its preparation of the draft payments order. No variance account will be established. OPG will bear the risk associated with the level of sales being different than forecast.

5 DARLINGTON REFURBISHMENT

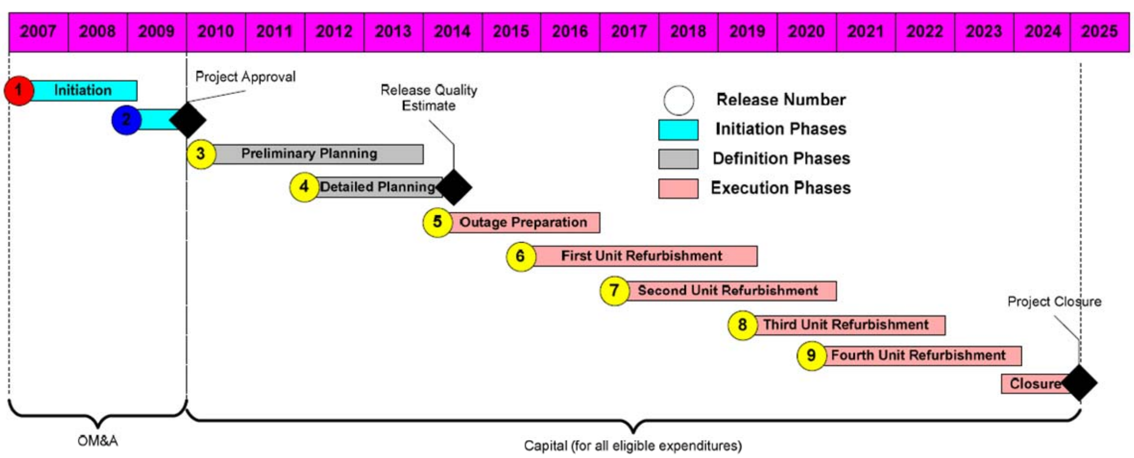
5.1 Darlington Refurbishment Project

OPG intends to refurbish the four units at Darlington and preliminary planning is underway. The refurbishment is expected to extend the operating life of the units by approximately 30 years, to about 2051.

OPG's position is that the Darlington Refurbishment Project ("DRP") is covered by section 6(2)4 of O. Reg. 53/05 because it will both refurbish the Darlington station and increase its output by allowing it to operate for a longer period.

OPG's Board of Directors approved the decision to proceed with the DRP on November 19, 2009. The Board of Directors also approved the release of funds for the definition phase of the project to complete preliminary planning and the overall timing and release strategy. Figure 1 shows the planned timeline for phases of the DRP. During the test period, preliminary planning will continue, and detailed planning is expected to begin. In 2014, following completion of the planning phases, there will be further approval by OPG's Board of Directors of the "release quality estimates" and the execution phases of the project will begin.

Figure 1: Overview of the Darlington Refurbishment Release Strategy



Source: Exh. D2-2-1, p. 10

OPG provided an Economic Feasibility Assessment of DRP as part of the application. That assessment concluded with high confidence that the DRP will have a levelized unit energy cost ("LUEC") of 6 to 8 cents per kWh ($2009). The projected cost of the DRP is in the range of $6 to $10 billion ($2009). OPG filed a letter from the OPA concurring that, at a LUEC of 6 to 8 cents per kWh, the DRP is an economic alternative to combined cycle gas turbines. OPG also filed a letter from the Minister of Energy and Infrastructure dated February 4, 2010. The Minister indicated that the government is satisfied that the analysis performed by OPG resulted in optimal decisions regarding Darlington Refurbishment and that the government concurs with the decision taken by OPG's Board of Directors on November 19, 2009. OPG indicated that it will bring forward an update on DRP and the planned expenditures and work plans for 2013-2014 in its next application.

In the current application, OPG seeks approval for the following:

- Test period OM&A costs of $5.9 million and $4.5 million in 2011 and 2012, respectively;
- Changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from extending the service life of Darlington to 2051 and the change in nuclear liabilities associated with Darlington Refurbishment;
- Disposition of the difference between forecast 2010 non-capital costs associated with DRP and the costs underlying the current payment amounts, which are a credit of approximately $23 million No objections were raised in respect of this issue and the account is addressed in Chapter 10; and
- An increase in rate base to reflect inclusion of Construction Work in Progress ("CWIP") for the DRP.

OPG's evidence was that the net effect of these requests is a reduction in the test period revenue requirement of $197.1 million. As noted in Table 14, the forecast capital expenditures for this project are $105.2 million in 2011 and $255.8 million in 2012.

Some parties questioned the extent to which OPG's Board of Directors has actually approved the DRP, and the scope of those approvals.

PWU argued that OPG is entitled to recover the cost of the DRP as prescribed by O. Reg. 53/05 section 6(2)4 if the Board finds the past expenditures were prudently incurred and future expenditures were prudently made. It is PWU's position that the test period costs are reasonable and prudent. The Society also submitted that the DRP budget should be approved as submitted. Board staff agreed that test period costs are appropriate and should be approved so that OPG can plan its work on the DRP.

Other parties indicated varying levels of support for OPG's requested approvals.

CME supported the DRP plan and urged the Board to find that OPG's evidence is sufficient to support a tentative conclusion that the DRP is likely to be economically feasible. However, CME called on the Board to make it clear in its decision that if OPG fails to objectively establish and confirm that the DRP continues to have positive economic feasibility in future proceedings the Board may require OPG to write down the value of Darlington assets for regulatory purposes.

SEC argued that the Board should approve the test period spending but suggested that OPG should aggressively limit its ongoing financial commitment in the event the project does not proceed. SEC suggested that the Board should clearly state that regardless of any approvals for spending in the test period, OPG remains at risk for the prudence of the project and the spending related to it. To address this concern, SEC urged the Board to include the following in its decision:

- OPG should be cautioned to use every effort to minimize the commitments it is making for spending beyond the test period, and to take all steps to ensure that the cost of any termination decision will be as low as possible;
- In the next payment amounts application, OPG should provide a full package of information supporting the project, equivalent to that which would be required for a leave to construct application, and should assume that no further spending will be authorized until the Board has reviewed that application. Alternatively OPG should obtain a binding legal approval for the project from another source, such as the government, if it wants further spending approvals from the Board; and
- If OPG decides not to return to the Board for 2013 rates, the company should be fully at risk for any spending and commitments in 2013 and beyond, and that barring extraordinary circumstances, no such spending will be recovered from ratepayers.[30]

[30] SEC Argument, para. 4.5.29.

AMPCO supported the exploration of a refurbishment option for Darlington but urged the Board to be clear that approval to proceed with further project definition does not constitute any kind of approval of the prudence of the project. AMPCO also questioned the reliability of OPG's cost estimates in the absence of evidence about its contracting strategies. AMPCO submitted that OPG should be required to inform the Board of its contracting and procurement plans. AMPCO cited ongoing problems with refurbishments at Point Lepreau and Bruce Power in support of its position that the Board should carefully monitor the progress and outlook of the DRP.

OPG suggested that SEC's and AMPCO's submissions amounted to micro-managing, which would put the DRP schedule at risk, could drive up project costs, and is not an appropriate role for the Board.

VECC submitted that the Board should explicitly reject any notion that its decision provides any level of approval for OPG's expenditures with respect to the DRP, as OPG has specifically said in its Argument in Chief that it is not seeking Board approval of the project. VECC also submitted that a DRP variance account be established to allow the Board to track OM&A expenses for future prudence review.

Board staff questioned the certainty of the DRP cost estimates, referring to cost over runs of previous projects. Board staff also questioned the comprehensiveness of the LUEC analysis and the depth of the OPA support as the OPA relied on OPG's economic input assumptions. CCC stated that the OPA's analysis was below the threshold of exhaustive and argued that the Board should place no weight on the OPA's support.

GEC argued that in the absence of any case supporting the economics of the project in comparison to other alternatives, the Board should not offer any assurance of cost recovery to OPG at this stage by accepting the capital budget as reasonable. GEC argued that there is no analysis to support OPG's assertion that the DRP is in the public interest. GEC submitted that, "Without a *prima facie* case that the project is likely to be in the public interest there can be no finding that the capital budget is reasonable."[31]

OPG indicated that it is not seeking approval of costs beyond the test period and so, in its view, the Board does not need to address the issue of the sufficiency of evidence for post-2012 costs. OPG submitted that what the Board should confirm in its decision is

[31] GEC Argument, p. 39.

that its approval of the test period revenue requirement impacts and accounting changes constitutes its agreement that OPG's proposed test period activities are reasonable based on the evidence. OPG further submitted that any subsequent review should only relate to the prudence of OPG's execution of test period activities and not to the prudence of having undertaken these activities.

With respect to public interest, OPG submitted that the Province has already determined that DRP is in the public interest, and referred to the Minister's letter endorsing the decision to proceed with the DRP, and the inclusion of the DRP in the Long Term Energy Plan.

<u>Results of Service Life Extension to 2051</u>

OPG proposed changes in rate base, return on rate base and tax expense resulting from the service life extension of Darlington. The major impacts of the service life extension are higher asset retirement obligation ("ARO") and asset retirement cost ("ARC"). However, due to the project end of service life of 2051, there is an overall net reduction to the revenue requirement in the test period. These accounting changes were made effective January 1, 2010.

Board staff questioned whether the definition phase of the DRP met the requirements of CICA Handbook section 3064 criteria for capitalization for projects under development since CICA Handbook section 3061 provided limited accounting guidance in this area. OPG replied that the correct reference is section 3061 and that it has properly followed the CICA guidance.

Several parties questioned whether the accounting changes were premature. Board staff noted that if the Board decided not to approve the revenue requirement impacts associated with service life extension of the DRP, this decision would introduce a separate and second set of books that would differ significantly from OPG's GAAP reporting. GEC submitted that if DRP does not proceed, the reductions in contributions to decommissioning costs will have to be made up by future ratepayers, possibly resulting in a disproportionate rate burden. GEC asserted that the revenue requirement impact of the proposed accounting changes should be not be implemented because there is no firm decision on the Darlington life extension plan.

SEC argued that the reduction in revenue requirement should not be implemented as it would be problematic in the event that DRP is later determined not to be the best generation option. As OPG has already implemented the accounting changes, SEC proposed a DRP Accounting Variance Account. Payments would be collected from ratepayers, but the equivalent of the proposed reduction in revenue requirement would accumulate in the account. If the DRP proceeds, ratepayers would be credited with the savings. OPG questioned whether SEC's proposed account could even be recognized for financial statement purposes as it would be a contingent asset, only realized if DRP did not proceed.

VECC noted that the impact of the DRP, with the CWIP in rate base removed, amounted to a credit to customers of $235.2 million of which $188.8 million is nuclear liability related. On the basis of the protection afforded OPG under the Ontario Nuclear Funds Agreement ("ONFA"), the nuclear liability deferral account and the ability to unwind the impact of depreciation rate changes, VECC submitted that the Board could approve OPG's DRP requests (with the exception of CWIP). VECC argued that if DRP does not proceed, the updated reference plan under ONFA and the operation of the nuclear liability deferral account will true up the impacts.

As noted above, OPG implemented the accounting impacts of the Darlington service life extension effective January 1, 2010. SEC and VECC argued that these changes were inappropriate. The parties argued that the changes had the effect of reducing the revenue requirement in 2010 by $64.2 million, and that this amount should be credited to ratepayers. SEC further added that the Board should declare OPG's 2010 rates interim, lest an argument of retroactivity impede implementation of the credit. OPG replied that the accounting changes with respect to ARO, ARC and Darlington life extension which took place on January 1, 2010 have been audited by external auditors. OPG characterized SEC's proposal as retroactive ratemaking.

OPG also argued that a complete reversal of these accounting adjustments would raise an issue of consistency with the Board's decision in EB-2007-0905 as it pertains to the Bruce facilities.

Board Findings

The Board agrees with OPG that section 6(2)4 of O. Reg. 53/05 applies to the DRP as it is designed to refurbish a generating facility to which O. Reg. 53/05 applies. All cost variances (both capital and operating expenses) will be captured in the account for later disposition. Therefore, the Board's mandate is to ensure that OPG recovers the costs of the DRP if the Board is satisfied that these costs were prudently incurred. However, in the Board's view this does not preclude the Board from assessing the reasonableness of the proposed expenditures before they are made. The Board agrees with OPG that the prudence review of those aspects of the work which are found to be reasonable in this proceeding will be limited to the differential between the proposed expenditures and the actual cost.

In this proceeding, the Board is of the view that its role is to determine the following:

- whether the planned capital and OM&A spending on the DRP in 2011 and 2012 is reasonable;
- whether OPG's decision to reflect the planned extension of the end of life for Darlington for accounting purposes is reasonable; and
- whether CWIP should be allowed in rate base.

Approval of the expenditures for the test period should not be taken as an acceptance of the business case underlying the entire project. Once the DRP reaches the stage of having a release quality cost estimate the Board expects to examine the reasonableness of proceeding with the project. At that time, the Board may consider establishing a framework within which prudence could be examined should the project proceed forward. Other approval mechanisms, including some form of pre-approval of future expenses, may also be considered. The Board's findings in this proceeding are not determinative of the outcome of that review.

The Board expects OPG to file updated information on its progress for examination in the next proceeding.

The Board accepts OPG's evidence that its Board of Directors has given approval to proceed with the DRP. Of course, as it is a phased project, the question of whether to continue with the project or terminate it will be addressed at each Board of Director approval stage. It remains open to OPG to recommend to its Board that the project not be continued, and it remains open to the Board of Directors to halt the project.

OPG urged the Board to find that the Minister's letter concurring with the DRP means that the DRP is, by definition, in the public interest. The Board declines to make such a finding, but is also of the view that it does not need to make a finding that the project as a whole is in the public interest in order to grant the approvals sought by OPG in this application. The Board disagrees with GEC's position that public interest must be determined before a determination on the capital budget. For purposes of this Decision, the Board's focus is on the reasonableness of the test period expenditures, including a determination as to whether they are supported by the business case. The Board also observes that nuclear refurbishment is included in the Supply Mix Directive, which is not subject to the Board's approval.

A number of parties expressed concerns about the quality of the business case for the DRP. The Board shares their concerns about the likely overall costs of the project and the ability of OPG to keep the project in the $6 billion to $10 billion range currently forecast. Quite apart from whether OPG has improved its performance, the Board has concerns because no CANDU plant has yet been refurbished on budget. Despite these limitations, the Board finds that for the purposes of approving the spending in the test period, the business case is a reasonable underpinning, and the Board approves the OM&A spending as forecast. OPG did not seek specific approval of the capital expenditures, but it did request the inclusion of CWIP in rate base and that request is addressed below. The Board does not normally give approval to capital expenditures for projects which come into service after the test period except in the case of a leave to construct application. With respect to all other capital budgets in this case, the Board has limited itself to addressing the amounts for items entering into service in the test period. However, the Board finds the forecast DRP capital expenditures for the test period to be reasonable.

If the results of the definition phase demonstrate that the costs will rise significantly, the Board expects that OPG's Board will reassess the project at that time. The Board notes the high level of confidence expressed by OPG's witnesses in the costs presented despite OPG's history of cost over-runs and the current experience with the cost overruns of refurbishments at Point Lepreau and Bruce. If there are cost overruns with the DRP, the Board does not expect OPG to suggest that they could not have been foreseen at this stage. This factor may well be considered in any prudence review.

As the DRP is a multi-year project the Board expects that in future payments cases the business case will be updated as OPG seeks further approvals for the project. The Board will therefore not require any additional reporting as requested by SEC, nor will there be any caveats placed in advance on what might happen if OPG does not file an application for 2013. As indicated in the findings related to the Pickering B Continued Operations Project, the Board is concerned that ratepayers bear a particular risk in relation to these large nuclear projects, which have a history of going over budget. In examining the project going forward, the Board will be interested in examining whether any performance incentives might be appropriate within the parameters of O. Reg. 53/05 and the variance account.

The second major issue is whether the changes in rate base, return on rate base, depreciation expense, tax expense and Bruce lease net revenues that result from service life extension to 2051 are appropriate, from a regulatory perspective.

The Board accepts OPG's evidence that the restatement of the service life extension is in accordance with the decision of the company's Board of Directors to approve the DRP, with GAAP, and as far as it affects net revenue from the Bruce lease arrangements, in accordance with the Board's decision in the previous proceeding.

The only concern with extending the service life for regulatory purposes is what the future impacts would be if a later decision was made to not proceed with the DRP, and the end of life dates were changed to an earlier date. Some parties were concerned that there might have to be large rate increases to recoup the funds not collected during the test period. The Board agrees with VECC that the impact of any future restatement can be reasonably managed, given the protection afforded the company through the ONFA, the nuclear liability deferral account and the possibility of the unwinding of the impact of depreciation rate changes. If DRP does not proceed, the inclusion of DRP in the updated reference plan under ONFA, which is expected in 2011 for the next five-year period of 2012-2016, would result in financial impacts being captured in the nuclear liability deferral account.

The Board notes that by not filing a 2010 payments case, OPG benefited from the changes in the accounting treatment of the DRP in 2010, but ratepayers did not. OPG could have sought an adjustment to the Reference Plan as a result of the changes, and that would have ensured that the revenue requirement impacts would be captured in the variance account; it is unfortunate that OPG chose not to do so. However, the Board is not prepared to accede to SEC and VECC's request to, in effect, reverse the 2010 accounting changes relating to the DRP, or to credit ratepayers with the difference that resulted. The 2010 rate year is not the subject of this application. The Board is not prepared to reopen one element of the previous decision without reviewing the entirety of the 2010 rate year.

5.2 Construction Work In Progress

OPG's application included a proposal to include Construction Work in Progress ("CWIP") for the DRP in rate base. This would result in an addition to rate base of $125.5 million in 2011 and $306.0 million in 2012. These additions to rate base would receive the approved weighted average cost of capital which would result in a revenue requirement of $11.1 million in 2011 and $26.8 million in 2012 for a total of $37.9 million for the test period. OPG also proposed that any recovery of depreciation on this capital would be deferred until the assets come into service. OPG maintained that there would be benefits to ratepayers from this proposal through rate smoothing and lower credit costs.

Two expert witnesses filed reports on this issue – Mr. Ralph Luciani of Charles River Associates on behalf of OPG and Mr. Paul Chernick on behalf of GEC. Both appeared as witnesses at the hearing.

Mr. Luciani's report was largely a presentation of examples in the US where CWIP has been allowed for the development of nuclear facilities and a discussion of their potential as precedents in OPG's situation. Mr. Luciani's report did not describe or discuss the various circumstances in which states had decided not to allow CWIP.

Mr. Chernick's report suggested that the cases in which CWIP has been allowed in the US were not applicable to OPG because the circumstances are quite different. He also reviewed the circumstances in several US jurisdictions which had decided not to allow CWIP, and suggested that they were more akin to the situation in Ontario.

OPG's position was that inclusion of CWIP in rate base is warranted in this case because it meets the criteria for qualifying investments specified by the Board in its EB-2009-0152 report, *The Regulatory Treatment of Infrastructure Investment in connection with the Rate-regulated Activities of Distributors and Transmitters in Ontario*, dated July 15, 2010 (the "Report").

OPG argued that the Board should take the criteria set out in the Report into account in evaluating the CWIP proposal and offered the following evidence in support of each:

> **The need for the project**: The Government of Ontario has endorsed the need for the project by concurring with OPG's decision to proceed with the project and by including it in the government's energy plans.

The public interest benefits of the project: The Minister's support and approval of the project is indicative that it is in the public interest. OPG noted that the Government of Ontario has indicated its support for the DRP, and that this support should be sufficient for the Board to conclude that the DRP is needed and in the public interest. OPG also pointed out that there is no provision in the Act or related regulations for the Board to grant approval for the project. While not currently obligated to undertake the DRP, OPG believes that Ontario's energy needs will require OPG to proceed with the project.

The overall cost of the project in absolute terms: The project will cost between $6 billion and $10 billion and is the largest project being undertaken by a regulated utility in Ontario.

The risks or particular challenges associated with the completion of the project: The project's risks and challenges are broadly similar to those faced by *Green Energy and Green Economy Act* ("Green Energy Act") projects, including the potential for delays, public controversy and the recovery of costs.

The cost of the project in proportion to the current rate base of the utility: The project's cost range of $6 billion to $10 billion is greater than OPG's $4 billion nuclear rate base for 2012. The upper bound of the range is greater than OPG's combined nuclear and hydroelectric rate base of $7.8 billion.

The reasons given for not relying on conventional cost recovery mechanisms: The reasons are rate shock, impact on credit metrics and the subsidy resulting from the difference between Interest During Construction ("IDC") rate and the Allowance for Funds Used during Construction ("AFUDC") rate. Rather than large increases of $350 million to $550 million in the revenue requirement when the DRP is added to rate base in 2020 and in subsequent years, the revenue requirement would increase more gradually starting in 2011. OPG's scenario would have rates increasing by 1 to 1.8% per year each year starting in 2011, rather than a few years with 5 to 10% increases starting in 2020.

Whether the utility is otherwise obligated to undertake the project: While OPG was directed by its shareholder to study the refurbishment of the Darlington units, it has not received a directive to complete the project. Pursuant to the

> Report, a utility will not have to establish that "but for" CWIP treatment, the project will not proceed.

OPG argued that the inclusion of CWIP in rate base for the DRP meets the criteria for qualifying investments specified by the Board in the Report.

OPG's case for CWIP was supported the PWU and the Society. The PWU submitted that this proceeding is not the forum to re-hear arguments about the appropriateness of alternative regulatory mechanisms but whether the alternative mechanisms contemplated by the Report should be applied in the case of the DRP. PWU criticized Mr. Chernick's evidence as a re-argument of matters decided in the Report rather than a consideration of the merits of the case presented by OPG.

Other parties, including Board staff, submitted that the Board should deny OPG's request.

First, parties disagreed with OPG's claim that the DRP falls within the scope of the Report as a qualifying investment, and that the CWIP proposal should be evaluated on this basis. These parties argued that the DRP is not a Green Energy Act related investment. They noted that the Report deals with rate-regulated activities of distributors and transmitters and that despite OPG's request during the Board's consultation on the Report, the scope of the Report was not expanded to include generation investments.

In reply argument, OPG submitted that the Report provides for the consideration, on a case-by-case basis, of applications to include CWIP in rate base in advance of a project being declared in-service. OPG sees its proposal as consistent with the Chair of the Board's statement of July 3, 2009 regarding the removal of barriers to infrastructure investment in Ontario.

Intervenors also argued that when evaluated on the basis of the factors suggested by OPG, the DRP did not warrant alternative regulatory mechanism (i.e. CWIP) treatment, arguing that:

- OPG had failed to demonstrate that significant rate shock would be avoided;
- It would be imprudent to recover costs when overall projected costs are not yet defined;

- It would be premature to grant recovery when the project lacks full authorization to proceed, as OPG's Board of Directors has only given permission to proceed with the definition phase of the project;
- The public interest would not be served since the proposed treatment is more costly to ratepayers on a Net Present Value basis;
- Proposals which front-end load costs are disadvantageous to rate-payers since ratepayers' financing costs are higher than OPG's;
- Intergenerational inequity results when ratepayers are asked to pay for costs and there is no corresponding benefit for them;
- OPG's existing credit risk has been unaffected by the DRP expenditures underway; and
- No evidence has been provided that any downward evaluations are forthcoming.

OPG argued that the Board should not consider any of the arguments regarding intergenerational inequity, the "used and useful" principle and differences in ratepayer and OPG financing costs as these have already been dealt with in the Report.

CCC and other intervenors commented that, based on OPG's own analysis, the rate shock would not be that significant, and in the meantime ratepayers will be paying for 10 years for an asset that is not yet in use.

CCC argued that OPG's concern with its credit metrics was hypothetical and unsupported by any evidence of the impact of not having CWIP. In response, OPG quoted Fitch Ratings, that "For regulated U.S. utilities, the availability of a cash return on construction work in progress (CWIP) would reduce the construction risk" and referenced Standard and Poor's observation that OPG had weak cash flow metrics. OPG stated that it is not surprising that it would not be able to quantify the impact of the DRP on its credit metrics until the Board's decision is issued, project financing finalized and rating agencies have had the opportunity to complete the assessment. OPG also pointed out that the incremental risk associated with the DRP is not reflected in OPG's current credit rating and cost of capital.

CME also observed that the timing of the request for CWIP treatment is inopportune, given the increases in electricity bills being experienced by customers, but suggested that OPG may wish to re-apply for this treatment once electricity rates have stabilized.

Board staff submitted that in the event the Board accepts the inclusion of CWIP in rate base, the return should be limited to interest costs similar to the treatment afforded Hydro One in the EB-2006-0501 decision. OPG argued that its circumstances are different from those faced by Hydro One, and so interest rate treatment should not apply. OPG submitted that as a result of this suggestion, OPG's shareholder would be subsidizing the DRP, which OPG estimates to be $200 million to $300 million.

Board Findings

The Board finds that the Report is clear that the policy could apply in other circumstances beyond the Green Energy Act and beyond transmission and distribution infrastructure. However, the Board finds that OPG's request for CWIP is premature, given that the DRP is only at the definition stage.

The Board notes that its policy, as set out in the Report, contemplates the adoption of these mechanisms in the context of an overall approval of a project, generally either through a leave to construct application or through a rates case. The Board notes that this is consistent with the approach taken by US jurisdictions that allow CWIP in rate base, other than those which allow for CWIP through legislation. As the Board is not considering the overall scope of the DRP at this time, it finds that it is premature to adopt any special treatment. The Minister's letter indicating support for the project is not sufficient for this purpose. While it may be persuasive, it does not bind the authorities that will need to approve the project. At the very least, it will require some form of approval under the *Environmental Assessment Act*, and will have to be included in the IPSP.

In filing Mr. Luciani's report in support of its position, OPG sought to persuade the Board that using CWIP to finance nuclear power plants was becoming the accepted approach in US jurisdictions. The Board allowed Mr. Luciani to give evidence despite the reservations expressed by several of the intervenors about his independence given the nature of his retainer which they asserted cast him in the role of advocate. The Board ruled that the evidence would be allowed but that it would take the nature of his retainer into account when considering the weight to be given it.

Of greater concern to the Board is the nature of Mr. Luciani's report itself. While his report did not purport to be a review of all US jurisdictions, it was a completely one-sided account of the issue as it included only those jurisdictions which had decided to allow CWIP and neglected to mention any that did not. In cross-examination, Mr.

Luciani admitted that there were many jurisdictions that had rejected CWIP as a funding mechanism. In the Board's view the contents of his report created a misleading impression about the level of acceptance of CWIP as a mechanism. The Board expects objectivity from independent expert witnesses.

In any event, the Board finds that most of the US jurisdictions that have allowed CWIP for nuclear plants have quite different circumstances than those facing OPG. The companies concerned are generally private sector operators who require incentives to build and the CWIP approvals have been granted in the context of overall project approvals. Neither of these circumstances applies to OPG.

The Board therefore gives little weight to Mr. Luciani's evidence and finds that it cannot be relied on by OPG as the underpinning for its request for CWIP.

The Board will not approve CWIP in rate base at this time. The Board is prepared to consider the proposal again in the future, but the Board will expect better evidence in support of the proposal. For example, prior to approval of CWIP, the Board would expect to see more persuasive evidence than was presented in this application as to the benefits for ratepayers in terms of improved credit metrics and rate smoothing. On the latter point regarding rate smoothing, the Board would expect to see additional evidence to support the proposition that ratepayers are better off if they begin to pay sooner for these large multi-year projects.

6 CORPORATE COSTS

6.1 Compensation

The following table summarizes historic and test period compensation levels.

Table 17: Compensation ($ million)

Organization	2007	2008	2009	2010	2011	2012
Nuclear	$1,187.90	$1,206.13	$1,265.01	$1,243.41	$1,196.23	$1,210.84
Regulated Hydro	42.29	45.14	45.47	47.87	50.36	52.73
Allocated Corporate Support	122.19	125.95	128.85	131.41	135.15	138.59
TOTAL REGULATED COSTS	**$1,352.38**	**$1,377.22**	**$1,439.33**	**$1,422.69**	**$1,381.74**	**$1,402.16**

Note1: Includes total wages, benefits, current service cost component of the Pension/OPEB costs and annual incentives.

Note 2: Does not reflect OPG's impact statement

Source: Issue 6.8, Exh. L-1-74

OPG employs approximately 10,000 staff in the regulated business, 95% of which support or are employed in the nuclear business. Of the staff in the regulated business, 90% are unionized: two thirds represented by the PWU and one third by the Society.

OPG stated that, as a result of collective bargaining, the general wage increase for the PWU and Society has been between 2% and 3% for the past number of years. As noted in the application, the forecast wage increase for each test year is 3% for management and 3% for both unions. OPG has forecast an additional 1% increase to account for step progressions and promotions for staff within the unions. OPG's labour agreement with the Society expired on December 31, 2010 and its agreement with the PWU expires on March 31, 2012.

OPG maintained that its staff must be highly skilled and noted that 73% of the positions require post secondary education. OPG indicated that these employees are in demand across the country. The OPG workforce is mature and OPG estimated that 20% to 25% will need to be replaced between 2010 and 2014.

Towers Perrin conducts a survey which compares compensation data among a variety of employers across Canada where job matches are sufficiently strong. Although OPG participates in the Towers Perrin study, the survey is not prepared specifically for OPG.

OPG used the data from the survey to prepare a chart comparing OPG's salary levels with those of other organizations in the survey. Specifically, the chart shows the variance between OPG's salary levels and the 75th percentile of the comparators for 30 positions. OPG selected the positions that were included in the chart based on its judgment of which ones were the best matches.[32] Together, these positions account for approximately 30% of OPG staff who work in the regulated businesses. The chart showed that OPG was above the 75th percentile for some positions, and below it for others, and was slightly above the 75th percentile on an overall basis.[33] OPG selected the 75th percentile as the most appropriate point of comparison (Towers Perrin provided data for the 10th, 25th, 50th, 75th, and 90th percentiles). Towers Perrin did not participate in the preparation of the chart, and did not provide OPG with advice concerning the best comparable positions, or the use of the 75th percentile as a comparator. Although the Towers Perrin survey included data on both base salaries and total cash compensation, the chart prepared by OPG used the base salary data only.

OPG maintained that the compensation for unionized employees is appropriately benchmarked at the 75th percentile of the market for companies surveyed by Towers Perrin due to the nature and complexity of work performed by OPG staff. OPG advised that the 30 positions in the survey accounted for 2,804 OPG employees. In order to bring this set of positions to the 75th percentile, $16 million would have to be removed from payroll, and in order to bring the positions to the 50th percentile, $37.7 million would have to be removed from payroll.

In response to recommendations of the Agency Review Panel,[34] management compensation has declined by 12.6% in the period 2007-2009. OPG benchmarks management compensation against the 50th percentile of market. In the impact statement filed on September 30, 2010, OPG stated that it is removing management wage escalation for the period to April 1, 2012 in response to the *Public Sector Compensation Restraint Act*. OPG proposed to offset the $12 million reduction related to management wages against the $13 million increase in Canadian Nuclear Safety Commission fees. The latter is discussed at section 4.3.1.

The Society and the PWU supported OPG's application. The Society submitted that if the Board believes that a 3% economic increase is unlikely to be granted by an

[32] Tr. Vol. 8, pp. 166-168.
[33] Exh. F4-3-1, pp. 30-31.
[34] The Agency Review Panel's June 27, 2007 report recommended changes to the way executive compensation would be determined at Ontario's five electricity sector institutions, which included OPG.

arbitrator, then it may consider the use of a variance account to capture any amount less than 3%. In the PWU's view, the Board needs to consider whether the current compensation rates for PWU represented staff was reasonable and prudent when the present collective agreement was entered into in April 2009. Regarding comparisons, the PWU submitted that simply comparing OPG compensation with other non-nuclear employers is not evidence of a lack of prudence on the part of OPG. The PWU also submitted that an assessment of compensation requires an assessment of productivity and skill level.

Board staff questioned OPG's choice to benchmark at the 75th percentile, noting that a number of positions OPG selected from the Towers Perrin survey are generic positions (i.e., labourer, warehouse supervisor). In addition, staff noted that OPG was not able to identify any positions that were exclusively related to specialized skills required of an employee working in a nuclear plant environment, because Towers Perrin did not categorize the positions in this way. Staff submitted that the rationale provided by OPG for use of the 75th percentile was not substantiated, and that the 50th percentile is more consistent with the use of the median by the Board in relation to Hydro One.[35] Staff submitted that it was appropriate to remove $37.7 million from annual revenue requirement based on moving the 30 positions to the 50th percentile. Staff also submitted that it was appropriate to reduce the revenue requirement associated with the Society wage increase from 4% to 2.5%, as this was more consistent with recent arbitration decisions entered into evidence by PWU. These arbitration decisions resulted in increases of 2%, 2.25% and 3%.

CME submitted that the Board can assume that the Towers Perrin report is likely representative of all OPG incumbents, and urged the Board to consider higher disallowances than those suggested by Board staff. CME extrapolated the Towers Perrin results to all employees and estimated reductions of $134.48 million assuming reductions to the 50th percentile. CCC supported CME's position.

SEC submitted it would be unfair to require OPG to move to the 50th percentile immediately and proposed a 25% reduction in 2011 (of the total amount required to match the 50th percentile) and 50% in 2012, amounting to reductions of $33.7 million for 2011 and $67.3 million for 2012. SEC observed that where the Board has set limits previously, regulated entities have responded favourably. SEC further proposed the elimination of the licence retention bonus. With respect to the licence retention bonus,

[35] Decision with Reasons, EB-2008-0272, May 28, 2009, pp. 28-31.

OPG maintained that it is appropriate due to the effort and resources required to retain licences and the comparable practice at Bruce Power.

OPG replied that it is bound by its collective agreements and that there is no basis for selecting the 50th percentile as the appropriate benchmark. OPG argued that skills and training requirements are extensive, even for positions viewed as generic by parties. OPG noted that intervenors relied on no evidence to support their view that the 50th percentile was the appropriate target.

With respect to the Ontario Hydro successor companies, OPG provided a wage comparison of OPG to Hydro One for comparable Society positions. Staff entered into evidence a similar comparison for certain PWU positions from the EB-2010-0002 Hydro One application. Board staff submitted that there is no justification for OPG to consistently pay its staff more than Hydro One for generic positions such as mechanical maintainer, regional field mechanic or labourer.

OPG maintained that its compensation compares favourably with the other successor companies, and that on a weighted average basis, OPG's wages are 10% lower than Bruce Power – the only other large nuclear operator in the province.

OPG noted that one Ontario Hydro successor company has undergone arbitration and received a 3% increase excluding progression and promotion. OPG argued that the Board staff position of 2.5% has no basis and that the reduction should be at most 0.5%.

As noted in the section on benchmarking, there was difficulty reviewing compensation data and trends due to OPG's use of headcount for the historical period and FTEs for the future period. Parties were generally of the view that FTEs should be used for all periods. SEC further submitted that OPG should be required to file compensation information in the format of Appendix 2K used for electricity distributors.[36] OPG responded that it would file the equivalent of Appendix 2K which is based on FTEs, to provide historical and forecast data on a comparable basis.

Board staff and SEC also submitted that OPG should be directed to file an independent full compensation study with its next application similar to the study that the Board

[36] Ontario Energy Board, Filing Requirements for Transmission and Distribution Applications, June 28, 2010.

required of Hydro One.[37] Board staff noted that, given total compensation costs of almost $2.8 billion over the test period, the cost of such a study would be reasonable.

OPG argued that an external study of compensation was not required because the study would be expensive, at a cost of about $0.5 million to $1 million, there are a limited number of nuclear operators in Canada, and OPG is bound by its collective agreements. OPG stated that if it was directed to complete a study, it would do so provided funding was allocated.

Board Findings

Compensation makes up a very significant component of OPG's total operating costs. The Board is concerned with both the number of staff and the level of compensation paid in light of the overall performance of the nuclear business. Each of these issues will be addressed separately.

The lack of comparable data (use of headcount for the historical period and FTEs for the future) make comparison and trending of staffing levels difficult. The Board must be able to see proposed staffing levels and compare those to previous period actuals. The Board therefore will direct OPG to file on a FTE basis in its next application and to restate historical years on that basis.

One of the reasons for the discontinuity between headcount and FTEs may be the extensive use of overtime, particularly in the nuclear division. The Board expects to examine the issue of overtime more closely in the next proceeding. The Board expects OPG to demonstrate that it has optimized the mix of potential staffing resources.

Despite this difficulty in comparing proposed staffing levels with past periods, the Board is of the view that OPG has opportunities to reduce the overall number of employees further as a means of controlling total costs and enhancing productivity. This was demonstrated by OPG's own evidence, as explained by OPG's witness and by Mr. Sequeira from ScottMadden, with respect to the Radiation Protection Function.[38]

The ScottMadden Phase 2 report observed that OPG's staffing levels per unit exceed both the industry median and Bruce Power, and that OPG staff levels are generally higher than the comparison panels (while noting that this may be influenced by OPG's

[37] Decision with Reasons, EB-2006-0501, August 16, 2007, p. 33.
[38] Tr. Vol. 3, p. 24.

practice of contracting out relatively few project based outage functions).[39] For this reason, the Board has also directed OPG to conduct a staff level analysis as part of its benchmarking studies for the next proceeding. (This issue is discussed more fully in Section 4.2, Benchmarking.) ScottMadden also conducted a pilot top-down staffing analysis for a single OPG function: the Radiation Protection Function. ScottMadden concluded that there was room for a potential reduction of 48 FTEs (28%) in the Radiation Protection Function, of which 13 FTEs could be eliminated altogether. Despite these findings, OPG failed to act on an opportunity to eliminate 13 FTEs, and instead eliminated only one.[40] This is only a single example concerning relatively few positions, but the Board is concerned that OPG has not acted more aggressively in a case where it has clear information that a particular function is overstaffed. Although collective agreements may make it difficult to eliminate positions quickly, it is not reasonable for ratepayers to bear these additional costs in the face of strong evidence that the positions are in excess of reasonable requirements. With 20 to 25% of staff expected to retire between 2010 and 2014, the Board concludes that OPG has a timely opportunity to review its organizational structure, taking actions to reassign functions and eliminate positions. The Board is not suggesting that a specific percentage of the retiring staff will not need to be replaced, but this may provide an opportunity for reducing the overall staffing complement without disrupting negotiated commitments with the unions.

As to the compensation, the Board finds that the compensation benchmark should generally be set at the 50th percentile. OPG suggests there is no evidence to support this conclusion, but the Board disagrees. This target level is consistent with the recommendations of the Agency Review Panel for executive employees, and indeed for management employees, OPG uses the 50th percentile as the benchmark. In the Board's view, there would need to be strong evidence to conclude that a higher percentile is warranted for non-management staff. OPG provided no such compelling evidence, but merely asserted that positions in the nuclear business required greater skills overall than the comparators. There was no documentation or analysis to support these assertions.

The evidence provided does not substantiate the assertion that the positions selected by OPG are sufficiently different to warrant the use of the 75th percentile. Although OPG stressed that its work requirements (particularly on the nuclear side) are highly

[39] Exh. F5-1-2, p. 26.
[40] Tr. Vol. 3, p. 27.

technical, the Board observes that many of the comparators in the Towers Perrin study would also require highly technical skills, and some of the comparators also operate nuclear facilities. Indeed the job classifications used in the Towers Perrin report are compared against each other on the basis that they are at least broadly speaking comparable. A number of the positions selected by OPG, such as labourer, also do not appear to be specifically related to highly technical nuclear plant work. In addition, most of the comparators were similarly large and unionized, and perform highly technical, though not necessarily nuclear plant, work. The Board recognizes that the analysis conducted by OPG to produce the chart is not comprehensive, and indeed was not likely intended to be comprehensive. Well over half of OPG's employees are not covered by the 30 positions listed in the chart. The data was not specifically prepared for the purpose of conducting a comprehensive comparison, and the data used in preparing the chart references base salary only.[41] Despite these limitations, the analysis provides sufficient evidence to conclude that for a significant proportion of OPG's staff the compensation is excessive based on market comparisons.

PWU argued that the comparative analysis, which uses non-nuclear entities, is not evidence of imprudence by OPG, and therefore there is no evidence to rebut the presumption that the expenses arising from the collective agreements are prudent. The Board does not agree.

The ratepayers should only be required to bear reasonable costs – and in determining reasonable costs the Board can be guided by market comparisons. It is the responsibility of the Board to send a clear signal that OPG must take responsibility for improving its performance. In order to achieve this, the Board will reduce the allowance for nuclear compensation costs by $55 million in 2011. This amount is derived by considering a number of factors:

- Reducing the compensation for the 30 positions from the Towers Perrin data would require a reduction of $37.7 million.
- Given the breadth of positions in the analysis and the prevailing pattern that wages are well in excess of the 50th percentile, it is reasonable to conclude that the same pattern exists for the vast majority of all staff positions in the company. There was certainly no evidence to suggest otherwise. Therefore, the total

[41] The Towers Perrin survey was filed confidentially with the Board as undertaking J8.5. The Towers Perrin Survey includes data both for base salary and total cash compensation. However, OPG appears to have used only the base salary information in preparing the chart. See Tr. Vol. 8, pp. 175-176.

adjustment to move all regulated staff to the 50th percentile is substantially in excess of $37.7 million.

- In determining the appropriate adjustment, the Board recognizes that it will be difficult for OPG to make significant savings through compensation levels alone in the short to medium-term given the collective agreements with its unions.
- OPG has already indicated that there will be no increase in management salaries through April 1, 2012, and this reduction was not incorporated into the original filing.
- The ScottMadden benchmarking analysis supports the conclusion that there is excess staff overall and that this is one component of OPG's relatively poor performance (in comparison to its peers). A further reduction in the allowance for compensation is warranted for this factor.
- The ScottMadden benchmarking analysis also demonstrates that OPG's overall performance is poor on certain key benchmarks, for example non-fuel operating costs. Compensation is a significant cost driver for this metric, and OPG's poor ranking supports the Board's decision to make reductions on account of compensation costs

The same reduction will apply in 2012, but there will also be an additional reduction of $35 million to represent further progress toward the 50th percentile, further progress in reducing excess headcount, and further progress toward achieving a reasonable level of cost performance. The total reduction for 2012 is $90 million.

While a more aggressive reduction was argued by some intervenors, the Board recognizes that changes to union contracts, to staffing levels and movement to the 50th percentile benchmark will take time. Indeed, the Board recognizes that OPG may not be able to achieve $145 million in savings in the test period through compensation reductions alone. The Board is making these adjustments so that payment amounts are based on a reasonable level of performance. If costs are in excess of a reasonable level of performance, then those excess costs are appropriately borne by the shareholder.

The Board is allocating this adjustment solely to the nuclear business for the purposes of setting the payment amounts. The Board is not ordering any reductions for the hydroelectric business because the benchmarking evidence for that business supports the conclusion that it is operated reasonably efficiently from an overall perspective, and therefore the Board is less concerned with the specific compensation levels for that part of the company. For the nuclear business the evidence is clear that overall performance is poor in comparison to its peers and the staffing levels and compensation exceed the comparators. On this basis an adjustment is necessary to ensure the payment amounts are just and reasonable.

Lastly, the Board directs OPG to conduct an independent compensation study to be filed with the next application. As noted above, OPG's compensation benchmarking analysis to date has not been comprehensive. The Board remains concerned about compensation costs, in light of the company's overall poor nuclear performance, and would be assisted by a comprehensive benchmarking study comparing OPG's total compensation with broadly comparable organizations. The study should cover a significant proportion of its positions. Compensation costs are a signification proportion of the total revenue requirement; OPG's position that such a study would be too expensive and of little value is therefore not reasonable. Consultation with Board staff and stakeholders concerning the scope of the study, in advance of issuing a Terms of Reference, is advised. The costs of the study are to be absorbed within the overall revenue requirement allowed for in this Decision. This has been already accounted for in the Regulatory Affairs budget, which anticipates studies in support of the company's next application.

6.2 Pension and Other Post Employment Benefits

Costs related to Pension and Other Post Employment Benefits ("OPEB") for the test period were forecast based on discount rates and assumptions in OPG's 2010-2014 business plan. The total amount requested for the test period is approximately $633 million. On September 30, 2010, OPG filed an Impact Statement in which it identified a significant decline in discount rates causing an increase in forecast pension and OPEB costs for the test period. Rather than revising the proposed revenue requirement, OPG requested approval for a variance account, "to record the revenue requirement impact of differences between forecast and actual pension and OPEB costs." The total forecast increase as a result of the update is $264.2 million, as summarized in the following table.

Table 18: Updated Pension and OPEB Costs ($ million)

	Nuclear		Regulated Hydroelectric	
	2011	2012	2011	2012
Pension Cost				
As per Chart 9, Exh.F4-3-1	$114.0	$162.8	$5.8	$8.1
Projection as of August 2010	210.2	245.9	10.6	12.3
Increase	96.2	83.1	4.8	4.2
OPEB Cost[1]				
As per Chart 9, Exh.F4-3-1	159.3	166.7	8.0	8.3
Projection as of August 2010	196.5	201.7	9.9	10.1
Increase	37.2	35.0	1.9	1.8
Total Test Period Increase		**$251.5**		**$12.7**

Note 1: Supplementary pension plans costs are included with OPEB costs
Source: Exh. N-1-1

Board staff submitted that it would be more appropriate for OPG to determine pension and OPEB costs on a cash basis because costs determined on that basis are more stable for ratemaking purposes than those calculated on an accounting basis. In support of its position, Board staff provided a table in its submission that illustrated pension and OPEB payments on an accounting basis as well as a cash basis. On a cash basis, the table identified a total amount of $568 million. This position was supported by CCC, CME, and SEC.

In reply, OPG noted that the Board had approved the accrual method in the previous case and argued that no evidence had been introduced on the cash method in the current proceeding. OPG pointed out that the Board staff tables did not reflect updated pension contributions for 2011 and 2012, as provided by Mercer. OPG maintained that including the updates demonstrates that the cash basis is no more stable than the accounting basis. As noted in OPG's reply submission, there are utilities regulated by the Board using the cash basis and others using the accounting basis.

Board staff further submitted that the variance account request should be denied, and its position was supported by CCC, CME, SEC and VECC. Board staff raised two materiality arguments in its submission. Staff noted that OPG had not informed its shareholder of the increased forecast cost as OPG suggested the increase was not material, and that balances in the Hydro One transmission pension variance account for the last two proceedings have not been material. On the first point, OPG replied that seeking shareholder approval before applying for a variance account is not an established requirement. On the second point, OPG maintained that there is no evidence that OPG's variances will be similar to the immaterial balances recorded by Hydro One.

VECC submitted that the Hydro One pension and OPEB variance accounts for its distribution business and its transmission business were established under specific and unique circumstances and should not be accepted as precedents by the Board. VECC maintained that the accounts are "not the result of decisions wherein the Board actually turns its mind to the appropriateness of allowing HONI to be fully protected from the risk associated with its pension cost forecasts."[42] OPG challenged this view and argued that the Hydro One decision confirmed that balances in the variance account would be subject to a prudence review.

In the previous proceeding the Board denied OPG's request for a pension and OPEB variance account. Board staff submitted that had the account been approved, an estimated $314 million credit to ratepayers would have been recorded for the period 2008 to 2010. This led staff to conclude that the request in the current proceeding should be denied because the pension and OPEB amounts included in the current application are lower than what OPG now believes it will incur in the test period. OPG responded that staff's conclusion amounts to retroactive ratemaking and further, that the staff analysis is not correct. Staff's analysis reflects a full year for 2008, but in OPG's view should reflect only 9 months. OPG also argued that staff has grossly overestimated the 2010 variance.

OPG also disagreed with the Board staff submission on pension and OPEB in three other areas:

- Board staff submitted that if the Board allows OPG to collect the forecast accounting OPEB costs, the variance should be placed in a segregated fund. OPG doubted whether the Board has jurisdiction to implement the proposal. SEC also disagreed with staff, expressing its concern with the precedent;
- Staff submitted that the undisclosed tax impact related to the amount to be tracked in the variance account is approximately $91 million. OPG responded that Board staff is incorrect in submitting that the consequences of taxes

[42] VECC Argument, para. 134.

regarding the update have not been identified, citing updates to the pre-filed evidence; and

- Board staff submitted that OPG should provide evidence that discusses alternatives to AA bond yields to forecast discount rates. In reply, OPG cited sections of the CICA handbook and asserted that the use of AA bond yields was appropriate.

Board Findings

OPG correctly points out that there is currently no consistency amongst utilities in the use of either the cash or accrual method to setting pension and other post employment benefit expenses. Both methodologies have been approved by the Board. The Board in this case sees no compelling reason to change OPG's existing approach of using the accrual method. Consistency in accounting treatment, in order to compare results year to year, is advantageous for purposes of assessing the level of costs for reasonableness. A consistent approach over time also ensures a greater level of fairness for ratepayers and the company.

The request for a variance account is denied. Pension and OPEB costs should be included in the forecast of expenses in the same way as other OM&A expenses, and then managed by the company within its overall operations. The Board finds that the forecast included in the pre-filed evidence was more rigorous because it was based on a set of internally consistent assumptions, while the update is based on the AA bond yields which will change. Accordingly, the Board finds that the allowance for pension and OPEB expenses in the pre-filed evidence is appropriate, as it is the best evidence on this matter.

The Board is reluctant to make selective updates to the evidence. The bond yields have changed, and will continue to change, as noted by the actuary in the updated statement. Further, the Board notes that the financial market conditions are variable and have indeed improved since the impact statement was filed. The Board concludes that an adjustment to the allowance is not warranted.

The Board sees no reason to depart from the use of AA bond yields at this time, with the exception of using more current data. However, OPG is directed to provide a fuller range and discussion of alternatives to the use of AA bond yields to forecast discount rates in its next application.

6.3 Centralized Support and Administrative Costs

Centralized Support and Administrative Costs include Corporate Support and Administrative Service Groups ("Corporate Support"), Centrally Held Costs and Hydroelectric Common Services that are related to the operation of OPG's business units. The costs are assigned/allocated to OPG's regulated and non-regulated businesses. The Centralized Support and Administrative Costs budget assigned/allocated to the regulated hydroelectric business totals $57.5 million in 2011 and $60.9 million in 2012. The amount assigned/allocated to the nuclear business totals $448.1 million for 2011 and $486.6 million for 2012. Details are set out in the following table.

Table 19: Allocation - Centralized Support and Administrative Costs

($ million)	2011 Plan	2012 Plan
Hydroelectric		
Corporate Support	$24.7	$26.1
Centrally Held	22.9	25.5
Common Hydroelectric	9.9	9.3
Total	57.5	60.9
Nuclear		
Corporate Support	249.1	252.3
Centrally Held	199.0	234.3
Total	**$448.1**	**$486.6**

Source: Exh. L-1-90, Exh. F3-1-1, Tables 2 and 3, Exh. F4-4-1, Tables 2 and 3

6.3.1 Corporate Support Costs

Corporate Support service group activities include Real Estate, Energy Markets, Business Services, IT, Finance, Corporate and Executive Services (Public Affairs, Regulatory/Strategic Planning, Emergency Preparedness, Law) and Human Resources. For these services OPG seeks approval for $24.8 million in 2011 and $26.3 million in 2012 for the regulated hydroelectric business, and $249.2 million in 2011 and $252.3 million in 2012 for the nuclear business. The budgeted and actual amounts for the years 2007 to 2012 are set out in the following table.

Table 20: Allocated Corporate Support Costs

($ million)	2007 Budget	2007 Actual	2008 Budget	2008 Actual	2009 Budget	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Hydroelectric	$23.3	$21.9	$28.3	$26.3	$28.9	$24.9	$25.1	$24.8	$26.3
Nuclear	$250.5	$240.7	$269.1	$237.6	$267.4	$234.5	$247.0	$249.0	$252.3

Source: Exh. F3-1-2, Tables 1 and 2

OPG filed two corporate function benchmark reports, one on Human Resources and the other on Finance. No submissions were filed on these reports.

In response to direction in the previous payment amounts decision, OPG retained Black & Veatch to review the cost allocation methodology with respect to the Board's three prong test (cost incurrence, cost allocation and cost/benefit). Black & Veatch concluded that OPG's cost allocation methodology meets current best practices and meets all aspects of the three prong test. No submissions were filed on corporate cost allocation.

Board staff commented on the Regulatory Affairs component of the Corporate Support costs. Board staff submitted that the Regulatory Affairs budget should be reduced by $2.238 million in 2011 and by $1.908 million in 2012. The Board staff submission was based on comparisons with 2008 actuals as a benchmark rate case year and 2009 actuals as a benchmark non-rate case year. Staff also submitted that there was no basis for the forecast increase in the Board's annual assessment. Board staff's position was supported by SEC and VECC and referenced by CCC in its submission.

OPG responded that the Board should reject Board staff's proposed cuts because they are based on faulty premises. OPG maintained that the 2008 Regulatory Affairs costs do not reflect all the costs related to the last application, as substantial costs were incurred and recorded in 2007. OPG also argued that the previous case is not a proxy for future proceedings because more work from other business units has shifted to Regulatory Affairs and the effort related to applications has increased. OPG noted that the next application will involve substantial issues, for example, IFRS and the Niagara Tunnel, and any studies directed by the Board in this proceeding. OPG also noted that in 2011 substantial resources will be required to assess incentive mechanisms, including stakeholder consultations. OPG also pointed out that the Regulatory Affairs budget includes costs for OPG's participation in the upcoming IPSP, IESO market rules development and OPG's strategic planning process.

CCC made submissions on the overall Corporate Support costs, arguing that they should be reduced because the costs appear discretionary at some level and there is a pattern of actual costs coming in below forecast. CCC submitted that the hydroelectric business costs should be reduced by the average of the variances over the three year period, amounting to a $2.46 million reduction for the hydroelectric allocation and a $24.7 million reduction to the nuclear business allocation.

OPG took issue with CCC's premise that OPG's historical under spending in Corporate Support warrants a cut to the amounts requested for the test period. OPG pointed to the variance explanations found in the evidence, which included the impact of Information Technology Special Initiatives, lower New Horizon System Solutions outsourcing agreement gainshare, deferrals such as the 2010 rate application, decreased advertising, one-time IT credit adjustments, and the management of staff vacancies. OPG noted that as a result of its cost control initiatives, the increase in allocated support costs in the test period is 1.2% annually, much less than the rate of inflation and expected growth.

Board Findings

The Board accepts OPG's evidence on the benchmarking studies and the cost allocation methodology.

OPG has provided credible evidence for the increase in the Regulatory Affairs costs. Accordingly, the Board will not direct any specific reduction to the Regulatory Affairs test period forecast.

The Board agrees with the submissions of CCC that there has been a history of under spending in the Corporate Support function and, in fact, the amount of under spending has been increasing from 2007 to 2009. The Board expects the cost savings impact of the efficiency improvement initiatives undertaken by OPG to be reflected in the company's forecasted budgets. History indicates that this has not been the case. However, for this test case period, the proposed budget is not unreasonable given 2009 actual spend and the 2010 budget. In addition, the Board's decision on compensation may affect total corporate support costs. For these reasons the Board will make no further adjustments to the budget.

6.3.2 Centrally Held Costs

Historic and forecast of test period centrally held costs are summarized in the following table.

Table 21: Centrally Held Costs ($ million)

Corporate Costs	2007 Actual	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
Pension/OPEB Related Costs (1)	$178.8	$116.7	$(27.7)	$118.5	$145.4	$213.1
OPG-Wide Insurance	19.1	16.3	17.0	16.9	17.4	18.0
Nuclear Insurance	7.6	7.8	7.3	8.6	11.3	13.4
Performance Incentives	40.8	45.3	40.3	45.8	46.2	46.7
IESO Non-Energy Charges	20.5	22.4	75.5	54.7	62.8	69.2
SR&ED Investment Tax Credits	0.0	(30.0)	(22.1)	(10.0)	(10.0)	(10.0)
Other	31.1	25.0	31.4	26.4	28.1	(1.4)
TOTAL	**$297.9**	**$203.5**	**$121.7**	**$260.9**	**$301.2**	**$349.0**

Note 1: Excludes current service costs included in compensation Table 17
Source: Exh. F4-4-1, Table 1

Similar to the corporate support costs, Black & Veatch reviewed the allocation of centrally held costs and came to the same conclusions.

Submissions were filed on pension and OPEB related costs, IESO non-energy charges, and nuclear insurance. Pension and OPEB costs are addressed earlier in this chapter, and IESO non-energy charges are addressed in Chapter 10. Nuclear insurance costs are addressed here.

Board staff submitted that the proposed increase in nuclear insurance costs should not be included in the revenue requirement, because the increase is based on federal government requirements which are in a proposed bill at the second reading stage. Similar bills have been introduced by the federal government numerous times in the past but all have failed to receive Royal Assent. SEC similarly submitted that it is premature to assume that nuclear insurance costs will increase and the appropriate cost level to use is the average for the last four years, $7.8 million per year.

OPG responded that it is appropriate and prudent to include the forecast nuclear insurance costs based on the proposed legislation. OPG establishes an operating budget through the annual business planning process, and it must operate within this budget. OPG stated that the timing related to the increase in nuclear insurance costs is uncertain, but that the forecast represents OPG's best estimate.

Board Findings

The Board agrees it is premature to increase nuclear insurance costs because of a bill that is still being debated by the federal government. The Board will reduce the 2011 proposed amount for nuclear insurance costs by $2.5 million, resulting in $8.8 million for 2011. This was obtained by taking the 2010 budget for nuclear insurance costs and increasing for inflation. The amount to be included for 2012 is $9 million.

6.4 Depreciation

OPG seeks approval for depreciation and amortization expense of $130.6 million for the regulated hydroelectric facilities and $491.8 million for the nuclear facilities for the test period. The nuclear station end of life assumption impacts on depreciation expense are discussed in Chapter 8.

OPG's internal Depreciation Review Committee ("DRC") is accountable for providing engineering, technical and financial review of asset service lives. Board staff observed that the 2009 DRC report showed a trend of increases to the useful lives of many nuclear assets resulting in annual reductions to depreciation expense starting in 2010. Board staff argued that OPG's depreciation expense may be overstated as the DRC has not completed its review of all nuclear assets, and the trend of increasing useful life is likely applicable. Board staff also submitted that the Board should direct OPG to file an independent depreciation study for its regulated facilities and the Bruce stations. Board staff noted that the Board has required this filing for other large utilities. SEC supported the staff submission.

OPG responded that the nuclear assets that have not been reviewed by the DRC are of a different nature and that it is unlikely that their service lives would be increased. OPG also pointed out that the majority of OPG's nuclear asset class lives are capped by assumptions for life limiting components for station life even if the asset could last longer.

OPG argued that an independent depreciation study would increase costs without providing value. While comparative data is likely available for hydroelectric assets, OPG argued that an independent consultant would have to rely on OPG's expertise for nuclear assets. OPG also referred to the Ganett Fleming report on OPG's depreciation review process which was filed in the previous proceeding. OPG stated that the report concluded that OPG's DRC process was adequate and did not burden the ratepayer with the cost of new systems or processes.

Board Findings

As discussed elsewhere in this Decision, the Board has accepted the end of service life estimates for the prescribed facilities as filed by OPG, including the extended service life for Darlington. No other issues were raised with respect to the depreciation expense for the test period.

The Board is satisfied with OPG's approach for the test period and notes that no concerns were raised with respect to the upward revisions related to the assets reviewed by the DRC. The Board further accepts OPG's explanation regarding the assets which were not reviewed and concludes that there is no evidence to indicate that OPG's depreciation levels are unreasonable for the test year. The Board will, however, direct OPG to file an independent depreciation study at the next proceeding. While the Ganett Fleming report commented on the process being followed it is important to also have an independent assessment of the assets. As noted in several submissions, an independent study is a typical requirement of utilities, conducted periodically. Given the level of depreciation expense involved, the Board concludes there is merit in OPG also providing such a study. Such a study provides assurance to the Board and all parties that the depreciation and amortization expenses, which are significant, are reasonable.

6.5 Taxes

OPG uses the taxes payable method for determining regulatory income tax of the prescribed facilities. The tax is allocated based on each business's regulatory taxable income. OPG seeks approval of test period income tax expense of $58.0 million and $129.8 million for the regulated hydroelectric and nuclear facilities respectively.

SEC submitted that tax deductions taken by OPG prior to April 1, 2008, amounting to $1,660.4 million, should be available for deduction by ratepayers and that there should be no regulatory tax liability for the test period. This matter is discussed in the tax loss variance account section in Chapter 10.

The Harmonized Sales Tax ("HST") came into force in Ontario on July 1, 2010. Utilities that received rate orders from the Board in early 2010 or before have been recovering applicable Ontario Retail Sales Tax in rates as part of their revenue requirement. In order to forecast the correct costs for 2011 cost of service applications, the embedded RST (or provincial sales tax) must be removed.

Board staff and SEC submitted that the revenue requirement impact of the HST input tax credits is a reduction of $6.0 million per annum, not the amount of $5.0 million included in the application.

In reply, OPG stated that the $6.0 million estimate is only based on 3 months of data which is unlikely to be representative. OPG also stated that HST is not a discrete entry, but forms part of the expenditure on underlying items. Further, OPG stated that increases in HST savings only occur as a result of increases in underlying costs attracting the tax.

Staff submitted that OPG should report back to the Board in its next application with details of twelve months of HST returns and the input tax credit (“ITC”) amounts related to the prescribed facilities. OPG replied that the information may not be meaningful because the ITC amounts do not necessarily correspond to HST savings. OPG also noted that producing such a report was resource intensive, and that the results would be corporate based and need to be allocated to the prescribed facilities.

Board Findings

The Board accepts OPG’s evidence with respect to HST. There was little substantial evidence to support the changes proposed by Board staff and the suggested differences are well below the materiality threshold. The Board therefore accepts OPG’s evidence as being reasonable. The Board will not direct OPG to provide details regarding its HST returns. The Board will however expect OPG to continue to demonstrate that the impacts of HST have been appropriately incorporated into its forecasts.

7 BRUCE LEASE – REVENUES AND COSTS

OPG leases the Bruce A and Bruce B generating stations and associated lands and facilities to Bruce Power. Sections 6(2)9 and 6(2)10 of O. Reg. 53/05 provide that the Board shall ensure that OPG recovers all the costs it incurs with respect to the Bruce nuclear generating stations, and that any revenues it earns from the Bruce Lease in excess of costs will be used to offset the nuclear payment amounts.

The decision of the previous payment amounts proceeding found that the Bruce generating stations should not be treated as if they were regulated facilities. OPG was directed to calculate all Bruce revenues and costs in accordance with GAAP for non-regulated businesses.

Bruce revenues are derived from base and supplemental payments as set out in the Bruce Lease, used fuel storage and long term disposal services, low and intermediate waste management services, and support and maintenance services as set out in the Bruce Site Services Agreement. Costs include depreciation, which includes asset retirement costs, taxes, accretion, earnings/losses on nuclear segregated funds, the cost of used fuel storage and disposal, and the cost of waste management.

Black & Veatch reviewed OPG's methodology for assigning and allocating revenue and cost to the Bruce facilities and under the Bruce Lease. Black & Veatch found the methodology to be appropriate and compliant with the Board's decision in the previous proceeding.

The Bruce Lease net revenues are forecast to be $128.1 million in 2011 and $143.0 million in 2012, as shown in the table below. If approved, these amounts would offset the nuclear revenue requirement.

Table 22: Bruce Lease Forecast Revenues and Costs

($ million)	2011 Plan	2012 Plan
Bruce Lease Revenues	$254.4	$268.7
Bruce Lease Costs		
Depreciation	34.5	34.5
Property Tax	13.6	14.1
Capital Tax	0.0	0.0
Accretion	294.5	307.2
(Earnings) Losses on Segregated Funds	(286.2)	(304.6)
Used Fuel Storage and Disposal	17.0	24.0
Waste Management Variable Expenses	0.8	0.7
Interest	11.9	6.9
Total Costs Before Income Tax	86.1	82.8
Income Tax – Current	0.0	8.6
Income Tax - Future	40.2	34.3
Total Bruce Lease Costs	126.3	125.7
Bruce Lease Net Revenues	**$128.1**	**$143.0**

Source: Exh. G2-2-1, Tables 1 and 5

Forecast amounts will be tracked against actual revenues and costs, and the variances will be recorded in the Bruce Lease Net Revenues Variance Account, which was established in the previous proceeding. Submissions related to the variance account can be found at Chapter 10.

The only issue raised with respect to the Bruce Lease was related to the impact on nuclear liability costs as a result of the Darlington Refurbishment Project and the new end of life date for Darlington. GEC submitted that the changes to the Bruce Lease costs that result from the 2051 end of life date for Darlington are not appropriate at this time. OPG replied that its application is consistent with GAAP accounting information as reflected in its audited financial statements. The Board's findings with respect to the Darlington Refurbishment Project can be found at Chapter 5 and the findings with respect to station end of life can be found at Chapter 8.

Board Findings

The Board approves OPG's test period forecast for the Bruce Lease net revenues. The Board finds that OPG has estimated the revenue and costs associated with the Bruce generating station in accordance with the methodology established by the Board in the previous proceeding, including the impact arising from the change in the end of life date for Darlington.

8 NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING

OPG incurs liabilities related to decommissioning its nuclear stations (including Bruce), nuclear used fuel, and low and intermediate level waste management (collectively "nuclear liabilities" or "asset retirement obligations"). The responsibility for funding these liabilities is described in the Ontario Nuclear Funds Agreement ("ONFA"). ONFA provides for the establishment of a reference plan for nuclear liabilities which must be updated every 5 years. The current reference plan was updated in November 2006.

8.1 Methodology

The ratemaking treatment for nuclear liabilities is complex and was a matter of considerable discussion in the previous proceeding. In the previous decision, the Board approved a methodology for the recovery of nuclear liabilities that recognized a return on rate base associated with asset retirement costs ("ARC") for Pickering and Darlington. The methodology required that the return on the ARC be limited to the weighted average accretion rate, which was 5.6 % at that time. It is now 5.58%. The portion of the rate base to which the accretion rate applies is equal to the lesser of (a) the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities, and (b) the average unamortized ARC included in the fixed asset balances for Pickering and Darlington.

Other costs associated with nuclear liabilities approved for recovery are the annual depreciation and amortization expenses associated with the ARC, and the variable expenses for the nuclear waste generated each year including expenses relating to low and intermediate level waste.

The Board approved a GAAP basis of accounting for determining the net revenue impact of nuclear liabilities associated with the Bruce facilities. Under this approach, the lease revenues and all cost items are recognized in accordance with GAAP, including accretion expense on the nuclear liabilities. Forecast earnings on the segregated funds related to the Bruce liabilities are included as a reduction of costs and an income tax (PILS) provision is calculated in accordance with GAAP.

OPG proposed to maintain the revenue requirement treatment for nuclear liabilities for Pickering, Darlington and the Bruce facilities which was approved in the previous proceeding.

In the previous decision the Board found that if there were external developments related to the ratemaking aspects of asset retirement obligations, parties could submit evidence and argue for alternative treatment in OPG's next hearing. In this application, OPG indicated that it would continue to investigate the impacts of the approved revenue requirement treatment on its ability to fully recover its nuclear liabilities, and that it may propose modifications to the existing treatment or an alternative treatment in a future application.

OPG stated that it monitors emerging issues with respect to methodologies for the recovery of asset retirement obligations across North America as part of its regular business activities. With the exception of the National Energy Board's ("NEB") review related to pipeline abandonment, OPG was not aware of any policy positions, papers or decisions related to the methodology for recovering asset retirement obligations that have been issued since the last proceeding. The NEB's ongoing review related to pipeline abandonment will examine the methodology for recovering asset retirement obligations. The company's position was that as that review was not yet complete, it would be premature to change OPG's approach at this time. CME agreed with OPG.

Board Findings

The Board agrees with OPG and CME that it would be premature to revise the existing methodology for the regulatory treatment of nuclear liabilities. The only relevant external development brought to the Board's attention is the NEB review and it is not yet complete. If the results of the NEB review, or any other external development, suggest a change in the Board's methodology may be warranted, the Board will revisit the issue in the next application.

The Board accepts the methodology used by OPG to calculate the revenue requirement impacts of OPG's nuclear liabilities.

8.2 Station End of Life Dates and Test Year Nuclear Liabilities

The following table shows the forecast amount of the average unfunded nuclear liabilities related to the Pickering and Darlington facilities and the average unamortized ARC included in the fixed asset balances for Pickering and Darlington. OPG calculated the return on rate base on the lesser of these two amounts using the average accretion rate of OPG's nuclear liabilities, which is 5.58% for the test period.

Table 23: Prescribed Facilities - Lesser of Asset Retirement Costs or Unfunded Nuclear Liability ($ million) Subject to Return Years Ending December 31, 2008, 2009, 2010, 2011 and 2012

Line No.	Description	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
	ASSET RETIREMENT OBLIGATION (ARO)					
1	Adjusted Opening Balance	$5,921.0	$6,151.2	$6,888.6	$7,136.8	$7,432.8
2	Closing Balance	6,151.2	6,391.2	7,136.8	7,432.8	7,748.0
3	Average Asset Retirement Obligation ((line 1 + line 2)/2)	6,036.1	6,271.2	7,012.7	7,284.8	7,590.4
	NUCLEAR SEGREGATED FUNDS BALANCE					
4	Adjusted Opening Balance	4,829.9	4,584.2	5,058.7	5,399.6	5,778.5
5	Closing Balance	4,584.2	5,058.7	5,399.6	5,778.5	6,160.7
6	Average Nuclear Segregated Funds Balance ((line 4 + line 5)/2)	4,707.0	4,821.5	5,229.2	5,589.1	5,969.6
	UNFUNDED NUCLEAR LIABILITY BALANCE (UNL)					
7	Adjusted Opening Balance (line 1 - line 4)	1,091.1	1,567.0	1,829.9	1,737.2	1,654.3
8	Closing Balance (line 2 - line 5)	1,567.0	1,332.5	1,737.2	1,654.3	1,587.3
9	Average Unfunded Nuclear Liability Balance ((line 7 + line 8)/2)	1,329.1	1,449.7	1,783.5	1,695.7	1,620.8
	ASSET RETIREMENT COSTS (ARC)					
10	Adjusted Opening Balance	1,345.7	1,221.7	1,573.1	1,539.9	1,506.7
11	Closing Balance	1,221.7	1,098.0	1,539.9	1,506.7	1,473.5
12	Average Asset Retirement Costs ((line 10 + line 11)/2)	1,283.7	1,159.8	1,556.5	1,523.3	1,490.1
13	**LESSER OF AVERAGE UNL OR ARC**	**$1,283.7**	**$1,159.8**	**$1,556.5**	**$1,523.3**	**$1,490.1**

Note: The 2010 adjusted opening balances for ARO and ARC include increases of $497.4 million and $475.2 million respectively for recognition of the Darlington Refurbishment Project.

Source: Exh. C2-1-2, Table 1

The test period revenue requirement impact of nuclear liabilities is $291.3 million for Pickering and Darlington and $110.3 million for the Bruce facilities. The following table summarizes historic and test period revenue requirement impacts.

Table 24: Revenue Requirement Impact of OPG's Nuclear Liabilities ($ million)

Line No.	Description	2008 Actual	2009 Actual	2010 Budget	2011 Plan	2012 Plan
	PRESCRIBED FACILITIES					
1	Depreciation of Asset Retirement Costs	$124.0	$123.8	$33.2	$33.2	$33.2
2	Used Fuel Storage & Disposal Variable Expenses	19.0	19.2	23.0	26.6	28.5
3	Low & Intermediate Level Waste Management Variable Expenses	1.7	3.5	1.1	0.8	0.8
	Return on Rate Base:					
4	Accretion Rate	53.9	65.0	86.9	85.0	83.1
5	Weighted Average Cost of Capital	17.8	0.0	0.0	0.0	0.0
6	**Total Revenue Requirement Impact**	**$216.4**	**$211.5**	**$144.2**	**$145.7**	**$145.6**
	(line 1 + line 2 + line 3 + line 4 + line 5)					
	BRUCE FACILITIES					
7	Depreciation of Asset Retirement Costs	$48.6	$48.5	$28.5	$28.5	$28.5
8	Used Fuel Storage & Disposal Variable Expenses	14.0	14.4	16.7	17.0	24.0
9	Low & Intermediate Level Waste Management Variable Expenses	11.2	4.4	0.9	0.8	0.7
10	Accretion	200.6	279.3	282.4	294.5	307.2
11	Less: Segregated Fund Earnings (Losses)	(138.0)	386.2	268.8	286.2	304.6
12	Return on Rate Base	15.4	0.0	0.0	0.0	0.0
13	**Total Revenue Requirement Impact**	**$427.6**	**$(39.5)**	**$59.6**	**$54.5**	**$55.8**
	(line 7 + line 8 + line 10 - line 11 + line 12)					

Source: Exh. C2-1-2, Table 5

The revenue requirement impact of the nuclear liabilities for the prescribed facilities decreases significantly in the period 2010-2012 as a result of OPG's decision to move to the definition phase of the DRP. The consequential impacts of the decision to proceed with the definition phase of the DRP are discussed in Chapter 5.

There was considerable examination in the proceeding of the effect of station end of life dates on the revenue requirement impacts of nuclear liabilities.

As noted in Chapter 5, OPG has assumed an end of life of 2051 for Darlington. The impacts of that decision on revenue requirement are discussed there, as is the Board's acceptance of that decision for rate-making purposes.

In addition, several issues were raised in relation to the appropriateness of the end of service life dates for Pickering A and Pickering B nuclear stations. For accounting and depreciation purposes, the end of service life date for Pickering B is September 30, 2014 and for Pickering A (units 1 and 4) it is December 31, 2021. OPG did not change the end of service life of the Pickering B station, even though the company is currently undertaking work designed to extend the life of two units to 2018 and the other two units to 2020. In addition, without the continued operations of Pickering B, the evidence is that it would be quite unlikely that Pickering A would continue operations because the two stations are operationally and economically interdependent. In summary, the station end of life dates are chosen on the basis of the level of certainty which exists regarding the DRP and the Pickering B Continued Operations project. OPG has a high level of confidence regarding the DRP and only a medium level of confidence regarding the Pickering B project.

All station end of life dates were recommended by OPG's Depreciation Review Committee ("DRC") in its 2009 report and approved by OPG senior management to be effective on January 1, 2010.

The station end of life dates affect the valuation of the asset retirement obligations and consequently ARC. Specifically, the decision to proceed with the DRP changes the valuation of the nuclear used fuel and decommissioning liabilities and the ARC for the prescribed facilities and the Bruce facilities. The changes in the asset retirement obligations and the ARC result in revenue requirement changes related to the return on rate base, depreciation expense, used fuel storage and disposal variable expense and income taxes for the prescribed facilities. For the Bruce facilities, the revenue requirement is impacted by changes to depreciation expense, accretion expense, used fuel storage and disposal variable expense and income taxes.

As noted in the DRP section of this Decision, the revenue requirement impact of the DRP is a considerable. The most significant contributor is a reduction in depreciation expense of $229.6 million arising from Darlington's asset retirement costs and the extension of service life impacts. Essentially, the obligations related to decommissioning the stations and dealing with the used fuel are pushed further into the future, thereby reducing the revenue requirement in the current period. These revenue requirement reductions are offset to some extent by the increased amount of used fuel.

OPG asserted that the accounting changes it has implemented to reflect the DRP and an end of life of 2051 are based on its accounting rules which are in accordance with GAAP. Some parties suggested that for regulatory accounting purposes, the end of station life for Darlington could remain at 2019.

As noted in the DRP chapter, there was considerable discussion about the scope of the Board's approval of the DRP. SEC cross-examined OPG on the connection between the scope of the Board's approval of the DRP and OPG's application with respect to depreciation and nuclear liabilities.

> MR. REEVE: There was a discussion around the approval of the Darlington refurbishment project; that's correct.
> MR. SHEPHERD: And you are not asking for approval of that. But I am right, am I not, that the depreciation expense and the asset retirement expense in the current application for Darlington assume that Darlington will be refurbished?
> MR. REEVE: That's correct.
> MR. SHEPHERD: And so if this Board approves the depreciation expense and the asset retirement expense – or, sorry, the decommissioning expense, it is on the assumption that Darlington refurbishment will take place?
> MR. REEVE: From an accounting standpoint, yes.[43]

Parties also queried OPG's decision to delay its determination as to whether to extend the station life of Pickering B under the Continued Operations project until 2012, and the dependence of Pickering A operations on Pickering B operations. OPG stated that it does not plan to operate the two units at Pickering A if Pickering B were to be closed in 2014 as this would result in significant technical and economic challenges to operate Pickering A alone.

OPG argued that its evidence is consistent with GAAP. With respect to Pickering B, OPG explained that it does not revise station end of life dates for depreciation purposes until it has a high degree of confidence in revised service life dates. As noted in the section of this decision on DRP, OPG stated that its Board of Directors has decided to proceed with the DRP by moving into the definition phase, and that the Province has

[43] Tr, Vol. 10, p. 102.

concurred with this decision. The internal DRC has high confidence that the refurbishment will proceed and hence recommended the Darlington end of life date of 2051.

OPG was asked to recalculate the impacts on the revenue requirement using a number of different scenarios for the station end of life. These alternative scenarios were as follows:

- Scenario 1A assumed that Darlington would be refurbished as planned and would operate until 2051, and that both Pickering A and Pickering B would continue to operate until 2020 and 2019, respectively, in accordance with current plans for Pickering B Continued Operations.

- Scenario 2 assumed that the DRP would not proceed and Darlington would therefore close in 2019. Both Pickering A and Pickering B would also close in 2014, assuming the Pickering B Continued Operations project does not proceed, because it would not be practical to operate Pickering A without Pickering B.

- Scenario 3 assumed no change in the status of Pickering A and B from that assumed in the application, but that the DRP would not proceed and that Darlington would therefore close in 2019.

- Scenario 4A assumed that the DRP would not proceed and Darlington would therefore close in 2019. This scenario also assumed that the Pickering B Continued Operations project goes ahead and therefore Pickering A and Pickering B would continue to operate until 2020 and 2019, respectively.

The analysis assumed that all other programs and expenditures were as proposed in the application (including CWIP for the DRP). The revenue requirement impact summarized in the following table is relative to the revenue requirement impact presented in the application (a reduction of $197.1 million).

Table 25: Summary of Test Period Revenue Requirement Impacts For Station End of Life Scenarios ($ million)

Description	Scenario 1A	Scenario 2	Scenario 3	Scenario 4A
PRESCRIBED FACILITIES				
Return on Rate Base:				
Accretion Rate on Lesser of ARC and UNL	3.2	(88.3)	(73.2)	(76.6)
Changes to Nuclear Station Service Life Impacts	4.0	(34.5)	(7.3)	(3.4)
Total Return on Rate Base Impact	7.2	(122.8)	(80.6)	(80.0)
Depreciation Expense:				
Asset Retirement Costs	28.2	190.9	181.1	139.4
Changes to Nuclear Station Service Life Impacts	(26.5)	227.8	48.5	22.4
Total Depreciation Expense Impact	1.7	418.7	229.6	161.8
Other Expenses:				
Used Fuel Storage and Disposal Variable Expenses	0.0	0.0	(8.2)	0.0
Income Taxes:				
Accretion Rate on Lesser of ARC and UNL	1.1	(30.6)	(25.3)	(26.5)
Changes to Nuclear Station Service Life Impacts	0.6	(5.6)	(1.2)	(0.5)
Depreciation Expense on Asset Retirement Costs	9.8	66.2	62.8	48.4
Used Fuel Storage and Disposal Variable Expenses	0.0	0.0	(2.8)	0.0
Depreciation Expense - Changes to Station Lives	(9.2)	79.0	16.8	7.8
Total Income Tax Impact	2.4	109.1	50.2	29.0
Total Revenue Requirement Impact - Prescribed	**11.3**	**405.1**	**191.0**	**110.8**
BRUCE FACILITIES				
Rate Base	0.0	0.0	0.0	0.0
Depreciation Expense Impact: Asset Retirement Costs	(1.7)	96.4	40.2	82.6
Other Expenses:				
Accretion	(2.8)	56.0	18.3	48.7
Used Fuel Storage and Disposal Variable Expenses	0.0	0.0	(4.2)	0.0
Total Other Expenses Impact	(2.8)	56.0	14.1	48.7
Income Taxes:				
Impact on Bruce Facilities' Income Tax Calculation	1.2	(38.8)	(13.9)	(33.4)
Impact on Prescribed Facilities' Income Tax Calculation	(1.2)	39.4	14.0	33.9
Total Income Tax Impact	0.0	0.6	0.1	0.5
Total Revenue Requirement Impact - Bruce	**(4.6)**	**153.0**	**54.4**	**131.7**
Total Revenue Requirement Impact	**6.7**	**558.1**	**245.4**	**242.5**

Source: J10.11 (Attachment 1 - Table 1 and Attachment 3 - Table 1) and J10.11 Addendum 2 (Attachment 1A - Table 1 and Attachment 4A - Table 1)

Board staff noted that the adoption of any of the scenarios for ratemaking purposes would introduce a separate and second set of books that may differ significantly from OPG's GAAP-based financial accounting and reporting.

Energy Probe submitted that it does not expect Pickering A to operate until 2021, and recommended a more proximate and more likely end of service life, but was not specific.

GEC argued that the DRP has not reached a stage where it is a firm decision that should trigger the accounting changes. At a minimum, GEC submitted that the revenue requirement should be adjusted upward to reflect scenario 4A. However, GEC did not accept that Pickering B Continued Operations project makes economic sense, and argued that scenario 2 should be applied for regulatory purposes at this time.

SEC argued that scenario 3 should be adopted, with impacts adjusted for income tax.

Board Findings

For the reasons set out Chapter 5 on DRP, the Board accepts 2051 as the Darlington station end of life for regulatory purposes.

Given the current uncertainty as to the success of the Pickering B Continued Operations project, the Board has some concerns about the assumption by OPG for accounting purposes that it can continue to operate Pickering A without Pickering B. However, changing the assumptions to align the end of life dates for these two stations has a relatively small revenue requirement impact which does not warrant the difficulties inherent in having separate accounting and regulatory accounts. There will be more information on the expected end of life for Pickering A and Pickering B in the next proceeding and a new end of life may well be adopted then.

9 CAPITAL STRUCTURE AND COST OF CAPITAL

This is the second cost of service application to set payment amounts for OPG's prescribed assets. Cost of capital was extensively reviewed in the previous proceeding. OPG's circumstances are different, in a number of respects, from those of other entities that the Board rate regulates. These are reflected in the different treatment that the Board approved for OPG in that proceeding.

Since the previous decision, the Board has conducted a consultation that reviewed cost of capital policies for all of the sectors rate-regulated by the Board, including OPG. The outcome of that process was the *Report of the Board on the Cost of Capital for Ontario's Regulated Utilities* issued on December 11, 2009 (the "Cost of Capital Report"). OPG and many of the stakeholders participated in that consultation.

OPG has applied for payment amounts based on a deemed capital structure of 53% debt and 47% equity. This was the structure approved in the previous proceeding.

OPG proposed that the ROE for 2011 be set on the basis of the Board's policy (although it used 9.85% as a placeholder) and that the level for 2012 be set using the Board's policy, but that it be determined now based on Global Insight data because Consensus Forecasts only go out 12 months.

For long-term debt, OPG proposed to use the weighted average cost of actual and forecasted debt for actual debt capitalization, and the Board's deemed long-term debt rate for any incremental, unfunded long-term debt capitalization. For short-term debt, OPG used a methodology to forecast the costs of its two main sources of short-term financing, namely its commercial paper program and its accounts receivable securitization program. OPG's proposed cost of capital followed that approved in the previous payments case, EB-2007-0905.

The proposed test period capitalization and cost of capital are summarized in the following tables for each of the years in the test period.

Table 26: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2011

Capitalization	Principal ($million)	Component (%)	Cost Rate (%)	Cost of Capital ($million)
Short-Term Debt	189.5	3.0%	2.64%	7.6
Existing/Planned Long-Term Debt	2,283.1	36.1%	5.53%	126.2
Other Long-Term Debt Provision	877.7	13.9%	5.87%	51.5
Total Debt	3,350.3	53.0%	5.53%	185.3
Common Equity	2,971.1	47.0%	9.85%	292.7
Rate Base Financed by Capital Structure	6,321.4	80.6%	7.56%	477.9
Adjustment for Lesser of UNL or ARC	1,523.3	19.4%	5.58%	85.0
Rate Base	7,844.7	100%	7.18%	562.9

Source: Exh. C1-1-1, Table 2

Table 27: Capitalization and Cost of Capital - Calendar Year Ending December 31, 2012

Capitalization	Principal ($million)	Component (%)	Cost Rate (%)	Cost of Capital ($million)
Short-Term Debt	189.5	2.9%	4.13%	10.4
Existing/Planned Long-Term Debt	2,502.8	38.8%	5.50%	137.6
Other Long-Term Debt Provision	725.2	11.2%	5.87%	42.6
Total Debt	3,417.5	53.0%	5.58%	190.6
Common Equity	3,030.6	47.0%	9.85%	298.5
Rate Base Financed by Capital Structure	6,448.1	81.2%	7.59%	489.1
Adjustment for Lesser of UNL or ARC	1,490.1	18.8%	5.58%	83.1
Rate Base	7,938.2	100%	7.21%	572.2

Source: Exh. C1-1-1, Table 1

The following issues were addressed in the proceeding:

- Technology-specific capital structures;
- Return on equity;
- Cost of short-term debt; and
- Cost of long-term debt.

Each issue is addressed in turn.

9.1 Technology-Specific Capital Structures

As noted above, OPG has used a deemed capital structure of 53% debt and 47% equity in its application. The deemed capital structure is applied to the rate base net of the Adjustment for the Lesser of Unfunded Nuclear Liabilities ("UNL") or Asset Retirement

Costs ("ARC"), which is applicable only to the nuclear business. OPG's proposal is consistent with the Board's decision in the previous proceeding.

In the previous proceeding, the Board set one overall capital structure for both regulated hydroelectric and nuclear businesses, but concluded that separate capital structures for the regulated hydroelectric business and the nuclear business was an approach worthy of further investigation at the next proceeding. This is the only issue related to capital structure examined during the proceeding.

In response to the Board's direction in the prior decision, OPG retained Ms. Kathleen McShane of Foster Associates Inc. to determine whether there was a basis on which to establish separate capital structures. Ms. McShane analysed five different quantitative methodologies and one non-quantitative method in her report. Ms McShane also appeared as a witness in the hearing. Ms. McShane concluded that none of the methodologies provided sufficiently robust information to serve as a basis for separate costs of capital and capital structure. Accordingly, OPG concluded that it was appropriate to continue to use a single capital structure for its prescribed facilities.

Pollution Probe filed a report prepared by Drs. Lawrence Kryzanowski and Gordon Roberts. They also appeared as witnesses. Their analysis is based on a heuristic methodology comparing the relative risk of electricity transmission and distribution-only utilities and an integrated (i.e. generation and transmission/distribution) utility versus solely hydroelectric and nuclear generation businesses. They concluded that the capital structure for the hydroelectric business should consist of 43% equity and the capital structure for the nuclear business should consist of 53% equity, subject to OPG's prescribed facilities retaining an equity thickness of 47% in aggregate, as determined in the previous proceeding.

GEC's witness, Mr. Paul Chernick, did not undertake an updated analysis specifically on the issue of technology-specific capital structures, but he did express the opinion that there was a difference in the business risks of hydroelectric and nuclear generation businesses. He testified that the Board could and should make a judgmental determination of the difference.

All consultants agreed that, as the ROE is to remain constant under the Board's Cost of Capital guidelines, the only way to reflect differences in business risk is by adjusting the equity thickness of one division relative to the other.

Pollution Probe maintained that there is no dispute that the nuclear division has a higher business risk than the hydroelectric division. Pollution Probe noted that the capital structure recommended by Drs. Kryzanowski and Roberts was consistent with credit metrics needed to obtain, on a "stand alone" basis, reasonable bond ratings in the "A" credit range. Pollution Probe commented that the methodologies used by Ms. McShane in her analysis are usually used to determine the rate of return, and not the capital structure.

Energy Probe submitted that the Board should deem a higher equity ratio for the nuclear business than the hydroelectric business, setting the nuclear business equity ratio at 50% and the regulated hydroelectric business equity ratio at 40%.

GEC submitted that setting a higher cost of capital for the nuclear business would be more accurate than applying the current combined value to both businesses. GEC submitted that OPG should develop project specific discount rates for large projects to capture business risk more fully in the analysis.

AMPCO, CME, CCC, PWU, SEC and VECC supported retaining a single capital structure for the regulated business. Among the reasons cited were the unnecessary complexity of maintaining two structures and the fact that OPG borrows as a company not by business unit. CCC also commented that the analysis conducted by Drs. Kryzanowski and Roberts was largely a qualitative approach.

Board staff argued that if the Board was inclined to approve technology-specific capital structures, then the Board should also apply the cost of debt on a technology-specific basis. Board staff noted that the nuclear liabilities are treated as a form of debt financing within the capital structure but are only incorporated, appropriately, into the rate base for OPG's regulated nuclear assets.

OPG argued that technology-specific capital structures add unnecessary complications to future applications. OPG noted that consumers do not buy power from particular producers, let alone based on generation type, and that the difference in equity ratios and resulting returns is small. OPG also argued that there is no compelling reason to accept the recommendations of Drs. Kryzanowski and Roberts. In OPG's view, the evidence did not extend the analysis beyond that provided in the previous proceeding and therefore the conclusion of the previous proceeding should be maintained.

If the Board is inclined to approve separate capital structures, OPG submitted that the only reasonable ratios would be 45% for the regulated hydroelectric business and 50% for nuclear. OPG also argued that Board staff is incorrect in concluding that cost of debt is specific to projects, noting that the cost of debt for the projects identified in the staff submission reflect OPG's corporate borrowing costs.

Board Findings

OPG has applied the same capital structure as was approved on a combined basis for its regulated hydroelectric and nuclear generation assets in the previous payments case. The Board finds that there is no evidence of any material change in OPG's business risk and that the deemed capital structure of 47% equity and 53% debt, after adjusting for the lesser of Unfunded Nuclear Liabilities or Asset Retirement Costs, remains appropriate.

The Board accepts that the business risks associated with the nuclear business are higher than those of the regulated hydroelectric business, and this is not contested by parties in this hearing. However, the Board finds that the evidence in this proceeding does not provide a sufficiently robust basis to set technology-specific costs of capital, by way of division-specific capital structures. In short, the Board finds an inadequate body of evidence to support a change from the conclusions reached by the Board in the previous proceeding.

The evidence of Drs. Kryzanowski and Roberts is a heuristic approach and is qualitative as much as quantitative in nature. Their evidence also largely employed the same techniques as contained in their evidence in the previous case. The difficulty for the Board is the dependence on qualitative assumptions and analysis. Their qualitative assessments of various forms of risk give rise to quantitative scorings that they then have translated into different capital structures corresponding to a cost of capital related to the risks of each business division and constrained by two conditions:

1) the weighted aggregate cost of capital for the two divisions should correspond with the 47% equity thickness set by the Board on an aggregate basis; and
2) the cost of capital and hence the deemed capital structure for the hydroelectric division should be commensurate with a business risk no less risky than that for electricity distributors and transmitters, for which the Board has deemed a 40% equity thickness.

As was discussed during oral cross-examination, these conditions restrict the allowable technology-specific capital structures to a very narrow band. The Board is concerned that different qualitative scorings might result in some different results from their analysis, even while adhering to the relative riskiness (in terms of ranking) of transmission and distribution utilities versus generation technologies. In other words, as was found in the previous case, the Board considers that the heuristic approach of Drs. Kryzanowski and Roberts is not robust enough to set technology-specific costs of capital and capital structures.

With respect to Ms. McShane's evidence, the Board acknowledges its more quantitative approach, but also acknowledges some of the concerns raised by parties. For the most part, the analytical approaches used by Ms. McShane are based on the CAPM model, and thus share the strengths and limitations. The CAPM is one of several techniques routinely used by this Board and other regulators in setting the Cost of Capital. However, as was acknowledged by OPG,[44] the CAPM is not used to set the capital structure, which must be derived indirectly. However, the Board considers that the paucity of comparator firms to be more telling in Ms. McShane's analysis not being able to derive a robust estimate of technology-specific capital structures.

There may thus be a lack of major hydroelectric and nuclear generators comparable to OPG's divisions and for which market data is available to apply the methods that Ms. McShane has used. It is not to say that there is not a real difference, but that the approaches put on the record in this proceeding, as in the previous case, are not sufficient to allow for robust estimates with sufficient precision to be derived, at least at this time.

The Board is also concerned that over time a further issue will arise in relation to the interaction between the individual equity ratios and the combined equity ratio. As the relative size of the hydroelectric and nuclear businesses changes (through major additions to rate base, for example) the issue will arise as to whether the overall ratio of 47% is to remain unchanged or whether the technology specific ratios are to remain unchanged. If the overall level of 47% is to remain unchanged, then this could result in ongoing variability in the technology specific levels, which may not be desirable. Likewise, if the technology specific ratios are to remain unchanged, it might result in changes to the overall ratio that are not warranted. The Board concludes that introducing this level of variability and complexity would not be appropriate.

[44] Exh. L-10-23 and Exh. L-6-7

The Board also accepts that implementing separate capital structures may not lead to any significant ratepayer benefits in the long term.

The primary argument put forward by those who support a separate capital structure is related to the assessment of large capital projects. The Board concludes that this difference in risk can and should be adequately accommodated in the direct valuation of the projects. OPG maintained that it already does so; other parties dispute this. This issue can be pursued further by the parties in subsequent proceedings.

Another argument advanced in favour of separate capital structures is greater transparency for consumers. The Board has some sympathy with this view, but has nonetheless concluded that the benefits from this greater transparency are not sufficient to warrant the complications involved with this approach based on the evidence advanced in this or the previous payments case.

9.2 Return on Equity

Two issues were raised in respect of the return on equity: whether the Board should adjust the ROE below the level established through the operation of the Board's policy, and how the ROE should be set for 2012.

9.2.1 Should the ROE be reduced?

OPG proposed that the ROE be determined according to the formula in the Cost of Capital Report, using data from *Consensus Forecasts*, the Bank of Canada and Bloomberg LLP three months in advance of the March 1, 2011 effective date for rates.

CME maintained that unregulated industries would forego full equity return on investment if external circumstances called for price constraint. CME argued that the Board is not required to award ROE at a specific level as this is not an objective or requirement in the Act, and could award a lower rate than applied for by OPG in order to protect consumers from rising electricity prices. CME pointed out that it would be inconsistent for the ROE to be fixed at a specific rate, when the Board, in some cases, can award a higher ROE, as, for example, contemplated by the *Report of the Board on The Regulatory Treatment of Infrastructure Investment in Connection with the Rate Regulated Activities of Distributors and Transmitters in Ontario*. Also, CME suggested that, if the ROE is considered to be an absolute number, any over-earnings in a rate year would have to be returned to ratepayers in a subsequent year.

OPG argued that it is a legal requirement to permit a utility the opportunity to earn a fair return on its invested capital, and that the Cost of Capital Report applies to all utilities regulated by the Board. As noted elsewhere in this Decision, OPG also argued that it has no obligation to have regard for costs over which it has no control.

CME also argued that the Board has always looked to sources and actual costs of funds when considering cost of capital issues, and should therefore take into account that OPG's capital structure is financed by interest free government loans or grants, taxes or money the government borrows in the debt markets. CME's position was that the approved ROE only needs to exceed the government's cost of debt.

OPG argued that there is no basis to use its shareholder's cost of capital as a guide to setting ROE. OPG pointed out that if this principle were applied then it would have to be applied symmetrically and there is no precedent for this approach. Further, OPG argued that it is inconsistent with the "stand-alone" principle which the Board accepted in the previous proceeding. OPG also submitted that CME's proposition violated a basic principle of finance – that the cost of capital should reflect the riskiness of the entity or the project in which the funds are invested, not the source of the funds.

Board Findings

The Board accepts OPG's proposal to use the ROE determined on the basis of the Board's Cost of Capital Report. In the Cost of Capital Report, the Board determined that the Fair Return Standard ("FRS") is the legal basis upon which the cost of capital is determined, stating:

> The Board is of the view that the FRS frames the discretion of a regulator, by setting out three requirements that must be satisfied by the cost of capital determinations of the tribunal. Meeting the standard is not optional; it is a legal requirement. As set out by Enbridge in their final comments, the Supreme Court of Canada has "described this requirement that approved rates must produce a fair return as an 'absolute' obligation."[footnote omitted] Notwithstanding this mandatory obligation, the Board notes that the FRS is sufficiently broad that the regulator that

> applies it must still use informed judgment and apply its discretion in the determination of a rate regulated entity's cost of capital.[45]

In the Cost of Capital Report, the Board also stated:

> The final "product" of this process, of course, is a Board policy. This was not a hearing process, and it does not - indeed cannot - set rates. The Board's refreshed cost of capital policies will be considered through rate hearings for the individual utilities, at which it is possible that specific evidence may be proffered and tested before the Board. Board panels assigned to these cases will look to the report for guidance in how the cost of capital should be determined. Board panels considering individual rate applications, however, are not bound by the Board's policy, and where justified by specific circumstances, may choose not to apply the policy (or a part of the policy).[46]

While the Board agrees that there is flexibility to apply a different ROE in appropriate circumstances, there was no evidence of a compelling reason to do so in this case. As discussed in the Cost of Capital Report regarding the legal requirement for the FRS, the Board does not agree with CME's proposal that OPG should be afforded a lower ROE to mitigate impacts on ratepayers. Rate mitigation, if warranted, is not applied specifically to the Cost of Capital; doing so would violate the FRS.

The Cost of Capital Report contemplates that a departure from the policy will only be considered where there is specific evidence in the hearing that it would be inappropriate to apply the policy in the specific circumstances of the utility. The Board finds that there was no such credible evidence in this case.

The Board also agrees with OPG that the source of its financing is not relevant for these purposes and will not adjust the ROE to reflect its shareholder's cost of debt. This issue was also raised in the previous payments decision and similar arguments were raised and addressed at that time. The Board finds that there has been no change in the evidence or circumstances which would warrant a change in approach.

9.2.2 How should the ROE for 2011 and 2012 be set?

OPG used an ROE of 9.85% for purposes of its application, but proposed that the ROE for 2011 be set using data for the month three months prior to the effective date of the

[45] Report of the Board on the Cost of Capital for Ontario's Regulated Utilities, EB-2009-0084, December 11, 2009, p. 13.
[46] *Ibid*, p. 18.

new payment amounts, as contemplated in the Cost of Capital Report. OPG proposed that the ROE for 2012 be set at the same time as the 2011 ROE but using data from Global Insight instead of the *Consensus Forecasts* used by the Board because the *Consensus Forecasts* data is only projected for 12 months.

Board staff argued that OPG's cost of capital parameters for 2011 should be set at the time this Decision is issued, but that the cost of capital parameters for 2012 should be updated prior to 2012. In support of this position, Board staff referred to recent Toronto Hydro-Electric Systems Limited ("THESL")[47] and Hydro One[48] cases, where updates of cost of capital parameters were implemented in the second year of multi-year applications.

SEC supported fixing the ROE now for the 24-month test period, citing simplicity and price stability, but expressed some reservations about forecasting markets two years out using the Global Insight forecast. SEC expressed concern about the adoption of a new data source without further review and concluded that ROE for 2011 and 2012 should be set at the same level, an approach that is consistent with that used under IRM. In the event this approach was not adopted by the Board, SEC supported Board staff's position. CME supported SEC's position.

OPG argued that the THESL and Hydro One cases should not be used as precedents because these utilities had already proposed to adjust their rates for the second year. OPG also took the position that SEC's comparison with IRM is inappropriate because OPG has no price escalation mechanism for its rates. With respect to SEC's concern about the Global Insight forecast, OPG noted that the Board had not expressed any concerns with the Global Insight forecast in the previous proceeding.

In the event that the Board directs the use of *Consensus Forecasts* data, OPG requested that a variance account be established to record the impacts of any differences arising from ROE approved in rates for 2012 and the 2012 ROE determined using September 2011 *Consensus Forecasts* data. OPG observed that this would be more efficient than updating the forecast and payment amounts for 2012, and would eliminate the need for the IESO to institute another change in the settlement system at the start of 2012.

[47] Decision with Reasons, EB-2009-0069, April 16, 2010.
[48] Decision with Reasons, EB-2009-0096, April 9, 2010.

Board Findings

The Board finds that the ROE for 2011 will be set using the data available for the three months prior to the effective date of the order, in accordance with the Board's Cost of Capital Report. The Board has calculated an ROE of 9.43% based on Bloomberg LLP, *Consensus Forecasts*, and Bank of Canada data for November 2010, which is three months in advance of March 1, 2011, and using the ROE methodology in Appendix B of the Cost of Capital Report. The detailed calculations to derive this ROE are contained in Appendix H of this Decision.

In the prior proceeding, the ROE was fixed at 8.57% for the entire test period spanning nearly two years. In part, this was a matter of timing – the decision in the previous payments case was issued on November 3, 2008, more than one third of the way through the test period. By that time there was knowledge of actual market conditions and returns and more current information for the remainder of the test period which justified approving one ROE for the entire test period.

The current application differs in that it has been filed and considered in advance of the proposed test period. OPG has proposed different treatment in setting different ROEs for each of the 2011 and 2012 test years. The Board considers it appropriate to set separate ROEs for each year of the test period. The issue is what data should be used for establishing the 2012 ROE.

The Board could adopt the same approach used in the THESL and Hydro One decisions which involves updating the ROE for 2012 using the data from *Consensus Forecasts,* Bank of Canada and Bloomberg LLP for the month 3 months prior to January 1, 2012 (i.e. September 2011) and the methodology in the Cost of Capital Report. The approach has the benefit of retaining all aspects of the ROE methodology and policy adopted by the Board, rather than adopting a new forecast method. However, it introduces procedural complications and it does necessitate the setting of new payment amounts for 2012. The Board finds that there is significant value, in terms of overall rate stability, in establishing one set of payment amounts in relation to the combined revenue requirement of the test period. In addition, if there were an update for the ROE for 2012, it would result in payment amount levels for 2012 which were derived from the 2012-specific ROE figure, but the blended test period revenue requirement impacts for all other components. The Board finds that a mechanistic update for one component of the revenue requirement, when the payment amounts in all other respects are the result of a blended revenue requirement covering the entire test period, is not appropriate in the circumstances.

The Board concludes that it is reasonable to use the Global Insight forecast for purposes of setting the ROE for 2012. The Board finds this approach is consistent with the Board's overarching policy and represents the best balance between rate stability, procedural efficiency and accurate forecasting. OPG has indicated in its Reply Argument that the ROE for 2012 is 9.55%, based on the Global Insight forecast and the Board's methodology. OPG shall file the relevant documentation as part of its draft payment amounts order, consistent with the methodology adopted by the Board in its Cost of Capital Report, supporting the derivation of the ROE for 2012.

9.3 Cost of Short-Term Debt

OPG's short-term debt is comprised of a commercial paper program and an accounts payable securitization program. OPG's estimates of the short-term debt rates for each of 2011 and 2012 are derived from Global Insight data from December 2009. OPG's short-term debt approach is consistent with that approved in the previous proceeding.

Board staff submitted that while OPG has its own methodology for forecasting short-term debt rates, it should update the rates to reflect more current data, namely data for the month three months prior to the effective date of the new payment amounts, and again prior to January 1, 2012 for the 2012 test year. In staff's view, this approach would be consistent with the Cost of Capital Report and with ensuring that all cost of capital parameters are based concurrently on the most recent data available and practical for setting rates for the test period. Board staff further argued that the updated rates should be supported with documentation respecting the calculations and source data.

SEC submitted that the short-term debt rates for both 2011 and 2012 should be updated using December 2010 forecasts. CME submitted that the Board should be consistent in how it determines the costs of short-term and long-term debt for government owned utilities.

OPG responded that Board staff had ignored the fact that the Board's Cost of Capital Report approved OPG to use the same approach for short-term debt that it used in the previous case. OPG also argued that Board staff had ignored the fact that the method approved in the previous case for setting short-term debt for OPG differs from the method used for electricity distributors. OPG prepared an Impact Statement prior to the oral hearing identifying items that exceed the $10 million materiality threshold and debt costs were not identified in the impact statement. OPG submitted that the short-term debt rate in the application is the same rate used for the business plan that underpins the application, and that it would be unfair for the Board to require it to selectively update the short-term debt costs for 2011.

Board Findings

The Board agrees with OPG that its approach to short-term debt rates is consistent with the previous decision, that it was accepted in the Cost of Capital Report, and that its forecast for the two test years is reasonable. The Board will not require OPG to update the short-term debt rates for either 2011 or 2012.

9.4 Cost of Long-Term Debt

OPG documented its actual and forecasted long-term debt for 2011 and 2012. OPG proposed that any unfunded portion of its long-term debt (the difference between the deemed long-term debt capitalization and actual or embedded debt) would attract the Board's deemed long-term debt rate based on data three months in advance of the effective date for the new prescribed payments. No parties opposed OPG's evidence with respect to its actual and forecasted long-term debt, but most parties opposed OPG's proposal for the cost of unfunded long-term debt.

Board staff argued that it is inappropriate for OPG to use the Board's deemed long-term debt rate as the cost for the unfunded portion of long-term debt. Board staff submitted that OPG's interpretation of the Board's Cost of Capital Report was inconsistent with the Board's policy and practice and that OPG's forecasted weighted average cost of existing and forecasted long-term debt should apply to the unfunded portion of long-term debt as well as to actual or embedded long-term debt.

SEC and VECC agreed with the Board staff submission, and argued that the Board should not adopt OPG's proposal because the deemed long-term debt rate is intended to be available only where there is no evidence of a utility's cost of long term debt.

OPG observed that Board staff relied on cases decided prior to the issuance of the Board's Cost of Capital Report, but noted that staff did not refer to the previous OPG case where the Board decided that it was appropriate to use the "hedged cost of planned debt" to calculate the cost of OPG's notional long-term debt. Further, OPG observed that as new debt is issued, it will be issued at future debt rates. OPG submitted that it has an active long-term borrowing program and it is not necessary to rely on the cost of historical debt as a proxy for future debt.

Board Findings

The Board agrees with Board staff's submission that the Board's deemed long-term debt rate is only intended to apply where a utility has no actual long term debt (or where the debt is held by an affiliate). This is not the case for OPG, and therefore OPG's weighted average cost of existing and forecasted long-term debt will apply to the unfunded portion of long-term debt as well as to actual or forecasted long-term debt in each test year.

OPG has suggested that this approach is not appropriate because the weighted average cost does not represent an appropriate proxy for future debt. The notional long-term debt, however, is not intended as a proxy for future debt. Forecast future debt is already incorporated into the calculations, and there was little evidence to suggest that notional debt would be replaced with actual debt during the test period. The notional debt remains a balancing item and therefore the Board concludes that the appropriate cost rate is determined using the weighted average cost of debt.

10 DEFERRAL AND VARIANCE ACCOUNTS

10.1 Introduction

OPG has three deferral and variance accounts for its hydroelectric business and nine accounts for its nuclear business. There are three additional accounts common to both businesses. Certain of these accounts were authorized under O. Reg. 53/05. All of these existing accounts were established pursuant to decisions in the first payments proceeding (EB-2007-0905), the motion proceeding (EB-2009-0038) or the accounting order proceeding (EB-2009-0174). OPG's evidence is that entries to these accounts during 2008, 2009 and 2010 have been made in accordance with the methodologies established in the relevant decisions. Interest on the accounts has been applied in accordance with the rates prescribed by the Board from time to time.

OPG proposed to clear the actual audited December 31, 2010 balances through payment amount riders. In its reply submission, OPG agreed to file audited 2010 deferral and variance account balances at the earliest possible time for possible inclusion in this Decision. No party objected to this approach. The audited balances were filed on February 7, 2011 and are presented in the table below.

Table 28: Summary of Deferral & Variance Accounts Balances from 2007 to 2009 and 2010 Audited Balances Proposed for Recovery ($million)

Account	Year End Balance 2007 (1)	Year End Balance 2008 (1)	Year End Balance 2009 (1)	Year End Balance 2010 (2)
Regulated Hydroelectric:				
Hydroelectric Water Conditions Variance	$6.3	$(21.6)	$(55.3)	$(70)
Ancillary Services Net Revenue Variance – Hydroelectric	7.2	(2.4)	(16.0)	(9)
Income & Other Taxes Variance	0.0	(0.2)	(0.3)	(8)
Tax Loss Variance	0.0	20.2	47.1	78
Interim Period Shortfall (Rider D)	0.0	(0.3)	(2.2)	(2)
Over/Under Recovery Variance – (2010)	0.0	0.0	0.0	(8)
Total	**13.5**	**(4.2)**	**(26.6)**	**(19)**
Nuclear:				
Pickering A Return To Service Deferral	183.8	129.5	81.8	33
Nuclear Liability Deferral	130.5	132.3	86.2	39
Nuclear Development Variance	11.7	(21.7)	(55.6)	(111)
Transmission Outages and Restrictions Variance	1.8	1.4	0.7	0
Ancillary Services Net Revenue Variance – Nuclear	(1.8)	(1.9)	(0.6)	0
Capacity Refurbishment Variance	0.0	(5.7)	(0.3)	(8)
Nuclear Fuel Cost Variance	0.0	(1.4)	(15.7)	6
Bruce Lease Net Revenue Variance	0.0	256.6	324.5	250
Income and Other Tax Variance	0.0	(7.8)	(12.1)	(32)
Tax Loss Variance	0.0	105.9	247.2	414
Interim Period Shortfall (Rider B)	0.0	0.3	6.6	7
Over/Under Recovery Variance – Nuclear (Rider A&C)	0.0	0.6	10.7	21
Total	**326**	**588.1**	**673.4**	**619**
Grand Total	**$339.5**	**$583.9**	**$646.8**	**$600**

(1) Source: Exh. H1-1-1, Table 1 (updated October 8, 2010)
(2) Source: Audited account balances (per Schedule of Regulatory Balances as at December 31, 2010 and Independent Auditors' Report), as filed on February 7, 2011

OPG proposed to clear the balances of all accounts (except the Tax Loss Variance Account) with payment riders effective from March 1, 2011 to December 31, 2012. OPG proposed to amortize the balance in the Tax Loss Variance Account over a 46 month period from March 1, 2011 to December 31, 2014. Based on forecast account balances, filed on October 8, 2010, of $17.4 million credit for hydroelectric and $690.1 million debit for nuclear, the forecast test period riders would be a credit of $1.66/MWh for hydroelectric and a charge of $5.06/MWh for nuclear. These riders will change to reflect the audited 2010 balances as filed on February 7, 2011. The 2010 year end balances summarized in Table 28 above, are proposed for recovery in the test period, except the tax loss variance account balances, which are proposed for recovery over a 46 month period.

OPG requested the continuation of the following accounts:

- Ancillary Service Net Revenue Variance Account – Hydroelectric and Nuclear
- Income and Other Taxes Variance Account
- Tax Loss Variance Account
- Hydroelectric Water Conditions Variance Account
- Hydroelectric Deferral and Variance Over/Under Recovery Variance Account
- Nuclear Liability Deferral Account
- Nuclear Development Variance Account
- Capacity Refurbishment Variance Account
- Nuclear Fuel Cost Variance Account
- Bruce Lease Net Revenues Variance Account
- Nuclear Deferral and Variance Over/Under Recovery Variance Account

OPG requested that the following accounts continue only for entries for amortization and interest and that the accounts be closed once the balances are recovered:

- Interim Period Shortfall (Rider D) Variance Account
- Pickering A Return to Service Deferral Account
- Transmission Outages and Restrictions Variance Account
- Interim Period Shortfall (Rider B) Variance Account

10.2 Existing Hydroelectric Accounts

No submissions were filed on the hydroelectric specific accounts.

Board Findings

The audited December 31, 2010 balances in the hydroelectric accounts are approved for disposition as proposed by OPG. The Board also approves the continuation of the hydroelectric accounts as proposed by OPG.

10.3 Existing Common and Nuclear Accounts

Intervenors made submissions on the following accounts: Tax Loss Variance Account (which is common to hydroelectric and nuclear); Nuclear Liability Deferral Account;

Capacity Refurbishment Variance Account; Nuclear Fuel Cost Variance Account; and the Bruce Lease Net Revenues Variance Account.

10.3.1 Tax Loss Variance Account

The Tax Loss Variance Account was established by the Board in the motion proceeding EB-2009-0038. That proceeding was held to review the Board's previous payments decision, and in particular the Board's decision in the area of tax losses for the period that preceded regulation by the Board and rate increase mitigation. The motion decision stated "the clearance of this account will be reviewed in OPG's next payment application hearing when a future panel of the Board reviews the tax analysis ordered in the Payments Decision [EB-2007-0905]." In the current proceeding, OPG seeks recovery of the December 31, 2010 balance in the account over a 46 month period. The audited balance is $492 million: $78 million is allocated to the hydroelectric business and $414 million is allocated to the nuclear business.

The Tax Loss Variance Account and the history of the tax losses is a matter of considerable complexity. It is useful to review the history of this issue through the various proceedings.

In the previous payments proceeding, OPG recognized that the revenue requirement increase it was requesting was significant and would result in a 19% increase in payment amounts. OPG identified that the regulatory taxable income calculation for the years 2005-2007, the period during which the Province established the payment amounts and before the period in which the Board set the amounts, resulted in tax losses for those years. OPG calculated the regulatory tax losses at the end of 2007 to be $990.2 million in total. OPG proposed to accelerate the application of the available tax losses to reduce the test period revenue requirement in order to mitigate the increase in the payment amounts to 14.8%. Specifically, OPG proposed to exclude the 2008-2009 test period tax provision from the revenue requirement and to reduce the revenue requirement by a further $228 million.

In the payments decision, the Board stated that it was not convinced that there were any regulatory tax losses to be carried forward to 2008 and later years. The Board directed OPG to file better information on its forecast of test period income tax provision and a re-analysis of the prior period tax returns in its next application. The Board also required OPG to provide mitigation in an amount that was proportional to the originally proposed mitigation amount (i.e. 22% of the revenue deficiency). The resulting mitigation was $168.7 million.

OPG filed a motion for a review and variance of the original decision related to these matters. The Board granted the motion and made the following decision:

> The Board varies the Payments Decision [EB-2007-0905] in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses.[49]

In the current proceeding, OPG's evidence is that the Board's EB-2007-0905 decision reduced OPG's revenue requirement by $342 million, consisting of $168.7 million for the mitigation amount and $172.5 million for the elimination of the tax provision for 2008 and 2009. This amount was also identified during the motion proceeding. OPG described the determination of this amount as follows:

- The amount of mitigation included in the EB-2007-0905 decision (excluding tax) was $168.7 million.
- The benchmark tax expense for the previous test period was $66 million.
- The provision for taxes and gross up is $106.5 million.
- The total is $341.2 million

In accordance with the Board's decision in EB-2007-0905, OPG recalculated its regulatory tax losses for the period April 1, 2005 to March 31, 2008 to be $188.5 million. OPG described the adjustments it made to the original estimate of $990.2 million to arrive at $188.5 million as follows:

- The Board's decision on the Pickering A Return to Service Deferral Account ("PARTS") required OPG to provide tax benefits to coincide with the timing of the recovery of the costs. OPG determined that this would reduce the tax loss by $147 million.
- The previous decision stated that any calculation of tax loss "in respect of the prescribed facilities should exclude revenues and expenses related to the Bruce

[49] Decision and Order, EB-2009-0038, May 11, 2009, p. 15.

lease." OPG determined that the tax loss should be reduced by $390 million as a result.

- The Board noted in the previous decision that the operating loss in 2007 was borne completely by OPG's shareholder, which reduced the tax loss by $234.2 million.
- OPG determined that a further $37 million reduction was required due to an update of information for 2007 and that a $6.5 million addition was required due to allocation of adjustments to the period prior to regulation.

OPG engaged Ernst & Young to apply specified procedures guided by section 9100 of the CICA Handbook to reconcile information in OPG's corporate tax returns to the determination of prior period tax losses for the prescribed facilities for 2005, 2006 and 2007. Ernst & Young was able to tie the numbers on the schedules back to the source documents with no exceptions.

From this amount of $188.5 million OPG deducted the $77.6 million in taxable income for the period January 1, 2008 through March 31, 2008. This left $110.9 million in remaining net cumulative losses, or a revenue requirement amount of $50.3 million.

The difference between the revenue requirement reduction ($342 million) and the remaining tax loss ($50.3 million), being $290.9 million, was booked to the account for the period April 1, 2008 through December 31, 2009. OPG forecast the amount for 2010 to be $195 million, being an annualized grossed-up amount of the $342 million revenue requirement reduction during the original 21 month test period. To these amounts OPG also applied interest at the Board prescribed levels.

SEC provided in its argument a detailed alternative estimate of the appropriate amounts to be considered in respect of this issue. SEC submitted that there should be no regulatory tax liability for the period 2008 to 2012 because of timing differences which SEC has determined are in the order of $1,660.4 million. In SEC's view, these amounts, which are tax deductions taken by OPG prior to April 1, 2008, should be available to ratepayers. SEC estimated that an amount between $450 million and $500 million would remain available for deduction in 2013 and beyond.

The principle that SEC relied on in its submission is "benefits follow costs" which SEC describes as meaning "if the ratepayers bear a cost in their rates, then any tax impacts that flow from that cost accrue to the ratepayers as well."[50] In particular, SEC is concerned with the application of this principle with respect to tax related timing differences. "Timing difference" refers to government tax policy which in SEC's words "allows taxpayers to front load their tax deductions, and thus save tax dollars, as a way of providing economic stimulus and incenting long term spending."[51] SEC asserted that the general pattern is one of tax savings in the early years and tax costs in later years and in general the regulatory system matches this by using a taxes payable approach to setting rates.

In OPG's case, however, SEC argued that the balance is disrupted because OPG became regulated part way through the tax benefit period, meaning that the shareholder will have gained from the tax benefits in the pre-regulation period and ratepayers will bear the balancing tax costs in the regulation period. In SEC's view, the appropriate approach is to re-examine the relevant periods to ensure ratepayers receive the benefits of these timing differences.

SEC reviewed the evidence and determined that OPG had $1,660.4 million of timing differences (including amounts related to Bruce) in the three years prior to April 1, 2008 which should be available to ratepayers. The largest component (over $1.2 billion) is related to nuclear waste and decommissioning costs. These amounts include impacts related to Bruce, because in SEC's view, when the Board decided that GAAP should be used to calculate the net Bruce lease revenue, the Board was "not intending to say that Bruce should be an exception to the "benefits follow costs" principle related to tax calculations."[52]

SEC further argued that the tax losses prior to April 1, 2005 should also be considered for potential availability to ratepayers and recommended that the Board direct OPG to prepare a detailed review of the losses at the next proceeding.

OPG opposed SEC's analysis on three principal grounds. First, OPG argued that SEC's analysis consists of untested evidence. In OPG's view, SEC's approach is a form of opinion/expert evidence and no authority has been provided for the positions taken in relation to the accounting and regulatory principles related to tax/accounting timing differences.

[50] SEC Argument, para. 10.2.9.
[51] SEC Argument, para. 10.2.16.
[52] SEC Argument, para. 10.2.63.

Second, OPG argued that SEC's analysis violates Board approved regulatory principles and does not comply with accepted tax and accounting practices. In OPG's view, tax loss carry forward is a concept which is recognized in the *Income Tax Act* and OEB regulated tax calculations but timing differences carried forward have no basis in accounting. OPG further argued that SEC's generalization regarding the pattern associated with timing differences is incorrect and pointed, for example, to testimony that deductions for nuclear liabilities are only available when actual cash expenditures are made. OPG also submitted that whereas it applies the deductions against earnings before tax and carries forward any resulting loss, SEC ignores earnings before tax and does not apply the deduction in the period for which it applies.

Third, OPG maintained that SEC's analysis is based on misinterpreted facts and faulty assumptions. OPG provided an analysis of why, in its view, SEC's analysis is flawed. For example, OPG explained that its treatment of the PARTS amounts, unlike SEC's proposal, is based on the Board's direction in the first payments decision which required that the timing of PARTS recovery match the timing of providing the associated tax cost or benefit to ratepayers. OPG also pointed to the incomplete nature of SEC's analysis and the lack of identification of adjustments to earnings that were additions. OPG further argued that SEC had incorrectly applied the "benefits follow cost" principle, and OPG has appropriately excluded Bruce lease revenues and costs from its tax loss determination. OPG also argued that SEC has ignored the provisions of O. Reg. 53/05 sections 6(2)5 and 6(2)6 which require the Board to accept the revenue requirement impact of accounting and tax policy prior to the effective date of the Board's first order.

OPG further argued that there is no basis to review the period before April 1, 2005 and therefore SEC's proposal that related evidence be provided at the next proceeding should be rejected.

CME supported SEC's submissions but also presented another approach related to the mitigation amount in relation to the original proceeding. CME pointed out that OPG's evidence in the original proceeding was that a 19% increase was excessive and needed to be reduced in order to bring the increase to about 14.8% to be reasonable. CME estimated this amount to be $360 million. OPG responded that the motion decision varied the original decision in a way that links the mitigation with the regulatory tax losses. OPG argued that CME has mischaracterized the nature of OPG's original proposal as being focused on mitigation.

VECC and CME argued that no amount associated with 2010 should be recoverable. In VECC's view, "The decision establishing the test period Tax Loss Variance Account never contemplates, either explicitly or implicitly, the operation of a similar account beyond 2009."[53] VECC asserted that it is clear in the decision that the variance to be tracked was limited to the test period. VECC went on to submit that if the Board rejects this argument, then at a minimum the $195 million for 2010 should be reduced by $26.2 million to reflect the reduced tax amounts related to nuclear liabilities in 2010. VECC also submitted that had OPG proposed the tracking of $195 million in the accounting order proceeding, EB-2009-0174, intervenors may have made submissions and the Board may have considered different relief. This position was supported by CME and SEC.

OPG replied that the accounting order proceeding was about the mechanics of booking entries in accounts in 2010 and that there was no need to make a request for this matter for the tax loss variance account. Further, OPG stated that it was not necessary to seek extended terms for any of the deferral and variance accounts:

> …payment amounts are established based on a test period, but they remain in place until changed by the OEB. Similarly, unless the OEB explicitly states otherwise, variance and deferral accounts established in relation to those payment amounts also continue until changed by the OEB.[54]

OPG also rejected VECC's proposal that the 2010 balance be reduced by $26.2 million related to the tax impacts of changes in nuclear liabilities. OPG maintained that the account does not cover changes in 2010 actual amounts resulting from the Darlington Refurbishment project:

> The revenue requirement impact pertaining to income taxes should be treated the same as the revenue requirement impact associated with non-tax factors. They are simply not relevant to the determination of the test period revenue requirement.[55]

CCC supported SEC's submission, but argued that the Board should defer consideration of the tax loss variance account to a separate proceeding, and that an independent expert should report on the issue. OPG objected to this suggestion

[53] VECC Argument, para. 119.
[54] Reply Argument, p. 196.
[55] Reply Argument, p. 156.

referring to direction in the EB-2007-0905 and EB-2009-0038 decisions which stated that the matter would be addressed in this payment amounts application.

Board Findings

The Board approves recovery of the balance in the Tax Loss Variance Account in accordance with OPG's proposal to recover the balances over a 46 month period. However, the riders that will be given effect by this Decision and subsequent payment order will be effective until December 31, 2012.

CCC argued that the matter should be deferred to another proceeding. The Board does not agree. It was made clear in the motion proceeding and the prior payments decision that the issues were to be resolved in this proceeding. It would only be appropriate to defer consideration of the issue if there were insufficient evidence on the record. That is not the case here.

SEC argued that the appropriate application of the "benefits follow costs" principle, which was articulated by the Board in the original payments decision, would see the inclusion of the impact of timing differences in the calculation of the tax amounts. The result of SEC's approach would be a proposed credit for ratepayers resulting from net timing differences of $1,660.4 million. Of this $1,660.4 million, SEC identified $1,052.4 million for the prescribed facilities and $608.0 million for Bruce.

OPG has pointed to significant deficiencies in SEC's analysis, and the Board finds that OPG's criticisms have merit. For example, the Board agrees that OPG's treatment of the amounts related to the PARTS account is consistent with the Board's prior decision which required that the timing of the tax effect be aligned with the recovery of the cost. The Board also accepts OPG's evidence that the effect of timing differences is not always as SEC has posited, and in particular not in the case of asset retirement costs. The Board also concurs with OPG's position that it is clear the Board intended for Bruce revenues and costs to be excluded from the analysis. For these reasons, the Board finds SEC's calculations and estimations to be unpersuasive.

With respect to amounts in the account for 2010, the Board finds that there is no basis in the motion decision for the proposition that this account was only effective during the prior test period. The section of the decision that has been quoted by the parties is as follows:

> The Board varies the Payments Decision [EB-2007-0905] in a manner that links the revenue requirement reduction and regulatory tax losses, and orders the establishment of a tax loss variance account to record any variance between the tax loss mitigation amount which underpins the rate order for the test period and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the Board's directions in the Payments Decision as to the re-calculation of those tax losses.[56]

The parties opposed to any recovery for 2010 point to the phrase "the tax loss mitigation amount which underpins the rate order for the test period" as the basis for their position that the account was only established for the duration of the test period. The Board does not agree that the decision is appropriately interpreted in that way for two reasons. First, the plain reading of the phrase indicates that the words "for the test period" are meant to describe the relevant rate order. Second, the Board indicated that the account was to be cleared, and the relevant issues addressed, in the next proceeding. While parties might have expected that the next proceeding would follow directly from the prior test period, having found that the original decision was in error and that the payment amounts included amounts which would need to be adjusted at a future time, it does not follow that the Board would have intended for the account to have a fixed duration for only the test period. In essence, the account was put in place to correct an error in the original decision and as long as those original payments were in place the error continued to exist.

The Board also rejects CME's argument that the account should be adjusted to reflect a quantification of the appropriate level of mitigation. The scope of the account was clearly set out in the motion decision and there is no suggestion that any amounts in addition to the description of the appropriate variance are to be contemplated for purposes of mitigation.

VECC argued that at a minimum the Board should reduce the 2010 balance by $26.2 million to reflect the reduced tax amounts related to nuclear liabilities in 2010 (as compared to the original test period). The Board does not agree. VECC is proposing an adjustment to the original mitigation amount ($341.2 million) to reflect one component of actual results, but the motion decision defined and fixed the original mitigation amount as "the tax loss mitigation amount which underpins the rate order for the test period." This wording effectively fixes the amount at the level which underpinned the original payment order and contemplates no adjustment for actual

[56] Decision and Order, EB-2009-0038, p. 15.

results in relation to regulatory taxes paid during the period. No adjustments have been made to reflect actual regulatory taxes for the original 2008 and 2009 test period; it would likewise be inappropriate to adjust the 2010 amount.

10.3.2 Nuclear Liability Deferral Account

OPG incurs costs associated with decommissioning its nuclear facilities and managing used fuel and low and intermediate level waste. These costs are recognized as expenses over the life of the nuclear stations and are included in payment amounts because they are part of the cost of operating the nuclear stations.

The Nuclear Liability Deferral Account (Transition) was established in 2007 in accordance with section 5.1(1) of O. Reg. 53/05 to capture the revenue requirement impact of any change in OPG's nuclear decommissioning liability arising from an approved reference plan under the Ontario Nuclear Funds Agreement ("ONFA"). Section 5.1(2) of the O. Reg. 53/05 provides that simple interest be applied on the monthly opening balance at an annual rate of 6%. That account was in effect until the Board's first order.

The previous proceeding established the current Nuclear Liability Deferral Account effective April 1, 2008 pursuant to section 5.2(1) of O. Reg. 53/05. The Board directed OPG to record the return on rate base using the average accretion rate on OPG's nuclear liabilities of 5.6% for the test period.

SEC observed that the balance in the account, as noted in the previous decision, was $130.5 million and that no changes to the reference plan under ONFA have taken place. SEC stated that the opening balance of the account on April 1, 2008, as noted in the current application, was $163.9 million with an amount of $31.3 million recorded in the first quarter of 2008.

OPG replied that the difference between nuclear liability costs embedded in payment amounts approved by the province for the period up to March 31, 2008 and those costs arising from the reference plan under ONFA are captured by the Nuclear Liability Deferral Account. OPG referred to the 2008 OPG Audited Financial Statement and the first quarter 2008 Financial Statements. Both noted an increase to the nuclear liability deferral account of $37 million of which $6 million is interest.

Board Findings

The Board is satisfied with OPG's explanation for the entries in the Nuclear Liability Deferral Account (Transition) for the first quarter of 2008 in relation to section 5.1(1) of O. Reg. 53/05.

10.3.3 Bruce Lease Net Revenues Variance Account

The Bruce Lease Net Revenues Variance Account was established to capture the difference between (i) the forecast costs and revenues related to Bruce that are factored into the test period payment amounts for Pickering and Darlington and (ii) OPG's actual revenues and costs in respect of Bruce based on Generally Accepted Accounting Principles. The cost impact of any changes in nuclear liabilities related to Bruce would also be recorded in this account. The balance in this account as of December 31, 2010 was $250 million.

Board staff noted that OPG proposed to recover the large balances in other accounts over an extended period to mitigate the impact on rates. In particular, OPG proposed to recover the balance in the Tax Loss Variance Account over 46 months, and in the previous proceeding the Board approved a 45 month recovery period for the Pickering A Return to Service Deferral Account (although OPG had proposed a 12 year recovery period). Accordingly, Board staff submitted that a 46 month recovery period was appropriate for the Bruce Lease Net Revenues Variance Account. CCC supported this proposal.

OPG replied that Board staff did not provide a target level for rate increases and that staff did not acknowledge the impact of deferring recovery on OPG. OPG also noted that extending the recovery period would push rate pressure into the next test period. OPG further argued that the Pickering A Return to Service account was not an appropriate example to follow because OPG's original proposal was for recovery over 12 years, with carrying costs based on the weighted average cost of capital, to match the underlying asset life. OPG rejected the view that accounts with large balances should be recovered over a longer term and argued that the extended recovery for the tax loss variance account provides sufficient rate mitigation.

SEC observed that the balance in the account is largely due to the loss on the segregated funds in 2008 and submitted that this was a one-time event that is not likely to recur. In SEC's view, the proposed recovery of almost $300 million during the test period for a one-time event is not appropriate and not in accordance with the original intent of the account. Like Board staff, SEC proposed that a 46 month period was appropriate. OPG replied that the Board's decision in the previous proceeding was clear on the need for the account and the account entries. OPG submitted that it is unnecessary to consider whether the balance is due to unusual one-time events or the original intention of the account.

Board Findings

The Board acknowledges that the balance in the account is significant and that an extended recovery period could provide additional rate mitigation. However, the Board concludes that further mitigation is not required in the context of this application. The proposed disposition period is approved.

10.3.4 Capacity Refurbishment Variance Account

The operation of this account in respect of the Pickering B Continued Operations project has already been addressed in Chapter 4.

The only other issue raised by the parties in respect of this account relates to the cost of Pickering B refurbishment studies. AMPCO submitted that the Board should disallow $4.9 million related to Pickering B refurbishment studies because in AMPCO's view it is clear that it was never worthwhile to study the refurbishment of Pickering B. OPG replied that the evaluation of Pickering B refurbishment was undertaken pursuant to a shareholder directive and that OPG's proposed spending was reviewed and approved in the previous proceeding and concluded that the Board should reject AMPCO's submission.

Board Findings

The Board will not remove the costs associated with the Pickering B refurbishment studies. These activities were prudently undertaken and the costs are therefore eligible for recovery under O. Reg. 53/05 and the account.

10.3.5 All Other Existing Common and Nuclear Accounts

The audited December 31, 2010 balances in the other common and nuclear accounts are approved for disposition as proposed by OPG. The Board also approves the continuation of the existing common and nuclear accounts as proposed by OPG.

10.4 New Accounts Proposed by OPG

10.4.1 IESO Non-energy Charges Variance Account

As a load customer, OPG pays IESO non-energy charges. OPG maintained that these charges are difficult to forecast, principally because of the Global Adjustment Mechanism. OPG noted that variances in the IESO non-energy charges have been material and have occurred in both directions in recent years. OPG also noted that effective January 1, 2011, O. Reg. 398/10 will change the method used to collect the Global Adjustment Mechanism, potentially compounding forecasting difficulties due to the uncertain impact on the behaviour of large volume consumers.

Board staff submitted that it would be reasonable for the Board to approve the account as the charges are largely pass-through and there are considerable challenges in forecasting them. If the account was approved, however, staff questioned whether OPG would have an incentive to implement energy efficiency measures and suggested that OPG should be required to demonstrate efforts to reduce consumption from the IESO grid. CCC was not opposed to OPG's account request and supported Board staff's suggestion that OPG be required to demonstrate efforts to reduce energy consumption prior to clearing the account. OPG responded that it was prepared to provide evidence that it is making efforts to reduce consumption which are economic and practical.

As an alternative, Board staff observed that the variance for years in which there were no vacuum building outages hovered around $10 million. Accordingly, Board staff submitted that it would not be unreasonable to deny the account on the basis that the amounts were not material. OPG responded that a variance of $10 million was material and highlighted its view that the level and volatility of the Global Adjustment Mechanism was expected to increase over time and that therefore the variance would increase substantially.

SEC agreed that IESO non-energy charges are material and can cause dramatic changes in the delivered cost of electricity. However, in SEC's view, the fact that the electricity bill may be unpredictable is a normal business risk, and part of the risks for which a cost of capital is allowed. SEC cautioned that approval of the account could encourage other utilities to seek broader protection against normal business risks. SEC observed that, if anything, OPG has less right than other ratepayers to have this variance account as 25% of the Global Adjustment Mechanism for the 12 month period ending August 2010 was paid to OPG.

OPG disagreed that these charges are a normal business risk arguing:

> While these charges may have been part of normal business risks several years ago, and may again return to some level of predictability in the future, in more recent years and for the test period, owing to volatile components of these charges, most notably the Global Adjustment, these charges are well outside normal business risks.[57]

Board Findings

Board staff and CCC have characterized these charges as a “pass-through”. However, these charges are only a pass-through if the Board accords that treatment to them. The concept of pass-through is appropriate, for example, in the case of the treatment of natural gas supply costs. Natural gas distribution utilities purchase natural gas and transportation services which are then sold to their customers without a mark-up. In these circumstances it is appropriate that the utility be kept whole, in other words that the supply costs are “passed through” to customers, through the use of a variance account. That is not the circumstance here. Electricity charges are a business expense for OPG, and while it may be difficult to forecast these charges and there are varying expectations for the rate of growth of these charges, they are certainly a business risk faced by all participants in the electricity sector in Ontario. Since this is a risk faced by all market participants, the Board concludes that it is a normal business risk. The request for the account is denied.

10.4.2 Pension and Other Post Employment Benefits Cost Variance Account

The Board has not approved the establishment of this account. Details are contained in Chapter 6.

10.5 New Accounts Proposed by Other Parties

A number of accounts were proposed by OPG or intervenors through argument. Each proposal for an account was made in the context of a specific issue in the hearing (for example, production forecast, other revenue, cost of capital, etc.). For purposes of this

[57] Reply Argument, p. 206.

Decision, the Board has addressed each proposal for an account in the context of the broader issue. The only new accounts to be established are for Surplus Baseload Generation (Hydroelectric) and the Hydroelectric Incentive Mechanism.

11 DESIGN AND DETERMINATION OF PAYMENT AMOUNTS

11.1 Design of Payment Amounts

OPG proposed no changes to the previously approved payment amounts design. Currently, the hydroelectric and nuclear payment amounts are each 100% variable amounts based on forecast production. OPG proposed that the payment amount for the regulated hydroelectric facilities be determined by dividing the hydroelectric revenue requirement by the forecast hydroelectric production. Based on OPG's filing, the payment amount would be $37.38/MWh. Similarly, OPG proposed that the payment amount for the prescribed nuclear facilities be determined by dividing the nuclear revenue requirement by the forecast nuclear production. Based on OPG's filing, the payment amount would be $55.34/MWh. No issues were raised with respect to this methodology and the Board finds that the previously approved methodology should continue. The precise levels of the payment amounts will be determined on the basis of the Board approved revenue requirements and production forecasts.

OPG proposed the use of separate payment riders for hydroelectric and nuclear for purposes of clearing the respective deferral and variance account balances. The precise levels of the payment riders will be determined on the basis of the Board approved deferral and variance account balances and production forecasts. The recovery of the deferral and variance account balances is dealt with in Chapter 10.

OPG also proposed to maintain the same Hydroelectric Incentive Mechanism. A number of parties opposed OPG's proposal. This issue is addressed below.

11.2 Hydroelectric Incentive Mechanism

In the previous proceeding, OPG proposed and the Board approved a hydroelectric incentive mechanism ("HIM"). Under the HIM, OPG receives the regulated payment amount for the actual average hourly net energy production over the month. For production above the monthly average hourly volume in a given hour, OPG receives market prices. For production below the monthly average hourly volume in a given hour, the amount payable to OPG at the regulated payment amount is reduced by the production shortfall multiplied by the market price. The purpose of the HIM is to incent OPG to move production from periods of low value to periods of higher value, based on market signals. The incremental revenues (above the regulated payment amounts) are retained by the company and not returned to ratepayers.

While there is some peaking capability at all the regulated hydroelectric facilities, the majority of peaking activity occurs at the Sir Adam Beck complex, and specifically the pump generating station ("PGS"). OPG can move substantial quantities of energy from off-peak to on-peak periods. The cost of pumping in the off-peak period is compared with the forecast value of the additional generation in the next on-peak period, and vice versa.

OPG estimated that between December 2008 and December 2009, the HIM reduced average market prices by $1.14/MWh, and in OPG's view this demonstrates the value of moving energy from off-peak to on-peak. The forecast HIM revenue for 2009 was $12.0 million, but the actual was $23.2 million. The forecast HIM revenue for 2010 was $8.0 million, but the year-to-date actual at the end of August 2010 was $11.0 million. For the test period, OPG forecasted HIM revenues of $13.3 million for 2011 and $16.3 million for 2012. OPG expects market price spreads to decline relative to 2009.

Board staff, AMPCO, CME, CCC, Energy Probe and VECC made submissions on the HIM. In general, parties submitted that the incentive was excessive and that a sharing mechanism was appropriate. Board staff proposed a graduated sharing mechanism combined with a thorough review of the HIM forecast methodology. CCC proposed that ratepayers receive 75% of the HIM revenues, with 25% for OPG. CME took the same position.

Board staff also submitted that the sharing mechanism would reduce the relative value of the HIM for OPG in comparison to pumping water in response to SBG conditions, thereby increasing the likelihood that OPG will pump water during SBG rather than spill it.

VECC submitted that the HIM should be discontinued in its entirety because, in VECC's view, OPG confirmed during the oral hearing that it could operate exactly as it does now in the absence of the HIM. In VECC's view there is no basis for providing an additional financial incentive related to the operation of these regulated assets; all proceeds should flow to the ratepayers. In the alternative, VECC supported a 75%/25% sharing between ratepayers and the shareholder (or 50%/50% sharing if 90% of the forecast level is built into the forecast revenue).

OPG responded that any sharing mechanism will tend to reduce the frequency and use of the PGS resulting in less time shifting of generation because the benefits to OPG will be reduced without reducing the risks. Further, OPG stated that while parties may view a sharing mechanism as beneficial, in OPG's view it comes at a cost of reduced market benefit for consumers.

Board staff submitted that due to the large proportion of energy supplied through contract pricing, the market price is largely irrelevant in establishing electricity costs for consumers. CCC also took the view that the claimed reduction in market prices was not supported by the evidence. OPG replied that it has no control over the Global Adjustment Mechanism and bases its decisions on market price spreads and maintained that "any decrease in HOEP does not necessarily result in a one-for-one increase in Global Adjustment payments."[58] OPG further asserted "any drop in HOEP will still result in savings to consumers."[59]

Energy Probe did not support a sharing mechanism. Energy Probe argued that the HIM formula is flawed, and noted that it had identified this situation in the previous proceeding and that the evidence in this proceeding confirmed that the flaw was significant. In Energy Probe's submission, the current formula subtracts 100% of energy used to pump from the calculation of hourly volume, thus reducing the hourly volume threshold which determines the base amount in the HIM formula, but when OPG generates from the PGS it recovers some of the energy used for pumping. Energy Probe submitted that this recovered energy is 44% of the energy consumed to pump. Therefore, the adjustment to hourly volume from PGS consumption should be 56% in Energy Probe's view, not 100%. Essentially, OPG is actually consuming 56% of the energy used to pump water while storing and recovering the remaining 44% when it releases the water from the PGS. Energy Probe concluded that the Board should eliminate the circularity or "second payment" in the present HIM formula, by adding a correction to the calculation of MWavg.

AMPCO also proposed that the formula be modified by adjusting the hourly average rate (for the month) to remove the effect of PGS's turn-around energy losses.

OPG acknowledged that pumping lowers the hourly volume, but went on to submit:

[58] Reply Argument, p. 29.
[59] Reply Argument, p. 29.

> However, to artificially increase the net energy used to determine the hourly volume by ignoring the energy used for pumping creates a fictional situation where the energy threshold is set higher than what is achieved in any given month.[60]

OPG maintained that if the threshold was set artificially high, the benefits to consumers and OPG would be reduced.

Board Findings

The purpose of the HIM is to provide OPG with incentives to operate the PGS in a way which benefits consumers. OPG maintained that it was appropriate to demonstrate the success of the HIM on the basis of market price spreads. However, market prices are only one component of the price paid by consumers for electricity generation, and even though OPG may have no control over the Global Adjustment Mechanism, the ultimate value for consumers from the HIM must be assessed in light of the actual generation costs borne by consumers, not just one component of those costs.

The evidence does not support a conclusion that the current structure of the HIM is providing significant benefits for consumers. It is clear that a substantial portion of the market is now under contract and that fluctuations in the market price are largely offset by variations in the Global Adjustment Mechanism. In relation to this issue, OPG argued that this effect is not one-for-one, but in relation to the issue of a variance account for IESO non-energy charges, OPG argued that lower market prices do result in corresponding increases in the Global Adjustment Mechanism. The Board finds that the net benefits to consumers are likely substantially less than estimated by OPG on the basis of market price differentials alone.

The Board also sees an important relationship between the HIM and SBG. In this Decision, the Board has decided that OPG will be compensated for SBG. Under these circumstances, the Board concludes that while there may be consumer benefits from OPG shifting production between low market value and high market value periods, this shifting is of greatest benefit to ratepayers if in the first instance it mitigates the level of SBG – when ratepayers will otherwise pay the regulated payment amount for generation lost through spill related to SBG.

The Board will not make the adjustment proposed by Energy Probe. While the Board agrees with Energy Probe's concern regarding the circularity of the formula and the

[60] Reply Argument, p. 30.

resulting addition to the incentive payment, the Board's conclusion is that it is more appropriate to re-visit the structure of the HIM in its entirety in the next proceeding rather than attempt to modify it in incremental ways in this proceeding. Instead, the Board will adjust the rate of incentive both directly and through the operation of the SBG variance account.

The Board finds that it is appropriate to reduce the level of incentive for OPG. The incentive is paid for directly by consumers; it is not the result of incremental business from other customers. This incentive is a premium paid by ratepayers to OPG so OPG will operate in a way which is of greater benefit to ratepayers. The Board has already found that OPG has not adequately substantiated its claim of consumer benefits, and therefore, until a more robust structure is established, the Board will require that 50% of the proceeds of the HIM be returned to customers and will incorporate HIM revenues into the revenue requirement as a revenue offset.

The Board will also adjust the HIM through its review of the SBG deferral account. OPG has indicated that it will use the PGS to mitigate SBG if the price spreads warrant it. However, for production that is lost due to SBG, ratepayers will compensate OPG directly for the full volume at the regulated payment level. The Board therefore expects OPG to use the PGS to the maximum extent possible to mitigate this additional direct cost on ratepayers. When assessing the circumstances which give rise to lost production due to SBG, the Board will examine the use of PGS and OPG will have to fully justify any instances in which the PGS is not used. If the Board finds that OPG could have, or should have, used the PGS to mitigate SBG, the Board will adjust the balance in the SBG account accordingly. The Board expects that this approach will have the effect of moderating the total level of incentive available to OPG, but concludes that it is a better structure to ensure direct benefits to ratepayers.

In recognition of the potential interaction between SBG and HIM, the Board will only incorporate a portion of the HIM revenue forecast into the revenue requirement: $5 million for 2011 and $7 million for 2012. The Board also directs OPG to establish a variance account to track all additional HIM net revenues above this forecast provision. Additional net revenues up to $5 million in 2011 and $7 million in 2012 will all be retained by OPG, and any additional net revenues beyond those levels will be shared equally between OPG and ratepayers.

The Board also directs OPG to re-address the HIM structure in its next application. Specifically, the Board expects OPG to provide a more comprehensive analysis of the benefits of the HIM for ratepayers, the interaction between the mechanism and SBG, and an assessment of potential alternative approaches in light of expected future conditions in the contracted and traded market. If OPG is unable to perform this analysis through lack of information, then the company should seek to have the analysis performed by an agency with access to the necessary information. It may well be appropriate for OPG to request that the IESO examine the issue and provide suitable evidence or for OPG to work with the IESO to prepare the evidence.

12 REPORTING AND RECORD KEEPING REQUIREMENTS

OPG currently has no obligation to file financial and operating reports with the Board on a regular basis. The Board established Electricity Reporting and Record Keeping Requirements ("RRR") in 2002. Distribution utilities file financial and operating information on a quarterly and annual basis in accordance with the RRR and as a condition of their licence.

At issue in this proceeding is what reporting requirements should be established for OPG and whether a RRR should be established for the company. Board staff proposed a list of potential RRR documents during the proceeding. OPG confirmed that it could provide many of the documents.

Board staff and SEC submitted that OPG should begin filing RRR in 2011. OPG did not object to the establishment of RRR, but submitted that a separate process would be appropriate in order to establish requirements which recognize cost considerations and are minimally intrusive. In OPG's view, its RRR should be tailored to its regulatory environment and the potential IRM regime. OPG referred to the Board's approach to RRR for natural gas utilities as an example of the process to follow.

In terms of financial information, OPG confirmed that it can provide information that is publicly available in its Management's Discussion & Analysis ("MD&A") and unaudited interim (quarterly) consolidated financial statements as well as its annual MD&A and audited consolidated financial statements, and when available its annual report. These documents reflect the financial performance of OPG as a whole.

OPG objected to providing audited financial statements for the prescribed facilities on an annual basis. The decision in the previous proceeding directed OPG to file audited financial statements for the prescribed facilities, and OPG provided those financial statements for 2008 and 2009 with the current application. OPG claimed that the statements are time consuming and cost $400,000 to produce. Further, OPG maintained that any comparison with Hydro One's capability to file separate financial statements for the distribution and transmission businesses is inappropriate as OPG's financial and monitoring systems were designed before identification of the prescribed facilities. OPG has one system for all accounts and one general ledger. OPG also observed that the statements were not referred to during the current proceeding.

Board staff submitted that OPG should prepare a report for the Board detailing the costs to develop the capability to produce audited annual financial statements for the prescribed facilities.

SEC argued that OPG should be required to establish appropriate systems that would lead to the efficient preparation of audited financial statements for the prescribed facilities. SEC noted that the prescribed facilities are the biggest part of OPG's business and that OPG receives substantial benefit from being regulated and that being regulated entails providing reliable, independent information. SEC suggested that OPG should take the opportunity to revise its systems in parallel with system changes for IFRS. SEC also argued that the reason evidence is not the subject of cross-examination is because its meaning is clear, and that the audited financial statements for the prescribed facilities assisted parties in understanding OPG's business.

OPG proposed the filing of an annual regulatory return as an alternative to audited financial statements for the prescribed facilities, although OPG noted specific requirements have not been defined. OPG was not persuaded by SEC's position that lack of reference to the audited financial statements is not an indication of limited value, and noted that documents that are important to the outcome of a hearing are typically discussed. OPG argued that there was no discernable value to be gained from Board staff's suggestion to prepare a report detailing the costs to develop the capability to produce the financial statements.

Board Findings

Regular reporting of financial and operating data is an important component of the overall regulatory structure. The data allows the Board to monitor the performance of utilities in years when they are not before the Board and provides consistent data over time for purposes of various analyses. Ongoing reporting will be particularly important as OPG migrates to an IRM regime.

The Board does not believe a separate consultation is required in order to establish initial reporting requirements for OPG. There is sufficient information before the Board at this time to determine appropriate reporting requirements for 2011 and 2012. The issue of reporting requirements can also be addressed again in the next proceeding. The Board concludes that determining the reporting requirements in the context of a payment amounts proceeding will be more efficient and less costly than undertaking a separate consultation process. The Board therefore finds that the following reports shall be filed, beginning in 2011:

- Unaudited balances of deferral and variance accounts within 60 days after calendar quarter end;
- The MD&A and financial statements as filed with the OSC within 60 days for the first three quarters, and within 120 days for December year-end statements as long as the OSC requires these documents to be filed;
- Nuclear unit capability factors and hydroelectric availability for the regulated facilities within 60 days for the first three quarters and within 120 days for December year end as reported in OPG's quarterly and annual MD&A;
- FTE information, similar to the presentation in Exhibit F4, tab 3, schedule 1, chart 1 by April 30th;
- Capital in-service additions and construction work in progress by April 30th; and
- An analysis of the actual annual regulatory return, after tax on rate base, both dollars and percentages, for the regulated business and a comparison with the regulatory return included in the payment amounts by June 30th of each year. It would be similar to what is set out in Exhibit C1, tab 1, schedule 1, table 7 for the historical period.

The Board may consider additional or modified reporting requirements for OPG when the company brings forward its incentive regulation mechanism proposal. As part of that application, OPG should propose the suite of RRR that might be applicable for its incentive plan period.

The Board finds that it is appropriate to continue to require OPG to provide annual audited financial statements for the prescribed facilities. OPG has stated that the current segment disclosure in its general purpose audited financial statements is in accordance with Canadian Generally Accepted Accounting Principles, and cannot be changed, since the segmented disclosure is consistent with OPG's management reporting structure. Given that more than 50% of OPG's business is regulated, the Board concludes that the financial statements should reflect this reality. There is no evidence that the regulatory framework for OPG, whereby a significant portion of its business is regulated by the Board, will be changed such that the Board is no longer the regulator. It may be that some investment will be required to provide audited financial statements for the regulated business, but given the size of OPG's regulated business and its significance in the overall Ontario electricity sector, and the expectation of ongoing regulation by the Board, the Board concludes that it is appropriate to continue to require that audited statements for the regulated business be prepared. The Board notes that audited statements for the regulated business were ordered in the prior decision, for reasons related to improved assessment of the revenue requirement, and there was no indication at that time that it would be a one-time requirement. There has been no change in circumstances and no new evidence that would lead the Board to conclude that a change in approach is appropriate. It will be up to OPG to determine how to most efficiently meet this ongoing requirement.

13 METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The Board prepared a report in 2006 establishing the methodology to be used for setting payment amounts for OPG. The report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, issued on November 30, 2006, stated that, "The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

The previous payment amounts proceeding (EB-2007-0905) was the first proceeding for OPG, and was considered under traditional cost of service regulation. While the current application is only the second cost of service application for OPG's prescribed facilities, both this application and the first one cover an approximately five-year period from 2008 to 2012.

Incentive regulation is an alternative to regular annual cost of service regulation and is generally comprised of a more formulaic or mechanistic approach to adjust revenues or rates for inflation while incentivizing productivity improvements. The process is also intended to avoid lengthy and costly annual hearings under cost of service approaches. The typical approach – and the one that the Board employs for both electricity and natural gas distribution – is that rates are initially set through a cost of service application, after which rates are adjusted annually through the incentive regulation mechanism. After a number of years, the rates, underlying costs and the incentive regulation plan are reviewed and, as necessary, reset. The Board first adopted incentive regulation (also known as performance-based regulation or PBR) for the electricity distribution sector with the 2000 Distribution Rate Handbook. Incentive regulation has been adopted for both electricity and natural gas distribution utilities.

OPG did not address the issue of incentive regulation in its original evidence. However, the Board decided that it would be appropriate to consider the issue in the proceeding. There were two components to this issue:

- When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

- What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

There was no pre-filed evidence on this matter. The record was completed through responses to interrogatories. There was also discussion of this issue in the technical conference and during the oral hearing.

OPG proposed, in response to an interrogatory, that following the conclusion of the current proceeding, the company would file an application setting out its proposal for incentive regulation. The proposal would be tested in a hearing and OPG would incorporate the results of that decision into its next cost of service application, which would then set base rates for incentive regulation. PWU supported OPG's proposal for development and consideration of incentive regulation, but expressed some reservations about whether incentive regulation is appropriate for OPG for the foreseeable future in light of the development of the long-term energy plan.

CCC was also not convinced that incentive regulation is necessarily appropriate for OPG, but concluded that there may be merit in having some elements of OPG's revenue requirement subject to incentives. CCC suggested that the Board hold a workshop to carefully consider whether incentive regulation could work for OPG.

SEC noted the complexity of OPG's operations and the recent changes in corporate culture and concluded that OPG is not ready for incentive regulation. SEC further submitted that the earliest incentive regulation should be considered is 2014 or 2015.

Board staff submitted that the development of incentive regulation is time and resource intensive and that it would be unrealistic to expect full development of a plan in 2011. Board staff held that the process to develop incentive regulation for OPG's prescribed assets would benefit from stakeholder input early in the process. Board staff observed that a total factor productivity study has not yet been commissioned; external experts have not been retained, and there appear to be no known incentive regulation regimes for utilities which would be analogous to OPG's regulated hydroelectric and nuclear generation businesses. Board staff also suggested that there could be separate incentive regulation plans for the regulated hydroelectric business and the regulated nuclear business because of the different operating characteristics of each.

Board staff provided some options for implementation of incentive regulation. One option would be to have OPG file an application for both IRM and implementation of rates for 2013. OPG argued that the option is impractical because it would not align with OPG's business planning cycle and that the costs would increase due to the resource requirement to respond to directions from the decision and undertake new studies. Another Board staff option would be to file a cost of service application for 2013 and in parallel file an incentive regulation application. In reply, OPG stated that the resource requirement for two applications would be extensive and it did not see how a one-year test period would be in ratepayers' interests.

OPG submitted that a third cost of service application is required to provide a robust starting point for incentive regulation. In its reply argument OPG proposed to file its IRM proposal as part of the cost of service application for 2013-2014; if the IRM proposal was adopted it could take effect in 2015. Alternatively, OPG stated that it could file an IRM proposal in 2013 after the conclusion of the next cost of service application.

Board Findings

The Board notes that its findings on this issue do not impact on the payment amounts arising from this Decision. However, the Board considers it important to give direction to OPG and other stakeholders regarding the future of incentive regulation as a means for setting payments for OPG's prescribed assets.

The Board remains convinced that an incentive regulation mechanism for setting payment amounts will be beneficial in the long-term. As noted in the Natural Gas Forum Report:

> The Board believes that a multi-year incentive regulation (IR) plan can be developed that will meet its criteria for an effective ratemaking framework: sustainable gains in efficiency, appropriate quality of service and an attractive investment environment. A properly designed plan will ensure downward pressure on rates by encouraging new levels of efficiency in Ontario's gas utilities – to the benefit of customers and shareholders. By implementing a multi-year IR framework, the Board also intends to provide the regulatory stability needed for investment in Ontario. The Board will establish the key parameters that will underpin the IR framework to ensure that its criteria are met and that all stakeholders have the same expectations of the plan.[61]

[61] Natural Gas Regulation in Ontario: A Renewed Policy Framework, Report on the Ontario Energy Board Natural Gas Forum, (RP-2004-0213), March 30, 2005, p. 22.

The Board is of the view that the benefits of incentive regulation identified in the Natural Gas Forum Report would also apply to OPG, given a suitable design.

The Board concurs with Board staff's submission that adequate time and effort is necessary to develop a suitable plan. OPG itself has acknowledged that the timeline that it first proposed is "aggressive". OPG has acknowledged that the company has not undertaken or commissioned any significant work on incentive regulation at this time.

The Board is not aware of IR plans applicable to generation-only utilities that might help in the development of a plan for OPG. While the Board and the industry have extensive experience with incentive regulation generally, it is not a matter of simply transferring a plan from natural gas or electricity distribution. Aspects of OPG's generation businesses must be suitably studied and accommodated in a plan. For example, development of a suitable X-factor will, in all likelihood, require a productivity study unique to OPG. Such efforts will require considerable time and resources.

The Board finds that, given the current situation, it is not practical to implement incentive regulation in time for implementation for payments for 2013. The Board therefore expects OPG to file another cost of service application for the 2013 and 2014 years.

However, the Board concludes that incentive regulation beginning in 2015 should be considered. To facilitate this, the Board will commence work in 2011 to lay out the scope of the required IRM and productivity studies to be filed by OPG. This review may include options and preferences on the general type(s) of incentive regulation mechanisms which may be suitable for setting payment amounts for OPG's regulated facilities. This preliminary process to consider incentive regulation mechanisms in the context of OPG's unique circumstances will allow for input from OPG and all other interested stakeholders.

The outcome of this review will serve as a starting point for OPG's subsequent application for an IRM regime which would commence in 2015. It is expected that the outcome of this review will be available no later than the first quarter of 2012.

Based on this preliminary review, and as a further step in the development of an incentive regulation mechanism, the Board expects OPG to provide a proposed work plan and status report for an independent productivity study as part of its 2013 and 2014 cost of service application, which would be expected in early 2012. OPG's plan would be examined during the proceeding.

Finally, the Board expects OPG to file an application for incentive regulation to be in effect starting in 2015. It is expected that such an application should be filed no later than the fourth quarter of 2013, and would be subject to a hearing in 2014. This would provide time for implementation on January 1, 2015.

The Board believes that this framework and timeline will allow for proper development of an incentive regulation plan while respecting the time and resource commitments necessary for OPG, the Board and stakeholders, and other regulatory activities.

In addition to the preliminary review work that the Board intends to undertake in 2011, the Board also expects OPG to engage stakeholders in meaningful discussions about the proposed incentive regulation mechanism in advance of the actual IRM regime filing.

14 IMPLEMENTATION AND COST AWARDS

14.1 Implementation

OPG proposed that its new payment amounts be made effective March 1, 2011.

On February 17, 2011, the Board issued an interim order making the current payment amounts interim effective March 1, 2011.

The new payment amounts will be made effective March 1, 2011. The Board understands that the IESO can implement this effective date through its billing processes without the necessity for a shortfall payment amounts rider to cover the period between March 1 and the date of the final payment amounts order.

The Board directs OPG to file with the Board, and copy to all intervenors, a draft payment amounts order which will include the final revenue requirement and payment amounts for the regulated hydroelectric and nuclear facilities, and reflect the findings made by the Board in this Decision. OPG should also include supporting schedules and a clear explanation of all calculations and assumptions used in deriving the payment amounts and the payment riders.

OPG is directed to provide a full description of each deferral and variance account as part of the draft payment amounts order.

OPG is directed to file the draft payment amounts order by March 21, 2011. Board staff and intervenors shall respond to OPG's draft payment order by March 28, 2011. OPG shall respond to any comments by Board staff and intervenors by April 4, 2011.

14.2 Cost Awards

A number of intervenors were deemed eligible for cost awards in this proceeding: Association of Major Power Consumers in Ontario, Canadian Manufacturers & Exporters, Consumers Council of Canada, Energy Probe Research Foundation, Green Energy Coalition, Pollution Probe, School Energy Coalition and Vulnerable Energy Consumers Coalition.

A cost awards decision will be issued after the steps set out below are completed.

1. Intervenors eligible for cost awards shall file with the Board and forward to OPG their respective cost claims by April 8, 2011.
2. OPG shall file with the Board and forward to the relevant intervenors any objections to the costs claimed, including any objections to cost claims filed prior to the issuance of this Decision, by April 15, 2011.
3. Intervenors whose costs have been objected to, may file with the Board and forward to OPG any response to the objection by April 21, 2011.

OPG shall pay the Board's costs of and incidental to this proceeding upon receipt of the Board's invoice.

DATED at Toronto, March 10, 2011

ONTARIO ENERGY BOARD

Original signed by

____

Cynthia Chaplin
Presiding Member

Original signed by

____

Marika Hare
Member

Original signed by

____

Cathy Spoel
Member

APPENDIX A

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

PROCEDURAL DETAILS
INCLUDING LISTS OF PARTIES AND WITNESSES

PROCEDURAL DETAILS INCLUDING LISTS OF PARTIES AND WITNESSES

THE PROCEEDING

OPG filed its application for new payment amounts on May 26, 2010. On June 4, 2010, the Board issued a Notice of Application and Oral Hearing which was published in accordance with the Board's direction.

The Board issued Procedural Order No.1 on June 29, 2010, which provided a draft issues list and made provision for an issues conference and submissions on issues. The procedural order made provision for submissions on OPG's request for confidential treatment of certain tax information, and sections of business plans and business case summaries. The procedural order also set out a schedule for the proceeding.

The key milestones in the proceeding are listed below:

- The final issues list was issued along with Procedural Order No. 3 on July 21, 2010.
- Interrogatories were filed by Board staff on July 22, 2010 and by intervenors on July 29, 2010. The majority of responses were filed on August 12, 2010.
- A technical conference was held on August 26, 2010.
- Parties filed evidence on August 31, 2010.
- Interrogatories on evidence were filed on September 7, 2010 and responses were filed on September 14, 2010.
- A settlement conference was held on September 14, 2010, however no settlement was achieved.
- Motions from the Consumers Council of Canada and Canadian Manufacturers & Exports were heard on September 30, 2010.
- The oral hearing took place on 16 days during the period October 4, 2010 to November 26, 2010.
- OPG filed its argument in chief on November 19, 2010.
- Board staff filed its submission on November 30, 2010 and intervenors filed their submissions on December 6 and 7, 2010.
- OPG's reply argument was filed on December 21, 2010.
- An interim order declaring payment amounts interim effective March 1, 2011 was issued on February 17, 2011.

Thirteen procedural orders were issued during the course of the proceeding, some dealing with the schedule of the proceeding, but many dealing with matters of confidentiality, including submissions and decisions on requests for confidential treatment of documents, and submissions and decisions on breaches of confidentiality.

PARTICIPANTS

Below is a list of participants and their representatives that were active either at the oral hearing or at another stage of the proceeding.

Ontario Power Generation Inc.	Charles Keizer Crawford Smith Carlton Mathias Andrew Barrett Barbara Reuber
Board Counsel and Staff	Michael Millar Violet Binette Ben Baksh Richard Battista Russell Chute Chris Cincar Keith Ritchie Duncan Skinner
Association of Major Power Consumers in Ontario	David Crocker Andrew Lord Tom Adams Shelley Grice
Canadian Manufacturers & Exporters	Peter Thompson Vince DeRose Jack Hughes
Consumers Council of Canada	Robert Warren Julie Girvan
Energy Probe Research Foundation	Peter Faye David MacIntosh Norman Rubin Lawrence Schwartz
Green Energy Coalition	David Poch

Pollution Probe Foundation	Basil Alexander Jack Gibbons
Power Workers' Union	Richard Stephenson Alfredo Bertolotti Judy Kwik
School Energy Coalition	Jay Shepherd Mark Garner
The Society of Energy Professionals	Jo-Anne Pickel Mike Belmore Stanley Pui
Vulnerable Energy Consumers Coalition	Michael Buonaguro James Wightman

In addition to the above, the Association of Power Producers of Ontario, Hydro One Networks Inc. and the Ontario Power Authority were registered intervenors in this proceeding. The Independent Electricity System Operator and the Ministry of Energy were registered observers in this proceeding.

WITNESSES

The following OPG employees appeared as witnesses.

Joan Frain	Manager, Water Policy and Planning, Business Services and Water Resources Division
Mario Mazza	Director, Business Support and Regulatory Affairs, Hydro Business Unit
David Peterson	Manager of Market Monitoring
Mark Shea	Asset and Technical Services Manager, Ottawa/St. Lawrence Plant Group
Randy Leavitt	Vice President, Nuclear Finance
Pierre Tremblay	Senior Vice President, Nuclear Programs and Training
Mark Elliott	Senior Vice President of Inspection and Maintenance Services

John Mauti	Director, Nuclear Reporting
Paul Pasquet	Senior Vice President, Pickering B
Michael Allen	Director, Nuclear Programs
Carla Carmichael	Director, Business Planning and Performance Reporting, Nuclear Finance
James Woodcroft	Manager, Outage Programs
Mark Arnone	Vice President, Refurbishment Execution
Fred Dermarkar	Director, Engineering Services
Jamie Lawrie	Director, Investment Management
Nathan Reeve	Vice President, Financial Services
Dietmar Reiner	Senior Vice President, Nuclear Refurbishment
Gary Rose	Director of Planning and Control
Laurie Swami	Vice President, Nuclear Regulatory Programs and Director of Licensing and Environment, Darlington New Nuclear Project
Lorraine Irvine	Vice President, Human Resources Projects
Jong Kim	Chief Technology Officer, Business Services and Information Technology
Tom Staines	Director of Finance – Corporate Functions, Finance
John Lee	Assistant Treasurer
Randy Pugh	Director, Ontario Regulatory Affairs, Regulatory Accounting and Finance
David Bell	Manager, Corporate Accounting
David Halperin	Director, Financial and Business Planning, Corporate Finance
Robin Heard	Vice President, Finance and Chief Controller

Andrew Barrett	Vice President, Regulatory Affairs and Corporate Strategy
Alex Kogan	Manager, Regulatory Finance

OPG also called the following expert witness: John Sequeira of ScottMadden Inc., Kathleen McShane of Foster Associates Inc. and Ralph Luciani of Charles River Associates.

The intervenors called the following expert witnesses:

- Lawrence Kryzanowski of Concordia University and Gordon Roberts of York University appearing for Pollution Probe
- Paul Chernick of Resource Insight Inc. appearing for GEC
- Bruce Sharp of Agent Energy Advisors Inc., whose evidence was entered by written affidavit, for CME

APPENDIX B

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

APPROVALS SOUGHT BY OPG IN EB-2010-0008

Filed: 2010-05-26
EB-2010-0008
Exhibit A1
Tab 2
Schedule 2
Page 1 of 3

APPROVALS

In this Application, OPG is seeking the following specific approvals:

- The approval of a revenue requirement of $1,435.7M for the regulated hydroelectric facilities and a revenue requirement of $5,473.9M for the nuclear facilities for the period of January 1, 2011 through December 31, 2012 (the "test period") as set out in Ex. I1-T1-S1.

- The approval of a rate base of $3,803.4M and $3,787.4M for the regulated hydroelectric facilities for the years 2011 and 2012, respectively and $4,041.3M and $4,150.8M for the nuclear facilities for the years 2011 and 2012, respectively, as summarized in Ex. B1-T1-S1.

- The inclusion of construction work in progress ("CWIP") amounts for the Darlington Refurbishment Project of $125.5M in 2011 and $306.0M in 2012 in the rate base for the nuclear facilities and recovery of the associated cost of capital as presented in Ex. D2-T2-S2.

- Approval of a production forecast of 38.4 TWh for the test period for the regulated hydroelectric facilities and 98.9 TWh for the test period for the nuclear facilities. The production forecast is presented in Exhibit E.

- Approval of a deemed capital structure of 53 per cent debt and 47 per cent equity and a combined rate of return on rate base of 7.18 per cent and 7.21 per cent for 2011 and 2012, respectively, including a rate of return on equity ("ROE") forecast of 9.85 per cent, as presented in Ex. C1-T1-S1.

- Approval of a payment amount for the regulated hydroelectric facilities, effective March 1, 2011 of $37.38/MWh for the average hourly net energy production (MWh) from the regulated facilities in any given month (the "hourly volume") for each hour of that month.

Production over the hourly volume will receive the market price from the Independent Electricity System Operator ("IESO")-administered energy market. Where production from the regulated hydroelectric facilities is less than the hourly volume, OPG's revenues will be adjusted by the difference between the hourly volume and the actual net energy production at the market price from the IESO-administered market. The payment amount for the regulated hydroelectric facilities is set out in Ex. I1-T2-S1.

- Approval of a payment amount for the nuclear facilities, effective March 1, 2011 of $55.34/MWh.

- Approval for recovery of the audited December 31, 2010 variance and deferral account balances for the regulated hydroelectric and nuclear facilities as described in Ex. H1-T1-S2 and disposition, beginning March 1, 2011, at a rate derived as described in Ex. H1-T2-S1.

- Approval to establish, re-establish or continue variance and deferral accounts as follows:
    - A variance account to record the deviation from forecast revenues associated with differences in regulated hydroelectric electricity production due to differences between forecast and actual water conditions.
    - A variance account to record the deviation from forecast net revenues for ancillary services from the regulated hydroelectric facilities and the nuclear facilities.
    - A variance account to record the deviation from forecast capital and non-capital costs and firm financial commitments associated with work to increase the output of, refurbish or add operating capacity to a regulated facility.
    - A variance account to record the deviation from forecast costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities.
    - A variance account to record the deviation between actual and forecast nuclear fuel costs.
    - A deferral account to record non-capital costs associated with the planned return-to-service of units at the Pickering A Generating Station.

- A deferral account to record the revenue requirement impact of any change in the nuclear decommissioning liability resulting from an approved reference plan as defined in the Ontario Nuclear Funds Agreement.
- A variance account to capture the tax impact of changes in tax rates, rules and assessments.
- A variance account to record the variance between the tax loss mitigation amount which underpins the EB-2007-0905 Payment Amounts Order and the tax loss amount resulting from the re-analysis of the prior period tax returns based on the OEB's directions in EB-2007-0905 Decision with Reasons as to the re-calculation of those tax losses.
- A variance account to capture differences between forecast and actual costs and revenues related to the lease of the Bruce nuclear facilities.
- A variance account to record the difference between forecast and actual IESO non-energy charges incurred by the regulated hydroelectric and nuclear facilities.
- A variance account to record the difference between forecast and actual pension and other post-employment benefit costs and associated tax effects related to the regulated hydroelectric and nuclear facilities.
- Variance accounts to record the over/under recovery amounts for the hydroelectric variance and deferral accounts and nuclear variance and deferral accounts, respectively.

Evidence supporting the continuation of existing variance and deferral accounts and the creation of new ones is provided in Ex. H1-T3-S1.

- An order from the OEB declaring OPG's current payment amounts interim as of March 1, 2011, if the order or orders approving the payment amounts are not implemented by March 1, 2011.

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APPENDIX C

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

DECISION ON MOTIONS, OCTOBER 4, 2010

DECISION ON CCC AND CME MOTIONS

Transcript: Oral Hearing, Volume 1, October 4, 2010, page 113

The Board sat on Thursday, September 30th, to hear motions by CCC and CME. Both motions sought the production of materials presented to the OPG board of directors in the period between April 1, 2010 and May 26, 2010.

The Board has decided not to order production of the materials sought in the CME and CCC motions. In the Board's view, these materials are not relevant to the determination of the issues before the Board in this proceeding. The Board will make its decision on the application and supporting materials filed by the applicant and the evidence of intervenors, all of which is subject to cross-examination.

This evidence goes to the financial and operational impacts of the application and of the alternatives which have been considered.

The material which has been sought through the motions includes the communication between OPG's management and its board of directors, seeking approval to file the application, delegated authority to deal with the proceeding, and the analysis of "likely prospects for success." This material does not form part of the application and does not enhance nor detract from the merits of the application.

The evidence is that no changes to the business plans and budgets which underpin the application were sought or made as a result of the board of directors' meeting. These plans and budgets have been filed.

Intervenors can explore, through the witness, whether alternatives to the application should have been considered, and the impacts of OPG's choices. None of this relies on what management presented to the board of directors.

Having found that the materials are not relevant and need not be produced, the question of privilege will not be addressed.

That concludes the Board's decision, and subject to any questions, we can continue with the cross-examination.

APPENDIX D

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

SECTION 78.1 OF THE *ONTARIO ENERGY BOARD ACT, 1998*, S.O.1998, C.5 (SCHEDULE B)

Excerpt: Section 78.1 of the *Ontario Energy Board Act*, *1998*, S.O.1998, c.15 (Schedule B).

Payments to prescribed generator

78.1 (1) The IESO shall make payments to a generator prescribed by the regulations, or to the OPA on behalf of a generator prescribed by the regulations, with respect to output that is generated by a unit at a generation facility prescribed by the regulations. 2004, c. 23, Sched. B, s. 15.

Payment amount

(2) Each payment referred to in subsection (1) shall be the amount determined,

(a) in accordance with the regulations to the extent the payment relates to a period that is on or after the day this section comes into force and before the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order in respect of the generator; and

(b) in accordance with the order of the Board then in effect to the extent the payment relates to a period that is on or after the later of,

(i) the day prescribed for the purposes of this subsection, and

(ii) the effective date of the Board's first order under this section in respect of the generator. 2004, c. 23, Sched. B, s. 15.

OPA may act as settlement agent

(3) The OPA may act as a settlement agent to settle amounts payable to a generator under this section. 2004, c. 23, Sched. B, s. 15.

Board orders

(4) The Board shall make an order under this section in accordance with the rules prescribed by the regulations and may include in the order conditions, classifications or practices, including rules respecting the calculation of the amount of the payment. 2004, c. 23, Sched. B, s. 15.

Fixing other prices

(5) The Board may fix such other payment amounts as it finds to be just and reasonable,

(a) on an application for an order under this section, if the Board is not satisfied that the amount applied for is just and reasonable; or

(b) at any other time, if the Board is not satisfied that the current payment amount is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Burden of proof

(6) Subject to subsection (7), the burden of proof is on the applicant in an application made under this section. 2004, c. 23, Sched. B, s. 15.

Order

(7) If the Board on its own motion or at the request of the Minister commences a proceeding to determine whether an amount that the Board may approve or fix under this section is just and reasonable,

(a) the burden of establishing that the amount is just and reasonable is on the generator; and

(b) the Board shall make an order approving or fixing an amount that is just and reasonable. 2004, c. 23, Sched. B, s. 15.

Application

(8) Subsections (4), (5) and (7) apply only on and after the day prescribed by the regulations for the purposes of subsection (2). 2004, c. 23, Sched. B, s. 15.

APPENDIX E

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

ONTARIO REGULATION 53/05

Ontario Energy Board Act, 1998
Loi de 1998 sur la Commission de l'énergie de l'Ontario

ONTARIO REGULATION 53/05

PAYMENTS UNDER SECTION 78.1 OF THE ACT

Consolidation Period: From February 19, 2008 to the e-Laws currency date.

Last amendment: O. Reg. 27/08.

This Regulation is made in English only.

Definition

0.1 In this Regulation,

"approved reference plan" means a reference plan, as defined in the Ontario Nuclear Funds Agreement, that has been approved by Her Majesty the Queen in right of Ontario in accordance with that agreement;

"nuclear decommissioning liability" means the liability of Ontario Power Generation Inc. for decommissioning its nuclear generation facilities and the management of its nuclear waste and used fuel;

"Ontario Nuclear Funds Agreement" means the agreement entered into as of April 1, 1999 by Her Majesty the Queen in right of Ontario, Ontario Power Generation Inc. and certain subsidiaries of Ontario Power Generation Inc., including any amendments to the agreement. O. Reg. 23/07, s. 1.

Prescribed generator

1. Ontario Power Generation Inc. is prescribed as a generator for the purposes of section 78.1 of the Act. O. Reg. 53/05, s. 1.

Prescribed generation facilities

2. The following generation facilities of Ontario Power Generation Inc. are prescribed for the purposes of section 78.1 of the Act:

1. The following hydroelectric generating stations located in The Regional Municipality of Niagara:
   i. Sir Adam Beck I.
   ii. Sir Adam Beck II.
   iii. Sir Adam Beck Pump Generating Station.
   iv. De Cew Falls I.
   v. De Cew Falls II.
2. The R. H. Saunders hydroelectric generating station on the St. Lawrence River.
3. Pickering A Nuclear Generating Station.
4. Pickering B Nuclear Generating Station.
5. Darlington Nuclear Generating Station. O. Reg. 53/05, s. 2; O. Reg. 23/07, s. 2.

Prescribed date for s. 78.1 (2) of the Act

3. April 1, 2008 is prescribed for the purposes of subsection 78.1 (2) of the Act. O. Reg. 53/05, s. 3.

Payment amounts under s. 78.1 (2) (a) of the Act

4. (1) For the purpose of clause 78.1 (2) (a) of the Act, the amount of a payment that the IESO is required to make with respect to a unit at a generation facility prescribed under section 2 is,

(a) for the hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2, $33.00 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

   (i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc.; and

(b) for the nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2, $49.50 per megawatt hour with respect to output that is generated during the period from April 1, 2005 to the later of,

(i) March 31, 2008, and

(ii) the day before the effective date of the Board's first order in respect of Ontario Power Generation Inc. O. Reg. 53/05, s. 4 (1).

(2) Despite subsection (1), for the purpose of clause 78.1 (2) (a) of the Act, if the total combined output of the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 exceeds 1,900 megawatt hours in any hour, the total amount of the payment that the IESO is required to make with respect to the units at those generation facilities is, for that hour, the sum of the following amounts:

1. The total amount determined for those facilities under clause (1) (a), for the first 1,900 megawatt hours of output.
2. The product obtained by multiplying the market price determined under the market rules by the number of megawatt hours of output in excess of 1,900 megawatt hours. O. Reg. 53/05, s. 4 (2).

(2.1) The total amount of the payment under subsection (2) shall be allocated to the hydroelectric generation facilities prescribed under paragraphs 1 and 2 of section 2 on a proportionate basis equal to each facility's percentage share of the total combined output in that hour for those facilities. O. Reg. 269/05, s. 1.

(2.2) Subsection (2.1) applies in respect of amounts payable on and after April 1, 2005. O. Reg. 269/05, s. 1.

(3) For the purpose of this section, the output of a generation facility shall be measured at the facility's delivery points, as determined in accordance with the market rules. O. Reg. 53/05, s. 4 (3).

Deferral and variance accounts

5. (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records capital and non-capital costs incurred and revenues earned or foregone on or after April 1, 2005 due to deviations from the forecasts as set out in the document titled "Forecast Information (as of Q3/2004) for Facilities Prescribed under Ontario Regulation 53/05" posted and available on the Ontario Energy Board website, that are associated with,

(a) differences in hydroelectric electricity production due to differences between forecast and actual water conditions;

(b) unforeseen changes to nuclear regulatory requirements or unforeseen technological changes which directly affect the nuclear generation facilities, excluding revenue requirement impacts described in subsections 5.1 (1) and 5.2 (1);

(c) changes to revenues for ancillary services from the generation facilities prescribed under section 2;

(d) acts of God, including severe weather events; and

(e) transmission outages and transmission restrictions that are not otherwise compensated for through congestion management settlement credits under the market rules. O. Reg. 23/07, s. 3.

(2) The calculation of revenues earned or foregone due to changes in electricity production associated with clauses (1) (a), (b), (d) and (e) shall be based on the following prices:

1. $33.00 per megawatt hour from hydroelectric generation facilities prescribed in paragraphs 1 and 2 of section 2.
2. $49.50 per megawatt hour from nuclear generation facilities prescribed in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 3.

(3) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

(4) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records non-capital costs incurred on or after January 1, 2005 that are associated with the planned return to service of all units at the Pickering A Nuclear Generating Station, including those units which the board of directors of Ontario Power Generation Inc. has determined should be placed in safe storage. O. Reg. 23/07, s. 3.

(5) For the purposes of subsection (4), the non-capital costs include, but are not restricted to,

(a) construction costs, assessment costs, pre-engineering costs, project completion costs and demobilization costs; and

(b) interest costs, recorded as simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account, transition

5.1 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records for the period up to the effective date of the Board's first order under section 78.1 of the Act the revenue requirement impact of any change in its nuclear decommissioning liability arising from an approved reference plan, approved after April 1, 2005, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 23/07, s. 3.

Nuclear liability deferral account

5.2 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under 78.1 of the Act, the revenue requirement impact of changes in its total nuclear decommissioning liability between,

(a) the liability arising from the approved reference plan incorporated into the Board's most recent order under section 78.1 of the Act; and

(b) the liability arising from the current approved reference plan. O. Reg. 23/07, s. 3.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 23/07, s. 3.

Nuclear development deferral account, transition

5.3 (1) Ontario Power Generation Inc. shall establish a deferral account in connection with section 78.1 of the Act that records, for the period up to the effective date of the Board's first order under section 78.1 of the Act, the costs incurred and firm financial commitments made on or after June 13, 2006, in the course of planning and preparation for the development of proposed new nuclear generation facilities that are associated with any one or more of the following activities:

1. Activities for carrying out an environmental assessment under the *Canadian Environmental Assessment Act*.
2. Activities for obtaining any governmental licence, authorization, permit or other approval.
3. Activities for carrying out a technology assessment or for defining all commercial and technical requirements to, or with, any third parties. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record simple interest on the monthly opening balance of the account at an annual rate of 6 per cent applied to the monthly opening balance in the account, compounded annually. O. Reg. 27/08, s. 1.

Nuclear development variance account

5.4 (1) Ontario Power Generation Inc. shall establish a variance account in connection with section 78.1 of the Act that records, on and after the effective date of the Board's first order under section 78.1 of the Act, differences between actual non-capital costs incurred and firm financial commitments made and the amount included in payments made under that section for planning and preparation for the development of proposed new nuclear generation facilities. O. Reg. 27/08, s. 1.

(2) Ontario Power Generation Inc. shall record interest on the balance of the account as the Board may direct. O. Reg. 27/08, s. 1.

Rules governing determination of payment amounts by Board

6. (1) Subject to subsection (2), the Board may establish the form, methodology, assumptions and calculations used in making an order that determines payment amounts for the purpose of section 78.1 of the Act. O. Reg. 53/05, s. 6 (1).

(2) The following rules apply to the making of an order by the Board that determines payment amounts for the purpose of section 78.1 of the Act:

1. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the variance account established under subsection 5 (1) over a period not to exceed three years, to the extent that the Board is satisfied that,
   i. the revenues recorded in the account were earned or foregone and the costs were prudently incurred, and
   ii. the revenues and costs are accurately recorded in the account.
2. In setting payment amounts for the assets prescribed under section 2, the Board shall not adopt any methodologies, assumptions or calculations that are based upon the contracting for all or any portion of the output of those assets.
3. The Board shall ensure that Ontario Power Generation Inc. recovers the balance recorded in the deferral account established under subsection 5 (4). The Board shall authorize recovery of the balance on a straight line basis over a period not to exceed 15 years.
4. The Board shall ensure that Ontario Power Generation Inc. recovers capital and non-capital costs, and firm financial commitments incurred to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2, including, but not limited to, assessment costs and pre-engineering costs and commitments,
   i. if the costs and financial commitments were within the project budgets approved for that purpose by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., or
   ii. if the costs and financial commitments were not approved by the board of directors of Ontario Power Generation Inc. before the making of the Board's first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., if the Board is satisfied that the costs were prudently incurred and that the financial commitments were prudently made.

4.1 The Board shall ensure that Ontario Power Generation Inc. recovers the costs incurred and firm financial commitments made in the course of planning and preparation for the development of proposed new nuclear generation facilities, to the extent the Board is satisfied that,
   i. the costs were prudently incurred, and
   ii. the financial commitments were prudently made.

5. In making its first order under section 78.1 of the Act in respect of Ontario Power Generation Inc., the Board shall accept the amounts for the following matters as set out in Ontario Power Generation Inc.'s most recently audited financial statements that were approved by the board of directors of Ontario Power Generation Inc. before the effective date of that order:
   i. Ontario Power Generation Inc.'s assets and liabilities, other than the variance account referred to in subsection 5 (1), which shall be determined in accordance with paragraph 1.
   ii. Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations.
   iii. Ontario Power Generation Inc.'s costs with respect to the Bruce Nuclear Generating Stations.
6. Without limiting the generality of paragraph 5, that paragraph applies to values relating to,
   i. capital cost allowances,
   ii. the revenue requirement impact of accounting and tax policy decisions, and
   iii. capital and non-capital costs and firm financial commitments to increase the output of, refurbish or add operating capacity to a generation facility referred to in section 2.
7. The Board shall ensure that the balances recorded in the deferral accounts established under subsections 5.1 (1) and 5.2 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent that the Board is satisfied that revenue requirement impacts are accurately recorded in the accounts, based on the following items, as reflected in the audited financial statements approved by the board of directors of Ontario Power Generation Inc.,
   i. return on rate base,
   ii. depreciation expense,
   iii. income and capital taxes, and

iv. fuel expense.

7.1 The Board shall ensure the balances recorded in the deferral account established under subsection 5.3 (1) and the variance account established under subsection 5.4 (1) are recovered on a straight line basis over a period not to exceed three years, to the extent the Board is satisfied that,

i. the costs were prudently incurred, and

ii. the financial commitments were prudently made.

8. The Board shall ensure that Ontario Power Generation Inc. recovers the revenue requirement impact of its nuclear decommissioning liability arising from the current approved reference plan.

9. The Board shall ensure that Ontario Power Generation Inc. recovers all the costs it incurs with respect to the Bruce Nuclear Generating Stations.

10. If Ontario Power Generation Inc.'s revenues earned with respect to any lease of the Bruce Nuclear Generating Stations exceed the costs Ontario Power Generation Inc. incurs with respect to those Stations, the excess shall be applied to reduce the amount of the payments required under subsection 78.1 (1) of the Act with respect to output from the nuclear generation facilities referred to in paragraphs 3, 4 and 5 of section 2. O. Reg. 23/07, s. 4; O. Reg. 27/08, s. 2.

7. OMITTED (PROVIDES FOR COMING INTO FORCE OF PROVISIONS OF THIS REGULATION). O. Reg. 53/05, s. 7.

APPENDIX F

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

FINAL ISSUES LIST

Ontario Power Generation Inc.
2011-2012 Payment Amounts for
Prescribed Generating Facilities
EB-2010-0008

FINAL ISSUES LIST

1. GENERAL

1.1 Has OPG responded appropriately to all relevant Board directions from previous proceedings?

1.2 Are OPG's economic and business planning assumptions for 2011-2012 an appropriate basis on which to set payment amounts?

1.3 Is the overall increase in 2011 and 2012 revenue requirement reasonable given the overall bill impact on consumers?

2. RATE BASE

2.1 What is the appropriate amount for rate base?

2.2 Is OPG's proposal to include CWIP in rate base for the Darlington Refurbishment Project appropriate?

3. CAPITAL STRUCTURE AND COST OF CAPITAL

3.1 What is the appropriate capital structure and rate of return on equity?

3.2 Are OPG's proposed costs for its long-term and short-term debt components of its capital structure appropriate?

3.3 Should the same capital structure and cost of capital be used for both OPG's regulated hydroelectric and nuclear businesses? If not, what capital structure and/or cost of capital parameters are appropriate for each business?

4. CAPITAL PROJECTS

Regulated Hydroelectric

4.1 Do the costs associated with the regulated hydroelectric projects, that are subject to section 6(2)4 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section? Are any additional costs prudent?

4.2 Are the capital budgets and/or financial commitments for 2011 and 2012 for the regulated hydroelectric business appropriate and supported by business cases?

4.3 Are the proposed in-service additions for regulated hydroelectric projects appropriate?

Nuclear

4.4 Do the costs associated with the nuclear projects, that are subject to section 6(2)4 and 6(2)4.1 of O. Reg. 53/05 and proposed for recovery, meet the requirements of that section? Are any additional costs prudent?

4.5 Are the capital budgets and/or financial commitments for 2011 and 2012 for the nuclear business appropriate and supported by business cases?

4.6 Are the proposed in-service additions for nuclear projects appropriate?

4.7 Is the proposed treatment for the Pickering Units 2 and 3 isolation project costs appropriate?

5. PRODUCTION FORECASTS

Regulated Hydroelectric

5.1 Is the proposed regulated hydroelectric production forecast appropriate?

Nuclear

5.2 Is the proposed nuclear production forecast appropriate?

6. OPERATING COSTS

Regulated Hydroelectric

6.1 Is the test period Operations, Maintenance and Administration budget for the regulated hydroelectric facilities appropriate?

6.2 Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's hydroelectric facilities reasonable?

Nuclear

6.3 Is the test period Operations, Maintenance and Administration budget for the nuclear facilities appropriate?

6.4 Is the benchmarking methodology reasonable? Are the benchmarking results and targets flowing from those results for OPG's nuclear facilities reasonable?

6.5 Has OPG responded appropriately to the observations and recommendations in the benchmarking report?

6.6 Is the forecast of nuclear fuel costs appropriate?

6.7 Are the proposed expenditures related to continued operations at Pickering B appropriate?

Corporate Costs

6.8 Are the 2011 and 2012 human resource related costs (wages, salaries, benefits, incentive payments, FTEs and pension costs) appropriate?

6.9 Are the “Centralized Support and Administrative Costs” (which include Corporate Support and Administrative Service Groups, Centrally Held Costs and Hydroelectric Common Services) and the allocation of the same to the regulated hydroelectric business and nuclear business appropriate?

6.10 Is OPG responding appropriately to the findings in the Human Resources and Finance Benchmarking Reports?

Other Costs

6.11 Are the amounts proposed to be included in the test period revenue requirement for other operating cost items, including depreciation expense, income and property taxes, appropriate?

6.12 Are the asset service fee amounts charged to the regulated hydroelectric business and nuclear business appropriate?

7. OTHER REVENUES

Regulated Hydroelectric

7.1 Are the proposed test period regulated hydroelectric business revenues from ancillary services, segregated mode of operation and water transactions appropriate?

Nuclear

7.2 Are the proposed test period nuclear business non-energy revenues appropriate?

Bruce Nuclear Generating Station

7.3 Are the test period costs related to the Bruce Nuclear Generating Station, and costs and revenues related to the Bruce lease appropriate?

8. NUCLEAR WASTE MANAGEMENT AND DECOMMISSIONING LIABILITIES

8.1 Have any regulatory or other bodies issued position or policy papers, or made decisions, with respect to Asset Retirement Obligations that the Board should consider in determining whether to retain the existing methodology or adopt a new or modified methodology?

8.2 Is the revenue requirement amount for nuclear liabilities related to nuclear waste management and decommissioning costs appropriately determined?

9. DESIGN OF PAYMENT AMOUNTS

9.1 Is the design of regulated hydroelectric and nuclear payment amounts appropriate?

9.2 Is the hydroelectric incentive mechanism appropriate?

10. DEFERRAL AND VARIANCE ACCOUNTS

10.1 Is the nature or type of costs recorded in the deferral and variance accounts appropriate?

10.2 Are the balances for recovery in each of the deferral and variance accounts appropriate?

10.3 Is the disposition methodology appropriate?

10.4 Is the proposed continuation of deferral and variance accounts appropriate?

10.5 Should the proposed variance account related to IESO non-energy charges be established?

10.6 What other deferral and variance accounts, if any, should be established for the test period?

11. REPORTING AND RECORD KEEPING REQUIREMENTS

11.1 What reporting and record keeping requirements should be established for OPG?

12. METHODOLOGIES FOR SETTING PAYMENT AMOUNTS

The Board Report, *A Regulatory Methodology for Setting Payment Amounts for the Prescribed Generation Assets of Ontario Power Generation Inc.*, EB-2006-0064, November 30, 2006, stated that, “The Board will implement an incentive regulation formula when it is satisfied that the base payment provides a robust starting point for that formula."

12.1 When would it be appropriate for the Board to establish incentive regulation, or other form of alternative rate regulation, for setting payment amounts?

12.2 What processes should be adopted to establish the framework for incentive regulation, or other form of alternative rate regulation, that would be applied in a future test period?

APPENDIX G

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

MEMORANDUM OF AGREEMENT BETWEEN OPG AND THE PROVINCE OF ONTARIO

Filed: 2010-05-26
EB-2010-0008
Exhibit A1-4-1
Attachment 2

Memorandum of Agreement

BETWEEN

Her Majesty the Crown In Right of Ontario (the "Shareholder")
And
Ontario Power Generation ("OPG")

Purpose

This document serves as the basis of agreement between Ontario Power Generation Inc. ("**OPG**") and its sole Shareholder, Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy (the "**Shareholder**") on mandate, governance, performance, and communications. This agreement is intended to promote a positive and co-operative working relationship between OPG and the Shareholder.

OPG will operate as a commercial enterprise with an independent Board of Directors, which will at all times exercise its fiduciary responsibility and a duty of care to act in the best interests of OPG.

A. Mandate

1. OPG's core mandate is electricity generation. It will operate its existing nuclear, hydroelectric, and fossil generating assets as efficiently and cost-effectively as possible, within the legislative and regulatory framework of the Province of Ontario and the Government of Canada, in particular, the Canadian Nuclear Safety Commission. OPG will operate these assets in a manner that mitigates the Province's financial and operational risk.

2. OPG's key nuclear objective will be the reduction of the risk exposure to the Province arising from its investment in nuclear generating stations in general and, in particular, the refurbishment of older units. OPG will continue to operate with a high degree of vigilance with respect to nuclear safety.

3. OPG will seek continuous improvement in its nuclear generation business and internal services. OPG will benchmark its performance in these areas against CANDU nuclear plants worldwide as well as against the top quartile of private and publicly- owned nuclear electricity generators in North America. OPG's top operational priority will be to improve the operation of its existing nuclear fleet.

4. With respect to investment in new generation capacity, OPG's priority will be hydro- electric generation capacity. OPG will seek to expand, develop and/or improve its hydro- electric generation capacity. This will include expansion and redevelopment on its existing sites as well as the pursuit of new projects where feasible. These investments will be taken by OPG through partnerships or on its own, as appropriate.

Filed: 2010-05-26
EB-2010-0008
Exhibit A1-4-1
Attachment 2

5. OPG will not pursue investment in non-hydro-electric renewable generation projects unless specifically directed to do so by the Shareholder.

6. OPG will continue to operate its fossil fleet, including coal plants, according to normal commercial principles taking into account the Government's coal replacement policy and recognizing the role that fossil plants play in the Ontario electricity market, until government regulation and/or unanimous shareholder declarations require the closure of coal stations.

7. OPG will operate in Ontario in accordance with the highest corporate standards, including but not limited to the areas of corporate governance, social responsibility and corporate citizenship.

8. OPG will operate in Ontario in accordance with the highest corporate standards for environmental stewardship taking into account the Government's coal replacement policy.

B <u>Governance Framework</u>

The governance relationship between OPG and the Shareholder is anchored on the following:

1. OPG will maintain a high level of accountability and transparency:

   - OPG is an *Ontario Business Corporations Act* ("OBCA") company and is subject to all of the governance requirements associated with the OBCA.
   - OPG is also subject to the *Freedom of Information and Protection of Privacy Act*, the *Public Sector Salary Disclosure Act* and the *Auditor General Act*.
   - OPG's regulated assets will be subject to public review and assessment by the Ontario Energy Board.
   - OPG will annually appear before a committee of the Legislature which will review OPG's financial and operational performance.

2. The Shareholder may at times direct OPG to undertake special initiatives. Such directives will be communicated as written declarations by way of a Unanimous Shareholder Agreement or Declaration in accordance with Section 108 of the OBCA, and be made public within a reasonable timeframe.

C. <u>Generation Performance and Investment Plans</u>

1. OPG will annually establish 3 –5 year performance targets based on operating and financial results as well as major project execution. Key measures are to be agreed upon with the Shareholder and the Minister of

2

Finance. These performance targets will be benchmarked against the performance of the top quartile of electricity generating companies in North America.

2. Benchmarking will need to take account of key specific operational and technology factors including the operation of CANDU reactors worldwide, the role that OPG's coal plants play in the Ontario electricity market with respect to load following, and the Government of Ontario's coal replacement policy.

3. OPG will annually prepare a 3 – 5 year investment plan for new projects.

4. Once approved by OPG's Board of Directors, OPG's annual performance targets and investment plan will be submitted to the Shareholder and the Minister of Finance for concurrence.

D. Financial Framework

1. As an OBCA corporation with a commercial mandate, OPG will operate on a financially sustainable basis and maintain the value of its assets for its shareholder, the Province of Ontario.

2. As a transition to a sustainable financial model, any significant new generation project approved by the OPG Board of Directors and agreed to by the Shareholder may receive financial support from the Province of Ontario, if and as appropriate.

E. Communication and Reporting

1. OPG and the Shareholder will ensure timely reports and information on major developments and issues that may materially impact the business of OPG or the interests of the Shareholder. Such reporting from OPG should be on an immediate or, at minimum, an expedited basis where an urgent material human safety or system reliability matter arises.

2. OPG will ensure the Minister of Finance receives timely reports and information on multi-year and annual plans and major developments that may have a material impact on the financial performance of OPG or the Shareholder.

3. The OPG Board of Directors and the Minister of Energy will meet on a quarterly basis to enhance mutual understanding of interrelated strategic matters.

4. OPG's Chair, President and Chief Executive Officer and the Minister of Energy will meet on a regular basis, approximately nine times per year.

5. OPG's Chair, President and Chief Executive Officer and the Minister of Finance will meet on an as needed basis.

6. OPG's senior management and senior officials of the Ministry of Energy and the Ministry of Finance will meet on a regular and as needed basis to discuss ongoing issues and clarify expectations or to address emergent issues.

7. OPG will provide officials in the Ministry of Energy and the Ministry of Finance with multi-year and annual business planning information, quarterly and monthly financial reports and briefings on OPG's operational and financial performance against plan.

8. In all other respects, OPG will communicate with government ministries and agencies in a manner typical for an Ontario corporation of its size and scope.

F. <u>Review of this Agreement</u>

This agreement will be reviewed and updated as required.

Dated: the 17th day of August, 2005

On Behalf of OPG:

Jake Epp
Chairman
Board of Directors

On Behalf of the Shareholder:

Her Majesty the Queen in Right of the Province of Ontario as represented by the Minister of Energy, Dwight Duncan

APPENDIX H

TO

DECISION WITH REASONS

ONTARIO POWER GENERATION INC.

EB-2010-0008

CALCULATION OF RETURN ON EQUITY BASED ON NOVEMBER 2010 DATA

Return on Equity and Deemed Long-term Debt Rate

Step 1: Analysis of Business Day Information in the Month

Month: November 2010

		Bond Yields (%)			Bond Yield Spreads (%)	
		Government of Canada		A-rated Utility	30-yr Govt over 10-yr Govt	30-yr Util over 30-yr Govt
Day		10-yr	30-yr	30-yr		
1	1-Nov-10	2.84	3.47	4.97	0.64	1.50
2	2-Nov-10	2.87	3.48	4.92	0.61	1.43
3	3-Nov-10	2.87	3.50	4.94	0.63	1.44
4	4-Nov-10	2.81	3.48	4.92	0.66	1.44
5	5-Nov-10	2.85	3.49	4.95	0.64	1.47
6	6-Nov-10					
7	7-Nov-10					
8	8-Nov-10	2.89	3.51	4.94	0.62	1.43
9	9-Nov-10	2.98	3.57	4.97	0.60	1.40
10	10-Nov-10	2.97	3.59	4.94	0.62	1.35
11	11-Nov-10	2.97	3.59	4.94	0.62	1.35
12	12-Nov-10	3.02	3.63	4.97	0.61	1.34
13	13-Nov-10					
14	14-Nov-10					
15	15-Nov-10	3.15	3.73	5.08	0.58	1.36
16	16-Nov-10	3.08	3.68	5.02	0.60	1.34
17	17-Nov-10	3.10	3.67	5.02	0.58	1.35
18	18-Nov-10	3.12	3.67	5.04	0.54	1.38
19	19-Nov-10	3.14	3.62	5.03	0.47	1.42
20	20-Nov-10					
21	21-Nov-10					
22	22-Nov-10	3.09	3.59	5.00	0.50	1.42
23	23-Nov-10	3.11	3.60	5.04	0.49	1.45
24	24-Nov-10	3.19	3.65	5.05	0.46	1.40
25	25-Nov-10	3.17	3.64	5.04	0.47	1.40
26	26-Nov-10	3.11	3.57	5.02	0.46	1.45
27	27-Nov-10					
28	28-Nov-10					
29	29-Nov-10	3.09	3.52	4.98	0.44	1.46
30	30-Nov-10	3.06	3.48	4.95	0.42	1.47
31						
		3.02	3.58	4.99	**0.556** ❶	**1.410** ❷
	Sources:	*Bank of Canada*		*Bloomberg L.P.*		

Step 2: 10-Year Government of Canada Bond Yield Forecast

Source: *Consensus Forecasts* Publication Date: November 8, 2010

	3-month	12-month	Average	
November 2010	2.800	3.300 ❸	**3.050**	%

Step 3: Long Canada Bond Forecast

10 Year Government of Canada Concensus Forecast (from Step 2)	❸	3.050	%
Actual Spread of 30-year over 10-year Government of Canada Bond Yield (from Step 1)	❶	0.556	%
Long Canada Bond Forecast (LCBF)	❹	**3.606**	%

Step 4: Return on Equity (ROE) forecast

Initial ROE			9.75	%
Change in Long Canada Bond Yield Forecast from September 2009				
LCBF (November 2010) (from Step 3	❹	3.606 %		
Base LCBF		4.250 %		
Difference		-0.644 %		
0.5 X Difference			-0.322	%
Change in A-rated Utility Bond Yield Spread from September 2009				
A-rated Utility Bond Yield Spread (November 2010) (from Step 1)	❷	1.410 %		
Base A-rated Utility Bond Yield Spread		1.415 %		
Difference		-0.005 %		
0.5 X Difference			-0.002	%
Return on Equity based on November 2010 data			**9.43**	%

Step 5: Deemed Long-term Debt Rate Forecast

Long Canada Bond Forecast for November 2010 (from Step 3)	❹	3.606	%
A-rated Utility Bond Yield Spread November 2010 (from Step 1)	❷	1.410	%
Deemed Long-term Debt Rate based on November 2010 data		**5.02**	%

References on Calculation Methods:

- **Return on Equity**: Appendix B of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.
- **Deemed Long-term Debt Rate**: Appendix C of the *Report of the Board on Cost of Capital for Ontario's Regulated Utilities*, issued December 11, 2009.

COMMISSION DE RÉGLEMENTATION ET D'APPELS DE L'ÎLE

THE ISLAND REGULATORY AND APPEALS COMMISSION
Prince Edward Island
Île-du-Prince-Édouard
CANADA

Docket UE20940
Order UE10-03

IN THE MATTER of an

application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

BEFORE THE COMMISSION

on Monday, the 12th day of July, 2010.

Maurice Rodgerson, Chair
John Broderick, Commissioner
Anne Petley, Commissioner
Ernest Arsenault, Commissioner

Order

Compared and Certified a True Copy

(Sgd) *Allison MacEwen*

Director, Technical and Regulatory Services

IN THE MATTER of an

application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

Contents

IN THE MATTER of an

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Appearances & Witnesses

1. **For Maritime Electric Company, Limited**
   Counsel:
   Spencer Campbell
   Thomas Laughlin

   Witnesses:
   Fred J. O'Brien, President & Chief Executive Officer
   John D. Gaudet, Vice President, Corporate Planning & Energy Supply
   J. William Geldert, Vice President, Finance & Administration, Chief Financial Officer & Corporate Secretary
   Steven D. Loggie, Vice President, Customer Service
   Kathleen C. McShane, Consultant, Foster Associates, Inc.

2. **For the Minister of Environment, Energy & Forestry, Government of Prince Edward Island**
   Counsel:
   J. Gordon MacKay

   Witnesses:
   Laurence D. Booth, Consultant
   Wayne MacQuarrie, PEI Energy Corporation

3. **Interveners**
   Roger King, PEI Senior Citizens' Federation
   Matthew MacCarville, Environmental Coalition of PEI
   John te Raa, Private Citizen

4. **Public Participants**
   Ernest Mutch & John Jamieson, PEI Federation of Agriculture
   Elwin Wyand, Edith Ling, Douglas Campbell and David Best, National Farmers Union District 1, Region 1
   Harold MacNevin, Dairy Farmers of Prince Edward Island

5. **For The Island Regulatory and Appeals Commission**
   Counsel:
   Ryan P.MacDonald

   Staff:
   Allison MacEwen, Director, Technical & Regulatory Services
   Mark Lanigan, Senior Analyst, Technical & Regulatory Services
   Linda Allen, Recording Secretary

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

Reasons for Order

1. Introduction & Background

[1] This is an application under the ***Electric Power Act***, R.S.P.E.I. 1988, Cap. E-4, by Maritime Electric Company, Limited (the "Applicant", "Maritime Electric" or the "Company") seeking, among other things, an Order or Orders of the Island Regulatory and Appeals Commission (the "Commission") approving amendments to the rates, tolls and charges for electric service for the period beginning August 1, 2010, and reconsideration of the 2nd block rate elimination.

[2] The Application was filed pursuant to Section 20(1) of the *Electric Power Act* (the "***Act***") which reads as follows:

Variation of rates, submission for review and approval	20. (1) Whenever any public utility wishes to vary any existing rates, tolls or charges, or to establish any new rates, tolls or charges for any service, it shall submit for the review and approval of the Commission a schedule of such proposed rates, tolls and charges together with and appended thereto all rules and regulations which, in any manner, relate to the rates, tolls and charges; the Commission may approve, after reviewing the schedule and rules and regulations submitted, the schedule of rates, tolls and charges and the rules and regulations either in whole or in part, or may determine and fix new rates, tolls and charges, and amend the rules and regulations as it sees fit. 2003,c.3.s.10.

[3] The Company's original application filed with the Commission on January 29, 2010 requested the following:

1. Approval to rebase the Energy Cost Adjustment Mechanism ("ECAM") which would increase the base charge for energy to $0.0940/kWh in 2010 and $0.0960/kWh effective April 1, 2011;
2. Permission to file an updated report on ECAM rebasing to the Commission by November 30, 2010;
3. Approval to continue the Point Lepreau replacement energy deferral, as well as approval of a 25-year amortization period for deferred replacement energy costs, beginning with the return to service expected March 1, 2011; and
4. Approval of a maximum allowed Return on Average Common Equity of 9.75 per cent for 2010 and 2011.

[4] In February, 2010 the Commission published a Notice of Application in local newspapers seeking public input. The following summarizes the responses received:

The PEI Senior Citizens' Federation and affiliate senior clubs across PEI filed petitions signed by members of each local club stating:

> "We the undersigned request that IRAC hold a public hearing to review the 2010 Rate Change Application submitted by Maritime Electric."

In addition, several of the petitions included letters from seniors which provided various comments such as:

a) the need for MECL to use time-of-day rates;
b) the Company should be required to "think outside the box and use more hydro, nuclear and wind power";
c) a public hearing like last year's would be useful to assist with their understanding;
d) concerns about the refurbishment of Point Lepreau, replacement energy costs and rate implications;
e) the elimination of the second block and the lack of information on the impact on certain customers; and
f) energy charge increases and the Company's conflicting statement of no cost increases in 2010.

The Federation of Agriculture provided correspondence on March 4, 2010 stating that the current application, along with a previously issued IRAC Order (UE08-01), have implications for the agricultural sector on PEI. The Federation suggested that a public hearing be held where they could participate and present their concerns.

The Commission received either directly, or via copy, three pieces of correspondence from Mr. John te Raa. The correspondence contained questions and referenced the need for full consideration of the true cost of electricity in setting rates. No mention was made regarding the requirement to hold a public hearing.

Mr. Roger King filed two emails with the Commission. His first email indicated that the Company's rate application is written in a confusing manner, does not explicitly state the rate changes proposed, and that the Company does not "think outside the box". Mr. King also stated that electric heat is the most efficient and is more environmentally-friendly, and that a combination of in-floor and domestic hot water heating with a "time of day" tariff is one obvious alternative to a second block rate. As well, he requested a public hearing be held to allow for full public input.

In his second email, Mr. King provided comments on Commission Order UE08-01 suggesting that the wording is unclear. He also stated that the elimination of the declining block is just one issue of many "requests for change" in the 2010 application that affect customers in both the short and long term. Mr. King concluded his email by stating that "a public hearing is necessary to have all public issues resolved where facts are sorted from fiction and Islanders are told one common and correct story".

Ira Smith provided a letter to the Commission expressing concern and support regarding the continuation of the Point Lepreau replacement energy deferral. Also, she stated the cost of the replacement energy and refurbishment costs should be incurred by today's consumers and not our children and grandchildren.

The Province of PEI, by letter dated February 19, 2010, filed a Notice of Intervention and requested the Commission schedule a public hearing for the purpose of the presentation of oral evidence with respect to this application. The Province also filed a series of interrogatories with respect to this application.

On March 2, 2010 the Hon. Richard Brown, Minister of Environment, Energy and Forestry, wrote the Commission requesting the Commission review and rescind Order UE08-01 with regard to the elimination of the reduced second block rate.

In addition, on March 5, 2010 Maritime Electric wrote the Commission seeking approval to suspend the implementation of UE08-01 based on the following reasons:

a. Discussion between Governments of PEI and Quebec concerning a potential energy supply agreement which would change electricity pricing in PEI beyond a reduced second block;
b. The need for a further cost allocation study which may impact all rates;
c. Further development of an updated Demand Side Management plan ("DSM"); and
d. Reconsideration of the reduced second block as part of the pending 2010 rate application will allow all interested parties, who have expressed concerns about the public awareness and lack of consultation of the reduced second block elimination, an opportunity to make their views and evidence known to the Commission.

[5] The Commission issued Order UE10-01 on March 9, 2010 which delayed the final step in the elimination of the second block rate, directed the Company to file further information on this issue, and instructed the Company that the 2nd block tariff would be reviewed as part of the 2010 rate application.

[6] Following the significant public interest in this application, in April, 2010, the Commission published a notice in local newspapers inviting parties to participate in a public hearing. Anyone interested in participating as an intervener was advised to file a Notice of Intervention stating their reason for intervention and invited interveners to present their evidence. Four (4) parties registered as interveners in this application:

- Government of PEI, as represented by the Minister of Environment, Energy and Forestry;
- PEI Senior Citizens' Federation, represented by Mr. Roger King;
- Environmental Coalition of PEI (ECO PEI), represented by Mr. Matthew MacCarville; and
- Mr. John te Raa, as a private citizen.

[7] Commission staff conducted two pre-hearing conferences with all parties participating. A process for interrogatories, Company responses and filing of expert and intervener evidence was agreed upon. The Commission website published all information filed making the information available to all parties and the general public.

[8] The public hearing was held June 14, 2010 thru June 18, 2010 in the Commission's main hearing room. The hearing participants included Mr. Spencer Campbell and Mr. Thomas Laughlin, legal counsel for Maritime Electric, Mr. Gordon MacKay, legal counsel for the Government of PEI, PEI Senior Citizens' Federation represented by Mr. Roger King, Environmental Coalition of PEI represented by Mr. Matthew MacCarville, and Mr. John te Raa, representing himself.

[9] Three groups—PEI Federation of Agriculture, as represented by Mr. Ernie Mutch and Mr. John Jamieson; National Famers Union Region 1 District 1, represented by Mr. Elwin Wyand, Ms. Edith Ling, Mr. Douglas Campbell and Mr. David Best, and Dairy Farmers of PEI, represented by Mr. Harold MacNevin—requested and received permission to speak at the hearing. All three groups spoke on behalf of the PEI farming community.

[10] There were members of the media in attendance; however, few members of the public attended the proceedings.

2. The Application

[11] The Company's original application filed with the Commission on January 29, 2010 requested approval of the following:

1. Rebasing of the Energy Cost Adjustment Mechanism ("ECAM") which would increase the base charge for energy incorporated into customer billings to $0.0940/kWh in 2010 and $0.0960/kWh effective April 1, 2010;
2. Filing of an updated ECAM rebasing report by November 30, 2010;
3. Continuation of the Point Lepreau replacement energy deferral and approval of a 25-year amortization of these deferred replacement energy costs beginning with the return to service expected to be March 1, 2011; and
4. Approval of a maximum allowed Return on Average Common Equity of 9.75 per cent for 2010 and 2011.

[12] The application incorporated the final step in the elimination of the second block reduced rate, which was approved in 2008 by Commission Order UE08-01 following a public process.

[13] As well, the Costs Recoverable from Customers (Post 2003)—or ECAM—balance, excluding Point Lepreau, is forecast to be $6,316,300 at the end of 2010 and $8,800,000 at the end of 2011. The Point Lepreau replacement energy costs to be recovered from customers, assuming a 25-year amortization beginning March 2011, would be $43,100,000 at the end of 2010 and $45,800,000 at the end of 2011.

[14] The application states there is no change requested in the monthly service charge for the various rate categories. The company proposes the consumer energy rate for electricity consumed will change from $0.1178 kWh for the first 2,000 kWh/month and $0.0914 kWh for the remaining monthly consumption, with a new combined rate of $0.1355 kWh month.

[15] The application would see the residential consumer using 650 kWh/month (or 7,800 kWh/year) experience a forecast annual electricity cost reduction of (0.5%) and (0.4%) in 2010 and 2011.

[16] The Company stated the application contains just and reasonable proposals which balance the interests of Maritime Electric and its customers and allows the Company to provide a high level of service at prices which are reasonable based upon their costs.

[17] On April 8 and 12, 2010 the Company filed supplemental affidavits requesting the Commission approve an amended application which proposed:

1. A continuation of the 2,000 kWh/month 2nd energy block pricing;
2. Rebasing of the Energy Cost Adjustment Mechanism ("ECAM") which would increase the base charge for energy incorporated into customer billings to $0.0990/kWh effective August 1, 2010, and $0.0900/kWh effective April 1, 2011;
3. MECL file an updated report of ECAM rebasing with the Commission by November 30, 2010;
4. A continuation of the Point Lepreau replacement energy deferral and the approval of a 25-year amortization of these deferred replacement energy costs beginning with the return to service expected to be March 1, 2011; and
5. A maximum allowed Return on Average Common Equity of 9.75 per cent for 2010 and 2011.

[18] Under this proposal the Costs Recoverable from Customers (Post 2003) or ECAM balance, excluding Point Lepreau is forecast to be $7,758,500 at the end of 2010 and $12,467,600 at the end of 2011. The Point Lepreau replacement energy costs to be recovered from customers, assuming a 25-year amortization beginning March 2011, would be $43,294,100 at the end of 2010 and $45,999,800 at the end of 2011. A Commission decision on the recovery of Point Lepreau replacement energy is requested in this amended application as well.

[19] The amended application states there is no change requested in the monthly service charge for the various rate categories. The energy rate for electricity is proposed to increase from $0.1178 kWh for the first 2,000 kWh/month and $0.0914 kWh for the remaining monthly consumption to $0.1455 kWh for the first 2,000 kWh/month and $0.1103 for the remaining monthly consumption. The amended application maintains the same pricing relationship between the second and first block rate.

[20] The amended application, as proposed, would see the residential consumer using 650 kWh/month (or 7,800 kWh/year) experience a forecast annual electricity cost reduction of (1.1%) in 2010 and no change in 2011 electricity costs over 2010.

[21] In addition, the amended application states the Revenue Requirement Recovery associated with the second block reinstatement would be allocated across all rate classes and adjustments would be made to the ECAM.

3. Discussion

3.1 Intervener—PEI Seniors Citizens' Federation

[22] The PEI Senior Citizens' Federation ("Seniors' Federation") presented information concerning demographics of PEI seniors, the economic situations many face in household budgets, and the increasing electricity cost component which reduces available funds for other essential expenditures such as food and shelter.

[23] The Seniors' Federation explained to the Commission seniors' energy needs and the difficulties many face to achieve energy conservation.

[24] The Seniors' Federation raised the following financial issues with the Commission:

- It supports Maritime Electric's objective to reduce customer debt;
- The chosen solution of increasing the basic rates by 15% for 2010 and a further 3% in 2011 is not endorsed;
- The majority of energy supply costs are declining—future customer rates should be declining too;
- NB Power set energy purchase prices but customer rates are also dependent on Maritime Electric's operating costs;
- Increased scrutiny of Maritime Electric's operating costs is required;
- Maritime Electric continues to request high annual capital expenditures and a high rate of return in a non-growth, low risk business activity; and
- Detailed future year estimates are difficult to reason/check by public observers and customers.

[25] The Seniors' Federation notes that the basic electricity rate increase applies to all rate tariff categories affecting every PEI resident, farmer and business, and is independent of the second block issue. It also notes that Maritime Electric is accumulating high customer debt during the Point Lepreau refurbishment and future nuclear power will cost significantly more. In addition, despite a static PEI energy demand situation and a Canadian economy battling with decline, Maritime Electric proposes increasing annual profits from $11.4 Million in 2009 to $12 Million in 2010 and $12.6 Million in 2011.

[26] The Seniors' Federation expressed concern over the Point Lepreau refurbishment project, the continued delays and the mounting cost of replacement energy which must be recovered from customers over future years. They believe this recovery through rates, along with the unknown future price of electricity from the nuclear generator, may make this an expensive energy source.

[27] In addition, concern was expressed about the cost of power from the NB Power Dalhousie generating facility which has increased substantially due to fuel costs, and the future plans for the plant appear to be uncertain based on public comments from NB Power.

[28] The Seniors' Federation made the following recommendations to the Commission:

- 2010 rates remain unchanged with the ECAM amortization period reduced to 8 months to contain customer debt to the Company;
- Return on Equity of 8% is suggested which better reflects the operational risks of the Company;
- A reduction in capital budget to 8% of revenue to a maximum of $15 Million;
- Have external consultants review general and administrative expenses and generation asset costs;
- Key Performance Indicators (KPIs) should be set to competitive benchmarks;
- Review viability of future participation in Point Lepreau considering the energy replacement costs, along with future energy costs from this source;
- Direct the Company to consider terminating its agreement with the Dalhousie generating facility; and
- Future rate applications be single year to enable timely rate changes each April.

[29] In response to Commission staff questioning during the hearing, the Seniors' Federation stated they took no position on the elimination of the second block even though many seniors are affected by this rate differential.

3.2 Intervener—John te Raa

[30] Mr. John te Raa presented evidence to the Commission concerning electric heating, its implications to the Company and to customers and rates. Electric heating results in a poor system load factor, an indicator of the efficiency usage of the electrical system. The higher the system electrical load factor the more efficient the use of the system and the less customer cross-subsidization of rates. For instance, Mr. te Raa provided evidence which states the electric load factor of an oil heat customer is 64% while that of an electric heat customer is 30%. The Company's data, provided through interrogatories, supports his claim that electric heat is having a greater influence on PEI with last year's peak load almost shifting to January from December.

[31] Mr. te Raa challenged the intervention by the Province of PEI which supported the retention of the second block. In general, Mr. te Raa states the Province is intervening to protect a small number of customers (7%) at the expense (subsidization) of the majority of customers. In fact, Mr. te Raa states low consumption customers, such as low income customers or families on social services, pay higher electricity bills to offset the discount provided to higher consumption customers.

[32] Mr. te Raa presented a proposal which would alter the current fee structure so that higher energy usage customers would pay a higher base service charge as a consequence of their impact on the system load factor and capacity requirements during peak energy consumption periods. Mr. te Raa stated the Commission should order the Company to create different rate classes within the Residential Rate category as well as set up a different rate class for electric heat customers, including those heating by heat pumps.

[33] Mr. te Raa also stated the ECAM's objective is the smoothing of rates within a set time frame and currently the ECAM just continues to grow and defer the real cost of energy to customers while delaying the proper customer price signals in rates. The ECAM rebasing in both the original application and the amended application shows a growing ECAM deferral account and is not operating as a rate smoothing mechanism.

3.3 Intervener—ECO PEI

[34] ECO PEI recommended the implementation of time-of-use rates and suggested the initiative to replace mechanical meters with digital meters should have taken advantage of the upgrade to install Smart meters. Smart meters could be utilized in a variety of environmentally friendly initiatives which ECO PEI believes have a direct benefit to customers. ECO PEI suggests the utility become more involved in fostering future electrical energy options which result in greater use of wind resources to heat our homes, such as wind/electric thermal storage. Transportation was suggested as a key focus for reducing Green House Gas ("GHG") emissions on the Island. While other GHG emissions on the Island have decreased, emissions from transportation have increased. ECOPEI suggested greater utilization of Grid Enabled Vehicles and noted the absence of recharge stations for electric vehicles.

[35] ECO PEI presented a variety of energy conservation and demand side management initiatives and themes which looked at consumer energy usage strategically over the longer term. Although their presentation did not focus on the specifics of this application, ECO PEI would like further development of smart grid and greater inter-regional cooperation in the Maritimes which would assist in the development and usage of the PEI's excellent wind resource.

3.4 Intervener—Government of PEI

[36] The Government of PEI, as represented by the Minister of Environment, Energy and Forestry, presented the evidence and expert testimony of Laurence Booth, Professor of Finance, Rotman School of Management, University of Toronto. Mr. Booth has extensive experience in financial affairs and has appeared before many regulatory boards providing evidence relating to Return on Equity ("ROE") for Canadian utilities.

[37] Mr. Booth informed the Commission the objective of rate of return regulation can be summarized as the "fair return standard" which has received wide acceptance due to the legal precedent established in the 1929 case ***Northwestern Utilities*** v ***City of Edmonton***. Mr. Justice Lamont's definition of fair rate of return states:

> "...that the company will be allowed as large a return on the capital invested in the enterprise as it would receive if it were investing the same amount in other securities possessing an attractiveness, stability and certainty equal to that of the company's enterprise."

[38] Economists, generally, refer to this principle as the opportunity cost and it is generally agreed that the return is applied to the book value of assets.

[39] Mr. Booth stated that most regulators in Canada have adopted an ROE formula approach in which Capital Asset Pricing Model ("CAPM") has been the predominant model used. The model is referred to as a risk positioning model and it tries to estimate a fair return being the risk free rate, plus a risk premium for the market and the company.

[40] Mr. Booth stated that utility stocks did not fair badly during the recent financial market declines and have since regained their pre-market crisis values. This is evidence of their low risk and the fair return approved by regulators using this formula CAPM approach.

[41] Mr. Booth stated the returns of US utilities are not comparable as these utilities are inherently riskier because the business climate in the US is generally riskier. This is evidenced by the financial crisis which originated in the US and the continued perilous economy there. He believes the Canadian economic climate is much healthier in that the recession is felt to be behind us and that Canadian government finances are much healthier than the structural deficit problems faced by the US government.

[42] Mr. Booth stated that in 2009 regulators have reviewed the formula results and made formula risk premium adjustments to take into consideration the financial crisis of 2009. This has resulted in 2009 ROE decisions by regulators being artificially high and these should come down as the financial markets regain liquidity and stability.

[43] Mr. Booth describes the Company as a small distribution utility with a low risk profile, as it is a monopoly provider on PEI, which is a low risk environment due to no significant exposure to a single resource like Newfoundland. Mr. Booth quotes an excerpt of the Standard & Poor's assessment of the Company, "strong business profile ... a mature, but stable economy with relatively low growth rates." Mr. Booth makes reference to the weakness of the Company being its small size, limited market access and significant deferrals. Mr. Booth dismisses the deferrals due to regulators ensuring their collection.

[44] Overall, Mr. Booth assesses the Company as a low risk Canadian utility, even though it has a corporate rating of BBB+, its secured debt is rated at A-. He indicates these ratings are below the averages for Canadian utilities.

[45] Mr. Booth recommends an ROE of 8.0% at the 40% legislated common equity ratio. In addition, he believes the legislated common equity ratio should be revisited once the financial markets have settled from the financial crisis of 2008/09.

[46] Mr. Wayne MacQuarrie, presented the PEI Government's position regarding the retention of the 2nd block reduced rate. In his affidavit, Mr. MacQuarrie stated the Government initially supported the elimination of the second block in 2008. However, due to changed circumstances, Government now feels the second block should be retained until various issues associated with electricity on PEI are resolved.

[47] Mr. MacQuarrie updated the Commission regarding ongoing Government negotiations for less expensive energy supply from other jurisdictions such as Quebec and Newfoundland. These suppliers are becoming viable options for PEI with the Open Access Transmission Tariff ("OATT") approved by many jurisdictions, and the development of a competitive energy supply market.

[48] Mr. MacQuarrie stated that the staged increase in the threshold for 2nd block qualification has improved price signals to consumers and the remaining consumers affected by the 2,000 kWh threshold have few viable options to reduce energy consumption. In addition, the retention of the second block at the current level will not result in a material change in consumer consumption or financial consequence to all ratepayers.

[49] Mr. MacQuarrie stated the Point Lepreau refurbishment and replacement energy expense and the uncertainty associated with the Dalhousie generating facility will have further rate burden on consumers and will impact energy consumption decisions.

3.5 Members of the Public

[50] Each of the three groups that attended and made presentations at the hearing expressed concern over electricity rates on PEI and their inability to recover these rising costs from the market place. In addition, each group expressed frustration over the Commission's previous decision to eliminate 2nd block reduced rate pricing. The farm groups stated that energy conservation and demand side management programs have been incorporated in their daily activities but farming operations require significant electricity consumption. Many government programs, which provide assistance for capital outlays to reduce farm energy bills, do not provide the appropriate cost benefit relationship to warrant investment. For instance, on-farm wind generated electricity requires changes in government electricity regulations to allow for net billing. It is believed net billing would provide a stronger business case as it results in a faster payback.

3.6 Applicant—Maritime Electric Company, Limited

[51] Maritime Electric presented evidence and expert testimony of Kathleen McShane, President of Foster & Associates, an economic consulting firm. Ms. McShane reiterated the fair return standard as the legal precedent upon which regulators must establish ROE amounts. Ms. McShane states the fair return standard gives a regulated utility the opportunity to:

- earn a return on investment commensurate with that of comparable risk enterprises;
- maintain its financial integrity; and
- attract capital on reasonable terms.

[52] Ms. McShane presented a view that Maritime Electric faces higher business risk than the average Canadian utility. This assessment referenced the following risk factors:

- Maritime Electric faces higher operating and supply risks relative to the typical Canadian distribution utility. An Island location dependent upon submarine cables and the requirement to maintain on-Island generation represents risks no other Canadian distribution utilities face in regards to supply disruption;
- PEI's ***Renewable Energy Act*** requires the Company to source 15% of its energy requirements from renewable sources with an increase to 30% contemplated, and significant penalties for non-compliance;
- Maritime Electric's small size and its limited potential for growth in serving a largely rural population with low-growth rates puts pressure on the aging infrastructure and upward pressure on rates;
- Regulatory risk for the Company has been a factor in the past noting the changed regulatory model to price cap regulation and then back to cost-of-service regulation;
- Maritime Electric continues to maintain significant deferral accounts for energy purchases for both ongoing energy supply and replacement of Point Lepreau energy due to the refurbishment. These deferral accounts require regulatory approvals for recovery and put pressure on the Company's financial position as evidenced by the operating financial ratios;
- Maritime Electric's corporate credit rating of BBB+ is lower than that of the average Canadian electric utility (A-) and the Standard & Poor's rating has noted the Company's poorer business metrics, such as lower than average earning before taxes interest coverage, funds from operation to total debt and challenged cash flow position; and
- Overall, Standard & Poor's have rated Maritime Electric's business risk profile as "Satisfactory" which is two rating categories below the average business risk profile assigned to Canadian utilities of "Excellent".

[53] Ms. McShane concluded the ROE of 9.75% on a common equity ratio of between 41% and 41.8% is not only reasonable but relatively low, based on approved ROE levels for other Canadian and US utilities.

[54] Ms. McShane acknowledged the role of formulas in ROE rate setting, however, she pointed to shortcomings in the formula approach in that measuring individual securities risk relative to the market is by a beta factor. Selecting a beta factor that appropriately measures security risk requires judgment that can lead to disagreement among evaluators. Ms. McShane suggested no one formula can measure all requirements of the fair return standard and pinpoint a fair return. In establishing a fair return, reliance on multiple tests, such as, CAPM, discounted cash flow and comparable earnings tests, is a better approach. Each test requires judgment in their application.

[55] Ms. McShane stated that this Commission has never adopted the CAPM formula as the means of ROE. Ms. McShane also stated the Commission has previously taken into consideration comparable earnings of other Atlantic Canadian electric utilities in setting ROE.

[56] Ms. McShane agreed that certain Canadian regulators have incorporated premiums in ROE to account for the impact of the financial crisis. Ms. McShane argued that the financial crisis has highlighted the flaw of the automatic formula approach as the formulas do not take into account all business risks in a timely fashion.

[57] Ms. McShane provided a table of approved ROE and common equity ratios for 2009. This table also provided US average ROE as well. The table outlines the 2009 average Canadian ROE of 9.52% with a common equity ratio of 40.5%. This includes the 9.85% ROE for Ontario Electricity Distributors for 2010. This 2010 OEB decision is 0.10% higher than the 2009 rate of 9.75%.

[58] In support of the written evidence filed as part of the application, Maritime Electric provided testimony from Company President, Mr. Fred O'Brien and a panel of members of Senior Management, consisting of: Mr. William Geldert, Mr. John Gaudet and Mr. Steve Loggie.

[59] Maritime Electric provided the Commission with a supplemental affidavit in support of retaining the second block in its current form for the following reasons:

- It may be premature due to ongoing discussions between the Governments of Quebec and PEI concerning a power purchase agreement which would reduce energy costs and could affect decisions concerning the elimination of the second block;

- Current DSM initiatives have been successful and the retention of the 2nd block will not have a material impact upon future Company DSM plans; and
- The retention of the second block does not cause material differences in the financial situation of the Company as the Revenue Requirement Recovery or revenue shortfall from the 2nd block will be spread across all rate classes, and these differences are not material.

[60] In addition, in response to comments raised during the hearing on the issue of net billing, the Company expressed concerns relating to cross-subsidization of ratepayers under net billing approaches.

[61] The Commission acknowledges and thanks all of the participants for their contributions.

4. Findings

[62] Upon completion of the public hearing and a review of the evidence and closing submissions of the parties, the Commission made the following determinations:

4.1 Point LePreau Replacement Energy

[63] The Company has a 4.72% participation agreement with NB Power Nuclear which entitles the Company to this portion of energy output from the facility. During the hearing the Commission heard the Company had little influence on the refurbishment decision due to its minor involvement with the facility. The 1994 participation agreement established the requirement to pay the monthly fixed overhead costs of the facility during refurbishment, as well as obtain replacement energy.

[64] During the hearing, the Company stated that future participation in Point Lepreau is more beneficial than trying to buy out its participation agreement responsibilities. The Company stated the Lepreau generating facility is still economically viable, in their opinion.

[65] Maritime Electric stated NB Power has not made any decisions regarding the customer rate recovery of replacement energy costs. While Maritime Electric is deferring the replacement energy costs it continues to make monthly payments to NB Power for its share of the operating and maintenance costs.

[66] At present, the refurbishment of Point LePreau is not complete and there have been several delays. The expected date of return to service is now scheduled as March 1, 2011; however, further delays are possible.

[67] The Commission heard the concerns expressed by both the Seniors' Federation and Mr. te Raa regarding the increasing deferred replacement energy costs. Effective January 1, 2009, and continuing to the return to service date of Point Lepreau, the Commission directed the deferral of replacement energy costs. The Company's application states the 2010 year-end balance of replacement energy costs are forecast to be $43.3 million and $46.0 million in 2011. This assumes a return to service of March 1, 2011 and the beginning of the 25-year amortization period requested in this application.

[68] The Commission has considered the information filed with the application concerning the amortization of replacement energy costs of other jurisdictions and notes that it is accepted regulatory practice to amortize costs over the future service life of the refurbished facility.

[69] The Commission, therefore, orders the Company to continue with the deferral of the replacement energy costs until the return to service of the Point Lepreau facility. The Commission further orders the Company to begin recovering replacement energy costs through rates over the expected future service life of the facility, currently estimated to be 25 years. The Commission directs the Company to provide updated information concerning the expected future service life once reliable estimates are established.

[70] The Commission is concerned over the lack of detailed evidence associated with the Point Lepreau facility. The Commission directs Maritime Electric to file, on a confidential basis, the cost estimates and economic analysis associated with their continued involvement with the facility.

4.2 ECAM Rebasing and Amortization Period

[71] The Company has filed the ECAM rebasing proposal contained in this application pursuant to Commission Order UE09-02. The Company's ECAM balances in the original application and amended application are forecast as follows:

	Calendar Year	ECAM Year End Balance
Original Application	2010	$6,122,255
	2011	$8,600,141
Amended Application (retain 2nd block)	2010	$7,758,524
	2011	$12,467,603

[72] The original application and supplemental amended application (retain 2nd block) contained ECAM rebasing proposals that had the following annual customer cost impact:

			2010		2011	
Rate Class	Demand KW/Month	Consumption kWh/Month	Original Application Apr 1	Amended (Retain 2nd Block) Aug 1	Original Application Apr 1	Amended (Retain 2nd Block) Aug 1
Residential - Rural	n/a	650	-0.5%	-1.1%	-0.4%	0.0%
General Service	0-20	500	2.1%	2.7%	0.5%	0.8%
General Service	30	3,000	2.1%	2.7%	0.5%	0.8%
General Service	50	5,000	2.2%	2.7%	0.4%	0.7%
General Service	250	250,000	-2.7%	-2.1%	-1.6%	-1.3%
Large Industrial	9,000	9,000,000	-9.3%	-9.0%	-5.3%	-4.9%
Small Industrial	50	5,000	2.0%	2.6%	0.3%	0.6%
Small Industrial	150	25,000	0.0%	0.5%	-0.5%	-0.2%
Small Industrial	500	300,000	-4.5%	-3.9%	-2.6%	-2.2%

[73] The amended application, with the retention of the 2nd block, incorporates an ECAM base energy charge of $0.0990/kWh effective August 1, 2010 and $0.0900kWh effective April 1, 2011.

[74] The Commission shares the concerns over the extent of deferrals for both replacement energy and normal energy supply. Interveners noted that in the amended application the Company ended up increasing the deferred energy charges. The Commission notes that, in addition to increasing the deferrals, the annual customer cost impact increased only slightly with the final result for 2011 being rural residential customers seeing no change in annual cost of electricity.

[75] In response to intervener and Commission questions, the Company stated their desire to eliminate deferred energy accounts and recover all costs from customers sooner. However, the Company stated their additional concern regarding the cost impact to customers. The Company's amended application was an attempt to balance the Company's interests, as well as the cost to customers, while maintaining the second block.

[76] The Commission is concerned by the mixed signals sent to all parties in the amended application. The base ECAM rate would be set at a rate that results in the deferred ECAM account increasing in value. This places further burden on future ratepayers who will ultimately cover these costs.

[77] Most interveners agreed that energy charges should reflect the true supply cost of energy and this would send the appropriate price signals to consumers regarding energy choices. In addition, the Commission heard that the overall cost of energy is important to seniors and this group wants an indication that energy rates are stabilizing. A reducing ECAM deferral balance is a step in that direction.

[78] The Commission has reviewed various ECAM rate scenarios and orders that the new base rate for ECAM be set at $0.0970kWh effective August 1, 2010 and that an additional $0.006kWh be added to the ECAM base rate for the period August 1, 2010 to December 31, 2010. This additional rate allows for recovery of energy costs associated with the delay in the rate application from the initially requested April 1, 2010 implementation date to the August 1, 2010 actual implementation date.

[79] The new ECAM base rate is forecast to result in year-end ECAM deferral account balances of $6,046,954 for 2010 and $5,709,184 for 2011. These balances are lower than both the original and amended applications. The new ECAM base rate will result in a year-over-year annual rural residential cost change of -0.2% in 2010 and 1.1% in 2011, assuming exchange rates and energy supply costs remain consistent with 2010 levels. The Commission considers this an appropriate rate change to achieve reduced deferrals.

[80] The Commission has considered the request from the Seniors' Federation to reduce the ECAM amortization period and increase the collection of deferred energy supply costs. The Seniors' Federation views this as more desirable than an increase in base rates as it would permit the rates to easily reduce if energy supply costs decrease. The Commission has considered this option and notes that the ECAM at one time was set at eight months; however, feels it is more important to have the ECAM base rate set at a level close to the actual energy supply costs, so that deferred energy costs are minimal into the future. Both the ECAM and the base rates are subject to regulatory control and can be adjusted to reflect reduced energy costs. Therefore, the Commission directs the Company to continue the 12-month amortization in the ECAM formula.

4.3 2nd Block Tariff and Rate Design

[81] The Company filed a supplemental affidavit amending the original application and requesting reconsideration of Commission Order UE08-01. This Order approved the elimination of the second block rate over a three-year period. Although the Company is not financially impacted by the second block

elimination, Maritime Electric stated that the circumstances regarding energy negotiations and their potential implications to the overall rate tariff, as well as progress on demand side management programs support the request for reconsideration.

[82] The Commission heard from farm groups concerning the financial impact of this rate elimination. These groups discussed their limited ability to reduce energy consumption within existing demand side management tools. In addition, current government programs, designed to financially assist farms install on-farm renewable generation, fall short in making a sound business case for the investment. Farm groups suggested that legislation and regulation changes are required by Government to improve the attractiveness of on-farm renewable energy infrastructure.

[83] The Commission was informed of the peculiarities which exist in the current rate tariff schedule. The current tariff schedule was forced on the Company with the legislated price cap regulation of 1994. For instance, within the residential rural tariff (and 2nd block discount) the following are some organizations which qualify:

- small and large scale farm organizations ,
- fish farms,
- campgrounds and trailer parks,
- hotels, motels and tourist courts,
- credit unions, and
- services incidental to fishing and farming.

[84] The Commission was informed by Company officials during the hearing that the tariff schedule which existed prior to 1994 was completely different with consideration given to the volume and nature of electricity usage. For instance, rate differences existed between 100 amp and 200 amp service.

[85] The Commission heard from Mr. John te Raa concerning the system efficiency implications of electric heat and apparent cross-subsidization of rates and charges between low- and high-energy usage customers. Mr. te Raa states the 2nd block tariff furthers this inequity. Mr. te Raa directed the Commission to the results of the 2008 *Cost of Service Study* filed as a response to a Government of PEI interrogatory in this application. This study highlights inequities between rate classes within the current tariff structure.

[86] During the hearing, Company officials acknowledged the results of the 2008 *Cost of Service Study* and advised the Commission that to consider the 2nd block rate issue in isolation of the other obvious inequities in the overall tariff structure would be unreasonable and unfair to all customers.

[87] The Commission noted Company comments which stated that a new cost of service study and a rate design proposal with a goal of tariff fairness within ranges is required.

[88] The Commission notes the preamble to the *Electric Power Act* which states: "***Whereas the rates, tolls and charges for electric power should be reasonable, publicly justifiable and not discriminatory***".

[89] This preamble instructs the Commission to ensure fairness within rate categories and that rates must be based on the cost of providing this service. That means rates do not take into consideration the characteristics of the customer such as farming, fishing, home heat or industrial usage. Rates developed with a rate design objective of fairness based on cost of service are the requirements of the legislation.

[90] The Commission appreciates that the farm community has faced significant economic challenges, but that fact alone does not permit the Commission to vary rates to assist that industry. In order to achieve rate fairness, rates must be based on the cost of providing service to a customer or class of customers.

[91] In true cost of service terms, the Commission was not presented with evidence that warrants retention of the declining 2nd block rate. However, evidence was heard that the residential rate class itself is seriously flawed. Adopted in 1994 from the NB Power rate structure, this rate structure is out of date.

[92] The Commission accepts the argument that any further changes to rate tariffs should await the outcome of a new rate design proposal based on a full cost of service study.

[93] Therefore, the Commission will defer the decision on the removal of the 2nd block tariff until a rate design proposal is approved by the Commission. The Commission orders the Company to prepare a complete rate design proposal with all the necessary supporting reports. The Commission has heard evidence that a new rate design process could result in some significant rate changes, both increases and decreases, for customers. Upon completion of the cost of service and rate design process, the Company is encouraged to engage in stakeholder consultations which explain the process and gain input on the proposed rate classifications. The rate design proposal will incorporate recommendations on the current 2nd block and any other potential rate additions or deletions. Further, the Commission directs that the impact of the increased use of electric heat on the system service requirements be separately considered and addressed in the rate design process.

[94] The rate design proposal must be filed with the Commission by December 31, 2011. This date provides time for the conclusion of inter-governmental power purchase agreement negotiations.

4.5 Rate of Return

[95] Maritime Electric is requesting approval of a 9.75% return on average common equity. Maritime Electric states that it faces higher business risk than other Atlantic Canada investor-owned electric utilities as it operates on a small island with an undiversified economy. The inability to spread risk throughout a diversified customer base means investors are more cautious on the outlook for Maritime Electric. The Company states this is evidenced by the Standard and Poor's BBB+ credit rating which indicates a stable outlook, but this rating is lower than other investor-owned utilities such as Emera's, Nova Scotia Power, and Newfoundland Power. In fact, Maritime Electric notes Standard and Poor's expressed concern about Maritime Electric's relatively poor cash flow position which is caused by the ECAM and delayed recovery of energy costs. The bond raters expressed concern about the relatively low earnings as a percentage of debt ("Interest Coverage Ratio").

[96] Section 24(1) of the *Electric Power Act* states return on investment shall be set by the Commission and reads as follows:

Return on investment, utility authorized to earn certain, computation of	24. (1) Every public utility shall be entitled to earn annually such return as the Commission considers just and reasonable, computed by using the rate base as fixed and determined by the Commission for each type of service furnished, rendered or supplied by such public utility, and the return shall be in addition to the expenses as the Commission may allow as reasonable and prudent and properly chargeable to operating account, and to all just allowances made by the Commission according to this Act and the rules and regulations made by the Commission hereunder.

[97] The Commission heard from expert witnesses who stated the principles of the fair return standard. In essence, a fair return is met if a utility can attract capital on reasonable terms, can maintain its financial integrity, and the return allowed is consistent with returns of businesses with similar risks. That standard was first established in Canada with the 1929 case, ***Northwest Utilities v. Edmonton (City)***.

[98] The Commission noted Mr. Booth's comments in which he stated the 2009 approved ROE was adjusted higher to take into consideration the 2008-2009 financial crisis. In fact, Mr. Booth suggested the Cost of Capital Review, by the Ontario Energy Board (OEB), was a consequence of the financial crisis. The Commission noted this decision was made after the economic financial problems and reflects the improved Canadian economy.

[99] The Commission noted testimony from both experts with different opinions regarding the risk profile of Maritime Electric in comparison to the Ontario distribution utilities. The Commission accepts that Maritime Electric, with its responsibilities for electricity supply, is different than Ontario electric distribution utilities. The Commission views this difference as significant.

[100] The Commission notes the lower than average Company corporate rating prepared by Standard & Poor's and the debt rating of BBB+, both lower than Canadian averages, is further evidence that the risk profile of Maritime Electric is higher.

[101] The Commission notes the 2009 Nova Scotia Power ROE, arising from a negotiated settlement agreement, of 9.35% on a common equity ratio of 37.5%. In addition, the Newfoundland Power ROE of 9.0% with a common equity ratio of 45% was approved for 2010.

[102] The Commission also notes decisions from the British Colombia Utilities Commission ("BCUC") regarding the ROE rates allowable for a benchmark utility (9.5%), Terasen Gas. In addition, as pointed out by Ms. McShane in her evidence, the BCUC decision stated:

> "The Commission Panel notes that CAPM is based on a theory that can neither be proved nor disproved, relies on a market risk premium which looks back over nine decades and depends on a relative risk factor of beta. The fact that the calculated beta for PNG (considered by Dr. Booth to be the most risky utility in Canada) was 0.26 in 2008 causes the Commission Panel to consider that betas conventionally calculated with reference to the S&P/TSX are distorted and require adjustment. The Commission Panel will give weight to the CAPM approach, but considers that the relative risk factor should be adjusted in a manner consistent with the practice generally followed by analysts so that it yields a result that accords with common sense and is not patently adsorb."

[103] The Commission finds this commentary particularly relevant. The Commission did not adopt a formula approach to ROE during a period of time when such an approach was used by regulators as the standard for setting ROE. The Commission sees little value in placing greater emphasis on a formula approach at a time when that approach is either being abandoned, altered or deviated. Judgement, taking into consideration comparators, current market conditions, and appropriate risk assessment, are also very relevant.

[104] The Commission notes the BCUC ROE decision for FortisBC of 9.75%, which is 0.25% above the benchmark BC ROE rate. This Commission views Maritime Electric as a higher risk than the benchmark BC utility and FortisBC due to a variety of factors such as utility size, nature of operations, economic climate within which it operates, and regulatory risk factors.

[105] Taking into consideration all the ROE evidence presented, the Commission finds an ROE of 9.75% to be fair and reasonable considering the risk factors of Maritime Electric, the allowed ROE of comparable regional and national jurisdictions, and the corporate business and debt ratings of Maritime Electric.

4.4 Revenue Requirement and Other Matters

[106] The rates of a public utility are designed to generate, in a fiscal year, what is known as the revenue requirement. The revenue requirement is the sum of all operating expenses, amortization or depreciation of capital assets, interest on debt, income tax and return on equity. Under traditional rate regulation, the revenue requirement approval is required to establish customer rates.

[107] With the establishment and approval of the ECAM approach to rate setting, the energy cost component of the revenue requirement is essentially established each month as the energy rates are set based on actual costs incurred by the company, plus or minus the net ECAM adjustment. The Commission assesses the Company's due diligence in obtaining the best price for energy supply. During the 2009 rate case, the evidence of Mr. Terry MacDonald, who reviewed the current Energy Purchase Agreements and provided energy pricing advice to the Commission, supports this information. As these same agreements are in place until March 2011, the Commission, therefore, accepts the energy supply costs of the Company as reasonable until that time.

[108] The remaining costs comprising the revenue requirement are assessed by the Commission for reasonableness. The *Electric Power Act* provides guidance to the Commission in Section 21(3) which reads:

Rate base, determination and fixing for each utility	21. (1) The Commission may . . . (3) (a) include all or any of (i) an allowance for necessary working capital, and (ii) any other fair and reasonable expenditure which the Commission thinks proper and basic to the public utility's operation;

[109] Expenditures of Maritime Electric are reviewed by the Commission monthly along with rate schedules. In addition, the rate application includes details of annual expenditure plans. The Commission has considered these estimates of expenditures using analysis and comparison of past expenditures and inquiries into proposed plans for future expenditures. In addition, the

public hearing provided an opportunity for further review into the reasonableness of the expenditures.

[110] The Seniors' Federation expressed concern about the oversight of Company operations and expenses in both the generation, general and administrative areas. In addition, they stated the current Key Performance Indicator ("KPI") monitoring tool employed by the Commission lacked credibility in that no external comparators are considered. The Commission acknowledges the shortcomings of the KPI measurement tool but views the process as valuable. The Commission notes there must be caution exercised in comparing organizations both within the utility sector and general business community. Considerable judgment must be exercised in the KPI review process. The Commission is involved in the process of benchmarking evaluation techniques, an issue currently being debated within the regulatory community across Canada.

[111] The Commission understands the concerns raised by the Seniors' Federation regarding Commission oversight of Company management and operations. While not always highly visible, this is a constant function of the Commission and a consideration woven into all interactions between the regulator and the utility. In addition, external expertise and consultants are employed from time to time to assist the Commission in this regard.

[112] Recent engagements by the Commission include: propriety of general and administrative expenses; assessment of power purchase contracts; demand side management plans; open access transmission tariff requirements, and the health and safety impacts of transmission lines.

[113] The Commission endeavors to make all such assessments available to the public, however, given the confidential nature of some matters, not all reviews are made public.

[114] The Commission, in its duty to ratepayers, must also be mindful of the costs of employing such expertise and satisfy itself that there is value to the Commission and ratepayers in such expenditures. The Commission, through normal regulatory processes, also affords the opportunity for interested parties to pose questions and raise concerns.

[115] The Seniors' Federation expressed concern about the value of Company capital expenditures and the implications for rates. All capital expenditures are approved by the Commission through a public process. The Company is required to provide detailed explanations for all proposed capital expenditures. The Commission not only questions company proposed initiatives, but also considers matters that should be explored. For example, following the Hurricane Juan damage in Nova Scotia, the Company was instructed to prepare and file a Contingency Readiness and Emergency Response Plan which covers a variety of contingencies such as submarine cable failures, transmission tower system failures, Emergency Response Plans and an Infrastructure Readiness Report. This initiative proved valuable when the 2008 ice storms caused considerable damage to transmission and distribution systems.

[116] The Seniors' Federation suggested a capital budget of 8 to 12% of revenue to a maximum of $15 Million, which would have the impact of reducing capital expenditures by $7 Million this year. The Commission places high value on system reliability and is concerned an artificial cap on capital expenditures might jeopardize necessary capital upgrades. Given the scrutiny of capital budgets and the necessary approval process, the Commission is not prepared to endorse such a cap.

[117] The Commission considers its website a valuable tool for providing information to the public and will continue to post relevant information to the site. The Commission will continue with the current capital budget approval process.

5. Disposition

[118] An Order will therefore issue implementing the findings and conclusions contained in these reasons.

IN THE MATTER of an application by Maritime Electric Company, Limited for approval of amendments to rates, tolls and charges.

Order

UPON receiving an application by Maritime Electric Company, Limited for approval of proposed amendments to its rates, tolls and charges;

AND UPON receiving a supplemental affidavit amending the original application to request reconsideration of the elimination of the 2nd block tariff;

AND UPON reviewing the additional evidence received in response to staff interrogatories and intervener interrogatories;

AND UPON reviewing and taking into consideration the evidence provided during the hearing by interveners and expert witnesses;

AND UPON review of previous Commission Orders concerning the Energy Cost Adjustment Mechanism (ECAM), Rate of Return, Point Lepreau replacement energy and 2nd block tariff elimination;

NOW THEREFORE, for the reasons given in the annexed Reasons for Order;

IT IS ORDERED THAT:

1. the Company shall continue deferral of Point Lepreau replacement energy costs until its return to service at which time the Company will begin amortization of this cost,

through the ECAM account, over the future expected service life of the refurbished facility;

2. the Company shall file a business case analysis associated with its continued involvement for both Point Lepreau and Dalhousie generating facilities;

3. the Company shall rebase the base rate of energy effective with meter readings taken on and after August 1, 2010 as follows:

	August 1, 2010	Additional Rate August 1, 2010 to December 31, 2010
ECAM Base Rate ($/kWh)	0.0970	0.006

4. the Company shall continue with a 12-month amortization period in the ECAM formula;

5. the maximum allowed return on average common equity is set at 9.75% for 2010 and 2011; and

6. the Company shall retain the 2,000 kWh second block reduced rate and include consideration of this issue in a rate design proposal to be filed with the Commission by December 31, 2011.

DATED at Charlottetown, Prince Edward Island, this 12th day of July, 2010.

BY THE COMMISSION:

Sgd) *Maurice Rodgerson*

Maurice Rodgerson, Chair

(Sgd) *John Broderick*

John Broderick, Commissioner

(Sgd) *Anne Petley*

Anne Petley, Commissioner

(Sgd) *Ernest Arsenault*

Ernest Arsenault, Commissioner

NOTICE

Section 12 of the ***Island Regulatory and Appeals Commission Act*** reads as follows:

> *12. The Commission may, in its absolute discretion, review, rescind or vary any order or decision made by it, or rehear any application before deciding it.*

Parties to this proceeding seeking a review of the Commission's decision or order in this matter may do so by filing with the Commission, at the earliest date, a written Request for Review, which clearly states the reasons for the review and the nature of the relief sought.

Sections 13.(1), 13(2), 13(3), and 13(4) of the ***Act*** provide as follows:

> *13.(1)An appeal lies from a decision or order of the Commission to the Court of Appeal upon a question of law or jurisdiction.*
>
> *(2) The appeal shall be made by filing a notice of appeal in the Court of Appeal within twenty days after the decision or order appealed from and the rules of court respecting appeals apply with the necessary changes.*
>
> *(3) The Commission shall be deemed to be a party to the appeal.*
>
> *(4) No costs shall be payable by any party to an appeal under this section unless the Court of Appeal, in its discretion, for special reasons, so orders.*

IRAC140A(04/07)

NOTE: In accordance with IRAC's *Records Retention and Disposition Schedule*, the material contained in the official file regarding this matter will be retained by the Commission for a period of 5 years.

3rd SESSION, 64th GENERAL ASSEMBLY
Province of Prince Edward Island
61 ELIZABETH II, 2012

CHAPTER 6

(Bill No. 26)

Electric Power (Energy Accord Continuation) Amendment Act

Honourable Wesley J. Sheridan
Minister of Finance, Energy and Municipal Affairs

GOVERNMENT BILL

MICHAEL D. FAGAN
Queen's Printer
Charlottetown, Prince Edward Island

CHAPTER 6

Electric Power (Energy Accord Continuation) Amendment Act

(Assented to December 7, 2012)

BE IT ENACTED by the Lieutenant Governor and the Legislative Assembly of the Province of Prince Edward Island as follows:

1. The *Electric Power Act* R.S.P.E.I. 1988, Cap. E-4 is amended by this Act.

2. Subsection 48(13) of the Act is repealed and the following substituted:

Return of portion of earnings to customers

(13) In the event that Maritime Electric Company, Limited's, return on average common equity exceeds the return on average common equity set out in Schedule 1, Maritime Electric Company, Limited, shall return to its customers, during the period March 1, 2013, to February 28, 2017, that portion of its earnings which exceed the return on average common equity set out in Schedule 1.

3. The Act is amended by the addition of the following after section 48:

input factors

48.1 (1) In this section, "input factors" means, in respect of Maritime Electric Company, Limited,

(a) the items and values set out in Schedule 4; and

(b) any such other factors concerning Maritime Electric Company, Limited, that the Commission determines to be input factors for the purposes of this section.

Required rates and conditions of service

(2) On and after March 1, 2013, Maritime Electric Company, Limited, shall provide service in the province at the rates, tolls and charges as are established as its lawful rates, tolls and charges pursuant to this section, and on the terms and conditions of service that were established and in effect immediately prior to March 1, 2013.

Lawful rates tolls and charges

(3) The rates, tolls and charges set out in Schedule 5, as adjusted pursuant to subsection (6), are the lawful rates, tolls and charges of Maritime Electric Company, Limited.

Continued application of energy cost adjustment mechanism

(4) For greater certainty, the rates, tolls and charges set out in Schedule 5 have been calculated pursuant to the application of the formula for the energy cost adjustment mechanism established pursuant to Commission Order UE05-01, as it has been revised by the Commission in subsequent

orders, and as modified to meet the requirements of the Prince Edward Island Energy Accord.

Entitlement to record and collect revenue requirement

(5) Maritime Electric Company, Limited, shall be entitled to record and collect in 2013, 2014 and 2015 the amount of total revenue requirement set out in Schedule 4.

Authority to vary

(6) Upon application by Maritime Electric Company, Limited, or the Government of Prince Edward Island, the Commission may, by order, amend Schedule 5 to vary the rates, tolls and charges as set out therein if the Commission is satisfied that a material change in the circumstances of Maritime Electric Company, Limited, has occurred with respect to any one or more of the input factors, either collectively or independently, of Maritime Electric Company, Limited.

Publication of order

(7) Every order made under subsection (6) shall be published in the Gazette.

Terminations of obligations and conditions

(8) The following obligations and conditions imposed by the Commission on Maritime Electric Company, Limited, in the orders specified, are terminated or varied as follows:

(a) the obligations and conditions imposed in Order UE11-04 in section 2 are terminated; and

(b) the obligations and conditions imposed in any other order of the Commission, including an order of the Commission referred to in subsection 48(7), which are inconsistent with this section and Schedule 4 are terminated or varied to the extent the order is no longer inconsistent with this section and Schedule 4.

Return of portion of earnings to customers

(9) In the event that Maritime Electric Company, Limited's, return on average common equity exceeds the return on average common equity set out in Schedule 4, Maritime Electric Company, Limited, shall return to its customers, during the period March 1, 2013, to February 28, 2017, that portion of its earnings which exceed the return on average common equity set out in Schedule 4.

4. (1) Section 50 of the Act is amended by addition of the following after subsection 50(1):

Statement of estimated costs, filing for continuation period

(1.1) On or before March 1, 2013, Maritime Electric Company, Limited, shall file with the Commission a statement of the estimated cost it expects to incur to generate and purchase the energy necessary to supply its customers for the period commencing March 1, 2013, and ending February 29, 2016, which estimates shall be based upon the inputs contained in Schedule 4.

(2) Subsection 50(2) of the Act is repealed and the following substituted:

(2) On or before March 15, 2016, Maritime Electric Company, Limited, shall file with the Commission a statement of the actual cost incurred by Maritime Electric Company, Limited, to generate and purchase the energy necessary to supply its customers for the period commencing March 1, 2011, and ending February 29, 2016.

Statement of actual costs, filing

(3) Subsection 50(3) of the Act is repealed and the following substituted:

(3) Where the actual cost to Maritime Electric Company, Limited, to generate and purchase energy necessary to supply its customers for the period of March 1, 2011, to February 29, 2016, is

Return or charge to customers where actual costs are less than or greater than estimated costs

(a) less than its estimated cost for that period, Maritime Electric Company, Limited, shall return the difference between the actual cost and the estimated cost to its customers with all such returns to be completed prior to March, 2017; and

(b) greater than its estimated cost for that period, Maritime Electric Company, Limited, is entitled to charge the difference between the actual cost and the estimated cost for that period to its customers with all such charges to be completed prior to March, 2017.

5. Section 48 of the Act is repealed and the following substituted:

48. (1) On and after March 1, 2016, Maritime Electric Company, Limited, shall provide service in the province at the rates, tolls and charges, and on the terms and conditions of service, that were established and in effect under this Act and the regulations immediately before March 1, 2016, until such time as those rates, tolls and charges, and those terms and conditions of service, are altered or modified under this Act.

Required rates and conditions of service

(2) On and after March 1, 2016, the Commission shall be deemed to have approved anything that was done by Maritime Electric Company, Limited, prudently and in accordance with good utility practice during the period beginning on November 1, 2010, and ending on February 29, 2016, that would otherwise have required the approval of the Commission under this Act.

Deemed approval of things done

(3) On and after March 1, 2016, the Commission shall be deemed to have determined that all costs and expenses recorded by Maritime Electric Company, Limited, in accordance with good utility practice for the period beginning March 1, 2011, and ending on February 29, 2016, are accurate, correct, reasonable and prudent.

Costs, expenses, returns deemed correct and reasonable

6. Section 48.1 of the Act is repealed and the following substituted:

48.1 On and after March 1, 2016, when approving or determining and fixing the rates, tolls and charges of Maritime Electric Company,

Recovery of deferred costs and annual expenses

Limited, the Commission shall allow Maritime Electric Company, Limited,

(a) to recover over such period of time and on such terms and conditions as the Commission considers just and reasonable,

(i) the deferred costs that Maritime Electric Company, Limited, incurred during the period from March 1, 2011 to February 29, 2016,

(ii) the unamortized portion of any deferred cost incurred before March 1, 2016, by Maritime Electric Company, Limited, and

(iii) a reasonable return on the unrecovered deferred costs referred to in subclauses (i) and (ii); and

(b) to recover, as an annual expense, the amounts payable by Maritime Electric Company, Limited, pursuant to any power purchase agreement Maritime Electric Company, Limited, has entered into before March 1, 2016, that continues in force on and after that date.

Depreciation account and rates of deprecation deemed proper and adequate

48.2 On and after March 1, 2016, the Commission shall be deemed to have ascertained and determined pursuant to section 23:

(a) that the depreciation account of Maritime Electric Company, Limited, as of March 1, 2016, is proper and adequate; and

(b) that the rates of depreciation used by Maritime Electric Company, Limited, in respect of the several classes of its property for the period March 1, 2011, to February 29, 2016, are proper and adequate.

7. The Act is amended by the addition of Schedules 4 and 5, as set out in the Schedule to this Act, after Schedule 3.

8. Schedules 1, 2, 3, 4 and 5 of the Act are repealed.

CONSEQUENTIAL AMENDMENTS

9. (1) The *Electric Power (Electricity-Rate Reduction) Amendment Act* S.P.E.I. 2010, c. 9 is amended by this section.

(2) Section 4 of the Act is repealed.

(3) Section 6 of the Act is repealed.

COMMENCEMENT

10. (1) Subject to subsection (2), this Act comes into force on March 1, 2013.

(2) Sections 5, 6 and 8 of this Act come into force on March 1, 2016.

SCHEDULE

SCHEDULE 4

Maritime Electric Company, Limited
Schedule of PEI Energy Accord Inputs

	2013	2014	2015
Summary of Forecast NPP and Sales			
Net Purchased & Produced (kWh)	1,166,945,243	1,180,774,832	1,193,232,159
Sales (kWh)			
Residential	474,574,000	482,642,000	490,123,000
General Service I	372,963,000	376,506,000	379,518,000
General Service II	7,190,000	7,251,000	7,294,000
Large Industrial	142,012,000	142,663,000	143,110,000
Small Industrial	70,728,000	71,117,000	71,579,000
Street Lighting	6,215,000	6,261,000	6,308,000
Unmetered	2,398,000	2,416,000	2,432,000
	1,076,080,000	1,088,856,000	1,100,364,000
ECAM Base Rate per kWh (Effective March 1)	0.09880	0.09365	0.08760
Capital Structure (Year End)			
Debt	56.50%	56.90%	58.10%
Equity	43.50%	43.10%	41.90%
	100.00%	100.00%	100.00%
Return on Average Common Equity	9.75%	9.75%	9.75%
Average Short Term Financing Rate	3.5%	3.6%	3.9%
Annual Capital Expenditures	25,333,000	27,849,235	26,872,201
Summary of Revenues and Expenses			
Basic Rate Revenue			
Residential	85,450,000	86,149,000	84,528,000
General Service I	60,545,000	60,455,000	58,612,000
General Service II	1,161,000	1,159,000	1,118,000
Large Industrial	14,538,000	14,050,000	12,885,000
Small Industrial	10,007,000	9,941,000	9,627,000
Street Lighting	2,289,000	2,262,000	2,183,000
Unmetered	412,000	407,000	392,000
	174,402,000	174,423,000	169,345,000
Other Revenue	7,133,960	6,634,939	8,507,507
Total Revenue	181,535,960	181,057,939	177,852,507
Operating Expenses			
Energy Costs	113,223,951	111,314,880	105,581,507
Distribution	4,361,382	4,665,024	5,021,271
Transmission - OATT	5,527,645	5,602,055	5,675,820
Corporate	12,893,649	13,200,326	13,516,223
Amortization - Fixed Assets & Other	15,554,944	16,389,141	17,173,918
Financing Expenses	11,868,424	12,120,748	12,555,568
Income Taxes	5,635,771	5,528,934	5,701,996
Net Earnings	12,470,194	12,236,831	12,626,204

SCHEDULE 5

Maritime Electric Company, Limited
Schedule of Rates

Rate Code		March 1, 2013	March 1, 2014	March 1, 2015
110	**Residential Urban**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Energy Charge per kWh for first 2,000 kWh	$ 0.1241	$ 0.1278	$ 0.1316
	Energy Charge per kWh for balance kWh	$ 0.0940	$ 0.0985	$ 0.1038
130	**Residential Rural**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1241	$ 0.1278	$ 0.1316
	Energy Charge per kWh for balance kWh	$ 0.0940	$ 0.0985	$ 0.1038
131	**Residential Seasonal**			
	Service Charge	$ 26.92	$ 26.92	$ 26.92
	Energy Charge per kWh for first 2,000 kWh	$ 0.1241	$ 0.1278	$ 0.1316
	Energy Charge per kWh for balance of kWh	$ 0.0940	$ 0.0985	$ 0.1038
133	**Residential Seasonal Option**			
	Service Charge	$ 37.50	$ 37.50	$ 37.50
	Energy Charge per kWh for first 2,000 kWh	$ 0.1241	$ 0.1278	$ 0.1316
	Energy Charge per kWh for balance of kWh	$ 0.0940	$ 0.0985	$ 0.1038
232	**General Service I**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1571	$ 0.1601	$ 0.1625
	Energy Charge per kWh for balance of kWh	$ 0.0950	$ 0.0996	$ 0.1049
233	**General Service I - Seasonal Operators Option**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW	$ 13.43	$ 13.43	$ 13.43
	Energy Charge per kWh for first 5,000 kWh	$ 0.1571	$ 0.1601	$ 0.1625
	Energy Charge per kWh for balance of kWh	$ 0.0950	$ 0.0996	$ 0.1049
250	**General Service II**			
	Service Charge	$ 24.57	$ 24.57	$ 24.57
	Demand Charge - per kW for first 20 kW	$ -	$ -	$ -
	Demand Charge - per kW for balance of kW:			
	(a) per kilowatt or	$ 5.68	$ 5.68	$ 5.68
	(b) the number of kilowatt hours consumed in the period times	$ 0.0284	$ 0.0284	$ 0.0284
	Energy Charge per kWh for first 5,000 kWh	$ 0.1572	$ 0.1602	$ 0.1626
	Energy Charge per kWh for next 5,000 kWh	$ 0.1132	$ 0.1173	$ 0.1218
	Energy Charge per kWh for balance of kWh	$ 0.1073	$ 0.1116	$ 0.1164
320	**Small Industrial**			
	Demand Charge - per kW	$ 7.46	$ 7.46	$ 7.46
	Energy Charge per kWh for first 100 kWh per kW billing demand	$ 0.1535	$ 0.1566	$ 0.1591
	Energy Charge per kWh for balance of kWh	$ 0.0664	$ 0.0717	$ 0.0784
310	**Large Industrial**			
	Demand Charge per kW	$ 14.50	$ 14.50	$ 14.50
	Energy Charge per kWh	$ 0.0616	$ 0.0634	$ 0.0653
340	**Long Term Contract** (Currently no customers in this rate category)			
	Demand Charge per kW	$ 15.51	$ 15.51	$ 15.51
	Energy Charge per kWh	$ 0.0780	$ 0.0830	$ 0.0869
330	**Short Term Contract** (Currently no customers in this rate category)			
	Demand Charge - per kW	$ 16.79	$ 16.79	$ 16.79
	Energy Charge per kWh for all kWh in the first block	$ 0.0778	$ 0.0814	$ 0.0887
	Energy Charge per kWh for balance of kWh in the month	$ 0.0607	$ 0.0661	$ 0.0730

Maritime Electric Company, Limited
Schedule of Rates

Rate Code	Lamp Wattage	Type		Annual kWh	Monthly kWh	March 1, 2013	March 1, 2014	March 1, 2015
620	200	HPS	St Lights - Rented	1033	86	$ 31.02	$ 31.70	$ 32.40
630	70	HPS	St Lights - Rented	389	32	$ 14.28	$ 14.59	$ 14.91
631	100	HPS	St Lights - Rented	553	46	$ 18.15	$ 18.55	$ 18.96
632	150	HPS	St Lights - Rented	799	66	$ 25.92	$ 26.49	$ 27.07
633	250	HPS	St Lights - Rented	1283	106	$ 35.23	$ 36.01	$ 36.80
634	400	HPS	St Lights - Rented	1886	157	$ 41.21	$ 42.12	$ 43.05
635	125	MV	St Lights - Rented	656	54	$ 14.13	$ 14.44	$ 14.76
636	175	MV	St Lights - Rented	881	73	$ 17.97	$ 18.37	$ 18.77
637	250	MV	St Lights - Rented	1210	101	$ 24.99	$ 25.54	$ 26.10
638	400	MV	St Lights - Rented	1906	158	$ 34.87	$ 35.64	$ 36.42
639	70	Lanterns	City Lanterns - Rented	389	32	$ 52.47	$ 53.62	$ 54.80
640	70	HPS	St Lights - Owned	389	32	$ 5.61	$ 5.73	$ 5.86
641	100	HPS	St Lights - Owned	553	46	$ 7.39	$ 7.55	$ 7.72
642	150	HPS	St Lights - Owned	779	65	$ 9.94	$ 10.16	$ 10.38
643	250	HPS	St Lights - Owned	1283	107	$ 15.73	$ 16.08	$ 16.43
644	400	HPS	St Lights - Owned	1886	157	$ 24.82	$ 25.37	$ 25.93
645	125	MV	St Lights - Owned	656	55	$ 8.38	$ 8.56	$ 8.75
646	175	MV	St Lights - Owned	881	73	$ 11.35	$ 11.60	$ 11.86
647	250	MV	St Lights - Owned	1210	101	$ 15.68	$ 16.02	$ 16.37
648	400	MV	St Lights - Owned	1906	159	$ 24.80	$ 25.35	$ 25.91
650	200	HPS	St Lights - Owned	1033	86	$ 13.69	$ 13.99	$ 14.30
720	200	HPS	Yard Lights - Rented	1033	86	$ 28.37	$ 28.99	$ 29.63
730	70	HPS	Yard Lights - Rented	389	32	$ 14.28	$ 14.59	$ 14.91
731	100	HPS	Yard Lights - Rented	553	46	$ 18.11	$ 18.51	$ 18.92
732	150	HPS	Yard Lights - Rented	799	66	$ 25.92	$ 26.49	$ 27.07
733	250	HPS	Yard Lights - Rented	1283	106	$ 35.23	$ 36.01	$ 36.80
734	400	HPS	Yard Lights - Rented	1886	157	$ 41.21	$ 42.12	$ 43.05
735	125	MV	Yard Lights - Rented	656	54	$ 14.13	$ 14.44	$ 14.76
736	175	MV	Yard Lights - Rented	881	73	$ 17.97	$ 18.37	$ 18.77
737	250	MV	Yard Lights - Rented	1210	100	$ 25.00	$ 25.55	$ 26.11
738	400	MV	Yard Lights - Rented	1906	158	$ 31.93	$ 32.63	$ 33.35
740	70	HPS	Yard Lights - Owned	389	32	$ 5.61	$ 5.73	$ 5.86
741	100	HPS	Yard Lights - Owned	553	46	$ 7.39	$ 7.55	$ 7.72
742	150	HPS	Yard Lights - Owned	779	65	$ 9.94	$ 10.16	$ 10.38
743	250	HPS	Yard Lights - Owned	1283	107	$ 15.73	$ 16.08	$ 16.43
744	400	HPS	Yard Lights - Owned	1886	157	$ 24.82	$ 25.37	$ 25.93
745	125	MV	Yard Lights - Owned	656	55	$ 8.38	$ 8.56	$ 8.75
746	175	MV	Yard Lights - Owned	881	73	$ 11.35	$ 11.60	$ 11.86
747	250	MV	Yard Lights - Owned	1210	101	$ 15.68	$ 16.02	$ 16.37
748	400	MV	Yard Lights - Owned	1906	159	$ 24.80	$ 25.35	$ 25.91
749	180	LPS	Yard Lights - Owned	869	72	$ 11.59	$ 11.84	$ 12.10
750	200	HPS	Yard Lights - Owned	1033	86	$ 13.69	$ 13.99	$ 14.30
751	135	LPS	Yard Lights - Owned	730	61	$ 9.22	$ 9.42	$ 9.63
752	90	LPS	Yard Lights - Owned	521	43	$ 6.46	$ 6.60	$ 6.75
753	250	Flood	Yard Lights - Rented	1283	107	$ 33.61	$ 34.35	$ 35.11
754	400	Flood	Yard Lights - Rented	1886	157	$ 41.86	$ 42.78	$ 43.72
755	250	Halide	Yard Lights - Rented	1148	95	$ 35.41	$ 36.19	$ 36.99
756	400	Halide	Yard Lights - Rented	1878	156	$ 43.58	$ 44.54	$ 45.52
757	1000	Halide	Yard Lights - Rented	4346	362	$ 74.80	$ 76.45	$ 78.13
758	70	Halide	St Lights - Owned	390	32	$ 5.06	$ 5.17	$ 5.28
759	100	Halide	St Lights - Owned	533	44	$ 6.91	$ 7.06	$ 7.22
760	175	Halide	St Lights - Owned	894	74	$ 11.60	$ 11.86	$ 12.12
761	250	Halide	St Lights - Owned	1148	95	$ 14.89	$ 15.22	$ 15.55
762	400	Halide	St Lights - Owned	1878	156	$ 24.34	$ 24.88	$ 25.43
763	1000	Halide	St Lights - Owned	4346	362	$ 56.34	$ 57.58	$ 58.85
764	100	LED	St Lights - Owned	410	34	$ 5.31	$ 5.43	$ 5.55
765	150	Halide	St Lights - Owned	759	63	$ 9.83	$ 10.05	$ 10.27

Maritime Electric Company, Limited
Schedule of Rates

			March 1, 2013		March 1, 2014		March 1, 2015
610	Pole Rental -Wood	$	4.38	$	4.38	$	4.38
611	Pole Rental -Concrete	$	7.96	$	7.96	$	7.96
	Unmetered Rates (based on 100 watt fixture)						
810	8 Hour Lighting per kWh	$	0.1555	$	0.1589	$	0.1624
	Minimum Charge	$	11.67	$	11.67	$	11.67
820	12 Hour Lighting per kWh	$	0.1555	$	0.1589	$	0.1624
	Minimum Charge	$	11.67	$	11.67	$	11.67
830	24 Hour Lighting per kWh	$	0.1555	$	0.1589	$	0.1624
	Minimum Charge	$	11.67	$	11.67	$	11.67
840	Air Raid & Fire Sirens	Currently no customers in this rate category					
850	Outdoor Christmas Lighting - 5.77¢ per watt of connected load per week						
234	Customer Owned Outdoor Recreational Lighting						
	Service Charge	$	24.57	$	24.57	$	24.57
	Energy Charge per kWh for first 5,000 kWh	$	0.1555	$	0.1589	$	0.1624
	Energy Charge per kWh for balance of kWh	$	0.0955	$	0.0976	$	0.0997
	Short Term Unmetered Rates	Currently no customers in this rate category					
	Energy Charge:						
	per kWh of estimated consumption	$	0.1555	$	0.1589	$	0.1624

Connection Charge:	Single-Phase	Three-Phase
A. Connecting to existing secondary voltage	$99.08	$99.08

B. Where transformer installations are required, the following connection charges will apply:

	Single-Phase	Three-Phase
(1) Up to and including 10 kVA	$148.87	$209.17
(2) 11 kVA to 15 kVA	$240.79	$301.01
(3) 16 kVA to 25 kVA	$269.20	$336.64
(4) 26 kVA to 37 kVA	$301.01	$336.64
(5) 38 kVA to 50 kVA	$336.64	$336.64
(6) 51 kVA to 75 kVA	$369.58	$523.96
(7) 76 kVA to 125 kVA	$431.07	$555.59
(8) Above 125 kVA	0	$594.94

CHAPTER 6

(Bill No. 26)

Electric Power (Energy Accord Continuation) Amendment Act

STAGE:	*DATE:*
1st Reading:	November 29, 2012
2nd Reading:	December 6, 2012
To Committee:	December 6, 2012
Reported:	December 6, 2012
3rd Reading and Pass:	December 7, 2012
Assent:	December 7, 2012

SIGNATURES:

Honourable H. Frank Lewis, Lieutenant Governor

Honourable Carolyn I. Bertram, Speaker

Clerk

Honourable Wesley J. Sheridan

Minister of Finance, Energy and Municipal Affairs

GOVERNMENT BILL

2012

3rd SESSION, 64th GENERAL ASSEMBLY

Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

ORDER NO. P. U. 46(2009)

IN THE MATTER OF
the *Public Utilities Act*, RSNL 1990, Chapter P-47 (the *"Act"*) and the *Electrical Power Control Act*, SNL 1994, Chapter E-5.1 (the *"EPCA"*) and regulations thereunder;

AND IN THE MATTER OF
a general rate application by Newfoundland Power Inc. to establish customer electricity rates for 2010;

AND IN THE MATTER OF an application for approval of customer rates, tolls and charges reflecting the determinations set out in Order No. P. U. 43(2009).

BEFORE:

Andy Wells
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

Dwanda Newman, LL.B.
Commissioner

WHEREAS Newfoundland Power Inc. ("Newfoundland Power") is a corporation duly organized and existing under the laws of the Province of Newfoundland and Labrador, is a public utility within the meaning of the *Act*, and is subject to the provisions of the *EPCA*; and

WHEREAS on May 28, 2009 Newfoundland Power filed a general rate application with the Board of Commissioners of Public Utilities (the "Board"), which was amended on September 28, 2009, (the "Application") for an Order or Orders of the Board approving among other things, proposed rates for the various customers of Newfoundland Power, to be effective January 1, 2010; and

WHEREAS Newfoundland Power and the Consumer Advocate filed a settlement agreement on September 23, 2009; and

WHEREAS on December 11, 2009 after a public hearing, the Board issued Order No. P. U. 43(2009) directing Newfoundland Power to *inter alia*:

(1) calculate and file a revised forecast average rate base and return on rate base for 2010 based on its proposals in the Application, incorporating the determinations set out in Order No. P. U. 43(2009), including the use of a return on common equity of 9.00% to calculate the rate of return on rate base for the 2010 test year;

(2) calculate and file a revised forecast total revenue requirement for the 2010 test year based on its proposals in the Application, incorporating the determinations set out in Order No. P. U. 43(2009);

(3) file a revised Schedule of Rates, Tolls and Charges which shall become effective for service provided on and after January 1, 2010, based on the proposals in the Application, incorporating the determinations set out in Order No. P. U. 43(2009); and

WHEREAS on December 16, 2009 Newfoundland Power submitted an application in compliance with Order No. P. U. 43(2009), with attached Schedules (the "Compliance Application"), proposing changes to electricity rates resulting in an average increase in electrical rates of 3.5% effective on monthly bills issued on and after January 1, 2010; and

WHEREAS the Compliance Application also proposed a change to the Rate Stabilization Clause included in Newfoundland Power's Rules and Regulations to provide for the recovery of the Energy Supply Cost Variance in accordance with Order No. P. U. 43(2009); and

WHEREAS the Compliance Application also proposed a revised definition of the Excess Earnings Account to reflect the Board's determinations in Order No. P. U. 43(2009) in respect of the range of return on rate base; and

WHEREAS the Board has reviewed the Compliance Application and is satisfied that the Compliance Application is based on Newfoundland Power's proposals in the Application and reflects the determinations of the Board set out in Order No. P. U. 43(2009).

IT IS THEREFORE ORDERED THAT:

1. The Board approves the forecast average rate base for 2010 of $871,585,000, pursuant to Section 80 of the *Act*.

2. The Board approves the rate of return on rate base for 2010 of 8.23% in a range of 8.05% to 8.41%, pursuant to Section 80 of the *Act*.

3. The Board approves the Schedule of Rates, Tolls and Charges of Newfoundland Power as set out in Schedule "A", to be effective for service provided on and after January 1, 2010, pursuant to Section 70(1) of the *Act*.

4. The Board approves the Rules and Regulations as set out in Schedule "B", to be effective January 1, 2010.

5. The Board approves the revised definition of the Excess Earnings Account as set out in Schedule "C".

6. Newfoundland Power shall pay the expenses of the Board arising from this Application.

Dated at St. John's, Newfoundland and Labrador this 24th day of December 2009.

Andy Wells
Chair & Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

Dwanda Newman, LL.B.
Commissioner

Barbara Thistle
Assistant Board Secretary

NEWFOUNDLAND POWER INC.
RATE #1.1
DOMESTIC SERVICE

Availability:

For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $15.57 per month

Energy Charge:
All kilowatt-hours .... @ 9.339¢ per kWh

Minimum Monthly Charge .... $15.57 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-10 kW

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $17.86 per month

Energy Charge:
All kilowatt-hours .... @ 11.098 ¢ per kWh

Minimum Monthly Charge, Single Phase .... $17.86 per month
Three Phase .... $35.72 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.2
GENERAL SERVICE 10-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovolt-amperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $20.57 per month

Demand Charge:
$8.63 per kW of billing demand in the months of December, January, February and March and $7.13 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kW of billing demand.. @ 8.611 ¢ per kWh
All excess kilowatt-hours.. @ 6.264 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.8 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:

Single Phase .... $20.57 per month
Three Phase .... $35.72 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $92.61 per month

Demand Charge:
$7.45 per kVA of billing demand in the months of December, January, February and March and $5.95 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 30,000 kilowatt-hours .... @ 8.581 ¢ per kWh
All excess kilowatt-hours .... @ 6.187 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.8 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: .... $185.23 per month

Demand Charge:
$7.04 per kVA of billing demand in the months of December, January, February and March and $5.54 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 100,000 kilowatt-hours .... @ 7.229 ¢ per kWh
All excess kilowatt-hours .... @ 6.122 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.8 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #4.1
STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service where the electricity is supplied by the Company and all fixtures, wiring and controls are provided, owned and maintained by the Company.

Monthly Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

	Sentinel/Standard	Post Top
High Pressure Sodium*		
100W (8,600 lumens)	$15.53	$16.68
150W (14,400 lumens)	19.91	-
250W (23,200 lumens)	26.86	-
400W (45,000 lumens)	37.26	-

* For all new installations and replacements.

Mercury Vapour		
175W (7,000 lumens)	$15.53	$16.68
250W (9,400 lumens)	19.91	-
400W (17,200 lumens)	26.86	-

Special poles used exclusively for lighting service**	
Wood	$ 6.76
30' Concrete or Metal, direct buried	9.81
45' Concrete or Metal, direct buried	14.95
25' Concrete or Metal, Post Top, direct buried	7.56
Underground Wiring (per run)**	
All sizes and types of fixtures	$11.96

** Where a pole or underground wiring run serves two fixtures paid for by different parties, the above rates for such poles and underground wiring may be shared equally between the two parties.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:
The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{(\text{Maximum Demand during Peak Period x 1573 hours})}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced by 50% as a result of the first failure to Curtail during a Winter. For each additional failure to Curtail, the Curtailment Credit will be reduced by a further 25% of the Curtailment Credit. If the Customer fails to Curtail three times during a Winter, the Customer forfeits 100% of the Curtailment Credit and the Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

The Company shall include a rate stabilization adjustment in its rates. This adjustment shall reflect the accumulated balance in the Company's Rate Stabilization Account ("RSA") and any change in the rates charged to the Company by Newfoundland and Labrador Hydro ("Hydro") as a result of the operation of its Rate Stabilization Plan ("RSP").

I. RATE STABILIZATION ADJUSTMENT ("A")

The Rate Stabilization Adjustment ("A") shall be calculated as the total of the Recovery Adjustment Factor and the Fuel Rider Adjustment.

The Recovery Adjustment Factor shall be recalculated annually, effective the first day of July in each year, to amortize over the following twelve (12) month period the annual plan recovery amount designated to be billed by Hydro to the Company, and the balance in the Company's RSA.

The Recovery Adjustment Factor expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{B + C}{D}$$

Where:

B = the annual plan recovery amount designated to be billed by Hydro during the next twelve (12) months commencing July 1 as a result of the operation of Hydro's RSP.

C = the balance in the Company's RSA as of March 31st of the current year.

D = the total kilowatt-hours sold by the Company for the 12 months ending March 31st of the current year.

The Fuel Rider Adjustment shall be recalculated annually, effective the first day of July in each year, to reflect changes in the RSP fuel rider applicable to Newfoundland Power. The Fuel Rider Adjustment expressed in cents per kilowatt-hour and calculated to the nearest 0.001 cent shall be calculated as follows:

$$\frac{E}{D} \times F$$

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

I. RATE STABILIZATION ADJUSTMENT ("A") (Cont'd)

Where:

D = corresponds to the D above.

E = the total kilowatt-hours of energy (including secondary energy) sold to the Company by Hydro during the 12 months ending March 31 of the current year.

F = the fuel rider designated to be charged to Newfoundland Power through Hydro's RSP.

The Rate Stabilization Adjustment ("A") shall be recalculated and be applied as of the effective date of a new wholesale mill rate by Hydro, by resetting the Fuel Rider Adjustment included in the Rate Stabilization Adjustment to zero.

II. RATE STABILIZATION ACCOUNT ("RSA")

The Company shall maintain a RSA which shall be increased or reduced by the following amounts expressed in dollars:

1. At the end of each month the RSA shall be:

(i) increased (reduced) by the amount actually charged (credited) to the Company by Hydro during the month as the result of the operation of its Rate Stabilization Plan.

(ii) increased (reduced) by the excess cost of fuel used by the Company during the month calculated as follows:

$$(G/H - P) \quad x \quad H$$

Where:

G = the cost in dollars of fuel and additives used during the month in the Company's thermal plants to generate electricity other than that generated at the request of Hydro.

H = the net kilowatt-hours generated in the month in the Company's thermal plants other than electricity generated at the request of Hydro.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

P = the 2nd block base rate in dollars per kilowatt-hour paid during the month by the Company to Hydro for firm energy.

(iii) reduced by the price differential of firmed-up secondary energy calculated as follows:

$$(P - J) \times K$$

Where:

J = the price in dollars per kilowatt-hour paid by the Company to Hydro during the month for secondary energy supplied by Deer Lake Power and delivered as firm energy to the Company.

K = the kilowatt-hours of such secondary energy supplied to the Company during the month.

P = corresponds to P above.

(iv) reduced (increased) by the amount billed by the Company during the month as the result of the operation of the Rate Stabilization Clause calculated as follows:

$$\frac{L \times A}{100}$$

Where:

L = the total kilowatt-hours sold by the Company during the month.

A = the Rate Stabilization Adjustment in effect during the month expressed in cents per kilowatt-hour.

(v) increased (reduced) by an interest charge (credit) on the balance in the RSA at the beginning of the month, at a monthly rate equivalent to the mid-point of the Company's allowed rate of return on rate base.

2. On the 31st of December in each year, the RSA shall be increased (reduced) by the amount that the Company billed customers under the Municipal Tax Clause for the calendar year is less (or greater) than the amount of municipal taxes paid for that year.

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

3. The annual kilowatt-hours used in calculating the Rate Stabilization Adjustment to the monthly streetlighting rates are as follows:

	Fixture Size (watts)				
	100	150	175	250	400
Mercury Vapour	-	-	840	1,189	1,869
High Pressure Sodium	546	802	-	1,273	1,995

4. On December 31st, 2007, the RSA shall be reduced (increased) by the amount that the increase in the Company's revenue for the year resulting from the change in base rates attributable to the flow through of Hydro's wholesale rate change, effective January 1, 2007, is greater (or less) than the amount of the increase in the Company's purchased power expense for the year resulting from the change in the base rate charged by Hydro effective January 1, 2007.

   The methodology to calculate the RSA adjustment at December 31, 2007 is as follows:

Calculation of increase in Revenue:	
2007 Revenue with Flow-through (Q)	$ -
2007 Revenue without Flow-through (R)	$ -
Increase in Revenue (S = Q – R)	$ -
Calculation of increase in Purchased Power Expense:	
2007 Purchased Power Expense with Hydro Increase (T)	$ -
2007 Purchased Power Expense without Hydro Increase (U)	$ -
Increase in Purchased Power Expense (V = T – U)	$ -
Adjustment to Rate Stabilization Account (W = S – V)	$ -

   Where:

   Q = Normalized revenue from base rates effective January 1, 2007.

   R = Normalized revenue from base rates determined based on rates pursuant to the operation of the Automatic Adjustment Formula for 2007.

   T = Normalized purchased power expense from Hydro's wholesale rate effective January 1, 2007 (not including RSP rate).

   U = Normalized purchased power expense determined based on Hydro's wholesale rate effective January 1, 2006 (not including RSP rate).

NEWFOUNDLAND POWER INC.

RATE STABILIZATION CLAUSE

II. RATE STABILIZATION ACCOUNT ("RSA") (Cont'd)

5. On December 31st of each year from 2008 until further order of the Board, the Rate Stabilization Account (RSA) shall be increased (reduced) by the Energy Supply Cost Variance.

   This Energy Supply Cost Variance identifies the change in purchased power cost that is related to the difference between purchasing energy at the 2nd block energy charge in the wholesale rate and the test year energy supply cost reflected in customer rates.

   The Energy Supply Cost Variance expressed in dollars shall be calculated as follows:

$$\frac{(A - B) \times (C - D)}{100}$$

   Where:

   A = the wholesale rate 2nd block charge per kWh.

   B = the test year energy supply cost per kWh determined by applying the wholesale energy rate to the test year energy purchases and expressed in ¢ per kWh.

   C = the weather normalized annual purchases in kWh.

   D = the test year annual purchases in kWh.

6. The RSA shall be adjusted by any other amount as ordered by the Board.

III. RATE CHANGES

The energy charges in each rate classification (other than the energy charge in the "Maximum Monthly Charge" in classifications having a demand charge) shall be adjusted as required to reflect the changes in the Rate Stabilization Adjustment. The new energy charges shall be determined by subtracting the previous Rate Stabilization Adjustment from the previous energy charges and adding the new Rate Stabilization Adjustment. The new energy charges shall apply to all bills based on consumption on and after the effective date of the adjustment.

Newfoundland Power Inc.

Excess Earnings Account

<u>Current Definition</u>

3.05 Excess Earnings Account 284xx

This account shall be credited with any earnings in excess of the upper limit of the allowed range of return on rate base as determined by the Board. Disposition of any balance in this account shall be as determined by the Board. For 2008 and subsequent years, all earnings in excess of an 8.55% rate of return on rate base shall, unless otherwise ordered by the Board, be credited to this account.

<u>Revised Definition</u>

3.05 Excess Earnings Account 284xx

This account shall be credited with any earnings in excess of the upper limit of the allowed range of return on rate base as determined by the Board. Disposition of any balance in this account shall be as determined by the Board. For 2010 and subsequent years, all earnings in excess of an 8.41% rate of return on rate base shall, unless otherwise ordered by the Board, be credited to this account.

Newfoundland & Labrador

BOARD OF COMMISSIONERS OF PUBLIC UTILITIES

ORDER NO. P.U. 17(2012)

IN THE MATTER OF
the *Electrical Power Control Act, 1994,* SNL 1994, Chapter E-5.1 (the *"EPCA"*) and the *Public Utilities Act,* RSNL 1990, Chapter P-47 (the *"Act"*) and regulations thereunder;

AND IN THE MATTER OF
the just and reasonable return on rate base for 2012 for Newfoundland Power Inc. pursuant to Section 80 of the *Act*.

BEFORE:

Andy Wells
Chair and Chief Executive Officer

Darlene Whalen, P.Eng.
Vice-Chair

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

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I. APPLICATION AND PROCEEDING

Application

Newfoundland Power Inc. ("Newfoundland Power") filed an application (the "Application") with the Board of Commissioners of Public Utilities (the "Board") on March 30, 2012 proposing that the Board:

1. approve a just and reasonable return on rate base for Newfoundland Power for 2012;

2. discontinue the use of the automatic adjustment formula for setting the allowed return on rate base for Newfoundland Power; and

3. approve a schedule of customer rates, tolls and charges based upon the rate of return on average rate base for 2012 as approved by the Board.

Background

The automatic adjustment formula was established for Newfoundland Power in Order Nos. P.U. 16(1998-99) and P.U. 36(1998-99) to allow the adjustment of the established annual rate of return on rate base in the years following a general rate application. In Order Nos. P.U. 43(2009) and P.U. 46(2009), following a general rate application from Newfoundland Power, the Board set the rate of return on rate base for 2010 and ordered that the automatic adjustment formula would be used to set the rate of return on rate base for 2011 and 2012. In Order No. P.U. 32(2010) the Board approved a rate of return on rate base for Newfoundland Power for 2011 of 7.96% based on the operation of the automatic adjustment formula. In the following year, upon application by Newfoundland Power, the Board in Order No. P.U. 25(2011) suspended the operation of the automatic adjustment formula for 2012 and determined that the 2011 rate of return on rate base of 7.96% would be continued for 2012 on an interim basis. The Board stated that the process and timing to be followed to determine a final just and reasonable rate of return on rate base for Newfoundland Power for 2012 and for the filing of Newfoundland Power's next general rate application would be subsequently established by the Board. On May 29, 2012 the Board directed Newfoundland Power to file a general rate application by September 14, 2012 to address the rate of return on rate base for 2013 and years thereafter. This Application seeks a final rate of return on rate base for 2012.

Application Process

Notice of the Application was published in newspapers throughout the Province beginning on April 9, 2012.

Registered intervenors for the proceeding were the Government appointed Consumer Advocate, Mr. Thomas Johnson, Newfoundland and Labrador Hydro ("Hydro"), represented by Mr. Geoff Young, and the Island Industrial Customers (the "Industrial Customers"), represented by Mr. Paul Coxworthy. Hydro and the Industrial Customers advised in their Intervenor Submissions that their participation in the proceeding would be limited. Newfoundland Power was represented by Mr. Ian Kelly, Q.C. and Mr. Gerard Hayes.

The Board was assisted throughout the proceeding by Ms. Maureen Greene, Q.C., who acted as Board Hearing Counsel, and Ms. Jacqueline Glynn, Board Counsel.

The parties agreed that the issue of a just and reasonable return on rate base for Newfoundland Power for 2012 would be addressed in this proceeding but that the issue of discontinuing the automatic adjustment formula would be addressed in a separate proceeding at a later date.

Evidence

Expert evidence was filed by Newfoundland Power and the Consumer Advocate, as follows:

(i) Kathleen C. McShane, Foster Associates Inc., and James H. Vander Weide, Financial Strategy Associates, March 30, 2012 (Newfoundland Power); and
(ii) Laurence D. Booth, May 16, 2012 (Consumer Advocate).

The Consumer Advocate filed 342 requests for information and Newfoundland Power filed 71 requests for information.

Settlement

After the filing of the expert evidence Newfoundland Power and the Consumer Advocate agreed to hold settlement discussions. Hydro and the Industrial Customers were advised that there would be settlement discussions but did not participate. From May 29, 2012 to June 1, 2012, settlement discussions were facilitated by Board Hearing Counsel. On June 5, 2012 a settlement agreement (the "Settlement Agreement") was executed, in which the parties agreed that:

(i) the rate of return on common equity to be used in determining a just and reasonable return on rate base for 2012 will be 8.80%;
(ii) the allowed rate of return on rate base for 2012 will be 8.14% within a range of 7.96% to 8.32%; and
(iii) Newfoundland Power will be granted deferred recovery of the full difference between the 8.38% return on common equity currently in rates and an 8.80% return on common equity, calculated on the basis of Newfoundland Power's 2010 test year costs. The recovery of the additional revenue requirement for 2012 of approximately $2.5 million will be deferred and fully recovered by Newfoundland Power.

Hydro and the Industrial Customers were provided with a copy of the Settlement Agreement.

Amended Application

On June 7, 2012 Newfoundland Power amended the Application incorporating the terms of the Settlement Agreement and seeking other relief necessary to give effect to the Settlement Agreement (the "Amended Application"). The Amended Application seeks an Order of the Board:

1. approving a just and reasonable rate of return on average rate base for Newfoundland Power for 2012 of 8.14% in a range of 7.96% to 8.32%;

2. approving the deferred recovery by Newfoundland Power of $2,487,000 in 2012 revenue in accordance with the proposed account definition;

3. approving the proposed definition for Newfoundland Power's Excess Earnings Account; and

4. declaring Newfoundland Power's 2012 current customer rates to be final rates from January 1, 2012.

Hearing

Notice of the hearing was published in newspapers throughout the Province beginning on June 2, 2012.

The hearing was held on June 12, 2012. At the hearing, the Settlement Agreement was entered on the record. Newfoundland Power requested that the Board grant the orders requested in the Amended Application. The Consumer Advocate stated that:

> *"In the current context of setting a just and reasonable return on rate base for 2012, the Consumer Advocate regards the settlement agreement as reasonable."* (Transcript, June 12, 2012, P.12/7-11)

Board Hearing Counsel advised:

> *"So, to summarize, I believe that the settlement agreement which is before the Commissioners which has been agreed to by the parties is fair and reasonable in the current circumstances and that it should be approved."* (Transcript, June 12, 2012, P.10/18-22)

Neither Hydro nor the Industrial Customers attended the hearing. Hydro filed correspondence indicating no objection to the Settlement Agreement. The Industrial Customers wrote to advise that the Settlement Agreement has been reviewed and that the Industrial Customers would not be seeking to enlarge their participation. The Board did not receive any other presentations or written comment in relation to the Application, the Settlement Agreement or the Amended Application.

II. BOARD DECISION

The Settlement Agreement and the Amended Application relate to the rate of return for Newfoundland Power for 2012 only. The cost of capital for years thereafter will be addressed in the general rate application to be filed by Newfoundland Power by September 14, 2012.

In Order No. P.U. 25(2011) the Board approved the continued use of the return on rate base of 7.96% for Newfoundland Power for 2012, on an interim basis, which reflects a return on equity of 8.38%. The proposal to use a return on equity of 8.80% in determining a just and reasonable return rate base for 2012 was accepted as reasonable by Newfoundland Power, the Consumer Advocate and Board Hearing Counsel and there was no objection filed by the other parties or other interested persons.

The rate of return on equity of 8.80% is within the range of reasonable rates of return as suggested by the expert evidence. Newfoundland Power provided expert evidence that a rate of return on equity for 2012 of 10.4% or 10.5% is just and reasonable. The Consumer Advocate provided expert evidence that a return of 8.15% is reasonable.

The Board notes that the proposed rate of return on equity of 8.80% is consistent with two recent decisions of other Canadian regulators. On December 8, 2011 the Alberta Utilities Commission established a generic rate of return of 8.75% for average risk utilities. This decision is filed in CA-NP-206. On November 25, 2011 the Régie de l'énergie established a rate of return of 8.9% for Gaz Métro, an above average risk utility. This decision is filed in CA-NP-202.

The Board accepts that the proposed rate of return on common equity of 8.80% to be used in determining a just and reasonable return on rate base for 2012 is reasonable for Newfoundland Power.

The accepted rate of return on common equity of 8.80% results in a calculated rate of return on rate base of 8.14%. The Board's financial consultants, Grant Thornton, reviewed the calculated return on rate base and revenue requirement and found the calculations to be accurate and complete. The Board accepts that the proposed rate of return on rate base for 2012 of 8.14% within a range of 7.96% to 8.32% is reasonable for Newfoundland Power. The Board approves the proposed changes to the definition of the Excess Earnings Account to reflect the agreed maximum allowable return on rate base of 8.32%.

The Settlement Agreement proposes that Newfoundland Power be granted deferred recovery of the full difference between the 8.38% return on common equity currently in rates and the proposed 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs. The recovery of the additional revenue requirement for 2012 of approximately $2.5 million is proposed to be deferred and fully recovered by the Newfoundland Power in accordance with a further Order of the Board. The Board finds that the proposed deferral of the costs associated with the increase in the return on common equity is a reasonable approach which contributes to rate stability as it avoids a further rate change in 2012 after the annual July 1 adjustment. The Board accepts the definition of the 2012 Cost of Capital Cost Recovery Deferral Account proposed in the Settlement Agreement.

Newfoundland Power also proposes that the current Newfoundland Power rates to customers, approved in Order No. P.U. 25(2011), be made final since a just and reasonable rate of return on rate base for 2012 has been determined. The Board accepts Newfoundland Power's proposal that Newfoundland Power's current customer rates be made final from January 1, 2012.

III. BOARD ORDER

IT IS THEREFORE ORDERED THAT:

1. **The proposed rate of return on average rate base for 2012 of 8.14% in a range of 7.96% to 8.32% is approved.**

2. **The proposal that Newfoundland Power establish a 2012 Cost of Capital Cost Recovery Deferral Account to allow for the deferred recovery of the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of Newfoundland Power's 2010 test year costs is approved, as set out in Schedule A.**

3. **The proposed revised definition of the Excess Earnings Account is approved, as set out in Schedule B.**

4. **Newfoundland Power's current customer rates shall be considered final rates from January 1, 2012, as set out in Schedule C.**

5. **Newfoundland Power shall pay the expenses of the Board arising from this application, including the expenses of the Consumer Advocate incurred by the Board.**

Dated at St. John's, Newfoundland and Labrador this 15th day of June, 2012.

Andy Wells
Chair and Chief Executive Officer

Darlene Whalen, P.Eng
Vice-Chair

Dwanda Newman, LL.B.
Commissioner

James Oxford
Commissioner

Cheryl Blundon
Board Secretary

Newfoundland Power Inc.

2012 Cost of Capital Cost Recovery Deferral Account

This account shall be charged with the full amount of the difference in revenue between an 8.38% return on common equity and an 8.80% return on common equity for 2012, calculated on the basis of the 2010 test year costs.

Disposition of the Balance in this Account

The disposition of this cost recovery deferral amount will be subject to a future order of the Board.

Newfoundland Power Inc.

3.05 Excess Earnings Account **284xx**

This account shall be credited with any earnings in excess of the upper limit of the allowed range of return on rate base as determined by the Board. Disposition of any balance in this account shall be as determined by the Board. For 2012 and subsequent years, all earnings in excess of an 8.32% rate of return on rate base shall, unless otherwise ordered by the Board, be credited to this account.

NEWFOUNDLAND POWER INC.
RATE #1.1
DOMESTIC SERVICE

Availability:

For Service to a Domestic Unit or to buildings or facilities which are on the same Serviced Premises as a Domestic Unit and used by the same Customer exclusively for domestic or household purposes, whether such buildings or facilities are included on the same meter as the Domestic Unit or metered separately.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ....$15.71 per month

Energy Charge:
All kilowatt-hours ....@ 10.407¢ per kWh

Minimum Monthly Charge ....$15.71 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #1.1S
DOMESTIC SEASONAL – OPTIONAL

Availability:

Available upon request for Service to Customers served under Rate #1.1 Domestic Service who have a minimum of 12 months of uninterrupted billing history at their current Serviced Premises.

Rate:

The Energy Charges provided for in Rate #1.1 Domestic Service Rate shall apply, subject to the following adjustments:

Winter Season Premium Adjustment (Billing months of December through April):
All kilowatt-hours ....@ 0.953¢ per kWh

Non-Winter Season Credit Adjustment (Billing Months of May through November):
All kilowatt-hours ....@ (1.297)¢ per kWh

Special Conditions:

1. An application for Service under this rate option shall constitute a binding contract between the Customer and the Company with an initial term of 12 months commencing the day after the first meter reading date following the request by the Customer, and renewing automatically on the anniversary date thereof for successive 12-month terms.

2. To terminate participation on this rate option on the renewal date, the Customer must notify the Company either in advance of the renewal date or no later than 60 days after the anniversary/renewal date. When acceptable notice of termination is provided to the Company, the Customer's billing may require adjustment to reverse any seasonal adjustments applied to charges for consumption after the automatic renewal date.

NEWFOUNDLAND POWER INC.
RATE #2.1
GENERAL SERVICE 0-10 kW

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is less than 10 kilowatts.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ....$18.03 per month

Energy Charge:
All kilowatt-hours ....@ 12.182 ¢ per kWh

Minimum Monthly Charge, Single Phase ....$18.03 per month
Three Phase ....$36.06 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.2
GENERAL SERVICE 10-100 kW (110 kVA)

Availability:

For Service (excluding Domestic Service) where the maximum demand occurring in the 12 months ending with the current month is 10 kilowatts or greater but less than 100 kilowatts (110 kilovoltamperes).

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ....$20.76 per month

Demand Charge:
$8.70 per kW of billing demand in the months of December, January, February and March and $7.20 per kW in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kW of billing demand ....@ 9.672 ¢ per kWh
All excess kilowatt-hours ....@ 7.303 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.96 cents per kWh plus the Basic Customer Charge, but not less than the Minimum Monthly Charge.

Minimum Monthly Charge:
Single Phase ....$20.76 per month
Three Phase ....$36.06 per month

Discount:

A discount of 1.5% of the amount of the current month's bill, but not less than $1.00, will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular Regulation 7 (n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.3
GENERAL SERVICE 110 kVA (100 kW) - 1000 kVA

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 110 kilovolt-amperes (100 kilowatts) or greater but less than 1000 kilovolt-amperes.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ....$93.47 per month

Demand Charge:
$7.51 per kVA of billing demand in the months of December, January, February and March and $6.01 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 150 kilowatt-hours per kVA of billing demand,
up to a maximum of 30,000 kilowatt-hours ....@ 9.642 ¢ per kWh
All excess kilowatt-hours ....@ 7.227¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.96 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #2.4
GENERAL SERVICE 1000 kVA AND OVER

Availability:

For Service where the maximum demand occurring in the 12 months ending with the current month is 1000 kilovolt-amperes or greater.

Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

Basic Customer Charge: ....$186.93 per month

Demand Charge:
$7.09 per kVA of billing demand in the months of December, January, February and March and $5.59 per kVA in all other months. The billing demand shall be the maximum demand registered on the meter in the current month.

Energy Charge:
First 100,000 kilowatt-hours ....@ 8.278 ¢ per kWh
All excess kilowatt-hours ....@ 7.162 ¢ per kWh

Maximum Monthly Charge:

The Maximum Monthly Charge shall be 16.96 cents per kWh plus the Basic Customer Charge.

Discount:

A discount of 1.5% of the amount of the current month's bill, up to a maximum of $500.00 will be allowed if the bill is paid within 10 days after it is issued.

General:

Details regarding metering [in particular, Regulation 7(n)], transformation [in particular, Regulation 9(k)], and other conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
RATE #4.1
STREET AND AREA LIGHTING SERVICE

Availability:

For Street and Area Lighting Service where the electricity is supplied by the Company and all fixtures, wiring and controls are provided, owned and maintained by the Company.

Monthly Rate: (Includes Municipal Tax and Rate Stabilization Adjustments)

	Sentinel/Standard	Post Top
High Pressure Sodium*		
100W (8,600 lumens)	$16.14	$17.30
150W (14,400 lumens)	20.77	-
250W (23,200 lumens)	28.17	-
400W (45,000 lumens)	39.22	-

* For all new installations and replacements.

Mercury Vapour

175W (7,000 lumens)	$16.14	$17.30
250W (9,400 lumens)	20.77	-
400W (17,200 lumens)	28.17	-

Special poles used exclusively for lighting service**

Wood	$ 6.82
30' Concrete or Metal, direct buried	9.90
45' Concrete or Metal, direct buried	15.08
25' Concrete or Metal, Post Top, direct buried	7.63

Underground Wiring (per run)**

All sizes and types of fixtures	$12.06

** Where a pole or underground wiring run serves two fixtures paid for by different parties, the above rates for such poles and underground wiring may be shared equally between the two parties.

General:

Details regarding conditions of service are provided in the Rules and Regulations. **This rate does not include the Harmonized Sales Tax (HST) which applies to electricity bills.**

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Availability:

For Customers billed on Rate #2.3 or #2.4 that can reduce their demand ("Curtail") by between 300 kW (330 kVA) and 5000 kW (5500 kVA) upon request by the Company during the Winter Peak Period. The Winter Peak Period is between 8 a.m. and 9 p.m. daily during the calendar months of December, January, February and March. The ability of a Customer to Curtail must be demonstrated to the Company's satisfaction prior to the Customer's availing of this rate option.

Credit for Curtailing:

If the Customer Curtails as requested for the duration of a Winter, the Company shall credit to the Customer's account the Curtailment Credit during May billing immediately following that Winter. The Curtailment Credit shall be determined by one of the following options:

Option 1:
The Customer will contract to reduce demand by a specific amount during Curtailment periods (the "Contracted Demand Reduction"). The Curtailment Credit for Option 1 is determined as follows:

Curtailment Credit = Contracted Demand Reduction x $29 per kVA

Option 2:

The Customer will contract to reduce demand to a Firm Demand level which the Customer's maximum demand must not exceed during a Curtailment period. The Curtailment Credit for Option 2 is determined as follows:

Maximum Demand Curtailed = (Maximum Winter Demand - Firm Demand)

$$\text{Peak Period Load Factor} = \frac{\text{kWh usage during Peak Period}}{\text{(Maximum Demand during Peak Period x 1573 hours)}}$$

Curtailment Credit = ((Maximum Demand Curtailed x 50%) + (Maximum Demand Curtailed x 50% x Peak Period Load Factor)) x $29 per kVA

Limitations on Requests to Curtail:

Curtailment periods will:
1. Not exceed 6 hours duration for any one occurrence.
2. Not be requested to start within 2 hours of the expiration of a prior Curtailment period.
3. Not exceed 100 hours duration in total during a winter period.

The Company shall request the Customer to Curtail at least 1 hour prior to the commencement of the Curtailment period.

NEWFOUNDLAND POWER INC.
CURTAILABLE SERVICE OPTION
(for Rates #2.3 and #2.4 only)

Failure to Curtail:

Failure to Curtail under Option 1 occurs when a Customer does not reduce its demand by the Contracted Demand Reduction for the duration of a Curtailment period. Failure to Curtail under Option 2 occurs when a Customer does not reduce its demand to the Firm Demand level or below for the duration of a Curtailment period.

The Curtailment Credit will be reduced by 50% as a result of the first failure to Curtail during a Winter. For each additional failure to Curtail, the Curtailment Credit will be reduced by a further 25% of the Curtailment Credit. If the Customer fails to Curtail three times during a Winter, the Customer forfeits 100% of the Curtailment Credit and the Customer will no longer be entitled to service under the Curtailable Service Option.

Notwithstanding the previous paragraph, no Curtailment Credit will be provided if the number of failures to Curtail equals the number of Curtailment requests.

Termination/Modification:

The Company requires six months written notice of the Customer's intention to either discontinue Curtailable Service Option or to modify the Contracted Demand Reduction or Firm Demand level.

General:

Services billed on this Service Option will have approved load monitoring equipment installed. For a customer that Curtails by using its own generation in parallel with the Company's electrical system, all Company interconnection guidelines will apply, and the Company has the option of monitoring the output of the Customer's generation. All costs associated with equipment required to monitor the Customer's generation will be charged to the Customer's account

Newfoundland & Labrador
BOARD OF COMMISSIONERS OF PUBLIC UTILITIES
120 TORBAY ROAD, ST. JOHN'S, NL

Website: www.pub.nl.ca
E-mail: ito@pub.nl.ca
Telephone: 1-709-726-8600
Toll free: 1-866-782-0006

STANDARD
& POOR'S
RATINGS SERVICES

RatingsDirect®

Issuer Ranking:

U.S. Regulated Water, Gas, And Electric Utilities, Strongest To Weakest

Primary Credit Analyst:
John W Whitlock, New York (1) 212-438-7678; john_whitlock@standardandpoors.com

Secondary Contact:
Matthew L O'Neill, New York (1) 212-438-4295; matthew_oneill@standardandpoors.com

Issuer Ranking:

U.S. Regulated Water, Gas, And Electric Utilities, Strongest To Weakest

Heading into the fourth quarter of 2012, nearly 88% of U.S. regulated electric, gas and water utilities had a stable outlook and the predominance of ratings is in the 'BBB' category, solidly investment grade. Although we anticipate the U.S. economic outlook to remain sluggish with only modest growth in customer consumption, we expect ratings stability for the industry to continue. Ratings stability stems from our expectations of sustained demand for utility services, responsive regulatory attention to cost recovery for needed capital investments, and as a consequence continued appetite by investors for utility debt and equity offerings. Moreover, the essential commodity that utilities provide and the rate-regulated nature of the businesses allow them to recover the bulk of their costs in rates they charge customers regardless of economic conditions.

The following list ranks all the rated companies in this industry from strongest to weakest based on rating and outlook. Companies with the same rating and outlook are further ranked by our opinion of credit quality based primarily on business risks for investment-grade companies and primarily on financial risks for speculative-grade companies.

Ratings are displayed as long-term rating/outlook or CreditWatch/short-term rating. A double dash (--) indicates no rating. Issuer credit ratings are identical for local and foreign currency unless noted with the "LC" and "FC" designations.

For the related industry report card, please see "A Stable Industry Outlook Supports Solid Ratings For U.S. Regulated Electric, Gas, And Water Utilities," published on Oct. 22, 2012.

U.S. Regulated Utilities

Company	Corporate credit rating*	Business profile	Financial profile	Liquidity
Madison Gas & Electric Co.	AA-/Stable/A-1+	Excellent	Intermediate	Adequate
Midwest Independent Transmission System Operator Inc.	A+/Stable/--	Excellent	Intermediate	Exceptional
American Transmission Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
Aqua Pennsylvania Inc.	A+/Stable/--	Excellent	Intermediate	Adequate
Washington Gas Light Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
WGL Holdings Inc.	A+/Stable/A-1	Excellent	Intermediate	Adequate
Baton Rouge Water Works Co. (The)	A+/Stable/--	Excellent	Intermediate	Strong
Golden State Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
American States Water Co.	A+/Stable/--	Excellent	Intermediate	Strong
Northwest Natural Gas Co.	A+/Stable/A-1	Excellent	Intermediate	Adequate
California Water Service Co.	A+/Negative/--	Excellent	Intermediate	Exceptional
California Independent System Operator Corp.	A/Stable/--	Excellent	Intermediate	Strong
San Diego Gas & Electric Co.	A/Stable/A-1	Excellent	Significant	Adequate
Southern California Gas Co.	A/Stable/A-1	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)

Piedmont Natural Gas Co. Inc.	A/Stable/A-1	Excellent	Intermediate	Adequate
Questar Gas Co.	A/Stable/--	Excellent	Intermediate	Adequate
Alabama Power Co.	A/Stable/A-1	Excellent	Significant	Adequate
Georgia Power Co.	A/Stable/A-1	Excellent	Significant	Adequate
Gulf Power Co.	A/Stable/A-1	Excellent	Significant	Adequate
New Jersey Natural Gas Co.	A/Stable/A-1	Excellent	Intermediate	Adequate
Laclede Gas Co.	A/Stable/A-1	Excellent	Intermediate	Strong
Laclede Group Inc. (The)	A/Stable/--	Excellent	Intermediate	Strong
Brooklyn Union Gas Co. (The)	A/Stable/--	Excellent	Significant	Adequate
KeySpan Gas East Corp.	A/Stable/--	Excellent	Significant	Adequate
Southern Co.	A/Stable/A-1	Excellent	Significant	Adequate
Questar Corp.	A/Stable/A-1	Excellent	Intermediate	Adequate
San Jose Water Co.	A/Stable/--	Excellent	Significant	Adequate
Mississippi Power Co.	A/Stable/A-1	Strong	Significant	Adequate
Connecticut Water Co. (The)	A/Negative/--	Excellent	Significant	Adequate
Connecticut Water Service Inc.	A/Negative/--	Excellent	Significant	Adequate
Central Hudson Gas & Electric Corp.	A/Watch Neg/--	Excellent	Significant	Strong
Wisconsin Electric Power Co.	A-/Positive/A-2	Excellent	Significant	Adequate
Wisconsin Gas LLC	A-/Positive/A-2	Excellent	Significant	Adequate
Wisconsin Energy Corp.	A-/Positive/A-2	Excellent	Significant	Adequate
NSTAR Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Yankee Gas Services Co.	A-/Stable/--	Excellent	Significant	Adequate
NSTAR Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Western Massachusetts Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Connecticut Light & Power Co.	A-/Stable/--	Excellent	Significant	Adequate
Public Service Co. of New Hampshire	A-/Stable/--	Excellent	Significant	Adequate
Consolidated Edison Co. of New York Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Orange and Rockland Utilities Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
York Water Co. (The)	A-/Stable/--	Excellent	Significant	Adequate
Middlesex Water Co.	A-/Stable/--	Excellent	Significant	Adequate
United Water New Jersey Inc.	A-/Stable/--	Excellent	Significant	Adequate
United Waterworks Inc.	A-/Stable/--	Excellent	Significant	Adequate
Indiana Gas Co. Inc.	A-/Stable/--	Excellent	Significant	Adequate
Boston Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Colonial Gas Co.	A-/Stable/--	Excellent	Significant	Adequate
Vectren Utility Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Southern Indiana Gas & Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
Virginia Electric & Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Florida Power & Light Co.	A-/Stable/A-2	Excellent	Intermediate	Adequate
Massachusetts Electric Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Narragansett Electric Co.	A-/Stable/--	Excellent	Significant	Adequate
New England Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Niagara Mohawk Power Corp.	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Wisconsin	A-/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of Colorado	A-/Stable/A-2	Excellent	Significant	Adequate
Northern States Power Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Southwestern Public Service Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Wisconsin Power & Light Co.	A-/Stable/A-2	Excellent	Significant	Adequate
Peoples Gas Light & Coke Co. (The)	A-/Stable/A-2	Excellent	Significant	Strong
North Shore Gas Co.	A-/Stable/--	Excellent	Significant	Strong
Peoples Energy Corp.	A-/Stable/--	Excellent	Significant	Strong
Wisconsin Public Service Corp.	A-/Stable/A-2	Excellent	Significant	Strong
MidAmerican Energy Co.	A-/Stable/A-2	Excellent	Significant	Adequate
PacifiCorp	A-/Stable/A-2	Excellent	Significant	Adequate
Northeast Utilities	A-/Stable/--	Excellent	Significant	Adequate
NSTAR LLC	A-/Stable/A-2	Excellent	Significant	Adequate
Consolidated Edison Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid USA	A-/Stable/A-2	Excellent	Significant	Adequate
National Grid Holdings Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
KeySpan Corp.	A-/Stable/--	Excellent	Significant	Adequate
Xcel Energy Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Integrys Energy Group Inc.	A-/Stable/A-2	Excellent	Significant	Strong
Dominion Resources Inc.	A-/Stable/A-2	Excellent	Significant	Adequate
Vectren Corp.	A-/Stable/--	Excellent	Significant	Adequate
NextEra Energy Inc.	A-/Stable/--	Strong	Intermediate	Adequate
Pennsylvania-American Water Co.	BBB+/Positive/--	Excellent	Significant	Adequate
New Jersey-American Water Co.	BBB+/Positive/--	Excellent	Significant	Adequate
American Water Works Co. Inc.	BBB+/Positive/A-2	Excellent	Significant	Adequate
American Water Capital Corp.	BBB+/Positive/A-2	Excellent	Significant	Adequate
Atlanta Gas Light Co.	BBB+/Stable/--	Excellent	Significant	Adequate
Nicor Gas Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Atmos Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Tampa Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
International Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Midwest LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
Michigan Electric Transmission Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
ITC Great Plains LLC	BBB+/Stable/--	Excellent	Aggressive	Adequate
CenterPoint Energy Houston Electric LLC	BBB+/Stable/--	Excellent	Aggressive	Strong
Cascade Natural Gas Corp.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Montana-Dakota Utilities Co.	BBB+/Stable/--	Excellent	Intermediate	Adequate
Southwest Gas Corp.	BBB+/Stable/--	Excellent	Significant	Adequate
Interstate Power & Light Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Public Service Co. of North Carolina Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
South Carolina Electric & Gas Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate

U.S. Regulated Utilities (cont.)				
Oncor Electric Delivery Co. LLC	BBB+/Stable/--	Excellent	Aggressive	Strong
Oklahoma Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Southern California Edison Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Potomac Electric Power Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Delmarva Power & Light Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Atlantic City Electric Co.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
Baltimore Gas & Electric Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Michigan Consolidated Gas Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Detroit Edison Co.	BBB+/Stable/A-2	Excellent	Significant	Adequate
ITC Holdings Corp.	BBB+/Stable/--	Excellent	Aggressive	Adequate
AGL Resources Inc.	BBB+/Stable/A-2	Excellent	Significant	Adequate
Alliant Energy Corp.	BBB+/Stable/A-2	Excellent	Significant	Adequate
MidAmerican Energy Holdings Co.	BBB+/Stable/--	Excellent	Aggressive	Adequate
TECO Energy Inc.	BBB+/Stable/--	Excellent	Significant	Adequate
SCANA Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
CenterPoint Energy Resources Corp.	BBB+/Stable/A-2	Excellent	Aggressive	Strong
CenterPoint Energy Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Strong
PEPCO Holdings Inc.	BBB+/Stable/A-2	Excellent	Aggressive	Adequate
South Jersey Gas Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
Sempra Energy	BBB+/Stable/A-2	Strong	Significant	Adequate
DTE Energy Co.	BBB+/Stable/A-2	Strong	Significant	Adequate
South Jersey Industries Inc.	BBB+/Stable/--	Strong	Significant	Adequate
OGE Energy Corp.	BBB+/Stable/A-2	Strong	Significant	Adequate
ALLETE Inc.	BBB+/Stable/A-2	Strong	Significant	Adequate
Duke Energy Kentucky Inc.	BBB+/Negative/--	Excellent	Significant	Adequate
Duke Energy Carolinas LLC	BBB+/Negative/A-2	Excellent	Significant	Adequate
Carolina Power & Light Co. d/b/a Progress Energy Carolinas Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Florida Power Corp. d/b/a Progress Energy Florida Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Indiana Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Ohio Inc.	BBB+/Negative/A-2	Strong	Significant	Adequate
Progress Energy Inc.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Duke Energy Corp.	BBB+/Negative/A-2	Excellent	Significant	Adequate
Central Maine Power Co.	BBB+/Watch Neg/A-2	Excellent	Aggressive	Adequate
New York State Electric & Gas Corp.	BBB+/Watch Neg/A-2	Excellent	Significant	Adequate
Rochester Gas & Electric Corp.	BBB+/Watch Neg/--	Excellent	Aggressive	Adequate
Public Service Electric & Gas Co.	BBB/Positive/A-2	Excellent	Significant	Strong
Cleco Power LLC	BBB/Positive/--	Excellent	Aggressive	Strong
Cleco Corp.	BBB/Positive/--	Excellent	Aggressive	Strong
Arizona Public Service Co.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
Pinnacle West Capital Corp.	BBB/Positive/A-2	Excellent	Aggressive	Adequate
PECO Energy Co.	BBB/Stable/A-2	Excellent	Significant	Strong

U.S. Regulated Utilities (cont.)				
Commonwealth Edison Co.	BBB/Stable/A-2	Excellent	Significant	Strong
PPL Electric Utilities Corp.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
AEP Texas Central Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
AEP Texas North Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
SEMCO Energy Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Westar Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Kansas Gas & Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Connecticut Natural Gas Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Southern Connecticut Gas Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
United Illuminating Co. (The)	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Utilities Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Louisville Gas & Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
LG&E and KU Energy LLC	BBB/Stable/--	Excellent	Aggressive	Adequate
Public Service Co. of Oklahoma	BBB/Stable/--	Excellent	Aggressive	Adequate
Ohio Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Appalachian Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Green Mountain Power Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kentucky Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Southwestern Electric Power Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Kansas City Power & Light Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
KCP&L Greater Missouri Operations Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
Entergy Gulf States Louisiana LLC	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Louisiana LLC	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Mississippi Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Arkansas Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Texas Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy New Orleans Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Great Plains Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
NorthWestern Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Portland General Electric Co.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
Avista Corp.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Puget Sound Energy Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
Idaho Power Co.	BBB/Stable/A-2	Excellent	Aggressive	Strong
El Paso Electric Co.	BBB/Stable/--	Excellent	Aggressive	Adequate
PPL Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
UIL Holdings Corp.	BBB/Stable/--	Excellent	Aggressive	Adequate
American Electric Power Co. Inc.	BBB/Stable/A-2	Excellent	Aggressive	Adequate
IDACORP Inc.	BBB/Stable/A-2	Excellent	Aggressive	Strong
System Energy Resources Inc.	BBB/Stable/--	Excellent	Significant	Adequate
Entergy Corp.	BBB/Stable/A-2	Strong	Significant	Adequate
Pacific Gas & Electric Co.	BBB/Stable/A-2	Strong	Significant	Adequate
PG&E Corp.	BBB/Stable/--	Strong	Significant	Adequate

U.S. Regulated Utilities (cont.)				
Indiana Michigan Power Co.	BBB/Stable/--	Strong	Aggressive	Adequate
Consumers Energy Co.	BBB-/Positive/--	Excellent	Aggressive	Adequate
Black Hills Power Inc.	BBB-/Positive/--	Excellent	Aggressive	Adequate
CMS Energy Corp.	BBB-/Positive/A-3	Excellent	Aggressive	Adequate
Black Hills Corp.	BBB-/Positive/--	Excellent	Aggressive	Adequate
Liberty Utilities Co.	BBB-/Positive/--	Excellent	Significant	Adequate
Trans-Allegheny Interstate Line Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNG Cos. LLC	BBB-/Stable/--	Excellent	Aggressive	Adequate
Bay State Gas Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ameren Illinois Co.	BBB-/Stable/A-3	Excellent	Significant	Adequate
Ameren Missouri	BBB-/Stable/A-3	Excellent	Significant	Adequate
West Penn Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Pennsylvania Electric Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Metropolitan Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Jersey Central Power & Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Ohio Edison Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Cleveland Electric Illuminating Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Toledo Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Potomac Edison Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Monongahela Power Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Duquesne Light Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Northern Indiana Public Service Co.	BBB-/Stable/--	Excellent	Aggressive	Adequate
Otter Tail Power Co.	BBB-/Stable/--	Excellent	Significant	Adequate
Empire District Electric Co.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Texas-New Mexico Power Co.	BBB-/Stable/--	Excellent	Aggressive	Strong
Public Service Co. of New Mexico	BBB-/Stable/--	Excellent	Aggressive	Strong
Indianapolis Power & Light Co.	BBB-/Stable/--	Excellent	Highly leveraged	Adequate
NiSource Inc.	BBB-/Stable/A-3	Excellent	Aggressive	Adequate
Duquesne Light Holdings Inc.	BBB-/Stable/--	Excellent	Aggressive	Adequate
PNM Resources Inc.	BBB-/Stable/--	Excellent	Aggressive	Strong
IPALCO Enterprises Inc.	BBB-/Stable/--	Excellent	Highly leveraged	Adequate
Hawaiian Electric Co. Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Edison International	BBB-/Stable/--	Strong	Aggressive	Adequate
Ameren Corp.	BBB-/Stable/A-3	Strong	Significant	Adequate
FirstEnergy Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Hawaiian Electric Industries Inc.	BBB-/Stable/A-3	Strong	Aggressive	Adequate
Ohio Valley Electric Corp.	BBB-/Stable/--	Strong	Aggressive	Adequate
Otter Tail Corp.	BBB-/Stable/--	Strong	Significant	Adequate
Dayton Power & Light Co.	BBB-/Watch Neg/--	Strong	Aggressive	Adequate
DPL Inc.	BBB-/Watch Neg/--	Strong	Aggressive	Adequate
SourceGas LLC	BB+/Stable/--	Excellent	Highly leveraged	Adequate

U.S. Regulated Utilities (cont.)				
Nevada Power Co.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Sierra Pacific Power Co.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
NV Energy Inc.	BB+/Stable/--	Excellent	Highly leveraged	Adequate
Puget Energy Inc.	BB+/Stable/--	Excellent	Aggressive	Strong
Tucson Electric Power Co.	BB+/Stable/--	Strong	Aggressive	Adequate

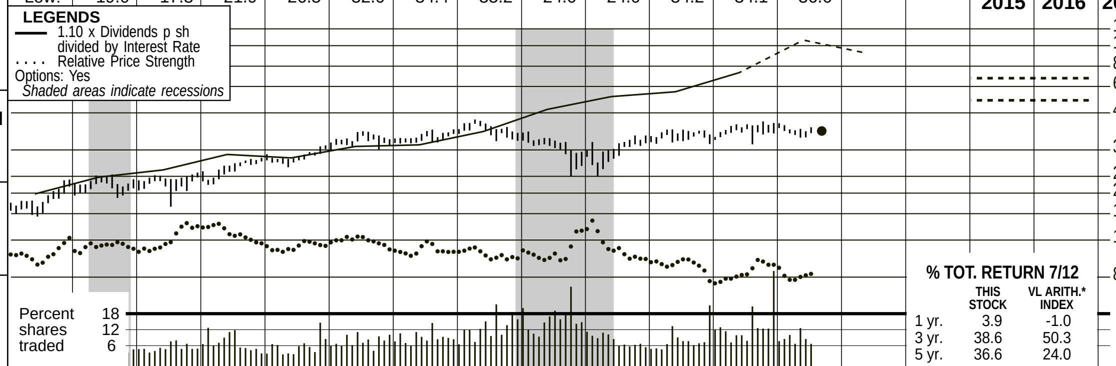
*Ratings as of Oct. 22, 2012.

AGL RESOURCES NYSE-GAS

RECENT PRICE **39.44** | P/E RATIO **13.5** (Trailing: 22.3 / Median: 13.0) | RELATIVE P/E RATIO **0.91** | DIV'D YLD **4.7%** | VALUE LINE

TIMELINESS 3 Raised 3/11/11
SAFETY 1 Raised 9/9/11
TECHNICAL 3 Raised 7/13/12
BETA .75 (1.00 = Market)

High:	24.5	25.0	29.3	33.7	39.3	40.1	44.7	39.1	37.5	40.1	43.7	42.9
Low:	19.0	17.3	21.9	26.5	32.0	34.4	35.2	24.0	24.0	34.2	34.1	36.6



Target Price Range
2015 | 2016 | 2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	70	(+90%)	21%
Low	55	(+25%)	10%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	1	1	0	1	1	0	0	2	0
to Sell	1	2	0	0	1	0	0	2	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	99	258	153
to Sell	118	63	159
Hld's(000)	50506	71384	71603

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	3.9	-1.0
3 yr.	38.6	50.3
5 yr.	36.6	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
21.91	22.75	23.36	18.71	11.25	19.04	15.32	15.25	23.89	34.98	33.73	32.64	36.41	29.88	30.42	20.00	*39.85*	*42.00*	Revenues per sh A	*47.55*
2.49	2.42	2.65	2.29	2.86	3.31	3.39	3.47	3.29	4.20	4.50	4.65	4.68	4.90	5.05	3.05	*6.05*	*6.55*	"Cash Flow" per sh	*7.80*
1.37	1.37	1.41	.91	1.29	1.50	1.82	2.08	2.28	2.48	2.72	2.72	2.71	2.88	3.00	2.12	*2.65*	*3.10*	Earnings per sh A B	*4.20*
1.06	1.08	1.08	1.08	1.08	1.08	1.08	1.11	1.15	1.30	1.48	1.64	1.68	1.72	1.76	1.90	*1.74*	*1.84*	Div'ds Decl'd per sh CF■	*2.00*
2.37	2.59	2.05	2.51	2.92	2.83	3.30	2.46	3.44	3.44	3.26	3.39	4.84	6.14	6.54	3.42	*5.95*	*6.05*	Cap'l Spending per sh	*6.40*
10.56	10.99	11.42	11.59	11.50	12.19	12.52	14.66	18.06	19.29	20.71	21.74	21.48	22.95	23.24	28.54	*29.25*	*30.35*	Book Value per sh D	*33.75*
55.70	56.60	57.30	57.10	54.00	55.10	56.70	64.50	76.70	77.70	77.70	76.40	76.90	77.54	78.00	117.00	*118.00*	*119.00*	Common Shs Outst'g E	*122.00*
13.8	14.7	13.9	21.4	13.6	14.6	12.5	12.5	13.1	14.3	13.5	14.7	12.3	11.2	12.5	12.6	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.86	.85	.72	1.22	.88	.75	.68	.71	.69	.76	.73	.78	.74	.75	.80	.82	*Value Line*		Relative P/E Ratio	*1.00*
5.6%	5.4%	5.5%	5.5%	6.2%	4.9%	4.7%	4.3%	3.9%	3.7%	4.0%	4.1%	5.0%	5.4%	4.7%	4.8%	*estimates*		Avg Ann'l Div'd Yield	*3.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $4296.0 mill. **Due in 5 Yrs** $100.0 mill.
LT Debt $3334.0 mill. **LT Interest** $200.0 mill.
(Total interest coverage: 6.5x)

Leases, Uncapitalized Annual rentals $95.0 mill.
Pension Assets-12/11 $754.0 mill. **Oblig.** $968.0 mill.
Pfd Stock None

Common Stock 117,515,999 shs. **as of 7/25/12**

MARKET CAP: $4.6 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
868.9	983.7	1832.0	2718.0	2621.0	2494.0	2800.0	2317.0	2373.0	2338.0	*4700*	*5000*	Revenues ($mill) A	*5800*
103.0	132.4	153.0	193.0	212.0	211.0	207.6	222.0	234.0	172.0	*310*	*370*	Net Profit ($mill)	*510*
36.0%	35.9%	37.0%	37.7%	37.8%	37.6%	40.5%	35.2%	35.9%	40.2%	*40.0%*	*40.0%*	Income Tax Rate	*40.0%*
11.9%	13.5%	8.4%	7.1%	8.1%	8.5%	7.4%	9.6%	9.9%	7.4%	*6.7%*	*7.4%*	Net Profit Margin	*8.8%*
58.3%	50.3%	54.0%	51.9%	50.2%	50.2%	50.3%	52.6%	48.0%	52.0%	*48.0%*	*46.0%*	Long-Term Debt Ratio	*40.0%*
41.7%	49.7%	46.0%	48.1%	49.8%	49.8%	49.7%	47.4%	52.0%	48.0%	*52.0%*	*54.0%*	Common Equity Ratio	*60.0%*
1704.3	1901.4	3008.0	3114.0	3231.0	3335.0	3327.0	3754.0	3486.0	8238.0	*6655*	*6715*	Total Capital ($mill)	*6915*
2194.2	2352.4	3178.0	3271.0	3436.0	3566.0	3816.0	4146.0	4405.0	7900.0	*8040*	*8185*	Net Plant ($mill)	*8490*
8.1%	8.9%	6.3%	7.9%	8.0%	7.7%	7.4%	6.9%	7.6%	3.0%	*5.5%*	*6.5%*	Return on Total Cap'l	*8.0%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.0%*	*10.0%*	Return on Shr. Equity	*12.5%*
14.5%	14.0%	11.0%	12.9%	13.2%	12.7%	12.6%	12.5%	12.9%	5.2%	*9.0%*	*10.0%*	Return on Com Equity	*12.5%*
7.0%	6.6%	5.6%	6.2%	6.3%	5.3%	5.1%	5.3%	5.6%	.7%	*3.0%*	*4.0%*	Retained to Com Eq	*6.5%*
52%	53%	49%	52%	52%	58%	60%	57%	57%	86%	*66%*	*59%*	All Div'ds to Net Prof	*48%*

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	24.0	69.0	87.0
Other	2138.0	2677.0	1793.0
Current Assets	2162.0	2746.0	1880.0
Accts Payable	184.0	294.0	383.0
Debt Due	1032.0	1338.0	962.0
Other	1212.0	1452.0	1115.0
Current Liab.	2428.0	3984.0	2460.0
Fix. Chg. Cov.	501%	325%	385%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	6.0%	5.5%	*10.0%*
"Cash Flow"	6.5%	6.0%	*10.5%*
Earnings	9.0%	4.5%	*8.0%*
Dividends	5.0%	7.5%	*2.0%*
Book Value	7.0%	5.5%	*5.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	995.0	377.0	307.0	638.0	2317.0
2010	1003	359.0	346.0	665.0	2373.0
2011	878.0	375.0	295.0	790.0	2338.0
2012	1404	686.0	*1000*	*1610*	*4700*
2013	*1600*	*800*	*1000*	*1600*	*5000*

Cal-endar	EARNINGS PER SHARE AB Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.55	.26	.16	.91	2.88
2010	1.73	.17	.29	.81	3.00
2011	1.59	.23	d.04	.37	2.12
2012	1.12	.28	*.40*	*.85*	*2.65*
2013	*1.40*	*.35*	*.50*	*.85*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID CF■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.42	.42	.42	.42	1.68
2009	.43	.43	.43	.43	1.72
2010	.44	.44	.44	.44	1.76
2011	.45	.45	.45	.55	1.90
2012	.36	.46	.46		

BUSINESS: AGL Resources Inc. is a public utility holding company. Its distribution subsidiaries include Atlanta Gas Light, Chattanooga Gas, Elizabethtown Gas, and Virginia Natural Gas. Acquired Nicor in 2011. The utilities have more than 2.3 million customers in Georgia, Virginia, Tennessee, New Jersey, and Florida. Engaged in nonregulated natural gas marketing and other allied services. Deregulated subsidiaries: Georgia Natural Gas markets natural gas at retail. Sold Utilipro, 3/01. Acquired Compass Energy Services, 10/07. BlackRock Inc. owns 6.8% of common stock; off./dir., less than 1.0% (3/12 Proxy). Pres. & CEO: John W. Somerhalder II. Inc.: GA. Addr.: Ten Peachtree Place N.E., Atlanta, GA 30309. Telephone: 404-584-4000. Internet: www.aglresources.com.

AGL Resources' earnings perked up in the second period. The bottom line rose by over 20% from the same period last year, a trend likely to continue over the next few quarters. That said, erratic weather patterns, along with challenges facing AGL's nonregulated segments, have caused us to lower our 2012 per-share estimate by $0.15, to $2.65 for the year.

Growth should be steady over the next few years, despite various obstacles in the company's path. Major concerns are that the slow economic recovery is hindering customer growth, and this, along with a lack of new rate filings, will likely be a headwind. Also, the Midstream segment which is likely to suffer from low natural gas prices (The supply glut caused storage pricing for the Jefferson Island facility to drop from $0.19 to $0.14) might present some problems. That said, the benefits gained from the Nicor merger (which made AGL Resources the largest gas distribution company in the country considerably increasing its volume production and geographic reach), should more than offset the pressure from the factors above.

The company is seeking to begin a major investment venture. The Accelerated Infrastructure Replacement (AIR) plan would enable AGL Resources to spend up to $135 million over the next five years, starting at the end of 2012. The venture would come on the heels of the ending of the Utility Infrastructure Enhancement (UIE) program, which is set to expire at the end of October. Much of the AIR venture would deal with pipeline maintenance, replacing over 150 miles of pipes, in turn enhancing customer service and paving the way for rate increases.

Despite obstacles, the long term looks steady. Previous favorable rate rulings are set to boost the top and bottom lines for the 3- to 5-year period. Furthermore, as stated above, the Nicor merger should help alleviate most of the pressure from a lackluster economic environment. That said, concerns remain regarding several segments that could be hurt by low gas prices.

Income investors will be most interested in this neutrally ranked equity, with its strong yield and high likelihood of future payout hikes.

Sahana Zutshi *September 7, 2012*

(A) Fiscal year ends December 31st. Ended September 30th prior to 2002.
(B) Diluted earnings per share. Excl. nonrecurring gains (losses):'99, $0.39; '00, $0.13; '01, $0.13; '03, ($0.07); '08, $0.13. Next earnings report due late October.
(C) Dividends historically paid early March, June, Sept., and Dec. ■ Div'd reinvest. plan available. (D) Includes intangibles. In 2011: $1918 million, $16.40/share.
(E) In millions. (F) Excluding special dividends from the Nicor merger.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	75

ALLETE NYSE-ALE

RECENT PRICE 41.43 | P/E RATIO 15.7 (Trailing: 19.3 Median: NMF) | RELATIVE P/E RATIO 1.03 | DIV'D YLD 4.5% | VALUE LINE

TIMELINESS 3 Lowered 8/12/11
SAFETY 2 New 10/1/04
TECHNICAL 3 Raised 5/11/12
BETA .70 (1.00 = Market)

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+20%)	9%
Low	35	(-15%)	1%

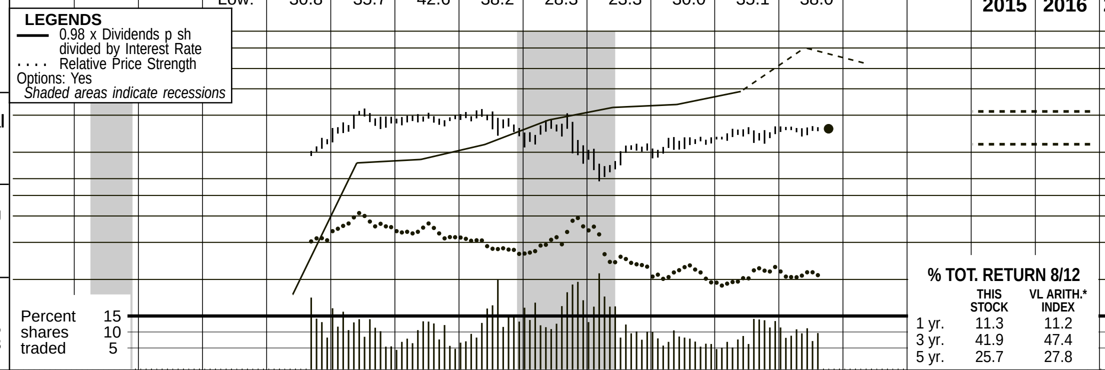
Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	1	0	1	0	0	0	1
to Sell	0	1	1	1	2	1	1	2	2

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	81	76	85
to Sell	52	65	58
Hld's(000)	22270	22589	22085

	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	37.5	51.7	49.3	51.3	49.0	35.3	37.9	42.5	42.6
Low:	30.8	35.7	42.6	38.2	28.3	23.3	30.0	35.1	38.0



% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.3	11.2
3 yr.	41.9	47.4
5 yr.	25.7	27.8

ALLETE, in its current configuration, began trading on September 21, 2004, the day after it spun off its automotive services business, ADESA (now KAR Auction Services, NYSE: KAR), to shareholders and effected a 1-for-3 reverse stock split. ALLETE shareholders received one share of ADESA for each ALLETE share held. Data for the "old" ALLETE are not shown because they are not comparable.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
- -	- -	25.30	24.50	25.23	27.33	24.57	21.57	25.34	24.75	*24.35*	*25.00*	Revenues per sh	*28.25*
- -	- -	2.97	3.85	4.14	4.42	4.23	3.57	4.35	4.91	*5.05*	*5.40*	"Cash Flow" per sh	*6.75*
- -	- -	1.35	2.48	2.77	3.08	2.82	1.89	2.19	2.65	*2.55*	*2.70*	Earnings per sh A	*3.75*
- -	- -	.30	1.25	1.45	1.64	1.72	1.76	1.76	1.78	*1.84*	*1.88*	Div'd Decl'd per sh B ■ †	*2.10*
- -	- -	2.12	1.95	3.37	6.82	9.24	9.05	6.95	6.38	*11.30*	*7.55*	Cap'l Spending per sh	*3.25*
- -	- -	21.23	20.03	21.90	24.11	25.37	26.41	27.26	28.78	*29.90*	*30.95*	Book Value per sh C	*35.00*
- -	- -	29.70	30.10	30.40	30.80	32.60	35.20	35.80	37.50	*39.00*	*40.00*	Common Shs Outst'g D	*41.50*
- -	- -	25.2	17.9	16.5	14.8	13.9	16.1	16.0	14.7	*Bold figures are*		Avg Ann'l P/E Ratio	*11.5*
- -	- -	1.33	.95	.89	.79	.84	1.07	1.02	.93	*Value Line*		Relative P/E Ratio	*.75*
- -	- -	.9%	2.8%	3.2%	3.6%	4.4%	5.8%	5.0%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*4.8%*
- -	- -	751.4	737.4	767.1	841.7	801.0	759.1	907.0	928.2	*950*	*1000*	Revenues ($mill)	*1175*
- -	- -	38.5	68.0	77.3	87.6	82.5	61.0	75.3	93.8	*95.0*	*105*	Net Profit ($mill)	*150*
- -	- -	38.8%	28.4%	37.5%	34.8%	34.3%	33.7%	37.2%	27.6%	*25.0%*	*25.0%*	Income Tax Rate	*25.0%*
- -	- -	1.8%	.4%	1.4%	6.6%	5.8%	12.8%	8.9%	2.7%	*6.0%*	*5.0%*	AFUDC % to Net Profit	*2.0%*
- -	- -	38.2%	39.1%	35.1%	35.6%	41.6%	42.8%	44.2%	44.3%	*46.5%*	*48.0%*	Long-Term Debt Ratio	*44.0%*
- -	- -	61.8%	60.9%	64.9%	64.4%	58.4%	57.2%	55.8%	55.7%	*53.5%*	*52.0%*	Common Equity Ratio	*56.0%*
- -	- -	1020.7	990.6	1025.6	1153.5	1415.4	1625.3	1747.6	1937.2	*2185*	*2375*	Total Capital ($mill)	*2600*
- -	- -	883.1	860.4	921.6	1104.5	1387.3	1622.7	1805.6	1982.7	*2325*	*2515*	Net Plant ($mill)	*2825*
- -	- -	5.1%	8.0%	8.6%	8.6%	6.7%	4.8%	5.4%	6.0%	*5.5%*	*5.5%*	Return on Total Cap'l	*7.0%*
- -	- -	6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	*8.5%*	*8.5%*	Return on Shr. Equity	*10.5%*
- -	- -	6.1%	11.3%	11.6%	11.8%	10.0%	6.6%	7.7%	8.7%	*8.5%*	*8.5%*	Return on Com Equity E	*10.5%*
- -	- -	4.7%	5.2%	5.0%	5.8%	3.9%	.5%	1.5%	2.9%	*2.5%*	*2.5%*	Retained to Com Eq	*4.5%*
- -	- -	23%	54%	57%	51%	61%	93%	81%	66%	*72%*	*70%*	All Div'ds to Net Prof	*57%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $875.8 mill. **Due in 5 Yrs** $221.0 mill.
LT Debt $808.4 mill. **LT Interest** $41.0 mill.
(LT interest earned: 3.6x)
Leases, Uncapitalized Annual rentals $10.9 mill.

Pension Assets-12/11 $432.4 mill. **Oblig.** $597.5 mill.

Pfd Stock None

Common Stock 38,288,789 shs.

MARKET CAP: $1.6 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-25.6	+29.1	+5.6
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	2.98	5.20	NA
Capacity at Peak (Mw)	1757	1812	NA
Peak Load, Winter (Mw) F	1414	1604	1599
Annual Load Factor (%)	81.2	79.0	NA
% Change Customers (avg.)	+1.4	+1.0	NA
Fixed Charge Cov. (%)	296	334	344

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	- -	-1.0%	*3.0%*
"Cash Flow"	- -	3.0%	*8.0%*
Earnings	- -	.5%	*9.0%*
Dividends	- -	12.0%	*3.0%*
Book Value	- -	5.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	199.6	164.7	178.8	216.0	759.1
2010	233.6	211.2	224.1	238.1	907.0
2011	242.2	219.9	226.9	239.2	928.2
2012	240.0	216.4	*243.6*	*250*	*950*
2013	*255*	*235*	*250*	*260*	*1000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.55	.29	.49	.56	1.89
2010	.68	.57	.56	.38	2.19
2011	1.07	.48	.57	.53	2.65
2012	.66	.39	*.80*	*.70*	*2.55*
2013	*.75*	*.50*	*.75*	*.70*	*2.70*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.43	.43	.43	.43	1.72
2009	.44	.44	.44	.44	1.76
2010	.44	.44	.44	.44	1.76
2011	.445	.445	.445	.445	1.78
2012	.46	.46	.46		

BUSINESS: ALLETE, Inc. is the parent company of Minnesota Power, which supplies electricity to 146,000 customers in northeastern MN, & Superior Water, Light & Power in northwestern WI. Electric revenue breakdown: taconite mining/processing, 24%; paper/wood products, 9%; other industrial, 10%; residential, 13%; commercial, 14%; wholesale, 13% other, 17%. Has real estate operation in FL. Discont. water-utility ops. in '01. Spun off automotive remarketing operation in '04. Generating sources: coal & lignite, 60%; hydro, 3%; other, 2%; purchased, 35%. '11 deprec. rate: 3.0%. Has 1,400 employees. Chairman, President & CEO: Alan R. Hodnik. Inc.: MN. Address: 30 West Superior St., Duluth, MN 55802-2093. Tel.: 218-279-5000. Internet: www.allete.com.

ALLETE's earnings are likely to be much better in the second half of 2012 than they were in the first half. The company's main utility subsidiary, Minnesota Power, gets current cost recovery for about half of its capital expenditures. This includes the two wind projects that are under construction. Each will provide 105 megawatts of capacity at an expected cost of $160 million. The bulk of the capital spending will be in the second half of 2012, and this will be reflected in the bottom line. In addition, this year Minnesota Power's operating and maintenance expenses were skewed towards the first half. Our 2012 earnings estimate is at the midpoint of ALLETE's targeted range of $2.45-$2.65 a share. (Note: If the Minnesota commission grants the utility a pension tracking mechanism that it requested, that would likely prompt management to raise its guidance.) Earnings will probably fall short of last year's tally because ALLETE recorded tax benefits of $0.26 a share in the first half of 2011.

We estimate that profits will advance in 2013. We assume a return to normal weather conditions in the first quarter; a mild winter in 2012 cost the company about $0.05 a share. A full year of income from the aforementioned wind projects will be a plus, too. We estimate a 6% earnings increase, to $2.70 a share.

ALLETE has some avenues for further earnings growth by mid-decade. Minnesota Power's mining customers are running at full capacity. Some of them have projects in various stages of development. This should boost the utility's load in the next few years. Minnesota Power has proposed a $350 million-$400 million environmental upgrade to a coal-fired unit, for which it needs the approval of the state commission. And there are significant opportunities for transmission investment, both on the utility's own and through its 8% equity interest in American Transmission Company.

This stock's dividend yield is slightly above average for a utility. We project strong earnings growth, and moderate dividend growth, over the 3- to 5-year period, but total return potential over that time frame is only about equal to the industry average.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrec. gain (loss): '04, 2¢; '05, ($1.84); gain (losses) on disc. ops.: '04, $2.57, '05, (16¢); '06, (2¢); loss from accounting change: '04, 27¢. Next egs. report due late Oct. (B) Div'ds historically paid in early Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred chgs. In '11: $9.22/sh. (D) In mill. (E) Rate base: Original cost deprec. Rate allowed on com. eq. in '10: 10.38%; earned on avg. com. eq., '11: 9.1%. Regulatory Climate: Average. (F) Summer peak in '10.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	75

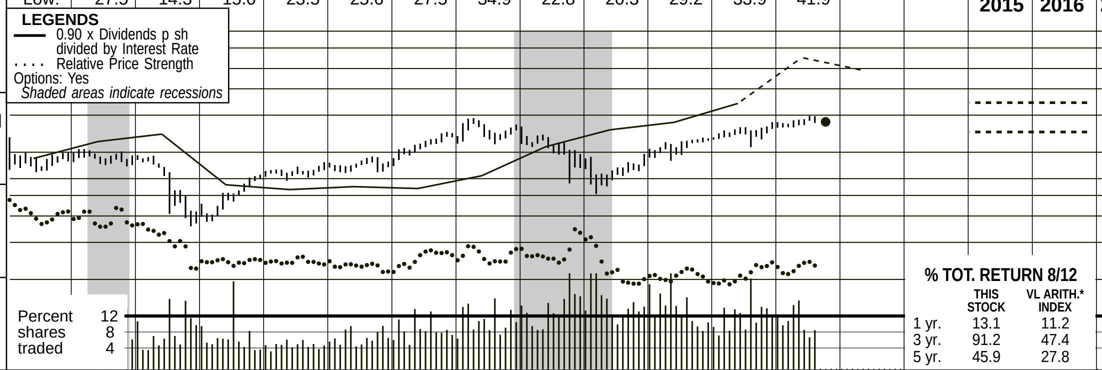
ALLIANT ENERGY NYSE-LNT

RECENT PRICE 44.64 | P/E RATIO 14.9 (Trailing: 16.5 Median: 14.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.1% | VALUE LINE

TIMELINESS **2** Raised 8/24/12
SAFETY **2** Raised 9/28/07
TECHNICAL **3** Raised 8/3/12
BETA .70 (1.00 = Market)

High:	33.2	31.0	25.1	28.8	30.6	40.0	46.5	42.4	31.5	37.7	44.5	47.7
Low:	27.5	14.3	15.0	23.5	25.6	27.5	34.9	22.8	20.3	29.2	33.9	41.9

LEGENDS
— 0.90 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	55	(+25%)	9%
Low	40	(-10%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	1	0	0
Options	0	0	1	0	0	0	0	0	0
to Sell	0	0	1	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	150	129	121
to Sell	127	147	150
Hld's(000)	60603	61552	62065

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	11.2
3 yr.	91.2	47.4
5 yr.	45.9	27.8

Alliant Energy, formerly called Interstate Energy Corporation, was formed on April 21, 1998 through the merger of WPL Holdings, IES Industries, and Interstate Power. WPL stockholders received one share of Interstate Energy stock for each WPL share, IES stockholders received 1.14 Interstate Energy shares for each IES share, and Interstate Power stockholders received 1.11 Interstate Energy shares for each Interstate Power share.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
28.26	28.19	25.56	28.02	28.93	31.15	33.33	31.02	30.81	33.02	*28.85*	*30.35*	Revenues per sh	*39.15*
4.52	4.19	4.69	5.46	4.33	5.12	4.56	4.21	5.21	5.65	*5.90*	*6.20*	"Cash Flow" per sh	*7.30*
1.18	1.57	1.85	2.21	2.06	2.69	2.54	1.89	2.75	2.75	*2.95*	*3.10*	Earnings per sh A	*3.60*
2.00	1.00	1.02	1.05	1.15	1.27	1.40	1.50	1.58	1.70	*1.80*	*1.90*	Div'd Decl'd per sh B ■ †	*2.20*
7.12	7.69	5.55	4.51	3.42	4.91	7.96	10.87	7.82	6.22	*9.00*	*6.95*	Cap'l Spending per sh	*7.40*
19.89	21.37	22.13	20.85	22.83	24.30	25.56	25.07	26.09	27.14	*29.75*	*30.80*	Book Value per sh C	*32.60*
92.30	110.96	115.74	117.04	116.13	110.36	110.45	110.66	110.89	111.02	*111.00*	*112.00*	Common Shs Outst'g D	*115.00*
19.9	12.7	14.0	12.6	16.8	15.1	13.4	13.9	12.5	14.5	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
1.09	.72	.74	.67	.91	.80	.81	.93	.80	.92	*Value Line*		Relative P/E Ratio	*.85*
8.5%	5.0%	3.9%	3.8%	3.3%	3.1%	4.1%	5.7%	4.6%	4.3%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*
2608.8	3128.2	2958.7	3279.6	3359.4	3437.6	3681.7	3432.8	3416.1	3665.3	*3200*	*3400*	Revenues ($mill)	*4500*
113.1	176.6	229.5	337.8	260.1	320.8	280.0	208.6	303.9	304.4	*325*	*345*	Net Profit ($mill)	*420*
24.2%	28.9%	26.7%	19.0%	43.8%	44.4%	33.4%	- -	30.1%	14.7%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
6.8%	11.7%	8.1%	3.0%	3.1%	2.4%	- -	- -	8.8%	6.0%	*6.0%*	*6.0%*	AFUDC % to Net Profit	*6.0%*
56.4%	44.8%	45.0%	41.6%	31.4%	32.4%	36.3%	44.3%	46.3%	45.7%	*45.5%*	*46.0%*	Long-Term Debt Ratio	*47.0%*
39.2%	50.0%	50.2%	53.1%	62.9%	61.9%	58.6%	51.2%	49.5%	50.9%	*51.5%*	*51.0%*	Common Equity Ratio	*50.5%*
4679.1	4738.4	5104.7	4599.1	4218.4	4329.5	4815.6	5423.0	5840.8	5921.2	*6405*	*6755*	Total Capital ($mill)	*7455*
3729.2	4432.6	5284.6	4866.2	4944.9	4679.9	5353.5	6203.0	6730.6	7037.1	*7400*	*7600*	Net Plant ($mill)	*8200*
4.1%	5.7%	6.1%	8.9%	7.5%	8.6%	7.0%	5.1%	6.6%	6.7%	*6.5%*	*6.5%*	Return on Total Cap'l	*7.0%*
5.5%	6.8%	8.2%	12.6%	9.0%	11.0%	9.1%	6.9%	9.7%	9.5%	*9.5%*	*9.5%*	Return on Shr. Equity	*10.5%*
5.8%	6.7%	8.2%	13.1%	9.1%	11.3%	9.3%	6.8%	9.9%	10.1%	*10.0%*	*10.0%*	Return on Com Equity E	*11.0%*
NMF	2.5%	3.8%	8.1%	4.0%	5.9%	3.8%	.9%	3.8%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
NMF	67%	58%	42%	59%	50%	62%	88%	64%	66%	*66%*	*66%*	All Div'ds to Net Prof	*64%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2917.0 mill. **Due in 5 Yrs** $649.2 mill.
LT Debt $2752.8 mill. **LT Interest** $155.0 mill.
(LT interest earned: 4.4x)

Pension Assets-12/11 $1081.4 mill. **Oblig.** $897.4 mill.
Pfd Stock $205.1 mill. **Pfd Div'd** $16.0 mill.
449,765 shs. $100 par; 6,599,460 shs. $25 par

Common Stock 110,976,142 shs.

MARKET CAP: $5.0 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-6.8	+2.8	+.9
Avg. Indust. Use (MWH)	10948	11213	11054
Avg. Indust. Revs. per KWH (¢)	6.33	6.80	6.51
Capacity at Peak (Mw)	5491	5425	5734
Peak Load, Summer (Mw)	5491	5425	5734
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.1	+.2	+.2
Fixed Charge Cov. (%)	256	306	237

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.0%	3.0%	*3.5%*
"Cash Flow"	-2.0%	-.5%	*6.5%*
Earnings	2.0%	5.0%	*6.5%*
Dividends	-3.0%	8.0%	*5.5%*
Book Value	.5%	3.5%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	949.9	742.3	885.7	854.9	3432.8
2010	890.2	741.6	951.7	832.6	3416.1
2011	945.0	819.5	1021.6	879.2	3665.3
2012	765.7	690.3	*1020*	*724*	*3200*
2013	*790*	*750*	*1100*	*760*	*3400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.30	.34	.77	.48	1.89
2010	.45	.44	1.31	.55	2.75
2011	.68	.44	1.12	.51	2.75
2012	.50	.58	*1.30*	*.57*	*2.95*
2013	*.55*	*.55*	*1.35*	*.65*	*3.10*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.35	.35	.35	.35	1.40
2009	.375	.375	.375	.375	1.50
2010	.395	.395	.395	.395	1.58
2011	.425	.425	.425	.425	1.70
2012	.45	.45	.45		

BUSINESS: Alliant Energy Corp., formerly named Interstate Energy, is a holding company formed through the merger of WPL Holdings, IES Industries, and Interstate Power. Supplies electricity, gas, and other services in Wisconsin, Iowa, and Minnesota. Elect. revs. by state: WI, 47%; IA, 50%; MN, 3%. Elect. rev.: residential, 37%; commercial, 23%; industrial, 28%; wholesale, 7%; other, 5%. Fuel sources, 2011: coal, 52%; nuclear, 17%; gas, 2%; other, 29%. Fuel costs: 45% of revs. 2011 depreciation rate: 4.6%. Estimated plant age: 10 years. Has 4,262 employees. Chairman & Chief Executive Officer: Patricia L. Kampling. Incorporated: Wisconsin. Address: 4902 N. Biltmore Lane, Madison, Wisconsin 53718. Telephone: 608-458-3311. Internet: www.alliantenergy.com.

Alliant Energy posted solid bottom-line performance for the second quarter. The utility business benefited from greater electric sales to residential and commercial customers. Higher income from subsidiary Interstate Power and Light's (IPL's) tax benefit rider also contributed, and so did lower operating costs. Looking forward, we expect decent results from the utilities going forward, assuming a stable economy and normal weather. Favorable earnings comparisons ought to continue in the coming quarters, and we project a nice share-net improvement for full-year 2012.

There have been some developments on the regulatory front. IPL, along with two parties representing Iowa consumers, has filed a proposed settlement with the Iowa Utilities Board (IUB) in its natural gas rate case. The three parties have agreed to increase IPL's natural gas service revenue by roughly $10.5 million. A time line for review of the settlement proposal by the IUB is unknown, though the original rate case was expected to be completed by April of 2013. IPL had previously requested a rate hike of $14.8 million, to recover natural gas system improvements and to compensate for higher costs. Elsewhere, subsidiary Wisconsin Power and Light has received approval from the Public Service Commission of Wisconsin to reduce retail gas base rates by 7% in 2013 and freeze gas rates in the following year. The utility has also requested to reduce overall retail electric rates by 2.5% next year, due to lower expected electric fuel costs. It will probably receive approval for the plan by yearend.

This stock is ranked to outperform the broader market for the coming six to 12 months. Looking further out, we anticipate higher revenues and share earnings for the company by 2015-2017. In addition, Alliant earns favorable marks for Safety, Financial Strength, and Price Stability. From the recent quotation, this issue has unimpressive, though fairly well-defined, total return potential for the coming years. Income-oriented investors may find this equity's healthy dividend yield attractive. However, investors seeking strong capital appreciation potential are probably better served elsewhere.

Michael Napoli, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecur. gains (losses): '01, (28¢); '03, net 24¢; '04, (58¢); '05, ($1.05); '06, 83¢; '07, $1.09; '08, 7¢; '09, (88¢); '10, (15¢); '11, (1¢). Next egs. rpt. due in November. (B) Div'ds historically paid in mid-Feb., May, Aug., and Nov. ■ Div'd reinvest. plan avail. † shareholder invest. plan avail. (C) Incl. deferred chgs. in '11: $92.1 mill., $0.83/sh. (D) In mill. (E) Rate base: Orig. cost. Regul. Clim.: WI, Above Avg.; IA, Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	95
Earnings Predictability	75

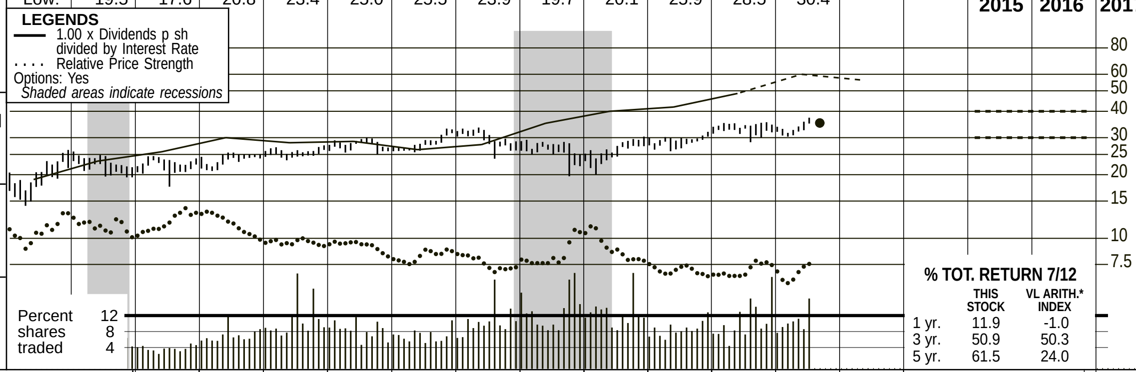
ATMOS ENERGY CORP. NYSE-ATO

RECENT PRICE **35.21** | P/E RATIO **13.7** (Trailing: 15.9 Median: 14.0) | RELATIVE P/E RATIO **0.93** | DIV'D YLD **4.0%** | VALUE LINE

TIMELINESS 2 Raised 8/17/12
SAFETY 2 Raised 12/16/05
TECHNICAL 3 Raised 7/13/12
BETA .70 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	25.8	24.5	25.5	27.6	30.0	33.1	33.5	29.3	30.3	32.0	35.6	37.3
Low:	19.5	17.6	20.8	23.4	25.0	25.5	23.9	19.7	20.1	25.9	28.5	30.4

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+15%)	7%
Low	30	(-15%)	1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	1	0	0	0	0
Options	0	0	0	0	0	0	0	2	0
to Sell	0	2	0	0	0	1	0	0	1

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	110	132	127
to Sell	116	103	117
Hld's(000)	50338	48646	50572

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	11.9	-1.0
3 yr.	50.9	50.3
5 yr.	61.5	24.0

Atmos Energy's history dates back to 1906 in the Texas Panhandle. Over the years, through various mergers, it became part of Pioneer Corporation, and, in 1981, Pioneer named its gas distribution division Energas. In 1983, Pioneer organized Energas as a separate subsidiary and distributed the outstanding shares of Energas to Pioneer shareholders. Energas changed its name to Atmos in 1988. Atmos acquired Trans Louisiana Gas in 1986, Western Kentucky Gas Utility in 1987, Greeley Gas in 1993, United Cities Gas in 1997, and others.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.82	54.39	46.50	61.75	75.27	66.03	79.52	53.69	53.12	48.15	***40.90***	***46.15***	**Revenues per sh A**	***63.10***
3.39	3.23	2.91	3.90	4.26	4.14	4.19	4.29	4.64	4.72	***4.90***	***5.10***	**"Cash Flow" per sh**	***5.65***
1.45	1.71	1.58	1.72	2.00	1.94	2.00	1.97	2.16	2.26	***2.25***	***2.35***	**Earnings per sh A B**	***2.70***
1.18	1.20	1.22	1.24	1.26	1.28	1.30	1.32	1.34	1.36	***1.38***	***1.40***	**Div'ds Decl'd per sh C■**	***1.48***
3.17	3.10	3.03	4.14	5.20	4.39	5.20	5.51	6.02	6.90	***7.75***	***7.95***	**Cap'l Spending per sh**	***8.80***
13.75	16.66	18.05	19.90	20.16	22.01	22.60	23.52	24.16	24.98	***28.10***	***30.20***	**Book Value per sh**	***34.65***
41.68	51.48	62.80	80.54	81.74	89.33	90.81	92.55	90.16	90.30	***90.00***	***91.00***	**Common Shs Outst'g D**	***103.00***
15.2	13.4	15.9	16.1	13.5	15.9	13.6	12.5	13.2	14.4	***Bold figures are***		**Avg Ann'l P/E Ratio**	***13.0***
.83	.76	.84	.86	.73	.84	.82	.83	.84	.90	***Value Line***		**Relative P/E Ratio**	***.85***
5.4%	5.2%	4.9%	4.5%	4.7%	4.2%	4.8%	5.3%	4.7%	4.2%	***estimates***		**Avg Ann'l Div'd Yield**	***4.2%***
950.8	2799.9	2920.0	4973.3	6152.4	5898.4	7221.3	4969.1	4789.7	4347.6	***3680***	***4200***	**Revenues ($mill) A**	***6500***
59.7	79.5	86.2	135.8	162.3	170.5	180.3	179.7	201.2	199.3	***205***	***215***	**Net Profit ($mill)**	***280***
37.1%	37.1%	37.4%	37.7%	37.6%	35.8%	38.4%	34.4%	38.5%	36.4%	***38.5%***	***38.5%***	**Income Tax Rate**	***38.5%***
6.3%	2.8%	3.0%	2.7%	2.6%	2.9%	2.5%	3.6%	4.2%	4.6%	***5.6%***	***5.1%***	**Net Profit Margin**	***4.3%***
53.9%	50.2%	43.2%	57.7%	57.0%	52.0%	50.8%	49.9%	45.4%	49.4%	***45.0%***	***45.0%***	**Long-Term Debt Ratio**	***49.0%***
46.1%	49.8%	56.8%	42.3%	43.0%	48.0%	49.2%	50.1%	54.6%	50.6%	***55.0%***	***55.0%***	**Common Equity Ratio**	***51.0%***
1243.7	1721.4	1994.8	3785.5	3828.5	4092.1	4172.3	4346.2	3987.9	4461.5	***4600***	***5000***	**Total Capital ($mill)**	***7000***
1300.3	1516.0	1722.5	3374.4	3629.2	3836.8	4136.9	4439.1	4793.1	5147.9	***5500***	***5800***	**Net Plant ($mill)**	***6700***
6.8%	6.2%	5.8%	5.3%	6.1%	5.9%	5.9%	5.9%	6.9%	6.1%	***6.0%***	***5.5%***	**Return on Total Cap'l**	***5.5%***
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	***8.0%***	***8.0%***	**Return on Shr. Equity**	***8.0%***
10.4%	9.3%	7.6%	8.5%	9.8%	8.7%	8.8%	8.3%	9.2%	8.8%	***8.0%***	***8.0%***	**Return on Com Equity**	***8.0%***
1.9%	2.8%	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.3%	***3.0%***	***3.0%***	**Retained to Com Eq**	***3.5%***
82%	70%	77%	73%	63%	65%	65%	68%	62%	62%	***61%***	***59%***	**All Div'ds to Net Prof**	***54%***

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2419.9 mill. **Due in 5 Yrs** $660.0 mill.
LT Debt $1956.3 mill. **LT Interest** $110.0 mill.
(LT interest earned: 3.1x; total interest coverage: 3.1x)
Leases, Uncapitalized Annual rentals $17.7 mill.
Pfd Stock None
Pension Assets-9/11 $280.2 mill. **Oblig.** $429.4 mill.
Common Stock 90,173,217 shs. **as of 8/3/12**
MARKET CAP: $3.2 billion (Mid Cap)

CURRENT POSITION ($MILL.)	**2010**	**2011**	**6/30/12**
Cash Assets	132.0	131.4	27.7
Other	743.2	879.6	748.0
Current Assets	875.2	1011.0	775.7
Accts Payable	266.2	291.2	178.2
Debt Due	486.2	208.8	463.6
Other	413.7	367.6	468.4
Current Liab.	1166.1	867.6	1110.2
Fix. Chg. Cov.	440%	432%	430%

ANNUAL RATES of change (per sh)	**Past 10 Yrs.**	**Past 5 Yrs.**	**Est'd '09-'11 to '15-'17**
Revenues	6.5%	-3.5%	*3.5%*
"Cash Flow"	4.5%	4.5%	*3.5%*
Earnings	7.0%	4.0%	*4.0%*
Dividends	1.5%	1.5%	*1.5%*
Book Value	6.5%	4.5%	*6.0%*

Fiscal Year Ends	**QUARTERLY REVENUES ($ mill.) A** Dec.31	Mar.31	Jun.30	Sep.30	**Full Fiscal Year**
2009	1716.3	1821.4	780.8	650.6	4969.1
2010	1292.9	1940.3	770.2	786.3	4789.7
2011	1133.3	1581.5	843.6	789.2	4347.6
2012	1101.2	1243.4	585.8	***749.6***	***3680***
2013	***1180***	***1415***	***825***	***780***	***4200***

Fiscal Year Ends	**EARNINGS PER SHARE A B E** Dec.31	Mar.31	Jun.30	Sep.30	**Full Fiscal Year**
2009	.83	1.29	.02	d.17	1.97
2010	1.00	1.17	d.03	.02	2.16
2011	.81	1.40	.04	.01	2.26
2012	.72	1.16	.33	***.04***	***2.25***
2013	***.82***	***1.38***	***.12***	***.03***	***2.35***

Cal-endar	**QUARTERLY DIVIDENDS PAID C■** Mar.31	Jun.30	Sep.30	Dec.31	**Full Year**
2008	.325	.325	.325	.33	1.31
2009	.33	.33	.33	.335	1.33
2010	.335	.335	.335	.34	1.35
2011	.34	.34	.34	.345	1.37
2012	.345	.345	.345		

BUSINESS: Atmos Energy Corporation is engaged primarily in the distribution and sale of natural gas to over three million customers via six regulated natural gas utility operations: Louisiana Division, West Texas Division, Mid-Tex Division, Mississippi Division, Colorado-Kansas Division, and Kentucky/Mid-States Division. Combined 2011 gas volumes: 281.5 MMcf. Breakdown: 57%, residential; 32%, commercial; 7%, industrial; and 4% other. 2011 depreciation rate 3.3%. Has around 4,750 employees. Officers and directors own 1.5% of common stock (12/11 Proxy). President and Chief Executive Officer: Kim R. Cocklin. Inc.: Texas. Address: Three Lincoln Centre, Suite 1800, 5430 LBJ Freeway, Dallas, Texas 75240. Telephone: 972-934-9227. Internet: www.atmosenergy.com.

From an earnings standpoint, it appears that Atmos Energy will have an unexciting fiscal 2012 (ends September 30th), compared to last year. Through the first nine months, the natural gas distribution division, accounting for the bulk of net income, was hurt partially by a 9% decline in throughput, as warmer weather conditions held back consumption. Moreover, revenue-related taxes here were lower because of decreased revenues on which the tax is calculated. But this segment benefited from rate hikes, particularly in the Texas, Louisiana, Mississippi, and Kentucky service areas. Meanwhile, results for the regulated transmission and storage segment (the second-biggest unit) were boosted nicely by rate design adjustments approved in the Atmos Pipeline—Texas case that became effective in May, 2011. Even so, we believe that the bottom line for fiscal 2012 will be about flat, at $2.25 a share. But assuming some improvement in the operating performance of the natural gas distribution segment, share net might well advance to $2.35 next year.

Non-strategic units are being divested. Atmos recently completed the sale of the natural gas distribution business in Missouri, Iowa, and Illinois (serving around 84,000 customers) to an affiliate of Algonquin Power & Utilities Corp. for $129 million. Furthermore, there was an announcement to sell the natural gas distribution segment in Georgia, representing roughly 64,000 customers, to an affiliate of Algonquin Power & Utilities Corp. for about $141 million. Pending regulatory approvals, the transaction is expected to close sometime during fiscal 2013. Management intends to use the proceeds from these deals to support growth initiatives in such key states as Texas and Louisiana.

The primary attraction here is the dividend yield, which is higher than the average of all gas utility stocks tracked by *Value Line*. Also, our 2015-2017 projections indicate that further, though modest, hikes in the well-covered payout are likely to occur. Other good attributes include a 2 (Above Average) rank for both Safety and Timeliness, plus an excellent score for Price Stability.

Frederick L. Harris, III *September 7, 2012*

(A) Fiscal year ends Sept. 30th. **(B)** Diluted shrs. Excl. nonrec. items: '03, d17¢; '06, d18¢; '07, d2¢; '09, 12¢; '10, 5¢; '11, (1¢). Excludes discontinued operations: '11, 10¢; '12, 7¢. Next egs. rpt. due early Nov. **(C)** Dividends historically paid in early March, June, Sept., and Dec. ■ Div. reinvestment plan. Direct stock purchase plan avail.
(D) In millions.
(E) Qtrs may not add due to change in shrs outstanding.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	90

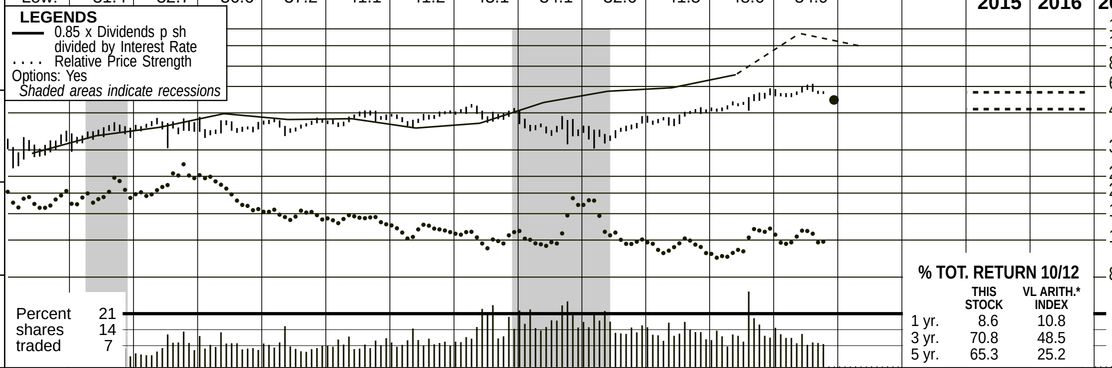
CON. EDISON NYSE-ED

RECENT PRICE 55.19 | P/E RATIO 14.2 (Trailing: 14.4 Median: 14.0) | RELATIVE P/E RATIO 0.98 | DIV'D YLD 4.4% | VALUE LINE

TIMELINESS 2 Raised 8/24/12
SAFETY 1 New 7/27/90
TECHNICAL 2 Raised 11/2/12
BETA .60 (1.00 = Market)

High:	43.4	45.4	46.0	45.6	49.3	49.3	52.9	49.3	46.3	51.0	62.7	66.0
Low:	31.4	32.7	36.6	37.2	41.1	41.2	43.1	34.1	32.6	41.5	48.6	54.9

Target Price Range
2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	6%
Low	50	(-10%)	2%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	1	0	0	1	0	0	1	0	0
Options	1	0	0	0	0	0	0	0	0
to Sell	2	1	0	1	0	1	2	0	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	300	279	269
to Sell	213	273	256
Hld's(000)	125157	121648	104538

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.6	10.8
3 yr.	70.8	48.5
5 yr.	65.3	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
29.62	30.24	30.46	35.04	44.48	45.41	39.65	43.51	40.24	47.66	47.14	48.23	49.62	46.36	45.69	44.17	*41.30*	*42.65*	Revenues per sh	*47.00*
4.97	5.08	5.29	5.74	5.51	5.70	5.44	5.12	4.54	5.27	5.28	5.77	5.99	5.86	6.24	6.61	*7.10*	*7.40*	"Cash Flow" per sh	*8.50*
2.93	2.95	3.04	3.13	2.74	3.21	3.13	2.83	2.32	2.99	2.95	3.48	3.36	3.14	3.47	3.57	*3.85*	*3.90*	Earnings per sh A	*4.25*
2.08	2.10	2.12	2.14	2.18	2.20	2.22	2.24	2.26	2.28	2.30	2.32	2.34	2.36	2.38	2.40	*2.42*	*2.44*	Div'd Decl'd per sh B ■	*2.50*
2.87	2.78	2.66	3.17	4.52	5.20	5.68	5.72	5.60	6.59	7.17	7.09	8.50	7.80	6.96	6.72	*7.55*	*7.30*	Cap'l Spending per sh	*7.25*
24.37	25.18	25.88	25.31	25.81	26.71	27.68	28.44	29.09	29.80	31.09	32.58	35.43	36.46	37.93	39.05	*40.50*	*42.00*	Book Value per sh C	*47.25*
234.99	235.49	232.83	213.81	212.03	212.15	213.93	225.84	242.51	245.29	257.46	272.02	273.72	281.12	291.62	292.89	*293.00*	*293.00*	Common Shs Outst'g D	*293.00*
10.1	10.9	15.3	14.0	12.0	12.0	13.3	14.3	18.2	15.1	15.5	13.8	12.3	12.5	13.3	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.63	.63	.80	.80	.78	.61	.73	.82	.96	.80	.84	.73	.74	.83	.85	.96	*Value Line*		Relative P/E Ratio	*.85*
7.0%	6.5%	4.6%	4.9%	6.6%	5.7%	5.3%	5.5%	5.3%	5.0%	5.0%	4.8%	5.7%	6.0%	5.2%	4.5%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $11873 mill. **Due in 5 Yrs** $3742.0 mill.
LT Debt $9842 mill. **LT Interest** $515.0 mill.
(LT interest earned: 3.8x)

Leases, Uncapitalized Annual rentals $50.0 mill.

Pension Assets-12/11 $7.80 bill. **Oblig.** $11.8 bill.

Pfd Stock None

Common Stock 292,892,396 shs.
as of 7/31/12
MARKET CAP: $16 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
8482.0	9827.0	9758.0	11690	12137	13120	13583	13032	13325	12938	*12100*	*12500*	Revenues ($mill)	*13800*
682.1	639.0	560.0	719.0	749.0	936.0	933.0	868.0	992.0	1062.0	*1140*	*1160*	Net Profit ($mill)	*1260*
36.9%	33.7%	34.3%	33.6%	35.2%	32.6%	36.0%	34.2%	36.0%	36.1%	*36.0%*	*36.0%*	Income Tax Rate	*36.0%*
2.2%	4.2%	7.7%	2.2%	1.6%	1.9%	1.7%	2.6%	2.4%	1.6%	*1.0%*	*1.0%*	AFUDC % to Net Profit	*1.0%*
50.1%	50.4%	47.4%	49.6%	50.2%	45.6%	48.3%	48.5%	48.6%	46.5%	*46.0%*	*46.0%*	Long-Term Debt Ratio	*45.5%*
48.1%	48.0%	51.0%	49.0%	48.5%	53.1%	50.6%	50.4%	50.4%	52.5%	*54.0%*	*54.0%*	Common Equity Ratio	*54.5%*
12302	13369	13828	14921	16515	16687	19160	20330	21952	21794	*22050*	*22775*	Total Capital ($mill)	*25300*
13329	15225	16106	17112	18445	19914	20874	22464	23863	25093	*26350*	*27500*	Net Plant ($mill)	*30200*
7.1%	6.3%	5.6%	6.3%	6.0%	7.0%	6.2%	5.7%	5.9%	6.2%	*6.5%*	*6.5%*	Return on Total Cap'l	*6.5%*
11.1%	9.6%	7.7%	9.6%	9.1%	10.3%	9.4%	8.3%	8.8%	9.1%	*9.5%*	*9.5%*	Return on Shr. Equity	*9.0%*
11.3%	9.8%	7.8%	9.7%	9.2%	10.4%	9.5%	8.4%	8.9%	9.2%	*9.5%*	*9.5%*	Return on Com Equity E	*9.0%*
4.0%	2.9%	.8%	2.6%	2.6%	3.9%	3.1%	2.5%	3.2%	3.1%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
65%	71%	89%	74%	73%	63%	67%	71%	65%	66%	*62%*	*62%*	All Div'ds to Net Prof	*58%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-.9	+3.6	-1.4
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	NMF	NMF	NMF
Peak Load, Summer (Mw)	12242	12963	14788
Annual Load Factor (%)	NMF	NMF	NMF
% Change Customers (yr-end)	NA	NA	NA
Fixed Charge Cov. (%)	296	331	360

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.0%	- -	.5%
"Cash Flow"	1.0%	4.5%	5.5%
Earnings	1.0%	4.5%	4.0%
Dividends	1.0%	1.0%	1.0%
Book Value	4.0%	4.5%	4.0%

QUARTERLY REVENUES ($ mill.)

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3423	2845	3489	3275	13032
2010	3462	3017	3707	3139	13325
2011	3349	2993	3629	2967	12938
2012	3078	2771	3438	*2813*	*12100*
2013	*3200*	*2900*	*3500*	*2900*	*12500*

EARNINGS PER SHARE A

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.66	.55	1.20	.73	3.14
2010	.80	.64	1.23	.80	3.47
2011	1.06	.56	1.30	.65	3.57
2012	.94	.73	1.50	*.68*	*3.85*
2013	*1.05*	*.65*	*1.45*	*.75*	*3.90*

QUARTERLY DIVIDENDS PAID B ■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.585	.585	.585	.585	2.34
2009	.59	.59	.59	.59	2.36
2010	.595	.595	.595	.595	2.38
2011	.60	.60	.60	.60	2.40
2012	.605	.605	.605		

BUSINESS: Consolidated Edison, Inc. is a holding company for Consolidated Edison Company of New York, Inc. (CECONY), which sells electricity, gas, and steam in most of New York City and Westchester County. Also owns Orange and Rockland Utilities (O&R, acquired 7/99), which operates in New York, New Jersey, and Pennsylvania. Has 3.6 million electric, 1.2 million gas customers. Pursues competitive energy opportunities through three wholly owned subsidiaries. Purchases most of its power. Fuel costs: 39% of revenues. '11 reported depreciation rates: 2.8%-3.1%. Has 15,000 employees. Chairman, President & CEO: Kevin Burke. Incorporated: New York. Address: 4 Irving Place, New York, New York 10003. Tel.: 212-460-4600. Internet: www.conedison.com.

Consolidated Edison's utility subsidiaries were hit hard by Hurricane Sandy. Between Consolidated Edison Company of New York and Orange and Rockland, over 1.3 million customers lost electricity. Management's preliminary estimate of the damage to both utilities is $425 million-$550 million. The company won't take a big hit to earnings in the current quarter because it will seek the regulators' permission to defer these costs for future recovery. What's more, its electric and gas (but not steam) operations in New York State operate under a regulatory mechanism that decouples revenues and volume, so most of the lost revenues from customers that were out of service won't hurt ConEd's income. The regulatory commissions in New York and New Jersey will review the company's performance regarding the storm.

CECONY has deferred its next rate case. The utility's electric and gas rate plans expire at the end of March and September, respectively. The steam rate plan expires at the end of September, as well. CECONY was to have filed its application this month, but deferred it "until a more appropriate time" following the aftereffects of Hurricane Sandy.

We continue to look for earnings growth in 2012 and 2013. Rate relief will help, as O&R received an electric tariff hike in mid-2012. Also, the customer count is rising, especially in gas, because the low price of natural gas has prompted numerous customers to switch from oil heat to gas heat.

We expect a dividend boost in the first quarter of 2013. That's been the pattern for a long time. We estimate another $0.02 a share (0.8%) raise in the annual disbursement.

This timely stock has lost more than 10% of its value since our August report. We believe this is merely a correction, as the quotation was above our 2015-2017 Target Price Range for a time. Even after the price decline, and reflecting the expected dividend hike, this high-quality equity has a dividend yield that is only average, by utility standards. The growth in the payout that we project over the 3- to 5-year period isn't enough to make this issue a compelling long-term selection.

Paul E. Debbas, CFA November 23, 2012

(A) Diluted EPS. Excl. nonrecurring losses: '02, 11¢; '03, 45¢; gain on discontinued operations: '08, $1.01. Next earnings report due late Jan. (B) Dividends historically paid in mid-Mar., mid-June, mid-Sept., and mid-Dec. ■ Div'd reinvestment plan available. (C) Incl. intangibles. In '11: $34.24/sh. (D) In millions. (E) Rate base: net original cost. Rate allowed on com. eq. for CECONY in '10: 10.15% electric, 9.6% gas and steam; O&R in '12 (electric) 9.4%, in '09 (gas) 10.3%; earned on avg. com. eq., '11: 9.5%. Regulatory Climate: Below Average.

Company's Financial Strength	A+
Stock's Price Stability	100
Price Growth Persistence	50
Earnings Predictability	85

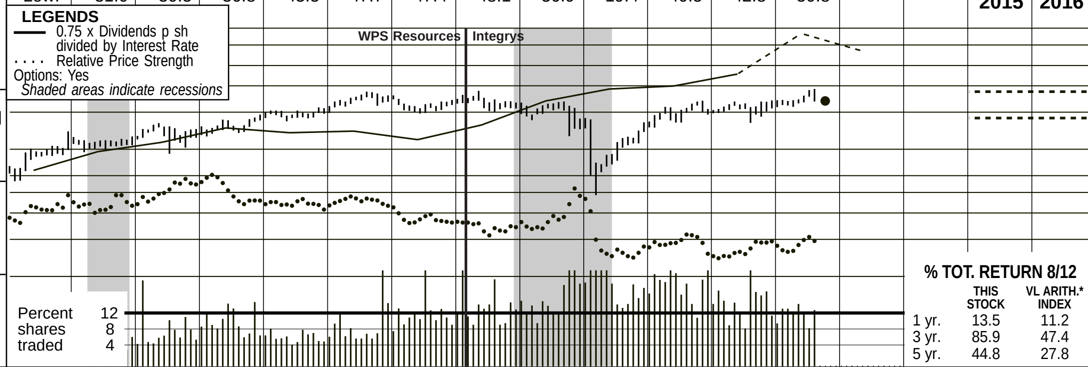
INTEGRYS ENERGY NYSE-TEG

RECENT PRICE	54.25	P/E RATIO	15.2 (Trailing: 17.4; Median: 15.0)	RELATIVE P/E RATIO	1.00	DIV'D YLD	5.0%	VALUE LINE

TIMELINESS	3	New 3/26/10
SAFETY	2	Raised 6/24/11
TECHNICAL	3	Raised 7/27/12

BETA .90 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	36.8	42.7	46.8	50.5	60.0	57.8	60.6	53.9	45.1	54.4	54.6	61.9
Low:	31.0	30.5	36.8	43.5	47.7	47.4	48.1	36.9	19.4	40.5	42.8	50.8



Target Price Range

2015	2016	2017

2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	60	(+10%)	7%
Low	45	(-15%)	1%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	2	0	12	6	2	4	4
to Sell	1	1	2	0	2	10	3	4	5

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	132	125	133
to Sell	134	147	131
Hld's(000)	38784	42436	40993

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.5	11.2
3 yr.	85.9	47.4
5 yr.	44.8	27.8

Integrys Energy Group was created as a holding company on February 21, 2007 to oversee the entire operations of the recently merged WPS Resources and Peoples Energy. WPS acquired Peoples in an agreement under which each common share of Peoples was converted into .825 share of WPS common. The combination took the new name of Integrys Energy Group. All data on this page prior to 2/21/07 are for WPS Resources only.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
83.55	117.07	131.26	173.37	160.01	135.44	184.86	98.71	67.27	60.44	*52.65*	*57.75*	Revenues per sh	*65.50*
5.91	6.23	6.98	7.40	6.33	5.19	4.69	5.34	6.70	6.13	*6.40*	*7.05*	"Cash Flow" per sh	*8.25*
2.74	2.76	4.07	4.09	3.51	2.48	1.58	2.28	3.24	2.88	*3.10*	*3.50*	Earnings per sh A	*4.00*
2.12	2.16	2.20	2.24	2.28	2.56	2.68	2.72	2.72	2.72	*2.72*	*2.72*	Div'd Decl'd per sh B ■	*2.80*
7.16	4.77	7.78	10.31	7.94	5.17	7.01	5.85	3.35	4.00	*8.15*	*10.10*	Cap'l Spending per sh	*9.00*
24.45	27.18	29.30	32.47	35.61	42.58	40.79	37.62	37.57	38.01	*38.50*	*39.35*	Book Value per sh C	*43.00*
32.01	36.91	37.26	40.16	43.06	75.99	75.99	75.98	77.35	77.91	*77.90*	*77.90*	Common Shs Outst'g D	*77.90*
14.0	14.9	11.5	13.4	14.7	21.4	30.7	14.8	14.7	17.5	*Bold figures are*		Avg Ann'l P/E Ratio	*12.5*
.76	.85	.61	.71	.79	1.14	1.85	.99	.94	1.11	*Value Line*		Relative P/E Ratio	*.85*
5.5%	5.3%	4.7%	4.1%	4.4%	4.8%	5.5%	8.1%	5.7%	5.4%	*estimates*		Avg Ann'l Div'd Yield	*5.6%*
2674.9	4321.3	4890.6	6962.7	6890.7	10292	14048	7499.8	5203.2	4708.7	*4100*	*4500*	Revenues ($mill)	*5100*
94.4	94.5	156.2	157.4	151.6	181.1	124.8	178.2	255.9	230.9	*250*	*280*	Net Profit ($mill)	*325*
20.8%	26.3%	16.1%	22.9%	22.9%	32.2%	29.1%	41.5%	40.4%	36.7%	*38.5%*	*38.5%*	Income Tax Rate	*38.5%*
3.2%	2.5%	1.7%	1.0%	.5%	.7%	5.8%	4.5%	.7%	.4%	*2.0%*	*2.0%*	AFUDC % to Net Profit	*2.0%*
48.3%	45.3%	43.1%	39.0%	44.8%	40.8%	42.1%	45.1%	42.2%	38.3%	*39.0%*	*41.5%*	Long-Term Debt Ratio	*44.0%*
45.8%	52.1%	54.4%	58.7%	53.4%	58.3%	57.0%	53.9%	56.8%	60.6%	*60.0%*	*57.5%*	Common Equity Ratio	*55.0%*
1708.3	1926.2	2008.6	2222.4	2871.9	5552.0	5438.7	5304.4	5118.5	4884.5	*4980*	*5350*	Total Capital ($mill)	*6075*
1610.2	1828.7	2002.6	2049.4	2534.8	4463.8	4773.3	4945.1	5013.4	5199.1	*5580*	*6100*	Net Plant ($mill)	*7350*
7.0%	6.1%	8.8%	8.0%	6.4%	4.5%	3.5%	4.6%	6.2%	5.9%	*6.0%*	*6.5%*	Return on Total Cap'l	*6.5%*
10.7%	9.0%	13.7%	11.6%	9.6%	5.5%	4.0%	6.1%	8.7%	7.7%	*8.0%*	*9.0%*	Return on Shr. Equity	*9.5%*
11.7%	9.1%	14.0%	11.8%	9.7%	5.5%	3.9%	6.1%	8.7%	7.7%	*8.0%*	*9.0%*	Return on Com Equity E	*9.5%*
3.1%	2.0%	6.6%	5.3%	3.4%	- -	NMF	NMF	2.3%	.7%	*1.0%*	*2.0%*	Retained to Com Eq	*3.0%*
74%	79%	54%	56%	65%	99%	NMF	118%	74%	91%	*86%*	*77%*	All Div'ds to Net Prof	*68%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $2401.0 mill. **Due in 5 Yrs** $1172.5 mill.
LT Debt $1735.0 mill. **LT Interest** $97.1 mill.
(LT interest earned: 4.1x)
Leases, Uncapitalized Annual rentals $8.5 mill.
Pension Assets-12/11 $1.10 bill. **Oblig.** $1.56 bill.
Pfd Stock $51.1 mill. **Pfd Div'd** $3.1 mill.
510,626 shs. 5.00% to 6.88%, callable $101 to $107.50; sinking fund began 11/1/79. All cumulative, $100 par.
Common Stock 77,912,113 shs.

MARKET CAP: $4.2 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.3	+3.2	+.9
Avg. C & I Use (KWH)	NA	NA	NA
Avg. C & I Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	3346	3078	3312
Peak Load, Summer (Mw)	2403	2421	2465
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.4	+.4
Fixed Charge Cov. (%)	219	314	302

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	1.5%	-13.5%	*-2.5%*
"Cash Flow"	1.0%	-2.5%	*5.5%*
Earnings	1.5%	-6.5%	*6.0%*
Dividends	3.0%	4.0%	*.5%*
Book Value	6.0%	3.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3200.8	1427.6	1297.8	1573.6	7499.8
2010	1903.4	1014.8	997.9	1287.1	5203.2
2011	1627.1	1010.8	938.7	1132.1	4708.7
2012	1251.3	841.9	*906.8*	*1100*	*4100*
2013	*1450*	*950*	*950*	*1150*	*4500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.89	.45	.63	.31	2.28
2010	.95	.82	.56	.91	3.24
2011	1.56	.38	.47	.48	2.88
2012	1.22	.62	*.41*	*.85*	*3.10*
2013	*1.70*	*.45*	*.45*	*.90*	*3.50*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.67	.67	.67	.67	2.68
2009	.68	.68	.68	.68	2.72
2010	.68	.68	.68	.68	2.72
2011	.68	.68	.68	.68	2.72
2012	.68	.68	.68		

BUSINESS: Integrys Energy Group, Inc. is a holding company for Wisconsin Public Service, Peoples Gas, and four other utility subsidiaries. Has 493,000 electric customers in WI and MI, 1.7 million gas customers in WI, IL, MN, and MI. Also has retail electric and gas marketing operations in the Northeast and Midwest. Electric revenue breakdown: residential, 29%; small commercial & industrial, 29%; large commercial & industrial, 19%; other, 23%. Generating sources: coal, 53%; other, 5%; purchased, 42%. Fuel costs: 62% of revenues. '11 deprec. rates (utility): 2.2%-3.3%. Has 4,600 employees. Chairman, President & Chief Executive Officer: Charles A. Schrock. Inc.: WI. Address: 130 East Randolph St., Chicago, IL 60601-6207. Tel.: 312-228-5400. Internet: www.integrysgroup.com.

Integrys Energy's gas utilities in Illinois have filed general rate cases. Peoples Gas (by far the larger of the two) and North Shore Gas are seeking a total of $88.1 million, based on a return of 10.75% on a common-equity ratio of 50%. New tariffs would take effect in July of 2013.

Wisconsin Public Service has a rate case pending, as well. The utility filed for electric and gas hikes of $85.1 million (9.2%) and $12.8 million (3.7%), respectively, based on a 10.3% return on a 52.37% common-equity ratio. The commission's staff is recommending a $20.5 million (2.1%) increase for electricity and a $3.9 million (1.2%) *decrease* for gas, based on a 10.3% return on a 51.65% common-equity ratio. New rates are expected to go into effect in January.

Gas rates will be raised in Minnesota this fall. The state regulators issued a written order calling for an $11 million (4.3%) increase, based on a 9.7% return on a 50.48% common-equity ratio.

The nonregulated energy services operation is facing increased competition. Low prices of power and natural gas have enabled new players to enter this business. This is affecting both volume and margins. Accordingly, we cut our 2013 share-earnings estimate from $3.70 to $3.50. Even so, we still think profits will advance significantly next year thanks in part to rate relief at the utilities. Also, we assume a return to normal weather conditions in 2013 after mild weather hurt earnings in the first half of 2012.

Mark-to-market gains or losses can make earnings hard to predict. These items lowered profits by $0.45 a share in 2011, but helped them by $0.06 a share in the first six months of 2012. We *include* them in our earnings presentation because they are an ongoing part of operations, but don't reflect any in our estimates because they are impossible to predict.

Better selections are available elsewhere. In our view, the yield—although above the utility mean—isn't high enough to compensate investors for the lack of near-term dividend growth potential and the subpar dividend growth prospects through 2015-2017. Increased competition in energy services is another cause for concern.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecur. losses: '09, $3.24; '10, 41¢; gains (loss) from discont. ops.: '07, $1.02; '08, 6¢; '09, 4¢; '11, (1¢); '12, 3¢. '11 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid mid-Mar., June, Sept. and Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $29.74/sh. (D) In mill. (E) Rate base: Net orig. cost. Rate allowed on com. eq. in WI in '11: 10.3%; in IL in '12: 9.45%; in MN in '12: 9.7%; earned on avg. com. eq, '11: 7.7%. Regulatory Climate: WI, Above Avg.; IL, Below Avg.

Company's Financial Strength	B++
Stock's Price Stability	80
Price Growth Persistence	50
Earnings Predictability	45

N.W. NAT'L GAS NYSE-NWN

RECENT PRICE **49.66** | P/E RATIO **19.2** (Trailing: 21.2; Median: 17.0) | RELATIVE P/E RATIO **1.30** | DIV'D YLD **3.6%** | VALUE LINE

TIMELINESS	**4** Lowered 5/13/11
SAFETY	**1** Raised 3/18/05
TECHNICAL	**3** Raised 7/20/12
BETA .55 (1.00 = Market)	

	High	Low
	26.8	21.7
	30.7	23.5
	31.3	24.0
	34.1	27.5
	39.6	32.4
	43.7	32.8
	52.8	39.8
	55.2	37.7
	46.5	37.7
	50.9	41.1
	49.0	39.6
	50.1	43.9

2015-17 PROJECTIONS

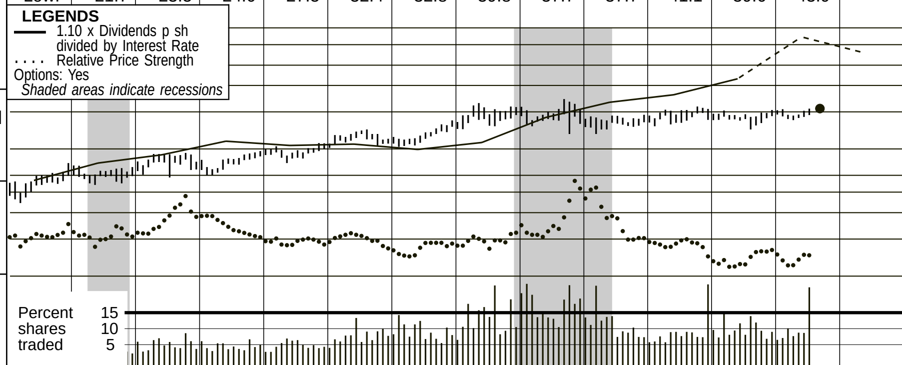
	Price	Gain	Ann'l Total Return
High	65	(+30%)	10%
Low	50	(Nil)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	1	0	0	0	1	0	0	0
to Sell	0	2	0	2	0	1	0	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	54	72	69
to Sell	66	43	58
Hld's(000)	16264	16071	16355



Target Price Range 2015 | 2016 | 2017
120 100 80 64 48 32 24 20 16 12 8

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.3	-1.0
3 yr.	21.9	50.3
5 yr.	39.8	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
16.86	15.82	16.77	18.17	21.09	25.78	25.07	23.57	25.69	33.01	37.20	39.13	39.16	38.17	30.56	31.72	*28.35*	*28.40*	Revenues per sh	*41.95*
3.86	3.72	3.24	3.72	3.68	3.86	3.65	3.85	3.92	4.34	4.76	5.41	5.31	5.20	5.18	5.00	*5.25*	*5.50*	"Cash Flow" per sh	*6.50*
1.97	1.76	1.02	1.70	1.79	1.88	1.62	1.76	1.86	2.11	2.35	2.76	2.57	2.83	2.73	2.39	*2.45*	*2.65*	Earnings per sh A	*3.45*
1.20	1.21	1.22	1.23	1.24	1.25	1.26	1.27	1.30	1.32	1.39	1.44	1.52	1.60	1.68	1.75	*1.78*	*1.82*	Div'ds Decl'd per sh B■	*1.94*
3.70	5.07	4.02	4.78	3.46	3.23	3.11	4.90	5.52	3.48	3.56	4.48	3.92	5.09	9.35	3.76	*4.45*	*5.00*	Cap'l Spending per sh	*7.10*
15.37	16.02	16.59	17.12	17.93	18.56	18.88	19.52	20.64	21.28	22.01	22.52	23.71	24.88	26.08	26.70	*27.75*	*28.15*	Book Value per sh D	*29.10*
22.56	22.86	24.85	25.09	25.23	25.23	25.59	25.94	27.55	27.58	27.24	26.41	26.50	26.53	26.58	26.76	*27.00*	*28.00*	Common Shs Outst'g C	*31.00*
11.7	14.4	26.7	14.5	12.4	12.9	17.2	15.8	16.7	17.0	15.9	16.7	18.1	15.2	17.0	19.0	*Bold figures are*		Avg Ann'l P/E Ratio	*17.0*
.73	.83	1.39	.83	.81	.66	.94	.90	.88	.91	.86	.89	1.09	1.01	1.08	1.20	*Value Line*		Relative P/E Ratio	*1.15*
5.2%	4.8%	4.5%	5.0%	5.6%	5.1%	4.5%	4.6%	4.2%	3.7%	3.7%	3.1%	3.3%	3.7%	3.6%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.3%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $754.9 mill. **Due in 5 Yrs** $200 mill.
LT Debt $641.7 mill. **LT Interest** $45.0 mill.

(Total interest coverage: 2.0x)

Pension Assets-12/11 $216 mill. **Oblig.** $391.1 mill.

Pfd Stock None

Common Stock 26,831,575 shares

MARKET CAP $1.3 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
641.4	611.3	707.6	910.5	1013.2	1033.2	1037.9	1012.7	812.1	848.8	*765*	*895*	Revenues ($mill)	*1300*
43.8	46.0	50.6	58.1	65.2	74.5	68.5	75.1	72.7	63.9	*66.0*	*74.0*	Net Profit ($mill)	*105*
34.9%	33.7%	34.4%	36.0%	36.3%	37.2%	36.9%	38.3%	40.5%	40.4%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
6.8%	7.5%	7.1%	6.4%	6.4%	7.2%	6.6%	7.4%	8.9%	7.5%	*8.7%*	*9.3%*	Net Profit Margin	*8.2%*
47.6%	49.7%	46.0%	47.0%	46.3%	46.3%	44.9%	47.7%	46.1%	47.3%	*45.5%*	*43.0%*	Long-Term Debt Ratio	*37.5%*
51.5%	50.3%	54.0%	53.0%	53.7%	53.7%	55.1%	52.3%	53.9%	52.7%	*54.5%*	*57.0%*	Common Equity Ratio	*62.5%*
937.3	1006.6	1052.5	1108.4	1116.5	1106.8	1140.4	1261.8	1284.8	1356.2	*1370*	*1390*	Total Capital ($mill)	*1440*
995.6	1205.9	1318.4	1373.4	1425.1	1495.9	1549.1	1670.1	1854.2	1893.9	*1985*	*2090*	Net Plant ($mill)	*2375*
5.9%	5.7%	5.9%	6.5%	7.1%	8.5%	7.7%	7.3%	7.0%	6.2%	*6.5%*	*7.0%*	Return on Total Cap'l	*8.5%*
8.9%	9.1%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*9.0%*	*9.5%*	Return on Shr. Equity	*12.0%*
8.5%	9.0%	8.9%	9.9%	10.9%	12.5%	10.9%	11.4%	10.5%	8.9%	*9.0%*	*9.5%*	Return on Com Equity	*12.0%*
1.9%	2.6%	2.7%	3.7%	4.5%	6.0%	4.5%	5.0%	4.0%	2.4%	*2.5%*	*3.0%*	Retained to Com Eq	*5.0%*
79%	72%	69%	63%	59%	52%	59%	56%	61%	73%	*73%*	*69%*	All Div'ds to Net Prof	*56%*

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	3.5	5.8	4.0
Other	326.8	342.9	182.8
Current Assets	330.3	348.7	186.8
Accts Payable	93.2	86.3	48.4
Debt Due	267.4	181.6	113.2
Other	107.6	146.6	103.3
Current Liab.	468.2	414.5	264.9
Fix. Chg. Cov.	366%	334%	285%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	1.0%	*4.0%*
"Cash Flow"	3.0%	3.5%	*4.0%*
Earnings	4.0%	4.5%	*4.5%*
Dividends	3.0%	4.5%	*2.5%*
Book Value	4.0%	4.0%	*2.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	437.4	149.1	116.9	309.3	1012.7
2010	286.5	162.4	95.1	268.1	812.1
2011	323.1	161.2	93.3	271.2	848.8
2012	317.5	106.6	*90.0*	*250.9*	*765*
2013	*305*	*145*	*125*	*220*	*795*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1.78	.12	d.25	1.18	2.83
2010	1.64	.26	d.28	1.11	2.73
2011	1.53	.08	d.31	1.09	2.39
2012	1.51	.05	*d.30*	*1.19*	*2.45*
2013	*1.65*	*.09*	*d.30*	*1.21*	*2.65*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.375	.375	.375	.395	1.52
2009	.395	.395	.395	.415	1.60
2010	.415	.415	.415	.435	1.68
2011	.435	.435	.435	.445	1.75
2012	.445	.445	.445		

BUSINESS: Northwest Natural Gas Co. distributes natural gas to 90 communities, 668,000 customers, in Oregon (90% of customers) and in southwest Washington state. Principal cities served: Portland and Eugene, OR; Vancouver, WA. Service area population: 2.5 mill. (77% in OR). Company buys gas supply from Canadian and U.S. producers; has transportation rights on Northwest Pipeline system. Owns local underground storage. Rev. breakdown: residential, 57%; commercial, 26%; industrial, gas transportation, and other, 17%. Employs 1,061. BlackRock Inc. owns 7.8% of shares; officers and directors, 1.7% (4/12 proxy). CEO: Gregg S. Kantor. Inc.: Oregon. Address: 220 NW 2nd Ave., Portland, OR 97209. Telephone: 503-226-4211. Internet: www.nwnatural.com.

Northwest Natural Gas' bottom line is set to advance marginally in 2012, with a projected 2.5% rise from 2011 year-end. The slow incline can be attributed mainly to increased operational expenses that have been plaguing the company since the beginning of the year. Therefore, we have lowered our 2012 and 2013 share-net estimates by a nickel each, to $2.45 and $2.65, respectively.

Customer growth might be relatively flat for the year, as a result of the slow economic recovery. The main segment impacted by this weak rebound is the construction segment, where new customer additions were under 1% from the previous quarter. We do not foresee a sudden reversal of this trend, and growth is likely to remain weak for the next few quarters.

Oregon remains a major focus at this time. The company has reached a partial settlement with the Oregon Public Utilities Commission (OPUC) on various miscellaneous items. However, several key issues, including ROE, recovery of pension expenses, and Northwest's environmental cost recovery proposal, remain on the table. The case might encounter several obstacles over the remainder of the year, as both the OPUC and the company have filed rebuttal and surrebuttal testimonies for various items on the agenda. A decision is scheduled for the end of the third quarter. A favorable outcome would provide a moderate boost to the top and bottom lines (an increase of $35 million annually), as well as strengthen Northwest Natural Gas' position in the state (as many of the proposed changes would benefit customers as well). Finally, management is keeping an eye on Oregon Governor Kitzhaber's 10-year energy plan for the state, which would provide various opportunities for new natural gas facilities over the next decade.

The long-term outlook is modestly upbeat at this juncture. Indeed, several major projects are set to moderately boost the top and bottom lines over the 3- to 5-year period. Eventually, too, the regional economy should pick up and boost growth.

Performance-minded investors should give this untimely equity a pass. For a utility, the shares are an average selection for income and total return potential.

Sahana Zutshi *September 7, 2012*

(A) Diluted earnings per share. Excludes non-recurring items: '98, $0.15; '00, $0.11; '06, ($0.06); '08, ($0.03); '09, 6¢. Next earnings report due late October.

(B) Dividends historically paid in mid-February, May, August, and November.
■ Dividend reinvestment plan available.
(C) In millions.

(D) Includes intangibles. In 2011: $371.4 million, $13.90/share.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	65
Earnings Predictability	90

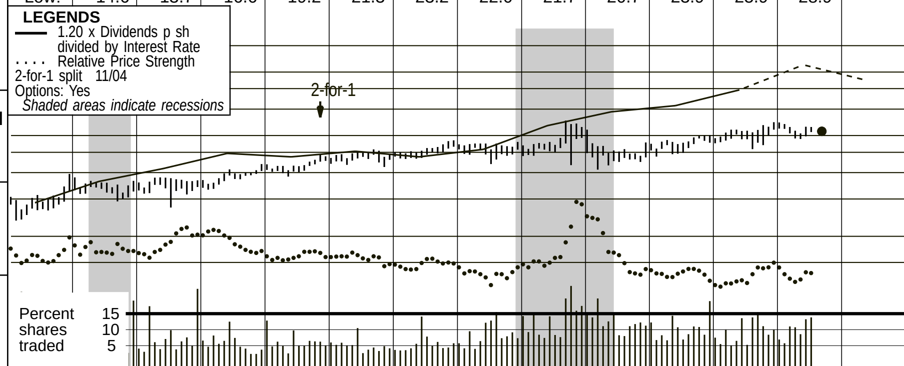
PIEDMONT NAT'L. GAS NYSE-PNY

RECENT PRICE	31.45	P/E RATIO	18.7 (Trailing: 21.0 / Median: 18.0)	RELATIVE P/E RATIO	1.26	DIV'D YLD	3.8%	VALUE LINE

TIMELINESS 3 Raised 6/22/12
SAFETY 2 New 7/27/90
TECHNICAL 3 Raised 8/3/12
BETA .65 (1.00 = Market)

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013
High:	19.0	19.0	22.0	24.3	25.8	28.4	28.0	35.3	32.0	30.1	34.7	34.6
Low:	14.6	13.7	16.6	19.2	21.3	23.2	22.0	21.7	20.7	23.9	25.9	28.9

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+25%)	10%
Low	30	(-5%)	3%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	0	0	0	0	0	0	0	0
to Sell	0	0	0	0	0	1	2	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	87	85	68
to Sell	80	85	92
Hld's(000)	32138	32579	32684

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	-1.0
3 yr.	43.8	50.3
5 yr.	64.7	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
11.59	12.84	12.45	10.97	13.01	17.06	12.57	18.14	19.95	22.96	25.80	23.37	28.52	22.36	21.48	19.83	*19.85*	*22.85*	Revenues per sh A	*25.70*
1.49	1.62	1.72	1.70	1.77	1.81	1.81	2.04	2.31	2.43	2.51	2.64	2.77	3.01	2.91	2.99	*3.00*	*3.20*	"Cash Flow" per sh	*3.45*
.84	.93	.98	.93	1.01	1.01	.95	1.11	1.27	1.32	1.28	1.40	1.49	1.67	1.55	1.57	*1.55*	*1.70*	Earnings per sh AB	*1.85*
.57	.61	.64	.68	.72	.76	.80	.82	.85	.91	.95	.99	1.03	1.07	1.11	1.15	*1.19*	*1.23*	Div'ds Decl'd per sh C■	*1.35*
1.64	1.52	1.48	1.58	1.65	1.29	1.21	1.16	1.85	2.50	2.74	1.85	2.47	1.76	2.75	3.37	*7.75*	*7.85*	Cap'l Spending per sh	*8.10*
6.53	6.95	7.45	7.86	8.26	8.63	8.91	9.36	11.15	11.53	11.83	11.99	12.11	12.67	13.35	13.79	*13.90*	*13.95*	Book Value per sh D	*14.65*
59.10	60.39	61.48	62.59	63.83	64.93	66.18	67.31	76.67	76.70	74.61	73.23	73.26	73.27	72.28	72.32	*71.00*	*70.00*	Common Shs Outst'g E	*68.00*
13.9	13.6	16.3	17.7	14.3	16.7	18.4	16.7	16.6	17.9	19.2	18.7	18.2	15.4	17.1	18.9	*Bold figures are*		Avg Ann'l P/E Ratio	*18.0*
.87	.78	.85	1.01	.93	.86	1.01	.95	.88	.95	1.04	.99	1.10	1.03	1.09	1.19	*Value Line*		Relative P/E Ratio	*1.20*
4.9%	4.8%	4.0%	4.1%	5.0%	4.5%	4.6%	4.4%	4.1%	3.8%	3.9%	3.8%	3.8%	4.1%	4.2%	3.9%	*estimates*		Avg Ann'l Div'd Yield	*3.9%*

CAPITAL STRUCTURE as of 4/30/12
Total Debt $1055.0 mill. **Due in 5 Yrs** $175.0 mill.
LT Debt $975.0 mill. **LT Interest** $46.1 mill.
(LT interest earned: 4.1x; total interest coverage: 3.4x)

Pension Assets-10/11 $259.5 mill. **Oblig.** $236.6 mill.

Pfd Stock None

Common Stock 71,903,935 shs. as of 6/1/12

MARKET CAP: $2.3 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
832.0	1220.8	1529.7	1761.1	1924.6	1711.3	2089.1	1638.1	1552.3	1433.9	*1250*	*1600*	Revenues ($mill) A	*1750*
62.2	74.4	95.2	101.3	97.2	104.4	110.0	122.8	111.8	113.6	*110*	*120*	Net Profit ($mill)	*125*
33.1%	34.8%	35.1%	33.7%	34.2%	33.0%	36.3%	28.5%	23.4%	24.6%	*30.0%*	*30.0%*	Income Tax Rate	*30.0%*
7.5%	6.1%	6.2%	5.8%	5.0%	6.1%	5.3%	7.5%	7.2%	7.9%	*8.8%*	*7.5%*	Net Profit Margin	*7.3%*
43.9%	42.2%	43.6%	41.4%	48.3%	48.4%	47.2%	44.1%	41.0%	40.4%	*50.0%*	*50.0%*	Long-Term Debt Ratio	*50.0%*
56.1%	57.8%	56.4%	58.6%	51.7%	51.6%	52.8%	55.9%	59.0%	59.6%	*50.0%*	*50.0%*	Common Equity Ratio	*50.0%*
1051.6	1090.2	1514.9	1509.2	1707.9	1703.3	1681.5	1660.5	1636.9	1671.9	*1955*	*1950*	Total Capital ($mill)	*1990*
1158.5	1812.3	1849.8	1939.1	2075.3	2141.5	2240.8	2304.4	2437.7	2627.3	*2700*	*2750*	Net Plant ($mill)	*2900*
7.8%	8.6%	7.8%	8.2%	7.2%	7.8%	8.2%	9.1%	8.4%	8.2%	*7.5%*	*8.0%*	Return on Total Cap'l	*8.5%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Shr. Equity	*13.0%*
10.6%	11.8%	11.1%	11.5%	11.0%	11.9%	12.4%	13.2%	11.6%	11.4%	*11.5%*	*12.0%*	Return on Com Equity	*13.0%*
1.7%	3.1%	3.7%	3.6%	2.8%	3.5%	3.9%	4.8%	3.3%	3.1%	*2.5%*	*3.5%*	Retained to Com Eq	*3.5%*
83%	74%	66%	68%	74%	70%	69%	64%	72%	73%	*77%*	*72%*	All Div'ds to Net Prof	*72%*

CURRENT POSITION ($MILL.)

	2010	2011	4/30/12
Cash Assets	5.6	6.8	10.4
Other	322.2	279.2	265.1
Current Assets	327.8	286.0	275.5
Accts Payable	115.7	129.7	103.4
Debt Due	302.0	331.0	80.0
Other	80.9	72.9	96.0
Current Liab.	498.6	534.1	279.4
Fix. Chg. Cov.	323%	323%	325%

ANNUAL RATES

of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	4.5%	-1.5%	*3.5%*
"Cash Flow"	5.5%	4.0%	*2.5%*
Earnings	5.0%	4.5%	*2.5%*
Dividends	4.5%	4.0%	*3.5%*
Book Value	5.0%	3.0%	*1.5%*

QUARTERLY REVENUES ($ mill.) A

Fiscal Year Ends	Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	779.6	455.4	180.3	222.8	1638.1
2010	673.7	472.9	211.6	194.1	1552.3
2011	652.0	392.6	197.3	192.0	1433.9
2012	471.8	308.4	*225*	*244.8*	*1250*
2013	*535*	*480*	*290*	*295*	*1600*

EARNINGS PER SHARE A B

Fiscal Year Ends	Jan.31	Apr.30	Jul.31	Oct.31	Full Fiscal Year
2009	1.10	.73	d.10	d.06	1.67
2010	1.14	.65	d.13	d.13	1.55
2011	1.16	.66	d.12	d.13	1.57
2012	1.05	.70	*d.10*	*d.10*	*1.55*
2013	*1.18*	*.70*	*d.09*	*d.09*	*1.70*

QUARTERLY DIVIDENDS PAID C■

Cal-endar	Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.25	.26	.26	.26	1.03
2009	.26	.27	.27	.27	1.07
2010	.27	.28	.28	.28	1.11
2011	.28	.29	.29	.29	1.15
2012	.29	.30	.30		

BUSINESS: Piedmont Natural Gas Company is primarily a regulated natural gas distributor, serving over 968,188 customers in North Carolina, South Carolina, and Tennessee. 2011 revenue mix: residential (46%), commercial (27%), industrial (7%), other (20%). Principal suppliers: Transco and Tennessee Pipeline. Gas costs: 60.0% of revenues. '11 deprec. rate: 3.2%. Estimated plant age: 10 years. Non-regulated operations: sale of gas-powered heating equipment; natural gas brokering; propane sales. Has about 1,782 employees. Off./dir. own about 1.2% of common stock, BlackRock; 7.6% (1/12 proxy). Chrmn., CEO, & Pres.: Thomas E. Skains. Inc.: NC. Addr.: 4720 Piedmont Row Drive, Charlotte, NC 28210. Telephone: 704-364-3120. Internet: www.piedmontng.com.

Piedmont Natural Gas posted generally good financial results for the April interim. Although the top line declined approximately 21%, that was due to a drop in year-over-year natural gas prices. Meanwhile, on the profitability front, cost of gas sold declined 11.7% as a function of revenues. This was partially offset by rising operating expenses. That figure increased 9.3% as a percentage of the top line. Nonetheless, on balance, PNY's second-quarter bottom line increased about 6%, to $0.70 a share. This was in line with our estimates. Consequently,

We have left our 2012 annual earnings estimates unchanged. The company will likely register a slight low single-digit bottom-line decline this year. This largely reflects warmer-than-normal first-quarter weather patterns when compared to last year. Elsewhere, Piedmont's equity investments have not been performing as well this year, as contributions from those ventures declined year to year.

Still, earnings advances should resume again next year. This should stem from additional residential and commercial customers, thanks to a slowly recovering construction market in PNY's service area. Capital expenditures are opening the opportunity for new power generation customers, as well.

The balance sheet is in adequate shape for the time being. During the first half of this year, Piedmont's cash reserves increased approximately 53%. That financial cushion now sits at more than $10 million. Meanwhile, the long-term debt burden also ticked higher. That figure increased almost 45%, to $975 million. However, this still represents a pretty standard level of debt for a utility company, and should be manageable.

Shares of Piedmont Natural Gas may appeal to investors with an eye on income generation. The stock offers an above-average yield and good dividend growth prospects. However, they have advanced almost 7% in price since our June review, and now trade inside our Target Price Range, thus limiting appreciation potential for the pull to 2015-2017. Moreover, our Timeliness Ranking System suggests PNY will likely mirror the broader market averages in the coming year.

Bryan J. Fong *September 7, 2012*

(A) Fiscal year ends October 31st.
(B) Diluted earnings. Excl. extraordinary item: '00, 8¢. Excl. nonrecurring gains (losses): '97, (2¢); '10, 41¢. Next earnings report due mid Sept. Quarters may not add to total due to change in shares outstanding.
(C) Dividends historically paid early-January, April, July, October.
■ Div'd reinvest. plan available; 5% discount.
(D) Includes deferred charges. In 2011: $527.6 million, $7.29/share.
(E) In millions, adjusted for stock split.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	55
Earnings Predictability	95

SOUTHERN CO. NYSE-SO

RECENT PRICE 42.95 | P/E RATIO 15.5 (Trailing: 16.9 Median: 15.0) | RELATIVE P/E RATIO 1.07 | DIV'D YLD 4.7% | VALUE LINE

TIMELINESS 2 Raised 8/24/12

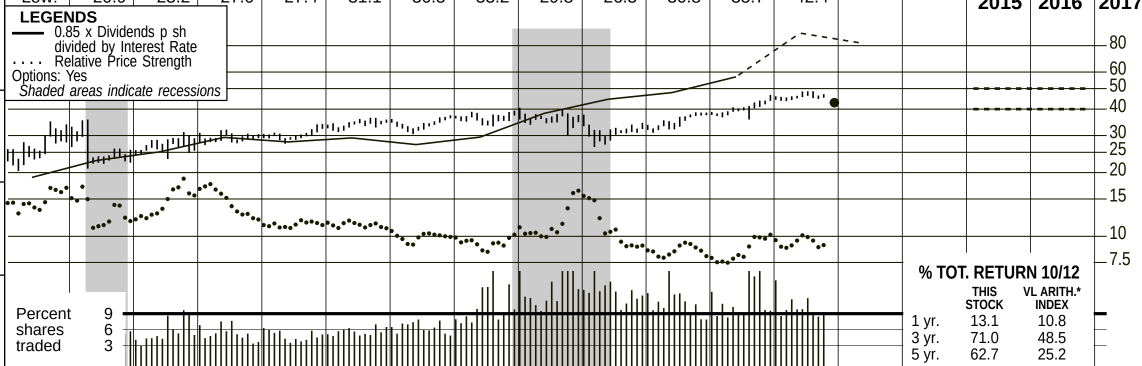
SAFETY 1 Raised 6/3/05

TECHNICAL 3 Lowered 11/23/12

BETA .55 (1.00 = Market)

	High:	Low:
1997	35.7	20.9
1998	31.1	23.2
1999	32.0	27.0
2000	34.0	27.4
2001	36.5	31.1
2002	37.4	30.5
2003	39.3	33.2
2004	40.6	29.8
2005	37.6	26.5
2006	38.6	30.8
2007	46.7	35.7
2008	48.6	42.4

LEGENDS
— 0.85 x Dividends p sh divided by Interest Rate
.... Relative Price Strength
Options: Yes
Shaded areas indicate recessions



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	50	(+15%)	8%
Low	40	(-5%)	3%

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	1	0	0	1	0	0	0
Options	0	1	0	1	2	3	2	2	1
to Sell	0	1	0	1	2	3	2	2	1

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	435	385	432
to Sell	307	387	331
Hld's(000)	374903	372243	338977

% TOT. RETURN 10/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	13.1	10.8
3 yr.	71.0	48.5
5 yr.	62.7	25.2

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
15.30	18.19	16.34	17.40	14.78	14.54	14.73	15.31	16.05	18.28	19.24	20.12	22.04	19.21	20.70	20.41	*19.10*	*19.55*	Revenues per sh	*21.75*
3.64	3.86	4.26	4.17	3.89	3.55	3.46	3.53	3.65	4.03	4.01	4.22	4.43	4.43	4.51	4.91	*5.15*	*5.45*	"Cash Flow" per sh	*6.25*
1.68	1.58	1.73	1.83	2.01	1.61	1.85	1.97	2.06	2.13	2.10	2.28	2.25	2.32	2.36	2.55	*2.65*	*2.80*	Earnings per sh A	*3.25*
1.26	1.30	1.34	1.34	1.34	1.34	1.36	1.39	1.42	1.48	1.54	1.60	1.66	1.73	1.80	1.87	*1.94*	*2.02*	Div'd Decl'd per sh B ■ †	*2.25*
1.82	2.68	2.87	3.85	3.27	3.75	3.79	2.72	2.85	3.20	4.01	4.65	5.10	5.70	4.85	5.23	*6.25*	*5.65*	Cap'l Spending per sh	*6.75*
13.61	13.91	14.04	13.82	15.69	11.43	12.16	13.13	13.86	14.42	15.24	16.23	17.08	18.15	19.21	20.32	*20.95*	*21.70*	Book Value per sh C	*25.75*
677.04	693.42	697.75	665.80	681.16	698.34	716.40	734.83	741.50	741.45	746.27	763.10	777.19	819.65	843.34	865.13	*868.00*	*870.00*	Common Shs Outst'g D	*915.00*
13.8	14.0	15.7	14.3	13.2	14.6	14.6	14.8	14.7	15.9	16.2	16.0	16.1	13.5	14.9	15.8	*Bold figures are*		Avg Ann'l P/E Ratio	*14.0*
.86	.81	.82	.82	.86	.75	.80	.84	.78	.85	.87	.85	.97	.90	.95	1.00	*Value Line*		Relative P/E Ratio	*.95*
5.5%	5.9%	4.9%	5.1%	5.0%	5.7%	5.0%	4.7%	4.7%	4.4%	4.5%	4.4%	4.6%	5.5%	5.1%	4.6%	*estimates*		Avg Ann'l Div'd Yield	*5.0%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $21987 mill. **Due in 5 Yrs** $7119.0 mill.
LT Debt $19459 mill. **LT Interest** $856.0 mill.
(LT interest earned: 4.8x)
Leases, Uncapitalized Annual rentals $121.0 mill.
Pension Assets-12/11 $6.80 bill. **Oblig.** $8.08 bill.
Pfd Stock $1082 mill. **Pfd Div'd** $65.0 mill.
Incl. 1 mill. shs. 4.20%-5.44% cum. pfd. ($100 par); 12 mill. shs. 4.95%-5.83% cum. pfd. ($1 par); 2 mill. shs. 6.0% noncum. pfd. ($25 par); 3 mill. shs. 6.0%-6.5% noncum. pfd. ($100 par); 14 mill. shs. 5.63%-6.5% noncum. pfd. ($1 par).
Common Stock 874,796,883 shs.
MARKET CAP: $38 billion (Large Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
10549	11251	11902	13554	14356	15353	17127	15743	17456	17657	*16600*	*17000*	Revenues ($mill)	*20000*
1510.0	1602.1	1589.0	1621.0	1608.0	1782.0	1807.0	1910.0	2040.0	2268.0	*2365*	*2510*	Net Profit ($mill)	*3040*
25.9%	27.0%	27.0%	26.9%	32.7%	31.9%	33.6%	31.9%	33.5%	35.0%	*32.0%*	*32.0%*	Income Tax Rate	*32.0%*
5.4%	4.6%	5.2%	4.4%	4.8%	9.5%	12.3%	14.9%	13.7%	10.2%	*13.0%*	*13.0%*	AFUDC % to Net Profit	*13.0%*
43.1%	45.9%	53.5%	53.2%	50.8%	51.2%	53.9%	53.2%	51.2%	50.0%	*52.0%*	*52.0%*	Long-Term Debt Ratio	*53.0%*
43.4%	43.6%	44.1%	44.3%	46.2%	44.9%	42.6%	43.6%	45.7%	47.1%	*45.5%*	*45.5%*	Common Equity Ratio	*45.0%*
20086	22135	23288	24131	24618	27608	31174	34091	35438	37307	*40025*	*41725*	Total Capital ($mill)	*52200*
24642	27534	28361	29480	31092	33327	35878	39230	42002	45010	*48275*	*50900*	Net Plant ($mill)	*61500*
8.6%	8.4%	8.1%	8.2%	8.2%	7.9%	7.1%	6.9%	7.0%	7.2%	*7.0%*	*7.0%*	Return on Total Cap'l	*7.0%*
13.2%	13.4%	14.7%	14.4%	13.3%	13.2%	12.6%	12.0%	11.8%	12.2%	*12.5%*	*12.5%*	Return on Shr. Equity	*12.5%*
15.1%	14.8%	14.9%	14.9%	13.8%	14.0%	13.1%	12.4%	12.2%	12.5%	*12.5%*	*13.0%*	Return on Com Equity E	*12.5%*
4.1%	4.4%	4.7%	4.6%	3.8%	4.3%	3.5%	3.2%	3.0%	3.4%	*3.5%*	*3.5%*	Retained to Com Eq	*4.0%*
76%	73%	69%	70%	73%	70%	74%	75%	77%	73%	*74%*	*72%*	All Div'ds to Net Prof	*69%*

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-4.8	+7.6	-2.7
Avg. Indust. Use (MWH)	3095	3332	3438
Avg. Indust. Revs. per KWH (¢)	6.04	6.20	6.37
Capacity at Yearend (Mw)	42932	42963	43555
Peak Load, Summer (Mw)	34471	36321	36956
Annual Load Factor (%)	60.6	62.2	59.0
% Change Customers (yr-end)	- -	+.3	-.1
Fixed Charge Cov. (%)	310	342	397

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	2.5%	*1.5%*
"Cash Flow"	2.0%	3.5%	*5.0%*
Earnings	3.0%	3.0%	*5.0%*
Dividends	3.0%	4.0%	*4.0%*
Book Value	3.5%	6.0%	*5.0%*

Cal-endar	QUARTERLY REVENUES (mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	3666	3885	4682	3510	15743
2010	4157	4208	5320	3771	17456
2011	4012	4521	5428	3696	17657
2012	3604	4181	5049	*3766*	*16600*
2013	*3800*	*4200*	*5200*	*3800*	*17000*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.41	.61	.99	.31	2.32
2010	.60	.62	.98	.18	2.36
2011	.49	.70	1.06	.30	2.55
2012	.42	.71	1.11	*.41*	*2.65*
2013	*.50*	*.75*	*1.20*	*.35*	*2.80*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ † Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.4025	.42	.42	.42	1.66
2009	.42	.4375	.4375	.4375	1.73
2010	.4375	.455	.455	.455	1.80
2011	.455	.4725	.4725	.4725	1.87
2012	.4725	.49	.49		

BUSINESS: The Southern Company, through its subsidiaries, supplies electricity to 4.4 million customers in about 120,000 square miles of Georgia, Alabama, Florida, and Mississippi. Also has competitive generation business. Electric revenue breakdown: residential, 35%; commercial, 30%; industrial, 19%; wholesale, 11%; other, 5%. Retail revenues by state: Georgia, 51%; Alabama, 33%; Florida, 9%; Mississippi, 7%. Generating sources: coal, 49%; oil & gas, 28%; nuclear, 15%; hydro, 2%; purchased, 6%. Fuel costs: 39% of revenues. '11 reported deprec. rate (utility): 3.2%. Has 26,400 employees. Chairman, President and CEO: Thomas A. Fanning. Inc.: Delaware. Address: 30 Ivan Allen Jr. Blvd., N.W., Atlanta, Georgia 30308. Tel.: 404-506-5000. Internet: www.southerncompany.com.

Southern Company's largest utility subsidiary, Georgia Power, is building two nuclear units. Georgia Power will have a 45.7% stake (about 1,000 megawatts) in Vogtle 3 and 4, which are scheduled to begin commercial operation in 2016 and 2017. The projected cost is $6.2 billion, which would comply with the cost estimate that has been certified by the Georgia Public Service Commission, but $425 million of costs are in dispute between the utility and its contractors. At least low financing costs have helped keep the project on budget.

Mississippi Power also has a large project under construction. The utility is building a 582-mw coal gasification plant at a projected cost of $2.88 billion. It is expected to begin commercial operation in May of 2014.

Earnings should improve in 2012 and 2013. At the start of this year, Georgia Power received the second of three annual rate hikes. The utility will get the final increase at the beginning of 2013. Southern Company's utilities in other jurisdictions have received rate relief this year, too. We have fine-tuned our 2012 share-net estimate up a nickel, to $2.65. This remains within the company's targeted range of $2.58-$2.70. For now, we're sticking with our 2013 profit forecast of $2.80 a share, but we are concerned about signs of a slowdown in the service area's economy.

A rate application is upcoming. In mid-2013, Georgia Power will file a general rate case for an order that will take effect at the start of 2014. Although there is regulatory risk whenever a utility puts forth a rate case, we note that Southern Company's utilities have typically done an effective job of managing the regulatory process.

Finances are solid. The fixed-charge coverage is well above the industry average. The common-equity ratio is in good shape, and returns on equity are healthy. Southern Company merits a Financial Strength rating of A, and its stock is ranked 1 (Highest) for Safety.

Timely Southern Company stock has a dividend yield that is slightly above the utility average. Total return potential to 2015-2017 is a cut below the industry average, however.

Paul E. Debbas, CFA *November 23, 2012*

(A) Diluted earnings. Excl. nonrecurring gain (loss): '03, 6¢; '09, (25¢). '10 EPS don't add due to change in shares. Next earnings report due late Jan. (B) Div'ds historically paid in early Mar., June, Sept., and Dec. ■ Div'd reinvestment plan avail. † Shareholder investment plan avail. (C) Incl. deferred charges. In '11: $6.27/sh. (D) In mill. (E) Rate base: AL, MS, fair value; FL, GA, orig. cost. Allowed return on com. eq. (blended): 12.5%. Earned on avg. com. eq., '11: 13.0%. Regulatory Climate: GA, AL Above Average; MS, FL Average.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	100

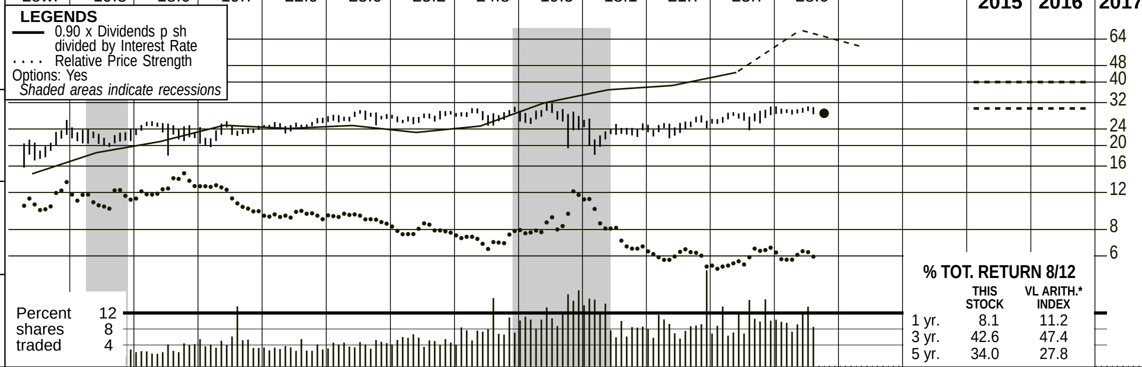
VECTREN CORP. NYSE-VVC

RECENT PRICE **28.47** | P/E RATIO **16.5** (Trailing: 14.8 Median: 15.0) | RELATIVE P/E RATIO **1.09** | DIV'D YLD **5.0%** | VALUE LINE

TIMELINESS	**3** Lowered 2/24/12
SAFETY	**2** Lowered 1/5/01
TECHNICAL	**3** Lowered 9/14/12
BETA .70 (1.00 = Market)	

High:	24.4	26.1	26.1	27.1	29.5	29.3	30.5	32.2	26.9	27.8	30.7	30.8
Low:	19.8	18.0	19.7	22.9	25.0	25.2	24.8	19.5	18.1	21.7	23.7	28.0

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	40	(+40%)	13%
Low	30	(+5%)	7%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	0	7	2	0	0	0	1	0	0
to Sell	0	8	2	0	1	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	103	127	94
to Sell	87	84	113
Hld's(000)	44409	45722	44943

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.1	11.2
3 yr.	42.6	47.4
5 yr.	34.0	27.8

Vectren was formed on March 31, 2000 through the merger of Indiana Energy and SIGCORP. The merger was consummated with a tax-free exchange of shares and has been accounted for as a pooling of interests. Indiana Energy common stockholders received one Vectren common share for each share held. SIGCORP stockholders exchanged each common share for 1.333 common shares of Vectren.

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
26.53	21.00	22.26	26.62	26.83	29.88	30.67	25.76	26.06	28.39	*27.10*	*28.55*	Revenues per sh	*33.50*
3.43	3.17	3.27	3.87	3.69	4.29	3.97	4.40	4.44	4.72	*4.75*	*5.25*	"Cash Flow" per sh	*6.65*
1.68	1.56	1.42	1.81	1.44	1.83	1.63	1.79	1.64	1.73	*1.75*	*1.90*	Earnings per sh A	*2.40*
1.07	1.11	1.15	1.19	1.23	1.27	1.31	1.35	1.37	1.39	*1.41*	*1.43*	Div'd Decl'd per sh B■†	*1.60*
3.22	3.12	3.66	3.04	3.70	4.38	4.83	5.33	3.39	3.92	*4.50*	*5.35*	Cap'l Spending per sh	*6.80*
12.79	14.18	14.42	15.01	15.43	16.16	16.68	17.23	17.61	17.89	*18.65*	*19.35*	Book Value per sh C	*21.00*
68.01	75.60	75.90	76.19	76.10	76.36	81.03	81.10	81.70	81.90	*83.00*	*84.00*	Common Shs Outst'g D	*88.00*
14.2	14.8	17.6	15.1	18.9	15.3	16.8	12.9	15.1	15.1	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.78	.84	.93	.80	1.02	.81	1.01	.86	.96	.97	*Value Line*		Relative P/E Ratio	*1.00*
4.5%	4.8%	4.6%	4.4%	4.5%	4.5%	4.8%	5.9%	5.5%	5.5%	*estimates*		Avg Ann'l Div'd Yield	*4.4%*
1804.3	1587.6	1689.8	2028.0	2041.6	2281.9	2484.7	2088.9	2129.5	2325.2	*2250*	*2400*	Revenues ($mill)	*2950*
114.0	111.2	108.0	136.8	108.8	143.1	129.0	145.0	133.7	141.6	*145*	*160*	Net Profit ($mill)	*210*
25.4%	25.3%	26.5%	24.4%	21.8%	34.7%	37.1%	26.5%	35.8%	37.9%	*37.0%*	*36.0%*	Income Tax Rate	*35.0%*
4.6%	4.5%	3.0%	1.4%	3.8%	2.8%	2.9%	4.1%	4.1%	4.0%	*3.5%*	*3.5%*	AFUDC % to Net Profit	*3.5%*
52.3%	50.0%	48.1%	51.2%	50.7%	50.2%	48.0%	52.4%	49.9%	51.6%	*51.0%*	*52.0%*	Long-Term Debt Ratio	*52.0%*
47.7%	50.0%	51.8%	48.8%	49.3%	49.8%	52.0%	47.6%	50.1%	48.4%	*49.0%*	*48.0%*	Common Equity Ratio	*48.0%*
1824.4	2144.7	2111.5	2341.3	2382.2	2479.1	2599.5	2937.7	2874.1	3025.0	*3150*	*3375*	Total Capital ($mill)	*3850*
1648.1	2003.7	2156.2	2251.9	2385.5	2539.7	2720.3	2878.8	2955.4	3032.6	*3150*	*3250*	Net Plant ($mill)	*3600*
7.7%	6.6%	6.4%	7.2%	6.0%	7.2%	6.5%	6.3%	6.1%	6.1%	*6.0%*	*6.0%*	Return on Total Cap'l	*7.0%*
13.1%	10.4%	9.9%	12.0%	9.3%	11.6%	9.5%	10.4%	9.3%	9.5%	*9.0%*	*9.5%*	Return on Shr. Equity	*11.0%*
13.1%	10.4%	9.9%	12.0%	9.3%	11.6%	9.5%	10.4%	9.3%	9.7%	*9.5%*	*10.0%*	Return on Com Equity E	*11.5%*
4.8%	3.0%	1.9%	4.0%	1.3%	3.8%	2.0%	2.6%	1.6%	1.9%	*2.0%*	*2.5%*	Retained to Com Eq	*3.5%*
63%	71%	81%	66%	86%	67%	80%	75%	83%	80%	*81%*	*75%*	All Div'ds to Net Prof	*67%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $1846.7 mill. **Due in 5 Yrs** $681.9 mill.
LT Debt $1554.0 mill. **LT Interest** $85.0 mill.
(LT interest earned: 3.6x)

Pension Assets-12/11 $261.0 mill. **Oblig.** $329.2 mill.

Pfd Stock None

Common Stock 82,059,592 shs. **as of 7/31/12**

MARKET CAP: $2.3 billion (Mid Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-5.3	11.5	-.3
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	NA	NA	NA
Capacity at Peak (Mw)	1493	1496	1494
Peak Load, Summer (Mw)	1143	1275	1220
Annual Load Factor (%)	56.2	58.1	57.1
% Change Customers (yr-end)	-.2	+.3	- -
Fixed Charge Cov. (%)	280	303	347

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	2.5%	3.5%	*4.0%*
"Cash Flow"	4.0%	4.5%	*6.5%*
Earnings	2.5%	1.0%	*5.5%*
Dividends	3.5%	3.0%	*2.5%*
Book Value	4.0%	3.5%	*3.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	795.2	375.5	349.6	568.6	2088.9
2010	740.3	402.4	422.7	564.1	2129.5
2011	682.6	475.8	539.4	627.4	2325.2
2012	604.6	470.6	*530*	*644.8*	*2250*
2013	*650*	*515*	*560*	*675*	*2400*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun. 30	Sep. 30	Dec. 31	Full Year
2009	.90	.07	.15	.67	1.79
2010	.78	.11	.20	.55	1.64
2011	.55	.18	.43	.56	1.73
2012	.62	.31	*.35*	*.47*	*1.75*
2013	*.60*	*.25*	*.45*	*.60*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B■† Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.325	.325	.325	.335	1.31
2009	.335	.335	.335	.340	1.35
2010	.340	.340	.340	.345	1.37
2011	.345	.345	.345	.350	1.39
2012	.350	.350	.350		

BUSINESS: Vectren is a holding company formed through the merger of Indiana Energy and SIGCORP. Supplies electricity and gas to an area nearly two-thirds of the state of Indiana. Owns gas distribution assets in Ohio. Has a customer base of 1,134,900. 2011 Electricity revenues: residential, 36%; commercial, 27%; industrial, 36%; other, 1%. 2011 Gas revenues: residential, 67%; commercial, 24%; other, 9%. Also provides energy-related products and services and has an investment subsidiary. Est'd plant age: electric, 8 years. '11 deprec. rate: 4.9%. Has 4,500 employees. Chairman, President, & CEO: Carl Chapman. Incorporated: IN. Address: One Vectren Square, Evansville, Indiana 47708. Telephone: 812-491-4000. Internet: www.vectren.com.

Vectren turned in a mixed performance for the second quarter. The company reported a modest decline in revenue for the period. However, operating costs and interest expense also declined, and share net of $0.31 compared favorably with the prior-year tally. The utility business experienced healthy results, and the Infrastructure Services business benefited from increasing demand and favorable construction conditions.

Bottom-line comparisons will likely prove less favorable for the remainder of the year. Weakness in the demand for coal will probably hurt the performance of the company's nonutility operations. Moreover, Vectren anticipates that its gas-marketing subsidiary, ProLiance, will incur a loss of between $0.13 and $0.23 per share for the full year, as a result of difficult market conditions. On the bright side, the company expects the good performance to continue in the Utility Group. Overall, we expect just a modest share-net advance for 2012. Earnings growth may well pick up in 2013, assuming a solid performance from the utility operations and a measure of improvement from the Nonutility Group. Efforts to deemphasize the commodities business ought to pay off going forward.

The Infrastructure Services business should continue to post strong results. This line ought to further benefit from healthy demand from work on transmission pipeline repairs and other services, too. Construction activity will likely remain strong as utilities and pipeline operators replace their aging natural gas and oil infrastructure, and as the demand for additional shale gas and oil infrastructure increases.

From the recent quotation, this stock has worthwhile total return potential for the coming years. Indeed, we anticipate moderate growth in revenues and share earnings, along with steady dividend payments, for the company over the pull to 2015-2017. Moreover, Vectren earns favorable marks for Safety, Price Stability, and Earnings Predictability. Although the issue is not a standout for year-ahead relative price performance, investors seeking exposure to the utility industry may find something to like here.

Michael Napoli, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrecur. gain (loss): '01, (13¢); '03, (6¢); '09, 15¢. Earnings may not sum due to rounding. Next egs report due early November. (B) Div'ds historically paid in early March, June, September, and December. ■Div'd reinvest. plan avail. † Shareholder invest. plan avail. (C) Incl. intang. In '11, $5.96/sh. (D) In millions. (E) Electric rate base determination: fair value. Rates allowed on elect. common equity range from 10.15% to 10.4%; earned on common equity in '11: 9.7%. Regulatory Climate: Above Average.

Company's Financial Strength	A
Stock's Price Stability	95
Price Growth Persistence	45
Earnings Predictability	90

WGL HOLDINGS NYSE-WGL

RECENT PRICE	P/E RATIO		RELATIVE P/E RATIO	DIV'D YLD	
39.78	15.4	(Trailing: 15.7 Median: 15.0)	1.04	4.0%	VALUE LINE

TIMELINESS **3** Raised 9/9/11

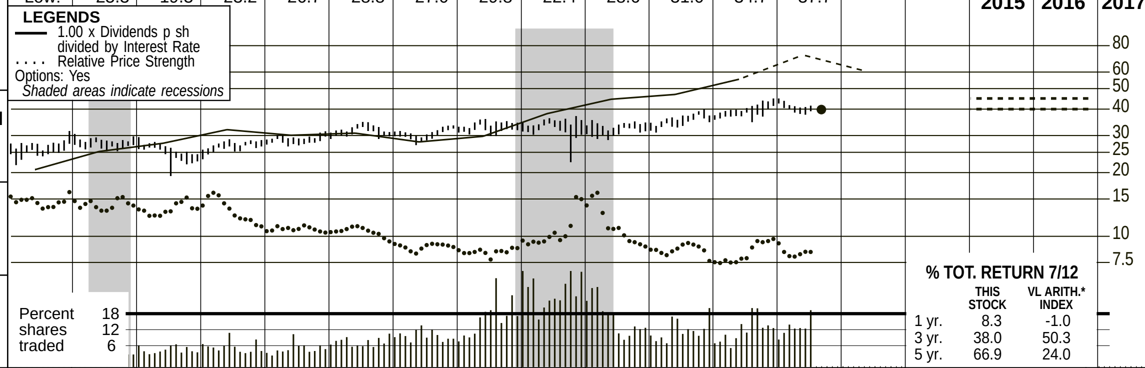
SAFETY **1** Raised 4/2/93

TECHNICAL **2** Raised 8/31/12

BETA .65 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	30.5	29.5	28.8	31.4	34.8	33.6	35.9	37.1	35.5	40.0	45.0	45.0
Low:	25.3	19.3	23.2	26.7	28.8	27.0	29.8	22.4	28.6	31.0	34.7	37.7

Target Price Range 2015 | 2016 | 2017



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+15%)	7%
Low	40	(Nil)	4%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	1	0
Options	0	1	0	0	0	0	0	0	0
to Sell	0	1	0	0	1	0	0	0	0

Institutional Decisions

	3Q2011	4Q2011	1Q2012
to Buy	85	88	81
to Sell	84	80	96
Hld's(000)	31165	31882	31569

% TOT. RETURN 7/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	8.3	-1.0
3 yr.	38.0	50.3
5 yr.	66.9	24.0

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
22.19	24.16	23.74	20.92	22.19	29.80	32.63	42.45	42.93	44.94	53.96	53.51	52.65	53.98	53.60	53.75	*48.35*	*53.15*	Revenues per sh A	*57.80*
2.93	3.02	2.79	2.74	3.20	3.24	2.63	4.00	3.87	3.97	3.84	3.89	4.34	4.44	4.11	4.01	*4.45*	*4.50*	"Cash Flow" per sh	*4.75*
1.85	1.85	1.54	1.47	1.79	1.88	1.14	2.30	1.98	2.13	1.94	2.09	2.44	2.53	2.27	2.25	*2.55*	*2.60*	Earnings per sh B	*2.85*
1.14	1.17	1.20	1.22	1.24	1.26	1.27	1.28	1.30	1.32	1.35	1.37	1.41	1.47	1.50	1.55	*1.59*	*1.63*	Div'ds Decl'd per sh C■	*1.75*
2.85	3.20	3.62	3.42	2.67	2.68	3.34	2.65	2.33	2.32	3.27	3.33	2.70	2.77	2.57	3.94	*5.85*	*4.85*	Cap'l Spending per sh	*4.80*
12.79	13.48	13.86	14.72	15.31	16.24	15.78	16.25	16.95	17.80	18.86	19.83	20.99	21.89	22.82	23.49	*24.55*	*25.60*	Book Value per sh D	*28.85*
43.70	43.70	43.84	46.47	46.47	48.54	48.56	48.63	48.67	48.65	48.89	49.45	49.92	50.14	50.54	51.20	*51.50*	*51.75*	Common Shs Outst'g E	*52.00*
11.5	12.7	17.2	17.3	14.6	14.7	23.1	11.1	14.2	14.7	15.5	15.6	13.7	12.6	15.1	17.0	*Bold figures are*		Avg Ann'l P/E Ratio	*15.0*
.72	.73	.89	.99	.95	.75	1.26	.63	.75	.78	.84	.83	.82	.84	.96	1.07	*Value Line*		Relative P/E Ratio	*1.00*
5.4%	5.0%	4.5%	4.8%	4.8%	4.6%	4.8%	5.0%	4.6%	4.2%	4.5%	4.2%	4.2%	4.6%	4.4%	4.1%	*estimates*		Avg Ann'l Div'd Yield	*4.1%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $648.6 mill. **Due in 5 Yrs** $189.2 mill.
LT Debt $588.1 mill. **LT Interest** $40.0 mill.
(LT interest earned: 6.2x; total interest coverage: 5.7x)
Pension Assets-9/11 $1,289.0 mill. **Oblig.** $896.5 mill.
Preferred Stock $28.2 mill. **Pfd. Div'd** $1.3 mill.

Common Stock 51,573,871 shs. **as of 7/31/12**

MARKET CAP: $2.1 billion (Mid Cap)

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
1584.8	2064.2	2089.6	2186.3	2637.9	2646.0	2628.2	2706.9	2708.9	2751.5	*2490*	*2750*	Revenues ($mill) A	*3005*
55.7	112.3	98.0	104.8	96.0	102.9	122.9	128.7	115.0	115.5	*130*	*135*	Net Profit ($mill)	*150*
34.0%	38.0%	38.2%	37.4%	39.0%	39.1%	37.1%	39.1%	38.7%	42.4%	*39.0%*	*39.0%*	Income Tax Rate	*39.0%*
3.5%	5.4%	4.7%	4.8%	3.6%	3.9%	4.7%	4.8%	4.2%	4.2%	*5.3%*	*4.9%*	Net Profit Margin	*5.0%*
45.7%	43.8%	40.9%	39.5%	37.8%	37.9%	35.9%	33.3%	33.4%	32.3%	*31.0%*	*30.0%*	Long-Term Debt Ratio	*28.0%*
52.4%	54.3%	57.2%	58.6%	60.4%	60.3%	62.4%	65.0%	65.0%	66.2%	*67.5%*	*68.5%*	Common Equity Ratio	*70.5%*
1462.5	1454.9	1443.6	1478.1	1526.1	1625.4	1679.5	1687.7	1774.4	1818.1	*1875*	*1940*	Total Capital ($mill)	*2130*
1606.8	1874.9	1915.6	1969.7	2067.9	2150.4	2208.3	2269.1	2346.2	2489.9	*2640*	*2805*	Net Plant ($mill)	*3350*
5.3%	9.1%	8.2%	8.5%	7.6%	7.6%	8.5%	8.8%	7.6%	7.5%	*8.0%*	*8.0%*	Return on Total Cap'l	*8.0%*
7.0%	13.7%	11.5%	11.7%	10.1%	10.2%	11.4%	11.4%	9.7%	9.4%	*10.5%*	*10.0%*	Return on Shr. Equity	*10.0%*
7.2%	14.0%	11.7%	12.0%	10.3%	10.4%	11.6%	11.6%	9.9%	9.5%	*10.5%*	*10.0%*	Return on Com Equity	*10.0%*
NMF	6.2%	4.1%	4.6%	3.2%	3.5%	5.0%	5.0%	3.3%	3.4%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
112%	56%	65%	62%	69%	66%	57%	57%	67%	64%	*62%*	*63%*	All Div'ds to Net Prof	*61%*

CURRENT POSITION ($MILL.)	2010	2011	6/30/12
Cash Assets	8.9	4.3	51.5
Other	708.4	720.4	724.8
Current Assets	717.3	724.7	776.3
Accts Payable	225.4	279.4	234.2
Debt Due	130.5	116.5	60.5
Other	188.2	180.8	251.9
Current Liab.	544.1	576.7	576.6
Fix. Chg. Cov.	536%	535%	535%

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	8.5%	2.5%	*1.0%*
"Cash Flow"	3.0%	1.5%	*2.0%*
Earnings	3.0%	3.0%	*3.5%*
Dividends	2.0%	2.5%	*2.5%*
Book Value	4.0%	5.0%	*4.0%*

Fiscal Year Ends	QUARTERLY REVENUES ($ mill.) A Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	826.2	1040.9	427.0	412.8	2706.9
2010	727.4	1056.6	459.7	465.2	2708.9
2011	795.9	1017.2	490.3	448.1	2751.5
2012	727.8	839.4	438.3	*484.5*	*2490*
2013	*790*	*905*	*505*	*550*	*2750*

Fiscal Year Ends	EARNINGS PER SHARE A B Dec.31	Mar.31	Jun.30	Sep.30	Full Fiscal Year
2009	1.03	1.65	.11	d.25	2.53
2010	1.01	1.64	d.07	d.29	2.27
2011	1.02	1.53	d.03	d.26	2.25
2012	1.13	1.58	.08	*d.24*	*2.55*
2013	*1.15*	*1.60*	*.10*	*d.25*	*2.60*

Cal-endar	QUARTERLY DIVIDENDS PAID C ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.34	.36	.36	.36	1.42
2009	.36	.37	.37	.37	1.47
2010	.37	.378	.378	.378	1.50
2011	.378	.39	.39	.39	1.55
2012	.39	.40	.40		

BUSINESS: WGL Holdings, Inc. is the parent of Washington Gas Light, a natural gas distributor in Washington, D.C. and adjacent areas of VA and MD to resident'l and comm'l users (1,082,983 meters). Hampshire Gas, a federally regulated sub., operates an underground gas-storage facility in WV. Non-regulated subs.: Wash. Gas Energy Svcs. sells and delivers natural gas and provides energy related products in the D.C. metro area; Wash. Gas Energy Sys. designs/installs comm'l heating, ventilating, and air cond. systems. Black Rock Inc. owns 7.4% of common stock; Off./dir. less than 1% (1/12 proxy). Chrmn. & CEO: Terry D. McCallister. Inc.: D.C. and VA. Addr.: 101 Const. Ave., N.W., Washington, D.C. 20080. Tel.: 202-624-6410. Internet: www.wglholdings.com.

WGL Holdings posted a better-than-expected bottom line for the June period. This happened despite the company registering an almost 11% decline in revenues, reflecting lower natural gas prices on a year-to-year basis. Indeed, this trend impacted both the regulated utility operations as well as the nonutility unit. On the profitability front, overall expenses declined 160 basis points as a function of the top line. On balance, the wider margins were able to offset the weaker revenues, and WGL's third-quarter earnings catapulted back into positive territory, at $0.08 a share. Consequently,

We have increased our 2012 and 2013 share-net estimates by a nickel each, to $2.55 and $2.60, respectively. The Regulated Utility division should continue to post solid gains as that unit was able to implement rate increases in Virginia and Maryland earlier this year. Additional gains will likely stem from an ever-increasing number of active customer accounts. Elsewhere, the Retail Energy-Marketing segment will likely get a boost from higher realized electric margins as a result of volume increases, customer growth, and favorable price conditions. At the Commercial Energy Systems unit, solar projects and previously delayed government contracts that are now beginning to pick up steam, augur well for prospects. Finally, the Wholesale Energy Solutions portion of WGL's business mix has been a bit of a detractor of late, as higher operation and maintenance expenses and costs related to the Commonwealth Pipeline project weigh on margins there. Still, advances at the company's other operations should contribute to a nice double-digit earnings advance this year.

The balance sheet is in good shape and continues to improve. Indeed, the cash and equivalents have increased almost twelvefold so far this year. That financial cushion now sits at more than $50 million. Meanwhile, the total debt load has declined almost 8%, and is well within manageable levels.

These shares may appeal to income-oriented investors. However, the stock is trading near the low end of our Target Price Range, thus limiting appreciation potential for the 3- to 5-year pull.

Bryan J. Fong *September 7, 2012*

(A) Fiscal years end Sept. 30th.
(B) Based on diluted shares. Excludes nonrecurring losses: '01, (13¢); '02, (34¢); '07, (4¢); '08, (14¢) discontinued operations: '06, (15¢). Qtly egs. may not sum to total, due to change in shares outstanding. Next earnings report due late Oct. (C) Dividends historically paid early February, May, August, and November. ■ Dividend reinvestment plan available.
(D) Includes deferred charges and intangibles. '11: $594.4 million, $11.56/sh.
(E) In millions, adjusted for stock split.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	60
Earnings Predictability	95

WISCONSIN ENERGY NYSE-WEC

RECENT PRICE	P/E RATIO	RELATIVE P/E RATIO	DIV'D YLD
37.87	16.0 (Trailing: 16.5 / Median: 14.0)	1.05	3.5%

VALUE LINE

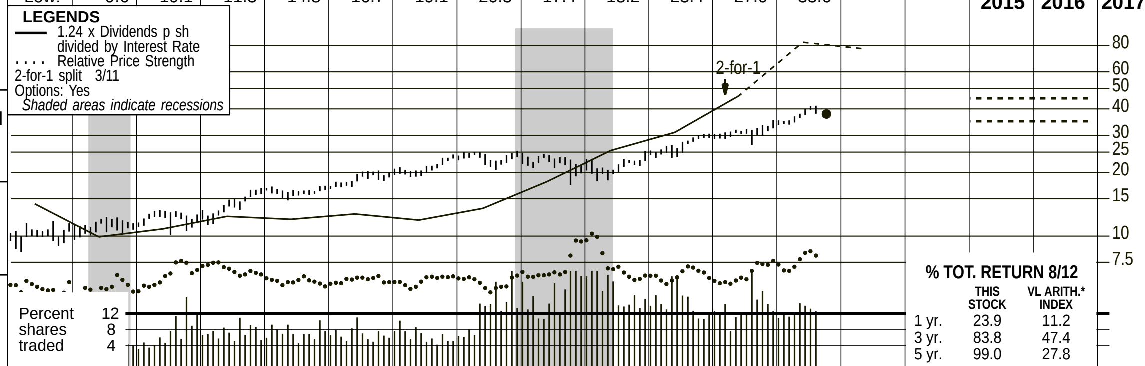
TIMELINESS 3 Lowered 1/13/12

SAFETY 1 Raised 3/23/12

TECHNICAL 3 Raised 8/3/12

BETA .65 (1.00 = Market)

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012
High:	12.3	13.2	16.8	17.3	20.4	24.3	25.2	24.8	25.3	30.5	35.4	41.5
Low:	9.6	10.1	11.3	14.8	16.7	19.1	20.5	17.4	18.2	23.4	27.0	33.6



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	45	(+20%)	8%
Low	35	(-10%)	2%

Insider Decisions

	O	N	D	J	F	M	A	M	J
to Buy	0	0	0	0	0	0	0	0	0
Options	4	0	2	0	2	3	4	5	0
to Sell	4	0	2	0	4	3	4	6	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	188	191	187
to Sell	175	178	178
Hld's(000)	158257	157172	146079

% TOT. RETURN 8/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	23.9	11.2
3 yr.	83.8	47.4
5 yr.	99.0	27.8

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
7.94	7.93	8.56	9.56	14.14	17.02	16.10	17.12	14.66	16.31	17.08	18.12	18.95	17.65	17.98	19.46	*18.45*	*19.75*	Revenues per sh	*22.50*
2.13	1.48	2.06	2.26	2.24	2.72	2.84	2.86	2.58	2.89	2.90	2.98	2.95	3.11	3.30	3.68	*3.90*	*4.15*	"Cash Flow" per sh	*5.00*
.99	.27	.83	.94	.54	.92	1.16	1.13	.93	1.28	1.32	1.42	1.52	1.60	1.92	2.18	*2.30*	*2.35*	Earnings per sh A	*2.75*
.75	.77	.78	.78	.69	.40	.40	.40	.42	.44	.46	.50	.54	.68	.80	1.04	*1.20*	*1.36*	Div'd Decl'd per sh B ■	*1.80*
1.77	1.56	1.76	2.22	2.64	3.01	2.54	2.95	2.85	3.40	4.17	5.28	4.86	3.50	3.41	3.60	*3.30*	*3.10*	Cap'l Spending per sh	*3.00*
8.71	8.25	8.23	8.44	8.50	8.91	9.22	9.96	10.65	11.46	12.35	13.25	14.27	15.26	16.26	17.20	*18.00*	*18.65*	Book Value per sh C	*20.50*
223.36	225.73	231.21	237.81	237.29	230.84	232.06	236.85	233.97	233.96	233.94	233.89	233.84	233.82	233.77	230.49	*230.50*	*230.50*	Common Shs Outst'g D	*230.50*
14.3	NMF	18.0	13.3	18.7	12.1	10.5	12.4	17.5	14.5	16.0	16.5	14.8	13.3	14.0	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*14.5*
.90	NMF	.94	.76	1.22	.62	.57	.71	.92	.77	.86	.88	.89	.89	.89	.90	*Value Line*		Relative P/E Ratio	*.95*
5.4%	6.0%	5.2%	6.3%	6.8%	3.6%	3.3%	2.8%	2.6%	2.4%	2.2%	2.1%	2.4%	3.2%	3.0%	3.3%	*estimates*		Avg Ann'l Div'd Yield	*4.5%*

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
3736.2	4054.3	3431.1	3815.5	3996.4	4237.8	4431.0	4127.9	4202.5	4486.4	*4250*	*4550*	Revenues ($mill)	*5200*
270.8	269.2	221.2	304.8	313.7	337.7	359.8	378.4	455.6	514.0	*535*	*550*	Net Profit ($mill)	*640*
37.4%	35.5%	37.5%	32.9%	35.8%	39.1%	37.6%	36.5%	35.4%	33.9%	*36.0%*	*36.5%*	Income Tax Rate	*36.5%*
4.1%	6.9%	10.0%	12.5%	19.0%	23.8%	27.2%	25.0%	18.6%	16.4%	*9.0%*	*7.0%*	AFUDC % to Net Profit	*6.0%*
59.8%	59.9%	56.2%	52.8%	51.3%	50.3%	54.8%	51.9%	50.6%	53.6%	*54.0%*	*53.5%*	Long-Term Debt Ratio	*52.5%*
39.6%	39.6%	43.3%	46.7%	48.2%	49.2%	44.8%	47.7%	49.0%	46.0%	*46.0%*	*46.5%*	Common Equity Ratio	*47.0%*
5400.3	5963.3	5762.3	5741.5	5992.8	6302.1	7442.0	7473.1	7764.5	8608.0	*9040*	*9300*	Total Capital ($mill)	*10025*
4398.8	5926.1	5903.1	6362.9	7052.5	7681.2	8517.0	9070.5	9601.5	10160	*10555*	*10870*	Net Plant ($mill)	*11525*
7.1%	6.3%	5.6%	7.0%	6.6%	7.0%	6.3%	6.4%	7.5%	7.5%	*7.5%*	*7.5%*	Return on Total Cap'l	*8.0%*
12.5%	11.3%	8.8%	11.2%	10.7%	10.8%	10.7%	10.5%	11.9%	12.9%	*13.0%*	*12.5%*	Return on Shr. Equity	*13.5%*
12.6%	11.4%	8.8%	11.3%	10.8%	10.9%	10.7%	10.6%	12.0%	12.9%	*13.0%*	*13.0%*	Return on Com Equity E	*13.5%*
8.3%	7.4%	4.9%	7.5%	7.1%	7.1%	7.0%	6.2%	7.0%	6.8%	*6.0%*	*5.5%*	Retained to Com Eq	*5.0%*
35%	35%	45%	34%	35%	35%	35%	42%	41%	47%	*52%*	*57%*	All Div'ds to Net Prof	*65%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $5191.8 mill. **Due in 5 Yrs** $1802.6 mill.
LT Debt $4297.5 mill. **LT Interest** $244.3 mill.
Incl. $120.0 mill. capitalized leases.
(LT interest earned: 3.9x)
Leases, Uncapitalized Annual rentals $16.3 mill.
Pension Assets-12/11 $1.26 bill. **Oblig.** $1.33 bill.
Pfd Stock $30.4 mill. **Pfd Div'd** $1.2 mill.
260,000 shs. 3.60%, $100 par, callable at $101; 44,498 shs. 6%, $100 par.
Common Stock 230,447,077 shs.

MARKET CAP: $8.7 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-8.1	+6.0	-.5
Avg. Indust. Use (MWH)	NA	NA	NA
Avg. Indust. Revs. per KWH (¢)	6.57	NA	NA
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	5812	5908	NA
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.2	+.3	+.2
Fixed Charge Cov. (%)	281	312	339

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	3.0%	3.0%	*3.5%*
"Cash Flow"	3.5%	4.0%	*7.0%*
Earnings	9.0%	10.0%	*6.5%*
Dividends	3.0%	14.0%	*13.5%*
Book Value	6.5%	7.0%	*4.0%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	1396.2	842.5	821.9	1067.3	4127.9
2010	1248.6	890.9	973.2	1089.8	4202.5
2011	1328.7	991.7	1052.8	1113.2	4486.4
2012	1191.2	944.7	*964.1*	*1150*	*4250*
2013	*1350*	*1000*	*1000*	*1200*	*4550*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.60	.27	.25	.48	1.60
2010	.55	.37	.47	.53	1.92
2011	.72	.41	.55	.49	2.18
2012	.74	.51	*.56*	*.49*	*2.30*
2013	*.80*	*.45*	*.56*	*.54*	*2.35*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.135	.135	.135	.135	.54
2009	.169	.169	.169	.169	.68
2010	.20	.20	.20	.20	.80
2011	.26	.26	.26	.26	1.04
2012	.30	.30	.30		

BUSINESS: Wisconsin Energy Corporation is a holding company for We Energies, which provides electric, gas & steam service in Wisconsin. Customers: 1.1 mill. elec., 1.1 mill. gas. Acq'd WICOR 4/00. Discontinued pump-manufacturing operations in '04. Sold Point Beach nuclear plant in '07. Electric revenue breakdown: residential, 36%; small commercial & industrial, 31%; large commercial & industrial, 24%; other, 9%. Generating sources: coal, 54%; gas, 7%; hydro, 1%; wind, 1%; purchased, 37%. Fuel costs: 42% of revs. '11 reported deprec. rate (utility): 2.8%. Has 4,600 employees. Chairman, President & CEO: Gale E. Klappa. Inc.: WI. Address: 231 W. Michigan St., P.O. Box 1331, Milwaukee, WI 53201. Tel.: 414-221-2345. Internet: www.wisconsinenergy.com.

Wisconsin Energy has a rate case pending in Wisconsin. The company's utilities in the state are seeking electric rate increases of $172.6 million (6.2%) in 2013 and $37.1 million in 2014, a gas rate decrease of $17.1 million in 2013, and small tariff hikes for steam. The staff of the Wisconsin commission is not contesting the 10.4%-10.5% returns on equity that the utilities are requesting. New rates should go into effect at the start of 2013.

An electric rate hike in Michigan took effect in late June. The regulators boosted Wisconsin Electric's tariffs by $9.2 million (5.2%), based on a 10.1% ROE. This was above the $7.7 million raise that the utility self-implemented six months earlier.

Earnings will likely advance at a mid-single-digit clip in 2012. This year, the utility avoided a rate increase by suspending $140.1 million of regulatory amortization. Average shares outstanding are down slightly, as well. We have raised our earnings estimate by a nickel a share due to favorable weather conditions. Our revised estimate is at the midpoint of Wisconsin Energy's targeted range of $2.28-$2.32 a share.

We have cut our 2013 earnings estimate by $0.05 a share. Wisconsin Energy's stock-repurchase authorization has $200 million remaining. We had estimated that the stock would be bought back next year, but are no longer doing so due to the high share price, which is up about 10% so far this year.

Wisconsin Energy has signaled that its dividends will probably be raised by more than 10% in 2013 and 2014. Over the past several years, the company has had a payout ratio that is well below the industry average. The board wants to change this, and is targeting a payout ratio of about 60% by 2014.

The high expected dividend growth is reflected in this stock's valuation. The dividend yield is nearly a full percentage point below the utility mean, and the relative price-earnings ratio is higher than it has been historically. Despite the strong dividend growth we project over the 3- to 5-year period, total return potential is unexciting because the quotation is already within our 2015-2017 Target Price Range.

Paul E. Debbas, CFA *September 21, 2012*

(A) Diluted EPS. Excl. nonrec. gains (losses): '99, (5¢); '00, 10¢ net; '02, (44¢); '03, (10¢) net; '04, (42¢); gains on disc. ops.: '04, 77¢; '05, 2¢; '06, 2¢; '09, 2¢; '10, 1¢; '11, 6¢. '11 EPS don't add due to rounding. Next earnings report due early Nov. (B) Div'ds historically paid in early Mar., June, Sept. & Dec. ■ Div'd reinvestment plan avail. (C) Incl. intang. In '11: $7.29/sh. (D) In mill., adj. for split. (E) Rate base: Net orig. cost. Rates all'd on com. eq. in WI in '10: 10.4%-10.5%; earned on avg. com. eq., '11: 13.1%. Regulat. Climate: Above Avg.

Company's Financial Strength	A
Stock's Price Stability	100
Price Growth Persistence	90
Earnings Predictability	95

XCEL ENERGY NYSE-XEL

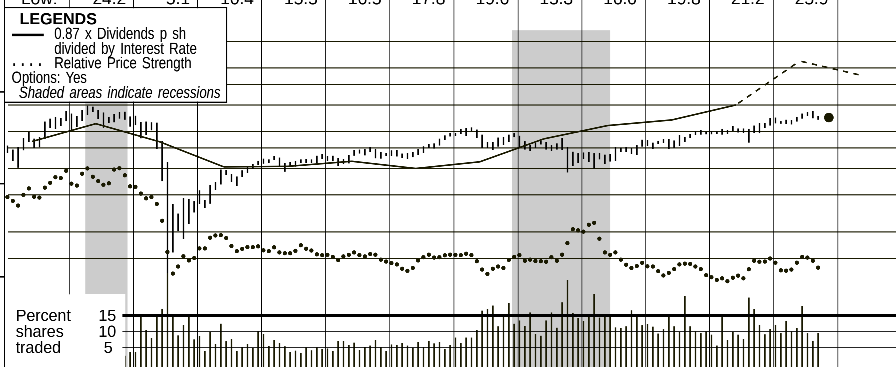
RECENT PRICE **27.89** | P/E RATIO **14.6** (Trailing: 15.1 / Median: 14.0) | RELATIVE P/E RATIO **0.96** | DIV'D YLD **3.9%** | VALUE LINE

TIMELINESS 1 Raised 11/2/12
SAFETY 2 Raised 5/14/04
TECHNICAL 2 Raised 11/2/12
BETA .65 (1.00 = Market)

High:	31.8	28.5	17.4	18.8	20.2	23.6	25.0	22.9	21.9	24.4	27.8	29.9
Low:	24.2	5.1	10.4	15.5	16.5	17.8	19.6	15.3	16.0	19.8	21.2	25.9

Target Price Range 2015 | 2016 | 2017

64 48 40 32 24 20 16 12 8 6



2015-17 PROJECTIONS

	Price	Gain	Ann'l Total Return
High	35	(+25%)	*10%*
Low	25	(-10%)	*2%*

Insider Decisions

	D	J	F	M	A	M	J	J	A
to Buy	0	0	2	0	0	0	0	0	0
Options	1	0	0	0	0	0	0	0	0
to Sell	1	0	0	0	0	0	0	0	0

Institutional Decisions

	4Q2011	1Q2012	2Q2012
to Buy	218	208	214
to Sell	171	208	200
Hld's(000)	298171	300995	279558

% TOT. RETURN 9/12

	THIS STOCK	VL ARITH.* INDEX
1 yr.	16.6	28.2
3 yr.	61.5	42.3
5 yr.	59.0	29.3

1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	© VALUE LINE PUB. LLC	15-17
19.22	18.32	18.46	18.42	34.11	43.56	23.89	19.90	20.84	23.86	24.16	23.40	24.69	21.08	21.38	21.90	*20.40*	*20.70*	Revenues per sh	*23.50*
4.33	3.92	4.30	4.13	4.12	5.09	3.14	3.35	3.27	3.28	3.61	3.45	3.50	3.48	3.51	3.79	*4.00*	*4.10*	"Cash Flow" per sh	*5.00*
1.91	1.61	1.84	1.43	1.60	2.27	.42	1.23	1.27	1.20	1.35	1.35	1.46	1.49	1.56	1.72	*1.85*	*1.90*	Earnings per sh A	*2.25*
1.37	1.40	1.43	1.45	1.48	1.50	1.13	.75	.81	.85	.88	.91	.94	.97	1.00	1.03	*1.07*	*1.11*	Div'd Decl'd per sh B ■	*1.35*
2.99	2.90	2.99	13.87	3.63	7.40	6.04	2.49	3.19	3.25	4.00	4.89	4.66	3.91	4.60	4.53	*5.40*	*6.30*	Cap'l Spending per sh	*4.50*
15.46	15.89	16.25	16.42	16.37	17.95	11.70	12.95	12.99	13.37	14.28	14.70	15.35	15.92	16.76	17.44	*18.25*	*19.40*	Book Value per sh C	*22.00*
138.13	149.24	152.70	155.73	339.79	345.02	398.71	398.96	400.46	403.39	407.30	428.78	453.79	457.51	482.33	486.49	*490.00*	*507.00*	Common Shs Outst'g D	*515.00*
12.5	15.5	15.2	16.6	14.3	12.4	NMF	11.6	13.6	15.4	14.8	16.7	13.7	12.7	14.1	14.2	*Bold figures are*		Avg Ann'l P/E Ratio	*13.0*
.78	.89	.79	.95	.93	.64	NMF	.66	.72	.82	.80	.89	.82	.85	.90	.90	*Value Line*		Relative P/E Ratio	*.85*
5.7%	5.6%	5.1%	6.1%	6.4%	5.3%	6.6%	5.2%	4.7%	4.6%	4.4%	4.0%	4.7%	5.1%	4.5%	4.2%	*estimates*		Avg Ann'l Div'd Yield	*4.7%*

2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013		15-17
9524.4	7937.5	8345.3	9625.5	9840.3	10034	11203	9644.3	10311	10655	*10000*	*10500*	Revenues ($mill)	*12150*
177.6	510.0	526.9	499.0	568.7	575.9	645.7	685.5	727.0	841.4	*900*	*955*	Net Profit ($mill)	*1150*
32.7%	23.7%	23.2%	25.8%	24.2%	33.8%	34.4%	35.1%	37.5%	35.8%	*34.5%*	*35.0%*	Income Tax Rate	*35.0%*
46.7%	8.9%	10.9%	8.5%	9.8%	12.5%	15.9%	16.8%	11.7%	9.4%	*12.0%*	*13.0%*	AFUDC % to Net Profit	*8.0%*
59.6%	55.3%	55.0%	51.7%	52.1%	49.7%	52.2%	51.6%	53.1%	51.1%	*53.5%*	*52.5%*	Long-Term Debt Ratio	*52.0%*
39.5%	43.8%	44.1%	47.3%	47.0%	49.4%	47.1%	47.7%	46.3%	48.9%	*46.5%*	*47.5%*	Common Equity Ratio	*48.0%*
11815	11790	11801	11398	12371	12748	14800	15277	17452	17331	*19325*	*20675*	Total Capital ($mill)	*23700*
18816	13667	14096	14696	15549	16676	17689	18508	20663	22353	*23950*	*26025*	Net Plant ($mill)	*29600*
5.4%	6.1%	6.2%	6.2%	6.2%	6.3%	6.0%	6.2%	5.7%	6.5%	*6.0%*	*6.0%*	Return on Total Cap'l	*6.5%*
3.7%	9.7%	9.9%	9.1%	9.6%	9.0%	9.1%	9.3%	8.9%	9.9%	*10.0%*	*9.5%*	Return on Shr. Equity	*10.0%*
3.7%	9.8%	10.0%	9.2%	9.7%	9.1%	9.2%	9.4%	8.9%	9.9%	*10.0%*	*9.5%*	Return on Com Equity E	*10.0%*
NMF	3.9%	3.9%	2.9%	3.6%	3.1%	3.8%	3.7%	3.6%	4.3%	*4.0%*	*4.0%*	Retained to Com Eq	*4.0%*
NMF	60%	62%	69%	63%	66%	59%	61%	59%	56%	*58%*	*58%*	All Div'ds to Net Prof	*60%*

CAPITAL STRUCTURE as of 6/30/12
Total Debt $10499 mill. **Due in 5 Yrs** $2224.4 mill.
LT Debt $8706.4 mill. **LT Interest** $592.0 mill.
Incl. $191.4 mill. capitalized leases.
(LT interest earned: 3.0x)

Leases, Uncapitalized Annual rentals $185.6 mill.
Pension Assets-12/11 $2.67 bill. **Oblig.** $3.23 bill.

Pfd Stock None

Common Stock 487,553,810 shs. **as of 7/26/12**
MARKET CAP: $14 billion (Large Cap)

ELECTRIC OPERATING STATISTICS

	2009	2010	2011
% Change Retail Sales (KWH)	-3.0	+3.0	+.4
Large C & I Use (MWH)	24225	24431	24286
Large C & I Revs. per KWH (¢)	5.34	5.65	5.90
Capacity at Peak (Mw)	NA	NA	NA
Peak Load, Summer (Mw)	21108	20517	21898
Annual Load Factor (%)	NA	NA	NA
% Change Customers (yr-end)	+.5	- -	+.4
Fixed Charge Cov. (%)	258	277	298

ANNUAL RATES of change (per sh)	Past 10 Yrs.	Past 5 Yrs.	Est'd '09-'11 to '15-'17
Revenues	-4.0%	-1.5%	*1.5%*
"Cash Flow"	-2.0%	1.0%	*5.5%*
Earnings	-1.0%	4.5%	*6.0%*
Dividends	-4.0%	3.5%	*5.0%*
Book Value	- -	4.5%	*4.5%*

Cal-endar	QUARTERLY REVENUES ($ mill.) Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	2695	2016	2315	2618	9644.3
2010	2807	2308	2629	2567	10311
2011	2817	2438	2832	2568	10655
2012	2578	2275	2724	*2423*	*10000*
2013	*2800*	*2350*	*2800*	*2550*	*10500*

Cal-endar	EARNINGS PER SHARE A Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2009	.38	.25	.48	.37	1.49
2010	.36	.29	.62	.29	1.56
2011	.42	.33	.69	.28	1.72
2012	.38	.38	.81	*.28*	*1.85*
2013	*.44*	*.38*	*.75*	*.33*	*1.90*

Cal-endar	QUARTERLY DIVIDENDS PAID B ■ Mar.31	Jun.30	Sep.30	Dec.31	Full Year
2008	.23	.23	.2375	.2375	.94
2009	.2375	.2375	.245	.245	.97
2010	.245	.245	.2525	.2525	1.00
2011	.2525	.2525	.26	.26	1.03
2012	.26	.26	.27	.27	

BUSINESS: Xcel Energy Inc. is the parent of Northern States Power, which supplies electricity to Minnesota, Wisconsin, North Dakota, South Dakota, & Michigan & gas to Minnesota, Wisconsin, North Dakota, & Michigan; Public Service of Colorado, which supplies electricity & gas to Colorado; & Southwestern Public Service, which supplies electricity to Texas & New Mexico. Customers: 3.4 mill. electric, 1.9 mill. gas. Elec. rev. breakdown: residential, 31%; sm. commercial & industrial, 35%; lg. commercial & industrial, 18%; other, 16%. Generating sources not avail. Fuel costs: 48% of revs. '11 reported depr. rate: 2.9%. Has 11,300 empls. Chairman, Pres. & CEO: Ben Fowke. Inc.: MN. Address: 414 Nicollet Mall, Minneapolis, MN 55401. Tel.: 612-330-5500. Web: www.xcelenergy.com.

Xcel Energy's Northern States Power subsidiary has rate cases pending in Wisconsin and South Dakota. In Wisconsin, the utility is seeking electric and gas tariff hikes of $39.1 million and $5.3 million, respectively, based on a return of 10.4% on a common-equity ratio of 52.5%. A decision is expected in the current quarter, with new rates taking effect in early 2013. In South Dakota, the utility filed for an electric increase of $19.4 million, based on a 10.65% return on a 52.89% common-equity ratio. An order is expected in late 2012 or early 2013.

The company intends to file other rate cases by the end of 2012. These include electric applications in Minnesota, Texas, New Mexico, and North Dakota, plus a gas petition in Colorado. Rate relief should come some time in 2013, except for New Mexico.

Frequent rate filings are the key reason why earnings have risen in recent years, and why we expect profits to advance again in 2012 and 2013. The company's utilities file these petitions in order to recover higher operating and maintenance expenses and place their capital spending in the rate base. (Among cost items, rising property taxes are a big concern.) As a result, Xcel is earning adequate returns on equity in most jurisdictions. The only current trouble spots are Minnesota, South Dakota (where it is earning an ROE of less than 4%) and Wisconsin (for the gas side of its business).

We have raised our 2012 earnings estimate by a dime a share. June- and September-quarter profits were above our expectation, due in part to favorable weather patterns. Our revised profit estimate is at the top of management's targeted range of $1.75-$1.85 a share. We have raised our 2013 forecast by a nickel a share, to $1.90. That's the midpoint of Xcel's guidance of $1.85-$1.95.

Timely Xcel Energy's dividend yield and 3- to 5-year total return potential are only about average, by utility standards. This is true even though we project healthy earnings and dividend growth through the 2015-2017 period. The stock's price-earnings ratio is just slightly below that of the broader market, which is not the norm for this equity.

Paul E. Debbas, CFA *November 2, 2012*

(A) Diluted EPS. Excl. nonrec. gain (loss): '02, ($6.27); '10, 5¢; gains (losses) on disc. ops.: '03, 27¢; '04, (30¢); '05, 3¢; '06, 1¢; '09, (1¢); '10, 1¢. '09 EPS don't add due to rounding. Next egs. report due early Feb. **(B)** Div'ds historically paid mid-Jan., Apr., July, and Oct. ■ Div'd reinvestment plan avail. **(C)** Incl. intang. In '11: $4.91/sh. **(D)** In mill. **(E)** Rate base: Varies. Rate all'd on com. eq.: MN '09 10.88%; WI '08 10.75%; CO '10 (elec.) 10.5%; CO '07 (gas) 10.25%; TX '86 15.05%; earned on avg. com. eq., '11: 10.1%. Regulatory Climate: Average.

Company's Financial Strength	B++
Stock's Price Stability	100
Price Growth Persistence	70
Earnings Predictability	100

THE VALUE LINE® Investment Survey®

Part 1
Summary & Index

File at the front of the *Ratings & Reports* binder. Last week's *Summary & Index* should be removed.

November 30, 2012

TABLE OF SUMMARY & INDEX CONTENTS

Summary & Index Page Number

SCREENS

The Median of Estimated
PRICE-EARNINGS RATIOS
of all stocks with earnings

14.5

26 Weeks Ago	Market Low 3-9-09	Market High 7-13-07
14.1	10.3	19.7

The Median of Estimated
DIVIDEND YIELDS
(next 12 months) of all dividend paying stocks under review

2.4%

26 Weeks Ago	Market Low 3-9-09	Market High 7-13-07
2.4%	4.0%	1.6%

The Estimated Median Price
APPRECIATION POTENTIAL
of all 1700 stocks in the hypothesized economic environment 3 to 5 years hence

65%

26 Weeks Ago	Market Low 3-9-09	Market High 7-13-07
80%	185%	35%

ANALYSES OF INDUSTRIES IN ALPHABETICAL ORDER WITH PAGE NUMBER

Numeral in parenthesis after the industry is rank for probable performance (next 12 months).

*Reviewed in this week's issue.

In three parts: This is Part 1, the Summary & Index. Part 2 is Selection & Opinion. Part 3 is Ratings & Reports. Volume LXVIII, No. 15.

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See back cover for important disclosures.

Index to Stocks

Prices quoted are as of November 19, 2012.
All shares are traded on the New York Stock Exchange except where noted.

PAGE NUMBERS
Bold type refers to Ratings and Reports;
italics to Selection & Opinion

Page (Selection & Opinion)	Page	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS Timeliness	RANKS Safety	RANKS Technical	Beta	3-5 year Target Price Range and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	702	**AAR Corp.**	AIR	**14.23**	**4**	**3**	**3**	1.30	40- 55 (180-285%)	**7.5**	**2.1**	1.90	.30	**64**	8/31	**.45**	.41	12/31	.075	.075	YES
	1967	AB InBev ADR	BUD	**84.67**	**2**	**1**	**3**	.90	90- 110 (5- 30%)	**18.0**	**1.8**	4.71	1.56	**19**	9/30	**1.15**	1.00	9/30	NIL	NIL	YES
	376	ABM Industries Inc.	ABM	**18.36**	**3**	**3**	**2**	.90	30- 45 (65-145%)	**11.6**	**3.2**	1.58	.58	**34**	7/31	**.37**	.51	12/31	.145	.14	YES
	1421	ACCO Brands	ACCO	**6.95**	**–**	**5**	**–**	1.65	16- 30 (130-330%)	**7.3**	**NIL**	.95	NIL	**87**	9/30	**.29**	.21	9/30	NIL	NIL	YES
	756	ACE Limited	ACE	**78.20**	**2**	**2**	**3**	.85	65- 90 (N- 15%)	**9.7**	**2.5**	8.08	1.96	**11**	9/30	**2.01**	2.22	3/31	◆.49	.47	YES
	2596	ACI Worldwide (NDQ)	ACIW	**41.77**	**2**	**3**	**3**	.95	50- 75 (20- 80%)	**32.1**	**NIL**	1.30	NIL	**14**	9/30	**.14**	.31	9/30	NIL	NIL	YES
	1215	AES Corp.	AES	**9.97**	**3**	**3**	**3**	1.20	19- 30 (90-200%)	**7.6**	**1.6**	1.31	.16	**92**	9/30	**.36**	d.08	12/31	.04	NIL	YES
	345	AFC Enterprises (NDQ)	AFCE	**25.48**	**▼2**	**3**	**3**	1.15	25- 35 (N- 35%)	**19.5**	**NIL**	1.31	NIL	**32**	9/30	**.29**	.25	9/30	NIL	NIL	YES
	156	AGCO Corp.	AGCO	**44.49**	**5**	**3**	**4**	1.50	75- 110 (70-145%)	**9.0**	**NIL**	4.92	NIL	**85**	9/30	**.96**	.87	9/30	NIL	NIL	YES
	540	AGL Resources	GAS	**37.81**	**3**	**1**	**3**	.75	55- 70 (45- 85%)	**12.6**	**4.9**	3.00	1.84	**28**	9/30	**.08**	d.04	12/31	.46	.549	YES
	2371	A.H. Belo	AHC	**4.69**	**4**	**5**	**3**	1.45	8- 16 (70-240%)	**NMF**	**5.1**	d.03	.24	**50**	9/30	**.06**	d.01	3/31	.06	.06	
244	**741**	AK Steel Holding	AKS	**3.66**	**5**	**5**	**3**	1.80	20- 35 (445-855%)	**NMF**	**NIL**	d.28	NIL	**91**	9/30	**d.25**	d.03	9/30	▼NIL	.05	YES
2649	**2323**	AMC Networks (NDQ)	AMCX	**51.28**	**–**	**3**	**–**	NMF	60- 90 (15- 75%)	**20.0**	**NIL**	2.56	NIL	**12**	9/30	**.51**	.56	12/31	NIL	NIL	YES
	1632	AMN Healthcare	AHS	**10.36**	**1**	**3**	**4**	1.05	14- 20 (35- 95%)	**24.1**	**NIL**	.43	NIL	**58**	9/30	**.12**	.02	9/30	NIL	NIL	YES
	2615	AOL, Inc.	AOL	**35.47**	**–**	**3**	**–**	1.15	25- 40 (N- 15%)	**31.1**	**NIL**	1.14	NIL	**56**	9/30	**.22**	d.02	9/30	NIL	NIL	YES
	1558	ASA Gold & Precious	ASA	**21.75**	**–**	**3**	**2**	1.05	25- 35 (15- 60%)	**NMF**	**1.8**	.09	.40	**79**	8/31	**24.90(q)**	34.84(q)	12/31	.35	.34	YES
2261	**922**	AT&T Inc.	T	**33.82**	**2**	**1**	**3**	.70	40- 50 (20- 50%)	**13.4**	**5.3**	2.52	1.80	**84**	9/30	**.63**	.61	3/31	▲.45	.44	YES
	1387	ATMI, Inc. (NDQ)	ATMI	**18.74**	**3**	**3**	**3**	1.25	35- 50 (85-165%)	**12.9**	**NIL**	1.45	NIL	**95**	9/30	**.44**	.25	9/30	NIL	NIL	YES
	1319	AVX Corp.	AVX	**9.84**	**5**	**3**	**2**	.90	13- 20 (30-105%)	**12.3**	**3.0**	.80	.30	**86**	9/30	**.17**	.36	12/31	.075	.075	YES
	2136	Aaron's Inc.	AAN	**29.31**	**3**	**3**	**2**	.85	35- 50 (20- 70%)	**13.4**	**0.2**	2.19	.07	**30**	9/30	**.46**	.36	3/31	▲.017	.015	YES
	204	Abaxis, Inc. (NDQ)	ABAX	**35.76**	**1**	**3**	**4**	1.20	50- 75 (40-110%)	**43.6**	**NIL**	.82	NIL	**45**	9/30	**.18**	.15	9/30	NIL	NIL	YES
	1594	Abbott Labs.	ABT	**62.92**	**–**	**1**	**–**	.60	90- 105 (45- 65%)	**12.0**	**3.2**	5.25	2.04	**31**	9/30	**1.30**	1.18	12/31	.51	.48	YES
244	**2202**	Abercrombie & Fitch	ANF	**43.80**	**3**	**3**	**3**	1.20	50- 75 (15- 70%)	**14.7**	**1.6**	2.98	.70	**18**	10/31	**.87**	.57	12/31	◆.175	.175	YES
	413	Aberdeen Australia Fd. (ASE)	IAF	**10.11**	**–**	**3**	**3**	1.30	14- 20 (40-100%)	**NMF**	**4.9**	NMF	.50	**–**	7/31	**9.79(q)**	11.22(q)	9/30	.16	.09	
	1202	Aberdeen Asia-Pac. Fd. (ASE)	FAX	**7.80**	**–**	**4**	**3**	.85	7- 12 (N- 55%)	**NMF**	**5.4**	NMF	.42	**–**	4/30	**7.55(q)**	7.75(q)	12/31	.105	.105	
	2597	Accenture Plc	ACN	**67.06**	**2**	**1**	**3**	.85	80- 95 (20- 40%)	**16.4**	**2.4**	4.08	1.62	**14**	8/31	**.88**	.91	12/31	▲.81	.675	YES
	946	Acme Packet (NDQ)	APKT	**17.98**	**3**	**3**	**1**	1.10	20- 30 (10- 65%)	**NMF**	**NIL**	.03	NIL	**90**	9/30	**d.08**	.11	9/30	NIL	NIL	YES
	2010	Activision Blizzard (NDQ)	ATVI	**11.24**	**3**	**3**	**3**	.75	25- 35 (120-210%)	**12.5**	**1.8**	.90	.20	**89**	9/30	**.20**	.13	9/30	NIL	NIL	YES
	157	Actuant Corp.	ATU	**27.05**	**3**	**3**	**3**	1.35	35- 55 (30-105%)	**12.4**	**0.1**	2.19	.04	**85**	8/31	**.55**	.50	12/31	.04	.04	YES
	1302	Acuity Brands	AYI	**62.57**	**2**	**3**	**3**	1.15	60- 90 (N- 45%)	**19.4**	**0.8**	3.23	.52	**41**	8/31	**.88**	.79	12/31	.13	.13	YES
	1203	Adams Express	ADX	**10.27**	**–**	**2**	**3**	.95	15- 20 (45- 95%)	**NMF**	**1.6**	NMF	.16	**–**	9/30	**13.08(q)**	10.76(q)	12/31	◆.05	.02	
	2573	Adobe Systems (NDQ)	ADBE	**32.92**	**3**	**3**	**3**	1.20	55- 80 (65-145%)	**20.2**	**NIL**	1.63	NIL	**47**	8/31	**.40**	.39	9/30	NIL	NIL	YES
	947	ADTRAN, Inc. (NDQ)	ADTN	**17.96**	**4**	**3**	**1**	.90	40- 55 (125-205%)	**14.1**	**2.0**	1.27	.36	**90**	9/30	**.15**	.56	12/31	.09	.09	YES
	2123	Advance Auto Parts	AAP	**77.79**	**▲4**	**3**	**4**	.85	100- 145 (30- 85%)	**14.4**	**0.3**	5.42	.24	**13**	9/30	**1.21**	1.41	3/31	.06	.06	YES
	1346	Advanced Energy (NDQ)	AEIS	**12.10**	**4**	**3**	**1**	1.40	25- 40 (105-230%)	**12.7**	**NIL**	.95	NIL	**88**	9/30	**.20**	.16	9/30	NIL	NIL	YES
2034	**1347**	Advanced Micro Dev.	AMD	**1.92**	**5**	**4**	**3**	1.55	9- 15 (370-680%)	**14.8**	**NIL**	.13	NIL	**88**	9/30	**d.20**	.15	9/30	NIL	NIL	YES
	2574	Advent Software (NDQ)	ADVS	**21.34**	**3**	**3**	**3**	1.00	35- 50 (65-135%)	**31.9**	**NIL**	.67	NIL	**47**	9/30	**.15**	.13	9/30	NIL	NIL	YES
	428	Advisory Board (NDQ)	ABCO	**43.68**	**1**	**2**	**4**	.80	▲ 35- 45 (N- 5%)	**46.5**	**NIL**	.94	NIL	**8**	9/30	**.21**	.15	9/30	NIL	NIL	YES
241	**1231**	AECOM Techn.	ACM	**20.58**	**4**	**3**	**3**	1.20	45- 65 (120-215%)	**7.9**	**NIL**	2.62	NIL	**68**	9/30	**.83**	.75	9/30	NIL	NIL	YES
	1102	Aegion Corp. (NDQ)	AEGN	**18.30**	**3**	**3**	**4**	1.15	35- 55 (90-200%)	**10.9**	**NIL**	1.68	NIL	**7**	9/30	**.50**	.27	9/30	NIL	NIL	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

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italics to Selection & Opinion

PAGE NUMBERS	NAME OF STOCK	Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
1545	AEGON	AEG	5.40	3	3	3	1.80	8- 12	(50-120%)	7.7	5.0	.70	.27	57	9/30	.22	.18	9/30	.123	NIL	YES
2203	Aeropostale	ARO	13.49	4	3	5	1.10	19- 30	(40-120%)	13.4	NIL	1.01	NIL	18	7/31	NIL	.04	9/30	NIL	NIL	YES
703	AeroVironment (NDQ)	AVAV	20.03	4	3	1	.75	40- 60	(100-200%)	12.1	NIL	1.65	NIL	64	7/31	d.06	.01	9/30	NIL	NIL	YES
796	Aetna Inc.	AET	41.71	3	3	2	.95	70- 110	(70-165%)	7.5	1.7	5.54	.70	55	9/30	1.55	1.40	12/31	.175	.175	YES
2532	Affiliated Managers	AMG	125.06	1	3	3	1.60	125- 185	(N- 50%)	33.3	NIL	3.76	NIL	33	9/30	1.04	.76	9/30	NIL	NIL	YES
205	Affymetrix Inc. (NDQ)	AFFX	3.17	4	5	4	1.30	7- 12	(120-280%)	NMF	NIL	d.13	NIL	45	9/30	d.03	d.14	9/30	NIL	NIL	YES
1546	Aflac Inc.	AFL	51.44	3	3	3	1.20	70- 105	(35-105%)	7.9	2.7	6.54	1.40	57	9/30	1.69	1.58	12/31	▲.35	.33	YES
111	Agilent Technologies	A	37.51	▼4	3	4	1.15	55- 80	(45-115%)	11.4	1.1	3.30	.40	60	10/31	◆1.20	.82	3/31	◆.10	NIL	YES
1320	Agilysys, Inc. (NDQ)	AGYS	7.82	3	4	3	1.55	11- 18	(40-130%)	43.4	NIL	.18	NIL	86	9/30	d.02	d.14	9/30	NIL	NIL	YES
1559	Agnico-Eagle Mines	AEM	55.42	2	3	1	1.00	45- 70	(N- 25%)	25.8	1.4	2.15	.80	79	9/30	.72	.55	12/31	.20	.16	YES
1581	Agrium, Inc.	AGU	101.23	3	3	4	1.45	135- 205	(35-105%)	10.4	1.0	9.78	1.00	73	9/30	1.34	1.85	9/30	▲.50	.055	YES
2431	Air Products & Chem.	APD	80.87	3	2	3	1.10	105- 140	(30- 75%)	14.3	3.2	5.67	2.56	21	9/30	1.42	1.51	3/31	◆.64	.58	YES
2533	Aircastle Ltd.	AYR	11.18	3	4	3	1.50	17- 30	(50-170%)	7.1	5.9	1.58	.66	33	9/30	.47	.31	12/31	▲.165	.15	YES
552	Airgas Inc.	ARG	89.06	3	3	3	1.00	110- 165	(25- 85%)	18.8	1.9	4.73	1.72	23	9/30	1.03	1.01	9/30	.40	.32	YES
1798	Akamai Technologies (NDQ)	AKAM	35.87	2	3	2	1.20	60- 95	(65-165%)	27.8	NIL	1.29	NIL	37	9/30	.27	.23	9/30	NIL	NIL	YES
302	Alaska Air Group	ALK	41.53	3	3	3	1.10	50- 75	(20- 80%)	8.3	NIL	4.98	NIL	63	9/30	2.09	1.79	9/30	NIL	NIL	YES
1039	Alaska Communic. (NDQ)	ALSK	1.94	4	4	1	.80	3- 5	(55-160%)	6.9	NIL	.28	NIL	75	9/30	.17	d.02	3/31	▼NIL	.05	YES
1702	Albany Int'l 'A'	AIN	21.06	3	3	2	1.40	30- 45	(40-115%)	14.8	2.7	1.42	.56	22	9/30	.29	.53	12/31	.14	.13	YES
1595	Albany Molecular (NDQ)	AMRI	3.92	3	4	4	1.10	4- 6	(N- 55%)	39.2	NIL	.10	NIL	31	9/30	NIL	d.19	9/30	NIL	NIL	YES
2432	Albemarle Corp.	ALB	56.38	4	3	4	1.30	70- 110	(25- 95%)	12.2	1.4	4.63	.80	21	9/30	1.10	1.28	3/31	.20	.175	YES
948	Alcatel-Lucent ADR(g)	ALU	1.01	5	5	1	1.60	2- 3	(100-195%)	NMF	NIL	d.03	NIL	90	9/30	d.06	.09	9/30	NIL	NIL	YES
1820 1569	Alcoa Inc.	AA	8.34	4	3	3	1.45	17- 25	(105-200%)	36.3	1.4	.23	.12	93	9/30	d.13	.15	12/31	.03	.03	YES
206	Alere Inc.	ALR	17.71	5	3	3	1.15	45- 70	(155-295%)	7.9	NIL	2.23	NIL	45	9/30	.43	.67	9/30	NIL	NIL	YES
1596	Alexion Pharmac. (NDQ)	ALXN	92.47	2	3	3	.80	100- 150	(10- 60%)	59.7	NIL	1.55	NIL	31	9/30	.46	.34	9/30	NIL	NIL	YES
2034 207	Align Techn. (NDQ)	ALGN	26.71	3	3	4	1.20	40- 60	(50-125%)	23.4	NIL	1.14	NIL	45	9/30	.28	.27	9/30	NIL	NIL	YES
757	Alleghany Corp.	Y	326.66	3	2	3	.80	355- 485	(10- 50%)	17.3	NIL	18.92	NIL	11	9/30	6.68	.50	9/30	NIL	NIL	
1570	Allegheny Techn.	ATI	26.43	5	3	3	1.55	80- 115	(205-335%)	20.8	2.7	1.27	.72	93	9/30	.32	.63	9/30	.18	.18	YES
303	Allegiant Travel (NDQ)	ALGT	72.69	2	3	4	.75	85- 125	(15- 70%)	14.9	NIL	▲4.88	NIL	63	9/30	.87	.49	9/30	NIL	NIL	YES
1597	Allergan, Inc.	AGN	90.98	2	1	3	.90	120- 145	(30- 60%)	22.4	0.2	4.06	.20	31	9/30	1.00	.86	12/31	.05	.05	YES
902	ALLETE	ALE	38.50	2	2	2	.70	35- 50	(N- 30%)	14.0	4.9	2.75	1.87	24	9/30	.74	.57	12/31	.46	.445	YES
429	Alliance Data Sys.	ADS	140.87	3	3	3	1.10	120- 180	(N- 30%)	15.6	NIL	9.04	NIL	8	9/30	2.37	2.16	9/30	NIL	NIL	YES
594	Alliance Resource (NDQ)	ARLP	56.21	4	3	2	1.05	80- 120	(40-115%)	8.4	8.2	6.69	4.61	97	9/30	1.41	2.16	12/31	▲1.085	.955	YES
2534	AllianceBernstein Hldg.	AB	16.63	3	3	4	1.40	30- 50	(80-200%)	10.2	8.7	1.63	1.44	33	9/30	.36	.30	12/31	▲.36	.26	YES
1204	AllianceBernstein Income	ACG	8.58	–	3	3	.45	8- 13	(N- 50%)	NMF	6.2	NMF	.53	–	6/30	9.20(q)	8.90(q)	9/30	.12	.12	
903	Alliant Energy	LNT	43.45	2	2	3	.70	40- 55	(N- 25%)	14.4	4.3	3.01	1.85	24	9/30	1.45	1.12	12/31	.45	.425	YES
704	Alliant Techsystems	ATK	59.35	3	3	2	.80	80- 120	(35-100%)	8.6	1.8	6.93	1.04	64	9/30	2.00	2.43	12/31	▲.26	.20	YES
819	Allscripts Healthcare (NDQ)	MDRX	12.27	–	3	–	NMF	13- 20	(5- 65%)	28.5	NIL	.43	NIL	78	9/30	.05	.10	9/30	NIL	NIL	YES
758	Allstate Corp.	ALL	39.68	3	2	3	1.05	45- 60	(15- 50%)	8.2	2.2	4.85	.88	11	9/30	1.46	.16	12/31	.22	.21	YES
828	Alnylam Pharmac. (NDQ)	ALNY	16.11	3	4	5	1.15	15- 25	(N- 55%)	NMF	NIL	d1.75	NIL	44	9/30	d.38	d.31	9/30	NIL	NIL	YES
595	Alpha Natural Res.	ANR	7.57	5	3	3	2.00	10- 15	(30-100%)	NMF	NIL	d1.15	NIL	97	9/30	d.16	.27	9/30	NIL	NIL	YES
1348	Altera Corp. (NDQ)	ALTR	31.09	4	2	2	1.00	55- 75	(75-140%)	15.1	1.3	2.06	.40	88	9/30	.49	.57	12/31	▲.10	.08	YES
2027	Alterra Capital Hldgs. (NDQ)	ALTE	22.14	3	3	3	1.05	25- 40	(15- 80%)	12.2	2.9	1.81	.64	52	9/30	.33	.48	12/31	.16	.14	YES
1703	Altra Holdings, Inc. (NDQ)	AIMC	17.00	4	3	2	1.45	25- 35	(45-105%)	10.8	1.4	1.58	.24	22	9/30	.32	.46	3/31	▲.06	NIL	
1992	Altria Group	MO	32.56	2	2	3	.55	30- 45	(N- 40%)	14.7	5.4	2.22	1.76	27	9/30	.58	.57	12/31	▲.44	.41	YES
2616	Amazon.com (NDQ)	AMZN	229.71	2	3	3	1.05	250- 380	(10- 65%)	NMF	NIL	.71	NIL	56	9/30	d.23	.14	9/30	NIL	NIL	YES
1571	AMCOL Int'l	ACO	30.12	3	3	4	1.35	40- 60	(35-100%)	13.9	2.7	2.17	.80	93	9/30	.58	.58	3/31	◆.20	.18	YES
2598	Amdocs Ltd.	DOX	32.62	2	3	3	.90	45- 65	(40-100%)	12.9	1.6	2.53	.52	14	9/30	.60	.49	3/31	.13	NIL	YES
797	Amedisys, Inc. (NDQ)	AMED	10.01	4	3	2	1.15	20- 30	(100-200%)	11.5	NIL	.87	NIL	55	9/30	.33	.36	9/30	NIL	NIL	YES
904	Ameren Corp.	AEE	29.08	4	3	2	.80	30- 45	(5- 55%)	11.7	5.6	2.49	1.64	24	9/30	1.54	1.50	12/31	.40	.40	YES
923	America Movil	AMX	23.26	3	3	4	1.15	35- 55	(50-135%)	9.2	1.3	2.52	.30	84	9/30	.62	.34	9/30	.15	.129	YES
982	Amer. Axle	AXL	9.82	4	5	3	2.15	18- 35	(85-255%)	7.9	NIL	1.24	NIL	72	9/30	.07	.48	9/30	NIL	NIL	YES
2640	Amer. Capital, Ltd. (NDQ)	ACAS	11.63	3	5	4	2.35	20- 40	(70-245%)	7.6	NIL	1.53	NIL	43	9/30	.60	d1.34	9/30	NIL	NIL	YES
1820 2204	Amer. Eagle Outfitters	AEO	18.84	▼2	3	3	.95	20- 35	(5- 85%)	13.5	2.3	1.40	.44	18	7/31	.21	.10	12/31	.11	.11	YES
905	Amer. Elec. Power	AEP	41.45	3	3	2	.65	40- 55	(N- 35%)	13.8	4.7	3.00	1.94	24	9/30	1.00	1.17	12/31	.47	.47	YES
2034 2535	Amer. Express	AXP	55.23	3	2	4	1.25	75- 105	(35- 90%)	11.9	1.4	4.63	.80	33	9/30	1.09	1.03	12/31	.20	.18	YES
759	Amer. Financial Group	AFG	38.47	3	3	3	1.05	45- 65	(15- 70%)	12.0	2.0	3.20	.78	11	9/30	.82	.90	12/31	▲.195	.175	YES
1432 2362	Amer. Greetings	AM	17.05	–	3	–	1.25	25- 40	(45-135%)	17.1	3.5	1.00	.60	82	8/31	d.13	.35	12/31	.15	.15	YES
2536	Amer. Int'l Group	AIG	32.39	–	5	–	1.65	NMF	(NMF)	10.7	NIL	3.02	NIL	33	9/30	1.00	d1.60	9/30	NIL	NIL	YES
1774	Amer. States Water	AWR	42.52	2	2	3	.70	45- 60	(5- 40%)	16.7	3.3	2.55	1.42	6	9/30	.97	.83	12/31	.355	.28	YES
1216	Amer. Superconductor (NDQ)	AMSC	2.49	3	5	4	1.60	3- 6	(20-140%)	NMF	NIL	d.79	NIL	92	9/30	d.29	d1.02	9/30	NIL	NIL	YES
577	Amer. Tower 'A'	AMT	73.71	2	3	3	.85	80- 120	(10- 65%)	39.4	2.5	1.87	1.82	69	9/30	.58	d.04	12/31	▲.23	NIL	YES
553	Amer. Vanguard Corp.	AVD	32.04	1	3	5	1.05	35- 50	(10- 55%)	23.1	0.4	1.39	.14	23	9/30	.28	.16	12/31	▲.07	.05	YES
1775	Amer. Water Works	AWK	36.99	2	3	3	.65	30- 55	(N- 50%)	16.9	2.7	2.19	1.00	6	9/30	.87	.73	12/31	.25	.23	YES
1103	Amer. Woodmark (NDQ)	AMWD	23.03	▲1	3	4	.90	25- 40	(10- 75%)	41.9	NIL	▲.55	NIL	7	10/31	◆.14	d.21	9/30	NIL	NIL	
	Amerigon Inc.	NAME CHANGED TO GENTHERM INC.																			
2537	Ameriprise Fin'l	AMP	59.74	2	3	3	1.40	80- 120	(35-100%)	12.4	3.0	4.80	1.80	33	9/30	.79	1.12	12/31	▲.45	.23	YES
208	AmerisourceBergen	ABC	40.69	3	2	3	.70	70- 95	(70-135%)	13.3	2.1	3.05	.84	45	9/30	.06	.54	12/31	▲.21	.13	YES
1740	Ametek, Inc.	AME	36.31	2	2	3	1.00	40- 55	(10- 50%)	18.4	0.7	1.97	.24	29	9/30	.48	.41	12/31	.06	.04	YES
829	Amgen (NDQ)	AMGN	85.40	2	1	3	.70	105- 130	(25- 50%)	13.2	1.8	6.46	1.56	44	9/30	1.66	1.39	12/31	.36	.28	YES
1388	Amkor Technology (NDQ)	AMKR	3.83	5	5	3	1.60	10- 18	(160-370%)	6.0	NIL	.64	NIL	95	9/30	.11	.11	9/30	NIL	NIL	YES
742	Ampco-Pittsburgh	AP	17.41	4	3	2	1.60	30- 40	(70-130%)	16.4	4.1	1.06	.72	91	9/30	.15	.29	12/31	.18	.18	
1321	Amphenol Corp.	APH	60.50	2	3	3	1.10	65- 95	(5- 55%)	16.3	0.7	3.71	.42	86	9/30	.90	.79	3/31	.105	.015	YES
2391	Anadarko Petroleum	APC	72.12	3	3	3	1.30	80- 120	(10- 65%)	16.4	0.5	4.39	.36	83	9/30	.24	d6.12	12/31	.09	.09	YES
1349	ANADIGICS Inc. (NDQ)	ANAD	1.27	4	5	4	1.50	4- 7	(215-450%)	NMF	NIL	d.86	NIL	88	9/30	d.24	d.15	9/30	NIL	NIL	YES
1350	Analog Devices (NDQ)	ADI	40.21	3	2	3	.95	50- 65	(25- 60%)	16.5	3.0	2.43	1.20	88	7/31	.56	.71	9/30	.30	.25	YES
1245 112	Analogic Corp. (NDQ)	ALOG	72.70	1	3	4	.85	70- 105	(N- 45%)	22.0	0.6	3.30	.40	60	7/31	.96	.45	12/31	.10	.10	YES
174	AngioDynamics (NDQ)	ANGO	10.53	4	3	2	.80	16- 25	(50-135%)	87.8	NIL	.12	NIL	40	8/31	d.02	.05	9/30	NIL	NIL	YES
1560	AngloGold Ashanti ADR	AU	31.09	4	3	1	1.10	55- 85	(75-175%)	11.3	1.7	2.75	.52	79	6/30	.65	.80	9/30	.121	.121	YES
1322	Anixter Int'l	AXE	58.91	3	3	3	1.25	85- 125	(45-110%)	10.4	NIL	5.68	NIL	86	9/30	1.41	1.52	9/30	NIL	NIL	YES
2205	ANN Inc.	ANN	33.96	2	3	2	1.25	45- 70	(35-105%)	14.0	NIL	2.42	NIL	18	7/31	.63	.47	9/30	NIL	NIL	YES
1514	Annaly Capital Mgmt.	NLY	14.74	4	3	2	.65	14- 20	(N- 35%)	7.3	13.6	2.01	2.00	20	9/30	.45	.65	12/31	▼.50	.60	YES
2575	ANSYS, Inc. (NDQ)	ANSS	67.79	3	3	2	1.10	70- 105	(5- 55%)	30.7	NIL	2.21	NIL	47	9/30	.54	.48	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

PAGE NUMBERS
Bold type refers to Ratings and Reports;
italics to Selection & Opinion

Page (Selection & Opinion)	Page (Ratings and Reports)	NAME OF STOCK	Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	2538	Aon plc	AON	56.35	2	2	3	.70	70- 95	(25- 70%)	15.8	1.1	3.56	.63	33	9/30	.62	.59	12/31	.158	.15	YES
	2392	Apache Corp.	APA	77.10	4	3	2	1.25	130- 190	(70-145%)	7.4	0.9	10.39	.68	83	9/30	.41	2.50	3/31	◆.17	.15	YES
	1515	Apartment Investment	AIV	24.63	3	3	3	1.45	25- 40	(N- 60%)	NMF	3.4	d.70	.84	20	9/30	d.07	d.27	12/31	.20	.12	YES
	1104	Apogee Enterprises (NDQ)	APOG	19.54	1	3	5	1.40	20- 35	(N- 80%)	28.7	1.8	.68	.36	7	8/31	.17	d.06	12/31	.09	.082	YES
	2000	Apollo Group 'A' (NDQ)	APOL	19.62	5	3	1	.70	55- 80	(180-310%)	7.2	NIL	2.72	NIL	98	8/31	.52	1.02	12/31	NIL	NIL	YES
	2641	Apollo Investment (NDQ)	AINV	8.00	3	4	3	1.35	15- 25	(90-215%)	7.0	10.0	1.15	.80	43	9/30	.22	d1.36	3/31	.20	.28	YES
2443	1399	Apple Inc. (NDQ)	AAPL	565.73	3	2	3	1.00	1090-1470	(95-160%)	10.8	1.9	52.27	10.60	94	9/30	8.67	7.06	12/31	2.65	NIL	YES
	1704	Applied Ind'l Techn.	AIT	37.50	2	3	3	1.05	45- 65	(20- 75%)	12.7	2.2	2.95	.84	22	9/30	.70	.61	12/31	.21	.19	YES
	1389	Applied Materials (NDQ)	AMAT	10.36	5	2	2	1.10	20- 30	(95-190%)	18.2	3.5	.57	.36	95	10/31	◆d.42	.34	12/31	.09	.08	YES
2450	1351	Applied Micro (NDQ)	AMCC	6.55	3	3	1	1.30	4- 6	(N- N%)	NMF	NIL	d.86	NIL	88	9/30	d.33	d.02	9/30	NIL	NIL	YES
	1171	AptarGroup	ATR	46.94	3	2	2	.90	65- 90	(40- 90%)	16.6	1.9	2.82	.88	46	9/30	.62	.72	12/31	.22	.22	YES
	1776	Aqua America	WTR	24.67	2	2	3	.60	25- 35	(N- 40%)	23.1	2.8	1.07	.70	6	9/30	.36	.30	12/31	▲.175	.165	YES
	430	Arbitron Inc.	ARB	36.22	3	3	3	.95	50- 75	(40-105%)	15.9	1.1	2.28	.40	8	9/30	.59	.55	3/31	◆.10	.10	YES
	743	ArcelorMittal	MT	14.84	4	3	3	1.70	35- 55	(135-270%)	27.5	5.1	.54	.75	91	9/30	d.46	.19	9/30	.188	.188	YES
	596	Arch Coal	ACI	6.89	5	3	2	1.75	10- 16	(45-130%)	NMF	1.7	d.41	.12	97	9/30	d.16	.04	12/31	.03	.11	YES
	1902	Archer Daniels Midl'd	ADM	25.55	4	2	3	.90	35- 50	(35- 95%)	11.6	2.7	2.20	.70	25	9/30	.44	.68	12/31	.175	.175	YES
	1643	Ariba, Inc.	ARBA					SEE FINAL SUPPLEMENT - PAGE 1643														
	318	Arkansas Best (NDQ)	ABFS	7.19	5	3	3	1.20	▼ 25- 40	(250-455%)	31.3	1.7	▼.23	.12	77	9/30	.24	.46	12/31	.03	.03	YES
	1105	Armstrong World Inds.	AWI	48.64	–	3	–	NMF	55- 80	(15- 65%)	17.9	NIL	2.72	NIL	7	9/30	1.24	.86	9/30	NIL	NIL	YES
	949	Arris Group (NDQ)	ARRS	13.69	2	3	3	1.25	15- 25	(10- 85%)	14.0	NIL	.98	NIL	90	9/30	.22	.21	9/30	NIL	NIL	YES
	1323	Arrow Electronics	ARW	36.45	4	3	2	1.20	35- 55	(N- 50%)	7.2	NIL	5.03	NIL	86	9/30	1.02	1.20	9/30	NIL	NIL	YES
	175	ArthroCare Corp. (NDQ)	ARTC	32.02	3	4	2	1.40	30- 55	(N- 70%)	23.4	NIL	1.37	NIL	40	9/30	.27	.05	9/30	NIL	NIL	YES
	578	Aruba Networks (NDQ)	ARUN	18.52	3	3	2	1.40	25- 35	(35- 90%)	NMF	NIL	.08	NIL	69	10/31	◆d.01	.03	12/31	NIL	NIL	YES
	2124	Asbury Automotive	ABG	29.17	2	5	5	1.85	30- 60	(5-105%)	11.4	NIL	2.57	NIL	13	9/30	.66	.38	9/30	NIL	NIL	YES
	2206	Ascena Retail Group (NDQ)	ASNA	19.91	3	3	3	1.05	30- 40	(50-100%)	13.3	NIL	1.50	NIL	18	7/31	.07	.18	9/30	NIL	NIL	YES
	554	Ashland Inc.	ASH	69.58	3	3	3	1.45	90- 140	(30-100%)	9.3	1.3	7.47	.90	23	9/30	1.87	1.01	12/31	◆.225	.175	YES
	777	Assoc. Banc-Corp (NDQ)	ASBC	12.61	3	3	3	1.00	17- 25	(35-100%)	12.5	2.5	1.01	.32	38	9/30	.26	.20	12/31	▲.08	.01	YES
	2539	Assurant Inc.	AIZ	34.61	4	2	3	1.00	45- 60	(30- 75%)	5.7	2.4	6.10	.84	33	9/30	1.52	.79	12/31	.21	.18	YES
	2028	Assured Guaranty	AGO	12.83	4	4	2	1.90	20- 35	(55-175%)	4.2	2.8	3.06	.36	52	9/30	.85	.21	12/31	.09	.045	YES
	158	Astec Inds. (NDQ)	ASTE	27.18	4	3	3	1.30	50- 70	(85-160%)	15.1	NIL	1.80	NIL	85	9/30	.30	.34	9/30	NIL	NIL	YES
	1502	Astoria Financial	AF	9.26	3	3	3	1.00	15- 20	(60-115%)	16.2	1.7	.57	.16	53	9/30	.14	.12	12/31	.04	.13	YES
	1598	AstraZeneca PLC (ADS)	AZN	44.84	4	2	3	.75	60- 80	(35- 80%)	7.3	6.4	6.11	2.85	31	9/30	1.51	2.54	9/30	.90	.85	YES
	820	athenahealth (NDQ)	ATHN	64.05	▼3	3	3	1.05	75- 115	(15- 80%)	97.0	NIL	.66	NIL	78	9/30	.17	.15	9/30	NIL	NIL	YES
	1217	Atlantic Power Corp.	AT	12.01	3	3	3	.75	15- 25	(25-110%)	NMF	9.9	d.11	1.19	92	9/30	d.06	d.40	12/31	◆.287	.277	YES
	924	Atlantic Tele-Network (NDQ)	ATNI	39.09	3	3	2	1.00	45- 70	(15- 80%)	14.3	2.6	2.73	1.00	84	9/30	1.02	.65	12/31	▲.25	.23	YES
2443	304	Atlas Air Worldwide (NDQ)	AAWW	42.26	3	4	4	1.65	70- 115	(65-170%)	9.1	NIL	▼4.66	NIL	63	9/30	1.26	1.07	9/30	NIL	NIL	YES
	1352	Atmel Corp. (NDQ)	ATML	4.72	4	3	2	1.05	10- 15	(110-220%)	15.7	NIL	.30	NIL	88	9/30	.05	.25	9/30	NIL	NIL	YES
	541	Atmos Energy	ATO	34.01	2	2	3	.70	30- 40	(N- 20%)	14.4	4.1	2.36	1.40	28	9/30	.09	.01	12/31	▲.35	.34	YES
625	2576	Autodesk, Inc. (NDQ)	ADSK	31.32	4	3	4	1.25	40- 65	(30-110%)	22.7	NIL	1.38	NIL	47	10/31	◆.25	.32	9/30	NIL	NIL	YES
	983	Autoliv, Inc.	ALV	56.92	4	3	4	1.30	105- 160	(85-180%)	9.6	3.5	5.95	2.00	72	9/30	1.30	1.48	12/31	▲.50	.45	YES
	2599	Automatic Data Proc. (NDQ)	ADP	55.22	1	1	3	.80	80- 95	(45- 70%)	18.2	3.2	3.03	1.74	14	9/30	.62	.61	3/31	▲.435	.395	YES
	2125	AutoNation, Inc.	AN	41.30	1	3	3	1.15	45- 65	(10- 55%)	15.0	NIL	2.76	NIL	13	9/30	.66	.48	9/30	NIL	NIL	YES
	2126	AutoZone Inc.	AZO	382.30	3	3	3	.65	395- 595	(5- 55%)	14.8	NIL	25.91	NIL	13	8/31	8.46	7.18	9/30	NIL	NIL	YES
	1599	Auxilium Pharmac. (NDQ)	AUXL	18.50	4	3	2	.85	25- 35	(35- 90%)	NMF	NIL	NIL	NIL	31	9/30	d.21	d.08	9/30	NIL	NIL	YES
	1353	Avago Technologies (NDQ)	AVGO	32.75	3	3	3	1.10	40- 55	(20- 70%)	NMF	2.0	NIL	.64	88	7/31	.58	.57	9/30	.16	.11	YES
	1516	AvalonBay Communities	AVB	129.97	3	3	3	1.05	125- 190	(N- 45%)	43.8	3.2	2.97	4.15	20	9/30	.89	.51	3/31	.97	.893	YES
	555	Avery Dennison	AVY	32.37	3	2	4	1.10	45- 60	(40- 85%)	14.8	3.3	2.19	1.08	23	9/30	.53	.33	12/31	.27	.25	YES
	2011	Avid Technology (NDQ)	AVID	6.06	5	3	3	1.10	18- 25	(195-315%)	22.4	NIL	.27	NIL	89	9/30	d.08	.01	9/30	NIL	NIL	YES
	2166	Avis Budget Group	CAR	17.34	3	4	5	2.35	25- 40	(45-130%)	6.8	NIL	2.54	NIL	26	9/30	1.46	1.02	9/30	NIL	NIL	YES
	2236	Avista Corp.	AVA	23.28	3	2	3	.70	25- 30	(5- 30%)	14.6	5.1	1.59	1.19	36	9/30	.10	.18	12/31	.29	.275	YES
	1324	Avnet, Inc.	AVT	28.73	4	3	3	1.20	30- 50	(5- 75%)	7.0	NIL	4.12	NIL	86	9/30	.70	.90	12/31	NIL	NIL	YES
	1012	Avon Products	AVP	14.28	4	4	4	1.00	20- 35	(40-145%)	25.1	1.7	.57	.24	54	9/30	.07	.38	12/31	▼.06	.23	YES
	2029	AXIS Capital Hldgs.	AXS	34.50	3	3	3	.85	35- 55	(N- 60%)	7.8	2.8	4.43	.98	52	9/30	1.63	1.27	12/31	.24	.23	YES
	1903	**B&G Foods**	BGS	28.79	2	3	1	1.10	25- 40	(N- 40%)	19.9	4.0	1.45	1.16	25	9/30	.35	.25	3/31	▲.29	.23	YES
	2502	BB&T Corp.	BBT	28.38	3	3	4	1.10	30- 50	(5- 75%)	10.4	3.0	2.72	.86	35	9/30	.66	.52	12/31	.20	.16	YES
	1040	BCE Inc.	BCE	42.19	3	3	2	.70	55- 85	(30-100%)	13.8	5.7	3.06	2.40	75	9/30	.76	.81	3/31	◆.568	.518	YES
	705	B/E Aerospace (NDQ)	BEAV	43.53	3	3	3	1.60	55- 85	(25- 95%)	14.1	NIL	3.08	NIL	64	9/30	.74	.64	9/30	NIL	NIL	YES
	1781	BGC Partners Inc. (NDQ)	BGCP	3.66	5	4	3	1.40	8- 13	(120-255%)	5.9	13.1	.62	.48-.34	76	6/30	.17	.21	12/31	▼.12	.17	YES
846	1572	BHP Billiton Ltd. ADR	BHP	70.31	4	3	3	1.40	90- 135	(30- 90%)	10.7	3.2	6.60	2.28(h)	93	6/30	2.05(p)	4.77(p)	9/30	▲1.14	1.10	YES
2444	346	BJ's Restaurants (NDQ)	BJRI	33.25	4	3	3	1.05	60- 90	(80-170%)	27.0	NIL	1.23	NIL	32	9/30	.24	.22	9/30	NIL	NIL	YES
	2577	BMC Software (NDQ)	BMC	39.59	3	3	3	.85	55- 80	(40-100%)	14.9	NIL	2.65	NIL	47	9/30	.61	.65	9/30	NIL	NIL	YES
	778	BOK Financial (NDQ)	BOKF	55.50	3	2	3	.95	65- 85	(15- 55%)	11.8	2.7	4.70	1.52	38	9/30	1.27	1.24	12/31	.38	.33	YES
1822	502	BP PLC ADR	BP	41.23	4	3	3	1.05	65- 95	(60-130%)	6.2	5.2	6.68	2.16	74	9/30	1.63	1.58	12/31	▲.54	.42	YES
	1517	BRE Properties	BRE	48.17	2	3	3	1.00	35- 50	(N- 5%)	74.1	3.2	.65	1.54	20	9/30	.17	.23	12/31	.385	.375	YES
	1041	BT Group ADR(g)	BT	35.52	3	3	4	1.00	40- 55	(15- 55%)	9.4	4.1	3.76	1.46	75	9/30	.91	.85	9/30	.905	.797	
	1232	Babcock & Wilcox	BWC	23.54	▼5	3	3	1.10	30- 50	(25-110%)	12.1	1.4	1.95	.32	68	9/30	.34	.39	12/31	▲.08	NIL	YES
2035	113	Badger Meter	BMI	43.56	1	3	4	1.00	40- 65	(N- 50%)	22.2	1.6	1.96	.68	60	9/30	.62	.46	12/31	.17	.16	YES
	2617	Baidu, Inc. (NDQ)	BIDU	92.42	3	3	3	1.25	215- 320	(135-245%)	16.8	NIL	5.51	NIL	56	9/30	1.37	.84	9/30	NIL	NIL	YES
	2405	Baker Hughes	BHI	41.62	4	3	2	1.40	85- 125	(105-200%)	12.4	1.4	3.37	.60	66	9/30	.60	1.11	12/31	.15	.15	YES
	1172	Ball Corp.	BLL	44.65	2	2	3	.95	55- 75	(25- 70%)	13.9	0.9	3.22	.40	46	9/30	.90	.80	12/31	.10	.07	YES
	1218	Ballard Power Sys. (NDQ)	BLDP	0.65	5	5	3	1.10	3- 6	(360-825%)	NMF	NIL	d.15	NIL	92	9/30	d.10	d.09	9/30	NIL	NIL	YES
	2339	Bally Technologies	BYI	45.07	2	3	4	1.30	80- 125	(80-175%)	13.9	NIL	3.25	NIL	71	9/30	.77	.45	12/31	NIL	NIL	YES
	2503	BancorpSouth	BXS	13.08	▼3	3	4	1.05	20- 30	(55-130%)	15.0	0.3	.87	.04	35	9/30	.25	.14	12/31	.01	.01	YES
2035	2504	Bank of America	BAC	9.49	3	4	4	1.90	11- 19	(15-100%)	16.4	0.4	.58	.04	35	9/30	NIL	.56	12/31	.01	.01	YES
	2505	Bank of Hawaii	BOH	43.40	3	3	3	.95	60- 90	(40-105%)	11.9	4.1	3.64	1.80	35	9/30	.92	.92	12/31	.45	.45	YES
	2506	Bank of Montreal (TSE)	BMO.TO	57.99b	3	2	3	.85	65- 90	(10- 55%)	9.7	5.0	5.95	2.88	35	7/31	1.42(b)	1.27(b)	12/31	▲.72(b)	.70(b)	YES
	2507	Bank of New York Mellon	BK	24.01	3	3	3	1.20	50- 80	(110-235%)	9.3	2.2	2.59	.52	35	9/30	.61	.53	12/31	.13	.13	YES
	2508	Bank of Nova Scotia (TSE)	BNS.TO	53.40b	3	2	3	.80	60- 80	(10- 50%)	11.3	4.3	4.74	2.28	35	7/31	1.69(b)	1.11(b)	12/31	▲.57(b)	.52(b)	YES
	176	Bard (C.R.)	BCR	97.28	3	1	4	.65	145- 175	(50- 80%)	14.5	0.8	6.72	.80	40	9/30	1.64	1.62	12/31	.20	.19	YES
	2167	Barnes & Noble	BKS	15.23	4	3	4	1.00	8- 13	(N- N%)	NMF	NIL	d.77	NIL	26	7/31	d.78	d.99	9/30	NIL	NIL	YES
	1741	Barnes Group	B	20.43	3	3	3	1.30	35- 55	(70-170%)	10.4	2.0	1.97	.40	29	9/30	.44	.44	12/31	.10	.10	YES
	1561	Barrick Gold	ABX	34.30	4	3	1	.90	40- 60	(15- 75%)	8.6	2.3	3.99	.80	79	9/30	.62	1.36	12/31	◆.20	.15	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

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Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

Page (Sel. & Op.)	Page	NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	1144	Bassett Furniture	(NDQ)	BSET	11.50	3	4	5	1.05	11- 18	(N- 55%)	31.1	1.7	.37	.20	48	8/31	.04	.02	12/31	.05	.035	
	177	Baxter Int'l Inc.		BAX	66.49	3	1	4	.70	75- 95	(15- 45%)	14.2	2.7	4.69	1.80	40	9/30	1.14	1.09	3/31	.45	.335	YES
	1106	Beacon Roofing	(NDQ)	BECN	30.90	2	3	4	1.15	40- 65	(30-110%)	20.1	NIL	1.54	NIL	7	6/30	.62	.51	9/30	NIL	NIL	YES
	1968	Beam Inc.		BEAM	54.30	–	3	–	NMF	65- 100	(20- 85%)	22.6	1.5	2.40	.82	19	9/30	.57	d.53	12/31	.205	.19	YES
244	1122	Beazer Homes USA		BZH	14.82	3	5	4	2.50	20- 35	(35-135%)	NMF	NIL	d4.10	NIL	2	9/30	d2.82	d2.85	9/30	NIL	NIL	YES
	2207	bebe stores	(NDQ)	BEBE	3.61	4	3	2	1.10	10- 15	(175-315%)	NMF	2.8	NIL	.10	18	9/30	d.03	.03	12/31	.025	.025	YES
	178	Becton, Dickinson		BDX	75.79	3	1	3	.65	115- 140	(50- 85%)	13.6	2.6	5.58	1.98	40	9/30	1.42	1.39	9/30	.45	.41	YES
1245	2168	Bed Bath & Beyond	(NDQ)	BBBY	57.53	3	1	2	.90	120- 145	(110-150%)	12.2	NIL	4.71	NIL	26	8/31	.98	.93	9/30	NIL	NIL	YES
	1303	Belden Inc.		BDC	34.68	3	3	3	1.55	55- 85	(60-145%)	10.3	0.6	3.38	.20	41	9/30	.77	.65	12/31	.05	.05	YES
	2324	Belo Corp. 'A'		BLC	7.17	3	5	4	1.75	7- 14	(N- 95%)	7.4	4.5	.97	.32	12	9/30	.22	.13	12/31	.08	.05	YES
	1173	Bemis Co.		BMS	33.21	2	2	3	.85	50- 65	(50- 95%)	14.6	3.0	2.27	1.00	46	9/30	.60	.56	12/31	.25	.24	YES
	1325	Benchmark Electronics		BHE	15.13	3	3	3	1.10	25- 35	(65-130%)	11.6	NIL	1.30	NIL	86	9/30	.31	.34	9/30	NIL	NIL	YES
	760	Berkley (W.R.)		WRB	39.20	2	2	3	.70	45- 60	(15- 55%)	15.3	0.9	2.57	.36	11	9/30	.61	.44	12/31	.09	.08	YES
	761	Berkshire Hathaway 'B'		BRKB	86.76	3	1	3	.80	110- 130	(25- 50%)	15.0	NIL	5.79	NIL	11	9/30	1.58	.92	9/30	NIL	NIL	YES
	2393	Berry Petroleum 'A'		BRY	32.44	4	3	4	1.80	60- 95	(85-195%)	9.4	1.1	3.46	.35	83	9/30	.71	.79	9/30	.08	.08	YES
★★	2169	Best Buy Co.		BBY	13.75	–	3	–	1.10	20- 35	(45-155%)	5.1	4.9	2.72	.68	26	10/31	◆.03	NA	12/31	▲.17	.16	YES
2649	2170	Big 5 Sporting Goods	(NDQ)	BGFV	13.65	2	4	1	1.50	14- 25	(5- 85%)	18.2	2.2	.75	.30	26	9/30	.38	.27	12/31	.075	.075	
	2137	Big Lots Inc.		BIG	27.90	4	3	3	.95	60- 90	(115-225%)	9.3	NIL	3.01	NIL	30	7/31	.36	.50	9/30	NIL	NIL	YES
	347	Biglari Hldgs.		BH	337.47	3	3	3	1.10	435- 650	(30- 95%)	14.6	NIL	23.05	NIL	32	6/30	3.63	6.49	9/30	NIL	NIL	
	209	Bio-Rad Labs. 'A'		BIO	102.29	3	3	3	.90	125- 190	(20- 85%)	18.7	NIL	5.47	NIL	45	9/30	1.48	1.61	9/30	NIL	NIL	YES
	1600	Biogen Idec Inc.	(NDQ)	BIIB	143.53	2	2	3	.80	125- 175	(N- 20%)	24.4	NIL	5.89	NIL	31	9/30	1.67	1.43	9/30	NIL	NIL	YES
2649	830	BioMarin Pharmac.	(NDQ)	BMRN	48.27	2	3	4	1.05	45- 70	(N- 45%)	NMF	NIL	d.45	NIL	44	9/30	d.04	d.16	9/30	NIL	NIL	YES
2649	973	BioScrip, Inc.	(NDQ)	BIOS	10.05	3	4	3	1.25	10- 16	(N- 60%)	77.3	NIL	.13	NIL	62	9/30	d.01	.01	9/30	NIL	NIL	YES
	950	Black Box	(NDQ)	BBOX	24.36	4	3	1	1.10	40- 65	(65-165%)	10.5	1.3	2.33	.32	90	9/30	.43	.74	3/31	.08	.07	YES
	2237	Black Hills		BKH	34.26	3	3	2	.80	25- 40	(N- 15%)	16.8	4.4	2.04	1.50	36	9/30	.42	d.29	12/31	.37	.365	YES
	2540	BlackRock, Inc.		BLK	191.16	3	3	3	1.20	230- 345	(20- 80%)	12.3	3.1	15.53	6.00	33	9/30	3.65	3.23	9/30	1.50	1.375	YES
	2642	Blackstone Group LP		BX	14.35	3	3	3	1.40	30- 40	(110-180%)	7.3	2.8	1.97	.40	43	9/30	.55	d.31	12/31	.10	.10	YES
	2541	Block (H&R)		HRB	18.03	3	3	3	.80	20- 30	(10- 65%)	12.7	4.4	1.42	.80	33	7/31	d.38	d.37	3/31	.20	.20	YES
	2618	Blue Nile	(NDQ)	NILE	36.35	2	3	1	1.20	45- 65	(25- 80%)	45.4	NIL	.80	NIL	56	9/30	.14	.13	9/30	NIL	NIL	YES
	1135	BlueLinx Holdings		BXC	2.23	4	5	5	1.35	3- 6	(35-170%)	NMF	NIL	d.27	NIL	1	9/30	d.06	d.10	9/30	NIL	NIL	
2650	1185	Blyth Inc.		BTH	16.36	4	3	1	1.30	35- 55	(115-235%)	6.4	1.2	2.55	.20	3	9/30	.04	.43	12/31	▲.10	.05	YES
	614	Boardwalk Pipeline		BWP	25.06	3	3	3	.80	30- 45	(20- 80%)	18.6	8.5	1.35	2.14	9	9/30	.27	.23	12/31	.533	.528	YES
	348	Bob Evans Farms	(NDQ)	BOBE	36.34	3	3	3	.95	40- 60	(10- 65%)	13.5	3.1	2.69	1.14	32	10/31	◆.53	.47	12/31	◆.275	.25	YES
	2208	Body Central Corp.	(NDQ)	BODY	10.16	4	3	5	1.05	25- 35	(145-245%)	13.0	NIL	.78	NIL	18	9/30	.01	.18	9/30	NIL	NIL	YES
2251	706	Boeing		BA	71.96	3	2	3	1.05	90- 125	(25- 75%)	14.2	2.4	5.06	1.76	64	9/30	1.35	1.46	12/31	.44	.42	YES
	707	Bombardier Inc. 'B'	(TSE)	BBDB.TO	3.13b	4	3	4	1.10	6- 10	(90-220%)	6.1	3.2	.51	.10	64	9/30	.12(b)	.11(b)	12/31	◆.025	.025	YES
	377	Booz Allen Hamilton		BAH	13.77	–	3	–	NMF	17- 25	(25- 80%)	10.0	2.9	1.38	.40	34	9/30	.27	.53	12/31	.09	NIL	YES
	984	BorgWarner		BWA	63.49	3	3	4	1.30	105- 155	(65-145%)	11.7	NIL	5.41	NIL	72	9/30	1.19	1.15	9/30	NIL	NIL	YES
	1969	Boston Beer 'A'		SAM	112.17	3	3	3	.70	110- 165	(N- 45%)	24.3	NIL	4.61	NIL	19	9/30	1.53	1.19	9/30	NIL	NIL	YES
	1518	Boston Properties		BXP	101.88	2	3	3	1.15	85- 125	(N- 25%)	58.6	2.6	1.74	2.60	20	9/30	.38	.48	3/31	▲.65	.55	YES
	179	Boston Scientific		BSX	5.21	4	3	3	1.00	10- 16	(90-205%)	12.7	NIL	.41	NIL	40	9/30	.10	.10	9/30	NIL	NIL	YES
	2340	Boyd Gaming		BYD	5.22	5	4	4	2.00	8- 14	(55-170%)	NMF	NIL	.04	NIL	71	9/30	d.11	.04	9/30	NIL	NIL	YES
	1742	Brady Corp.		BRC	30.83	3	3	3	1.10	35- 50	(15- 60%)	13.7	2.5	2.25	.76	29	10/31	◆.59	.62	3/31	◆.19	.185	
	2001	Bridgepoint Education		BPI	8.90	5	4	2	1.30	10- 25	(10-180%)	3.7	NIL	2.40	NIL	98	9/30	.56	.78	9/30	NIL	NIL	YES
	1705	Briggs & Stratton		BGG	19.25	4	3	3	1.15	20- 30	(5- 55%)	15.8	2.5	1.22	.48	22	9/30	d.28	d.10	3/31	.12	.11	YES
2034	579	Brightpoint, Inc.		CELL	SEE FINAL SUPPLEMENT - PAGE 2034																		
	349	Brinker Int'l		EAT	29.30	▼3	3	3	1.25	35- 55	(20- 90%)	12.7	2.7	2.30	.80	32	9/30	.37	.30	12/31	.20	.16	YES
	378	Brink's (The) Co.		BCO	26.24	▲4	3	4	1.05	45- 65	(70-150%)	11.5	1.5	2.29	.40	34	9/30	.50	.60	12/31	.10	.10	YES
	1601	Bristol-Myers Squibb		BMY	32.03	3	1	2	.70	45- 55	(40- 70%)	14.7	4.2	2.18	1.36	31	9/30	.41	.56	12/31	.34	.34	YES
	305	Bristow Group		BRS	49.99	1	3	4	1.25	65- 100	(30-100%)	13.5	1.6	3.69	.80	63	9/30	.80	.07	12/31	.20	.15	YES
	1993	Brit. Amer Tobac. ADR		BTI	102.21	3	2	3	.70	115- 160	(15- 55%)	14.4	4.1	7.08	4.22	27	6/30	3.22(p)	3.11(p)	12/31	1.36	1.19	YES
	951	Broadcom Corp. 'A'	(NDQ)	BRCM	31.25	4	3	2	1.10	50- 75	(60-140%)	20.6	1.3	1.52	.40	90	9/30	.38	.56	12/31	.10	.09	YES
	1400	Brocade Communic.	(NDQ)	BRCD	5.54	3	4	2	1.30	7- 12	(25-115%)	14.6	NIL	.38	NIL	94	10/31	◆.11	.01	9/30	NIL	NIL	YES
	798	Brookdale Senior Living		BKD	24.74	3	5	3	1.90	25- 45	(N- 80%)	NMF	NIL	NIL	NIL	55	9/30	d.10	d.06	9/30	NIL	NIL	YES
	1031	Brookfield Asset Mgmt.		BAM	33.38	2	3	3	1.20	50- 75	(50-125%)	17.8	1.7	1.88	.56	15	9/30	.49	.36	3/31	.14	.13	YES
	1706	Brooks Automation	(NDQ)	BRKS	7.27	5	3	4	1.45	14- 20	(95-175%)	8.1	4.4	.90	.32	22	9/30	.08	.19	12/31	.08	.08	YES
	2542	Brown & Brown		BRO	26.15	3	2	3	.75	35- 45	(35- 70%)	18.5	1.4	1.41	.36	33	9/30	.34	.30	12/31	▲.09	.085	YES
	1970	Brown-Forman 'B'		BFB	66.83	1	1	3	.70	65- 80	(N- 20%)	24.3	1.5	2.75	1.02	19	7/31	.69	.54	12/31	▲.255	.447	YES
	2156	Brown Shoe		BWS	15.74	▲2	3	3	1.40	19- 30	(20- 90%)	13.7	1.8	▲1.15	.28	61	10/31	◆.60	.51	12/31	.07	.07	YES
2650	114	Bruker Corp.	(NDQ)	BRKR	14.11	3	3	3	1.15	19- 30	(35-115%)	17.4	NIL	.81	NIL	60	9/30	.24	.12	9/30	NIL	NIL	YES
	2302	Brunswick Corp.		BC	25.08	3	4	5	1.95	35- 55	(40-120%)	15.7	0.2	1.60	.05	17	9/30	.02	.05	12/31	.05	.05	YES
	615	Buckeye Partners L.P.		BPL	48.33	3	2	3	.80	70- 95	(45- 95%)	14.6	8.6	3.30	4.15	9	9/30	.87	.64	12/31	1.038	1.025	YES
	2209	Buckle (The), Inc.		BKE	49.00	2	3	3	1.00	60- 85	(20- 75%)	14.2	2.0	3.45	1.00	18	10/31	◆.88	.81	12/31	.20	.20	YES
	350	Buffalo Wild Wings	(NDQ)	BWLD	72.01	3	3	3	.95	90- 135	(25- 85%)	21.4	NIL	3.36	NIL	32	9/30	.57	.61	9/30	NIL	NIL	YES
	1904	Bunge Ltd.		BG	71.76	3	3	3	1.30	75- 115	(5- 60%)	9.8	1.6	7.31	1.12	25	9/30	2.08	.86	12/31	.27	.25	YES
	351	Burger King Worldwide		BKW	15.44	–	3	–	NMF	14- 20	(N- 30%)	35.9	1.0	.43	.16	32	9/30	.02	NA	12/31	▲.04	NIL	YES
	2578	**CA, Inc.**		CA	21.99	4	2	3	.95	40- 55	(80-150%)	10.4	4.5	2.11	1.00	47	9/30	.48	.47	12/31	.25	.05	YES
	2600	CACI Int'l		CACI	51.49	3	3	3	.85	105- 160	(105-210%)	7.7	NIL	6.70	NIL	14	9/30	1.49	1.41	9/30	NIL	NIL	YES
	708	CAE Inc.	(TSE)	CAE.TO	9.60	4	3	4	.90	14- 20	(45-110%)	12.8	2.1	.75	.20	64	9/30	.17(b)	.15(b)	12/31	.05(b)	.04(b)	YES
	1032	CBRE Group		CBG	17.79	3	4	4	1.70	25- 45	(40-155%)	13.5	NIL	1.32	NIL	15	9/30	.26	.24	9/30	NIL	NIL	YES
	2325	CBS Corp. 'B'		CBS	34.49	2	3	3	1.50	40- 60	(15- 75%)	12.5	1.4	2.75	.48	12	9/30	.65	.50	12/31	▲.12	.10	YES
	1633	CDI Corp.		CDI	15.65	3	3	4	1.20	19- 30	(20- 90%)	18.4	3.3	.85	.52	58	9/30	.27	.13	12/31	.13	.13	
	352	CEC Entertainment		CEC	30.52	4	3	3	1.10	55- 85	(80-180%)	11.1	3.1	▼2.74	.96	32	9/30	.45	.61	12/31	▲.24	.20	YES
	1354	CEVA, Inc.	(NDQ)	CEVA	14.56	4	3	1	1.25	25- 35	(70-140%)	24.3	NIL	.60	NIL	88	9/30	.11	.20	9/30	NIL	NIL	YES
	1582	CF Industries		CF	203.65	3	3	4	1.30	205- 310	(N- 50%)	7.5	0.9	26.99	1.75	73	9/30	5.85	5.16	12/31	.40	.40	YES
	140	CH Energy Group		CHG	64.89	–	1	–	.60	45- 55	(N- N%)	20.1	3.4	3.23	2.22	39	9/30	.60	.55	12/31	.555	.555	
	379	C.H. Robinson	(NDQ)	CHRW	59.81	3	2	2	.90	85- 115	(40- 90%)	19.7	2.2	3.04	1.32	34	9/30	.72	.70	12/31	.33	.29	YES
	799	CIGNA Corp.		CI	51.90	2	3	2	1.05	80- 120	(55-130%)	7.9	0.1	6.58	.04	55	9/30	1.69	1.20	9/30	NIL	NIL	YES
	1782	CME Group	(NDQ)	CME	54.45	3	3	2	1.10	70- 105	(30- 95%)	16.5	3.3	3.31	1.80	76	9/30	.70	.95	12/31	.45	.28	YES
	906	CMS Energy Corp.		CMS	23.26	3	3	3	.75	20- 30	(N- 30%)	14.4	4.3	1.62	1.01	24	9/30	.54	.53	12/31	.24	.21	YES
	762	CNA Fin'l		CNA	27.79	3	3	3	1.30	40- 60	(45-115%)	9.6	2.2	2.89	.60	11	9/30	.82	.34	12/31	.15	.10	YES
★★	159	CNH Global NV		CNH	45.74	–	3	–	1.85	70- 105	(55-130%)	10.4	NIL	4.39	NIL	85	9/30	1.34	1.13	9/30	NIL	NIL	YES

(●) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

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Page (Sel. & Op.)	Page	NAME OF STOCK		Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	2601	CSG Systems Int'l	(NDQ)	CSGS	18.15	3	3	2	.80	20- 35	(10- 95%)	11.8	NIL	1.54	NIL	14	9/30	.31	.31	9/30	NIL	NIL	YES
	337	CSX Corp.		CSX	19.68	4	3	3	1.20	35- 50	(80-155%)	11.3	2.8	1.74	.56	51	9/30	.44	.43	12/31	.14	.12	YES
	1326	CTS Corp.		CTS	8.27	▼4	3	3	1.25	12- 18	(45-120%)	10.0	1.7	.83	.14	86	9/30	.20	.17	12/31	.035	.035	YES
	1583	CVR Partners, LP		UAN	25.19	–	3	–	NMF	25- 40	(N- 60%)	15.4	7.9	1.64	1.98	73	9/30	.43	.50	12/31	▼.496	.572	YES
	974	CVS Caremark Corp.		CVS	45.08	2	1	3	.80	70- 90	(55-100%)	12.7	1.4	3.54	.65	62	9/30	.85	.70	12/31	.163	.125	YES
	2171	Cabela's Inc.		CAB	47.47	2	3	4	1.30	45- 65	(N- 35%)	17.7	NIL	2.68	NIL	26	9/30	.60	.47	9/30	NIL	NIL	YES
	1021	Cablevision Sys. 'A'		CVC	13.90	–	4	–	NMF	20- 35	(45-150%)	11.8	4.3	1.18	.60	42	9/30	.14	.14	12/31	.15	.15	YES
	2433	Cabot Corp.		CBT	36.23	3	3	5	1.25	45- 65	(25- 80%)	10.4	2.2	3.50	.80	21	9/30	.75	.76	12/31	.20	.18	YES
	556	Cabot Microelectr's	(NDQ)	CCMP	30.13	–	3	–	NMF	60- 90	(100-200%)	14.1	NIL	2.14	NIL	23	9/30	.49	.40	9/30	NIL	NIL	YES
	520	Cabot Oil & Gas 'A'		COG	49.09	1	3	2	1.25	45- 70	(N- 45%)	53.4	0.2	.92	.08	67	9/30	.21	.17	12/31	.02	.015	YES
	2579	Cadence Design Sys.	(NDQ)	CDNS	12.66	2	3	3	1.25	13- 19	(5- 50%)	18.9	NIL	.67	NIL	47	9/30	.21	.10	9/30	NIL	NIL	YES
	2341	Caesars Entertainment	(NDQ)	CZR	5.43	–	4	–	NMF	12- 18	(120-230%)	NMF	NIL	d5.32	NIL	71	9/30	d4.03	NA	9/30	NIL	NIL	YES
	1905	Cal-Maine Foods	(NDQ)	CALM	43.65	2	3	3	1.00	35- 50	(N- 15%)	14.1	2.3	3.10	1.02	25	8/31	.39	.13	12/31	▼.13	.044	YES
	1906	Calavo Growers	(NDQ)	CVGW	23.90	3	3	4	.85	45- 70	(90-195%)	13.2	2.7	1.81	.65	25	7/31	.38	.18	12/31	▲.65	.55	
	401	Calgon Carbon		CCC	12.21	5	3	3	1.15	17- 25	(40-105%)	24.9	NIL	.49	NIL	70	9/30	.04	.25	9/30	NIL	NIL	YES
	1777	California Water		CWT	17.29	3	3	3	.65	20- 30	(15- 75%)	17.6	3.6	.98	.63	6	6/30	.31	.29	12/31	.158	.154	YES
	2303	Callaway Golf		ELY	6.20	▲3	4	3	1.05	7- 11	(15- 75%)	NMF	0.6	d.58	.04	17	9/30	d.50	d.37	12/31	.01	.01	YES
2650	2434	Cambrex Corp.		CBM	9.58	3	5	1	1.05	10- 19	(5-100%)	12.4	NIL	.77	NIL	21	9/30	.06	.10	9/30	NIL	NIL	YES
	1519	Camden Property Trust		CPT	64.81	2	3	3	1.10	65- 95	(N- 45%)	49.9	3.5	1.30	2.24	20	9/30	.32	.16	12/31	.56	.49	YES
	1573	Cameco Corp.	(TSE)	CCO.TO	17.14	4	3	3	1.10	40- 60	(135-250%)	11.8	2.3	1.45	.40	93	9/30	.13	.26	12/31	◆.10	.10	YES
	2406	Cameron Int'l Corp.		CAM	53.37	3	3	3	1.45	70- 105	(30- 95%)	14.5	NIL	3.67	NIL	66	9/30	.90	.78	9/30	NIL	NIL	YES
	1907	Campbell Soup		CPB	36.95	2	2	2	.55	40- 55	(10- 50%)	14.5	3.1	2.55	1.16	25	10/31	◆.88	.82	3/31	◆.29	.29	YES
	2509	Can. Imperial Bank	(TSE)	CM.TO	77.79b	3	2	3	.90	90- 120	(15- 55%)	9.9	4.8	7.87	3.76	35	7/31	2.00(b)	1.89(b)	12/31	▲.94(b)	.90(b)	YES
	338	Can. National Railway		CNI	85.52	3	2	3	1.10	105- 140	(25- 65%)	14.8	1.8	5.79	1.50	51	9/30	1.52	1.35	12/31	.375	.319	YES
	2394	Can. Natural Res.	(TSE)	CNQ.TO	27.52	4	3	2	1.25	55- 85	(100-210%)	13.2	1.8	2.08	.50	83	9/30	.32	.65	12/31	.105	.09	YES
	339	Can. Pacific Railway		CP	92.80	1	3	3	1.30	100- 150	(10- 60%)	17.6	1.5	5.28	1.40	51	9/30	1.30	1.12	12/31	.35	.29	YES
	1983	Canon Inc. ADR(g)		CAJ	34.85	4	2	2	1.00	60- 80	(70-130%)	14.3	4.2	2.43	1.45	96	9/30	.55	.83	9/30	.762	.78	YES
	2543	Capital One Fin'l		COF	58.14	3	3	3	1.40	60- 90	(5- 55%)	7.8	0.3	7.45	.20	33	9/30	2.03	1.88	12/31	.05	.05	YES
1645	2643	Capital Trust		CT					SEE LATEST REPORT														
	2644	CapitalSource		CSE	7.88	2	4	3	1.65	10- 17	(25-115%)	13.1	0.5	.60	.04	43	9/30	.14	d.26	9/30	.01	.01	YES
	1503	Capitol Fed. Fin'l	(NDQ)	CFFN	11.77	3	3	3	.60	14- 20	(20- 70%)	24.0	2.9	.49	.34	53	9/30	.11	.10	12/31	.075	.075	YES
2253	2407	CARBO Ceramics		CRR	74.99	4	3	1	1.10	75- 110	(N- 45%)	17.0	1.4	4.41	1.08	66	9/30	1.04	1.59	12/31	.27	.24	YES
	210	Cardinal Health		CAH	39.63	3	1	3	.80	70- 85	(75-115%)	11.8	2.8	3.35	1.10	45	9/30	.79	.68	3/31	▲.275	.215	YES
	2002	Career Education	(NDQ)	CECO	2.82	5	4	5	.85	8- 13	(185-360%)	NMF	NIL	d.78	NIL	98	9/30	d.47	.26	9/30	NIL	NIL	YES
	180	CareFusion Corp.		CFN	27.24	3	3	2	.80	35- 55	(30-100%)	13.6	NIL	2.00	NIL	40	6/30	.48	.52	12/31	NIL	NIL	YES
	353	Caribou Coffee	(NDQ)	CBOU	11.40	3	4	3	.95	▲ 17- 30	(50-165%)	23.3	NIL	.49	NIL	32	9/30	.07	.07	9/30	NIL	NIL	YES
	1743	Carlisle Cos.		CSL	54.40	2	2	4	1.05	75- 100	(40- 85%)	12.4	1.5	4.37	.80	29	9/30	1.08	.85	12/31	.20	.18	YES
	2127	CarMax, Inc.		KMX	34.22	3	3	2	1.20	40- 65	(15- 90%)	18.0	NIL	1.90	NIL	13	8/31	.48	.49	9/30	NIL	NIL	YES
	2304	Carnival Corp.		CCL	38.24	3	3	2	1.15	40- 60	(5- 55%)	19.8	2.6	1.93	1.00	17	8/31	1.53	1.69	12/31	.25	.25	YES
	744	Carpenter Technology		CRS	46.20	2	3	4	1.40	65- 100	(40-115%)	13.2	1.6	3.50	.72	91	9/30	.74	.53	12/31	.18	.18	YES
	1814	Carriage Services		CSV	11.20	1	3	4	.70	10- 14	(N- 25%)	18.1	0.9	.62	.10	5	9/30	.03	.04	12/31	.025	.025	
	2102	Carter's Inc.		CRI	52.02	2	3	3	.90	70- 105	(35-100%)	16.8	NIL	3.09	NIL	16	9/30	.99	.58	9/30	NIL	NIL	YES
2252	1707	Cascade Corp.		CASC	64.95	–	3	–	1.40	65- 100	(N- 55%)	13.4	2.2	4.85	1.40	22	7/31	1.11	1.23	12/31	.35	.25	
625	402	Casella Waste Sys.	(NDQ)	CWST	4.43	3	5	3	1.55	13- 25	(195-465%)	21.1	NIL	.21	NIL	70	7/31	d.31	d.12	9/30	NIL	NIL	YES
	1946	Casey's Gen'l Stores	(NDQ)	CASY	46.85	▼4	3	3	.70	60- 90	(30- 90%)	12.1	1.4	3.86	.66	59	7/31	1.01	1.03	12/31	.165	.15	YES
	2544	Cash Amer. Int'l		CSH	36.32	4	3	3	.95	60- 90	(65-150%)	7.9	0.4	4.61	.14	33	9/30	1.02	1.08	12/31	◆.035	.035	YES
2252	160	Caterpillar Inc.		CAT	83.62	4	3	3	1.35	125- 190	(50-125%)	9.7	2.5	8.64	2.08	85	9/30	2.54	1.93	12/31	.52	.46	YES
	2210	Cato Corp.		CATO	28.22	3	3	2	.90	25- 40	(N- 40%)	12.9	3.5	2.19	1.00	18	10/31	◆.16	.21	9/30	.25	.23	YES
	925	Cbeyond, Inc.	(NDQ)	CBEY	7.20	3	3	2	1.00	10- 15	(40-110%)	NMF	NIL	d.09	NIL	84	9/30	.06	d.04	9/30	NIL	NIL	YES
	2305	Cedar Fair L.P.		FUN	33.74	3	3	5	1.00	40- 60	(20- 80%)	14.5	4.7	2.33	1.60	17	9/30	2.51	2.74	12/31	.40	.70	YES
	1327	Celestica Inc.		CLS	7.29	5	3	2	1.30	13- 19	(80-160%)	7.1	NIL	1.03	NIL	86	9/30	.21	.23	9/30	NIL	NIL	YES
	1602	Celgene Corp.	(NDQ)	CELG	75.18	2	2	4	.75	100- 140	(35- 85%)	18.3	NIL	4.10	NIL	31	9/30	.97	.81	9/30	NIL	NIL	YES
	1107	CEMEX ADS		CX	8.97	3	4	5	1.70	12- 20	(35-125%)	NMF	NIL	d.44	NIL	7	9/30	d.18	d.76	9/30	NIL	NIL	YES
	907	CenterPoint Energy		CNP	19.38	3	2	3	.75	17- 25	(N- 30%)	15.3	4.3	1.27	.83	24	9/30	.40	.38	12/31	.203	.198	YES
	414	Central Europe/Russia		CEE	31.15	–	4	3	1.40	40- 70	(30-125%)	NMF	0.8	NMF	.25	–	4/30	36.72(q)	51.84(q)	9/30	NIL	NIL	
	1971	Central European Dist.	(NDQ)	CEDC	1.86	4	5	4	1.80	NMF	(NMF)	NMF	NIL	NMF	NIL	19	9/30	NIL	.06	9/30	NIL	NIL	YES
1051	1186	Central Garden & Pet	(NDQ)	CENT	10.71	3	4	4	1.00	14- 25	(30-135%)	15.3	NIL	.70	NIL	3	6/30	.47	.31	9/30	NIL	NIL	
	1042	CenturyLink Inc.		CTL	37.91	3	2	3	.75	35- 50	(N- 30%)	15.0	7.6	2.53	2.90	75	9/30	.66	.61	12/31	◆.725	.725	YES
	211	Cepheid	(NDQ)	CPHD	30.08	4	4	2	1.40	40- 70	(35-135%)	NMF	NIL	.01	NIL	45	9/30	d.09	.03	9/30	NIL	NIL	YES
1650	557	Ceradyne Inc.	(NDQ)	CRDN	34.94	–	3	–	1.15	40- 60	(15- 70%)	23.9	1.7	1.46	.60	23	6/30	.28	.76	9/30	.15	NIL	YES
	821	Cerner Corp.	(NDQ)	CERN	77.47	3	3	3	.85	85- 125	(10- 60%)	32.7	NIL	2.37	NIL	78	9/30	.56	.45	9/30	NIL	NIL	YES
	212	Charles River		CRL	39.92	3	3	4	.95	50- 80	(25-100%)	18.3	NIL	2.18	NIL	45	9/30	.46	.37	9/30	NIL	NIL	YES
	731	Chart Industries	(NDQ)	GTLS	59.86	1	3	3	1.80	80- 120	(35-100%)	20.0	NIL	3.00	NIL	49	9/30	.66	.59	9/30	NIL	NIL	YES
2036	1799	Check Point Software	(NDQ)	CHKP	44.86	3	1	3	.80	75- 95	(65-110%)	14.6	NIL	3.07	NIL	37	9/30	.73	.63	9/30	NIL	NIL	YES
	115	Checkpoint Systems		CKP	8.34	3	3	2	1.05	15- 20	(80-140%)	NMF	NIL	.03	NIL	60	9/30	d.13	d1.17	9/30	NIL	NIL	YES
	354	Cheesecake Factory	(NDQ)	CAKE	33.97	2	3	3	1.25	40- 60	(20- 75%)	16.9	1.4	2.01	.48	32	9/30	.49	.36	12/31	.12	NIL	YES
	1744	Chemed Corp.		CHE	66.17	3	3	3	.80	80- 120	(20- 80%)	14.1	1.1	4.68	.72	29	9/30	1.07	1.04	12/31	.18	.16	YES
	779	Chemical Financial	(NDQ)	CHFC	21.35	3	3	4	1.00	30- 45	(40-110%)	11.5	3.9	1.85	.84	38	9/30	.48	.42	9/30	▲.21	.20	
	521	Chesapeake Energy		CHK	17.47	4	3	1	1.35	30- 40	(70-130%)	25.0	2.0	.70	.35	67	9/30	.10	.72	12/31	.088	.088	YES
2651	503	Chevron Corp.		CVX	104.35	3	1	3	.95	130- 160	(25- 55%)	7.1	3.4	14.62	3.60	74	9/30	2.69	3.92	12/31	.90	.81	YES
	1233	Chicago Bridge & Iron		CBI	37.58	3	3	3	1.65	55- 85	(45-125%)	11.6	0.5	3.23	.20	68	9/30	.82	.67	9/30	.05	.05	YES
	2211	Chico's FAS		CHS	18.16	2	3	3	1.25	25- 35	(40- 95%)	15.5	1.3	1.17	.23	18	10/31	◆.25	.16	9/30	.053	.05	YES
247	2212	Children's Place	(NDQ)	PLCE	47.82	3	3	2	1.05	70- 105	(45-120%)	13.9	NIL	3.45	NIL	18	10/31	◆1.60	1.33	9/30	NIL	NIL	YES
	985	China Auto. Sys.	(NDQ)	CAAS	4.86	4	4	5	1.40	8- 14	(65-190%)	7.0	NIL	.69	NIL	72	9/30	.12	.10	9/30	NIL	NIL	YES
	415	China Fund (The)		CHN	22.57	–	3	3	1.00	35- 50	(55-120%)	NMF	1.1	NMF	.25	–	4/30	25.10(q)	35.23(q)	9/30	NIL	NIL	
	1584	China Green Agriculture		CGA	3.10	–	5	–	1.15	11- 20	(255-545%)	1.9	NIL	1.65	NIL	73	9/30	◆.32	.40	9/30	NIL	NIL	YES
2252	355	Chipotle Mex. Grill		CMG	270.26	3	3	3	.95	390- 585	(45-115%)	29.0	NIL	9.32	NIL	32	9/30	2.27	1.90	9/30	NIL	NIL	YES
	1908	Chiquita Brands Int'l		CQB	6.79	4	4	4	1.30	8- 14	(20-105%)	30.9	NIL	.22	NIL	25	9/30	d1.45	d.63	9/30	NIL	NIL	YES
625	2342	Choice Hotels Int'l		CHH	31.36	–	3	–	NMF	35- 55	(10- 75%)	17.0	2.4	1.85	.74	71	9/30	.63	.71	12/31	.185	.185	YES
	2213	Christopher & Banks		CBK	3.00	2	5	4	1.25	5- 9	(65-200%)	NMF	NIL	d.53	NIL	18	7/31	d.06	d.37	9/30	NIL	.06	YES
	763	Chubb Corp.		CB	76.14	1	1	3	.85	75- 90	(N- 20%)	11.5	2.2	6.61	1.64	11	9/30	1.98	.88	12/31	▲.41	.39	YES
	1187	Church & Dwight		CHD	52.59	2	1	3	.60	55- 70	(5- 35%)	20.2	1.8	2.60	.96	3	9/30	.66	.54	12/31	.24	.17	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

Page (Selection & Opinion)	Page (Ratings & Reports)	NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	RANKS Safety	RANKS Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
625	952	Ciena Corp.	(NDQ)	CIEN	14.07	5	5	2	1.50	17- 30	(20-115%)	NMF	NIL	d.61	NIL	90	7/31	d.30	d.33	9/30	NIL	NIL	YES
	522	Cimarex Energy		XEC	63.55	3	3	3	1.35	65- 100	(N- 55%)	14.1	0.8	4.51	.48	67	9/30	.97	1.45	12/31	.12	.10	YES
	1043	Cincinnati Bell		CBB	5.03	3	4	3	1.05	4- 7	(N- 40%)	41.9	NIL	.12	NIL	75	9/30	.01	.07	9/30	NIL	NIL	YES
	764	Cincinnati Financial	(NDQ)	CINF	39.63	2	2	3	.95	35- 50	(N- 25%)	22.1	4.1	1.79	1.63	11	9/30	.64	.12	3/31	◆.408	.403	YES
	2306	Cinemark Hldgs.		CNK	26.14	3	3	4	1.00	30- 45	(15- 70%)	17.5	3.2	1.49	.84	17	9/30	.41	.41	12/31	.21	.21	YES
	380	Cintas Corp.	(NDQ)	CTAS	40.07	2	2	4	.95	50- 65	(25- 60%)	15.7	1.6	2.55	.64	34	8/31	.60	.52	12/31	▲.64	.54	YES
2444	1355	Cirrus Logic	(NDQ)	CRUS	30.83	▼2	3	3	1.15	60- 105	(95-240%)	14.3	NIL	2.15	NIL	88	9/30	.79	.33	9/30	NIL	NIL	YES
242	953	Cisco Systems	(NDQ)	CSCO	18.30	3	1	2	1.00	35- 40	(90-120%)	10.8	3.1	1.70	.56	90	10/31	.39	.33	12/31	▲.14	.06	YES
	2214	Citi Trends	(NDQ)	CTRN	12.17	3	4	4	1.15	14- 25	(15-105%)	27.0	NIL	.45	NIL	18	10/31	◆d.25	d.46	9/30	NIL	NIL	YES
2035	2510	Citigroup Inc.		C	36.10	3	4	3	2.05	80- 130	(120-260%)	8.8	0.1	4.09	.04	35	9/30	1.06	1.23	12/31	.01	.01	YES
	2580	Citrix Sys.	(NDQ)	CTXS	61.16	3	3	3	1.05	90- 130	(45-115%)	32.0	NIL	1.91	NIL	47	9/30	.41	.49	9/30	NIL	NIL	YES
	2511	City National Corp.		CYN	48.48	3	3	3	1.05	55- 80	(15- 65%)	12.0	2.5	4.04	1.20	35	9/30	1.10	.77	12/31	.25	.20	YES
	1174	CLARCOR Inc.		CLC	44.33	3	3	2	.90	55- 80	(25- 80%)	17.4	1.2	2.55	.54	46	8/31	.60	.63	12/31	▲.135	.12	YES
243	605	Clean Energy Fuels	(NDQ)	CLNE	12.33	3	4	4	1.40	20- 35	(60-185%)	NMF	NIL	d.65	NIL	4	9/30	d.19	d.16	9/30	NIL	NIL	YES
	403	Clean Harbors		CLH	56.77	▲3	3	3	.80	50- 75	(N- 30%)	21.1	NIL	▲2.69	NIL	70	9/30	.54	.70	9/30	NIL	NIL	YES
2043	926	Clearwire Corp.	(NDQ)	CLWR	2.21	3	5	1	1.45	3- 6	(35-170%)	NMF	NIL	d1.11	NIL	84	9/30	d.22	d.53	9/30	NIL	NIL	YES
	908	Cleco Corp.		CNL	39.56	3	1	3	.65	40- 45	(N- 15%)	16.0	3.5	2.48	1.38	24	9/30	1.05	1.08	12/31	.338	.313	YES
	745	Cliffs Natural Res.		CLF	35.29	5	3	4	1.95	100- 150	(185-325%)	4.6	7.1	7.62	2.50	91	9/30	.61	4.27	12/31	◆.625	.28	YES
	1188	Clorox Co.		CLX	74.10	2	2	3	.60	90- 125	(20- 70%)	17.2	3.5	4.30	2.61	3	9/30	1.01	.98	3/31	◆.64	.60	YES
	2172	Coach Inc.		COH	56.59	3	3	3	1.20	85- 125	(50-120%)	14.7	2.1	3.85	1.20	26	9/30	.77	.73	3/31	◆.30	.225	YES
	1972	Coca-Cola		KO	37.24	2	1	3	.60	50- 60	(35- 60%)	18.0	2.9	2.07	1.08	19	9/30	.50	.52	12/31	.51	.47	YES
	1973	Coca-Cola Bottling	(NDQ)	COKE	64.98	3	3	3	.70	80- 120	(25- 85%)	18.1	1.5	3.59	1.00	19	9/30	1.09	1.06	12/31	.25	.25	
	1974	Coca-Cola Enterprises		CCE	30.10	3	3	3	.95	50- 75	(65-150%)	12.2	2.2	2.47	.67	19	9/30	.89	.88	12/31	.16	.13	YES
	116	Cognex Corp.	(NDQ)	CGNX	33.40	3	3	3	1.05	50- 80	(50-140%)	20.6	1.3	1.62	.44	60	9/30	.41	.42	12/31	.11	.10	YES
	2602	Cognizant Technology	(NDQ)	CTSH	66.15	3	2	2	1.10	120- 165	(80-150%)	17.5	NIL	3.77	NIL	14	9/30	.91	.73	9/30	NIL	NIL	YES
	117	Coherent, Inc.	(NDQ)	COHR	43.82	5	3	3	1.00	65- 95	(50-115%)	15.8	NIL	2.77	NIL	60	9/30	.52	1.25	9/30	NIL	NIL	YES
	381	Coinstar Inc.	(NDQ)	CSTR	45.12	4	3	3	.90	95- 145	(110-220%)	10.3	NIL	▼4.36	NIL	34	9/30	1.26	1.18	9/30	NIL	NIL	YES
	2215	Coldwater Creek	(NDQ)	CWTR	4.77	3	5	5	1.50	2- 3	(N- N%)	NMF	NIL	d2.60	NIL	18	7/31	d.56	d1.20	9/30	NIL	NIL	YES
	1189	Colgate-Palmolive		CL	106.91	2	1	3	.60	140- 170	(30- 60%)	19.5	2.4	5.47	2.58	3	9/30	1.36	1.31	12/31	.62	.58	YES
	1820	Collective Brands		PSS	SEE FINAL SUPPLEMENT - PAGE 1820																		
	2103	Columbia Sportswear	(NDQ)	COLM	55.40	3	3	3	1.00	55- 85	(N- 55%)	15.8	1.6	3.50	.88	16	9/30	1.88	1.98	12/31	.22	.22	YES
	1708	Columbus McKinnon	(NDQ)	CMCO	14.61	3	3	3	1.35	20- 35	(35-140%)	9.0	NIL	1.62	NIL	22	9/30	.42	.32	9/30	NIL	NIL	YES
	1022	Comcast Corp.	(NDQ)	CMCSA	36.01	2	3	3	.95	45- 65	(25- 80%)	19.4	1.8	1.86	.65	42	9/30	.46	.33	3/31	.163	.113	YES
	780	Comerica Inc.		CMA	28.66	3	3	4	1.25	45- 70	(55-145%)	10.9	2.1	2.62	.60	38	9/30	.61	.51	3/31	.15	.10	YES
	781	Commerce Bancshs.(•)	(NDQ)	CBSH	36.81	3	1	3	.85	40- 50	(10- 35%)	12.7	2.4	2.89	.90	38	9/30	.71	.69	12/31	.219	.208	YES
	746	Commercial Metals		CMC	13.30	3	3	3	1.55	20- 30	(50-125%)	10.2	3.6	1.31	.48	91	8/31	.26	d1.05	12/31	.12	.12	YES
	986	Commercial Vehicle	(NDQ)	CVGI	7.04	5	5	3	1.75	13- 25	(85-255%)	5.2	NIL	1.36	NIL	72	9/30	.12	.26	9/30	NIL	NIL	YES
	800	Community Health		CYH	29.47	3	3	4	1.35	50- 75	(70-155%)	8.0	NIL	3.69	NIL	55	9/30	.86	.86	9/30	NIL	NIL	YES
	1585	Compass Minerals Int'l		CMP	76.63	3	3	4	.95	95- 140	(25- 85%)	20.9	2.8	3.66	2.15	73	9/30	.28	1.03	12/31	.495	.45	YES
	822	Computer Prog. & Sys.	(NDQ)	CPSI	51.27	3	3	3	.80	85- 125	(65-145%)	17.9	3.6	2.87	1.84	78	9/30	.63	.54	12/31	◆.46	.36	YES
	2603	Computer Sciences		CSC	35.91	3	2	1	1.00	50- 65	(40- 80%)	13.1	2.2	2.74	.80	14	9/30	.83	.85	12/31	.20	.20	YES
	2581	Compuware Corp.	(NDQ)	CPWR	8.49	3	3	1	.95	11- 16	(30- 90%)	20.2	NIL	.42	NIL	47	9/30	.05	.10	9/30	NIL	NIL	YES
	954	Comtech Telecom.	(NDQ)	CMTL	24.76	4	3	2	.70	25- 40	(N- 60%)	17.1	4.6	1.45	1.15	90	7/31	.38	.42	12/31	.275	.275	YES
	319	Con-way Inc.		CNW	27.13	5	3	3	1.25	45- 70	(65-160%)	14.4	1.5	1.89	.40	77	9/30	.45	.52	12/31	.10	.10	YES
1250	1909	ConAgra Foods		CAG	27.86	3	1	3	.65	35- 40	(25- 45%)	13.3	3.6	2.10	1.00	25	8/31	.44	.31	12/31	▲.25	.24	YES
	1800	Concur Techn.	(NDQ)	CNQR	62.98	2	3	2	1.20	95- 145	(50-130%)	NMF	NIL	d.08	NIL	37	9/30	d.13	d.26	9/30	NIL	NIL	YES
	181	Conmed Corp.	(NDQ)	CNMD	26.55	3	3	4	.85	35- 50	(30- 90%)	14.4	2.3	1.85	.60	40	9/30	.33	.33	12/31	.15	NIL	YES
	2395	ConocoPhillips		COP	55.73	–	1	–	NMF	75- 90	(35- 60%)	8.8	4.7	6.33	2.64	83	9/30	1.46	2.52	12/31	.66	.66	YES
	597	CONSOL Energy		CNX	32.81	4	3	3	1.70	50- 75	(50-130%)	46.9	1.5	.70	.50	97	9/30	.09	.73	12/31	.125	.125	YES
	1044	Consol. Communic.	(NDQ)	CNSL	13.94	4	3	4	.85	20- 30	(45-115%)	30.3	11.1	.46	1.55	75	9/30	d.01	.19	3/31	.387	.387	YES
	141	Consol. Edison		ED	54.75	2	1	2	.60	50- 60	(N- 10%)	14.1	4.5	3.88	2.44	39	9/30	1.50	1.30	12/31	.605	.60	YES
	2363	Consolidated Graphics		CGX	32.67	▲3	3	1	1.40	50- 75	(55-130%)	14.7	NIL	2.22	NIL	82	9/30	.68	.69	9/30	NIL	NIL	YES
	1975	Constellation Brands		STZ	34.62	2	3	3	.95	45- 70	(30-100%)	16.0	NIL	2.16	NIL	19	8/31	.71	.77	9/30	NIL	NIL	YES
	382	Convergys Corp.		CVG	15.11	2	3	3	1.20	▼ 18- 25	(20- 65%)	15.0	1.3	1.01	.20	34	9/30	.26	.23	3/31	.05	NIL	YES
	213	Cooper Cos.		COO	92.65	1	3	3	.90	80- 120	(N- 30%)	16.2	0.1	5.73	.06	45	7/31	1.45	1.15	9/30	.03	.03	YES
	1304	Cooper Inds.		CBE	77.36	–	3	–	1.20	70- 105	(N- 35%)	17.5	1.1	4.43	.84	41	9/30	1.16	.98	12/31	▼.52	.29	YES
	987	Cooper Tire & Rubber		CTB	23.97	3	3	2	1.60	30- 40	(25- 65%)	7.4	1.8	3.25	.42	72	9/30	1.17	.42	12/31	.105	.105	YES
	306	Copa Holdings, S.A.		CPA	93.56	1	3	4	.95	115- 170	(25- 80%)	10.3	2.2	9.12	2.10	63	9/30	2.52	1.59	9/30	NIL	NIL	YES
	606	Copano Energy	(NDQ)	CPNO	31.15	2	3	3	1.15	30- 45	(N- 45%)	53.7	7.6	.58	2.36	4	9/30	.23	.06	12/31	.575	.575	YES
	2128	Copart, Inc.	(NDQ)	CPRT	29.58	2	2	3	.85	35- 45	(20- 50%)	19.1	NIL	1.55	NIL	13	7/31	.35	.30	9/30	NIL	NIL	YES
2650	1947	Core-Mark Holding	(NDQ)	CORE	42.80	3	3	3	.80	45- 70	(5- 65%)	15.4	1.8	2.78	.76	59	9/30	.90	1.03	12/31	▲.19	.17	
1645	2408	Core Laboratories		CLB	101.73	3	3	3	1.05	120- 180	(20- 75%)	21.4	1.1	4.76	1.15	66	9/30	1.14	.93	12/31	.28	.25	YES
	2003	Corinthian Colleges	(NDQ)	COCO	2.18	4	5	5	1.15	4- 7	(85-220%)	7.3	NIL	.30	NIL	98	9/30	.06	d.04	9/30	NIL	NIL	YES
	1305	Corning Inc.		GLW	11.05	4	3	3	1.25	20- 30	(80-170%)	7.7	3.3	1.44	.36	41	9/30	.34	.51	12/31	▲.09	.075	YES
	431	Corporate Executive		CEB	41.25	3	3	3	1.00	40- 60	(N- 45%)	26.6	1.8	1.55	.74	8	9/30	d.01	.42	12/31	.175	.15	YES
	1033	Corrections Corp. Amer.		CXW	33.17	2	3	4	1.05	30- 50	(N- 50%)	20.3	2.4	1.63	.80	15	9/30	.43	.37	12/31	.20	NIL	YES
	432	CoStar Group	(NDQ)	CSGP	81.94	1	3	2	1.00	75- 115	(N- 40%)	43.6	NIL	1.88	NIL	8	9/30	.47	.28	9/30	NIL	NIL	YES
	2138	Costco Wholesale	(NDQ)	COST	96.57	1	1	2	.75	120- 145	(25- 50%)	21.3	1.1	4.54	1.10	30	8/31	1.39	1.08	12/31	.275	.24	YES
	1976	Cott Corp.		COT	8.64	4	4	3	1.10	16- 25	(85-190%)	13.5	2.8	.64	.24	19	9/30	.15	.17	12/31	▲.06	NIL	YES
	1603	Covance Inc.		CVD	55.03	3	3	2	1.05	55- 85	(N- 55%)	22.2	NIL	2.48	NIL	31	9/30	.69	.67	9/30	NIL	NIL	YES
	1219	Covanta Holding Corp.		CVA	17.61	3	3	3	.90	20- 30	(15- 70%)	29.8	3.4	.59	.60	92	9/30	.25	.35	12/31	.15	.075	YES
	801	Coventry Health Care		CVH	42.95	–	3	–	1.25	35- 55	(N- 30%)	13.8	1.2	3.11	.50	55	9/30	.78	.82	12/31	.125	NIL	YES
	182	Covidien Plc		COV	56.75	3	2	4	.85	60- 85	(5- 50%)	13.0	1.9	4.37	1.07	40	9/30	1.02	1.08	12/31	▲.26	.225	YES
1245	356	Cracker Barrel	(NDQ)	CBRL	63.13	1	3	3	1.00	65- 95	(5- 50%)	13.4	3.2	4.70	2.00	32	7/31	1.47	1.00	12/31	▲.50	.25	YES
	1745	Crane Co.		CR	41.37	3	3	3	1.35	65- 95	(55-130%)	10.3	2.7	4.02	1.12	29	9/30	.97	.89	12/31	.28	.26	YES
	2545	Crawford & Co. 'B'		CRDB	5.84	3	4	1	1.10	11- 19	(90-225%)	8.7	2.1	.67	.12	33	9/30	.33	.17	12/31	.03	.02	
2036	1356	Cree, Inc.	(NDQ)	CREE	30.80	3	3	4	1.20	60- 90	(95-190%)	29.6	NIL	1.04	NIL	88	9/30	.14	.12	12/31	NIL	NIL	YES
	2157	Crocs, Inc.	(NDQ)	CROX	12.59	4	4	3	1.70	30- 45	(140-255%)	7.8	NIL	1.61	NIL	61	9/30	.49	.33	9/30	NIL	NIL	YES
	1634	Cross Country Health.	(NDQ)	CCRN	3.95	4	4	4	1.05	12- 20	(205-405%)	28.2	NIL	.14	NIL	58	9/30	d.02	.06	9/30	NIL	NIL	YES
	523	Crosstex Energy	(NDQ)	XTXI	12.12	4	5	4	2.25	20- 35	(65-190%)	NMF	4.0	d.09	.48	67	9/30	d.09	d.04	12/31	.12	.10	YES
	580	Crown Castle Int'l		CCI	65.87	3	3	3	1.20	60- 90	(N- 35%)	84.4	NIL	.78	NIL	69	9/30	.14	.15	9/30	NIL	NIL	YES
	1175	Crown Holdings		CCK	36.90	3	3	3	.90	70- 105	(90-185%)	11.9	NIL	3.10	NIL	46	9/30	1.00	1.01	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

PAGE NUMBERS (italics to Selection & Opinion)	PAGE NUMBERS (Bold type refers to Ratings and Reports)	NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	RANKS Safety	RANKS Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	183	CryoLife Inc.		CRY	5.79	3	3	4	1.10	12- 18	(105-210%)	24.1	1.7	.24	.10	40	9/30	.06	.07	12/31	◆.025	NIL	YES
	2619	Ctrip.com Int'l ADR	(NDQ)	CTRP	17.61	4	3	1	1.15	40- 60	(125-240%)	18.9	NIL	.93	NIL	56	9/30	.22	.33	9/30	NIL	NIL	YES
	1328	Cubic Corp.		CUB	48.40	3	3	3	1.05	55- 85	(15- 75%)	15.1	0.6	3.21	.28	86	3/31	.91	.75	9/30	.12	.09	YES
	1604	Cubist Pharm.	(NDQ)	CBST	40.42	2	3	3	.75	45- 65	(10- 60%)	17.8	NIL	2.27	NIL	31	9/30	.55	.33	9/30	NIL	NIL	YES
	2512	Cullen/Frost Bankers		CFR	54.80	3	1	3	.85	60- 75	(10- 35%)	14.3	3.6	3.82	1.96	35	9/30	.95	.89	12/31	.48	.46	YES
	1145	Culp Inc.		CFI	12.46	2	3	4	.90	18- 25	(45-100%)	10.3	1.0	1.21	.12	48	7/31	.34	.18	12/31	.03	NIL	
	161	Cummins Inc.		CMI	98.72	4	3	3	1.45	145- 215	(45-120%)	12.1	2.0	8.17	2.00	85	9/30	1.86	2.35	12/31	.50	.40	YES
	1709	Curtiss-Wright		CW	30.09	3	3	3	1.10	40- 65	(35-115%)	11.3	1.2	2.67	.36	22	9/30	.24	.73	12/31	.09	.16	YES
	214	Cutera, Inc.	(NDQ)	CUTR	8.96	3	4	4	.80	10- 17	(10- 90%)	NMF	NIL	d.22	NIL	45	9/30	d.06	d.21	9/30	NIL	NIL	YES
	184	Cyberonics	(NDQ)	CYBX	52.28	▲1	3	2	.85	55- 80	(5- 55%)	29.7	NIL	1.76	NIL	40	10/31	◆.44	.32	9/30	NIL	NIL	YES
2050	1390	Cymer Inc.	(NDQ)	CYMI	80.54	–	3	–	1.10	65- 95	(N- 20%)	83.9	NIL	.96	NIL	95	9/30	.31	.36	9/30	NIL	NIL	YES
	1357	Cypress Semic.	(NDQ)	CY	9.31	4	3	1	1.25	20- 30	(115-220%)	11.0	4.7	.85	.44	88	9/30	.20	.37	3/31	.11	.09	YES
	2435	Cytec Inds.		CYT	67.09	1	3	4	1.45	60- 90	(N- 35%)	18.1	0.7	3.71	.50	21	9/30	.91	1.10	12/31	.125	.125	YES
	1520	**DDR Corp.**		DDR	15.32	3	4	4	2.05	20- 35	(30-130%)	NMF	3.7	.09	.57	20	9/30	.04	d.18	3/31	.12	.08	YES
	1205	DNP Select Inc. Fund		DNP	9.36	–	2	3	.70	10- 14	(5- 50%)	NMF	8.3	NMF	.78	–	6/30	8.44(q)	8.01(q)	12/31	NIL	NIL	
	581	DSP Group	(NDQ)	DSPG	5.71	3	3	3	1.15	5- 8	(N- 40%)	NMF	NIL	d.35	NIL	69	9/30	d.11	d.21	9/30	NIL	NIL	YES
	2604	DST Systems		DST	56.24	3	2	4	1.00	70- 95	(25- 70%)	13.9	1.4	4.05	.80	14	9/30	.96	.90	12/31	.40	.35	YES
★★	2216	DSW Inc.		DSW	62.29	▲1	3	3	1.05	85- 125	(35-100%)	17.7	1.2	3.51	.72	18	10/31	◆1.02	.88	9/30	.18	.15	YES
	909	DTE Energy		DTE	59.18	2	3	3	.75	50- 70	(N- 20%)	14.9	4.2	3.98	2.48	24	9/30	1.31	1.07	12/31	▲.62	.588	YES
245	2012	DTS, Inc.	(NDQ)	DTSI	15.05	4	3	1	1.15	50- 70	(230-365%)	14.9	NIL	1.01	NIL	89	9/30	d1.04	.17	9/30	NIL	NIL	YES
	1206	DWS High Income		KHI	9.77	–	4	3	.70	8- 13	(N- 35%)	NMF	9.7	NMF	.95	–	5/31	9.45(q)	9.88(q)	9/30	.199	.225	
	102	Daimler AG	(PNK)	DDAIF	46.52	5	3	4	1.55	90- 135	(95-190%)	7.9	6.1	5.86	2.86	80	9/30	◆1.35	1.81	9/30	NIL	NIL	
★★	2013	Daktronics Inc.	(NDQ)	DAKT	8.14	3	3	3	1.10	17- 25	(110-205%)	13.6	2.9	▲.60	.24	89	10/31	◆.27	.09	9/30	NIL	NIL	YES
	988	Dana Holding Corp.		DAN	13.41	4	4	3	2.50	20- 35	(50-160%)	8.4	1.5	1.60	.20	72	9/30	.26	.45	12/31	.05	NIL	YES
	1746	Danaher Corp.		DHR	52.90	3	2	3	1.00	90- 125	(70-135%)	15.6	0.2	3.39	.10	29	9/30	.77	.73	12/31	.025	.025	YES
	357	Darden Restaurants		DRI	51.90	3	3	3	1.00	60- 90	(15- 75%)	13.5	3.9	3.85	2.00	32	8/31	.85	.78	12/31	.50	.43	YES
	802	DaVita Inc.		DVA	114.00	2	3	3	.65	110- 160	(N- 40%)	17.7	NIL	6.45	NIL	55	9/30	1.50	1.45	9/30	NIL	NIL	YES
	2605	DealerTrack Hldgs.	(NDQ)	TRAK	24.59	3	3	3	1.15	35- 50	(40-105%)	49.2	NIL	.50	NIL	14	9/30	d.28	.15	9/30	NIL	NIL	YES
	1910	Dean Foods		DF	16.85	3	3	1	.70	20- 30	(20- 80%)	12.9	NIL	1.31	NIL	25	9/30	.33	.18	9/30	NIL	NIL	YES
	2158	Deckers Outdoor	(NDQ)	DECK	33.59	5	3	1	1.30	90- 135	(170-300%)	9.1	NIL	3.68	NIL	61	9/30	1.18	1.59	9/30	NIL	NIL	YES
	162	Deere & Co.		DE	86.25	3	2	4	1.35	115- 155	(35- 80%)	10.7	2.1	8.09	1.84	85	7/31	1.98	1.69	12/31	.46	.41	YES
★★	1401	Dell Inc.	(NDQ)	DELL	9.13	5	3	4	.95	20- 30	(120-230%)	8.8	3.5	▼1.04	.32	94	10/31	◆.27	.49	12/31	▲.08	NIL	YES
	307	Delta Air Lines		DAL	9.55	4	4	5	1.40	15- 25	(55-160%)	4.9	NIL	▼1.96	NIL	63	9/30	.90	.91	9/30	NIL	NIL	YES
	2364	Deluxe Corp.		DLX	29.20	3	3	4	1.25	35- 55	(20- 90%)	8.4	3.4	3.47	1.00	82	9/30	.81	.71	12/31	.25	.25	YES
	2396	Denbury Resources		DNR	15.50	5	3	4	1.65	25- 40	(60-160%)	11.5	NIL	1.35	NIL	83	9/30	.33	.37	9/30	NIL	NIL	YES
2651	831	Dendreon Corp.	(NDQ)	DNDN	4.17	3	5	5	1.40	15- 20	(260-380%)	NMF	NIL	d2.35	NIL	44	9/30	d1.04	d1.00	9/30	NIL	NIL	YES
	185	Dentsply Int'l	(NDQ)	XRAY	38.93	2	2	3	.95	55- 70	(40- 80%)	16.7	0.6	2.33	.24	40	9/30	.51	.46	3/31	.055	.055	YES
1643	1045	Deutsche Telekom ADR	(PNK)	DTEGY	10.62	4	2	3	.80	20- 25	(90-135%)	15.2	8.3	.70	.88	75	9/30	◆.15	.32	9/30	NIL	NIL	
	524	Devon Energy		DVN	53.49	4	3	3	1.20	80- 125	(50-135%)	14.3	1.5	3.73	.80	67	9/30	.88	1.40	12/31	.20	.17	YES
2446	2004	DeVry Inc.		DV	25.77	4	3	4	.70	40- 60	(55-135%)	11.4	1.3	2.26	.34	98	9/30	.49	.83	3/31	▲.17	.15	YES
	215	DexCom Inc.	(NDQ)	DXCM	12.72	3	4	3	1.30	14- 25	(10- 95%)	NMF	NIL	d.56	NIL	45	9/30	d.25	d.20	9/30	NIL	NIL	YES
	1977	Diageo plc		DEO	116.38	1	1	3	.85	120- 145	(5- 25%)	19.4	2.3	6.00	2.71	19	6/30	2.51(p)	1.82(p)	12/31	1.68	1.606	YES
244	1911	Diamond Foods	(NDQ)	DMND	13.34	–	4	–	.60	50- 75	(275-460%)	14.8	NIL	▼.90	NIL	25	4/30	◆d.22	.52	9/30	NIL	.045	YES
	2409	Diamond Offshore		DO	66.77	3	3	4	1.20	95- 140	(40-110%)	13.7	5.2	4.87	3.50	66	9/30	1.28	1.85	12/31	.875	.875	YES
	2173	Dick's Sporting Goods		DKS	51.50	2	3	4	1.15	60- 90	(15- 75%)	19.4	1.0	2.65	.50	26	10/31	.40	.32	12/31	.125	.50	YES
	1422	Diebold, Inc.		DBD	29.26	5	2	3	.90	50- 65	(70-120%)	14.4	4.0	2.03	1.17	87	9/30	.39	.69	12/31	.285	.28	YES
	709	DigitalGlobe, Inc.		DGI	24.64	2	3	2	1.00	30- 40	(20- 60%)	27.1	NIL	.91	NIL	64	9/30	.18	.02	9/30	NIL	NIL	YES
	1801	Digital River	(NDQ)	DRIV	13.51	4	3	4	1.05	25- 35	(85-160%)	46.6	NIL	.29	NIL	37	9/30	d.02	.15	9/30	NIL	NIL	YES
	2139	Dillard's, Inc.		DDS	84.90	2	3	3	1.60	100- 155	(20- 85%)	13.1	0.2	6.48	.20	30	10/31	.96	.50	12/31	.05	.05	YES
	358	DineEquity Inc.		DIN	61.99	▲2	4	3	1.35	55- 95	(N- 55%)	10.4	NIL	▲5.98	NIL	32	9/30	3.14	.86	9/30	NIL	NIL	YES
	1023	DIRECTV	(NDQ)	DTV	49.06	3	3	3	.90	105- 160	(115-225%)	10.0	NIL	4.89	NIL	42	9/30	.90	.70	9/30	NIL	NIL	YES
	2546	Discover Fin'l Svcs.		DFS	40.81	2	3	4	1.30	55- 80	(35- 95%)	9.3	1.0	4.37	.40	33	8/31	1.21	1.18	12/31	.10	.06	YES
	2326	Discovery Communic.	(NDQ)	DISCA	56.87	3	3	3	.95	65- 95	(15- 65%)	17.9	NIL	3.17	NIL	12	9/30	.57	.59	9/30	NIL	NIL	YES
	1024	Dish Network 'A'	(NDQ)	DISH	35.02	▲3	3	3	1.25	45- 70	(30-100%)	21.2	NIL	1.65	NIL	42	9/30	d.35	.71	9/30	NIL	NIL	YES
243	2327	Disney (Walt)		DIS	47.91	3	1	3	1.00	60- 75	(25- 55%)	14.8	1.3	3.23	.60	12	9/30	.68	.59	9/30	NIL	NIL	YES
	1146	Dixie Group	(NDQ)	DXYN	3.45	4	4	5	1.00	7- 11	(105-220%)	11.9	NIL	.29	NIL	48	9/30	.02	.02	9/30	NIL	NIL	
	2014	Dolby Labs.		DLB	31.80	4	3	3	.90	50- 80	(55-150%)	13.0	NIL	2.44	NIL	89	9/30	.61	.71	9/30	NIL	NIL	YES
	1912	Dole Food		DOLE	11.03	▼4	3	2	1.15	14- 20	(25- 80%)	8.2	NIL	▼1.35	NIL	25	9/30	◆d.17	d.54	9/30	NIL	NIL	YES
	2140	Dollar General		DG	48.47	3	3	3	.60	75- 110	(55-125%)	15.9	NIL	3.04	NIL	30	7/31	.64	.42	9/30	NIL	NIL	YES
	2141	Dollar Tree, Inc.	(NDQ)	DLTR	40.45	3	1	3	.55	70- 85	(75-110%)	15.1	NIL	2.67	NIL	30	10/31	◆.51	.44	9/30	NIL	NIL	YES
	142	Dominion Resources		D	50.28	2	2	2	.70	45- 65	(N- 30%)	16.4	4.5	3.06	2.24	39	9/30	.86	.69	12/31	.528	.493	YES
	359	Domino's Pizza		DPZ	40.89	▲1	4	3	1.15	35- 50	(N- 20%)	19.4	NIL	2.11	NIL	32	9/30	.44	.35	9/30	NIL	NIL	YES
	1710	Donaldson Co.		DCI	33.29	3	3	2	1.10	35- 55	(5- 65%)	17.5	1.1	1.90	.36	22	7/31	.47	.42	12/31	.09	.075	YES
	2365	Donnelley (R.R) & Sons	(NDQ)	RRD	9.15	5	3	2	1.35	20- 30	(120-230%)	5.0	11.4	1.84	1.04	82	9/30	.51	.51	12/31	.26	.26	YES
	989	Dorman Products	(NDQ)	DORM	32.00	1	3	5	1.20	30- 45	(N- 40%)	16.8	NIL	1.90	NIL	72	9/30	.54	.41	9/30	NIL	NIL	YES
	163	Douglas Dynamics		PLOW	13.24	4	2	2	.80	15- 20	(15- 50%)	17.9	6.2	.74	.82	85	9/30	.10	.18	9/30	.205	.20	YES
	1711	Dover Corp.		DOV	62.98	3	2	3	1.20	95- 130	(50-105%)	12.1	2.2	5.20	1.40	22	9/30	1.32	1.19	12/31	.35	.315	YES
	1586	Dow Chemical		DOW	28.78	4	3	3	1.30	55- 85	(90-195%)	13.0	4.7	2.21	1.34	73	9/30	.42	.62	12/31	.32	.25	YES
	1978	Dr Pepper Snapple		DPS	43.45	2	3	2	.75	55- 80	(25- 85%)	13.8	3.2	3.16	1.40	19	9/30	.79	.71	3/31	◆.34	.32	YES
	2328	DreamWorks Animation	(NDQ)	DWA	19.23	3	3	4	.95	25- 35	(30- 80%)	21.1	NIL	.91	NIL	12	9/30	.29	.23	9/30	NIL	NIL	YES
	1712	Dresser-Rand Group		DRC	51.75	3	3	3	1.35	80- 115	(55-120%)	16.5	NIL	3.13	NIL	22	9/30	.54	.51	9/30	NIL	NIL	YES
	990	Drew Industries		DW	30.50	1	3	3	1.15	35- 55	(15- 80%)	17.6	NIL	1.73	NIL	72	9/30	.43	.25	9/30	NIL	NIL	YES
	2410	Dril-Quip, Inc.		DRQ	70.65	2	3	3	1.50	85- 125	(20- 75%)	23.2	NIL	3.05	NIL	66	9/30	.73	.58	9/30	NIL	NIL	YES
2253	1587	Du Pont		DD	42.93	3	1	3	1.15	95- 120	(120-180%)	10.4	4.1	4.14	1.74	73	9/30	.44	.69	12/31	.43	.41	YES
	143	Duke Energy		DUK	60.99	3	2	2	.60	55- 75	(N- 25%)	16.7	5.1	3.65	3.09	39	9/30	1.01	1.35	12/31	.765	.75	YES
	1521	Duke Realty Corp.		DRE	13.18	3	3	4	1.50	13- 20	(N- 50%)	NMF	5.2	d.34	.68	20	9/30	d.11	d.14	12/31	.17	.17	YES
	433	Dun & Bradstreet		DNB	75.60	3	3	2	.75	105- 160	(40-110%)	10.4	2.0	7.25	1.52	8	9/30	1.76	1.42	12/31	.38	.36	YES
	360	Dunkin' Brands Group	(NDQ)	DNKN	30.01	–	3	–	NMF	▲ 40- 60	(35-100%)	21.1	2.0	1.42	.60	32	9/30	.37	.28	12/31	◆.15	NIL	YES
626	927	Dycom Inds.		DY	15.39	4	3	3	1.40	30- 45	(95-190%)	14.7	NIL	1.05	NIL	84	10/31	◆.36	.38	9/30	NIL	NIL	YES
	732	Dynamic Materials	(NDQ)	BOOM	13.22	4	4	3	1.65	25- 40	(90-205%)	10.8	1.2	1.22	.16	49	9/30	.28	.32	12/31	.04	.04	YES
	1783	**E*Trade Fin'l**	(NDQ)	ETFC	8.17	5	4	3	1.70	17- 30	(110-265%)	20.4	NIL	.40	NIL	76	9/30	d.10	.24	9/30	NIL	NIL	YES
	1402	EMC Corp.		EMC	24.34	3	2	4	.95	35- 50	(45-105%)	18.7	NIL	1.30	NIL	94	9/30	.28	.27	9/30	NIL	NIL	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter.

For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

Page (Selection & Opinion)	Page (Ratings & Reports)	NAME OF STOCK		Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	% appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	525	EOG Resources		EOG	118.61	2	3	3	1.20	125- 190	(5- 60%)	21.8	0.6	5.45	.70	67	9/30	1.73	.83	12/31	.17	.16	YES
	526	EQT Corp.		EQT	61.43	2	3	3	1.20	65- 100	(5- 65%)	36.3	1.4	1.69	.88	67	9/30	.24	.45	12/31	.22	.22	YES
	329	Eagle Bulk Shipping	(NDQ)	EGLE	2.34	▲4	5	5	2.00	3- 7	(30-200%)	NMF	NIL	d6.52	NIL	81	9/30	d1.77	d.40	9/30	NIL	NIL	YES
	1108	Eagle Materials		EXP	54.54	1	3	5	1.25	30- 45	(N- N%)	42.0	0.7	1.30	.40	7	9/30	.49	.14	3/31	◆.10	.10	YES
	2620	EarthLink, Inc.	(NDQ)	ELNK	6.49	5	3	5	.70	11- 16	(70-145%)	72.1	3.1	.09	.20	56	9/30	.01	.07	12/31	.05	.05	YES
	2513	East West Bancorp	(NDQ)	EWBC	20.77	3	4	3	1.35	25- 40	(20- 95%)	10.9	1.9	1.91	.40	35	9/30	.48	.41	12/31	.10	.05	YES
	2436	Eastman Chemical		EMN	58.37	2	2	4	1.30	85- 110	(45- 90%)	10.0	1.8	5.83	1.04	21	9/30	1.57	1.19	12/31	.26	.26	YES
	991	Eaton Corp.		ETN	50.25	3	2	3	1.15	85- 115	(70-130%)	11.1	3.0	4.53	1.52	72	9/30	1.07	1.08	12/31	.38	.34	YES
	2547	Eaton Vance Corp.		EV	30.22	▲2	3	3	1.35	45- 70	(50-130%)	15.5	2.6	1.95	.80	33	10/31	◆.45	.40	12/31	▲.20	.19	YES
	2621	eBay Inc.	(NDQ)	EBAY	47.92	2	2	3	1.10	55- 75	(15- 55%)	23.3	NIL	2.06	NIL	56	9/30	.45	.37	9/30	NIL	NIL	YES
	582	Echelon Corp.	(NDQ)	ELON	2.27	5	4	3	1.15	11- 18	(385-695%)	NMF	NIL	d.28	NIL	69	9/30	d.10	.02	9/30	NIL	NIL	YES
	1025	EchoStar Corp.	(NDQ)	SATS	31.20	3	3	4	.90	30- 45	(N- 45%)	39.5	NIL	.79	NIL	42	9/30	.26	d.22	9/30	NIL	NIL	YES
	558	Ecolab Inc.		ECL	70.00	1	1	3	.80	75- 90	(5- 30%)	21.1	1.1	3.32	.80	23	9/30	.87	.75	12/31	.20	.175	YES
	2238	Edison Int'l		EIX	44.13	3	3	3	.75	35- 55	(N- 25%)	17.0	3.0	2.59	1.32	36	9/30	.81	1.31	12/31	.325	.32	YES
1821	186	Edwards Lifesciences		EW	85.03	2	1	3	.70	115- 140	(35- 65%)	29.2	NIL	2.91	NIL	40	9/30	.58	.38	9/30	NIL	NIL	YES
	361	Einstein Noah Rest.	(NDQ)	BAGL	15.54	3	3	2	1.15	20- 30	(30- 95%)	15.4	3.2	1.01	.50	32	9/30	.21	.17	12/31	.125	.125	
	2239	El Paso Electric		EE	30.82	3	2	2	.70	30- 45	(N- 45%)	13.8	3.4	2.23	1.04	36	9/30	1.29	1.40	12/31	.25	.22	YES
	616	El Paso Pipeline		EPB	35.97	1	3	3	.70	40- 60	(10- 65%)	16.6	6.4	2.17	2.32	9	9/30	.55	.46	12/31	▲.58	.49	YES
	710	Elbit Systems	(NDQ)	ESLT	34.71	3	2	3	.75	60- 85	(75-145%)	8.8	3.5	3.93	1.20	64	9/30	1.18	1.06	12/31	.30	.36	
	1391	Electro Scientific	(NDQ)	ESIO	10.34	4	3	3	1.05	16- 25	(55-140%)	15.4	3.1	.67	.32	95	9/30	.23	.31	12/31	.08	.08	YES
	2015	Electronic Arts	(NDQ)	EA	13.71	4	3	1	1.00	30- 45	(120-230%)	11.3	NIL	1.21	NIL	89	9/30	.15	.05	9/30	NIL	NIL	YES
	1423	Electr. for Imaging	(NDQ)	EFII	16.96	3	3	4	1.05	25- 35	(45-105%)	18.4	NIL	.92	NIL	87	9/30	.21	.16	9/30	NIL	NIL	YES
	1013	Elizabeth Arden	(NDQ)	RDEN	46.24	1	3	2	1.30	50- 75	(10- 60%)	19.3	NIL	2.39	NIL	54	9/30	.44	.31	9/30	NIL	NIL	YES
	383	EMCOR Group		EME	32.50	2	3	3	1.25	30- 45	(N- 40%)	14.3	0.6	2.27	.20	34	9/30	.59	.47	12/31	.05	.05	YES
	1358	EMCORE Corp.	(NDQ)	EMKR	4.35	3	5	5	1.70	3- 6	(N- 40%)	NMF	NIL	d.12	NIL	88	6/30	d.38	d.48	9/30	NIL	NIL	YES
	1306	Emerson Electric		EMR	48.95	3	1	2	1.05	75- 90	(55- 85%)	12.5	3.4	3.92	1.64	41	9/30	1.11	.98	12/31	▲.41	.40	YES
	910	Empire Dist. Elec.		EDE	20.27	3	2	3	.65	19- 25	(N- 25%)	15.4	4.9	1.32	1.00	24	9/30	.60	.60	12/31	.25	NIL	YES
	1403	Emulex Corp.		ELX	6.58	4	3	3	1.05	15- 25	(130-280%)	11.0	NIL	.60	NIL	94	9/30	.13	.05	12/31	NIL	NIL	YES
	607	Enbridge Inc.	(TSE)	ENB.TO	38.63	2	1	3	.60	40- 45	(5- 15%)	22.2	2.9	1.74	1.13	4	9/30	.34	.32	12/31	.283	.245	YES
	527	Encana Corp.		ECA	21.12	3	3	3	1.20	25- 35	(20- 65%)	26.1	3.8	.81	.80	67	9/30	.36	.23	12/31	.20	.20	YES
	1605	Endo Health Solns.	(NDQ)	ENDP	27.24	3	3	3	.75	45- 65	(65-140%)	8.3	NIL	3.27	NIL	31	9/30	.45	.34	9/30	NIL	NIL	YES
		Endo Pharmac. Hldgs.							NAME CHANGED TO ENDO HEALTH SOLNS.														
	528	Energen Corp.		EGN	43.57	3	3	3	1.20	65- 100	(50-130%)	11.8	1.3	3.68	.56	67	9/30	.44	.75	12/31	.14	.135	YES
	1190	Energizer Holdings		ENR	77.21	2	3	4	.95	100- 150	(30- 95%)	11.3	2.1	6.81	1.60	3	9/30	1.76	1.10	12/31	.40	NIL	YES
	617	Energy Transfer		ETP	42.92	3	2	4	.80	45- 65	(5- 50%)	27.7	8.4	1.55	3.60	9	9/30	.13	.19	12/31	◆.894	.894	YES
2652	404	EnergySolutions		ES	2.91	3	5	3	1.40	9- 17	(210-485%)	5.8	NIL	.50	NIL	70	9/30	.11	d.04	9/30	NIL	NIL	YES
2651	1220	EnerNOC, Inc.	(NDQ)	ENOC	12.09	2	4	1	1.60	13- 20	(10- 65%)	NMF	NIL	d.24	NIL	92	9/30	2.21	1.77	9/30	NIL	NIL	YES
	2411	Ensco plc		ESV	55.54	2	3	3	1.25	70- 105	(25- 90%)	9.7	2.7	5.75	1.50	66	9/30	1.48	.88	12/31	◆.375	.35	YES
	911	Entergy Corp.		ETR	62.55	3	2	2	.70	60- 85	(N- 35%)	13.1	5.3	4.79	3.32	24	9/30	1.89	3.53	12/31	.83	.83	YES
	618	Enterprise Products		EPD	51.36	3	3	4	.85	60- 90	(15- 75%)	19.8	5.1	2.60	2.60	9	9/30	.66	.55	12/31	▲.65	.613	YES
2651	832	Enzo Biochem		ENZ	2.64	3	4	3	1.45	3- 5	(15- 90%)	NMF	NIL	d.20	NIL	44	7/31	d.69	d.11	9/30	NIL	NIL	YES
	1606	Enzon Pharmac.	(NDQ)	ENZN	6.23	3	4	2	.95	6- 9	(N- 45%)	28.3	NIL	.22	NIL	31	9/30	.08	d.18	9/30	NIL	NIL	YES
	434	Equifax, Inc.		EFX	50.25	1	2	4	.90	70- 95	(40- 90%)	16.4	1.4	3.06	.72	8	9/30	.75	.65	12/31	.18	.16	YES
1050	1802	Equinix, Inc.	(NDQ)	EQIX	182.90	1	3	4	1.20	265- 400	(45-120%)	60.6	NIL	3.02	NIL	37	9/30	.57	.20	9/30	NIL	NIL	YES
	1522	Equity Residential		EQR	54.70	3	3	3	1.05	60- 90	(10- 65%)	71.0	3.1	.77	1.68	20	9/30	.52	.10	12/31	.338	.338	YES
	955	Ericsson ADR(g)	(NDQ)	ERIC	8.68	4	3	2	1.15	12- 18	(40-105%)	13.8	4.3	.63	.37	90	9/30	.15	.20	9/30	NIL	NIL	YES
	765	Erie Indemnity Co.	(NDQ)	ERIE	65.25	2	2	3	.70	60- 80	(N- 25%)	21.5	3.6	3.04	2.37	11	9/30	.96	.93	12/31	.553	.515	
	1747	ESCO Technologies		ESE	35.21	3	3	3	1.00	50- 75	(40-115%)	14.5	0.9	2.43	.32	29	9/30	.65	.57	3/31	.08	.08	YES
	711	Esterline Technologies		ESL	58.04	3	3	4	1.20	70- 105	(20- 80%)	10.3	NIL	5.61	NIL	64	7/31	1.12	1.21	9/30	NIL	NIL	YES
2043	1147	Ethan Allen Interiors		ETH	28.83	2	3	3	1.30	30- 40	(5- 40%)	20.2	1.2	1.43	.36	48	9/30	.38	.25	3/31	.09	.07	YES
	416	European Equity Fund		EEA	6.66	–	4	3	1.20	9- 14	(35-110%)	NMF	2.3	NMF	.15	–	6/30	6.91(q)	9.20(q)	9/30	NIL	NIL	
	2030	Everest Re Group Ltd.		RE	103.83	2	1	3	.75	125- 155	(20- 50%)	7.1	1.8	14.67	1.92	52	9/30	4.05	2.70	12/31	◆.48	.48	YES
	833	Exelixis,Inc.	(NDQ)	EXEL	4.82	5	5	5	1.25	9- 16	(85-230%)	NMF	NIL	d1.19	NIL	44	9/30	d.20	.60	9/30	NIL	NIL	YES
	144	Exelon Corp.		EXC	29.19	4	3	2	.80	35- 55	(20- 90%)	11.5	7.2	2.53	2.10-1.75	39	9/30	.77	.90	12/31	.525	.525	YES
2445	2622	Expedia Inc.	(NDQ)	EXPE	58.30	–	3	–	NMF	65- 100	(10- 70%)	20.5	0.9	2.84	.52	56	9/30	1.20	1.22	12/31	.13	.14	YES
	384	Expeditors Int'l	(NDQ)	EXPD	36.20	▲3	2	2	1.05	▼ 55- 80	(50-120%)	21.9	1.5	1.65	.56	34	9/30	.42	.50	12/31	.28	.25	YES
1644	2217	Express, Inc.		EXPR	11.40	5	3	3	1.10	30- 50	(165-340%)	7.7	NIL	1.48	NIL	18	7/31	.18	.14	9/30	NIL	NIL	YES
2652	975	Express Scripts	(NDQ)	ESRX	52.18	3	2	3	.95	105- 145	(100-180%)	13.1	NIL	3.99	NIL	62	9/30	1.02	.66	9/30	NIL	NIL	YES
	1404	Extreme Networks	(NDQ)	EXTR	3.50	4	4	3	1.15	8- 13	(130-270%)	17.5	NIL	.20	NIL	94	9/30	.02	.02	12/31	NIL	NIL	YES
2447	504	Exxon Mobil Corp.		XOM	87.67	3	1	3	.80	110- 135	(25- 55%)	10.4	2.6	8.44	2.28	74	9/30	2.09	2.13	12/31	.57	.47	YES
	2548	EZCORP, Inc.	(NDQ)	EZPW	17.83	5	3	3	1.00	40- 65	(125-265%)	6.3	NIL	2.85	NIL	33	9/30	.75	.72	9/30	NIL	NIL	YES
2254	956	**F5 Networks**	(NDQ)	FFIV	88.08	3	3	4	.95	160- 245	(80-180%)	22.8	NIL	3.86	NIL	90	9/30	.85	.84	9/30	NIL	NIL	YES
	118	FARO Technologies	(NDQ)	FARO	35.13	4	3	4	1.15	55- 80	(55-130%)	28.6	NIL	1.23	NIL	60	9/30	.21	.38	9/30	NIL	NIL	YES
	119	FEI Company	(NDQ)	FEIC	52.47	1	3	2	1.10	80- 125	(50-140%)	17.9	0.6	2.93	.32	60	9/30	.71	.63	3/31	◆.08	NIL	YES
	1307	FLIR Systems	(NDQ)	FLIR	19.72	4	3	2	.90	40- 60	(105-205%)	13.1	1.6	1.51	.31	41	9/30	.37	.40	12/31	.07	.06	YES
	1588	FMC Corp.		FMC	53.74	2	3	4	1.25	45- 70	(N- 30%)	14.5	0.7	3.70	.38	73	9/30	.79	.70	12/31	.09	.075	YES
	2412	FMC Technologies		FTI	41.37	3	3	2	1.35	70- 110	(70-165%)	19.2	NIL	2.15	NIL	66	9/30	.41	.50	9/30	NIL	NIL	YES
2034	1392	FSI Int'l		FSII					SEE FINAL SUPPLEMENT - PAGE 2034														
	385	FTI Consulting		FCN	28.42	4	3	2	.70	50- 75	(75-165%)	12.7	NIL	2.24	NIL	34	9/30	.60	.70	9/30	NIL	NIL	YES
246	2623	Facebook Inc.	(NDQ)	FB	22.92	–	3	–	NMF	35- 55	(55-140%)	NMF	NIL	.18	NIL	56	9/30	d.02	NA	9/30	NIL	NIL	YES
	435	FactSet Research		FDS	90.72	3	2	4	1.00	135- 180	(50-100%)	20.3	1.4	4.48	1.24	8	8/31	1.08	.96	12/31	.31	.27	YES
	2606	Fair Isaac		FICO	41.78	3	3	3	1.15	65- 100	(55-140%)	15.2	0.2	2.75	.08	14	9/30	.60	.64	12/31	.02	.02	YES
	1359	Fairchild Semic.		FCS	12.20	4	3	2	1.45	30- 40	(145-230%)	10.3	NIL	1.18	NIL	88	9/30	.19	.28	9/30	NIL	NIL	YES
	2142	Family Dollar Stores		FDO	69.36	3	3	3	.50	75- 115	(10- 65%)	16.9	1.2	4.10	.84	30	8/31	.75	.67	12/31	.21	.18	YES
	1136	Fastenal Co.	(NDQ)	FAST	41.47	3	2	4	1.05	50- 65	(20- 55%)	26.1	2.0	1.59	.84	1	9/30	.37	.33	12/31	▲.21	.14	YES
	992	Federal-Mogul Corp.	(NDQ)	FDML	7.27	5	4	2	1.70	25- 40	(245-450%)	9.7	NIL	.75	NIL	72	9/30	d.11	.34	9/30	NIL	NIL	YES
	1523	Federal Rlty. Inv. Trust		FRT	101.29	1	3	3	1.05	75- 115	(N- 15%)	40.0	2.9	2.53	2.92	20	9/30	.60	.51	3/31	.73	.69	YES
	164	Federal Signal		FSS	5.36	3	3	4	1.40	8- 13	(50-145%)	12.8	NIL	.42	NIL	85	9/30	.07	.03	9/30	NIL	NIL	YES
	2549	Federated Investors		FII	19.39	3	3	4	1.05	30- 45	(55-130%)	11.3	5.0	1.72	.96	33	9/30	.43	.37	12/31	.24	.24	YES
1245	308	FedEx Corp.		FDX	87.00	4	2	3	1.00	▼ 135- 185	(55-115%)	13.7	0.6	6.35	.56	63	8/31	1.45	1.46	12/31	.14	.13	YES
	1524	FelCor Lodging Tr.		FCH	3.95	▼4	5	5	2.20	8- 15	(105-280%)	NMF	NIL	d.86	NIL	20	9/30	d.23	d.27	9/30	NIL	NIL	YES
	559	Ferro Corp.		FOE	2.49	5	4	4	2.05	5- 9	(100-260%)	24.9	NIL	.10	NIL	23	9/30	d.02	.21	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

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italics to Selection & Opinion

Page	Page	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
1644	2104	Fifth & Pacific Co.	FNP	11.67	3	5	3	1.65	9- 17	(N- 45%)	NMF	NIL	.08	NIL	16	9/30	d.05	.05	9/30	NIL	NIL	YES
	782	Fifth Third Bancorp (NDQ)	FITB	14.48	3	3	3	1.30	20- 30	(40-105%)	9.6	2.8	1.51	.40	38	9/30	.38	.40	12/31	▲.10	.08	YES
	583	Finisar Corp. (NDQ)	FNSR	12.07	5	4	2	1.90	40- 65	(230-440%)	13.9	NIL	.87	NIL	69	7/31	d.07	.11	9/30	NIL	NIL	YES
	2218	Finish Line (The) (NDQ)	FINL	20.94	2	3	3	1.10	30- 45	(45-115%)	12.2	1.1	1.72	.24	18	8/31	.49	.38	12/31	.06	.05	YES
	2550	First Cash Fin'l Svcs (NDQ)	FCFS	47.20	2	3	3	.90	60- 85	(25- 80%)	16.0	NIL	2.95	NIL	33	9/30	.67	.59	9/30	NIL	NIL	YES
	2514	First Commonwealth	FCF	6.10	3	4	4	1.10	11- 19	(80-210%)	13.0	3.3	.47	.20	35	9/30	.09	.08	12/31	.05	.03	YES
	783	First Horizon National	FHN	9.59	▲3	3	4	1.20	11- 16	(15- 65%)	17.4	0.4	.55	.04	38	9/30	.10	.12	3/31	.01	.01	YES
	784	First Midwest Bancorp (NDQ)	FMBI	12.15	3	3	3	1.25	13- 20	(5- 65%)	NMF	0.3	d.22	.04	38	9/30	d.65	.09	3/31	◆.01	.01	YES
	1504	First Niagara Finl Group (NDQ)	FNFG	7.31	4	3	3	.90	14- 20	(90-175%)	10.4	4.4	.70	.32	53	9/30	.14	.19	12/31	.08	.16	YES
	1221	First Solar, Inc. (NDQ)	FSLR	24.15	4	3	1	1.45	30- 45	(25- 85%)	4.4	NIL	5.55	NIL	92	9/30	1.27	2.26	9/30	NIL	NIL	YES
	145	FirstEnergy Corp.	FE	41.56	3	2	3	.75	45- 60	(10- 45%)	12.6	5.3	3.30	2.20	39	9/30	1.01	1.27	12/31	.55	.55	YES
1050	785	FirstMerit Corp. (NDQ)	FMER	13.41	3	3	3	1.00	16- 25	(20- 85%)	10.6	4.8	1.27	.64	38	9/30	.32	.29	12/31	◆.16	.16	YES
	2607	Fiserv Inc. (NDQ)	FISV	73.62	2	2	3	.95	95- 130	(30- 75%)	13.2	NIL	5.57	NIL	14	9/30	1.27	1.16	9/30	NIL	NIL	YES
	1329	Flextronics Int'l (NDQ)	FLEX	5.80	4	3	3	1.30	12- 17	(105-195%)	5.9	NIL	.99	NIL	86	9/30	.26	.18	9/30	NIL	NIL	YES
	1913	Flowers Foods	FLO	22.64	3	3	2	.50	25- 35	(10- 55%)	21.4	2.9	1.06	.66	25	9/30	.22	.23	12/31	◆.16	.15	YES
	1713	Flowserve Corp.	FLS	138.23	1	3	3	1.45	125- 190	(N- 35%)	15.1	1.0	9.15	1.44	22	9/30	2.07	1.92	3/31	◆.36	.32	YES
	1234	Fluor Corp.	FLR	52.57	4	3	3	1.30	90- 140	(70-165%)	14.4	1.2	3.66	.64	68	9/30	.86	.78	3/31	.16	.125	YES
	1505	Flushing Financial (NDQ)	FFIC	14.60	3	3	3	1.00	16- 25	(10- 70%)	12.4	3.6	1.18	.52	53	9/30	.29	.33	9/30	.13	.13	YES
	2219	Foot Locker	FL	33.56	1	3	4	1.05	35- 55	(5- 65%)	12.9	2.1	2.60	.72	18	10/31	◆.63	.43	3/31	◆.18	.165	YES
	103	Ford Motor	F	10.83	4	4	3	1.50	19- 30	(75-175%)	7.5	1.8	1.44	.20	80	9/30	.40	.46	12/31	.05	NIL	YES
	1034	Forest City Enterpr.	FCEA	14.50	3	5	4	1.60	11- 20	(N- 40%)	NMF	NIL	d.15	NIL	15	7/31	d.28	.03	9/30	NIL	NIL	YES
	1607	Forest Labs.	FRX	32.46	3	3	3	.80	30- 45	(N- 40%)	41.1	NIL	.79	NIL	31	9/30	.15	.91	9/30	NIL	NIL	YES
	2397	Forest Oil	FST	6.70	–	4	–	NMF	13- 20	(95-200%)	13.7	NIL	.49	NIL	83	9/30	.10	.25	9/30	NIL	NIL	YES
	436	Forrester Research (NDQ)	FORR	28.21	3	3	3	.80	▼ 35- 55	(25- 95%)	27.1	2.0	1.04	.56	8	9/30	.26	.34	12/31	.14	NIL	YES
	2645	Fortress Investment	FIG	4.22	3	4	4	2.15	9- 15	(115-255%)	6.6	4.7	.64	.20	43	9/30	.12	.08	12/31	.05	NIL	YES
	1148	Fortune Brands Home	FBHS	27.99	–	3	–	NMF	20- 30	(N- 5%)	26.9	NIL	1.04	NIL	48	9/30	.29	.01	9/30	NIL	NIL	YES
1434	320	Forward Air (NDQ)	FWRD	31.90	3	3	2	1.15	50- 75	(55-135%)	17.8	1.3	1.79	.40	77	9/30	.41	.44	12/31	.10	.07	YES
	2174	Fossil Inc. (NDQ)	FOSL	84.04	3	3	3	1.30	140- 210	(65-150%)	14.5	NIL	5.80	NIL	26	9/30	1.28	1.09	9/30	NIL	NIL	YES
	1235	Foster Wheeler AG (NDQ)	FWLT	21.67	3	3	4	1.70	30- 45	(40-110%)	13.0	NIL	1.67	NIL	68	9/30	.54	.31	9/30	NIL	NIL	YES
	1308	Franklin Electric (NDQ)	FELE	56.90	1	3	5	1.15	70- 100	(25- 75%)	17.1	1.0	3.33	.58	41	9/30	.91	.80	12/31	.145	.135	YES
	2551	Franklin Resources	BEN	130.58	2	2	4	1.35	115- 155	(N- 20%)	13.9	0.9	9.41	1.16	33	9/30	2.32	1.89	12/31	.27	.25	YES
	2143	Fred's Inc. 'A' (NDQ)	FRED	13.59	3	3	2	.85	18- 27	(30-100%)	13.5	2.0	1.01	.27	30	10/31	◆.18	.24	9/30	.06	.05	
	1574	Freep't-McMoRan C&G	FCX	38.28	3	3	3	1.65	50- 70	(30- 85%)	9.1	3.4	4.21	1.31	93	9/30	.86	1.10	12/31	.313	.25	YES
	1914	Fresh Del Monte Prod.	FDP	25.22	3	3	3	.85	30- 45	(20- 80%)	10.9	1.6	2.31	.40	25	9/30	.40	.21	12/31	◆.10	.10	YES
	1948	Fresh Market (The) (NDQ)	TFM	60.15	2	3	2	.85	65- 100	(10- 65%)	40.4	NIL	1.49	NIL	59	7/31	.28	.22	9/30	NIL	NIL	YES
	1046	Frontier Communic. (NDQ)	FTR	4.41	3	3	1	.95	6- 9	(35-105%)	15.8	9.1	.28	.40	75	9/30	.07	.05	12/31	.10	.188	YES
	330	Frontline Ltd.	FRO	3.98	3	5	5	1.60	4- 7	(N- 75%)	NMF	NIL	d1.28	NIL	81	6/30	d.31	d.30	9/30	NIL	.02	YES
	993	Fuel Sys. Solns. (NDQ)	FSYS	14.03	4	3	3	1.15	35- 55	(150-290%)	23.4	NIL	.60	NIL	72	9/30	d.03	d.02	9/30	NIL	NIL	YES
	405	Fuel Tech, Inc. (NDQ)	FTEK	3.58	5	4	1	1.45	▼ 11- 18	(205-405%)	11.2	NIL	.32	NIL	70	9/30	.05	.11	9/30	NIL	NIL	YES
2652	1222	FuelCell Energy (NDQ)	FCEL	0.90	5	5	3	1.40	1- 2	(10-120%)	NMF	NIL	d.04	NIL	92	7/31	d.06	d.07	9/30	NIL	NIL	YES
	1984	FUJIFILM Hldgs. ADR(g)(PNK)	FUJIY	17.50	5	2	2	.80	40- 55	(130-215%)	9.8	2.9	1.78	.50	96	6/30	.07	.37	9/30	.219	.186	
1432	560	Fuller (H.B.)	FUL	31.54	3	3	4	1.25	30- 50	(N- 60%)	14.1	1.1	2.23	.34	23	8/31	.48	.47	12/31	.085	.075	YES
	1149	Furniture Brands	FBN	0.97	4	5	5	1.55	3- 5	(210-415%)	NMF	NIL	d.54	NIL	48	9/30	d.33	d.45	9/30	NIL	NIL	YES
	386	**G&K Services 'A'** (NDQ)	GKSR	32.28	3	3	4	.90	45- 65	(40-100%)	13.5	2.4	2.40	.78	34	9/30	.62	.45	12/31	.195	.13	YES
	1748	GATX Corp.	GMT	41.17	2	3	3	1.20	50- 70	(20- 70%)	15.5	2.9	2.66	1.20	29	9/30	.75	.70	12/31	.30	.29	YES
	2175	GNC Holdings	GNC	35.08	–	3	–	NMF	40- 60	(15- 70%)	14.7	1.3	2.39	.44	26	9/30	.60	.45	12/31	.11	NIL	YES
	1223	GT Advanced Tech. (NDQ)	GTAT	3.19	5	4	2	1.60	16- 25	(400-685%)	3.0	NIL	1.08	NIL	92	9/30	.02	NA	9/30	NIL	NIL	YES
	1207	Gabelli Equity	GAB	5.45	–	3	2	1.30	6- 9	(10- 65%)	NMF	NIL	NMF	NIL	–	6/30	5.31(q)	6.15(q)	9/30	NIL	NIL	
	2552	Gallagher (Arthur J.)	AJG	36.24	1	1	3	.75	35- 40	(N- 10%)	18.2	3.8	1.99	1.36	33	9/30	.50	.41	12/31	.34	.33	YES
	2176	GameStop Corp.	GME	25.92	4	3	2	.85	35- 55	(35-110%)	8.2	3.9	3.15	1.00	26	10/31	◆.38	.39	12/31	◆.25	NIL	YES
	2372	Gannett Co.	GCI	17.37	2	4	3	1.60	17- 30	(N- 75%)	7.6	4.6	2.28	.80	50	9/30	.51	.41	3/31	.20	.08	YES
	2220	Gap (The), Inc.	GPS	34.43	1	2	4	1.00	35- 50	(N- 45%)	15.7	1.5	2.20	.53	18	10/31	◆.63	.38	3/31	.125	.113	YES
2445	165	Gardner Denver	GDI	69.00	–	3	–	1.30	75- 115	(10- 65%)	13.4	0.3	5.16	.20	85	9/30	1.30	1.42	12/31	.05	.05	YES
	1309	Garmin Ltd. (NDQ)	GRMN	37.73	3	3	3	1.05	40- 60	(5- 60%)	13.1	5.0	2.87	1.90	41	9/30	.72	.77	12/31	.45	.40	YES
	437	Gartner Inc.	IT	46.03	2	3	3	1.05	40- 65	(N- 40%)	24.5	NIL	1.88	NIL	8	9/30	.33	.31	9/30	NIL	NIL	YES
		Gaylord Entertainm.						NAME CHANGED TO RYMAN HOSPITALITY														
	331	Genco Shipping	GNK	2.56	5	5	1	2.05	▼ 5- 9	(95-250%)	NMF	NIL	▼d2.70	NIL	81	9/30	d.90	.04	9/30	NIL	NIL	YES
	1749	GenCorp Inc.	GY	8.34	3	4	4	1.35	12- 20	(45-140%)	92.7	NIL	.09	NIL	29	8/31	d.15	.02	9/30	NIL	NIL	YES
	1208	Gen'l Amer. Invest	GAM	26.81	–	3	3	1.10	40- 60	(50-125%)	NMF	0.7	NMF	.18	–	9/30	33.86(q)	26.66(q)	9/30	NIL	NIL	
	1310	Gen'l Cable	BGC	27.02	3	3	5	1.85	45- 70	(65-160%)	9.6	NIL	2.81	NIL	41	9/30	.60	.33	9/30	NIL	NIL	YES
	928	Gen'l Communic. 'A' (NDQ)	GNCMA	7.71	4	3	2	1.20	14- 20	(80-160%)	24.9	NIL	.31	NIL	84	9/30	.09	.15	9/30	NIL	NIL	YES
	712	Gen'l Dynamics	GD	63.91	4	1	3	1.00	90- 110	(40- 70%)	9.1	3.2	7.05	2.04	64	9/30	1.70	1.83	12/31	.51	.47	YES
2254	1750	Gen'l Electric	GE	20.66	2	3	3	1.20	30- 45	(45-120%)	12.8	3.3	1.62	.68	29	9/30	.36	.30	12/31	.17	.15	YES
	1915	Gen'l Mills	GIS	40.46	3	1	3	.50	50- 60	(25- 50%)	15.3	3.3	2.65	1.32	25	8/31	.66	.64	12/31	.33	.305	YES
	104	General Motors	GM	24.93	3	3	3	1.25	40- 60	(60-140%)	7.3	NIL	3.42	NIL	80	9/30	.93	1.03	9/30	NIL	NIL	YES
	2159	Genesco Inc.	GCO	55.28	3	3	3	1.15	80- 115	(45-110%)	10.7	NIL	5.17	NIL	61	7/31	.50	.22	9/30	NIL	NIL	YES
	340	Genesee & Wyoming	GWR	70.76	3	3	3	1.25	75- 110	(5- 55%)	22.5	NIL	3.14	NIL	51	9/30	.71	.79	9/30	NIL	NIL	YES
2652	216	Genomic Health (NDQ)	GHDX	26.80	3	3	3	.80	30- 45	(10- 70%)	NMF	NIL	.22	NIL	45	9/30	.11	.10	9/30	NIL	NIL	YES
	1224	GenOn Energy	GEN	2.36	–	5	–	.85	2- 4	(N- 70%)	NMF	NIL	d.20	NIL	92	9/30	d.11	d.05	9/30	NIL	NIL	YES
	994	Gentex Corp. (NDQ)	GNTX	16.78	3	3	1	1.25	35- 50	(110-200%)	12.4	3.1	1.35	.52	72	9/30	.29	.30	12/31	.13	.12	YES
	995	Gentherm Inc. (NDQ)	THRM	11.44	3	3	2	1.60	19- 30	(65-160%)	18.5	NIL	.62	NIL	72	9/30	.09	d.07	9/30	NIL	NIL	YES
	996	Genuine Parts	GPC	61.33	2	1	3	.80	85- 100	(40- 65%)	14.5	3.2	4.24	1.98	72	9/30	1.11	.97	12/31	.495	.45	YES
	1547	Genworth Fin'l	GNW	5.57	3	4	2	2.40	15- 25	(170-350%)	4.8	NIL	1.17	NIL	57	9/30	.25	.21	9/30	NIL	NIL	YES
	1035	Geo Group (The)	GEO	27.57	2	3	4	.95	30- 45	(10- 65%)	18.8	2.9	1.47	.80	15	9/30	.27	.34	12/31	.20	NIL	YES
	713	GeoEye, Inc. (NDQ)	GEOY	29.99	–	3	–	1.00	45- 65	(50-115%)	14.3	NIL	2.09	NIL	64	9/30	.51	.51	9/30	NIL	NIL	YES
	1589	Georgia Gulf	GGC	43.06	3	4	5	2.00	40- 65	(N- 50%)	14.4	0.7	3.00	.32	73	9/30	1.12	.99	12/31	.08	NIL	YES
	747	Gibraltar Inds. (NDQ)	ROCK	12.80	4	4	3	1.55	20- 35	(55-175%)	18.8	NIL	.68	NIL	91	9/30	.24	.26	9/30	NIL	NIL	YES
	2105	Gildan Activewear	GIL	32.90	2	3	3	1.10	45- 70	(35-115%)	14.4	1.1	2.29	.35	16	6/30	.66	.75	9/30	.075	.075	YES
246	1608	Gilead Sciences (NDQ)	GILD	74.82	3	3	5	.70	70- 100	(N- 35%)	20.9	NIL	3.58	NIL	31	9/30	.85	.95	9/30	NIL	NIL	YES
	2646	Gladstone Capital (NDQ)	GLAD	8.17	3	4	3	1.35	11- 19	(35-135%)	7.6	10.3	1.07	.84	43	9/30	.26	d.03	12/31	◆.21	.21	YES
	1161	Glatfelter	GLT	16.17	2	3	3	1.20	20- 30	(25- 85%)	11.1	2.2	1.46	.36	10	9/30	.46	.28	12/31	.09	.09	YES
	1609	GlaxoSmithKline ADR(g)	GSK	42.39	3	1	3	.70	50- 60	(20- 40%)	11.2	5.6	3.78	2.38	31	9/30	.71	.86	12/31	◆.528	.521	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

PAGE NUMBERS (*Selection & Opinion*)	PAGE NUMBERS (**Ratings and Reports**)	NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	2553	Global Payments		GPN	42.45	3	2	3	.85	55- 75	(30- 75%)	13.9	0.2	3.05	.08	33	8/31	.79	.79	12/31	.02	.02	YES
	2380	Global Sources	(NDQ)	GSOL	6.01	4	3	4	1.25	9- 14	(50-135%)	7.4	NIL	.81	NIL	65	9/30	◆.23	.11	9/30	NIL	NIL	
	332	Golar LNG Ltd.	(NDQ)	GLNG	40.07	2	3	2	1.60	75- 110	(85-175%)	17.9	4.0	▼2.24	1.60	81	6/30	.44	NIL	9/30	▲.40	.275	YES
	1562	Goldcorp Inc.		GG	40.76	▲3	3	1	.95	65- 95	(60-135%)	18.5	1.5	2.20	.60	79	9/30	.54	.55	12/31	.135	.113	YES
	1784	Goldman Sachs		GS	118.30	3	3	4	1.25	175- 265	(50-125%)	9.0	1.7	13.15	2.00	76	9/30	2.85	d.84	12/31	▲.50	.35	YES
	997	Goodyear Tire		GT	11.29	4	4	1	1.80	20- 35	(75-210%)	5.2	NIL	2.18	NIL	72	9/30	.53	.72	9/30	NIL	NIL	YES
2255	2624	Google, Inc.	(NDQ)	GOOG	668.21	3	2	3	.90	970-1310	(45- 95%)	19.0	NIL	35.23	NIL	56	9/30	6.53	8.33	9/30	NIL	NIL	YES
	166	Gorman-Rupp Co.	(ASE)	GRC	26.64	4	3	3	1.25	30- 45	(15- 70%)	17.8	1.5	1.50	.40	85	9/30	.32	.37	12/31	.10	.09	YES
	1714	Graco Inc.		GGG	46.77	▲2	3	3	1.15	50- 80	(5- 70%)	18.1	1.9	2.59	.90	22	9/30	.60	.60	12/31	.225	.21	YES
	1311	Grainger (W.W.)		GWW	191.20	3	1	4	.95	245- 300	(30- 55%)	17.1	1.8	11.15	3.50	41	9/30	2.81	2.51	12/31	◆.80	.66	YES
	1236	Granite Construction		GVA	29.09	3	3	3	1.15	35- 55	(20- 90%)	14.8	1.8	1.96	.52	68	9/30	.94	.93	3/31	.13	.13	YES
	912	G't Plains Energy		GXP	20.15	3	3	3	.75	17- 25	(N- 25%)	14.3	4.3	1.41	.87	24	9/30	.95	.91	12/31	▲.218	.213	YES
	1330	Greatbatch, Inc.		GB	21.95	3	3	3	.75	35- 55	(60-150%)	11.0	NIL	1.99	NIL	86	9/30	.46	.41	9/30	NIL	NIL	YES
	1949	Green Mtn. Coffee	(NDQ)	GMCR	27.33	4	4	1	1.00	75- 125	(175-355%)	10.3	NIL	2.65	NIL	59	6/30	.46	.37	9/30	NIL	NIL	YES
	2031	Greenlight Capital Re	(NDQ)	GLRE	22.67	▼4	3	3	1.00	35- 50	(55-120%)	4.9	NIL	4.58	NIL	52	9/30	1.23	d.12	9/30	NIL	NIL	YES
	1176	Greif, Inc.		GEF	42.48	4	3	4	1.15	55- 85	(30-100%)	10.5	4.0	4.06	1.68	46	7/31	.75	1.18	12/31	.42	.42	YES
	1751	Griffon Corp.		GFF	8.68	4	3	3	1.25	17- 25	(95-190%)	25.5	1.2	.34	.10	29	9/30	.04	.07	12/31	▲.025	NIL	YES
	2129	Group 1 Automotive		GPI	59.28	1	3	4	1.55	75- 110	(25- 85%)	11.9	1.0	4.98	.60	13	9/30	1.32	1.01	12/31	◆.15	.13	YES
	2106	Guess Inc.		GES	23.82	5	3	1	1.25	55- 85	(130-255%)	9.9	3.4	2.40	.80	16	7/31	.49	.84	9/30	.20	.20	YES
	766	**HCC Insurance Hldgs.**		HCC	35.98	1	3	3	.85	40- 60	(10- 65%)	11.5	1.8	3.14	.66	11	9/30	1.05	.56	12/31	▲.165	.155	YES
	1525	HCP Inc.		HCP	45.29	2	3	3	1.05	40- 65	(N- 45%)	24.0	4.4	1.89	2.00	20	9/30	.45	.41	12/31	.50	.48	YES
	1150	HNI Corp.		HNI	27.35	3	3	2	1.30	35- 55	(30-100%)	19.0	3.5	1.44	.96	48	9/30	.55	.56	12/31	.24	.23	YES
	2177	HSN, Inc.	(NDQ)	HSNI	51.78	3	3	3	.95	55- 85	(5- 65%)	45.0	1.4	1.15	.72	26	9/30	.39	.40	12/31	▲.18	.125	YES
	217	Haemonetics Corp.(•)		HAE	40.59	2	2	4	.65	50- 65	(25- 60%)	22.3	NIL	1.82	NIL	45	9/30	.45	.36	9/30	NIL	NIL	YES
	1916	Hain Celestial Group	(NDQ)	HAIN	61.90	1	3	3	.95	60- 90	(N- 45%)	25.8	NIL	2.40	NIL	25	9/30	.40	.29	9/30	NIL	NIL	YES
	2413	Halliburton Co.		HAL	31.71	4	3	3	1.40	65- 95	(105-200%)	10.1	1.1	3.13	.36	66	9/30	.65	.92	12/31	◆.09	.09	YES
	786	Hancock Holding	(NDQ)	HBHC	30.96	3	3	3	1.00	45- 70	(45-125%)	12.8	3.1	2.41	.96	38	9/30	.58	.54	12/31	◆.24	.24	YES
	2107	Hanesbrands, Inc.		HBI	34.41	1	3	3	1.20	45- 65	(30- 90%)	10.6	NIL	3.24	NIL	16	9/30	1.11	.91	9/30	NIL	NIL	YES
	767	Hanover Insurance		THG	34.88	3	2	3	.80	70- 95	(100-170%)	9.6	3.4	3.65	1.20	11	9/30	.89	d.21	9/30	.30	.275	YES
	2307	Harley-Davidson		HOG	47.97	3	3	4	1.50	60- 90	(25- 90%)	15.2	1.3	3.16	.62	17	9/30	.59	.78	12/31	.155	.25	YES
	1312	Harman Int'l		HAR	37.57	3	3	3	1.50	75- 110	(100-195%)	10.0	1.6	3.75	.60	41	9/30	.79	.69	12/31	.15	.075	YES
	957	Harmonic, Inc.	(NDQ)	HLIT	4.24	5	3	2	1.10	10- 14	(135-230%)	12.5	NIL	.34	NIL	90	9/30	.07	.11	9/30	NIL	NIL	YES
	2647	Harris & Harris Group	(NDQ)	TINY	3.26	3	3	4	1.40	5- 7	(55-115%)	9.9	NIL	.33	NIL	43	6/30	d.06	.68	9/30	NIL	NIL	YES
	1331	Harris Corp.		HRS	46.59	3	2	3	1.00	65- 85	(40- 80%)	9.0	3.2	5.18	1.48	86	9/30	1.14	1.09	12/31	.37	.28	YES
	1950	Harris Teeter Super.		HTSI	37.03	3	3	2	.65	35- 55	(N- 50%)	14.0	1.6	2.65	.60	59	9/30	.57	.50	3/31	▲.15	.13	YES
	387	Harsco Corp.		HSC	19.34	4	3	3	1.40	25- 35	(30- 80%)	14.0	4.2	1.38	.82	34	9/30	.39	.40	3/31	.205	.205	YES
	2381	Harte-Hanks		HHS	5.31	5	3	2	1.05	14- 20	(165-275%)	7.0	6.4	.76	.34	65	9/30	.14	.19	12/31	.085	.08	YES
	2554	Hartford Fin'l Svcs.		HIG	20.86	3	4	4	2.05	30- 55	(45-165%)	6.6	1.9	3.17	.40	33	9/30	.78	.05	3/31	.10	.10	YES
	2308	Hasbro, Inc.	(NDQ)	HAS	37.40	3	2	3	.80	45- 60	(20- 60%)	13.2	3.9	2.83	1.44	17	9/30	1.20	1.27	12/31	.36	.30	YES
	2178	Haverty Furniture		HVT	16.11	3	3	3	.85	19- 30	(20- 85%)	25.6	1.0	.63	.16	26	9/30	.15	.01	12/31	.04	NIL	
	2240	Hawaiian Elec.		HE	24.18	3	2	3	.70	25- 30	(5- 25%)	14.8	5.1	1.63	1.24	36	9/30	.49	.50	12/31	.31	.31	YES
	309	Hawaiian Hldgs.	(NDQ)	HA	5.86	4	4	3	1.10	9- 15	(55-155%)	4.0	NIL	▼1.47	NIL	63	9/30	.77	.59	9/30	NIL	NIL	YES
	1109	Headwaters Inc.		HW	6.58	2	5	5	1.60	5- 10	(N- 50%)	NMF	NIL	d.05	NIL	7	9/30	.05	d.05	9/30	NIL	NIL	YES
	1526	Health Care REIT		HCN	60.08	2	3	3	.85	65- 95	(10- 60%)	52.2	5.2	1.15	3.14	20	9/30	.16	.22	12/31	◆.74	.715	YES
	803	Health Mgmt. Assoc.		HMA	8.05	3	5	2	1.50	17- 30	(110-275%)	9.1	NIL	.88	NIL	55	9/30	.18	.17	9/30	NIL	NIL	YES
	804	Health Net		HNT	24.40	3	3	3	1.00	30- 45	(25- 85%)	15.8	NIL	1.54	NIL	55	9/30	.38	.84	9/30	NIL	NIL	YES
	1527	Healthcare R'lty Trust		HR	23.44	3	3	3	.95	19- 30	(N- 30%)	NMF	5.1	.12	1.20	20	9/30	.07	NIL	12/31	.30	.30	YES
	388	Healthcare Svcs.	(NDQ)	HCSG	22.06	1	3	4	.75	20- 35	(N- 60%)	31.1	3.2	.71	.70	34	9/30	.17	.15	12/31	▲.165	.16	YES
	805	Healthways Inc.	(NDQ)	HWAY	9.64	3	3	3	1.20	18- 25	(85-160%)	25.4	NIL	.38	NIL	55	9/30	.15	.28	9/30	NIL	NIL	YES
	321	Heartland Express	(NDQ)	HTLD	13.69	4	2	3	.80	19- 25	(40- 85%)	18.8	0.6	▲.73	.08	77	9/30	.14	.17	12/31	.02	.02	YES
	714	HEICO Corp.		HEI	39.00	3	3	2	1.10	50- 70	(30- 80%)	21.7	0.3	1.80	.13	64	7/31	.43	.38	9/30	▲.06	.048	YES
	1635	Heidrick & Struggles	(NDQ)	HSII	11.63	4	3	3	1.05	30- 45	(160-285%)	15.1	4.5	.77	.52	58	9/30	.23	d1.82	12/31	.13	.13	YES
	1917	Heinz (H.J.)		HNZ	58.72	2	1	3	.65	70- 85	(20- 45%)	16.6	3.5	3.53	2.06	25	10/31	◆.90	.81	12/31	.515	.48	YES
	1014	Helen of Troy Ltd.	(NDQ)	HELE	29.13	4	3	3	1.10	50- 80	(70-175%)	8.5	NIL	3.44	NIL	54	8/31	.72	.74	9/30	NIL	NIL	YES
	2414	Helix Energy Solutions		HLX	16.65	4	3	4	1.80	25- 35	(50-110%)	11.8	NIL	1.41	NIL	66	9/30	.14	.43	9/30	NIL	NIL	YES
	2415	Helmerich & Payne		HP	51.64	3	3	2	1.45	75- 110	(45-115%)	9.2	0.5	5.60	.28	66	9/30	◆1.39	1.11	12/31	.07	.07	YES
	2608	Henry (Jack) & Assoc.	(NDQ)	JKHY	38.29	2	2	2	.85	40- 55	(5- 45%)	19.1	1.2	2.00	.46	14	9/30	.49	.42	12/31	◆.115	.105	YES
	1918	Herbalife, Ltd.		HLF	46.50	3	3	3	1.00	60- 85	(30- 85%)	11.2	2.6	4.15	1.20	25	9/30	1.04	.87	12/31	.30	.20	YES
	1919	Hershey Co.		HSY	72.60	2	2	3	.60	80- 110	(10- 50%)	21.7	2.3	3.35	1.68	25	9/30	.87	.84	12/31	▲.42	.345	YES
626	2179	Hertz Global Hldgs.		HTZ	14.79	3	4	4	1.85	25- 40	(70-170%)	14.5	NIL	1.02	NIL	26	9/30	.55	.47	9/30	NIL	NIL	YES
	505	Hess Corp.		HES	50.49	3	3	2	1.30	85- 125	(70-150%)	8.8	0.8	5.75	.40	74	9/30	1.46	1.12	9/30	.10	.10	YES
★★	1405	Hewlett-Packard		HPQ	13.30	4	3	2	1.00	35- 55	(165-315%)	NMF	4.0	▼d7.18	.53	94	10/31	◆d3.49	.12	3/31	◆.132	.12	YES
	2437	Hexcel Corp.		HXL	25.28	3	3	4	1.50	30- 40	(20- 60%)	17.6	NIL	1.44	NIL	21	9/30	.39	.32	9/30	NIL	NIL	YES
846	1610	Hi-Tech Pharmacal	(NDQ)	HITK	33.50	4	3	2	.95	35- 50	(5- 50%)	12.2	NIL	2.74	NIL	31	7/31	.44	1.05	9/30	NIL	NIL	YES
	2180	Hibbett Sports	(NDQ)	HIBB	53.50	2	3	4	1.00	70- 100	(30- 85%)	18.8	NIL	2.84	NIL	26	10/31	◆.71	.59	9/30	NIL	NIL	YES
	218	Hill-Rom Hldgs.		HRC	26.97	5	3	3	1.05	40- 60	(50-120%)	12.7	1.9	2.12	.50	45	9/30	.56	.72	9/30	.125	.113	YES
	1815	Hillenbrand, Inc.		HI	19.60	3	3	2	.70	20- 30	(N- 55%)	11.7	3.9	1.67	.77	5	6/30	.34	.36	9/30	.193	.19	YES
	1920	Hillshire Brands		HSH	26.89	–	3	–	NMF	25- 40	(N- 50%)	16.7	1.9	1.61	.52	25	9/30	.41	.10	12/31	.125	.575	YES
	1985	Hitachi, Ltd. ADR(g)	(PNK)	HTHIY	54.91	5	3	3	.90	85- 125	(55-130%)	9.3	1.5	5.93	.83	96	6/30	.02	.07	9/30	NIL	NIL	
	506	HollyFrontier Corp.		HFC	43.58	–	3	–	NMF	45- 70	(5- 60%)	6.1	1.8	7.09	.80	74	9/30	2.94	2.48	12/31	▲.20	.088	YES
	219	Hologic, Inc.	(NDQ)	HOLX	19.43	3	3	3	1.05	30- 45	(55-130%)	12.8	NIL	1.52	NIL	45	9/30	.37	.34	9/30	NIL	NIL	YES
245	1137	Home Depot		HD	63.33	1	1	3	.90	60- 75	(N- 20%)	19.4	1.8	3.27	1.16	1	10/31	.74	.60	12/31	◆.29	.29	YES
	105	Honda Motor ADR(g)		HMC	32.23	3	2	3	.95	50- 65	(55-100%)	12.2	2.7	2.64	.86	80	9/30	.59	.44	9/30	.242	.381	YES
	1752	Honeywell Int'l		HON	60.44	2	1	3	1.15	85- 100	(40- 65%)	12.9	2.7	4.68	1.64	29	9/30	1.20	.88	12/31	▲.41	.373	YES
	1921	Hormel Foods		HRL	31.30	3	1	2	.65	40- 50	(30- 60%)	15.6	2.2	2.01	.68	25	10/31	◆.49	.43	12/31	.15	.128	YES
	1123	Horton D.R.		DHI	19.02	2	3	5	1.40	20- 30	(5- 60%)	21.6	0.8	.88	.15	2	9/30	.30	.11	12/31	.038	.038	YES
	1611	Hospira Inc.		HSP	29.58	4	3	4	.75	55- 80	(85-170%)	13.2	NIL	2.24	NIL	31	9/30	.47	.66	9/30	NIL	NIL	YES
	1528	Hospitality Properties		HPT	21.74	3	3	4	1.20	30- 50	(40-130%)	18.3	8.6	1.19	1.88	20	9/30	.24	.32	12/31	▲.47	.45	YES
	1529	Host Hotels & Resorts		HST	14.17	3	3	3	1.50	20- 35	(40-145%)	67.5	2.3	.21	.32	20	9/30	d.05	d.05	12/31	▲.08	.04	YES
	2221	Hot Topic, Inc.	(NDQ)	HOTT	9.54	3	3	4	.75	14- 20	(45-110%)	22.2	3.4	.43	.32	18	10/31	◆.10	.07	12/31	.08	.07	YES
	1124	Hovnanian Enterpr. 'A'		HOV	4.95	3	5	4	2.15	4- 8	(N- 60%)	NMF	NIL	d.35	NIL	2	7/31	d.02	d.47	9/30	NIL	NIL	YES
	322	Hub Group	(NDQ)	HUBG	31.07	3	3	2	1.15	45- 70	(45-125%)	15.4	NIL	2.02	NIL	77	9/30	.50	.44	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

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Page (Sel. & Op.)	Page	NAME OF STOCK		Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	1313	Hubbell Inc. 'B'		HUBB	81.74	2	2	4	1.10	85- 115	(5- 40%)	15.0	2.0	5.45	1.64	41	9/30	1.45	1.37	12/31	.41	.38	YES
626	1506	Hudson City Bancorp	(NDQ)	HCBK	8.03	–	4	–	.90	9- 15	(10- 85%)	14.9	4.0	.54	.32	53	9/30	.12	.17	12/31	.08	.08	YES
	806	Humana Inc.		HUM	66.95	4	3	2	1.00	110- 165	(65-145%)	8.5	1.6	7.84	1.04	55	9/30	2.62	2.67	3/31	.26	.25	YES
	323	Hunt (J.B.)	(NDQ)	JBHT	59.64	2	3	3	1.05	60- 90	(N- 50%)	22.1	0.9	2.70	.56	77	9/30	.65	.57	12/31	.14	.13	YES
	787	Huntington Bancshs.	(NDQ)	HBAN	6.11	3	3	4	1.30	7- 12	(15- 95%)	8.3	2.6	.74	.16	38	9/30	.19	.16	3/31	.04	.04	YES
	715	Huntington Ingalls		HII	40.59	–	3	–	NMF	35- 55	(N- 35%)	11.8	NIL	3.43	NIL	64	9/30	.74	d4.79	9/30	NIL	NIL	YES
	2438	Huntsman Corp.		HUN	16.62	3	4	5	1.10	20- 30	(20- 80%)	9.3	2.4	1.78	.40	21	9/30	.49	d.14	12/31	.10	.10	YES
	389	Huron Consulting	(NDQ)	HURN	32.17	3	4	3	.80	40- 65	(25-100%)	13.8	NIL	2.33	NIL	34	9/30	.47	.05	9/30	NIL	NIL	YES
	120	Hutchinson Techn.	(NDQ)	HTCH	1.60	4	5	3	1.80	2- 4	(25-150%)	NMF	NIL	d1.74	NIL	60	9/30	d.54	d.34	9/30	NIL	NIL	YES
	2343	Hyatt Hotels		H	36.28	3	3	3	1.15	55- 80	(50-120%)	41.2	NIL	.88	NIL	71	9/30	.18	.16	9/30	NIL	NIL	YES
	2625	**IAC/InterActiveCorp**	(NDQ)	IACI	43.15	3	3	4	.75	80- 120	(85-180%)	20.1	2.2	2.15	.96	56	9/30	.43	.69	12/31	.24	.12	YES
	187	ICU Medical	(NDQ)	ICUI	58.71	2	3	3	.65	65- 95	(10- 60%)	20.7	NIL	2.84	NIL	40	9/30	.82	.65	9/30	NIL	NIL	YES
1245	438	IHS Inc.		IHS	89.75	3	3	2	.90	▼ 90- 135	(N- 50%)	31.1	NIL	2.89	NIL	8	8/31	.66	.62	9/30	NIL	NIL	
	121	II-VI Inc.	(NDQ)	IIVI	15.88	4	3	3	1.20	20- 30	(25- 90%)	15.1	NIL	1.05	NIL	60	9/30	.21	.29	9/30	NIL	NIL	YES
	913	ITC Holdings		ITC	77.51	2	2	3	.75	100- 135	(30- 75%)	19.3	2.0	4.01	1.54	24	9/30	.98	.85	12/31	.378	.353	YES
	1753	ITT Corp.		ITT	21.34	–	2	–	NMF	35- 45	(65-110%)	12.3	1.7	1.74	.36	29	9/30	.44	.30	12/31	.091	.091	YES
	2005	ITT Educational		ESI	17.28	5	3	5	.70	80- 120	(365-595%)	2.4	NIL	7.26	NIL	98	9/30	1.83	2.48	9/30	NIL	NIL	YES
	2108	Iconix Brand Group	(NDQ)	ICON	18.95	3	3	2	1.35	20- 35	(5- 85%)	12.4	NIL	1.53	NIL	16	9/30	.38	.34	9/30	NIL	NIL	YES
	2241	IDACORP, Inc.		IDA	41.31	3	3	3	.70	35- 55	(N- 35%)	12.6	3.7	3.29	1.52	36	9/30	1.84	2.16	12/31	▲.38	.30	YES
	1715	IDEX Corp.		IEX	42.87	3	3	3	1.15	55- 80	(30- 85%)	15.4	1.9	2.78	.80	22	9/30	.66	.71	12/31	◆.20	.17	YES
	220	IDEXX Labs.	(NDQ)	IDXX	92.62	2	1	3	.90	90- 110	(N- 20%)	29.2	NIL	3.17	NIL	45	9/30	.76	.66	9/30	NIL	NIL	YES
	733	Illinois Tool Works		ITW	59.55	2	1	3	1.00	85- 105	(45- 75%)	14.2	2.6	4.19	1.52	49	9/30	1.09	1.00	3/31	.38	.36	YES
	221	Illumina Inc.	(NDQ)	ILMN	50.07	3	3	5	.95	60- 90	(20- 80%)	42.8	NIL	1.17	NIL	45	9/30	.22	.15	9/30	NIL	NIL	YES
	1406	Imation Corp.		IMN	3.99	4	3	2	.85	6- 9	(50-125%)	NMF	NIL	d.68	NIL	94	9/30	d.26	d.17	9/30	NIL	NIL	YES
	2309	IMAX Corp.		IMAX	21.98	3	4	4	1.25	35- 60	(60-175%)	25.6	NIL	.86	NIL	17	9/30	.22	.12	9/30	NIL	NIL	YES
	507	Imperial Oil Ltd.	(ASE)	IMO	43.94	3	2	3	1.15	65- 85	(50- 95%)	10.8	1.1	4.07	.48	74	9/30	1.22	.99	3/31	.12	.11	YES
	834	Incyte Corp.	(NDQ)	INCY	17.57	3	5	5	1.25	35- 70	(100-300%)	NMF	NIL	d.34	NIL	44	9/30	d.17	d.42	9/30	NIL	NIL	YES
	417	India Fund (The)		IFN	21.78	–	3	3	1.25	35- 55	(60-155%)	NMF	0.2	NMF	.05	–	6/30	23.18	32.33	9/30	NIL	NIL	YES
	619	Inergy, L.P.	(NDQ)	NRGY	18.87	–	3	–	.95	25- 35	(30- 85%)	32.0	6.1	.59	1.16	9	9/30	◆d.38	d.42	12/31	▼.29	.705	YES
	958	Infinera Corp.	(NDQ)	INFN	4.53	4	4	2	1.20	8- 13	(75-185%)	NMF	NIL	d.27	NIL	90	9/30	d.07	d.21	9/30	NIL	NIL	YES
1645	1803	Informatica Corp.	(NDQ)	INFA	27.17	4	3	1	.95	30- 45	(10- 65%)	39.4	NIL	.69	NIL	37	9/30	.14	.24	9/30	NIL	NIL	YES
2037	2609	Infosys Ltd. ADR	(NDQ)	INFY	43.27	4	2	1	1.00	100- 135	(130-210%)	13.9	1.8	3.12	.80	14	9/30	.75	.72	12/31	.256	.28	YES
	1754	Ingersoll-Rand		IR	46.44	2	3	3	1.20	65- 100	(40-115%)	13.2	1.4	3.53	.64	29	9/30	1.07	.81	12/31	.16	.12	YES
	1951	Ingles Markets	(NDQ)	IMKTA	16.04	3	3	3	.95	30- 40	(85-150%)	8.3	4.1	1.94	.66	59	6/30	.54	.52	12/31	.165	.165	
	1407	Ingram Micro 'A'		IM	15.48	3	3	3	.95	30- 45	(95-190%)	8.1	NIL	1.92	NIL	94	9/30	.35	.33	9/30	NIL	NIL	YES
	1922	Ingredion Inc.		INGR	62.86	3	3	3	1.10	55- 85	(N- 35%)	11.7	1.7	5.37	1.04	25	9/30	1.52	1.20	12/31	▲.26	.16	YES
	2181	Insight Enterprises	(NDQ)	NSIT	15.12	4	3	3	1.35	35- 50	(130-230%)	6.7	NIL	2.27	NIL	26	9/30	.43	.38	9/30	NIL	NIL	YES
	1636	Insperity Inc.		NSP	27.86	3	3	4	1.10	30- 45	(10- 60%)	15.8	2.4	1.76	.68	58	9/30	.45	.16	12/31	◆.17	.15	YES
	188	Insulet Corp.	(NDQ)	PODD	21.25	2	3	2	1.20	25- 40	(20- 90%)	NMF	NIL	d.82	NIL	40	9/30	d.26	d.29	9/30	NIL	NIL	YES
	189	Integra LifeSciences	(NDQ)	IART	37.45	3	3	3	.95	50- 80	(35-115%)	12.3	NIL	3.05	NIL	40	9/30	.85	.77	9/30	NIL	NIL	YES
	1360	Integrated Device	(NDQ)	IDTI	5.82	4	3	3	1.20	12- 18	(105-210%)	24.3	NIL	.24	NIL	88	9/30	.07	.08	9/30	NIL	NIL	YES
	914	Integrys Energy		TEG	52.75	3	2	3	.90	45- 60	(N- 15%)	15.5	5.2	3.41	2.72	24	9/30	.93	.47	12/31	.68	.68	YES
2037	1361	Intel Corp.	(NDQ)	INTC	20.25	5	1	3	1.00	35- 45	(75-120%)	9.2	4.4	2.20	.90	88	9/30	.58	.65	12/31	.225	.21	YES
		Inteliquent, Inc.								SEE NEUTRAL TANDEM													
	1015	Inter Parfums	(NDQ)	IPAR	17.96	3	3	2	1.30	16- 25	(N- 40%)	20.9	1.8	.86	.32	54	9/30	.33	.34	3/31	.08	.08	YES
	1785	IntercontinentalExch.		ICE	130.03	3	3	2	1.10	210- 315	(60-140%)	15.8	NIL	8.23	NIL	76	9/30	1.79	1.80	9/30	NIL	NIL	YES
	584	InterDigital Inc.	(NDQ)	IDCC	40.80	3	3	1	.95	50- 75	(25- 85%)	6.9	1.0	5.94	.40	69	9/30	5.56	.57	12/31	.10	.10	YES
	1151	Interface Inc. 'A'	(NDQ)	IFSIA	14.07	3	3	4	1.50	19- 30	(35-115%)	18.0	0.7	.78	.10	48	9/30	.19	.19	12/31	▲.025	.02	YES
	585	Intermec Inc.		IN	7.06	3	3	1	1.15	15- 25	(110-255%)	32.1	NIL	.22	NIL	69	9/30	.12	.01	9/30	NIL	NIL	YES
2037	1408	Int'l Business Mach.		IBM	190.35	3	1	3	.85	235- 285	(25- 50%)	12.9	1.8	14.70	3.50	94	9/30	3.33	3.19	12/31	.85	.75	YES
	561	Int'l Flavors & Frag.		IFF	63.27	2	1	3	.80	75- 90	(20- 40%)	15.4	2.1	4.12	1.36	23	9/30	1.08	1.00	12/31	▲.34	.31	YES
	2344	Int'l Game Tech.		IGT	13.01	3	3	3	1.35	30- 40	(130-205%)	10.4	1.8	1.25	.24	71	9/30	.38	.24	12/31	.06	.06	YES
	1162	Int'l Paper		IP	35.59	3	3	3	1.40	50- 75	(40-110%)	13.6	3.4	2.61	1.20	10	9/30	.51	1.19	12/31	▲.30	.263	YES
	1362	Int'l Rectifier		IRF	15.36	4	3	2	1.15	25- 35	(65-130%)	NMF	NIL	d.40	NIL	88	9/30	d.20	.31	12/31	NIL	NIL	YES
	2310	Int'l Speedway 'A'	(NDQ)	ISCA	25.57	4	3	3	.95	30- 45	(15- 75%)	18.1	0.8	1.41	.20	17	8/31	d.02	.24	9/30	NIL	NIL	YES
	2382	Interpublic Group		IPG	9.91	3	3	3	1.20	15- 25	(50-150%)	12.9	2.4	.77	.24	65	9/30	.15	.16	12/31	◆.06	.06	YES
	1363	Intersil Corp. 'A'	(NDQ)	ISIL	6.96	4	3	2	1.10	15- 25	(115-260%)	33.1	6.9	.21	.48	88	9/30	.02	.06	12/31	.12	.12	YES
	2582	Intuit Inc.	(NDQ)	INTU	58.95	3	1	3	.90	90- 110	(55- 85%)	17.6	1.2	3.35	.68	47	10/31	◆d.03	d.10	3/31	◆.17	.15	YES
	190	Intuitive Surgical	(NDQ)	ISRG	542.49	3	3	3	1.20	495- 745	(N- 35%)	33.0	NIL	16.45	NIL	40	9/30	3.54	3.05	9/30	NIL	NIL	YES
	222	Invacare Corp.		IVC	13.07	4	3	4	.90	20- 30	(55-130%)	16.3	0.4	.80	.05	45	9/30	.21	.59	3/31	◆.013	.013	YES
	2555	Invesco Ltd.		IVZ	24.04	3	4	3	1.45	35- 60	(45-150%)	13.9	3.0	1.73	.73	33	9/30	.38	.36	12/31	.173	.123	YES
	1786	Investment Techn.		ITG	8.50	5	3	1	1.10	19- 30	(125-255%)	23.6	NIL	.36	NIL	76	9/30	.01	.25	9/30	NIL	NIL	YES
	1507	Investors Bancorp	(NDQ)	ISBC	16.73	2	3	4	.75	20- 30	(20- 80%)	18.2	1.2	.92	.20	53	9/30	.23	.19	12/31	▲.05	NIL	YES
	2416	ION Geophysical		IO	6.21	3	5	4	2.30	12- 20	(95-220%)	13.2	NIL	.47	NIL	66	9/30	.11	.06	9/30	NIL	NIL	YES
2255	716	iRobot Corp.	(NDQ)	IRBT	17.22	4	3	1	1.00	40- 60	(130-250%)	13.1	NIL	1.31	NIL	64	9/30	.54	.50	9/30	NIL	NIL	YES
	390	Iron Mountain		IRM	33.31	3	3	2	.95	40- 60	(20- 80%)	25.4	3.2	1.31	1.08	34	9/30	.34	.37	12/31	.27	.25	YES
2038	835	Isis Pharmac.	(NDQ)	ISIS	8.88	3	4	2	.90	13- 20	(45-125%)	NMF	NIL	d1.10	NIL	44	9/30	d.33	d.27	9/30	NIL	NIL	YES
	586	Itron Inc.	(NDQ)	ITRI	40.80	4	3	2	1.15	75- 105	(85-155%)	10.6	NIL	3.86	NIL	69	9/30	.97	.86	9/30	NIL	NIL	YES
	1923	**J&J Snack Foods**	(NDQ)	JJSF	60.46	2	2	2	.70	55- 75	(N- 25%)	20.7	1.0	2.92	.59	25	9/30	1.03	.85	12/31	.13	.118	
	1332	JDS Uniphase	(NDQ)	JDSU	11.05	4	4	2	1.65	20- 35	(80-215%)	14.4	NIL	.77	NIL	86	9/30	.15	.18	9/30	NIL	NIL	YES
2039	2515	JPMorgan Chase		JPM	40.59	2	3	4	1.25	55- 80	(35- 95%)	7.9	3.3	5.15	1.35	35	9/30	1.40	1.02	12/31	.30	.25	YES
	929	j2 Global	(NDQ)	JCOM	29.30	3	3	3	.95	30- 40	(N- 35%)	12.1	3.2	2.42	.93	84	9/30	.69	.54	12/31	▲.225	.205	YES
	1333	Jabil Circuit		JBL	18.26	5	3	2	1.35	40- 55	(120-200%)	9.3	2.0	1.97	.36	86	8/31	.44	.55	12/31	.08	.08	YES
	362	Jack in the Box	(NDQ)	JACK	26.26	3	3	3	.95	20- 30	(N- 15%)	16.5	NIL	1.59	NIL	32	9/30	◆.39	.49	9/30	NIL	NIL	YES
	1237	Jacobs Engineering		JEC	39.70	3	3	3	1.35	60- 90	(50-125%)	12.3	NIL	3.22	NIL	68	9/30	.83	.74	9/30	NIL	NIL	YES
	2556	Janus Capital Group		JNS	8.27	3	3	2	1.85	13- 20	(55-140%)	14.3	2.9	.58	.24	33	9/30	.14	.15	12/31	.06	.05	YES
	418	Japan Equity Fund		JEQ	5.17	–	4	3	.75	7- 11	(35-115%)	NMF	1.0	NMF	.05	–	4/30	6.12(q)	6.53(q)	9/30	NIL	NIL	
	419	Japan Smaller Cap Fd		JOF	6.99	–	4	3	.75	10- 16	(45-130%)	NMF	0.7	NMF	.05	–	2/28	8.85(q)	9.80(q)	9/30	NIL	NIL	
	1191	Jarden Corp.		JAH	52.24	2	3	4	1.35	45- 70	(N- 35%)	18.9	NIL	2.76	NIL	3	9/30	1.00	1.03	9/30	NIL	.086	YES
246	1787	Jefferies Group		JEF	16.00	–	3	–	1.45	35- 50	(120-215%)	11.3	1.9	1.41	.30	76	8/31	.31	.30	12/31	.075	.075	YES
	310	JetBlue Airways	(NDQ)	JBLU	5.00	4	4	3	1.25	11- 19	(120-280%)	10.0	NIL	▼.50	NIL	63	9/30	.14	.11	9/30	NIL	NIL	YES
2038	223	Johnson & Johnson		JNJ	69.25	2	1	3	.65	85- 100	(25- 45%)	13.3	3.5	5.20	2.44	45	9/30	1.25	1.24	12/31	.61	.57	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

Page (Selection & Opinion)	Page (Ratings & Reports)	NAME OF STOCK		Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	% appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	998	Johnson Controls		JCI	26.03	3	3	3	1.30	45- 70	(75-170%)	9.4	2.9	2.77	.76	72	9/30	.77	.75	12/31	▲.19	.16	YES
	2109	Jones Group (The)		JNY	11.33	3	3	2	1.55	14- 20	(25- 75%)	9.4	1.8	1.21	.20	16	9/30	.42	.48	12/31	.05	.05	YES
	1036	Jones Lang LaSalle		JLL	76.59	3	3	4	1.40	90- 135	(20- 75%)	14.7	0.5	5.21	.40	15	9/30	1.10	.76	12/31	.20	.15	YES
627	2222	Joseph A. Bank	(NDQ)	JOSB	47.05	3	3	3	1.00	60- 90	(30- 90%)	11.9	NIL	3.95	NIL	18	7/31	.83	.74	9/30	NIL	NIL	YES
	2373	Journal Communications		JRN	5.40	3	4	2	1.70	8- 14	(50-160%)	10.4	NIL	.52	NIL	50	9/30	.14	.07	9/30	NIL	NIL	YES
	598	Joy Global		JOY	57.07	4	3	3	1.60	95- 140	(65-145%)	7.0	1.2	8.21	.70	97	7/31	1.81	1.61	9/30	.175	.175	YES
	959	Juniper Networks		JNPR	16.36	3	3	2	1.20	30- 45	(85-175%)	24.8	NIL	.66	NIL	90	9/30	.15	.20	9/30	NIL	NIL	YES
	2160	**K-Swiss, Inc.**	(NDQ)	KSWS	2.95	3	4	4	1.00	8- 15	(170-410%)	NMF	NIL	d.42	NIL	61	9/30	d.05	d.38	9/30	NIL	NIL	YES
1433	1125	KB Home		KBH	14.08	3	4	5	1.55	14- 25	(N- 80%)	NMF	0.7	d.11	.10	2	8/31	.04	d.13	12/31	.025	.063	YES
	1238	KBR, Inc.		KBR	27.07	3	3	4	1.35	40- 65	(50-140%)	10.6	0.7	2.56	.20	68	9/30	.65	.62	12/31	.05	.05	YES
	2648	KKR & Co. L.P.		KKR	14.02	3	2	3	1.35	35- 45	(150-220%)	5.3	6.8	2.67	.96	43	9/30	.69	d.91	12/31	.24	.10	YES
	122	KLA-Tencor	(NDQ)	KLAC	44.25	4	3	2	1.25	65- 100	(45-125%)	14.3	3.6	3.10	1.60	60	9/30	.84	1.17	12/31	.40	.35	YES
	1755	Kadant Inc.		KAI	23.39	3	3	3	1.25	35- 55	(50-135%)	10.8	NIL	2.16	NIL	29	9/30	.66	.47	9/30	NIL	NIL	YES
	1756	Kaman Corp.		KAMN	33.44	2	3	4	1.15	45- 70	(35-110%)	13.4	1.9	2.49	.64	29	9/30	.59	.47	3/31	.16	.16	YES
	341	Kansas City South'n		KSU	75.89	3	3	3	1.30	95- 140	(25- 85%)	21.9	1.0	3.47	.78	51	9/30	.82	.78	12/31	.195	NIL	YES
	1716	Kaydon Corp.		KDN	21.76	–	3	–	NMF	45- 70	(105-220%)	12.5	3.7	1.74	.80	22	9/30	.44	.47	3/31	.20	.20	YES
	1924	Kellogg		K	54.74	3	1	2	.55	70- 90	(30- 65%)	15.8	3.2	3.46	1.76	25	9/30	.82	.80	12/31	.44	.43	YES
	1637	Kelly Services 'A'	(NDQ)	KELYA	13.12	4	3	3	1.25	25- 35	(90-165%)	9.6	1.5	1.36	.20	58	9/30	.43	.49	12/31	.05	.05	YES
	2557	Kemper Corp.		KMPR	29.12	3	3	3	1.15	40- 60	(35-105%)	12.9	3.3	2.25	.96	33	9/30	.42	.06	12/31	.24	.24	
	734	Kennametal Inc.		KMT	36.50	4	3	4	1.40	65- 95	(80-160%)	11.1	1.8	3.29	.64	49	9/30	.57	.88	12/31	.16	.14	YES
	1432	Kenneth Cole 'A'		KCP					SEE FINAL SUPPLEMENT - PAGE 1432														
	2516	KeyCorp		KEY	8.17	3	3	3	1.25	10- 15	(20- 85%)	9.0	2.4	.91	.20	35	9/30	.23	.24	12/31	◆.05	.03	YES
	1152	Kimball Int'l 'B'	(NDQ)	KBALB	12.00	2	3	3	1.20	10- 14	(N- 15%)	22.2	1.7	.54	.20	48	9/30	.13	NIL	12/31	.05	.05	YES
	1192	Kimberly-Clark		KMB	86.00	1	1	3	.55	95- 115	(10- 35%)	16.5	3.4	5.21	2.96	3	9/30	1.30	1.09	3/31	◆.74	.70	YES
	1530	Kimco Realty		KIM	18.81	2	3	4	1.25	17- 25	(N- 35%)	52.3	4.5	.36	.84	20	9/30	.08	.08	3/31	▲.21	.19	YES
	620	Kinder Morgan Energy		KMP	79.87	1	2	3	.75	90- 120	(15- 50%)	33.0	6.3	2.42	5.04	9	9/30	.57	.44	12/31	▲1.26	1.16	YES
	1563	Kinross Gold		KGC	9.62	3	3	1	1.00	19- 30	(100-210%)	10.0	1.7	.96	.16	79	9/30	.22	.19	9/30	.08	.06	YES
	333	Kirby Corp.		KEX	56.56	4	3	3	1.15	80- 120	(40-110%)	14.8	NIL	3.81	NIL	81	9/30	.95	.94	9/30	NIL	NIL	YES
	1788	Knight Capital Group		KCG	2.54	4	4	5	.75	4- 6	(55-135%)	NMF	NIL	d6.11	NIL	76	9/30	d6.30	.28	9/30	NIL	NIL	YES
	324	Knight Transportation		KNX	15.11	3	3	3	.85	25- 40	(65-165%)	17.4	1.6	.87	.24	77	9/30	.21	.21	12/31	.06	.06	YES
	2144	Kohl's Corp.		KSS	52.23	3	2	3	.95	90- 120	(70-130%)	10.8	2.6	4.83	1.37	30	10/31	.91	.80	12/31	.32	.25	YES
	1986	Konami Corp. ADS		KNM	23.72	4	3	1	.85	40- 60	(70-155%)	14.4	3.0	1.65	.70	96	6/30	.25	.36	9/30	NIL	NIL	
	420	Korea Fund		KF	37.88	–	4	3	1.10	50- 80	(30-110%)	NMF	0.3	NMF	.10	–	6/30	40.51(q)	54.59(q)	9/30	NIL	NIL	
	1638	Korn/Ferry Int'l		KFY	13.31	4	3	2	1.20	25- 35	(90-165%)	15.3	NIL	.87	NIL	58	7/31	.22	.33	9/30	NIL	NIL	YES
		Kraft Foods							NAME CHANGED TO MONDELEZ INT'L														
	1952	Kraft Foods Group	(NDQ)	KRFT	44.89	–	2	–	NMF	45- 60	(N- 35%)	17.0	4.5	2.64	2.00	59	9/30	.79	NA	9/30	NIL	NIL	YES
	363	Krispy Kreme		KKD	7.54	▲2	4	2	1.25 ▲	9- 16	(20-110%)	14.2	NIL	▲.53	NIL	32	10/31	◆.12	.07	9/30	NIL	NIL	YES
	1953	Kroger Co.		KR	24.63	3	2	2	.60	40- 50	(60-105%)	9.9	2.4	2.48	.60	59	7/31	.51	.47	12/31	▲.15	.115	YES
	562	Kronos Worldwide		KRO	15.00	5	3	3	1.40	30- 40	(100-165%)	7.1	4.0	2.11	.60	23	9/30	.30	.74	12/31	.15	.15	YES
	1393	Kulicke & Soffa	(NDQ)	KLIC	10.26	4	5	3	1.65	12- 20	(15- 95%)	7.5	NIL	1.36	NIL	95	9/30	.89	.03	9/30	NIL	NIL	YES
	1987	Kyocera Corp. ADR(g)		KYO	92.88	4	1	3	1.00	125- 155	(35- 65%)	15.6	1.6	5.94	1.51	96	9/30	1.32	1.46	9/30	.753	.729	
	717	**L-3 Communic.**		LLL	74.85	4	2	3	.90	105- 145	(40- 95%)	9.2	2.7	8.10	2.05	64	9/30	1.98	2.22	12/31	.50	.45	YES
	191	LCA-Vision	(NDQ)	LCAV	3.24	4	4	5	1.40	5- 8	(55-145%)	NMF	NIL	d.31	NIL	40	9/30	d.19	d.20	9/30	NIL	NIL	YES
	999	LKQ Corp.	(NDQ)	LKQ	21.25	2	3	3	.95	25- 35	(20- 65%)	22.4	NIL	.95	NIL	72	9/30	.18	.17	9/30	NIL	NIL	YES
	1364	LSI Corp.		LSI	6.73	3	3	3	1.25	30- 45	(345-570%)	9.1	NIL	.74	NIL	88	9/30	.17	.05	9/30	NIL	NIL	YES
	1153	La-Z-Boy Inc.		LZB	15.84	2	3	4	1.45	20- 30	(25- 90%)	20.3	NIL	.78	NIL	48	7/31	.08	.04	9/30	NIL	NIL	YES
	807	Laboratory Corp.		LH	83.65	3	1	3	.70	135- 165	(60- 95%)	11.6	NIL	7.21	NIL	55	9/30	1.76	1.61	9/30	NIL	NIL	YES
	542	Laclede Group		LG	39.16	3	2	3	.55	40- 55	(N- 40%)	14.7	4.3	2.67	1.70	28	9/30	◆d.03	d.13	3/31	▲.425	.415	YES
	1394	Lam Research	(NDQ)	LRCX	34.68	3	3	3	1.20	60- 90	(75-160%)	22.1	NIL	1.57	NIL	95	9/30	.02	.57	12/31	NIL	NIL	YES
	2383	Lamar Advertising	(NDQ)	LAMR	40.69	3	4	3	1.55	20- 35	(N- N%)	86.6	NIL	.47	NIL	65	9/30	.12	.04	9/30	NIL	NIL	YES
	1193	Lancaster Colony	(NDQ)	LANC	73.29	2	1	2	.70	65- 75	(N- N%)	18.3	2.1	4.00	1.53	3	9/30	.98	.78	9/30	.36	.33	YES
	123	Landauer, Inc.		LDR	57.30	2	3	3	.80	70- 100	(20- 75%)	20.7	3.8	2.77	2.20	60	6/30	.69	.59	12/31	.55	.55	
	2345	Las Vegas Sands		LVS	43.43	4	3	3	2.55	85- 130	(95-200%)	17.0	2.3	2.55	1.00	71	9/30	.42	.44	12/31	.25	NIL	YES
	1365	Lattice Semiconductor	(NDQ)	LSCC	3.93	4	3	2	1.25	7- 10	(80-155%)	49.1	NIL	.08	NIL	88	9/30	d.02	.11	9/30	NIL	NIL	YES
	1016	Lauder (Estee)		EL	57.70	3	2	2	1.00	75- 105	(30- 80%)	22.9	1.2	2.52	.72	54	9/30	.79	.71	12/31	▲.72	.525	YES
2256	735	Lawson Products	(NDQ)	LAWS	8.51	4	4	4	1.20	12- 17	(40-100%)	NMF	5.6	d.10	.48	49	9/30	d.15	d.25	9/30	.12	.12	
	1239	Layne Christensen	(NDQ)	LAYN	21.40	4	3	3	1.35	40- 65	(85-205%)	13.3	NIL	1.61	NIL	68	7/31	.25	.54	9/30	NIL	NIL	YES
	2558	Lazard Ltd.		LAZ	28.41	3	3	2	1.20	55- 80	(95-180%)	20.6	2.8	1.38	.80	33	9/30	.26	.49	12/31	.20	.16	YES
	930	Leap Wireless	(NDQ)	LEAP	6.30	5	5	2	1.40	7- 14	(10-120%)	NMF	NIL	d2.19	NIL	84	9/30	d1.14	d.58	9/30	NIL	NIL	YES
1051	2311	LeapFrog Enterpr. 'A'		LF	7.94	3	4	4	1.35	13- 20	(65-150%)	9.6	NIL	.83	NIL	17	9/30	.60	.35	9/30	NIL	NIL	YES
	1000	Lear Corp.		LEA	42.28	3	3	3	1.15	60- 90	(40-115%)	7.8	1.3	5.44	.56	72	9/30	1.29	1.08	12/31	◆.14	.125	YES
1246	2006	Learning Tree Int'l	(NDQ)	LTRE	5.50	–	4	–	.95	6- 10	(10- 80%)	NMF	NIL	d.24	NIL	98	6/30	d.19	.05	9/30	NIL	NIL	
	1154	Leggett & Platt		LEG	26.93	2	2	2	1.10	30- 45	(10- 65%)	17.2	4.4	1.57	1.18	48	9/30	.45	.31	12/31	▲.29	.28	YES
	2559	Legg Mason		LM	25.38	3	3	2	1.60	45- 65	(75-155%)	11.8	1.7	2.15	.44	33	9/30	.60	.39	3/31	.11	.08	YES
1434	1126	Lennar Corp.		LEN	36.81	2	3	5	1.80	35- 50	(N- 35%)	29.7	0.4	1.24	.16	2	8/31	.40	.11	12/31	.04	.04	YES
	1717	Lennox Int'l		LII	50.33	1	3	4	1.00	60- 85	(20- 70%)	19.0	1.6	2.65	.80	22	9/30	.97	.64	12/31	▲.20	.18	YES
627	1424	Lexmark Int'l 'A'		LXK	24.04	4	3	2	.90	30- 40	(25- 65%)	6.2	5.0	3.87	1.20	87	9/30	.94	.95	12/31	.30	.25	YES
	1209	Liberty All-Star		USA	4.46	–	2	3	1.10	6- 9	(35-100%)	NMF	5.4	NMF	.24	–	6/30	5.16(q)	5.74(q)	9/30	.06	.06	
	1026	Liberty Global	(NDQ)	LBTYA	56.80	3	3	4	1.20	60- 95	(5- 65%)	NMF	NIL	d.41	NIL	42	9/30	d.08	d1.23	9/30	NIL	NIL	YES
	1531	Liberty Property		LRY	33.93	3	3	3	1.25	30- 45	(N- 35%)	32.3	5.6	1.05	1.90	20	9/30	.24	.27	12/31	.475	.475	YES
	224	Life Technologies	(NDQ)	LIFE	47.96	3	2	3	.90	65- 85	(35- 75%)	11.5	NIL	4.16	NIL	45	9/30	.92	.94	9/30	NIL	NIL	YES
	808	LifePoint Hospitals	(NDQ)	LPNT	36.19	3	3	3	1.05	65- 85	(80-135%)	10.9	NIL	3.32	NIL	55	9/30	.60	.77	9/30	NIL	NIL	YES
	1612	Lilly (Eli)		LLY	47.03	3	1	3	.80	35- 45	(N- N%)	14.0	4.2	3.37	1.96	31	9/30	.79	1.13	12/31	.49	.49	YES
	2223	Limited Brands		LTD	48.31	2	3	4	1.20	45- 70	(N- 45%)	16.5	2.1	2.92	1.00	18	10/31	◆.25	.31	12/31	◆.25	.20	YES
	1718	Lincoln Elec Hldgs.	(NDQ)	LECO	44.73	3	3	4	1.25	55- 80	(25- 80%)	13.8	1.5	3.25	.68	22	9/30	.80	.66	12/31	.17	.155	YES
	1548	Lincoln Nat'l Corp.		LNC	24.20	3	3	3	2.00	40- 55	(65-125%)	5.7	2.0	4.23	.48	57	9/30	1.18	1.00	3/31	▲.12	.08	YES
	1719	Lindsay Corp.		LNN	74.65	2	3	5	1.35	65- 95	(N- 25%)	19.1	0.6	3.90	.46	22	8/31	.68	.46	12/31	.115	.09	YES
	1366	Linear Technology	(NDQ)	LLTC	31.97	3	3	3	1.00	45- 65	(40-105%)	16.0	3.1	2.00	1.00	88	9/30	.45	.46	12/31	.25	.24	YES
	2626	LinkedIn		LNKD	105.53	–	3	–	NMF	95- 145	(N- 35%)	NMF	NIL	.19	NIL	56	9/30	.02	d.02	9/30	NIL	NIL	YES
	529	Linn Energy, LLC	(NDQ)	LINE	38.99	2	3	3	.85	45- 70	(15- 80%)	22.8	7.5	1.71	2.94	67	9/30	.45	.44	12/31	.725	.69	YES
249	2329	Lions Gate Entertain.		LGF	15.64	1	5	3	.55	25- 45	(60-190%)	10.6	NIL	1.48	NIL	12	9/30	.53	d.19	9/30	NIL	NIL	YES
	2330	Live Nation Entertain.		LYV	8.72	4	4	3	1.55	11- 19	(25-120%)	NMF	NIL	d.22	NIL	12	9/30	.31	.27	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

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Page (Selection & Opinion)	Page (Ratings & Reports)	NAME OF STOCK	Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
1821	718	Lockheed Martin	LMT	90.48	3	1	3	.80	100- 120	(10- 35%)	11.3	5.1	8.01	4.60	64	9/30	2.21	1.99	12/31	▲1.15	1.00	YES
	2560	Loews Corp.	L	40.84	3	2	3	1.10	50- 70	(20- 70%)	13.0	0.6	3.14	.25	33	9/30	.44	.44	12/31	.063	.063	YES
	1409	Logitech Int'l (NDQ)	LOGI	6.84	5	3	3	1.20	14- 20	(105-190%)	7.9	NIL	.87	NIL	94	9/30	.14	.10	9/30	NIL	NIL	YES
	1994	Lorillard Inc.	LO	119.22	3	2	3	.55	185- 250	(55-110%)	13.0	5.2	9.17	6.20	27	9/30	2.17	1.94	12/31	1.55	1.30	YES
	1163	Louisiana-Pacific	LPX	16.55	2	5	2	1.90	15- 25	(N- 50%)	25.5	NIL	.65	NIL	10	9/30	.20	d.19	9/30	NIL	NIL	YES
★★	1138	Lowe's Cos.	LOW	33.96	▲2	2	3	.95	40- 55	(20- 60%)	17.6	1.9	1.93	.64	1	10/31	◆.40	.35	3/31	◆.16	.14	YES
	2224	lululemon athletica (NDQ)	LULU	71.23	2	3	4	1.40	80- 120	(10- 70%)	35.3	NIL	2.02	NIL	18	7/31	.39	.26	9/30	NIL	NIL	YES
2256	1139	Lumber Liquidators	LL	54.34	1	3	4	1.10	50- 70	(N- 30%)	33.8	NIL	1.61	NIL	1	9/30	.46	.24	9/30	NIL	NIL	YES
	2182	Luxottica Group ADR(g)	LUX	38.54	1	3	4	1.10	40- 60	(5- 55%)	23.5	1.7	1.64	.65	26	9/30	.37	.31	9/30	NIL	NIL	YES
626	2517	**M&T Bank Corp.**	MTB	98.18	1	3	4	1.05	110- 165	(10- 70%)	12.9	2.9	7.64	2.80	35	9/30	2.17	1.53	9/30	.70	.70	YES
	1127	M.D.C. Holdings	MDC	34.32	1	3	5	1.25	35- 55	(N- 60%)	32.1	2.9	1.07	1.00	2	9/30	.41	d.68	12/31	.25	.25	YES
	530	MDU Resources	MDU	20.02	3	1	3	1.00	25- 30	(25- 50%)	15.9	3.4	1.26	.69	67	9/30	.38	.34	3/31	▲.173	.168	YES
	1367	MEMC Elec. Mat'ls	WFR	2.42	4	4	3	1.60	7- 11	(190-355%)	34.6	NIL	.07	NIL	88	9/30	d.24	.03	9/30	NIL	NIL	YES
	1210	MFS Multimarket	MMT	7.21	–	4	3	.55	6- 10	(N- 40%)	NMF	7.1	NMF	.51	–	4/30	7.41(q)	7.45(q)	9/30	.12	.13	
	915	MGE Energy (NDQ)	MGEE	49.18	1	1	3	.60	45- 55	(N- 10%)	16.6	3.2	2.97	1.58	24	9/30	1.02	.91	12/31	◆.395	.383	
1645	2561	MGIC Investment	MTG	1.68	–	5	–	2.45	NMF	(NMF)	NMF	NIL	d1.18	NIL	33	9/30	d1.22	d.86	9/30	NIL	NIL	YES
	2346	MGM Resorts Int'l	MGM	9.60	5	4	3	2.25	14- 25	(45-160%)	NMF	NIL	d.61	NIL	71	9/30	d.23	d.14	9/30	NIL	NIL	YES
	1395	MKS Instruments (NDQ)	MKSI	24.01	3	3	1	1.15	30- 45	(25- 85%)	21.4	2.7	1.12	.64	95	9/30	.05	.57	12/31	◆.16	.15	YES
	1720	MSC Industrial Direct	MSM	70.30	3	2	3	1.00	125- 170	(80-140%)	15.6	1.7	4.52	1.20	22	8/31	1.11	.93	12/31	▲.30	.25	YES
	124	MTS Systems (NDQ)	MTSC	46.00	▼3	3	3	.90	65- 95	(40-105%)	11.3	2.6	4.06	1.20	60	9/30	◆.94	.94	12/31	▲.30	.25	
	1532	Mack-Cali R'lty	CLI	25.02	4	3	3	1.20	30- 50	(20-100%)	39.7	7.2	.63	1.80	20	9/30	.16	.24	12/31	.45	.45	YES
	392	Macquarie Infrastructure	MIC	41.40	1	5	3	2.05	40- 75	(N- 80%)	43.1	6.9	.96	2.85	34	9/30	d.04	.14	12/31	▲.688	.20	YES
	2145	Macy's Inc.	M	40.93	2	3	3	1.35	50- 75	(20- 85%)	11.6	2.3	3.52	.95	30	10/31	.36	.32	3/31	.20	.10	YES
	2161	Madden (Steven) Ltd. (NDQ)	SHOO	43.11	2	3	3	1.05	50- 75	(15- 75%)	15.1	NIL	2.86	NIL	61	9/30	.86	.74	9/30	NIL	NIL	YES
	2331	Madison Square Garden(NDQ)	MSG	44.28	3	3	3	.85	35- 50	(N- 15%)	31.6	NIL	1.40	NIL	12	9/30	.26	.28	12/31	NIL	NIL	YES
	621	Magellan Midstream(●)	MMP	42.85	1	3	3	.85	30- 40	(N- N%)	20.9	4.5	2.05	1.94	9	9/30	.35	.49	12/31	▲.485	.40	YES
	1001	Magna Int'l 'A'	MGA	44.42	2	3	3	1.20	80- 120	(80-170%)	8.0	2.5	5.56	1.10(h)	72	9/30	1.13	.94	12/31	.275	.25	YES
	2110	Maidenform Brands	MFB	17.53	3	3	4	1.20	30- 45	(70-155%)	10.8	NIL	1.63	NIL	16	9/30	.46	.44	9/30	NIL	NIL	YES
	2610	Manhattan Assoc. (NDQ)	MANH	58.88	1	3	3	.85	70- 105	(20- 80%)	20.5	NIL	2.87	NIL	14	9/30	.69	.70	9/30	NIL	NIL	YES
	167	Manitowoc Co.	MTW	14.04	3	4	4	2.10	20- 35	(40-150%)	14.5	0.6	.97	.08	85	9/30	.17	.18	12/31	.08	.08	YES
	1639	Manpower Inc.	MAN	36.91	4	3	3	1.30	70- 110	(90-200%)	13.5	2.3	2.73	.86	58	9/30	.79	.97	12/31	.43	.40	YES
	2611	ManTech Int'l 'A' (NDQ)	MANT	24.62	4	3	2	.80	55- 80	(125-225%)	9.1	3.4	2.71	.84	14	9/30	.66	.94	12/31	.21	.42	YES
	1549	Manulife Fin'l	MFC	12.14	3	3	4	1.60	25- 35	(105-190%)	12.6	4.3	.96	.52	57	9/30	d.14	d.73	12/31	.13	.124	YES
	2398	Marathon Oil Corp.	MRO	31.13	–	2	–	NMF	35- 45	(10- 45%)	12.5	2.2	2.50	.68	83	9/30	.63	.57	12/31	.17	.15	YES
1822	508	Marathon Petroleum	MPC	56.57	–	3	–	NMF	50- 75	(N- 35%)	6.5	2.5	8.71	1.40	74	9/30	3.59	3.16	12/31	.35	.25	YES
	2347	Marcus Corp.	MCS	10.82	4	3	1	1.25	16- 25	(50-130%)	14.4	3.1	.75	.34	71	8/31	.37	.42	12/31	.085	.085	
	2183	MarineMax	HZO	7.50	3	4	5	1.65	15- 25	(100-235%)	NMF	NIL	.06	NIL	26	9/30	d.07	d.25	9/30	NIL	NIL	YES
	768	Markel Corp.	MKL	482.00	2	2	3	.80	685- 925	(40- 90%)	21.6	NIL	22.36	NIL	11	9/30	4.96	4.62	9/30	NIL	NIL	YES
	2348	Marriott Int'l	MAR	35.45	–	3	–	1.25	50- 75	(40-110%)	18.5	1.5	1.92	.52	71	9/30	.44	.29	12/31	.13	.10	YES
	2562	Marsh & McLennan	MMC	35.08	3	3	3	.75	40- 60	(15- 70%)	15.3	2.6	2.29	.92	33	9/30	.39	.24	12/31	.23	.22	YES
	1194	Martha Stewart	MSO	2.46	–	4	–	1.30	6- 9	(145-265%)	NMF	NIL	d.96	NIL	3	9/30	d.76	d.18	9/30	NIL	NIL	YES
	1110	Martin Marietta	MLM	85.41	2	3	4	1.15	90- 135	(5- 60%)	30.3	1.9	2.82	1.60	7	9/30	1.36	1.08	12/31	◆.40	.40	YES
	960	Marvell Technology (NDQ)	MRVL	7.70	5	3	3	1.25	20- 30	(160-290%)	7.6	3.1	1.01	.24	90	10/31	◆.20	.40	12/31	.06	NIL	YES
	1111	Masco Corp.	MAS	15.44	2	3	4	1.40	20- 30	(30- 95%)	37.7	1.9	.41	.30	7	9/30	.13	.08	12/31	.075	.075	YES
	225	Masimo Corp. (NDQ)	MASI	21.59	3	3	4	1.00	45- 70	(110-225%)	18.8	NIL	1.15	NIL	45	9/30	.24	.24	9/30	NIL	NIL	YES
	1240	MasTec	MTZ	21.76	2	3	3	1.15	25- 40	(15- 85%)	12.5	NIL	1.74	NIL	68	9/30	.53	.36	9/30	NIL	NIL	YES
	2563	MasterCard Inc.	MA	478.68	2	3	3	1.10	520- 775	(10- 60%)	20.3	0.3	23.59	1.20	33	9/30	6.17	5.63	12/31	.30	.15	YES
	1575	Materion Corp.	MTRN	19.66	4	3	2	1.65	45- 65	(130-230%)	13.2	1.5	1.49	.30	93	9/30	.39	.65	12/31	.075	NIL	YES
	334	Matson, Inc.	MATX	21.46	–	3	–	NMF	35- 55	(65-155%)	15.0	2.8	1.43	.60	81	9/30	.45	.21	12/31	.15	.315	YES
	2312	Mattel, Inc. (NDQ)	MAT	35.84	1	2	3	.85	35- 45	(N- 25%)	13.6	3.5	2.63	1.24	17	9/30	1.04	.85	12/31	.31	.23	YES
	1816	Matthews Int'l (NDQ)	MATW	28.87	4	3	2	.90	50- 75	(75-160%)	11.8	1.4	2.45	.40	5	9/30	◆.61	.71	12/31	▲.10	.09	YES
	1368	Maxim Integrated (NDQ)	MXIM	27.45	3	3	3	1.10	30- 50	(10- 80%)	14.5	3.5	1.89	.96	88	9/30	.47	.46	12/31	▲.24	.22	YES
	391	MAXIMUS Inc.	MMS	59.07	1	2	4	.80	65- 90	(10- 50%)	21.2	0.7	2.79	.40	34	9/30	◆.74	.64	12/31	.09	.09	YES
	2374	McClatchy Co.	MNI	2.96	4	5	4	2.05	4- 7	(35-135%)	6.0	NIL	.49	NIL	50	9/30	.04	.11	9/30	NIL	NIL	YES
	1925	McCormick & Co.	MKC	64.56	1	1	3	.60	80- 95	(25- 45%)	19.6	2.1	3.30	1.36	25	8/31	.78	.69	12/31	.31	.28	YES
	1757	McDermott Int'l	MDR	10.09	4	3	3	1.85	25- 40	(150-295%)	9.5	NIL	1.06	NIL	29	9/30	.21	.04	9/30	NIL	NIL	YES
2256	364	McDonald's Corp.	MCD	85.04	3	1	3	.60	110- 130	(30- 55%)	15.6	3.6	5.45	3.08	32	9/30	1.43	1.45	12/31	▲.77	.70	YES
	2366	McGraw-Hill	MHP	50.97	–	3	–	1.10	NMF	(NMF)	NMF	2.0	NMF	1.02	82	9/30	1.10	1.21	12/31	◆.255	.25	YES
	226	McKesson Corp.	MCK	92.71	3	1	3	.75	120- 145	(30- 55%)	12.8	0.9	7.27	.88	45	9/30	1.92	1.49	3/31	.20	.20	YES
	1926	Mead Johnson Nutrition	MJN	66.82	3	3	2	.65	65- 95	(N- 40%)	21.3	1.8	3.14	1.20	25	9/30	.69	.70	12/31	.30	.26	YES
	1177	MeadWestvaco	MWV	29.27	3	3	3	1.25	45- 70	(55-140%)	17.3	3.7	1.69	1.08	46	9/30	.39	.70	12/31	.25	.25	YES
	125	Measurement Specialties(NDQ)	MEAS	30.16	3	3	3	1.45	40- 65	(35-115%)	14.0	NIL	2.16	NIL	60	9/30	.64	.42	9/30	NIL	NIL	YES
	823	MedAssets (NDQ)	MDAS	15.76	3	3	3	.85	18- 25	(15- 60%)	50.8	NIL	.31	NIL	78	9/30	.09	d.02	9/30	NIL	NIL	YES
	2375	Media General 'A'	MEG	4.02	3	5	2	1.75	3- 7	(N- 75%)	NMF	NIL	d2.72	NIL	50	9/30	d.81	d1.32	9/30	NIL	NIL	YES
	227	Medical Action Inds. (NDQ)	MDCI	2.65	4	3	4	1.15	4- 6	(50-125%)	11.0	NIL	.24	NIL	45	9/30	.02	.01	9/30	NIL	NIL	
	1613	Medicines Company (NDQ)	MDCO	20.89	3	3	3	1.05	25- 40	(20- 90%)	22.0	NIL	.95	NIL	31	9/30	.17	.12	9/30	NIL	NIL	YES
846	1614	Medicis Pharmac.	MRX	43.25	–	3	–	1.05	75- 110	(75-155%)	16.4	1.0	2.63	.44	31	6/30	.52	.68	12/31	.10	.08	YES
	824	Medidata Solutions (NDQ)	MDSO	41.60	3	3	3	.95	35- 55	(N- 30%)	34.7	NIL	1.20	NIL	78	9/30	.16	.31	9/30	NIL	NIL	YES
	809	MEDNAX, Inc.	MD	73.78	2	3	2	1.00	85- 130	(15- 75%)	14.7	NIL	5.01	NIL	55	9/30	1.32	1.19	9/30	NIL	NIL	YES
	192	Medtronic, Inc.	MDT	41.81	3	1	3	.85	60- 70	(45- 65%)	11.4	2.6	3.68	1.08	40	10/31	◆.88	.84	12/31	.26	.243	YES
	2349	Melco Crown Ent. ADR (NDQ)	MPEL	14.50	3	3	4	1.80	25- 40	(70-175%)	20.1	NIL	.72	NIL	71	9/30	.17	.21	9/30	NIL	NIL	YES
2040	1369	Mellanox Technologies (NDQ)	MLNX	84.71	2	3	3	1.05	100- 150	(20- 75%)	17.7	NIL	4.78	NIL	88	9/30	1.37	.13	9/30	NIL	NIL	YES
850	2225	Men's Wearhouse	MW	33.00	3	3	3	1.05	45- 70	(35-110%)	10.8	2.5	3.06	.84	18	7/31	1.15	1.09	12/31	.18	.12	YES
	2583	Mentor Graphics (NDQ)	MENT	14.25	3	3	2	1.05	25- 35	(75-145%)	11.0	NIL	1.30	NIL	47	7/31	.16	.04	9/30	NIL	NIL	YES
2445	1615	Merck & Co.	MRK	43.34	3	1	3	.80	45- 55	(5- 25%)	11.9	3.9	3.64	1.68	31	9/30	.95	.94	12/31	.42	.38	YES
		Mercury Computer Sys.							NAME CHANGED TO MERCURY SYSTEMS													
	769	Mercury General	MCY	39.63	3	2	2	.70	40- 55	(N- 40%)	15.6	6.2	2.54	2.45	11	9/30	.62	.72	12/31	▲.613	.61	YES
	1410	Mercury Systems (NDQ)	MRCY	8.32	5	4	3	1.00	17- 30	(105-260%)	NMF	NIL	d.05	NIL	94	9/30	d.08	.09	12/31	NIL	NIL	YES
	2367	Meredith Corp.	MDP	29.79	3	3	2	1.10	45- 65	(50-120%)	10.3	5.4	2.90	1.60	82	9/30	.55	.48	12/31	.383	.383	YES
	228	Meridian Bioscience (NDQ)	VIVO	20.02	3	3	3	.85	20- 30	(N- 50%)	23.0	3.8	.87	.76	45	9/30	.21	.18	12/31	.19	.19	YES
	1002	Meritor, Inc.	MTOR	3.94	5	5	3	2.25	7- 13	(80-230%)	3.6	NIL	1.10	NIL	72	9/30	.32	.45	9/30	NIL	NIL	YES
	1550	MetLife Inc.	MET	32.02	3	3	3	1.65	55- 85	(70-165%)	6.0	2.3	5.35	.74	57	9/30	1.32	.93	12/31	.74	.74	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

PAGE NUMBERS		NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
1643	931	Metro PCS Communic.		PCS	11.00	–	3	–	1.05	12- 18	(10- 65%)	12.2	NIL	.90	NIL	84	9/30	.38	.19	9/30	NIL	NIL	YES
	126	Mettler-Toledo Int'l		MTD	179.18	3	3	3	1.05	190- 285	(5- 60%)	17.1	NIL	10.46	NIL	60	9/30	2.28	2.09	9/30	NIL	NIL	YES
	421	Mexico Fund		MXF	26.40	–	4	4	1.10	25- 40	(N- 50%)	NMF	0.8	NMF	.20	–	7/31	27.41(q)	29.89(q)	6/30	NIL	NIL	
	2111	Michael Kors Hldgs.		KORS	50.61	–	3	–	NMF	60- 90	(20- 80%)	32.9	NIL	1.54	NIL	16	9/30	.49	.22	9/30	NIL	NIL	YES
	1334	Micrel Inc.	(NDQ)	MCRL	9.35	3	3	3	1.05	12- 18	(30- 95%)	24.6	1.8	.38	.17	86	9/30	.08	.15	12/31	▲.043	.04	YES
	1370	Microchip Technology	(NDQ)	MCHP	29.94	3	3	2	1.05	60- 90	(100-200%)	14.8	4.7	2.02	1.41	88	9/30	d.11	.40	12/31	▲.352	.348	YES
	1371	Micron Technology	(NDQ)	MU	5.54	4	4	3	1.35	11- 18	(100-225%)	NMF	NIL	d.19	NIL	88	8/31	d.24	d.14	9/30	NIL	NIL	YES
	2584	MICROS Systems	(NDQ)	MCRS	44.52	3	3	3	1.05	65- 95	(45-115%)	19.8	NIL	2.25	NIL	47	9/30	.50	.45	12/31	NIL	NIL	YES
246	2585	Microsoft Corp.	(NDQ)	MSFT	26.73	3	1	3	.85	50- 60	(85-125%)	9.1	3.4	2.95	.92	47	9/30	.53	.68	12/31	▲.23	.20	YES
	1721	Middleby Corp. (The)	(NDQ)	MIDD	126.98	2	3	2	1.20	120- 180	(N- 40%)	19.0	NIL	6.67	NIL	22	9/30	1.60	1.26	9/30	NIL	NIL	YES
	1778	Middlesex Water	(NDQ)	MSEX	18.10	2	2	3	.70	18- 25	(N- 40%)	17.9	4.1	1.01	.75	6	9/30	.38	.32	12/31	▲.188	.185	
	1155	Miller (Herman)	(NDQ)	MLHR	19.45	5	3	3	1.25	30- 45	(55-130%)	12.2	1.9	1.60	.36	48	8/31	.38	.42	3/31	.09	.022	YES
	932	Millicom Int'l Cellular	(PNK)	MIICF	82.44	▼4	3	3	1.35	90- 135	(10- 65%)	9.5	3.1	8.70	2.55	84	6/30	2.09	1.33	9/30	NIL	NIL	
	229	Mindray Medical (ADS)		MR	33.02	3	3	3	1.10	50- 80	(50-140%)	19.4	1.2	1.70	.40	45	9/30	.42	.31	9/30	NIL	NIL	YES
	1722	Mine Safety Appliance		MSA	37.08	3	3	3	1.10	50- 75	(35-100%)	15.5	3.0	2.40	1.12	22	9/30	.51	.54	12/31	.28	.26	YES
	563	Minerals Techn.		MTX	71.51	2	2	3	1.10	80- 105	(10- 45%)	16.8	0.3	4.25	.20	23	9/30	1.05	.95	12/31	◆.05	.05	YES
	1003	Modine Mfg.		MOD	6.48	5	4	2	1.65	12- 20	(85-210%)	20.3	NIL	.32	NIL	72	9/30	d.26	.02	9/30	NIL	NIL	
	1156	Mohawk Inds.		MHK	83.28	2	3	4	1.30	85- 125	(N- 50%)	20.4	NIL	4.08	NIL	48	9/30	1.01	.83	9/30	NIL	NIL	YES
	1335	Molex Inc.	(NDQ)	MOLX	25.93	3	2	3	1.25	30- 40	(15- 55%)	15.7	3.4	1.65	.88	86	9/30	.40	.47	12/31	.22	.20	YES
	1979	Molson Coors Brewing		TAP	40.28	4	2	2	.60	65- 85	(60-110%)	11.2	3.2	3.61	1.28	19	9/30	1.37	1.05	12/31	◆.32	.32	YES
1051	1927	Mondelez Int'l	(NDQ)	MDLZ	25.83	–	2	–	NMF	30- 40	(15- 55%)	17.1	2.0	1.51	.52	25	9/30	.37	.58	12/31	.29	.29	YES
	2130	Monro Muffler Brake	(NDQ)	MNRO	32.43	3	3	3	.70	40- 60	(25- 85%)	19.1	1.3	1.70	.42	13	9/30	.36	.47	9/30	.10	.09	YES
	2439	Monsanto Co.		MON	88.33	2	3	3	1.00	105- 155	(20- 75%)	21.2	1.7	4.16	1.50	21	8/31	d.44	d.22	12/31	▲.375	.30	YES
	1980	Monster Beverage	(NDQ)	MNST	45.23	3	3	4	.75	65- 100	(45-120%)	22.6	NIL	2.00	NIL	19	9/30	.47	.44	9/30	NIL	NIL	YES
	2384	Monster Worldwide		MWW	5.47	4	4	2	1.35	18- 30	(230-450%)	15.6	NIL	.35	NIL	65	9/30	.09	.13	9/30	NIL	NIL	YES
	439	Moody's Corp.		MCO	46.21	1	3	4	1.25	45- 70	(N- 50%)	14.8	1.4	3.13	.64	8	9/30	.75	.57	12/31	.16	.14	YES
	719	Moog Inc. 'A'		MOGA	35.06	3	3	2	1.20	50- 75	(45-115%)	9.8	NIL	3.59	NIL	64	9/30	.91	.83	9/30	NIL	NIL	
	1789	Morgan Stanley		MS	16.52	3	4	3	1.70	30- 45	(80-170%)	39.3	1.2	.42	.20	76	9/30	d.55	1.15	12/31	.05	.05	YES
	1590	Mosaic Company		MOS	51.20	4	3	3	1.55	85- 125	(65-145%)	10.7	2.0	4.80	1.00	73	8/31	1.01	1.17	12/31	.25	.05	YES
	961	Motorola Solutions		MSI	53.40	–	2	–	NMF	65- 90	(20- 70%)	16.1	1.9	3.31	1.04	90	9/30	.84	.66	3/31	.26	.22	YES
627	2184	Movado Group		MOV	30.00	1	3	2	1.25	30- 45	(N- 50%)	19.1	0.7	1.57	.20	26	7/31	.32	.16	9/30	.05	.03	YES
	736	Mueller Inds.		MLI	45.33	2	3	4	1.10	40- 55	(N- 20%)	19.8	1.1	2.29	.50	49	9/30	.41	.27	12/31	▲.125	.10	YES
	1723	Mueller Water Prod.		MWA	4.99	3	5	5	1.65	6- 10	(20-100%)	45.4	1.4	.11	.07	22	9/30	.03	d.04	12/31	.018	.018	YES
	509	Murphy Oil Corp.		MUR	57.70	3	2	4	1.25	105- 140	(80-145%)	10.8	2.2	5.34	1.25	74	9/30	1.17	1.73	12/31	.313	.275	YES
	1758	Myers Inds.		MYE	14.20	2	3	4	1.45	16- 25	(15- 75%)	14.1	2.3	1.01	.32	29	9/30	.20	.14	12/31	.08	.07	YES
	1616	Mylan Inc.	(NDQ)	MYL	25.94	2	3	3	1.05	25- 35	(N- 35%)	17.6	NIL	1.47	NIL	31	9/30	.51	.36	9/30	NIL	NIL	YES
	836	Myriad Genetics	(NDQ)	MYGN	30.57	2	3	5	.75	30- 45	(N- 45%)	19.7	NIL	1.55	NIL	44	9/30	.36	.29	12/31	NIL	NIL	YES
	1112	**NCI Bldg. Sys.**		NCS	11.21	3	5	3	1.60	16- 30	(45-170%)	15.6	NIL	.72	NIL	7	7/31	.05	d.38	9/30	NIL	NIL	YES
	1336	NCR Corp.		NCR	22.39	3	3	5	1.20	35- 55	(55-145%)	12.5	NIL	1.79	NIL	86	9/30	.42	.26	9/30	NIL	NIL	YES
2653	933	NII Holdings	(NDQ)	NIHD	5.06	5	4	2	1.55	19- 30	(275-495%)	NMF	NIL	d1.76	NIL	84	9/30	d.48	d.02	9/30	NIL	NIL	YES
	737	NN Inc.	(NDQ)	NNBR	7.45	4	4	4	1.60	18- 30	(140-305%)	5.0	NIL	1.50	NIL	49	9/30	.22	.20	9/30	NIL	NIL	YES
2040	837	NPS Pharmac.	(NDQ)	NPSP	9.39	3	4	5	.90	12- 20	(30-115%)	NMF	NIL	d.51	NIL	44	9/30	d.04	d.14	9/30	NIL	NIL	YES
	1225	NRG Energy		NRG	19.75	3	3	2	1.10	19- 30	(N- 50%)	NMF	1.8	d.10	.36	92	9/30	d.01	d.24	12/31	.09	NIL	YES
	934	NTELOS Hldgs.	(NDQ)	NTLS	15.79	–	3	–	NMF	25- 35	(60-120%)	11.9	10.6	1.33	1.68	84	9/30	.22	.31	3/31	.42	.42	YES
	2242	NV Energy Inc.		NVE	17.84	2	3	3	.85	18- 25	(N- 40%)	14.5	4.0	1.23	.72	36	9/30	.94	.73	12/31	.17	.13	YES
	1128	NVR, Inc.		NVR	876.84	1	3	4	1.00	865-1295	(N- 50%)	22.1	NIL	39.66	NIL	2	9/30	NA	7.98	9/30	NIL	NIL	
	1790	NYSE Euronext		NYX	22.73	4	3	2	1.40	40- 60	(75-165%)	10.0	5.3	2.27	1.20	76	9/30	.44	.71	12/31	.30	.30	YES
	2417	Nabors Inds.		NBR	13.69	3	3	2	1.55	35- 55	(155-300%)	7.9	NIL	1.73	NIL	66	9/30	.42	.30	9/30	NIL	NIL	YES
	1791	Nasdaq OMX Group	(NDQ)	NDAQ	23.30	4	3	3	1.20	45- 70	(95-200%)	8.8	2.2	2.65	.52	76	9/30	.62	.67	12/31	.13	NIL	YES
	1954	Nash Finch Co.	(NDQ)	NAFC	20.16	4	3	2	.70	35- 50	(75-150%)	7.4	3.6	2.73	.72	59	9/30	◆1.12	.87	12/31	.18	.18	YES
	2518	Nat'l Bank of Canada	(TSE)	NA.TO	75.18b	2	2	3	.70	85- 115	(15- 55%)	9.3	4.3	8.06	3.24	35	7/31	2.14(b)	1.71(b)	12/31	◆.79(b)	.71(b)	YES
	2385	National CineMedia	(NDQ)	NCMI	13.33	3	3	3	1.25	17- 25	(30- 90%)	21.2	6.9	.63	.92	65	9/30	.30	.33	12/31	.22	.22	YES
	2564	Nat'l Fin'l Partners		NFP	16.71	3	4	4	1.80	25- 40	(50-140%)	25.7	NIL	.65	NIL	33	9/30	NIL	.21	9/30	NIL	NIL	YES
	531	National Fuel Gas		NFG	51.46	2	2	2	1.00	75- 100	(45- 95%)	20.3	2.8	2.53	1.46	67	9/30	.58	.45	12/31	.365	.355	YES
	127	National Instruments	(NDQ)	NATI	24.50	3	3	3	.95	30- 45	(20- 85%)	31.8	2.3	.77	.56	60	9/30	.20	.11	12/31	.14	.10	YES
	2418	National Oilwell Varco		NOV	73.29	3	3	3	1.55	115- 175	(55-140%)	12.0	0.8	6.12	.56	66	9/30	1.43	1.25	12/31	▲.13	.12	YES
	1759	National Presto Ind.		NPK	73.47	3	3	2	.95	50- 75	(N- N%)	15.5	8.2	4.73	6.00	29	9/30	1.36	1.80	9/30	NIL	NIL	
	599	Natural Resource		NRP	18.14	4	3	2	1.10	25- 35	(40- 95%)	11.8	12.1	1.54	2.20	97	9/30	.48	.57	12/31	.55	.55	YES
	230	Natus Medical	(NDQ)	BABY	11.05	3	3	5	1.05	20- 30	(80-170%)	27.6	NIL	.40	NIL	45	9/30	d.07	.01	9/30	NIL	NIL	YES
	2185	Nautilus Inc.		NLS	3.17	3	5	5	1.50	4- 7	(25-120%)	10.2	NIL	.31	NIL	26	9/30	.04	.01	9/30	NIL	NIL	YES
	393	Navigant Consulting		NCI	9.99	3	3	5	.85	19- 30	(90-200%)	10.0	NIL	1.00	NIL	34	9/30	.22	.20	9/30	NIL	NIL	YES
	168	Navistar Int'l		NAV	19.66	3	3	2	1.60	30- 45	(55-130%)	NMF	NIL	d2.49	NIL	85	7/31	d.20	.79	9/30	NIL	NIL	YES
	1164	Neenah Paper		NP	25.31	3	4	3	1.30	35- 60	(40-135%)	9.5	2.4	2.66	.60	10	9/30	.56	.42	3/31	▲.15	.12	YES
	1617	Nektar Therapeutics	(NDQ)	NKTR	6.16	3	4	5	1.05	15- 25	(145-305%)	NMF	NIL	d1.24	NIL	31	9/30	d.38	d.21	9/30	NIL	NIL	YES
	1928	Nestle SA ADS	(PNK)	NSRGY	63.22	1	1	3	.65	75- 90	(20- 40%)	17.9	3.3	3.54	2.11	25	6/30	1.73(p)	1.56(p)	9/30	NIL	NIL	
	1411	NetApp, Inc.	(NDQ)	NTAP	30.89	3	3	2	1.15	45- 65	(45-110%)	25.7	NIL	1.20	NIL	94	10/31	.30	.44	9/30	NIL	NIL	YES
2258	2627	Netflix, Inc.	(NDQ)	NFLX	81.36	3	3	5	.90	90- 135	(10- 65%)	NMF	NIL	.22	NIL	56	9/30	.13	1.16	9/30	NIL	NIL	YES
	962	NETGEAR	(NDQ)	NTGR	34.00	3	3	3	1.10	55- 80	(60-135%)	14.6	NIL	2.33	NIL	90	9/30	.61	.70	9/30	NIL	NIL	YES
	1804	NetSuite Inc.		N	59.28	2	3	2	1.20	65- 100	(10- 70%)	NMF	NIL	d.43	NIL	37	9/30	d.11	d.10	9/30	NIL	NIL	YES
	963	NeuStar Inc.		NSR	38.20	2	3	3	.85	50- 75	(30- 95%)	15.5	NIL	2.46	NIL	90	9/30	.68	.51	9/30	NIL	NIL	YES
1821	935	Neutral Tandem	(NDQ)	IQNT	2.21	–	3	–	.95	17- 25	(NMF)	3.6	NIL	.62	NIL	84	9/30	.24	.18	9/30	NIL	NIL	YES
	422	New Germany Fund		GF	15.12	–	3	3	1.30	20- 30	(30-100%)	NMF	0.7	NMF	.10	–	6/30	15.20(q)	20.12(q)	9/30	NIL	NIL	
	543	New Jersey Resources		NJR	39.60	3	1	3	.65	45- 55	(15- 40%)	13.3	4.0	2.97	1.60	28	6/30	.10	.23	12/31	▲.40	.36	
	2007	New Orient. Ed. ADS		EDU	19.05	4	3	2	1.05	35- 55	(85-190%)	43.3	NIL	.44	NIL	98	8/31	.62	.58	9/30	NIL	NIL	YES
	2226	New York & Co.		NWY	3.36	3	5	5	1.45	4- 7	(20-110%)	NMF	NIL	d.06	NIL	18	7/31	d.07	d.25	9/30	NIL	NIL	
	1508	New York Community		NYCB	12.69	3	3	3	.85	16- 25	(25- 95%)	11.3	7.9	1.12	1.00	53	9/30	.29	.27	12/31	.25	.25	YES
2258	2376	New York Times		NYT	8.07	4	3	1	1.20	12- 18	(50-125%)	15.5	NIL	.52	NIL	50	9/30	d.02	.04	9/30	NIL	NIL	YES
	1195	Newell Rubbermaid		NWL	21.35	2	3	4	1.25	30- 45	(40-110%)	15.8	2.8	1.35	.60	3	9/30	.37	.15	12/31	▲.15	.08	YES
	532	Newfield Exploration		NFX	24.44	4	3	3	1.40	50- 75	(105-205%)	11.8	NIL	2.08	NIL	67	9/30	.48	1.04	9/30	NIL	NIL	YES
	564	NewMarket Corp.		NEU	252.22	2	3	3	1.25	280- 420	(10- 65%)	15.6	1.2	16.20	3.00	23	9/30	4.91	3.48	12/31	.75	.75	YES
	1564	Newmont Mining		NEM	46.79	4	3	1	.80	45- 70	(N- 50%)	10.9	3.0	4.29	1.40	79	9/30	.74	1.27	12/31	.35	.35	YES
	128	Newport Corp.	(NDQ)	NEWP	11.96	4	3	3	1.45	20- 30	(65-150%)	14.2	NIL	.84	NIL	60	9/30	.20	.27	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

PAGE NUMBERS
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PAGE NUMBERS		NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	2332	News Corp.	(NDQ)	NWS	**24.45**	**1**	**3**	**3**	1.25	30- 40	(25- 65%)	**16.1**	**0.7**	1.52	.17	**12**	9/30	**.37**	.29	12/31	.085	.095	YES
	2399	Nexen Inc.	(TSE)	NXY.TO	**25.32b**	**–**	**3**	**–**	1.15	30- 40	(20- 60%)	**18.2**	**0.8**	1.39	.20	**83**	9/30	**.11(b)**	.32(b)	3/31	◆.05(b)	.05(b)	YES
	146	NextEra Energy		NEE	**67.71**	**3**	**2**	**3**	.70	70- 95	(5- 40%)	**15.6**	**3.8**	4.33	2.55	**39**	9/30	**.98**	1.20	12/31	.60	.55	YES
	2162	NIKE, Inc. 'B'		NKE	**96.32**	**3**	**1**	**3**	.80	120- 150	(25- 55%)	**18.5**	**1.7**	5.20	1.68	**61**	8/31	**1.27**	1.36	12/31	▲.42	.31	YES
	544	NiSource Inc.		NI	**23.82**	**1**	**3**	**3**	.80	20- 30	(N- 25%)	**15.7**	**4.0**	1.52	.96	**28**	9/30	**.06**	.12	12/31	.24	.23	YES
	106	Nissan Motor ADR(g)	(PNK)	NSANY	**18.55**	**3**	**3**	**2**	.95	30- 45	(60-145%)	**9.0**	**2.0**	2.05	.38	**80**	6/30	**.43**	.50	9/30	.251	.124	
	2419	Noble Corp.		NE	**34.34**	**3**	**3**	**4**	1.35	60- 90	(75-160%)	**10.7**	**NIL**	3.20	NIL	**66**	9/30	**.45**	.53	9/30	NIL	NIL	YES
	2400	Noble Energy		NBL	**93.83**	**3**	**3**	**3**	1.20	110- 165	(15- 75%)	**16.6**	**1.1**	5.65	1.00	**83**	9/30	**1.23**	2.39	12/31	▲.25	.22	YES
	964	Nokia Corp. ADR		NOK	**2.94**	**4**	**4**	**1**	1.15	6- 8	(105-170%)	**NMF**	**3.4**	d.20	.10-.25	**90**	9/30	**d.09**	.05	9/30	NIL	NIL	YES
	1724	Nordson Corp.	(NDQ)	NDSN	**60.59**	**1**	**3**	**2**	1.25	55- 85	(N- 40%)	**15.9**	**1.0**	3.80	.60	**22**	7/31	**1.03**	.81	9/30	▲.15	.125	YES
	2146	Nordstrom, Inc.		JWN	**56.47**	**2**	**3**	**3**	1.40	70- 110	(25- 95%)	**15.0**	**2.1**	3.77	1.17	**30**	10/31	**.71**	.59	12/31	◆.27	.23	YES
1246	**342**	Norfolk Southern		NSC	**58.03**	**4**	**2**	**3**	1.10	▼ 80- 105	(40- 80%)	**11.0**	**3.4**	5.27	2.00	**51**	9/30	**1.24**	1.59	12/31	.50	.43	YES
	147	Northeast Utilities		NU	**38.17**	**3**	**2**	**3**	.70	35- 50	(N- 30%)	**15.6**	**3.7**	2.44	1.42	**39**	9/30	**.66**	.51	12/31	.343	.275	YES
	788	Northern Trust Corp.	(NDQ)	NTRS	**47.35**	**3**	**3**	**3**	1.10	65- 100	(35-110%)	**14.8**	**2.5**	3.19	1.20	**38**	9/30	**.73**	.70	12/31	.30	.28	YES
	720	Northrop Grumman		NOC	**64.72**	**3**	**1**	**3**	.85	80- 95	(25- 45%)	**9.4**	**3.4**	6.90	2.20	**64**	9/30	**1.82**	1.86	12/31	◆.55	.50	YES
	1509	Northwest Bancshares	(NDQ)	NWBI	**11.43**	**3**	**3**	**3**	.75	14- 20	(20- 75%)	**16.1**	**4.4**	.71	.50	**53**	9/30	**.17**	.17	12/31	.12	.11	YES
	545	Northwest Nat. Gas		NWN	**41.72**	**3**	**1**	**2**	.55	50- 65	(20- 55%)	**15.9**	**4.4**	2.63	1.82	**28**	9/30	**d.30**	d.31	12/31	▲.455	.445	YES
	2243	NorthWestern Corp.		NWE	**33.94**	**3**	**3**	**3**	.70	30- 45	(N- 35%)	**15.4**	**4.4**	2.21	1.51	**36**	9/30	**.30**	.41	12/31	.37	.36	YES
	1618	Novartis AG ADR		NVS	**59.49**	**2**	**1**	**3**	.65	65- 80	(10- 35%)	**15.3**	**4.1**	3.88	2.41	**31**	9/30	**1.01**	1.01	9/30	NIL	NIL	YES
	1619	Novo Nordisk ADR(g)		NVO	**154.48**	**1**	**1**	**4**	.80	155- 190	(N- 25%)	**23.4**	**1.7**	6.59	2.55	**31**	9/30	**1.78**	1.29	9/30	NIL	NIL	YES
	1017	Nu Skin Enterprises		NUS	**43.98**	**3**	**3**	**3**	1.00	65- 95	(50-115%)	**13.5**	**2.0**	3.25	.87	**54**	9/30	**.87**	.72	12/31	◆.20	.16	YES
	2586	Nuance Communic.	(NDQ)	NUAN	**21.57**	**3**	**3**	**2**	1.20	25- 40	(15- 85%)	**32.7**	**NIL**	▲.66	NIL	**47**	9/30	**◆.36**	d.02	9/30	NIL	NIL	YES
	748	Nucor Corp.		NUE	**40.51**	**4**	**3**	**3**	1.15	65- 95	(60-135%)	**20.4**	**3.7**	1.99	1.49	**91**	9/30	**.35**	.57	12/31	.365	.363	YES
	1929	NutriSystem Inc.	(NDQ)	NTRI	**7.38**	**4**	**3**	**2**	.85	20- 30	(170-305%)	**10.7**	**9.5**	.69	.70	**25**	9/30	**.09**	.21	12/31	.175	.175	YES
1644	**193**	NuVasive, Inc.	(NDQ)	NUVA	**13.91**	**5**	**3**	**4**	1.15	25- 40	(80-190%)	**81.8**	**NIL**	.17	NIL	**40**	9/30	**.05**	d1.69	9/30	NIL	NIL	YES
	1211	Nuveen Muni Value Fund		NUV	**10.50**	**–**	**1**	**3**	.45	10- 12	(N- 15%)	**NMF**	**4.8**	NMF	.50	**–**	4/30	**10.05(q)**	9.19(q)	9/30	.117	.117	
	1372	NVIDIA Corp.	(NDQ)	NVDA	**11.70**	**3**	**3**	**2**	1.30	25- 35	(115-200%)	**11.7**	**2.6**	1.00	.30	**88**	10/31	**.33**	.29	12/31	▲.075	NIL	YES
	916	**OGE Energy**		OGE	**56.01**	**3**	**2**	**2**	.75	50- 65	(N- 15%)	**15.9**	**2.9**	3.52	1.64	**24**	9/30	**1.87**	1.80	12/31	.393	.375	YES
	565	OM Group		OMG	**19.89**	**5**	**3**	**3**	1.55	40- 60	(100-200%)	**12.3**	**NIL**	1.62	NIL	**23**	9/30	**.17**	d2.18	9/30	NIL	NIL	YES
	129	OSI Systems	(NDQ)	OSIS	**62.24**	**–**	**3**	**–**	.85	70- 100	(10- 60%)	**21.8**	**NIL**	2.85	NIL	**60**	9/30	**.31**	.24	9/30	NIL	NIL	YES
	510	Occidental Petroleum		OXY	**75.46**	**4**	**2**	**3**	1.20	95- 125	(25- 65%)	**10.7**	**2.9**	7.06	2.22	**74**	9/30	**1.70**	2.18	3/31	.54	.46	YES
	2420	Oceaneering Int'l		OII	**54.79**	**3**	**3**	**3**	1.40	60- 90	(10- 65%)	**19.0**	**1.3**	2.89	.72	**66**	9/30	**.78**	.72	12/31	◆.18	.15	YES
1247	**1425**	Office Depot		ODP	**3.00**	**3**	**5**	**5**	2.05	3- 5	(N- 65%)	**NMF**	**NIL**	NIL	NIL	**87**	9/30	**.06**	NIL	9/30	NIL	NIL	YES
★★	**1426**	OfficeMax		OMX	**9.39**	**3**	**4**	**4**	1.80	10- 17	(5- 80%)	**12.7**	**0.9**	.74	.08	**87**	9/30	**.27**	.25	12/31	▲.02	NIL	YES
	2421	Oil States Int'l		OIS	**66.83**	**3**	**3**	**3**	1.55	120- 180	(80-170%)	**8.0**	**NIL**	8.38	NIL	**66**	9/30	**1.97**	1.67	9/30	NIL	NIL	YES
	325	Old Dominion Freight	(NDQ)	ODFL	**33.39**	**2**	**3**	**2**	1.10	40- 60	(20- 80%)	**15.7**	**NIL**	2.13	NIL	**77**	9/30	**.59**	.45	9/30	NIL	NIL	YES
	789	Old Nat'l Bancorp		ONB	**11.49**	**3**	**3**	**3**	1.00	15- 25	(30-120%)	**12.5**	**3.1**	.92	.36	**38**	9/30	**.20**	.18	12/31	◆.09	.07	YES
	770	Old Republic		ORI	**10.27**	**3**	**3**	**2**	1.10	15- 20	(45- 95%)	**NMF**	**6.9**	d.01	.71	**11**	9/30	**d.11**	d.43	9/30	.178	.175	YES
	1591	Olin Corp.		OLN	**20.32**	**3**	**3**	**3**	1.25	25- 40	(25- 95%)	**11.0**	**3.9**	1.85	.80	**73**	9/30	**.35**	.58	12/31	.20	.20	YES
	976	Omnicare, Inc.		OCR	**34.24**	**3**	**3**	**3**	1.00	60- 90	(75-165%)	**9.9**	**1.6**	3.47	.56	**62**	9/30	**.86**	.54	9/30	▲.14	.04	YES
	231	Omnicell, Inc.	(NDQ)	OMCL	**15.25**	**2**	**3**	**2**	.95	20- 35	(30-130%)	**23.8**	**NIL**	.64	NIL	**45**	9/30	**.20**	.09	9/30	NIL	NIL	YES
	2386	Omnicom Group		OMC	**46.82**	**▼2**	**2**	**3**	1.00	75- 100	(60-115%)	**12.4**	**2.6**	3.78	1.20	**65**	9/30	**.74**	.72	12/31	.30	.25	YES
	2016	OmniVision Techn.	(NDQ)	OVTI	**14.33**	**3**	**3**	**3**	1.20	17- 25	(20- 75%)	**23.5**	**NIL**	.61	NIL	**89**	7/31	**.04**	.68	9/30	NIL	NIL	YES
	1640	On Assignment		ASGN	**18.76**	**2**	**3**	**5**	1.50	30- 45	(60-140%)	**16.8**	**NIL**	1.12	NIL	**58**	9/30	**.33**	.21	9/30	NIL	NIL	YES
	1373	ON Semiconductor	(NDQ)	ONNN	**5.93**	**5**	**3**	**3**	1.45	13- 20	(120-235%)	**9.3**	**NIL**	.64	NIL	**88**	9/30	**.15**	.24	9/30	NIL	NIL	YES
	2628	1-800-FLOWERS.COM	(NDQ)	FLWS	**2.89**	**3**	**4**	**4**	1.55	7- 11	(140-280%)	**12.6**	**NIL**	.23	NIL	**56**	9/30	**d.07**	d.08	9/30	NIL	NIL	
	608	ONEOK Inc.		OKE	**45.90**	**1**	**3**	**3**	.95	35- 50	(N- 10%)	**25.1**	**2.9**	1.83	1.32	**4**	9/30	**.31**	.29	12/31	.33	.28	YES
	1620	Onyx Pharmac.	(NDQ)	ONXX	**73.01**	**3**	**4**	**4**	.85	90- 150	(25-105%)	**NMF**	**NIL**	d3.92	NIL	**31**	9/30	**d1.15**	d.58	9/30	NIL	NIL	YES
	1805	Open Text Corp.	(NDQ)	OTEX	**55.29**	**3**	**3**	**2**	.90	85- 125	(55-125%)	**21.9**	**NIL**	2.52	NIL	**37**	9/30	**.33**	.60	9/30	NIL	NIL	YES
	2587	Oracle Corp.	(NDQ)	ORCL	**30.14**	**3**	**1**	**2**	.95	45- 55	(50- 80%)	**11.4**	**0.8**	2.65	.24	**47**	8/31	**.53**	.48	12/31	.06	.06	YES
	721	Orbital Sciences		ORB	**12.56**	**3**	**3**	**2**	.95	25- 40	(100-220%)	**12.2**	**NIL**	1.03	NIL	**64**	9/30	**.33**	.28	9/30	NIL	NIL	YES
	2629	Orbitz Worldwide		OWW	**2.17**	**5**	**5**	**4**	1.55	7- 13	(225-500%)	**8.3**	**NIL**	.26	NIL	**56**	9/30	**.14**	.11	9/30	NIL	NIL	YES
	130	Orbotech Ltd.	(NDQ)	ORBK	**7.92**	**4**	**3**	**2**	.85	16- 25	(100-215%)	**NMF**	**NIL**	d.77	NIL	**60**	9/30	**d.36**	.34	9/30	NIL	NIL	YES
	2131	O'Reilly Automotive	(NDQ)	ORLY	**91.48**	**3**	**2**	**3**	.70	105- 145	(15- 60%)	**18.3**	**NIL**	5.01	NIL	**13**	9/30	**1.32**	1.10	9/30	NIL	NIL	YES
2040	**2350**	Orient-Express Hotels		OEH	**11.58**	**–**	**4**	**–**	1.75	16- 25	(40-115%)	**96.5**	**NIL**	.12	NIL	**71**	9/30	**.17**	.19	9/30	NIL	NIL	YES
	1226	Ormat Technologies		ORA	**17.45**	**4**	**3**	**1**	1.15	35- 55	(100-215%)	**30.6**	**0.9**	.57	.16	**92**	9/30	**.13**	.02	9/30	.04	.04	YES
1826	**169**	Oshkosh Corp.		OSK	**28.51**	**–**	**4**	**–**	1.65	30- 55	(5- 95%)	**11.0**	**NIL**	2.60	NIL	**85**	9/30	**.65**	.48	9/30	NIL	NIL	YES
	917	Otter Tail Corp.	(NDQ)	OTTR	**23.56**	**3**	**3**	**3**	.90	20- 35	(N- 50%)	**19.2**	**5.1**	1.23	1.19	**24**	9/30	**.35**	.20	12/31	.298	.298	YES
241	**2258**	Overseas Shipholding		OSGIQ	SEE FINAL SUPPLEMENT - PAGE 241																		
	2630	Overstock.com	(NDQ)	OSTK	**14.60**	**2**	**4**	**2**	1.40	14- 25	(N- 70%)	**54.1**	**NIL**	.27	NIL	**56**	9/30	**.11**	d.33	9/30	NIL	NIL	YES
	232	Owens & Minor		OMI	**28.88**	**3**	**2**	**3**	.70	40- 55	(40- 90%)	**15.5**	**3.3**	1.86	.94	**45**	9/30	**.39**	.53	12/31	.22	.20	YES
1822	**1113**	Owens Corning		OC	**32.69**	**3**	**3**	**3**	1.30	60- 90	(85-175%)	**13.9**	**NIL**	2.35	NIL	**7**	9/30	**.33**	1.01	9/30	NIL	NIL	YES
	1178	Owens-Illinois		OI	**19.38**	**4**	**3**	**5**	1.50	40- 60	(105-210%)	**7.3**	**NIL**	2.65	NIL	**46**	9/30	**.69**	.84	9/30	NIL	NIL	YES
	2112	Oxford Inds.		OXM	**53.29**	**1**	**4**	**2**	1.60	60- 95	(15- 80%)	**18.7**	**1.4**	2.85	.72	**16**	7/31	**.30**	.21	12/31	.15	.13	YES
	2186	**PC Connection**	(NDQ)	PCCC	**11.05**	**3**	**3**	**1**	1.15	14- 20	(25- 80%)	**8.9**	**13.8**	1.24	1.52	**26**	9/30	**.37**	.35	12/31	▲.38	NIL	
	1621	PDL BioPharma	(NDQ)	PDLI	**7.46**	**3**	**4**	**3**	.75	8- 13	(5- 75%)	**5.0**	**8.0**	1.50	.60	**31**	9/30	**.32**	.28	12/31	.15	.15	YES
	2244	PG&E Corp.		PCG	**40.52**	**3**	**3**	**3**	.50	35- 55	(N- 35%)	**14.8**	**4.5**	2.74	1.82	**36**	9/30	**.87**	.68	12/31	.455	.455	YES
	1374	PMC-Sierra	(NDQ)	PMCS	**4.88**	**5**	**3**	**3**	1.20	14- 20	(185-310%)	**13.6**	**NIL**	.36	NIL	**88**	9/30	**.10**	.16	9/30	NIL	NIL	YES
	2519	PNC Financial Serv.		PNC	**54.91**	**3**	**3**	**3**	1.30	85- 125	(55-130%)	**8.2**	**2.9**	6.67	1.60	**35**	9/30	**1.64**	1.55	12/31	.40	.35	YES
	2245	PNM Resources		PNM	**20.29**	**3**	**3**	**3**	.90	20- 30	(N- 50%)	**14.8**	**2.9**	1.37	.58	**36**	9/30	**.69**	.61	12/31	.145	.125	YES
	2440	PPG Inds.		PPG	**120.05**	**1**	**1**	**4**	1.05	135- 165	(10- 35%)	**16.2**	**2.0**	7.43	2.36	**21**	9/30	**2.18**	1.96	12/31	.59	.57	YES
	148	PPL Corp.		PPL	**28.37**	**3**	**3**	**2**	.65	30- 45	(5- 60%)	**12.7**	**5.2**	2.24	1.47	**39**	9/30	**.61**	.76	3/31	◆.36	.35	YES
2259	**233**	PSS World Medical	(NDQ)	PSSI	**28.56**	**–**	**3**	**–**	.75	30- 40	(5- 40%)	**24.6**	**NIL**	1.16	NIL	**45**	9/30	**.26**	.37	9/30	NIL	NIL	YES
2448	**2113**	PVH Corp.		PVH	**111.24**	**2**	**3**	**3**	1.25	110- 170	(N- 55%)	**16.5**	**0.1**	6.75	.15	**16**	7/31	**1.25**	1.07	12/31	.038	.037	YES
	600	PVR Partners, L.P.		PVR	**23.59**	**3**	**3**	**3**	1.20	25- 40	(5- 70%)	**NMF**	**9.2**	d.45	2.16	**97**	9/30	**.03**	.29	12/31	▲.54	.50	YES
	170	PACCAR Inc.	(NDQ)	PCAR	**42.33**	**3**	**3**	**3**	1.25	60- 85	(40-100%)	**14.5**	**1.9**	2.91	.80	**85**	9/30	**.66**	.77	12/31	.20	.88	YES
	2227	Pacific Sunwear	(NDQ)	PSUN	**1.62**	**3**	**5**	**1**	1.35	3- 6	(85-270%)	**NMF**	**NIL**	d.48	NIL	**18**	7/31	**d.26**	d.26	9/30	NIL	NIL	YES
	1179	Packaging Corp.		PKG	**35.85**	**1**	**3**	**4**	1.15	40- 65	(10- 80%)	**17.2**	**2.8**	2.09	1.00	**46**	9/30	**.55**	.43	12/31	.25	.20	YES
	2441	Pall Corp.		PLL	**60.41**	**3**	**2**	**3**	1.00	75- 105	(25- 75%)	**20.5**	**1.7**	2.95	1.00	**21**	7/31	**.73**	.82	12/31	▲.25	.175	YES
	234	Palomar Med. Techn.	(NDQ)	PMTI	**8.30**	**3**	**3**	**2**	1.05	13- 19	(55-130%)	**NMF**	**NIL**	d.32	NIL	**45**	9/30	**d.25**	.81	9/30	NIL	NIL	YES
	1565	Pan Amer. Silver	(NDQ)	PAAS	**18.87**	**4**	**3**	**1**	1.30	50- 70	(165-270%)	**11.9**	**1.1**	1.59	.20	**79**	9/30	**.25**	.42	12/31	.05	.025	YES
	1988	Panasonic Corp.(g)		PC	**5.22**	**4**	**3**	**1**	.85	19- 30	(265-475%)	**9.5**	**3.1**	.55	.16	**96**	6/30	**.07**	d.16	9/30	NIL	NIL	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS: **Bold type refers to Ratings and Reports;** *italics to Selection & Opinion*

Page (Bold)	Page (Italic)	NAME OF STOCK	Exch.	Ticker Symbol	Recent Price	Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	% appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
1052	2631	Pandora Media		P	7.51	–	4	–	NMF	20- 30	(165-300%)	NMF	NIL	d.09	NIL	56	7/31	d.03	d.02	9/30	NIL	NIL	YES
	365	Panera Bread Co.	(NDQ)	PNRA	163.46	2	2	4	.95	185- 255	(15- 55%)	25.6	NIL	6.38	NIL	32	9/30	1.24	.97	9/30	NIL	NIL	YES
	1955	Pantry (The), Inc.	(NDQ)	PTRY	12.00	4	4	3	.90	15- 25	(25-110%)	12.9	NIL	.93	NIL	59	6/30	.65	.84	9/30	NIL	NIL	YES
	366	Papa John's Int'l	(NDQ)	PZZA	48.59	2	3	4	.80	45- 65	(N- 35%)	17.0	NIL	2.85	NIL	32	9/30	.55	.44	9/30	NIL	NIL	YES
	1622	Par Pharmaceutical		PRX	SEE FINAL REPORT																		
	2588	Parametric Technology	(NDQ)	PMTC	19.47	3	3	3	1.20	35- 55	(80-180%)	15.0	NIL	1.30	NIL	47	9/30	.40	.35	9/30	NIL	NIL	YES
	1623	PAREXEL Int'l	(NDQ)	PRXL	32.00	2	3	3	1.35	45- 65	(40-105%)	22.9	NIL	1.40	NIL	31	9/30	.29	.20	9/30	NIL	NIL	YES
	566	Park Electrochemical		PKE	23.85	3	3	3	1.20	30- 50	(25-110%)	23.6	1.7	1.01	.40	23	8/31	.16	.37	12/31	.10	.10	
	790	Park National	(ASE)	PRK	62.35	3	3	3	.95	85- 125	(35-100%)	11.9	6.0	5.26	3.76	38	9/30	.78	1.23	12/31	.94	.94	
	1760	Park-Ohio	(NDQ)	PKOH	19.77	3	4	2	1.70	40- 65	(100-230%)	5.4	NIL	3.69	NIL	29	9/30	.88	.69	9/30	NIL	NIL	
	1761	Parker-Hannifin		PH	81.05	4	2	3	1.15	125- 165	(55-105%)	13.0	2.0	6.23	1.64	29	9/30	1.57	1.91	12/31	.41	.37	YES
	2032	PartnerRe Ltd.		PRE	79.98	2	3	3	.70	85- 130	(5- 65%)	9.6	3.1	8.34	2.48	52	9/30	3.90	2.41	12/31	◆.62	.60	YES
	235	Patterson Cos.	(NDQ)	PDCO	36.02	▼3	2	3	.90	50- 65	(40- 80%)	16.4	1.6	2.20	.56	45	10/31	◆.44	.43	12/31	.14	.12	YES
	2612	Paychex, Inc.	(NDQ)	PAYX	31.93	3	1	2	.85	50- 60	(55- 90%)	20.0	4.2	1.60	1.33	14	8/31	.42	.41	12/31	▲.33	.32	YES
2251	601	Peabody Energy		BTU	25.39	4	3	2	1.60	35- 55	(40-115%)	10.3	1.3	2.47	.34	97	9/30	.79	1.02	12/31	.085	.085	YES
2443	1930	Peet's Coffee & Tea		PEET	SEE FINAL SUPPLEMENT - PAGE 2443																		
	609	Pembina Pipeline Corp.	(TSE)	PPL.TO	27.69	3	3	3	.60	25- 40	(N- 45%)	36.4	6.0	.76	1.67	4	9/30	.11	.22	12/31	◆.405	.39	
	567	Penford Corp.	(NDQ)	PENX	7.25	3	4	5	1.40	10- 16	(40-120%)	23.4	NIL	.31	NIL	23	8/31	d.35	d.26	9/30	NIL	NIL	
	533	Pengrowth Energy		PGH	5.17	5	3	1	1.30	19- 30	(270-480%)	30.4	9.3	.17	.48	67	6/30	.08	.27	12/31	▼.12	.206	YES
★★	2351	Penn Nat'l Gaming	(NDQ)	PENN	47.35	3	3	4	1.40	55- 80	(15- 70%)	19.1	NIL	2.48	NIL	71	9/30	.44	.60	9/30	NIL	NIL	YES
		Penn Virginia Res.			NAME CHANGED TO PVR PARTNERS																		
	2147	Penney (J.C.)		JCP	16.75	4	3	2	1.20	19- 30	(15- 80%)	NMF	NIL	d.66	NIL	30	10/31	d.93	.16	9/30	▼NIL	.20	YES
	1533	Penn. R.E.I.T.		PEI	15.86	3	4	4	1.75	20- 35	(25-120%)	NMF	4.0	d.54	.64	20	9/30	d.27	d1.05	12/31	.16	.15	YES
	2132	Penske Auto		PAG	28.75	2	4	5	1.50	35- 60	(20-110%)	12.4	1.8	2.31	.52	13	9/30	.60	.61	12/31	▲.13	.09	YES
		Pentair, Inc.			NAME CHANGED TO PENTAIR, LTD.																		
	1762	Pentair, Ltd.		PNR	45.54	–	3	–	1.10	65- 95	(45-110%)	16.0	1.9	2.84	.88	29	9/30	.64	.58	12/31	.22	.20	YES
	1510	People's United Fin'l	(NDQ)	PBCT	11.79	3	3	3	.65	20- 30	(70-155%)	14.7	5.4	.80	.64	53	9/30	.18	.15	12/31	.16	.158	YES
	2133	Pep Boys		PBY	10.35	3	4	5	1.30	11- 19	(5- 85%)	13.8	0.6	.75	.06-.12	13	7/31	.13	.26	9/30	NIL	.03	YES
	149	Pepco Holdings		POM	19.10	3	3	2	.75	19- 30	(N- 55%)	14.4	5.7	1.33	1.08	39	9/30	.47	.35	12/31	.27	.27	YES
	1981	PepsiCo, Inc.		PEP	68.78	3	1	3	.60	110- 135	(60- 95%)	16.0	3.2	4.31	2.21	19	9/30	1.20	1.25	9/30	.538	.515	YES
	131	PerkinElmer Inc.		PKI	30.58	2	3	4	.95	35- 50	(15- 65%)	14.3	0.9	2.14	.28	60	9/30	.45	.41	12/31	.07	.07	YES
	1624	Perrigo Co.	(NDQ)	PRGO	101.92	2	3	2	.70	120- 180	(20- 75%)	20.6	0.4	4.95	.36	31	9/30	1.12	.89	12/31	▲.09	.08	YES
	2114	Perry Ellis Int'l	(NDQ)	PERY	21.28	3	3	3	1.55	35- 50	(65-135%)	10.5	NIL	2.03	NIL	16	10/31	◆.25	.40	9/30	NIL	NIL	YES
	977	PetMed Express	(NDQ)	PETS	10.82	3	3	3	.70	11- 16	(N- 50%)	13.9	5.5	.78	.60	62	9/30	.20	.19	12/31	◆.15	.125	YES
	511	Petroleo Brasileiro ADR		PBR	19.10	4	3	3	1.55	45- 65	(135-240%)	6.8	1.0	2.82	.20	74	6/30	d.10	1.02	9/30	NIL	.15	YES
	2187	PetSmart, Inc.	(NDQ)	PETM	68.87	2	3	2	.80	70- 105	(N- 50%)	19.2	1.0	3.59	.69	26	10/31	.75	.50	12/31	.165	.14	YES
2446	1625	Pfizer, Inc.		PFE	24.14	2	1	3	.75	30- 35	(25- 45%)	15.4	3.6	1.57	.88	31	9/30	.43	.31	12/31	.22	.20	YES
	978	PharMerica Corp.		PMC	13.45	4	3	1	.80	25- 40	(85-195%)	10.7	NIL	1.26	NIL	62	9/30	.33	.31	9/30	NIL	NIL	YES
	1989	Philips Electronics NV(g)		PHG	25.07	3	3	3	1.25	35- 55	(40-120%)	19.7	4.0	1.27	1.00	96	6/30	.22	d.47	9/30	NIL	NIL	YES
	1995	Philip Morris Int'l		PM	86.86	3	2	3	.75	95- 130	(10- 50%)	15.6	3.9	5.57	3.40	27	9/30	1.32	1.35	12/31	▲.85	.77	YES
	512	Phillips 66		PSX	48.12	–	3	–	NMF	35- 55	(N- 15%)	8.6	2.1	5.59	1.00	74	9/30	2.51	NA	12/31	▲.25	NIL	YES
	1551	Phoenix (The) Cos.		PNX	22.82	5	5	4	2.00	50- 95	(120-315%)	4.0	NIL	5.75	NIL	57	6/30	.20	.86	9/30	NIL	NIL	YES
	1396	Photronics Inc.	(NDQ)	PLAB	4.86	5	5	3	1.90	9- 16	(85-230%)	7.4	NIL	.66	NIL	95	7/31	.16	.23	9/30	NIL	NIL	YES
	546	Piedmont Natural Gas		PNY	29.48	3	2	2	.65	30- 40	(N- 35%)	17.4	4.1	1.69	1.20	28	7/31	d.06	d.12	12/31	.30	.29	YES
	2188	Pier 1 Imports		PIR	19.75	2	3	3	2.05	25- 35	(25- 75%)	16.6	0.8	1.19	.16	26	8/31	.19	.14	12/31	.04	NIL	YES
	2352	Pinnacle Entertain.		PNK	12.45	3	4	3	1.90	18- 30	(45-140%)	11.5	NIL	1.08	NIL	71	9/30	.30	.23	9/30	NIL	NIL	YES
	2246	Pinnacle West Capital		PNW	49.58	3	2	3	.70	45- 60	(N- 20%)	14.4	4.4	3.45	2.20	36	9/30	2.21	2.24	12/31	▲.545	.525	YES
	2401	Pioneer Natural Res.		PXD	105.15	3	3	4	1.50	135- 200	(30- 90%)	26.4	0.1	3.99	.08	83	9/30	.82	1.35	12/31	.04	.04	YES
	1792	Piper Jaffray Cos.		PJC	28.02	2	3	2	1.30	50- 75	(80-170%)	12.7	NIL	2.20	NIL	76	9/30	.72	d.23	9/30	NIL	NIL	YES
	1427	Pitney Bowes		PBI	11.10	4	3	2	.95	13- 19	(15- 70%)	5.6	13.5	1.98	1.50	87	9/30	.47	.61	12/31	.375	.37	YES
	622	Plains All Amer. Pipe.		PAA	45.73	3	3	4	.80	45- 65	(N- 40%)	17.6	4.7	2.60	2.17	9	9/30	.64	.74	12/31	▲.543	.498	YES
	1337	Plantronics Inc.		PLT	32.09	3	3	2	1.20	50- 75	(55-135%)	13.7	1.2	2.35	.40	86	9/30	.61	.60	12/31	◆.10	.05	YES
2653	1338	Plexus Corp.	(NDQ)	PLXS	22.41	5	3	3	1.25	40- 60	(80-170%)	8.4	NIL	2.66	NIL	86	9/30	.66	.52	9/30	NIL	NIL	YES
	1165	Plum Creek Timber		PCL	41.64	2	3	4	.95	35- 50	(N- 20%)	34.7	4.0	1.20	1.68	10	9/30	.36	.31	12/31	.42	.42	YES
	2313	Polaris Inds.		PII	81.61	1	3	5	1.30	75- 115	(N- 40%)	17.4	1.9	4.69	1.57	17	9/30	1.33	.95	12/31	.37	.225	YES
	965	Polycom, Inc.	(NDQ)	PLCM	9.61	3	3	1	1.00	14- 20	(45-110%)	NMF	NIL	.04	NIL	90	9/30	d.08	.13	9/30	NIL	NIL	YES
	2314	Pool Corp.	(NDQ)	POOL	40.50	1	3	4	1.05	40- 60	(N- 50%)	20.0	1.6	2.03	.64	17	9/30	.59	.50	12/31	.16	.14	YES
	2520	Popular Inc.	(NDQ)	BPOP	18.85	3	4	4	1.20	65- 105	(245-455%)	7.5	NIL	2.52	NIL	35	9/30	.45	.30	9/30	NIL	NIL	YES
	2247	Portland General		POR	25.53	3	2	2	.75	25- 30	(N- 20%)	13.0	4.3	1.96	1.10	36	9/30	.50	.36	3/31	.27	.265	YES
	749	POSCO ADR(g)		PKX	73.87	4	3	2	1.30	115- 175	(55-135%)	7.1	2.8	10.47	2.09	91	6/30	3.53(p)	6.46(p)	9/30	.442	.575	YES
	1931	Post Holdings		POST	33.89	–	3	–	NMF	35- 50	(5- 50%)	20.2	NIL	1.68	NIL	25	6/30	.46	NA	9/30	NIL	NIL	YES
	1592	Potash Corp.		POT	38.00	5	3	4	1.35	65- 95	(70-150%)	12.5	2.2	3.04	.84	73	9/30	.74	.94	3/31	◆.21	.07	YES
	1166	Potlatch Corp.	(NDQ)	PCH	38.22	2	3	4	1.05	40- 55	(5- 45%)	30.3	3.2	1.26	1.24	10	9/30	.46	.63	9/30	.31	.51	YES
	1314	Power-One	(NDQ)	PWER	3.95	▼5	4	1	1.45	6- 10	(50-155%)	8.4	NIL	.47	NIL	41	9/30	.13	.27	9/30	NIL	NIL	YES
	568	Praxair Inc.		PX	105.65	3	2	3	.95	140- 190	(35- 80%)	17.8	2.3	5.94	2.41	23	9/30	1.39	1.40	12/31	.55	.50	YES
247	722	Precision Castparts		PCP	176.53	3	2	3	1.20	180- 240	(N- 35%)	17.3	0.1	10.18	.12	64	9/30	2.28	2.03	12/31	.03	.03	YES
	2565	Price (T. Rowe) Group	(NDQ)	TROW	64.43	2	3	3	1.25	60- 85	(N- 30%)	17.9	2.3	3.59	1.45	33	9/30	.94	.71	12/31	.34	.31	YES
	2632	priceline.com	(NDQ)	PCLN	625.50	3	3	5	1.05	1035-1555	(65-150%)	18.8	NIL	33.27	NIL	56	9/30	NA	9.95	9/30	NIL	NIL	YES
	2148	PriceSmart	(NDQ)	PSMT	75.28	2	3	4	1.00	85- 125	(15- 65%)	27.1	0.8	2.78	.60	30	8/31	.58	.42	9/30	.30	.30	YES
	2566	Principal Fin'l Group		PFG	26.70	3	3	3	1.85	45- 65	(70-145%)	9.4	3.1	2.83	.84	33	9/30	.45	.61	12/31	.21	.70	YES
	791	PrivateBancorp	(NDQ)	PVTB	15.76	2	4	5	1.25	18- 30	(15- 90%)	14.6	0.3	1.08	.04	38	9/30	.27	.14	9/30	.01	.01	YES
	1196	Procter & Gamble		PG	67.92	2	1	3	.60	90- 110	(35- 60%)	17.2	3.3	3.95	2.25	3	9/30	1.06	1.01	12/31	.562	.525	YES
	771	Progressive (Ohio)		PGR	21.47	3	3	3	.95	25- 35	(15- 65%)	16.5	1.9	1.30	.41	11	9/30	.22	.29	9/30	NIL	NIL	YES
	1534	Prologis		PLD	33.34	–	3	–	NMF	40- 60	(20- 80%)	NMF	3.5	d.06	1.18	20	9/30	d.10	.12	9/30	.28	.28	YES
	1552	Protective Life		PL	25.48	4	3	3	1.55	35- 55	(35-115%)	7.2	2.8	3.56	.72	57	9/30	.88	.98	12/31	.18	.16	YES
	1511	Provident Fin'l Svcs.		PFS	13.64	3	3	3	.90	17- 25	(25- 85%)	11.8	3.8	1.16	.52	53	9/30	.28	.27	12/31	.13	.12	YES
	1553	Prudential Fin'l		PRU	49.81	3	3	3	1.85	80- 125	(60-150%)	7.0	3.3	7.10	1.65	57	9/30	1.53	1.07	12/31	▲1.60	1.45	YES
	150	Public Serv. Enterprise		PEG	29.78	4	1	3	.75	35- 40	(20- 35%)	12.6	4.9	2.36	1.45	39	9/30	.68	.86	9/30	.355	.343	YES
	1535	Public Storage		PSA	144.94	2	2	3	.95	120- 165	(N- 15%)	39.8	3.2	3.64	4.58	20	9/30	1.18	.69	12/31	1.10	.95	YES
241	1339	Pulse Electronics		PULS	SEE FINAL SUPPLEMENT - PAGE 241																		
	1129	PulteGroup, Inc.		PHM	15.90	2	4	5	1.50	17- 30	(5- 90%)	15.9	NIL	1.00	NIL	2	9/30	.30	d.34	9/30	NIL	NIL	YES
	534	QEP Resources		QEP	27.63	4	3	3	1.35	40- 60	(45-115%)	21.9	0.4	1.26	.10	67	9/30	d.02	.57	12/31	◆.02	.02	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

PAGE NUMBERS		NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	838	QIAGEN N.V.	(NDQ)	QGEN	17.53	3	3	4	.85	20- 30	(15- 70%)	27.4	NIL	.64	NIL	44	9/30	.12	.15	9/30	NIL	NIL	YES
	1375	QLogic Corp.	(NDQ)	QLGC	8.92	4	3	2	1.00	20- 30	(125-235%)	11.4	NIL	.78	NIL	88	9/30	.13	.26	9/30	NIL	NIL	YES
	569	Quaker Chemical		KWR	48.52	2	3	3	1.45	55- 85	(15- 75%)	14.1	2.0	3.43	.98	23	9/30	.80	1.03	3/31	◆.245	.24	
	966	Qualcomm Inc.	(NDQ)	QCOM	62.09	2	2	3	.85	85- 115	(35- 85%)	17.5	1.6	3.55	1.00	90	9/30	.72	.68	12/31	.25	.215	YES
	825	Quality Systems	(NDQ)	QSII	18.30	5	3	3	.90	45- 65	(145-255%)	13.7	3.8	1.34	.70	78	9/30	.26	.35	3/31	.175	.175	YES
	1114	Quanex Bldg. Prod.		NX	19.80	3	4	4	1.30	20- 35	(N- 75%)	53.5	0.9	.37	.17	7	7/31	.12	.30	9/30	.04	.04	YES
	1241	Quanta Services		PWR	25.29	3	3	3	1.30	35- 50	(40-100%)	16.3	NIL	1.55	NIL	68	9/30	.45	.25	9/30	NIL	NIL	YES
2653	1412	Quantum Corporation		QTM	1.23	4	5	1	1.85	2- 4	(65-225%)	NMF	NIL	d.18	NIL	94	9/30	d.05	.02	9/30	NIL	NIL	YES
	810	Quest Diagnostics		DGX	57.89	3	2	3	.75	85- 120	(45-105%)	12.3	2.1	4.71	1.20	55	9/30	1.18	1.18	3/31	▲.30	.17	YES
	1643	Quest Software		QSFT					SEE FINAL SUPPLEMENT - PAGE 1643														
	535	Questar Corp.		STR	19.06	3	1	2	.75	25- 30	(30- 55%)	15.8	3.6	1.21	.68	67	9/30	.19	.20	12/31	.17	.163	YES
1436	839	Questcor Pharmac.	(NDQ)	QCOR	24.63	3	3	1	.80	90- 135	(265-450%)	6.8	3.2	3.62	.80	44	9/30	.91	.35	12/31	▲.20	NIL	YES
	536	Quicksilver Res.		KWK	2.98	5	4	3	1.65	6- 10	(100-235%)	NMF	NIL	d.08	NIL	67	9/30	d.04	.03	9/30	NIL	NIL	YES
1058	2115	Quiksilver Inc.		ZQK	3.87	3	5	3	1.85	6- 11	(55-185%)	22.8	NIL	.17	NIL	16	7/31	.07	.06	9/30	NIL	NIL	YES
	1725	**RBC Bearings**	(NDQ)	ROLL	44.81	2	3	3	1.30	60- 85	(35- 90%)	16.6	NIL	2.70	NIL	22	9/30	.60	.52	9/30	NIL	NIL	YES
2260	587	RF Micro Devices	(NDQ)	RFMD	4.04	3	4	1	1.40	8- 14	(100-245%)	NMF	NIL	.01	NIL	69	9/30	d.05	.05	9/30	NIL	NIL	YES
	772	RLI Corp.		RLI	67.38	3	2	3	.80	60- 85	(N- 25%)	16.1	1.9	4.19	1.28	11	9/30	1.02	1.23	12/31	◆.32	.30	YES
	2422	RPC Inc.		RES	11.10	4	3	2	1.55	18- 25	(60-125%)	10.9	2.9	1.02	.32	66	9/30	.30	.38	12/31	.08	.067	YES
	570	RPM Int'l		RPM	26.78	1	3	3	1.05	30- 45	(10- 70%)	14.9	3.4	1.80	.90	23	8/31	.64	.59	12/31	▲.225	.215	YES
	1806	Rackspace Hosting		RAX	64.55	2	3	3	1.25	60- 95	(N- 45%)	75.1	NIL	.86	NIL	37	9/30	.19	.14	9/30	NIL	NIL	YES
	2189	RadioShack Corp.		RSH	2.00	4	4	1	1.10	4- 7	(100-250%)	NMF	NIL	d.61	NIL	26	9/30	d.47	NIL	9/30	NIL	NIL	YES
	1643	RailAmerica		RA					SEE FINAL SUPPLEMENT - PAGE 1643														
	1932	Ralcorp Holdings		RAH	71.12	–	2	–	NMF	70- 95	(N- 35%)	19.3	NIL	3.68	NIL	25	6/30	.60	1.17	9/30	NIL	NIL	YES
	2116	Ralph Lauren		RL	156.54	3	3	3	1.15	150- 230	(N- 45%)	18.9	1.0	8.27	1.60	16	9/30	2.29	2.46	12/31	.40	.20	YES
	1376	Rambus Inc.	(NDQ)	RMBS	4.57	4	5	1	1.60	7- 14	(55-205%)	NMF	NIL	d1.17	NIL	88	9/30	d.52	NIL	9/30	NIL	NIL	YES
	2402	Range Resources Corp.		RRC	67.70	2	3	3	1.25	65- 100	(N- 50%)	69.8	0.2	.97	.16	83	9/30	.20	.29	9/30	.04	.04	YES
	1793	Raymond James Fin'l		RJF	37.56	1	3	3	1.45	45- 65	(20- 75%)	13.9	1.4	2.70	.52	76	9/30	.60	.54	12/31	.13	.13	YES
	1167	Rayonier Inc.		RYN	48.56	2	3	3	.95	60- 90	(25- 85%)	20.5	3.7	2.37	1.82	10	9/30	.62	.71	12/31	.44	.40	YES
	723	Raytheon Co.		RTN	55.26	3	1	3	.75	70- 90	(25- 65%)	10.0	3.6	5.50	2.00	64	9/30	1.51	1.43	3/31	◆.50	.43	YES
	2017	RealD Inc.		RLD	9.93	5	4	3	1.10	19- 30	(90-200%)	NMF	NIL	d.01	NIL	89	9/30	d.08	.33	9/30	NIL	NIL	YES
	2633	RealNetworks, Inc.	(NDQ)	RNWK	7.00	–	4	–	NMF	6- 10	(N- 45%)	NMF	NIL	d1.35	NIL	56	9/30	d.63	d.15	9/30	NIL	NIL	YES
	1536	Realty Income Corp.		O	38.42	2	3	3	.85	35- 50	(N- 30%)	40.9	4.7	.94	1.82	20	9/30	.19	.25	12/31	▲.454	.435	YES
	2589	Red Hat, Inc.		RHT	48.90	3	3	3	1.15	65- 100	(35-105%)	58.9	NIL	.83	NIL	47	8/31	.18	.20	9/30	NIL	NIL	YES
	367	Red Robin Gourmet	(NDQ)	RRGB	31.86	3	3	4	1.20	40- 60	(25- 90%)	16.2	NIL	1.97	NIL	32	9/30	.24	.24	9/30	NIL	NIL	YES
	1726	Regal Beloit		RBC	66.12	3	3	4	1.10	75- 110	(15- 65%)	13.6	1.1	4.86	.76	22	9/30	1.29	1.13	3/31	.19	.18	YES
	2315	Regal Entertainment		RGC	15.28	3	5	4	.90	18- 35	(20-130%)	17.4	5.5	.88	.84	17	9/30	.17	.16	12/31	.21	.21	YES
	840	Regeneron Pharmac.	(NDQ)	REGN	160.44	1	3	5	1.05	170- 255	(5- 60%)	32.6	NIL	4.92	NIL	44	9/30	1.72	d.68	9/30	NIL	NIL	YES
	2521	Regions Financial		RF	6.47	3	4	5	1.35	9- 15	(40-130%)	8.5	0.6	.76	.04	35	9/30	.21	.07	3/31	.01	.01	YES
	1018	Regis Corp.		RGS	16.53	4	3	3	1.15	25- 35	(50-110%)	16.2	1.5	1.02	.24	54	9/30	.08	.26	12/31	.06	.06	YES
	1554	Reinsurance Group		RGA	49.25	3	2	3	.95	55- 75	(10- 50%)	6.8	1.9	7.19	.96	57	9/30	1.35	1.60	12/31	.24	.18	YES
	750	Reliance Steel		RS	55.81	3	3	3	1.50	70- 110	(25- 95%)	10.1	1.8	5.50	1.00	91	9/30	1.30	1.13	12/31	▲.25	.12	YES
	2033	RenaissanceRe Hldgs.		RNR	80.18	3	2	3	.70	95- 125	(20- 55%)	9.2	1.4	8.68	1.09	52	9/30	2.07	.62	12/31	.27	.26	YES
	2149	Rent-A-Center	(NDQ)	RCII	35.21	3	3	2	1.10	40- 60	(15- 70%)	10.6	1.8	3.31	.64	30	9/30	.67	.60	12/31	.16	.16	YES
	406	Republic Services		RSG	27.32	4	3	3	.90	40- 60	(45-120%)	14.3	3.5	1.91	.96	70	9/30	.47	.53	3/31	.235	.22	YES
1646	588	Research in Motion	(NDQ)	RIMM	9.59	4	3	2	1.25	7- 11	(N- 15%)	NMF	NIL	d.82	NIL	69	8/31	d.27	.80	9/30	NIL	NIL	YES
	236	ResMed Inc.		RMD	40.72	2	2	3	.80	55- 75	(35- 85%)	18.9	1.7	2.15	.68	45	9/30	.49	.33	12/31	▲.17	NIL	YES
	394	Resources Connection	(NDQ)	RECN	11.28	3	3	4	1.05	25- 40	(120-255%)	11.3	2.1	1.00	.24	34	8/31	.12	.06	12/31	.06	.05	YES
	1996	Reynolds American		RAI	41.99	2	2	2	.55	45- 60	(5- 45%)	14.2	5.6	2.96	2.36	27	9/30	.79	.74	12/31	.59	.56	YES
	602	Rhino Resource Partners		RNO	13.44	–	3	–	NMF	25- 35	(85-160%)	12.6	13.2	1.07	1.78	97	9/30	.31	.36	12/31	.445	.48	
	1576	Rio Tinto plc		RIO	48.14	5	3	4	1.60	80- 115	(65-140%)	6.5	3.7	7.44	1.80	93	6/30	3.16(p)	3.99(p)	9/30	.74	.536	YES
	979	Rite Aid Corp.		RAD	1.05	4	5	3	1.25	2- 3	(90-185%)	NMF	NIL	d.17	NIL	62	8/31	d.05	d.11	9/30	NIL	NIL	YES
2260	967	Riverbed Technology	(NDQ)	RVBD	17.23	3	3	1	1.25	30- 45	(75-160%)	16.1	NIL	1.07	NIL	90	9/30	.28	.12	9/30	NIL	NIL	YES
	1727	Robbins & Myers		RBN	59.66	–	3	–	1.25	70- 105	(15- 75%)	16.0	0.3	3.72	.20	22	8/31	.92	.77	12/31	.05	.045	YES
	1641	Robert Half Int'l		RHI	27.06	3	3	3	1.10	50- 70	(85-160%)	16.8	2.3	1.61	.63	58	9/30	.41	.31	12/31	.15	.14	YES
	1180	Rock-Tenn 'A'		RKT	65.00	3	3	3	1.15	95- 140	(45-115%)	10.7	1.4	6.05	.90	46	9/30	1.39	1.70	12/31	▲.225	.20	YES
	1315	Rockwell Automation		ROK	77.89	3	3	3	1.30	95- 145	(20- 85%)	14.1	2.4	5.54	1.88	41	9/30	1.38	1.39	12/31	.47	.425	YES
	724	Rockwell Collins		COL	55.01	3	1	3	1.05	90- 105	(65- 90%)	11.7	2.2	4.70	1.20	64	9/30	1.32	1.13	12/31	.30	.24	YES
	132	Rofin-Sinar Techn.	(NDQ)	RSTI	19.47	3	3	2	1.30	30- 40	(55-105%)	15.0	NIL	1.30	NIL	60	9/30	.35	.60	9/30	NIL	NIL	YES
	1340	Rogers Corp.		ROG	42.12	2	3	2	1.10	60- 85	(40-100%)	14.4	NIL	2.92	NIL	86	9/30	.69	.92	9/30	NIL	NIL	YES
	395	Rollins, Inc.		ROL	21.90	2	2	3	.85	▲ 30- 40	(35- 85%)	26.7	1.6	.82	.35	34	9/30	.22	.20	12/31	.08	.07	YES
	1728	Roper Inds.		ROP	111.07	2	2	3	1.05	115- 160	(5- 45%)	20.9	0.5	5.31	.55	22	9/30	1.24	1.12	12/31	.138	.11	YES
	2228	Ross Stores	(NDQ)	ROST	55.55	2	2	3	.75	65- 95	(15- 70%)	15.2	1.0	3.66	.56	18	10/31	◆.72	.63	12/31	◆.14	.11	YES
	2018	Rovi Corp.	(NDQ)	ROVI	14.90	4	3	2	.95	40- 65	(170-335%)	7.6	NIL	1.97	NIL	89	9/30	.50	.63	9/30	NIL	NIL	YES
	2423	Rowan Cos. plc		RDC	32.76	3	3	3	1.50	40- 60	(20- 85%)	18.3	NIL	1.79	NIL	66	9/30	.21	.25	9/30	NIL	NIL	YES
	2522	Royal Bank of Canada	(TSE)	RY.TO	56.53b	2	2	3	.80	70- 95	(25- 70%)	11.3	4.4	5.01	2.46	35	7/31	1.47(b)	1.04(b)	12/31	▲.60(b)	.54(b)	YES
	2316	Royal Caribbean Cruises		RCL	33.77	3	4	3	1.70	40- 70	(20-105%)	13.7	1.4	2.46	.48	17	9/30	1.69	1.82	12/31	▲.12	NIL	YES
	513	Royal Dutch Shell 'A'		RDSA	66.24	3	1	2	1.05	90- 110	(35- 65%)	7.9	5.2	8.35	3.44	74	9/30	2.28	2.15	12/31	◆.86	.84	YES
	1212	Royce Value Trust		RVT	12.67	–	3	3	1.20	18- 25	(40- 95%)	NMF	NIL	NMF	NIL	–	6/30	14.34(q)	17.19(q)	9/30	NIL	NIL	
	368	Ruby Tuesday		RT	7.50	▲3	4	3	1.50	▼ 13- 20	(75-165%)	25.0	NIL	.30	NIL	32	8/31	.04	.05	12/31	NIL	NIL	YES
	2229	rue21, inc.	(NDQ)	RUE	28.12	3	3	4	1.10	50- 80	(80-185%)	14.2	NIL	1.98	NIL	18	7/31	.36	.31	9/30	NIL	NIL	YES
	326	Ryder System		R	45.37	3	3	2	1.25	75- 110	(65-140%)	10.5	2.7	4.33	1.24	77	9/30	1.28	1.09	12/31	.31	.29	YES
	1130	Ryland Group		RYL	32.36	2	4	5	1.35	19- 30	(N- N%)	33.0	0.4	.98	.12	2	9/30	.21	d.09	12/31	.03	.03	YES
	2353	Ryman Hospitality		RHP	32.26	3	3	3	1.85	50- 70	(55-115%)	29.6	3.6	1.09	1.17	71	9/30	d.06	d.03	9/30	NIL	NIL	YES
847	396	**SAIC, Inc.**		SAI	11.20	▼4	2	2	.65	30- 40	(170-255%)	8.0	4.3	1.40	.48	34	7/31	.32	.32	12/31	.12	NIL	YES
	2590	SAP AG		SAP	73.47	2	2	3	1.10	100- 130	(35- 75%)	21.5	1.3	3.41	.94	47	9/30	.67	.89	9/30	NIL	NIL	YES
	589	SBA Communications	(NDQ)	SBAC	67.01	2	3	3	1.20	60- 90	(N- 35%)	NMF	NIL	d.54	NIL	69	9/30	d.43	d.30	9/30	NIL	NIL	YES
	2613	SEI Investments	(NDQ)	SEIC	21.87	2	2	3	1.05	40- 55	(85-150%)	16.3	1.5	1.34	.32	14	9/30	.29	.27	9/30	NIL	NIL	YES
	2354	SHFL entertainment	(NDQ)	SHFL	13.70	3	4	5	1.40	17- 30	(25-120%)	15.9	NIL	.86	NIL	71	7/31	.18	.17	9/30	NIL	NIL	YES
	1779	SJW Corp.		SJW	23.35	3	3	3	.85	30- 40	(30- 70%)	19.3	3.0	1.21	.71	6	9/30	.53	.44	12/31	.178	.173	
	1537	SL Green Realty		SLG	72.83	2	3	4	1.55	90- 135	(25- 85%)	31.5	1.4	2.31	1.00	20	9/30	.09	.08	12/31	.25	.10	YES
	2567	SLM Corporation	(NDQ)	SLM	16.96	3	4	3	1.55	18- 30	(5- 75%)	7.7	2.9	2.21	.50	33	9/30	.58	.36	12/31	◆.125	.10	YES
	1763	SPX Corp.		SPW	66.78	3	3	3	1.35	95- 140	(40-110%)	14.7	1.5	4.55	1.00	29	9/30	1.05	1.21	12/31	.25	.25	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS **Bold type refers to Ratings and Reports;** *italics to Selection & Opinion*

PAGE NUMBERS (*Selection & Opinion*)	PAGE NUMBERS (**Ratings and Reports**)	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS Timeliness	RANKS Safety	RANKS Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	1956	Safeway Inc.	SWY	**16.76**	3	3	2	.65	30- 45	(80-170%)	**8.1**	**4.5**	2.07	.75	**59**	9/30	**.45**	.38	12/31	.175	.145	YES
	1131	St. Joe Corp.	JOE	**21.34**	3	3	4	1.10	25- 35	(15- 65%)	**NMF**	**NIL**	d.02	NIL	**2**	9/30	**d.01**	d.03	9/30	NIL	NIL	YES
★★	**194**	St. Jude Medical	STJ	**35.75**	▼4	2	4	.90	75- 100	(110-180%)	**10.2**	**2.6**	3.51	.92	**40**	9/30	**.83**	.78	12/31	.23	.21	YES
	2150	Saks Inc.	SKS	**10.48**	4	4	2	1.25	13- 20	(25- 90%)	**21.4**	**NIL**	.49	NIL	**30**	10/31	**.12**	.11	9/30	NIL	NIL	YES
	1807	salesforce.com	CRM	**147.32**	2	3	3	1.15	190- 290	(30- 95%)	**NMF**	**NIL**	d.23	NIL	**37**	10/31	◆**d.19**	d.03	9/30	NIL	NIL	YES
	1019	Sally Beauty	SBH	**24.49**	2	4	3	1.15	25- 45	(N- 85%)	**16.0**	**NIL**	1.53	NIL	**54**	9/30	◆**.35**	.29	9/30	NIL	NIL	YES
	1933	Sanderson Farms	(NDQ) SAFM	**47.95**	3	3	1	.65	50- 80	(5- 65%)	**25.6**	**1.4**	1.87	.68	**25**	7/31	**1.25**	d2.51	12/31	.17	.17	YES
	1413	SanDisk Corp.	(NDQ) SNDK	**39.30**	3	4	1	1.35	50- 80	(25-105%)	**15.5**	**NIL**	2.53	NIL	**94**	9/30	**.48**	1.20	9/30	NIL	NIL	YES
		Sanmina-SCI Corp.						NAME CHANGED TO SANMINA CORP.														
	1341	Sanmina Corp.	(NDQ) SANM	**9.11**	4	5	2	1.75	18- 35	(100-285%)	**5.8**	**NIL**	1.56	NIL	**86**	9/30	**.46**	.47	9/30	NIL	NIL	YES
	1626	Sanofi ADR	SNY	**43.27**	3	1	3	.85	45- 55	(5- 25%)	**18.3**	**4.2**	2.37	1.80	**31**	9/30	**.77**	.99	9/30	NIL	NIL	YES
2653	**1808**	Sapient Corp.	(NDQ) SAPE	**10.75**	3	3	2	1.15	15- 25	(40-135%)	**18.5**	**NIL**	.58	NIL	**37**	9/30	**.15**	.13	9/30	NIL	NIL	YES
	1729	Sauer-Danfoss	SHS	**38.79**	4	3	4	1.35	70- 110	(80-185%)	**9.8**	**3.6**	3.94	1.40	**22**	9/30	**.84**	1.18	12/31	.35	NIL	YES
	151	SCANA Corp.	SCG	**45.60**	2	2	3	.65	40- 55	(N- 20%)	**13.9**	**4.4**	3.29	2.02	**39**	9/30	**.91**	.81	3/31	.495	.485	YES
	1414	ScanSource	(NDQ) SCSC	**28.95**	4	3	2	1.15	40- 55	(40- 90%)	**10.8**	**NIL**	2.68	NIL	**94**	9/30	**.63**	.67	9/30	NIL	NIL	YES
	237	Schein (Henry)	(NDQ) HSIC	**79.49**	3	3	3	.80	75- 115	(N- 45%)	**17.1**	**NIL**	4.64	NIL	**45**	9/30	**1.08**	.99	9/30	NIL	NIL	YES
	2424	Schlumberger Ltd.	SLB	**70.69**	3	2	3	1.25	130- 180	(85-155%)	**15.5**	**1.6**	4.55	1.10	**66**	9/30	**1.06**	.96	3/31	.275	.25	YES
	751	Schnitzer Steel	(NDQ) SCHN	**28.00**	4	3	4	1.55	50- 80	(80-185%)	**16.0**	**2.7**	1.75	.75	**91**	8/31	**.10**	1.33	12/31	.188	.017	YES
★★	**2368**	Scholastic Corp.	(NDQ) SCHL	**32.11**	▼4	3	3	1.05	40- 65	(25-100%)	**13.4**	**1.7**	2.40	.55	**82**	8/31	**d1.02**	d.77	12/31	.125	.10	YES
	571	Schulman (A.)	(NDQ) SHLM	**24.87**	3	3	4	1.05	25- 35	(N- 40%)	**14.4**	**3.1**	1.73	.78	**23**	8/31	**.38**	.19	12/31	▲.195	.17	YES
	1794	Schwab (Charles)	(NDQ) SCHW	**12.89**	3	3	3	1.15	20- 30	(55-135%)	**16.7**	**1.9**	.77	.24	**76**	9/30	**.19**	.18	12/31	.06	.06	YES
	1997	Schweitzer-Mauduit Int'l	SWM	**36.31**	3	3	3	.90	70- 105	(95-190%)	**9.6**	**1.7**	3.80	.60	**27**	9/30	**.95**	.77	12/31	◆.15	.075	YES
	2355	Scientific Games	(NDQ) SGMS	**7.64**	5	4	5	1.50	13- 20	(70-160%)	**29.4**	**NIL**	.26	NIL	**71**	9/30	**d.30**	d.04	9/30	NIL	NIL	YES
	1197	Scotts Miracle-Gro	SMG	**41.21**	3	3	3	.90	50- 70	(20- 70%)	**17.2**	**3.2**	2.40	1.30	**3**	9/30	**d.60**	d1.16	12/31	◆.325	.30	YES
	2377	Scripps (E.W.) 'A'	SSP	**9.44**	1	5	2	1.30	11- 20	(15-110%)	**14.8**	**NIL**	.64	NIL	**50**	9/30	**.21**	d.19	9/30	NIL	NIL	YES
	2333	Scripps Networks	SNI	**60.15**	1	2	2	1.00	90- 120	(50-100%)	**16.8**	**0.8**	3.59	.48	**12**	9/30	**.78**	.65	12/31	◆.12	.10	YES
	2019	SeaChange Int'l	(NDQ) SEAC	**8.96**	3	3	3	1.00	14- 20	(55-125%)	**19.9**	**NIL**	.45	NIL	**89**	7/31	**.04**	.12	9/30	NIL	NIL	YES
	2425	Seadrill Ltd.	SDRL	**38.96**	3	3	4	1.45	40- 55	(5- 40%)	**12.0**	**8.6**	3.24	3.36	**66**	6/30	**1.09**	.65	9/30	▲.84	.75	YES
	1415	Seagate Technology	(NDQ) STX	**27.09**	3	3	5	1.35	50- 75	(85-175%)	**4.5**	**4.7**	6.00	1.28	**94**	9/30	**1.45**	.34	12/31	.32	.18	YES
	1181	Sealed Air	SEE	**16.75**	4	3	5	.95	30- 45	(80-170%)	**13.7**	**3.1**	1.22	.52	**46**	9/30	**.28**	.48	12/31	.13	.13	YES
1435	**1157**	Sealy Corp.	ZZ	**2.19**	–	5	–	1.65	3- 6	(35-175%)	**NMF**	**NIL**	NIL	NIL	**48**	8/31	**NIL**	.04	9/30	NIL	NIL	
★★	**2151**	Sears Holdings	(NDQ) SHLD	**47.86**	3	3	3	1.10	50- 75	(5- 55%)	**NMF**	**NIL**	d2.48	NIL	**30**	10/31	◆**d1.99**	d2.57	9/30	NIL	NIL	YES
	811	Select Med. Hldgs.	SEM	**10.74**	3	3	3	1.00	14- 20	(30- 85%)	**11.2**	**NIL**	.96	NIL	**55**	9/30	**.17**	.17	9/30	NIL	NIL	YES
	773	Selective Ins. Group	(NDQ) SIGI	**17.91**	▼3	3	3	.90	25- 35	(40- 95%)	**13.3**	**2.9**	1.35	.52	**11**	9/30	**.34**	d.33	12/31	.13	.13	YES
	2248	Sempra Energy	SRE	**65.91**	3	2	3	.80	65- 85	(N- 30%)	**15.5**	**3.8**	4.25	2.48	**36**	9/30	**1.09**	1.22	12/31	.60	.48	YES
	1377	Semtech Corp.	(NDQ) SMTC	**24.27**	3	3	3	1.00	40- 60	(65-145%)	**22.1**	**NIL**	1.10	NIL	**88**	7/31	**.15**	.40	9/30	NIL	NIL	YES
	841	Senomyx, Inc.	(NDQ) SNMX	**1.71**	4	5	2	1.00	4- 7	(135-310%)	**NMF**	**NIL**	d.20	NIL	**44**	9/30	**d.05**	d.07	9/30	NIL	NIL	YES
	1934	Sensient Techn.	SXT	**35.48**	2	3	2	.90	45- 65	(25- 85%)	**13.9**	**2.5**	2.56	.88	**25**	9/30	**.66**	.64	12/31	.22	.21	YES
	1817	Service Corp. Int'l	SCI	**13.91**	2	3	3	1.10	14- 20	(N- 45%)	**17.4**	**1.7**	.80	.24	**5**	9/30	**.19**	.15	12/31	.06	.05	YES
	1027	Shaw Commun. 'B'	(TSE) SJRB.TO	**21.55b**	3	3	2	.60	30- 45	(40-110%)	**12.8**	**4.5**	1.68	.97	**42**	8/31	**.28(b)**	.37(b)	12/31	◆.242(b)	.23(b)	YES
	1242	Shaw Group	SHAW	**43.97**	–	3	–	1.50	40- 60	(N- 35%)	**17.9**	**NIL**	2.46	NIL	**68**	8/31	**.82**	.59	9/30	NIL	NIL	YES
	936	Shenandoah Telecom.	(NDQ) SHEN	**13.15**	3	3	3	.85	20- 30	(50-130%)	**30.6**	**2.5**	.43	.33	**84**	9/30	**.06**	.15	12/31	.33	.33	
	1140	Sherwin-Williams	SHW	**157.01**	1	1	3	.70	120- 150	(N- N%)	**22.5**	**1.1**	6.98	1.71	**1**	9/30	**2.24**	1.71	12/31	.39	.365	YES
		Shuffle Master						NAME CHANGED TO SHFL ENTERTAINMENT														
	1764	Siemens AG (ADS)	SI	**100.20**	3	3	2	1.40	135- 200	(35-100%)	**12.0**	**3.8**	8.34	3.84	**29**	9/30	**1.79**	1.68	9/30	NIL	NIL	YES
846	**2020**	Sigma Designs	(NDQ) SIGM	**5.75**	3	4	2	1.00	7- 12	(20-110%)	**NMF**	**NIL**	d1.31	NIL	**89**	7/31	**d.40**	d.69	9/30	NIL	NIL	YES
	572	Sigma-Aldrich	(NDQ) SIAL	**70.94**	3	1	3	1.00	80- 100	(15- 40%)	**18.7**	**1.1**	3.80	.80	**23**	9/30	**.92**	.95	12/31	◆.20	.18	YES
	1182	Silgan Holdings	(NDQ) SLGN	**43.18**	3	3	3	.75	50- 75	(15- 75%)	**14.8**	**1.1**	2.91	.48	**46**	9/30	**1.13**	1.12	12/31	.12	.11	YES
	2021	Silicon Image	(NDQ) SIMG	**4.50**	3	4	2	1.30	9- 15	(100-235%)	**30.0**	**NIL**	.15	NIL	**89**	9/30	**.08**	.01	9/30	NIL	NIL	YES
	1378	Silicon Labs.	(NDQ) SLAB	**40.07**	3	3	1	1.05	50- 75	(25- 85%)	**26.2**	**NIL**	1.53	NIL	**88**	9/30	**.24**	.29	9/30	NIL	NIL	YES
	1566	Silver Wheaton	SLW	**36.90**	3	3	1	1.50	50- 75	(35-105%)	**20.1**	**1.1**	1.84	.40	**79**	9/30	**.34**	.38	12/31	▼.07	.09	YES
	1538	Simon Property Group	SPG	**148.95**	3	3	4	1.20	140- 205	(N- 40%)	**45.8**	**3.0**	3.25	4.40	**20**	9/30	**.84**	.93	12/31	▲1.10	1.10	YES
	1115	Simpson Manufacturing	SSD	**31.36**	3	3	3	1.15	25- 35	(N- 10%)	**28.0**	**1.6**	1.12	.50	**7**	9/30	**.27**	.40	12/31	.125	.125	YES
	2334	Sinclair Broadcast	(NDQ) SBGI	**11.27**	3	4	3	1.50	12- 20	(5- 75%)	**7.1**	**5.3**	1.59	.60	**12**	9/30	**.32**	.24	12/31	◆.15	.12	YES
	238	Sirona Dental	(NDQ) SIRO	**61.90**	▲1	3	3	1.05	70- 100	(15- 60%)	**23.7**	**NIL**	2.61	NIL	**45**	9/30	◆**.62**	.24	9/30	NIL	NIL	YES
	2317	Six Flags Entertainment	SIX	**57.00**	3	3	3	.95	45- 70	(N- 25%)	**32.6**	**6.3**	1.75	3.60	**17**	9/30	**3.19**	3.48	12/31	▲.90	.06	YES
	2163	Skechers U.S.A.	SKX	**16.96**	2	3	2	1.15	30- 45	(75-165%)	**30.3**	**NIL**	.56	NIL	**61**	9/30	**.22**	.07	9/30	NIL	NIL	YES
	1342	Skullcandy, Inc.	(NDQ) SKUL	**8.25**	–	3	–	NMF	30- 45	(265-445%)	**6.8**	**NIL**	1.21	NIL	**86**	9/30	**.23**	.17	9/30	NIL	NIL	YES
	311	SkyWest	(NDQ) SKYW	**11.35**	3	3	3	1.15 ▲	20- 35	(75-210%)	**10.0**	**1.4**	1.13	.16	**63**	9/30	**.40**	NIL	12/31	.04	.04	YES
1247	**1379**	Skyworks Solutions	(NDQ) SWKS	**20.66**	3	3	3	1.30	45- 70	(120-240%)	**14.1**	**NIL**	1.47	NIL	**88**	9/30	**.32**	.34	9/30	NIL	NIL	YES
	1935	Smart Balance	(NDQ) SMBL	**10.76**	3	3	1	.70	10- 15	(N- 40%)	**32.6**	**NIL**	.33	NIL	**25**	9/30	**.03**	.06	9/30	NIL	NIL	YES
	1730	Smith (A.O.)	AOS	**60.41**	1	3	3	1.00	45- 70	(N- 15%)	**20.2**	**1.3**	2.99	.80	**22**	9/30	**.71**	.58	12/31	.20	.16	YES
	590	Smith Micro Software	(NDQ) SMSI	**1.19**	3	5	5	1.30	3- 5	(150-320%)	**NMF**	**NIL**	d.26	NIL	**69**	9/30	**d.13**	d.28	9/30	NIL	NIL	YES
	1936	Smithfield Foods	SFD	**22.00**	5	3	1	1.30	25- 35	(15- 60%)	**12.9**	**NIL**	1.70	NIL	**25**	7/31	**.40**	.67	9/30	NIL	NIL	YES
	1937	Smucker (J.M.)	SJM	**84.49**	2	1	2	.70	100- 120	(20- 40%)	**16.0**	**2.5**	5.28	2.08	**25**	10/31	◆**1.45**	1.29	12/31	.52	.48	YES
	1731	Snap-on Inc.	SNA	**76.80**	2	2	3	1.10	80- 110	(5- 45%)	**14.4**	**2.0**	5.35	1.52	**22**	9/30	**1.26**	1.16	12/31	▲.38	.32	YES
	1938	Snyder's-Lance	(NDQ) LNCE	**23.47**	2	3	3	.60	25- 35	(5- 50%)	**21.1**	**2.7**	1.11	.64	**25**	9/30	**.28**	.16	12/31	.16	.16	YES
	2634	Sohu.com Inc.	(NDQ) SOHU	**36.49**	4	3	2	1.25	75- 115	(105-215%)	**13.8**	**NIL**	2.64	NIL	**56**	9/30	**.63**	1.17	9/30	NIL	NIL	YES
	1809	Solera Hldgs.	SLH	**49.35**	3	3	3	.80	75- 115	(50-135%)	**19.7**	**1.1**	2.50	.52	**37**	9/30	**.48**	.44	12/31	.125	.10	YES
	2134	Sonic Automotive	SAH	**19.30**	3	4	4	1.80	25- 40	(30-105%)	**10.8**	**0.5**	1.78	.10	**13**	9/30	**.40**	.33	3/31	.025	.025	YES
	369	Sonic Corp.	(NDQ) SONC	**9.69**	3	3	3	1.15 ▲	19- 30	(95-210%)	**14.9**	**NIL**	.65	NIL	**32**	8/31	**.25**	.20	12/31	NIL	NIL	YES
	1183	Sonoco Products	SON	**29.66**	3	2	3	.95	45- 60	(50-100%)	**13.4**	**4.0**	2.22	1.20	**46**	9/30	**.55**	.66	12/31	.30	.29	YES
	1990	Sony Corp. ADR(g)	SNE	**10.19**	4	3	2	1.00	30- 50	(195-390%)	**24.9**	**3.0**	.41	.31	**96**	6/30	**d.31**	d.19	9/30	NIL	NIL	YES
	2190	Sotheby's	BID	**29.22**	3	3	3	1.50	45- 70	(55-140%)	**14.1**	**1.1**	2.07	.32	**26**	9/30	**d.48**	d.44	12/31	.08	.08	YES
	547	South Jersey Inds.	SJI	**47.77**	3	2	2	.65	55- 70	(15- 45%)	**14.6**	**3.6**	3.28	1.70	**28**	9/30	**.13**	.01	12/31	.403	.768	
	152	Southern Co.	SO	**42.77**	2	1	3	.55	40- 50	(N- 15%)	**15.4**	**4.7**	2.77	2.02	**39**	9/30	**1.11**	1.06	12/31	.49	.473	YES
	1577	Southern Copper	SCCO	**34.78**	3	3	3	1.55	50- 75	(45-115%)	**13.7**	**2.9**	2.53	1.00	**93**	9/30	**.63**	.78	12/31	◆2.75	.693	YES
	312	Southwest Airlines	LUV	**9.10**	4	3	3	1.00 ▼	20- 30	(120-230%)	**14.9**	**0.4**	▼.61	.04	**63**	9/30	**.13**	.15	3/31	◆.01	.005	YES
	548	Southwest Gas	SWX	**40.72**	3	3	3	.75	45- 70	(10- 70%)	**13.6**	**3.0**	3.00	1.24	**28**	9/30	**d.09**	d.34	3/31	.295	.265	YES
	537	Southwestern Energy	SWN	**36.09**	3	3	3	1.15	45- 65	(25- 80%)	**23.9**	**NIL**	1.51	NIL	**67**	9/30	**.38**	.50	9/30	NIL	NIL	YES
	1957	Spartan Stores	(NDQ) SPTN	**14.08**	4	3	3	.75	20- 30	(40-115%)	**9.8**	**2.3**	1.44	.32	**59**	9/30	**.47**	.45	12/31	.08	.065	YES
	610	Spectra Energy	SE	**27.72**	3	3	4	1.00	35- 50	(25- 80%)	**17.9**	**4.4**	1.55	1.22	**4**	9/30	**.27**	.38	12/31	▲.305	.28	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

PAGE NUMBERS
Bold type refers to Ratings and Reports;
italics to Selection & Opinion

Page	Page	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
1823	1198	Spectrum Brands	SPB	45.30	2	3	4	1.10	45- 65	(N- 45%)	16.0	NIL	2.84	NIL	3	9/30	◆.50	.47	9/30	NIL	NIL	YES
	2318	Speedway Motorsports	TRK	16.19	4	3	4	.95	19- 30	(15- 85%)	14.7	3.7	1.10	.60	17	9/30	.27	.58	12/31	.15	.10	
2260	725	Spirit AeroSystems	SPR	14.74	4	3	3	1.35	40- 60	(170-305%)	24.2	NIL	.61	NIL	64	9/30	d2.02	.47	9/30	NIL	NIL	YES
1247	313	Spirit Airlines (NDQ)	SAVE	16.74	–	3	–	NMF	40- 55	(140-230%)	9.3	NIL	1.80	NIL	63	9/30	.43	.38	9/30	NIL	NIL	YES
2043	937	Sprint Nextel Corp.	S	5.55	–	4	–	1.35	6- 9	(10- 60%)	NMF	NIL	d1.21	NIL	84	9/30	d.26	d.10	9/30	NIL	NIL	YES
	2230	Stage Stores	SSI	24.40	1	3	2	1.40	30- 45	(25- 85%)	19.7	1.7	1.24	.42	18	10/31	◆d.28	d.36	9/30	▲.10	.09	YES
	1004	Standard Motor Prod.	SMP	18.32	3	4	1	1.70	30- 50	(65-175%)	10.4	2.4	1.77	.44	72	9/30	.76	.61	12/31	◆.09	.07	YES
	1132	Standard Pacific Corp.	SPF	6.45	3	5	5	1.75	5- 10	(N- 55%)	28.0	NIL	.23	NIL	2	9/30	.05	d.02	9/30	NIL	NIL	YES
	1428	Standard Register	SR	0.58	4	5	2	1.15	3- 5	(415-760%)	NMF	NIL	d.03	NIL	87	9/30	d.09	d.13	9/30	NIL	.05	
	1765	Standex Int'l	SXI	46.49	2	3	4	1.10	50- 80	(10- 70%)	11.9	0.7	3.90	.32	29	9/30	.93	.95	12/31	▲.08	.07	
	1732	Stanley Black & Decker	SWK	69.86	3	2	3	1.10	85- 115	(20- 65%)	11.7	2.8	5.95	1.96	22	9/30	1.40	1.34	12/31	.49	.41	YES
	1243	Stantec Inc. (TSE)	STN.TO	37.39	2	3	3	.95	50- 75	(35-100%)	13.7	1.6	2.73	.60	68	9/30	.74	.63	3/31	◆.15	NIL	YES
	1429	Staples, Inc. (NDQ)	SPLS	12.21	4	3	4	1.00	35- 45	(185-270%)	8.5	3.6	1.44	.44	87	10/31	.46	.47	12/31	.11	.10	YES
	370	Starbucks Corp. (NDQ)	SBUX	49.74	3	2	3	1.10	70- 90	(40- 80%)	24.4	1.7	2.04	.84	32	9/30	.46	.37	12/31	▲.21	.17	YES
2654	1810	StarTek, Inc.	SRT	4.05	3	5	3	1.10	4- 6	(N- 50%)	NMF	NIL	d.27	NIL	37	9/30	d.08	d.45	9/30	NIL	NIL	YES
	2356	Starwood Hotels	HOT	52.91	2	3	4	1.55	75- 110	(40-110%)	21.7	2.4	2.44	1.25	71	9/30	.58	.42	12/31	▲1.25	.50	YES
	2523	State Street Corp.	STT	45.29	3	3	2	1.50	60- 90	(30-100%)	10.6	2.2	4.27	1.00	35	9/30	1.36	1.10	12/31	.24	.18	YES
	752	Steel Dynamics (NDQ)	STLD	12.67	4	4	3	1.65	25- 40	(95-215%)	15.8	3.2	.80	.40	91	9/30	.15	.19	12/31	.10	.10	YES
	1158	Steelcase, Inc. 'A'	SCS	10.55	3	3	3	1.15	18- 25	(70-135%)	12.1	3.4	.87	.36	48	8/31	.25	.15	12/31	.09	.06	YES
	2152	Stein Mart (NDQ)	SMRT	7.16	3	4	2	1.35	10- 16	(40-125%)	17.0	NIL	.42	NIL	30	7/31	.02	.03	9/30	NIL	NIL	YES
	407	Stericycle Inc. (NDQ)	SRCL	89.90	2	2	3	.70	105- 140	(15- 55%)	25.9	NIL	3.47	NIL	70	9/30	.84	.71	9/30	NIL	NIL	YES
	195	STERIS Corp.	STE	33.10	3	3	2	.90	45- 65	(35- 95%)	14.8	2.3	2.23	.76	40	9/30	.46	.50	12/31	.19	.17	YES
	1818	Stewart Enterpr. 'A' (NDQ)	STEI	7.37	2	3	3	1.10	8- 13	(10- 75%)	16.0	2.2	.46	.16	5	7/31	.11	.12	12/31	.04	.035	YES
	1795	Stifel Financial Corp.	SF	30.57	3	3	3	1.15	55- 85	(80-180%)	14.4	NIL	2.13	NIL	76	9/30	.60	.35	9/30	NIL	NIL	YES
	1567	Stillwater Mining	SWC	10.96	4	4	1	2.00	17- 30	(55-175%)	32.2	NIL	.34	NIL	79	9/30	.12	.37	9/30	NIL	NIL	YES
	1380	STMicroelectronics	STM	5.88	5	3	1	1.30	9- 14	(55-140%)	53.5	6.8	.11	.40	88	9/30	d.03	.09	3/31	◆.10	.10	YES
	1819	StoneMor Partners L.P. (NDQ)	STON	21.93	2	4	3	.75	17- 30	(N- 35%)	NMF	10.8	d.24	2.36	5	9/30	.05	d.01	12/31	▲.59	.585	YES
247	2008	Strayer Education (NDQ)	STRA	49.76	5	3	4	.75	105- 160	(110-220%)	9.0	2.0	5.51	1.00-NIL	98	9/30	.36	1.20	12/31	1.00	1.00	YES
	196	Stryker Corp.	SYK	53.00	3	1	3	.80	70- 85	(30- 60%)	12.5	1.6	4.23	.85	40	9/30	.97	.91	12/31	.213	.18	YES
	2319	Sturm, Ruger & Co.	RGR	48.83	2	3	5	.85	65- 100	(35-105%)	13.1	3.1	3.73	1.53	17	9/30	.88	.56	12/31	▲.382	.141	YES
	623	Suburban Propane	SPH	39.93	3	3	4	.70	40- 60	(N- 50%)	16.0	8.5	2.50	3.41	9	6/30	d.26	d.19	12/31	◆.853	.853	YES
	514	Suncor Energy (TSE)	SU.TO	32.59	4	3	3	1.30	60- 85	(85-160%)	10.3	1.6	3.16	.52	74	9/30	1.01	.76	12/31	.13	.11	YES
1820	515	Sunoco, Inc.	SUN	SEE FINAL SUPPLEMENT - PAGE 1820																		
	1227	SunPower Corp. (NDQ)	SPWR	4.00	4	4	2	1.70	8- 13	(100-225%)	15.4	NIL	.26	NIL	92	9/30	.03	.16	9/30	NIL	NIL	YES
	812	Sunrise Senior Living	SRZ	14.32	–	5	–	2.80	6- 12	(N- N%)	NMF	NIL	d.02	NIL	55	9/30	.35	d.12	9/30	NIL	NIL	YES
	1228	Suntech Power ADS	STP	0.77	4	5	5	1.85	1- 2	(30-160%)	0.5	NIL	1.61	NIL	92	3/31	d.74	.18	9/30	NIL	NIL	YES
	2524	SunTrust Banks	STI	26.99	3	3	4	1.25	35- 55	(30-105%)	11.9	1.3	2.26	.35	35	9/30	.59	.40	12/31	.05	.05	YES
	1005	Superior Inds. Int'l	SUP	17.77	3	3	3	1.15	25- 35	(40- 95%)	15.9	3.6	1.12	.64	72	9/30	.27	.11	12/31	.16	.16	YES
2260	1958	SUPERVALU INC.	SVU	2.57	4	5	3	.85	4- 7	(55-170%)	10.7	NIL	.24	NIL	59	8/31	NIL	.28	9/30	▼NIL	.088	YES
	197	SurModics, Inc. (NDQ)	SRDX	18.79	2	3	2	.80	20- 30	(5- 60%)	27.2	NIL	.69	NIL	40	9/30	.17	.06	9/30	NIL	NIL	YES
	2525	Susquehanna Bancshs. (NDQ)	SUSQ	9.60	3	3	4	1.20	17- 25	(75-160%)	10.9	2.9	.88	.28	35	9/30	.20	.12	12/31	▲.07	.03	YES
	1959	Susser Holdings (NDQ)	SUSS	36.97	3	3	3	.75	45- 70	(20- 90%)	20.5	NIL	1.80	NIL	59	9/30	.32	1.06	9/30	NIL	NIL	YES
	423	Swiss Helvetia Fund	SWZ	10.69	–	3	3	.85	11- 16	(5- 50%)	NMF	1.9	NMF	.20	–	6/30	11.70(q)	16.15(q)	9/30	.01	.011	
2040	968	Sycamore Networks (NDQ)	SCMR	2.73	–	3	–	NMF	9- 16	(230-485%)	NMF	NIL	d.30	NIL	90	7/31	d.03	d.09	9/30	NIL	NIL	YES
	2591	Symantec Corp. (NDQ)	SYMC	18.19	3	3	2	.95	25- 35	(35- 90%)	19.8	NIL	.92	NIL	47	9/30	.27	.24	9/30	NIL	NIL	YES
	1416	Synaptics (NDQ)	SYNA	24.76	4	3	1	.95	35- 55	(40-120%)	12.9	NIL	1.92	NIL	94	9/30	.37	.57	9/30	NIL	NIL	YES
	2022	Synchronoss Techn. (NDQ)	SNCR	17.99	3	3	2	1.30	60- 90	(235-400%)	15.0	NIL	1.20	NIL	89	9/30	.28	.23	9/30	NIL	NIL	YES
	2592	Synopsys, Inc. (NDQ)	SNPS	31.98	3	1	3	.80	35- 45	(10- 40%)	17.7	NIL	1.81	NIL	47	7/31	.43	.37	9/30	NIL	NIL	YES
	2526	Synovus Financial	SNV	2.26	3	5	5	1.25	4- 8	(75-255%)	18.8	1.8	.12	.04	35	9/30	.02	.02	12/31	.01	.01	YES
	1939	Synutra Int'l (NDQ)	SYUT	4.33	–	4	–	1.20	17- 30	(295-595%)	3.4	NIL	1.28	NIL	25	9/30	d.77	.15	9/30	NIL	NIL	
	1960	Sysco Corp.	SYY	30.47	3	1	2	.70	50- 60	(65- 95%)	13.9	3.7	2.20	1.12	59	9/30	.49	.51	3/31	▲.28	.27	YES
	792	**TCF Financial**	TCB	11.34	3	3	3	1.15	19- 30	(70-165%)	13.8	1.8	.82	.20	38	9/30	.06	.20	12/31	.05	.05	YES
	1796	TD Ameritrade Holding (NDQ)	AMTD	15.45	3	3	2	1.10	30- 40	(95-160%)	13.9	2.3	1.11	.36	76	9/30	.26	.29	12/31	▲.09	.06	YES
	1343	TE Connectivity	TEL	34.72	3	3	2	1.25	55- 85	(60-145%)	10.9	2.4	3.19	.84	86	9/30	.76	.89	12/31	◆.21	.18	YES
	153	TECO Energy	TE	16.41	3	2	2	.85	17- 25	(5- 50%)	14.0	5.4	1.17	.88	39	9/30	.42	.42	12/31	.22	.215	YES
	2231	TJX Companies	TJX	44.08	2	1	3	.80	50- 60	(15- 35%)	16.8	1.0	2.62	.46	18	10/31	.62	.53	12/31	.115	.095	YES
	1006	TRW Automotive	TRW	47.87	4	4	4	2.00	75- 130	(55-170%)	7.8	NIL	6.15	NIL	72	9/30	1.24	1.37	9/30	NIL	NIL	YES
	424	Taiwan Fund	TWN	15.17	–	4	3	.95	19- 30	(25-100%)	NMF	1.0	NMF	.15	–	2/28	18.14(q)	19.60(q)	9/30	NIL	NIL	
	1381	Taiwan Semic. ADR	TSM	16.34	3	3	3	1.00	25- 35	(55-115%)	14.7	3.1	1.11	.50	88	9/30	.32	.20	9/30	.50	.53	YES
	2023	Take-Two Interactive (NDQ)	TTWO	12.35	3	3	3	1.20	18- 25	(45-100%)	4.6	NIL	2.70	NIL	89	9/30	d.15	d.57	9/30	NIL	NIL	YES
	538	Talisman Energy	TLM	11.31	4	3	1	1.50	19- 30	(70-165%)	18.9	2.5	.60	.28	67	9/30	d.04	.24	12/31	◆.068	.135	YES
	2153	Target Corp.	TGT	63.01	2	2	2	.90	80- 110	(25- 75%)	13.6	2.3	4.65	1.47	30	10/31	◆.81	.82	12/31	.36	.30	YES
2444	726	TASER Int'l (NDQ)	TASR	8.11	2	4	2	1.20	11- 19	(35-135%)	32.4	NIL	.25	NIL	64	9/30	.07	.02	9/30	NIL	NIL	YES
	107	Tata Motors ADR	TTM	24.61	4	3	5	1.35	45- 65	(85-165%)	7.9	1.3	3.11	.33	80	9/30	.62	.60	9/30	.354	.438	YES
	1642	Team Health Hldgs.	TMH	27.54	2	3	2	1.05	25- 40	(N- 45%)	16.9	NIL	1.63	NIL	58	9/30	.44	.23	9/30	NIL	NIL	YES
	1417	Tech Data (NDQ)	TECD	45.46	4	3	2	1.00	70- 100	(55-120%)	7.8	NIL	5.86	NIL	94	10/31	◆1.21	1.26	9/30	NIL	NIL	YES
	842	Techne Corp. (NDQ)	TECH	70.38	3	1	3	.75	85- 100	(20- 40%)	22.1	1.7	3.18	1.20	44	9/30	.70	.74	12/31	▲.30	.28	YES
	1578	Teck Resources Ltd. 'B' (TSE)	TCKB.TO	32.13b	3	3	3	1.85	45- 70	(40-120%)	11.2	2.8	2.87	.90	93	9/30	.31(b)	1.38(b)	3/31	▲.45(b)	.40(b)	YES
	1733	Tecumseh Products 'A' (NDQ)	TECUA	4.48	3	5	2	1.45	12- 20	(170-345%)	NMF	NIL	d.85	NIL	22	9/30	d.22	d1.12	9/30	NIL	NIL	YES
	335	Teekay Corp.	TK	30.56	3	3	4	1.50	40- 65	(30-115%)	NMF	4.1	.14	1.26	81	9/30	d.29	d3.67	12/31	.316	.316	YES
	938	Telecom N. Zealand (PNK)	NZTCY	9.75	–	3	–	NMF	10- 15	(5- 55%)	13.9	6.1	.70	.59	84	6/30	.38(p)	.49(p)	12/31	.373	NIL	YES
	727	Teledyne Technologies	TDY	62.26	2	3	3	.95	65- 95	(5- 55%)	14.6	NIL	4.25	NIL	64	9/30	1.14	.91	9/30	NIL	NIL	YES
	198	Teleflex Inc.	TFX	68.63	2	2	3	.80	90- 120	(30- 75%)	15.1	2.0	4.55	1.36	40	9/30	1.04	.82	12/31	.34	.34	YES
	1047	Telefonica SA ADR(g)	TEF	12.94	4	4	1	.95	20- 35	(55-170%)	6.8	NIL	1.89	NIL	75	9/30	.45	.40	12/31	▼NIL	1.02	YES
	939	Telephone & Data	TDS	22.39	5	3	3	.90	50- 80	(125-255%)	16.5	2.2	1.36	.49	84	9/30	.27	.63	12/31	◆.123	.118	YES
	397	TeleTech Holdings (NDQ)	TTEC	16.10	3	3	2	1.10	40- 55	(150-240%)	11.3	NIL	1.43	NIL	34	9/30	.39	.35	9/30	NIL	NIL	YES
	969	Tellabs, Inc. (NDQ)	TLAB	2.72	4	4	2	.90	5- 8	(85-195%)	45.3	2.9	.06	.08	90	9/30	.02	d.10	12/31	.02	.02	YES
	940	TELUS Corporation (TSE)	T.TO	63.87	2	3	3	.55	55- 80	(N- 25%)	15.7	4.0	4.08	2.56	84	9/30	1.08	1.00	3/31	▲.64	.58	YES
	425	Templeton Emerg'g	EMF	18.57	–	4	3	1.30	25- 40	(35-115%)	NMF	1.6	NMF	.30	–	5/31	18.28(q)	23.84(q)	9/30	NIL	NIL	
2262	1159	Tempur-Pedic	TPX	24.89	5	4	3	1.40	55- 95	(120-280%)	8.3	NIL	3.00	NIL	48	9/30	.70	.90	9/30	NIL	NIL	YES
	813	Tenet Healthcare(●)	THC	27.49	3	5	3	1.25	40- 75	(45-175%)	45.8	NIL	.60	NIL	55	9/30	.28	.08	9/30	NIL	NIL	YES
	1734	Tennant Co.	TNC	36.00	3	3	2	1.30	50- 70	(40- 95%)	15.5	2.0	2.33	.72	22	9/30	.47	.50	12/31	▲.18	.17	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

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2261	1007	Tenneco Inc.		TEN	29.71	3	4	2	2.35	55- 95	(85-220%)	7.9	NIL	3.75	NIL	72	9/30	.85	.67	9/30	NIL	NIL	YES
	2593	Teradata Corp.		TDC	61.97	2	2	3	.95	75- 105	(20- 70%)	24.6	NIL	2.52	NIL	47	9/30	.60	.51	9/30	NIL	NIL	YES
	1397	Teradyne Inc.		TER	15.35	4	3	3	1.45	17- 25	(10- 65%)	10.3	NIL	1.49	NIL	95	9/30	.39	.25	9/30	NIL	NIL	YES
	171	Terex Corp.		TEX	22.71	3	4	4	2.05	40- 65	(75-185%)	10.2	NIL	2.22	NIL	85	9/30	.62	.30	9/30	NIL	NIL	YES
1435	108	Tesla Motors	(NDQ)	TSLA	32.92	3	4	3	1.25	40- 65	(20- 95%)	NMF	NIL	d1.26	NIL	80	9/30	d1.05	d.63	9/30	NIL	NIL	YES
	516	Tesoro Corp.		TSO	39.93	3	3	2	1.30	50- 80	(25-100%)	9.1	1.5	4.41	.60	74	9/30	1.92	2.39	12/31	▲.15	NIL	YES
	1382	Tessera Technologies	(NDQ)	TSRA	14.53	3	3	3	1.25	30- 45	(105-210%)	NMF	2.8	.01	.40	88	9/30	d.02	d.20	12/31	.10	NIL	YES
	408	Tetra Tech	(NDQ)	TTEK	25.11	3	3	4	1.15	50- 70	(100-180%)	14.0	NIL	1.79	NIL	70	9/30	.47	.42	12/31	NIL	NIL	YES
	2426	TETRA Technologies		TTI	6.41	4	3	3	1.80	15- 25	(135-290%)	8.9	NIL	.72	NIL	66	9/30	.20	.18	9/30	NIL	NIL	YES
	1627	Teva Pharmac. ADR		TEVA	38.76	4	1	3	.60	70- 85	(80-120%)	7.2	2.9	5.41	1.11	31	9/30	1.28	1.25	9/30	.248	.231	YES
	1116	Texas Inds.		TXI	44.58	3	4	4	1.55	30- 45	(N- N%)	NMF	NIL	d.80	NIL	7	8/31	d.09	d.27	9/30	NIL	.075	YES
	1383	Texas Instruments	(NDQ)	TXN	28.90	3	1	3	.90	45- 55	(55- 90%)	14.2	2.9	2.03	.84	88	9/30	.67	.51	12/31	▲.21	.17	YES
	371	Texas Roadhouse	(NDQ)	TXRH	16.52	3	3	3	1.00	25- 35	(50-110%)	15.3	2.2	1.08	.36	32	9/30	.25	.22	12/31	◆.09	.08	YES
	1766	Textron, Inc.		TXT	23.57	3	3	4	1.60	40- 60	(70-155%)	10.8	0.3	2.18	.08	29	9/30	.48	.44	3/31	.02	.02	YES
	426	Thai Fund		TTF	18.05	–	5	4	1.10	▲ 18- 35	(N- 95%)	NMF	1.6	NMF	.28	–	6/30	17.92(q)	14.93(q)	9/30	.102	.121	
	133	Thermo Fisher Sci.		TMO	61.41	3	2	4	.95	75- 105	(20- 70%)	12.1	1.0	5.06	.60	60	9/30	1.19	1.07	3/31	▲.15	NIL	YES
	440	Thomson Reuters	(TSE)	TRI.TO	27.15	4	2	3	.75	▼ 45- 65	(65-140%)	13.0	4.7	2.09	1.28	8	9/30	◆.54	.56	12/31	◆.32	.31	
	2320	Thor Inds.		THO	41.21	1	3	4	1.05	45- 65	(10- 60%)	15.0	1.7	2.75	.72	17	7/31	.84	.66	12/31	▲.18	.15	YES
	199	Thoratec Corp.	(NDQ)	THOR	35.39	3	3	3	.90	55- 85	(55-140%)	19.2	NIL	1.84	NIL	40	9/30	.49	.41	9/30	NIL	NIL	YES
2257	1767	3M Company		MMM	89.57	3	1	3	.80	120- 150	(35- 65%)	13.7	2.6	6.54	2.36	29	9/30	1.65	1.52	12/31	.59	.55	YES
	1811	TIBCO Software	(NDQ)	TIBX	25.32	3	3	4	1.05	30- 40	(20- 60%)	32.1	NIL	.79	NIL	37	8/31	.15	.14	9/30	NIL	NIL	YES
	2427	Tidewater Inc.		TDW	43.98	3	3	3	1.10	60- 90	(35-105%)	12.2	2.3	3.60	1.00	66	9/30	.83	d.10	12/31	◆.25	.25	YES
	2191	Tiffany & Co.		TIF	60.93	4	3	3	1.20	80- 120	(30- 95%)	16.1	2.1	3.79	1.28	26	7/31	.72	.86	3/31	◆.32	.29	YES
	372	Tim Hortons		THI	46.39	3	2	3	.90	65- 85	(40- 85%)	16.5	1.8	2.81	.84	32	9/30	.68	.64	12/31	.21	.167	YES
	2335	Time Warner		TWX	45.28	2	3	3	1.10	60- 90	(35-100%)	13.2	2.3	3.42	1.04	12	9/30	.86	.78	12/31	.26	.235	YES
	1028	Time Warner Cable		TWC	92.38	3	3	4	1.00	110- 165	(20- 80%)	15.0	2.4	6.17	2.24	42	9/30	1.41	1.08	12/31	.56	.48	YES
	738	Timken Co.		TKR	39.92	4	3	4	1.40	75- 110	(90-175%)	9.1	2.3	4.38	.92	49	9/30	.92	1.12	12/31	◆.23	.20	YES
	1008	Titan Int'l		TWI	19.16	3	3	5	1.85	45- 65	(135-240%)	7.0	0.1	2.74	.02	72	9/30	.59	.29	12/31	.005	.005	YES
247	1579	Titanium Metals		TIE	16.58	–	3	–	1.75	25- 40	(50-140%)	22.1	1.8	.75	.30	93	9/30	.11	.14	12/31	.075	.075	YES
	1133	Toll Brothers		TOL	31.15	1	3	4	1.30	30- 40	(N- 30%)	30.0	NIL	1.04	NIL	2	7/31	.36	.25	9/30	NIL	NIL	YES
	1940	Tootsie Roll Ind.		TR	26.65	1	1	3	.70	30- 35	(15- 30%)	28.1	1.2	.95	.33	25	9/30	.39	.32	12/31	.08	.078	
	1555	Torchmark Corp.		TMK	50.92	1	2	3	1.20	50- 65	(N- 30%)	9.4	1.2	5.39	.60	57	9/30	1.29	1.22	12/31	.15	.12	YES
	1735	Toro Co.		TTC	42.04	3	3	3	1.10	40- 60	(N- 45%)	17.4	1.0	2.42	.44	22	7/31	.67	.56	12/31	.11	.10	YES
	2527	Toronto-Dominion	(TSE)	TD.TO	79.57b	3	2	3	.85	95- 130	(20- 65%)	10.8	3.9	7.35	3.08	35	7/31	1.78(b)	1.58(b)	12/31	▲.77(b)	.68(b)	YES
	517	Total ADR		TOT	48.94	3	1	2	1.10	80- 100	(65-105%)	6.7	6.1	7.30	3.00	74	9/30	1.85	1.75	12/31	◆.733	.763	YES
	2568	Total System Svcs.		TSS	21.66	▼3	3	3	.90	30- 40	(40- 85%)	15.8	1.8	1.37	.40	33	9/30	.32	.30	12/31	.10	.07	YES
	398	Towers Watson & Co.		TW	50.36	4	2	4	.90	90- 120	(80-140%)	10.1	0.9	5.00	.46	34	9/30	.82	.82	3/31	◆.115	.10	YES
	109	Toyota Motor ADR(g)		TM	83.31	3	3	3	.90	145- 215	(75-160%)	11.9	1.9	7.00	1.55	80	9/30	◆2.06	.57	12/31	◆.749	.493	YES
	1141	Tractor Supply	(NDQ)	TSCO	89.32	2	2	4	.90	110- 150	(25- 70%)	22.6	1.0	3.95	.92	1	9/30	.69	.58	12/31	◆.20	.12	YES
	1229	TransAlta Corp.	(TSE)	TA.TO	15.04b	4	3	2	.70	25- 40	(65-165%)	20.1	7.7	.75	1.16	92	9/30	.18(b)	.22(b)	3/31	.29(b)	.29(b)	YES
	611	TransCanada Corp.		TRP	45.65	2	2	3	.85	50- 70	(10- 55%)	20.2	3.9	2.26	1.76	4	9/30	.53	.54	12/31	.44	.411	YES
249	728	TransDigm Group		TDG	130.09	3	3	3	1.00	180- 275	(40-110%)	17.4	NIL	7.46	NIL	64	9/30	◆1.63	1.20	9/30	NIL	NIL	YES
	2428	Transocean Ltd.		RIG	45.46	3	3	3	1.35	80- 120	(75-165%)	12.5	NIL	3.65	NIL	66	9/30	1.24	.03	9/30	NIL	.79	YES
2040	774	Travelers Cos.		TRV	69.54	2	1	3	.85	80- 100	(15- 45%)	9.7	2.6	7.18	1.84	11	9/30	2.22	.79	12/31	.46	.41	YES
	573	Tredegar Corp.		TG	17.74	3	3	2	1.10	25- 35	(40- 95%)	13.6	1.4	1.30	.24	23	9/30	.45	.40	3/31	.06	.045	YES
	1941	TreeHouse Foods		THS	51.88	4	3	2	.55	60- 90	(15- 75%)	17.8	NIL	2.92	NIL	25	9/30	.70	.85	9/30	NIL	NIL	YES
	1117	Trex Co.		TREX	38.74	2	4	4	1.40	45- 75	(15- 95%)	16.9	NIL	2.29	NIL	7	9/30	.36	NIL	9/30	NIL	NIL	YES
	1213	Tri-Continental		TY	15.66	–	2	3	1.00	25- 30	(60- 90%)	NMF	3.2	NMF	.50	–	6/30	18.02(q)	17.24(q)	9/30	.155	.07	
	1316	Trimble Nav. Ltd.	(NDQ)	TRMB	54.27	1	3	2	1.35	65- 100	(20- 85%)	29.3	NIL	1.85	NIL	41	9/30	.42	.22	9/30	NIL	NIL	YES
	739	Trinity Inds.		TRN	29.84	2	3	3	1.70	40- 60	(35-100%)	9.1	1.5	3.28	.44	49	9/30	.80	.40	12/31	.11	.09	YES
	1384	TriQuint Semic.	(NDQ)	TQNT	4.47	4	4	2	1.50	9- 15	(100-235%)	20.3	NIL	.22	NIL	88	9/30	.02	.11	9/30	NIL	NIL	YES
	729	Triumph Group		TGI	63.55	3	3	4	1.10	80- 120	(25- 90%)	10.4	0.3	6.12	.16	64	9/30	1.53	1.13	12/31	.04	.04	YES
1823	2117	True Religion Apparel	(NDQ)	TRLG	24.93	–	3	–	1.25	35- 50	(40-100%)	13.2	3.2	1.89	.80	16	9/30	.49	.51	12/31	.20	NIL	YES
	2192	Tumi Holdings		TUMI	21.45	–	3	–	NMF	20- 35	(N- 65%)	27.9	NIL	.77	NIL	26	9/30	.15	NA	9/30	NIL	NIL	YES
	1199	Tupperware Brands		TUP	63.98	3	3	3	1.10	95- 140	(50-120%)	13.6	2.4	4.71	1.56	3	9/30	.85	.17	12/31	.36	.30	YES
	1048	tw telecom	(NDQ)	TWTC	25.66	2	3	3	1.30	30- 40	(15- 55%)	41.4	NIL	.62	NIL	75	9/30	.14	.10	9/30	NIL	NIL	YES
1646	1768	Tyco Int'l		TYC					SEE LATEST REPORT														
★★	1942	Tyson Foods 'A'		TSN	18.72	3	3	1	1.00	20- 35	(5- 85%)	11.3	1.1	▲1.65	.20	25	9/30	◆.51	.26	3/31	▲.05	.04	YES
	1539	**UDR, Inc.**		UDR	22.85	3	3	3	1.05	30- 40	(30- 75%)	NMF	3.9	d.09	.88	20	9/30	d.04	d.14	12/31	.22	.20	YES
	549	UGI Corp.		UGI	31.63	3	2	3	.70	30- 40	(N- 25%)	12.6	3.4	2.51	1.08	28	9/30	d.13	d.20	3/31	◆.27	.26	YES
	154	UIL Holdings		UIL	33.35	3	2	2	.70	35- 45	(5- 35%)	15.5	5.2	2.15	1.73	39	9/30	.31	.24	3/31	.432	.432	YES
	2249	UNS Energy		UNS	40.50	3	3	3	.70	40- 65	(N- 60%)	16.6	4.2	2.44	1.72	36	9/30	1.21	1.46	9/30	.43	.42	YES
	1244	URS Corp.		URS	34.46	3	3	3	1.25	60- 90	(75-160%)	7.3	2.3	4.75	.80	68	9/30	1.28	.98	3/31	.20	NIL	YES
	314	US Airways Group		LCC	12.07	3	5	5	1.60	17- 30	(40-150%)	4.2	NIL	2.88	NIL	63	9/30	1.24	.41	9/30	NIL	NIL	YES
	409	US Ecology	(NDQ)	ECOL	21.45	2	3	3	.95	30- 45	(40-110%)	16.1	3.4	1.33	.72	70	9/30	.44	.33	12/31	.18	.18	YES
	1118	USG Corp.		USG	26.00	3	5	5	1.70	20- 40	(N- 55%)	NMF	NIL	d.59	NIL	7	9/30	d.29	d.53	9/30	NIL	NIL	YES
	2193	Ulta Salon	(NDQ)	ULTA	89.02	2	3	3	1.30	135- 200	(50-125%)	31.2	NIL	2.85	NIL	26	7/31	.54	.38	9/30	NIL	NIL	YES
	2403	Ultra Petroleum		UPL	22.15	4	3	1	1.10	35- 50	(60-125%)	15.1	NIL	1.47	NIL	83	9/30	.64	.72	9/30	NIL	NIL	YES
	134	Ultratech, Inc.	(NDQ)	UTEK	28.86	▼3	3	3	1.10	40- 55	(40- 90%)	15.5	NIL	1.86	NIL	60	9/30	.45	.39	9/30	NIL	NIL	YES
	2118	Under Armour		UA	51.26	2	3	3	1.25	70- 105	(35-105%)	39.4	NIL	1.30	NIL	16	9/30	.54	.44	9/30	NIL	NIL	YES
	2119	Unifi, Inc.		UFI	13.18	3	5	5	1.30	17- 30	(30-130%)	20.3	NIL	.65	NIL	16	9/30	.11	.01	9/30	NIL	NIL	
	399	UniFirst Corp.		UNF	70.20	2	3	3	.90	75- 110	(5- 55%)	14.9	0.2	4.71	.15	34	8/31	1.13	.90	3/31	.038	.038	YES
	1943	Unilever PLC ADR(g)		UL	37.16	2	1	3	.75	40- 50	(10- 35%)	16.6	3.4	2.24	1.26	25	6/30	.91(p)	1.00	12/31	◆.316	.307	YES
	343	Union Pacific		UNP	119.71	3	2	3	1.15	150- 200	(25- 65%)	13.8	2.3	8.66	2.76	51	9/30	2.19	1.85	3/31	▲.69	.60	YES
	1418	Unisys Corp.		UIS	15.94	5	5	2	1.85	30- 55	(90-245%)	6.4	NIL	2.48	NIL	94	9/30	.29	1.63	9/30	NIL	NIL	YES
	315	United Cont'l Hldgs.	(NDQ)	UAL	19.70	5	4	4	1.60	35- 60	(80-205%)	8.0	NIL	▼2.46	NIL	63	9/30	1.35	2.00	9/30	NIL	NIL	YES
1052	1961	United Natural Foods	(NDQ)	UNFI	51.07	1	3	3	.75	45- 70	(N- 35%)	22.7	NIL	2.25	NIL	59	7/31	.51	.36	12/31	NIL	NIL	YES
	2635	United Online	(NDQ)	UNTD	5.37	–	4	–	1.05	9- 16	(70-200%)	12.2	7.4	.44	.40	56	9/30	.05	.13	12/31	.10	.10	YES
	316	United Parcel Serv.		UPS	71.44	3	1	3	.85	115- 145	(60-105%)	14.9	3.2	4.80	2.28	63	9/30	1.06	1.06	12/31	.57	.52	YES
2042	1736	United Rentals		URI	40.30	3	5	4	1.65	40- 75	(N- 85%)	9.5	NIL	4.26	NIL	22	9/30	1.35	.92	9/30	NIL	NIL	YES
	793	U.S. Bancorp		USB	32.08	2	3	4	1.05	35- 55	(10- 70%)	10.9	2.6	2.95	.82	38	9/30	.74	.64	12/31	.195	.125	YES
	941	U.S. Cellular		USM	33.95	5	3	3	1.10	55- 85	(60-150%)	18.4	NIL	1.85	NIL	84	9/30	.42	.73	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

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Page (Selection & Opinion)	Page (Ratings & Reports)	NAME OF STOCK	Ticker Symbol	Recent Price	RANKS: Timeliness	RANKS: Safety	RANKS: Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS: Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	753	U.S. Steel Corp.	X	21.15	4	3	4	1.75	60- 85	(185-300%)	12.3	0.9	1.72	.20	91	9/30	.28	.15	12/31	.05	.05	YES
	1430	United Stationers (NDQ)	USTR	29.53	2	3	3	1.15	40- 60	(35-105%)	10.4	1.9	2.85	.56	87	9/30	.91	.81	3/31	▲.14	.13	
2262	1769	United Technologies	UTX	76.58	3	1	3	1.00	115- 140	(50- 85%)	14.0	2.8	5.47	2.14	29	9/30	1.37	1.47	12/31	.535	.48	YES
2262	843	United Therapeutics (NDQ)	UTHR	51.18	3	3	3	.90	125- 185	(145-260%)	9.5	NIL	5.41	NIL	44	9/30	1.46	1.38	9/30	NIL	NIL	YES
2041	814	UnitedHealth Group	UNH	52.91	3	2	3	1.00	95- 125	(80-135%)	10.3	1.6	5.14	.85	55	9/30	1.50	1.17	12/31	.213	.163	YES
	1998	Universal Corp.	UVV	48.06	3	3	2	.80	45- 65	(N- 35%)	9.6	4.2	5.02	2.00	27	9/30	1.68	d.54	3/31	▲.50	.49	YES
	2024	Universal Electronics (NDQ)	UEIC	16.05	4	3	3	1.05	35- 50	(120-210%)	9.4	NIL	1.71	NIL	89	9/30	.54	.53	9/30	NIL	NIL	
	1119	Universal Forest (NDQ)	UFPI	34.90	3	3	3	1.25	45- 65	(30- 85%)	22.4	1.1	1.56	.40	7	9/30	.28	.29	12/31	.20	.20	YES
	815	Universal Health Sv. 'B'	UHS	42.87	4	3	3	.95	75- 110	(75-155%)	9.5	0.5	4.50	.20	55	9/30	.91	.86	9/30	.05	.05	YES
	1556	Unum Group	UNM	19.78	3	3	3	1.30	30- 45	(50-130%)	6.2	2.6	3.20	.52	57	9/30	.80	.74	12/31	.13	.105	YES
	2232	Urban Outfitters (NDQ)	URBN	37.07	▼2	3	2	1.00	50- 70	(35- 90%)	21.8	NIL	1.70	NIL	18	10/31	◆.40	.33	9/30	NIL	NIL	YES
★★	970	UTStarcom Holdings (NDQ)	UTSI	0.90	5	5	1	1.50	2- 4	(120-345%)	45.0	NIL	.02	NIL	90	9/30	NIL	.05	9/30	NIL	NIL	YES
	816	**VCA Antech** (NDQ)	WOOF	19.70	3	3	4	.95	25- 35	(25- 80%)	13.9	NIL	1.42	NIL	55	9/30	.38	.35	9/30	NIL	NIL	YES
	2120	V.F. Corp.	VFC	156.99	2	2	3	.90	180- 245	(15- 55%)	15.6	2.2	10.05	3.48	16	9/30	3.52	2.87	12/31	▲.87	.72	YES
1442	2357	Vail Resorts	MTN	54.79	1	3	2	1.25	50- 75	(N- 35%)	37.8	1.4	1.45	.75	71	7/31	d1.50	d1.49	12/31	.188	.15	YES
	2387	Valassis Communic.	VCI	25.40	3	4	2	2.00	25- 45	(N- 75%)	7.7	NIL	3.29	NIL	65	9/30	.78	.58	9/30	NIL	NIL	YES
846	1628	Valeant Pharm. Int'l	VRX	55.29	–	3	–	NMF	70- 110	(25-100%)	11.8	NIL	4.70	NIL	31	9/30	1.15	.66	9/30	NIL	NIL	YES
	518	Valero Energy	VLO	30.11	3	3	3	1.35	40- 60	(35-100%)	5.7	2.3	5.29	.70	74	9/30	1.83	2.11	12/31	.175	.15	YES
	1770	Valmont Inds.	VMI	136.69	2	3	5	1.25	130- 195	(N- 45%)	16.2	0.7	8.42	.90	29	9/30	2.12	1.59	12/31	.225	.18	YES
	574	Valspar Corp.	VAL	57.79	2	3	4	.95	55- 80	(N- 40%)	16.8	1.4	3.45	.80	23	10/31	◆.79	d3.18	12/31	.20	.18	YES
	2388	ValueClick Inc. (NDQ)	VCLK	18.09	3	3	4	1.20	30- 45	(65-150%)	14.6	NIL	1.24	NIL	65	9/30	.27	.47	9/30	NIL	NIL	YES
	2194	ValueVision Media (NDQ)	VVTV	1.75	3	5	2	1.20	3- 5	(70-185%)	NMF	NIL	d.42	NIL	26	10/31	d.08	d.13	9/30	NIL	NIL	YES
2446	200	Varian Medical Sys.	VAR	69.11	3	1	2	.85	105- 130	(50- 90%)	16.9	NIL	4.08	NIL	40	9/30	1.08	.95	9/30	NIL	NIL	YES
	918	Vectren Corp.	VVC	28.11	3	2	2	.70	30- 40	(5- 40%)	15.6	5.1	1.80	1.42	24	9/30	.48	.43	12/31	▲.355	.35	YES
	135	Veeco Instruments (NDQ)	VECO	27.67	4	4	4	1.60	45- 80	(65-190%)	31.1	NIL	.89	NIL	60	9/30	.34	1.33	9/30	NIL	NIL	YES
	1540	Ventas, Inc.	VTR	64.52	1	3	3	1.10	55- 80	(N- 25%)	37.7	4.0	1.71	2.61	20	9/30	.39	.35	9/30	.62	.575	YES
847	971	Verifone Systems	PAY	30.10	4	4	5	1.35	45- 75	(50-150%)	9.6	NIL	3.15	NIL	90	7/31	.75	.49	9/30	NIL	NIL	YES
2447	2636	VeriSign Inc. (NDQ)	VRSN	40.61	2	3	3	.90	60- 95	(50-135%)	21.7	NIL	1.87	NIL	56	9/30	.46	.36	9/30	NIL	NIL	YES
	441	Verisk Analytics (NDQ)	VRSK	48.03	2	2	3	.60	55- 70	(15- 45%)	24.5	NIL	1.96	NIL	8	9/30	.48	.41	9/30	NIL	NIL	YES
2042	942	Verizon Communic.	VZ	42.81	2	1	3	.70	55- 70	(30- 65%)	16.5	4.8	2.60	2.06	84	9/30	.64	.56	12/31	▲.515	.50	YES
	844	Vertex Pharmac. (NDQ)	VRTX	41.43	3	3	4	.85	60- 90	(45-115%)	NMF	NIL	.33	NIL	44	9/30	d.27	1.02	9/30	NIL	NIL	YES
	2336	Viacom Inc. 'B' (NDQ)	VIAB	50.40	2	3	3	1.15	85- 125	(70-150%)	8.6	2.2	5.85	1.10	12	9/30	◆1.21	1.06	12/31	.275	.25	YES
	1771	Viad Corp.	VVI	19.64	3	3	2	1.10	20- 35	(N- 80%)	18.5	2.0	1.06	.40	29	9/30	1.01	.06	12/31	▲.10	.04	YES
	591	ViaSat, Inc. (NDQ)	VSAT	35.72	3	3	3	.95	45- 70	(25- 95%)	NMF	NIL	d.37	NIL	69	9/30	d.18	.18	9/30	NIL	NIL	YES
	1962	Village Super Market (NDQ)	VLGEA	35.78	3	2	3	.75	45- 60	(25- 70%)	14.0	2.8	2.55	1.00	59	7/31	.65	.64	12/31	◆.25	.10	
	1029	Virgin Media (NDQ)	VMED	33.63	3	3	4	1.40	45- 70	(35-110%)	13.6	0.5	2.48	.16	42	9/30	.66	d.37	9/30	.04	.04	YES
	2569	Visa Inc.	V	145.65	2	3	3	1.05	230- 340	(60-135%)	21.1	0.9	6.89	1.32	33	9/30	1.54	1.27	12/31	▲.33	.22	YES
	1344	Vishay Intertechnology	VSH	9.11	5	3	3	1.30	20- 30	(120-230%)	8.3	NIL	1.10	NIL	86	9/30	.15	.31	9/30	NIL	NIL	YES
	1009	Visteon Corp.	VC	49.60	–	3	–	NMF	70- 105	(40-110%)	18.4	NIL	2.69	NIL	72	9/30	.28	.79	9/30	NIL	NIL	YES
	2195	Vitamin Shoppe	VSI	59.83	1	3	4	.80	65- 100	(10- 65%)	28.6	NIL	2.09	NIL	26	9/30	.54	.40	9/30	NIL	NIL	YES
	2594	VMware, Inc.	VMW	86.45	3	3	3	1.15	110- 160	(25- 85%)	48.8	NIL	1.77	NIL	47	9/30	.36	.41	9/30	NIL	NIL	YES
	943	Vodafone Group ADR(g)(NDQ)	VOD	25.58	3	2	2	.75	35- 45	(35- 75%)	10.2	5.9	2.50	1.52	84	9/30	1.26(p)	1.23(p)	9/30	1.011	.987	YES
	239	Volcano Corp. (NDQ)	VOLC	26.91	3	3	4	.80	40- 55	(50-105%)	86.8	NIL	.31	NIL	45	9/30	.04	.05	9/30	NIL	NIL	YES
	944	Vonage Holdings	VG	2.21	5	5	1	1.20	3- 5	(35-125%)	6.9	NIL	.32	NIL	84	9/30	.09	.10	9/30	NIL	NIL	YES
	1541	Vornado R'lty Trust	VNO	74.36	3	3	4	1.20	80- 115	(10- 55%)	23.2	3.7	3.20	2.76	20	9/30	1.24	.20	12/31	.69	.69	YES
	1120	Vulcan Materials	VMC	48.25	–	4	–	1.10	20- 35	(N- N%)	NMF	0.1	.27	.04	7	9/30	.12	.17	12/31	.01	.01	YES
	1010	**WABCO Hldgs.**	WBC	59.26	3	3	4	1.35	95- 145	(60-145%)	12.0	NIL	4.95	NIL	72	9/30	1.19	1.22	9/30	NIL	NIL	YES
	1200	WD-40 Co. (NDQ)	WDFC	46.89	2	2	2	.70	45- 65	(N- 40%)	20.6	2.7	2.28	1.25	3	8/31	.56	.61	12/31	.29	.27	YES
	550	WGL Holdings Inc.	WGL	37.27	3	1	2	.65	40- 45	(5- 20%)	14.3	4.3	2.61	1.60	28	9/30	◆d.10	d.26	12/31	.40	.388	YES
	2358	WMS Industries	WMS	16.36	5	3	4	1.15	30- 45	(85-175%)	13.9	NIL	1.18	NIL	71	9/30	.17	.24	12/31	NIL	NIL	YES
		W.P. Carey & Co. LLC						NAME CHANGED TO W.P. CAREY INC.														
	1037	W.P. Carey Inc.	WPC	47.85	3	3	3	.90	40- 60	(N- 25%)	18.7	5.4	2.56	2.60	15	6/30	.78	1.94	12/31	▲.65	.56	
	2389	WPP PLC ADR (NDQ)	WPPGY	64.83	2	3	4	1.20	80- 125	(25- 95%)	13.5	3.3	4.79	2.12	65	6/30	1.56(p)	1.43(p)	12/31	◆.698	.587	YES
	172	Wabash National	WNC	7.26	4	4	3	1.75	15- 25	(105-245%)	5.7	NIL	1.27	NIL	85	9/30	.30	.02	9/30	NIL	NIL	YES
	1737	Wabtec Corp.	WAB	81.02	2	3	3	1.10	80- 120	(N- 50%)	15.0	0.2	5.40	.20	22	9/30	1.30	.96	12/31	.05	.03	YES
248	2154	Wal-Mart Stores	WMT	69.02	2	1	3	.60	95- 115	(40- 65%)	13.3	2.3	5.18	1.59	30	10/31	◆1.08	.97	12/31	◆.398	NIL	YES
	980	Walgreen Co.	WAG	32.65	3	1	3	.80	55- 65	(70-100%)	11.0	3.4	2.97	1.10	62	8/31	.48	.57	12/31	.275	.225	YES
	603	Walter Energy	WLT	29.83	5	3	3	1.90	80- 120	(170-300%)	6.9	1.7	4.35	.50	97	9/30	.48	1.21	12/31	.125	.125	YES
2448	2121	Warnaco Group	WRC	71.11	–	3	–	1.20	60- 90	(N- 25%)	16.8	NIL	4.23	NIL	16	9/30	1.15	1.07	9/30	NIL	NIL	YES
	1629	Warner Chilcott plc (NDQ)	WCRX	11.99	–	3	–	.95	30- 45	(150-275%)	9.4	4.2	1.28	.50	31	9/30	.45	.13	12/31	.25	NIL	YES
	1512	Washington Federal (NDQ)	WAFD	16.27	3	3	4	1.00	20- 30	(25- 85%)	12.2	2.0	1.33	.32	53	9/30	.33	.28	12/31	.08	.06	YES
	2378	Washington Post	WPO	350.91	3	2	2	.85	490- 665	(40- 90%)	16.2	2.8	21.65	9.80	50	9/30	6.79	d.50	12/31	2.45	2.35	
	1542	Washington R.E.I.T.	WRE	25.01	3	3	3	.95	30- 45	(20- 80%)	47.2	4.8	.53	1.20	20	9/30	.14	.04	12/31	▼.30	.434	YES
	410	Waste Connections	WCN	31.23	3	3	3	.70	▲ 40- 60	(30- 90%)	18.9	1.3	1.65	.42	70	9/30	.40	.42	12/31	▲.10	.09	YES
	411	Waste Management	WM	31.62	3	2	3	.80	▼ 35- 50	(10- 60%)	14.5	4.6	2.18	1.47	70	9/30	.61	.62	12/31	.355	.34	YES
	136	Waters Corp.	WAT	83.17	3	2	3	.90	110- 150	(30- 80%)	17.0	NIL	4.88	NIL	60	9/30	1.12	1.10	9/30	NIL	NIL	YES
1824	1142	Watsco, Inc.	WSO	72.01	2	3	3	.90	80- 120	(10- 65%)	21.1	3.4	3.41	2.48	1	9/30	1.19	1.02	12/31	.62	.57	YES
	1630	Watson Pharmac.	WPI	84.99	2	2	3	.75	115- 155	(35- 80%)	12.4	NIL	6.84	NIL	31	9/30	1.35	1.09	9/30	NIL	NIL	YES
	1738	Watts Water Techn.	WTS	38.05	3	3	2	1.10	45- 65	(20- 70%)	13.7	1.2	2.77	.44	22	9/30	.53	.63	12/31	.11	.11	YES
	1168	Wausau Paper	WPP	8.01	▼5	3	3	1.20	12- 18	(50-125%)	29.7	1.5	.27	.12	10	9/30	.06	.11	12/31	.03	.03	YES
247	2429	Weatherford Int'l	WFT	9.47	4	3	3	1.65	30- 45	(215-375%)	8.5	NIL	1.12	NIL	66	3/31	.16	.05	9/30	NIL	NIL	YES
	826	WebMD Health (NDQ)	WBMD	13.56	4	3	1	.75	25- 35	(85-160%)	NMF	NIL	d.21	NIL	78	9/30	d.02	.19	9/30	NIL	NIL	YES
	1812	Websense Inc. (NDQ)	WBSN	13.42	5	3	3	1.05	30- 45	(125-235%)	14.9	NIL	.90	NIL	37	9/30	.23	.20	9/30	NIL	NIL	YES
	2528	Webster Fin'l	WBS	20.76	3	3	3	1.40	18- 30	(N- 45%)	11.7	1.9	1.78	.40	35	9/30	.48	.45	12/31	.10	.05	YES
2658	2196	Weight Watchers	WTW	55.35	3	3	4	.95	85- 130	(55-135%)	12.9	1.3	4.30	.70	26	9/30	1.20	1.09	12/31	.175	.175	YES
	1543	Weingarten Realty	WRI	26.41	3	3	4	1.30	20- 35	(N- 35%)	NMF	4.4	.26	1.16	20	9/30	.08	d.35	12/31	.29	.275	YES
	1963	Weis Markets	WMK	38.60	3	1	3	.65	50- 60	(30- 55%)	13.0	3.1	2.98	1.20	59	9/30	.64	.63	12/31	.30	1.30	
	817	WellPoint, Inc.	WLP	55.94	4	3	2	.95	85- 125	(50-125%)	7.4	2.1	7.53	1.15	55	9/30	2.15	1.90	12/31	.288	.25	YES
	2529	Wells Fargo	WFC	32.40	2	3	4	1.35	50- 70	(55-115%)	9.2	2.7	3.53	.88	35	9/30	.88	.72	12/31	.22	.12	YES
	373	Wendy's Company (NDQ)	WEN	4.53	5	3	3	1.00	▼ 6- 10	(30-120%)	30.2	3.5	▼.15	.16	32	9/30	.03	.05	12/31	▲.04	.02	YES
1248	327	Werner Enterprises (NDQ)	WERN	22.90	4	3	2	.90	30- 50	(30-120%)	15.9	0.9	1.44	.20	77	9/30	.34	.40	3/31	.05	.05	YES
2036	1317	WESCO Int'l	WCC	62.58	3	3	4	1.45	75- 115	(20- 85%)	12.2	NIL	5.15	NIL	41	9/30	1.25	1.11	9/30	NIL	NIL	YES

★★ Supplementary Report in this week's issue.
▲ Arrow indicates the direction of a change. When it appears with the Latest Dividend, the arrow signals that a change in the regular payment rate has occurred in the latest quarter. For Timeliness, 3-5 year Target Price Range, or Estimated Earnings 12 months to 6-30-13, the arrow indicates a change since the preceding week. When a diamond ◆ (indicating a new figure) appears alongside the latest quarterly earnings results, the rank change probably was primarily caused by the earnings report. In other cases, the change is due to the dynamics of the ranking system and could simply be the result of the improvement or weakening of other stocks.

PAGE NUMBERS
Bold type refers to Ratings and Reports; *italics to Selection & Opinion*

PAGE NUMBERS		NAME OF STOCK		Ticker Symbol	Recent Price	RANKS Timeliness	Safety	Technical	Beta	3-5 year Target Price Range	and % appreciation potential	Current P/E Ratio	% Est'd Yield next 12 mos.	Est'd Earns. 12 mos. to 6-30-13	(f) Est'd Div'd next 12 mos.	Industry Rank	LATEST RESULTS Qtr. Ended	Earns. Per sh.	Year Ago	Qtr. Ended	Latest Div'd	Year Ago	Do Options Trade?
	2197	West Marine	(NDQ)	WMAR	10.24	4	3	4	.95	12- 18	(15- 75%)	14.0	NIL	.73	NIL	26	9/30	.43	.42	9/30	NIL	NIL	
	240	West Pharmac. Svcs.		WST	51.66	3	3	4	.80	60- 90	(15- 75%)	19.0	1.5	2.72	.76	45	9/30	.52	.53	12/31	▲.19	.18	YES
	919	Westar Energy		WR	27.89	2	2	3	.70	25- 35	(N- 25%)	13.6	4.8	2.05	1.34	24	9/30	1.10	.98	12/31	.33	.32	YES
	1419	Western Digital	(NDQ)	WDC	35.00	4	3	4	1.30	70- 100	(100-185%)	4.1	2.9	8.60	1.00	94	9/30	2.36	1.10	12/31	▲.25	NIL	YES
2447	2570	Western Union		WU	12.74	5	3	3	1.05	20- 30	(55-135%)	8.4	3.9	1.51	.50	33	9/30	.46	.40	12/31	▲.125	.16	YES
	575	Westlake Chemical		WLK	74.53	1	3	5	1.35	70- 105	(N- 40%)	15.6	1.0	4.77	.75	23	9/30	1.30	1.01	12/31	◆.188	.074	YES
	1964	Weston (George)	(TSE)	WN.TO	64.06	▲3	2	2	.45	90- 125	(40- 95%)	13.2	2.2	4.84	1.44	59	9/30	◆1.49	1.93	12/31	◆.36	.36	YES
	2233	Wet Seal 'A'	(NDQ)	WTSLA	2.81	4	3	2	1.00	4- 6	(40-115%)	NMF	NIL	d.16	NIL	18	10/31	◆d.11	.05	9/30	NIL	NIL	YES
	2571	WEX Inc.		WXS	69.50	2	3	3	1.10	85- 130	(20- 85%)	15.7	NIL	4.44	NIL	33	9/30	1.08	.99	9/30	NIL	NIL	YES
	1169	Weyerhaeuser Co.		WY	25.98	1	3	3	1.10	25- 40	(N- 55%)	34.6	2.7	.75	.69	10	9/30	.22	.28	12/31	▲.17	.15	YES
	1772	Whirlpool Corp.		WHR	98.12	2	3	4	1.30	100- 150	(N- 55%)	12.3	2.0	7.95	2.00	29	9/30	1.80	2.35	12/31	.50	.50	YES
	1965	Whole Foods Market	(NDQ)	WFM	91.41	2	3	3	1.05	100- 150	(10- 65%)	32.3	0.9	2.83	.80	59	9/30	.60	.42	3/31	▲.20	.14	YES
	2369	Wiley (John) & Sons		JWA	41.27	4	3	2	.90	75- 115	(80-180%)	11.6	2.6	3.55	1.06	82	7/31	.52	.68	12/31	.24	.20	YES
	612	Williams Cos.		WMB	32.67	–	3	–	NMF	25- 40	(N- 20%)	26.6	4.0	1.23	1.30	4	9/30	.25	.40	12/31	▲.325	.25	YES
	624	Williams Partners L.P.		WPZ	50.95	3	3	4	1.05	55- 85	(10- 65%)	19.3	6.5	2.64	3.32	9	9/30	.38	.92	12/31	▲.808	.747	YES
	2198	Williams-Sonoma		WSM	45.02	1	3	2	1.15	60- 85	(35- 90%)	16.7	2.1	2.69	.96	26	10/31	.49	.41	12/31	.22	.17	YES
	1049	Windstream Corp.	(NDQ)	WIN	8.36	4	3	3	.90	11- 17	(30-105%)	14.9	12.0	.56	1.00	75	9/30	.12	.17	3/31	.25	.25	YES
	2321	Winnebago		WGO	13.66	▲2	4	4	1.50	12- 20	(N- 45%)	31.0	NIL	.44	NIL	17	8/31	.14	.12	9/30	NIL	NIL	YES
	794	Wintrust Financial	(NDQ)	WTFC	36.34	2	3	4	1.10	35- 50	(N- 40%)	15.5	0.5	2.34	.18	38	9/30	.66	.65	9/30	.09	.09	YES
	920	Wisconsin Energy		WEC	36.67	3	1	3	.60	35- 45	(N- 25%)	15.6	3.6	2.35	1.32	24	9/30	.67	.55	12/31	.30	.26	YES
	2164	Wolverine World Wide		WWW	42.58	3	2	4	.80	60- 80	(40- 90%)	18.0	1.1	2.37	.48	61	9/30	.72	.82	12/31	.12	.12	YES
	137	Woodward, Inc.	(NDQ)	WWD	35.00	3	3	2	1.40	55- 80	(55-130%)	15.5	0.9	2.26	.32	60	9/30	.66	.60	12/31	.08	.07	YES
	2337	World Wrestling Ent.		WWE	7.87	4	3	2	.80	12- 17	(50-115%)	21.3	6.1	.37	.48	12	9/30	.05	.14	12/31	.12	.12	YES
	754	Worthington Inds.		WOR	22.21	2	3	5	1.35	25- 40	(15- 80%)	11.0	2.3	2.02	.52	91	8/31	.49	.35	12/31	.13	.12	YES
		Wright Express							NAME CHANGED TO WEX INC.														
	201	Wright Medical	(NDQ)	WMGI	19.67	3	3	3	.95	30- 45	(55-130%)	NMF	NIL	d.09	NIL	40	9/30	d.14	d.42	9/30	NIL	NIL	YES
	2359	Wyndham Worldwide		WYN	49.12	2	4	4	1.80	45- 75	(N- 55%)	14.6	1.9	3.37	.92	71	9/30	1.11	1.08	12/31	.23	.15	YES
	2360	Wynn Resorts	(NDQ)	WYNN	105.79	3	3	3	1.80	185- 275	(75-160%)	17.7	3.8	5.99	4.00	71	9/30	1.48	1.05	12/31	.50	.50	YES
	775	**XL Group plc**		XL	24.12	3	4	3	1.50	25- 40	(5- 65%)	11.9	1.8	2.03	.44	11	9/30	.61	.28	12/31	.11	.11	YES
	2637	XO Group		XOXO	7.50	3	3	3	.95	13- 20	(75-165%)	20.8	NIL	.36	NIL	56	9/30	.08	.04	9/30	NIL	NIL	YES
	2250	Xcel Energy Inc.		XEL	26.14	1	2	3	.60	25- 35	(N- 35%)	13.7	4.2	1.91	1.10	36	9/30	.81	.69	12/31	.27	.26	YES
	845	XenoPort, Inc.	(NDQ)	XNPT	7.53	3	5	3	.90	14- 25	(85-230%)	NMF	NIL	d1.43	NIL	44	9/30	d.41	d.53	9/30	NIL	NIL	YES
	1431	Xerox Corp.		XRX	6.42	4	3	2	1.25	12- 17	(85-165%)	6.8	2.6	.94	.17	87	9/30	.21	.23	3/31	.043	.043	YES
	1385	Xilinx Inc.	(NDQ)	XLNX	33.50	3	2	3	.90	45- 60	(35- 80%)	17.2	2.6	1.95	.88	88	9/30	.46	.47	12/31	.22	.19	YES
1248	2638	**Yahoo! Inc.**	(NDQ)	YHOO	18.36	3	3	3	.95	25- 35	(35- 90%)	17.0	NIL	1.08	NIL	56	9/30	.33	.23	9/30	NIL	NIL	YES
1823	374	Yum! Brands		YUM	73.32	▲2	2	4	.90	70- 95	(N- 30%)	20.5	1.9	3.57	1.37	32	9/30	.99	.83	3/31	◆.335	.285	YES
★★	2199	**Zale Corp.**		ZLC	7.28	3	5	1	1.55	9- 17	(25-135%)	8.8	NIL	.83	NIL	26	10/31	◆d.88	d.99	9/30	NIL	NIL	YES
	592	Zebra Techn. 'A'	(NDQ)	ZBRA	37.77	3	3	3	1.00	55- 85	(45-125%)	14.5	NIL	2.60	NIL	69	9/30	.64	.64	9/30	NIL	NIL	YES
	1944	Zhongpin	(NDQ)	HOGS	10.81	–	5	–	1.20	20- 40	(85-270%)	5.4	NIL	2.01	NIL	25	9/30	.30	.46	9/30	NIL	NIL	YES
	202	Zimmer Holdings		ZMH	65.82	2	2	4	.95	85- 115	(30- 75%)	12.5	1.2	5.25	.80	40	9/30	1.02	1.01	12/31	.18	NIL	YES
	2530	Zions Bancorp.	(NDQ)	ZION	19.71	3	3	4	1.50	20- 30	(N- 50%)	12.8	0.2	1.54	.04	35	9/30	.34	.35	12/31	.01	.01	YES
250	2200	Zipcar, Inc.	(NDQ)	ZIP	7.03	–	3	–	NMF	14- 20	(100-185%)	63.9	NIL	.11	NIL	26	9/30	.10	.02	9/30	NIL	NIL	YES
	2442	Zoltek Cos.	(NDQ)	ZOLT	6.45	4	3	4	1.80	11- 17	(70-165%)	9.6	NIL	.67	NIL	21	6/30	.16	d.05	9/30	NIL	NIL	YES
848	2234	Zumiez Inc.	(NDQ)	ZUMZ	20.03	4	3	2	1.25	35- 55	(75-175%)	12.9	NIL	1.55	NIL	18	7/31	.17	.08	9/30	NIL	NIL	YES
	138	Zygo Corp.	(NDQ)	ZIGO	13.65	4	3	3	1.25	40- 60	(195-340%)	10.9	NIL	1.25	NIL	60	9/30	.13	.35	9/30	NIL	NIL	
1824	2025	Zynga Inc.	(NDQ)	ZNGA	2.19	–	4	–	NMF	6- 9	(175-310%)	NMF	NIL	d.28	NIL	89	9/30	d.07	NA	9/30	NIL	NIL	YES

(•) All data adjusted for announced stock split or stock dividend. See back page of Ratings & Reports.
◆ New figure this week.
(b) Canadian Funds.
(d) Deficit.
(f) The estimate may reflect a probable increase or decrease. If a dividend boost or cut is possible but not probable, two figures are shown, the first is the more likely.
(g) Dividends subject to foreign withholding tax for U.S. residents.
(h) Est'd Earnings & Est'd Dividends after conversion to U.S. dollars at Value Line estimated translation rate.
(j) All Index data expressed in hundreds.
(p) 6 months (q) Asset Value
N=Negative figure NA=Not available NMF=No meaningful figure

INDUSTRIES, IN ORDER OF TIMELINESS*

Arrow (▲▼) before name indicates that a **significant change in Rank** has occurred since the preceding week.

1 Retail Building Supply
2 Homebuilding
3 Household Products
4 Oil/Gas Distribution
5 Funeral Services
6 Water Utility
7 Building Materials
8 Information Services
9 Pipeline MLPs
10 Paper/Forest Products
11 Insurance (Prop/Cas.)
12 Entertainment
13 Retail Automotive
14 IT Services
15 Property Management
16 Apparel
17 Recreation
18 Retail (Softlines)
19 Beverage
20 R.E.I.T.
21 Chemical (Diversified)
22 Machinery
23 Chemical (Specialty)
24 Electric Util. (Central)
25 Food Processing
26 Retail (Hardlines)
27 Tobacco
28 Natural Gas Utility
29 Diversified Co.
30 Retail Store
31 Drug
32 Restaurant
33 Financial Svcs. (Div.)
34▲ Industrial Services
35 Bank
36 Electric Utility (West)
37 E-Commerce
38 Bank (Midwest)
39 Electric Utility (East)
40 Med Supp Invasive
41 Electrical Equipment
42▲ Cable TV
43 Public/Private Equity
44 Biotechnology
45 Med Supp Non-Invasive
46 Packaging & Container
47 Computer Software
48 Furn/Home Furnishings
49 Metal Fabricating
50 Newspaper
51 Railroad
52▼ Reinsurance
53 Thrift
54 Toiletries/Cosmetics
55 Medical Services
56 Internet
57 Insurance (Life)
58 Human Resources
59 Retail/Wholesale Food
60▼ Precision Instrument
61 Shoe
62 Pharmacy Services
63 Air Transport
64 Aerospace/Defense
65 Advertising
66 Oilfield Svcs/Equip.
67 Natural Gas (Div.)
68 Engineering & Const
69 Wireless Networking
70 Environmental
71 Hotel/Gaming
72 Auto Parts
73 Chemical (Basic)
74 Petroleum (Integrated)
75 Telecom. Utility
76 Securities Brokerage
77 Trucking
78 Healthcare Information
79 Precious Metals
80 Automotive
81 Maritime
82 Publishing
83 Petroleum (Producing)
84 Telecom. Services
85 Heavy Truck & Equip
86 Electronics
87 Office Equip/Supplies
88 Semiconductor
89 Entertainment Tech
90 Telecom. Equipment
91 Steel
92 Power
93 Metals & Mining (Div.)
94 Computers/Peripherals
95 Semiconductor Equip
96 Foreign Electronics
97 Coal
98 Educational Services

***Based on the Timeliness™ ranks of the stocks in the industry**

Noteworthy Rank Changes

Listed below are some of the stocks whose Timeliness ranks have changed this week. We include mostly rank changes caused by fundamentals such as new earnings reports. Even when a significant change in earnings momentum has been forecast, the stock's rank will not be affected until the actual results, confirming that forecast, are reported. In most cases, we omit stocks that have been bumped up or down in rank by the dynamism of the ranking system.

STOCKS MOVING UP IN TIMELINESS RANK

Stock Name	Old Rank	New Rank	Reason for Change	Earnings Est. 12 months to 6-30-13
Amer. Woodmark	2	1	Higher than expected earnings. Oct. quarter 14¢ vs. year ago d21¢. Our estimate was 7¢.	$.55
Brown Shoe	3	2	Higher than expected earnings. Oct. period 60¢ vs. year ago 51¢. Our estimate was 49¢.	1.15
Cyberonics	2	1	Higher than expected earnings. Oct. period 44¢ vs. year ago 32¢. Our estimate was 38¢.	1.76
DSW Inc. (B)	2	1	Surprise factor, greater than average gain. Oct. period $1.02 vs. year ago 88¢. Our estimate was 95¢.	Under Review
Krispy Kreme	3	2	Higher than expected earnings. Oct. period 12¢ vs. year ago 7¢. Our estimate was 7¢.	(A)
Lowe's Cos. (B)	3	2	Surprise factor, greater than average gain. Oct. period 40¢ vs. year ago 35¢. Our estimate was 35¢.	1.93
Sirona Dental	2	1	Surprise factor, greater than average gain. Sept. quarter 62¢ vs. year ago 24¢. Our estimate was 51¢.	Under Review

STOCKS MOVING DOWN IN TIMELINESS RANK

Stock Name	Old Rank	New Rank	Reason for Change	Earnings Est. 12 months to 6-30-13
AFC Enterprises	1	2	Dynamism of the ranking system.	(A)
Amer. Eagle Outfitters	1	2	Dynamism of the ranking system.	
Cirrus Logic	1	2	Dynamism of the ranking system.	
Dole Food	3	4	Lower than expected earnings. Sept. period d17¢ vs. year ago d54¢. Our estimate was 15¢.	$1.35
MTS Systems	2	3	Surprise factor, earnings reversal. Management forecasts 72-82¢ for the Dec. quarter vs. year ago 98¢. Our estimate was $1.00.	Under Review
Omnicom Group	1	2	Dynamism of the ranking system.	
Patterson Cos.	2	3	Surprise factor, decreasing profit growth. Oct. period 44¢ vs. year ago 43¢. Our estimate was 50¢.	2.20
Scholastic Corp. (B)	3	4	Lower than expected earnings. Management forecasts $1.40-$1.60 for the May year vs. year ago $3.93. Our estimate was $2.40.	Under Review
Urban Outfitters	1	2	Dynamism of the ranking system.	

(A) New full-page report in this week's Ratings & Reports.
(B) Supplementary report in this week's Ratings & Reports.

TIMELY STOCKS IN TIMELY INDUSTRIES

Retail Building Supply (INDUSTRY RANK 1)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1137	Home Depot	63.33	1	1	3	0.90	19.4	1.8	N- 20%
1138	Lowe's Cos.	33.96	2	2	3	0.95	17.6	1.9	20- 60%
1139	Lumber Liquidators	54.34	1	3	4	1.10	33.8	NIL	N- 30%
1140	Sherwin-Williams	157.01	1	1	3	0.70	22.5	1.1	N- N%
1141	Tractor Supply	89.32	2	2	4	0.90	22.6	1.0	25- 70%
1142	Watsco, Inc.	72.01	2	3	3	0.90	21.1	3.4	10- 65%

Homebuilding (INDUSTRY RANK 2)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1123	Horton D.R.	19.02	2	3	5	1.40	21.6	0.8	5- 60%
1126	Lennar Corp.	36.81	2	3	5	1.80	29.7	0.4	N- 35%
1127	M.D.C. Holdings	34.32	1	3	5	1.25	32.1	2.9	N- 60%
1128	NVR, Inc.	876.84	1	3	4	1.00	22.1	NIL	N- 50%
1129	PulteGroup, Inc.	15.90	2	4	5	1.50	15.9	NIL	5- 90%
1130	Ryland Group	32.36	2	4	5	1.35	33.0	0.4	N- N%
1133	Toll Brothers	31.15	1	3	4	1.30	30.0	NIL	N- 30%

Household Products (INDUSTRY RANK 3)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1187	Church & Dwight	52.59	2	1	3	0.60	20.2	1.8	5- 35%
1188	Clorox Co.	74.10	2	2	3	0.60	17.2	3.5	20- 70%
1189	Colgate-Palmolive	106.91	2	1	3	0.60	19.5	2.4	30- 60%
1190	Energizer Holdings	77.21	2	3	4	0.95	11.3	2.1	30- 95%
1191	Jarden Corp.	52.24	2	3	4	1.35	18.9	NIL	N- 35%
1192	Kimberly-Clark	86.00	1	1	3	0.55	16.5	3.4	10- 35%
1193	Lancaster Colony	73.29	2	1	2	0.70	18.3	2.1	N- N%
1195	Newell Rubbermaid	21.35	2	3	4	1.25	15.8	2.8	40-110%
1196	Procter & Gamble	67.92	2	1	3	0.60	17.2	3.3	35- 60%
1198	Spectrum Brands	45.30	2	3	4	1.10	16.0	NIL	N- 45%
1200	WD-40 Co.	46.89	2	2	2	0.70	20.6	2.7	N- 40%

Oil/Gas Distribution (INDUSTRY RANK 4)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
606	Copano Energy	31.15	2	3	3	1.15	53.7	7.6	N- 45%
607	Enbridge Inc.	38.63	2	1	3	0.60	22.2	2.9	5- 15%
608	ONEOK Inc.	45.90	1	3	3	0.95	25.1	2.9	N- 10%
611	TransCanada Corp.	45.65	2	2	3	0.85	20.2	3.9	10- 55%

Funeral Services (INDUSTRY RANK 5)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1814	Carriage Services	11.20	1	3	4	0.70	18.1	0.9	N- 25%
1817	Service Corp. Int'l	13.91	2	3	3	1.10	17.4	1.7	N- 45%
1818	Stewart Enterpr. 'A'	7.37	2	3	3	1.10	16.0	2.2	10- 75%
1819	StoneMor Partners L.P.	21.93	2	4	3	0.75	NMF	10.8	N- 35%

Water Utility (INDUSTRY RANK 6)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1774	Amer. States Water	42.52	2	2	3	0.70	16.7	3.3	5- 40%
1775	Amer. Water Works	36.99	2	3	3	0.65	16.9	2.7	N- 50%
1776	Aqua America	24.67	2	2	3	0.60	23.1	2.8	N- 40%
1778	Middlesex Water	18.10	2	2	3	0.70	17.9	4.1	N- 40%

Building Materials (INDUSTRY RANK 7)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1103	Amer. Woodmark	23.03	1	3	4	0.90	41.9	NIL	10- 75%
1104	Apogee Enterprises	19.54	1	3	5	1.40	28.7	1.8	N- 80%
1106	Beacon Roofing	30.90	2	3	4	1.15	20.1	NIL	30-110%
1108	Eagle Materials	54.54	1	3	5	1.25	42.0	0.7	N- N%
1109	Headwaters Inc.	6.58	2	5	5	1.60	NMF	NIL	N- 50%
1110	Martin Marietta	85.41	2	3	4	1.15	30.3	1.9	5- 60%
1111	Masco Corp.	15.44	2	3	4	1.40	37.7	1.9	30- 95%
1117	Trex Co.	38.74	2	4	4	1.40	16.9	NIL	15- 95%

Information Services (INDUSTRY RANK 8)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
428	Advisory Board	43.68	1	2	4	0.80	46.5	NIL	N- 5%
432	CoStar Group	81.94	1	3	2	1.00	43.6	NIL	N- 40%
434	Equifax, Inc.	50.25	1	2	4	0.90	16.4	1.4	40- 90%
437	Gartner Inc.	46.03	2	3	3	1.05	24.5	NIL	N- 40%
439	Moody's Corp.	46.21	1	3	4	1.25	14.8	1.4	N- 50%
441	Verisk Analytics	48.03	2	2	3	0.60	24.5	NIL	15- 45%

Pipeline MLPs (INDUSTRY RANK 9)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
616	El Paso Pipeline	35.97	1	3	3	0.70	16.6	6.4	10- 65%
620	Kinder Morgan Energy	79.87	1	2	3	0.75	33.0	6.3	15- 50%
621	Magellan Midstream	42.85	1	3	3	0.85	20.9	4.5	N- N%

Paper/Forest Products (INDUSTRY RANK 10)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1161	Glatfelter	16.17	2	3	3	1.20	11.1	2.2	25- 85%
1163	Louisiana-Pacific	16.55	2	5	2	1.90	25.5	NIL	N- 50%
1165	Plum Creek Timber	41.64	2	3	4	0.95	34.7	4.0	N- 20%
1166	Potlatch Corp.	38.22	2	3	4	1.05	30.3	3.2	5- 45%
1167	Rayonier Inc.	48.56	2	3	3	0.95	20.5	3.7	25- 85%
1169	Weyerhaeuser Co.	25.98	1	3	3	1.10	34.6	2.7	N- 55%

Insurance (Prop/Cas.) (INDUSTRY RANK 11)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
756	ACE Limited	78.20	2	2	3	0.85	9.7	2.5	N- 15%
760	Berkley (W.R.)	39.20	2	2	3	0.70	15.3	0.9	15- 55%
763	Chubb Corp.	76.14	1	1	3	0.85	11.5	2.2	N- 20%
764	Cincinnati Financial	39.63	2	2	3	0.95	22.1	4.1	N- 25%
765	Erie Indemnity Co.	65.25	2	2	3	0.70	21.5	3.6	N- 25%
766	HCC Insurance Hldgs.	35.98	1	3	3	0.85	11.5	1.8	10- 65%
768	Markel Corp.	482.00	2	2	3	0.80	21.6	NIL	40- 90%
774	Travelers Cos.	69.54	2	1	3	0.85	9.7	2.6	15- 45%

Entertainment (INDUSTRY RANK 12)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
2325	CBS Corp. 'B'	34.49	2	3	3	1.50	12.5	1.4	15- 75%
2329	Lions Gate Entertain.	15.64	1	5	3	0.55	10.6	NIL	60-190%
2332	News Corp.	24.45	1	3	3	1.25	16.1	0.7	25- 65%
2333	Scripps Networks	60.15	1	2	2	1.00	16.8	0.8	50-100%
2335	Time Warner	45.28	2	3	3	1.10	13.2	2.3	35-100%
2336	Viacom Inc. 'B'	50.40	2	3	3	1.15	8.6	2.2	70-150%

Retail Automotive (INDUSTRY RANK 13)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
2124	Asbury Automotive	29.17	2	5	5	1.85	11.4	NIL	5-105%
2125	AutoNation, Inc.	41.30	1	3	3	1.15	15.0	NIL	10- 55%
2128	Copart, Inc.	29.58	2	2	3	0.85	19.1	NIL	20- 50%
2129	Group 1 Automotive	59.28	1	3	4	1.55	11.9	1.0	25- 85%
2132	Penske Auto	28.75	2	4	5	1.50	12.4	1.8	20-110%

IT Services (INDUSTRY RANK 14)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
2596	ACI Worldwide	41.77	2	3	3	0.95	32.1	NIL	20- 80%
2597	Accenture Plc	67.06	2	1	3	0.85	16.4	2.4	20- 40%
2598	Amdocs Ltd.	32.62	2	3	3	0.90	12.9	1.6	40-100%
2599	Automatic Data Proc.	55.22	1	1	3	0.80	18.2	3.2	45- 70%
2607	Fiserv Inc.	73.62	2	2	3	0.95	13.2	NIL	30- 75%
2608	Henry (Jack) & Assoc.	38.29	2	2	2	0.85	19.1	1.2	5- 45%
2610	Manhattan Assoc.	58.88	1	3	3	0.85	20.5	NIL	20- 80%
2613	SEI Investments	21.87	2	2	3	1.05	16.3	1.5	85-150%

Property Management (INDUSTRY RANK 15)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1031	Brookfield Asset Mgmt.	33.38	2	3	3	1.20	17.8	1.7	50-125%
1033	Corrections Corp. Amer.	33.17	2	3	4	1.05	20.3	2.4	N- 50%
1035	Geo Group (The)	27.57	2	3	4	0.95	18.8	2.9	10- 65%

Apparel (INDUSTRY RANK 16)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
2102	Carter's Inc.	52.02	2	3	3	0.90	16.8	NIL	35-100%
2105	Gildan Activewear	32.90	2	3	3	1.10	14.4	1.1	35-115%
2107	Hanesbrands, Inc.	34.41	1	3	3	1.20	10.6	NIL	30- 90%
2112	Oxford Inds.	53.29	1	4	2	1.60	18.7	1.4	15- 80%
2113	PVH Corp.	111.24	2	3	3	1.25	16.5	0.1	N- 55%
2118	Under Armour	51.26	2	3	3	1.25	39.4	NIL	35-105%
2120	V.F. Corp.	156.99	2	2	3	0.90	15.6	2.2	15- 55%

Recreation (INDUSTRY RANK 17)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
2312	Mattel, Inc.	35.84	1	2	3	0.85	13.6	3.5	N- 25%
2313	Polaris Inds.	81.61	1	3	5	1.30	17.4	1.9	N- 40%
2314	Pool Corp.	40.50	1	3	4	1.05	20.0	1.6	N- 50%
2319	Sturm, Ruger & Co.	48.83	2	3	5	0.85	13.1	3.1	35-105%
2320	Thor Inds.	41.21	1	3	4	1.05	15.0	1.7	10- 60%
2321	Winnebago	13.66	2	4	4	1.50	31.0	NIL	N- 45%

Retail (Softlines) (INDUSTRY RANK 18)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
2204	Amer. Eagle Outfitters	18.84	2	3	3	0.95	13.5	2.3	5- 85%
2205	ANN Inc.	33.96	2	3	2	1.25	14.0	NIL	35-105%
2209	Buckle (The), Inc.	49.00	2	3	3	1.00	14.2	2.0	20- 75%
2211	Chico's FAS	18.16	2	3	3	1.25	15.5	1.3	40- 95%
2213	Christopher & Banks	3.00	2	5	4	1.25	NMF	NIL	65-200%
2216	DSW Inc.	62.29	1	3	3	1.05	17.7	1.2	35-100%
2218	Finish Line (The)	20.94	2	3	3	1.10	12.2	1.1	45-115%
2219	Foot Locker	33.56	1	3	4	1.05	12.9	2.1	5- 65%
2220	Gap (The), Inc.	34.43	1	2	4	1.00	15.7	1.5	N- 45%
2223	Limited Brands	48.31	2	3	4	1.20	16.5	2.1	N- 45%
2224	lululemon athletica	71.23	2	3	4	1.40	35.3	NIL	10- 70%
2228	Ross Stores	55.55	2	2	3	0.75	15.2	1.0	15- 70%
2230	Stage Stores	24.40	1	3	2	1.40	19.7	1.7	25- 85%
2231	TJX Companies	44.08	2	1	3	0.80	16.8	1.0	15- 35%
2232	Urban Outfitters	37.07	2	3	2	1.00	21.8	NIL	35- 90%

Beverage (INDUSTRY RANK 19)

Page No.	Industry (Industry Rank)	Recent Price	Timeliness	Safety	Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd. 3-5 Year Price Apprec.
1967	AB InBev ADR	84.67	2	1	3	0.90	18.0	1.8	5- 30%
1970	Brown-Forman 'B'	66.83	1	1	3	0.70	24.3	1.5	N- 20%
1972	Coca-Cola	37.24	2	1	3	0.60	18.0	2.9	35- 60%
1975	Constellation Brands	34.62	2	3	3	0.95	16.0	NIL	30-100%
1977	Diageo plc	116.38	1	1	3	0.85	19.4	2.3	5- 25%
1978	Dr Pepper Snapple	43.45	2	3	2	0.75	13.8	3.2	25- 85%

TIMELY STOCKS IN TIMELY INDUSTRIES

Page No.	Industry (Industry Rank)	Recent Price	RANKS Timeliness	RANKS Safety	RANKS Technical	Beta	Current P/E Ratio	% Est'd Yield	Est'd 3-5 Year Price Apprec.
	R.E.I.T. (INDUSTRY RANK 20)								
1517	BRE Properties	48.17	2	3	3	1.00	74.1	3.2	N- 5%
1518	Boston Properties	101.88	2	3	3	1.15	58.6	2.6	N- 25%
1519	Camden Property Trust	64.81	2	3	3	1.10	49.9	3.5	N- 45%
1523	Federal Rlty. Inv. Trust	101.29	1	3	3	1.05	40.0	2.9	N- 15%
1525	HCP Inc.	45.29	2	3	3	1.05	24.0	4.4	N- 45%
1526	Health Care REIT	60.08	2	3	3	0.85	52.2	5.2	10- 60%
1530	Kimco Realty	18.81	2	3	4	1.25	52.3	4.5	N- 35%
1535	Public Storage	144.94	2	2	3	0.95	39.8	3.2	N- 15%
1536	Realty Income Corp.	38.42	2	3	3	0.85	40.9	4.7	N- 30%
1537	SL Green Realty	72.83	2	3	4	1.55	31.5	1.4	25- 85%
1540	Ventas, Inc.	64.52	1	3	3	1.10	37.7	4.0	N- 25%
	Chemical (Diversified) (INDUSTRY RANK 21)								
2435	Cytec Inds.	67.09	1	3	4	1.45	18.1	0.7	N- 35%
2436	Eastman Chemical	58.37	2	2	4	1.30	10.0	1.8	45- 90%
2439	Monsanto Co.	88.33	2	3	3	1.00	21.2	1.7	20- 75%
2440	PPG Inds.	120.05	1	1	4	1.05	16.2	2.0	10- 35%
	Machinery (INDUSTRY RANK 22)								
1704	Applied Ind'l Techn.	37.50	2	3	3	1.05	12.7	2.2	20- 75%
1713	Flowserve Corp.	138.23	1	3	3	1.45	15.1	1.0	N- 35%
1714	Graco Inc.	46.77	2	3	3	1.15	18.1	1.9	5- 70%
1717	Lennox Int'l	50.33	1	3	4	1.00	19.0	1.6	20- 70%
1719	Lindsay Corp.	74.65	2	3	5	1.35	19.1	0.6	N- 25%
1721	Middleby Corp. (The)	126.98	2	3	2	1.20	19.0	NIL	N- 40%
1724	Nordson Corp.	60.59	1	3	2	1.25	15.9	1.0	N- 40%
1725	RBC Bearings	44.81	2	3	3	1.30	16.6	NIL	35- 90%
1728	Roper Inds.	111.07	2	2	3	1.05	20.9	0.5	5- 45%
1730	Smith (A.O.)	60.41	1	3	3	1.00	20.2	1.3	N- 15%
1731	Snap-on Inc.	76.80	2	2	3	1.10	14.4	2.0	5- 45%
1737	Wabtec Corp.	81.02	2	3	3	1.10	15.0	0.2	N- 50%
	Chemical (Specialty) (INDUSTRY RANK 23)								
553	Amer. Vanguard Corp.	32.04	1	3	5	1.05	23.1	0.4	10- 55%
558	Ecolab Inc.	70.00	1	1	3	0.80	21.1	1.1	5- 30%
561	Int'l Flavors & Frag.	63.27	2	1	3	0.80	15.4	2.1	20- 40%
563	Minerals Techn.	71.51	2	2	3	1.10	16.8	0.3	10- 45%
564	NewMarket Corp.	252.22	2	3	3	1.25	15.6	1.2	10- 65%
569	Quaker Chemical	48.52	2	3	3	1.45	14.1	2.0	15- 75%
570	RPM Int'l	26.78	1	3	3	1.05	14.9	3.4	10- 70%
574	Valspar Corp.	57.79	2	3	4	0.95	16.8	1.4	N- 40%
575	Westlake Chemical	74.53	1	3	5	1.35	15.6	1.0	N- 40%
	Electric Util. (Central) (INDUSTRY RANK 24)								
902	ALLETE	38.50	2	2	2	0.70	14.0	4.9	N- 30%
903	Alliant Energy	43.45	2	2	3	0.70	14.4	4.3	N- 25%
909	DTE Energy	59.18	2	3	3	0.75	14.9	4.2	N- 20%
913	ITC Holdings	77.51	2	2	3	0.75	19.3	2.0	30- 75%
915	MGE Energy	49.18	1	1	3	0.60	16.6	3.2	N- 10%
919	Westar Energy	27.89	2	2	3	0.70	13.6	4.8	N- 25%
	Food Processing (INDUSTRY RANK 25)								
1903	B&G Foods	28.79	2	3	1	1.10	19.9	4.0	N- 40%
1905	Cal-Maine Foods	43.65	2	3	3	1.00	14.1	2.3	N- 15%
1907	Campbell Soup	36.95	2	2	2	0.55	14.5	3.1	10- 50%
1916	Hain Celestial Group	61.90	1	3	3	0.95	25.8	NIL	N- 45%
1917	Heinz (H.J.)	58.72	2	1	3	0.65	16.6	3.5	20- 45%
1919	Hershey Co.	72.60	2	2	3	0.60	21.7	2.3	10- 50%
1923	J&J Snack Foods	60.46	2	2	2	0.70	20.7	1.0	N- 25%
1925	McCormick & Co.	64.56	1	1	3	0.60	19.6	2.1	25- 45%
1928	Nestle SA ADS	63.22	1	1	3	0.65	17.9	3.3	20- 40%
1934	Sensient Techn.	35.48	2	3	2	0.90	13.9	2.5	25- 85%
1937	Smucker (J.M.)	84.49	2	1	2	0.70	16.0	2.5	20- 40%
1938	Snyder's-Lance	23.47	2	3	3	0.60	21.1	2.7	5- 50%
1940	Tootsie Roll Ind.	26.65	1	1	3	0.70	28.1	1.2	15- 30%
1943	Unilever PLC ADR	37.16	2	1	3	0.75	16.6	3.4	10- 35%
	Retail (Hardlines) (INDUSTRY RANK 26)								
2170	Big 5 Sporting Goods	13.65	2	4	1	1.50	18.2	2.2	5- 85%
2171	Cabela's Inc.	47.47	2	3	4	1.30	17.7	NIL	N- 35%
2173	Dick's Sporting Goods	51.50	2	3	4	1.15	19.4	1.0	15- 75%
2180	Hibbett Sports	53.50	2	3	4	1.00	18.8	NIL	30- 85%
2182	Luxottica Group ADR	38.54	1	3	4	1.10	23.5	1.7	5- 55%
2184	Movado Group	30.00	1	3	2	1.25	19.1	0.7	N- 50%
2187	PetSmart, Inc.	68.87	2	3	2	0.80	19.2	1.0	N- 50%
2188	Pier 1 Imports	19.75	2	3	3	2.05	16.6	0.8	25- 75%
2193	Ulta Salon	89.02	2	3	3	1.30	31.2	NIL	50-125%
2195	Vitamin Shoppe	59.83	1	3	4	0.80	28.6	NIL	10- 65%
2198	Williams-Sonoma	45.02	1	3	2	1.15	16.7	2.1	35- 90%
	Tobacco (INDUSTRY RANK 27)								
1992	Altria Group	32.56	2	2	3	0.55	14.7	5.4	N- 40%
1996	Reynolds American	41.99	2	2	2	0.55	14.2	5.6	5- 45%
	Natural Gas Utility (INDUSTRY RANK 28)								
541	Atmos Energy	34.01	2	2	3	0.70	14.4	4.1	N- 20%
544	NiSource Inc.	23.82	1	3	3	0.80	15.7	4.0	N- 25%
	Diversified Co. (INDUSTRY RANK 29)								
1740	Ametek, Inc.	36.31	2	2	3	1.00	18.4	0.7	10- 50%
1743	Carlisle Cos.	54.40	2	2	4	1.05	12.4	1.5	40- 85%
1748	GATX Corp.	41.17	2	3	3	1.20	15.5	2.9	20- 70%
1750	Gen'l Electric	20.66	2	3	3	1.20	12.8	3.3	45-120%
1752	Honeywell Int'l	60.44	2	1	3	1.15	12.9	2.7	40- 65%
1754	Ingersoll-Rand	46.44	2	3	3	1.20	13.2	1.4	40-115%
1756	Kaman Corp.	33.44	2	3	4	1.15	13.4	1.9	35-110%
1758	Myers Inds.	14.20	2	3	4	1.45	14.1	2.3	15- 75%
1765	Standex Int'l	46.49	2	3	4	1.10	11.9	0.7	10- 70%
1770	Valmont Inds.	136.69	2	3	5	1.25	16.2	0.7	N- 45%
1772	Whirlpool Corp.	98.12	2	3	4	1.30	12.3	2.0	N- 55%
	Retail Store (INDUSTRY RANK 30)								
2138	Costco Wholesale	96.57	1	1	2	0.75	21.3	1.1	25- 50%
2139	Dillard's, Inc.	84.90	2	3	3	1.60	13.1	0.2	20- 85%
2145	Macy's Inc.	40.93	2	3	3	1.35	11.6	2.3	20- 85%
2146	Nordstrom, Inc.	56.47	2	3	3	1.40	15.0	2.1	25- 95%
2148	PriceSmart	75.28	2	3	4	1.00	27.1	0.8	15- 65%
2153	Target Corp.	63.01	2	2	2	0.90	13.6	2.3	25- 75%
2154	Wal-Mart Stores	69.02	2	1	3	0.60	13.3	2.3	40- 65%
	Drug (INDUSTRY RANK 31)								
1596	Alexion Pharmac.	92.47	2	3	3	0.80	59.7	NIL	10- 60%
1597	Allergan, Inc.	90.98	2	1	3	0.90	22.4	0.2	30- 60%
1600	Biogen Idec Inc.	143.53	2	2	3	0.80	24.4	NIL	N- 20%
1602	Celgene Corp.	75.18	2	2	4	0.75	18.3	NIL	35- 85%
1604	Cubist Pharm.	40.42	2	3	3	0.75	17.8	NIL	10- 60%
1616	Mylan Inc.	25.94	2	3	3	1.05	17.6	NIL	N- 35%
1618	Novartis AG ADR	59.49	2	1	3	0.65	15.3	4.1	10- 35%
1619	Novo Nordisk ADR	154.48	1	1	4	0.80	23.4	1.7	N- 25%
1623	PAREXEL Int'l	32.00	2	3	3	1.35	22.9	NIL	40-105%
1624	Perrigo Co.	101.92	2	3	2	0.70	20.6	0.4	20- 75%
1625	Pfizer, Inc.	24.14	2	1	3	0.75	15.4	3.6	25- 45%
1630	Watson Pharmac.	84.99	2	2	3	0.75	12.4	NIL	35- 80%
	Restaurant (INDUSTRY RANK 32)								
345	AFC Enterprises	25.48	2	3	3	1.15	19.5	NIL	N- 35%
354	Cheesecake Factory	33.97	2	3	3	1.25	16.9	1.4	20- 75%
356	Cracker Barrel	63.13	1	3	3	1.00	13.4	3.2	5- 50%
358	DineEquity Inc.	61.99	2	4	3	1.35	10.4	NIL	N- 55%
359	Domino's Pizza	40.89	1	4	3	1.15	19.4	NIL	N- 20%
363	Krispy Kreme	7.54	2	4	2	1.25	14.2	NIL	20-110%
365	Panera Bread Co.	163.46	2	2	4	0.95	25.6	NIL	15- 55%
366	Papa John's Int'l	48.59	2	3	4	0.80	17.0	NIL	N- 35%
374	Yum! Brands	73.32	2	2	4	0.90	20.5	1.9	N- 30%
	Financial Svcs. (Div.) (INDUSTRY RANK 33)								
2532	Affiliated Managers	125.06	1	3	3	1.60	33.3	NIL	N- 50%
2537	Ameriprise Fin'l	59.74	2	3	3	1.40	12.4	3.0	35-100%
2538	Aon plc	56.35	2	2	3	0.70	15.8	1.1	25- 70%
2546	Discover Fin'l Svcs.	40.81	2	3	4	1.30	9.3	1.0	35- 95%
2547	Eaton Vance Corp.	30.22	2	3	3	1.35	15.5	2.6	50-130%
2550	First Cash Fin'l Svcs	47.20	2	3	3	0.90	16.0	NIL	25- 80%
2551	Franklin Resources	130.58	2	2	4	1.35	13.9	0.9	N- 20%
2552	Gallagher (Arthur J.)	36.24	1	1	3	0.75	18.2	3.8	N- 10%
2563	MasterCard Inc.	478.68	2	3	3	1.10	20.3	0.3	10- 60%
2565	Price (T. Rowe) Group	64.43	2	3	3	1.25	17.9	2.3	N- 30%
2569	Visa Inc.	145.65	2	3	3	1.05	21.1	0.9	60-135%
2571	WEX Inc.	69.50	2	3	3	1.10	15.7	NIL	20- 85%
	Industrial Services (INDUSTRY RANK 34)								
380	Cintas Corp.	40.07	2	2	4	0.95	15.7	1.6	25- 60%
382	Convergys Corp.	15.11	2	3	3	1.20	15.0	1.3	20- 65%
383	EMCOR Group	32.50	2	3	3	1.25	14.3	0.6	N- 40%
388	Healthcare Svcs.	22.06	1	3	4	0.75	31.1	3.2	N- 60%
392	Macquarie Infrastructure	41.40	1	5	3	2.05	43.1	6.9	N- 80%
391	MAXIMUS Inc.	59.07	1	2	4	0.80	21.2	0.7	10- 50%
395	Rollins, Inc.	21.90	2	2	3	0.85	26.7	1.6	35- 85%
399	UniFirst Corp.	70.20	2	3	3	0.90	14.9	0.2	5- 55%
	Bank (INDUSTRY RANK 35)								
2515	JPMorgan Chase	40.59	2	3	4	1.25	7.9	3.3	35- 95%
2517	M&T Bank Corp.	98.18	1	3	4	1.05	12.9	2.9	10- 70%
2518	Nat'l Bank of Canada	75.18	2	2	3	0.70	9.3	4.3	15- 55%
2522	Royal Bank of Canada	56.53	2	2	3	0.80	11.3	4.4	25- 70%
2529	Wells Fargo	32.40	2	3	4	1.35	9.2	2.7	55-115%

Timely Stocks

Stocks Ranked 1 (Highest) for Relative Price Performance (Next 12 Months)

Page No.	Stock Name	Ticker	Recent Price	Ranks Safety	Ranks Technical	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
1632	AMN Healthcare	AHS	**10.36**	**3**	**4**	24.1	NIL	Human Resources	58
204	Abaxis, Inc.	ABAX	**35.76**	**3**	**4**	43.6	NIL	Med Supp Non-Invasive	45
428	Advisory Board	ABCO	**43.68**	**2**	**4**	46.5	NIL	Information Services	8
2532	Affiliated Managers	AMG	**125.06**	**3**	**3**	33.3	NIL	Financial Svcs. (Div.)	33
553	Amer. Vanguard Corp.	AVD	**32.04**	**3**	**5**	23.1	0.4	Chemical (Specialty)	23
1103	Amer. Woodmark ■	AMWD	**23.03**	**3**	**4**	41.9	NIL	Building Materials	7
112	Analogic Corp.	ALOG	**72.70**	**3**	**4**	22.0	0.6	Precision Instrument	60
1104	Apogee Enterprises	APOG	**19.54**	**3**	**5**	28.7	1.8	Building Materials	7
2599	Automatic Data Proc.	ADP	**55.22**	**1**	**3**	18.2	3.2	IT Services	14
2125	AutoNation, Inc.	AN	**41.30**	**3**	**3**	15.0	NIL	Retail Automotive	13
113	Badger Meter	BMI	**43.56**	**3**	**4**	22.2	1.6	Precision Instrument	60
305	Bristow Group	BRS	**49.99**	**3**	**4**	13.5	1.6	Air Transport	63
1970	Brown-Forman 'B'	BFB	**66.83**	**1**	**3**	24.3	1.5	Beverage	19
520	Cabot Oil & Gas 'A'	COG	**49.09**	**3**	**2**	53.4	0.2	Natural Gas (Div.)	67
339	Can. Pacific Railway	CP	**92.80**	**3**	**3**	17.6	1.5	Railroad	51
1814	Carriage Services	CSV	**11.20**	**3**	**4**	18.1	0.9	Funeral Services	5
731	Chart Industries	GTLS	**59.86**	**3**	**3**	20.0	NIL	Metal Fabricating	49
763	Chubb Corp.	CB	**76.14**	**1**	**3**	11.5	2.2	Insurance (Prop/Cas.)	11
213	Cooper Cos.	COO	**92.65**	**3**	**3**	16.2	0.1	Med Supp Non-Invasive	45
306	Copa Holdings, S.A.	CPA	**93.56**	**3**	**4**	10.3	2.2	Air Transport	63
432	CoStar Group	CSGP	**81.94**	**3**	**2**	43.6	NIL	Information Services	8
2138	Costco Wholesale	COST	**96.57**	**1**	**2**	21.3	1.1	Retail Store	30
356	Cracker Barrel	CBRL	**63.13**	**3**	**3**	13.4	3.2	Restaurant	32
184	Cyberonics ■	CYBX	**52.28**	**3**	**2**	29.7	NIL	Med Supp Invasive	40
2435	Cytec Inds.	CYT	**67.09**	**3**	**4**	18.1	0.7	Chemical (Diversified)	21
2216	DSW Inc. ■	DSW	**62.29**	**3**	**3**	17.7	1.2	Retail (Softlines)	18
1977	Diageo plc	DEO	**116.38**	**1**	**3**	19.4	2.3	Beverage	19
359	Domino's Pizza ■	DPZ	**40.89**	**4**	**3**	19.4	NIL	Restaurant	32
989	Dorman Products	DORM	**32.00**	**3**	**5**	16.8	NIL	Auto Parts	72
990	Drew Industries	DW	**30.50**	**3**	**3**	17.6	NIL	Auto Parts	72
1108	Eagle Materials	EXP	**54.54**	**3**	**5**	42.0	0.7	Building Materials	7
558	Ecolab Inc.	ECL	**70.00**	**1**	**3**	21.1	1.1	Chemical (Specialty)	23
616	El Paso Pipeline	EPB	**35.97**	**3**	**3**	16.6	6.4	Pipeline MLPs	9
1013	Elizabeth Arden	RDEN	**46.24**	**3**	**2**	19.3	NIL	Toiletries/Cosmetics	54
434	Equifax, Inc.	EFX	**50.25**	**2**	**4**	16.4	1.4	Information Services	8
1802	Equinix, Inc.	EQIX	**182.90**	**3**	**4**	60.6	NIL	E-Commerce	37
119	FEI Company	FEIC	**52.47**	**3**	**2**	17.9	0.6	Precision Instrument	60
1523	Federal Rlty. Inv. Trust	FRT	**101.29**	**3**	**3**	40.0	2.9	R.E.I.T.	20
1713	Flowserve Corp.	FLS	**138.23**	**3**	**3**	15.1	1.0	Machinery	22
2219	Foot Locker	FL	**33.56**	**3**	**4**	12.9	2.1	Retail (Softlines)	18
1308	Franklin Electric	FELE	**56.90**	**3**	**5**	17.1	1.0	Electrical Equipment	41
2552	Gallagher (Arthur J.)	AJG	**36.24**	**1**	**3**	18.2	3.8	Financial Svcs. (Div.)	33
2220	Gap (The), Inc.	GPS	**34.43**	**2**	**4**	15.7	1.5	Retail (Softlines)	18
2129	Group 1 Automotive	GPI	**59.28**	**3**	**4**	11.9	1.0	Retail Automotive	13
766	HCC Insurance Hldgs.	HCC	**35.98**	**3**	**3**	11.5	1.8	Insurance (Prop/Cas.)	11
1916	Hain Celestial Group	HAIN	**61.90**	**3**	**3**	25.8	NIL	Food Processing	25
2107	Hanesbrands, Inc.	HBI	**34.41**	**3**	**3**	10.6	NIL	Apparel	16
388	Healthcare Svcs.	HCSG	**22.06**	**3**	**4**	31.1	3.2	Industrial Services	34
1137	Home Depot	HD	**63.33**	**1**	**3**	19.4	1.8	Retail Building Supply	1
1192	Kimberly-Clark	KMB	**86.00**	**1**	**3**	16.5	3.4	Household Products	3
620	Kinder Morgan Energy	KMP	**79.87**	**2**	**3**	33.0	6.3	Pipeline MLPs	9
1717	Lennox Int'l	LII	**50.33**	**3**	**4**	19.0	1.6	Machinery	22
2329	Lions Gate Entertain.	LGF	**15.64**	**5**	**3**	10.6	NIL	Entertainment	12
1139	Lumber Liquidators	LL	**54.34**	**3**	**4**	33.8	NIL	Retail Building Supply	1
2182	Luxottica Group ADR	LUX	**38.54**	**3**	**4**	23.5	1.7	Retail (Hardlines)	26
2517	M&T Bank Corp.	MTB	**98.18**	**3**	**4**	12.9	2.9	Bank	35
1127	M.D.C. Holdings	MDC	**34.32**	**3**	**5**	32.1	2.9	Homebuilding	2
915	MGE Energy	MGEE	**49.18**	**1**	**3**	16.6	3.2	Electric Util. (Central)	24
392	Macquarie Infrastructure	MIC	**41.40**	**5**	**3**	43.1	6.9	Industrial Services	34
621	Magellan Midstream	MMP	**42.85**	**3**	**3**	20.9	4.5	Pipeline MLPs	9
2610	Manhattan Assoc.	MANH	**58.88**	**3**	**3**	20.5	NIL	IT Services	14
2312	Mattel, Inc.	MAT	**35.84**	**2**	**3**	13.6	3.5	Recreation	17
391	MAXIMUS Inc.	MMS	**59.07**	**2**	**4**	21.2	0.7	Industrial Services	34
1925	McCormick & Co.	MKC	**64.56**	**1**	**3**	19.6	2.1	Food Processing	25
439	Moody's Corp.	MCO	**46.21**	**3**	**4**	14.8	1.4	Information Services	8
2184	Movado Group	MOV	**30.00**	**3**	**2**	19.1	0.7	Retail (Hardlines)	26
1128	NVR, Inc.	NVR	**876.84**	**3**	**4**	22.1	NIL	Homebuilding	2
1928	Nestle SA ADS	NSRGY	**63.22**	**1**	**3**	17.9	3.3	Food Processing	25
2332	News Corp.	NWS	**24.45**	**3**	**3**	16.1	0.7	Entertainment	12
544	NiSource Inc.	NI	**23.82**	**3**	**3**	15.7	4.0	Natural Gas Utility	28
1724	Nordson Corp.	NDSN	**60.59**	**3**	**2**	15.9	1.0	Machinery	22
1619	Novo Nordisk ADR	NVO	**154.48**	**1**	**4**	23.4	1.7	Drug	31
608	ONEOK Inc.	OKE	**45.90**	**3**	**3**	25.1	2.9	Oil/Gas Distribution	4
2112	Oxford Inds.	OXM	**53.29**	**4**	**2**	18.7	1.4	Apparel	16
2440	PPG Inds.	PPG	**120.05**	**1**	**4**	16.2	2.0	Chemical (Diversified)	21
1179	Packaging Corp.	PKG	**35.85**	**3**	**4**	17.2	2.8	Packaging & Container	46
2313	Polaris Inds.	PII	**81.61**	**3**	**5**	17.4	1.9	Recreation	17
2314	Pool Corp.	POOL	**40.50**	**3**	**4**	20.0	1.6	Recreation	17
570	RPM Int'l	RPM	**26.78**	**3**	**3**	14.9	3.4	Chemical (Specialty)	23
1793	Raymond James Fin'l	RJF	**37.56**	**3**	**3**	13.9	1.4	Securities Brokerage	76
840	Regeneron Pharmac.	REGN	**160.44**	**3**	**5**	32.6	NIL	Biotechnology	44
2377	Scripps (E.W.) 'A'	SSP	**9.44**	**5**	**2**	14.8	NIL	Newspaper	50
2333	Scripps Networks	SNI	**60.15**	**2**	**2**	16.8	0.8	Entertainment	12
1140	Sherwin-Williams	SHW	**157.01**	**1**	**3**	22.5	1.1	Retail Building Supply	1
238	Sirona Dental ■	SIRO	**61.90**	**3**	**3**	23.7	NIL	Med Supp Non-Invasive	45
1730	Smith (A.O.)	AOS	**60.41**	**3**	**3**	20.2	1.3	Machinery	22
2230	Stage Stores	SSI	**24.40**	**3**	**2**	19.7	1.7	Retail (Softlines)	18
2320	Thor Inds.	THO	**41.21**	**3**	**4**	15.0	1.7	Recreation	17
1133	Toll Brothers	TOL	**31.15**	**3**	**4**	30.0	NIL	Homebuilding	2
1940	Tootsie Roll Ind.	TR	**26.65**	**1**	**3**	28.1	1.2	Food Processing	25
1555	Torchmark Corp.	TMK	**50.92**	**2**	**3**	9.4	1.2	Insurance (Life)	57
1316	Trimble Nav. Ltd.	TRMB	**54.27**	**3**	**2**	29.3	NIL	Electrical Equipment	41
1961	United Natural Foods	UNFI	**51.07**	**3**	**3**	22.7	NIL	Retail/Wholesale Food	59
2357	Vail Resorts	MTN	**54.79**	**3**	**2**	37.8	1.4	Hotel/Gaming	71
1540	Ventas, Inc.	VTR	**64.52**	**3**	**3**	37.7	4.0	R.E.I.T.	20
2195	Vitamin Shoppe	VSI	**59.83**	**3**	**4**	28.6	NIL	Retail (Hardlines)	26
575	Westlake Chemical	WLK	**74.53**	**3**	**5**	15.6	1.0	Chemical (Specialty)	23
1169	Weyerhaeuser Co.	WY	**25.98**	**3**	**3**	34.6	2.7	Paper/Forest Products	10
2198	Williams-Sonoma	WSM	**45.02**	**3**	**2**	16.7	2.1	Retail (Hardlines)	26
2250	Xcel Energy Inc.	XEL	**26.14**	**2**	**3**	13.7	4.2	Electric Utility (West)	36

■ **Newly added this week.**

Rank 1 Deletions:
AFC Enterprises; Amer. Eagle Outfitters; Cirrus Logic; Omnicom Group; Urban Outfitters.

Rank removed–see supplement or report:
None.

Continued from preceding page

TIMELY STOCKS

Stocks Ranked 2 (Above Average) for Relative Price Performance in the Next 12 Months

Page No.	Stock Name	Ticker	Recent Price	Ranks: Technical	Ranks: Safety	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
1967	AB InBev ADR	BUD	84.67	1	3	18.0	1.8	Beverage	19
756	ACE Limited	ACE	78.20	2	3	9.7	2.5	Insurance (Prop/Cas.)	11
2596	ACI Worldwide	ACIW	41.77	3	3	32.1	NIL	IT Services	14
345	AFC Enterprises ▼	AFCE	25.48	3	3	19.5	NIL	Restaurant	32
922	AT&T Inc.	T	33.82	1	3	13.4	5.3	Telecom. Services	84
2597	Accenture Plc	ACN	67.06	1	3	16.4	2.4	IT Services	14
1302	Acuity Brands	AYI	62.57	3	3	19.4	0.8	Electrical Equipment	41
1559	Agnico-Eagle Mines	AEM	55.42	3	1	25.8	1.4	Precious Metals	79
1798	Akamai Technologies	AKAM	35.87	3	2	27.8	NIL	E-Commerce	37
1596	Alexion Pharmac.	ALXN	92.47	3	3	59.7	NIL	Drug	31
303	Allegiant Travel	ALGT	72.69	3	4	14.9	NIL	Air Transport	63
1597	Allergan, Inc.	AGN	90.98	1	3	22.4	0.2	Drug	31
902	ALLETE	ALE	38.50	2	2	14.0	4.9	Electric Util. (Central)	24
903	Alliant Energy	LNT	43.45	2	3	14.4	4.3	Electric Util. (Central)	24
1992	Altria Group	MO	32.56	2	3	14.7	5.4	Tobacco	27
2616	Amazon.com	AMZN	229.71	3	3	NMF	NIL	Internet	56
2598	Amdocs Ltd.	DOX	32.62	3	3	12.9	1.6	IT Services	14
2204	Amer. Eagle Outfitters ▼	AEO	18.84	3	3	13.5	2.3	Retail (Softlines)	18
1774	Amer. States Water	AWR	42.52	2	3	16.7	3.3	Water Utility	6
577	Amer. Tower 'A'	AMT	73.71	3	3	39.4	2.5	Wireless Networking	69
1775	Amer. Water Works	AWK	36.99	3	3	16.9	2.7	Water Utility	6
2537	Ameriprise Fin'l	AMP	59.74	3	3	12.4	3.0	Financial Svcs. (Div.)	33
1740	Ametek, Inc.	AME	36.31	2	3	18.4	0.7	Diversified Co.	29
829	Amgen	AMGN	85.40	1	3	13.2	1.8	Biotechnology	44
1321	Amphenol Corp.	APH	60.50	3	3	16.3	0.7	Electronics	86
2205	ANN Inc.	ANN	33.96	3	2	14.0	NIL	Retail (Softlines)	18
2538	Aon plc	AON	56.35	2	3	15.8	1.1	Financial Svcs. (Div.)	33
1704	Applied Ind'l Techn.	AIT	37.50	3	3	12.7	2.2	Machinery	22
1776	Aqua America	WTR	24.67	2	3	23.1	2.8	Water Utility	6
949	Arris Group	ARRS	13.69	3	3	14.0	NIL	Telecom. Equipment	90
2124	Asbury Automotive	ABG	29.17	5	5	11.4	NIL	Retail Automotive	13
541	Atmos Energy	ATO	34.01	2	3	14.4	4.1	Natural Gas Utility	28
1903	B&G Foods	BGS	28.79	3	1	19.9	4.0	Food Processing	25
1517	BRE Properties	BRE	48.17	3	3	74.1	3.2	R.E.I.T.	20
1172	Ball Corp.	BLL	44.65	2	3	13.9	0.9	Packaging & Container	46
2339	Bally Technologies	BYI	45.07	3	4	13.9	NIL	Hotel/Gaming	71
1106	Beacon Roofing	BECN	30.90	3	4	20.1	NIL	Building Materials	7
1173	Bemis Co.	BMS	33.21	2	3	14.6	3.0	Packaging & Container	46
760	Berkley (W.R.)	WRB	39.20	2	3	15.3	0.9	Insurance (Prop/Cas.)	11
2170	Big 5 Sporting Goods	BGFV	13.65	4	1	18.2	2.2	Retail (Hardlines)	26
1600	Biogen Idec Inc.	BIIB	143.53	2	3	24.4	NIL	Drug	31
830	BioMarin Pharmac.	BMRN	48.27	3	4	NMF	NIL	Biotechnology	44
2618	Blue Nile	NILE	36.35	3	1	45.4	NIL	Internet	56
1518	Boston Properties	BXP	101.88	3	3	58.6	2.6	R.E.I.T.	20
1031	Brookfield Asset Mgmt.	BAM	33.38	3	3	17.8	1.7	Property Management	15
2156	Brown Shoe ▲	BWS	15.74	3	3	13.7	1.8	Shoe	61
2209	Buckle (The), Inc.	BKE	49.00	3	3	14.2	2.0	Retail (Softlines)	18
2325	CBS Corp. 'B'	CBS	34.49	3	3	12.5	1.4	Entertainment	12
799	CIGNA Corp.	CI	51.90	3	2	7.9	0.1	Medical Services	55
974	CVS Caremark Corp.	CVS	45.08	1	3	12.7	1.4	Pharmacy Services	62
2171	Cabela's Inc.	CAB	47.47	3	4	17.7	NIL	Retail (Hardlines)	26
2579	Cadence Design Sys.	CDNS	12.66	3	3	18.9	NIL	Computer Software	47
1905	Cal-Maine Foods	CALM	43.65	3	3	14.1	2.3	Food Processing	25
1519	Camden Property Trust	CPT	64.81	3	3	49.9	3.5	R.E.I.T.	20
1907	Campbell Soup	CPB	36.95	2	2	14.5	3.1	Food Processing	25
2644	CapitalSource	CSE	7.88	4	3	13.1	0.5	Public/Private Equity	43
1743	Carlisle Cos.	CSL	54.40	2	4	12.4	1.5	Diversified Co.	29
744	Carpenter Technology	CRS	46.20	3	4	13.2	1.6	Steel	91
2102	Carter's Inc.	CRI	52.02	3	3	16.8	NIL	Apparel	16
1602	Celgene Corp.	CELG	75.18	2	4	18.3	NIL	Drug	31
354	Cheesecake Factory	CAKE	33.97	3	3	16.9	1.4	Restaurant	32
2211	Chico's FAS	CHS	18.16	3	3	15.5	1.3	Retail (Softlines)	18
2213	Christopher & Banks	CBK	3.00	5	4	NMF	NIL	Retail (Softlines)	18
1187	Church & Dwight	CHD	52.59	1	3	20.2	1.8	Household Products	3
764	Cincinnati Financial	CINF	39.63	2	3	22.1	4.1	Insurance (Prop/Cas.)	11
380	Cintas Corp.	CTAS	40.07	2	4	15.7	1.6	Industrial Services	34
1355	Cirrus Logic ▼	CRUS	30.83	3	3	14.3	NIL	Semiconductor	88
1188	Clorox Co.	CLX	74.10	2	3	17.2	3.5	Household Products	3
1972	Coca-Cola	KO	37.24	1	3	18.0	2.9	Beverage	19
1189	Colgate-Palmolive	CL	106.91	1	3	19.5	2.4	Household Products	3
1022	Comcast Corp.	CMCSA	36.01	3	3	19.4	1.8	Cable TV	42
1800	Concur Techn.	CNQR	62.98	3	2	NMF	NIL	E-Commerce	37
141	Consol. Edison	ED	54.75	1	2	14.1	4.5	Electric Utility (East)	39
1975	Constellation Brands	STZ	34.62	3	3	16.0	NIL	Beverage	19
382	Convergys Corp.	CVG	15.11	3	3	15.0	1.3	Industrial Services	34
606	Copano Energy	CPNO	31.15	3	3	53.7	7.6	Oil/Gas Distribution	4
2128	Copart, Inc.	CPRT	29.58	2	3	19.1	NIL	Retail Automotive	13
1033	Corrections Corp. Amer.	CXW	33.17	3	4	20.3	2.4	Property Management	15
1604	Cubist Pharm.	CBST	40.42	3	3	17.8	NIL	Drug	31
1145	Culp Inc.	CFI	12.46	3	4	10.3	1.0	Furn/Home Furnishings	48
909	DTE Energy	DTE	59.18	3	3	14.9	4.2	Electric Util. (Central)	24
802	DaVita Inc.	DVA	114.00	3	3	17.7	NIL	Medical Services	55
185	Dentsply Int'l	XRAY	38.93	2	3	16.7	0.6	Med Supp Invasive	40
2173	Dick's Sporting Goods	DKS	51.50	3	4	19.4	1.0	Retail (Hardlines)	26
709	DigitalGlobe, Inc.	DGI	24.64	3	2	27.1	NIL	Aerospace/Defense	64
2139	Dillard's, Inc.	DDS	84.90	3	3	13.1	0.2	Retail Store	30
358	DineEquity Inc. ▲	DIN	61.99	4	3	10.4	NIL	Restaurant	32
2546	Discover Fin'l Svcs.	DFS	40.81	3	4	9.3	1.0	Financial Svcs. (Div.)	33
142	Dominion Resources	D	50.28	2	2	16.4	4.5	Electric Utility (East)	39
1978	Dr Pepper Snapple	DPS	43.45	3	2	13.8	3.2	Beverage	19
2410	Dril-Quip, Inc.	DRQ	70.65	3	3	23.2	NIL	Oilfield Svcs/Equip.	66
525	EOG Resources	EOG	118.61	3	3	21.8	0.6	Natural Gas (Div.)	67
526	EQT Corp.	EQT	61.43	3	3	36.3	1.4	Natural Gas (Div.)	67
2436	Eastman Chemical	EMN	58.37	2	4	10.0	1.8	Chemical (Diversified)	21
2547	Eaton Vance Corp. ▲	EV	30.22	3	3	15.5	2.6	Financial Svcs. (Div.)	33
2621	eBay Inc.	EBAY	47.92	2	3	23.3	NIL	Internet	56
186	Edwards Lifesciences	EW	85.03	1	3	29.2	NIL	Med Supp Invasive	40
383	EMCOR Group	EME	32.50	3	3	14.3	0.6	Industrial Services	34
607	Enbridge Inc.	ENB.TO	38.63	1	3	22.2	2.9	Oil/Gas Distribution	4
1190	Energizer Holdings	ENR	77.21	3	4	11.3	2.1	Household Products	3
1220	EnerNOC, Inc.	ENOC	12.09	4	1	NMF	NIL	Power	92
2411	Ensco plc	ESV	55.54	3	3	9.7	2.7	Oilfield Svcs/Equip.	66
765	Erie Indemnity Co.	ERIE	65.25	2	3	21.5	3.6	Insurance (Prop/Cas.)	11
1147	Ethan Allen Interiors	ETH	28.83	3	3	20.2	1.2	Furn/Home Furnishings	48
2030	Everest Re Group Ltd.	RE	103.83	1	3	7.1	1.8	Reinsurance	52
1588	FMC Corp.	FMC	53.74	3	4	14.5	0.7	Chemical (Basic)	73
2218	Finish Line (The)	FINL	20.94	3	3	12.2	1.1	Retail (Softlines)	18
2550	First Cash Fin'l Svcs	FCFS	47.20	3	3	16.0	NIL	Financial Svcs. (Div.)	33
2607	Fiserv Inc.	FISV	73.62	2	3	13.2	NIL	IT Services	14
2551	Franklin Resources	BEN	130.58	2	4	13.9	0.9	Financial Svcs. (Div.)	33
1948	Fresh Market (The)	TFM	60.15	3	2	40.4	NIL	Retail/Wholesale Food	59
1748	GATX Corp.	GMT	41.17	3	3	15.5	2.9	Diversified Co.	29
2372	Gannett Co.	GCI	17.37	4	3	7.6	4.6	Newspaper	50
437	Gartner Inc.	IT	46.03	3	3	24.5	NIL	Information Services	8
1750	Gen'l Electric	GE	20.66	3	3	12.8	3.3	Diversified Co.	29
996	Genuine Parts	GPC	61.33	1	3	14.5	3.2	Auto Parts	72
1035	Geo Group (The)	GEO	27.57	3	4	18.8	2.9	Property Management	15
2105	Gildan Activewear	GIL	32.90	3	3	14.4	1.1	Apparel	16
1161	Glatfelter	GLT	16.17	3	3	11.1	2.2	Paper/Forest Products	10
332	Golar LNG Ltd.	GLNG	40.07	3	2	17.9	4.0	Maritime	81
1714	Graco Inc. ▲	GGG	46.77	3	3	18.1	1.9	Machinery	22
1525	HCP Inc.	HCP	45.29	3	3	24.0	4.4	R.E.I.T.	20
217	Haemonetics Corp.	HAE	40.59	2	4	22.3	NIL	Med Supp Non-Invasive	45
1109	Headwaters Inc.	HW	6.58	5	5	NMF	NIL	Building Materials	7
1526	Health Care REIT	HCN	60.08	3	3	52.2	5.2	R.E.I.T.	20
1917	Heinz (H.J.)	HNZ	58.72	1	3	16.6	3.5	Food Processing	25
2608	Henry (Jack) & Assoc.	JKHY	38.29	2	2	19.1	1.2	IT Services	14
1919	Hershey Co.	HSY	72.60	2	3	21.7	2.3	Food Processing	25
2180	Hibbett Sports	HIBB	53.50	3	4	18.8	NIL	Retail (Hardlines)	26
1752	Honeywell Int'l	HON	60.44	1	3	12.9	2.7	Diversified Co.	29
1123	Horton D.R.	DHI	19.02	3	5	21.6	0.8	Homebuilding	2
1313	Hubbell Inc. 'B'	HUBB	81.74	2	4	15.0	2.0	Electrical Equipment	41
323	Hunt (J.B.)	JBHT	59.64	3	3	22.1	0.9	Trucking	77
187	ICU Medical	ICUI	58.71	3	3	20.7	NIL	Med Supp Invasive	40
913	ITC Holdings	ITC	77.51	2	3	19.3	2.0	Electric Util. (Central)	24
220	IDEXX Labs.	IDXX	92.62	1	3	29.2	NIL	Med Supp Non-Invasive	45
733	Illinois Tool Works	ITW	59.55	1	3	14.2	2.6	Metal Fabricating	49
1754	Ingersoll-Rand	IR	46.44	3	3	13.2	1.4	Diversified Co.	29
188	Insulet Corp.	PODD	21.25	3	2	NMF	NIL	Med Supp Invasive	40
561	Int'l Flavors & Frag.	IFF	63.27	1	3	15.4	2.1	Chemical (Specialty)	23
1507	Investors Bancorp	ISBC	16.73	3	4	18.2	1.2	Thrift	53
1923	J&J Snack Foods	JJSF	60.46	2	2	20.7	1.0	Food Processing	25
2515	JPMorgan Chase	JPM	40.59	3	4	7.9	3.3	Bank	35
1191	Jarden Corp.	JAH	52.24	3	4	18.9	NIL	Household Products	3
223	Johnson & Johnson	JNJ	69.25	1	3	13.3	3.5	Med Supp Non-Invasive	45
1756	Kaman Corp.	KAMN	33.44	3	4	13.4	1.9	Diversified Co.	29
1152	Kimball Int'l 'B'	KBALB	12.00	3	3	22.2	1.7	Furn/Home Furnishings	48
1530	Kimco Realty	KIM	18.81	3	4	52.3	4.5	R.E.I.T.	20
363	Krispy Kreme ▲	KKD	7.54	4	2	14.2	NIL	Restaurant	32
999	LKQ Corp.	LKQ	21.25	3	3	22.4	NIL	Auto Parts	72
1153	La-Z-Boy Inc.	LZB	15.84	3	4	20.3	NIL	Furn/Home Furnishings	48
1193	Lancaster Colony	LANC	73.29	1	2	18.3	2.1	Household Products	3
123	Landauer, Inc.	LDR	57.30	3	3	20.7	3.8	Precision Instrument	60
1154	Leggett & Platt	LEG	26.93	2	2	17.2	4.4	Furn/Home Furnishings	48
1126	Lennar Corp.	LEN	36.81	3	5	29.7	0.4	Homebuilding	2
2223	Limited Brands	LTD	48.31	3	4	16.5	2.1	Retail (Softlines)	18
1719	Lindsay Corp.	LNN	74.65	3	5	19.1	0.6	Machinery	22
529	Linn Energy, LLC	LINE	38.99	3	3	22.8	7.5	Natural Gas (Div.)	67
1163	Louisiana-Pacific	LPX	16.55	5	2	25.5	NIL	Paper/Forest Products	10
1138	Lowe's Cos. ▲	LOW	33.96	2	3	17.6	1.9	Retail Building Supply	1
2224	lululemon athletica	LULU	71.23	3	4	35.3	NIL	Retail (Softlines)	18
2145	Macy's Inc.	M	40.93	3	3	11.6	2.3	Retail Store	30
2161	Madden (Steven) Ltd.	SHOO	43.11	3	3	15.1	NIL	Shoe	61
1001	Magna Int'l 'A'	MGA	44.42	3	3	8.0	2.5	Auto Parts	72
768	Markel Corp.	MKL	482.00	2	3	21.6	NIL	Insurance (Prop/Cas.)	11
1110	Martin Marietta	MLM	85.41	3	4	30.3	1.9	Building Materials	7
1111	Masco Corp.	MAS	15.44	3	4	37.7	1.9	Building Materials	7
1240	MasTec	MTZ	21.76	3	3	12.5	NIL	Engineering & Const	68
2563	MasterCard Inc.	MA	478.68	3	3	20.3	0.3	Financial Svcs. (Div.)	33
809	MEDNAX, Inc.	MD	73.78	3	2	14.7	NIL	Medical Services	55

▲ Arrow indicates the direction of a change in Timeliness. ■ Newly added this week.

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TIMELY STOCKS

Stocks Ranked 2 (Above Average) for Relative Price Performance in the Next 12 Months

Page No.	Stock Name	Ticker	Recent Price	Ranks Technical	Ranks Safety	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
1369	Mellanox Technologies	MLNX	84.71	3	3	17.7	NIL	Semiconductor	88
1721	Middleby Corp. (The)	MIDD	126.98	3	2	19.0	NIL	Machinery	22
1778	Middlesex Water	MSEX	18.10	2	3	17.9	4.1	Water Utility	6
563	Minerals Techn.	MTX	71.51	2	3	16.8	0.3	Chemical (Specialty)	23
1156	Mohawk Inds.	MHK	83.28	3	4	20.4	NIL	Furn/Home Furnishings	48
2439	Monsanto Co.	MON	88.33	3	3	21.2	1.7	Chemical (Diversified)	21
736	Mueller Inds.	MLI	45.33	3	4	19.8	1.1	Metal Fabricating	49
1758	Myers Inds.	MYE	14.20	3	4	14.1	2.3	Diversified Co.	29
1616	Mylan Inc.	MYL	25.94	3	3	17.6	NIL	Drug	31
836	Myriad Genetics	MYGN	30.57	3	5	19.7	NIL	Biotechnology	44
2242	NV Energy Inc.	NVE	17.84	3	3	14.5	4.0	Electric Utility (West)	36
2518	Nat'l Bank of Canada	NA.TO	75.18	2	3	9.3	4.3	Bank	35
531	National Fuel Gas	NFG	51.46	2	2	20.3	2.8	Natural Gas (Div.)	67
1804	NetSuite Inc.	N	59.28	3	2	NMF	NIL	E-Commerce	37
963	NeuStar Inc.	NSR	38.20	3	3	15.5	NIL	Telecom. Equipment	90
1195	Newell Rubbermaid	NWL	21.35	3	4	15.8	2.8	Household Products	3
564	NewMarket Corp.	NEU	252.22	3	3	15.6	1.2	Chemical (Specialty)	23
2146	Nordstrom, Inc.	JWN	56.47	3	3	15.0	2.1	Retail Store	30
1618	Novartis AG ADR	NVS	59.49	1	3	15.3	4.1	Drug	31
325	Old Dominion Freight	ODFL	33.39	3	2	15.7	NIL	Trucking	77
231	Omnicell, Inc.	OMCL	15.25	3	2	23.8	NIL	Med Supp Non-Invasive	45
2386	Omnicom Group ▼	OMC	46.82	2	3	12.4	2.6	Advertising	65
1640	On Assignment	ASGN	18.76	3	5	16.8	NIL	Human Resources	58
2630	Overstock.com	OSTK	14.60	4	2	54.1	NIL	Internet	56
2113	PVH Corp.	PVH	111.24	3	3	16.5	0.1	Apparel	16
365	Panera Bread Co.	PNRA	163.46	2	4	25.6	NIL	Restaurant	32
366	Papa John's Int'l	PZZA	48.59	3	4	17.0	NIL	Restaurant	32
1623	PAREXEL Int'l	PRXL	32.00	3	3	22.9	NIL	Drug	31
2032	PartnerRe Ltd.	PRE	79.98	3	3	9.6	3.1	Reinsurance	52
2132	Penske Auto	PAG	28.75	4	5	12.4	1.8	Retail Automotive	13
131	PerkinElmer Inc.	PKI	30.58	3	4	14.3	0.9	Precision Instrument	60
1624	Perrigo Co.	PRGO	101.92	3	2	20.6	0.4	Drug	31
2187	PetSmart, Inc.	PETM	68.87	3	2	19.2	1.0	Retail (Hardlines)	26
1625	Pfizer, Inc.	PFE	24.14	1	3	15.4	3.6	Drug	31
2188	Pier 1 Imports	PIR	19.75	3	3	16.6	0.8	Retail (Hardlines)	26
1792	Piper Jaffray Cos.	PJC	28.02	3	2	12.7	NIL	Securities Brokerage	76
1165	Plum Creek Timber	PCL	41.64	3	4	34.7	4.0	Paper/Forest Products	10
1166	Potlatch Corp.	PCH	38.22	3	4	30.3	3.2	Paper/Forest Products	10
2565	Price (T. Rowe) Group	TROW	64.43	3	3	17.9	2.3	Financial Svcs. (Div.)	33
2148	PriceSmart	PSMT	75.28	3	4	27.1	0.8	Retail Store	30
791	PrivateBancorp	PVTB	15.76	4	5	14.6	0.3	Bank (Midwest)	38
1196	Procter & Gamble	PG	67.92	1	3	17.2	3.3	Household Products	3
1535	Public Storage	PSA	144.94	2	3	39.8	3.2	R.E.I.T.	20
1129	PulteGroup, Inc.	PHM	15.90	4	5	15.9	NIL	Homebuilding	2
569	Quaker Chemical	KWR	48.52	3	3	14.1	2.0	Chemical (Specialty)	23
966	Qualcomm Inc.	QCOM	62.09	2	3	17.5	1.6	Telecom. Equipment	90
1725	RBC Bearings	ROLL	44.81	3	3	16.6	NIL	Machinery	22
1806	Rackspace Hosting	RAX	64.55	3	3	75.1	NIL	E-Commerce	37
2402	Range Resources Corp.	RRC	67.70	3	3	69.8	0.2	Petroleum (Producing)	83
1167	Rayonier Inc.	RYN	48.56	3	3	20.5	3.7	Paper/Forest Products	10
1536	Realty Income Corp.	O	38.42	3	3	40.9	4.7	R.E.I.T.	20
236	ResMed Inc.	RMD	40.72	2	3	18.9	1.7	Med Supp Non-Invasive	45
1996	Reynolds American	RAI	41.99	2	2	14.2	5.6	Tobacco	27
1340	Rogers Corp.	ROG	42.12	3	2	14.4	NIL	Electronics	86
395	Rollins, Inc.	ROL	21.90	2	3	26.7	1.6	Industrial Services	34
1728	Roper Inds.	ROP	111.07	2	3	20.9	0.5	Machinery	22
2228	Ross Stores	ROST	55.55	2	3	15.2	1.0	Retail (Softlines)	18
2522	Royal Bank of Canada	RY.TO	56.53	2	3	11.3	4.4	Bank	35
1130	Ryland Group	RYL	32.36	4	5	33.0	0.4	Homebuilding	2
2590	SAP AG	SAP	73.47	2	3	21.5	1.3	Computer Software	47
589	SBA Communications	SBAC	67.01	3	3	NMF	NIL	Wireless Networking	69
2613	SEI Investments	SEIC	21.87	2	3	16.3	1.5	IT Services	14
1537	SL Green Realty	SLG	72.83	3	4	31.5	1.4	R.E.I.T.	20
1807	salesforce.com	CRM	147.32	3	3	NMF	NIL	E-Commerce	37
1019	Sally Beauty	SBH	24.49	4	3	16.0	NIL	Toiletries/Cosmetics	54
151	SCANA Corp.	SCG	45.60	2	3	13.9	4.4	Electric Utility (East)	39
1934	Sensient Techn.	SXT	35.48	3	2	13.9	2.5	Food Processing	25
1817	Service Corp. Int'l	SCI	13.91	3	3	17.4	1.7	Funeral Services	5
2163	Skechers U.S.A.	SKX	16.96	3	2	30.3	NIL	Shoe	61
1937	Smucker (J.M.)	SJM	84.49	1	2	16.0	2.5	Food Processing	25
1731	Snap-on Inc.	SNA	76.80	2	3	14.4	2.0	Machinery	22
1938	Snyder's-Lance	LNCE	23.47	3	3	21.1	2.7	Food Processing	25
152	Southern Co.	SO	42.77	1	3	15.4	4.7	Electric Utility (East)	39
1198	Spectrum Brands	SPB	45.30	3	4	16.0	NIL	Household Products	3
1765	Standex Int'l	SXI	46.49	3	4	11.9	0.7	Diversified Co.	29
1243	Stantec Inc.	STN.TO	37.39	3	3	13.7	1.6	Engineering & Const	68
2356	Starwood Hotels	HOT	52.91	3	4	21.7	2.4	Hotel/Gaming	71
407	Stericycle Inc.	SRCL	89.90	2	3	25.9	NIL	Environmental	70
1818	Stewart Enterpr. 'A'	STEI	7.37	3	3	16.0	2.2	Funeral Services	5
1819	StoneMor Partners L.P.	STON	21.93	4	3	NMF	10.8	Funeral Services	5
2319	Sturm, Ruger & Co.	RGR	48.83	3	5	13.1	3.1	Recreation	17
197	SurModics, Inc.	SRDX	18.79	3	2	27.2	NIL	Med Supp Invasive	40
2231	TJX Companies	TJX	44.08	1	3	16.8	1.0	Retail (Softlines)	18
2153	Target Corp.	TGT	63.01	2	2	13.6	2.3	Retail Store	30
726	TASER Int'l	TASR	8.11	4	2	32.4	NIL	Aerospace/Defense	64
1642	Team Health Hldgs.	TMH	27.54	3	2	16.9	NIL	Human Resources	58
727	Teledyne Technologies	TDY	62.26	3	3	14.6	NIL	Aerospace/Defense	64
198	Teleflex Inc.	TFX	68.63	2	3	15.1	2.0	Med Supp Invasive	40
940	TELUS Corporation	T.TO	63.87	3	3	15.7	4.0	Telecom. Services	84
2593	Teradata Corp.	TDC	61.97	2	3	24.6	NIL	Computer Software	47
2335	Time Warner	TWX	45.28	3	3	13.2	2.3	Entertainment	12
1141	Tractor Supply	TSCO	89.32	2	4	22.6	1.0	Retail Building Supply	1
611	TransCanada Corp.	TRP	45.65	2	3	20.2	3.9	Oil/Gas Distribution	4
774	Travelers Cos.	TRV	69.54	1	3	9.7	2.6	Insurance (Prop/Cas.)	11
1117	Trex Co.	TREX	38.74	4	4	16.9	NIL	Building Materials	7
739	Trinity Inds.	TRN	29.84	3	3	9.1	1.5	Metal Fabricating	49
1048	tw telecom	TWTC	25.66	3	3	41.4	NIL	Telecom. Utility	75
409	US Ecology	ECOL	21.45	3	3	16.1	3.4	Environmental	70
2193	Ulta Salon	ULTA	89.02	3	3	31.2	NIL	Retail (Hardlines)	26
2118	Under Armour	UA	51.26	3	3	39.4	NIL	Apparel	16
399	UniFirst Corp.	UNF	70.20	3	3	14.9	0.2	Industrial Services	34
1943	Unilever PLC ADR	UL	37.16	1	3	16.6	3.4	Food Processing	25
793	U.S. Bancorp	USB	32.08	3	4	10.9	2.6	Bank (Midwest)	38
1430	United Stationers	USTR	29.53	3	3	10.4	1.9	Office Equip/Supplies	87
2232	Urban Outfitters ▼	URBN	37.07	3	2	21.8	NIL	Retail (Softlines)	18
2120	V.F. Corp.	VFC	156.99	2	3	15.6	2.2	Apparel	16
1770	Valmont Inds.	VMI	136.69	3	5	16.2	0.7	Diversified Co.	29
574	Valspar Corp.	VAL	57.79	3	4	16.8	1.4	Chemical (Specialty)	23
2636	VeriSign Inc.	VRSN	40.61	3	3	21.7	NIL	Internet	56
441	Verisk Analytics	VRSK	48.03	2	3	24.5	NIL	Information Services	8
942	Verizon Communic.	VZ	42.81	1	3	16.5	4.8	Telecom. Services	84
2336	Viacom Inc. 'B'	VIAB	50.40	3	3	8.6	2.2	Entertainment	12
2569	Visa Inc.	V	145.65	3	3	21.1	0.9	Financial Svcs. (Div.)	33
1200	WD-40 Co.	WDFC	46.89	2	2	20.6	2.7	Household Products	3
2389	WPP PLC ADR	WPPGY	64.83	3	4	13.5	3.3	Advertising	65
1737	Wabtec Corp.	WAB	81.02	3	3	15.0	0.2	Machinery	22
2154	Wal-Mart Stores	WMT	69.02	1	3	13.3	2.3	Retail Store	30
1142	Watsco, Inc.	WSO	72.01	3	3	21.1	3.4	Retail Building Supply	1
1630	Watson Pharmac.	WPI	84.99	2	3	12.4	NIL	Drug	31
2529	Wells Fargo	WFC	32.40	3	4	9.2	2.7	Bank	35
919	Westar Energy	WR	27.89	2	3	13.6	4.8	Electric Util. (Central)	24
2571	WEX Inc.	WXS	69.50	3	3	15.7	NIL	Financial Svcs. (Div.)	33
1772	Whirlpool Corp.	WHR	98.12	3	4	12.3	2.0	Diversified Co.	29
1965	Whole Foods Market	WFM	91.41	3	3	32.3	0.9	Retail/Wholesale Food	59
2321	Winnebago ▲	WGO	13.66	4	4	31.0	NIL	Recreation	17
794	Wintrust Financial	WTFC	36.34	3	4	15.5	0.5	Bank (Midwest)	38
754	Worthington Inds.	WOR	22.21	3	5	11.0	2.3	Steel	91
2359	Wyndham Worldwide	WYN	49.12	4	4	14.6	1.9	Hotel/Gaming	71
374	Yum! Brands ▲	YUM	73.32	2	4	20.5	1.9	Restaurant	32
202	Zimmer Holdings	ZMH	65.82	2	4	12.5	1.2	Med Supp Invasive	40

▲ Arrow indicates the direction of a change in Timeliness. ■ Newly added this week.

Rank 2 Deletions:
athenahealth; BancorpSouth; Brinker Int'l; MTS Systems; Patterson Cos.; Selective Ins. Group; Total System Svcs.; Ultratech, Inc.

Rank removed–see supplement or report:
None.

Rank 3 Deletions:
Agilent Technologies; CTS Corp.; Casey's Gen'l Stores; Dole Food; FelCor Lodging Tr.; Greenlight Capital Re; Millicom Int'l Cellular; SAIC, Inc.; St. Jude Medical; Scholastic Corp.

Rank removed–see supplement or report:
CNH Global NV.

CONSERVATIVE STOCKS
Stocks Ranked 1 (Highest) for Relative Safety

Page No.	Stock Name	Recent Price	Rank Time-liness	Rank Tech-nical	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
1967	AB InBev ADR	84.67	2	3	18.0	1.8	Beverage	19
540	AGL Resources	37.81	3	3	12.6	4.9	Natural Gas Utility	28
922	AT&T Inc.	33.82	2	3	13.4	5.3	Telecom. Services	84
1594	Abbott Labs.	62.92	–	3	12.0	3.2	Drug	31
2597	Accenture Plc	67.06	2	3	16.4	2.4	IT Services	14
1597	Allergan, Inc.	90.98	2	3	22.4	0.2	Drug	31
829	Amgen (NDQ)	85.40	2	3	13.2	1.8	Biotechnology	44
2599	Automatic Data Proc. (NDQ)	55.22	1	3	18.2	3.2	IT Services	14
176	Bard (C.R.)	97.28	3	4	14.5	0.8	Med Supp Invasive	40
177	Baxter Int'l Inc.	66.49	3	4	14.2	2.7	Med Supp Invasive	40
178	Becton, Dickinson	75.79	3	3	13.6	2.6	Med Supp Invasive	40
2168	Bed Bath & Beyond (NDQ)	57.53	3	2	12.2	NIL	Retail (Hardlines)	26
761	Berkshire Hathaway 'B'	86.76	3	3	15.0	NIL	Insurance (Prop/Cas.)	11
1601	Bristol-Myers Squibb	32.03	3	2	14.7	4.2	Drug	31
1970	Brown-Forman 'B'	66.83	1	3	24.3	1.5	Beverage	19
140	CH Energy Group	64.89	–	3	20.1	3.4	Electric Utility (East)	39
974	CVS Caremark Corp.	45.08	2	3	12.7	1.4	Pharmacy Services	62
210	Cardinal Health	39.63	3	3	11.8	2.8	Med Supp Non-Invasive	45
1799	Check Point Software (NDQ)	44.86	3	3	14.6	NIL	E-Commerce	37
503	Chevron Corp.	104.35	3	3	7.1	3.4	Petroleum (Integrated)	74
763	Chubb Corp.	76.14	1	3	11.5	2.2	Insurance (Prop/Cas.)	11
1187	Church & Dwight	52.59	2	3	20.2	1.8	Household Products	3
953	Cisco Systems (NDQ)	18.30	3	2	10.8	3.1	Telecom. Equipment	90
908	Cleco Corp.	39.56	3	3	16.0	3.5	Electric Util. (Central)	24
1972	Coca-Cola	37.24	2	3	18.0	2.9	Beverage	19
1189	Colgate-Palmolive	106.91	2	3	19.5	2.4	Household Products	3
781	Commerce Bancshs. (NDQ)	36.81	3	3	12.7	2.4	Bank (Midwest)	38
1909	ConAgra Foods	27.86	3	3	13.3	3.6	Food Processing	25
2395	ConocoPhillips	55.73	–	–	8.8	4.7	Petroleum (Producing)	83
141	Consol. Edison	54.75	2	2	14.1	4.5	Electric Utility (East)	39
2138	Costco Wholesale (NDQ)	96.57	1	2	21.3	1.1	Retail Store	30
2512	Cullen/Frost Bankers	54.80	3	3	14.3	3.6	Bank	35
1977	Diageo plc	116.38	1	3	19.4	2.3	Beverage	19
2327	Disney (Walt)	47.91	3	3	14.8	1.3	Entertainment	12
2141	Dollar Tree, Inc. (NDQ)	40.45	3	3	15.1	NIL	Retail Store	30
1587	Du Pont	42.93	3	3	10.4	4.1	Chemical (Basic)	73
558	Ecolab Inc.	70.00	1	3	21.1	1.1	Chemical (Specialty)	23
186	Edwards Lifesciences	85.03	2	3	29.2	NIL	Med Supp Invasive	40
1306	Emerson Electric	48.95	3	2	12.5	3.4	Electrical Equipment	41
607	Enbridge Inc. (TSE)	38.63	2	3	22.2	2.9	Oil/Gas Distribution	4
2030	Everest Re Group Ltd.	103.83	2	3	7.1	1.8	Reinsurance	52
504	Exxon Mobil Corp.	87.67	3	3	10.4	2.6	Petroleum (Integrated)	74
2552	Gallagher (Arthur J.)	36.24	1	3	18.2	3.8	Financial Svcs. (Div.)	33
712	Gen'l Dynamics	63.91	4	3	9.1	3.2	Aerospace/Defense	64
1915	Gen'l Mills	40.46	3	3	15.3	3.3	Food Processing	25
996	Genuine Parts	61.33	2	3	14.5	3.2	Auto Parts	72
1609	GlaxoSmithKline ADR	42.39	3	3	11.2	5.6	Drug	31
1311	Grainger (W.W.)	191.20	3	4	17.1	1.8	Electrical Equipment	41
1917	Heinz (H.J.)	58.72	2	3	16.6	3.5	Food Processing	25
1137	Home Depot	63.33	1	3	19.4	1.8	Retail Building Supply	1
1752	Honeywell Int'l	60.44	2	3	12.9	2.7	Diversified Co.	29
1921	Hormel Foods	31.30	3	2	15.6	2.2	Food Processing	25
220	IDEXX Labs. (NDQ)	92.62	2	3	29.2	NIL	Med Supp Non-Invasive	45
733	Illinois Tool Works	59.55	2	3	14.2	2.6	Metal Fabricating	49
1361	Intel Corp. (NDQ)	20.25	5	3	9.2	4.4	Semiconductor	88
1408	Int'l Business Mach.	190.35	3	3	12.9	1.8	Computers/Peripherals	94
561	Int'l Flavors & Frag.	63.27	2	3	15.4	2.1	Chemical (Specialty)	23
2582	Intuit Inc. (NDQ)	58.95	3	3	17.6	1.2	Computer Software	47
223	Johnson & Johnson	69.25	2	3	13.3	3.5	Med Supp Non-Invasive	45
1924	Kellogg	54.74	3	2	15.8	3.2	Food Processing	25
1192	Kimberly-Clark	86.00	1	3	16.5	3.4	Household Products	3
1987	Kyocera Corp. ADR	92.88	4	3	15.6	1.6	Foreign Electronics	96
807	Laboratory Corp.	83.65	3	3	11.6	NIL	Medical Services	55
1193	Lancaster Colony (NDQ)	73.29	2	2	18.3	2.1	Household Products	3
1612	Lilly (Eli)	47.03	3	3	14.0	4.2	Drug	31
718	Lockheed Martin	90.48	3	3	11.3	5.1	Aerospace/Defense	64
530	MDU Resources	20.02	3	3	15.9	3.4	Natural Gas (Div.)	67
915	MGE Energy (NDQ)	49.18	1	3	16.6	3.2	Electric Util. (Central)	24
1925	McCormick & Co.	64.56	1	3	19.6	2.1	Food Processing	25
364	McDonald's Corp.	85.04	3	3	15.6	3.6	Restaurant	32
226	McKesson Corp.	92.71	3	3	12.8	0.9	Med Supp Non-Invasive	45
192	Medtronic, Inc.	41.81	3	3	11.4	2.6	Med Supp Invasive	40
1615	Merck & Co.	43.34	3	3	11.9	3.9	Drug	31
2585	Microsoft Corp. (NDQ)	26.73	3	3	9.1	3.4	Computer Software	47
1928	Nestle SA ADS (PNK)	63.22	1	3	17.9	3.3	Food Processing	25
543	New Jersey Resources	39.60	3	3	13.3	4.0	Natural Gas Utility	28
2162	NIKE, Inc. 'B'	96.32	3	3	18.5	1.7	Shoe	61
720	Northrop Grumman	64.72	3	3	9.4	3.4	Aerospace/Defense	64
545	Northwest Nat. Gas	41.72	3	2	15.9	4.4	Natural Gas Utility	28
1618	Novartis AG ADR	59.49	2	3	15.3	4.1	Drug	31
1619	Novo Nordisk ADR	154.48	1	4	23.4	1.7	Drug	31
1211	Nuveen Muni Value Fund	10.50	–	3	NMF	4.8	Investment Co.	–
2587	Oracle Corp. (NDQ)	30.14	3	2	11.4	0.8	Computer Software	47
2440	PPG Inds.	120.05	1	4	16.2	2.0	Chemical (Diversified)	21
2612	Paychex, Inc. (NDQ)	31.93	3	2	20.0	4.2	IT Services	14
1981	PepsiCo, Inc.	68.78	3	3	16.0	3.2	Beverage	19
1625	Pfizer, Inc.	24.14	2	3	15.4	3.6	Drug	31
1196	Procter & Gamble	67.92	2	3	17.2	3.3	Household Products	3
150	Public Serv. Enterprise	29.78	4	3	12.6	4.9	Electric Utility (East)	39
535	Questar Corp.	19.06	3	2	15.8	3.6	Natural Gas (Div.)	67
723	Raytheon Co.	55.26	3	3	10.0	3.6	Aerospace/Defense	64
724	Rockwell Collins	55.01	3	3	11.7	2.2	Aerospace/Defense	64
513	Royal Dutch Shell 'A'	66.24	3	2	7.9	5.2	Petroleum (Integrated)	74
1626	Sanofi ADR	43.27	3	3	18.3	4.2	Drug	31
1140	Sherwin-Williams	157.01	1	3	22.5	1.1	Retail Building Supply	1
572	Sigma-Aldrich (NDQ)	70.94	3	3	18.7	1.1	Chemical (Specialty)	23
1937	Smucker (J.M.)	84.49	2	2	16.0	2.5	Food Processing	25
152	Southern Co.	42.77	2	3	15.4	4.7	Electric Utility (East)	39
196	Stryker Corp.	53.00	3	3	12.5	1.6	Med Supp Invasive	40
2592	Synopsys, Inc. (NDQ)	31.98	3	3	17.7	NIL	Computer Software	47
1960	Sysco Corp.	30.47	3	2	13.9	3.7	Retail/Wholesale Food	59
2231	TJX Companies	44.08	2	3	16.8	1.0	Retail (Softlines)	18
842	Techne Corp. (NDQ)	70.38	3	3	22.1	1.7	Biotechnology	44
1627	Teva Pharmac. ADR	38.76	4	3	7.2	2.9	Drug	31
1383	Texas Instruments (NDQ)	28.90	3	3	14.2	2.9	Semiconductor	88
1767	3M Company	89.57	3	3	13.7	2.6	Diversified Co.	29
1940	Tootsie Roll Ind.	26.65	1	3	28.1	1.2	Food Processing	25
517	Total ADR	48.94	3	2	6.7	6.1	Petroleum (Integrated)	74
774	Travelers Cos.	69.54	2	3	9.7	2.6	Insurance (Prop/Cas.)	11
1943	Unilever PLC ADR	37.16	2	3	16.6	3.4	Food Processing	25
316	United Parcel Serv.	71.44	3	3	14.9	3.2	Air Transport	63
1769	United Technologies	76.58	3	3	14.0	2.8	Diversified Co.	29
200	Varian Medical Sys.	69.11	3	2	16.9	NIL	Med Supp Invasive	40
942	Verizon Communic.	42.81	2	3	16.5	4.8	Telecom. Services	84
550	WGL Holdings Inc.	37.27	3	2	14.3	4.3	Natural Gas Utility	28
2154	Wal-Mart Stores	69.02	2	3	13.3	2.3	Retail Store	30
980	Walgreen Co.	32.65	3	3	11.0	3.4	Pharmacy Services	62
1963	Weis Markets	38.60	3	3	13.0	3.1	Retail/Wholesale Food	59
920	Wisconsin Energy	36.67	3	3	15.6	3.6	Electric Util. (Central)	24

CONSERVATIVE STOCKS
Stocks Ranked 2 (Above Average) for Relative Safety

Page No.	Stock Name	Recent Price	Rank Time-liness	Rank Tech-nical	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
756	ACE Limited	78.20	2	3	9.7	2.5	Insurance (Prop/Cas.)	11
1203	Adams Express	10.27	–	3	NMF	1.6	Investment Co.	–
428	Advisory Board (NDQ)	43.68	1	4	46.5	NIL	Information Services	8
2431	Air Products & Chem.	80.87	3	3	14.3	3.2	Chemical (Diversified)	21
757	Alleghany Corp.	326.66	3	3	17.3	NIL	Insurance (Prop/Cas.)	11
902	ALLETE	38.50	2	2	14.0	4.9	Electric Util. (Central)	24
903	Alliant Energy	43.45	2	3	14.4	4.3	Electric Util. (Central)	24
758	Allstate Corp.	39.68	3	3	8.2	2.2	Insurance (Prop/Cas.)	11
1348	Altera Corp. (NDQ)	31.09	4	2	15.1	1.3	Semiconductor	88
1992	Altria Group	32.56	2	3	14.7	5.4	Tobacco	27
2535	Amer. Express	55.23	3	4	11.9	1.4	Financial Svcs. (Div.)	33
1774	Amer. States Water	42.52	2	3	16.7	3.3	Water Utility	6
208	AmerisourceBergen	40.69	3	3	13.3	2.1	Med Supp Non-Invasive	45
1740	Ametek, Inc.	36.31	2	3	18.4	0.7	Diversified Co.	29
1350	Analog Devices (NDQ)	40.21	3	3	16.5	3.0	Semiconductor	88
2538	Aon plc	56.35	2	3	15.8	1.1	Financial Svcs. (Div.)	33
1399	Apple Inc. (NDQ)	565.73	3	3	10.8	1.9	Computers/Peripherals	94
1389	Applied Materials (NDQ)	10.36	5	2	18.2	3.5	Semiconductor Equip	95
1171	AptarGroup	46.94	3	2	16.6	1.9	Packaging & Container	46
1776	Aqua America	24.67	2	3	23.1	2.8	Water Utility	6
1902	Archer Daniels Midl'd	25.55	4	3	11.6	2.7	Food Processing	25
2539	Assurant Inc.	34.61	4	3	5.7	2.4	Financial Svcs. (Div.)	33
1598	AstraZeneca PLC (ADS)	44.84	4	3	7.3	6.4	Drug	31
541	Atmos Energy	34.01	2	3	14.4	4.1	Natural Gas Utility	28
555	Avery Dennison	32.37	3	4	14.8	3.3	Chemical (Specialty)	23
2236	Avista Corp.	23.28	3	3	14.6	5.1	Electric Utility (West)	36
778	BOK Financial (NDQ)	55.50	3	3	11.8	2.7	Bank (Midwest)	38
1172	Ball Corp.	44.65	2	3	13.9	0.9	Packaging & Container	46
2506	Bank of Montreal (TSE)	57.99	3	3	9.7	5.0	Bank	35
2508	Bank of Nova Scotia (TSE)	53.40	3	3	11.3	4.3	Bank	35
1173	Bemis Co.	33.21	2	3	14.6	3.0	Packaging & Container	46
760	Berkley (W.R.)	39.20	2	3	15.3	0.9	Insurance (Prop/Cas.)	11
1600	Biogen Idec Inc. (NDQ)	143.53	2	3	24.4	NIL	Drug	31
706	Boeing	71.96	3	3	14.2	2.4	Aerospace/Defense	64
1993	Brit. Amer Tobac. ADR	102.21	3	3	14.4	4.1	Tobacco	27
2542	Brown & Brown	26.15	3	3	18.5	1.4	Financial Svcs. (Div.)	33
615	Buckeye Partners L.P.	48.33	3	3	14.6	8.6	Pipeline MLPs	9
2578	CA, Inc.	21.99	4	3	10.4	4.5	Computer Software	47
379	C.H. Robinson (NDQ)	59.81	3	2	19.7	2.2	Industrial Services	34
1907	Campbell Soup	36.95	2	2	14.5	3.1	Food Processing	25
2509	Can. Imperial Bank (TSE)	77.79	3	3	9.9	4.8	Bank	35
338	Can. National Railway	85.52	3	3	14.8	1.8	Railroad	51
1983	Canon Inc. ADR	34.85	4	2	14.3	4.2	Foreign Electronics	96
1743	Carlisle Cos.	54.40	2	4	12.4	1.5	Diversified Co.	29
1602	Celgene Corp. (NDQ)	75.18	2	4	18.3	NIL	Drug	31
907	CenterPoint Energy	19.38	3	3	15.3	4.3	Electric Util. (Central)	24
1042	CenturyLink Inc.	37.91	3	3	15.0	7.6	Telecom. Utility	75
764	Cincinnati Financial (NDQ)	39.63	2	3	22.1	4.1	Insurance (Prop/Cas.)	11
380	Cintas Corp. (NDQ)	40.07	2	4	15.7	1.6	Industrial Services	34
1188	Clorox Co.	74.10	2	3	17.2	3.5	Household Products	3

Continued from preceding page

Stocks Ranked 2 (Above Average) for Relative Safety

Page No.	Stock Name		Recent Price	Rank Timeliness	Rank Technical	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
2602	Cognizant Technology	(NDQ)	66.15	3	2	17.5	NIL	IT Services	14
2603	Computer Sciences		35.91	3	1	13.1	2.2	IT Services	14
2128	Copart, Inc.	(NDQ)	29.58	2	3	19.1	NIL	Retail Automotive	13
182	Covidien Plc		56.75	3	4	13.0	1.9	Med Supp Invasive	40
1205	DNP Select Inc. Fund		9.36	–	3	NMF	8.3	Investment Co.	–
2604	DST Systems		56.24	3	4	13.9	1.4	IT Services	14
1746	Danaher Corp.		52.90	3	3	15.6	0.2	Diversified Co.	29
162	Deere & Co.		86.25	3	4	10.7	2.1	Heavy Truck & Equip	85
185	Dentsply Int'l	(NDQ)	38.93	2	3	16.7	0.6	Med Supp Invasive	40
1045	Deutsche Telekom ADR	(PNK)	10.62	4	3	15.2	8.3	Telecom. Utility	75
1422	Diebold, Inc.		29.26	5	3	14.4	4.0	Office Equip/Supplies	87
142	Dominion Resources		50.28	2	2	16.4	4.5	Electric Utility (East)	39
163	Douglas Dynamics		13.24	4	2	17.9	6.2	Heavy Truck & Equip	85
1711	Dover Corp.		62.98	3	3	12.1	2.2	Machinery	22
143	Duke Energy		60.99	3	2	16.7	5.1	Electric Utility (East)	39
1402	EMC Corp.		24.34	3	4	18.7	NIL	Computers/Peripherals	94
2436	Eastman Chemical		58.37	2	4	10.0	1.8	Chemical (Diversified)	21
991	Eaton Corp.		50.25	3	3	11.1	3.0	Auto Parts	72
2621	eBay Inc.	(NDQ)	47.92	2	3	23.3	NIL	Internet	56
2239	El Paso Electric		30.82	3	2	13.8	3.4	Electric Utility (West)	36
710	Elbit Systems	(NDQ)	34.71	3	3	8.8	3.5	Aerospace/Defense	64
910	Empire Dist. Elec.		20.27	3	3	15.4	4.9	Electric Util. (Central)	24
617	Energy Transfer		42.92	3	4	27.7	8.4	Pipeline MLPs	9
911	Entergy Corp.		62.55	3	2	13.1	5.3	Electric Util. (Central)	24
434	Equifax, Inc.		50.25	1	4	16.4	1.4	Information Services	8
765	Erie Indemnity Co.	(NDQ)	65.25	2	3	21.5	3.6	Insurance (Prop/Cas.)	11
384	Expeditors Int'l	(NDQ)	36.20	3	2	21.9	1.5	Industrial Services	34
975	Express Scripts	(NDQ)	52.18	3	3	13.1	NIL	Pharmacy Services	62
435	FactSet Research		90.72	3	4	20.3	1.4	Information Services	8
1136	Fastenal Co.	(NDQ)	41.47	3	4	26.1	2.0	Retail Building Supply	1
308	FedEx Corp.		87.00	4	3	13.7	0.6	Air Transport	63
145	FirstEnergy Corp.		41.56	3	3	12.6	5.3	Electric Utility (East)	39
2607	Fiserv Inc.	(NDQ)	73.62	2	3	13.2	NIL	IT Services	14
2551	Franklin Resources		130.58	2	4	13.9	0.9	Financial Svcs. (Div.)	33
1984	FUJIFILM Hldgs. ADR	(PNK)	17.50	5	2	9.8	2.9	Foreign Electronics	96
2220	Gap (The), Inc.		34.43	1	4	15.7	1.5	Retail (Softlines)	18
2553	Global Payments		42.45	3	3	13.9	0.2	Financial Svcs. (Div.)	33
2624	Google, Inc.	(NDQ)	668.21	3	3	19.0	NIL	Internet	56
217	Haemonetics Corp.		40.59	2	4	22.3	NIL	Med Supp Non-Invasive	45
767	Hanover Insurance		34.88	3	3	9.6	3.4	Insurance (Prop/Cas.)	11
1331	Harris Corp.		46.59	3	3	9.0	3.2	Electronics	86
2308	Hasbro, Inc.	(NDQ)	37.40	3	3	13.2	3.9	Recreation	17
2240	Hawaiian Elec.		24.18	3	3	14.8	5.1	Electric Utility (West)	36
321	Heartland Express	(NDQ)	13.69	4	3	18.8	0.6	Trucking	77
2608	Henry (Jack) & Assoc.	(NDQ)	38.29	2	2	19.1	1.2	IT Services	14
1919	Hershey Co.		72.60	2	3	21.7	2.3	Food Processing	25
105	Honda Motor ADR		32.23	3	3	12.2	2.7	Automotive	80
1313	Hubbell Inc. 'B'		81.74	2	4	15.0	2.0	Electrical Equipment	41
913	ITC Holdings		77.51	2	3	19.3	2.0	Electric Util. (Central)	24
1753	ITT Corp.		21.34	–	–	12.3	1.7	Diversified Co.	29
507	Imperial Oil Ltd.	(ASE)	43.94	3	3	10.8	1.1	Petroleum (Integrated)	74
2609	Infosys Ltd. ADR	(NDQ)	43.27	4	1	13.9	1.8	IT Services	14
914	Integrys Energy		52.75	3	3	15.5	5.2	Electric Util. (Central)	24
1923	J&J Snack Foods	(NDQ)	60.46	2	2	20.7	1.0	Food Processing	25
2648	KKR & Co. L.P.		14.02	3	3	5.3	6.8	Public/Private Equity	43
620	Kinder Morgan Energy		79.87	1	3	33.0	6.3	Pipeline MLPs	9
2144	Kohl's Corp.		52.23	3	3	10.8	2.6	Retail Store	30
1952	Kraft Foods Group	(NDQ)	44.89	–	–	17.0	4.5	Retail/Wholesale Food	59
1953	Kroger Co.		24.63	3	2	9.9	2.4	Retail/Wholesale Food	59
717	L-3 Communic.		74.85	4	3	9.2	2.7	Aerospace/Defense	64
542	Laclede Group		39.16	3	3	14.7	4.3	Natural Gas Utility	28
1016	Lauder (Estee)		57.70	3	2	22.9	1.2	Toiletries/Cosmetics	54
1154	Leggett & Platt		26.93	2	2	17.2	4.4	Furn/Home Furnishings	48
1209	Liberty All-Star		4.46	–	3	NMF	5.4	Investment Co.	–
224	Life Technologies	(NDQ)	47.96	3	3	11.5	NIL	Med Supp Non-Invasive	45
2560	Loews Corp.		40.84	3	3	13.0	0.6	Financial Svcs. (Div.)	33
1994	Lorillard Inc.		119.22	3	3	13.0	5.2	Tobacco	27
1138	Lowe's Cos.		33.96	2	3	17.6	1.9	Retail Building Supply	1
1720	MSC Industrial Direct		70.30	3	3	15.6	1.7	Machinery	22
2398	Marathon Oil Corp.		31.13	–	–	12.5	2.2	Petroleum (Producing)	83
768	Markel Corp.		482.00	2	3	21.6	NIL	Insurance (Prop/Cas.)	11
2312	Mattel, Inc.	(NDQ)	35.84	1	3	13.6	3.5	Recreation	17
391	MAXIMUS Inc.		59.07	1	4	21.2	0.7	Industrial Services	34
769	Mercury General		39.63	3	2	15.6	6.2	Insurance (Prop/Cas.)	11
1778	Middlesex Water	(NDQ)	18.10	2	3	17.9	4.1	Water Utility	6
563	Minerals Techn.		71.51	2	3	16.8	0.3	Chemical (Specialty)	23
1335	Molex Inc.	(NDQ)	25.93	3	3	15.7	3.4	Electronics	86
1979	Molson Coors Brewing		40.28	4	2	11.2	3.2	Beverage	19
1927	Mondelez Int'l	(NDQ)	25.83	–	–	17.1	2.0	Food Processing	25
961	Motorola Solutions		53.40	–	–	16.1	1.9	Telecom. Equipment	90
509	Murphy Oil Corp.		57.70	3	4	10.8	2.2	Petroleum (Integrated)	74
2518	Nat'l Bank of Canada	(TSE)	75.18	2	3	9.3	4.3	Bank	35
531	National Fuel Gas		51.46	2	2	20.3	2.8	Natural Gas (Div.)	67
146	NextEra Energy		67.71	3	3	15.6	3.8	Electric Utility (East)	39
342	Norfolk Southern		58.03	4	3	11.0	3.4	Railroad	51
147	Northeast Utilities		38.17	3	3	15.6	3.7	Electric Utility (East)	39
916	OGE Energy		56.01	3	2	15.9	2.9	Electric Util. (Central)	24
510	Occidental Petroleum		75.46	4	3	10.7	2.9	Petroleum (Integrated)	74
2386	Omnicom Group		46.82	2	3	12.4	2.6	Advertising	65
2131	O'Reilly Automotive	(NDQ)	91.48	3	3	18.3	NIL	Retail Automotive	13
232	Owens & Minor		28.88	3	3	15.5	3.3	Med Supp Non-Invasive	45
2441	Pall Corp.		60.41	3	3	20.5	1.7	Chemical (Diversified)	21
365	Panera Bread Co.	(NDQ)	163.46	2	4	25.6	NIL	Restaurant	32
1761	Parker-Hannifin		81.05	4	3	13.0	2.0	Diversified Co.	29
235	Patterson Cos.	(NDQ)	36.02	3	3	16.4	1.6	Med Supp Non-Invasive	45
1995	Philip Morris Int'l		86.86	3	3	15.6	3.9	Tobacco	27
546	Piedmont Natural Gas		29.48	3	2	17.4	4.1	Natural Gas Utility	28
2246	Pinnacle West Capital		49.58	3	3	14.4	4.4	Electric Utility (West)	36
2247	Portland General		25.53	3	2	13.0	4.3	Electric Utility (West)	36
568	Praxair Inc.		105.65	3	3	17.8	2.3	Chemical (Specialty)	23
722	Precision Castparts		176.53	3	3	17.3	0.1	Aerospace/Defense	64
1535	Public Storage		144.94	2	3	39.8	3.2	R.E.I.T.	20
966	Qualcomm Inc.	(NDQ)	62.09	2	3	17.5	1.6	Telecom. Equipment	90
810	Quest Diagnostics		57.89	3	3	12.3	2.1	Medical Services	55
772	RLI Corp.		67.38	3	3	16.1	1.9	Insurance (Prop/Cas.)	11
1932	Ralcorp Holdings		71.12	–	–	19.3	NIL	Food Processing	25
1554	Reinsurance Group		49.25	3	3	6.8	1.9	Insurance (Life)	57
2033	RenaissanceRe Hldgs.		80.18	3	3	9.2	1.4	Reinsurance	52
236	ResMed Inc.		40.72	2	3	18.9	1.7	Med Supp Non-Invasive	45
1996	Reynolds American		41.99	2	2	14.2	5.6	Tobacco	27
395	Rollins, Inc.		21.90	2	3	26.7	1.6	Industrial Services	34
1728	Roper Inds.		111.07	2	3	20.9	0.5	Machinery	22
2228	Ross Stores	(NDQ)	55.55	2	3	15.2	1.0	Retail (Softlines)	18
2522	Royal Bank of Canada	(TSE)	56.53	2	3	11.3	4.4	Bank	35
396	SAIC, Inc.		11.20	4	2	8.0	4.3	Industrial Services	34
2590	SAP AG		73.47	2	3	21.5	1.3	Computer Software	47
2613	SEI Investments	(NDQ)	21.87	2	3	16.3	1.5	IT Services	14
194	St. Jude Medical		35.75	4	4	10.2	2.6	Med Supp Invasive	40
151	SCANA Corp.		45.60	2	3	13.9	4.4	Electric Utility (East)	39
2424	Schlumberger Ltd.		70.69	3	3	15.5	1.6	Oilfield Svcs/Equip.	66
2333	Scripps Networks		60.15	1	2	16.8	0.8	Entertainment	12
2248	Sempra Energy		65.91	3	3	15.5	3.8	Electric Utility (West)	36
1731	Snap-on Inc.		76.80	2	3	14.4	2.0	Machinery	22
1183	Sonoco Products		29.66	3	3	13.4	4.0	Packaging & Container	46
547	South Jersey Inds.		47.77	3	2	14.6	3.6	Natural Gas Utility	28
1732	Stanley Black & Decker		69.86	3	3	11.7	2.8	Machinery	22
370	Starbucks Corp.	(NDQ)	49.74	3	3	24.4	1.7	Restaurant	32
407	Stericycle Inc.	(NDQ)	89.90	2	3	25.9	NIL	Environmental	70
153	TECO Energy		16.41	3	2	14.0	5.4	Electric Utility (East)	39
2153	Target Corp.		63.01	2	2	13.6	2.3	Retail Store	30
198	Teleflex Inc.		68.63	2	3	15.1	2.0	Med Supp Invasive	40
2593	Teradata Corp.		61.97	2	3	24.6	NIL	Computer Software	47
133	Thermo Fisher Sci.		61.41	3	4	12.1	1.0	Precision Instrument	60
440	Thomson Reuters	(TSE)	27.15	4	3	13.0	4.7	Information Services	8
372	Tim Hortons		46.39	3	3	16.5	1.8	Restaurant	32
1555	Torchmark Corp.		50.92	1	3	9.4	1.2	Insurance (Life)	57
2527	Toronto-Dominion	(TSE)	79.57	3	3	10.8	3.9	Bank	35
398	Towers Watson & Co.		50.36	4	4	10.1	0.9	Industrial Services	34
1141	Tractor Supply	(NDQ)	89.32	2	4	22.6	1.0	Retail Building Supply	1
611	TransCanada Corp.		45.65	2	3	20.2	3.9	Oil/Gas Distribution	4
1213	Tri-Continental		15.66	–	3	NMF	3.2	Investment Co.	–
549	UGI Corp.		31.63	3	3	12.6	3.4	Natural Gas Utility	28
154	UIL Holdings		33.35	3	2	15.5	5.2	Electric Utility (East)	39
343	Union Pacific		119.71	3	3	13.8	2.3	Railroad	51
814	UnitedHealth Group		52.91	3	3	10.3	1.6	Medical Services	55
2120	V.F. Corp.		156.99	2	3	15.6	2.2	Apparel	16
918	Vectren Corp.		28.11	3	2	15.6	5.1	Electric Util. (Central)	24
441	Verisk Analytics	(NDQ)	48.03	2	3	24.5	NIL	Information Services	8
1962	Village Super Market	(NDQ)	35.78	3	3	14.0	2.8	Retail/Wholesale Food	59
943	Vodafone Group ADR	(NDQ)	25.58	3	2	10.2	5.9	Telecom. Services	84
1200	WD-40 Co.	(NDQ)	46.89	2	2	20.6	2.7	Household Products	3
2378	Washington Post		350.91	3	2	16.2	2.8	Newspaper	50
411	Waste Management		31.62	3	3	14.5	4.6	Environmental	70
136	Waters Corp.		83.17	3	3	17.0	NIL	Precision Instrument	60
1630	Watson Pharmac.		84.99	2	3	12.4	NIL	Drug	31
919	Westar Energy		27.89	2	3	13.6	4.8	Electric Util. (Central)	24
1964	Weston (George)	(TSE)	64.06	3	2	13.2	2.2	Retail/Wholesale Food	59
2164	Wolverine World Wide		42.58	3	4	18.0	1.1	Shoe	61
2250	Xcel Energy Inc.		26.14	1	3	13.7	4.2	Electric Utility (West)	36
1385	Xilinx Inc.	(NDQ)	33.50	3	3	17.2	2.6	Semiconductor	88
374	Yum! Brands		73.32	2	4	20.5	1.9	Restaurant	32
202	Zimmer Holdings		65.82	2	4	12.5	1.2	Med Supp Invasive	40

HIGHEST DIVIDEND YIELDING STOCKS (Based upon estimated year-ahead dividends per share)

Page No.	Stock Name	Recent Price	Time-liness	Safety Rank	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
2186	PC Connection	11.05	3	3	8.9	13.8	Retail (Hardlines)	26
1514	Annaly Capital Mgmt.	14.74	4	3	7.3	13.6	R.E.I.T.	20
1427	Pitney Bowes	11.10	4	3	5.6	13.5	Office Equip/Supplies	87
602	Rhino Resource Partners	13.44	–	3	12.6	13.2	Coal	97
599	Natural Resource	18.14	4	3	11.8	12.1	Coal	97
1049	Windstream Corp.	8.36	4	3	14.9	12.0	Telecom. Utility	75
2365	Donnelley (R.R) & Sons	9.15	5	3	5.0	11.4	Publishing	82
1044	Consol. Communic.	13.94	4	3	30.3	11.1	Telecom. Utility	75
1819	StoneMor Partners L.P.	21.93	2	4	NMF	10.8	Funeral Services	5
934	NTELOS Hldgs.	15.79	–	3	11.9	10.6	Telecom. Services	84
2646	Gladstone Capital	8.17	3	4	7.6	10.3	Public/Private Equity	43
2641	Apollo Investment	8.00	3	4	7.0	10.0	Public/Private Equity	43
1217	Atlantic Power Corp.	12.01	3	3	NMF	9.9	Power	92
1206	DWS High Income	9.77	–	4	NMF	9.7	Investment Co.	–
1929	NutriSystem Inc.	7.38	4	3	10.7	9.5	Food Processing	25
533	Pengrowth Energy	5.17	5	3	30.4	9.3	Natural Gas (Div.)	67
600	PVR Partners, L.P.	23.59	3	3	NMF	9.2	Coal	97
1046	Frontier Communic.	4.41	3	3	15.8	9.1	Telecom. Utility	75
2534	AllianceBernstein Hldg.	16.63	3	3	10.2	8.7	Financial Svcs. (Div.)	33
615	Buckeye Partners L.P.	48.33	3	2	14.6	8.6	Pipeline MLPs	9
1528	Hospitality Properties	21.74	3	3	18.3	8.6	R.E.I.T.	20
2425	Seadrill Ltd.	38.96	3	3	12.0	8.6	Oilfield Svcs/Equip.	66
614	Boardwalk Pipeline	25.06	3	3	18.6	8.5	Pipeline MLPs	9
623	Suburban Propane	39.93	3	3	16.0	8.5	Pipeline MLPs	9
617	Energy Transfer	42.92	3	2	27.7	8.4	Pipeline MLPs	9
1205	DNP Select Inc. Fund	9.36	–	2	NMF	8.3	Investment Co.	–
1045	Deutsche Telekom ADR	10.62	4	2	15.2	8.3	Telecom. Utility	75
594	Alliance Resource	56.21	4	3	8.4	8.2	Coal	97
1759	National Presto Ind.	73.47	3	3	15.5	8.2	Diversified Co.	29
1621	PDL BioPharma	7.46	3	4	5.0	8.0	Drug	31
1583	CVR Partners, LP	25.19	–	3	15.4	7.9	Chemical (Basic)	73
1508	New York Community	12.69	3	3	11.3	7.9	Thrift	53
1229	TransAlta Corp.	15.04	4	3	20.1	7.7	Power	92
1042	CenturyLink Inc.	37.91	3	2	15.0	7.6	Telecom. Utility	75
606	Copano Energy	31.15	2	3	53.7	7.6	Oil/Gas Distribution	4
529	Linn Energy, LLC	38.99	2	3	22.8	7.5	Natural Gas (Div.)	67
2635	United Online	5.37	–	4	12.2	7.4	Internet	56
1532	Mack-Cali R'lty	25.02	4	3	39.7	7.2	R.E.I.T.	20
745	Cliffs Natural Res.	35.29	5	3	4.6	7.1	Steel	91
1210	MFS Multimarket	7.21	–	4	NMF	7.1	Investment Co.	–
1363	Intersil Corp. 'A'	6.96	4	3	33.1	6.9	Semiconductor	88
392	Macquarie Infrastructure	41.40	1	5	43.1	6.9	Industrial Services	34
2385	National CineMedia	13.33	3	3	21.2	6.9	Advertising	65
770	Old Republic	10.27	3	3	NMF	6.9	Insurance (Prop/Cas.)	11
2648	KKR & Co. L.P.	14.02	3	2	5.3	6.8	Public/Private Equity	43
1380	STMicroelectronics	5.88	5	3	53.5	6.8	Semiconductor	88
624	Williams Partners L.P.	50.95	3	3	19.3	6.5	Pipeline MLPs	9
1598	AstraZeneca PLC (ADS)	44.84	4	2	7.3	6.4	Drug	31
616	El Paso Pipeline	35.97	1	3	16.6	6.4	Pipeline MLPs	9
2381	Harte-Hanks	5.31	5	3	7.0	6.4	Advertising	65
620	Kinder Morgan Energy	79.87	1	2	33.0	6.3	Pipeline MLPs	9
2317	Six Flags Entertainment	57.00	3	3	32.6	6.3	Recreation	17
1204	AllianceBernstein Income	8.58	–	3	NMF	6.2	Investment Co.	–
163	Douglas Dynamics	13.24	4	2	17.9	6.2	Heavy Truck & Equip	85
769	Mercury General	39.63	3	2	15.6	6.2	Insurance (Prop/Cas.)	11
102	Daimler AG	46.52	5	3	7.9	6.1	Automotive	80
619	Inergy, L.P.	18.87	–	3	32.0	6.1	Pipeline MLPs	9
938	Telecom N. Zealand	9.75	–	3	13.9	6.1	Telecom. Services	84
517	Total ADR	48.94	3	1	6.7	6.1	Petroleum (Integrated)	74
2337	World Wrestling Ent.	7.87	4	3	21.3	6.1	Entertainment	12
790	Park National	62.35	3	3	11.9	6.0	Bank (Midwest)	38
609	Pembina Pipeline Corp.	27.69	3	3	36.4	6.0	Oil/Gas Distribution	4
2533	Aircastle Ltd.	11.18	3	4	7.1	5.9	Financial Svcs. (Div.)	33
943	Vodafone Group ADR	25.58	3	2	10.2	5.9	Telecom. Services	84
1040	BCE Inc.	42.19	3	3	13.8	5.7	Telecom. Utility	75
149	Pepco Holdings	19.10	3	3	14.4	5.7	Electric Utility (East)	39
904	Ameren Corp.	29.08	4	3	11.7	5.6	Electric Util. (Central)	24
1609	GlaxoSmithKline ADR	42.39	3	1	11.2	5.6	Drug	31
735	Lawson Products	8.51	4	4	NMF	5.6	Metal Fabricating	49
1531	Liberty Property	33.93	3	3	32.3	5.6	R.E.I.T.	20
1996	Reynolds American	41.99	2	2	14.2	5.6	Tobacco	27
977	PetMed Express	10.82	3	3	13.9	5.5	Pharmacy Services	62
2315	Regal Entertainment	15.28	3	5	17.4	5.5	Recreation	17
1202	Aberdeen Asia-Pac. Fd.	7.80	–	4	NMF	5.4	Investment Co.	–
1992	Altria Group	32.56	2	2	14.7	5.4	Tobacco	27
1209	Liberty All-Star	4.46	–	2	NMF	5.4	Investment Co.	–
2367	Meredith Corp.	29.79	3	3	10.3	5.4	Publishing	82
1510	People's United Fin'l	11.79	3	3	14.7	5.4	Thrift	53
153	TECO Energy	16.41	3	2	14.0	5.4	Electric Utility (East)	39
1037	W.P. Carey Inc.	47.85	3	3	18.7	5.4	Property Management	15
922	AT&T Inc.	33.82	2	1	13.4	5.3	Telecom. Services	84
911	Entergy Corp.	62.55	3	2	13.1	5.3	Electric Util. (Central)	24
145	FirstEnergy Corp.	41.56	3	2	12.6	5.3	Electric Utility (East)	39
1790	NYSE Euronext	22.73	4	3	10.0	5.3	Securities Brokerage	76
2334	Sinclair Broadcast	11.27	3	4	7.1	5.3	Entertainment	12
502	BP PLC ADR	41.23	4	3	6.2	5.2	Petroleum (Integrated)	74
2409	Diamond Offshore	66.77	3	3	13.7	5.2	Oilfield Svcs/Equip.	66
1521	Duke Realty Corp.	13.18	3	3	NMF	5.2	R.E.I.T.	20
1526	Health Care REIT	60.08	2	3	52.2	5.2	R.E.I.T.	20
914	Integrys Energy	52.75	3	2	15.5	5.2	Electric Util. (Central)	24
1994	Lorillard Inc.	119.22	3	2	13.0	5.2	Tobacco	27
148	PPL Corp.	28.37	3	3	12.7	5.2	Electric Utility (East)	39
513	Royal Dutch Shell 'A'	66.24	3	1	7.9	5.2	Petroleum (Integrated)	74
154	UIL Holdings	33.35	3	2	15.5	5.2	Electric Utility (East)	39
2371	A.H. Belo	4.69	4	5	NMF	5.1	Newspaper	50
743	ArcelorMittal	14.84	4	3	27.5	5.1	Steel	91
2236	Avista Corp.	23.28	3	2	14.6	5.1	Electric Utility (West)	36
143	Duke Energy	60.99	3	2	16.7	5.1	Electric Utility (East)	39
618	Enterprise Products	51.36	3	3	19.8	5.1	Pipeline MLPs	9
2240	Hawaiian Elec.	24.18	3	2	14.8	5.1	Electric Utility (West)	36

STOCKS WITH HIGH 3- TO 5-YEAR PRICE APPRECIATION POTENTIAL

Some of the stocks tabulated below are very risky and appreciation potentialities tentative. Please read the full-page reports in Ratings & Reports to gain an understanding of the risks entailed. Some of these stocks may not be timely investment commitments. (See the Performance Ranks below.)

Page No.	Stock Name	Recent Price	3- to 5-year Potential	Time-liness	Safety Rank	Industry Group	Industry Rank
2005	ITT Educational	17.28	480%	5	3	Educational Services	98
1364	LSI Corp.	6.73	455%	3	3	Semiconductor	88
1939	Synutra Int'l	4.33	445%	–	4	Food Processing	25
1584	China Green Agriculture	3.10	400%	–	5	Chemical (Basic)	73
933	NII Holdings	5.06	385%	5	4	Telecom. Services	84
533	Pengrowth Energy	5.17	375%	5	3	Natural Gas (Div.)	67
1911	Diamond Foods	13.34	370%	–	4	Food Processing	25
1988	Panasonic Corp.	5.22	370%	4	3	Foreign Electronics	96
2629	Orbitz Worldwide	2.17	360%	5	5	Internet	56
968	Sycamore Networks	2.73	360%	–	3	Telecom. Equipment	90
839	Questcor Pharmac.	24.63	355%	3	3	Biotechnology	44
1342	Skullcandy, Inc.	8.25	355%	–	3	Electronics	86
318	Arkansas Best	7.19	350%	5	3	Trucking	77
2520	Popular Inc.	18.85	350%	3	4	Bank	35
404	EnergySolutions	2.91	345%	3	5	Environmental	70
992	Federal-Mogul Corp.	7.27	345%	5	4	Auto Parts	72
2384	Monster Worldwide	5.47	340%	4	4	Advertising	65
1349	ANADIGICS Inc.	1.27	335%	4	5	Semiconductor	88
583	Finisar Corp.	12.07	335%	5	4	Wireless Networking	69
402	Casella Waste Sys.	4.43	330%	3	5	Environmental	70
831	Dendreon Corp.	4.17	320%	3	5	Biotechnology	44
2022	Synchronoss Techn.	17.99	315%	3	3	Entertainment Tech	89
1149	Furniture Brands	0.97	310%	4	5	Furn/Home Furnishings	48
1634	Cross Country Health.	3.95	305%	4	4	Human Resources	58
405	Fuel Tech, Inc.	3.58	305%	5	4	Environmental	70
2012	DTS, Inc.	15.05	300%	4	3	Entertainment Tech	89
1990	Sony Corp. ADR	10.19	295%	4	3	Foreign Electronics	96
2429	Weatherford Int'l	9.47	295%	4	3	Oilfield Svcs/Equip.	66
2160	K-Swiss, Inc.	2.95	290%	3	4	Shoe	61
1570	Allegheny Techn.	26.43	270%	5	3	Metals & Mining (Div.)	93
2002	Career Education	2.82	270%	5	4	Educational Services	98
1367	MEMC Elec. Mat'ls	2.42	270%	4	4	Semiconductor	88
1388	Amkor Technology	3.83	265%	5	5	Semiconductor Equip	95
1949	Green Mtn. Coffee	27.33	265%	4	4	Retail/Wholesale Food	59
138	Zygo Corp.	13.65	265%	4	3	Precision Instrument	60
1547	Genworth Fin'l	5.57	260%	3	4	Insurance (Life)	57
2011	Avid Technology	6.06	255%	5	3	Entertainment Tech	89
745	Cliffs Natural Res.	35.29	255%	5	3	Steel	91
1733	Tecumseh Products 'A'	4.48	255%	3	5	Machinery	22
2217	Express, Inc.	11.40	250%	5	3	Retail (Softlines)	18
1374	PMC-Sierra	4.88	250%	5	3	Semiconductor	88
2018	Rovi Corp.	14.90	250%	4	3	Entertainment Tech	89
2000	Apollo Group 'A'	19.62	245%	5	3	Educational Services	98
2207	bebe stores	3.61	245%	4	3	Retail (Softlines)	18
753	U.S. Steel Corp.	21.15	245%	4	3	Steel	91
1405	Hewlett-Packard	13.30	240%	4	3	Computers/Peripherals	94
1929	NutriSystem Inc.	7.38	240%	4	3	Food Processing	25
725	Spirit AeroSystems	14.74	240%	4	3	Aerospace/Defense	64
2025	Zynga Inc.	2.19	240%	–	4	Entertainment Tech	89
702	AAR Corp.	14.23	235%	4	3	Aerospace/Defense	64
2158	Deckers Outdoor	33.59	235%	5	3	Shoe	61
2631	Pandora Media	7.51	235%	–	4	Internet	56
590	Smith Micro Software	1.19	235%	3	5	Wireless Networking	69
970	UTStarcom Holdings	0.90	235%	5	5	Telecom. Equipment	90
603	Walter Energy	29.83	235%	5	3	Coal	97
1421	ACCO Brands	6.95	230%	–	5	Office Equip/Supplies	87
2417	Nabors Inds.	13.69	230%	3	3	Oilfield Svcs/Equip.	66
1429	Staples, Inc.	12.21	230%	4	3	Office Equip/Supplies	87
206	Alere Inc.	17.71	225%	5	3	Med Supp Non-Invasive	45
960	Marvell Technology	7.70	225%	5	3	Telecom. Equipment	90
1617	Nektar Therapeutics	6.16	225%	3	4	Drug	31
993	Fuel Sys. Solns.	14.03	220%	4	3	Auto Parts	72
2381	Harte-Hanks	5.31	220%	5	3	Advertising	65
1635	Heidrick & Struggles	11.63	220%	4	3	Human Resources	58
1757	McDermott Int'l	10.09	220%	4	3	Diversified Co.	29
737	NN Inc.	7.45	220%	4	4	Metal Fabricating	49
1565	Pan Amer. Silver	18.87	220%	4	3	Precious Metals	79
1551	Phoenix (The) Cos.	22.82	220%	5	5	Insurance (Life)	57
841	Senomyx, Inc.	1.71	220%	4	5	Biotechnology	44
396	SAIC, Inc.	11.20	215%	4	2	Industrial Services	34
1629	Warner Chilcott plc	11.99	215%	–	3	Drug	31
2628	1-800-FLOWERS.COM	2.89	210%	3	4	Internet	56
2426	TETRA Technologies	6.41	210%	4	3	Oilfield Svcs/Equip.	66
743	ArcelorMittal	14.84	205%	4	3	Steel	91
1403	Emulex Corp.	6.58	205%	4	3	Computers/Peripherals	94
1194	Martha Stewart	2.46	205%	–	4	Household Products	3
843	United Therapeutics	51.18	205%	3	3	Biotechnology	44
205	Affymetrix Inc.	3.17	200%	4	5	Med Supp Non-Invasive	45
2157	Crocs, Inc.	12.59	200%	4	4	Shoe	61
1404	Extreme Networks	3.50	200%	4	4	Computers/Peripherals	94
834	Incyte Corp.	17.57	200%	3	5	Biotechnology	44
310	JetBlue Airways	5.00	200%	4	4	Air Transport	63
825	Quality Systems	18.30	200%	5	3	Healthcare Information	78
1159	Tempur-Pedic	24.89	200%	5	4	Furn/Home Furnishings	48
2208	Body Central Corp.	10.16	195%	4	3	Retail (Softlines)	18
2548	EZCORP, Inc.	17.83	195%	5	3	Financial Svcs. (Div.)	33
2106	Guess Inc.	23.82	195%	5	3	Apparel	16
397	TeleTech Holdings	16.10	195%	3	3	Industrial Services	34
2617	Baidu, Inc.	92.42	190%	3	3	Internet	56
1573	Cameco Corp.	17.14	190%	4	3	Metals & Mining (Div.)	93
2510	Citigroup Inc.	36.10	190%	3	4	Bank	35
1783	E*Trade Fin'l	8.17	190%	5	4	Securities Brokerage	76
1524	FelCor Lodging Tr.	3.95	190%	4	5	R.E.I.T.	20
803	Health Mgmt. Assoc.	8.05	190%	3	5	Medical Services	55
1786	Investment Techn.	8.50	190%	5	3	Securities Brokerage	76
716	iRobot Corp.	17.22	190%	4	3	Aerospace/Defense	64
511	Petroleo Brasileiro ADR	19.10	190%	4	3	Petroleum (Integrated)	74
394	Resources Connection	11.28	190%	3	3	Industrial Services	34
1341	Sanmina Corp.	9.11	190%	4	5	Electronics	86
939	Telephone & Data	22.39	190%	5	3	Telecom. Services	84

BIGGEST "FREE FLOW" CASH GENERATORS

Stocks of companies that have earned more "cash flow" in the last 5 years than was required to build plant and pay dividends

Page No.	Stock Name	Recent Price	Ratio "Cash Flow" To Cash Out	Time-liness	Safety Rank	Industry Group	Industry Rank
839	Questcor Pharmac.	24.63	77.29	3	3	Biotechnology	44
1799	Check Point Software	44.86	48.22	3	1	E-Commerce	37
2108	Iconix Brand Group	18.95	34.06	3	3	Apparel	16
1607	Forest Labs.	32.46	26.51	3	3	Drug	31
1128	NVR, Inc.	876.84	26.16	1	3	Homebuilding	2
2632	priceline.com	625.50	25.14	3	3	Internet	56
2166	Avis Budget Group	17.34	23.18	3	4	Retail (Hardlines)	26
1608	Gilead Sciences	74.82	20.89	3	3	Drug	31
1566	Silver Wheaton	36.90	20.64	3	3	Precious Metals	79
2577	BMC Software	39.59	19.69	3	3	Computer Software	47
1721	Middleby Corp. (The)	126.98	17.12	2	3	Machinery	22
1354	CEVA, Inc.	14.56	16.19	4	3	Semiconductor	88
1374	PMC-Sierra	4.88	15.74	5	3	Semiconductor	88
836	Myriad Genetics	30.57	13.97	2	3	Biotechnology	44
1980	Monster Beverage	45.23	13.86	3	3	Beverage	19
1785	IntercontinentalExch.	130.03	13.48	3	3	Securities Brokerage	76
2005	ITT Educational	17.28	13.20	5	3	Educational Services	98
1605	Endo Health Solns.	27.24	13.11	3	3	Drug	31
2575	ANSYS, Inc.	67.79	12.76	3	3	Computer Software	47
1629	Warner Chilcott plc	11.99	12.39	–	3	Drug	31
1803	Informatica Corp.	27.17	12.16	4	3	E-Commerce	37
2018	Rovi Corp.	14.90	12.04	4	3	Entertainment Tech	89
2388	ValueClick Inc.	18.09	12.01	3	3	Advertising	65
2563	MasterCard Inc.	478.68	11.71	2	3	Financial Svcs. (Div.)	33
809	MEDNAX, Inc.	73.78	11.67	2	3	Medical Services	55
1014	Helen of Troy Ltd.	29.13	11.24	4	3	Toiletries/Cosmetics	54
2584	MICROS Systems	44.52	11.16	3	3	Computer Software	47
929	j2 Global	29.30	11.08	3	3	Telecom. Services	84
1316	Trimble Nav. Ltd.	54.27	10.99	1	3	Electrical Equipment	41
2014	Dolby Labs.	31.80	10.77	4	3	Entertainment Tech	89
219	Hologic, Inc.	19.43	10.67	3	3	Med Supp Non-Invasive	45
584	InterDigital Inc.	40.80	10.67	3	4	Wireless Networking	69
2600	CACI Int'l	51.49	10.55	3	3	IT Services	14
1393	Kulicke & Soffa	10.26	10.07	4	5	Semiconductor Equip	95
1602	Celgene Corp.	75.18	9.94	2	2	Drug	31
225	Masimo Corp.	21.59	9.84	3	3	Med Supp Non-Invasive	45
2593	Teradata Corp.	61.97	9.71	2	2	Computer Software	47
975	Express Scripts	52.18	9.60	3	2	Pharmacy Services	62
199	Thoratec Corp.	35.39	9.56	3	3	Med Supp Invasive	40
801	Coventry Health Care	42.95	9.54	–	3	Medical Services	55
133	Thermo Fisher Sci.	61.41	9.21	3	2	Precision Instrument	60
1811	TIBCO Software	25.32	9.11	3	3	E-Commerce	37
396	SAIC, Inc.	11.20	8.95	4	2	Industrial Services	34
1317	WESCO Int'l	62.58	8.94	3	3	Electrical Equipment	41
971	Verifone Systems	30.10	8.81	4	4	Telecom. Equipment	90
1791	Nasdaq OMX Group	23.30	8.59	4	3	Securities Brokerage	76
2587	Oracle Corp.	30.14	8.59	3	1	Computer Software	47
1416	Synaptics	24.76	8.57	4	3	Computers/Peripherals	94
2645	Fortress Investment	4.22	8.27	3	4	Public/Private Equity	43
1630	Watson Pharmac.	84.99	8.27	2	2	Drug	31
2339	Bally Technologies	45.07	8.23	2	3	Hotel/Gaming	71
237	Schein (Henry)	79.49	7.99	3	3	Med Supp Non-Invasive	45
960	Marvell Technology	7.70	7.92	5	3	Telecom. Equipment	90
2161	Madden (Steven) Ltd.	43.11	7.71	2	3	Shoe	61
976	Omnicare, Inc.	34.24	7.57	3	3	Pharmacy Services	62
1414	ScanSource	28.95	7.56	4	3	Computers/Peripherals	94
956	F5 Networks	88.08	7.53	3	3	Telecom. Equipment	90
1235	Foster Wheeler AG	21.67	7.47	3	3	Engineering & Const	68
1322	Anixter Int'l	58.91	7.46	3	3	Electronics	86
950	Black Box	24.36	7.46	4	3	Telecom. Equipment	90
1614	Medicis Pharmac.	43.25	7.38	–	3	Drug	31
1378	Silicon Labs.	40.07	7.23	3	3	Semiconductor	88
953	Cisco Systems	18.30	7.11	3	1	Telecom. Equipment	90
1746	Danaher Corp.	52.90	7.10	3	2	Diversified Co.	29
2570	Western Union	12.74	7.10	5	3	Financial Svcs. (Div.)	33
817	WellPoint, Inc.	55.94	7.03	4	3	Medical Services	55
829	Amgen	85.40	6.81	2	1	Biotechnology	44
183	CryoLife Inc.	5.79	6.79	3	3	Med Supp Invasive	40
2573	Adobe Systems	32.92	6.75	3	3	Computer Software	47
2336	Viacom Inc. 'B'	50.40	6.74	2	3	Entertainment	12
1728	Roper Inds.	111.07	6.70	2	2	Machinery	22
2610	Manhattan Assoc.	58.88	6.67	1	3	IT Services	14
2551	Franklin Resources	130.58	6.56	2	2	Financial Svcs. (Div.)	33
1737	Wabtec Corp.	81.02	6.50	2	3	Machinery	22
2110	Maidenform Brands	17.53	6.46	3	3	Apparel	16
1417	Tech Data	45.46	6.43	4	3	Computers/Peripherals	94
1159	Tempur-Pedic	24.89	6.43	5	4	Furn/Home Furnishings	48
1399	Apple Inc.	565.73	6.31	3	2	Computers/Peripherals	94
2576	Autodesk, Inc.	31.32	6.27	4	3	Computer Software	47
429	Alliance Data Sys.	140.87	6.21	3	3	Information Services	8
1401	Dell Inc.	9.13	6.21	5	3	Computers/Peripherals	94
383	EMCOR Group	32.50	6.21	2	3	Industrial Services	34
949	Arris Group	13.69	6.17	2	3	Telecom. Equipment	90
2611	ManTech Int'l 'A'	24.62	6.16	4	3	IT Services	14
438	IHS Inc.	89.75	6.13	3	3	Information Services	8
1244	URS Corp.	34.46	6.12	3	3	Engineering & Const	68
962	NETGEAR	34.00	6.11	3	3	Telecom. Equipment	90
1328	Cubic Corp.	48.40	6.09	3	3	Electronics	86
2605	DealerTrack Hldgs.	24.59	6.01	3	3	IT Services	14
1600	Biogen Idec Inc.	143.53	5.98	2	2	Drug	31
722	Precision Castparts	176.53	5.94	3	2	Aerospace/Defense	64
1348	Altera Corp.	31.09	5.89	4	2	Semiconductor	88
1796	TD Ameritrade Holding	15.45	5.89	3	3	Securities Brokerage	76
1786	Investment Techn.	8.50	5.85	5	3	Securities Brokerage	76
1712	Dresser-Rand Group	51.75	5.82	3	3	Machinery	22
1610	Hi-Tech Pharmacal	33.50	5.81	4	3	Drug	31
2158	Deckers Outdoor	33.59	5.80	5	3	Shoe	61
1360	Integrated Device	5.82	5.80	4	3	Semiconductor	88
2571	WEX Inc.	69.50	5.80	2	3	Financial Svcs. (Div.)	33
408	Tetra Tech	25.11	5.79	3	3	Environmental	70

BEST PERFORMING STOCKS

(Measured by Price Change in the Last 13 Weeks)

Page No.	Stock Name	Ticker	Recent Price	Percent Change In Price	Time-liness	Safety Rank
2215	Coldwater Creek	CWTR	4.77	133.8%	3	5
1124	Hovnanian Enterpr. 'A'	HOV	4.95	97.2%	3	5
1425	Office Depot	ODP	3.00	89.9%	3	5
2199	Zale Corp.	ZLC	7.28	89.6%	3	5
2374	McClatchy Co.	MNI	2.96	74.1%	4	5
2630	Overstock.com	OSTK	14.60	72.2%	2	4
1426	OfficeMax	OMX	9.39	70.7%	3	4
2170	Big 5 Sporting Goods	BGFV	13.65	69.1%	2	4
812	Sunrise Senior Living	SRZ	14.32	60.4%	–	5
832	Enzo Biochem	ENZ	2.64	58.1%	3	4
726	TASER Int'l	TASR	8.11	47.2%	2	4
2121	Warnaco Group	WRC	71.11	46.7%	–	3
557	Ceradyne Inc.	CRDN	34.94	43.1%	–	3
2545	Crawford & Co. 'B'	CRDB	5.84	41.4%	3	4
1810	StarTek, Inc.	SRT	4.05	40.1%	3	5
2561	MGIC Investment	MTG	1.68	38.8%	–	5
1118	USG Corp.	USG	26.00	38.5%	3	5
1108	Eagle Materials	EXP	54.54	37.8%	1	3
1632	AMN Healthcare	AHS	10.36	36.5%	1	3
1390	Cymer Inc.	CYMI	80.54	36.4%	–	3
1125	KB Home	KBH	14.08	34.7%	3	4
1614	Medicis Pharmac.	MRX	43.25	34.7%	–	3
233	PSS World Medical	PSSI	28.56	34.3%	–	3
973	BioScrip, Inc.	BIOS	10.05	34.2%	3	4
588	Research in Motion	RIMM	9.59	33.9%	4	3
813	Tenet Healthcare	THC	27.49	33.7%	3	5
1772	Whirlpool Corp.	WHR	98.12	33.6%	2	3
2176	GameStop Corp.	GME	25.92	33.0%	4	3
1117	Trex Co.	TREX	38.74	32.7%	2	4
2178	Haverty Furniture	HVT	16.11	32.6%	3	3
2006	Learning Tree Int'l	LTRE	5.50	32.2%	–	4
2007	New Orient. Ed. ADS	EDU	19.05	31.9%	4	3
1608	Gilead Sciences	GILD	74.82	31.7%	3	3
1157	Sealy Corp.	ZZ	2.19	31.1%	–	5
311	SkyWest	SKYW	11.35	30.2%	3	3
2316	Royal Caribbean Cruises	RCL	33.77	29.6%	3	4
2323	AMC Networks	AMCX	51.28	29.4%	–	3
1147	Ethan Allen Interiors	ETH	28.83	29.2%	2	3
830	BioMarin Pharmac.	BMRN	48.27	28.8%	2	3
1707	Cascade Corp.	CASC	64.95	28.7%	–	3
2534	AllianceBernstein Hldg.	AB	16.63	28.5%	3	3

WORST PERFORMING STOCKS

(Measured by Price Change in the Last 13 Weeks)

Page No.	Stock Name	Ticker	Recent Price	Percent Change In Price	Time-liness	Safety Rank
935	Neutral Tandem	IQNT	2.21	–79.9%	–	3
1185	Blyth Inc.	BTH	16.36	–62.2%	4	3
1347	Advanced Micro Dev.	AMD	1.92	–52.8%	5	4
1223	GT Advanced Tech.	GTAT	3.19	–48.6%	5	4
2005	ITT Educational	ESI	17.28	–47.8%	5	3
1342	Skullcandy, Inc.	SKUL	8.25	–47.0%	–	3
2234	Zumiez Inc.	ZUMZ	20.03	–42.5%	4	3
725	Spirit AeroSystems	SPR	14.74	–42.4%	4	3
839	Questcor Pharmac.	QCOR	24.63	–39.7%	3	3
1216	Amer. Superconductor	AMSC	2.49	–38.5%	3	5
741	AK Steel Holding	AKS	3.66	–37.5%	5	5
582	Echelon Corp.	ELON	2.27	–36.8%	5	4
1971	Central European Dist.	CEDC	1.86	–36.5%	4	5
1218	Ballard Power Sys.	BLDP	0.65	–35.0%	5	5
2207	bebe stores	BEBE	3.61	–35.0%	4	3
835	Isis Pharmac.	ISIS	8.88	–34.8%	3	4
1911	Diamond Foods	DMND	13.34	–34.5%	–	4
2158	Deckers Outdoor	DECK	33.59	–34.4%	5	3
193	NuVasive, Inc.	NUVA	13.91	–34.4%	5	3
2341	Caesars Entertainment	CZR	5.43	–33.9%	–	4
1314	Power-One	PWER	3.95	–33.5%	5	4
1405	Hewlett-Packard	HPQ	13.30	–33.3%	4	3
716	iRobot Corp.	IRBT	17.22	–33.2%	4	3
2012	DTS, Inc.	DTSI	15.05	–32.9%	4	3
2011	Avid Technology	AVID	6.06	–32.7%	5	3
2217	Express, Inc.	EXPR	11.40	–32.5%	5	3
2000	Apollo Group 'A'	APOL	19.62	–31.7%	5	3
2147	Penney (J.C.)	JCP	16.75	–31.4%	4	3
318	Arkansas Best	ABFS	7.19	–30.8%	5	3
1929	NutriSystem Inc.	NTRI	7.38	–30.7%	4	3
1379	Skyworks Solutions	SWKS	20.66	–30.3%	3	3
797	Amedisys, Inc.	AMED	10.01	–30.2%	4	3
405	Fuel Tech, Inc.	FTEK	3.58	–30.2%	5	4
1551	Phoenix (The) Cos.	PNX	22.82	–29.7%	5	5
533	Pengrowth Energy	PGH	5.17	–29.6%	5	3
1406	Imation Corp.	IMN	3.99	–29.3%	4	3
1988	Panasonic Corp.	PC	5.22	–28.6%	4	3
2008	Strayer Education	STRA	49.76	–28.5%	5	3
1629	Warner Chilcott plc	WCRX	11.99	–28.5%	–	3
1428	Standard Register	SR	0.58	–28.4%	4	5
1375	QLogic Corp.	QLGC	8.92	–28.3%	4	3

WIDEST DISCOUNTS FROM BOOK VALUE

Stocks whose ratios of recent price to book value are lowest

Page No.	Stock Name	Ticker	Recent Price	Book Value Per sh.*	Percent Price-to-Book Value	Timeliness	Safety Rank	Beta	P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
329	Eagle Bulk Shipping	EGLE	2.34	37.35	6%	4	5	2.00	NMF	NIL	Maritime	81
331	Genco Shipping	GNK	2.56	25.20	10%	5	5	2.05	NMF	NIL	Maritime	81
1547	Genworth Fin'l	GNW	5.57	32.60	17%	3	4	2.40	4.8	NIL	Insurance (Life)	57
1228	Suntech Power ADS	STP	0.77	3.45	22%	4	5	1.85	0.5	NIL	Power	92
120	Hutchinson Techn.	HTCH	1.60	7.00	23%	4	5	1.80	NMF	NIL	Precision Instrument	60
1406	Imation Corp.	IMN	3.99	17.65	23%	4	3	0.85	NMF	NIL	Computers/Peripherals	94
935	Neutral Tandem	IQNT	2.21	9.05	24%	–	3	0.95	3.6	NIL	Telecom. Services	84
2002	Career Education	CECO	2.82	10.80	26%	5	4	0.85	NMF	NIL	Educational Services	98
227	Medical Action Inds.	MDCI	2.65	9.35	28%	4	3	1.15	11.0	NIL	Med Supp Non-Invasive	45
933	NII Holdings	NIHD	5.06	17.30	29%	5	4	1.55	NMF	NIL	Telecom. Services	84
2189	RadioShack Corp.	RSH	2.00	6.65	30%	4	4	1.10	NMF	NIL	Retail (Hardlines)	26
2340	Boyd Gaming	BYD	5.22	16.40	32%	5	4	2.00	NMF	NIL	Hotel/Gaming	71
1733	Tecumseh Products 'A'	TECUA	4.48	13.80	32%	3	5	1.45	NMF	NIL	Machinery	22
595	Alpha Natural Res.	ANR	7.57	22.95	33%	5	3	2.00	NMF	NIL	Coal	97
2003	Corinthian Colleges	COCO	2.18	6.65	33%	4	5	1.15	7.3	NIL	Educational Services	98
1990	Sony Corp. ADR	SNE	10.19	30.60	33%	4	3	1.00	24.9	3.0	Foreign Electronics	96
1545	AEGON	AEG	5.40	15.45	35%	3	3	1.80	7.7	5.0	Insurance (Life)	57
1584	China Green Agriculture	CGA	3.10	8.82	35%	–	5	1.15	1.9	NIL	Chemical (Basic)	73
2561	MGIC Investment	MTG	1.68	4.85	35%	–	5	2.45	NMF	NIL	Financial Svcs. (Div.)	33
559	Ferro Corp.	FOE	2.49	6.65	37%	5	4	2.05	24.9	NIL	Chemical (Specialty)	23
1984	FUJIFILM Hldgs. ADR	FUJIY	17.50	47.75	37%	5	2	0.80	9.8	2.9	Foreign Electronics	96
743	ArcelorMittal	MT	14.84	39.30	38%	4	3	1.70	27.5	5.1	Steel	91
1224	GenOn Energy	GEN	2.36	6.25	38%	–	5	0.85	NMF	NIL	Power	92
2554	Hartford Fin'l Svcs.	HIG	20.86	55.05	38%	3	4	2.05	6.6	1.9	Financial Svcs. (Div.)	33
1908	Chiquita Brands Int'l	CQB	6.79	17.60	39%	4	4	1.30	30.9	NIL	Food Processing	25
1227	SunPower Corp.	SPWR	4.00	10.15	39%	4	4	1.70	15.4	NIL	Power	92
318	Arkansas Best	ABFS	7.19	18.10	40%	5	3	1.20	31.3	1.7	Trucking	77
1988	Panasonic Corp.	PC	5.22	12.10	43%	4	3	0.85	9.5	3.1	Foreign Electronics	96
311	SkyWest	SKYW	11.35	26.55	43%	3	3	1.15	10.0	1.4	Air Transport	63
1548	Lincoln Nat'l Corp.	LNC	24.20	55.45	44%	3	3	2.00	5.7	2.0	Insurance (Life)	57
2536	Amer. Int'l Group	AIG	32.39	71.20	45%	–	5	1.65	10.7	NIL	Financial Svcs. (Div.)	33
1149	Furniture Brands	FBN	0.97	2.15	45%	4	5	1.55	NMF	NIL	Furn/Home Furnishings	48
2504	Bank of America	BAC	9.49	20.55	46%	3	4	1.90	16.4	0.4	Bank	35
1783	E*Trade Fin'l	ETFC	8.17	17.90	46%	5	4	1.70	20.4	NIL	Securities Brokerage	76
2520	Popular Inc.	BPOP	18.85	39.70	47%	3	4	1.20	7.5	NIL	Bank	35
1552	Protective Life	PL	25.48	53.90	47%	4	3	1.55	7.2	2.8	Insurance (Life)	57
588	Research in Motion	RIMM	9.59	20.55	47%	4	3	1.25	NMF	NIL	Wireless Networking	69
596	Arch Coal	ACI	6.89	14.50	48%	5	3	1.75	NMF	1.7	Coal	97
1634	Cross Country Health.	CCRN	3.95	8.15	48%	4	4	1.05	28.2	NIL	Human Resources	58
1786	Investment Techn.	ITG	8.50	17.85	48%	5	3	1.10	23.6	NIL	Securities Brokerage	76
2539	Assurant Inc.	AIZ	34.61	70.20	49%	4	2	1.00	5.7	2.4	Financial Svcs. (Div.)	33
2028	Assured Guaranty	AGO	12.83	26.45	49%	4	4	1.90	4.2	2.8	Reinsurance	52
1396	Photronics Inc.	PLAB	4.86	9.85	49%	5	5	1.90	7.4	NIL	Semiconductor Equip	95
1789	Morgan Stanley	MS	16.52	32.70	51%	3	4	1.70	39.3	1.2	Securities Brokerage	76
970	UTStarcom Holdings	UTSI	0.90	1.75	51%	5	5	1.50	45.0	NIL	Telecom. Equipment	90
565	OM Group	OMG	19.89	38.25	52%	5	3	1.55	12.3	NIL	Chemical (Specialty)	23
1554	Reinsurance Group	RGA	49.25	94.60	52%	3	2	0.95	6.8	1.9	Insurance (Life)	57
797	Amedisys, Inc.	AMED	10.01	18.75	53%	4	3	1.15	11.5	NIL	Medical Services	55
404	EnergySolutions	ES	2.91	5.45	53%	3	5	1.40	5.8	NIL	Environmental	70
1504	First Niagara Finl Group	FNFG	7.31	13.90	53%	4	3	0.90	10.4	4.4	Thrift	53
2384	Monster Worldwide	MWW	5.47	10.40	53%	4	4	1.35	15.6	NIL	Advertising	65
939	Telephone & Data	TDS	22.39	41.28	54%	5	3	0.90	16.5	2.2	Telecom. Services	84
1788	Knight Capital Group	KCG	2.54	4.65	55%	4	4	0.75	NMF	NIL	Securities Brokerage	76
2533	Aircastle Ltd.	AYR	11.18	19.95	56%	3	4	1.50	7.1	5.9	Financial Svcs. (Div.)	33
1911	Diamond Foods	DMND	13.34	23.85	56%	–	4	0.60	14.8	NIL	Food Processing	25
1550	MetLife Inc.	MET	32.02	56.95	56%	3	3	1.65	6.0	2.3	Insurance (Life)	57
2510	Citigroup Inc.	C	36.10	63.75	57%	3	4	2.05	8.8	0.1	Bank	35
1221	First Solar, Inc.	FSLR	24.15	41.50	58%	4	3	1.45	4.4	NIL	Power	92
1595	Albany Molecular	AMRI	3.92	6.60	59%	3	4	1.10	39.2	NIL	Drug	31
767	Hanover Insurance	THG	34.88	58.90	59%	3	2	0.80	9.6	3.4	Insurance (Prop/Cas.)	11
1553	Prudential Fin'l	PRU	49.81	84.95	59%	3	3	1.85	7.0	3.3	Insurance (Life)	57
762	CNA Fin'l	CNA	27.79	46.45	60%	3	3	1.30	9.6	2.2	Insurance (Prop/Cas.)	11
985	China Auto. Sys.	CAAS	4.86	8.05	60%	4	4	1.40	7.0	NIL	Auto Parts	72
2559	Legg Mason	LM	25.38	42.40	60%	3	3	1.60	11.8	1.7	Financial Svcs. (Div.)	33
1225	NRG Energy	NRG	19.75	33.10	60%	3	3	1.10	NMF	1.8	Power	92
2521	Regions Financial	RF	6.47	10.75	60%	3	4	1.35	8.5	0.6	Bank	35
2011	Avid Technology	AVID	6.06	9.75	62%	5	3	1.10	22.4	NIL	Entertainment Tech	89
2526	Synovus Financial	SNV	2.26	3.65	62%	3	5	1.25	18.8	1.8	Bank	35
1556	Unum Group	UNM	19.78	31.65	62%	3	3	1.30	6.2	2.6	Insurance (Life)	57
1569	Alcoa Inc.	AA	8.34	13.00	64%	4	3	1.45	36.3	1.4	Metals & Mining (Div.)	93
521	Chesapeake Energy	CHK	17.47	27.25	64%	4	3	1.35	25.0	2.0	Natural Gas (Div.)	67
222	Invacare Corp.	IVC	13.07	20.30	64%	4	3	0.90	16.3	0.4	Med Supp Non-Invasive	45
179	Boston Scientific	BSX	5.21	8.00	65%	4	3	1.00	12.7	NIL	Med Supp Invasive	40
969	Tellabs, Inc.	TLAB	2.72	4.20	65%	4	4	0.90	45.3	2.9	Telecom. Equipment	90
702	AAR Corp.	AIR	14.23	21.47	66%	4	3	1.30	7.5	2.1	Aerospace/Defense	64
206	Alere Inc.	ALR	17.71	26.75	66%	5	3	1.15	7.9	NIL	Med Supp Non-Invasive	45
511	Petroleo Brasileiro ADR	PBR	19.10	29.15	66%	4	3	1.55	6.8	1.0	Petroleum (Integrated)	74
335	Teekay Corp.	TK	30.56	46.25	66%	3	3	1.50	NMF	4.1	Maritime	81
2417	Nabors Inds.	NBR	13.69	20.55	67%	3	3	1.55	7.9	NIL	Oilfield Svcs/Equip.	66
1107	CEMEX ADS	CX	8.97	13.20	68%	3	4	1.70	NMF	NIL	Building Materials	7
1637	Kelly Services 'A'	KELYA	13.12	19.40	68%	4	3	1.25	9.6	1.5	Human Resources	58
751	Schnitzer Steel	SCHN	28.00	41.15	68%	4	3	1.55	16.0	2.7	Steel	91
1431	Xerox Corp.	XRX	6.42	9.40	68%	4	3	1.25	6.8	2.6	Office Equip/Supplies	87
1502	Astoria Financial	AF	9.26	13.50	69%	3	3	1.00	16.2	1.7	Thrift	53
1407	Ingram Micro 'A'	IM	15.48	22.50	69%	3	3	0.95	8.1	NIL	Computers/Peripherals	94
130	Orbotech Ltd.	ORBK	7.92	11.50	69%	4	3	0.85	NMF	NIL	Precision Instrument	60
1792	Piper Jaffray Cos.	PJC	28.02	40.85	69%	2	3	1.30	12.7	NIL	Securities Brokerage	76
2020	Sigma Designs	SIGM	5.75	8.35	69%	3	4	1.00	NMF	NIL	Entertainment Tech	89
2524	SunTrust Banks	STI	26.99	38.90	69%	3	3	1.25	11.9	1.3	Bank	35
1344	Vishay Intertechnology	VSH	9.11	13.20	69%	5	3	1.30	8.3	NIL	Electronics	86
2429	Weatherford Int'l	WFT	9.47	13.70	69%	4	3	1.65	8.5	NIL	Oilfield Svcs/Equip.	66
817	WellPoint, Inc.	WLP	55.94	81.35	69%	4	3	0.95	7.4	2.1	Medical Services	55
1347	Advanced Micro Dev.	AMD	1.92	2.75	70%	5	4	1.55	14.8	NIL	Semiconductor	88
2640	Amer. Capital, Ltd.	ACAS	11.63	16.60	70%	3	5	2.35	7.6	NIL	Public/Private Equity	43
174	AngioDynamics	ANGO	10.53	15.09	70%	4	3	0.80	87.8	NIL	Med Supp Invasive	40
1146	Dixie Group	DXYN	3.45	4.90	70%	4	4	1.00	11.9	NIL	Furn/Home Furnishings	48
2362	Amer. Greetings	AM	17.05	23.85	71%	–	3	1.25	17.1	3.5	Publishing	82
1944	Zhongpin	HOGS	10.81	15.25	71%	–	5	1.20	5.4	NIL	Food Processing	25
1801	Digital River	DRIV	13.51	18.75	72%	4	3	1.05	46.6	NIL	E-Commerce	37
992	Federal-Mogul Corp.	FDML	7.27	10.10	72%	5	4	1.70	9.7	NIL	Auto Parts	72

***If fiscal 2012 Book Value not available, estimate used.**

LOWEST P/Es

Stocks with the lowest estimated current P/E ratios

Page No.	Stock Name	Recent Price	Current P/E Ratio	Time-liness	Safety Rank	Industry Group	Industry Rank
1228	Suntech Power ADS	0.77	0.5	4	5	Power	92
1584	China Green Agriculture	3.10	1.9	–	5	Chemical (Basic)	73
2005	ITT Educational	17.28	2.4	5	3	Educational Services	98
1223	GT Advanced Tech.	3.19	3.0	5	4	Power	92
1939	Synutra Int'l	4.33	3.4	–	4	Food Processing	25
1002	Meritor, Inc.	3.94	3.6	5	5	Auto Parts	72
935	Neutral Tandem	2.21	3.6	–	3	Telecom. Services	84
2001	Bridgepoint Education	8.90	3.7	5	4	Educational Services	98
309	Hawaiian Hldgs.	5.86	4.0	4	4	Air Transport	63
1551	Phoenix (The) Cos.	22.82	4.0	5	5	Insurance (Life)	57
1419	Western Digital	35.00	4.1	4	3	Computers/Peripherals	94
2028	Assured Guaranty	12.83	4.2	4	4	Reinsurance	52
314	US Airways Group	12.07	4.2	3	5	Air Transport	63
1221	First Solar, Inc.	24.15	4.4	4	3	Power	92
1415	Seagate Technology	27.09	4.5	3	3	Computers/Peripherals	94
745	Cliffs Natural Res.	35.29	4.6	5	3	Steel	91
2023	Take-Two Interactive	12.35	4.6	3	3	Entertainment Tech	89
1547	Genworth Fin'l	5.57	4.8	3	4	Insurance (Life)	57
307	Delta Air Lines	9.55	4.9	4	4	Air Transport	63
2031	Greenlight Capital Re	22.67	4.9	4	3	Reinsurance	52
2365	Donnelley (R.R) & Sons	9.15	5.0	5	3	Publishing	82
737	NN Inc.	7.45	5.0	4	4	Metal Fabricating	49
1621	PDL BioPharma	7.46	5.0	3	4	Drug	31
2169	Best Buy Co.	13.75	5.1	–	3	Retail (Hardlines)	26
986	Commercial Vehicle	7.04	5.2	5	5	Auto Parts	72
997	Goodyear Tire	11.29	5.2	4	4	Auto Parts	72
2648	KKR & Co. L.P.	14.02	5.3	3	2	Public/Private Equity	43
1760	Park-Ohio	19.77	5.4	3	4	Diversified Co.	29
1944	Zhongpin	10.81	5.4	–	5	Food Processing	25
1427	Pitney Bowes	11.10	5.6	4	3	Office Equip/Supplies	87
2539	Assurant Inc.	34.61	5.7	4	2	Financial Svcs. (Div.)	33
1548	Lincoln Nat'l Corp.	24.20	5.7	3	3	Insurance (Life)	57
518	Valero Energy	30.11	5.7	3	3	Petroleum (Integrated)	74
172	Wabash National	7.26	5.7	4	4	Heavy Truck & Equip	85
404	EnergySolutions	2.91	5.8	3	5	Environmental	70
1341	Sanmina Corp.	9.11	5.8	4	5	Electronics	86
1781	BGC Partners Inc.	3.66	5.9	5	4	Securities Brokerage	76
1329	Flextronics Int'l	5.80	5.9	4	3	Electronics	86
1388	Amkor Technology	3.83	6.0	5	5	Semiconductor Equip	95
2374	McClatchy Co.	2.96	6.0	4	5	Newspaper	50
1550	MetLife Inc.	32.02	6.0	3	3	Insurance (Life)	57
707	Bombardier Inc. 'B'	3.13	6.1	4	3	Aerospace/Defense	64
506	HollyFrontier Corp.	43.58	6.1	–	3	Petroleum (Integrated)	74
502	BP PLC ADR	41.23	6.2	4	3	Petroleum (Integrated)	74
1424	Lexmark Int'l 'A'	24.04	6.2	4	3	Office Equip/Supplies	87
1556	Unum Group	19.78	6.2	3	3	Insurance (Life)	57
2548	EZCORP, Inc.	17.83	6.3	5	3	Financial Svcs. (Div.)	33
1185	Blyth Inc.	16.36	6.4	4	3	Household Products	3
1418	Unisys Corp.	15.94	6.4	5	5	Computers/Peripherals	94
508	Marathon Petroleum	56.57	6.5	–	3	Petroleum (Integrated)	74

Page No.	Stock Name	Recent Price	Current P/E Ratio	Time-liness	Safety Rank	Industry Group	Industry Rank
1576	Rio Tinto plc	48.14	6.5	5	3	Metals & Mining (Div.)	93
2645	Fortress Investment	4.22	6.6	3	4	Public/Private Equity	43
2554	Hartford Fin'l Svcs.	20.86	6.6	3	4	Financial Svcs. (Div.)	33
2181	Insight Enterprises	15.12	6.7	4	3	Retail (Hardlines)	26
517	Total ADR	48.94	6.7	3	1	Petroleum (Integrated)	74
2166	Avis Budget Group	17.34	6.8	3	4	Retail (Hardlines)	26
511	Petroleo Brasileiro ADR	19.10	6.8	4	3	Petroleum (Integrated)	74
839	Questcor Pharmac.	24.63	6.8	3	3	Biotechnology	44
1554	Reinsurance Group	49.25	6.8	3	2	Insurance (Life)	57
1342	Skullcandy, Inc.	8.25	6.8	–	3	Electronics	86
1047	Telefonica SA ADR	12.94	6.8	4	4	Telecom. Utility	75
1431	Xerox Corp.	6.42	6.8	4	3	Office Equip/Supplies	87
1039	Alaska Communic.	1.94	6.9	4	4	Telecom. Utility	75
584	InterDigital Inc.	40.80	6.9	3	3	Wireless Networking	69
944	Vonage Holdings	2.21	6.9	5	5	Telecom. Services	84
603	Walter Energy	29.83	6.9	5	3	Coal	97
2641	Apollo Investment	8.00	7.0	3	4	Public/Private Equity	43
1324	Avnet, Inc.	28.73	7.0	4	3	Electronics	86
985	China Auto. Sys.	4.86	7.0	4	4	Auto Parts	72
2381	Harte-Hanks	5.31	7.0	5	3	Advertising	65
598	Joy Global	57.07	7.0	4	3	Coal	97
1553	Prudential Fin'l	49.81	7.0	3	3	Insurance (Life)	57
1008	Titan Int'l	19.16	7.0	3	3	Auto Parts	72
2533	Aircastle Ltd.	11.18	7.1	3	4	Financial Svcs. (Div.)	33
1327	Celestica Inc.	7.29	7.1	5	3	Electronics	86
503	Chevron Corp.	104.35	7.1	3	1	Petroleum (Integrated)	74
2030	Everest Re Group Ltd.	103.83	7.1	2	1	Reinsurance	52
562	Kronos Worldwide	15.00	7.1	5	3	Chemical (Specialty)	23
749	POSCO ADR	73.87	7.1	4	3	Steel	91
2334	Sinclair Broadcast	11.27	7.1	3	4	Entertainment	12
2000	Apollo Group 'A'	19.62	7.2	5	3	Educational Services	98
1323	Arrow Electronics	36.45	7.2	4	3	Electronics	86
1552	Protective Life	25.48	7.2	4	3	Insurance (Life)	57
1627	Teva Pharmac. ADR	38.76	7.2	4	1	Drug	31
1421	ACCO Brands	6.95	7.3	–	5	Office Equip/Supplies	87
1514	Annaly Capital Mgmt.	14.74	7.3	4	3	R.E.I.T.	20
1598	AstraZeneca PLC (ADS)	44.84	7.3	4	2	Drug	31
2642	Blackstone Group LP	14.35	7.3	3	3	Public/Private Equity	43
2003	Corinthian Colleges	2.18	7.3	4	5	Educational Services	98
104	General Motors	24.93	7.3	3	3	Automotive	80
1178	Owens-Illinois	19.38	7.3	4	3	Packaging & Container	46
1244	URS Corp.	34.46	7.3	3	3	Engineering & Const	68
2392	Apache Corp.	77.10	7.4	4	3	Petroleum (Producing)	83
2324	Belo Corp. 'A'	7.17	7.4	3	5	Entertainment	12
987	Cooper Tire & Rubber	23.97	7.4	3	3	Auto Parts	72
2380	Global Sources	6.01	7.4	4	3	Advertising	65
1954	Nash Finch Co.	20.16	7.4	4	3	Retail/Wholesale Food	59
1396	Photronics Inc.	4.86	7.4	5	5	Semiconductor Equip	95
817	WellPoint, Inc.	55.94	7.4	4	3	Medical Services	55
702	AAR Corp.	14.23	7.5	4	3	Aerospace/Defense	64

HIGHEST P/Es

Stocks with the highest estimated current P/E ratios

Page No.	Stock Name	Recent Price	Current P/E Ratio	Time-liness	Safety Rank	Industry Group	Industry Rank
820	athenahealth	64.05	97.0	3	3	Healthcare Information	78
2350	Orient-Express Hotels	11.58	96.5	–	4	Hotel/Gaming	71
1749	GenCorp Inc.	8.34	92.7	3	4	Diversified Co.	29
174	AngioDynamics	10.53	87.8	4	3	Med Supp Invasive	40
239	Volcano Corp.	26.91	86.8	3	3	Med Supp Non-Invasive	45
2383	Lamar Advertising	40.69	86.6	3	4	Advertising	65
580	Crown Castle Int'l	65.87	84.4	3	3	Wireless Networking	69
1390	Cymer Inc.	80.54	83.9	–	3	Semiconductor Equip	95
193	NuVasive, Inc.	13.91	81.8	5	3	Med Supp Invasive	40
973	BioScrip, Inc.	10.05	77.3	3	4	Pharmacy Services	62
1806	Rackspace Hosting	64.55	75.1	2	3	E-Commerce	37
1517	BRE Properties	48.17	74.1	2	3	R.E.I.T.	20
2620	EarthLink, Inc.	6.49	72.1	5	3	Internet	56
1522	Equity Residential	54.70	71.0	3	3	R.E.I.T.	20
2402	Range Resources Corp.	67.70	69.8	2	3	Petroleum (Producing)	83
1529	Host Hotels & Resorts	14.17	67.5	3	3	R.E.I.T.	20
2200	Zipcar, Inc.	7.03	63.9	–	3	Retail (Hardlines)	26
1802	Equinix, Inc.	182.90	60.6	1	3	E-Commerce	37
1596	Alexion Pharmac.	92.47	59.7	2	3	Drug	31
2589	Red Hat, Inc.	48.90	58.9	3	3	Computer Software	47
1518	Boston Properties	101.88	58.6	2	3	R.E.I.T.	20
2630	Overstock.com	14.60	54.1	2	4	Internet	56
606	Copano Energy	31.15	53.7	2	3	Oil/Gas Distribution	4
1114	Quanex Bldg. Prod.	19.80	53.5	3	4	Building Materials	7
1380	STMicroelectronics	5.88	53.5	5	3	Semiconductor	88
520	Cabot Oil & Gas 'A'	49.09	53.4	1	3	Natural Gas (Div.)	67
1530	Kimco Realty	18.81	52.3	2	3	R.E.I.T.	20
1526	Health Care REIT	60.08	52.2	2	3	R.E.I.T.	20
823	MedAssets	15.76	50.8	3	3	Healthcare Information	78
1519	Camden Property Trust	64.81	49.9	2	3	R.E.I.T.	20
2605	DealerTrack Hldgs.	24.59	49.2	3	3	IT Services	14
1365	Lattice Semiconductor	3.93	49.1	4	3	Semiconductor	88
2594	VMware, Inc.	86.45	48.8	3	3	Computer Software	47
1542	Washington R.E.I.T.	25.01	47.2	3	3	R.E.I.T.	20
597	CONSOL Energy	32.81	46.9	4	3	Coal	97
1801	Digital River	13.51	46.6	4	3	E-Commerce	37
428	Advisory Board	43.68	46.5	1	2	Information Services	8
1538	Simon Property Group	148.95	45.8	3	3	R.E.I.T.	20
813	Tenet Healthcare	27.49	45.8	3	5	Medical Services	55
2618	Blue Nile	36.35	45.4	2	3	Internet	56
1723	Mueller Water Prod.	4.99	45.4	3	5	Machinery	22
969	Tellabs, Inc.	2.72	45.3	4	4	Telecom. Equipment	90
2177	HSN, Inc.	51.78	45.0	3	3	Retail (Hardlines)	26
970	UTStarcom Holdings	0.90	45.0	5	5	Telecom. Equipment	90
1516	AvalonBay Communities	129.97	43.8	3	3	R.E.I.T.	20
204	Abaxis, Inc.	35.76	43.6	1	3	Med Supp Non-Invasive	45
432	CoStar Group	81.94	43.6	1	3	Information Services	8
1320	Agilysys, Inc.	7.82	43.4	3	4	Electronics	86
2007	New Orient. Ed. ADS	19.05	43.3	4	3	Educational Services	98
392	Macquarie Infrastructure	41.40	43.1	1	5	Industrial Services	34

Page No.	Stock Name	Recent Price	Current P/E Ratio	Time-liness	Safety Rank	Industry Group	Industry Rank
221	Illumina Inc.	50.07	42.8	3	3	Med Supp Non-Invasive	45
1108	Eagle Materials	54.54	42.0	1	3	Building Materials	7
1103	Amer. Woodmark	23.03	41.9	1	3	Building Materials	7
1043	Cincinnati Bell	5.03	41.9	3	4	Telecom. Utility	75
1048	tw telecom	25.66	41.4	2	3	Telecom. Utility	75
2343	Hyatt Hotels	36.28	41.2	3	3	Hotel/Gaming	71
1607	Forest Labs.	32.46	41.1	3	3	Drug	31
1536	Realty Income Corp.	38.42	40.9	2	3	R.E.I.T.	20
1948	Fresh Market (The)	60.15	40.4	2	3	Retail/Wholesale Food	59
1523	Federal Rlty. Inv. Trust	101.29	40.0	1	3	R.E.I.T.	20
1535	Public Storage	144.94	39.8	2	2	R.E.I.T.	20
1532	Mack-Cali R'lty	25.02	39.7	4	3	R.E.I.T.	20
1025	EchoStar Corp.	31.20	39.5	3	3	Cable TV	42
577	Amer. Tower 'A'	73.71	39.4	2	3	Wireless Networking	69
1803	Informatica Corp.	27.17	39.4	4	3	E-Commerce	37
2118	Under Armour	51.26	39.4	2	3	Apparel	16
1789	Morgan Stanley	16.52	39.3	3	4	Securities Brokerage	76
1595	Albany Molecular	3.92	39.2	3	4	Drug	31
2357	Vail Resorts	54.79	37.8	1	3	Hotel/Gaming	71
1111	Masco Corp.	15.44	37.7	2	3	Building Materials	7
1540	Ventas, Inc.	64.52	37.7	1	3	R.E.I.T.	20
609	Pembina Pipeline Corp.	27.69	36.4	3	3	Oil/Gas Distribution	4
1569	Alcoa Inc.	8.34	36.3	4	3	Metals & Mining (Div.)	93
526	EQT Corp.	61.43	36.3	2	3	Natural Gas (Div.)	67
351	Burger King Worldwide	15.44	35.9	–	3	Restaurant	32
2224	lululemon athletica	71.23	35.3	2	3	Retail (Softlines)	18
824	Medidata Solutions	41.60	34.7	3	3	Healthcare Information	78
1165	Plum Creek Timber	41.64	34.7	2	3	Paper/Forest Products	10
1367	MEMC Elec. Mat'ls	2.42	34.6	4	4	Semiconductor	88
1169	Weyerhaeuser Co.	25.98	34.6	1	3	Paper/Forest Products	10
1139	Lumber Liquidators	54.34	33.8	1	3	Retail Building Supply	1
2532	Affiliated Managers	125.06	33.3	1	3	Financial Svcs. (Div.)	33
1363	Intersil Corp. 'A'	6.96	33.1	4	3	Semiconductor	88
190	Intuitive Surgical	542.49	33.0	3	3	Med Supp Invasive	40
620	Kinder Morgan Energy	79.87	33.0	1	2	Pipeline MLPs	9
1130	Ryland Group	32.36	33.0	2	4	Homebuilding	2
2111	Michael Kors Hldgs.	50.61	32.9	–	3	Apparel	16
821	Cerner Corp.	77.47	32.7	3	3	Healthcare Information	78
2586	Nuance Communic.	21.57	32.7	3	3	Computer Software	47
840	Regeneron Pharmac.	160.44	32.6	1	3	Biotechnology	44
2317	Six Flags Entertainment	57.00	32.6	3	3	Recreation	17
1935	Smart Balance	10.76	32.6	3	3	Food Processing	25
726	TASER Int'l	8.11	32.4	2	4	Aerospace/Defense	64
1531	Liberty Property	33.93	32.3	3	3	R.E.I.T.	20
1965	Whole Foods Market	91.41	32.3	2	3	Retail/Wholesale Food	59
1567	Stillwater Mining	10.96	32.2	4	4	Precious Metals	79
2596	ACI Worldwide	41.77	32.1	2	3	IT Services	14
585	Intermec Inc.	7.06	32.1	3	3	Wireless Networking	69
1127	M.D.C. Holdings	34.32	32.1	1	3	Homebuilding	2
1811	TIBCO Software	25.32	32.1	3	3	E-Commerce	37

STOCKS WITH HIGHEST ANNUAL TOTAL RETURNS (NEXT 3 TO 5 YEARS)

(Estimated compound annual stock price appreciation plus estimated annual dividend income.)

Page No.	Stock Name	Recent Price	Est'd Total Return	Time-liness	Safety Rank	Industry Group	Industry Rank
935	Neutral Tandem	2.21	76%	–	3	Telecom. Services	84
741	AK Steel Holding	3.66	66%	5	5	Steel	91
1218	Ballard Power Sys.	0.65	62%	5	5	Power	92
1428	Standard Register	0.58	62%	4	5	Office Equip/Supplies	87
582	Echelon Corp.	2.27	59%	5	4	Wireless Networking	69
1223	GT Advanced Tech.	3.19	59%	5	4	Power	92
1347	Advanced Micro Dev.	1.92	58%	5	4	Semiconductor	88
2005	ITT Educational	17.28	55%	5	3	Educational Services	98
1364	LSI Corp.	6.73	54%	3	3	Semiconductor	88
1939	Synutra Int'l	4.33	53%	–	4	Food Processing	25
533	Pengrowth Energy	5.17	51%	5	3	Natural Gas (Div.)	67
1584	China Green Agriculture	3.10	50%	–	5	Chemical (Basic)	73
1988	Panasonic Corp.	5.22	49%	4	3	Foreign Electronics	96
933	NII Holdings	5.06	48%	5	4	Telecom. Services	84
318	Arkansas Best	7.19	47%	5	3	Trucking	77
1911	Diamond Foods	13.34	47%	–	4	Food Processing	25
2629	Orbitz Worldwide	2.17	47%	5	5	Internet	56
839	Questcor Pharmac.	24.63	47%	3	3	Biotechnology	44
2520	Popular Inc.	18.85	46%	3	4	Bank	35
1342	Skullcandy, Inc.	8.25	46%	–	3	Electronics	86
968	Sycamore Networks	2.73	46%	–	3	Telecom. Equipment	90
404	EnergySolutions	2.91	45%	3	5	Environmental	70
992	Federal-Mogul Corp.	7.27	45%	5	4	Auto Parts	72
2384	Monster Worldwide	5.47	45%	4	4	Advertising	65
1349	ANADIGICS Inc.	1.27	44%	4	5	Semiconductor	88
402	Casella Waste Sys.	4.43	44%	3	5	Environmental	70
583	Finisar Corp.	12.07	44%	5	4	Wireless Networking	69
831	Dendreon Corp.	4.17	43%	3	5	Biotechnology	44
1149	Furniture Brands	0.97	43%	4	5	Furn/Home Furnishings	48
2022	Synchronoss Techn.	17.99	43%	3	3	Entertainment Tech	89
1634	Cross Country Health.	3.95	42%	4	4	Human Resources	58
405	Fuel Tech, Inc.	3.58	42%	5	4	Environmental	70
1990	Sony Corp. ADR	10.19	42%	4	3	Foreign Electronics	96
2012	DTS, Inc.	15.05	41%	4	3	Entertainment Tech	89
2160	K-Swiss, Inc.	2.95	41%	3	4	Shoe	61
2429	Weatherford Int'l	9.47	41%	4	3	Oilfield Svcs/Equip.	66
1570	Allegheny Techn.	26.43	40%	5	3	Metals & Mining (Div.)	93
745	Cliffs Natural Res.	35.29	40%	5	3	Steel	91
2002	Career Education	2.82	39%	5	4	Educational Services	98
1367	MEMC Elec. Mat'ls	2.42	39%	4	4	Semiconductor	88
1929	NutriSystem Inc.	7.38	39%	4	3	Food Processing	25
1388	Amkor Technology	3.83	38%	5	5	Semiconductor Equip	95
1781	BGC Partners Inc.	3.66	38%	5	4	Securities Brokerage	76
2207	bebe stores	3.61	38%	4	3	Retail (Softlines)	18
1547	Genworth Fin'l	5.57	38%	3	4	Insurance (Life)	57
1949	Green Mtn. Coffee	27.33	38%	4	4	Retail/Wholesale Food	59
138	Zygo Corp.	13.65	38%	4	3	Precision Instrument	60
2011	Avid Technology	6.06	37%	5	3	Entertainment Tech	89
2217	Express, Inc.	11.40	37%	5	3	Retail (Softlines)	18
2381	Harte-Hanks	5.31	37%	5	3	Advertising	65

Page No.	Stock Name	Recent Price	Est'd Total Return	Time-liness	Safety Rank	Industry Group	Industry Rank
1405	Hewlett-Packard	13.30	37%	4	3	Computers/Peripherals	94
1374	PMC-Sierra	4.88	37%	5	3	Semiconductor	88
2018	Rovi Corp.	14.90	37%	4	3	Entertainment Tech	89
1733	Tecumseh Products 'A'	4.48	37%	3	5	Machinery	22
753	U.S. Steel Corp.	21.15	37%	4	3	Steel	91
702	AAR Corp.	14.23	36%	4	3	Aerospace/Defense	64
2000	Apollo Group 'A'	19.62	36%	5	3	Educational Services	98
1635	Heidrick & Struggles	11.63	36%	4	3	Human Resources	58
960	Marvell Technology	7.70	36%	5	3	Telecom. Equipment	90
725	Spirit AeroSystems	14.74	36%	4	3	Aerospace/Defense	64
1429	Staples, Inc.	12.21	36%	4	3	Office Equip/Supplies	87
603	Walter Energy	29.83	36%	5	3	Coal	97
2025	Zynga Inc.	2.19	36%	–	4	Entertainment Tech	89
1421	ACCO Brands	6.95	35%	–	5	Office Equip/Supplies	87
2158	Deckers Outdoor	33.59	35%	5	3	Shoe	61
2645	Fortress Investment	4.22	35%	3	4	Public/Private Equity	43
2417	Nabors Inds.	13.69	35%	3	3	Oilfield Svcs/Equip.	66
2631	Pandora Media	7.51	35%	–	4	Internet	56
396	SAIC, Inc.	11.20	35%	4	2	Industrial Services	34
590	Smith Micro Software	1.19	35%	3	5	Wireless Networking	69
970	UTStarcom Holdings	0.90	35%	5	5	Telecom. Equipment	90
1629	Warner Chilcott plc	11.99	35%	–	3	Drug	31
206	Alere Inc.	17.71	34%	5	3	Med Supp Non-Invasive	45
743	ArcelorMittal	14.84	34%	4	3	Steel	91
2365	Donnelley (R.R) & Sons	9.15	34%	5	3	Publishing	82
1524	FelCor Lodging Tr.	3.95	34%	4	5	R.E.I.T.	20
993	Fuel Sys. Solns.	14.03	34%	4	3	Auto Parts	72
1363	Intersil Corp. 'A'	6.96	34%	4	3	Semiconductor	88
2648	KKR & Co. L.P.	14.02	34%	3	2	Public/Private Equity	43
1757	McDermott Int'l	10.09	34%	4	3	Diversified Co.	29
737	NN Inc.	7.45	34%	4	4	Metal Fabricating	49
1617	Nektar Therapeutics	6.16	34%	3	4	Drug	31
1565	Pan Amer. Silver	18.87	34%	4	3	Precious Metals	79
1551	Phoenix (The) Cos.	22.82	34%	5	5	Insurance (Life)	57
825	Quality Systems	18.30	34%	5	3	Healthcare Information	78
841	Senomyx, Inc.	1.71	34%	4	5	Biotechnology	44
2641	Apollo Investment	8.00	33%	3	4	Public/Private Equity	43
2106	Guess Inc.	23.82	33%	5	3	Apparel	16
2628	1-800-FLOWERS.COM	2.89	33%	3	4	Internet	56
2426	TETRA Technologies	6.41	33%	4	3	Oilfield Svcs/Equip.	66
205	Affymetrix Inc.	3.17	32%	4	5	Med Supp Non-Invasive	45
1573	Cameco Corp.	17.14	32%	4	3	Metals & Mining (Div.)	93
2510	Citigroup Inc.	36.10	32%	3	4	Bank	35
1403	Emulex Corp.	6.58	32%	4	3	Computers/Peripherals	94
1404	Extreme Networks	3.50	32%	4	4	Computers/Peripherals	94
310	JetBlue Airways	5.00	32%	4	4	Air Transport	63
1194	Martha Stewart	2.46	32%	–	4	Household Products	3
939	Telephone & Data	22.39	32%	5	3	Telecom. Services	84
1159	Tempur-Pedic	24.89	32%	5	4	Furn/Home Furnishings	48
843	United Therapeutics	51.18	32%	3	3	Biotechnology	44

STOCKS WITH HIGHEST PROJECTED 3- TO 5-YEAR DIVIDEND YIELD

Based upon the projected dividend per share 3 to 5 years hence divided by the recent price

Page No.	Stock Name	Recent Price	Est'd Future Yield	Time-liness	Safety Rank	Industry Group	Industry Rank
2641	Apollo Investment	8.00	22%	3	4	Public/Private Equity	43
2645	Fortress Investment	4.22	19%	3	4	Public/Private Equity	43
602	Rhino Resource Partners	13.44	16%	–	3	Coal	97
2534	AllianceBernstein Hldg.	16.63	14%	3	3	Financial Svcs. (Div.)	33
1514	Annaly Capital Mgmt.	14.74	14%	4	3	R.E.I.T.	20
2365	Donnelley (R.R) & Sons	9.15	13%	5	3	Publishing	82
2648	KKR & Co. L.P.	14.02	12%	3	2	Public/Private Equity	43
599	Natural Resource	18.14	12%	4	3	Coal	97
533	Pengrowth Energy	5.17	12%	5	3	Natural Gas (Div.)	67
1049	Windstream Corp.	8.36	12%	4	3	Telecom. Utility	75
1217	Atlantic Power Corp.	12.01	11%	3	3	Power	92
1583	CVR Partners, LP	25.19	11%	–	3	Chemical (Basic)	73
1044	Consol. Communic.	13.94	11%	4	3	Telecom. Utility	75
1045	Deutsche Telekom ADR	10.62	11%	4	2	Telecom. Utility	75
2646	Gladstone Capital	8.17	11%	3	4	Public/Private Equity	43
934	NTELOS Hldgs.	15.79	11%	–	3	Telecom. Services	84
1621	PDL BioPharma	7.46	11%	3	4	Drug	31
600	PVR Partners, L.P.	23.59	11%	3	3	Coal	97
1427	Pitney Bowes	11.10	11%	4	3	Office Equip/Supplies	87
1819	StoneMor Partners L.P.	21.93	11%	2	4	Funeral Services	5
594	Alliance Resource	56.21	10%	4	3	Coal	97
614	Boardwalk Pipeline	25.06	10%	3	3	Pipeline MLPs	9
615	Buckeye Partners L.P.	48.33	10%	3	2	Pipeline MLPs	9
617	Energy Transfer	42.92	10%	3	2	Pipeline MLPs	9
2425	Seadrill Ltd.	38.96	10%	3	3	Oilfield Svcs/Equip.	66
623	Suburban Propane	39.93	10%	3	3	Pipeline MLPs	9
745	Cliffs Natural Res.	35.29	9%	5	3	Steel	91
606	Copano Energy	31.15	9%	2	3	Oil/Gas Distribution	4
1046	Frontier Communic.	4.41	9%	3	3	Telecom. Utility	75
1528	Hospitality Properties	21.74	9%	3	3	R.E.I.T.	20
1363	Intersil Corp. 'A'	6.96	9%	4	3	Semiconductor	88
529	Linn Energy, LLC	38.99	9%	2	3	Natural Gas (Div.)	67
2385	National CineMedia	13.33	9%	3	3	Advertising	65
1929	NutriSystem Inc.	7.38	9%	4	3	Food Processing	25
1380	STMicroelectronics	5.88	9%	5	3	Semiconductor	88
938	Telecom N. Zealand	9.75	9%	–	3	Telecom. Services	84
943	Vodafone Group ADR	25.58	9%	3	2	Telecom. Services	84
624	Williams Partners L.P.	50.95	9%	3	3	Pipeline MLPs	9
1598	AstraZeneca PLC (ADS)	44.84	8%	4	2	Drug	31
2642	Blackstone Group LP	14.35	8%	3	3	Public/Private Equity	43
2305	Cedar Fair L.P.	33.74	8%	3	3	Recreation	17
1042	CenturyLink Inc.	37.91	8%	3	2	Telecom. Utility	75
523	Crosstex Energy	12.12	8%	4	5	Natural Gas (Div.)	67
1520	DDR Corp.	15.32	8%	3	4	R.E.I.T.	20
102	Daimler AG	46.52	8%	5	3	Automotive	80
1521	Duke Realty Corp.	13.18	8%	3	3	R.E.I.T.	20
616	El Paso Pipeline	35.97	8%	1	3	Pipeline MLPs	9
2381	Harte-Hanks	5.31	8%	5	3	Advertising	65
619	Inergy, L.P.	18.87	8%	–	3	Pipeline MLPs	9
620	Kinder Morgan Energy	79.87	8%	1	2	Pipeline MLPs	9

Page No.	Stock Name	Recent Price	Est'd Future Yield	Time-liness	Safety Rank	Industry Group	Industry Rank
1532	Mack-Cali R'lty	25.02	8%	4	3	R.E.I.T.	20
392	Macquarie Infrastructure	41.40	8%	1	5	Industrial Services	34
1508	New York Community	12.69	8%	3	3	Thrift	53
517	Total ADR	48.94	8%	3	1	Petroleum (Integrated)	74
1229	TransAlta Corp.	15.04	8%	4	3	Power	92
2337	World Wrestling Ent.	7.87	8%	4	3	Entertainment	12
1545	AEGON	5.40	7%	3	3	Insurance (Life)	57
2533	Aircastle Ltd.	11.18	7%	3	4	Financial Svcs. (Div.)	33
1992	Altria Group	32.56	7%	2	2	Tobacco	27
1040	BCE Inc.	42.19	7%	3	3	Telecom. Utility	75
1983	Canon Inc. ADR	34.85	7%	4	2	Foreign Electronics	96
618	Enterprise Products	51.36	7%	3	3	Pipeline MLPs	9
2549	Federated Investors	19.39	7%	3	3	Financial Svcs. (Div.)	33
332	Golar LNG Ltd.	40.07	7%	2	3	Maritime	81
1526	Health Care REIT	60.08	7%	2	3	R.E.I.T.	20
1531	Liberty Property	33.93	7%	3	3	R.E.I.T.	20
1994	Lorillard Inc.	119.22	7%	3	2	Tobacco	27
1549	Manulife Fin'l	12.14	7%	3	3	Insurance (Life)	57
769	Mercury General	39.63	7%	3	2	Insurance (Prop/Cas.)	11
2367	Meredith Corp.	29.79	7%	3	3	Publishing	82
1370	Microchip Technology	29.94	7%	3	3	Semiconductor	88
1759	National Presto Ind.	73.47	7%	3	3	Diversified Co.	29
770	Old Republic	10.27	7%	3	3	Insurance (Prop/Cas.)	11
609	Pembina Pipeline Corp.	27.69	7%	3	3	Oil/Gas Distribution	4
1996	Reynolds American	41.99	7%	2	2	Tobacco	27
2334	Sinclair Broadcast	11.27	7%	3	4	Entertainment	12
2317	Six Flags Entertainment	57.00	7%	3	3	Recreation	17
792	TCF Financial	11.34	7%	3	3	Bank (Midwest)	38
335	Teekay Corp.	30.56	7%	3	3	Maritime	81
2635	United Online	5.37	7%	–	4	Internet	56
1542	Washington R.E.I.T.	25.01	7%	3	3	R.E.I.T.	20
2570	Western Union	12.74	7%	5	3	Financial Svcs. (Div.)	33
922	AT&T Inc.	33.82	6%	2	1	Telecom. Services	84
904	Ameren Corp.	29.08	6%	4	3	Electric Util. (Central)	24
318	Arkansas Best	7.19	6%	5	3	Trucking	77
2236	Avista Corp.	23.28	6%	3	2	Electric Utility (West)	36
502	BP PLC ADR	41.23	6%	4	3	Petroleum (Integrated)	74
1041	BT Group ADR	35.52	6%	3	3	Telecom. Utility	75
2506	Bank of Montreal	57.99	6%	3	2	Bank	35
2324	Belo Corp. 'A'	7.17	6%	3	5	Entertainment	12
2169	Best Buy Co.	13.75	6%	–	3	Retail (Hardlines)	26
2541	Block (H&R)	18.03	6%	3	3	Financial Svcs. (Div.)	33
707	Bombardier Inc. 'B'	3.13	6%	4	3	Aerospace/Defense	64
780	Comerica Inc.	28.66	6%	3	3	Bank (Midwest)	38
954	Comtech Telecom.	24.76	6%	4	3	Telecom. Equipment	90
2395	ConocoPhillips	55.73	6%	–	1	Petroleum (Producing)	83
1357	Cypress Semic.	9.31	6%	4	3	Semiconductor	88
163	Douglas Dynamics	13.24	6%	4	2	Heavy Truck & Equip	85
1586	Dow Chemical	28.78	6%	4	3	Chemical (Basic)	73
910	Empire Dist. Elec.	20.27	6%	3	2	Electric Util. (Central)	24

HIGH RETURNS EARNED ON TOTAL CAPITAL

Stocks with high average returns on capital in last 5 years ranked by earnings retained to common equity

Page No.	Stock Name	Ticker	Recent Price	Avg. Retained to Com. Eq.	Avg. Return On Cap.	Time-liness	Safety Rank	Beta	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
1995	Philip Morris Int'l	PM	86.86	460%	44%	3	2	0.75	15.6	3.9	Tobacco	27
2126	AutoZone Inc.	AZO	382.30	214%	34%	3	3	0.65	14.8	NIL	Retail Automotive	13
345	AFC Enterprises	AFCE	25.48	206%	35%	2	3	1.15	19.5	NIL	Restaurant	32
2005	ITT Educational	ESI	17.28	198%	92%	5	3	0.70	2.4	NIL	Educational Services	98
1994	Lorillard Inc.	LO	119.22	181%	104%	3	2	0.55	13.0	5.2	Tobacco	27
1366	Linear Technology	LLTC	31.97	171%	37%	3	3	1.00	16.0	3.1	Semiconductor	88
437	Gartner Inc.	IT	46.03	164%	42%	2	3	1.05	24.5	NIL	Information Services	8
2645	Fortress Investment	FIG	4.22	112%	43%	3	4	2.15	6.6	4.7	Public/Private Equity	43
2408	Core Laboratories	CLB	101.73	82%	39%	3	3	1.05	21.4	1.1	Oilfield Svcs/Equip.	66
718	Lockheed Martin	LMT	90.48	73%	36%	3	1	0.80	11.3	5.1	Aerospace/Defense	64
1918	Herbalife, Ltd.	HLF	46.50	60%	42%	3	3	1.00	11.2	2.6	Food Processing	25
2000	Apollo Group 'A'	APOL	19.62	59%	55%	5	3	0.70	7.2	NIL	Educational Services	98
1235	Foster Wheeler AG	FWLT	21.67	58%	44%	3	3	1.70	13.0	NIL	Engineering & Const	68
430	Arbitron Inc.	ARB	36.22	57%	56%	3	3	0.95	15.9	1.1	Information Services	8
2008	Strayer Education	STRA	49.76	56%	58%	5	3	0.75	9.0	2.0	Educational Services	98
1189	Colgate-Palmolive	CL	106.91	52%	38%	2	1	0.60	19.5	2.4	Household Products	3
1408	Int'l Business Mach.	IBM	190.35	52%	32%	3	1	0.85	12.9	1.8	Computers/Peripherals	94
1401	Dell Inc.	DELL	9.13	47%	35%	5	3	0.95	8.8	3.5	Computers/Peripherals	94
2203	Aeropostale	ARO	13.49	46%	46%	4	3	1.10	13.4	NIL	Retail (Softlines)	18
1223	GT Advanced Tech.	GTAT	3.19	46%	60%	5	4	1.60	3.0	NIL	Power	92
839	Questcor Pharmac.	QCOR	24.63	46%	44%	3	3	0.80	6.8	3.2	Biotechnology	44
1608	Gilead Sciences	GILD	74.82	45%	32%	3	3	0.70	20.9	NIL	Drug	31
2597	Accenture Plc	ACN	67.06	43%	62%	2	1	0.85	16.4	2.4	IT Services	14
2172	Coach Inc.	COH	56.59	42%	48%	3	3	1.20	14.7	2.1	Retail (Hardlines)	26
2563	MasterCard Inc.	MA	478.68	41%	43%	2	3	1.10	20.3	0.3	Financial Svcs. (Div.)	33
1781	BGC Partners Inc.	BGCP	3.66	40%	32%	5	4	1.40	5.9	13.1	Securities Brokerage	76
2632	priceline.com	PCLN	625.50	38%	36%	3	3	1.05	18.8	NIL	Internet	56
2617	Baidu, Inc.	BIDU	92.42	36%	36%	3	3	1.25	16.8	NIL	Internet	56
2618	Blue Nile	NILE	36.35	36%	35%	2	3	1.20	45.4	NIL	Internet	56
2366	McGraw-Hill	MHP	50.97	36%	33%	–	3	1.10	NMF	2.0	Publishing	82
2231	TJX Companies	TJX	44.08	36%	35%	2	1	0.80	16.8	1.0	Retail (Softlines)	18
2313	Polaris Inds.	PII	81.61	34%	32%	1	3	1.30	17.4	1.9	Recreation	17
584	InterDigital Inc.	IDCC	40.80	33%	33%	3	3	0.95	6.9	1.0	Wireless Networking	69
588	Research in Motion	RIMM	9.59	32%	32%	4	3	1.25	NMF	NIL	Wireless Networking	69
724	Rockwell Collins	COL	55.01	32%	33%	3	1	1.05	11.7	2.2	Aerospace/Defense	64
944	Vonage Holdings	VG	2.21	32%	38%	5	5	1.20	6.9	NIL	Telecom. Services	84
2228	Ross Stores	ROST	55.55	31%	33%	2	2	0.75	15.2	1.0	Retail (Softlines)	18
2585	Microsoft Corp.	MSFT	26.73	30%	37%	3	1	0.85	9.1	3.4	Computer Software	47
1929	NutriSystem Inc.	NTRI	7.38	25%	38%	4	3	0.85	10.7	9.5	Food Processing	25
2209	Buckle (The), Inc.	BKE	49.00	24%	34%	2	3	1.00	14.2	2.0	Retail (Softlines)	18
1619	Novo Nordisk ADR	NVO	154.48	24%	34%	1	1	0.80	23.4	1.7	Drug	31
435	FactSet Research	FDS	90.72	23%	31%	3	2	1.00	20.3	1.4	Information Services	8
379	C.H. Robinson	CHRW	59.81	19%	33%	3	2	0.90	19.7	2.2	Industrial Services	34
594	Alliance Resource	ARLP	56.21	17%	32%	4	3	1.05	8.4	8.2	Coal	97
431	Corporate Executive	CEB	41.25	17%	106%	3	3	1.00	26.6	1.8	Information Services	8
1002	Meritor, Inc.	MTOR	3.94	10%	402%	5	5	2.25	3.6	NIL	Auto Parts	72
123	Landauer, Inc.	LDR	57.30	6%	32%	2	3	0.80	20.7	3.8	Precision Instrument	60
2612	Paychex, Inc.	PAYX	31.93	6%	38%	3	1	0.85	20.0	4.2	IT Services	14
1577	Southern Copper	SCCO	34.78	4%	31%	3	3	1.55	13.7	2.9	Metals & Mining (Div.)	93
822	Computer Prog. & Sys.	CPSI	51.27	3%	39%	3	3	0.80	17.9	3.6	Healthcare Information	78

BARGAIN BASEMENT STOCKS

Stocks with current price-earnings multiples and price-to-"net" working capital ratios that are in the bottom quartile of the Value Line universe

("Net" working capital equals current assets less all liabilities including long-term debt and preferred)

Page No.	Stock Name	Ticker	Recent Price	Percent Price-to "Net" Wkg. Capital	Current P/E Ratio	Percent Price-to Book Value	Time-liness	Safety Rank	Beta	% Est'd Yield	Industry Group	Industry Rank
1584	China Green Agriculture	CGA	3.10	66%	1.9	35%	–	5	1.15	NIL	Chemical (Basic)	73
935	Neutral Tandem	IQNT	2.21	68%	3.6	24%	–	3	0.95	NIL	Telecom. Services	84
1407	Ingram Micro 'A'	IM	15.48	84%	8.1	69%	3	3	0.95	NIL	Computers/Peripherals	94
1325	Benchmark Electronics	BHE	15.13	107%	11.6	74%	3	3	1.10	NIL	Electronics	86
985	China Auto. Sys.	CAAS	4.86	119%	7.0	60%	4	4	1.40	NIL	Auto Parts	72
1417	Tech Data	TECD	45.46	119%	7.8	95%	4	3	1.00	NIL	Computers/Peripherals	94
1784	Goldman Sachs	GS	118.30	130%	9.0	84%	3	3	1.25	1.7	Securities Brokerage	76
1984	FUJIFILM Hldgs. ADR	FUJIY	17.50	132%	9.8	37%	5	2	0.80	2.9	Foreign Electronics	96
1327	Celestica Inc.	CLS	7.29	148%	7.1	92%	5	3	1.30	NIL	Electronics	86
2186	PC Connection	PCCC	11.05	150%	8.9	98%	3	3	1.15	13.8	Retail (Hardlines)	26
1314	Power-One	PWER	3.95	150%	8.4	90%	5	4	1.45	NIL	Electrical Equipment	41
1375	QLogic Corp.	QLGC	8.92	163%	11.4	115%	4	3	1.00	NIL	Semiconductor	88
1414	ScanSource	SCSC	28.95	166%	10.8	123%	4	3	1.15	NIL	Computers/Peripherals	94
1787	Jefferies Group	JEF	16.00	170%	11.3	93%	–	3	1.45	1.9	Securities Brokerage	76
1344	Vishay Intertechnology	VSH	9.11	192%	8.3	69%	5	3	1.30	NIL	Electronics	86
960	Marvell Technology	MRVL	7.70	193%	7.6	91%	5	3	1.25	3.1	Telecom. Equipment	90
1637	Kelly Services 'A'	KELYA	13.12	195%	9.6	68%	4	3	1.25	1.5	Human Resources	58
405	Fuel Tech, Inc.	FTEK	3.58	200%	11.2	87%	5	4	1.45	NIL	Environmental	70
1324	Avnet, Inc.	AVT	28.73	206%	7.0	105%	4	3	1.20	NIL	Electronics	86
1393	Kulicke & Soffa	KLIC	10.26	207%	7.5	121%	4	5	1.65	NIL	Semiconductor Equip	95
1998	Universal Corp.	UVV	48.06	209%	9.6	92%	3	3	0.80	4.2	Tobacco	27
1706	Brooks Automation	BRKS	7.27	239%	8.1	93%	5	3	1.45	4.4	Machinery	22
2158	Deckers Outdoor	DECK	33.59	256%	9.1	160%	5	3	1.30	NIL	Shoe	61
2181	Insight Enterprises	NSIT	15.12	258%	6.7	95%	4	3	1.35	NIL	Retail (Hardlines)	26
1403	Emulex Corp.	ELX	6.58	260%	11.0	102%	4	3	1.05	NIL	Computers/Peripherals	94
138	Zygo Corp.	ZIGO	13.65	278%	10.9	182%	4	3	1.25	NIL	Precision Instrument	60
1372	NVIDIA Corp.	NVDA	11.70	289%	11.7	153%	3	3	1.30	2.6	Semiconductor	88
394	Resources Connection	RECN	11.28	290%	11.3	129%	3	3	1.05	2.1	Industrial Services	34
1338	Plexus Corp.	PLXS	22.41	294%	8.4	122%	5	3	1.25	NIL	Electronics	86
2222	Joseph A. Bank	JOSB	47.05	297%	11.9	190%	3	3	1.00	NIL	Retail (Softlines)	18
2311	LeapFrog Enterpr. 'A'	LF	7.94	301%	9.6	180%	3	4	1.35	NIL	Recreation	17
1409	Logitech Int'l	LOGI	6.84	314%	7.9	111%	5	3	1.20	NIL	Computers/Peripherals	94
2548	EZCORP, Inc.	EZPW	17.83	319%	6.3	105%	5	3	1.00	NIL	Financial Svcs. (Div.)	33
1004	Standard Motor Prod.	SMP	18.32	326%	10.4	134%	3	4	1.70	2.4	Auto Parts	72
2442	Zoltek Cos.	ZOLT	6.45	334%	9.6	73%	4	3	1.80	NIL	Chemical (Diversified)	21

UNTIMELY STOCKS

Stocks ranked 5 (Lowest) for Relative Price Performance in the next 12 months

Page No.	Stock Name	Recent Price	Rank Safety	Rank Technical	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
156	AGCO Corp.	44.49	3	4	9.0	NIL	Heavy Truck & Equip	85
741	AK Steel Holding	3.66	5	3	NMF	NIL	Steel	91
1319	AVX Corp.	9.84	3	2	12.3	3.0	Electronics	86
1347	Advanced Micro Dev.	1.92	4	3	14.8	NIL	Semiconductor	88
948	Alcatel-Lucent ADR	1.01	5	1	NMF	NIL	Telecom. Equipment	90
206	Alere Inc.	17.71	3	3	7.9	NIL	Med Supp Non-Invasive	45
1570	Allegheny Techn.	26.43	3	3	20.8	2.7	Metals & Mining (Div.)	93
595	Alpha Natural Res.	7.57	3	3	NMF	NIL	Coal	97
1388	Amkor Technology	3.83	5	3	6.0	NIL	Semiconductor Equip	95
2000	Apollo Group 'A'	19.62	3	1	7.2	NIL	Educational Services	98
1389	Applied Materials	10.36	2	2	18.2	3.5	Semiconductor Equip	95
596	Arch Coal	6.89	3	2	NMF	1.7	Coal	97
318	Arkansas Best	7.19	3	3	31.3	1.7	Trucking	77
2011	Avid Technology	6.06	3	3	22.4	NIL	Entertainment Tech	89
1781	BGC Partners Inc.	3.66	4	3	5.9	13.1	Securities Brokerage	76
1232	Babcock & Wilcox ■	23.54	3	3	12.1	1.4	Engineering & Const	68
1218	Ballard Power Sys.	0.65	5	3	NMF	NIL	Power	92
2340	Boyd Gaming	5.22	4	4	NMF	NIL	Hotel/Gaming	71
2001	Bridgepoint Education	8.90	4	2	3.7	NIL	Educational Services	98
1706	Brooks Automation	7.27	3	4	8.1	4.4	Machinery	22
401	Calgon Carbon	12.21	3	3	24.9	NIL	Environmental	70
2002	Career Education	2.82	4	5	NMF	NIL	Educational Services	98
1327	Celestica Inc.	7.29	3	2	7.1	NIL	Electronics	86
952	Ciena Corp.	14.07	5	2	NMF	NIL	Telecom. Equipment	90
745	Cliffs Natural Res.	35.29	3	4	4.6	7.1	Steel	91
117	Coherent, Inc.	43.82	3	3	15.8	NIL	Precision Instrument	60
986	Commercial Vehicle	7.04	5	3	5.2	NIL	Auto Parts	72
319	Con-way Inc.	27.13	3	3	14.4	1.5	Trucking	77
102	Daimler AG	46.52	3	4	7.9	6.1	Automotive	80
2158	Deckers Outdoor	33.59	3	1	9.1	NIL	Shoe	61
1401	Dell Inc.	9.13	3	4	8.8	3.5	Computers/Peripherals	94
2396	Denbury Resources	15.50	3	4	11.5	NIL	Petroleum (Producing)	83
1422	Diebold, Inc.	29.26	2	3	14.4	4.0	Office Equip/Supplies	87
2365	Donnelley (R.R) & Sons	9.15	3	2	5.0	11.4	Publishing	82
1783	E*Trade Fin'l	8.17	4	3	20.4	NIL	Securities Brokerage	76
2620	EarthLink, Inc.	6.49	3	5	72.1	3.1	Internet	56
582	Echelon Corp.	2.27	4	3	NMF	NIL	Wireless Networking	69
833	Exelixis,Inc.	4.82	5	5	NMF	NIL	Biotechnology	44
2217	Express, Inc.	11.40	3	3	7.7	NIL	Retail (Softlines)	18
2548	EZCORP, Inc.	17.83	3	3	6.3	NIL	Financial Svcs. (Div.)	33
992	Federal-Mogul Corp.	7.27	4	2	9.7	NIL	Auto Parts	72
559	Ferro Corp.	2.49	4	4	24.9	NIL	Chemical (Specialty)	23
583	Finisar Corp.	12.07	4	2	13.9	NIL	Wireless Networking	69
405	Fuel Tech, Inc.	3.58	4	1	11.2	NIL	Environmental	70
1222	FuelCell Energy	0.90	5	3	NMF	NIL	Power	92
1984	FUJIFILM Hldgs. ADR	17.50	2	2	9.8	2.9	Foreign Electronics	96
1223	GT Advanced Tech.	3.19	4	2	3.0	NIL	Power	92
331	Genco Shipping	2.56	5	1	NMF	NIL	Maritime	81
2106	Guess Inc.	23.82	3	1	9.9	3.4	Apparel	16
957	Harmonic, Inc.	4.24	3	2	12.5	NIL	Telecom. Equipment	90

Page No.	Stock Name	Recent Price	Rank Safety	Rank Technical	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
2381	Harte-Hanks	5.31	3	2	7.0	6.4	Advertising	65
218	Hill-Rom Hldgs.	26.97	3	3	12.7	1.9	Med Supp Non-Invasive	45
1985	Hitachi, Ltd. ADR	54.91	3	3	9.3	1.5	Foreign Electronics	96
2005	ITT Educational	17.28	3	5	2.4	NIL	Educational Services	98
1361	Intel Corp.	20.25	1	3	9.2	4.4	Semiconductor	88
1786	Investment Techn.	8.50	3	1	23.6	NIL	Securities Brokerage	76
1333	Jabil Circuit	18.26	3	2	9.3	2.0	Electronics	86
562	Kronos Worldwide	15.00	3	3	7.1	4.0	Chemical (Specialty)	23
930	Leap Wireless	6.30	5	2	NMF	NIL	Telecom. Services	84
1409	Logitech Int'l	6.84	3	3	7.9	NIL	Computers/Peripherals	94
2346	MGM Resorts Int'l	9.60	4	3	NMF	NIL	Hotel/Gaming	71
960	Marvell Technology	7.70	3	3	7.6	3.1	Telecom. Equipment	90
1410	Mercury Systems	8.32	4	3	NMF	NIL	Computers/Peripherals	94
1002	Meritor, Inc.	3.94	5	3	3.6	NIL	Auto Parts	72
1155	Miller (Herman)	19.45	3	3	12.2	1.9	Furn/Home Furnishings	48
1003	Modine Mfg.	6.48	4	2	20.3	NIL	Auto Parts	72
933	NII Holdings	5.06	4	2	NMF	NIL	Telecom. Services	84
193	NuVasive, Inc.	13.91	3	4	81.8	NIL	Med Supp Invasive	40
565	OM Group	19.89	3	3	12.3	NIL	Chemical (Specialty)	23
1373	ON Semiconductor	5.93	3	3	9.3	NIL	Semiconductor	88
2629	Orbitz Worldwide	2.17	5	4	8.3	NIL	Internet	56
1374	PMC-Sierra	4.88	3	3	13.6	NIL	Semiconductor	88
533	Pengrowth Energy	5.17	3	1	30.4	9.3	Natural Gas (Div.)	67
1551	Phoenix (The) Cos.	22.82	5	4	4.0	NIL	Insurance (Life)	57
1396	Photronics Inc.	4.86	5	3	7.4	NIL	Semiconductor Equip	95
1338	Plexus Corp.	22.41	3	3	8.4	NIL	Electronics	86
1592	Potash Corp.	38.00	3	4	12.5	2.2	Chemical (Basic)	73
1314	Power-One ■	3.95	4	1	8.4	NIL	Electrical Equipment	41
825	Quality Systems	18.30	3	3	13.7	3.8	Healthcare Information	78
536	Quicksilver Res.	2.98	4	3	NMF	NIL	Natural Gas (Div.)	67
2017	RealD Inc.	9.93	4	3	NMF	NIL	Entertainment Tech	89
1576	Rio Tinto plc	48.14	3	4	6.5	3.7	Metals & Mining (Div.)	93
2355	Scientific Games	7.64	4	5	29.4	NIL	Hotel/Gaming	71
1936	Smithfield Foods	22.00	3	1	12.9	NIL	Food Processing	25
1380	STMicroelectronics	5.88	3	1	53.5	6.8	Semiconductor	88
2008	Strayer Education	49.76	3	4	9.0	2.0	Educational Services	98
939	Telephone & Data	22.39	3	3	16.5	2.2	Telecom. Services	84
1159	Tempur-Pedic	24.89	4	3	8.3	NIL	Furn/Home Furnishings	48
1418	Unisys Corp.	15.94	5	2	6.4	NIL	Computers/Peripherals	94
315	United Cont'l Hldgs.	19.70	4	4	8.0	NIL	Air Transport	63
941	U.S. Cellular	33.95	3	3	18.4	NIL	Telecom. Services	84
970	UTStarcom Holdings	0.90	5	1	45.0	NIL	Telecom. Equipment	90
1344	Vishay Intertechnology	9.11	3	3	8.3	NIL	Electronics	86
944	Vonage Holdings	2.21	5	1	6.9	NIL	Telecom. Services	84
2358	WMS Industries	16.36	3	4	13.9	NIL	Hotel/Gaming	71
603	Walter Energy	29.83	3	3	6.9	1.7	Coal	97
1168	Wausau Paper ■	8.01	3	3	29.7	1.5	Paper/Forest Products	10
1812	Websense Inc.	13.42	3	3	14.9	NIL	E-Commerce	37
373	Wendy's Company	4.53	3	3	30.2	3.5	Restaurant	32
2570	Western Union	12.74	3	3	8.4	3.9	Financial Svcs. (Div.)	33

■ Newly added this week.

HIGHEST DIVIDEND YIELDING NON-UTILITY STOCKS

Based upon estimated year-ahead dividends per share

Page No.	Stock Name	Recent Price	Timeliness	Safety Rank	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
2186	PC Connection	11.05	3	3	8.9	13.8	Retail (Hardlines)	26
1514	Annaly Capital Mgmt.	14.74	4	3	7.3	13.6	R.E.I.T.	20
1427	Pitney Bowes	11.10	4	3	5.6	13.5	Office Equip/Supplies	87
602	Rhino Resource Partners	13.44	–	3	12.6	13.2	Coal	97
1781	BGC Partners Inc.	3.66	5	4	5.9	13.1†	Securities Brokerage	76
599	Natural Resource	18.14	4	3	11.8	12.1	Coal	97
2365	Donnelley (R.R) & Sons	9.15	5	3	5.0	11.4	Publishing	82
1819	StoneMor Partners L.P.	21.93	2	4	NMF	10.8	Funeral Services	5
934	NTELOS Hldgs.	15.79	–	3	11.9	10.6	Telecom. Services	84
2646	Gladstone Capital	8.17	3	4	7.6	10.3	Public/Private Equity	43
2641	Apollo Investment	8.00	3	4	7.0	10.0	Public/Private Equity	43
1217	Atlantic Power Corp.	12.01	3	3	NMF	9.9	Power	92
1206	DWS High Income	9.77	–	4	NMF	9.7	Investment Co.	–
1929	NutriSystem Inc.	7.38	4	3	10.7	9.5	Food Processing	25
533	Pengrowth Energy	5.17	5	3	30.4	9.3	Natural Gas (Div.)	67
600	PVR Partners, L.P.	23.59	3	3	NMF	9.2	Coal	97
2534	AllianceBernstein Hldg.	16.63	3	3	10.2	8.7	Financial Svcs. (Div.)	33
615	Buckeye Partners L.P.	48.33	3	2	14.6	8.6	Pipeline MLPs	9
1528	Hospitality Properties	21.74	3	3	18.3	8.6	R.E.I.T.	20
2425	Seadrill Ltd.	38.96	3	3	12.0	8.6	Oilfield Svcs/Equip.	66
614	Boardwalk Pipeline	25.06	3	3	18.6	8.5	Pipeline MLPs	9
623	Suburban Propane	39.93	3	3	16.0	8.5	Pipeline MLPs	9
617	Energy Transfer	42.92	3	2	27.7	8.4	Pipeline MLPs	9
1205	DNP Select Inc. Fund	9.36	–	2	NMF	8.3	Investment Co.	–
594	Alliance Resource	56.21	4	3	8.4	8.2	Coal	97
1759	National Presto Ind.	73.47	3	3	15.5	8.2	Diversified Co.	29
1621	PDL BioPharma	7.46	3	4	5.0	8.0	Drug	31
1583	CVR Partners, LP	25.19	–	3	15.4	7.9	Chemical (Basic)	73
1508	New York Community	12.69	3	3	11.3	7.9	Thrift	53
1229	TransAlta Corp.	15.04	4	3	20.1	7.7	Power	92
606	Copano Energy	31.15	2	3	53.7	7.6	Oil/Gas Distribution	4
529	Linn Energy, LLC	38.99	2	3	22.8	7.5	Natural Gas (Div.)	67
2635	United Online	5.37	–	4	12.2	7.4	Internet	56
1532	Mack-Cali R'lty	25.02	4	3	39.7	7.2	R.E.I.T.	20
745	Cliffs Natural Res.	35.29	5	3	4.6	7.1	Steel	91
1210	MFS Multimarket	7.21	–	4	NMF	7.1	Investment Co.	–
1363	Intersil Corp. 'A'	6.96	4	3	33.1	6.9	Semiconductor	88
392	Macquarie Infrastructure	41.40	1	5	43.1	6.9	Industrial Services	34
2385	National CineMedia	13.33	3	3	21.2	6.9	Advertising	65
770	Old Republic	10.27	3	3	NMF	6.9	Insurance (Prop/Cas.)	11
2648	KKR & Co. L.P.	14.02	3	2	5.3	6.8	Public/Private Equity	43
1380	STMicroelectronics	5.88	5	3	53.5	6.8	Semiconductor	88
624	Williams Partners L.P.	50.95	3	3	19.3	6.5	Pipeline MLPs	9
1598	AstraZeneca PLC (ADS)	44.84	4	2	7.3	6.4	Drug	31
616	El Paso Pipeline	35.97	1	3	16.6	6.4	Pipeline MLPs	9
2381	Harte-Hanks	5.31	5	3	7.0	6.4	Advertising	65
620	Kinder Morgan Energy	79.87	1	2	33.0	6.3	Pipeline MLPs	9
2317	Six Flags Entertainment	57.00	3	3	32.6	6.3	Recreation	17
1204	AllianceBernstein Income	8.58	–	3	NMF	6.2	Investment Co.	–
163	Douglas Dynamics	13.24	4	2	17.9	6.2	Heavy Truck & Equip	85

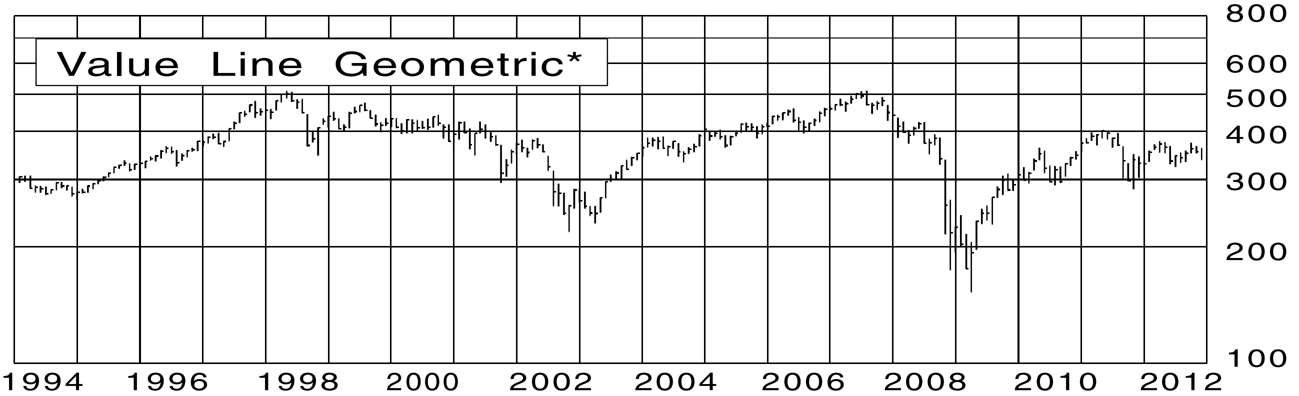
Page No.	Stock Name	Recent Price	Timeliness	Safety Rank	Current P/E Ratio	% Est'd Yield	Industry Group	Industry Rank
769	Mercury General	39.63	3	2	15.6	6.2	Insurance (Prop/Cas.)	11
102	Daimler AG	46.52	5	3	7.9	6.1	Automotive	80
619	Inergy, L.P.	18.87	–	3	32.0	6.1	Pipeline MLPs	9
938	Telecom N. Zealand	9.75	–	3	13.9	6.1	Telecom. Services	84
517	Total ADR	48.94	3	1	6.7	6.1	Petroleum (Integrated)	74
2337	World Wrestling Ent.	7.87	4	3	21.3	6.1	Entertainment	12
790	Park National	62.35	3	3	11.9	6.0	Bank (Midwest)	38
609	Pembina Pipeline Corp.	27.69	3	3	36.4	6.0	Oil/Gas Distribution	4
2533	Aircastle Ltd.	11.18	3	4	7.1	5.9	Financial Svcs. (Div.)	33
943	Vodafone Group ADR	25.58	3	2	10.2	5.9	Telecom. Services	84
1609	GlaxoSmithKline ADR	42.39	3	1	11.2	5.6	Drug	31
735	Lawson Products	8.51	4	4	NMF	5.6	Metal Fabricating	49
1531	Liberty Property	33.93	3	3	32.3	5.6	R.E.I.T.	20
1996	Reynolds American	41.99	2	2	14.2	5.6	Tobacco	27
977	PetMed Express	10.82	3	3	13.9	5.5	Pharmacy Services	62
2315	Regal Entertainment	15.28	3	5	17.4	5.5	Recreation	17
1202	Aberdeen Asia-Pac. Fd.	7.80	–	4	NMF	5.4	Investment Co.	–
1992	Altria Group	32.56	2	2	14.7	5.4	Tobacco	27
1209	Liberty All-Star	4.46	–	2	NMF	5.4	Investment Co.	–
2367	Meredith Corp.	29.79	3	3	10.3	5.4	Publishing	82
1510	People's United Fin'l	11.79	3	3	14.7	5.4	Thrift	53
1037	W.P. Carey Inc.	47.85	3	3	18.7	5.4	Property Management	15
922	AT&T Inc.	33.82	2	1	13.4	5.3	Telecom. Services	84
1790	NYSE Euronext	22.73	4	3	10.0	5.3	Securities Brokerage	76
2334	Sinclair Broadcast	11.27	3	4	7.1	5.3	Entertainment	12
502	BP PLC ADR	41.23	4	3	6.2	5.2	Petroleum (Integrated)	74
2409	Diamond Offshore	66.77	3	3	13.7	5.2	Oilfield Svcs/Equip.	66
1521	Duke Realty Corp.	13.18	3	3	NMF	5.2	R.E.I.T.	20
1526	Health Care REIT	60.08	2	3	52.2	5.2	R.E.I.T.	20
1994	Lorillard Inc.	119.22	3	2	13.0	5.2	Tobacco	27
513	Royal Dutch Shell 'A'	66.24	3	1	7.9	5.2	Petroleum (Integrated)	74
2371	A.H. Belo	4.69	4	5	NMF	5.1	Newspaper	50
743	ArcelorMittal	14.84	4	3	27.5	5.1	Steel	91
618	Enterprise Products	51.36	3	3	19.8	5.1	Pipeline MLPs	9
1527	Healthcare R'lty Trust	23.44	3	3	NMF	5.1	R.E.I.T.	20
718	Lockheed Martin	90.48	3	1	11.3	5.1	Aerospace/Defense	64
1545	AEGON	5.40	3	3	7.7	5.0	Insurance (Life)	57
2506	Bank of Montreal	57.99	3	2	9.7	5.0	Bank	35
2549	Federated Investors	19.39	3	3	11.3	5.0	Financial Svcs. (Div.)	33
1309	Garmin Ltd.	37.73	3	3	13.1	5.0	Electrical Equipment	41
1424	Lexmark Int'l 'A'	24.04	4	3	6.2	5.0	Office Equip/Supplies	87
413	Aberdeen Australia Fd.	10.11	–	3	NMF	4.9	Investment Co.(Foreign)	–
2169	Best Buy Co.	13.75	–	3	5.1	4.9	Retail (Hardlines)	26
2509	Can. Imperial Bank	77.79	3	2	9.9	4.8	Bank	35
785	FirstMerit Corp.	13.41	3	3	10.6	4.8	Bank (Midwest)	38

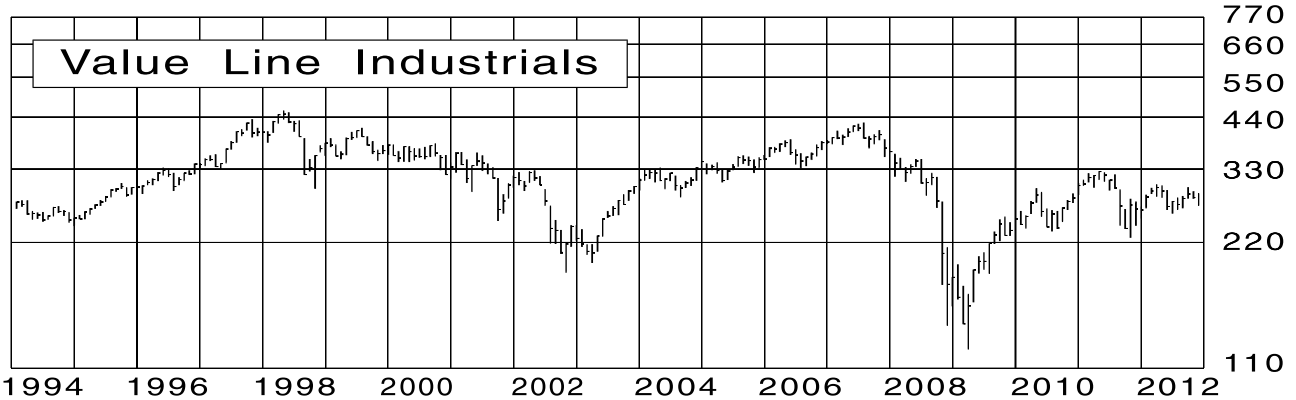
† Dividend cut possible

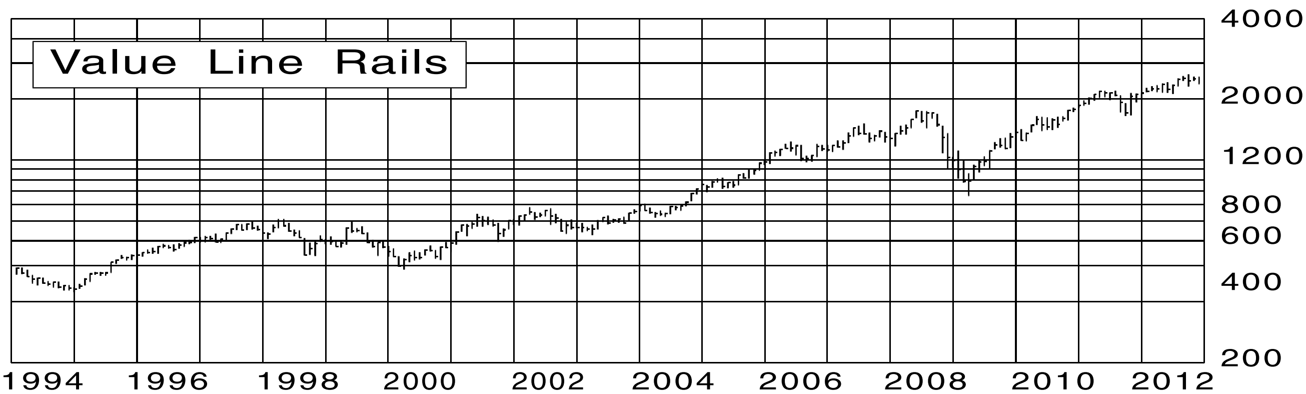
HIGHEST GROWTH STOCKS

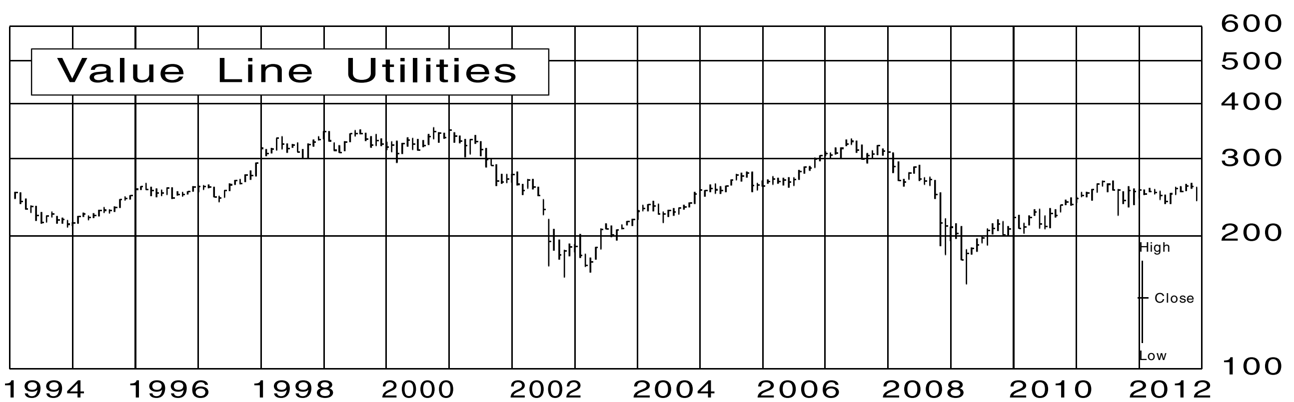
(To be included, a company's annual growth of sales, cash flow, earnings, dividends and book value must together have averaged 10% or more over the past 10 years and be expected to average at least 10% in the coming 3-5 years.)

Page No.	Stock Name	Ticker	Recent Price	Growth Past 10 Years	Est'd Growth 3-5 Years	Time-liness	Safety Rank	Beta	Current P/E Ratio	% Est'd Yield	Estimated 3-5 Year Price Appreciation	Industry Group	Industry Rank
2573	Adobe Systems	ADBE	32.92	12%	12%	3	3	1.20	20.2	NIL	65-145%	Computer Software	47
2123	Advance Auto Parts	AAP	77.79	19%	13%	4	3	0.85	14.4	0.3	30- 85%	Retail Automotive	13
1581	Agrium, Inc.	AGU	101.23	19%	14%	3	3	1.45	10.4	1.0	35-105%	Chemical (Basic)	73
552	Airgas Inc.	ARG	89.06	13%	14%	3	3	1.00	18.8	1.9	25- 85%	Chemical (Specialty)	23
594	Alliance Resource	ARLP	56.21	15%	12%	4	3	1.05	8.4	8.2	40-115%	Coal	97
553	Amer. Vanguard Corp.	AVD	32.04	13%	19%	1	3	1.05	23.1	0.4	10- 55%	Chemical (Specialty)	23
1740	Ametek, Inc.	AME	36.31	13%	14%	2	2	1.00	18.4	0.7	10- 50%	Diversified Co.	29
1321	Amphenol Corp.	APH	60.50	17%	13%	2	3	1.10	16.3	0.7	5- 55%	Electronics	86
2575	ANSYS, Inc.	ANSS	67.79	22%	12%	3	3	1.10	30.7	NIL	5- 55%	Computer Software	47
1399	Apple Inc.	AAPL	565.73	33%	30%	3	2	1.00	10.8	1.9	95-160%	Computers/Peripherals	94
2206	Ascena Retail Group	ASNA	19.91	15%	18%	3	3	1.05	13.3	NIL	50-100%	Retail (Softlines)	18
1572	BHP Billiton Ltd. ADR	BHP	70.31	19%	12%	4	3	1.40	10.7	3.2	30- 90%	Metals & Mining (Div.)	93
346	BJ's Restaurants	BJRI	33.25	16%	15%	4	3	1.05	27.0	NIL	80-170%	Restaurant	32
2393	Berry Petroleum 'A'	BRY	32.44	16%	14%	4	3	1.80	9.4	1.1	85-195%	Petroleum (Producing)	83
1969	Boston Beer 'A'	SAM	112.17	15%	15%	3	3	0.70	24.3	NIL	N- 45%	Beverage	19
951	Broadcom Corp. 'A'	BRCM	31.25	17%	13%	4	3	1.10	20.6	1.3	60-140%	Telecom. Equipment	90
2600	CACI Int'l	CACI	51.49	17%	15%	3	3	0.85	7.7	NIL	105-210%	IT Services	14
520	Cabot Oil & Gas 'A'	COG	49.09	13%	14%	1	3	1.25	53.4	0.2	N- 45%	Natural Gas (Div.)	67
2406	Cameron Int'l Corp.	CAM	53.37	16%	14%	3	3	1.45	14.5	NIL	30- 95%	Oilfield Svcs/Equip.	66
1946	Casey's Gen'l Stores	CASY	46.85	13%	12%	4	3	0.70	12.1	1.4	30- 90%	Retail/Wholesale Food	59
557	Ceradyne Inc.	CRDN	34.94	25%	12%	–	3	1.15	23.9	1.7	15- 70%	Chemical (Specialty)	23
821	Cerner Corp.	CERN	77.47	18%	14%	3	3	0.85	32.7	NIL	10- 60%	Healthcare Information	78
1233	Chicago Bridge & Iron	CBI	37.58	16%	15%	3	3	1.65	11.6	0.5	45-125%	Engineering & Const	68
2211	Chico's FAS	CHS	18.16	20%	15%	2	3	1.25	15.5	1.3	40- 95%	Retail (Softlines)	18
403	Clean Harbors	CLH	56.77	21%	12%	3	3	0.80	21.1	NIL	N- 30%	Environmental	70
745	Cliffs Natural Res.	CLF	35.29	21%	15%	5	3	1.95	4.6	7.1	185-325%	Steel	91
2172	Coach Inc.	COH	56.59	27%	17%	3	3	1.20	14.7	2.1	50-120%	Retail (Hardlines)	26
2602	Cognizant Technology	CTSH	66.15	41%	21%	3	2	1.10	17.5	NIL	80-150%	IT Services	14
2128	Copart, Inc.	CPRT	29.58	16%	13%	2	2	0.85	19.1	NIL	20- 50%	Retail Automotive	13
2408	Core Laboratories	CLB	101.73	17%	14%	3	3	1.05	21.4	1.1	20- 75%	Oilfield Svcs/Equip.	66
431	Corporate Executive	CEB	41.25	12%	16%	3	3	1.00	26.6	1.8	N- 45%	Information Services	8
161	Cummins Inc.	CMI	98.72	13%	15%	4	3	1.45	12.1	2.0	45-120%	Heavy Truck & Equip	85
1746	Danaher Corp.	DHR	52.90	16%	14%	3	2	1.00	15.6	0.2	70-135%	Diversified Co.	29
2158	Deckers Outdoor	DECK	33.59	28%	13%	5	3	1.30	9.1	NIL	170-300%	Shoe	61
2396	Denbury Resources	DNR	15.50	15%	12%	5	3	1.65	11.5	NIL	60-160%	Petroleum (Producing)	83
2173	Dick's Sporting Goods	DKS	51.50	17%	13%	2	3	1.15	19.4	1.0	15- 75%	Retail (Hardlines)	26
2141	Dollar Tree, Inc.	DLTR	40.45	16%	16%	3	1	0.55	15.1	NIL	75-110%	Retail Store	30
989	Dorman Products	DORM	32.00	15%	12%	1	3	1.20	16.8	NIL	N- 40%	Auto Parts	72
525	EOG Resources	EOG	118.61	18%	12%	2	3	1.20	21.8	0.6	5- 60%	Natural Gas (Div.)	67
2621	eBay Inc.	EBAY	47.92	35%	14%	2	2	1.10	23.3	NIL	15- 55%	Internet	56
2411	Ensco plc	ESV	55.54	17%	17%	2	3	1.25	9.7	2.7	25- 90%	Oilfield Svcs/Equip.	66
975	Express Scripts	ESRX	52.18	23%	17%	3	2	0.95	13.1	NIL	100-180%	Pharmacy Services	62
2412	FMC Technologies	FTI	41.37	16%	18%	3	3	1.35	19.2	NIL	70-165%	Oilfield Svcs/Equip.	66
435	FactSet Research	FDS	90.72	17%	15%	3	2	1.00	20.3	1.4	50-100%	Information Services	8
1136	Fastenal Co.	FAST	41.47	14%	15%	3	2	1.05	26.1	2.0	20- 55%	Retail Building Supply	1
2550	First Cash Fin'l Svcs	FCFS	47.20	16%	17%	2	3	0.90	16.0	NIL	25- 80%	Financial Svcs. (Div.)	33
2174	Fossil Inc.	FOSL	84.04	18%	19%	3	3	1.30	14.5	NIL	65-150%	Retail (Hardlines)	26
340	Genesee & Wyoming	GWR	70.76	14%	13%	3	3	1.25	22.5	NIL	5- 55%	Railroad	51
2105	Gildan Activewear	GIL	32.90	20%	15%	2	3	1.10	14.4	1.1	35-115%	Apparel	16
1562	Goldcorp Inc.	GG	40.76	34%	17%	3	3	0.95	18.5	1.5	60-135%	Precious Metals	79
1949	Green Mtn. Coffee	GMCR	27.33	32%	34%	4	4	1.00	10.3	NIL	175-355%	Retail/Wholesale Food	59
388	Healthcare Svcs.	HCSG	22.06	13%	12%	1	3	0.75	31.1	3.2	N- 60%	Industrial Services	34
2415	Helmerich & Payne	HP	51.64	12%	15%	3	3	1.45	9.2	0.5	45-115%	Oilfield Svcs/Equip.	66
2180	Hibbett Sports	HIBB	53.50	16%	13%	2	3	1.00	18.8	NIL	30- 85%	Retail (Hardlines)	26
323	Hunt (J.B.)	JBHT	59.64	14%	14%	2	3	1.05	22.1	0.9	N- 50%	Trucking	77
2609	Infosys Ltd. ADR	INFY	43.27	28%	14%	4	2	1.00	13.9	1.8	130-210%	IT Services	14
584	InterDigital Inc.	IDCC	40.80	26%	12%	3	3	0.95	6.9	1.0	25- 85%	Wireless Networking	69
2582	Intuit Inc.	INTU	58.95	14%	13%	3	1	0.90	17.6	1.2	55- 85%	Computer Software	47
333	Kirby Corp.	KEX	56.56	13%	13%	4	3	1.15	14.8	NIL	40-110%	Maritime	81
2161	Madden (Steven) Ltd.	SHOO	43.11	16%	14%	2	3	1.05	15.1	NIL	15- 75%	Shoe	61
2584	MICROS Systems	MCRS	44.52	19%	13%	3	3	1.05	19.8	NIL	45-115%	Computer Software	47
1721	Middleby Corp. (The)	MIDD	126.98	30%	14%	2	3	1.20	19.0	NIL	N- 40%	Machinery	22
1980	Monster Beverage	MNST	45.23	45%	20%	3	3	0.75	22.6	NIL	45-120%	Beverage	19
2332	News Corp.	NWS	24.45	12%	12%	1	3	1.25	16.1	0.7	25- 65%	Entertainment	12
2162	NIKE, Inc. 'B'	NKE	96.32	13%	12%	3	1	0.80	18.5	1.7	25- 55%	Shoe	61
2146	Nordstrom, Inc.	JWN	56.47	12%	13%	2	3	1.40	15.0	2.1	25- 95%	Retail Store	30
1619	Novo Nordisk ADR	NVO	154.48	20%	12%	1	1	0.80	23.4	1.7	N- 25%	Drug	31
129	OSI Systems	OSIS	62.24	14%	13%	–	3	0.85	21.8	NIL	10- 60%	Precision Instrument	60
2420	Oceaneering Int'l	OII	54.79	18%	13%	3	3	1.40	19.0	1.3	10- 65%	Oilfield Svcs/Equip.	66
325	Old Dominion Freight	ODFL	33.39	14%	15%	2	3	1.10	15.7	NIL	20- 80%	Trucking	77
1805	Open Text Corp.	OTEX	55.29	17%	13%	3	3	0.90	21.9	NIL	55-125%	E-Commerce	37
365	Panera Bread Co.	PNRA	163.46	25%	16%	2	2	0.95	25.6	NIL	15- 55%	Restaurant	32
1624	Perrigo Co.	PRGO	101.92	15%	16%	2	3	0.70	20.6	0.4	20- 75%	Drug	31
2187	PetSmart, Inc.	PETM	68.87	19%	12%	2	3	0.80	19.2	1.0	N- 50%	Retail (Hardlines)	26
966	Qualcomm Inc.	QCOM	62.09	17%	13%	2	2	0.85	17.5	1.6	35- 85%	Telecom. Equipment	90
825	Quality Systems	QSII	18.30	24%	12%	5	3	0.90	13.7	3.8	145-255%	Healthcare Information	78
2422	RPC Inc.	RES	11.10	21%	16%	4	3	1.55	10.9	2.9	60-125%	Oilfield Svcs/Equip.	66
750	Reliance Steel	RS	55.81	13%	14%	3	3	1.50	10.1	1.8	25- 95%	Steel	91
236	ResMed Inc.	RMD	40.72	21%	14%	2	2	0.80	18.9	1.7	35- 85%	Med Supp Non-Invasive	45
395	Rollins, Inc.	ROL	21.90	17%	12%	2	2	0.85	26.7	1.6	35- 85%	Industrial Services	34
2228	Ross Stores	ROST	55.55	17%	17%	2	2	0.75	15.2	1.0	15- 70%	Retail (Softlines)	18
2590	SAP AG	SAP	73.47	18%	12%	2	2	1.10	21.5	1.3	35- 75%	Computer Software	47
2613	SEI Investments	SEIC	21.87	13%	13%	2	2	1.05	16.3	1.5	85-150%	IT Services	14
2354	SHFL entertainment	SHFL	13.70	12%	13%	3	4	1.40	15.9	NIL	25-120%	Hotel/Gaming	71
751	Schnitzer Steel	SCHN	28.00	20%	16%	4	3	1.55	16.0	2.7	80-185%	Steel	91
1415	Seagate Technology	STX	27.09	16%	15%	3	3	1.35	4.5	4.7	85-175%	Computers/Peripherals	94
1577	Southern Copper	SCCO	34.78	24%	13%	3	3	1.55	13.7	2.9	45-115%	Metals & Mining (Div.)	93
370	Starbucks Corp.	SBUX	49.74	18%	19%	3	2	1.10	24.4	1.7	40- 80%	Restaurant	32
752	Steel Dynamics	STLD	12.67	16%	13%	4	4	1.65	15.8	3.2	95-215%	Steel	91
1141	Tractor Supply	TSCO	89.32	21%	17%	2	2	0.90	22.6	1.0	25- 70%	Retail Building Supply	1
1316	Trimble Nav. Ltd.	TRMB	54.27	18%	16%	1	3	1.35	29.3	NIL	20- 85%	Electrical Equipment	41
814	UnitedHealth Group	UNH	52.91	22%	12%	3	2	1.00	10.3	1.6	80-135%	Medical Services	55
815	Universal Health Sv. 'B'	UHS	42.87	13%	12%	4	3	0.95	9.5	0.5	75-155%	Medical Services	55
2232	Urban Outfitters	URBN	37.07	25%	13%	2	3	1.00	21.8	NIL	35- 90%	Retail (Softlines)	18
518	Valero Energy	VLO	30.11	14%	14%	3	3	1.35	5.7	2.3	35-100%	Petroleum (Integrated)	74
1770	Valmont Inds.	VMI	136.69	13%	12%	2	3	1.25	16.2	0.7	N- 45%	Diversified Co.	29
591	ViaSat, Inc.	VSAT	35.72	13%	13%	3	3	0.95	NMF	NIL	25- 95%	Wireless Networking	69
410	Waste Connections	WCN	31.23	14%	12%	3	3	0.70	18.9	1.3	30- 90%	Environmental	70
1317	WESCO Int'l	WCC	62.58	14%	13%	3	3	1.45	12.2	NIL	20- 85%	Electrical Equipment	41
1965	Whole Foods Market	WFM	91.41	13%	17%	2	3	1.05	32.3	0.9	10- 65%	Retail/Wholesale Food	59









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Company	2015-2017 Earnings	2015-2017 Dividends	BookValue	Beginning Book	Mid Year Book	Return		Dividend Payout		
AGL Resources Inc.	4.2	2	33.75	31.55	32.65	12.86	0.13	47.6%	47.61905	52.38095
ALLETE Inc.	3.75	2.1	35.00	33.35	34.18	10.97	0.11	56.0%	56	44
Alliant Energy Corp.	3.6	2.2	32.60	31.20	31.90	11.29	0.11	61.1%	61.11111	38.88889
Atmos Energy Corp.	2.7	1.48	34.65	33.43	34.04	7.93	0.08	54.8%	54.81481	45.18519
Consolidated Edison	4.25	2.5	47.25	45.50	46.38	9.16	0.09	58.8%	58.82353	41.17647
Integrys Energy Group Inc.	4	2.8	43.00	41.80	42.40	9.43	0.09	70.0%	70	30
Northwest Natural Gas	3.45	1.94	29.10	27.59	28.35	12.17	0.12	56.2%	56.23188	43.76812
Piedmont Natural Gas	1.85	1.35	14.65	14.15	14.40	12.85	0.13	73.0%	72.97297	27.02703
Southern Company	3.25	2.25	25.75	24.75	25.25	12.87	0.13	69.2%	69.23077	30.76923
Vectren Corp.	2.4	1.6	21.00	20.20	20.60	11.65	0.12	66.7%	66.66667	33.33333
WGL Holdings Inc.	2.85	1.75	28.85	27.75	28.30	10.07	0.10	61.4%	61.40351	38.59649
Wisconsin Energy Corp.	2.75	1.8	20.50	19.55	20.03	13.73	0.14	65.5%	65.45455	34.54545
Xcel Energy Inc.	2.25	1.35	22.00	21.10	21.55	10.44	0.10	60.0%	60	40

Source: Value Line Issue 3 September 7, 2012, Issue 1 November 23, 2012, Issue 5 September 21, 2012, Issue 11 November 2, 2012

Company Name	Ticker Sym	Return on Average Equity[Y07]	Return on Average Equity[Y08]	Return on Average Equity[Y09]	Return on Average Equity[Y10]	Return on Average Equity[Y11]	07-11 Average
AGL RESOURCES INC	GAS	12.905	13.1	12.937	13.025	6.704	11.73
ALLETE INC	ALE	12.44	10.512	6.945	7.903	9.128	9.39
ALLIANT ENERGY CORP	LNT	15.951	10.464	3.967	10.151	10.28	10.16
ATMOS ENERGY CORP	ATO	9.325	8.976	9.031	9.453	9.365	9.23
CONSOLIDATED EDISON INC	ED	10.878	12.741	8.703	9.31	9.343	10.20
INTEGRYS ENERGY GROUP INC	TEG	10.538	3.99	-2.38	7.664	7.752	5.51
NORTHWEST NATURAL GAS CO	NWN	12.475	11.368	11.661	10.74	9.079	11.06
PIEDMONT NATURAL GAS CO	PNY	11.853	12.461	13.533	14.999	11.578	12.88
SOUTHERN CO	SO	14.598	13.577	11.672	12.709	13.043	13.12
VECTREN CORP	VVC	11.886	9.979	9.684	9.428	9.751	10.15
WGL HOLDINGS INC	WGL	11.343	11.49	11.222	9.763	9.936	10.75
WISCONSIN ENERGY CORP	WEC	11.209	11.159	11.078	12.39	13.552	11.88
XCEL ENERGY INC	XEL	9.459	9.669	9.499	9.782	10.113	9.70

Source: S&P Research Insight

Dollar Amounts

Dollar Amounts	2011 4q Common Equity	Short Debt	Long Debt	Pref	2011 3q Common Equity	Short Debt	Long Debt	Pref
AGL Resources Inc.	3339	1321	3561	0	1881	2	2702	0
ALLETE Inc.	1079.3	1.1	863.3	0	1051.4	5.6	857.2	0
Alliant Energy Corp.	3014.8	102.8	2764.5	145.1	3003.4	22.1	2765	145.1
Atmos Energy Corp.	2267762	389985	2206324	0	2255421	206396	2208551	0
Consolidated Edison	11436	0	10673	213	11454	0	10674	213
Integrys Energy Group Inc.	2961.5	303.3	2122	51.1	2967.3	240.2	2081.6	51.1
Northwest Natural Gas	714488	141600	681700	0	696605	181200	641700	0
Piedmont Natural Gas	996923	331000	675000	0	996923	331000	675000	0
Southern Company	17578	859	20364	707	17633	137	20624	707
Vectren Corp.	1346.6	142.8	1208.2	0	1452.3	216.4	1719.1	0
WGL Holdings Inc.	1235719	227984	634138	28173	1202715	39421	664317	28173
Wisconsin Energy Corp.	3963.3	669.9	4646.9	30.4	3940.7	496.7	4650.7	30.4
Xcel Energy Inc.	8482198	219000	9908435	0	8431303	50000	9912571	104980

Dollar Amounts	2011 2q Common Equity	Short Debt	Long Debt	Pref	2011 1q Common Equity	Short Debt	Long Debt	Pref
AGL Resources Inc.	1914	144	2174	0	1920	26	2173	0
ALLETE Inc.	1037.8	2.5	783.6	0	1012.1	0.5	784	0
Alliant Energy Corp.	2929.2	0	2764.9	145.1	2922.5	32.4	2764.9	185.1
Atmos Energy Corp.	2335824	0	2208540	0	2373979	0	2159757	0
Consolidated Edison	11251	0	10674	213	11231	464	10675	213
Integrys Energy Group Inc.	2982.2	57.6	2282.5	51.1	3001.2	67.9	2312.6	51.1
Northwest Natural Gas	714628	185400	591700	0	723228	186435	601700	0
Piedmont Natural Gas	1022238	269500	735000	0	1046944	103500	731843	0
Southern Company	16982	857	19908	707	16465	1243	19568	707
Vectren Corp.	1446.3	144.5	1719.7	0	1456.2	122.3	1720.8	0
WGL Holdings Inc.	1252176	13022	664342	28173	1264008	15722	667031	28173
Wisconsin Energy Corp.	3947.6	542.4	4365.2	30.4	3904.7	281.5	4818.9	30.4
Xcel Energy Inc.	8234565	656000	9317483	104980	8181483	531500	9318884	104980

Sum of Cap Structures

	4q	3q	2q	1q
AGL Resources Inc.	8221	4585	4232	4119
ALLETE Inc.	1943.7	1914.2	1823.9	1796.6
Alliant Energy Corp.	6027.2	5935.6	5839.2	5904.9
Atmos Energy Corp.	4864071	4670368	4544364	4533736
Consolidated Edison	22322	22341	22138	22583
Integrys Energy Group Inc.	5437.9	5340.2	5373.4	5432.8
Northwest Natural Gas	1537788	1519505	1491728	1511363
Piedmont Natural Gas	2002923	2002923	2026738	1882287
Southern Company	39508	39101	38454	37983
Vectren Corp.	2697.6	3387.8	3310.5	3299.3
WGL Holdings Inc.	2126014	1934626	1957713	1974934
Wisconsin Energy Corp.	9310.5	9118.5	1934626	9035.5
Xcel Energy Inc.	18609633	18498854	18313028	18136847

Cap Structures

Cap Structures	4q Common Equity	Short Debt	Long Debt	Pref	3q Common Equity	Short Debt	Long Debt	Pref
AGL Resources Inc.	40.62	16.07	43.32	0.00	41.03	0.04	58.93	0.00
ALLETE Inc.	55.53	0.06	44.42	0.00	54.93	0.29	44.78	0.00
Alliant Energy Corp.	50.02	1.71	45.87	2.41	50.60	0.37	46.58	2.44
Atmos Energy Corp.	46.62	8.02	45.36	0.00	48.29	4.42	47.29	0.00
Consolidated Edison	51.23	0.00	47.81	0.95	51.27	0.00	47.78	0.95
Integrys Energy Group Inc.	54.46	5.58	39.02	0.94	55.57	4.50	38.98	0.96
Northwest Natural Gas	46.46	9.21	44.33	0.00	45.84	11.92	42.23	0.00
Piedmont Natural Gas	49.77	16.53	33.70	0.00	49.77	16.53	33.70	0.00
Southern Company	44.49	2.17	51.54	1.79	45.10	0.35	52.75	1.81
Vectren Corp.	49.92	5.29	44.79	0.00	42.87	6.39	50.74	0.00
WGL Holdings Inc.	58.12	10.72	29.83	1.33	62.17	2.04	34.34	1.46
Wisconsin Energy Corp.	42.57	7.20	49.91	0.33	43.22	5.45	51.00	0.33
Xcel Energy Inc.	45.58	1.18	53.24	0.00	45.58	0.27	53.58	0.57

Cap Structures	2q Common Equity	Short Debt	Long Debt	Pref	1q Common Equity	Short Debt	Long Debt	Pref
AGL Resources Inc.	45.23	3.40	51.37	0.00	46.61	0.63	52.76	0.00
ALLETE Inc.	56.90	0.14	42.96	0.00	56.33	0.03	43.64	0.00
Alliant Energy Corp.	50.16	0.00	47.35	2.48	49.49	0.55	46.82	3.13
Atmos Energy Corp.	51.40	0.00	48.60	0.00	52.36	0.00	47.64	0.00
Consolidated Edison	50.82	0.00	48.22	0.96	49.73	2.05	47.27	0.94
Integrys Energy Group Inc.	55.50	1.07	42.48	0.95	55.24	1.25	42.57	0.94
Northwest Natural Gas	47.91	12.43	39.67	0.00	47.85	12.34	39.81	0.00
Piedmont Natural Gas	50.44	13.30	36.27	0.00	55.62	5.50	38.88	0.00
Southern Company	44.16	2.23	51.77	1.84	43.35	3.27	51.52	1.86
Vectren Corp.	43.69	4.36	51.95	0.00	44.14	3.71	52.16	0.00
WGL Holdings Inc.	63.96	0.67	33.93	1.44	64.00	0.80	33.77	1.43
Wisconsin Energy Corp.	62.17	2.04	34.34	1.46	43.22	3.12	53.33	0.34
Xcel Energy Inc.	44.97	3.58	50.88	0.57	45.11	2.93	51.38	0.58

4 Quarter Avg

	Common Equity	Short Debt	Long Debt	Pref	Total Debt	
AGL Resources Inc.	43.4	5.0	51.6	0.0	56.6	0.4
ALLETE Inc.	55.9	0.1	43.9	0.0	44.1	0.6
Alliant Energy Corp.	50.1	0.7	46.7	2.6	47.3	0.5
Atmos Energy Corp.	49.7	3.1	47.2	0.0	50.3	0.5
Consolidated Edison	50.8	0.5	47.8	1.0	48.3	0.5
Integrys Energy Group Inc.	55.2	3.1	40.8	0.9	43.9	0.6
Northwest Natural Gas	47.0	11.5	41.5	0.0	53.0	0.5
Piedmont Natural Gas	51.4	13.0	35.6	0.0	48.6	0.5
Southern Company	44.3	2.0	51.9	1.8	53.9	0.4
Vectren Corp.	45.2	4.9	49.9	0.0	54.8	0.5
WGL Holdings Inc.	62.1	3.6	33.0	1.4	36.5	0.6
Wisconsin Energy Corp.	47.8	4.4	47.1	0.6	51.6	0.5
Xcel Energy Inc.	45.3	2.0	52.3	0.4	54.3	0.5
Average	**49.85**	**4.15**	**45.33**	**0.68**		

GAS - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:05

Date	Close
9/4/2012	40.38
9/5/2012	40.38
9/6/2012	41.00
9/7/2012	40.87
9/10/2012	40.87
9/11/2012	40.78
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9/13/2012	41.49
9/14/2012	41.21
9/17/2012	40.95
9/18/2012	41.07
9/19/2012	41.17
9/20/2012	41.30
9/21/2012	41.28
9/24/2012	41.48
9/25/2012	41.31
9/26/2012	41.34
9/27/2012	40.87
9/28/2012	40.91
10/1/2012	40.63
10/2/2012	40.84
10/3/2012	41.02
10/4/2012	41.34
10/5/2012	41.30
10/8/2012	41.17
10/9/2012	41.05
10/10/2012	40.82
10/11/2012	40.65
10/12/2012	40.13
10/15/2012	40.46
10/16/2012	40.96
10/17/2012	41.21
10/18/2012	41.24
10/19/2012	40.74
10/22/2012	40.48
10/23/2012	39.86
10/24/2012	40.09
10/25/2012	40.44
10/26/2012	40.28
10/31/2012	40.83
11/1/2012	40.23
11/2/2012	39.57
11/5/2012	39.18
11/6/2012	39.27
11/7/2012	38.73
11/8/2012	38.48
11/9/2012	38.36
11/12/2012	38.19
11/13/2012	38.25
11/14/2012	37.38
11/15/2012	37.13
11/16/2012	37.79
11/19/2012	37.81

11/20/2012	37.96
11/21/2012	37.70
11/23/2012	37.55
11/26/2012	38.39
11/27/2012	38.41
11/28/2012	38.69
11/29/2012	38.77
11/30/2012	38.98
Average	40.03

ALE - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:05

Date	Close
9/4/2012	41.97
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9/6/2012	41.74
9/7/2012	41.61
9/10/2012	41.62
9/11/2012	41.43
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9/17/2012	41.31
9/18/2012	41.38
9/19/2012	41.49
9/20/2012	41.41
9/21/2012	41.81
9/24/2012	42.41
9/25/2012	42.07
9/26/2012	42.28
9/27/2012	41.93
9/28/2012	41.74
10/1/2012	41.53
10/2/2012	41.43
10/3/2012	41.34
10/4/2012	41.58
10/5/2012	41.62
10/8/2012	41.61
10/9/2012	41.58
10/10/2012	41.61
10/11/2012	41.59
10/12/2012	41.24
10/15/2012	41.59
10/16/2012	41.53
10/17/2012	42.06
10/18/2012	42.03
10/19/2012	41.67
10/22/2012	41.62
10/23/2012	41.52
10/24/2012	41.45
10/25/2012	41.55
10/26/2012	41.38
10/31/2012	41.62
11/1/2012	41.43
11/2/2012	41.20
11/5/2012	41.06
11/6/2012	41.23
11/7/2012	40.00
11/8/2012	40.26
11/9/2012	40.14
11/12/2012	39.70
11/13/2012	39.39
11/14/2012	39.12
11/15/2012	38.56
11/16/2012	38.49
11/19/2012	38.50

11/20/2012	38.14
11/21/2012	37.98
11/23/2012	38.09
11/26/2012	38.17
11/27/2012	38.18
11/28/2012	38.42
11/29/2012	38.85
11/30/2012	39.21
Average	40.83

LNT - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:07

Date	Close
9/4/2012	44.41
9/5/2012	44.35
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9/7/2012	44.80
9/10/2012	44.76
9/11/2012	44.64
9/12/2012	44.26
9/13/2012	44.64
9/14/2012	44.19
9/17/2012	43.79
9/18/2012	43.69
9/19/2012	43.70
9/20/2012	43.58
9/21/2012	43.17
9/24/2012	43.77
9/25/2012	43.66
9/26/2012	43.85
9/27/2012	43.24
9/28/2012	43.39
10/1/2012	43.20
10/2/2012	43.49
10/3/2012	44.17
10/4/2012	44.52
10/5/2012	44.15
10/8/2012	44.41
10/9/2012	44.47
10/10/2012	44.17
10/11/2012	44.40
10/12/2012	44.11
10/15/2012	44.56
10/16/2012	44.60
10/17/2012	45.23
10/18/2012	45.30
10/19/2012	45.17
10/22/2012	44.92
10/23/2012	44.65
10/24/2012	44.33
10/25/2012	44.49
10/26/2012	44.49
10/31/2012	44.70
11/1/2012	44.83
11/2/2012	44.05
11/5/2012	43.50
11/6/2012	43.83
11/7/2012	42.79
11/8/2012	42.77
11/9/2012	43.70
11/12/2012	43.58
11/13/2012	43.46
11/14/2012	42.76
11/15/2012	42.38
11/16/2012	43.46
11/19/2012	43.45

11/20/2012	43.85
11/21/2012	43.76
11/23/2012	43.72
11/26/2012	43.94
11/27/2012	44.04
11/28/2012	44.20
11/29/2012	44.41
11/30/2012	44.82
Average	44.07

ATO - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:09

Date	Close
9/4/2012	35.58
9/5/2012	35.25
9/6/2012	35.70
9/7/2012	35.31
9/10/2012	35.81
9/11/2012	35.45
9/12/2012	35.26
9/13/2012	35.88
9/14/2012	35.36
9/17/2012	35.25
9/18/2012	35.37
9/19/2012	35.54
9/20/2012	35.66
9/21/2012	35.70
9/24/2012	36.30
9/25/2012	36.08
9/26/2012	35.81
9/27/2012	35.56
9/28/2012	35.79
10/1/2012	35.31
10/2/2012	35.33
10/3/2012	35.43
10/4/2012	35.92
10/5/2012	36.08
10/8/2012	36.20
10/9/2012	35.89
10/10/2012	35.93
10/11/2012	35.95
10/12/2012	35.68
10/15/2012	35.66
10/16/2012	36.34
10/17/2012	36.86
10/18/2012	36.53
10/19/2012	35.95
10/22/2012	35.94
10/23/2012	35.35
10/24/2012	35.24
10/25/2012	35.65
10/26/2012	35.80
10/31/2012	35.97
11/1/2012	36.03
11/2/2012	35.27
11/5/2012	35.28
11/6/2012	35.57
11/7/2012	34.62
11/8/2012	34.48
11/9/2012	34.92
11/12/2012	34.18
11/13/2012	34.23
11/14/2012	33.65
11/15/2012	33.20
11/16/2012	33.61
11/19/2012	34.01

11/20/2012	34.48
11/21/2012	34.27
11/23/2012	34.20
11/26/2012	34.66
11/27/2012	34.78
11/28/2012	34.65
11/29/2012	34.82
11/30/2012	35.01
Average	35.34

ED - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:10

Date	Close
9/4/2012	60.88
9/5/2012	60.33
9/6/2012	61.06
9/7/2012	60.63
9/10/2012	60.49
9/11/2012	60.31
9/12/2012	60.18
9/13/2012	60.99
9/14/2012	59.81
9/17/2012	59.61
9/18/2012	59.48
9/19/2012	59.46
9/20/2012	59.48
9/21/2012	59.10
9/24/2012	59.48
9/25/2012	59.46
9/26/2012	60.09
9/27/2012	59.58
9/28/2012	59.89
10/1/2012	59.48
10/2/2012	59.65
10/3/2012	59.76
10/4/2012	60.43
10/5/2012	60.22
10/8/2012	60.14
10/9/2012	59.95
10/10/2012	60.07
10/11/2012	60.17
10/12/2012	59.83
10/15/2012	59.82
10/16/2012	59.81
10/17/2012	60.61
10/18/2012	60.73
10/19/2012	60.47
10/22/2012	59.90
10/23/2012	59.70
10/24/2012	59.57
10/25/2012	60.01
10/26/2012	59.97
10/31/2012	60.38
11/1/2012	59.73
11/2/2012	59.20
11/5/2012	58.00
11/6/2012	57.76
11/7/2012	56.26
11/8/2012	56.42
11/9/2012	55.74
11/12/2012	55.12
11/13/2012	55.19
11/14/2012	55.23
11/15/2012	54.43
11/16/2012	54.98
11/19/2012	54.75

11/20/2012	54.43
11/21/2012	54.21
11/23/2012	54.10
11/26/2012	54.88
11/27/2012	54.84
11/28/2012	55.37
11/29/2012	55.44
11/30/2012	55.79
Average	58.57

TEG - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:11

Date	Close
9/4/2012	54.34
9/5/2012	53.96
9/6/2012	54.74
9/7/2012	54.29
9/10/2012	54.26
9/11/2012	54.25
9/12/2012	53.37
9/13/2012	53.86
9/14/2012	53.48
9/17/2012	53.26
9/18/2012	52.90
9/19/2012	52.90
9/20/2012	52.76
9/21/2012	52.47
9/24/2012	52.65
9/25/2012	52.63
9/26/2012	52.87
9/27/2012	52.27
9/28/2012	52.20
10/1/2012	54.62
10/2/2012	55.03
10/3/2012	55.06
10/4/2012	55.23
10/5/2012	55.20
10/8/2012	55.52
10/9/2012	55.32
10/10/2012	55.29
10/11/2012	54.95
10/12/2012	54.48
10/15/2012	54.91
10/16/2012	54.79
10/17/2012	55.77
10/18/2012	55.61
10/19/2012	55.18
10/22/2012	54.70
10/23/2012	53.80
10/24/2012	53.52
10/25/2012	53.85
10/26/2012	53.57
10/31/2012	54.04
11/1/2012	53.95
11/2/2012	53.55
11/5/2012	52.88
11/6/2012	54.26
11/7/2012	52.30
11/8/2012	52.00
11/9/2012	52.00
11/12/2012	51.90
11/13/2012	52.17
11/14/2012	51.76
11/15/2012	51.42
11/16/2012	52.65
11/19/2012	52.75

11/20/2012	52.87
11/21/2012	52.58
11/23/2012	52.60
11/26/2012	53.29
11/27/2012	53.35
11/28/2012	52.84
11/29/2012	52.79
11/30/2012	53.17
Average	53.62

NWN - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:13

Date	Close
9/4/2012	49.84
9/5/2012	49.28
9/6/2012	49.23
9/7/2012	48.59
9/10/2012	48.84
9/11/2012	48.72
9/12/2012	48.16
9/13/2012	48.83
9/14/2012	48.78
9/17/2012	48.53
9/18/2012	48.74
9/19/2012	48.60
9/20/2012	48.80
9/21/2012	48.86
9/24/2012	49.11
9/25/2012	48.89
9/26/2012	48.93
9/27/2012	48.96
9/28/2012	49.24
10/1/2012	49.25
10/2/2012	49.47
10/3/2012	49.78
10/4/2012	50.00
10/5/2012	50.18
10/8/2012	50.47
10/9/2012	50.37
10/10/2012	50.40
10/11/2012	49.86
10/12/2012	49.09
10/15/2012	49.29
10/16/2012	49.61
10/17/2012	49.68
10/18/2012	49.55
10/19/2012	48.74
10/22/2012	48.44
10/23/2012	47.53
10/24/2012	47.60
10/25/2012	47.89
10/26/2012	47.78
10/31/2012	46.53
11/1/2012	45.52
11/2/2012	44.92
11/5/2012	44.91
11/6/2012	44.37
11/7/2012	43.40
11/8/2012	42.94
11/9/2012	42.77
11/12/2012	42.39
11/13/2012	42.50
11/14/2012	42.17
11/15/2012	41.74
11/16/2012	41.82
11/19/2012	41.72

11/20/2012	42.19
11/21/2012	42.16
11/23/2012	42.17
11/26/2012	43.23
11/27/2012	43.28
11/28/2012	43.32
11/29/2012	43.82
11/30/2012	43.86
Average	46.98

PNY - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:14

Date	Close
9/4/2012	31.79
9/5/2012	31.44
9/6/2012	32.00
9/7/2012	32.11
9/10/2012	32.44
9/11/2012	32.22
9/12/2012	31.78
9/13/2012	32.54
9/14/2012	32.53
9/17/2012	32.37
9/18/2012	32.65
9/19/2012	32.66
9/20/2012	32.50
9/21/2012	32.98
9/24/2012	33.39
9/25/2012	33.01
9/26/2012	32.93
9/27/2012	32.58
9/28/2012	32.48
10/1/2012	32.15
10/2/2012	32.06
10/3/2012	32.02
10/4/2012	32.13
10/5/2012	32.25
10/8/2012	32.10
10/9/2012	31.77
10/10/2012	31.74
10/11/2012	31.64
10/12/2012	31.28
10/15/2012	31.25
10/16/2012	31.71
10/17/2012	32.21
10/18/2012	32.32
10/19/2012	32.25
10/22/2012	31.77
10/23/2012	31.52
10/24/2012	31.59
10/25/2012	31.64
10/26/2012	31.57
10/31/2012	31.87
11/1/2012	31.65
11/2/2012	31.19
11/5/2012	31.11
11/6/2012	31.32
11/7/2012	29.97
11/8/2012	29.79
11/9/2012	29.84
11/12/2012	29.65
11/13/2012	29.64
11/14/2012	29.15
11/15/2012	28.77
11/16/2012	29.25
11/19/2012	29.48

11/20/2012	29.78
11/21/2012	29.77
11/23/2012	29.67
11/26/2012	30.28
11/27/2012	30.34
11/28/2012	30.19
11/29/2012	30.76
11/30/2012	30.86
Average	31.44

SO - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:15

Date	Close
9/4/2012	45.47
9/5/2012	45.37
9/6/2012	46.07
9/7/2012	45.91
9/10/2012	45.69
9/11/2012	45.42
9/12/2012	45.32
9/13/2012	45.92
9/14/2012	45.05
9/17/2012	44.93
9/18/2012	44.96
9/19/2012	45.17
9/20/2012	45.24
9/21/2012	45.26
9/24/2012	45.82
9/25/2012	45.74
9/26/2012	46.11
9/27/2012	45.92
9/28/2012	46.09
10/1/2012	45.67
10/2/2012	45.57
10/3/2012	45.85
10/4/2012	45.97
10/5/2012	45.97
10/8/2012	46.07
10/9/2012	45.95
10/10/2012	45.96
10/11/2012	45.72
10/12/2012	45.61
10/15/2012	45.65
10/16/2012	45.89
10/17/2012	46.54
10/18/2012	46.80
10/19/2012	46.64
10/22/2012	46.55
10/23/2012	46.20
10/24/2012	46.04
10/25/2012	46.23
10/26/2012	46.33
10/31/2012	46.84
11/1/2012	46.02
11/2/2012	45.77
11/5/2012	44.62
11/6/2012	44.14
11/7/2012	42.80
11/8/2012	43.26
11/9/2012	43.03
11/12/2012	42.58
11/13/2012	42.95
11/14/2012	42.88
11/15/2012	42.54
11/16/2012	42.69
11/19/2012	42.77

11/20/2012	42.43
11/21/2012	42.28
11/23/2012	42.03
11/26/2012	42.63
11/27/2012	42.79
11/28/2012	42.76
11/29/2012	43.29
11/30/2012	43.55
Average	44.94

VVC - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:16

Date	Close
9/4/2012	28.66
9/5/2012	28.50
9/6/2012	28.64
9/7/2012	28.46
9/10/2012	28.54
9/11/2012	28.47
9/12/2012	28.38
9/13/2012	28.57
9/14/2012	28.38
9/17/2012	27.98
9/18/2012	27.84
9/19/2012	27.93
9/20/2012	28.25
9/21/2012	28.56
9/24/2012	28.95
9/25/2012	28.60
9/26/2012	28.85
9/27/2012	28.62
9/28/2012	28.60
10/1/2012	28.34
10/2/2012	28.60
10/3/2012	28.84
10/4/2012	29.15
10/5/2012	29.10
10/8/2012	29.10
10/9/2012	28.93
10/10/2012	28.93
10/11/2012	29.04
10/12/2012	28.78
10/15/2012	28.85
10/16/2012	29.27
10/17/2012	29.62
10/18/2012	29.67
10/19/2012	29.31
10/22/2012	29.19
10/23/2012	28.87
10/24/2012	28.80
10/25/2012	29.00
10/26/2012	29.28
10/31/2012	29.57
11/1/2012	29.76
11/2/2012	29.45
11/5/2012	29.19
11/6/2012	29.59
11/7/2012	28.90
11/8/2012	28.55
11/9/2012	28.64
11/12/2012	28.57
11/13/2012	28.35
11/14/2012	27.99
11/15/2012	27.62
11/16/2012	28.00
11/19/2012	28.11

11/20/2012	28.17
11/21/2012	28.19
11/23/2012	28.33
11/26/2012	28.50
11/27/2012	28.78
11/28/2012	28.71
11/29/2012	28.98
11/30/2012	29.25
Average	28.73

WGL - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:17

Date	Close
9/4/2012	39.63
9/5/2012	39.62
9/6/2012	40.24
9/7/2012	40.14
9/10/2012	40.35
9/11/2012	40.26
9/12/2012	40.06
9/13/2012	40.90
9/14/2012	39.99
9/17/2012	39.69
9/18/2012	39.65
9/19/2012	39.40
9/20/2012	39.81
9/21/2012	40.10
9/24/2012	40.61
9/25/2012	40.51
9/26/2012	40.65
9/27/2012	40.42
9/28/2012	40.25
10/1/2012	39.84
10/2/2012	39.89
10/3/2012	39.78
10/4/2012	39.89
10/5/2012	39.70
10/8/2012	39.51
10/9/2012	39.29
10/10/2012	39.28
10/11/2012	39.19
10/12/2012	39.09
10/15/2012	39.44
10/16/2012	39.69
10/17/2012	40.03
10/18/2012	40.14
10/19/2012	39.55
10/22/2012	39.17
10/23/2012	38.93
10/24/2012	38.99
10/25/2012	39.37
10/26/2012	39.50
10/31/2012	39.77
11/1/2012	39.80
11/2/2012	38.98
11/5/2012	39.08
11/6/2012	39.33
11/7/2012	38.13
11/8/2012	37.92
11/9/2012	38.19
11/12/2012	37.75
11/13/2012	37.85
11/14/2012	37.34
11/15/2012	36.85
11/16/2012	37.03
11/19/2012	37.27

11/20/2012	37.13
11/21/2012	37.28
11/23/2012	37.30
11/26/2012	37.99
11/27/2012	37.81
11/28/2012	37.81
11/29/2012	38.60
11/30/2012	39.06
Average	39.19

WEC - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:18

Date	Close
9/4/2012	38.38
9/5/2012	38.35
9/6/2012	38.59
9/7/2012	38.15
9/10/2012	37.87
9/11/2012	37.87
9/12/2012	37.43
9/13/2012	37.78
9/14/2012	37.37
9/17/2012	37.15
9/18/2012	36.87
9/19/2012	36.86
9/20/2012	36.79
9/21/2012	36.73
9/24/2012	37.18
9/25/2012	37.40
9/26/2012	37.71
9/27/2012	37.39
9/28/2012	37.67
10/1/2012	37.51
10/2/2012	37.47
10/3/2012	37.70
10/4/2012	37.93
10/5/2012	38.10
10/8/2012	38.20
10/9/2012	38.19
10/10/2012	38.15
10/11/2012	38.14
10/12/2012	38.16
10/15/2012	38.46
10/16/2012	38.67
10/17/2012	38.83
10/18/2012	38.77
10/19/2012	38.50
10/22/2012	38.17
10/23/2012	37.87
10/24/2012	37.60
10/25/2012	37.80
10/26/2012	37.88
10/31/2012	38.47
11/1/2012	38.36
11/2/2012	38.20
11/5/2012	37.36
11/6/2012	37.51
11/7/2012	36.92
11/8/2012	36.86
11/9/2012	36.32
11/12/2012	36.44
11/13/2012	36.75
11/14/2012	36.48
11/15/2012	36.12
11/16/2012	36.37
11/19/2012	36.67

11/20/2012	36.53
11/21/2012	36.45
11/23/2012	36.19
11/26/2012	36.40
11/27/2012	36.68
11/28/2012	36.90
11/29/2012	37.16
11/30/2012	37.53
Average	37.51

XEL - Daily - Fixed - Sep 1 2012 : Nov 30 2012 - From top to bottom - Yahoo Date:Dec 11 2012 12:52:20

Date	Close
9/4/2012	28.08
9/5/2012	28.03
9/6/2012	28.34
9/7/2012	28.10
9/10/2012	28.11
9/11/2012	28.01
9/12/2012	27.93
9/13/2012	28.33
9/14/2012	28.14
9/17/2012	27.85
9/18/2012	27.45
9/19/2012	27.42
9/20/2012	27.43
9/21/2012	27.32
9/24/2012	27.59
9/25/2012	27.65
9/26/2012	27.75
9/27/2012	27.45
9/28/2012	27.71
10/1/2012	27.47
10/2/2012	27.65
10/3/2012	27.83
10/4/2012	27.97
10/5/2012	27.94
10/8/2012	27.95
10/9/2012	27.84
10/10/2012	27.71
10/11/2012	27.72
10/12/2012	27.62
10/15/2012	27.74
10/16/2012	27.83
10/17/2012	28.21
10/18/2012	28.27
10/19/2012	28.04
10/22/2012	28.00
10/23/2012	27.89
10/24/2012	27.65
10/25/2012	28.03
10/26/2012	27.99
10/31/2012	28.25
11/1/2012	28.13
11/2/2012	27.90
11/5/2012	27.50
11/6/2012	27.49
11/7/2012	26.96
11/8/2012	26.78
11/9/2012	26.50
11/12/2012	26.11
11/13/2012	26.25
11/14/2012	26.36
11/15/2012	26.03
11/16/2012	26.27
11/19/2012	26.14

11/20/2012	26.11
11/21/2012	26.13
11/23/2012	26.02
11/26/2012	26.31
11/27/2012	26.45
11/28/2012	26.53
11/29/2012	26.72
11/30/2012	27.05
Average	27.44

GAS US $ ↑ 37.615 -.345 N37.61/37.62N 2x4

At 16:11 d Vol 175,889 O 38.01N H 38.2583D L 37.52N Val 6.659M

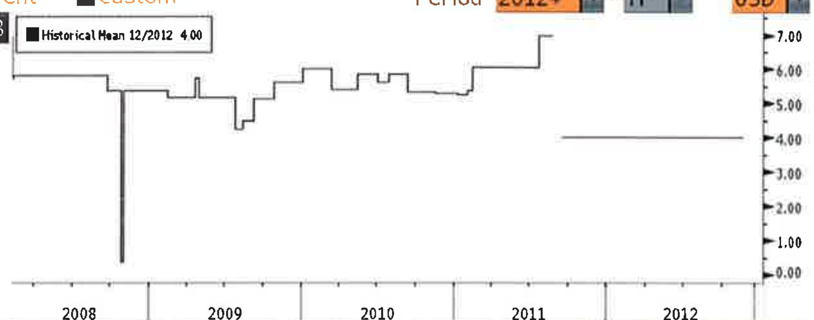
GAS US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

AGL Resources Inc — Last Event (Guidance) 11/01/12

Estimate: LTG

Consensus: Standard | 28 Days | Post Event | Custom — Period 2012+ - Yr — USD

Consensus	12/2012	12/2013
Mean Estimate	4.000	
Median Estimate	4.000	
High Estimate	4.000	
Low Estimate	4.000	
Standard Deviation		
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	1(1)	
P/E 15.48 Est P/E	14.205	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	PERM DENIED	Req. Entitlement	11/18/12	4.000	0.000		

ALE US $ ↑ 37.76 -.38 P37.75 /37.80Y 2x2
At 16:12 d Vol 207,141 O 38.14N H 38.39D L 37.73N Val 7.886M

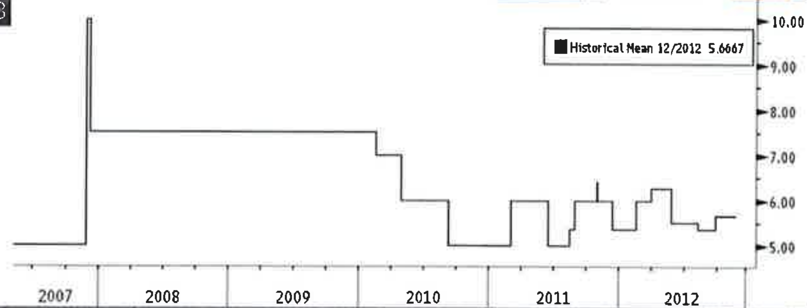
ALE US Equity 95) Actions 96) Alert BEst Consensus Detail

ALLETE Inc
Last Event (Guidance) 10/31/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom Period 2012+ - USD

Consensus	12/2012	12/2013
Mean Estimate	5.667	
Median Estimate	6.000	
High Estimate	6.000	
Low Estimate	5.000	
Standard Deviation	0.577	
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	3(3)	
P/E 16.00 Est P/E	14.643	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	PERM DENIED	Req. Entitlement	11/01/12	5.000	0.000		
2)	Sidoti & Company LLC	OWEN	11/01/12	6.000	0.000		
3)	D.A. Davidson & Co	BATES	10/31/12	6.000	0.000		

LNT US $ ↓ 43.82 -.03 N43.80/43.82N 12x3

..... At 16:12 d Vol 559,404 O 43.99N H 44.12P L 43.73Y Val 24.533M

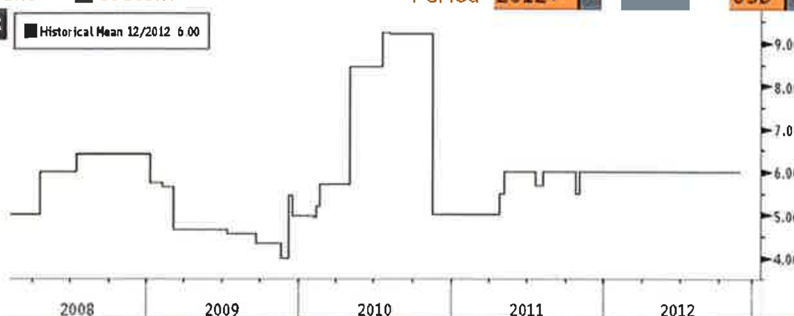
LNT US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

Alliant Energy Corp — Last Event (Guidance) 11/09/12

Estimate: LTG

Consensus: Standard | 28 Days | Post Event | Custom — Period 2012+ - USD

Consensus	12/2012	12/2013
Mean Estimate	6.000	
Median Estimate	6.000	
High Estimate	7.000	
Low Estimate	5.000	
Standard Deviation	1.000	
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	3(3)	
P/E 15.88 Est P/E	14.670	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1) ■	D.A. Davidson & Co	BATES	11/10/12	7.000	0.000		
2)	PERM DENIED	Req. Entitlement	10/23/12	5.000	0.000		
3)	PERM DENIED	Req. Entitlement	08/03/12	6.000	0.000		

ATO US $ ↑ 34.29 +.16 P34.28 /34.30T 2x1

..... At 16:12 d Vol 281,444 O 34.41T H 34.46N L 33.9901D Val 9.635M ExDiv

ATO US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

Atmos Energy Corp

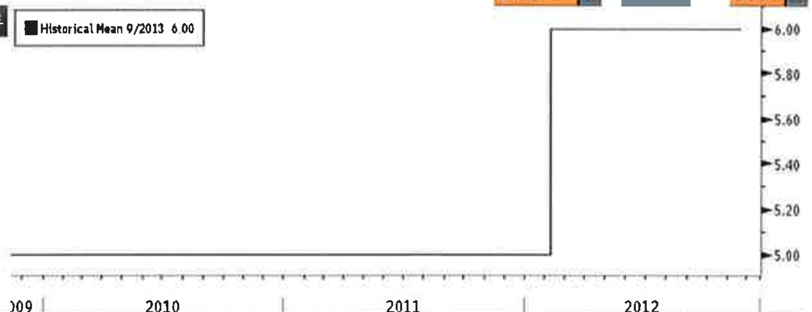
Last Event (Guidance) 11/07/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom

Period 2013+ - USD

Consensus	9/2013	9/2014
Mean Estimate	6.000	
Median Estimate	6.000	
High Estimate	6.000	
Low Estimate	6.000	
Standard Deviation		
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	1(1)	
P/E 14.72 Est P/E	14.094	



	Broker	Analyst	Date	9/2013	Change	9/2014	Change
1)	PERM DENIED	Req. Entitlement	08/29/12	6.000	0.000		

ED US $ ↓ 53.84 -.59 P53.84 /53.85Z 7x4

At 16:13 d Vol 1,029,605 O 54.45N H 54.55Y L 53.63P Val 55.714M

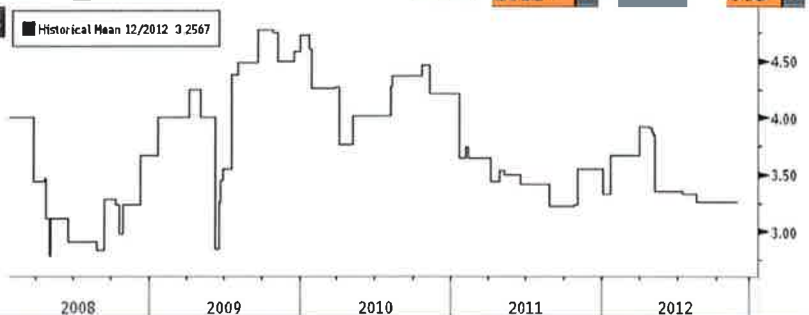
ED US Equity 95) Actions 96) Alert BEst Consensus Detail

Consolidated Edison Inc Last Event (Guidance) 11/05/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom Period 2012+ - USD

Consensus	12/2012	12/2013
Mean Estimate	3.257	
Median Estimate	3.300	
High Estimate	3.470	
Low Estimate	3.000	
Standard Deviation	0.238	
4 Weeks Change	-0.003	
4 Weeks Up/Down	0 / 1	
Number of Estimates	3(3)	
P/E 14.24 Est P/E	14.248	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	PERM DENIED	Req. Entitlement	11/06/12	3.000	0.000		
2)	PERM DENIED	Req. Entitlement	11/06/12	3.470	-0.010		
3)	■ Jefferies	FREMONT	07/11/12	3.300	NA		

TEG US $ ↓ **52.34** -.53 P52.34/52.37N 3x1

At 16:13 d Vol 263,563 O 52.96N H 53.08D L 52.14P Val 13.849M

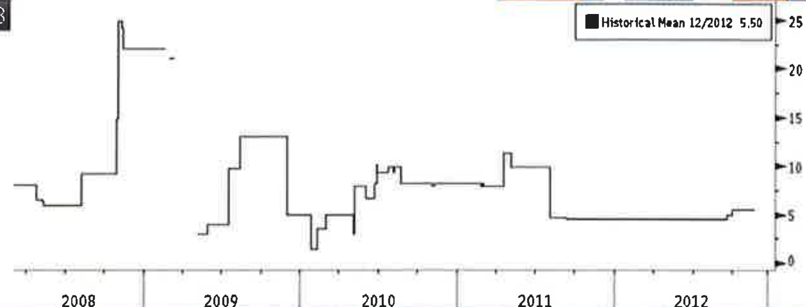
TEG US Equity 95) Actions 96) Alert BEst Consensus Detail

Integrys Energy Group Inc Last Event (Guidance) 11/05/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom Period 2012+ - Yr USD

Consensus	12/2012	12/2013
Mean Estimate	5.500	
Median Estimate	5.500	
High Estimate	6.000	
Low Estimate	5.000	
Standard Deviation	0.707	
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	3(2)	
P/E 15.53 Est P/E	16.408	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	SunTrust Robinson Humphr	AGHA	11/07/12	5.000	0.000		
2)	D.A. Davidson & Co	BATES	11/07/12	6.000	0.000		
3)	PERM DENIED	Req. Entitlement	05/04/12	3.900	NA		

NWN US $ ↓ 41.87 -.32 N41.84 /41.88N 1x1
..... At 16:15 d Vol 57,213 O 42.29N H 42.3799D L 41.84N Val 2.415M

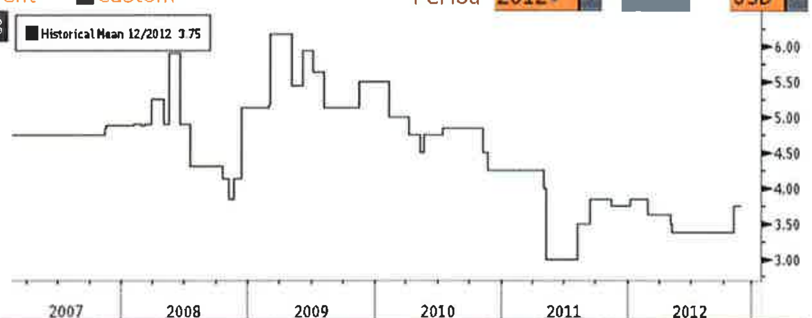
NWN US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

Northwest Natural Gas Co — Last Event (Guidance) 11/06/12

Estimate: LTG

Consensus: Standard | 28 Days | Post Event | Custom — Period 2012+ - USD

Consensus	12/2012	12/2013
Mean Estimate	3.750	
Median Estimate	3.750	
High Estimate	4.500	
Low Estimate	3.000	
Standard Deviation	0.866	
4 Weeks Change	0.375	
4 Weeks Up/Down	1 / 0	
Number of Estimates	4(4)	
P/E 17.74 Est P/E	17.330	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	D.A. Davidson & Co	BATES	11/07/12	3.000	0.000		
2)	Sidoti & Company LLC	OWEN	11/06/12	3.000	0.000		
3)	Brean Murray Carret & Co	GAUGLER	10/31/12	4.500	1.500		
4)	PERM DENIED	Req. Entitlement	09/05/12	4.500	0.000		

PNY US $ ↑ **29.65** -.13 Y29.63 /29.66N 6x6

..... At 16:17 d Vol 116,235 O 29.75T H 29.85J L 29.61N Val 3.455M

PNY US Equity 95) Actions 96) Alert BEst Consensus Detail

Piedmont Natural Gas Co Inc

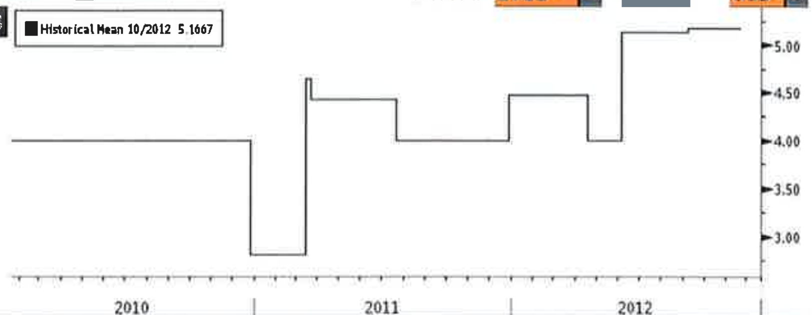
Last Event (Guidance) 11/13/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom

Period 2012+ - USD

Consensus	10/2012	10/2013
Mean Estimate	5.167	
Median Estimate	4.000	
High Estimate	7.500	
Low Estimate	4.000	
Standard Deviation	2.021	
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	3(3)	
P/E 19.01 Est P/E	18.325	



	Broker	Analyst	Date	10/2012	Change	10/2013	Change
1)	Sidoti & Company LLC	OWEN	10/18/12	4.000	0.000		
2)	PERM DENIED	Req. Entitlement	09/11/12	4.000	0.000		
3)	PERM DENIED	Req. Entitlement	09/07/12	7.500	0.100		

SO US $ ↓ 41.94 -.49 N41.94 /41.95T 8 x12
At 16:18 d Vol 4,073,691 O 42.45Z H 42.66T L 41.78P Val 172.263M

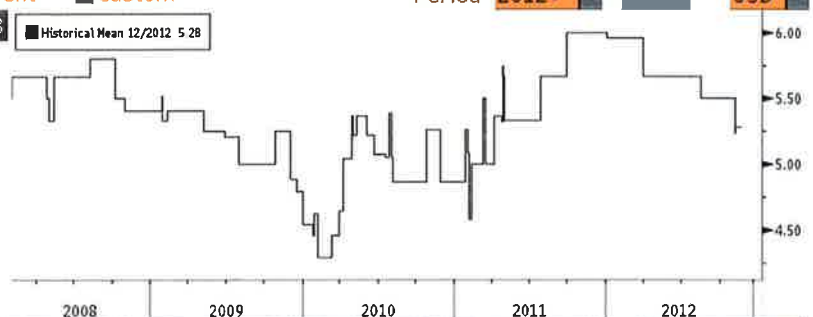
SO US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

Southern Co/The — Last Event (Guidance) 11/05/12

Estimate: LTG

Consensus: Standard | 28 Days | Post Event | Custom — Period 2012 - USD

Consensus	12/2012	12/2013
Mean Estimate	5.280	
Median Estimate	5.000	
High Estimate	6.000	
Low Estimate	5.000	
Standard Deviation	0.438	
4 Weeks Change	-0.220	
4 Weeks Up/Down	0 / 1	
Number of Estimates	5(5)	
P/E 16.64 Est P/E	15.941	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	Jefferies	FREMONT	11/06/12	5.400	NA		
2)	SunTrust Robinson Humphr	AGHA	11/06/12	5.000	0.000		
3)	PERM DENIED	Req. Entitlement	11/06/12	6.000	0.000		
4)	PERM DENIED	Req. Entitlement	11/05/12	5.000	-1.000		
5)	BGC Partners	KONOLIGE	08/16/12	5.000	NA		

VVC US $ ↓ 28.05 -.12 T28.04 /28.05N 1x2

..... At 16:18 d Vol 140,866 O 28.14Z H 28.27N L 27.99K Val 3.961M

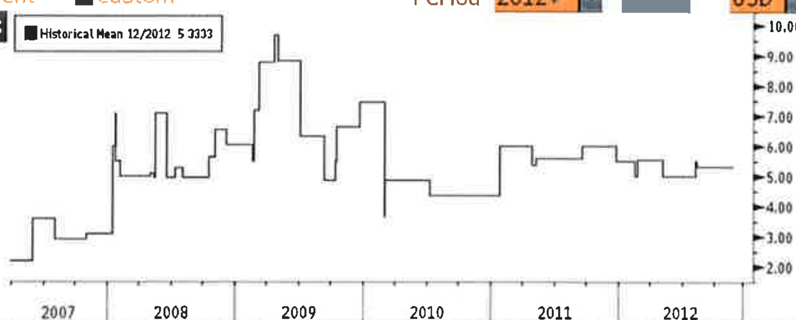
VVC US Equity 95) Actions 96) Alert BEst Consensus Detail

Vectren Corp Last Event (Guidance) 11/05/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom Period 2012+ - USD

Consensus	12/2012	12/2013
Mean Estimate	5.333	
Median Estimate	5.000	
High Estimate	6.000	
Low Estimate	5.000	
Standard Deviation	0.577	
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	4(3)	
P/E 14.24 Est P/E	15.644	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	PERM DENIED	Req. Entitlement	11/06/12	6.000	0.000	[redacted]	
2)	PERM DENIED	Req. Entitlement	08/21/12	5.000	0.000		
3)	■ Brean Murray Carret & Co	GAUGLER	08/08/12	5.000	NA		
4)	PERM DENIED	Req. Entitlement	05/04/12	6.700	0.100		

WGL US $ ↑ 37.08 -.05 Z37.07 /37.11Y 1x3

At 16:18 d Vol 123,583 O 37.30N H 37.30N L 36.81Z Val 4.587M

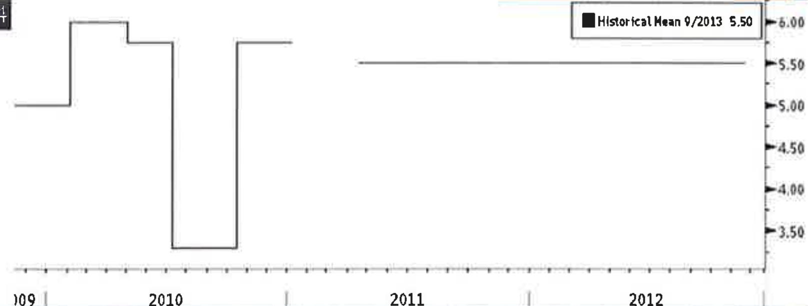
WGL US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

WGL Holdings Inc — Last Event (Guidance) 11/15/12

Estimate: LTG

Consensus: Standard | 28 Days | Post Event | Custom — Period 2013 - USD

Consensus	9/2013	9/2014
Mean Estimate	5.500	
Median Estimate	5.500	
High Estimate	5.500	
Low Estimate	5.500	
Standard Deviation		
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	1(1)	
P/E 13.78 Est P/E	14.958	



	Broker	Analyst	Date	9/2013	Change	9/2014	Change
1)	PERM DENIED	Req. Entitlement	09/05/12	5.500	0.000		

WEC US $ ↑ 36.22 -.31 K36.21/36.23N 7x10

..... At 16:20 d Vol 701,647 O 36.60N H 36.75D L 36.14Z Val 25.569M

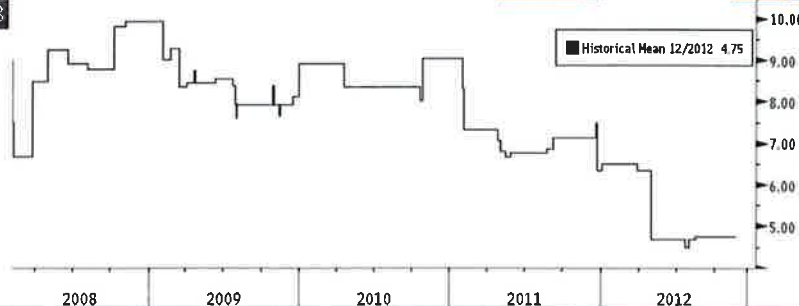
WEC US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

Wisconsin Energy Corp | Last Event (Guidance) 10/31/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom | Period 2012 - | USD

Consensus	12/2012	12/2013
Mean Estimate	4.750	
Median Estimate	5.000	
High Estimate	5.000	
Low Estimate	4.000	
Standard Deviation	0.500	
4 Weeks Change	0.000	
4 Weeks Up/Down	0 / 0	
Number of Estimates	4(4)	
P/E 15.03 Est P/E	15.512	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1)	PERM DENIED	Req. Entitlement	11/04/12	5.000	0.000	[redacted]	[redacted]
2) ■	D.A. Davidson & Co	BATES	11/01/12	4.000	0.000	[redacted]	[redacted]
3)	PERM DENIED	Req. Entitlement	10/31/12	5.000	0.000	[redacted]	[redacted]
4) ■	BGC Partners	KONOLIGE	08/16/12	5.000	NA	[redacted]	[redacted]

XEL US $ ↑ 25.92 -.19 T25.91/25.92N 4x44
At 16:22 d Vol 1,382,041 O 26.14N H 26.19P L 25.85T Val 35.956M

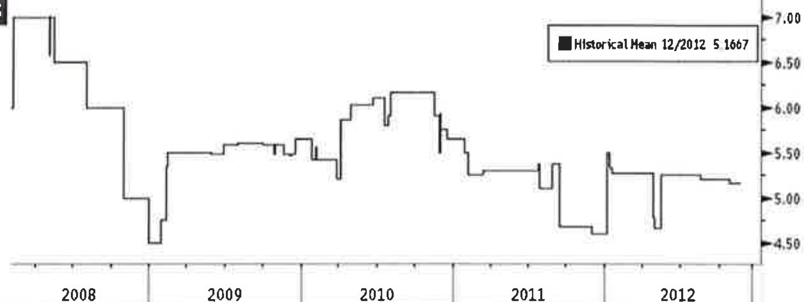
XEL US Equity | 95) Actions | 96) Alert | BEst Consensus Detail

Xcel Energy Inc Last Event (Guidance) 11/09/12

Estimate LTG

Consensus Standard 28 Days Post Event Custom Period 2012+ - USD

Consensus	12/2012	12/2013
Mean Estimate	5.167	
Median Estimate	5.000	
High Estimate	6.000	
Low Estimate	5.000	
Standard Deviation	0.408	
4 Weeks Change	-0.033	
4 Weeks Up/Down	0 / 0	
Number of Estimates	7(6)	
P/E 14.16 Est P/E	14.410	



	Broker	Analyst	Date	12/2012	Change	12/2013	Change
1) ■	SunTrust Robinson Humphr	AGHA	10/26/12	5.000	0.000		
2)	PERM DENIED	Req. Entitlement	10/25/12	5.000	0.000		
3) ■	BGC Partners	KONOLIGE	10/25/12	5.000	0.000		
4)	PERM DENIED	Req. Entitlement	10/25/12	5.000	NA		
5) ■	D.A. Davidson & Co	BATES	10/25/12	5.000	0.000		
6)	PERM DENIED	Req. Entitlement	10/25/12	6.000	0.000		
7) ■	Jefferies	FREMONT	05/15/12	1.900	0.000		