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Request IR-311:

In your response to CBA/SBA IR-118 (b), you note that "…if, in any 60 month period, NS Power's prudently incurred costs in providing the Transmission Facilitation Service are greater than amounts payable by and received from Nalcor, NSPML is to pay the difference to NS Power. In that event, NSPML would seek recovery of such amounts from Nova Scotia customers through the Project Cost Assessment…"

(a) Please explain why Nova Scotia customers should be responsible for costs incurred by NS Power which are greater than what is payable by and received from Nalcor.

(b) Please provide a numerical example of a situation where NS Power incurs costs that are greater than what is payable by and received from Nalcor.

Response IR-311:

(a) The NS customer will benefit from all of the attributes of the Maritime Link such as the NS Block, dispatchability of the energy and access to surplus. Although the scenario presented is not likely to occur, this is a part of the larger commercial transaction and must be considered in the totality of the agreements. The premise of the commercial arrangements is that NSPML will receive 20 percent of the energy for 20 percent of the total project costs. This item is considered part of the total project costs and as such, the Company would seek recovery for such costs.

(b) Please refer to CanWEA IR-107.

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Request IR-312:

With reference to response CA/SBA IR-118(c), page 2, lines 14 to 16, will costs for redispatch to accommodate transmission services provided to Nalcor under the NSTUA, as tracked and managed by NS Power using its existing fuel and generation dispatch reconciliation processes, be identifiable for subsequent review by the NSUARB, and if so, how?

Response IR-312:

The costs will be tracked and could be reviewed by the UARB as part of a FAM Audit or another process determined by the UARB.

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Request IR-313:

In your response to CBA/SBA IR-120 (a) you note that "…At this time it is not known whether or not Nalcor contemplates requesting additional transmission capacity over and above 330 MW before the end of the Initial Term..."

(a) Please explain how it is possible that Nalcor can request additional transmission capacity over 330 MW.

(b) Isn't 330 MW the maximum that Nalcor is entitled to for its Nalcor Surplus Energy? If not please provide an explanation.

Response IR-313:

Nalcor is entitled to transmission capacity through Nova Scotia calculated as being the difference between the amount of the NS Block and the design capacity of the Maritime Link.

During the first five years of the term, while the Supplemental Energy is being delivered, the maximum available capacity available to Nalcor would be approximately 330 MW (500 MW Maritime Link capacity less 170 MW base NS Block) during Peak hours for the entire year and approximately 300 MW (500 MW Maritime Link capacity less 200 MW Supplemental Energy component of NS Block) during Off-Peak for November, December, January, February and March, and otherwise the full 500 MW for off-Peak for the remainder of the year.

After the delivery of the Supplemental Energy, Nalcor would be entitled to up to approximately 500 MW in all off-Peak hours.

Under Section 2.1(b) of the NSTUA, Nalcor has given its hourly estimate of maximum capacity it requires for all hours during the Term, which ranges from 150 MW to 330 MW. If it intends to request additional capacity above the amounts set out in Section 2.1 (b) it must give NSPML

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sufficient notice to plan, build, commission and pay for any upgrades necessary to accommodate this request.

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Request IR-314:

In your response to CBA/SBA IR-124 you note that "…It is NSPML's obligation to provide the path through Nova Scotia. That path is created, at times, by redispatching the NS generation to avoid more costly transmission upgrades, and therefore the transmission provider's cost…" You also make reference to Section 3.3 of the Agency and Service Agreement. Section 3.3 (a) of the Agency and Service Agreement states that, "The Parties anticipate that the costs incurred by NS Power in providing the Transmission Facilitation Service in accordance with Sections 3.1 and 3.2 (the "NS Power Incurred Costs"), <u>including tariff charges for ancillary services, Redispatch costs</u>, system maintenance costs, system capital costs and the Transmission Loss Differential, <u>shall be offset by the Nalcor Charges, which shall be retained by NS Power</u>." (Underlining added for emphasis).

(a) Please explain why under Section 2.3(b) (xi) of the NSTUA, Nalcor shall not be obliged to reimburse Emera for Ancillary Service charges attributable to Redispatch.

(b) If Nalcor charges do not offset the Ancillary Service charges attributable to Redispatch, can there be any justification to pass these costs on to Nova Scotia customers?

Response IR-314:

The structure of the commercial agreements creates the responsibility to allow a path through Nova Scotia. This is part of the total transaction value proposition. As such, when the path is created by redispatching generation, which may involve some ancillary service, those costs would affect NS Power's account in order to support the flow of the Nalcor Energy. For the provision of those services and the transmission path, Nalcor will pay a transmission tariff to NS Power.

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It is expected through the term of the Agreement that the revenues from the tariff will offset the cost of redispatch, capital upgrades and system maintenance.

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Request IR-315:

With reference to response to CA/SBA IR-148:

(a) Does NSPML believe that the cost of Lingan units' conversion to synchronous condenser operation should be considered part of the LCC technology option costs for the purpose of comparison with the VSG option?

(b) Will Lingan units be allowed to retire under the VSG technology option?

(c) Should the costs associated with the retirement of Lingan units and rehabilitation of the site be taken in consideration while comparing the VSC option costs with the LCC option? If not, please explain why.

(d) Please identify the costs associated with conversion of Lingan units into synchronous condensers.

(e) Please identify the costs associated with the retirement of Lingan units and rehabilitation of the site.

Response IR-315:

(a) Yes.

(b) Running a Lingan unit as a synchronous condenser would allow the retirement of many components of the units and modification of the generator so that it will no longer be coupled to a steam turbine.

(c) While the VSC technology would not require the continued utilization Lingan facilities in a manner that the LCC would, the Lingan site will not likely be retired until the last of

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four units is no longer required, so only the incremental cost of adding synchronous capacity would need to be assessed in the comparison, which would include some decommissioning costs to facilitate the equipment.

(d) NSPML has not studied the complete cost of converting Lingan units.

(e) NS Power has not performed a detailed study of decommissioning the Lingan units since the decommissioning would likely occur, under all alternatives studied for the Application, when the last unit is retired and if the site is no longer required.

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Request IR-316:

With reference to the response to CA/SBA IR-161, stating that "…The option of building the system only to provide reliable delivery of the 170 MW for the province of Nova Scotia was not studied, as this option was not consistent with the agreements reached with Nalcor…" and the response to NSUARB IR-3, stating that "…The NS Block could not be delivered reliably without the construction and operation of this [Granite Canal to Bottom Brook, 230 kV] AC line…"

(a) Did NSPML enter into negotiations and reach the agreements with Nalcor before conducting studies for different options?

(b) If the answer to part (a) is 'no', explain what scenarios were studied, based on what considerations they were selected, and why no studies have been performed for the delivery of the 170 MW to NS.

(c) Have any studies been done under the assumption that up to 300 MW will flow via the Maritime Link Project, which is the limit to be retained in NS before 2025? If so, please provide the study.

(d) Would the third 230 kV line from Granite Canal into Bottom Brook Substation be required under the part (c) scenario?

(e) Is it the NS Block in particular, or the entire 500 MW power flow, that cannot be reliably delivered to Nova Scotia, and/or wheeled to New Brunswick and New England, without the construction and operation of the Granite Canal to Bottom Brook 230 kV AC line?

Response IR-316:

(a) No. Please refer to UARB IR-145.

(b) Based on agreements in principle between Nalcor and NSPML, options were studied to facilitate delivery of up to 500 MW from Newfoundland to Nova Scotia, with 250 MW identified as a "firm" delivery requirement. The 250 MW firm delivery was needed to accommodate the base load requirements in Nova Scotia (subsequently identified as the NS Block) along with the surplus energy for peaking requirements. The full 500 MW "non-firm" delivery satisfied the mutual interests of Nalcor and NSPML for export opportunities (Nalcor) and for availability of market-priced renewable power (NSPML). As the size of the NS Block was finalized in agreements between Nalcor and NSPML, new studies were not commissioned to evaluate the feasibility of delivering only this block of power, because a system built to these reduced specifications would have been unable to dependably accommodate the surplus energy deliveries to NSPML.

(c) No studies have been undertaken which explicitly focused on a 300 MW delivery with NS Block of firm capacity. Under these reduced capacity specifications, the system could not dependably supply the NS Block and the surplus energy.

(d) Although no studies have been undertaken with an objective of 300 MW of total capacity (implying NSBlock of "firm" capacity), the capacity of the system without the Granite Canal to Bottom Brook circuit has been tested. The "firm" capacity of the system in this scenario is dependent on system conditions and generation dispatch in Newfoundland, but in most cases, it falls below 170 MW. In many cases, it would fall below 150 MW. It is important to note that the commercial agreements are based upon the 20 For 20 Principle and a 300 MW Maritime Link would not meet the requirements of both parties.

(e) It is the target "firm" delivery of 250 MW that cannot be dependably supplied without the Granite Canal to Bottom Brook line. The NS Block cannot be dependably supplied without the Granite Canal to Bottom Brook line.

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Request IR-317:

With reference to the response to CA/SBA IR-162:

(a) Would the NS ratepayers benefit in any way from wheeling energy from the Maritime Link Project to New Brunswick and New England? If so, please specify the benefits.

(b) Would NS ratepayers support any costs attributable to ensuring capability to wheel energy to New Brunswick and New England (including all the costs of the transmission reinforcement projects directly attributable to the wheeling capability)? If so, please specify the costs.

(c) Please confirm that the "supplementary block (in the first five years) or economy purchases" mentioned in the response that can be retained in NS is limited to 130 MW until 2025 (i.e., 300 MW-170 MW=130 MW) without additional transmission reinforcement in NS.

(d) Please confirm that the "supplementary block" can be retained in NS only if additional operating reserves become available in NS, and that without additional reserves in NS, the limit for retained capacity is 170 MW (the NS Block only).

(e) Please confirm that the costs associated with the procurement, operation and maintenance of the additional operating reserves in NS have not been included in the analysis of the cost and benefits of the Maritime Link Project proposal.

Response IR-317:

(a) Please refer to NSUARB IR-10 and SBA/CA IR-162. A list of benefits of the Maritime Link to customers is reproduced below from page 17 of the Application:

"Additionally, of the available alternatives, only the Maritime Link Project:

- increases rate predictability for electricity customers through long-term (35 year) 3 fixed cost contract,
- provides greater long-term electricity security,
- offers a strategic transformational opportunity for enhanced access to competitive markets,
- offers access to large, new, renewable electricity supplies for a minimum of 50 years,
- offers specific quantities of renewable energy at a stable cost for 35 years
- provides enhanced reliability,
- strengthens Nova Scotia's connection to the North American grid to prepare for and to take advantage of many future energy scenarios,
- supports the development of additional intermittent renewable energy resources in 13 Nova Scotia, such as wind and tidal."

(b) Please refer to CA IR-64 regarding NS upgrades. Nova Scotia customers will not be responsible for any upgrades in New Brunswick or New England.

(c) Please refer to CA/SBA IR-363.

(d) The limit for energy staying in Nova Scotia is 300 MW. The supplemental block is delivered off-peak and, as such, is not in conflict with the 170 MW.

(e) Please refer to CA/SBA IR-332 (a).

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Request IR-318:

With reference to the response to CA/SBA IR-170, stating that "…without the [second 345kV/230kV transformer at Woodbine] the Maritime Link would be significantly restricted [when the existing transformer fails]…"

(a) Would the Maritime Link be restricted to 250 MW or more without a second transformer when the existing transformer at Woodbine fails? If not, please specify the restricted capacity.

(b) Would NS be able to continue receiving its NS Block if the second transformer at Woodbine does not exist and the existing transformer at Woodbine fails?

(c) Please specify the reliability requirements referred to in the response to CA/SBA IR-170 requiring installation of a second transformer at Woodbine substation.

Response IR-318:

(a) The Maritime Link is not restricted as long as one of the two 345/230-kV transformers is in service at Woodbine. In a scenario with only one 345/230-kV transformer installed at Woodbine, the loss of the transformer would leave no connection to the 230-kV system at Woodbine, and the capacity of the Nova Scotia system to accept the Maritime Link delivery would be significantly reduced due to the need to back feed Maritime Link deliveries through other 345/230-kV transformation at remote locations on the NS Power system. These transformer sites are already designed and operated to capacity limits. The extent of the capacity reduction would depend on system configuration and generation dispatch. In most circumstances, the Nova Scotia system could absorb less than 250 MW after the loss of the transformer. In other circumstances, the system would not be able to accept even the NS Block amount, and in some cases, the HVdc system would be run back to 0 MW. Please reference response to McMaster IR-17.

(b) As indicated in Part (a), the ability to accept power from the Maritime Link, with no 345/230-kV transformation at Woodbine, will be dependent on system configuration and generation dispatch. Nova Scotia would not be able to receive its NS Block for most conditions.

(c) The reliability requirements referred to in the response to CA/SBA IR-170 are based on the inability of the Maritime Link to meet energy delivery commitments under the contingency loss of the existing transformer at Woodbine. As mentioned in the response, transformer repairs can take up to twelve months. During this time, it should be possible to manage the system configuration and generation dispatch in Nova Scotia to ensure operation of the Maritime Link at reduced capacity (see Part (a) above), but various contingency events will create risks of further curtailment of deliveries to Nova Scotia (Please reference McMaster IR-17). The installation of a second transformer at Woodbine is a prudent measure to avoid these reliability risks.

CONFIDENTIAL (Attachment only)

Request IR-319:

With reference to the response to CA/SBA IR-192 (a), stating that "… Draft Technical Specifications for Converters are in progress and are scheduled for completion by the end of March 2013…" please provide a copy of the completed Technical Specifications as soon as they become available.

Response IR-319:

Please refer to Confidential Attachment 1 for a copy of the Technical Specification.

CA/SBA IR-319 Attachment 1 has been removed due to confidentiality.

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Request IR-320:

With reference to the responses to CA/SBA IR-192 (b), CA/SBA IR-199, and Hingorani IR-10, Attachment 2 (CONFIDENTIAL)

(a) Please confirm that the estimated cost of spare converter transformers is identical to the cost specified in Hingorani IR-10, Attachment 2 (CONFIDENTIAL), Table 2-1, for the converter transformers.

(b) Please confirm that the cost of the two spare converter transformers, one for each converter station, has not been included in the estimated cost of the Maritime Link Project.

Response IR-320:

(a) Confirmed.

(b) Attachment 1 (Hingorani IR-10) required the manufacturers to include the cost of one spare converter transformer at each converter station (Section 5.2). The cost of these transformers is included in the estimated cost.

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Request IR-321:

With reference to response CA/SBA IR-215 and Appendix 4.01 of the Application, please provide any and all workpapers and electronic spreadsheets relevant to the estimates of annual O&M expenses for both the LCP Phase 1 facilities and the Maritime Link, as used in Appendix 4.01.

Response IR-321:

The annual O&M cost projections contained in the Financial Model are at a screening level and will continue to be refined between now and when the Project begins operation (expected in 2017). Attachment 1 provides additional information relating to what was contained in the Financial Model and agrees to the totals in that model as contained in the tab titled "V. O&M Forecast".

Annual Projected O&M Costs - Screening Level

Summary	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**
Muskrat Falls																				
Overhead, Personnel, Service Contracts, Inspection Services, Lender's Engineer	$ 4,220,705	$ 8,652,445	$ 8,868,756	$ 9,090,475	$ 9,317,736	$ 9,550,680	$ 9,789,447	$ 10,116,874	$ 10,369,796	$ 10,629,041	$ 10,894,767	$ 11,167,136	$ 11,446,314	$ 11,732,472	$ 12,025,784	$ 12,326,429	$ 12,634,589	$ 12,950,454	$ 13,274,215	$ 13,606,071
Provision for Sustaining Capital, Equipment and Vehicles	$ 1,513,384	$ 3,102,437	$ 3,179,998	$ 3,259,498	$ 3,340,985	$ 3,424,510	$ 3,510,123	$ 3,763,258	$ 3,857,339	$ 3,953,773	$ 3,997,444	$ 4,097,380	$ 4,199,815	$ 4,304,810	$ 4,412,430	$ 4,522,741	$ 4,635,810	$ 4,751,705	$ 4,870,497	$ 4,992,260
Insurance	$ 297,397	$ 609,664	$ 624,905	$ 640,528	$ 656,541	$ 672,955	$ 689,778	$ 707,023	$ 724,699	$ 742,816	$ 761,386	$ 780,421	$ 799,932	$ 819,930	$ 840,428	$ 861,439	$ 882,975	$ 905,049	$ 927,675	$ 950,867
Contingency	$ 531,367	$ 1,089,302	$ 1,116,534	$ 1,144,448	$ 1,173,059	$ 1,202,385	$ 1,232,445	$ 1,288,063	$ 1,320,265	$ 1,353,272	$ 1,381,586	$ 1,416,126	$ 1,451,529	$ 1,487,817	$ 1,525,013	$ 1,563,138	$ 1,602,216	$ 1,642,272	$ 1,683,329	$ 1,725,412
Water management - Note 1	$ 763,073	$ 1,556,670	$ 1,587,803	$ 1,619,559	$ 1,651,950	$ 1,684,989	$ 1,718,689	$ 1,753,063	$ 1,788,124	$ 1,823,887	$ 1,860,364	$ 1,897,572	$ 1,935,523	$ 1,974,233	$ 2,013,718	$ 2,053,993	$ 2,095,072	$ 2,136,974	$ 2,179,713	$ 2,223,308
Water lease - Note 1	$ 14,147,787	$ 14,430,743	$ 14,719,358	$ 15,013,745	$ 15,314,020	$ 15,620,300	$ 15,932,706	$ 16,251,360	$ 16,576,387	$ 16,907,915	$ 17,246,073	$ 17,590,995	$ 17,942,815	$ 18,301,671	$ 18,667,705	$ 19,041,059	$ 19,421,880	$ 19,810,317	$ 20,206,524	$ 20,610,654
Total	**$ 21,473,713**	**$ 29,441,260**	**$ 30,097,354**	**$ 30,768,252**	**$ 31,454,292**	**$ 32,155,819**	**$ 32,873,188**	**$ 33,879,641**	**$ 34,636,610**	**$ 35,410,703**	**$ 36,141,621**	**$ 36,949,629**	**$ 37,775,927**	**$ 38,620,934**	**$ 39,485,078**	**$ 40,368,797**	**$ 41,272,542**	**$ 42,196,771**	**$ 43,141,954**	**$ 44,108,571**
Labrador Island Link																				
Inspection Services, Lender's Engineer	$ 6,408,390	$ 6,568,600	$ 6,732,815	$ 6,901,135	$ 7,068,910	$ 7,250,505	$ 7,431,767	$ 7,617,562	$ 7,808,001	$ 9,083,304	$ 9,310,386	$ 9,543,146	$ 9,781,725	$ 10,026,268	$ 10,276,924	$ 10,533,848	$ 10,797,194	$ 11,067,124	$ 11,343,802	$ 11,627,397
Provision for Sustaining Capital, Equipment and Vehicles - Note 2	$ 3,125,558	$ 3,203,697	$ 8,782,956	$ 3,365,884	$ 9,472,426	$ 3,536,282	$ 3,624,689	$ 3,715,306	$ 3,808,189	$ 10,430,343	$ 3,990,902	$ 4,090,674	$ 4,192,941	$ 4,297,765	$ 11,800,976	$ 4,515,339	$ 4,628,222	$ 4,743,928	$ 4,862,526	$ 13,351,721
Insurance	$ 2,968,313	$ 3,042,520	$ 3,118,583	$ 3,196,548	$ 3,274,260	$ 3,358,373	$ 3,442,333	$ 3,528,391	$ 3,616,601	$ 3,697,679	$ 3,790,121	$ 3,884,874	$ 3,981,996	$ 4,081,546	$ 4,183,584	$ 4,288,174	$ 4,395,378	$ 4,505,263	$ 4,617,894	$ 4,733,342
Contingency	$ 1,250,226	$ 1,281,482	$ 1,313,519	$ 1,346,357	$ 1,403,803	$ 1,414,516	$ 1,449,879	$ 1,486,126	$ 1,523,279	$ 1,667,455	$ 1,709,141	$ 1,751,869	$ 1,795,666	$ 1,840,558	$ 1,886,572	$ 1,933,736	$ 1,982,079	$ 2,031,631	$ 2,082,422	$ 2,134,483
Total	**$ 13,752,487**	**$ 14,096,299**		**$ 14,809,924**	**$ 21,219,399**	**$ 15,559,676**	**$ 15,948,668**	**$ 16,347,385**	**$ 16,756,069**	**$ 24,878,780**	**$ 18,800,550**	**$ 19,270,563**	**$ 19,752,328**	**$ 20,246,136**	**$ 28,148,057**	**$ 21,271,096**	**$ 21,802,874**	**$ 22,347,946**	**$ 22,906,644**	**$ 31,846,942**
Maritime Link																				
Personnel, Service Contracts,	$ 3,416,879	$ 4,669,734	$ 4,786,477	$ 4,906,139	$ 5,028,793	$ 5,150,015	$ 5,283,375	$ 5,415,460	$ 5,550,846	$ 6,816,760	$ 7,232,872	$ 7,413,694	$ 7,599,036	$ 7,789,012	$ 7,983,737	$ 8,183,331	$ 8,387,914	$ 8,597,612	$ 8,812,552	$ 9,032,866
Provision for Sustaining Capital, Equipment and Vehicles - Note 2	$ 1,482,617	$ 2,026,243	$ 9,010,630	$ 2,128,821	$ 9,466,793	$ 2,492,390	$ 2,292,508	$ 2,349,820	$ 2,408,566	$ 10,710,808	$ 2,528,441	$ 2,591,652	$ 2,656,443	$ 2,722,854	$ 12,116,024	$ 2,860,699	$ 2,932,216	$ 3,005,522	$ 3,080,660	$ 13,708,169
Insurance	$ 3,328,567	$ 4,549,041	$ 4,662,768	$ 4,779,337	$ 4,898,820	$ 5,013,816	$ 5,146,823	$ 5,275,493	$ 5,407,381	$ 5,542,565	$ 5,673,856	$ 5,815,702	$ 5,961,095	$ 6,110,122	$ 6,262,875	$ 6,419,447	$ 6,579,933	$ 6,744,432	$ 6,913,042	$ 7,085,869
Contingency	$ 1,045,999	$ 1,429,532	$ 1,465,270	$ 1,501,902	$ 1,539,449	$ 1,607,195	$ 1,617,384	$ 1,657,819	$ 1,699,264	$ 1,910,817	$ 1,986,951	$ 2,036,625	$ 2,087,540	$ 2,139,729	$ 2,193,222	$ 2,248,052	$ 2,304,254	$ 2,361,860	$ 2,420,907	$ 2,481,429
Total	**$ 9,274,061**	**$ 12,674,550**	**$ 19,925,145**	**$ 13,316,199**	**$ 20,933,856**	**$ 14,263,415**	**$ 14,340,090**	**$ 14,698,592**	**$ 15,066,057**	**$ 24,980,950**	**$ 17,422,119**	**$ 17,857,672**	**$ 18,304,114**	**$ 18,761,717**	**$ 28,555,858**	**$ 19,711,529**	**$ 20,204,317**	**$ 20,709,425**	**$ 21,227,161**	**$ 32,308,332**
Maritime Link Expenses (in millions)	$9.3	$12.7	$19.9	$13.3	$20.9	$14.3	$14.3	$14.7	$15.1	$25.0	$17.4	$17.9	$18.3	$18.8	$28.6	$19.7	$20.2	$20.7	$21.2	$32.3
20% of total estimated O & M of LCP Phase	$8.9	$11.2	$10.0	$11.8	$14.7	$12.4	$12.6	$13.0	$13.3	$17.1	$14.5	$14.8	$15.2	$15.5	$19.2	$16.3	$16.7	$17.1	$17.5	$21.7

The amounts on rows 30 and 31 correspond to the Financial Appendix 4.01 rows 17 & 18.

Note 1

The lease entry represents the cost of water power rights for Muskrat Falls calculated in accordance with the lease between Nalcor and the NL. The lease is exhibit 8.1 in the water management application, see NL PUB website.

The water management fees represent Nalcor's estimate for the cost of staffing the water management committee and the cost of any systems and other tools necessary to undertake water management in coordination with Churchill Falls.

Nalcor has assumed that all the benefits of water management will accrue to Muskrat Falls and therefore all the costs have been assigned to Muskrat Falls.

Note 2

Cable surveys are included in "Provision for Sustaining Capital, Equipment and Vehicles" in the Labrador Island Link and Maritime Link categories

Annual Projected O&M Costs - Screening

Summary	2037	2038	2039	2040	2041	2042	2043	2044	2045	2046	2047	2048	2049	2050	2051	2052
Muskrat Falls																
Overhead, Personnel, Service Contracts, Inspection Services, Lender's Engineer	$ 13,946,223	$ 14,294,878	$ 14,652,250	$ 15,018,556	$ 15,394,020	$ 15,778,871	$ 16,173,342	$ 16,577,676	$ 16,992,118	$ 17,416,921	$ 17,852,344	$ 18,298,653	$ 18,756,119	$ 19,225,022	$ 19,705,647	$ 20,198,289
Provision for Sustaining Capital, Equipment and Vehicles	$ 5,117,066	$ 5,244,993	$ 5,376,118	$ 5,510,521	$ 5,648,284	$ 5,789,491	$ 5,934,228	$ 6,082,584	$ 6,234,649	$ 6,390,515	$ 6,550,278	$ 6,714,035	$ 6,881,885	$ 7,053,933	$ 7,230,281	$ 7,411,038
Insurance	$ 974,639	$ 999,005	$ 1,023,980	$ 1,049,580	$ 1,075,819	$ 1,102,715	$ 1,130,282	$ 1,158,539	$ 1,187,503	$ 1,217,191	$ 1,247,620	$ 1,278,811	$ 1,310,781	$ 1,343,551	$ 1,377,139	$ 1,411,568
Contingency	$ 1,768,547	$ 1,812,761	$ 1,858,080	$ 1,904,532	$ 1,952,145	$ 2,000,949	$ 2,050,972	$ 2,102,247	$ 2,154,803	$ 2,208,673	$ 2,263,890	$ 2,320,487	$ 2,378,499	$ 2,437,962	$ 2,498,911	$ 2,561,383
Water management - Note 1	$ 2,267,774	$ 2,313,129	$ 2,359,392	$ 2,406,580	$ 2,454,711	$ 2,503,805	$ 2,553,882	$ 2,604,959	$ 2,657,058	$ 2,710,199	$ 2,764,403	$ 2,819,692	$ 2,876,085	$ 2,933,607	$ 2,992,279	$ 3,052,125
Water lease - Note 1	$ 21,022,867	$ 21,443,325	$ 21,872,191	$ 22,309,635	$ 22,755,828	$ 23,210,944	$ 23,675,163	$ 24,148,666	$ 24,631,640	$ 25,124,272	$ 25,626,758	$ 26,139,293	$ 26,662,079	$ 27,195,321	$ 27,739,227	$ 28,294,011
Total	**$ 45,097,116**	**$ 46,108,091**	**$ 47,142,011**	**$ 48,199,403**	**$ 49,280,807**	**$ 50,386,774**	**$ 51,517,870**	**$ 52,674,672**	**$ 53,857,770**	**$ 55,067,771**	**$ 56,305,293**	**$ 57,570,969**	**$ 58,865,449**	**$ 60,189,394**	**$ 61,543,484**	**$ 62,928,414**
Labrador Island Link																
Inspection Services, Lender's Engineer	$ 11,918,082	$ 12,216,034	$ 12,521,435	$ 12,834,470	$ 13,155,332	$ 13,484,215	$ 13,813,188	$ 14,166,854	$ 14,521,025	$ 14,884,051	$ 15,256,152	$ 15,637,556	$ 16,028,495	$ 16,429,207	$ 16,839,937	$ 17,260,936
Provision for Sustaining Capital, Equipment and Vehicles - Note 2	$ 5,108,691	$ 5,236,409	$ 5,367,319	$ 5,501,502	$ 15,106,247	$ 5,780,015	$ 6,345,482	$ 6,072,629	$ 6,224,444	$ 17,091,332	$ 6,539,557	$ 6,703,046	$ 6,870,622	$ 7,042,388	$ 19,337,273	$ 7,398,908
Insurance	$ 4,851,675	$ 4,972,967	$ 5,097,291	$ 5,224,723	$ 5,355,342	$ 5,489,225	$ 5,623,145	$ 5,767,117	$ 5,911,295	$ 6,059,077	$ 6,210,554	$ 6,365,818	$ 6,524,964	$ 6,688,088	$ 6,855,290	$ 7,026,672
Contingency	$ 2,187,845	$ 2,242,541	$ 2,298,604	$ 2,356,070	$ 2,414,971	$ 2,475,346	$ 2,578,182	$ 2,600,660	$ 2,665,676	$ 2,732,318	$ 2,800,626	$ 2,870,642	$ 2,942,408	$ 3,015,968	$ 3,091,367	$ 3,168,652
Total	**$ 24,066,293**	**$ 24,667,950**	**$ 25,284,649**	**$ 25,916,765**	**$ 36,031,892**	**$ 27,228,802**	**$ 28,359,997**	**$ 28,607,260**	**$ 29,322,441**	**$ 40,766,779**	**$ 30,806,890**	**$ 31,577,062**	**$ 32,366,489**	**$ 33,175,651**	**$ 46,123,868**	**$ 34,855,168**
Maritime Link																
Personnel, Service Contracts,	$ 9,258,688	$ 9,490,155	$ 9,727,409	$ 9,970,594	$ 10,219,859	$ 10,475,355	$ 10,737,239	$ 11,005,670	$ 11,280,812	$ 11,562,832	$ 11,851,903	$ 12,148,200	$ 12,451,905	$ 12,763,203	$ 13,082,283	$ 13,409,340
Provision for Sustaining Capital, Equipment and Vehicles - Note 2	$ 3,236,618	$ 3,317,533	$ 3,400,472	$ 3,485,484	$ 15,509,535	$ 3,661,936	$ 3,753,485	$ 3,847,322	$ 3,943,505	$ 17,547,615	$ 4,143,145	$ 4,246,723	$ 4,352,891	$ 4,461,714	$ 19,853,515	$ 4,687,588
Insurance	$ 7,263,015	$ 7,444,591	$ 7,630,705	$ 7,821,473	$ 8,017,010	$ 8,217,435	$ 8,422,871	$ 8,633,443	$ 8,849,279	$ 9,070,511	$ 9,297,274	$ 9,529,705	$ 9,767,948	$ 10,012,147	$ 10,262,450	$ 10,519,012
Contingency	$ 2,543,465	$ 2,607,052	$ 2,672,228	$ 2,739,034	$ 2,807,509	$ 2,877,697	$ 2,949,640	$ 3,023,381	$ 3,098,965	$ 3,176,439	$ 3,255,850	$ 3,337,246	$ 3,420,678	$ 3,506,195	$ 3,593,849	$ 3,683,696
Total	**$ 22,301,786**	**$ 22,859,330**	**$ 23,430,814**	**$ 24,016,584**	**$ 36,553,913**	**$ 25,232,424**	**$ 25,863,234**	**$ 26,509,815**	**$ 27,172,560**	**$ 41,357,397**	**$ 28,548,171**	**$ 29,261,876**	**$ 29,993,422**	**$ 30,743,258**	**$ 46,792,098**	**$ 32,299,635**
Maritime Link Expenses (in millions)	$22.3	$22.9	$23.4	$24.0	$36.6	$25.2	$25.9	$26.5	$27.2	$41.4	$28.5	$29.3	$30.0	$30.7	$46.8	$32.3
20% of total estimated O & M of LCP Phase	$18.3	$18.7	$19.2	$19.6	$24.4	$20.6	$21.1	$21.6	$22.1	$27.4	$23.1	$23.7	$24.2	$24.8	$30.9	$26.0

The amounts on rows 30 and 31 correspond

<u>Note 1</u>

The lease entry represents the cost of water

The water management fees represent Nalcc

Nalcor has assumed that all the benefits of w

Note 2

Cable surveys are included in "Provision for S

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Request IR-322:

With reference to response CA/SBA IR-230, please provide the "database model" in electronic format.

Response IR-322:

The "database model" refers to the Strategist Input files provided to Ventyx. Please refer to CA/SBA IR-331 (c).

NON-CONFIDENTIAL

Request IR-323:

With reference to Response CA/SBA IR-239:

(a) Please clarify whether the "two unit retirements by 2020" constraint was modeled as a minimum constraint or an equality constraint.

(b) Please clarify whether "by 2020" means "before 2020" or "by the end of 2020."

(c) Please explain why this constraint was modeled.

(d) Please explain whether there were also other set constraints, for spans of years and/or collections of coal units, that guided the formulation of input assumptions regarding retirement schedules in each of the alternative runs conducted with Strategist.

Response IR-323:

(a) This was an input constraint to put the Maritime Link, Other Import and Indigenous Wind alternatives on an equal basis.

(b) The term “by 2020” means by the beginning of 2020.

(c) With increasing renewables resources coming into service including COMFIT, REA wind projects in 2015 and the Maritime Link in 2017, these units will experience reduced capacity factors. Retiring these units will have no impact on reliability as the minimum planning reserve margin of 20 percent above firm load will be maintained. Please refer to SBA IR-243 Attachment 2. Coal unit retirements also align with federal and provincial regulations aimed at reducing fossil fuel generation and carbon dioxide emissions.

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(d) Please refer to SBA IR-295.

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Request IR-324:

With reference to Response CA/SBA IR-242(b) and our understanding that the PROVIEW module optimizes resource addition decisions while the Generation and Fuel (GAF) module of Strategist optimizes economic dispatch decisions:

(a) Does PROVIEW include minimum load constraints for units, or only the GAF module?

(b) Do final resource build and dispatch schedules minimize the NPV of capital and operating costs, given the data and other modeling assumptions, or only an approximate optimum since two modules are used in the analysis? Provide sufficient model documentation to support the answer.

Response IR-324:

(a) Strategist PROVIEW module is responsible for resource optimization and as such it does not contain resource dispatch parameters. Unit minimum load is defined in the GAF module. Within Strategist software, PROVIEW and GAF modules work together to consider all resource dispatch restrictions in order to come to an optimal solution.

(b) The optimal resource plan has the lowest NPV cost (capital and operating). Strategist modules are designed to communicate and work together as an integrated optimization engine. Ventyx Strategist software documentation is proprietary information and it can be requested directly from Ventyx.

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Request IR-325:

With reference to Response CA/SBA IR-246(a-b), please confirm that for new units, start fuel was omitted, or otherwise explain.

Response IR-325:

Appendix 6.03, page 19 gives the four natural gas resource options. The CT 50 MW and CC 150 MW options are units with which NS Power has experience and their heat rates are based on historical average heat rates which capture start-up costs. The CT 100 MW and CC 250 MW options are units with which NS Power does not have experience and their heat rates are based on manufacturer's data which does not capture start-up costs.

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Request IR-326:

With reference to response CA/SBA IR-248, which refers to the responses to Liberty IR-4 and Liberty IR-5, please provide any documentation that summarizes or explains the assumptions behind the multi-fuel world-wide supply and demand model upon which the PIRA natural gas, HFO and LFO price forecasts shown in Liberty IR-5 Confidential Attachment 1 and Confidential Attachment 2 are based.

Response IR-326:

Please refer to the Nova Scotia Power Confidential FAM data room, binder titled "PIRA Scenario Planning Service: Annual Guidebook 2012".

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Request IR-327:

With reference to your response to CA/SBA IR-257 please explain what the rationale was for considering the Other Import alternative if it was clear that it would not be a valid alternative by virtue of it not satisfying the same criteria as the Maritime Link.

Response IR-327:

The Other Import Alternative was considered because the non-emitting import energy may qualify as renewable. The Other Import Alternative would be a valid alternative if the non-emitting import energy qualifies as renewable.

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Request IR-328:

With reference to your response to CA/SBA IR-260 please provide a listing of the tariff related costs applicable to the transmission upgrades that are assumed in the 25% adder.

Response IR-328:

The costs assumed to be covered in the 25 percent adder include operations, maintenance, administration, taxes and payments in lieu of taxes associated with the transmission upgrade as part of an integrated transmission system with a total transmission tariff escalating conservatively at 1 percent per year.

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Request IR-329:

With reference to your response to CA/SBA IR-274 please provide the NS to NB and NB to NS increases in transfer capability as a result of the Maritime Link.

Response IR-329:

Firm 'export' capacity from NS to NB increases to 330 MW. Firm 'import' capacity to NS does not change as it remains dependent on dynamic system conditions in the Moncton area. Non-firm import capacity increases based on the opportunity to offset scheduled exports on the NS-NB tie but the magnitude remains dependent on system conditions such as import flows on the Maritime Link, transmission system constraints in NS, and generating dispatch in NB. With all factors noted in a stable state, for every MW being exported there will be the capability to import a MW, i.e: for 100 MW export there would be 100 MW import capability in theory.

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Request IR-330:

In your response to CA/SBA IR-275 and the reference you make to NSUARB IR-68, you note that if NS retains more than 171 MW of power from the Maritime Link the requirements for Operating Reserve within NS will increase.

(a) Please confirm that during transfers of 500 MW to NS, the Maritime Link becomes the single largest contingency in the Nova Scotia System.

(b) Please provide an analysis of the increase in Operating Reserves, including the 10-minute Operating Reserve Requirement, when the Maritime Link is transferring 500 MW to NS.

Response IR-330:

(a) After the installation of the Maritime Link, the largest single contingency in Nova Scotia will be 475 MW (500 MW minus losses). Section 5.4.1(f) of NPCC Directory 1 Design and Operation of the Bulk Power System requires that the system must be stable following the "simultaneous permanent loss of both poles of a direct current bipolar facility without an AC fault". System studies currently underway treat the loss of 475 MW as a single contingency.

(b) Please refer to McMaster IR-2 (d) and CA/SBA IR-332.

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Request IR-331:

With reference to response CA/SBA IR-277:

(a) Please clarify whether the document provided in Exh. M-14(C) NSPML-NSPI (CA-SBA) IR-277 Att 1 CONFIDENTIAL ELECTRONIC is the output of a 03/06/13 Strategist run or the date of printing a report from a run executed before the Application was filed.

(b) Please provide the electronic output files produced by Strategist that were actually used to prepare the twelve cases shown in Synapse IR-11 Attachment 2, as well as any other cases reported in the application, as a .TXT format file, with proper pagination and in landscape mode to avoid line wrap.

(c) Please provide the corresponding set of Strategist input files in native .TXT file format or Excel file format for each run.

(d) Given that monthly level results were not produced, please explain the quality assurance checks that were performed.

Response IR-331:

(a) The report provided in CA/SBA IR-277 Attachment 1 is from a case that was completed before the Application was filed (Maritime Link Base Load case) and dated at the time of printing.

(b-c) Please refer to Confidential Attachments 1 through 26 for the Strategist output and input reports for each case given in the Application. The attachment and the associated case is given in the table below:

CONFIDENTIAL (Attachment Only)

Output Reports	Input Reports	Case
Attachment 1	Attachment 14	Maritime Link Base Load
Attachment 2	Attachment 15	Other Import Base Load
Attachment 3	Attachment 16	Indigenous Wind Base Load
Attachment 4	Attachment 17	Maritime Link Low Load
Attachment 5	Attachment 18	Other Import Low Load
Attachment 6	Attachment 19	Indigenous Wind Low Load
Attachment 7	Attachment 20	Maritime Link Base Load, High Gas & Power
Attachment 8	Attachment 21	Other Import Base Load, High Gas & Power
Attachment 9	Attachment 22	Indigenous Wind Base Load, High Gas & Power
Attachment 10	Attachment 23	Maritime Link Base Load, Low Gas & Power
Attachment 11	Attachment 24	Other Import Base Load, Low Gas & Power
Attachment 12	Attachment 25	Indigenous Wind Base Load, Low Gas & Power
Attachment 13	Attachment 26	Maritime Link Base Load, Higher Imports (500MW NFLD tieline in 2025)

(d) Strategist has a graphical user interface which allows the user to view and modify the data. Input and output data can be viewed in the interface to ensure that it has been entered correctly and to verify and validate the results.

CA/SBA IR-331

Attachments 1 to 26

have been removed due to confidentiality

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Request IR-332:

With reference to response NSUARB IR-68, stating that "…NS is currently required to carry 171 MW of 10-minute Operating Reserve. If NS retains more than 171 MW of power from the Maritime Link Project, the requirements for Operating Reserve within NS will increase..." and to EAC IR-22, stating that "…This limit [300 MW] reflects a transmission constraint that currently limits the amount of energy from the Maritime Link that can remain in Nova Scotia to 300 MW..."

(a) Please identify the amount of additional operating reserve required to meet the 300 MW maximum amount of power retained by NS.

(b) Explain by what means the requirement for additional operating reserves is intended to be met.

(c) Identify the costs associated with the provision of additional operating reserves to meet 300 MW of power from the Maritime Link Projects retained in NS.

(d) Please confirm that the amount of power that can be retained by NS in excess of the NS Block cannot exceed 130 MW, and only to the extent additional operating reserves are procured in NS.

(e) Please provide a list of existing resources with their nameplate capability values available to NS and capable of providing 10-minute non-spinning reserves.

(f) Please provide a list of existing resources with their nameplate capability values available to NS that normally would be designated as 10-minute spinning reserves, and indicate the typical size of the reserved capacity for each resource.

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Response IR-332:

(a) If NS Power takes 300 MW of energy on the Maritime Link, it will need to position its system to withstand the loss of that contingency. With the NS Block as firm energy, capacity backed, it does not change Nova Scotia's position as it will displace a coal-fired plant. Only the amount in excess of the NS Block is what Nova Scotia would be required to carry as additional reserve and this could be purchased or available in-province generation. The 300 MW limit remains unchanged for Nova Scotia and therefore creates no new reserve requirement.

(b – c) The additional reserve is the same reserve which exists today in Nova Scotia for the same 300 MW limit which is due to two Lingan units being lost; Wreck Cove hydro (up to 230 MW) , six combustion turbines (up to 180 MW), Tufts Cove 4-6 (up to 150 MW), spinning reserve or idle hydro units and interruptible load. The 300 MW level is already within NS Power's reserve limit and will not result in any additional costs.

(d) Confirmed. This is why NSPML limited the ML import capability to 300 MW from the ML and has indicated the additional incremental benefit of $495M would require further study.

(e) Please refer to the table below for a list of existing resources with their nameplate capacities that are capable of providing 10-minute non-spinning reserve. Additionally, NS Power participates in reserve sharing with NB Power and this will be delivered within 10 minutes.

Unit	Unit Type	Nameplate Capacity (MW)
Burnside 1	Combustion Turbine	30.0
Burnside 2	Combustion Turbine	30.0
Burnside 3	Combustion Turbine	30.0
Victoria Junction 1	Combustion Turbine	30.0
Victoria Junction 2	Combustion Turbine	30.0

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Unit	**Unit Type**	**Nameplate Capacity (MW)**
Tusket	Combustion Turbine	24.0
Wreck Cove	Hydro	230.0
Avon	Hydro	6.8
Black River	Hydro	22.5
Nictaux	Hydro	8.3
Lequille	Hydro	11.2
Paradise	Hydro	4.7
Mersey	Hydro	42.5
Sissiboo	Hydro	24.0
Bear River	Hydro	13.4

(f) Spinning reserve is optimized within the hour by system operators. Spinning reserve is generally provided by units that are serving the regulation or load following needs of the system. On line units that are dispatched but with up-regulation capability, this can include steam units on AGC, combustion turbines and Wreck Cove or other hydro units when online will account for spinning reserve.

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Request IR-333:

With reference to response Synapse IR-11, Attachment 5, please provide these same tabulations in Excel-compatible format.

Response IR-333:

Please refer to Electronic Attachment 1.

Maritime Link Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	472,514	487,564	430,930	327,121	336,969	355,925	364,973	378,815	389,038	398,912	408,722	419,724	430,481	442,141	445,828	468,286	477,171	491,604	508,413	527,666	564,516	580,312	607,756	638,207	663,395	696,755
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports *	0	0	52,251	90,078	92,690	95,791	100,670	107,154	120,638	124,036	133,142	136,165	141,018	142,870	156,748	155,652	160,576	165,393	177,011	189,022	182,346	194,718	201,125	206,799	220,212	229,781
Total Operating Cost (k$)	**592,093**	**618,246**	**623,768**	**567,959**	**580,464**	**602,893**	**616,539**	**636,912**	**639,517**	**653,166**	**671,805**	**685,881**	**701,543**	**715,436**	**732,727**	**754,145**	**768,010**	**787,646**	**815,803**	**847,127**	**877,362**	**905,919**	**939,506**	**975,696**	**1,014,363**	**1,057,688**
Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Combined Cycles Units	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	49,593	48,696	47,798	46,900	46,002	99,860	97,971	96,082	94,193	92,304	90,415
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**195,331**	**202,337**	**190,600**	**188,085**	**185,473**	**237,533**	**244,308**	**229,937**	**226,051**	**222,107**	**218,113**

Total Operating Cost NPV (k$)	$9,030,492
Total Capital Cost NPV (k$)	$1,745,566
Total Planning Period NPV (k$)	$10,776,058

* Imports over the NS-NB Tieline and surplus energy from Maritime Link

Other Import Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	472,514	487,564	423,295	298,639	308,079	326,077	332,129	343,824	351,144	360,981	371,389	378,763	389,687
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	173,975	173,923	174,201	153,334	153,948	153,908	154,200	154,496
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports *	0	0	60,390	122,639	124,468	129,998	137,174	141,867	147,726	150,241	158,709	164,167	167,366
Total Operating Cost (k$)	**592,093**	**618,246**	**645,760**	**660,372**	**676,751**	**706,689**	**724,522**	**746,867**	**741,854**	**756,879**	**777,306**	**792,307**	**808,642**
Capital Costs													
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324
Combustion Turbines & Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**

Other Import Base Load	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	400,357	408,952	408,744	417,277	424,861	442,262	463,253	484,035	502,656	524,877	544,349	573,281	606,500
Renewables IPPs	155,123	155,097	155,404	155,714	156,356	156,344	156,665	156,990	157,647	157,652	157,988	158,328	159,002
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports *	170,122	177,956	202,297	206,667	216,247	226,109	241,177	256,354	264,102	268,689	275,845	282,751	299,822
Total Operating Cost (k$)	**824,921**	**843,046**	**869,519**	**884,807**	**905,021**	**934,136**	**972,718**	**1,011,246**	**1,040,881**	**1,069,710**	**1,099,057**	**1,137,666**	**1,191,452**
Capital Costs													
Other Import (Contract Energy)	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Combustion Turbines & Combined Cycle	0	6,997	14,007	13,751	13,495	65,868	64,660	63,451	62,243	61,034	59,826	58,617	57,409
Total Capital Costs (k$)	**56,883**	**63,369**	**69,804**	**68,913**	**67,967**	**119,599**	**117,604**	**115,565**	**113,488**	**111,374**	**109,227**	**107,050**	**104,844**

Total Operating Cost NPV (k$)	$10,182,719
Total Capital Cost NPV (k$)	$730,867
Total Planning Period NPV (k$)	$10,913,585

* Imports over the upgraded NS-NB Tieline.

Indigenous Wind Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	472,514	487,564	468,799	475,766	455,986	484,207	495,206	509,050	523,439	538,292	572,792	570,193	586,775
Renewables IPPs	119,579	130,682	140,588	150,760	165,759	166,431	166,454	166,813	146,029	146,730	146,782	147,170	147,566
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789
Imports *	0	0	42,012	43,339	0	0	0	0	0	0	0	0	0
Less Exports *	0	0	3,082	2,083	7,606	9,011	6,956	6,594	5,710	2,217	235	7,896	597
Total Operating Cost (k$)	**592,093**	**618,246**	**648,316**	**667,782**	**615,666**	**643,191**	**656,292**	**670,889**	**665,411**	**684,497**	**721,058**	**711,220**	**735,532**
Capital Costs													
Incremental Wind	0	0	0	0	55,217	-4,185	63,150	97,643	114,337	121,382	123,199	122,182	119,629
Combustion Turbine & Combined Cycles	0	0	0	0	82,098	68,470	68,757	68,885	68,867	68,713	68,436	113,861	112,535
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**137,315**	**64,285**	**131,907**	**166,528**	**183,203**	**190,096**	**191,635**	**236,043**	**232,164**

Indigenous Wind Base Load	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	603,565	644,613	688,063	714,460	748,422	803,592	829,003	811,816	850,067	871,289	923,540	964,092	1,022,131
Renewables IPPs	150,398	150,523	150,986	151,458	152,268	152,430	155,296	155,856	156,753	159,515	160,157	160,814	161,810
Incremental Wind	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports *	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports *	372	212	184	206	193	172	212	575	397	375	294	261	249
Total Operating Cost (k$)	**755,619**	**796,986**	**840,967**	**867,857**	**902,692**	**958,081**	**986,584**	**969,644**	**1,009,030**	**1,033,312**	**1,086,344**	**1,127,646**	**1,186,764**
Capital Costs													
Incremental Wind	123,978	111,819	117,171	117,789	115,841	112,503	117,123	103,251	109,153	118,998	106,780	110,015	45,435
Combustion Turbine & Combined Cycles	111,113	109,602	137,308	135,110	132,842	130,511	128,121	180,432	176,947	173,417	169,845	201,250	196,970
Total Capital Costs (k$)	**235,091**	**221,421**	**254,479**	**252,898**	**248,683**	**243,014**	**245,244**	**283,683**	**286,101**	**292,415**	**276,625**	**311,265**	**242,405**

Total Operating Cost NPV (k$)	$9,720,584
Total Capital Cost NPV (k$)	$1,922,137
Total Planning Period NPV (k$)	$11,642,720

* Imports and Exports over the NS-NB Tieline.

ML Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	465,585	478,463	427,406	324,389	332,917	293,935	297,627	306,947	317,612	314,454	319,166	321,966	325,755	330,611	321,299	327,016	330,440	336,988	341,432	348,439	355,891	364,989	370,581	377,904	385,269	393,530
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	155,203	154,931	154,988	130,376	130,763	130,496	130,558	130,622	131,015	130,752	130,820	130,888	131,287	131,030	131,103	131,177	131,581	131,330	131,409	131,489	131,899
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports *	0	0	46,000	82,710	84,682	65,456	68,250	71,755	75,988	82,553	86,072	86,386	86,974	85,827	96,529	98,868	98,346	96,146	101,566	104,565	109,391	110,001	114,556	116,781	119,097	119,969
Total Operating Cost (k$)	**585,164**	**609,145**	**613,993**	**557,858**	**568,403**	**514,593**	**520,808**	**533,691**	**523,976**	**527,771**	**535,734**	**538,910**	**543,351**	**547,453**	**548,581**	**556,704**	**559,674**	**564,420**	**574,028**	**584,106**	**596,459**	**606,571**	**616,467**	**626,094**	**635,855**	**645,399**
Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**145,738**	**153,641**	**142,802**	**141,185**	**139,471**	**137,673**	**146,337**	**133,855**	**131,858**	**129,802**	**127,698**

Total Operating Cost NPV (k$)	$7,416,326
Total Capital Cost NPV (k$)	$1,525,928
Total Planning Period NPV (k$)	$8,942,254

* Imports over the NS-NB Tieline and surplus energy from Maritime Link

OI Low Load	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Unit Cost	465,585	478,463	414,028	297,408	300,266	277,454	282,132	292,900	292,124	292,740	294,991	299,153	304,474
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	178,000	177,958	178,246	153,868	154,492	154,463	154,766	155,074
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports *	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157
Total Operating Cost (k$)	**585,164**	**609,145**	**634,032**	**649,416**	**663,492**	**619,254**	**631,260**	**645,415**	**628,963**	**634,975**	**645,011**	**650,148**	**656,798**
Capital Costs													
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**

OI Low Load	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Total Unit Cost	310,603	301,365	303,769	306,094	313,756	315,341	324,971	330,972	331,123	339,695	350,750	356,086	364,498
Renewables IPPs	155,713	155,699	156,017	156,339	156,994	156,995	157,329	157,667	158,338	158,356	158,707	159,061	159,749
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports *	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost (k$)	**663,385**	**666,315**	**676,022**	**682,196**	**688,796**	**699,368**	**712,656**	**727,408**	**737,793**	**750,246**	**763,297**	**775,314**	**787,663**
Capital Costs													
Other Import (Contract Energy)	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Total Capital Costs (k$)	**56,883**	**56,373**	**55,797**	**55,162**	**54,471**	**53,731**	**52,944**	**52,114**	**51,245**	**50,340**	**49,401**	**48,432**	**47,435**

Total Operating Cost NPV (k$)	$8,602,058
Total Capital Cost NPV (k$)	$585,072
Total Planning Period NPV (k$)	$9,187,130

* Imports over the upgraded NS-NB Tieline.

Indigenous Wind Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	465,585	478,463	466,288	463,134	484,285	427,635	437,783	445,314	451,845	460,072	468,917	473,060	480,069
Renewables IPPs	119,579	130,682	140,588	150,760	159,599	164,174	164,081	164,322	139,896	140,474	140,401	140,662	140,927
Incremental Wind	0	0	0	0	770	788	801	817	833	853	867	884	902
Imports *	0	0	35,975	41,563	0	0	0	0	0	0	0	0	0
Less Exports *	0	0	4,957	3,917	3,926	15,185	18,123	19,947	20,092	22,256	21,224	22,010	23,755
Total Operating Cost (k$)	**585,164**	**609,145**	**637,893**	**651,539**	**640,729**	**577,413**	**584,541**	**590,506**	**572,482**	**579,144**	**588,961**	**592,596**	**598,143**
Capital Costs													
Incremental Wind	0	0	0	0	30,838	-4,073	35,686	56,095	66,018	70,256	71,413	70,901	69,483
Combustion Turbine & Combined Cycles	0	0	0	0	49,165	41,370	41,488	41,516	41,461	41,329	41,126	40,859	40,532
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**80,003**	**37,297**	**77,174**	**97,612**	**107,479**	**111,585**	**112,540**	**111,760**	**110,015**

Indigenous Wind Low Load	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	472,709	490,174	520,516	515,603	525,186	533,993	545,105	595,852	613,418	628,324	641,568	653,254	659,609
Renewables IPPs	141,526	141,474	141,756	142,044	142,664	142,636	142,941	143,251	143,897	143,893	144,223	144,559	145,231
Incremental Wind	923	938	957	976	1,000	1,016	1,036	1,056	1,082	1,099	1,121	1,144	1,171
Imports *	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports *	3,737	133	35,039	16,783	30,409	16,389	19,341	51,328	54,051	52,645	52,308	48,298	41,547
Total Operating Cost (k$)	**611,421**	**632,453**	**628,190**	**641,840**	**638,442**	**661,255**	**669,741**	**688,832**	**704,346**	**720,671**	**734,604**	**750,659**	**764,464**
Capital Costs													
Incremental Wind	67,575	65,401	63,083	60,687	58,249	55,788	53,314	50,833	48,349	45,863	43,376	36,659	-4,842
Combustion Turbine & Combined Cycles	40,150	39,717	88,831	87,412	85,953	84,458	82,929	136,125	133,547	130,943	128,314	125,664	122,994
Total Capital Costs (k$)	**107,725**	**105,118**	**151,915**	**148,099**	**144,202**	**140,245**	**136,243**	**186,958**	**181,896**	**176,806**	**171,690**	**162,323**	**118,152**

Total Operating Cost NPV (k$)	$8,185,364
Total Capital Cost NPV (k$)	$1,078,842
Total Planning Period NPV (k$)	$9,264,206

* Imports and Exports over the NS-NB Tieline.

ML Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	495,689	518,655	460,678	372,775	385,226	405,362	412,811	434,269	445,419	455,849	469,103	479,802	490,225	487,181	474,768	476,338	497,979	519,969	557,267	594,195	639,384	677,334	717,226	754,467	804,687	861,882
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports *	0	0	58,183	88,489	91,374	94,635	99,415	102,327	118,951	123,322	131,107	139,582	146,846	163,521	198,437	234,276	242,124	248,195	252,746	259,214	261,783	268,280	273,027	280,037	287,423	297,452
Total Operating Cost (k$)	**615,269**	**649,337**	**659,449**	**612,024**	**627,404**	**651,174**	**663,122**	**687,538**	**694,211**	**709,390**	**730,151**	**749,375**	**767,116**	**781,127**	**803,356**	**840,821**	**870,366**	**898,813**	**940,392**	**983,848**	**1,031,667**	**1,076,503**	**1,120,879**	**1,165,195**	**1,222,866**	**1,290,486**
Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Combined Cycles Units			0	0	0	0	0	0	0	0	0	0	0	0	0	49,593	48,696	47,798	46,900	46,002	99,860	97,971	96,082	94,193	92,304	90,415
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**195,331**	**202,337**	**190,600**	**188,085**	**185,473**	**237,533**	**244,308**	**229,937**	**226,051**	**222,107**	**218,113**

Total Operating Cost NPV (k$)	$9,960,675
Total Capital Cost NPV (k$)	$1,745,566
Total Planning Period NPV (k$)	$11,706,242

* Imports over the NS-NB Tieline and surplus energy from Maritime Link

OI Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	495,689	518,655	464,910	386,348	396,382	414,484	426,325	443,199	453,291	463,192	478,196	489,101	499,629
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	173,975	173,923	174,201	153,334	153,948	153,908	154,200	154,496
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports *	0	0	60,322	92,568	99,400	105,545	108,493	106,581	114,542	118,538	125,754	133,920	141,223
Total Operating Cost (k$)	**615,269**	**649,337**	**687,307**	**718,009**	**739,985**	**770,643**	**790,038**	**810,956**	**810,816**	**827,387**	**851,158**	**872,398**	**892,441**
Capital Costs													
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324
Combustion Turbines & Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**

OI Base Load, High Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	492,587	476,533	462,952	460,119	462,085	465,961	471,036	503,618	535,634	616,609	611,368	662,531	721,884
Renewables IPPs	155,123	155,097	155,404	155,714	156,356	156,344	156,665	156,990	157,647	157,652	157,988	158,328	159,002
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports *	163,240	197,132	240,790	261,022	276,902	309,240	339,671	353,240	362,226	370,711	376,909	389,782	405,782
Total Operating Cost (k$)	**910,269**	**929,804**	**962,219**	**982,003**	**1,002,899**	**1,040,966**	**1,078,995**	**1,127,714**	**1,171,983**	**1,263,464**	**1,267,140**	**1,333,947**	**1,412,796**
Capital Costs													
Other Import (Contract Energy)	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Combustion Turbines & Combined Cycle	0	6,997	14,007	13,751	13,495	65,868	64,660	63,451	62,243	61,034	59,826	58,617	57,409
Total Capital Costs (k$)	**56,883**	**63,369**	**69,804**	**68,913**	**67,967**	**119,599**	**117,604**	**115,565**	**113,488**	**111,374**	**109,227**	**107,050**	**104,844**

Total Operating Cost NPV (k$)	$11,184,998
Total Capital Cost NPV (k$)	$730,867
Total Planning Period NPV (k$)	$11,915,865

* Imports over the upgraded NS-NB Tieline.

Indigenous Wind Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	495,689	518,655	494,520	506,005	488,977	518,879	531,002	546,223	564,309	584,213	650,754	667,107	714,274
Renewables IPPs	119,579	130,682	140,588	150,760	165,759	166,431	166,454	166,813	146,029	146,730	146,782	147,170	147,566
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789
Imports *	0	0	51,910	56,392	0	0	0	0	0	0	0	0	0
Less Exports *	0	0	4,931	4,382	9,123	10,827	11,215	12,264	11,449	297	247	316	296
Total Operating Cost (k$)	**615,269**	**649,337**	**682,086**	**708,775**	**647,140**	**676,047**	**687,830**	**702,392**	**700,541**	**732,338**	**799,008**	**815,716**	**863,332**
Capital Costs													
Incremental Wind	0	0	0	0	55,217	-4,185	63,150	97,643	114,337	121,382	123,199	122,182	119,629
Combustion Turbine & Combined Cycles	0	0	0	0	82,098	68,470	68,757	68,885	68,867	68,713	68,436	113,861	112,535
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**137,315**	**64,285**	**131,907**	**166,528**	**183,203**	**190,096**	**191,635**	**236,043**	**232,164**

Indigenous Wind Base Load, High Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	763,381	834,243	930,940	968,903	1,002,881	1,101,929	1,120,821	1,074,469	1,129,090	1,147,555	1,216,114	1,297,988	1,378,074
Renewables IPPs	150,398	150,523	150,986	151,458	152,268	152,430	155,296	155,856	156,753	159,515	160,157	160,814	161,810
Incremental Wind	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports *	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports *	357	336	218	215	214	189	242	334	316	372	361	315	296
Total Operating Cost (k$)	**915,451**	**986,491**	**1,083,810**	**1,122,291**	**1,157,131**	**1,256,401**	**1,278,372**	**1,232,538**	**1,288,135**	**1,309,582**	**1,378,852**	**1,461,489**	**1,542,661**
Capital Costs													
Incremental Wind	123,978	111,819	117,171	117,789	115,841	112,503	117,123	103,251	109,153	118,998	106,780	110,015	45,435
Combustion Turbine & Combined Cycles	111,113	109,602	137,308	135,110	132,842	130,511	128,121	180,432	176,947	173,417	169,845	201,250	196,970
Total Capital Costs (k$)	**235,091**	**221,421**	**254,479**	**252,898**	**248,683**	**243,014**	**245,244**	**283,683**	**286,101**	**292,415**	**276,625**	**311,265**	**242,405**

Total Operating Cost NPV (k$)	$11,158,565
Total Capital Cost NPV (k$)	$1,922,137
Total Planning Period NPV (k$)	$13,080,702

* Imports and Exports over the NS-NB Tieline.

ML Base Load, Low Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	407,536	422,161	411,907	313,973	320,138	330,892	351,767	356,680	367,376	376,342	386,610	396,431	407,285	417,485	429,504	420,208	432,469	445,236	462,681	482,531	492,580	507,745	528,789	546,969	563,144	577,933
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports *	0	0	50,675	82,957	85,398	92,503	87,361	99,412	110,573	113,822	121,999	125,384	128,512	130,629	134,225	136,719	138,966	141,707	146,993	150,026	146,405	153,561	156,950	162,103	170,913	185,162
Total Operating Cost (k$)	**527,116**	**552,843**	**603,169**	**547,689**	**556,340**	**574,572**	**590,024**	**607,035**	**607,791**	**620,383**	**638,550**	**651,807**	**665,841**	**678,539**	**693,880**	**687,134**	**701,698**	**717,592**	**740,053**	**762,996**	**769,485**	**792,197**	**816,365**	**839,762**	**864,813**	**894,247**
Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Combined Cycles Units	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	49,593	48,696	47,798	46,900	46,002	99,860	97,971	96,082	94,193	92,304	90,415
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**195,331**	**202,337**	**190,600**	**188,085**	**185,473**	**237,533**	**244,308**	**229,937**	**226,051**	**222,107**	**218,113**

Total Operating Cost NPV (k$)	$8,360,729
Total Capital Cost NPV (k$)	$1,745,566
Total Planning Period NPV (k$)	$10,106,295

* Imports over the NS-NB Tieline and surplus energy from Maritime Link

OI Base Load, Low Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	407,536	422,161	407,417	286,254	294,017	308,258	324,548	334,340	337,590	353,167	352,629	354,178	362,626
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	173,975	173,923	174,201	153,334	153,948	153,908	154,200	154,496
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports *	0	0	59,421	116,772	119,195	126,440	124,628	129,242	139,365	133,904	151,921	160,720	165,656
Total Operating Cost (k$)	**527,116**	**552,843**	**628,912**	**642,120**	**657,416**	**685,312**	**704,397**	**724,758**	**719,939**	**732,729**	**751,758**	**764,276**	**779,871**
Capital Costs													
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324
Combustion Turbines & Combined Cycle	0	0	0	0	0	0	0	0	0	0	0	0	0
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**

OI Base Load, Low Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	380,062	386,933	413,333	419,363	441,137	423,480	441,285	459,805	477,782	495,302	503,591	510,707	525,894
Renewables IPPs	155,123	155,097	155,404	155,714	156,356	156,344	156,665	156,990	157,647	157,652	157,988	158,328	159,002
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports *	163,942	172,249	167,641	175,621	171,514	181,885	186,611	193,660	198,948	206,778	222,951	244,203	256,470
Total Operating Cost (k$)	**798,446**	**815,320**	**839,451**	**855,846**	**876,563**	**871,130**	**896,183**	**924,322**	**950,853**	**978,224**	**1,005,405**	**1,036,544**	**1,067,495**
Capital Costs													
Other Import (Contract Energy)	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Combustion Turbines & Combined Cycle	0	6,997	14,007	13,751	13,495	65,868	64,660	63,451	62,243	61,034	59,826	58,617	57,409
Total Capital Costs (k$)	**56,883**	**63,369**	**69,804**	**68,913**	**67,967**	**119,599**	**117,604**	**115,565**	**113,488**	**111,374**	**109,227**	**107,050**	**104,844**

Total Operating Cost NPV (k$)	$9,662,832
Total Capital Cost NPV (k$)	$730,867
Total Planning Period NPV (k$)	$10,393,699

* Imports over the upgraded NS-NB Tieline.

Indigenous Wind Base Load, Low Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	407,536	422,161	450,572	452,951	437,166	455,712	470,752	483,702	497,478	510,362	541,241	522,434	535,208
Renewables IPPs	119,579	130,682	140,588	150,760	165,759	166,431	166,454	166,813	146,029	146,730	146,782	147,170	147,566
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789
Imports *	0	0	38,482	39,293	0	0	0	0	0	0	0	0	0
Less Exports *	0	0	484	519	7,282	6,644	7,248	7,786	6,716	6,656	998	10,054	9,346
Total Operating Cost (k$)	**527,116**	**552,843**	**629,157**	**642,485**	**597,169**	**617,061**	**631,546**	**644,349**	**638,444**	**652,128**	**688,744**	**661,304**	**675,217**
Capital Costs													
Incremental Wind	0	0	0	0	55,217	-4,185	63,150	97,643	114,337	121,382	123,199	122,182	119,629
Combustion Turbine & Combined Cycles	0	0	0	0	82,098	68,470	68,757	68,885	68,867	68,713	68,436	113,861	112,535
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**137,315**	**64,285**	**131,907**	**166,528**	**183,203**	**190,096**	**191,635**	**236,043**	**232,164**

Indigenous Wind Base Load, Low Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	532,930	563,785	588,145	604,934	629,593	661,388	673,281	645,100	669,914	684,644	710,968	723,901	757,396
Renewables IPPs	150,398	150,523	150,986	151,458	152,268	152,430	155,296	155,856	156,753	159,515	160,157	160,814	161,810
Incremental Wind	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports *	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports *	5,354	701	1,275	983	622	303	276	2,606	1,820	1,838	875	1,710	448
Total Operating Cost (k$)	**680,002**	**715,668**	**739,958**	**757,554**	**783,435**	**815,747**	**830,797**	**800,897**	**827,454**	**845,205**	**873,192**	**886,007**	**921,831**
Capital Costs													
Incremental Wind	123,978	111,819	117,171	117,789	115,841	112,503	117,123	103,251	109,153	118,998	106,780	110,015	45,435
Combustion Turbine & Combined Cycles	111,113	109,602	137,308	135,110	132,842	130,511	128,121	180,432	176,947	173,417	169,845	201,250	196,970
Total Capital Costs (k$)	**235,091**	**221,421**	**254,479**	**252,898**	**248,683**	**243,014**	**245,244**	**283,683**	**286,101**	**292,415**	**276,625**	**311,265**	**242,405**

Total Operating Cost NPV (k$)	$8,809,017
Total Capital Cost NPV (k$)	$1,922,137
Total Planning Period NPV (k$)	$10,731,153

* Imports and Exports over the NS-NB Tieline.

NON-CONFIDENTIAL

Request IR-334:

With reference to response Synapse IR-11:

(a) Columns b, c, g and h of Electronic Attachment 1 to the response to Synapse IR-11 contain values. Please confirm that these values are consistent with those shown in Attachment 5 to the response to Synapse IR-11.

(b) Please provide calculations showing how the values shown in Attachment 5 to the response to Synapse IR-11 were derived from input assumptions and/or results from Strategist runs, including all supporting spreadsheets (with original excel formulas intact) and other documents underlying the computation of those values.

(c) With regard to the values shown on lines 4-6 on page 3 of 4 of the response to Synapse IR-11 (a), please provide calculations showing how these values were derived from input assumptions and/or results from Strategist runs, including all supporting spreadsheets (with original excel formulas intact) and other documents underlying the adjustments to the study period costs of the Maritime Link cases for the 35 year depreciation life of the Project versus the 50 year operating life included in Attachment 2 to the response to Synapse IR-11 (a).

Response IR-334:

(a) Confirmed.

(b) Please refer to SBA IR-331 parts (b) and (c) for the input and output reports for these cases. Please refer to Electronic Attachment 1 for the values from the Strategist reports used to develop the costs in Synapse IR-11 Attachment 5.

(c) The study period costs of the Maritime Link cases have been adjusted to account for the 35 year depreciation life of the Project versus the 50 year operating life. The capital cost for the Maritime Link represents the cost of the energy for the NS Block and Supplemental energy; there are no operating costs modeled for this energy. For years 36-50, when the Project is fully depreciated there is no capital cost in the model either and the NS Block Energy has no cost associated with it in those 15 years. This would not be the case when the Maritime Link is in operation. At year 51 the model assumes the Maritime Link is replaced-in-kind and this capital cost would again be associated with the energy from the NS Block. The issue only occurs in the end effects period because in the planning period the Maritime Link project has not yet been fully depreciated.

To correct this, an adjustment to the study period cost was calculated. A purchased power agreement (PPA) for this energy was assumed based on market forecasts and escalating at inflation for the 15 years between when the Maritime Link project capital cost is fully depreciated and when the Maritime Link is replaced. This 15 year PPA was repeated every 50 years to "infinity" (which is the year 2500 in the calculation). The NPV of the annual costs were taken from the year 2041 to 2500 which converges to the study period cost adders:

Base Load and Low Load = $134 M
High Power & Gas Price Sensitivity = $170 M
Low Power & Gas Price Sensitivity = $111 M

Please see Electronic Attachment 2 which shows the calculation of the adders.

The starting price for the PPA in 2040 is given in Electronic Attachment 3.

ML Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	461,170	476,192	419,554	315,791	325,613	344,524	353,557	367,369	377,561	387,408	397,189	408,170	418,899	430,525	434,184	456,553	465,428	479,857	496,666	516,002	552,645	568,450	596,199	626,850	652,182	685,714
Total Emissions Cost (Ash removal)	1,149	1,178	1,181	1,135	1,162	1,206	1,221	1,252	1,281	1,308	1,337	1,359	1,386	1,421	1,449	1,537	1,548	1,552	1,552	1,469	1,676	1,667	1,362	1,162	1,018	846
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	52,251	90,078	92,690	95,791	100,670	107,154	120,638	124,036	133,142	136,165	141,018	142,870	156,748	155,652	160,576	165,393	177,011	189,022	182,346	194,718	201,125	206,799	220,212	229,781
Total Operating Cost	**592,093**	**618,246**	**623,768**	**567,959**	**580,464**	**602,893**	**616,539**	**636,912**	**639,517**	**653,166**	**671,805**	**685,881**	**701,543**	**715,436**	**732,727**	**754,145**	**768,010**	**787,646**	**815,803**	**847,127**	**877,362**	**905,919**	**939,506**	**975,696**	**1,014,363**	**1,057,688**
ML Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	472,514	487,564	430,930	327,121	336,969	355,925	364,973	378,815	389,038	398,912	408,722	419,724	430,481	442,141	445,828	468,286	477,171	491,604	508,413	527,666	564,516	580,312	607,756	638,207	663,395	696,755
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	52,251	90,078	92,690	95,791	100,670	107,154	120,638	124,036	133,142	136,165	141,018	142,870	156,748	155,652	160,576	165,393	177,011	189,022	182,346	194,718	201,125	206,799	220,212	229,781
Total Operating Cost (k$)	**592,093**	**618,246**	**623,768**	**567,959**	**580,464**	**602,893**	**616,539**	**636,912**	**639,517**	**653,166**	**671,805**	**685,881**	**701,543**	**715,436**	**732,727**	**754,145**	**768,010**	**787,646**	**815,803**	**847,127**	**877,362**	**905,919**	**939,506**	**975,696**	**1,014,363**	**1,057,688**
Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Combined Cycles Units			0	0	0	0	0	0	0	0	0	0	0	0	0	49,593	48,696	47,798	46,900	46,002	99,860	97,971	96,082	94,193	92,304	90,415
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**195,331**	**202,337**	**190,600**	**188,085**	**185,473**	**237,533**	**244,308**	**229,937**	**226,051**	**222,107**	**218,113**

Total Operating Cost NPV (k$)	$9,030,492
Total Capital Cost NPV (k$)	$1,745,566
Total Planning Period NPV (k$)	$10,776,058

OI Base Load

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	461,170	476,192	411,925	287,311	296,716	314,691	320,715	332,381	339,687	349,495	359,878	367,213	378,110	388,748	397,309	397,060	405,603	413,168	430,505	451,904	472,733	491,268	513,439	532,853	561,886	595,978
Total Emissions Cost (Ash removal)	1,149	1,178	1,175	1,133	1,168	1,192	1,219	1,249	1,262	1,291	1,316	1,355	1,382	1,414	1,449	1,490	1,480	1,498	1,562	1,155	1,108	1,193	1,243	1,301	1,199	327
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	162,074	239,094	244,204	250,614	255,220	261,176	242,984	245,657	247,208	249,378	251,590	254,442	256,138	258,477	260,862	263,913	265,765	268,287	270,857	274,123	276,144	278,863	281,635	285,131
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	0	0	60,390	122,639	124,468	129,998	137,174	141,867	147,726	150,241	158,709	164,167	167,366	170,122	177,956	202,297	206,667	216,247	226,109	241,177	256,354	264,102	268,689	275,845	282,751	299,822
Total Operating Cost	**592,093**	**618,246**	**661,715**	**726,360**	**747,581**	**783,328**	**805,820**	**833,842**	**831,505**	**848,589**	**870,606**	**887,485**	**905,736**	**924,240**	**944,086**	**972,593**	**989,955**	**1,012,578**	**1,043,557**	**1,084,340**	**1,125,112**	**1,157,356**	**1,188,202**	**1,219,932**	**1,260,973**	**1,317,582**

OI Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	472,514	487,564	423,295	298,639	308,079	326,077	332,129	343,824	351,144	360,981	371,389	378,763	389,687	400,357	408,952	408,744	417,277	424,861	442,262	463,253	484,035	502,656	524,877	544,349	573,281	606,500
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	173,975	173,923	174,201	153,334	153,948	153,908	154,200	154,496	155,123	155,097	155,404	155,714	156,356	156,344	156,665	156,990	157,647	157,652	157,988	158,328	159,002
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	0	0	60,390	122,639	124,468	129,998	137,174	141,867	147,726	150,241	158,709	164,167	167,366	170,122	177,956	202,297	206,667	216,247	226,109	241,177	256,354	264,102	268,689	275,845	282,751	299,822
Total Operating Cost (k$)	**592,093**	**618,246**	**645,760**	**660,372**	**676,751**	**706,689**	**724,522**	**746,867**	**741,854**	**756,879**	**777,306**	**792,307**	**808,642**	**824,921**	**843,046**	**869,519**	**884,807**	**905,021**	**934,136**	**972,718**	**1,011,246**	**1,040,881**	**1,069,710**	**1,099,057**	**1,137,666**	**1,191,452**

Capital Costs

Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Combustion Turbines & Combined Cycle			0	0	0	0	0	0	0	0	0	0	0	0	6,997	14,007	13,751	13,495	65,868	64,660	63,451	62,243	61,034	59,826	58,617	57,409
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**	**56,883**	**63,369**	**69,804**	**68,913**	**67,967**	**119,599**	**117,604**	**115,565**	**113,488**	**111,374**	**109,227**	**107,050**	**104,844**

Total Operating Cost NPV (k$)	$10,182,719
Total Capital Cost NPV (k$)	$730,867
Total Planning Period NPV (k$)	$10,913,585

Indigenous Wind Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	461,170	476,192	457,398	464,336	444,541	472,735	483,715	497,533	511,894	526,737	561,284	558,560	575,265	592,457	633,881	677,574	704,106	738,165	793,366	818,785	801,312	839,720	861,028	913,292	953,876	1,011,913
Total Emissions Cost (Ash removal)	1,149	1,178	1,206	1,236	1,250	1,277	1,296	1,322	1,350	1,361	1,313	1,438	1,314	912	537	294	159	62	31	23	309	152	66	52	21	23
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	167,286	167,994	168,043	168,433	147,682	148,422	148,501	148,924	149,355	152,426	152,585	153,088	153,603	154,464	154,662	157,792	158,403	159,360	162,399	163,099	163,815	164,883
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost	**592,093**	**618,246**	**667,317**	**739,441**	**743,821**	**740,925**	**754,709**	**766,397**	**766,095**	**784,439**	**825,270**	**821,921**	**838,075**	**855,770**	**907,470**	**956,416**	**984,822**	**1,015,570**	**1,078,096**	**1,108,027**	**1,097,668**	**1,143,892**	**1,170,275**	**1,222,546**	**1,267,768**	**1,327,372**
Indigenous Wind Base Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	472,514	487,564	468,799	475,766	455,986	484,207	495,206	509,050	523,439	538,292	572,792	570,193	586,775	603,565	644,613	688,063	714,460	748,422	803,592	829,003	811,816	850,067	871,289	923,540	964,092	1,022,131
Renewables IPPs	119,579	130,682	140,588	150,760	165,759	166,431	166,454	166,813	146,029	146,730	146,782	147,170	147,566	150,398	150,523	150,986	151,458	152,268	152,430	155,296	155,856	156,753	159,515	160,157	160,814	161,810
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports	0	0	42,012	43,339	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports	0	0	3,082	2,083	7,606	9,011	6,956	6,594	5,710	2,217	235	7,896	597	372	212	184	206	193	172	212	575	397	375	294	261	249
Total Operating Cost (k$)	**592,093**	**618,246**	**648,316**	**667,782**	**615,666**	**643,191**	**656,292**	**670,889**	**665,411**	**684,497**	**721,058**	**711,220**	**735,532**	**755,619**	**796,986**	**840,967**	**867,857**	**902,692**	**958,081**	**986,584**	**969,644**	**1,009,030**	**1,033,312**	**1,086,344**	**1,127,646**	**1,186,764**
Capital Costs																										
Incremental Wind	0	0	0	0	55,217	-4,185	63,150	97,643	114,337	121,382	123,199	122,182	119,629	123,978	111,819	117,171	117,789	115,841	112,503	117,123	103,251	109,153	118,998	106,780	110,015	45,435
Combustion Turbine & Combined Cycles	0	0	0	0	82,098	68,470	68,757	68,885	68,867	68,713	68,436	113,861	112,535	111,113	109,602	137,308	135,110	132,842	130,511	128,121	180,432	176,947	173,417	169,845	201,250	196,970
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**137,315**	**64,285**	**131,907**	**166,528**	**183,203**	**190,096**	**191,635**	**236,043**	**232,164**	**235,091**	**221,421**	**254,479**	**252,898**	**248,683**	**243,014**	**245,244**	**283,683**	**286,101**	**292,415**	**276,625**	**311,265**	**242,405**

Total Operating Cost NPV (k$)	$9,720,584
Total Capital Cost NPV (k$)	$1,922,137
Total Planning Period NPV (k$)	$11,642,720

ML Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	454,223	467,075	416,020	313,045	321,540	282,585	286,259	295,544	306,189	303,017	307,697	310,474	314,242	319,073	309,715	315,420	318,877	325,397	329,804	336,782	344,212	353,276	358,843	366,133	373,467	381,695
Total Emissions Cost (Ash removal)	1,167	1,193	1,191	1,149	1,182	1,155	1,173	1,209	1,228	1,242	1,274	1,296	1,318	1,343	1,389	1,401	1,368	1,396	1,433	1,461	1,484	1,518	1,544	1,576	1,607	1,641
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	150,804	155,203	154,931	154,988	130,376	130,763	130,496	130,558	130,622	131,015	130,752	130,820	130,888	131,287	131,030	131,103	131,177	131,581	131,330	131,409	131,489	131,899
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	46,000	82,710	84,682	65,456	68,250	71,755	75,988	82,553	86,072	86,386	86,974	85,827	96,529	98,868	98,346	96,146	101,566	104,565	109,391	110,001	114,556	116,781	119,097	119,969
Total Operating Cost	**585,164**	**609,145**	**613,993**	**557,858**	**568,403**	**514,593**	**520,808**	**533,691**	**523,976**	**527,771**	**535,734**	**538,910**	**543,351**	**547,453**	**548,581**	**556,704**	**559,674**	**564,420**	**574,028**	**584,106**	**596,459**	**606,571**	**616,467**	**626,094**	**635,855**	**645,399**

ML Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	465,585	478,463	427,406	324,389	332,917	293,935	297,627	306,947	317,612	314,454	319,166	321,966	325,755	330,611	321,299	327,016	330,440	336,988	341,432	348,439	355,891	364,989	370,581	377,904	385,269	393,530
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	155,203	154,931	154,988	130,376	130,763	130,496	130,558	130,622	131,015	130,752	130,820	130,888	131,287	131,030	131,103	131,177	131,581	131,330	131,409	131,489	131,899
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	46,000	82,710	84,682	65,456	68,250	71,755	75,988	82,553	86,072	86,386	86,974	85,827	96,529	98,868	98,346	96,146	101,566	104,565	109,391	110,001	114,556	116,781	119,097	119,969
Total Operating Cost (k$)	**585,164**	**609,145**	**613,993**	**557,858**	**568,403**	**514,593**	**520,808**	**533,691**	**523,976**	**527,771**	**535,734**	**538,910**	**543,351**	**547,453**	**548,581**	**556,704**	**559,674**	**564,420**	**574,028**	**584,106**	**596,459**	**606,571**	**616,467**	**626,094**	**635,855**	**645,399**

Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**145,738**	**153,641**	**142,802**	**141,185**	**139,471**	**137,673**	**146,337**	**133,855**	**131,858**	**129,802**	**127,698**

Total Operating Cost NPV (k$)	$7,416,326
Total Capital Cost NPV (k$)	$1,525,928
Total Planning Period NPV (k$)	$8,942,254

OI Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	454,223	467,075	402,646	286,062	288,877	266,056	270,715	281,477	280,704	281,298	283,535	287,666	292,978	299,078	289,795	292,204	294,520	302,168	303,687	313,317	319,294	319,376	327,900	338,951	344,254	352,631
Total Emissions Cost (Ash removal)	1,167	1,193	1,187	1,150	1,193	1,203	1,223	1,228	1,226	1,247	1,261	1,292	1,302	1,331	1,374	1,370	1,380	1,392	1,459	1,459	1,482	1,552	1,600	1,604	1,637	1,672
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	162,074	239,094	244,204	254,639	259,256	265,221	243,518	246,202	247,763	249,944	252,167	255,032	256,739	259,091	261,488	264,551	266,416	268,951	271,534	274,813	276,848	279,582	282,367	285,879
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost	**585,164**	**609,145**	**649,987**	**715,405**	**734,322**	**695,893**	**712,557**	**732,390**	**718,614**	**726,684**	**738,311**	**745,326**	**753,892**	**762,704**	**767,356**	**779,096**	**787,345**	**796,353**	**808,789**	**824,278**	**841,274**	**854,268**	**868,739**	**884,172**	**898,620**	**913,793**

OI Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	465,585	478,463	414,028	297,408	300,266	277,454	282,132	292,900	292,124	292,740	294,991	299,153	304,474	310,603	301,365	303,769	306,094	313,756	315,341	324,971	330,972	331,123	339,695	350,750	356,086	364,498
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	178,000	177,958	178,246	153,868	154,492	154,463	154,766	155,074	155,713	155,699	156,017	156,339	156,994	156,995	157,329	157,667	158,338	158,356	158,707	159,061	159,749
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost (k$)	**585,164**	**609,145**	**634,032**	**649,416**	**663,492**	**619,254**	**631,260**	**645,415**	**628,963**	**634,975**	**645,011**	**650,148**	**656,798**	**663,385**	**666,315**	**676,022**	**682,196**	**688,796**	**699,368**	**712,656**	**727,408**	**737,793**	**750,246**	**763,297**	**775,314**	**787,663**

Capital Costs																										
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**	**56,883**	**56,373**	**55,797**	**55,162**	**54,471**	**53,731**	**52,944**	**52,114**	**51,245**	**50,340**	**49,401**	**48,432**	**47,435**

Total Operating Cost NPV (k$)	$8,602,058
Total Capital Cost NPV (k$)	$585,072
Total Planning Period NPV (k$)	$9,187,130

Wind Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	454,223	467,075	454,874	451,696	472,821	416,163	426,290	433,797	440,304	448,505	457,329	461,440	468,423	461,118	478,801	508,854	504,055	513,527	522,422	533,487	584,201	601,925	616,941	630,337	642,062	648,401
Total Emissions Cost (Ash removal)	1,167	1,193	1,218	1,243	1,270	1,278	1,298	1,322	1,346	1,373	1,393	1,425	1,450	1,396	1,178	1,467	1,353	1,464	1,376	1,423	1,456	1,298	1,188	1,036	997	1,013
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	160,369	164,962	164,882	165,139	140,729	141,328	141,268	141,546	141,829	142,450	142,413	142,713	143,020	143,664	143,651	143,977	144,308	144,979	144,992	145,344	145,703	146,402
Incremental Wind	0	0	0	0	770	788	801	817	833	853	867	884	902	923	938	957	976	1,000	1,016	1,036	1,056	1,082	1,099	1,121	1,144	1,171
Imports	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost	**585,164**	**609,145**	**664,805**	**726,809**	**764,447**	**680,546**	**693,337**	**698,564**	**686,729**	**698,286**	**713,308**	**716,541**	**722,957**	**713,833**	**741,736**	**777,348**	**774,214**	**780,339**	**796,271**	**808,853**	**866,118**	**891,336**	**908,118**	**920,999**	**936,961**	**944,469**

Indigenous Wind Low Load	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	465,585	478,463	466,288	463,134	484,285	427,635	437,783	445,314	451,845	460,072	468,917	473,060	480,069	472,709	490,174	520,516	515,603	525,186	533,993	545,105	595,852	613,418	628,324	641,568	653,254	659,609
Renewables IPPs	119,579	130,682	140,588	150,760	159,599	164,174	164,081	164,322	139,896	140,474	140,401	140,662	140,927	141,526	141,474	141,756	142,044	142,664	142,636	142,941	143,251	143,897	143,893	144,223	144,559	145,231
Incremental Wind	0	0	0	0	770	788	801	817	833	853	867	884	902	923	938	957	976	1,000	1,016	1,036	1,056	1,082	1,099	1,121	1,144	1,171
Imports	0	0	35,975	41,563	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports	0	0	4,957	3,917	3,926	15,185	18,123	19,947	20,092	22,256	21,224	22,010	23,755	3,737	133	35,039	16,783	30,409	16,389	19,341	51,328	54,051	52,645	52,308	48,298	41,547
Total Operating Cost (k$)	**585,164**	**609,145**	**637,893**	**651,539**	**640,729**	**577,413**	**584,541**	**590,506**	**572,482**	**579,144**	**588,961**	**592,596**	**598,143**	**611,421**	**632,453**	**628,190**	**641,840**	**638,442**	**661,255**	**669,741**	**688,832**	**704,346**	**720,671**	**734,604**	**750,659**	**764,464**

Capital Costs																										
Incremental Wind	0	0	0	0	30,838	-4,073	35,686	56,095	66,018	70,256	71,413	70,901	69,483	67,575	65,401	63,083	60,687	58,249	55,788	53,314	50,833	48,349	45,863	43,376	36,659	-4,842
Combustion Turbine & Combined Cycles	0	0	0	0	49,165	41,370	41,488	41,516	41,461	41,329	41,126	40,859	40,532	40,150	39,717	88,831	87,412	85,953	84,458	82,929	136,125	133,547	130,943	128,314	125,664	122,994
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**80,003**	**37,297**	**77,174**	**97,612**	**107,479**	**111,585**	**112,540**	**111,760**	**110,015**	**107,725**	**105,118**	**151,915**	**148,099**	**144,202**	**140,245**	**136,243**	**186,958**	**181,896**	**176,806**	**171,690**	**162,323**	**118,152**

Total Operating Cost NPV (k$)	$8,185,364
Total Capital Cost NPV (k$)	$1,078,842
Total Planning Period NPV (k$)	$9,264,206

ML Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	484,348	507,278	449,290	361,427	373,842	393,939	401,353	422,772	433,894	444,291	457,523	468,186	478,584	475,536	463,167	464,857	486,672	508,836	546,375	583,444	627,653	666,053	706,463	743,820	794,216	851,521
Total Emissions Cost (Ash removal)	1,146	1,182	1,193	1,153	1,189	1,228	1,263	1,301	1,330	1,363	1,385	1,421	1,447	1,450	1,406	1,287	1,112	938	696	556	1,535	1,085	568	452	276	166
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	58,183	88,489	91,374	94,635	99,415	102,327	118,951	123,322	131,107	139,582	146,846	163,521	198,437	234,276	242,124	248,195	252,746	259,214	261,783	268,280	273,027	280,037	287,423	297,452
Total Operating Cost	**615,269**	**649,337**	**659,449**	**612,024**	**627,404**	**651,174**	**663,122**	**687,538**	**694,211**	**709,390**	**730,151**	**749,375**	**767,116**	**781,127**	**803,356**	**840,821**	**870,366**	**898,813**	**940,392**	**983,848**	**1,031,667**	**1,076,503**	**1,120,879**	**1,165,195**	**1,222,866**	**1,290,486**

ML Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	495,689	518,655	460,678	372,775	385,226	405,362	412,811	434,269	445,419	455,849	469,103	479,802	490,225	487,181	474,768	476,338	497,979	519,969	557,267	594,195	639,384	677,334	717,226	754,467	804,687	861,882
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	58,183	88,489	91,374	94,635	99,415	102,327	118,951	123,322	131,107	139,582	146,846	163,521	198,437	234,276	242,124	248,195	252,746	259,214	261,783	268,280	273,027	280,037	287,423	297,452
Total Operating Cost (k$)	**615,269**	**649,337**	**659,449**	**612,024**	**627,404**	**651,174**	**663,122**	**687,538**	**694,211**	**709,390**	**730,151**	**749,375**	**767,116**	**781,127**	**803,356**	**840,821**	**870,366**	**898,813**	**940,392**	**983,848**	**1,031,667**	**1,076,503**	**1,120,879**	**1,165,195**	**1,222,866**	**1,290,486**

Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Combined Cycles Units			0	0	0	0	0	0	0	0	0	0	0	0	0	49,593	48,696	47,798	46,900	46,002	99,860	97,971	96,082	94,193	92,304	90,415
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**195,331**	**202,337**	**190,600**	**188,085**	**185,473**	**237,533**	**244,308**	**229,937**	**226,051**	**222,107**	**218,113**

Total Operating Cost NPV (k$)	$9,960,675
Total Capital Cost NPV (k$)	$1,745,566
Total Planning Period NPV (k$)	$11,706,242

OI Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Thermal Cost	484,348	507,278	453,520	375,005	384,994	403,052	414,874	431,698	441,769	451,646	466,631	477,511	488,015
Total Emissions Cost (Ash removal)	1,146	1,182	1,195	1,148	1,194	1,237	1,256	1,306	1,326	1,352	1,371	1,395	1,419
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	162,074	239,094	244,204	250,614	255,220	261,176	242,984	245,657	247,208	249,378	251,590
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports	0	0	60,322	92,568	99,400	105,545	108,493	106,581	114,542	118,538	125,754	133,920	141,223
Total Operating Cost	**615,269**	**649,337**	**703,262**	**783,997**	**810,815**	**847,282**	**871,336**	**897,932**	**900,467**	**919,097**	**944,458**	**967,576**	**989,535**
OI Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	495,689	518,655	464,910	386,348	396,382	414,484	426,325	443,199	453,291	463,192	478,196	489,101	499,629
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	173,975	173,923	174,201	153,334	153,948	153,908	154,200	154,496
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports	0	0	60,322	92,568	99,400	105,545	108,493	106,581	114,542	118,538	125,754	133,920	141,223
Total Operating Cost (k$)	**615,269**	**649,337**	**687,307**	**718,009**	**739,985**	**770,643**	**790,038**	**810,956**	**810,816**	**827,387**	**851,158**	**872,398**	**892,441**
Capital Costs													
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324
Combustion Turbines & Combined Cycle			0	0	0	0	0	0	0	0	0	0	0
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**
Total Operating Cost NPV (k$)	$11,184,998												
Total Capital Cost NPV (k$)	$730,867												
Total Planning Period NPV (k$)	$11,915,865												

OI Base Load, High Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	480,977	464,937	451,355	448,545	450,481	454,349	459,949	491,919	523,937	606,055	600,440	651,885	711,640
Total Emissions Cost (Ash removal)	1,415	1,402	1,402	1,379	1,409	1,416	893	1,504	1,502	359	732	451	48
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	254,442	256,138	258,477	260,862	263,913	265,765	268,287	270,857	274,123	276,144	278,863	281,635	285,131
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	163,240	197,132	240,790	261,022	276,902	309,240	339,671	353,240	362,226	370,711	376,909	389,782	405,782
Total Operating Cost	**1,009,588**	**1,030,845**	**1,065,293**	**1,087,151**	**1,110,457**	**1,150,388**	**1,190,617**	**1,241,581**	**1,288,458**	**1,381,956**	**1,388,015**	**1,457,253**	**1,538,926**
OI Base Load, High Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	492,587	476,533	462,952	460,119	462,085	465,961	471,036	503,618	535,634	616,609	611,368	662,531	721,884
Renewables IPPs	155,123	155,097	155,404	155,714	156,356	156,344	156,665	156,990	157,647	157,652	157,988	158,328	159,002
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	163,240	197,132	240,790	261,022	276,902	309,240	339,671	353,240	362,226	370,711	376,909	389,782	405,782
Total Operating Cost (k$)	**910,269**	**929,804**	**962,219**	**982,003**	**1,002,899**	**1,040,966**	**1,078,995**	**1,127,714**	**1,171,983**	**1,263,464**	**1,267,140**	**1,333,947**	**1,412,796**
Capital Costs													
Other Import (Contract Energy)	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Combustion Turbines & Combined Cycle	0	6,997	14,007	13,751	13,495	65,868	64,660	63,451	62,243	61,034	59,826	58,617	57,409
Total Capital Costs (k$)	**56,883**	**63,369**	**69,804**	**68,913**	**67,967**	**119,599**	**117,604**	**115,565**	**113,488**	**111,374**	**109,227**	**107,050**	**104,844**

Indigenous Wind Base Load, High Power & Gas Prices

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	484,348	507,278	483,109	494,568	477,525	507,398	519,497	534,689	552,748	572,795	639,642	655,615	702,993	752,755	823,932	920,694	958,684	992,669	1,091,711	1,110,603	1,064,084	1,118,875	1,137,335	1,205,900	1,287,772	1,367,856
Total Emissions Cost (Ash removal)	1,146	1,182	1,216	1,241	1,257	1,286	1,310	1,338	1,366	1,223	916	1,298	1,086	431	115	51	24	17	23	23	190	20	25	19	21	23
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	167,286	167,994	168,043	168,433	147,682	148,422	148,501	148,924	149,355	152,426	152,585	153,088	153,603	154,464	154,662	157,792	158,403	159,360	162,399	163,099	163,815	164,883
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost	**615,269**	**649,337**	**693,037**	**769,679**	**776,812**	**775,597**	**790,505**	**803,570**	**806,964**	**830,360**	**903,231**	**918,836**	**965,574**	**1,015,587**	**1,097,100**	**1,199,293**	**1,239,265**	**1,270,029**	**1,376,433**	**1,399,845**	**1,360,320**	**1,422,914**	**1,446,541**	**1,515,121**	**1,601,665**	**1,683,315**

Indigenous Wind Base Load, High Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	495,689	518,655	494,520	506,005	488,977	518,879	531,002	546,223	564,309	584,213	650,754	667,107	714,274	763,381	834,243	930,940	968,903	1,002,881	1,101,929	1,120,821	1,074,469	1,129,090	1,147,555	1,216,114	1,297,988	1,378,074
Renewables IPPs	119,579	130,682	140,588	150,760	165,759	166,431	166,454	166,813	146,029	146,730	146,782	147,170	147,566	150,398	150,523	150,986	151,458	152,268	152,430	155,296	155,856	156,753	159,515	160,157	160,814	161,810
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports	0	0	51,910	56,392	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports	0	0	4,931	4,382	9,123	10,827	11,215	12,264	11,449	297	247	316	296	357	336	218	215	214	189	242	334	316	372	361	315	296
Total Operating Cost (k$)	**615,269**	**649,337**	**682,086**	**708,775**	**647,140**	**676,047**	**687,830**	**702,392**	**700,541**	**732,338**	**799,008**	**815,716**	**863,332**	**915,451**	**986,491**	**1,083,810**	**1,122,291**	**1,157,131**	**1,256,401**	**1,278,372**	**1,232,538**	**1,288,135**	**1,309,582**	**1,378,852**	**1,461,489**	**1,542,661**

Capital Costs

Incremental Wind	0	0	0	0	55,217	-4,185	63,150	97,643	114,337	121,382	123,199	122,182	119,629	123,978	111,819	117,171	117,789	115,841	112,503	117,123	103,251	109,153	118,998	106,780	110,015	45,435
Combustion Turbine & Combined Cycles	0	0	0	0	82,098	68,470	68,757	68,885	68,867	68,713	68,436	113,861	112,535	111,113	109,602	137,308	135,110	132,842	130,511	128,121	180,432	176,947	173,417	169,845	201,250	196,970
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**137,315**	**64,285**	**131,907**	**166,528**	**183,203**	**190,096**	**191,635**	**236,043**	**232,164**	**235,091**	**221,421**	**254,479**	**252,898**	**248,683**	**243,014**	**245,244**	**283,683**	**286,101**	**292,415**	**276,625**	**311,265**	**242,405**

Total Operating Cost NPV (k$)	$11,158,565
Total Capital Cost NPV (k$)	$1,922,137
Total Planning Period NPV (k$)	$13,080,702

ML Base Load, Low Power & Gas Prices

	2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Thermal Cost	396,382	410,865	400,536	302,664	308,805	319,507	340,396	345,280	355,949	364,886	375,126	384,918	395,743	405,903	417,898	408,701	420,944	433,682	451,094	470,916	481,220	496,326	517,316	535,437	551,562	566,935
Total Emissions Cost (Ash removal)	959	1,101	1,176	1,114	1,139	1,190	1,176	1,205	1,232	1,261	1,290	1,319	1,347	1,387	1,410	1,312	1,330	1,360	1,392	1,420	1,165	1,225	1,278	1,337	1,386	803
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	50,675	82,957	85,398	92,503	87,361	99,412	110,573	113,822	121,999	125,384	128,512	130,629	134,225	136,719	138,966	141,707	146,993	150,026	146,405	153,561	156,950	162,103	170,913	185,162
Total Operating Cost	**527,116**	**552,843**	**603,169**	**547,689**	**556,340**	**574,572**	**590,024**	**607,035**	**607,791**	**620,383**	**638,550**	**651,807**	**665,841**	**678,539**	**693,880**	**687,134**	**701,698**	**717,592**	**740,053**	**762,996**	**769,485**	**792,197**	**816,365**	**839,762**	**864,813**	**894,247**

ML Base Load, Low Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	407,536	422,161	411,907	313,973	320,138	330,892	351,767	356,680	367,376	376,342	386,610	396,431	407,285	417,485	429,504	420,208	432,469	445,236	462,681	482,531	492,580	507,745	528,789	546,969	563,144	577,933
Renewables IPPs	119,579	130,682	140,588	150,760	150,804	151,178	150,896	150,943	129,842	130,219	129,941	129,992	130,044	130,425	130,151	130,207	130,263	130,649	130,379	130,439	130,500	130,890	130,626	130,690	130,756	131,152
Maritime Link (Base Block and Supplemental)	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Imports	0	0	50,675	82,957	85,398	92,503	87,361	99,412	110,573	113,822	121,999	125,384	128,512	130,629	134,225	136,719	138,966	141,707	146,993	150,026	146,405	153,561	156,950	162,103	170,913	185,162
Total Operating Cost (k$)	**527,116**	**552,843**	**603,169**	**547,689**	**556,340**	**574,572**	**590,024**	**607,035**	**607,791**	**620,383**	**638,550**	**651,807**	**665,841**	**678,539**	**693,880**	**687,134**	**701,698**	**717,592**	**740,053**	**762,996**	**769,485**	**792,197**	**816,365**	**839,762**	**864,813**	**894,247**

Capital Costs																										
Maritime Link	0	0	22,033	155,703	160,477	151,105	155,948	146,514	143,824	141,413	139,011	146,145	135,823	147,261	146,988	145,738	153,641	142,802	141,185	139,471	137,673	146,337	133,855	131,858	129,802	127,698
Combined Cycles Units			0	0	0	0	0	0	0	0	0	0	0	0	0	49,593	48,696	47,798	46,900	46,002	99,860	97,971	96,082	94,193	92,304	90,415
Total Capital Costs (k$)	**0**	**0**	**22,033**	**155,703**	**160,477**	**151,105**	**155,948**	**146,514**	**143,824**	**141,413**	**139,011**	**146,145**	**135,823**	**147,261**	**146,988**	**195,331**	**202,337**	**190,600**	**188,085**	**185,473**	**237,533**	**244,308**	**229,937**	**226,051**	**222,107**	**218,113**

Total Operating Cost NPV (k$)	$8,360,729
Total Capital Cost NPV (k$)	$1,745,566
Total Planning Period NPV (k$)	$10,106,295

OI Base Load, Low Power & Gas Prices

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Total Thermal Cost	396,382	410,865	396,085	275,064	282,820	296,950	313,261	323,042	326,250	341,794	341,194	342,695	351,113
Total Emissions Cost (Ash removal)	959	1,101	1,137	995	1,002	1,113	1,092	1,103	1,145	1,178	1,240	1,287	1,318
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	162,074	239,094	244,204	250,614	255,220	261,176	242,984	245,657	247,208	249,378	251,590
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports	0	0	59,421	116,772	119,195	126,440	124,628	129,242	139,365	133,904	151,921	160,720	165,656
Total Operating Cost	**527,116**	**552,843**	**644,867**	**708,108**	**728,245**	**761,952**	**785,694**	**811,734**	**809,590**	**824,439**	**845,058**	**859,453**	**876,965**

	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Total Thermal Cost	368,548	375,407	401,798	407,817	429,575	411,974	429,745	448,226	466,157	483,655	491,901	499,326	514,510
Total Emissions Cost (Ash removal)	1,318	1,331	1,340	1,351	1,367	1,310	1,344	1,385	1,430	1,452	1,495	1,186	1,189
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	254,442	256,138	258,477	260,862	263,913	265,765	268,287	270,857	274,123	276,144	278,863	281,635	285,131
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	163,942	172,249	167,641	175,621	171,514	181,885	186,611	193,660	198,948	206,778	222,951	244,203	256,470
Total Operating Cost	**897,765**	**916,360**	**942,525**	**960,994**	**984,120**	**980,551**	**1,007,805**	**1,038,189**	**1,067,329**	**1,096,716**	**1,126,280**	**1,159,851**	**1,193,624**

OI Base Load, Low Power & Gas Prices	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**	**2026**	**2027**
Total Unit Cost	407,536	422,161	407,417	286,254	294,017	308,258	324,548	334,340	337,590	353,167	352,629	354,178	362,626
Renewables IPPs	119,579	130,682	146,119	173,106	173,374	173,975	173,923	174,201	153,334	153,948	153,908	154,200	154,496
Other Import (Contract Energy)	0	0	15,955	65,988	70,830	76,639	81,298	86,975	89,650	91,710	93,300	95,178	97,094
Imports	0	0	59,421	116,772	119,195	126,440	124,628	129,242	139,365	133,904	151,921	160,720	165,656
Total Operating Cost (k$)	**527,116**	**552,843**	**628,912**	**642,120**	**657,416**	**685,312**	**704,397**	**724,758**	**719,939**	**732,729**	**751,758**	**764,276**	**779,871**
Capital Costs													
Other Import (Contract Energy)	0	0	8,118	56,906	57,450	57,845	58,103	58,234	58,249	58,158	57,968	57,687	57,324
Combustion Turbines & Combined Cycle			0	0	0	0	0	0	0	0	0	0	0
Total Capital Costs (k$)	**0**	**0**	**8,118**	**56,906**	**57,450**	**57,845**	**58,103**	**58,234**	**58,249**	**58,158**	**57,968**	**57,687**	**57,324**

OI Base Load, Low Power & Gas Prices	**2028**	**2029**	**2030**	**2031**	**2032**	**2033**	**2034**	**2035**	**2036**	**2037**	**2038**	**2039**	**2040**
Total Unit Cost	380,062	386,933	413,333	419,363	441,137	423,480	441,285	459,805	477,782	495,302	503,591	510,707	525,894
Renewables IPPs	155,123	155,097	155,404	155,714	156,356	156,344	156,665	156,990	157,647	157,652	157,988	158,328	159,002
Other Import (Contract Energy)	99,319	101,041	103,074	105,148	107,557	109,421	111,622	113,867	116,476	118,492	120,875	123,306	126,129
Imports	163,942	172,249	167,641	175,621	171,514	181,885	186,611	193,660	198,948	206,778	222,951	244,203	256,470
Total Operating Cost (k$)	**798,446**	**815,320**	**839,451**	**855,846**	**876,563**	**871,130**	**896,183**	**924,322**	**950,853**	**978,224**	**1,005,405**	**1,036,544**	**1,067,495**
Capital Costs													
Other Import (Contract Energy)	56,883	56,373	55,797	55,162	54,471	53,731	52,944	52,114	51,245	50,340	49,401	48,432	47,435
Combustion Turbines & Combined Cycle	0	6,997	14,007	13,751	13,495	65,868	64,660	63,451	62,243	61,034	59,826	58,617	57,409
Total Capital Costs (k$)	**56,883**	**63,369**	**69,804**	**68,913**	**67,967**	**119,599**	**117,604**	**115,565**	**113,488**	**111,374**	**109,227**	**107,050**	**104,844**

Total Operating Cost NPV (k$)	$9,662,832
Total Capital Cost NPV (k$)	$730,867
Total Planning Period NPV (k$)	$10,393,699

Indigenous Wind Base Load, Low Power & Gas Prices

	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Total Thermal Cost	396,382	410,865	439,168	441,525	425,721	444,241	459,255	472,179	485,927	498,781	529,695	510,872	523,608	521,341	552,737	577,618	594,591	619,351	651,162	663,062	634,610	659,583	674,332	700,728	713,524	747,168
Total Emissions Cost (Ash removal)	959	1,101	1,209	1,232	1,249	1,276	1,302	1,328	1,356	1,385	1,351	1,367	1,406	1,393	853	331	148	48	31	23	295	137	117	46	182	32
Hydro Fixed Costs	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195	10,195
Transaction Purchase Cost	119,579	130,682	140,588	150,760	167,286	167,994	168,043	168,433	147,682	148,422	148,501	148,924	149,355	152,426	152,585	153,088	153,603	154,464	154,662	157,792	158,403	159,360	162,399	163,099	163,815	164,883
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports	0	0	57,930	112,915	119,022	87,161	89,872	87,294	93,321	96,033	102,257	101,051	100,157	97,751	108,211	113,162	114,615	110,489	117,611	118,734	124,902	131,857	133,703	132,966	136,860	137,287
Total Operating Cost	**527,116**	**552,843**	**649,090**	**716,626**	**725,000**	**712,430**	**730,255**	**741,049**	**740,134**	**756,508**	**793,718**	**774,162**	**786,509**	**785,135**	**826,642**	**856,498**	**875,296**	**896,742**	**935,892**	**952,304**	**930,951**	**963,739**	**983,630**	**1,009,975**	**1,027,578**	**1,062,637**

Indigenous Wind Base Load, Low Power & Gas Prices	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
Total Unit Cost	407,536	422,161	450,572	452,951	437,166	455,712	470,752	483,702	497,478	510,362	541,241	522,434	535,208	532,930	563,785	588,145	604,934	629,593	661,388	673,281	645,100	669,914	684,644	710,968	723,901	757,396
Renewables IPPs	119,579	130,682	140,588	150,760	165,759	166,431	166,454	166,813	146,029	146,730	146,782	147,170	147,566	150,398	150,523	150,986	151,458	152,268	152,430	155,296	155,856	156,753	159,515	160,157	160,814	161,810
Incremental Wind	0	0	0	0	1,527	1,563	1,588	1,620	1,653	1,692	1,719	1,754	1,789	2,028	2,061	2,102	2,145	2,196	2,231	2,497	2,547	2,607	2,884	2,942	3,001	3,072
Imports	0	0	38,482	39,293	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Less Exports	0	0	484	519	7,282	6,644	7,248	7,786	6,716	6,656	998	10,054	9,346	5,354	701	1,275	983	622	303	276	2,606	1,820	1,838	875	1,710	448
Total Operating Cost (k$)	**527,116**	**552,843**	**629,157**	**642,485**	**597,169**	**617,061**	**631,546**	**644,349**	**638,444**	**652,128**	**688,744**	**661,304**	**675,217**	**680,002**	**715,668**	**739,958**	**757,554**	**783,435**	**815,747**	**830,797**	**800,897**	**827,454**	**845,205**	**873,192**	**886,007**	**921,831**

Capital Costs																										
Incremental Wind	0	0	0	0	55,217	-4,185	63,150	97,643	114,337	121,382	123,199	122,182	119,629	123,978	111,819	117,171	117,789	115,841	112,503	117,123	103,251	109,153	118,998	106,780	110,015	45,435
Combustion Turbine & Combined Cycles	0	0	0	0	82,098	68,470	68,757	68,885	68,867	68,713	68,436	113,861	112,535	111,113	109,602	137,308	135,110	132,842	130,511	128,121	180,432	176,947	173,417	169,845	201,250	196,970
Total Capital Costs (k$)	**0**	**0**	**0**	**0**	**137,315**	**64,285**	**131,907**	**166,528**	**183,203**	**190,096**	**191,635**	**236,043**	**232,164**	**235,091**	**221,421**	**254,479**	**252,898**	**248,683**	**243,014**	**245,244**	**283,683**	**286,101**	**292,415**	**276,625**	**311,265**	**242,405**

Total Operating Cost NPV (k$)	$8,809,017
Total Capital Cost NPV (k$)	$1,922,137
Total Planning Period NPV (k$)	$10,731,153

Adder to End Effect Costs of a 15 year PPA every 50 years (assumes ML Capital costs are depreciated over 35 yrs and ML has a 50 year operating life).
Base Load and Low Load

	ML Capital Investment		**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $102 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$134**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $134
			$/MWh	**GWh**	**$M**	**$M**
2015	0				0	0.00
2016	0				0	0.00
2017					0	0.00
2018			**0**	895	0	0.00
2019			**0**	895	0	0.00
2020			**0**	895	0	0.00
2021			**0**	895	0	0.00
2022			**0**	895	0	0.00
2023			**0**	895	0	0.00
2024			**0**	895	0	0.00
2025			**0**	895	0	0.00
2026			**0**	895	0	0.00
2027			**0**	895	0	0.00
2028			**0**	895	0	0.00
2029			**0**	895	0	0.00
2030			**0**	895	0	0.00
2031			**0**	895	0	0.00
2032			**0**	895	0	0.00
2033			**0**	895	0	0.00
2034		Year 1 to 35 depreciation of	**0**	895	0	0.00
2035		ML project (runs into year	**0**	895	0	0.00
2036		36 due to Oct/2017 start)	**0**	895	0	0.00
2037			**0**	895	0	0.00
2038			**0**	895	0	0.00
2039			**0**	895	0	0.00
2040			**0**	895	0	0.00
2041		End Effects Period begins	**0**	895	0	0.00
2042		in 2041.	**0**	895	0	0.00
2043			**0**	895	0	0.00
2044			**0**	895	0	0.00
2045			**0**	895	0	0.00
2046			**0**	895	0	0.00
2047			**0**	895	0	0.00
2048			**0**	895	0	0.00
2049			**0**	895	0	0.00
2050			**0**	895	0	0.00
2051			**0**	895	0	0.00
2052			**0**	895	0	0.00
2053	0		**132**	895	118	10.57
2054	0		**135**	895	121	10.12
2055	0		**137**	895	123	9.68
2056	0		**140**	895	125	9.27
2057	0		**143**	895	128	8.87
2058	0		**146**	895	131	8.49
2059	0	Year 36 to 50 after ML	**149**	895	133	8.13
2060	0	project is depreciated.	**152**	895	136	7.78
2061	0	PPA for the NS Block	**155**	895	139	7.45
2062	0	is assumed. →	**158**	895	141	7.13
2063	0		**161**	895	144	6.83
2064	0		**164**	895	147	6.53
2065	0		**168**	895	150	6.25
2066	0		**171**	895	153	5.99
2067	0		**174**	895	156	5.73

	ML Capital Investment		PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $102 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $134	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $134
			$/MWh	**GWh**	**$M**	**$M**
2068			**0**	895	0	0.00
2069			**0**	895	0	0.00
2070			**0**	895	0	0.00
2071			**0**	895	0	0.00
2072			**0**	895	0	0.00
2073			**0**	895	0	0.00
2074			**0**	895	0	0.00
2075			**0**	895	0	0.00
2076			**0**	895	0	0.00
2077			**0**	895	0	0.00
2078			**0**	895	0	0.00
2079			**0**	895	0	0.00
2080			**0**	895	0	0.00
2081			**0**	895	0	0.00
2082			**0**	895	0	0.00
2083			**0**	895	0	0.00
2084		Replacement in-kind	**0**	895	0	0.00
2085		of ML Project in end effects	**0**	895	0	0.00
2086		period evergy 50 years.	**0**	895	0	0.00
2087			**0**	895	0	0.00
2088			**0**	895	0	0.00
2089			**0**	895	0	0.00
2090			**0**	895	0	0.00
2091			**0**	895	0	0.00
2092			**0**	895	0	0.00
2093			**0**	895	0	0.00
2094			**0**	895	0	0.00
2095			**0**	895	0	0.00
2096			**0**	895	0	0.00
2097			**0**	895	0	0.00
2098			**0**	895	0	0.00
2099			**0**	895	0	0.00
2100			**0**	895	0	0.00
2101			**0**	895	0	0.00
2102			**0**	895	0	0.00
2103	0		**355**	895	318	1.19
2104	0		**363**	895	325	1.14
2105	0		**370**	895	331	1.09
2106	0		**377**	895	338	1.04
2107	0		**385**	895	344	1.00
2108	0		**392**	895	351	0.95
2109	0		**400**	895	358	0.91
2110	0		**408**	895	365	0.87
2111	0		**417**	895	373	0.84
2112	0		**425**	895	380	0.80
2113	0		**433**	895	388	0.77
2114	0		**442**	895	396	0.73
2115	0		**451**	895	404	0.70
2116	0		**460**	895	412	0.67
2117	0		**469**	895	420	0.64

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $102 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$134**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $134
	$/MWh	**GWh**	**$M**	**$M**
2118	**0**	895	0	0.00
2119	**0**	895	0	0.00
2120	**0**	895	0	0.00
2121	**0**	895	0	0.00
2122	**0**	895	0	0.00
2123	**0**	895	0	0.00
2124	**0**	895	0	0.00
2125	**0**	895	0	0.00
2126	**0**	895	0	0.00
2127	**0**	895	0	0.00
2128	**0**	895	0	0.00
2129	**0**	895	0	0.00
2130	**0**	895	0	0.00
2131	**0**	895	0	0.00
2132	**0**	895	0	0.00
2133	**0**	895	0	0.00
2134	**0**	895	0	0.00
2135	**0**	895	0	0.00
2136	**0**	895	0	0.00
2137	**0**	895	0	0.00
2138	**0**	895	0	0.00
2139	**0**	895	0	0.00
2140	**0**	895	0	0.00
2141	**0**	895	0	0.00
2142	**0**	895	0	0.00
2143	**0**	895	0	0.00
2144	**0**	895	0	0.00
2145	**0**	895	0	0.00
2146	**0**	895	0	0.00
2147	**0**	895	0	0.00
2148	**0**	895	0	0.00
2149	**0**	895	0	0.00
2150	**0**	895	0	0.00
2151	**0**	895	0	0.00
2152	**0**	895	0	0.00
2153	**957**	895	856	0.13
2154	**976**	895	874	0.13
2155	**996**	895	891	0.12
2156	**1,015**	895	909	0.12
2157	**1,036**	895	927	0.11
2158	**1,056**	895	946	0.11
2159	**1,078**	895	964	0.10
2160	**1,099**	895	984	0.10
2161	**1,121**	895	1,003	0.09
2162	**1,144**	895	1,023	0.09
2163	**1,166**	895	1,044	0.09
2164	**1,190**	895	1,065	0.08
2165	**1,214**	895	1,086	0.08
2166	**1,238**	895	1,108	0.08
2167	**1,263**	895	1,130	0.07

	PPA starting in 2053		Annual Cost of PPA	
	Base Year			
	2040			
ML Capital	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
Investment	$102		(2041 and beyond)	PV of Annual costs
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$134**	$134
	$/MWh	**GWh**	**$M**	**$M**
2168	**0**	895	0	0.00
2169	**0**	895	0	0.00
2170	**0**	895	0	0.00
2171	**0**	895	0	0.00
2172	**0**	895	0	0.00
2173	**0**	895	0	0.00
2174	**0**	895	0	0.00
2175	**0**	895	0	0.00
2176	**0**	895	0	0.00
2177	**0**	895	0	0.00
2178	**0**	895	0	0.00
2179	**0**	895	0	0.00
2180	**0**	895	0	0.00
2181	**0**	895	0	0.00
2182	**0**	895	0	0.00
2183	**0**	895	0	0.00
2184	**0**	895	0	0.00
2185	**0**	895	0	0.00
2186	**0**	895	0	0.00
2187	**0**	895	0	0.00
2188	**0**	895	0	0.00
2189	**0**	895	0	0.00
2190	**0**	895	0	0.00
2191	**0**	895	0	0.00
2192	**0**	895	0	0.00
2193	**0**	895	0	0.00
2194	**0**	895	0	0.00
2195	**0**	895	0	0.00
2196	**0**	895	0	0.00
2197	**0**	895	0	0.00
2198	**0**	895	0	0.00
2199	**0**	895	0	0.00
2200	**0**	895	0	0.00
2201	**0**	895	0	0.00
2202	**0**	895	0	0.00
2203	**2,575**	895	2,305	0.01
2204	**2,627**	895	2,351	0.01
2205	**2,679**	895	2,398	0.01
2206	**2,733**	895	2,446	0.01
2207	**2,788**	895	2,495	0.01
2208	**2,844**	895	2,545	0.01
2209	**2,900**	895	2,596	0.01
2210	**2,958**	895	2,648	0.01
2211	**3,018**	895	2,701	0.01
2212	**3,078**	895	2,755	0.01
2213	**3,139**	895	2,810	0.01
2214	**3,202**	895	2,866	0.01
2215	**3,266**	895	2,923	0.01
2216	**3,332**	895	2,982	0.01
2217	**3,398**	895	3,041	0.01

	PPA starting in 2053			
	Base Year		Annual Cost of PPA	
	2040			
ML Capital Investment	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
	$102		(2041 and beyond)	PV of Annual costs
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$134**	$134
	$/MWh	**GWh**	**$M**	**$M**
2218	**0**	895	0	0.00
2219	**0**	895	0	0.00
2220	**0**	895	0	0.00
2221	**0**	895	0	0.00
2222	**0**	895	0	0.00
2223	**0**	895	0	0.00
2224	**0**	895	0	0.00
2225	**0**	895	0	0.00
2226	**0**	895	0	0.00
2227	**0**	895	0	0.00
2228	**0**	895	0	0.00
2229	**0**	895	0	0.00
2230	**0**	895	0	0.00
2231	**0**	895	0	0.00
2232	**0**	895	0	0.00
2233	**0**	895	0	0.00
2234	**0**	895	0	0.00
2235	**0**	895	0	0.00
2236	**0**	895	0	0.00
2237	**0**	895	0	0.00
2238	**0**	895	0	0.00
2239	**0**	895	0	0.00
2240	**0**	895	0	0.00
2241	**0**	895	0	0.00
2242	**0**	895	0	0.00
2243	**0**	895	0	0.00
2244	**0**	895	0	0.00
2245	**0**	895	0	0.00
2246	**0**	895	0	0.00
2247	**0**	895	0	0.00
2248	**0**	895	0	0.00
2249	**0**	895	0	0.00
2250	**0**	895	0	0.00
2251	**0**	895	0	0.00
2252	**0**	895	0	0.00
2253	**6,932**	895	6,204	0.00
2254	**7,071**	895	6,328	0.00
2255	**7,212**	895	6,455	0.00
2256	**7,356**	895	6,584	0.00
2257	**7,503**	895	6,716	0.00
2258	**7,654**	895	6,850	0.00
2259	**7,807**	895	6,987	0.00
2260	**7,963**	895	7,127	0.00
2261	**8,122**	895	7,269	0.00
2262	**8,284**	895	7,415	0.00
2263	**8,450**	895	7,563	0.00
2264	**8,619**	895	7,714	0.00
2265	**8,792**	895	7,868	0.00
2266	**8,967**	895	8,026	0.00
2267	**9,147**	895	8,186	0.00

ML Capital Investment	PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $102 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $134	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $134
	$/MWh	**GWh**	**$M**	**$M**
2268	**0**	895	0	0.00
2269	**0**	895	0	0.00
2270	**0**	895	0	0.00
2271	**0**	895	0	0.00
2272	**0**	895	0	0.00
2273	**0**	895	0	0.00
2274	**0**	895	0	0.00
2275	**0**	895	0	0.00
2276	**0**	895	0	0.00
2277	**0**	895	0	0.00
2278	**0**	895	0	0.00
2279	**0**	895	0	0.00
2280	**0**	895	0	0.00
2281	**0**	895	0	0.00
2282	**0**	895	0	0.00
2283	**0**	895	0	0.00
2284	**0**	895	0	0.00
2285	**0**	895	0	0.00
2286	**0**	895	0	0.00
2287	**0**	895	0	0.00
2288	**0**	895	0	0.00
2289	**0**	895	0	0.00
2290	**0**	895	0	0.00
2291	**0**	895	0	0.00
2292	**0**	895	0	0.00
2293	**0**	895	0	0.00
2294	**0**	895	0	0.00
2295	**0**	895	0	0.00
2296	**0**	895	0	0.00
2297	**0**	895	0	0.00
2298	**0**	895	0	0.00
2299	**0**	895	0	0.00
2300	**0**	895	0	0.00
2301	**0**	895	0	0.00
2302	**0**	895	0	0.00
2303	**18,658**	895	16,699	0.00
2304	**19,031**	895	17,033	0.00
2305	**19,412**	895	17,374	0.00
2306	**19,800**	895	17,721	0.00
2307	**20,196**	895	18,076	0.00
2308	**20,600**	895	18,437	0.00
2309	**21,012**	895	18,806	0.00
2310	**21,432**	895	19,182	0.00
2311	**21,861**	895	19,566	0.00
2312	**22,298**	895	19,957	0.00
2313	**22,744**	895	20,356	0.00
2314	**23,199**	895	20,763	0.00
2315	**23,663**	895	21,179	0.00
2316	**24,136**	895	21,602	0.00
2317	**24,619**	895	22,034	0.00

ML Capital Investment	PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $102 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $134	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $134
	$/MWh	**GWh**	**$M**	**$M**
2318	**0**	895	0	0.00
2319	**0**	895	0	0.00
2320	**0**	895	0	0.00
2321	**0**	895	0	0.00
2322	**0**	895	0	0.00
2323	**0**	895	0	0.00
2324	**0**	895	0	0.00
2325	**0**	895	0	0.00
2326	**0**	895	0	0.00
2327	**0**	895	0	0.00
2328	**0**	895	0	0.00
2329	**0**	895	0	0.00
2330	**0**	895	0	0.00
2331	**0**	895	0	0.00
2332	**0**	895	0	0.00
2333	**0**	895	0	0.00
2334	**0**	895	0	0.00
2335	**0**	895	0	0.00
2336	**0**	895	0	0.00
2337	**0**	895	0	0.00
2338	**0**	895	0	0.00
2339	**0**	895	0	0.00
2340	**0**	895	0	0.00
2341	**0**	895	0	0.00
2342	**0**	895	0	0.00
2343	**0**	895	0	0.00
2344	**0**	895	0	0.00
2345	**0**	895	0	0.00
2346	**0**	895	0	0.00
2347	**0**	895	0	0.00
2348	**0**	895	0	0.00
2349	**0**	895	0	0.00
2350	**0**	895	0	0.00
2351	**0**	895	0	0.00
2352	**0**	895	0	0.00
2353	**50,220**	895	44,947	0.00
2354	**51,225**	895	45,846	0.00
2355	**52,249**	895	46,763	0.00
2356	**53,294**	895	47,698	0.00
2357	**54,360**	895	48,652	0.00
2358	**55,447**	895	49,625	0.00
2359	**56,556**	895	50,618	0.00
2360	**57,687**	895	51,630	0.00
2361	**58,841**	895	52,663	0.00
2362	**60,018**	895	53,716	0.00
2363	**61,218**	895	54,790	0.00
2364	**62,443**	895	55,886	0.00
2365	**63,691**	895	57,004	0.00
2366	**64,965**	895	58,144	0.00
2367	**66,265**	895	59,307	0.00

		PPA starting in 2053			
		Base Year		Annual Cost of PPA	
		2040			
	ML Capital	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
	Investment	$102		(2041 and beyond)	PV of Annual costs
		Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
		2.0%		**$134**	$134
		$/MWh	**GWh**	**$M**	**$M**
2368		**0**	895	0	0.00
2369		**0**	895	0	0.00
2370		**0**	895	0	0.00
2371		**0**	895	0	0.00
2372		**0**	895	0	0.00
2373		**0**	895	0	0.00
2374		**0**	895	0	0.00
2375		**0**	895	0	0.00
2376		**0**	895	0	0.00
2377		**0**	895	0	0.00
2378		**0**	895	0	0.00
2379		**0**	895	0	0.00
2380		**0**	895	0	0.00
2381		**0**	895	0	0.00
2382		**0**	895	0	0.00
2383		**0**	895	0	0.00
2384		**0**	895	0	0.00
2385		**0**	895	0	0.00
2386		**0**	895	0	0.00
2387		**0**	895	0	0.00
2388		**0**	895	0	0.00
2389		**0**	895	0	0.00
2390		**0**	895	0	0.00
2391		**0**	895	0	0.00
2392		**0**	895	0	0.00
2393		**0**	895	0	0.00
2394		**0**	895	0	0.00
2395		**0**	895	0	0.00
2396		**0**	895	0	0.00
2397		**0**	895	0	0.00
2398		**0**	895	0	0.00
2399		**0**	895	0	0.00
2400		**0**	895	0	0.00
2401		**0**	895	0	0.00
2402		**0**	895	0	0.00
2403		**135,172**	895	120,979	0.00
2404		**137,876**	895	123,399	0.00
2405		**140,633**	895	125,867	0.00
2406		**143,446**	895	128,384	0.00
2407		**146,315**	895	130,952	0.00
2408		**149,241**	895	133,571	0.00
2409		**152,226**	895	136,242	0.00
2410		**155,270**	895	138,967	0.00
2411		**158,376**	895	141,746	0.00
2412		**161,543**	895	144,581	0.00
2413		**164,774**	895	147,473	0.00
2414		**168,070**	895	150,422	0.00
2415		**171,431**	895	153,431	0.00
2416		**174,860**	895	156,500	0.00
2417		**178,357**	895	159,630	0.00

ML Capital Investment	PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $102 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $134	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $134
	$/MWh	**GWh**	**$M**	**$M**
2418	**0**	895	0	0.00
2419	**0**	895	0	0.00
2420	**0**	895	0	0.00
2421	**0**	895	0	0.00
2422	**0**	895	0	0.00
2423	**0**	895	0	0.00
2424	**0**	895	0	0.00
2425	**0**	895	0	0.00
2426	**0**	895	0	0.00
2427	**0**	895	0	0.00
2428	**0**	895	0	0.00
2429	**0**	895	0	0.00
2430	**0**	895	0	0.00
2431	**0**	895	0	0.00
2432	**0**	895	0	0.00
2433	**0**	895	0	0.00
2434	**0**	895	0	0.00
2435	**0**	895	0	0.00
2436	**0**	895	0	0.00
2437	**0**	895	0	0.00
2438	**0**	895	0	0.00
2439	**0**	895	0	0.00
2440	**0**	895	0	0.00
2441	**0**	895	0	0.00
2442	**0**	895	0	0.00
2443	**0**	895	0	0.00
2444	**0**	895	0	0.00
2445	**0**	895	0	0.00
2446	**0**	895	0	0.00
2447	**0**	895	0	0.00
2448	**0**	895	0	0.00
2449	**0**	895	0	0.00
2450	**0**	895	0	0.00
2451	**0**	895	0	0.00
2452	**0**	895	0	0.00
2453	**363,828**	895	325,626	0.00
2454	**371,105**	895	332,139	0.00
2455	**378,527**	895	338,782	0.00
2456	**386,097**	895	345,557	0.00
2457	**393,819**	895	352,468	0.00
2458	**401,696**	895	359,518	0.00
2459	**409,730**	895	366,708	0.00
2460	**417,924**	895	374,042	0.00
2461	**426,283**	895	381,523	0.00
2462	**434,808**	895	389,153	0.00
2463	**443,505**	895	396,937	0.00
2464	**452,375**	895	404,875	0.00
2465	**461,422**	895	412,973	0.00
2466	**470,651**	895	421,232	0.00
2467	**480,064**	895	429,657	0.00
2468	**0**	895	0	0.00
2469	**0**	895	0	0.00
2470	**0**	895	0	0.00
2471	**0**	895	0	0.00
2472	**0**	895	0	0.00
2473	**0**	895	0	0.00
2474	**0**	895	0	0.00
2475	**0**	895	0	0.00
2476	**0**	895	0	0.00
2477	**0**	895	0	0.00
2478	**0**	895	0	0.00
2479	**0**	895	0	0.00
2480	**0**	895	0	0.00
2481	**0**	895	0	0.00
2482	**0**	895	0	0.00
2483	**0**	895	0	0.00
2484	**0**	895	0	0.00
2485	**0**	895	0	0.00
2486	**0**	895	0	0.00

		PPA starting in 2053			
		Base Year		Annual Cost of PPA	
		2040			
	ML Capital Investment	PPA price $/MWh (BaseYr$)		End Effects Adder (2041 and beyond)	Check of NPV: PV of Annual costs
		$102			
		Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
		2.0%		**$134**	$134
		$/MWh	**GWh**	**$M**	**$M**
2487		**0**	895	0	0.00
2488		**0**	895	0	0.00
2489		**0**	895	0	0.00
2490		**0**	895	0	0.00
2491		**0**	895	0	0.00
2492		**0**	895	0	0.00
2493		**0**	895	0	0.00
2494		**0**	895	0	0.00
2495		**0**	895	0	0.00
2496		**0**	895	0	0.00
2497		**0**	895	0	0.00
2498		**0**	895	0	0.00
2499		**0**	895	0	0.00
2500		**0**	895	0	0.00

Adder to End Effect Costs of a 15 year PPA every 50 years (assumes ML Capital costs are depreciated over 35 yrs and ML has a 50 year operating life).
High Power - High Gas Sensitivity

	ML Capital Investment		PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
			$/MWh	**GWh**	**$M**	**$M**
2015	0				0	0.00
2016	0				0	0.00
2017					0	0.00
2018			**0**	895	0	0.00
2019			**0**	895	0	0.00
2020			**0**	895	0	0.00
2021			**0**	895	0	0.00
2022			**0**	895	0	0.00
2023			**0**	895	0	0.00
2024			**0**	895	0	0.00
2025			**0**	895	0	0.00
2026			**0**	895	0	0.00
2027			**0**	895	0	0.00
2028			**0**	895	0	0.00
2029			**0**	895	0	0.00
2030			**0**	895	0	0.00
2031			**0**	895	0	0.00
2032			**0**	895	0	0.00
2033			**0**	895	0	0.00
2034		Year 1 to 35 depreciation of	**0**	895	0	0.00
2035		ML project (runs into year	**0**	895	0	0.00
2036		36 due to Oct/2017 start)	**0**	895	0	0.00
2037			**0**	895	0	0.00
2038			**0**	895	0	0.00
2039			**0**	895	0	0.00
2040			**0**	895	0	0.00
2041		End Effects Period begins	**0**	895	0	0.00
2042		in 2041.	**0**	895	0	0.00
2043			**0**	895	0	0.00
2044			**0**	895	0	0.00
2045			**0**	895	0	0.00
2046			**0**	895	0	0.00
2047			**0**	895	0	0.00
2048			**0**	895	0	0.00
2049			**0**	895	0	0.00
2050			**0**	895	0	0.00
2051			**0**	895	0	0.00
2052			**0**	895	0	0.00
2053	0		**168**	895	150	13.45
2054	0		**171**	895	153	12.87
2055	0		**175**	895	156	12.32
2056	0		**178**	895	160	11.79
2057	0		**182**	895	163	11.29
2058	0		**186**	895	166	10.81
2059	0	Year 36 to 50 after ML	**189**	895	169	10.34
2060	0	project is depreciated.	**193**	895	173	9.90
2061	0	PPA for the NS Block	**197**	895	176	9.48
2062	0	is assumed. →	**201**	895	180	9.07
2063	0		**205**	895	183	8.68
2064	0		**209**	895	187	8.31
2065	0		**213**	895	191	7.96
2066	0		**217**	895	195	7.62
2067	0		**222**	895	198	7.29

	ML Capital Investment		PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $170	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
			$/MWh	**GWh**	**$M**	**$M**
2068			**0**	895	0	0.00
2069			**0**	895	0	0.00
2070			**0**	895	0	0.00
2071			**0**	895	0	0.00
2072			**0**	895	0	0.00
2073			**0**	895	0	0.00
2074			**0**	895	0	0.00
2075			**0**	895	0	0.00
2076			**0**	895	0	0.00
2077			**0**	895	0	0.00
2078			**0**	895	0	0.00
2079			**0**	895	0	0.00
2080			**0**	895	0	0.00
2081			**0**	895	0	0.00
2082			**0**	895	0	0.00
2083			**0**	895	0	0.00
2084		Replacement in-kind	**0**	895	0	0.00
2085		of ML Project in end effects	**0**	895	0	0.00
2086		period evergy 50 years.	**0**	895	0	0.00
2087			**0**	895	0	0.00
2088			**0**	895	0	0.00
2089			**0**	895	0	0.00
2090			**0**	895	0	0.00
2091			**0**	895	0	0.00
2092			**0**	895	0	0.00
2093			**0**	895	0	0.00
2094			**0**	895	0	0.00
2095			**0**	895	0	0.00
2096			**0**	895	0	0.00
2097			**0**	895	0	0.00
2098			**0**	895	0	0.00
2099			**0**	895	0	0.00
2100			**0**	895	0	0.00
2101			**0**	895	0	0.00
2102			**0**	895	0	0.00
2103	0		**452**	895	405	1.51
2104	0		**461**	895	413	1.45
2105	0		**471**	895	421	1.38
2106	0		**480**	895	430	1.32
2107	0		**490**	895	438	1.27
2108	0		**499**	895	447	1.21
2109	0		**509**	895	456	1.16
2110	0		**519**	895	465	1.11
2111	0		**530**	895	474	1.06
2112	0		**540**	895	484	1.02
2113	0		**551**	895	493	0.97
2114	0		**562**	895	503	0.93
2115	0		**574**	895	513	0.89
2116	0		**585**	895	524	0.86
2117	0		**597**	895	534	0.82

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
	$/MWh	**GWh**	**$M**	**$M**
2118	**0**	895	0	0.00
2119	**0**	895	0	0.00
2120	**0**	895	0	0.00
2121	**0**	895	0	0.00
2122	**0**	895	0	0.00
2123	**0**	895	0	0.00
2124	**0**	895	0	0.00
2125	**0**	895	0	0.00
2126	**0**	895	0	0.00
2127	**0**	895	0	0.00
2128	**0**	895	0	0.00
2129	**0**	895	0	0.00
2130	**0**	895	0	0.00
2131	**0**	895	0	0.00
2132	**0**	895	0	0.00
2133	**0**	895	0	0.00
2134	**0**	895	0	0.00
2135	**0**	895	0	0.00
2136	**0**	895	0	0.00
2137	**0**	895	0	0.00
2138	**0**	895	0	0.00
2139	**0**	895	0	0.00
2140	**0**	895	0	0.00
2141	**0**	895	0	0.00
2142	**0**	895	0	0.00
2143	**0**	895	0	0.00
2144	**0**	895	0	0.00
2145	**0**	895	0	0.00
2146	**0**	895	0	0.00
2147	**0**	895	0	0.00
2148	**0**	895	0	0.00
2149	**0**	895	0	0.00
2150	**0**	895	0	0.00
2151	**0**	895	0	0.00
2152	**0**	895	0	0.00
2153	**1,217**	895	1,089	0.17
2154	**1,242**	895	1,111	0.16
2155	**1,266**	895	1,133	0.16
2156	**1,292**	895	1,156	0.15
2157	**1,318**	895	1,179	0.14
2158	**1,344**	895	1,203	0.14
2159	**1,371**	895	1,227	0.13
2160	**1,398**	895	1,251	0.12
2161	**1,426**	895	1,276	0.12
2162	**1,455**	895	1,302	0.11
2163	**1,484**	895	1,328	0.11
2164	**1,513**	895	1,355	0.10
2165	**1,544**	895	1,382	0.10
2166	**1,575**	895	1,409	0.10
2167	**1,606**	895	1,437	0.09

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
	$/MWh	**GWh**	**$M**	**$M**
2168	**0**	895	0	0.00
2169	**0**	895	0	0.00
2170	**0**	895	0	0.00
2171	**0**	895	0	0.00
2172	**0**	895	0	0.00
2173	**0**	895	0	0.00
2174	**0**	895	0	0.00
2175	**0**	895	0	0.00
2176	**0**	895	0	0.00
2177	**0**	895	0	0.00
2178	**0**	895	0	0.00
2179	**0**	895	0	0.00
2180	**0**	895	0	0.00
2181	**0**	895	0	0.00
2182	**0**	895	0	0.00
2183	**0**	895	0	0.00
2184	**0**	895	0	0.00
2185	**0**	895	0	0.00
2186	**0**	895	0	0.00
2187	**0**	895	0	0.00
2188	**0**	895	0	0.00
2189	**0**	895	0	0.00
2190	**0**	895	0	0.00
2191	**0**	895	0	0.00
2192	**0**	895	0	0.00
2193	**0**	895	0	0.00
2194	**0**	895	0	0.00
2195	**0**	895	0	0.00
2196	**0**	895	0	0.00
2197	**0**	895	0	0.00
2198	**0**	895	0	0.00
2199	**0**	895	0	0.00
2200	**0**	895	0	0.00
2201	**0**	895	0	0.00
2202	**0**	895	0	0.00
2203	**3,276**	895	2,932	0.02
2204	**3,342**	895	2,991	0.02
2205	**3,409**	895	3,051	0.02
2206	**3,477**	895	3,112	0.02
2207	**3,546**	895	3,174	0.02
2208	**3,617**	895	3,237	0.02
2209	**3,690**	895	3,302	0.01
2210	**3,763**	895	3,368	0.01
2211	**3,839**	895	3,436	0.01
2212	**3,915**	895	3,504	0.01
2213	**3,994**	895	3,574	0.01
2214	**4,074**	895	3,646	0.01
2215	**4,155**	895	3,719	0.01
2216	**4,238**	895	3,793	0.01
2217	**4,323**	895	3,869	0.01

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
	$/MWh	**GWh**	**$M**	**$M**
2218	**0**	895	0	0.00
2219	**0**	895	0	0.00
2220	**0**	895	0	0.00
2221	**0**	895	0	0.00
2222	**0**	895	0	0.00
2223	**0**	895	0	0.00
2224	**0**	895	0	0.00
2225	**0**	895	0	0.00
2226	**0**	895	0	0.00
2227	**0**	895	0	0.00
2228	**0**	895	0	0.00
2229	**0**	895	0	0.00
2230	**0**	895	0	0.00
2231	**0**	895	0	0.00
2232	**0**	895	0	0.00
2233	**0**	895	0	0.00
2234	**0**	895	0	0.00
2235	**0**	895	0	0.00
2236	**0**	895	0	0.00
2237	**0**	895	0	0.00
2238	**0**	895	0	0.00
2239	**0**	895	0	0.00
2240	**0**	895	0	0.00
2241	**0**	895	0	0.00
2242	**0**	895	0	0.00
2243	**0**	895	0	0.00
2244	**0**	895	0	0.00
2245	**0**	895	0	0.00
2246	**0**	895	0	0.00
2247	**0**	895	0	0.00
2248	**0**	895	0	0.00
2249	**0**	895	0	0.00
2250	**0**	895	0	0.00
2251	**0**	895	0	0.00
2252	**0**	895	0	0.00
2253	**8,818**	895	7,892	0.00
2254	**8,995**	895	8,050	0.00
2255	**9,175**	895	8,211	0.00
2256	**9,358**	895	8,375	0.00
2257	**9,545**	895	8,543	0.00
2258	**9,736**	895	8,714	0.00
2259	**9,931**	895	8,888	0.00
2260	**10,130**	895	9,066	0.00
2261	**10,332**	895	9,247	0.00
2262	**10,539**	895	9,432	0.00
2263	**10,750**	895	9,621	0.00
2264	**10,965**	895	9,813	0.00
2265	**11,184**	895	10,009	0.00
2266	**11,407**	895	10,210	0.00
2267	**11,636**	895	10,414	0.00

	PPA starting in 2053			
	Base Year		Annual Cost of PPA	
	2040			
ML Capital	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
Investment	$130		(2041 and beyond)	PV of Annual costs
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$170**	$170
	$/MWh	**GWh**	**$M**	**$M**
2268	**0**	895	0	0.00
2269	**0**	895	0	0.00
2270	**0**	895	0	0.00
2271	**0**	895	0	0.00
2272	**0**	895	0	0.00
2273	**0**	895	0	0.00
2274	**0**	895	0	0.00
2275	**0**	895	0	0.00
2276	**0**	895	0	0.00
2277	**0**	895	0	0.00
2278	**0**	895	0	0.00
2279	**0**	895	0	0.00
2280	**0**	895	0	0.00
2281	**0**	895	0	0.00
2282	**0**	895	0	0.00
2283	**0**	895	0	0.00
2284	**0**	895	0	0.00
2285	**0**	895	0	0.00
2286	**0**	895	0	0.00
2287	**0**	895	0	0.00
2288	**0**	895	0	0.00
2289	**0**	895	0	0.00
2290	**0**	895	0	0.00
2291	**0**	895	0	0.00
2292	**0**	895	0	0.00
2293	**0**	895	0	0.00
2294	**0**	895	0	0.00
2295	**0**	895	0	0.00
2296	**0**	895	0	0.00
2297	**0**	895	0	0.00
2298	**0**	895	0	0.00
2299	**0**	895	0	0.00
2300	**0**	895	0	0.00
2301	**0**	895	0	0.00
2302	**0**	895	0	0.00
2303	**23,735**	895	21,243	0.00
2304	**24,210**	895	21,668	0.00
2305	**24,694**	895	22,101	0.00
2306	**25,188**	895	22,543	0.00
2307	**25,692**	895	22,994	0.00
2308	**26,206**	895	23,454	0.00
2309	**26,730**	895	23,923	0.00
2310	**27,264**	895	24,402	0.00
2311	**27,810**	895	24,890	0.00
2312	**28,366**	895	25,388	0.00
2313	**28,933**	895	25,895	0.00
2314	**29,512**	895	26,413	0.00
2315	**30,102**	895	26,941	0.00
2316	**30,704**	895	27,480	0.00
2317	**31,318**	895	28,030	0.00

ML Capital Investment	PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
	$/MWh	**GWh**	**$M**	**$M**
2318	**0**	895	0	0.00
2319	**0**	895	0	0.00
2320	**0**	895	0	0.00
2321	**0**	895	0	0.00
2322	**0**	895	0	0.00
2323	**0**	895	0	0.00
2324	**0**	895	0	0.00
2325	**0**	895	0	0.00
2326	**0**	895	0	0.00
2327	**0**	895	0	0.00
2328	**0**	895	0	0.00
2329	**0**	895	0	0.00
2330	**0**	895	0	0.00
2331	**0**	895	0	0.00
2332	**0**	895	0	0.00
2333	**0**	895	0	0.00
2334	**0**	895	0	0.00
2335	**0**	895	0	0.00
2336	**0**	895	0	0.00
2337	**0**	895	0	0.00
2338	**0**	895	0	0.00
2339	**0**	895	0	0.00
2340	**0**	895	0	0.00
2341	**0**	895	0	0.00
2342	**0**	895	0	0.00
2343	**0**	895	0	0.00
2344	**0**	895	0	0.00
2345	**0**	895	0	0.00
2346	**0**	895	0	0.00
2347	**0**	895	0	0.00
2348	**0**	895	0	0.00
2349	**0**	895	0	0.00
2350	**0**	895	0	0.00
2351	**0**	895	0	0.00
2352	**0**	895	0	0.00
2353	**63,886**	895	57,178	0.00
2354	**65,164**	895	58,321	0.00
2355	**66,467**	895	59,488	0.00
2356	**67,796**	895	60,678	0.00
2357	**69,152**	895	61,891	0.00
2358	**70,535**	895	63,129	0.00
2359	**71,946**	895	64,391	0.00
2360	**73,385**	895	65,679	0.00
2361	**74,852**	895	66,993	0.00
2362	**76,349**	895	68,333	0.00
2363	**77,876**	895	69,699	0.00
2364	**79,434**	895	71,093	0.00
2365	**81,023**	895	72,515	0.00
2366	**82,643**	895	73,966	0.00
2367	**84,296**	895	75,445	0.00

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
	$/MWh	**GWh**	**$M**	**$M**
2368	**0**	895	0	0.00
2369	**0**	895	0	0.00
2370	**0**	895	0	0.00
2371	**0**	895	0	0.00
2372	**0**	895	0	0.00
2373	**0**	895	0	0.00
2374	**0**	895	0	0.00
2375	**0**	895	0	0.00
2376	**0**	895	0	0.00
2377	**0**	895	0	0.00
2378	**0**	895	0	0.00
2379	**0**	895	0	0.00
2380	**0**	895	0	0.00
2381	**0**	895	0	0.00
2382	**0**	895	0	0.00
2383	**0**	895	0	0.00
2384	**0**	895	0	0.00
2385	**0**	895	0	0.00
2386	**0**	895	0	0.00
2387	**0**	895	0	0.00
2388	**0**	895	0	0.00
2389	**0**	895	0	0.00
2390	**0**	895	0	0.00
2391	**0**	895	0	0.00
2392	**0**	895	0	0.00
2393	**0**	895	0	0.00
2394	**0**	895	0	0.00
2395	**0**	895	0	0.00
2396	**0**	895	0	0.00
2397	**0**	895	0	0.00
2398	**0**	895	0	0.00
2399	**0**	895	0	0.00
2400	**0**	895	0	0.00
2401	**0**	895	0	0.00
2402	**0**	895	0	0.00
2403	**171,954**	895	153,899	0.00
2404	**175,393**	895	156,977	0.00
2405	**178,901**	895	160,117	0.00
2406	**182,479**	895	163,319	0.00
2407	**186,129**	895	166,585	0.00
2408	**189,851**	895	169,917	0.00
2409	**193,648**	895	173,315	0.00
2410	**197,521**	895	176,782	0.00
2411	**201,472**	895	180,317	0.00
2412	**205,501**	895	183,924	0.00
2413	**209,611**	895	187,602	0.00
2414	**213,803**	895	191,354	0.00
2415	**218,080**	895	195,181	0.00
2416	**222,441**	895	199,085	0.00
2417	**226,890**	895	203,067	0.00

ML Capital Investment	PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
	$/MWh	**GWh**	**$M**	**$M**
2418	**0**	895	0	0.00
2419	**0**	895	0	0.00
2420	**0**	895	0	0.00
2421	**0**	895	0	0.00
2422	**0**	895	0	0.00
2423	**0**	895	0	0.00
2424	**0**	895	0	0.00
2425	**0**	895	0	0.00
2426	**0**	895	0	0.00
2427	**0**	895	0	0.00
2428	**0**	895	0	0.00
2429	**0**	895	0	0.00
2430	**0**	895	0	0.00
2431	**0**	895	0	0.00
2432	**0**	895	0	0.00
2433	**0**	895	0	0.00
2434	**0**	895	0	0.00
2435	**0**	895	0	0.00
2436	**0**	895	0	0.00
2437	**0**	895	0	0.00
2438	**0**	895	0	0.00
2439	**0**	895	0	0.00
2440	**0**	895	0	0.00
2441	**0**	895	0	0.00
2442	**0**	895	0	0.00
2443	**0**	895	0	0.00
2444	**0**	895	0	0.00
2445	**0**	895	0	0.00
2446	**0**	895	0	0.00
2447	**0**	895	0	0.00
2448	**0**	895	0	0.00
2449	**0**	895	0	0.00
2450	**0**	895	0	0.00
2451	**0**	895	0	0.00
2452	**0**	895	0	0.00
2453	**462,830**	895	414,233	0.00
2454	**472,087**	895	422,517	0.00
2455	**481,528**	895	430,968	0.00
2456	**491,159**	895	439,587	0.00
2457	**500,982**	895	448,379	0.00
2458	**511,002**	895	457,347	0.00
2459	**521,222**	895	466,493	0.00
2460	**531,646**	895	475,823	0.00
2461	**542,279**	895	485,340	0.00
2462	**553,125**	895	495,047	0.00
2463	**564,187**	895	504,948	0.00
2464	**575,471**	895	515,046	0.00
2465	**586,980**	895	525,347	0.00
2466	**598,720**	895	535,854	0.00
2467	**610,694**	895	546,571	0.00
2468	**0**	895	0	0.00
2469	**0**	895	0	0.00
2470	**0**	895	0	0.00
2471	**0**	895	0	0.00
2472	**0**	895	0	0.00
2473	**0**	895	0	0.00
2474	**0**	895	0	0.00
2475	**0**	895	0	0.00
2476	**0**	895	0	0.00
2477	**0**	895	0	0.00
2478	**0**	895	0	0.00
2479	**0**	895	0	0.00
2480	**0**	895	0	0.00
2481	**0**	895	0	0.00
2482	**0**	895	0	0.00
2483	**0**	895	0	0.00
2484	**0**	895	0	0.00
2485	**0**	895	0	0.00
2486	**0**	895	0	0.00

	ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $130 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$170**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $170
		$/MWh	**GWh**	**$M**	**$M**
2487		**0**	895	0	0.00
2488		**0**	895	0	0.00
2489		**0**	895	0	0.00
2490		**0**	895	0	0.00
2491		**0**	895	0	0.00
2492		**0**	895	0	0.00
2493		**0**	895	0	0.00
2494		**0**	895	0	0.00
2495		**0**	895	0	0.00
2496		**0**	895	0	0.00
2497		**0**	895	0	0.00
2498		**0**	895	0	0.00
2499		**0**	895	0	0.00
2500		**0**	895	0	0.00

Adder to End Effect Costs of a 15 year PPA every 50 years (assumes ML Capital costs are depreciated over 35 yrs and ML has a 50 year operating life).
Low Power - Low Gas Sensitivity

	ML Capital Investment		**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $84 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$111**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $111
			$/MWh	**GWh**	**$M**	**$M**
2015	0				0	0.00
2016	0				0	0.00
2017					0	0.00
2018			**0**	895	0	0.00
2019			**0**	895	0	0.00
2020			**0**	895	0	0.00
2021			**0**	895	0	0.00
2022			**0**	895	0	0.00
2023			**0**	895	0	0.00
2024			**0**	895	0	0.00
2025			**0**	895	0	0.00
2026			**0**	895	0	0.00
2027			**0**	895	0	0.00
2028			**0**	895	0	0.00
2029			**0**	895	0	0.00
2030			**0**	895	0	0.00
2031			**0**	895	0	0.00
2032			**0**	895	0	0.00
2033			**0**	895	0	0.00
2034		Year 1 to 35 depreciation of	**0**	895	0	0.00
2035		ML project (runs into year	**0**	895	0	0.00
2036		36 due to Oct/2017 start)	**0**	895	0	0.00
2037			**0**	895	0	0.00
2038			**0**	895	0	0.00
2039			**0**	895	0	0.00
2040			**0**	895	0	0.00
2041		End Effects Period begins	**0**	895	0	0.00
2042		in 2041.	**0**	895	0	0.00
2043			**0**	895	0	0.00
2044			**0**	895	0	0.00
2045			**0**	895	0	0.00
2046			**0**	895	0	0.00
2047			**0**	895	0	0.00
2048			**0**	895	0	0.00
2049			**0**	895	0	0.00
2050			**0**	895	0	0.00
2051			**0**	895	0	0.00
2052			**0**	895	0	0.00
2053	0		**109**	895	98	8.73
2054	0		**111**	895	100	8.36
2055	0		**114**	895	102	8.00
2056	0		**116**	895	104	7.66
2057	0		**118**	895	106	7.33
2058	0		**120**	895	108	7.02
2059	0	Year 36 to 50 after ML	**123**	895	110	6.72
2060	0	project is depreciated.	**125**	895	112	6.43
2061	0	PPA for the NS Block	**128**	895	114	6.15
2062	0	is assumed. →	**130**	895	117	5.89
2063	0		**133**	895	119	5.64
2064	0		**136**	895	121	5.40
2065	0		**138**	895	124	5.17
2066	0		**141**	895	126	4.94
2067	0		**144**	895	129	4.73

	ML Capital Investment		**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $84 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$111**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $111
			$/MWh	**GWh**	**$M**	**$M**
2068			**0**	895	0	0.00
2069			**0**	895	0	0.00
2070			**0**	895	0	0.00
2071			**0**	895	0	0.00
2072			**0**	895	0	0.00
2073			**0**	895	0	0.00
2074			**0**	895	0	0.00
2075			**0**	895	0	0.00
2076			**0**	895	0	0.00
2077			**0**	895	0	0.00
2078			**0**	895	0	0.00
2079			**0**	895	0	0.00
2080			**0**	895	0	0.00
2081			**0**	895	0	0.00
2082			**0**	895	0	0.00
2083			**0**	895	0	0.00
2084		Replacement in-kind	**0**	895	0	0.00
2085		of ML Project in end effects	**0**	895	0	0.00
2086		period evergy 50 years.	**0**	895	0	0.00
2087			**0**	895	0	0.00
2088			**0**	895	0	0.00
2089			**0**	895	0	0.00
2090			**0**	895	0	0.00
2091			**0**	895	0	0.00
2092			**0**	895	0	0.00
2093			**0**	895	0	0.00
2094			**0**	895	0	0.00
2095			**0**	895	0	0.00
2096			**0**	895	0	0.00
2097			**0**	895	0	0.00
2098			**0**	895	0	0.00
2099			**0**	895	0	0.00
2100			**0**	895	0	0.00
2101			**0**	895	0	0.00
2102			**0**	895	0	0.00
2103	0		**294**	895	263	0.98
2104	0		**300**	895	268	0.94
2105	0		**305**	895	273	0.90
2106	0		**312**	895	279	0.86
2107	0		**318**	895	284	0.82
2108	0		**324**	895	290	0.79
2109	0		**331**	895	296	0.75
2110	0		**337**	895	302	0.72
2111	0		**344**	895	308	0.69
2112	0		**351**	895	314	0.66
2113	0		**358**	895	320	0.63
2114	0		**365**	895	327	0.61
2115	0		**372**	895	333	0.58
2116	0		**380**	895	340	0.56
2117	0		**387**	895	347	0.53

	PPA starting in 2053			
	Base Year		Annual Cost of PPA	
	2040			
ML Capital Investment	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
	$84		(2041 and beyond)	PV of Annual costs
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$111**	$111
	$/MWh	**GWh**	**$M**	**$M**
2118	**0**	895	0	0.00
2119	**0**	895	0	0.00
2120	**0**	895	0	0.00
2121	**0**	895	0	0.00
2122	**0**	895	0	0.00
2123	**0**	895	0	0.00
2124	**0**	895	0	0.00
2125	**0**	895	0	0.00
2126	**0**	895	0	0.00
2127	**0**	895	0	0.00
2128	**0**	895	0	0.00
2129	**0**	895	0	0.00
2130	**0**	895	0	0.00
2131	**0**	895	0	0.00
2132	**0**	895	0	0.00
2133	**0**	895	0	0.00
2134	**0**	895	0	0.00
2135	**0**	895	0	0.00
2136	**0**	895	0	0.00
2137	**0**	895	0	0.00
2138	**0**	895	0	0.00
2139	**0**	895	0	0.00
2140	**0**	895	0	0.00
2141	**0**	895	0	0.00
2142	**0**	895	0	0.00
2143	**0**	895	0	0.00
2144	**0**	895	0	0.00
2145	**0**	895	0	0.00
2146	**0**	895	0	0.00
2147	**0**	895	0	0.00
2148	**0**	895	0	0.00
2149	**0**	895	0	0.00
2150	**0**	895	0	0.00
2151	**0**	895	0	0.00
2152	**0**	895	0	0.00
2153	**790**	895	707	0.11
2154	**806**	895	722	0.11
2155	**822**	895	736	0.10
2156	**839**	895	751	0.10
2157	**855**	895	766	0.09
2158	**873**	895	781	0.09
2159	**890**	895	797	0.08
2160	**908**	895	813	0.08
2161	**926**	895	829	0.08
2162	**945**	895	845	0.07
2163	**963**	895	862	0.07
2164	**983**	895	880	0.07
2165	**1,002**	895	897	0.07
2166	**1,022**	895	915	0.06
2167	**1,043**	895	933	0.06

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $84 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$111**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $111
	$/MWh	**GWh**	**$M**	**$M**
2168	**0**	895	0	0.00
2169	**0**	895	0	0.00
2170	**0**	895	0	0.00
2171	**0**	895	0	0.00
2172	**0**	895	0	0.00
2173	**0**	895	0	0.00
2174	**0**	895	0	0.00
2175	**0**	895	0	0.00
2176	**0**	895	0	0.00
2177	**0**	895	0	0.00
2178	**0**	895	0	0.00
2179	**0**	895	0	0.00
2180	**0**	895	0	0.00
2181	**0**	895	0	0.00
2182	**0**	895	0	0.00
2183	**0**	895	0	0.00
2184	**0**	895	0	0.00
2185	**0**	895	0	0.00
2186	**0**	895	0	0.00
2187	**0**	895	0	0.00
2188	**0**	895	0	0.00
2189	**0**	895	0	0.00
2190	**0**	895	0	0.00
2191	**0**	895	0	0.00
2192	**0**	895	0	0.00
2193	**0**	895	0	0.00
2194	**0**	895	0	0.00
2195	**0**	895	0	0.00
2196	**0**	895	0	0.00
2197	**0**	895	0	0.00
2198	**0**	895	0	0.00
2199	**0**	895	0	0.00
2200	**0**	895	0	0.00
2201	**0**	895	0	0.00
2202	**0**	895	0	0.00
2203	**2,127**	895	1,904	0.01
2204	**2,170**	895	1,942	0.01
2205	**2,213**	895	1,981	0.01
2206	**2,257**	895	2,020	0.01
2207	**2,303**	895	2,061	0.01
2208	**2,349**	895	2,102	0.01
2209	**2,396**	895	2,144	0.01
2210	**2,444**	895	2,187	0.01
2211	**2,492**	895	2,231	0.01
2212	**2,542**	895	2,275	0.01
2213	**2,593**	895	2,321	0.01
2214	**2,645**	895	2,367	0.01
2215	**2,698**	895	2,415	0.01
2216	**2,752**	895	2,463	0.01
2217	**2,807**	895	2,512	0.01

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $84 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = **$111**	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $111
	$/MWh	**GWh**	**$M**	**$M**
2218	**0**	895	0	0.00
2219	**0**	895	0	0.00
2220	**0**	895	0	0.00
2221	**0**	895	0	0.00
2222	**0**	895	0	0.00
2223	**0**	895	0	0.00
2224	**0**	895	0	0.00
2225	**0**	895	0	0.00
2226	**0**	895	0	0.00
2227	**0**	895	0	0.00
2228	**0**	895	0	0.00
2229	**0**	895	0	0.00
2230	**0**	895	0	0.00
2231	**0**	895	0	0.00
2232	**0**	895	0	0.00
2233	**0**	895	0	0.00
2234	**0**	895	0	0.00
2235	**0**	895	0	0.00
2236	**0**	895	0	0.00
2237	**0**	895	0	0.00
2238	**0**	895	0	0.00
2239	**0**	895	0	0.00
2240	**0**	895	0	0.00
2241	**0**	895	0	0.00
2242	**0**	895	0	0.00
2243	**0**	895	0	0.00
2244	**0**	895	0	0.00
2245	**0**	895	0	0.00
2246	**0**	895	0	0.00
2247	**0**	895	0	0.00
2248	**0**	895	0	0.00
2249	**0**	895	0	0.00
2250	**0**	895	0	0.00
2251	**0**	895	0	0.00
2252	**0**	895	0	0.00
2253	**5,726**	895	5,125	0.00
2254	**5,840**	895	5,227	0.00
2255	**5,957**	895	5,332	0.00
2256	**6,076**	895	5,438	0.00
2257	**6,198**	895	5,547	0.00
2258	**6,322**	895	5,658	0.00
2259	**6,448**	895	5,771	0.00
2260	**6,577**	895	5,887	0.00
2261	**6,709**	895	6,004	0.00
2262	**6,843**	895	6,124	0.00
2263	**6,980**	895	6,247	0.00
2264	**7,119**	895	6,372	0.00
2265	**7,262**	895	6,499	0.00
2266	**7,407**	895	6,629	0.00
2267	**7,555**	895	6,762	0.00

	PPA starting in 2053			
	Base Year		Annual Cost of PPA	
	2040			
ML Capital Investment	PPA price $/MWh (BaseYr$)		End Effects Adder (2041 and beyond)	Check of NPV: PV of Annual costs
	$84			
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$111**	$111
	$/MWh	**GWh**	**$M**	**$M**
2268	**0**	895	0	0.00
2269	**0**	895	0	0.00
2270	**0**	895	0	0.00
2271	**0**	895	0	0.00
2272	**0**	895	0	0.00
2273	**0**	895	0	0.00
2274	**0**	895	0	0.00
2275	**0**	895	0	0.00
2276	**0**	895	0	0.00
2277	**0**	895	0	0.00
2278	**0**	895	0	0.00
2279	**0**	895	0	0.00
2280	**0**	895	0	0.00
2281	**0**	895	0	0.00
2282	**0**	895	0	0.00
2283	**0**	895	0	0.00
2284	**0**	895	0	0.00
2285	**0**	895	0	0.00
2286	**0**	895	0	0.00
2287	**0**	895	0	0.00
2288	**0**	895	0	0.00
2289	**0**	895	0	0.00
2290	**0**	895	0	0.00
2291	**0**	895	0	0.00
2292	**0**	895	0	0.00
2293	**0**	895	0	0.00
2294	**0**	895	0	0.00
2295	**0**	895	0	0.00
2296	**0**	895	0	0.00
2297	**0**	895	0	0.00
2298	**0**	895	0	0.00
2299	**0**	895	0	0.00
2300	**0**	895	0	0.00
2301	**0**	895	0	0.00
2302	**0**	895	0	0.00
2303	**15,411**	895	13,793	0.00
2304	**15,720**	895	14,069	0.00
2305	**16,034**	895	14,350	0.00
2306	**16,355**	895	14,637	0.00
2307	**16,682**	895	14,930	0.00
2308	**17,015**	895	15,229	0.00
2309	**17,356**	895	15,533	0.00
2310	**17,703**	895	15,844	0.00
2311	**18,057**	895	16,161	0.00
2312	**18,418**	895	16,484	0.00
2313	**18,786**	895	16,814	0.00
2314	**19,162**	895	17,150	0.00
2315	**19,545**	895	17,493	0.00
2316	**19,936**	895	17,843	0.00
2317	**20,335**	895	18,200	0.00

	PPA starting in 2053			
	Base Year		Annual Cost of PPA	
	2040			
ML Capital Investment	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
	$84		(2041 and beyond)	PV of Annual costs
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$111**	$111
	$/MWh	**GWh**	**$M**	**$M**
2318	**0**	895	0	0.00
2319	**0**	895	0	0.00
2320	**0**	895	0	0.00
2321	**0**	895	0	0.00
2322	**0**	895	0	0.00
2323	**0**	895	0	0.00
2324	**0**	895	0	0.00
2325	**0**	895	0	0.00
2326	**0**	895	0	0.00
2327	**0**	895	0	0.00
2328	**0**	895	0	0.00
2329	**0**	895	0	0.00
2330	**0**	895	0	0.00
2331	**0**	895	0	0.00
2332	**0**	895	0	0.00
2333	**0**	895	0	0.00
2334	**0**	895	0	0.00
2335	**0**	895	0	0.00
2336	**0**	895	0	0.00
2337	**0**	895	0	0.00
2338	**0**	895	0	0.00
2339	**0**	895	0	0.00
2340	**0**	895	0	0.00
2341	**0**	895	0	0.00
2342	**0**	895	0	0.00
2343	**0**	895	0	0.00
2344	**0**	895	0	0.00
2345	**0**	895	0	0.00
2346	**0**	895	0	0.00
2347	**0**	895	0	0.00
2348	**0**	895	0	0.00
2349	**0**	895	0	0.00
2350	**0**	895	0	0.00
2351	**0**	895	0	0.00
2352	**0**	895	0	0.00
2353	**41,481**	895	37,126	0.00
2354	**42,311**	895	37,868	0.00
2355	**43,157**	895	38,625	0.00
2356	**44,020**	895	39,398	0.00
2357	**44,901**	895	40,186	0.00
2358	**45,799**	895	40,990	0.00
2359	**46,715**	895	41,809	0.00
2360	**47,649**	895	42,646	0.00
2361	**48,602**	895	43,499	0.00
2362	**49,574**	895	44,369	0.00
2363	**50,565**	895	45,256	0.00
2364	**51,577**	895	46,161	0.00
2365	**52,608**	895	47,084	0.00
2366	**53,660**	895	48,026	0.00
2367	**54,733**	895	48,986	0.00

ML Capital Investment	**PPA starting in 2053** Base Year 2040 PPA price $/MWh (BaseYr$) $84 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $111	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $111
	$/MWh	**GWh**	**$M**	**$M**
2368	**0**	895	0	0.00
2369	**0**	895	0	0.00
2370	**0**	895	0	0.00
2371	**0**	895	0	0.00
2372	**0**	895	0	0.00
2373	**0**	895	0	0.00
2374	**0**	895	0	0.00
2375	**0**	895	0	0.00
2376	**0**	895	0	0.00
2377	**0**	895	0	0.00
2378	**0**	895	0	0.00
2379	**0**	895	0	0.00
2380	**0**	895	0	0.00
2381	**0**	895	0	0.00
2382	**0**	895	0	0.00
2383	**0**	895	0	0.00
2384	**0**	895	0	0.00
2385	**0**	895	0	0.00
2386	**0**	895	0	0.00
2387	**0**	895	0	0.00
2388	**0**	895	0	0.00
2389	**0**	895	0	0.00
2390	**0**	895	0	0.00
2391	**0**	895	0	0.00
2392	**0**	895	0	0.00
2393	**0**	895	0	0.00
2394	**0**	895	0	0.00
2395	**0**	895	0	0.00
2396	**0**	895	0	0.00
2397	**0**	895	0	0.00
2398	**0**	895	0	0.00
2399	**0**	895	0	0.00
2400	**0**	895	0	0.00
2401	**0**	895	0	0.00
2402	**0**	895	0	0.00
2403	**111,650**	895	99,927	0.00
2404	**113,883**	895	101,925	0.00
2405	**116,161**	895	103,964	0.00
2406	**118,484**	895	106,043	0.00
2407	**120,854**	895	108,164	0.00
2408	**123,271**	895	110,327	0.00
2409	**125,736**	895	112,534	0.00
2410	**128,251**	895	114,785	0.00
2411	**130,816**	895	117,080	0.00
2412	**133,432**	895	119,422	0.00
2413	**136,101**	895	121,810	0.00
2414	**138,823**	895	124,247	0.00
2415	**141,599**	895	126,731	0.00
2416	**144,431**	895	129,266	0.00
2417	**147,320**	895	131,851	0.00

	ML Capital Investment	PPA starting in 2053 Base Year 2040 PPA price $/MWh (BaseYr$) $84 Escalation: 2.0%	ML Base Block Energy	Annual Cost of PPA End Effects Adder (2041 and beyond) NPV (2015$) = $111	Check of NPV: PV of Annual costs Sum 2041 to 2500 = $111
		$/MWh	**GWh**	**$M**	**$M**
2418		**0**	895	0	0.00
2419		**0**	895	0	0.00
2420		**0**	895	0	0.00
2421		**0**	895	0	0.00
2422		**0**	895	0	0.00
2423		**0**	895	0	0.00
2424		**0**	895	0	0.00
2425		**0**	895	0	0.00
2426		**0**	895	0	0.00
2427		**0**	895	0	0.00
2428		**0**	895	0	0.00
2429		**0**	895	0	0.00
2430		**0**	895	0	0.00
2431		**0**	895	0	0.00
2432		**0**	895	0	0.00
2433		**0**	895	0	0.00
2434		**0**	895	0	0.00
2435		**0**	895	0	0.00
2436		**0**	895	0	0.00
2437		**0**	895	0	0.00
2438		**0**	895	0	0.00
2439		**0**	895	0	0.00
2440		**0**	895	0	0.00
2441		**0**	895	0	0.00
2442		**0**	895	0	0.00
2443		**0**	895	0	0.00
2444		**0**	895	0	0.00
2445		**0**	895	0	0.00
2446		**0**	895	0	0.00
2447		**0**	895	0	0.00
2448		**0**	895	0	0.00
2449		**0**	895	0	0.00
2450		**0**	895	0	0.00
2451		**0**	895	0	0.00
2452		**0**	895	0	0.00
2453		**300,516**	895	268,962	0.00
2454		**306,527**	895	274,341	0.00
2455		**312,657**	895	279,828	0.00
2456		**318,910**	895	285,425	0.00
2457		**325,288**	895	291,133	0.00
2458		**331,794**	895	296,956	0.00
2459		**338,430**	895	302,895	0.00
2460		**345,199**	895	308,953	0.00
2461		**352,103**	895	315,132	0.00
2462		**359,145**	895	321,434	0.00
2463		**366,328**	895	327,863	0.00
2464		**373,654**	895	334,420	0.00
2465		**381,127**	895	341,109	0.00
2466		**388,750**	895	347,931	0.00
2467		**396,525**	895	354,890	0.00
2468		**0**	895	0	0.00
2469		**0**	895	0	0.00
2470		**0**	895	0	0.00
2471		**0**	895	0	0.00
2472		**0**	895	0	0.00
2473		**0**	895	0	0.00
2474		**0**	895	0	0.00
2475		**0**	895	0	0.00
2476		**0**	895	0	0.00
2477		**0**	895	0	0.00
2478		**0**	895	0	0.00
2479		**0**	895	0	0.00
2480		**0**	895	0	0.00
2481		**0**	895	0	0.00
2482		**0**	895	0	0.00
2483		**0**	895	0	0.00
2484		**0**	895	0	0.00
2485		**0**	895	0	0.00
2486		**0**	895	0	0.00

			Annual Cost of PPA	
	PPA starting in 2053			
	Base Year			
	2040			
ML Capital Investment	PPA price $/MWh (BaseYr$)		End Effects Adder	Check of NPV:
	$84		(2041 and beyond)	PV of Annual costs
	Escalation:	ML Base Block Energy	NPV (2015$) =	Sum 2041 to 2500 =
	2.0%		**$111**	$111
	$/MWh	**GWh**	**$M**	**$M**
2487	**0**	895	0	0.00
2488	**0**	895	0	0.00
2489	**0**	895	0	0.00
2490	**0**	895	0	0.00
2491	**0**	895	0	0.00
2492	**0**	895	0	0.00
2493	**0**	895	0	0.00
2494	**0**	895	0	0.00
2495	**0**	895	0	0.00
2496	**0**	895	0	0.00
2497	**0**	895	0	0.00
2498	**0**	895	0	0.00
2499	**0**	895	0	0.00
2500	**0**	895	0	0.00

	Energy Prices - US$/MWh MassHub - Low			Energy Prices - US$/MWh MassHub - Base			Energy Prices - US$/MWh MassHub - High		
	7 X 24	*On Peak*	*Off Peak*	*7 X 24*	*On Peak*	*Off Peak*	*7 X 24*	*On Peak*	*Off Peak*
2015	$40.47	$46.53	$34.85	$49.25	$56.76	$42.30	$63.08	$72.30	$54.58
2016	$42.57	$49.51	$36.37	$51.74	$60.34	$44.06	$66.12	$76.62	$56.75
2017	$43.25	$49.48	$37.64	$52.45	$60.22	$45.46	$67.01	$76.63	$58.34
2018	$43.96	$49.88	$38.50	$53.24	$60.67	$46.40	$67.94	$77.20	$59.42
2019	$45.15	$51.32	$39.42	$54.64	$62.39	$47.47	$69.65	$79.31	$60.73
2020	$47.25	$53.70	$41.20	$57.13	$65.16	$49.61	$72.71	$82.62	$63.47
2021	$48.38	$55.13	$42.26	$58.59	$66.92	$51.03	$74.78	$85.02	$65.49
2022	$50.44	$57.49	$44.14	$61.03	$69.64	$53.35	$77.86	$88.33	$68.52
2023	$51.45	$58.64	$45.02	$62.25	$71.04	$54.41	$79.42	$90.10	$69.89
2024	$52.48	$59.82	$45.92	$63.50	$72.46	$55.50	$81.01	$91.90	$71.29
2025	$53.53	$61.01	$46.84	$64.77	$73.91	$56.61	$82.63	$93.74	$72.71
2026	$54.60	$62.23	$47.78	$66.06	$75.38	$57.74	$84.28	$95.61	$74.17
2027	$55.69	$63.48	$48.73	$67.38	$76.89	$58.90	$85.97	$97.53	$75.65
2028	$56.80	$64.75	$49.71	$68.73	$78.43	$60.08	$87.69	$99.48	$77.16
2029	$57.94	$66.04	$50.70	$70.10	$80.00	$61.28	$89.44	$101.47	$78.71
2030	$59.10	$67.36	$51.72	$71.51	$81.60	$62.50	$91.23	$103.50	$80.28
2031	$60.28	$68.71	$52.75	$72.94	$83.23	$63.75	$93.06	$105.57	$81.89
2032	$61.48	$70.09	$53.80	$74.40	$84.90	$65.03	$94.92	$107.68	$83.52
2033	$62.71	$71.49	$54.88	$75.88	$86.59	$66.33	$96.82	$109.83	$85.19
2034	$63.97	$72.92	$55.98	$77.40	$88.33	$67.66	$98.75	$112.03	$86.90
2035	$65.25	$74.38	$57.10	$78.95	$90.09	$69.01	$100.73	$114.27	$88.64
2036	$66.55	$75.86	$58.24	$80.53	$91.89	$70.39	$102.74	$116.55	$90.41
2037	$67.88	$77.38	$59.40	$82.14	$93.73	$71.80	$104.80	$118.88	$92.22
2038	$69.24	$78.93	$60.59	$83.78	$95.61	$73.23	$106.89	$121.26	$94.06
2039	$70.63	$80.51	$61.80	$85.46	$97.52	$74.70	$109.03	$123.69	$95.94
2040	$72.04	$82.12	$63.04	$87.17	$99.47	$76.19	$111.21	$126.16	$97.86

on peak hr/wk	80	
off-peak hrs/wk	88	
hrs / wk	168	
ML on-peak	80	71%
ML offpeak	32	29%
total ML	112	

2040	7 x 16	10% long-term adder	Total $/Mwh
Low	$76.67	$7.67	$84.33
Base	$92.82	$9.28	$102.10
High	$118.07	$11.81	$129.88

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Request IR-335:

With reference to response Synapse IR-11(a), page 2, line 26 to page 3, line 6, please clarify how the pricing for energy corresponding to the NS block in years 2041 to 2052 is accounted for separately from the pricing for the remainder of the 50 year life of ML:

(a) What is the present value of the NS Block energy cost from the end of the 35 year contracts to the end of economic life (2052 to 2067) under the Base Load case?

(b) What is the present value of the NS Block energy cost for the next 50 year cycle, and how is this cost split between capital cost and operating cost?

(c) What other costs are included in the present value cost of $134 million referenced in line 4?

Response IR-335:

(a-c) Please refer to CA/SBA IR-334 part (c).

Request IR-336:

With respect to CanWEA IR-001 Attachment 1:

(a) Indicate which of the existing generation resources and IPPs shown in Attachment 1 are expected to be qualified to meet NSPI's Renewable Electricity Regulations obligations in 2013, 2014, 2015, and 2020.

(b) For each resource identified under part (a), specify whether it produces "renewable low-impact electricity," "heritage renewable electricity," "imported electricity," or some other classification, corresponding to the definitions in Nova Scotia's Renewable Electricity Regulations made under Section 5 of the Electricity Act.

(c) For each of the existing resources and IPPs identified under part (a), provide the historic monthly energy output since 2009 in the same format that was provided in the response to Confidential CA/SBA IR-67. If monthly data are not available, provide the total annual MWh or annual capacity factor for each resource. Provide this information for all generation resources and IPPs that are <u>not</u> included in the response to Confidential CA/SBA IR-67 Attachment 1 or Confidential CA/SBA IR-71 Attachment 1.

Response IR-336:

(a) Please refer to: Renewable Electricity Regulations made under Section 5 of the Electricity Act S.N.S. 2004, c. 25 O.I.C. 2010-381 (October 12, 2010), N.S. Reg. 155/2010 as amended up to O.I.C. 2013-13 (January 17, 2013), N.S. Reg. 11/2013, for details on renewable energy regulations for 2011-2020.

Please refer to CanWEA IR-1 Attachment 1, page 3 for the breakdown of pre-2001 and post 2001 renewable generation.

Please refer to CanWEA IR-1 Attachment 1, page 1-3 for the list of all renewable energy available in 2013, and please refer to SBA IR-67 (c) for the list of additional renewable generation scheduled to come online after 2013.

All post 2001 renewable generation qualifies for RES compliance for the years 2013 and 2014.

Pre 2001 renewable generation along with all post 2001 renewable energy qualifies for RES compliance for the years 2015 and 2020.

(b) Please refer to the Renewable Electricity Regulations made under Section 5 of the Electricity Act S.N.S. 2004, c. 25 O.I.C. 2010-381 (October 12, 2010), N.S. Reg. 155/2010 as amended up to O.I.C. 2013-13 (January 17, 2013), N.S. Reg. 11/2013 for the following definitions:

- "heritage renewable electricity" means all electricity that was contracted for or supplied by a load-serving entity in the Province before January 1, 2002, and that, in the opinion of the Minister, is generated from renewable sources;

- "renewable low-impact electricity" means electricity produced from any of the following:

    (i) Solar energy,

    (ii) Wind energy,

    (iii) Run-of-the-river hydroelectric energy,

    (iv) Ocean-powered energy,

    (v) Tidal energy,

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(vi) Wave energy,

(vii) Biomass that has been harvested in a sustainable manner,

(viii) Landfill gas,

(ix) Any resource that, in the opinion of the Minister and consistent with Canadian standards, is able to be replenished through natural processes or through sustainable management practices so that the resource is not depleted at current levels of consumption;

Please refer to CanWEA IR-1 Attachment 1 which identifies identified types of generation and in-service dates. Wind, hydro, and biomass generation are considered to be “renewable low-impact electricity”. All renewable generation developed before January 1, 2002 is considered “heritage renewable electricity” and can be counted towards 2015 RES compliance. Maritime Link imports will qualify as “renewable low-impact electricity” and will apply to the 2020 requirement.

(c) Please refer to Attachment 1 which provides the historic monthly energy output since 2009 for the facilities not identified in SBA IR-67 Confidential Attachment 1. Please note that hydro records are kept for hydro systems rather than for individual hydro units. The list of hydro units which make up hydro systems can be found in CanWEA IR-1 Attachment 1.

2009 Monthly Generating Facility Net Energy Output (GWh)

Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Wreck Cove	31.8	24.4	24.3	13.3	45.0	6.0	31.2	30.9	6.8	25.4	21.5	28.4	289.1
Annapolis	2.2	2.2	2.6	2.3	2.8	2.5	2.9	2.3	2.5	2.5	2.7	2.4	30.0
Avon	2.6	2.9	2.8	4.8	2.0	1.4	0.6	0.4	1.3	3.4	2.4	3.5	28.2
Black River	13.8	6.9	14.1	16.2	7.5	4.8	2.4	2.8	8.7	12.9	10.7	13.6	114.6
Nictaux	5.6	5.1	5.9	5.6	5.6	3.5	0.8	(0.0)	(0.0)	(0.0)	3.5	5.8	41.4
Lequille	3.0	1.5	4.2	6.9	1.4	0.5	2.4	0.9	0.9	3.9	2.8	2.7	30.9
Paradise	3.0	2.1	3.1	3.1	3.3	1.1	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	1.6	17.4
Mersey	26.5	24.3	26.0	24.5	26.9	22.5	14.0	14.9	13.6	20.4	26.3	27.2	267.2
Sissiboo	8.0	5.7	11.3	13.6	11.0	7.3	6.7	3.9	5.7	8.6	4.9	10.1	96.8
Bear	5.2	3.5	4.5	5.4	5.8	4.5	5.1	1.7	2.2	1.9	1.3	2.2	43.2
Tusket	1.2	1.2	1.3	0.2	0.8	0.7	0.9	0.5	0.9	1.2	1.2	1.1	11.2
Ros/Harm	0.4	0.2	0.3	1.4	0.5	(0.0)	0.0	(0.0)	(0.0)	(0.0)	(0.0)	0.3	3.2
St. Margarets	2.4	2.1	3.6	3.6	2.8	0.7	0.5	0.7	3.0	2.4	2.6	2.7	27.0
Sheet Harbour	6.1	3.1	6.8	5.7	4.2	1.7	3.7	3.8	2.6	3.8	4.7	5.3	51.5
Dickie Brook	0.7	1.5	1.1	1.0	1.2	0.6	1.0	0.3	0.1	0.4	0.7	1.2	9.9
Fall River	0.2	0.2	0.4	0.3	0.3	0.0	0.2	-	(0.0)	(0.0)	0.1	0.4	2.0
Sackville Landfill	0.7	0.6	0.7	0.7	0.7	0.8	0.8	0.8	0.8	0.7	0.8	0.8	8.9
Black River Hydro	0.2	0.1	0.1	0.2	0.1	0.2	0.2	0.1	0.2	0.1	0.2	0.2	1.7
Brooklyn Power	12.4	10.9	9.9	8.6	10.4	10.2	12.3	13.5	8.8	11.5	11.2	14.7	134.3
Morgan Falls Power Company	0.2	0.2	0.2	0.3	0.2	0.0	0.1	0.0	0.1	0.2	0.2	0.2	1.7
FW Taylor Lumber Company	0.4	0.4	0.4	0.4	0.4	0.4	0.0	0.4	0.4	0.4	0.4	0.4	4.5

2010 Monthly Generating Facility Net Energy Output (GWh)

Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Wreck Cove	29.2	16.1	6.1	31.2	37.4	33.5	23.2	19.8	30.3	21.2	31.0	61.4	340.5
Annapolis	1.7	2.0	2.5	2.4	2.7	2.5	2.5	2.6	2.5	2.0	1.9	2.3	27.7
Avon	3.2	1.3	4.0	2.1	0.7	0.7	1.1	0.3	0.5	0.6	2.3	4.2	20.8
Black River	13.2	10.8	14.5	7.7	5.2	3.4	4.0	0.2	0.1	6.7	11.0	12.5	89.3
Nictaux	5.5	5.3	5.9	5.7	2.9	1.9	2.2	2.2	0.6	1.6	5.8	5.8	45.5
Lequille	1.5	1.8	6.0	1.8	(0.0)	0.6	1.0	0.6	0.2	2.0	5.9	5.3	26.7
Paradise	3.3	3.3	3.7	3.5	1.8	0.5	0.8	1.3	0.3	(0.0)	(0.0)	3.0	21.7
Mersey	28.9	25.2	26.3	24.7	13.9	13.1	8.5	15.2	12.8	12.1	25.1	28.8	234.5
Sissiboo	9.0	7.2	8.1	5.9	5.4	3.4	3.7	0.1	2.8	6.4	8.5	11.5	72.0
Bear	4.0	3.9	4.9	3.7	1.7	2.1	1.6	2.0	0.8	1.6	3.5	4.0	33.8
Tusket	1.3	1.1	1.4	0.9	0.0	0.2	0.5	0.1	0.0	0.5	1.0	1.5	8.6
Ros/Harm	0.2	0.2	0.3	0.2	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.1	0.2	0.3	1.4
St. Margarets	2.3	2.1	2.5	2.7	0.3	0.2	1.2	0.5	1.0	0.9	3.0	3.4	20.2
Sheet Harbour	4.7	3.2	4.9	3.2	1.0	3.8	3.6	1.9	0.8	3.0	4.9	6.9	42.0
Dickie Brook	0.9	0.7	0.8	0.7	0.4	0.6	0.5	0.0	(0.0)	(0.0)	0.1	0.6	5.2
Fall River	0.1	0.2	0.3	(0.0)	0.0	0.0	0.1	(0.0)	0.0	0.1	0.3	0.3	1.6
Sackville Landfill	0.8	0.7	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	0.8	9.5
Black River Hydro	0.1	0.1	0.2	0.1	0.1	0.2	0.1	0.2	0.1	0.1	0.1	0.2	1.7
Brooklyn Power	10.6	11.1	9.6	13.6	14.1	16.0	12.1	14.1	14.2	9.8	13.6	15.1	154.0
Morgan Falls Power Company	0.1	0.1	0.2	0.3	0.0	0.0	0.1	0.0	0.0	0.1	0.1	0.3	1.3
FW Taylor Lumber Company	0.4	0.4	0.4	0.4	0.4	0.4	0.1	0.4	0.4	0.4	0.4	0.3	4.5

2011 Monthly Generating Facility Net Energy Output (GWh)

Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Wreck Cove	43.6	27.4	36.5	31.3	54.6	28.1	36.1	10.4	12.9	35.3	17.7	23.7	357.5
Annapolis	2.5	2.2	2.4	2.7	2.4	2.5	2.8	1.4	1.9	2.0	1.3	2.0	26.1
Avon	4.0	2.2	3.9	2.5	3.2	3.0	0.8	0.4	0.4	2.1	1.6	2.2	26.3
Black River	13.0	12.1	14.8	8.9	10.7	5.8	2.9	4.2	2.6	1.8	5.3	11.5	93.6
Nictaux	5.8	5.1	5.7	5.7	4.7	-	-	-	-	0.7	5.7	5.7	39.1
Lequille	2.8	2.6	4.3	2.2	3.3	0.8	0.2	2.2	0.2	4.1	5.1	4.9	32.7
Paradise	3.5	3.3	3.4	3.2	2.9	0.7	1.0	2.5	2.8	2.8	2.6	3.2	31.9
Mersey	30.5	27.3	30.2	28.7	21.8	22.0	10.8	9.6	12.5	11.5	11.1	21.3	237.2
Sissiboo	9.4	7.9	13.0	10.4	10.7	6.6	1.8	4.4	3.1	7.8	6.0	9.7	90.8
Bear	4.3	4.5	5.5	6.4	5.5	5.1	4.3	2.1	0.1	1.4	4.4	4.9	48.3
Tusket	1.3	1.1	1.7	1.5	1.4	0.5	0.1	0.5	0.2	1.0	1.1	1.3	11.8
Ros/Harm	0.3	0.2	0.3	0.3	0.4	0.0	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	1.6
St. Margarets	2.2	3.0	3.3	3.0	3.1	0.9	0.0	0.4	(0.0)	2.0	3.4	3.2	24.5
Sheet Harbour	5.8	3.5	6.6	4.7	6.2	4.0	4.0	4.4	1.1	6.7	6.4	3.4	56.7
Dickie Brook	0.4	0.8	0.8	0.8	0.7	0.9	0.5	0.6	0.6	0.7	0.8	0.2	7.6
Fall River	0.2	0.2	0.3	0.2	0.3	0.1	0.1	0.2	0.1	0.3	0.3	0.3	2.8
Sackville Landfill	0.7	0.6	0.7	0.6	0.7	0.7	0.8	0.7	0.7	0.8	0.8	0.8	8.7
Black River Hydro	0.1	0.1	0.2	0.1	0.2	0.1	0.1	0.2	0.1	0.1	0.2	0.1	1.7
Brooklyn Power	15.2	12.9	13.2	12.4	12.0	13.0	14.5	12.1	10.4	11.3	14.6	14.0	155.5
Morgan Falls Power Company	0.3	0.0	0.1	0.2	0.2	0.1	0.0	0.0	0.0	0.1	0.1	0.2	1.2
FW Taylor Lumber Company	0.3	0.3	0.4	0.4	0.4	0.4	0.1	0.4	0.4	0.4	0.4	0.4	4.3

2012 Monthly Generating Facility Net Energy Output (GWh)

Plant	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Wreck Cove	18.0	17.0	28.8	23.7	18.4	19.5	13.8	5.6	9.4	31.3	34.0	29.1	248.7
Annapolis	2.0	1.8	1.8	1.9	2.4	2.9	2.4	2.5	2.6	2.1	2.4	2.5	27.1
Avon	4.2	2.1	3.0	1.8	1.1	0.3	2.1	0.1	0.5	2.4	3.2	3.5	24.4
Black River	13.2	11.8	5.6	5.9	5.3	3.0	0.4	0.2	1.1	9.1	12.1	11.9	79.6
Nictaux	5.9	5.3	5.1	3.1	3.4	2.2	0.7	(0.0)	1.7	2.6	5.5	5.6	40.9
Lequille	2.8	1.6	2.8	1.8	1.5	0.2	0.1	(0.0)	1.2	2.1	2.4	2.8	19.4
Paradise	3.1	2.9	2.1	1.5	1.7	0.4	0.0	(0.0)	0.8	1.3	1.5	2.1	17.4
Mersey	24.2	26.1	22.7	15.8	14.9	15.5	14.8	5.2	11.3	13.1	19.9	15.3	198.9
Sissiboo	8.1	6.1	7.7	5.4	8.6	7.4	5.9	3.0	2.2	1.0	4.1	8.6	68.1
Bear	4.1	4.3	4.9	4.2	3.6	3.5	1.7	0.1	0.6	0.1	0.2	0.3	27.6
Tusket	1.4	1.1	1.1	0.6	1.3	0.2	0.2	0.2	0.4	1.0	1.1	1.1	9.7
Ros/Harm	(0.0)	0.2	0.4	0.1	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)	0.6
St. Margarets	3.7	2.8	2.6	4.0	2.5	(0.0)	(0.0)	-	0.0	(0.0)	(0.1)	(0.1)	15.3
Sheet Harbour	7.7	5.7	4.5	2.8	3.2	1.6	0.4	1.2	(0.0)	9.5	4.7	3.5	44.9
Dickie Brook	-	(0.0)	-	(0.0)	(0.0)	0.8	0.8	0.2	0.5	0.9	(0.0)	(0.0)	3.1
Fall River	0.4	0.3	0.2	0.1	0.2	0.0	0.0	0.0	0.2	0.3	0.2	0.2	2.2
Sackville Landfill	0.7	0.6	0.7	0.6	0.7	0.6	0.6	0.6	0.6	0.6	0.6	0.6	7.7
Black River Hydro	0.2	0.1	0.1	0.2	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	1.7
Brooklyn Power	11.9	9.8	13.6	13.6	14.2	11.1	14.0	13.9	13.2	12.3	13.9	14.5	156.1
Morgan Falls Power Company	0.2	0.2	0.3	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	1.0
FW Taylor Lumber Company	0.4	0.3	0.4	0.4	0.4	0.4	0.1	0.4	0.4	0.4	0.4	0.4	4.4

NON-CONFIDENTIAL

Request IR-337:

With reference to CA/SBA IR-2 and Application, page 16, lines 2-6:

(a) Please explain and quantify how the transmission upgrades postulated for the “Other Import” alternative would increase Nova Scotia’s capacity to develop new intermittent sources of electricity, such as wind, and incorporate them in the Nova Scotia’s electrical transmission system.

Response IR-337:

The premise in the request is not accurate. The referenced section of the Application is not about the “Other Import”, the comments are about the Maritime Link Project. As indicated in the prior response (CA/SBA IR-2), there are limitations in the “Other Import” as it relies on the same sources of energy. Nova Scotia would not use the “Other Import” transmission upgrades to buy energy and capacity while also relying on it for back-up for intermittent sources.

NON-CONFIDENTIAL

Request IR-338:

With reference to CA/SBA IR-22 and Application, page 101, line 19 to page 102, line 9:

(a) Why did NSPML <u>not</u> require Ventyx to apply the Strategist model to analyze possible optimal combinations among the seven options?

(b) Could Ventyx have applied the Strategist model to analyze possible optimal combinations among the seven options if they had wanted to perform such analysis?

Response IR-338:

(a) NSPML requested Ventyx to optimize the three alternatives for each load case and provided the inputs do so. In each of these six resource plan optimizations Strategist was able to choose from the four natural gas options as to the timing and number to add. Please refer to SBA IR-70 for an explanation of why these options were chosen versus other combinations.

(b) No. Strategist does not optimize the size of resources it chooses. It chooses from discreet resources.

NON-CONFIDENTIAL

Request IR-339:

With reference to CA/SBA IR-24 and Application, page 101, line 19 to page 102, line 9:

(a) Does Ventyx have a Strategist technical reference guide for client use?

(b) If yes, please provide.

(c) If your answer to part (a) is no, please provide a detailed description of the Strategist model components and their mathematical structure and assumptions prepared by Ventyx. The technical description document should describe the scope and limitations of the optimization capabilities of Strategist with respect to both long-term resource planning decisions (build, retire, repower, retrofit) and system commitment and dispatch decisions. Other model aspects to describe (among others) include:

(i) Method for modeling transmission constraints and power flows;

(ii) Methods for modeling forced, planned, and scheduled outages;

(iii) Method and extent of modeling daily, weekly, and seasonal unit commitment decisions for energy dispatch;

(iv) Method for modeling planning reserves, accounting for inter-area transfers;

(v) Method for modeling operating reserves;

(vi) Method for modeling multi-area energy markets.

Response IR-339:

(a-c) Please refer to CA/SBA IR-23, CA/SBA IR-288 and CA/SBA IR-351 (b).

NON-CONFIDENTIAL

Request IR-340:

With reference to CA/SBA IR-32 and Application, page 105, lines 6-8:

(a) Please explain whether the Strategist model is able to optimize the closure dates of generation units?

(b) If so, provide a table of the units and the range of possible retirement dates assumed in the model runs. If different across runs, provide the table for each run.

Response IR-340:

(a) Yes.

(b) Please refer to CA/SBA IR-287 (b).

NON-CONFIDENTIAL

Request IR-341:

With reference to CA/SBA IR-35 and Application, page 107, line 8, the following questions refer to the Renewable Electricity Regulations ("Regulations") made under Section 5 of the Electricity Act, as amended January 17, 2013:

(a) Identify the facility name, installed capacity, technology type, and location of each of the generation resources that NSPI plans to rely on to meet its renewable electricity standard requirements for 2013 through 2020, inclusive. Indicate which of these resources are currently under contract, which specific resources are required under the Regulations, and which resources are still in development.

(b) For each resource identified in sub-part (a) above, provide the expected annual MWh output from each of these resources for the period 2013 through 2020, inclusive, that NSPI will plan to use toward meeting its renewable electricity standard obligation in each year. For wind resources, both existing and proposed, provide all available data, information, and analyses regarding the expected energy profile.

Response IR-341:

(a) Please refer to CanWEA IR-1 Attachment 1 for facility names, technology type of all generating units on the NS Power system, including renewable energy generating facilities. Please refer to the following link for the location of wind generators http://www.nspower.ca/en/home/aboutnspower/makingelectricity/renewable/map.aspx.

All projects identified as Independent Power Producers are under contract. Please refer to SBA IR-336 for further details on regulations and units still under development.

NON-CONFIDENTIAL

(b) Please refer to Synapse IR-36 for details on methodology used to calculate forecasted wind power production. Please refer to CA/SBA IR-67 for historical wind generation output in order to derive forecasted wind generation values. Please refer to CA/SBA IR-336 Confidential Attachment 1 for the remainder of the renewable generation historical monthly production values. Please refer to Appendix 6.02, Table 2.1 for the annual production forecast of existing wind generation developments.

NON-CONFIDENTIAL

Request IR-342:

With reference to CA/SBA IR-37 and Application, page 107, lines 8-9:

(a) Is it possible that a 10% slice of Muskrat Falls generation coupled with additional indigenous wind in Nova Scotia might constitute a more economic solution than the Maritime Link Project?

(b) If no, please provide all studies, memoranda or related information supporting your response.

Response IR-342:

(a-b) No, this combination would not provide the capacity to close one coal unit and would necessitate additional cost not lower cost. Please see Liberal IR-11, SBA IR-20 (c), and SBA IR-70.

NON-CONFIDENTIAL

Request IR-343:

With reference to CA/SBA IR-42 and Application, page 108, line 16-18, please provide projected local production and Maritimes natural gas demand data through 2025.

Response IR-343:

Please refer to Attachment 1. Pages 31 and 32 contain information pertaining to production (Deep Panuke is forecast to produce most of its gas in the first 5-7 years of its life). Page 33 contains demand information.

National Energy Board
Office national de l'énergie

Canada's Energy Future:

ENERGY SUPPLY AND DEMAND PROJECTIONS TO 2035

AN ENERGY MARKET ASSESSMENT NOVEMBER 2011

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LIST OF ACRONYMS AND ABBREVIATIONS

ACTL	Alberta Carbon Trunk Line
CAPEX	capital expenditure
CAPP	Canadian Association of Petroleum Producers
CBM	coalbed methane
CCS	carbon capture and storage
CNG	compressed natural gas
CO_2	carbon dioxide
CSS	cyclic steam stimulation
DSM	demand side management
EGH	EnerGuide for Houses
EMA	Energy Market Assessment
EOR	enhanced oil recovery
ERCB	Energy Resources Conservation Board
EV	electric vehicle
GDP	gross domestic product
GHG	greenhouse gas
GO	gross output
IEA	International Energy Agency
IP	initial production
LNG	liquefied natural gas
NEB	National Energy Board
NECB	National Energy Code for Buildings
NGLs	natural gas liquids
NGV	natural gas vehicle
OECD	Organisation for Economic Co-operation and Development
PHEV	plug-in hybrid vehicles
PHRCC	Petroleum Human Resources Council of Canada
SAGD	steam-assisted gravity drainage
SOEP	Sable Offshore Energy Project
THAI™	toe-to-heel air injection
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

LIST OF UNITS

bbl	barrels
bbl/d	barrels per day
Bcf	billion cubic feet
Bcf/d	billion cubic feet per day
GW	gigawatt
GW.h	gigawatt hour
kg	kilogram
km	kilometre
m^3	cubic metre
m^3/d	cubic metres per day
MMcf	million cubic feet
MMBtu	million British thermal units
Mt	megatonne
MW	megawatt
PJ	petajoules
$ or Cdn$	Canadian dollars
US$	U.S. dollars
Tcf	trillion cubic feet
TW.h	terawatt hour

FOREWORD

The National Energy Board (the NEB or the Board) is an independent federal regulator whose purpose is to promote safety and security, environmental protection and efficient infrastructure and markets in the Canadian public interest[1] within the mandate set by Parliament for the regulation of pipelines, energy development, and trade.

The Board's main responsibilities include regulating the construction and operation of interprovincial and international oil and gas pipelines, international power lines, and designated interprovincial power lines. Furthermore, the Board regulates the tolls and tariffs for the pipelines under its jurisdiction. With respect to the specific energy commodities, the Board regulates the export of natural gas, oil, natural gas liquids and electricity, and the import of natural gas. Additionally, the Board regulates oil and gas exploration and development on frontier lands and offshore areas not covered by provincial or federal management agreements.

The Board also monitors energy markets, and provides its view of the reasonably foreseeable requirements for energy use in Canada having regard to trends in the discovery of oil and gas.[2] The Board periodically publishes assessments of Canadian supply and demand of energy and natural gas markets in support of its ongoing market monitoring. These assessments address various aspects of energy markets in Canada. This Energy Market Assessment (EMA), *Canada's Energy Future: Energy Supply and Demand Projections to 2035*, is one such assessment. This particular EMA projects Canadian energy supply and demand trends out to 2035.

In addition to its own quantitative analysis undertaken in this assessment, the NEB sought the views of Canadian energy experts and interested stakeholders through consultation sessions held in the spring of 2011. The NEB would like to take this opportunity to thank the participants in the consultation process. The views collected helped shape the report's assumptions and analysis.

If a party wishes to rely on material from this report in any regulatory proceeding before the NEB, it may submit the material, just as it may submit any public document. Under these circumstances, the submitting party in effect adopts the material and that party could be required to answer questions pertaining to the material.

This report does not provide an indication about whether any application will be approved or not. The Board will decide on specific applications based on the material in evidence before it at that time.

Comments or questions on this report can be directed to:
Abha Bhargava, Project Manager at abha.bhargava@neb-one.gc.ca

1 The public interest is inclusive of all Canadians and refers to a balance of economic, environmental, and social considerations that change as society's values and preferences evolve over time.

2 This activity is undertaken pursuant to the Board's responsibilities under Part VI of the *National Energy Board Act* and the Board's decision in GHR-1-87.

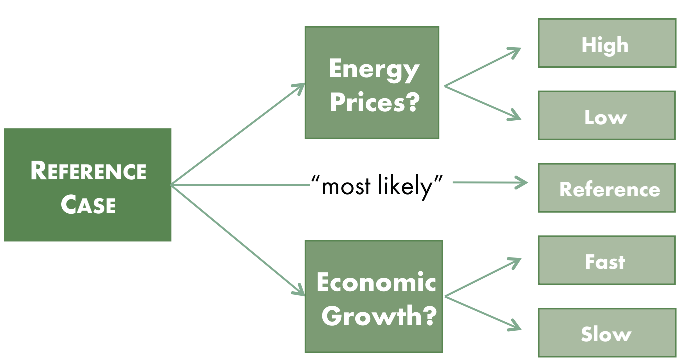
Executive Summary

Background

- This report is a continuation of the NEB's Energy Futures series. The Board released the last full report, *Canada's Energy Future: Reference Case and Scenarios to 2030*, in 2007. This was followed by *2009 Reference Case Scenario: Canadian Energy Demand and Supply to 2020*, which provided an update to the 2007 Reference Case Scenario in light of the rapidly changing economic conditions occurring at the time.
- *Canada's Energy Future: Energy Supply and Demand Projections to 2035* includes a Reference Case and four sensitivity cases projecting energy supply and demand to 2035.[3] The Reference Case is a baseline projection and is considered the "mostly likely" outcome for Canada's energy future, given the underlying assumptions.
- Each sensitivity case differs from the Reference Case by changing one key assumption (Figure ES.1). The NEB's suite of models then estimates the impact on the energy system and economy. Sensitivity analysis is a simple and effective means for analyzing uncertainty by isolating the effect of a change in one variable. This approach differs from the 2007 report's three scenarios, wherein each scenario was a self-contained view of a possible outcome for Canada's energy future. At that time, each scenario was developed independently of the others and included its own internally consistent set of assumptions.

FIGURE ES.1

Price and GDP Growth to 2035, All Cases



	WTI Oil Price, 2010US$/bbl, 2035	HH Natural Gas Price, 2010US$/MMBtu, 2035	Real GDP Growth, 2010-2035
High	$155	$10.70	2.3%
Low	$85	$6.40	2.3%
Reference	$115	$8.00	2.3%
Fast	$121	$8.90	3.2%
Slow	$112	$6.75	1.8%

3 The last year for which detailed energy demand data is available is 2009. As a result, the energy demand projections in this report begin in 2010. In general, historical data on economic indicators, prices and production are available for 2010 and these projections begin in 2011.

- As with previous versions, *Canada's Energy Future: Energy Supply and Demand Projections to 2035* provides a valuable opportunity for the Board to communicate with Canadians on current and emerging energy trends.
- In developing this report, the NEB met with various energy experts and interested stakeholders, including representatives from industry and industry associations, government, environmental non-governmental organizations and academia to gather input and feedback on the preliminary projections. The information obtained from these consultations helped shape the key assumptions and final projections.

Key Findings

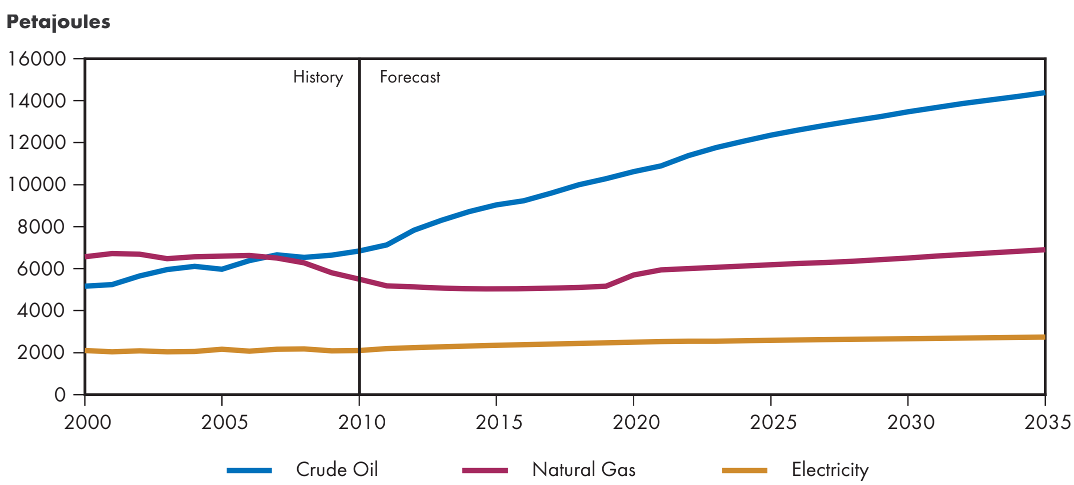
- The key findings of *Canada's Energy Future: Energy Supply and Demand Projections to 2035* are:
    - **Energy supply grows to record levels**

      The emergence of unconventional production as the dominant source of supply growth over the projection period drives this result (Figure ES.2). Based in input assumptions, oil sands production is expected to triple by 2035, increasing its share to 86 per cent of Canada's total oil supply, up from 54 per cent currently. Conventional oil production continues its historical decline over the projection period. However, an increase in oil-directed drilling and the application of multi-stage hydraulic fracturing in tight oil plays results in growing production in the near term. East coast offshore oil production maintains near current levels until 2025, as new production facilities are built. By 2025, production begins a steady decline until the end of the projection period.

      By 2016, increasing Canadian tight and shale gas development reverse the current downward trajectory in Canadian natural gas production. The trend continues, with production reaching the record levels of 2001 near the end of the projection period. A majority of the new supply originates in British Columbia, which has several shale and tight gas plays currently under development. A number of prospective shale resources have been identified in Alberta and producer interest has grown of late. However, given the early stages of this development, specific Alberta shale gas plays have not

FIGURE ES.2

Production of Crude Oil, Natural Gas and Electricity, Reference Case



been separated out from the conventional and tight gas categories in these projections. Given further development, this could have an upward influence on future projections.

Electricity supply also increases to record levels, as new generating capacity is built to meet steadily increasing demand. A number of federal and provincial policies and regulations result in a cleaner electricity supply mix in Canada. The addition of more renewable-based capacity, such as wind, hydro and biomass, as well as the application of carbon capture and storage (CCS) technology, reduce the emissions intensity of the electricity sector.

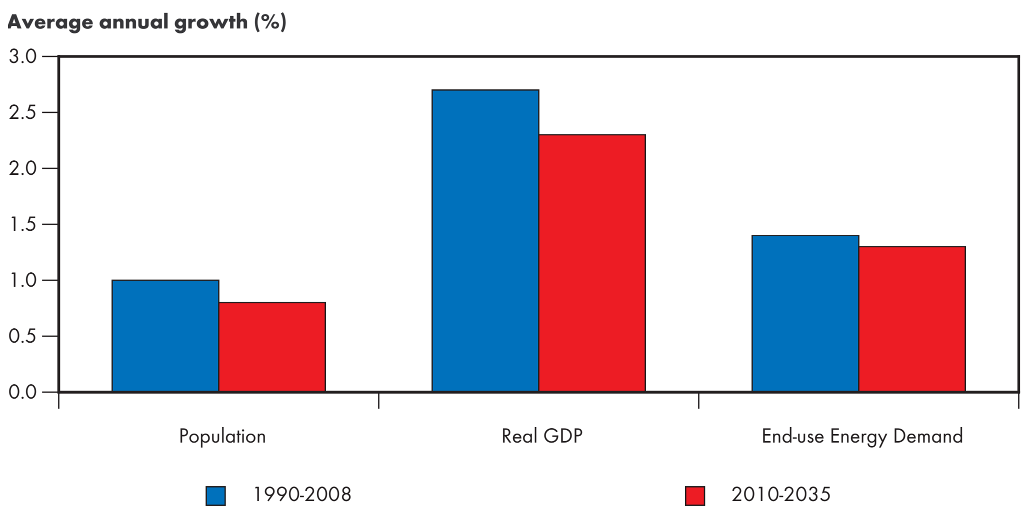
- **Energy demand growth slows from its historical pace**

Total end-use energy demand growth slows from 1.4 per cent per year between 1990 and 2008[4] to 1.3 per cent per year over the projection period. Despite this modest slowing in aggregate demand growth, the detailed results indicate a marked slowdown in many of the energy demand drivers (Figure ES.3). These drivers include slowing population growth, higher energy prices, lower than historical economic growth, and enhanced efficiency and conservation programs. Compared to historical growth rates, energy demand growth in the commercial and transportation sectors slows considerably. In the commercial sector, average annual growth falls from 2.0 per cent historically to 1.0 per cent in the projection, while transportation growth falls from 1.9 per cent to 1.4 per cent. In addition, federal and provincial government programs result in notable penetration of biodiesel and ethanol in the transportation sector. Demand growth in the residential sector falls from 0.7 per cent per year over the 1990 to 2008 period to 0.6 per cent from 2010 to 2035.

Offsetting this slowdown is demand growth in the industrial sector, which made up nearly half of Canadian energy demand in 2010. Robust growth in a number of industries outweighs the declines in energy intensity exhibited by this sector over the

FIGURE ES.3

Comparison of Historical and Projected Growth Rates of Population, Real Gross Domestic Product (GDP), and End-use Energy Demand, Reference Case



4 The 1990 to 2008 period is used for a historical reference period in this report. Historical data for 2009 is available but given the significant impact of the 2009 global recession on the economy and energy demand, the 1990-2008 period is more illustrative when comparing future trends to history.

outlook period. Industrial energy demand grows at 1.6 per cent per year over the projection period, compared to 1.2 per cent over the 1990 to 2008 period.

- **Supply and Demand will impact trade and infrastructure**

  Changing trends in energy supply and demand will have important implications for energy trade and needs for additional infrastructure. Oil sands production growth, coupled with modest growth in petroleum product demand, more than triples net crude oil available for export by 2035. Meanwhile, increased demand for natural gas in Canada is expected to reduce the net natural gas available for export gradually until 2020. After 2020 net natural gas available for export is flat for the remainder of the outlook period. Net electricity available for export doubles over the outlook period.

- There are four key simplifying assumptions for this report:
  - All energy production will find markets and infrastructure will be built as needed. The analysis of these factors was not undertaken.
  - Economic factors are the key determinant of various energy supply and demand outcomes. Other considerations, such as environmental and socio-economic impacts are important factors in Canada's energy future but remain beyond the scope of this report.
  - Only policies and programs that are law or near law at the time of writing are included in the projections. As a result, any policies under consideration, or new policies developed after the projections were completed, are not included in this analysis.
  - Energy markets are evolving constantly. The analysis presented in this report is based on the best available information at the time.
- Overall, *Canada's Energy Future: Energy Supply and Demand Projections to 2035* suggests that energy markets in Canada will continue to function well, providing adequate energy for Canadians. In the Reference Case, oil, natural gas and electricity supply remain robust, while end-use energy demand growth increases at a slightly slower pace than the historical rate. While energy from fossil fuels remains the dominant source of supply, various programs and policies encourage emerging fuels and technologies to gain market share.

Introduction

- This report projects energy supply and demand for Canada to the year 2035. It includes a Reference Case, with baseline projections based on the current macroeconomic outlook, a moderate view of energy prices, and government policies and programs in place at the time the report was prepared. It is considered the "most likely" outcome for Canada's energy future, given the underlying assumptions.
- In addition to the Reference Case, the report considers four sensitivity cases to provide a broader perspective and reflect the uncertainty around energy prices and economic growth. The four sensitivity cases are referred to as the High and Low Cases (for high and low prices) and the Fast and Slow Cases (for fast and slow economic growth).
- The following chapters discuss the key factors influencing the Reference and sensitivity cases, highlighting key changes in Canadian energy supply and demand trends. The detailed data tables supporting this discussion are available in the Appendices on the *NEB website*.

KEY DRIVERS

- This report considers five cases – a Reference Case, which reflects a moderate view of future energy prices and economic growth – and four sensitivity cases. These sensitivity cases represent a range of possible outcomes for the Canadian energy system over the projection period. Higher and lower crude oil and natural gas prices characterize the first two cases, whereas faster and slower growth of the Canadian economy distinguishes the other two cases. These four sensitivities are referred to as the High, Low, Fast and Slow Cases.

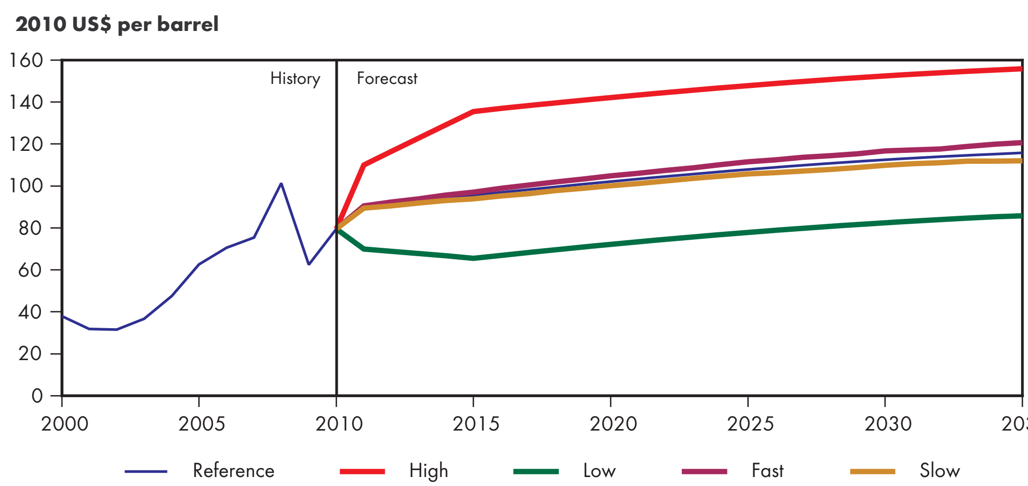
Energy Prices

Crude Oil Prices

- In the Reference Case, the West Texas Intermediate (WTI) crude oil price is assumed to average US$90/bbl in 2011. The real price increases slowly over the projection period, reaching US$115/bbl by 2035 (in U.S. 2010 dollars) (Figure 2.1). This gradual increase takes place as the global economy continues to recover from the 2009 global recession and as supplies become increasingly difficult to access. Price growth in the oil price outlook reflects global energy supply and demand fundamentals that imply an increasingly tight global crude oil market over the long term.
- In the Low Case, the WTI crude oil price is assumed to be US$30/bbl below the Reference Case price, reaching just over US$85/bbl in 2035. In the High Case, it is assumed to be $40 higher than the Reference Case price, growing to US$155/bbl by 2035.

FIGURE 2.1

West Texas Intermediate Crude Oil Price at Cushing, Oklahoma, All Cases



- In the Fast and Slow Cases, the oil price is assumed to differ by only a few dollars above and below the Reference Case. Faster or slower economic growth in Canada and the U.S. is expected to have a relatively small impact on global crude oil demand and the crude oil price. In the Fast Case, the oil price reaches nearly US$121/bbl by 2035 while in the Slow Case it is US$112/bbl.
- In early 2011, the North American benchmark WTI oil price began trading at a significant discount to the Brent oil price, a major crude oil price marker in Europe. Historically, the two prices have tracked very closely to one another. This spread, which has reached more than US$20/bbl in 2011, is largely due to excess supply of crude oil available in the U.S. Midwest. This excess supply is a result of increasing Canadian and U.S. crude oil production and insufficient take-away pipeline capacity at Cushing, Oklahoma (the pricing point for the WTI contract). The assumption that infrastructure will be built as necessary suggests that this excess supply will only be temporary, and the spread between Brent and WTI will dissipate over time.

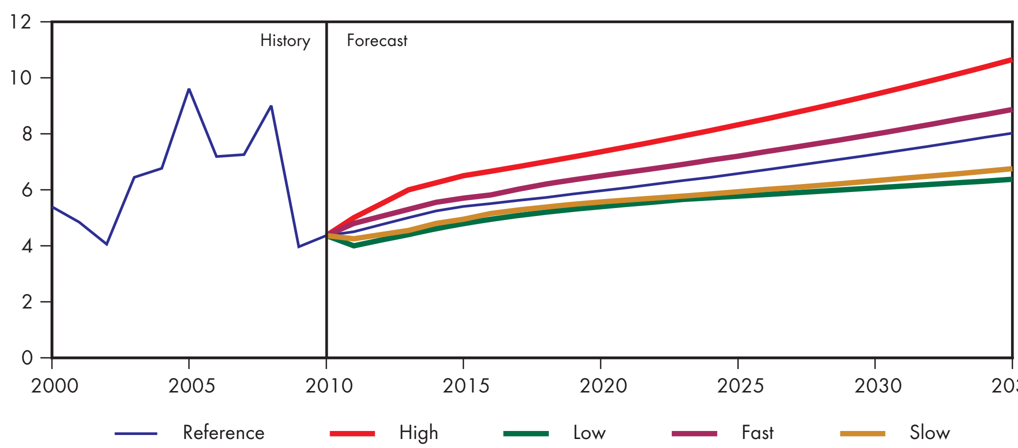
Natural Gas Prices

- The Henry Hub price of natural gas in the Reference Case is assumed to increase from US$4.50/MMBtu in 2011 to US$8.00/MMBtu in 2035 (in U.S. 2010 dollars) (Figure 2.2). The increase in the real price reflects growing demand for natural gas in North America and gradually increasing costs of discovering and producing the gas.
- Historically, the price of natural gas tended to move in relation to the oil price, with natural gas trading at a small discount to an energy equivalency-ratio of 6:1 (oil prices in US$/bbl relative to gas prices in US$/MMBtu). This ratio has increased in the past several years to 18:1 in 2010. This is due to the large new natural gas production potential brought about by increased utilization of multi-stage hydraulic fracturing technology combined with few opportunities to switch between petroleum-based fuels and natural gas. In the Reference Case, the ratio slowly declines to just over 14:1 by 2035 based on the oil and gas price projections. With considerable uncertainty surrounding the crude oil and natural gas price relationship, price projections for oil and natural gas were developed independently.
- In the Low Case, the natural gas price is assumed to reach US$6.40/MMBtu by 2035 and US$10.70/MMBtu in the High Case.

FIGURE 2.2

Henry Hub Natural Gas Price at Louisiana, All Cases

2010 US$ per MMBtu



- Unlike oil prices, which are determined in a global market, the Henry Hub natural gas price is primarily determined on a continental basis, as the North American market lacks significant links to global natural gas markets. The impact of North American economic growth on the natural gas price is larger than on the oil price. As a result, the natural gas price varies more widely than the oil price from the Reference Case in the Fast and Slow Cases, reaching US$8.90/MMBtu and US$6.75/MMBtu, respectively, by 2035.

Electricity Prices

- Electricity prices are determined in regional markets. Consumer prices for electricity are mainly composed of generation, transmission and distribution costs. Prices are generally lowest in the hydro-based provinces (British Columbia, Manitoba, and Quebec), which benefit from a high proportion of low-cost heritage assets, such as hydro-generating stations. These assets are often many decades old and the costs to build them are largely paid off.
- Prices in most jurisdictions are based on the actual cost of providing service to consumers, including a regulated rate of return on the generation, transmission and distribution assets. Provincial and, in some cases, municipal regulators are responsible for approving these costs. All provinces and the territories except Alberta and Ontario follow this model. In Alberta, competitive wholesale markets determine electricity prices. Ontario is a hybrid of the two methodologies, with both regulated and market-based prices.
- Typically, prices tend to be higher for residential customers and lower for large volume commercial and industrial customers, reflecting the cost of serving these markets. In addition, large customers may have direct access to wholesale markets, where power costs can be lower than the rates offered by the retail distribution utilities. This requires open access[5] to transmission systems (or wholesale access). All provinces have some form of wholesale access.
- In the Reference Case, the average retail electricity price (including the residential, commercial and industrial prices) is projected to be 42 per cent higher in 2035 compared to 2010, in real terms. This reflects the increasing cost of sourcing new generation and planned improvements to transmission systems. Electricity prices in the sensitivity cases do not differ widely from the Reference Case.

Coal Prices

- Canadian coal prices for power generation vary substantially by region, with prices in Western Canada generally lower, reflecting the cost of integrated mining and power generation (mine mouth power plants). Prices of coal imported to Nova Scotia, New Brunswick and Ontario reflect the competitive international market.
- In all sensitivity cases, coal prices are assumed to stay relatively constant in real terms, staying at 2011 levels over the projection period.

5 Open access to transmission in this report refers to the possibility for eligible market participants (e.g. utilities, direct customers, exporters) to have access to transmission lines under a set of rules, conditions and tariffs. Open access is essential for competitive wholesale power markets, allowing eligible buyers to purchase electricity from the most competitive generation sources.

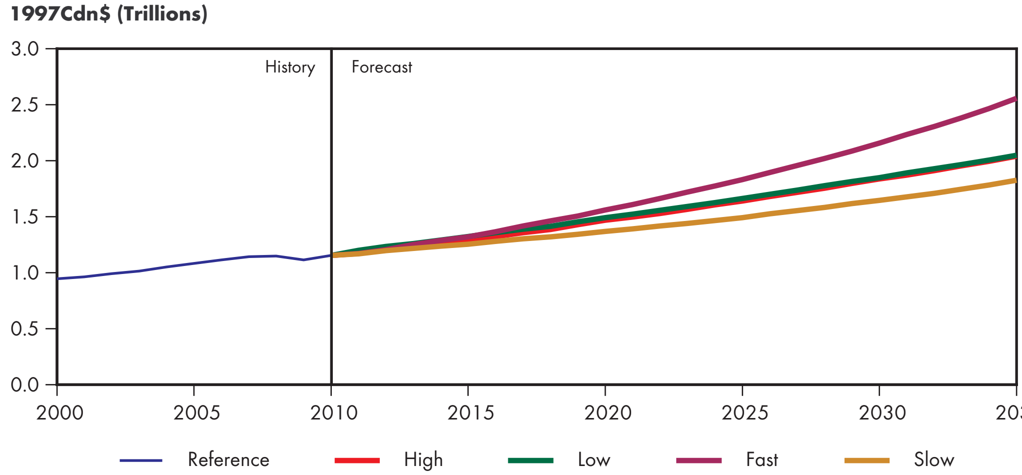
Economic Growth

- The Canadian economy is a key driver of the energy picture in all five cases (Figure 2.3). Economic growth, industrial output, inflation, exchange rates and population growth are key macroeconomic factors that influence the energy supply and demand outlook.
- Overall, the global economy continues to recover from the 2009 recession, with developing nations returning to brisk growth. Developed nations have recovered more slowly by comparison, but most have returned to positive GDP growth. This trend is projected to continue, with economies in countries like China, India and Brazil becoming increasingly important drivers of global economic growth. The Reference Case macroeconomic outlook reflects these underlying global trends.
- Canadian real GDP growth is estimated to be 2.6 per cent in 2011, reflecting a continuation of the economic recovery.
- Long-term economic growth is dependent on the growth of Canada's population, labour force and productivity. Productivity growth is expected to improve over the Reference Case projections while slowing population and labour force growth trends will have a dampening effect on economic growth. From 2010 to 2035, annual GDP growth is projected to average 2.3 per cent.
- Energy prices influence economic conditions in Canada. In particular, the global crude oil price has influenced the exchange rate, especially in recent years. As the crude oil price moved higher, such as in the first half of 2008, the Canadian dollar has appreciated against the American dollar. Similarly, the currency has tended to depreciate when crude oil prices fall. The High and Low Cases explore the economic and energy dynamics resulting from different price assumptions.
- The pace of future economic growth represents a key uncertainty for Canadian energy supply and demand. The Fast and Slow Cases capture a range of this uncertainty. In the Fast Case, the Canadian economy exhibits average annual growth of 3.2 per cent; for the Slow Case this is 1.8 per cent. U.S. economic growth, Canadian labour participation and labour productivity were altered from the Reference Case to construct the two economic growth sensitivity cases.

FIGURE 2.3

Real Gross Domestic Product, All Cases

1997Cdn$ (Trillions)



Key Uncertainties to the Outlook

- Future movements in the global crude oil price are a key uncertainty. While the High and Low Cases capture much of this volatility, the possibility for even higher or lower prices, or dramatic short-term price swings, exists and could have future implications.
- Economic conditions can have a significant impact on the Canadian energy system as evidenced by the wide swings in energy supply, demand and prices brought about by the 2009 global recession. The Fast and Slow Cases represent a wide range of economic outcomes, but the potential remains for periods of growth outside of the range included in the analysis.
- In recent years, developments in multi-stage hydraulic fracturing technology have allowed previously untapped shale and tight natural gas resources to be economically developed. The result has been significant additions to production and resources in the U.S. and, increasingly, Canada. These lower-cost additions have partially offset long-term declines in conventional gas production in North America and have contributed to lower prices in the last few years.

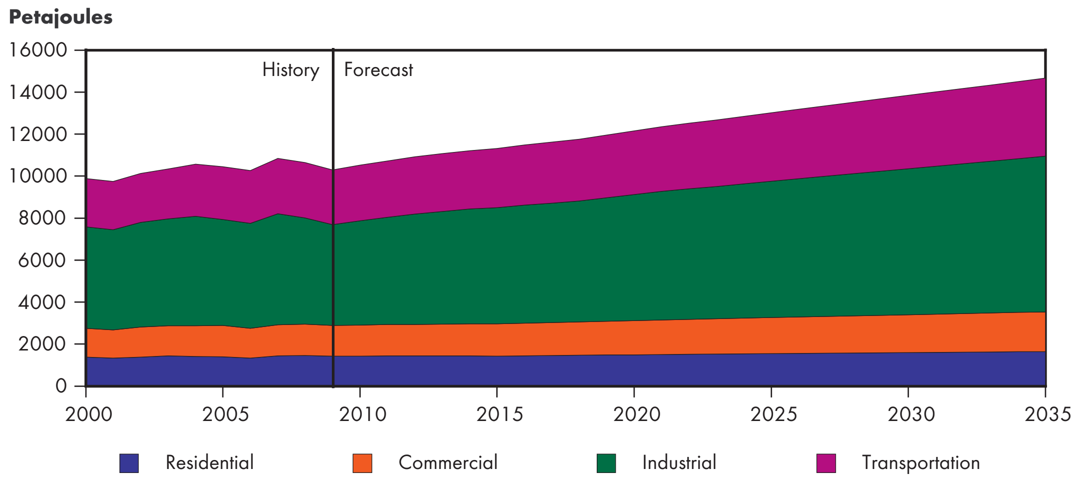
  The widespread development of these natural gas resources is still relatively new in Canada and observers have noted various environmental factors associated with the process. As a result, achieving robust production levels of shale and tight gas at the price levels included in this analysis remains an uncertainty. In particular, Alberta natural gas shale plays are in the early stages of development and there is potential for production to be different than this analysis projects.
- Exploitation of tight oil resources, which also employs multi-stage hydraulic fracturing technology, is in its early stages. If such technology becomes more widely applied, as it has in extracting tight and shale gas, conventional oil production could be higher than in the Reference Case projection.
- As noted earlier, the Reference and four sensitivity cases include only policies and programs that are law or near law at the time of writing. As a result, any policies under consideration, or new policies developed after the projections were completed, are not included in this analysis.
- Over the 25-year outlook period, it is likely that developments beyond the realm of normal expectations will occur, such as geopolitical events or technological breakthroughs. Likewise, new information will become available and trends, policies and technology will evolve. Readers of this report should consider the projections a baseline for discussing Canada's energy future, not a prediction of what will take place.

ENERGY DEMAND OUTLOOK

- In this report, end-use (secondary) energy demand includes energy used in four sectors: residential, commercial (includes institutional and pipelines), industrial and transportation.[6]
- In the Reference Case, total end-use energy demand increases by an average of 1.3 per cent per year (Figure 3.1). This growth is led by the industrial sector, which grows at an annual average rate of 1.6 per cent, followed by transportation at 1.4 per cent. Residential and commercial demands grow at average annual rates of 0.6 and 1.0 per cent, respectively.
- Overall, energy demand growth slows modestly compared to history, where demand grew at an average of 1.4 per cent per year from 1990 to 2008. The industrial sector, which grows faster than its 1990 to 2008 average rate of 1.2 per cent per year, largely drives this level of energy demand growth. Industrial growth is related to strong growth in energy-intensive manufacturing industries, as well as energy used in the oil and gas sector. Demand growth projections in the residential, commercial, and transportation sectors are lower than historical levels. From 1990 to 2008, the residential sector grew at an average annual rate of 0.7 per cent, commercial by 2.0 per cent, and transportation at 1.9 per cent.
- Total energy intensity, measured as energy use per dollar of real Canadian GDP, decreases by an average annual rate of 1.1 per cent over the projection period. This continues the

FIGURE 3.1

Energy Demand by Sector, Reference Case



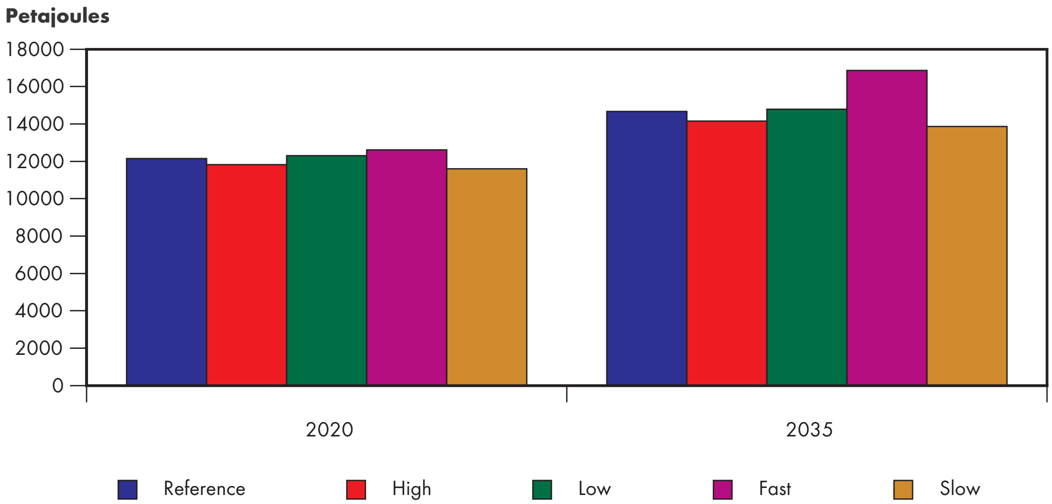
6 End-use energy demand excludes the energy used to generate electricity. The data used in this analysis is primarily sourced from Statistics Canada, Natural Resources Canada's Office of Energy Efficiency, and Environment Canada.

historical trend where energy intensity declined by an average of 1.2 per cent per year from 1990 to 2008.[7]

- There are several new programs, policies and standards that are included in the Reference Case that were not included in previous NEB outlooks. Two examples are the recent *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*[8] and the *Renewable Fuels Regulations*.[9] Policies or regulations that are currently in development but not finalized are not included.
- In the Low Case, total end-use energy demand grows at an average annual rate of 1.4 per cent. In the High Case, growth slows to an annual average of 1.2 per cent.
- In the Fast Case, total end-use energy demand grows at an average annual rate of 1.9 per cent. In the Slow Case, total end-use energy demand grows at an annual average rate of 1.1 per cent.
- In 2035, end-use energy demand in the case with the largest demand growth (Fast) is 22 per cent, or over 3 000 petajoules (PJ), higher than the case with the smallest demand growth (Slow) (Figure 3.2).

FIGURE 3.2

Energy Demand, 2020 and 2035, All Cases



7 Energy intensity reflects improvements in energy efficiency, but also other factors such as industrial structure and types of energy-using services demanded. Economic growth driven by energy-intensive sectors will put upward pressure on energy intensity, while efficiency improvements and growth in less energy-intensive sectors (such as the service sector) will dampen growth in energy intensity. For more on Canadian energy intensity trends, see Natural Resource Canada's Office of Energy Efficiency: http://oee.nrcan.gc.ca/ . For additional information on energy demand and intensity trends, refer to the NEB's Energy Demand reports, available at: http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgdmnd/nrgdmnd-eng.html

8 Canada Gazette, *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations*, 23 September 2010. Available at: http://www.gazette.gc.ca/rp-pr/p2/2010/2010-10-13/html/sor-dors201-eng.html

9 Canada Gazette, *Renewable Fuels Regulations*, 23 September 2010. Available at : http://www.gazette.gc.ca/rp-pr/p2/2010/2010-09-01/html/sor-dors189-eng.html

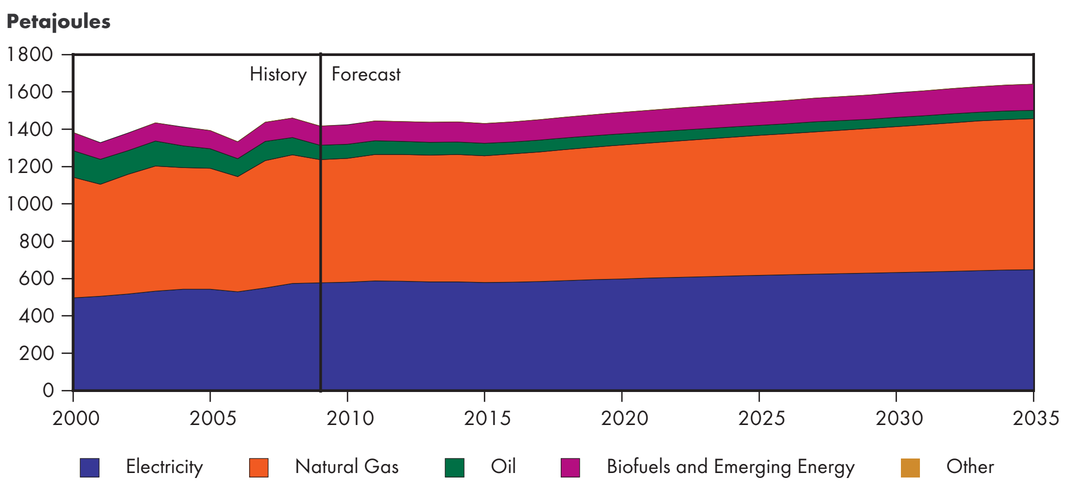
Energy Consumption by Sector

Residential Sector

- Residential energy use is the energy consumed by Canadian households. This includes energy used for space and water heating, air conditioning, large appliances, and other energy-using devices like televisions and computers.
- In 2009, Canadian residential energy demand was 1 419 PJ, and accounted for 14 per cent of total Canadian energy demand. Residential energy demand increases at an average annual rate of 0.6 per cent over the projection period, reaching 1 664 PJ in 2035 (Figure 3.3). Residential is the slowest-growing sector, and its share of total energy demand drops to 11 per cent by 2035.
- Demand management programs and policies contribute to the low energy demand growth in the residential sector. Federal programs, such as the ecoEnergy Retrofit-Homes program, have been employed with various provincial programs. Space heating energy efficiency will benefit from new federal regulations for furnaces and boilers. In 2009 and 2010, amendments to the federal *Energy Efficiency Act* have increased minimum energy performance standards for more than a dozen home devices. There has also been a renewed commitment for utility-based demand side management (DSM) programs.
- All provinces and territories have voluntary programs encouraging greater energy efficiency in new homes and equipment. Many of these programs offer incentives to consumers such as rebates, low-interest loans, and education and awareness campaigns. Also, several provinces have recently moved forward with building codes that include more stringent minimum energy performance standards. Based on the federal EnerGuide for Houses (EGH) rating system, Ontario, British Columbia, Manitoba, and Nova Scotia have essentially mandated requirements for an EGH 80 rating for new homes.[10] New home

FIGURE 3.3

Residential Sector Energy Demand by Fuel, Reference Case[(a)]



(a) Biofuels and Emerging Energy include wood, biomass, biofuels blended with heating oil, and solar and geothermal hot water heating.

10 An EnerGuide rating of 80 represents an energy-efficient new house. For perspective, a typical new home in 2002 would rate between 70-71 and an early 1970s home would rate approximately 65. For more information, see the NEB Energy Briefing Note Codes, Standards and Regulations Influencing Energy Demand, 2008. Available at: http://www.neb-one.gc.ca/clf-nsi/rnrgynfmtn/nrgyrprt/nrgdmnd/cdstndrdrgltn2008/cdstndrdrgltn-eng.html

energy performance is often part of broad emissions and energy reduction strategies (e.g. British Columbia's *Clean Energy Act* and Ontario's *Green Energy Act*).

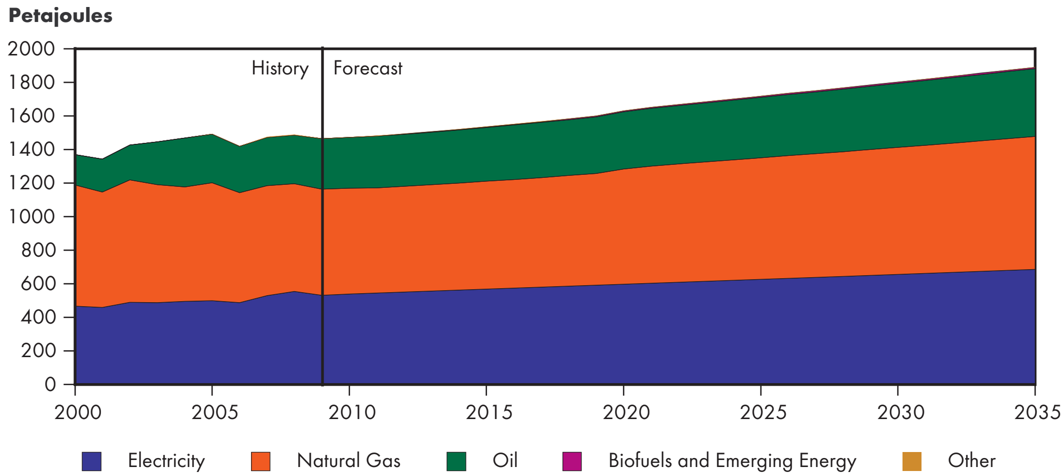
- Natural gas and electricity make up the majority of the energy used in the residential sector, accounting for 87 per cent of residential energy use in 2009. Over the projection period, the share of electricity remains stable at 40 per cent, while the natural gas share increases slightly from 47 to 50 per cent. The share of oil used for heating in the residential sector continues its historical decline. This is aided by the recent amendment to *Canada's Renewable Fuels Regulations* that requires two per cent renewable fuel content in heating oil. Solar and geothermal hot water heating gains marginal market share over the course of the projection period, accounting for 0.2 per cent of total residential energy demand in 2035, or three PJ.
- Energy prices, end-use energy requirements and regional availability of fuel, determine the mix of fuel used across Canada. Atlantic Canada meets almost all its residential energy needs with electricity, oil and biomass, as natural gas has been available in very limited areas. Quebec, Manitoba and British Columbia have relatively low cost hydroelectricity supply and rely more heavily on electric energy. Alberta and Saskatchewan rely more heavily on natural gas than other provinces.
- Emerging natural gas infrastructure in Nova Scotia and New Brunswick has allowed natural gas to penetrate the residential, commercial, and industrial sectors. In the Reference Case, the share of natural gas in total residential demand increases from 1.1 to 2.2 per cent in Nova Scotia, and 1.6 to 3.2 per cent in New Brunswick.
- In the Low Case, residential energy demand grows at an average annual rate of 0.62 per cent. In the High Case, growth slows to an annual average of 0.50 per cent.
- In the Fast Case, residential energy demand grows at an average annual rate of 0.64 per cent. In the Slow Case, residential demand grows at an annual average rate of 0.56 per cent.
- In 2035, energy demand in the case with the largest demand growth (Fast) is four per cent higher than the case with the smallest demand growth (High), a difference of 60 PJ.

Commercial Sector

- The commercial sector is a broad category that includes offices, retail, warehousing, government and institutional buildings, utilities, communications, and other service industries. It also includes energy consumed by street lighting and oil and natural gas transmission pipelines. The buildings portion of the commercial sector uses energy for space and water heating, air conditioning, lighting, and electrical plug load. The pipeline portion uses energy to power pumps or compressors that move the oil and natural gas through the pipeline.
- In 2009, Canadian commercial energy demand was 1 466 PJ, and accounted for 14 per cent of total Canadian energy demand. Commercial energy demand increases at an average of 1.0 per cent per year over the outlook period, reaching 1 891 PJ in 2035 in the Reference Case (Figure 3.4). Its share of total demand decreases to 13 per cent by 2035.
- An extensively revised National Energy Code for Buildings (NECB) was finalized in the spring of 2011. This companion to the National Building Code puts a greater emphasis on energy performance in buildings than in the past. The code change is expected to improve energy performance in new commercial, institutional, and multi-unit residential complexes by 25 per cent over the previous code (1997). Adoption of the new NECB is ultimately up to the provincial, territorial, or, in some cases, municipal authority. However, this revision

FIGURE 3.4

Commercial Sector Energy Demand by Fuel, Reference Case



took a consensus-based approach with broad stakeholder support including that of the provinces, so it is likely to be adopted.

- Several provinces have taken a pre-emptive approach and specified building energy performance ahead of new national standards. British Columbia, Ontario, Manitoba, and Nova Scotia have scheduled requirements in the 2010 to 2012 timeframe.
- The commercial sector demand projection also includes the impact of more stringent energy efficiency regulations on heating, ventilation, air conditioning and electronics in the 2010 to 2012 timeframe.
- In the Low Case, commercial energy demand grows at an average annual rate of 1.0 per cent. In the High Case, growth slows slightly to an annual average of 0.9 per cent.
- In the Fast Case, commercial energy demand grows at an average annual rate of 1.2 per cent. In the Slow Case, commercial demand grows at an annual average rate of 1.0 per cent.
- In 2035, energy demand in the case with the largest demand growth (Fast) is six per cent higher than the case with the smallest demand growth (High), a difference of over 110 PJ.

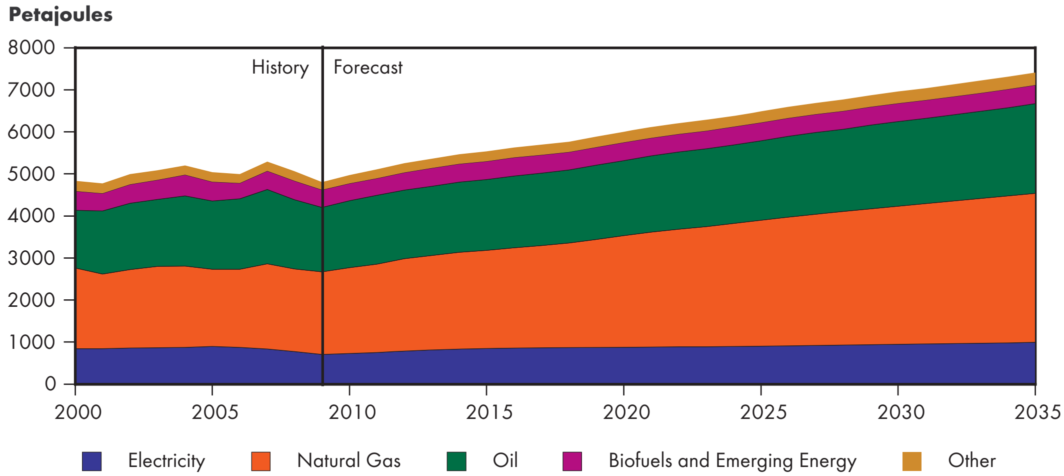
Industrial Sector

- The industrial sector includes manufacturing, forestry, fisheries, agriculture, construction, and mining. The majority of industrial energy use is consumed by a handful of energy-intensive industries, such as iron and steel, aluminum, cement, chemicals and fertilizers, and pulp and paper manufacturing, petroleum refining, and oil and gas extraction.[11]
- The industrial sector makes up the largest share of Canadian end-use energy demand, accounting for 47 per cent, or 4 803 PJ, in 2009. It is also the fastest-growing sector over the projection period, increasing at an average annual rate of 1.6 per cent to 7 413 PJ in 2035 (Figure 3.5). In the Reference Case, its share of total demand increases to 51 per cent in 2035.

11 In 2009, energy-intensive industries accounted for 78 per cent of industrial energy demand. Other industries, such as light manufacturing, agriculture, forestry and construction, each consume a relatively small proportion of industrial energy use, but taken together account for 22 per cent.

FIGURE 3.5

Industrial Sector Energy Demand by Fuel, Reference Case



- The Canadian industrial demand projection is closely related to the economic growth projections discussed in Chapter 2, as well as the projections of oil and gas production. In particular, the global economic recovery and increasing oil sands production are key drivers of the industrial demand projection.[12]
- Various utility DSM programs focused on the industrial sector, as well as federal and provincial programs aimed at energy savings, have been maintained or expanded in recent years. These are included in the Reference Case projection.
- Several provinces have made commitments and enacted enabling legislation to participate in the Western Climate Initiative cap-and-trade system. However, its potential effects on demand are not included in the projections, as the final regulations are still in development.
- In the industrial sector, energy demand in the High Case grows slightly faster than in the Low Case (average annual growth rates of 1.51 and 1.49 per cent, respectively). This is an opposite trend from the other sectors, where demand growth in the High Case is less than in the Low Case. The difference is due to oil and gas production activity in the industrial sector. In the High Case, oil and gas production is higher, and so is demand for energy used in its production (and vice-versa for the Low Case). For the other energy-intensive industrial sectors, higher energy prices lead to lower demand as the energy used in producing goods becomes more expensive. These trends are more evident in the regional results. For example, in Alberta, an energy-producing province, industrial demand in the High Case grows about 0.5 per cent per year faster than the Low Case. Conversely, in Ontario industrial demand in the High Case grows about 0.7 per cent per year slower than in the Low Case.
- In the Fast Case, industrial energy demand grows at an average annual rate of 2.3 per cent per year. In the Slow Case, industrial demand grows at an annual average rate of 1.4 per cent per year.
- In 2035, energy demand in the case with the largest demand growth (Fast) is 25 per cent higher than the case with the smallest demand growth (Slow), a difference of nearly 1 800 PJ.

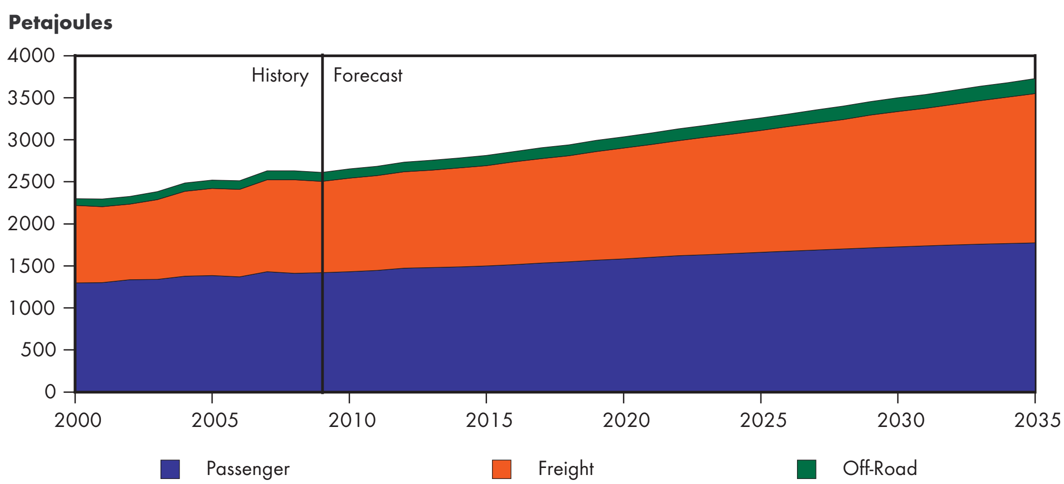
12 For more on energy use by oil sands, see the Crude Oil Supply Outlook, Chapter 4.

Transportation Sector

- The transportation sector includes passenger and freight on-road transportation, as well as air, rail, marine, and non-industrial off-road travel.[13]
- The transportation sector accounted for 25 per cent of total end-use demand in 2009, or 2 611 PJ. It grows at an average annual rate of 1.4 per cent over the Reference Case projection to 3 729 PJ in 2035 (Figure 3.6). Its share of total energy demand remains at 25 per cent throughout the outlook period.
- The freight side of the transportation sector is the main driver of transportation demand growth, growing at an average annual rate of 1.9 per cent over the projection period. The passenger sector is projected to grow about half as fast, at 0.9 per cent per year (Figure 3.6). Freight activity is strongly related to industrial activity, hence the higher growth in freight energy use.
- In late 2010, the federal government finalized regulations for light duty vehicle emissions. The *Passenger Automobile and Light Truck Greenhouse Gas Emission Regulations* set progressively more stringent limitations on tailpipe emissions for new vehicles in the 2012 to 2016 timeframe. The regulation is based on manufacturers' fleet make-up from 2011. It is expected that a large portion of the emissions reductions will coincide with an improvement in fuel economy, which will put downward pressure on vehicle energy demand.
- The transportation emissions reductions strategy aligns Canada's regulations with the U.S. regulations. Regulations for heavy-duty trucks for the 2014 to 2018 period,[14] and light-duty vehicles beyond 2016, are currently in development. Therefore, these are not included in this projection.

FIGURE 3.6

Transportation Sector Energy Demand by Mode, Reference Case



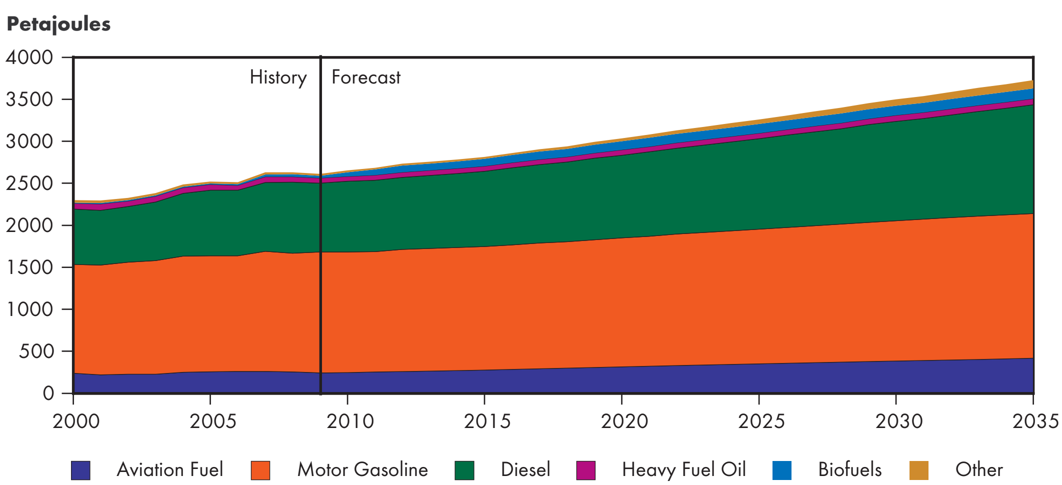
13 Passenger and freight transportation demand includes consumption by foreign airline and marine consumers. Non-industrial off-road demand includes all-terrain vehicles, lawnmowers, and miscellaneous small equipment. It accounts for less than five per cent of transportation demand. Industrial off-road demand is included in the industrial sector.

14 Environment Canada, *Consultation Document for Discussion of the Main Elements of the Proposed Regulations under the Canadian Environmental Protection Act*, *1999* to *Limit Greenhouse Gas Emissions from New On-Road Heavy-Duty Vehicles and Engines*, 9 August 2011. (Proposed regulations expected in early 2012). Available at: http://www.ec.gc.ca/lcpe-cepa/default.asp?lang=En&n=A7A02DDF-1

- In 2009, gasoline and diesel accounted for 87 per cent of transportation energy use. This share declines to 81 per cent in the Reference Case by 2035. Gasoline's share declines from 55 per cent in 2009 to 46 per cent due to slow growth of the passenger sector (which consumes the majority of gasoline) and the increasing penetration of alternative transportation fuels over the projection period. The share of diesel increases from 31 per cent in 2009 to 35 per cent in 2035 (Figure 3.7). This is due to strong growth in the freight sector, which consumes the majority of diesel.
- Canada's *Renewable Fuels Regulations* set a minimum requirement of five per cent renewable fuel content in gasoline starting in December 2010. The regulation was recently amended to include two per cent renewable content in diesel and heating distillate oil starting in July 2011. This, in combination with various provincial regulations, causes the share of biofuels in the transportation to increase from 1.1 per cent of total transportation demand in 2009, to 3.3 per cent in the Reference Case by 2035.
- Several provinces are supportive of alternative vehicle technologies and alternative fuels. Quebec, Ontario, Manitoba, and British Columbia have programs and policies to support growth in electric vehicles (EV) and plug-in hybrid vehicles (PHEV), including rebates and pilot projects. In 2035, EV and PHEV use 7.5 PJ of electricity, 0.5 per cent of total passenger transportation demand. This is approximately equivalent to 700 000 EV and PHEVs on the road.[15]
- There is also growing interest in natural gas vehicles (NGV), with much of the interest in the western provinces. The most likely application of NGVs is for medium and heavy-duty trucks, especially in fleet operations. At the time of writing, no specific policy incentives or subsidies are in place to encourage widespread NGV uptake. However, the oil to natural gas price spread in the projection supports a modestly paced, incremental increase in NGV to target markets. In 2035, freight NGVs use 60 PJ of natural gas, 3.5 per cent of

FIGURE 3.7

Transportation Sector Energy Demand by Fuel, Reference Case[(a)]



(a) Heavy fuel oil is used in marine and rail transportation. Biofuels include ethanol and biodiesel blended with petroleum products. Other includes natural gas, electricity, and propane.

15 Assuming 200 watt hour /km per EV, driving 15 000 km/yr. Consistent with *Electric Vehicle Technology Roadmap for Canada*, EV Industry Steering Committee, 2010. Available at: http://canmetenergy-canmetenergie.nrcan-rncan.gc.ca/eng/transportation/hybrid_electric_vehicles/evtrm.html

total freight demand. This is approximately equivalent to 56 000 medium- and heavy-duty freight NGVs.[16]

- British Columbia's Renewable and Low-carbon Fuel Requirement calls for a ten per cent decrease in carbon intensity for transportation fuels by 2020. The Reference Case assumes this will be met in part by decreasing gasoline and diesel fuel shares, and increases in ethanol, biodiesel, EV/PHEV, and NGV over the 2012 to 2020 timeframe.
- In the Low Case, transportation energy demand grows at an average annual rate of 1.7 per cent. In the High Case, growth slows to an annual average of 1.1 per cent.
- In the Fast Case, transportation energy demand grows at an average annual rate of 2.1 per cent. In the Slow Case, transportation demand grows at an annual average rate of 1.0 per cent.
- In 2035, energy demand in the case with the largest demand growth (Fast) is 33 per cent higher than the case with the smallest demand growth (Slow), a difference of over 1 100 PJ.

Key Uncertainties to the Outlook

- Policies, programs, and regulations are continually under development at the federal, provincial, territorial, and municipal levels to meet various government commitments, objectives, and targets. Implementing policies that are currently in development or making other changes to meet existing targets, may have significant implications for energy demand. These effects may be in the form of reducing energy demand growth, or changing the types of energy Canadians use.
- The oil and gas industry is one of the main sources of energy demand growth in the industrial sector. In recent years, this industry has undergone rapid transformations in both the types of resources extracted, and the technologies used to extract them. Depending on the future development of these resources and technologies, the energy used in this industry may be higher or lower than projected.

16 Assuming heavy trucks travelling 200 000 km/yr with a fuel efficiency of 62 l/100km, and medium trucks traveling 60 000 km/yr with a fuel efficiency of 39 l/100km. This is consistent with *National Gas Use in the Canadian Transportation Sector*, *Natural Gas Use in Transportation Roundtable*. There are many more EVs assumed than NGVs, but much less electricity use. This difference is due to passenger EVs being relatively less energy-intensive per kilometre travelled, and travelling few kilometres per year.

Crude Oil Outlook

Crude Oil and Bitumen Resources

- Canada has abundant resources of crude oil, with an estimated remaining ultimate potential of 54.5 billion cubic metres (343 billion barrels). Of this, oil sands bitumen accounts for 90 per cent and conventional crude oil makes up 10 per cent. Alberta currently accounts for all of the bitumen resources. Efforts are ongoing to assess bitumen deposits in Saskatchewan; however, no official estimate of resource size is yet available. For conventional crude oil, 72 per cent of the estimated remaining resources are found in the frontier regions that include East Coast offshore, northern Canada and other frontier basins that are still relatively unexplored.[17] The more developed conventional light and conventional heavy oil deposits in the Western Canada Sedimentary Basin (WCSB) account for the remaining 28 per cent.
- Resources become reserves only after it is proven that economic recovery can be achieved. Canada has remaining oil reserves of 27.5 billion cubic metres (173 billion barrels), with 98 per cent of this attributed to oil sands bitumen, and the remaining to conventional oil sources.[18] According to the Oil & Gas Journal,[19] Canada is in third place globally in terms of proven oil reserves, behind Saudi Arabia and Venezuela.
- There is considerable potential to add to Canada's oil reserves. The Grosmont Carbonate formation accounts for 21 per cent of the oil sands resources in Alberta, but has not yet been assigned any reserves. New extraction technologies are being piloted and the establishment of economic recovery in this area would boost oil sands reserves. Similarly, oil sands reserves could be recognized for Saskatchewan in the future.
- The application of horizontal drilling and multi-stage hydraulic fracturing has given new life to previously low-producing or unproductive oil reservoirs in the WCSB. This technology has the potential to be applied in many regions of Canada. Since this extraction technology is still in its early stages of development in Canada, the ultimate impact on resource potential is unclear.
- Prospects for enhanced oil recovery by means of carbon dioxide flooding have increased through federal and provincial government financial support of several projects in western Canada designed to capture carbon dioxide from large emitters and distribute it to candidate oil pools. Since it is early days for this initiative, the full impact will remain unclear for some time.

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17 Further detail on Canada's oil resources can be found in Appendix 3.1

18 Further detail on Canada's oil reserves can be found in Appendix 3.2

19 Oil & Gas Journal, December 6, 2010

Canadian Crude Oil Production Outlook

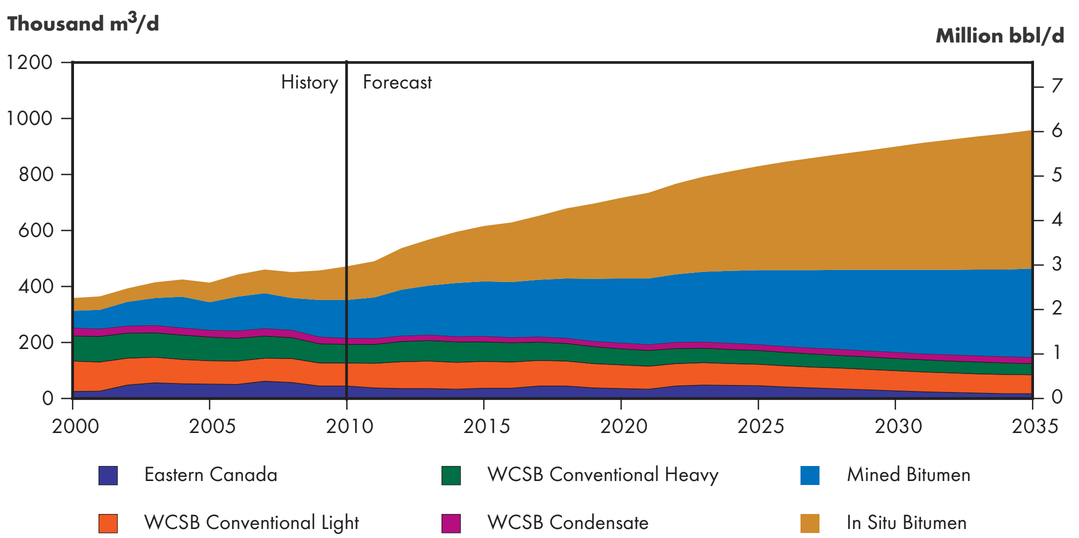
- By 2035, Canadian crude oil production in the Reference Case reaches 958 thousand m^3/d (6.0 million bbl/d), or about double 2010 production rates. In 2035, oil sands account for nearly 85 per cent of production, compared to 54 per cent in 2010. Figure 4.1 illustrates the Reference Case oil production outlook. The major drivers of increased oil production levels are:
    - Higher oil prices and lower natural gas prices have encouraged a switch to more oil-directed drilling, with 63 per cent of drilling efforts in the first quarter of 2011 targeting oil, and the remaining targeting natural gas.
    - Oil sands activity is rebounding from the effects of the 2009 global recession, and benefiting from increased levels of both domestic and foreign investment.
    - Conventional crude oil in the WCSB has reversed its long-standing declining trend. Production is ramping up based on the successful application of horizontal drilling and multi-stage hydraulic fracturing methods to tight oil[20] reservoirs. Because this technology is in its infancy and the full impact on future production levels unclear, the incremental production volumes assumed in the projection are limited. Decline resumes in the 2015 to 2016 timeframe.
- In Eastern Canada, the Newfoundland and Labrador offshore fields dominate production. Production in this area has been declining, but this decline will moderate with the addition of two large fields. The Hebron Field is scheduled to begin production in 2017. In the Reference Case, an additional field is assumed to be discovered and commences operation by 2022.

Oil Sands Production

- In the Reference Case, the assumed oil price (US$90/bbl WTI in 2011) is sufficient to promote active growth in oil sands capacity. Several projects put on hold because of the

F I G U R E 4 . 1

Total Canadian Oil Production, Reference Case



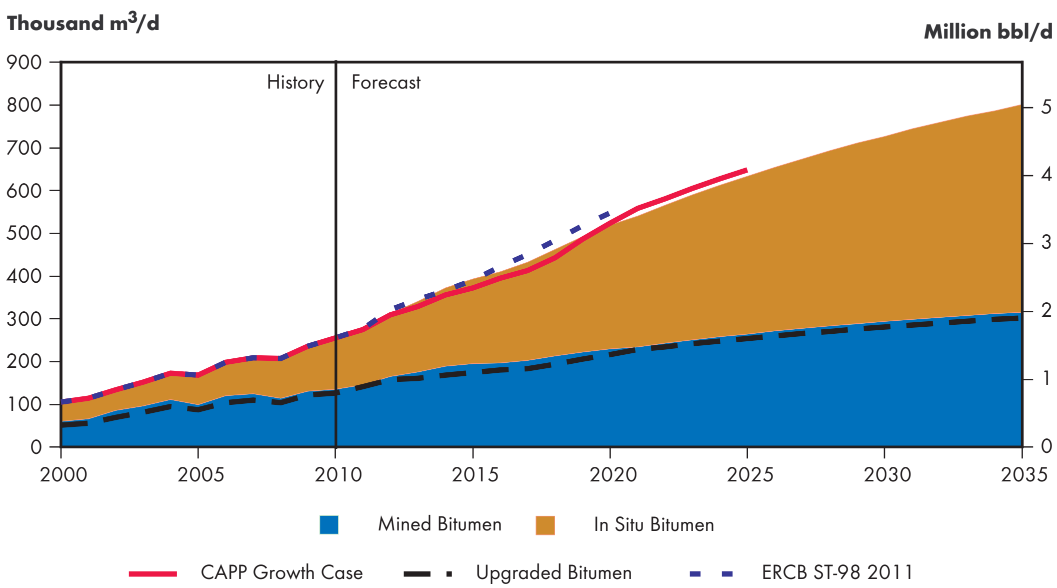
20 Tight oil refers to oil produced from organic-rich shales or from low permeability sandstone, siltstone, limestone or dolostone reservoirs. Tight oil reservoirs typically require the combination of horizontal drilling and multi-stage hydraulic fracturing to establish sufficient fluid flow to achieve economic rates of recovery.

2009 global recession have restarted. Several major operating companies have announced expansion plans and foreign entities are investing significant amounts of capital to buy oil sands interests, in many cases forming partnerships with Canadian companies.

- By 2035, in the Reference Case, oil sands bitumen production is projected to reach 811 thousand m^3/d (5.1 million bbl/d), three times the production for 2010. The majority of the growth occurs in the in situ category. In situ projects are smaller and less expensive to build so the cost of entry is lower. Also, 80 per cent of the oil sands reserves are considered well suited to in situ extraction, versus 20 per cent for mining methods.[21]
- Oil sands production forecasts released by the Canadian Association of Petroleum Producers (CAPP)[22] and the Energy Resources Conservation Board (ERCB)[23] are shown on Figure 4.2. In 2020, the ERCB projection is about six per cent higher than the NEB Reference Case, while CAPP is about two per cent higher.
- The first four to five years of the projection period is characterized by projects already under construction or in the late stages of planning. Over the longer-term, the list of currently proposed projects, many of which are in the early planning stage, suggest that bitumen production could reach 1.3 million m^3/d (8.3 million bbl/d).[24] Only a portion of these projects can reasonably be expected to proceed. While this analysis involves a review of most proposed projects, greater emphasis is placed on defining a reasonable rate of growth, considering historical growth profiles, projected economic returns and capital expenditure requirements.

FIGURE 4.2

Oil Sands Production, Reference Case



21 Energy Resources Conservation Board, *ERCB ST-98 2011*, *Alberta's Energy Reserves 2010 and Supply / Demand Outlook 2011-2020*, June 2011. Available at: www.ercb.ca

22 Canadian Association of Petroleum Producers, *Crude Oil Forecast, Markets & Pipelines*, June 2011. Available at: www.capp.ca

23 Energy Resources Conservation Board, *ERCB ST-98 2011*, *Alberta's Energy Reserves 2010 and Supply / Demand Outlook 2011-2020*, June 2011. Available at: www.ercb.ca

24 Strategy West, *Existing and Proposed Canadian Commercial Oil Sands Projects*, January 2011. Available at: www.strategywest.com

- In the Reference Case, the average annual growth rate between 2010 and 2020 is about nine per cent for in situ projects and about five per cent for bitumen mining projects. In the later part of the projection period growth rates ease, as higher production levels result in more need for maintenance capital and fewer high-quality reservoirs remain untapped. The average annual growth rate between 2025 and 2035 is about three per cent for in situ projects and about two per cent for mining projects.

Oil Sands Upgrading

- In early 2011, the Alberta government signed an agreement with North West Upgrading Inc. to process bitumen in the province under the provincial bitumen royalty-in-kind initiative.[25] Upgraded bitumen volumes from the first phase of the North West Upgrader project in 2014 and subsequent phases in 2021 and 2027, are included in the Reference Case.
- Table 4.1 sets out estimates, based on publicly available industry information, of the cost to build a given type of oil sands project, and the oil price required to encourage a producer to undertake such a project. For example, integrated mining and upgrading projects are estimated to cost in the order of Cdn$85,000 to $105,000/bbl (in 2010 Canadian dollars) of capacity to build, requiring an oil price of US$85 to $95/bbl (in 2010 U.S. dollars) to make a greenfield project economic.
- Both mining and in situ operations provide bitumen feedstock to upgraders. In 2010, essentially all mined production and about 11 per cent of in situ production was upgraded.[26] In the Reference Case projection, upgraded bitumen volumes roughly double to 302 thousand m^3/d (1.9 million bbl/d) by 2035, but do not keep pace with the overall increase in bitumen production. The portion of total bitumen production that is upgraded declines from 49 per cent in 2010 to 37 per cent in 2035. Over the period 2008 to 2010 the differential between light and heavy crude oil prices has been relatively narrow, and is projected to remain narrow for the near to medium term. This, combined with the very high capital costs of constructing upgraders, is not supportive of building greenfield upgrading facilities.

TABLE 4.1

Estimated Initial Capital Expenditure (CAPEX) and Threshold[(a)] Prices for New Oil Sands Projects

	CAPEX ($Cdn / bbl of capacity, Cdn$2010)	**Economic Threshold** (WTI US$ equivalent / bbl, US$2010)
Mining, Extraction and Upgrading	$85,000-$105,000	$85-$95
Mining and Extraction Only (No upgrading)	$60,000-$75,000	$65-$75
Steam-assisted Gravity Drainage (SAGD)/Cyclic Steam Stimulation (CSS)	$25,000-$40,000	$50-$60

(a) Includes a realistic after-tax rate of return, commonly in the order of 10 to 15%.

25 Northwest Upgrading News Release, 16 February 2011. Available at: http://www.northwestupgrading.com/images/pdf/press_releases/BRIK_Announcement_News_Release_Feb_16.2011.pdf

26 Energy Resources Conservation Board, *ERCB ST-98 2011*, *Alberta's Energy Reserves 2010 and Supply / Demand Outlook 2011-2020*, June 2011. Available at: www.ercb.ca

Natural Gas for Oil Sands

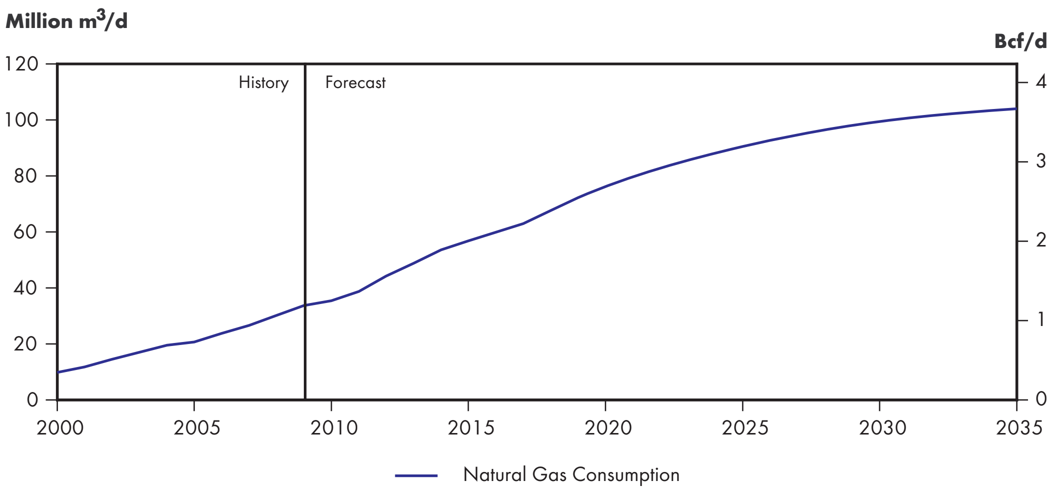
- Oil sands bitumen extraction is energy-intensive, and requires large volumes of natural gas as fuel and feedstock. New technologies[27] and efficiency enhancements are expected to decrease the intensity of gas use over time. As well, as operators gain experience with their projects they are able to make them more energy-efficient. For the Reference Case, gas use intensity is assumed to improve by 0.5 per cent annually for mining-only, integrated mining and upgrading projects. For in situ projects, intensity is assumed to improve by 1.5 per cent annually.
- In the Reference Case, requirements for purchased natural gas, including for cogeneration associated with oil sands projects, rise to 104 million m^3/d (3.7 Bcf/d) by 2035 (Figure 4.3).

Conventional Oil Production

- Figure 4.4 shows the historical and projected production for conventional crude oil in the WCSB. For Saskatchewan and Manitoba, the charts indicate a resurgence in production taking place over the period 2006 to 2015. For Alberta, the period of increased production extends from 2009 to 2014. In part, this is explained by increased activity due to higher oil prices. Further, it is also indicative of the application of horizontal drilling and multi-stage hydraulic fracturing methods to tight oil plays, such as the Bakken play in Saskatchewan. Other formations, such as the Viking, Lower Shaunavon, Cardium, and Lower Amaranth are also showing increased production. These wells tend to be much more prolific than vertical wells.
- In 2010, drilling activity was higher than in 2009 with more than 60 per cent of wells targeting oil and the remaining targeting natural gas, a reversal of the long-term historical trend of drilling more gas than oil wells. Horizontal drilling in Western Canada for both oil and gas was at record levels in 2010.

F I G U R E 4 . 3

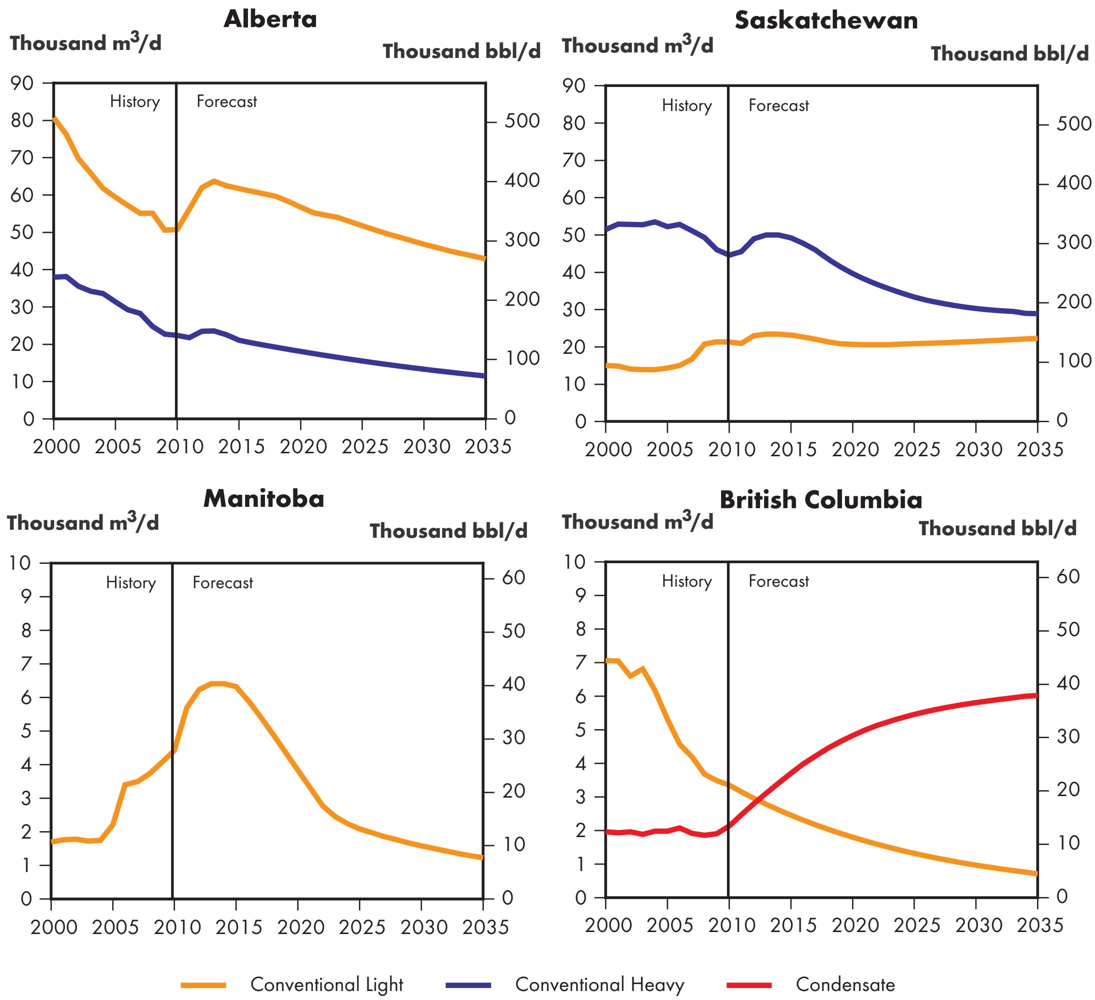
Purchased Natural Gas for Oil Sands, Reference Case



27 For example, there are a number of solvent-added processes currently being used, and others in the pilot stage, that feature small amounts of solvents such as butane and propane added to the steam injected in SAGD and CSS projects that increase recovery efficiency. There are also a number of pilot projects that are testing electrical–stimulation methods. The Toe-to-Heel Air Injection (THAI™) is an in situ combustion method that uses very little natural gas and is gaining traction.

FIGURE 4.4

Western Canada Sedimentary Basin Conventional Oil Production, Reference Case



- Manitoba production has been increasing since 2006, with production expected to reach 6.5 thousand m³/d (41 thousand bbl/d) by 2014, before declining.
- The exploitation of tight oil reservoirs in Canada is in its early stages and it is quite possible that resource estimates and production projections will need revisions in future analyses.
- The projections also include carbon dioxide (CO_2) flooding enhanced oil recovery (EOR) in Saskatchewan and Alberta. Saskatchewan has two projects currently in operation, at the Weyburn and Midale oil fields, and a third project has been announced. In Alberta, the provincial government has approved an application from Enhance Energy Inc. and partner North West Upgrading Inc. to build the Alberta Carbon Trunk Line (ACTL).[28] This project will receive funding from both the Alberta government ($495 million) and the Canadian government ($63 million). In the Reference Case, it is assumed that EOR production from this project will begin in 2015.

28 The ACTL is designed to gather CO_2 from several sources in Alberta's Industrial Heartland (near Edmonton) and transport the CO_2 to existing mature oil fields throughout South-Central Alberta, to facilitate CO_2-EOR recovery.

- In British Columbia, conventional oil production shows a consistent decline. However, volumes of condensate are growing because of increasing production of liquids-rich natural gas in that province.
- Eastern Canada production includes relatively small amounts of oil production from Ontario but primarily represents the Newfoundland and Labrador offshore fields (Figure 4.5). Production from this region has been in decline since 2006.With the recent addition of the North Amethyst pool and several additional satellite pools offshore Newfoundland to be connected over the 2012 to 2015 period, the current decline will be pushed into the future.

Total Canada Oil Production

- The differences in the oil production projections for the five cases reflect the oil price assumptions and the recent success of horizontal drilling and multi-stage hydraulic fracturing applied to reservoirs in the WCSB (Figure 4.6). In all cases, there is an increase

FIGURE 4.5

Eastern Canada Oil Production, All Cases

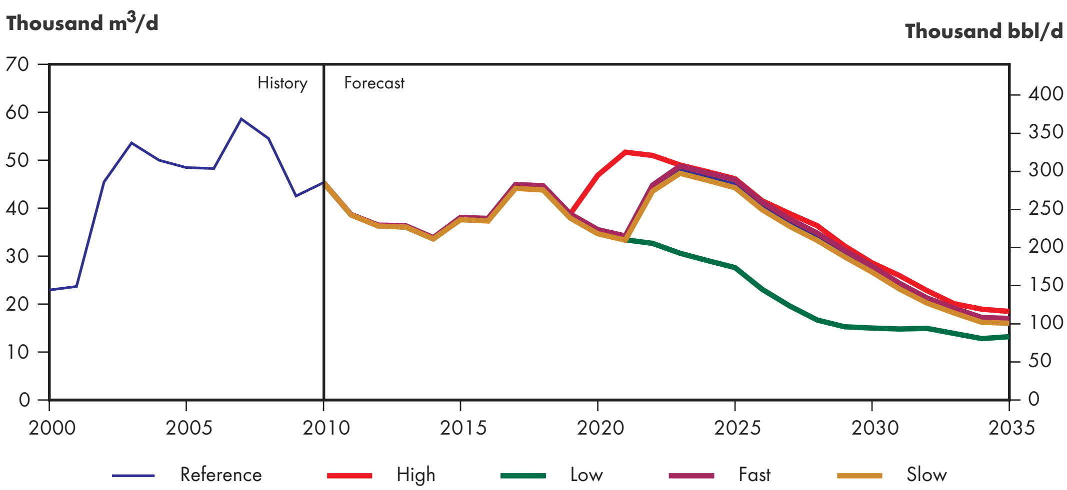
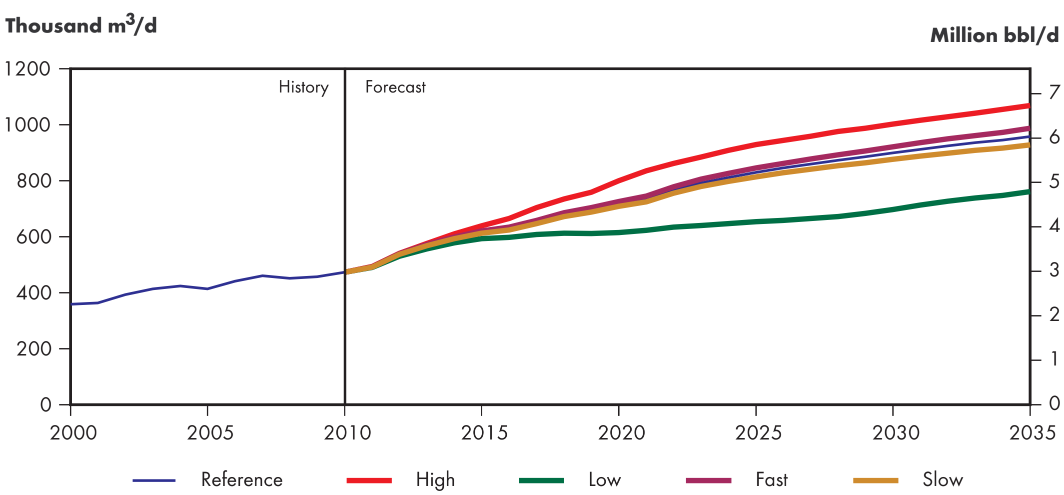


FIGURE 4.6

Total Canada Oil Production, All Cases



in conventional production over the period from 2010 to about 2015, mostly due to increased production from tight oil plays. However, production growth is predominantly from oil sands.

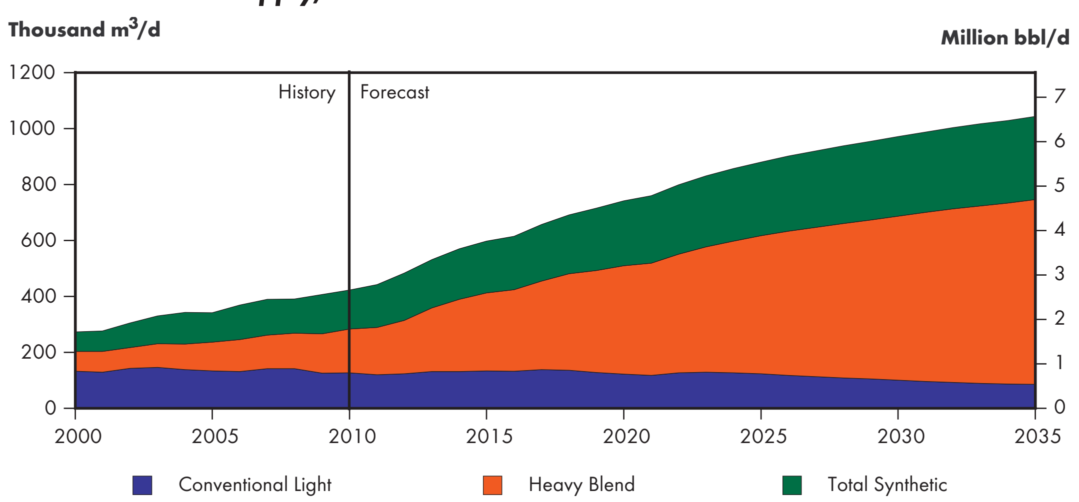
- For Eastern Canada, in the Reference Case it is assumed a new offshore discovery of 500 million barrels in size begins production in 2022. In the High Case, it is assumed this new discovery comes on two years earlier, in 2020, and that higher prices also serve to extend the life of existing pools. For the Low Case, no new pool discovery is assumed.
- In the Reference Case, production reaches 958 thousand m^3/d (6.0 million bbl/d) by 2035, double 2010 levels. In the High Case, production is 1.1 million m^3/d (6.7 million bbl/d), 11 per cent higher relative to the Reference Case. In the Low Case, production growth slows, but still reaches 760 thousand m^3/d (4.8 million bbl/d) by 2035.
- For the Fast and Slow Cases, because the oil price assumptions are only slightly different than in the Reference Case, the production profiles are also only slightly different. Production in the Fast Case is three per cent greater, while in the Slow Case it is three per cent lower by 2035.

Supply and Demand Balance

- Net available oil supply (Figure 4.7) is the amount of oil production that is available to the market after adjustments for processing losses, blending requirements for heavy oil and non-upgraded bitumen, and volumes of condensate diluents that are locally recycled. Upgrading yields vary among the different bitumen upgrading facilities, but in aggregate, about 85 per cent of bitumen feedstock is turned into a synthetic crude oil product. All of the non-upgraded bitumen and most of the conventional heavy production must be blended with a light hydrocarbon, usually condensate, to reduce its viscosity and allow it to meet specifications for pipeline transportation. About 23 per cent of the condensate used for blending is recovered in upgrading facilities and refineries in Alberta and Saskatchewan, and returned for re-use.
- Typically, blended bitumen contains about 30 per cent condensate, while blended conventional heavy crude oil contains about seven per cent condensate. The rising volume of heavy blend shown in Figure 4.7 results in a growing demand for condensate

FIGURE 4.7

Net Available Oil Supply, Reference Case



and other light hydrocarbon diluents. It is assumed that condensate imports or similar products from the U.S. or from offshore sources, combined with the manufacture of diluents in Canadian refineries and upgraders, will meet most of the diluent demand. To a small degree, butanes, synthetic crude oil and light conventional crude oil are currently used for blending. Growth in volumes from these sources to meet demand is difficult to predict. In the Reference Case, volumes from these latter sources will grow at five per cent annually. Based on this assumption, blending requirements are met by 12 thousand m^3/d (76 thousand bbl/d) of butanes, 17 thousand m^3/d (100 thousand bbl/d) of light crude oil (synthetic and conventional) and 127 thousand m^3/d (800 thousand bbl/d) of condensate by 2035. This would require 106 thousand m^3/d (670 thousand bbl/d) of condensate to be imported.

- Required crude oil feedstock for refining is a function of petroleum product demand. The oil refining sector in Canada relies on both domestic and imported crude to produce the products that Canadians use. Canada also imports refined petroleum products, as it is economic to do so in some regions.
- From 2011 to 2035, total Canadian refinery feedstock requirements rise by 28 per cent to 379 thousand m^3/d (2.4 million bbl/d) in the Reference Case.
- Canadian crude oil available for export has been rising and will continue to respond to increases in supply from Alberta's oil sands and changes in supply from conventional sources. Crude oil available for export is surplus to domestic demand and responds directly to increases or decreases in supply.
- In the Reference Case, total crude oil (light and heavy) available for export rises 148 per cent to 801 thousand m^3/d (5.0 million bbl/d) from 2011 to 2035. Light crude oil exports peak at 224 thousand m^3/d (1.4 million bbl/d) in 2024 and gradually decline to 201 thousand m^3/d (1.3 million bbl/d) in 2035 (Figure 4.8). The decline reflects lower production of light crude oil and increased domestic demand. Heavy crude oil exports rise by 243 per cent to 600 thousand m^3/d (3.8 million bbl/d) reflecting increases in production from Alberta's oil sands (Figure 4.9).

FIGURE 4.8

Supply and Demand Balance, Light Crude Oil, Reference Case

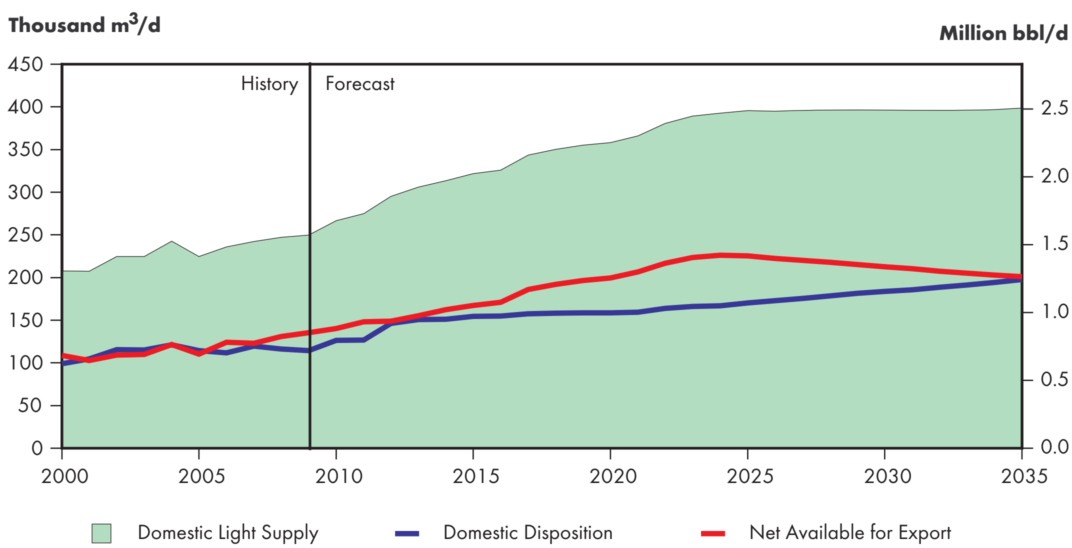
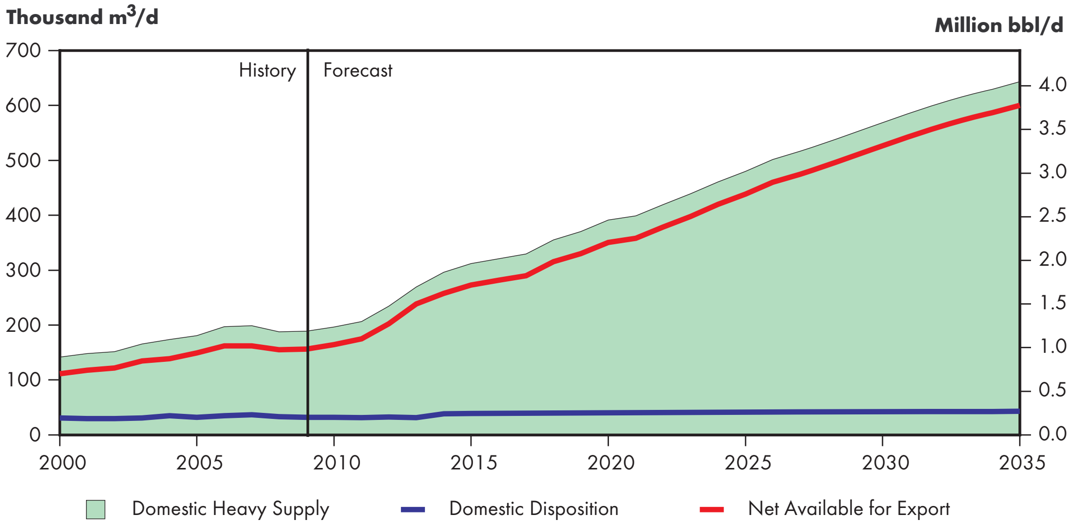


FIGURE 4.9

Supply and Demand Balance, Heavy Crude Oil, Reference Case



- In the Fast and Slow Cases, total oil available for export grows by 174 and 159 per cent, respectively over the next 25 years.
- In the High and Low Cases, total oil available for export grows by 211 and 103 per cent, respectively over the next 25 years.

Key Uncertainties to the Outlook

- These long-term projections envision gradually changing prices. However, oil price spikes in either direction are not uncommon. Periods of lower oil prices would slow activity levels. The exchange rate is also important, because oil exporters are paid for their product in U.S. dollars and a rising Canadian dollar means lower economic returns.
- While the outlook for cost inflation is relatively low at the time of writing, there are a number of large oil sands projects in the construction and planning stage. These projects will be facing competition for labour and materials from conventional oil and gas projects, as well as other large projects. Although companies have taken steps to control construction costs, cost inflation does have the potential to slow the pace of expansion.
- According to the Petroleum Human Resources Council of Canada (PHRCC) the oil and gas industry faces a major challenge in the coming years. There is evidence that a shortage of skilled workers is developing as the workforce ages and overall demand for labour increases. Many of the oil and gas industry's most experienced and skilled workers will be retiring in the next decade. At the same time, the Canadian labour force is shrinking. Under a scenario of high oil and gas prices, the PHRCC is predicting a requirement of 130,000 new hires by 2020.[29] This challenge is being addressed through a number of government and industry initiatives, but a potential labour shortage may increase construction costs and the pace of oil development.

29 Petroleum Human Resources Council of Canada, *The Decade Ahead: Labour Market Projections and Analysis to 2020*, March 2011. Available at: http://www.petrohrsc.ca/

- Rules and regulations regarding oil sands development continue to evolve. For example, the Government of Alberta has issued new rules regarding tailings ponds[30] and water use,[31] and recently announced a plan to rescind about 20 per cent of oil sands leases to establish conservation areas.[32]
- Industry and governments in many jurisdictions are currently examining issues related to multi-stage hydraulic fracturing. These include the amount of fresh water used in the fracturing process, maintaining the separation between fracturing fluids and ground water, and the chemical composition and safe disposal of fracturing fluids. There is potential for these developments to affect the pace and level of production.
- Over the 25-year outlook period, it is possible that technological breakthroughs will occur that accelerate the pace of development in conventional and/or oil sands resources.
- A key simplifying assumption in this report is that there will be sufficient infrastructure to deliver Canadian oil production, and that there will be sufficient markets, domestically and internationally, to absorb the projected production levels.

30 Energy Resources Conservation Board, ERCB Directive 074 *Tailings Performance Criteria and Requirements for Oil Sands Mining Schemes*, 3 February 2009. Available at: www.ercb.ca

31 Energy Resources Conservation Board, *Draft Directive*, *Requirements for Water Measurement*, *Reporting*, *and Use for Thermal In Situ Oil Sands Schemes*, 18 February 2009. Available at: www.ercb.ca

32 Government of Alberta, *Draft Lower Athabasca Integrated Regional Plan 2011 – 2021*, 5 April 2011. Available at: *https://landuse.alberta.ca/Documents/LARP%20Draft%20Lower%20Athabasca%20Regional%20Plan%20Strategic%20Plan%20and%20Implementation%20Plan-P3-2011-03.pdf*

NATURAL GAS OUTLOOK

Natural Gas Resources

- According to the latest Board resource assessment,[33] there were 11 940 billion m^3 (424 Tcf) of remaining marketable natural gas resources in Canada as of year-end 2009. Most of this was conventional natural gas at 9 742 billion m^3 (346 Tcf) (Table 5.1). That estimate was limited, however, by what few modern assessments are publicly available on tight gas, shale gas, and coalbed methane (CBM) resources in Canada. For the purpose of this report, additional marketable resources have been assigned to these categories (available in Appendix A4.1) and remaining Canadian potential is assumed to be 18 811 billion m^3 (664 Tcf) in the Reference Case, current to year-end 2010. However, there is greater certainty around the shale gas and CBM estimates based on provincial reserves data and completed studies. There is less certainty around the tight gas estimates given the limited number of studies and work currently underway. The estimate of 18 811 billion m^3 (664 Tcf) should therefore be treated as tentative.
- Tight gas is a subset of the conventional gas category, and refers to gas produced from low-permeability reservoirs.[34] Tight gas reservoirs will typically not have sufficient natural pathways through the rock for natural gas to successfully flow to the wellbore. Therefore they require some form of artificial stimulation to create pathways, such as multi-stage hydraulic fracturing. Currently, the total tight gas resource potential of Canada is not well known, though is expected to be very large given trends in development, especially for the Montney play and Deep Basin tight gas plays of Alberta and British Columbia.
- Frontier resources, another subset of conventional gas, include gas resources in Northern Canada and offshore resources. For the purpose of this report, Northern Canada is estimated to contain 3 283 billion m^3 (116 Tcf) of remaining marketable gas, of which

TABLE 5.1

Remaining Marketable Natural Gas Resources, as of 31 December 2009

	WCSB	West Coast	Northern Canada	Ontario	East Coast	Canada(a)
billion m^3	5 542	485	3 285	33	2 591	**11 940**
Tcf	197	17	117	1	91	**424**

(a) Totals may not add due to rounding

33 National Energy Board, Ultimate Potential for *Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, May 2011. Available at www.neb-one.gc.ca.

34 The areas of tight gas recognized in this report include: certain Cretaceous zones in the Deep Basin; the Milk River, Medicine Hat and Second White Specks formations in southeast Alberta and southwest Saskatchewan; and the Jean Marie and Montney formations in northeastern British Columbia.

53 per cent is in the Mackenzie-Beaufort area and 34 per cent in the Arctic Islands. Remaining marketable gas off the East Coast is estimated at 2 548 billion m^3 (90 Tcf) and frontier British Columbia[35] is estimated to contain 485 billion m^3 (17 Tcf) of remaining marketable gas.

- Unconventional gas resources in this report are shale gas and CBM. As of 2010, there were 68 billion m^3 (2.4 Tcf) remaining CBM reserves in Alberta.[36] Shales of the Horn River Basin in northeastern British Columbia were estimated to contain 2 198 billion m^3 (78 Tcf) of remaining marketable gas at the end of 2010.[37] There are other potential shale gas resources in Canada that could add to this total. However, potential shale resources have not yet been assessed because of their very early stage of development. These include the Duvernay and Exshaw plays in Alberta, the Utica shale in Quebec, and Horton Bluff shale in New Brunswick.

Canadian Natural Gas Production Outlook

Drilling

- Canadian natural gas production has dropped 15 per cent since 2008, a direct result of a downturn in drilling activity due to gas price declines. Activity in the last few years has increasingly focused on deeper conventional, tight, and shale gas resources as technological advancements in horizontal drilling and/or multi-stage hydraulic fracturing have lowered their supply costs.[38] Shallow gas resources largely remain unprofitable throughout the projection period.
- Deeper wells generally produce more natural gas than shallow wells. Average initial production[39] (IP) rates in Western Canada have climbed over the last few years with lower proportions of shallow wells being drilled. The average IP in Western Canada for all wells drilled in 2005 was 13.6 thousand m^3/d (0.48 MMcf/d), in 2010 the average was 24.9 thousand m^3/d (0.88 MMcf/d), and it is expected that, in 2035, the average IP will be 64.6 thousand m^3/d (2.28 MMcf/d).
- Better prospects tend to be drilled earlier in the development of a particular resource area. As activity shifts over time to less-prolific areas, the average IP of new wells would tend to decline. However, improvements in drilling and well completion technology over time may offset these declines and allow IP rates to remain constant. The assumption of constant IPs is applied to most areas in Western Canada. The exceptions are some tight gas areas where IPs have been increasing and shallow gas areas where IPs have consistently been declining.
- In this analysis, IPs are held constant over the projection period for the Montney tight gas play (113.3 thousand m^3/d (4 MMcf/d) marketable gas) and Horn River shale gas play (226.6 thousand m^3/d (8 MMcf/d) marketable gas). Average IP rates have consistently been increasing over the last few years as wells have gotten longer (horizontal part of a well) and

35 Intermontane basins (basins between mountain ranges) and offshore.

36 Energy Resources Conservation Board, *ERCB*, *ST98-2011*, *Alberta's Energy Reserves 2010 and Supply/Demand Outlook 2011-2020*, June 2011. Available at www.ercb.ca.

37 National Energy Board, *Ultimate Potential for Unconventional Natural Gas in Northeastern British Columbia's Horn River Basin*, May 2011. Available at www.neb-one.gc.ca.

38 National Energy Board, *Natural Gas Supply Costs in Western Canada in 2009*, November 2010. Available at: www.neb-one.gc.ca

39 The highest average monthly production rate over the first three months of production.

more hydraulic fracture stages per well are applied. Future IPs are expected to level off as an optimal number of fracture stages are reached and activity moves to the non-core areas over time.

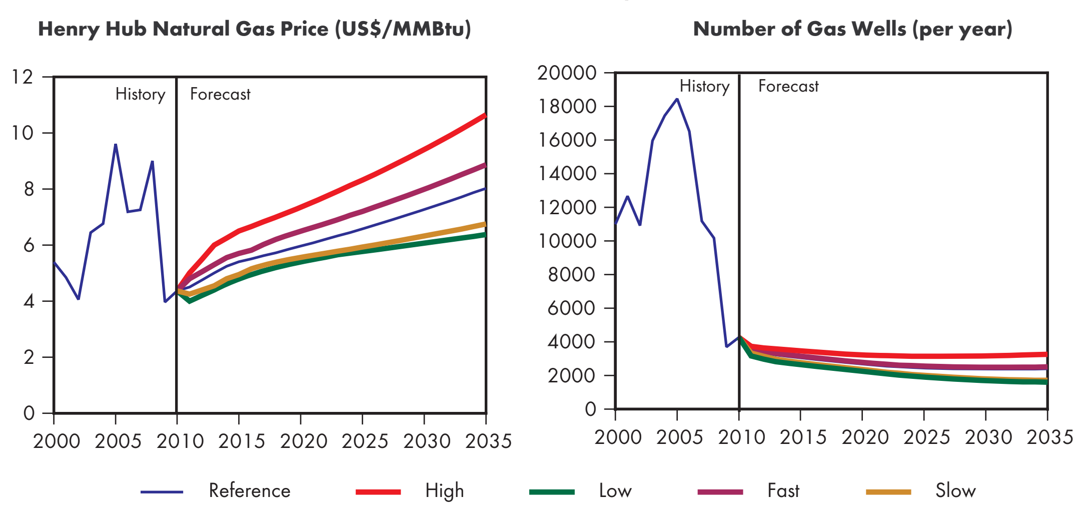
- Natural gas prices gradually climb in the Reference Case projection. This leads to increased drilling activity, especially for the more economic resources like deeper tight gas and shale gas. However, gas wells drilled per year remain about one-fifth of the peaks seen in 2005 through 2008 (Figure 5.1). Strong production rates from the deeper wells lead to increased production in the latter half of the projection, as additions of new gas outpace production declines from older wells. This would lead to increased revenues available to fund additional drilling, and thus more gas wells and more gas production.
- Higher gas prices in the High Case lead to an increase in wells drilled (over 3 000 wells per year over the projection period), higher gas production, and greater capital spending. The High Case, while still having a significant proportion of deep wells, has the highest proportion of shallow wells compared to the other four cases because the higher prices allow for economic production from shallow wells.
- The Low Case sees a gradual decline in gas wells over the projection period as revenues to fund capital are below Reference Case levels due to lower prices and lower production. In 2035, around 1 600 gas wells are projected to be drilled, as compared to over 4 000 in 2010. The Low Case sees the highest proportion of the more economic deeper wells, and the lowest proportion of the less economic shallow wells.
- Gas prices in the Fast Case are slightly higher than the Reference Case, leading to about 100 more gas wells per year than in the Reference Case.
- The number of gas wells in the Slow Case is just slightly above the Low Case by about 120 wells a year.

Production

- Canadian marketable natural gas production in the Reference Case declines slightly until 2015, from 383.2 million m^3/d (13.5 Bcf/d) in 2011 to 372.3 million m^3/d (13.1 Bcf/d) in

FIGURE 5.1

***Natural Gas Prices and Natural Gas Wells Drilled, All Cases** (a)*



(a) Chart does not include the proposed gas wells for the Mackenzie Delta.

2015. Production then starts to increase, reaching 510.2 million m³/d (18.0 Bcf/d) in 2035 (Figure 5.2). Natural gas from the deeper and more productive conventional, tight, and shale wells more than compensates for production declines from older wells and less gas being added from shallower areas. With higher-productivity wells, it takes fewer wells to maintain overall production than it did before.

- Recently, companies have been focusing on tight and shale resources. These include the Montney tight gas play in northeast British Columbia and western Alberta, the Horn River shale gas resource in northeastern British Columbia, and the Cretaceous tight gas zones in the Deep Basin in western Alberta, shown in Figure 5.3. This focus is expected to continue throughout the projection period as these resources have some of the best economics in Western Canada.
- Montney production includes natural gas liquids (NGLs) that sell at prices linked to oil prices, which are higher than gas prices on an energy-equivalent basis, making drilling more profitable. Montney production from British Columbia grows from 24.3 million m³/d (857 MMcf/d) in 2011 to 144.5 million m³/d (5.1 Bcf/d) in 2035, with

FIGURE 5.2

Natural Gas Production by Type, Reference Case

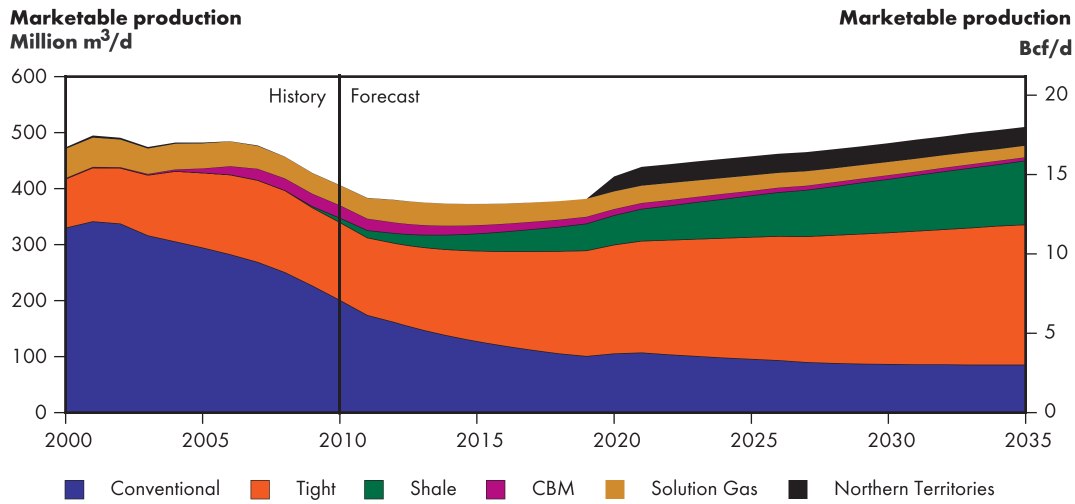
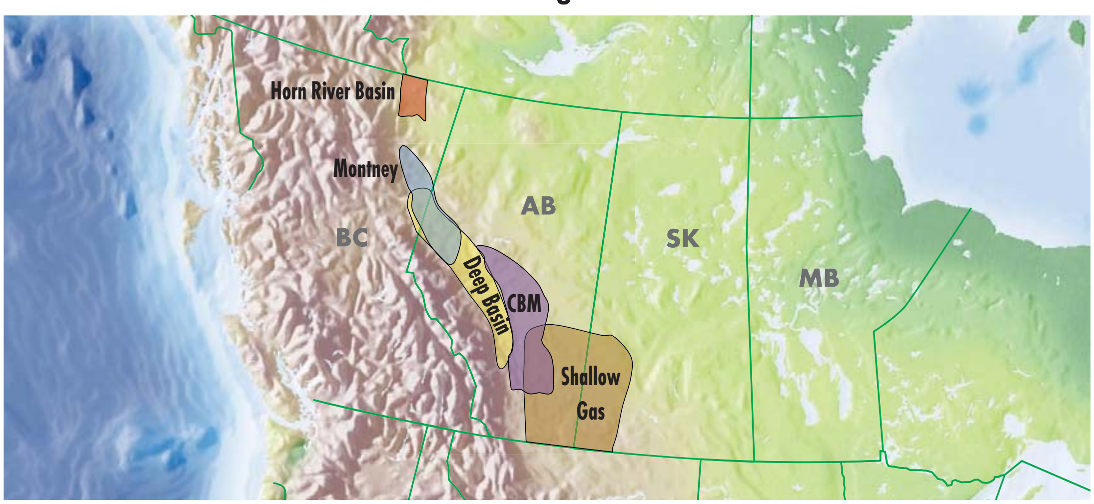


FIGURE 5.3

Western Canada Natural Gas Production Regions



a total of 937 billion m^3 (33.1 Tcf) produced over the projection period in the Reference Case.[40]

- Horn River shale gas producers benefit from strong production rates, with total shale gas production increasing from 13.4 million m^3/d (473 MMcf/d) in 2011 to 114.3 millionm^3/d (4.0 Bcf/d) in 2035. Total production from the Horn River shales is 594.9 billion m^3 (21.0 Tcf) over the Reference Case projection.
- Economics for the Cretaceous tight gas zones in the Alberta Deep Basin benefit from higher NGL contents, existing infrastructure, and recent changes to the Alberta royalty regime. Production from these zones in the Reference Case increases from 51.0 million m^3/d (1.8 Bcf/d) in 2011 to 79.3 million m^3/d (2.8 Bcf/d) in 2035, as production from new wells more than offsets production declines from older wells.
- The trend toward targeting tight gas and shale gas brings about some pronounced shifts in Canadian production. By 2014, tight gas production becomes larger than all other conventional production in Canada and stays larger over the projection period, accounting for 49 per cent of total Canadian production in 2035 in the Reference Case. The proportion of shale gas also grows, making up 22 per cent of production in 2035. The growth of the Montney tight gas play and Horn River shale play increases production in northeast British Columbia, surpassing Alberta production by 2019 and remaining higher for the rest of the projection period. The production projections in this report do not separate specific shale gas plays in Alberta from the conventional and tight gas categories. The various shale targets in Alberta are prospective and insufficient information is available to identify their properties reliably. If shale gas activity was to accelerate significantly in Alberta, it could have an upward influence on future projections.
- CBM production declines over the projection period, as investment is drawn to other resources. CBM activity will be concentrated in the Horseshoe Canyon resource, as producers are able to drill a shallow CBM well in roughly one day and those with an existing land base will find the play provides adequate economics. Smaller producers who lack financial resources to drill deeper wells may still be able to drill shallow CBM wells efficiently. In the Reference Case, CBM production drops from 21.0 million m^3/d (743 MMcf/d) in 2011 to 6.5 million m^3/d (230 MMcf/d) in 2035.
- Production of solution gas (gas produced from oil wells) increases slightly through 2014 along with conventional oil production. As conventional and tight oil production decreases over the projection period after 2014, so does the production of solution gas. Total solution gas in Canada declines to 20.5 million m^3/d (0.7 Bcf/d) by 2035 from about 36.7 million m^3/d (1.3 Bcf/d) currently.
- Atlantic Canada total natural gas production is projected at 7.9 million m^3/d (280 MMcf/d) in 2011, 18.8 million m^3/d (665 MMcf/d) in 2021, and 15.0 million m^3/d (528 MMcf/d) in 2035. Production at the Sable Offshore Energy Project (SOEP) continues to decline and ends by 2018. However, Nova Scotia's total production increases in November 2011 as the offshore Deep Panuke project starts producing, more than compensating for SOEP declines.[41] New Brunswick onshore production is currently at about 0.6 million m^3/d (20 MMcf/d) and is projected to stay relatively flat over the projection period. There is shale gas potential in the province that could potentially increase production but its assessment is at too early of a stage to include in this projection.

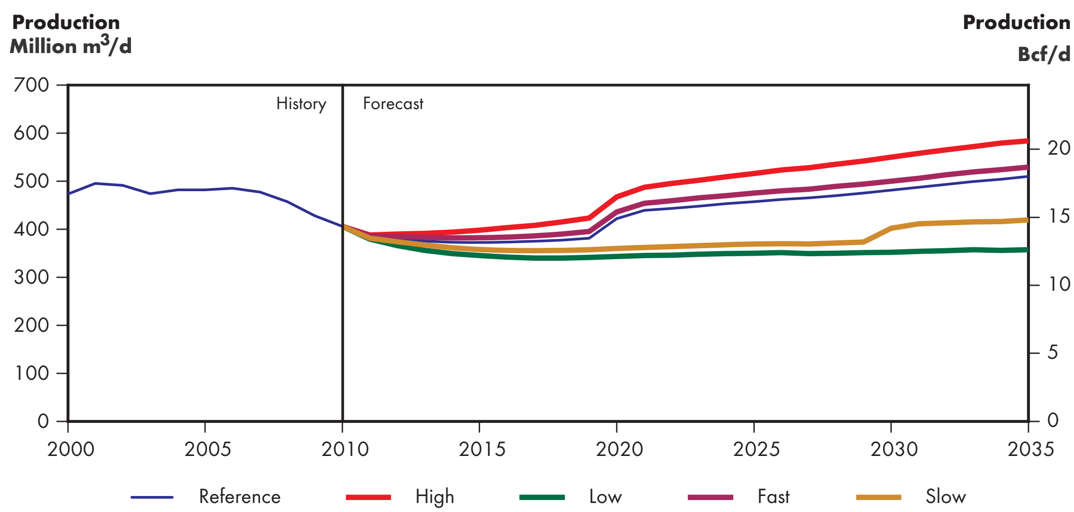
40 Remaining marketable natural gas, as of 2010, is estimated to range from 1 562 billion m^3 in the Low Case to 6 195 billion m^3 in the High Case (55 to 219 Tcf) for the Montney play.

41 Deep Panuke is expected to produce a total of 25.5 billion m^3 (900 Bcf) over the next 15 years.

- The projected increase in 2020 and 2021 Atlantic Canada production comes from offshore Newfoundland. Currently, natural gas is produced with oil from Newfoundland's offshore oil projects, but is being re-injected into the reservoir to maintain pressure for oil production rather than reaching a market. On the assumption that oil production from these fields will taper off, by 2020, gas re-injection could be discontinued and gas could potentially be delivered to market via compressed natural gas (CNG) or liquefied natural gas (LNG) tankers or possibly by pipeline. In the Reference Case, Newfoundland gas is slated to reach market in 2020, but this could be delayed by the discovery of additional oil pools or unfavourable economics of bringing the gas to market. In 2020, Newfoundland marketable production is projected at 8.9 million m^3/d (313 MMcf/d) and ramps up to an estimated 14.2 million m^3/d (500 MMcf/d) from 2021 to 2035.
- Marketable natural gas production in Ontario is projected to continue declining, from 0.5 million m^3/d (16 MMcf/d) in 2011 to zero by 2031. Shale gas potential exists in Quebec; however, insufficient data is available and Quebec shale production is not included in the projection.
- Currently, there is 0.5 million m^3/d (18 MMcf/d) marketable natural gas production in the NWT and Yukon. Recent production declines continue until Mackenzie Delta natural gas reaches market. Given the price assumptions, Mackenzie gas is assumed to begin flowing in 2020 in the Reference, Fast, and High Cases, but not until 2030 in the Slow Case, and not at all in the Low Case (Figure 5.4). Mackenzie marketable production in the first year is projected to average 27.0 million m^3/d (953 MMcf/d) and 34.0 million m^3/d (1.2 Bcf/d) over the remainder of the projection period.
- Marketable Canadian natural gas production in the High Case reaches 584.2 million m^3/d (20.6 Bcf/d) in 2035. Production increases in tight, shale, and Mackenzie gas exceed other conventional gas declines.
- Production in the Low Case remains mostly constant over the projection period, at 357.1 million m^3/d (12.6 Bcf/d) in 2035. Tight gas and shale gas production increases over the projection, but is offset by declines in non-tight conventional gas. There is no production from Mackenzie and Newfoundland in this case.

FIGURE 5.4

Total Canadian Marketable Gas Production, All Cases



- Production in the Fast Case grows slightly faster than in the Reference Case. Total Canadian production reaches 528.8 million m³/d (18.7 Bcf/d) in 2035. Production of Mackenzie and Newfoundland gas both start in 2020.
- In the Slow Case, Canadian production increases slightly over the projection period to reach 418.7 million m³/d (14.8 Bcf/d) in 2035, with Mackenzie gas coming on in 2030 and no marketable production from Newfoundland.

Supply and Demand Balance

- The difference between Canadian production and demand is the net amount of gas that would be available for export each year (net exports). In the Reference Case, this volume trends slightly downwards (Figure 5.5), except for a bump in 2020 that marks the onset of Mackenzie and Newfoundland production. In 2011, 131.0 million m³/d (4.6 Bcf/d) is available for export and in 2035 that decreases to 102.3 million m³/d (3.6 Bcf/d), a 22 per cent drop. The increase in natural gas demand in Canada outweighs the increase in Canadian marketable production over the projection period, leading to the slightly declining trend in net gas available for export. Natural gas supply increases by 33 per cent from 2011 to 2035, but demand (excluding natural gas used in production and processing) increases by 62 per cent, from 252.0 million m³/d (8.9 Bcf/d) in 2011 to 407.7 million m³/d (14.4 Bcf/d) in 2035. Demand increases in Canada are largely from the oil sands sector and for power generation.
- Net gas available for export is highest in the High Case (Figure 5.6), increasing by 34 per cent from 2011 to reach 186.5 million m³/d (6.6 Bcf/d) in 2035. This is a result of higher production than in the Reference Case, but slightly lower demand due to the dampening effect of higher prices.
- In the Low Case, lower production levels drive the decrease in net gas available for export, as production drops six per cent from 2011 to 2035. Without Mackenzie gas to boost production levels, the supply and demand projections in the Low Case imply Canada becomes a net importer of gas by 2029.
- Net gas available for export in the Fast Case is very similar to the Reference Case until the mid 2020s, with production and demand very similar in the two cases. After about 2025,

FIGURE 5.5

Canadian Net Natural Gas Available for Export, Reference Case

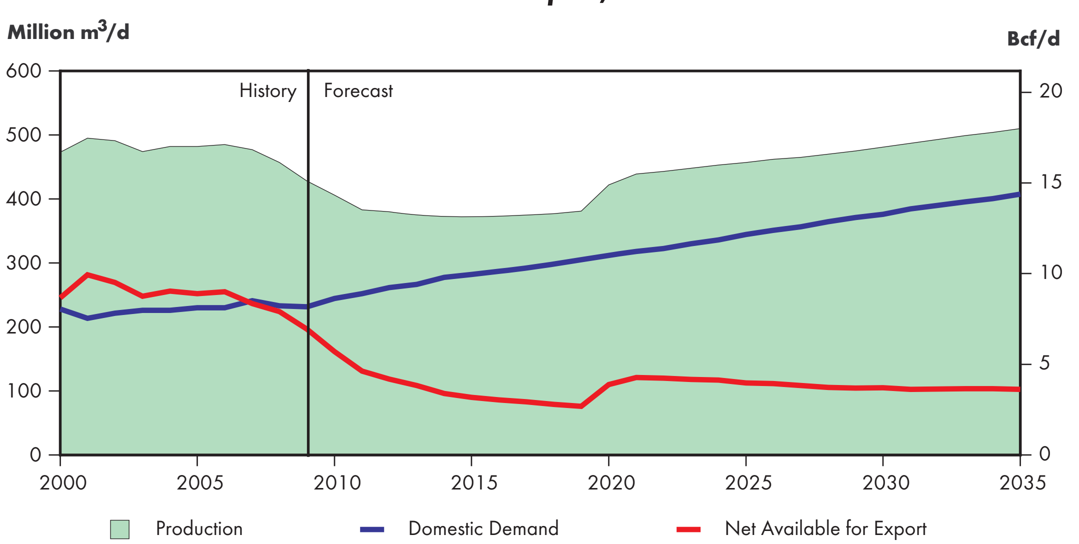
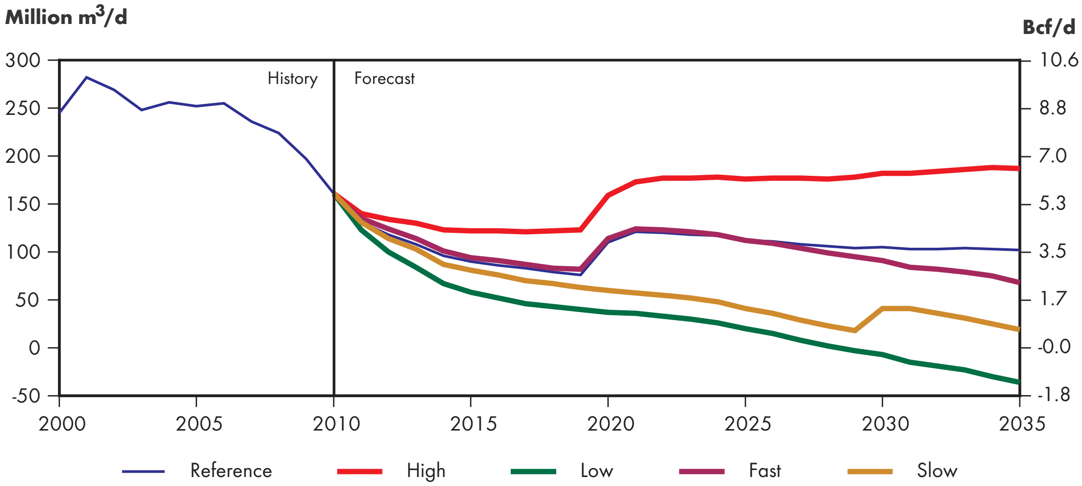


FIGURE 5.6

Canadian Net Natural Gas Available for Export, All Cases



demand grows faster than production when compared to the Reference Case, leading to a decline in net gas available for export. In 2035, net gas available for export reaches 68.3 million m³/d (2.4 Bcf/d).

- The Slow Case sees a downward trend in net gas available for export over the projection period, except for an increase in 2030 from Mackenzie gas. Net gas available for export drops to nearly zero by 2035, as production grows slower than demand.

Key Uncertainties to the Outlook

- Future natural gas prices are a key uncertainty in the production projections. The Reference and four sensitivity cases cover a wide range of natural gas prices to assess possible price volatility in the future. Since 2000, annual average gas prices in North America have had large swings, doubling from 2003 to 2005 and then falling by more than half from 2008 to 2009. These price swings have significant implications for the industry, including swings in producer revenues and the amount of capital re-invested into the industry.
- As stated in the Crude Oil Chapter, potential labour shortages could impact the pace of development in the oil and gas sector.
- The large and rapid growth of shale gas production in the U.S. has outweighed production declines from other resources. The overall increase in U.S. production has helped to dampen North American natural gas prices since 2009. The future growth of U.S. shale gas production and its impact on North American gas prices will influence Canadian production, producer revenues and the amount of Canadian gas demanded by the U.S. If the U.S. begins to export significant volumes of U.S.-produced LNG, oversupply conditions could be reduced.
- Demand for natural gas, in Canada and internationally, could vary beyond the range considered in this analysis. The growth of gas use for power generation could ramp up more quickly, either to replace older coal plants or if planned new nuclear plants are not built. Domestic natural gas demand could also vary due to production or technology changes in fuel requirements for the oil sands. Changes in demand for Canadian and U.S. natural gas would have an impact on North American natural gas prices.

- Industry and governments in many jurisdictions are currently examining issues related to multi-stage hydraulic fracturing. These include the amount of fresh water used in the fracturing process, maintaining the separation between fracturing fluids and ground water, and the chemical composition and safe disposal of fracturing fluids. There is potential for these developments to affect the pace and level of production.
- Other potential uncertainties include the development of additional natural gas sources, like other shale deposits in Alberta, British Columbia or elsewhere in Canada. The development of gas hydrates is also a possibility in the longer term.
- Average well production rates could be higher or lower than assumed in this analysis.
- This report and its analysis makes a simplifying assumption that there will be sufficient infrastructure to move Canadian gas to domestic and export markets and that there will be enough demand in export markets for Canadian gas. Any shortfall in infrastructure or market demand for Canadian gas will reduce the projections of future production.

Natural Gas Liquids Outlook

Natural Gas Liquids Supply and Disposition

- Raw natural gas as it comes from the wellhead is mostly composed of methane, but also contains various heavier hydrocarbons as well as some contaminants.[42] These heavier hydrocarbons, which consist of ethane, propane, butanes and pentanes plus,[43] are called natural gas liquids or NGLs.
- In Canada, most NGLs are produced at gas processing plants, with the remainder produced as a byproduct of oil refining. Hundreds of field plants located in the gas-producing areas of British Columbia, Alberta and Saskatchewan account for most propane, butanes and pentanes plus production, and some ethane production. The majority of ethane production is concentrated in the straddle plants, with the difference coming from field plants with ethane extraction capability. The straddle plants are large gas processing facilities located on major gas pipelines close to consuming centres or gas export points in Alberta and British Columbia. At these locations, these plants have access to high volumes of gas that allow them to take advantage of economies of scale to overcome the high capital investment required for ethane extraction (also called deep-cut extraction).
- Refineries account for only about six per cent of total NGL production. However, they contribute a larger share of propane and butanes production, accounting for approximately 11 and 19 per cent of propane and butanes production, respectively. Oil sands off-gas NGL production only represented one per cent of total NGL production in 2009, but it is expected to increase in the future.
- In the Reference Case, total Canadian NGL production is expected to decline. A fall in ethane production is the biggest contributor to the declining trend in total NGL production. In general, production of propane, butanes and pentanes plus is expected to decline in the near term but stabilize after 2015, as discussed below (Figure 6.1).
- In the Reference Case, propane supply declines in the near term, due to falling non-tight conventional natural gas production. It starts a slow recovery in 2014 when new natural gas production from Montney and increased off-gas processing increases supply. Domestic demand for propane is projected to grow 0.3 per cent per year over the projection period. Propane available for export is expected to decrease early in the projection period, but stabilize from 2015 onwards.
- The production of butanes in the Reference Case behaves similarly to propane. Production is expected to decline from 2010 to 2015, and then stabilize until a mild recovery in 2021. Butanes demand is expected to grow at 1.7 per cent per year over the projection period,

42 Common contaminants are water, carbon dioxide, and hydrogen sulphide.

43 Pentanes plus, or condensate, is a gaseous mixture comprised of pentane and heavier hydrocarbons.

as use of butanes as diluents in oil sands production continues. Refinery butanes demand grows marginally over the projection period, as no significant expansions in Canadian refinery capacity are expected in the long term and ethanol makes further inroads into the Canadian gasoline pool, supported by government biofuels mandates. The combination of growing demand and the decline in butanes supply makes Canada a net importer of butanes after 2013.

- Pentanes plus supply is expected to decline early in the Reference Case projection period, and then stabilize from 2020 onwards. Growth in oil sands production will be the main driver of condensate demand. Although some synthetic crude oil could be used for bitumen dilution in the future, bitumen diluent demand is expected to grow at an average rate of 5.7 per cent per year over the projection period, outstripping available domestic supplies. Imports of condensate increase at an average rate of 10 per cent per year over the projection period, reaching 106 thousand m^3/d (668 thousand bbl/d) by 2035 (Figure 6.2).

FIGURE 6.1

Natural Gas Liquids Production, Reference Case

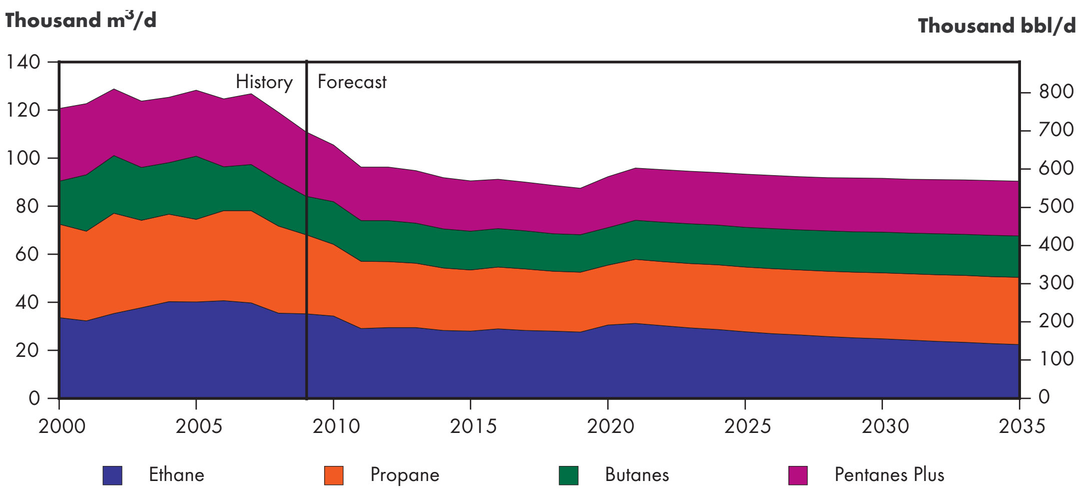
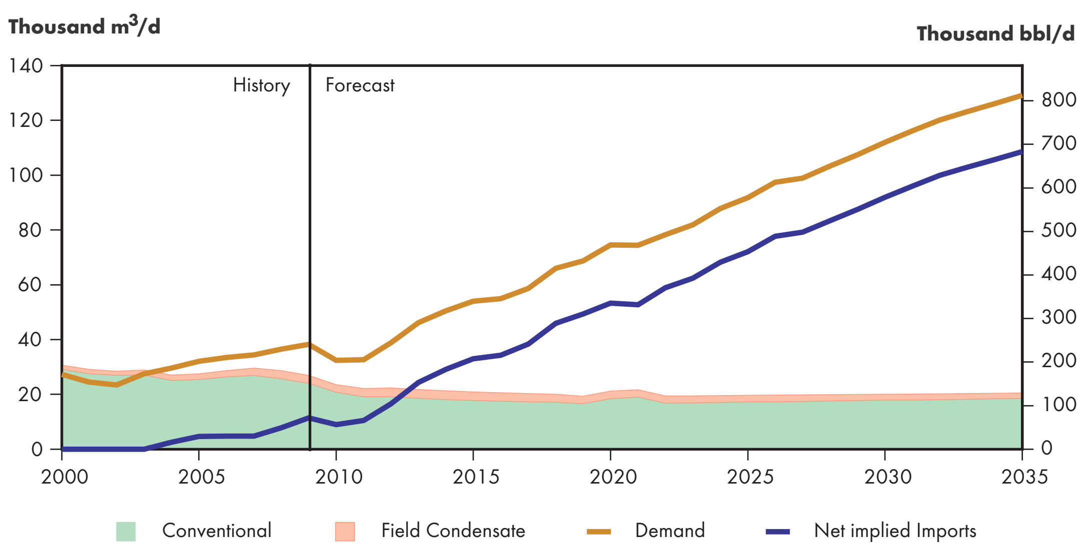


FIGURE 6.2

Pentanes Plus Supply and Demand, Reference Case



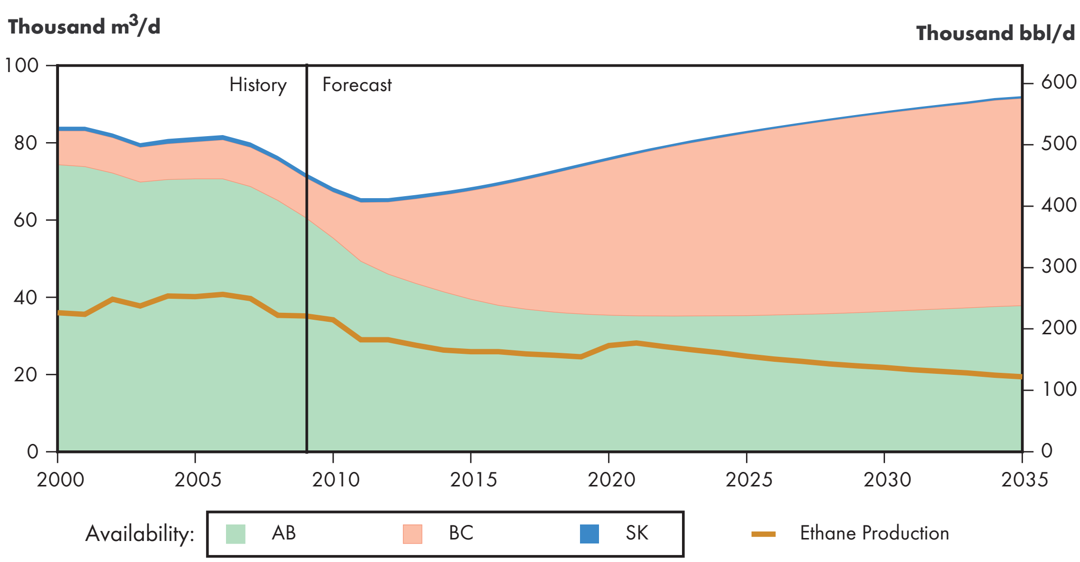
- The cases with higher prices (Fast and High) show a slight recovery of propane, butanes and pentanes production post-2021. In the lower price cases (Slow and Low), the decline in NGL supply is slightly greater compared to the Reference Case.

Ethane Supply and Demand

- The amount of NGLs available from natural gas production, particularly ethane, increases in the Reference Case after 2012 due to rising gas production from the Montney play in British Columbia and to a lesser extent the Deep Basin in Alberta (Figure 6.3). Approximately half of the total ethane available in raw gas production in Western Canada is currently extracted. If no new ethane extraction capacity is developed to process new tight gas production in British Columbia and within Alberta, the percentage of ethane recovered will decline.
- Despite the growing availability of ethane in raw gas in the Reference Case, ethane production is expected to decline in the projection (Figure 6.3). This occurs because gas production growth is largely occurring in British Columbia where ethane extraction capacity is minimal. In Alberta, non-tight conventional production is falling while gas demand is rising. These factors combine to reduce the amount of gas reaching the major ethane extraction facilities located near Alberta's borders. Transfers of British Columbia gas into Alberta are expected to increase, but they are not significant enough to reverse the downward trend of the gas available for ethane extraction in the province. Mackenzie Delta gas could increase Western Canada gas supplies available for ethane extraction for a few years, after which ethane production continues to fall.
- The wave of cancellations and downsizing of upgrading projects in Alberta after the 2009 global recession has negatively affected off-gas supply. In the short term, ethane from off-gas is projected to start in mid-2011 at very low levels of 0.1 thousand m^3/d (0.6 thousand bbl/d), ramping up to 1.78 thousand m^3/d (11.2 thousand bbl/d) by late 2013. However, a significant amount of actual and future upgrading capacity that has not yet incorporated off-gas processing could result in more ethane from off-gas in the future.

FIGURE 6.3

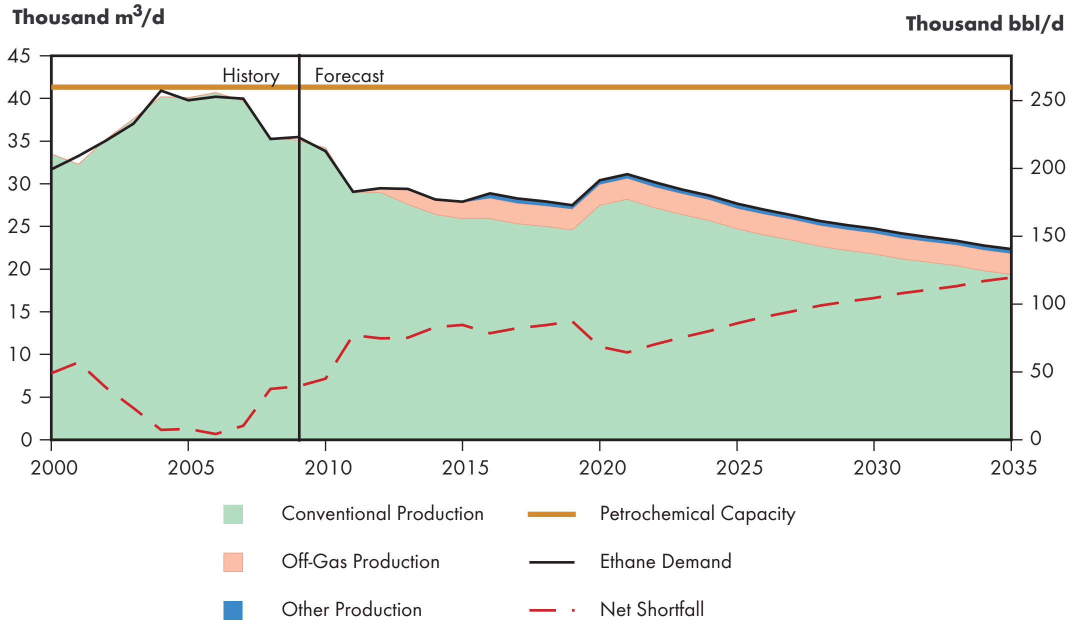
Western Canada Sedimentary Basin Ethane Availability in Raw Gas and Ethane Production, Reference Case



- The Alberta government's Incremental Ethane Extraction Program has been successful in developing additional supplies of ethane for Alberta's petrochemical industry. As of July 2011, two projects are in operation.[44] Five additional projects[45] are under consideration and could further increase future ethane production. There are also several proposals to import ethane into Canada.[46]
- Alberta's ethane demand is mostly concentrated in the petrochemical sector. Ethane demand in Alberta has become supply-constrained as ethane supplies have fallen in recent years below the petrochemical capacity. In the absence of other sources such as imports or new indigenous supply, ethane consumption is expected to continue to decline (Figure 6.4).
- Although growing tight gas production in British Columbia and Alberta could offer a new source of ethane supplies for Western Canada, there is little information about potential projects to produce ethane from this new source. Therefore, the Reference Case assumes no building of new ethane extraction (deep-cut) facilities over the projection period.

FIGURE 6.4

Ethane Supply and Demand Balance, Reference Case



44 Rimbey Ethane Extraction Project (0.79 thousand m^3/d (5 thousand bbl/d)) and the Empress V Expansion Deep Cut Project (1.11 thousand m^3/d (7.0 thousand bbl/d)).

45 Musreau Deep Cut Project (0.9 thousand m^3/d (6.0 thousand bbl/d)), Harmattan Plant Co-Stream Project (1.91 thousand m^3/d (12.0 thousand bbl/d)), Scotford Fuel Gas Recovery Project (0.19 thousand m^3/d (1.2 thousand bbl/d)), Hidden Lake Streaming Project (0.40 thousand m^3/d (2.5 thousand bbl/d)), and Williams Off-gas Ethane Extraction Project (1.59 thousand m^3/d (10.0 thousand bbl/d)).

46 In Eastern Canada, there are four proposals under different stages of development to deliver ethane produced from the Marcellus shale gas area into Sarnia. It is expected that ethane import flows could start at approximately 7.15 thousand m^3/d (45 thousand bbl/d) by 2014, with the potential to reach up to 9.53 thousand m^3/d (60 thousand bbl/d) pending the closing of commercial agreements and regulatory approval. In Western Canada, there is an ethane pipeline import project (Vantage) currently under review by the Board. The project looks to build a pipeline to import ethane from the Bakken oil play in North Dakota to Alberta. If regulatory approval is granted, the pipeline could start shipping 4.77 thousand m^3/d (30 thousand bbl/d) of ethane in late 2012, which could increase up to 9.53 thousand m^3/d (45 thousand bbl/d) by 2017.

Key Uncertainties to the Outlook

- Projects to import ethane into Canada are currently under consideration. These are not included in the projection because they are currently pending regulatory decisions. If approved and constructed, they will be included in future projections.
- NGLs are a byproduct of natural gas production, and NGL supply is sensitive to any Canadian natural gas supply uncertainties. Since NGL content varies between formations, the mix of natural gas production sources also has an impact on future NGL supply.
- If new deep-cut gas processing facilities are developed to extract ethane from the growing availability of tight gas in the Montney region of British Columbia, total NGL supply could be higher than projected.
- A significant amount of actual and future upgrading capacity has not yet incorporated off-gas processing. If this were to change, it could result in more ethane supplies from this non-conventional source in the future.

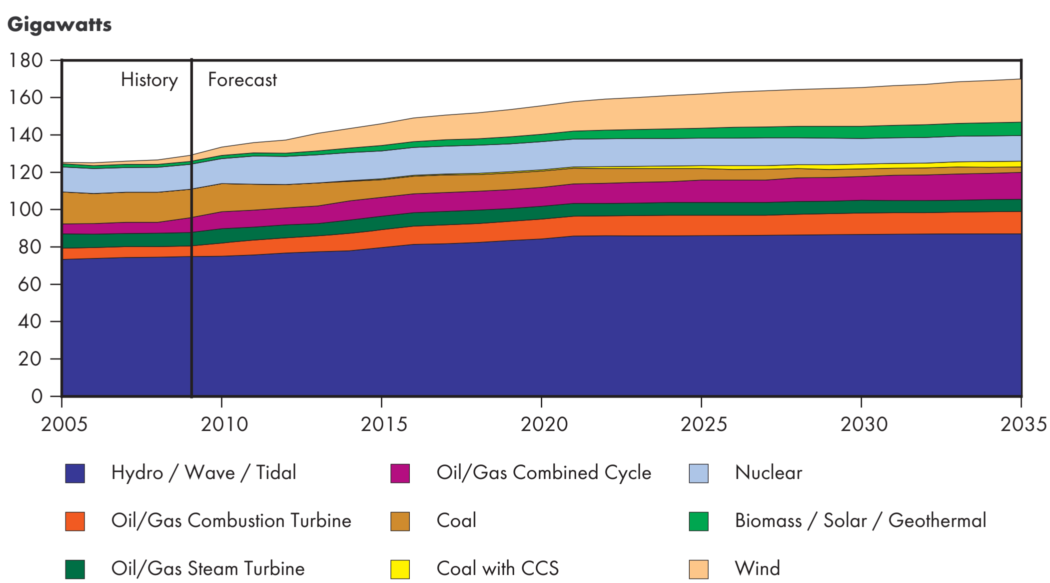
ELECTRICITY OUTLOOK

Capacity and Generation

- The electricity supply mix varies significantly among the provinces and territories. The electricity supply projections are driven by the demand projections (Chapter 3), as well as provincial and utility electricity system plans. Unlike oil and gas, technology is not sufficiently advanced to allow electricity to be economically stored in large quantities. Thus, an adequate amount of generating and transmission capacity is required to keep supply and demand in balance.
- Total generation capacity is projected to increase by 27 per cent over the projection period, with natural gas-fired and renewable-based capacity showing the largest increases. This capacity increase is driven by two key factors. First, as existing power facilities age, they will need to be replaced for reliability, economic and/or environmental reasons. Second, sufficient capacity will need to be constructed to meet growing demand while maintaining sufficient reserve margins.
- Total installed capacity is projected to increase from 133 GW in 2010 to 170 GW by 2035 (Figure 7.1). Total new gross capacity additions amount to 55 GW of which 19 GW are for replacement and 36 GW to service incremental demand and export markets. The capacity increases occur in all provinces and territories, with most increases in the larger electricity markets of Quebec, Ontario, British Columbia and Alberta.

FIGURE 7.1

Electricity Generating Capacity, Reference Case



- Canadian electricity generation increases at an average annual rate of 1.0 per cent over the projection period, with faster growth in the 2010 to 2020 timeframe (Figure 7.2). The main sources of base load generation vary among the provinces over the projection period. In Quebec, British Columbia and Manitoba, baseload generation is projected to remain predominantly hydro-based. In Saskatchewan, generation continues to be mainly coal-fired, with implementation of Carbon Capture and Storage (CCS) technology growing over the projection period. Alberta gradually shifts from coal to natural gas to meet baseload electricity demand. Nuclear continues to play a key role in providing baseload generation in New Brunswick and Ontario, while contributing a small share to baseload generation in Quebec. The anticipated hydro development of the Lower Churchill in Labrador, and the related transmission expansion in Atlantic Canada, is projected to reduce fossil-fuelled baseload generation in Nova Scotia and New Brunswick. Generation to serve demand during peak periods comes mostly from gas-fired and, especially in isolated areas, oil-fired power plants over the projection period.
- The projected changes in generation mix (Figure 7.3) reflect government and industry efforts to curb energy-related GHG emissions and take into account provincial energy strategies, utility expansion plans, and the relative economics of generation options. Canadian electricity supply becomes cleaner over the projection period, as the share of non-CO_2-emitting generation sources (such as nuclear, renewable and plants with CCS) increases from 76 per cent in 2010 to 79 per cent in 2035. The share of renewable-based generation increases from 62 per cent in 2010 to 68 per cent in 2035.
- In the four sensitivity cases, the environmental policies and technological drivers are the same as in the Reference Case. Therefore, in the short- to medium-term, installed capacity is the same in all five cases. In this timeframe, total generation and flows of electricity differ between the cases to reflect differences in demand (Figure 7.4).
- After 2020, installed capacity differs as the differences in demand between the cases become more pronounced. This is especially true for the Fast Case, where electricity demand is over 15 per cent higher than the Reference Case in 2035. The Fast Case has higher natural gas, hydro, and other renewable capacity to help meet this higher demand.

FIGURE 7.2

Generation by Fuel, Reference Case

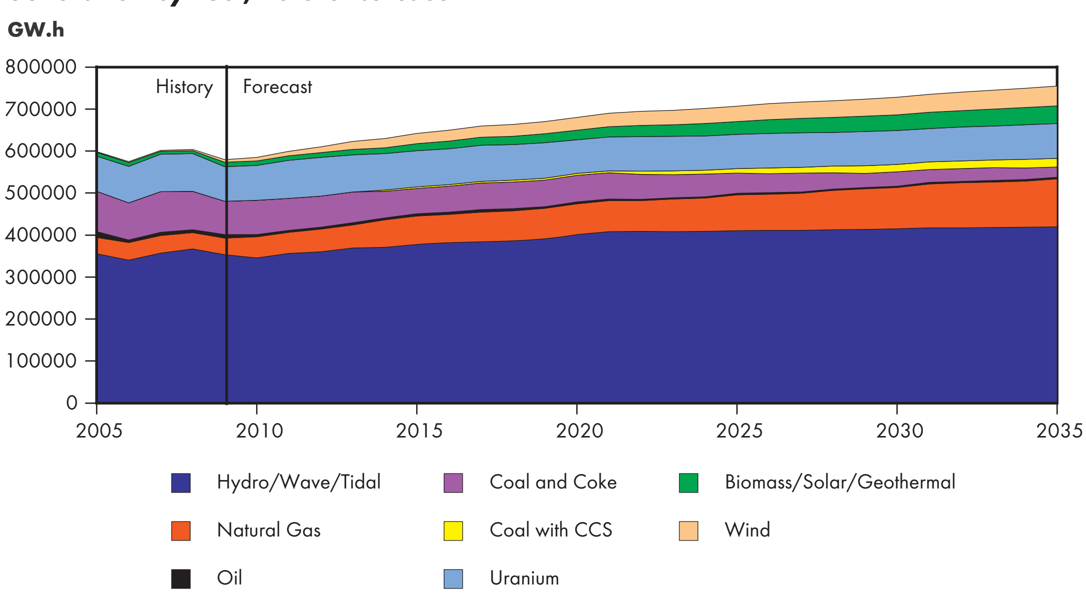


FIGURE 7.3

Canadian Generation Mix in 2010 and 2035, Reference Case

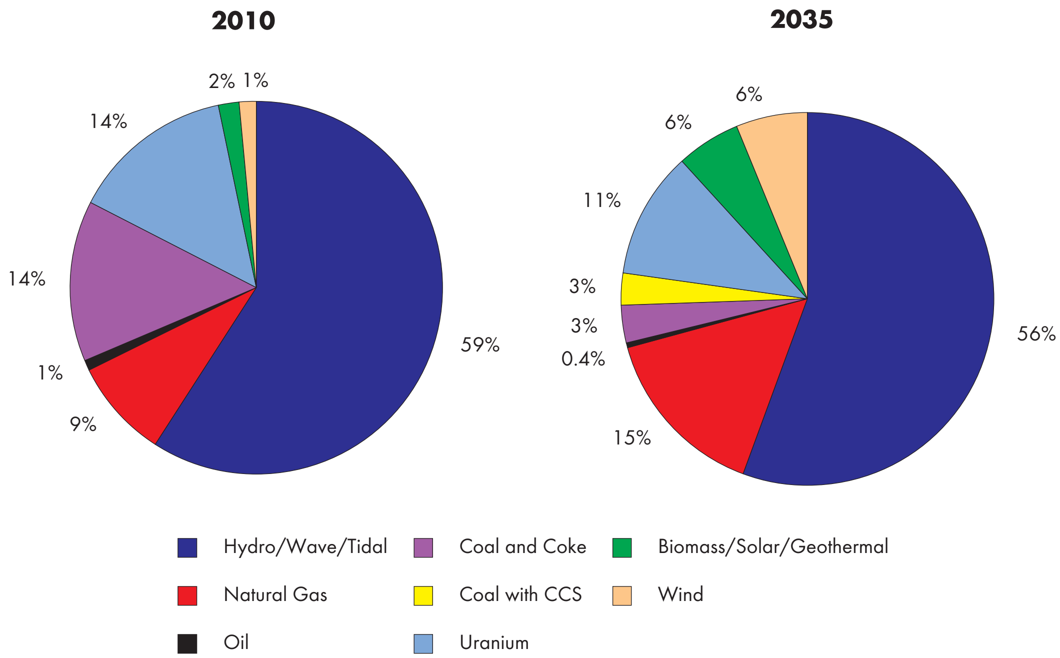
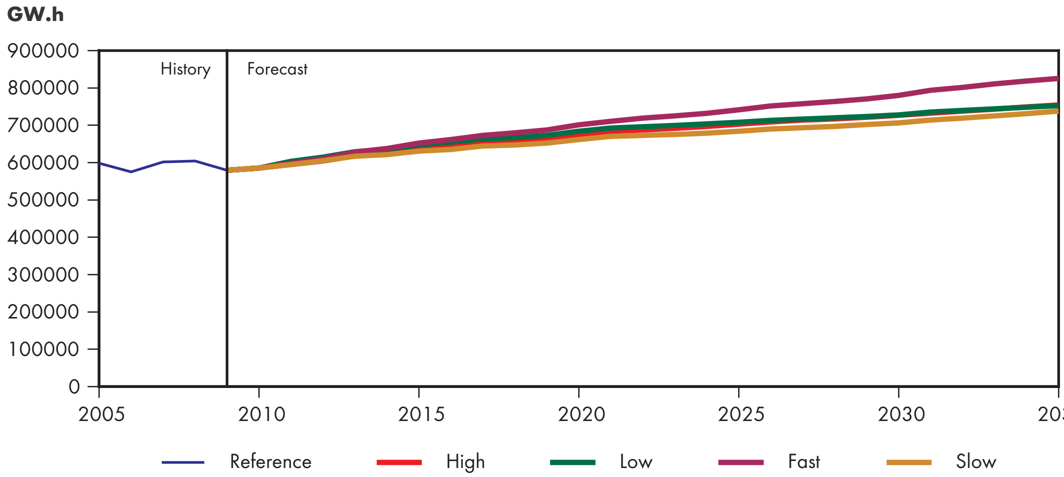


FIGURE 7.4

Canadian Electricity Generation, All Cases



Hydro

- Canada is a world leader in hydroelectricity generation. Hydroelectricity will remain a dominant source of electricity supply in Canada over the projection period. It has the advantages of being a flexible, low-cost source of non-CO_2 emitting base load electricity, which contributes to maintaining competitive and stable electricity prices.[47]

47 Hydro power is flexible in the sense that the output from hydro generating stations can be adjusted quickly with variations in demand. This is often referred to as the load-following characteristic of hydro power. Hydro power can contribute to maintaining price stability because it is not subject to volatility of fuel costs.

- By taking into account provincial utility planned projects, the Reference Case assumes significant hydropower expansion. Hydro-based capacity, including small hydro, increases from 75 GW in 2010 to 87 GW in 2035. This capacity expansion reflects a number of large hydro projects currently under construction as well as utility-planned projects including Muskrat Falls (824 MW) in Labrador, Romaine (1 550 MW) and Eastmain1-A/ Sarcelles (918 MW) in Quebec, Keeyask (630 MW) in Manitoba and Peace River Site C (900 MW) in British Columbia.
- As a result of projected hydro-based capacity expansion, annual hydroelectricity production increases from 346 TW.h in 2010 to 420 TW.h in 2035. Due to faster growth in other forms of generation, such as wind-based and gas-fired generation, the share of hydroelectricity declines from 59 per cent of total generation in 2010 to 56 per cent in 2035.

Non-hydro Renewable

- In addition to abundant hydro resources, Canada has significant non-hydro renewable resources including wind power, biomass, solar, tidal and wave power. These technologies have grown in the last few years, despite challenges relating to availability and cost. Policy and incentives have helped their growth, such as Ontario's feed-in tariff.
- Wind power has experienced strong growth in recent years. Over the projection period, it makes the largest contribution to non-hydro renewable growth. The availability of large hydro storage capacity in Canada facilitates the development of wind power as hydro may be used as a back-up source of power when intermittent wind resources are not available.
- Total installed wind power capacity quintuples over the projection period, reaching 23 GW in 2035. The largest capacity additions are in Quebec, Ontario and Alberta. The share of wind-based generation triples from less than two per cent of total generation to six per cent by 2035. Total combined capacity of biomass, solar and geothermal is also expected to grow, with net capacity additions over the projection period of over 5 400 MW, accounting for nearly six per cent of total generation by 2035.

Nuclear

- Nuclear energy currently accounts for 14 per cent of total electricity generation in Canada.[48] It plays a significantly larger role in Ontario, accounting for 50 per cent of electricity generation in 2010. Excluding hydro, nuclear is currently the only baseload generation option that provides emission-free electricity at prices that are competitive with other generation options if construction costs are well managed.
- Annual nuclear generation is projected to increase slightly over the entire projection period, rising from 82 TW.h in 2010 to 83 TW.h in 2035. As a result of higher growth in other types of generation, such as wind and gas-fired, the share of nuclear in total electricity generation declines to 11 per cent by 2035, compared to 14 per cent in 2010.
- These projections include the Point-Lepreau generating station in New Brunswick resuming service in 2012, and the Gentilly-2 nuclear generating station in Quebec being refurbished. In Ontario, two new 1 000-MW reactors are projected to come online, one in 2021 and the other in 2023, in addition to the current and planned refurbishments.

48 Based on statistics from the International Energy Agency, this is the same share as in the world electricity supply.

Coal-Fired

- A key feature of the electricity supply outlook is the declining role of coal used in power generation. This trend reflects various government and industry initiatives to limit GHGs, including stricter regulation of GHG emissions from large industrial polluters such as coal-fired power plants and the complete phase-out of coal in power generation in Ontario. Natural gas is expected to replace part of the retired coal-fired power plants.
- By year-end 2014, the remaining coal-fired power plants in Ontario totaling over 4 000 MW of capacity will be retired. Additional retirements occur in Alberta, Saskatchewan and Nova Scotia. At the national level, over 9 000 MW of coal-fired capacity will be retired over the 2010 to 2035 period, or about two-thirds of the total coal-fired capacity in 2010.
- Coal-fired generation is projected to decline from 78 TW.h in 2010 to 41 TW.h by 2035. As a result, the share of non-CCS coal-fired generation declines from 14 per cent in 2010 to three per cent in 2035.
- By 2035, CCS capacity in Alberta and Saskatchewan increases to nearly 3 000 MW. Much of the growth in CCS occurs after 2020, replacing retired coal capacity or as a retrofit to existing coal plants.

Natural Gas-Fired

- Several factors support a greater role for natural gas power generation in Canada. They include: lower GHG emissions than coal-fired power plants; shorter construction time and permitting delays; lower investment costs than coal or nuclear power plants; the ability to be built in smaller increments to better match load growth; and well-developed gas supply infrastructure in Canada. The recent low price of natural gas has also enhanced the attractiveness of this form of generation.
- Total gas-fired capacity increases from 18 GW in 2010 to 28 GW by 2035 in the Reference Case. Capacity increases in several provinces, with Alberta registering the largest increase. This is due to the continued use of gas in cogeneration facilities for oil sands development and the continued substitution of coal generation with gas.
- Annual gas-fired generation more than doubles over the projection period, rising from 50 TW.h in 2010 to 114 TW.h in 2035. The share of gas-fired generation increases from nine per cent in 2010 to 15 per cent in 2035.

Oil-Fired

- Oil-fired power plants currently account for four per cent of total installed capacity in Canada. They are used to generate electricity during peak demand periods or in areas where other generation options are not widely available, such as Yukon, Northwest Territories and Nunavut.
- In the Reference Case, total oil-fired plant capacity is projected to decline from 5 519 MW in 2010 to 4 282 MW by 2035. This reflects the retirements of ageing units, which are typically replaced by renewable units or natural-gas fired units when possible.
- Due to its low utilization, oil-fired generation currently accounts for about one per cent of total generation and is expected to maintain a very small share over the projection period.

Exports, Imports and Interprovincial Transfers

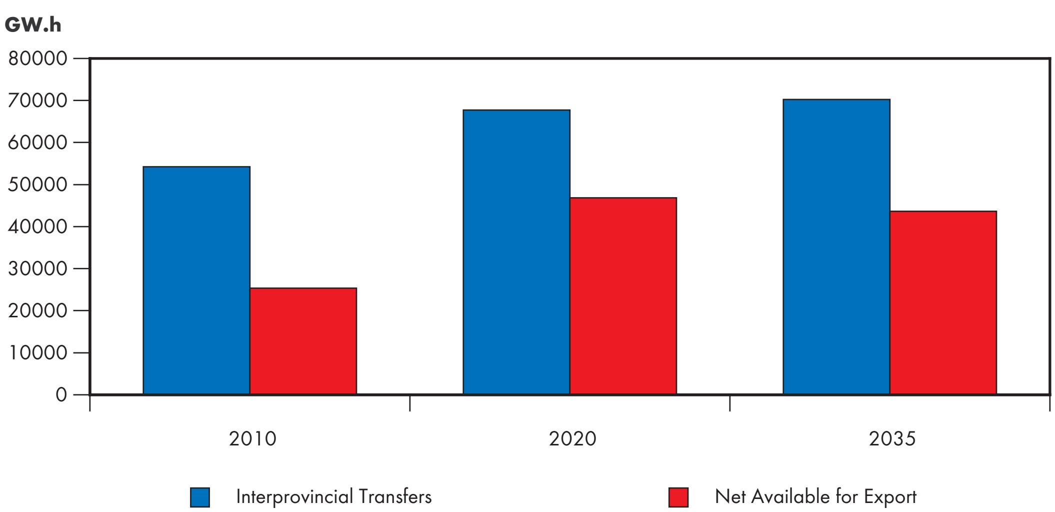
- Canada is a net exporter of electricity. Exports originate mostly from hydro-based provinces and generally account for less than ten per cent of total generation. The levels of annual exports are largely influenced by hydro conditions as well as local supply and demand balances. In the 2005 to 2010 period, annual exports fluctuated in the range of 43 TW.h to 56 TW.h. Canada's electricity imports have fluctuated in the range of 17 TW.h to 24 TW.h. Most imports occur during off-peak periods when prices in neighboring markets are low.
- In the Reference Case, net electricity available for export has the potential to increase significantly. This is largely due to the projected growing surplus of clean and competitively-priced power from hydro-based provinces. By 2035, net electricity available for export is projected to reach 44 TW.h annually compared to 25 TW.h in 2010 (Figure 7.5).
- Inter-provincial electricity transfers are projected to increase from 54 TW.h in 2010 to 70 TW.h in 2035. A portion of this increase comes from the Lower Churchill hydro development in Labrador, assumed to begin operating in 2019. The power not used by Newfoundland and Labrador moves through other Atlantic provinces, where Nova Scotia uses a portion and the rest is exported.

Key Uncertainties to the Outlook

- Electricity supply projections are demand-driven. Therefore, factors that will have an impact on the demand side will impact the supply side. Technological developments, new policies, and changing prospects of fuel supply and fuel prices may influence the choice of generation options and the generation mix in the future. In some cases, social and local acceptability of electricity infrastructure projects is an important factor as well.
- The relative economics of new power plant projects depend on fuel and overall capital costs. These vary by the type of technology under consideration. In general, the fuel cost of renewables is considered as nil, and fossil-fuel generation typically has a higher fuel cost component than nuclear generation. Uncertainty in the costs of the fuels used in power

FIGURE 7.5

Net Electricity Available for Export and Interprovincial Transfers, Reference Case



generation has an impact on the type of technologies and projects that are pursued and therefore on the future supply mix.

- Currently, non-hydro renewables, such as wind and solar power, have higher costs than conventional sources of generation. Their deployment is supported in some markets by financial incentives such as feed-in-tariffs. There are also reliability concerns for how much variable renewable-based generation may be integrated into a power system. Reduction or elimination of incentives without a corresponding cost reduction due to technological improvement, or grid integration issues, may constrain growth of these generation sources.
- Government regulation and policies impacting investments and operations of power plants continue to evolve. These may impact the outlook.

COAL OUTLOOK

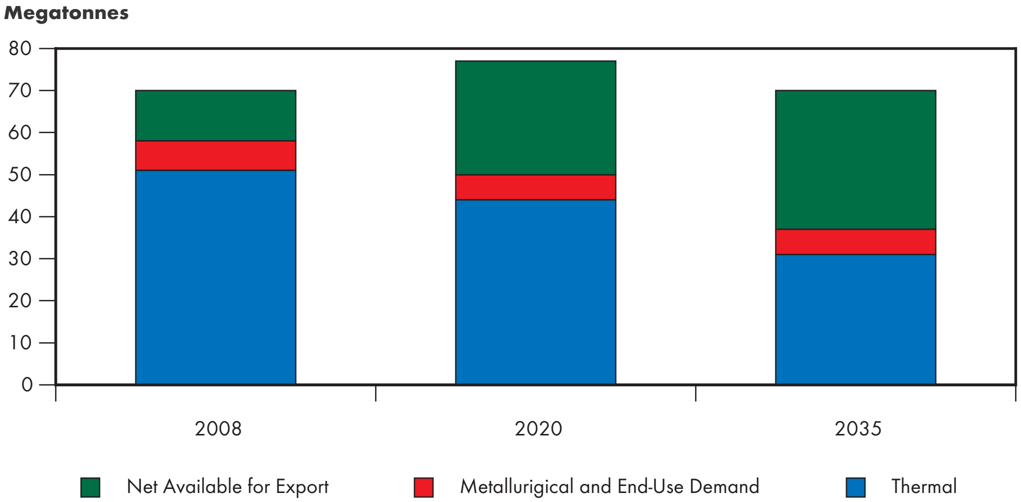
- Coal is the major source of power generation worldwide, accounting for over 40 per cent currently. In projections by the International Energy Agency (IEA) and Energy Information Administration, this share ranges between about 32 per cent and 43 per cent by 2035. The higher end of the range assumes that relevant policies remain similar to today. The lower end reflects expectations for new policies that would limit emissions from industries including power generation. Concerns about the eventual impact of burning coal on air quality and the ability to meet GHG emissions targets create uncertainty about the outlook for coal consumption. In contrast to these concerns, there is a renewed interest in cost-efficient economic development, as coal remains one of the lowest-cost primary energy sources.
- One reason for the relative low cost of coal is its abundance and wide distribution globally. According to the IEA, the world's total proven recoverable coal reserves are 935 billion tonnes spread across 70 countries. This would take about 150 years to deplete at current production rates. Canada holds about 6.6 billion tonnes of proven recoverable coal reserves, or 100 years of production at the current production rate.[49]
- Power generation accounts for two-thirds of coal consumption worldwide (using mostly thermal coals), with the remainder used mainly by the steel industry (using metallurgical coals). The IEA's 'new policies' scenario[50] projects global coal demand to increase by about 0.6 per cent per year until 2035, with the shares between the power and industrial sectors remaining similar to today. Almost all of the growth in coal demand occurs in the developing economies, such as China and India. Coal demand in the OECD countries is expected to decline in absolute terms.
- In Canada, thermal demand accounts for about 88 per cent of coal consumption, mostly for electric power generation (Figure 8.1). Within Canada, the decline in thermal coal demand is much greater than the increasing demand in the steel and other industrial sectors over the outlook period. About 80 per cent of coal exports are the higher-grade metallurgical coals. For the most part, these are shipped from west coast ports to Japan and Southeast Asia. Smaller amounts are sent to the U.S., Central America and Europe. Both types of coal are imported to Ontario and Atlantic Canada.
- A key feature of the declining domestic coal demand and imports is the phase-out of coal generation in Ontario by 2015. Primarily due to this initiative, imports of coal into Canada decrease from 20.5 megatonnes (Mt) in 2008 to 7.2 Mt in 2015, and decline moderately thereafter. Some declines in coal demand occur in other provinces, reflecting

49 Natural Resources Canada, *Canadian Minerals Yearbook (CMY) – 2009*.
Available at: http://www.nrcan.gc.ca/mms-smm/busi-indu/cmy-amc/2009revu/coa-cha-eng.htm

50 International Energy Agency, *World Energy Outlook 2010, November 2010*.
Available at: http://www.iea.org/weo/index.asp

FIGURE 8.1

Canadian Coal Production and Disposition, Reference Case



plant retirements and efficiency improvements from retrofits and new units. Coal demand in Alberta and Saskatchewan peaks in 2019 and 2023, respectively. Demand in the steel industry is expected to increase, but not reach the pre-2009 levels. Overall, Canadian demand for coal decreases from 58.4 Mt in 2008 to 37.2 Mt in 2035.

- The great majority of Canadian coal resources are located in Western Canada. Coal production in Western Canada increases at a high rate from 2012 to 2016, due to multiple mining projects that come on stream. Most of these projects plan to produce metallurgical coal for export, increasing the exports of metallurgical coal from 26.5 Mt in 2008 to 40.3 Mt in 2016. In the East, small amounts of coal have been produced in New Brunswick and Nova Scotia. However, with the closure of the Minto mine in New Brunswick, reported coal production in the Maritimes is now zero. This region is not expected to produce much coal until 2014, when a new metallurgical coal mine (for export) opens in Nova Scotia. In contrast to the declining domestic demand and imports, total Canadian coal production increases from 67.8 Mt in 2008 to 94.7 Mt in 2035. In this period, net coal available for export increases at an average annual growth rate of 6.7 per cent in the Reference Case.
- Relative to the Reference Case, there is slightly more and less demand for coal in the High and Low Cases, respectively. This is because more natural gas (and less coal) is used for power generation when gas prices are low. In 2035, coal production is 94.8 Mt in the High Case and 94.5 Mt in the Low Case. The Fast and Slow Economic Growth Cases vary more from the Reference Case due to changes in the steel industry's demand. Total production is 95.8 Mt in the Fast Case, and 93.9 Mt in the Slow Case.

Key Uncertainties to the Outlook

- The assumption regarding coal plant retirements is a key uncertainty in the coal demand projection. Based on anticipated regulatory action,[51] industry is pursuing alternatives to coal in power generation. The electricity capacity projections reflect this, as retiring coal plants are replaced with cleaner options, including natural gas and plants with CCS.
- The increase in coal exports is expected to offset the decline in domestic demand; however, the potential exists for these export markets to switch to other sources of energy and rely less on coal supply from exporting countries such as Canada.

51 The proposed *Reduction of Carbon Dioxide Emissions from Coal-Fired Generation of Electricity Regulations* for public consultation were released August 2011. Available at: http://www.ec.gc.ca/Content/2/E/5/2E5D45F6-E0A4-45C4-A49D-A3514E740296/E_Consultation.pdf

Conclusions

- *Canada's Energy Future: Energy Supply and Demand Projections to 2035* provides a projection of Canadian energy supply and demand to the year 2035. The projections employ currently available information, trends, policies and technologies to form a view of the Canadian energy system over the next 25 years. Over the projection period, new information will become available, trends, policies and technology will evolve, and certain assumptions made in the report may no longer apply. Readers of this report should consider the projections a baseline for discussing Canada's energy future, not a prediction of what will take place.
- The results of the Reference Case imply three broad conclusions:
  - **Energy supply grows to record levels**

    New and innovative ways of producing energy causes Canadian energy supply to reach its highest levels ever. Oil production doubles by 2035, with oil sands providing the majority of new production. Natural gas production reverses its historical declining trend by 2016 with tight and shale gas extraction driving production above record levels by the end of the projection period. Electricity production grows gradually as renewables, such as wind, hydro and biomass, make up a greater portion of the generating mix.
  - **Energy demand growth slows from its historical pace**

    Slower population and economic growth, higher energy prices, and enhanced efficiency and conservation programs all contribute to slowing demand in the residential, commercial and transportation sectors. In the industrial sector, strong oil and gas production, as well as robust economic growth in a number of energy-intensive industries, result in faster demand growth than the historical pace.
  - **Supply and demand will impact trade and infrastructure**

    Record supply levels and slowing demand results in sizeable surplus energy available for export. Net oil and electricity available for export increase considerably, while net natural gas available for export declines gradually before leveling off by 2020.
- In addition to the Reference Case, the Report employs four sensitivity cases: High, Low, Fast and Slow. These sensitivity cases attempt to provide a broader perspective and reflect the uncertainty around energy prices and economic growth. The High and Low Cases highlight Canada's role as both a large producer and consumer of energy. The Fast and Slow Cases suggest that the economy and energy demand remain closely linked.

  Finally, the projections suggest Canadians can expect energy markets to continue to function well. Supplies of oil, natural gas and electricity remain in excess of Canadian requirements for the foreseeable future.

Alternative or Emerging Technologies	New and emerging environmentally-friendly technologies used as an alternative to existing resource-intensive methods to produce energy. Alternative technologies make limited use of resources, and include fuel cells and clean coal technologies, for example.
Barrel	One barrel is equal to approximately 0.159 cubic metres or 158.99 litres or 35 imperial gallons.
Baseload (electricity)	The minimum amount of electric power delivered or required over a given period.
Biomass	Organic material, such as wood, crop waste, municipal solid waste, hog fuel and pulping liquor, processed for energy production.
Biodiesel	It is a diesel fuel substitute that can be made from vegetable oil or recycled cooking oil.
Bitumen or crude bitumen	A highly viscous mixture, mainly hydrocarbons heavier than pentanes. In its natural state, it is not usually recoverable at a commercial rate through a well because it is too thick to flow.
Butane	A light hydrocarbon gas composed of four carbon atoms and 10 hydrogen atoms with a straight–chain or branch chain molecular structure, obtained from natural gas processing and petroleum refining. It could be easily stored in liquid for transportation. The main use of Butanes are in gasoline manufacturing, petrochemicals, and fuel applications (lighters, cooking and camping).
Capacity (Electricity)	The maximum amount of power that a device can generate, use or transfer, usually expressed in megawatts.
Carbon capture and storage (CCS) or carbon capture and sequestration	A method of capturing (and storing) CO_2, such that it is not released into the atmosphere, hence reducing GHG emissions. Carbon dioxide is compressed into a transportable form, moved by pipeline or tanker, and stored in some medium, such as a deep geological formation.

CO2 flooding	CO2 flooding is a process of enhanced oil recovery, in which CO_2, in a liquid form, is injected into oil-bearing reservoirs in an effort to increase the amount of oil that can be extracted.
Coalbed methane (CBM)	An unconventional form of natural gas that is trapped within the matrix of coal seams. Coalbed methane is distinct from typical sandstone or other conventional gas reservoir, as the methane is stored within the coal by a process called adsorption.
Cogeneration	Production of electricity and another form of useful thermal energy, such as heat or steam, from the same energy source. Either the by-product heat from industrial processes can be used to power an electrical generator or surplus heat from an electric generator can be used for industrial purposes.
Condensate	A low-density mixture comprised mainly of pentanes and heavier hydrocarbons recovered as a liquid from field separators, scrubbers or other oil and gas gathering facilities or at the inlet of a natural gas processing plant before the gas is processed.
Conventional crude oil	Crude oil, which at a particular point in time, can be technically and economically produced through a well using normal production practices and without altering the natural viscous state of the oil.
Conventional natural gas	Natural gas that is found in the reservoir and produced through a wellbore with known technology and where the drive for production is provided by expansion of the gas or by pressure from an underlying aquifer.
Compressed natural gas (CNG)	Natural gas that has been compressed to between 2,500 and 4,000 psi such that it can be transported in pressurized containers. Compression reduces the volume by a factor of 300 (or more) compared with gas at normal temperature and pressure.
Crude Oil	A mixture of hydrocarbons of different molecular weights that exists in the liquid phase in underground reservoirs and remains liquid at atmospheric pressure and temperature. Crude oil may contain small amounts of sulphur and other non-hydrocarbons, but does not include liquids obtained from the processing of natural gas.
Cyclic steam stimulation (CSS)	A repeatable, thermal in situ recovery technique involving steam injection followed by oil production from wells injected with steam. Steam injection increases oil mobility and allows heated bitumen to flow into a well.

Deep-cut facilities	A gas plant next to or within gas field plants or gas pipelines that can extract ethane and other natural gas liquids using turbo-expander or absorption technologies.
Demand-side management	Actions undertaken by a utility that result in a change and/or sustained reduction in demand for energy. This can reduce or delay new capital investment in power plants, pipelines or other infrastructure and improve overall system efficiency.
Diluent	Any lighter hydrocarbon, usually pentanes plus, added to heavy crude oil or bitumen in order to facilitate its transport in crude oil pipelines.
End-use demand	Energy used by consumers in the residential, commercial, industrial and transportation sectors. This is also referred to as secondary energy demand.
Energy efficiency	Technologies and measures that reduce the amount of energy and/or fuel required for the same work.
Energy intensity	The amount of energy used per unit of activity. Two common forms of energy intensity are energy use per capita and energy use per unit of GDP.
Enhanced oil recovery (EOR)	The extraction of additional crude oil from reservoirs through a production process other than natural depletion. Includes both secondary and tertiary recovery processes such as pressure maintenance, cycling, water flooding, thermal methods, chemical flooding, and the use of miscible and immiscible displacement fluids.
Ethane	The simplest straight-chain hydrocarbon structure with two carbon atoms. It is mainly produced from natural gas processing or as a by-product of petroleum refining. Its main use is as petrochemical feedstock for ethylene manufacturing.
Feedstock	Natural gas or other hydrocarbons used as an essential component of a process for the production of a product.
Fossil fuel	Hydrocarbon-based fuel sources such as coal, natural gas, natural gas liquids and crude oil.
Frontier areas	Generally, the northern and offshore areas of Canada.
Fuel economy	The average amount of fuel consumed by a vehicle to travel a certain distance, measured in litres per 100 kilometres.
Gas hydrates	Ice-like substances composed of water and natural gas that form when gases combine with water at low temperature and high pressure. They are typically found under large portions of the world's Arctic areas and deep under the oceans.

Gas well	A well bore with one or more geological horizons capable of producing natural gas.
Generation (electricity)	The process of producing electric energy by transforming other forms of energy. Also, the amount of energy produced.
Geothermal energy	The use of geothermal heat to generate electricity. Also used to describe ground-source heating and cooling (also known as geoexchange or ground-source heat pump).
Greenhouse gases (GHG)	Gases such as carbon dioxide, methane and nitrogen oxide, which actively contribute to the atmospheric greenhouse effect. Greenhouse gases also include gases generated through industrial processes such as hydroflurocarbons, perflurocarbons and sulphur hexafluoride.
Gross Domestic Product (GDP)	GDP is a measure of economic activity within a country. It is the market value of all goods and services in a year within Canada's borders.
Heating oil	Also known as No. 2 fuel oil. A distillate fuel oil commonly used for household space heating.
Heavy crude oil	Generally, a crude oil that has a density greater than 900 kg/m3.
Henry Hub (price)	Henry Hub is the pricing point for natural gas futures traded on the New York Mercantile Exchange. The hub is a point on the natural gas pipeline owned by Sabine Pipe Line and located in Louisiana.
Heritage assets	Existing generation (and/or transmission) equipment and facilities that were built well in the past and are largely paid for.
Hydroelectric generation	A form of renewable energy wherein electricity is produced from hydropower.
In situ recovery	The recovery of bitumen through the use of wellbores, generally in areas where depth of burial precludes surface-mining operations.
Integrated mining/ upgrading plant	A combined mining and upgrading operation where oil sands are mined from open pits. The bitumen is then separated from the sand and upgraded by a refining process.
Light crude oil	Generally, crude oil having a density less than 900 kg/m^3. Also a collective term used to refer to conventional light crude oil, upgraded heavy crude oil and pentanes plus.

Liquefied natural gas (LNG)	Liquefied natural gas is natural gas in its liquid form. Natural gas is liquefied by cooling to minus 162 degrees Celsius (minus 260 degrees Fahrenheit), and the process reduces the volume of gas by more than 600 times, allowing for efficient transport via LNG tanker.
Marketable natural gas	The volume of gas that can be sold to the market after allowing for removal of impurities and after accounting for any volumes used to fuel surface facilities. As used in this report for undiscovered volumes, it is determined by applying the average surface loss from existing pools in that formation to the recoverable volumes of undiscovered pools of the same formation.
Metallurgical coal	Anthracite or high-grade bituminous coal primarily used in the steelmaking industry.
Mine mouth generation	A method of integrated mining and power generation, wherein a power generation facility is located near its source coal mine.
Multi-stage hydraulic fracturing	A technique in which fluids are injected underground, in multiple stages, to create or expand existing fractures in the rock, allowing oil or gas to flow out of the formation, or to flow at a faster rate.
Natural gas liquids (NGL)	Those hydrocarbon components recovered from natural gas as liquids. These liquids include, but are not limited to, ethane, propane, butanes and pentanes plus.
Net available for export	Total production of a commodity less domestic demand for that commodity. The remainder equals the net (gross exports less gross imports) of the commodity available for export.
Oil sands	Sand and other rock material that contains bitumen. Each particle of oil sand is coated with a layer of water and a thin film of bitumen.
Oil sands off-gas	A mixture of hydrogen and light hydrocarbon gases produced when bitumen is upgraded to produce synthetic crude oil.
Peak demand	The maximum load consumed or produced in a stated period of time
Pentanes Plus	A low density mixture mainly of pentanes and heavier hydrocarbons obtained from the processing of raw gas, condensate or crude oil. Includes isopentane, natural gasoline, and plant condensate.

Petroleum product — A wide range of products derived from crude oil through the refining process such as gasoline, diesel, heating oil, and jet fuel, among others.

Primary energy demand — The total requirement for all uses of energy, including energy used by the final consumer, intermediate uses of energy in transforming one energy form to another, and energy used by suppliers in providing energy to the market.

Propane — A light hydrocarbon gas composed of three carbon atoms and six hydrogen atoms which can be easily stored in a liquid form, and is obtained from natural gas processing and petroleum refining. Propane main uses are as fuel in heating applications, cooking and camping, aerosol propellants and petrochemicals.

Real price — Price levels that are held constant at a base year, eliminating the effect of inflation.

Reliability — The degree of performance of any element of an electricity system, which results in electricity being delivered to customers within acceptable standards and in the amount desired. Reliability can be measured by frequency, duration or magnitude of adverse effects on electricity supply.

Reserve margin — Reserve margin, or reserve capacity, is a measure of available capacity over and above the capacity needed to meet peak demand.

Reserves — Reserves are estimated remaining marketable quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on: analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable, and shall be disclosed.

Reserves - Proven — Proved reserves are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.

Resources (Oil and Natural Gas) — As used in this report, resources refers to the remaining total volume of recoverable oil and natural gas that is thought to exist. Resources include deposits not economic to extract at current oil and gas prices, but may become economic as prices rise. Resources also include an undiscovered component, which may have been bypassed in current wells or have yet to be found. Resources can also include an additional amount of oil and gas that may be recovered as technology improves beyond current capabilities.

Resources – Ultimate Potential	An estimate of all the resources that may become recoverable or marketable, having regard for the geological prospects and anticipated technology.
Secondary energy demand	See End-use demand.
Shale gas	A form of unconventional gas that is trapped within shale, a sedimentary rock originally deposited as clay or silt and characterised by extremely low permeability. The majority of the gas exists as free gas or adsorbed gas though some gas can also be found in a dissolved state within the organic material.
Solar energy	Includes active and passive solar heat collection systems and photovoltaics.
Solution gas	Natural gas produced along with oil from oil wells.
Steam assisted gravity drainage (SAGD)	SAGD is a steam stimulation technique using pairs of horizontal wells in which the bitumen drains, by gravity, into the producing wellbore, after it has been heated by the steam. In contrast to cyclic steam stimulation, steam injection and oil production are continuous and simultaneous.
Straddle plant	A reprocessing plant located on a gas pipeline. It extracts natural gas liquids from previously processed gas.
Supply cost	All costs associated with resource exploitation as an average cost per unit of production over the project life. It includes capital costs associated with exploration, development, production, operating costs, taxes, royalties and producer rate of return.
Synthetic crude oil	Synthetic crude oil is a mixture of hydrocarbons generally similar to light sweet crude oil, derived by upgrading crude bitumen or heavy crude oil.
Tailings ponds	A man-made earthen structure designed to store the waste-water slurry, or tailings, from mining and extraction processes, and allow the settling of solids from the water. Oil sands mining and hot-water extraction processes produce tailings that are a mixture of water, clay, sand and residual bitumen.
Thermal coal	Lignite, sub-bituminous or lower-grade bituminous coal primarily used for power generation or heating purposes.
Tight gas	A form of unconventional natural gas that is held in the pore space of a rock that has a lower permeability or ability to flow than usual for that type of rock.

Tight oil Oil produced from organic-rich shales or from low permeability sandstone, siltstone, limestone or dolostone reservoirs. Tight oil reservoirs typically require the combination of horizontal drilling and multi-stage hydraulic fracturing to establish sufficient fluid flow to achieve economic rates of recovery.

Unconventional crude oil Crude oil that is not classified as conventional crude oil (e.g., bitumen).

Unconventional natural gas Natural gas that is contained in a non-traditional reservoir rock that requires significant additional stimulus to allow gas flow. It may be that the gas is held by the matrix material such as coal, ice, or shale; or where the reservoir has an unusually low amount of porosity and permeability. In this report unconventional gas is divided into coalbed methane, shale gas and gas hydrates.

Upgrading (bitumen) The process of converting bitumen or heavy crude oil into a higher quality crude oil either by the removal of carbon (coking) or the addition of hydrogen (hydroprocessing).

Wave / Tidal power Also known as tidal energy, tidal or wave power makes use of the rise and fall in sea levels, or tidal flow, to create hydropower.

West Texas Intermediate (WTI) WTI is a light sweet crude oil, produced in the United States, which is the benchmark grade of crude oil for North American price quotations.

Imperial and Metric Conversions

Unit		**Equivalent**
m	metre	3.28 feet
m^3	cubic metres	6.3 barrels (oil); 35.3 cubic feet (gas)
t	metric tonne	2200 pounds

Energy Content Equivalents

Energy Measure		**Energy Content**
GJ	gigajoule	0.95 million btu
PJ	petajoule	1 000 000 GJ

Electricity

W	Watt	1 joule per second
MW	megawatt	One million watts
GW.h	gigawatt hour	3 600 GJ or 1 000 MW.h
TW.h	terawatt hour	3.6 PJ or 1 000 GW.h

Natural Gas

Mcf	thousand cubic feet	1.05 GJ
Bcf	billion cubic feet	1.05 PJ
Tcf	trillion cubic feet	1.05 EJ

Natural Gas Liquids

m^3	ethane	18.36 GJ
m^3	propane	25.53 GJ
m^3	butane	28.62 GJ

Crude Oil

m^3	Light	38.51 GJ
m^3	Heavy	40.90 GJ
m^3	Pentanes plus	35.17 GJ

Coal

t	Anthracite	27.70 GJ
t	Bituminous	27.6 GJ
t	Subbituminous	18.80 GJ
t	Lignite	14.40 GJ

Petroleum Products

m^3	Aviation Gasoline	33.52 GJ
m^3	Motor Gasoline	34.66 GJ
m^3	Petrochemical Feedstock	35.17 GJ
m^3	Naphtha Specialties	35.17 GJ
m^3	Aviation Turbo Fuel	35.93 GJ
m^3	Kerosene	37.68 GJ
m^3	Diesel	38.68 GJ
m^3	Light Fuel Oil	38.68 GJ
m^3	Lubricants	39.16 GJ
m^3	Heavy Fuel Oil	41.73 GJ
m^3	Still Gas	41.73 GJ
m^3	Asphalt	44.46 GJ
m^3	Petroleum Coke	42.38 GJ
m^3	Other Products	39.82 GJ

GUIDE TO APPENDICES

Appendices are available on the Boards' Website at www.neb-one.gc.ca, and include the following detailed data.

Appendix 1 Key Drivers

Table A1.1	Economic Indicators, Canada
Tables A1.2 to A1.12	Economic Indicators, Provinces and Territories

Appendix 2 Energy Demand

Table A2.1	Demand, Reference Case, Canada
Tables A2.2 to A2.14	Demand, Reference Case, Provinces and Territories
Table A2.15	Demand, Low Case, Canada
Tables A2.16 to A2.28	Demand, Low Case, Provinces and Territories
Table A2.29	Demand, High Case, Canada
Tables A2.30 to A2.42	Demand, High Case, Provinces and Territories
Table A2.43	Demand, Fast Case, Canada
Tables A2.44 to A2.56	Demand, Fast Case, Provinces and Territories
Table A2.57	Demand, Slow Case, Canada
Tables A2.58 to A2.70	Demand, Slow Case, Provinces and Territories

Appendix 3 Oil and Natural Gas Liquids

Table A3.1	Crude Oil and Bitumen Ultimate Potential Resources
Table A3.2	Crude Oil and Bitumen Reserves
Table A3.3	Refinery Feedstock Requirements and Sources, Canada
Tables A3.4 to A3.8	Refinery Feedstock Requirements and Sources, Provinces
Table A3.9	Supply and Disposition of Light Domestic Crude Oil and Equivalent, Canada
Table A3.10	Supply and Disposition of Heavy Domestic Crude Oil and Equivalent, Canada
Table A3.11 to A3.14	NGL Supply, Demand and Potential Exports, Reference Case
Table A3.15 to A3.18	NGL Supply, Demand and Potential Exports, Low Case
Table A3.19 to A3.22	NGL Supply, Demand and Potential Exports, High Case

Appendix 4 Natural Gas

Appendix 5 Electricity

Appendix 6 Coal

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Request IR-344:

With reference to CA/SBA IR-43 and Application, page 108, line 19, please define what available volume would be "sufficient" for Nova Scotia to import from Canaport.

Response IR-344:

There is no specific number associated with the concept of sufficient volume. Please refer to CA/SBA IR-5 (e). The sufficient volume would be whatever we could secure in the competition to attract gas to an LNG terminal, the demand volume would be the gas burn we forecast and the forecast burn is dependent upon the gas price compared to other sources. Therefore, if LNG is sourced on world markets "sufficient" volume will depend on what volume we could secure from suppliers that is more economic than our alternative.

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Request IR-345:

With reference to CA/SBA IR-45 and Application page 108, lines 22-23:

(a) Please provide any reports or workpapers that estimate the capital cost or firm transportation contract cost to procure additional natural gas from the U.S.

Response IR-345:

Please refer to Attachment 1.

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Tennessee Gas Pipeline Co, LLC
Northeast Expansion

January 2013

KINDER MORGAN

Agenda

- **Kinder Morgan**
- **Tennessee Gas Pipeline**
  - System overview
  - Northeast supply access
  - Recent expansions
  - TGP Northeast Expansion
- **Discussion**

Maritime Link CA/SBA IR-345 Attachment 1 Page 2 of 18

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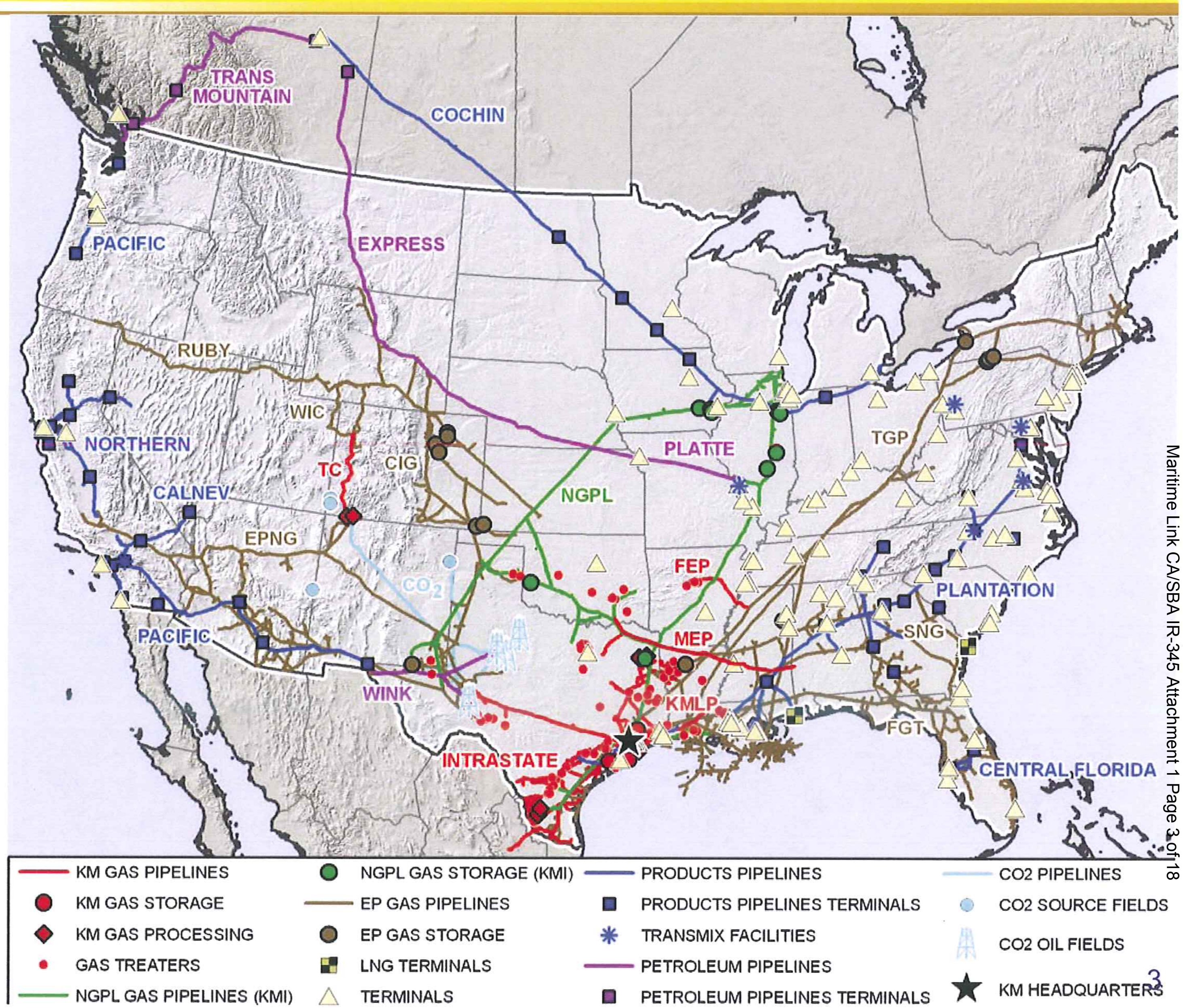
The Kinder Morgan System

- 4th largest energy company in North America
  - Enterprise value ~ $95 billion
- Largest natural gas network in U.S.
  - 62,000 miles of natural gas pipeline
  - Connected to every important U.S. natural gas resource play
- Largest independent transporter of petroleum products in U.S.
- Largest transporter of CO_2 in U.S.
- 2nd largest oil producer in Texas
- Largest independent terminal operator in U.S.
- Only Oilsands pipeline serving West Coast



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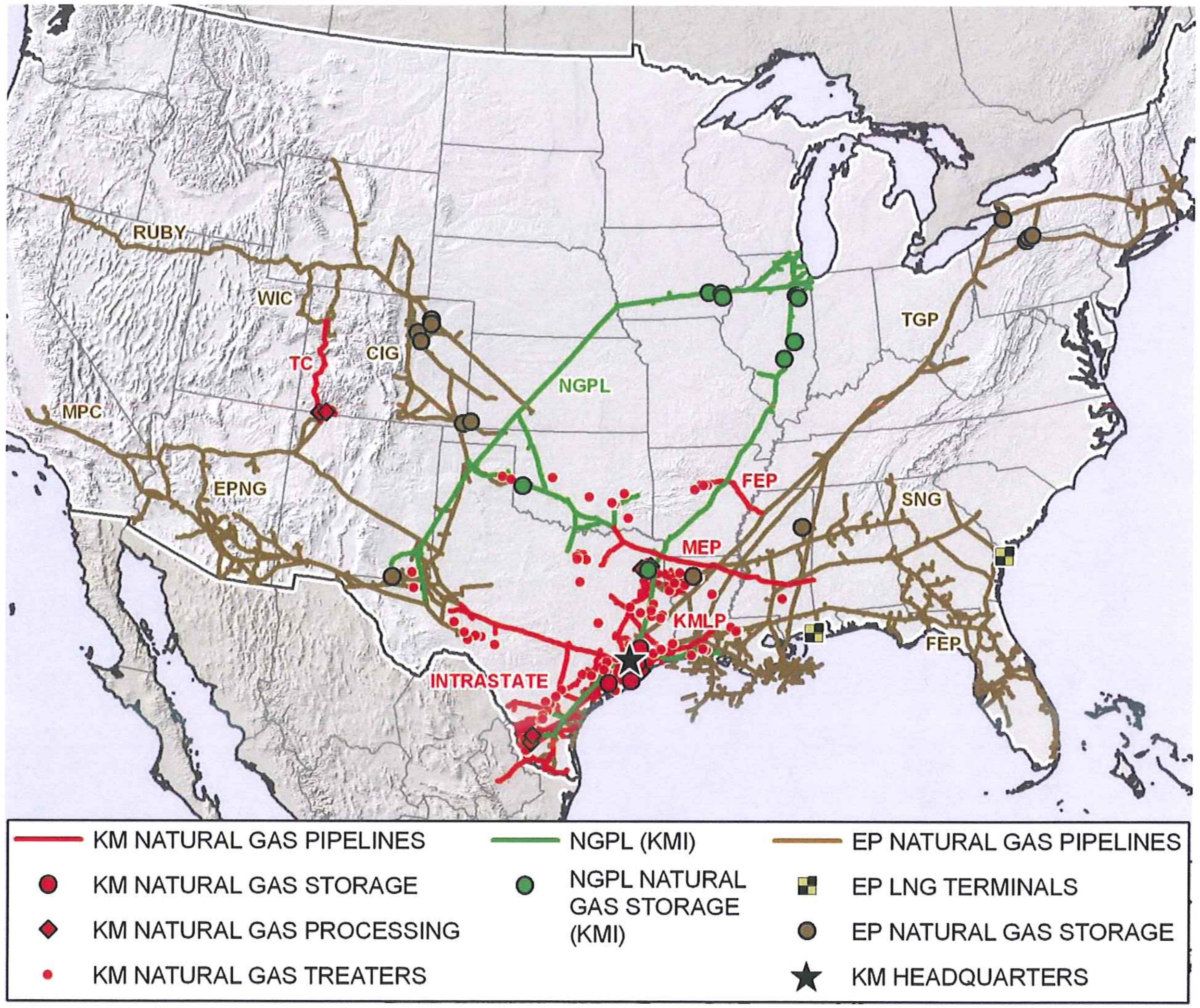
(KMP/EPB/KMI)

Natural Gas Pipelines Segment

Well-positioned connecting key natural gas resource plays with major demand centers

Long-term Growth Drivers:

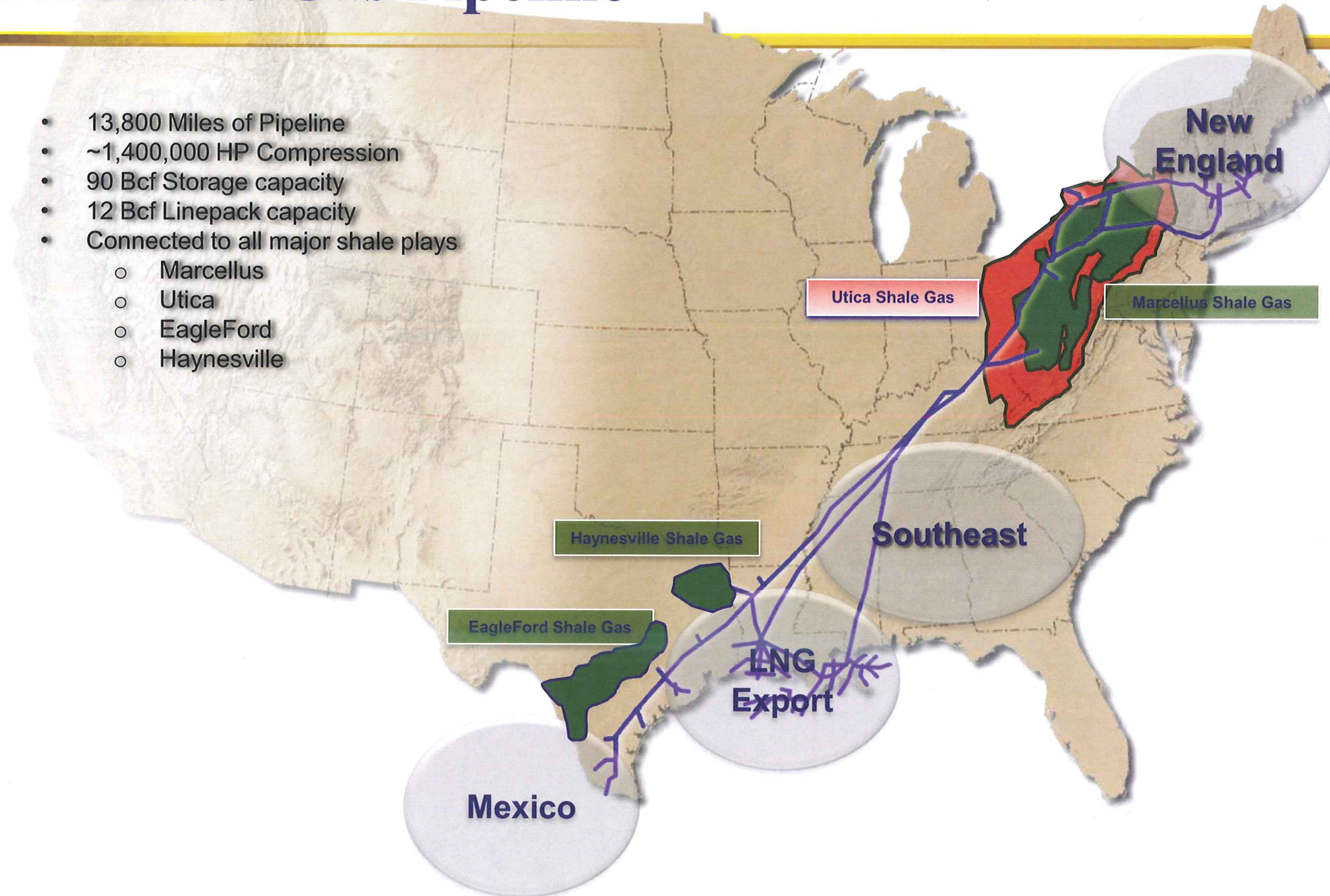
- **Natural gas the logical fuel of choice**
  - — **Cheap, abundant, domestic and clean**
- **With El Paso acquisition, KM has an unparalleled natural gas network**
  - — **Sources natural gas from every important U.S. natural gas resource play**
    - Eagle Ford, Marcellus, Utica, Haynesville, Fayetteville and Barnett
  - — **Connected to every major demand center in the U.S.**
- **Demand growth and shifting supply from multiple basins lead to:**
  - — **Existing pipeline / storage expansions**
  - — **New pipeline development**
- **Expand service offerings to customers**
- **LNG exports**
- **Acquisitions**



Maritime Link CA/SBA IR-345 Attachment 1 Page 4 of 18

Tennessee Gas Pipeline

- 13,800 Miles of Pipeline
- ~1,400,000 HP Compression
- 90 Bcf Storage capacity
- 12 Bcf Linepack capacity
- Connected to all major shale plays
  - Marcellus
  - Utica
  - EagleFord
  - Haynesville



TGP Northeast Market

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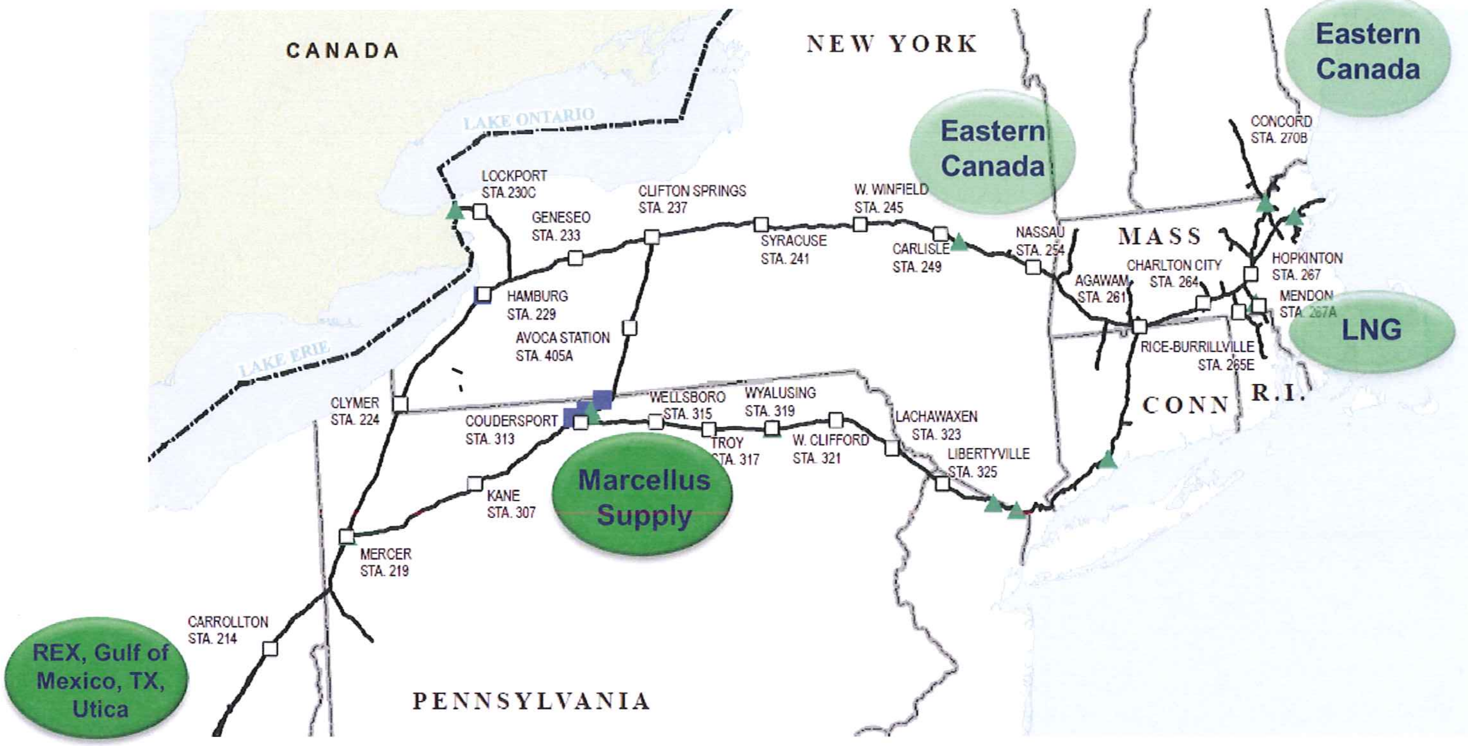

New England LDC Shippers

Connecticut Natural Gas	Colonial Gas
Southern Connecticut Gas	Essex County Gas
Berkshire Gas	Narragansett Electric
Yankee Gas Services	Northern Utilities
Nstar Gas	Fitchburg G&E
Columbia Gas of MA (Bay State)	EnergyNorth Nat Gas
Boston Gas	Blackstone Gas
City of Holyoke	City of Westfield

New York and New Jersey LDC Shippers

National Fuel Distribution
Consolidated Edison
Orange & Rockland
National Grid (BUG, LILCO)
Central Hudson G&E
NYSEG
Rochester G&E
Niagara Mohawk
Corning Nat Gas

Northeast Interconnections

Algonquin	National Fuel
Iroquois	Distrigas/GDF Suez
Maritimes & Northeast	Transcanada
Portland Natural Gas	Columbia Gas
Transco	Dominion

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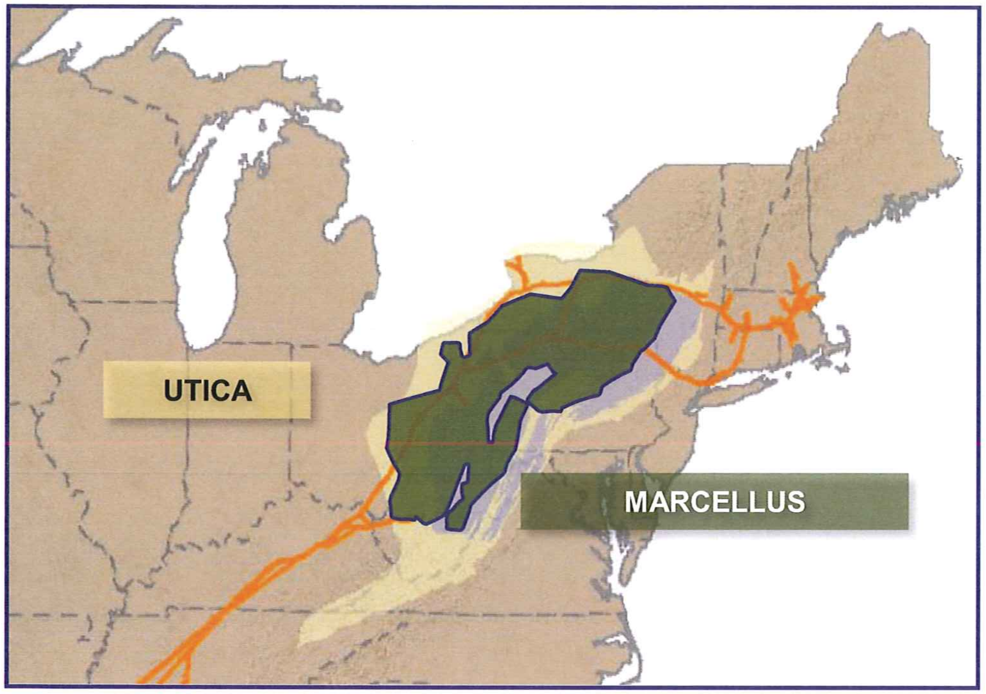
TGP Northeast Supply Position:
Unmatched Access to Market Area Supply

2.4 BCF/day receipt into pipeline

TGP – Superior access to Northeast Shale



Marcellus Shale

- 8.9 Bcf/d – Receipt capacity
- 2.4 Bcf/d – Avg. Daily Receipts (Dec-12.)
- Continued growth

Utica Shale

- TGP well positioned to receive supply
- 0.8 Bcf/d – Receipt capacity into TGP

Marcellus Receipts by Pipeline

Pipeline	Dec 2012 MDth day	% of Total
TGP	**2,464**	**33%**
National Fuel	248	3%
Dominion	462	6%
TETCO	513	7%
Columbia Gas	390	5%
Stagecoach	652	9%
Equitrans	418	6%
Millennium	130	2%
Transco	1,816	24%
Empire	228	3%
Nat Fuel Prod	95	1%
TOTAL	**7,416**	

Source: Bentek

.8 utica gas

Marcellus Suppliers and Shippers

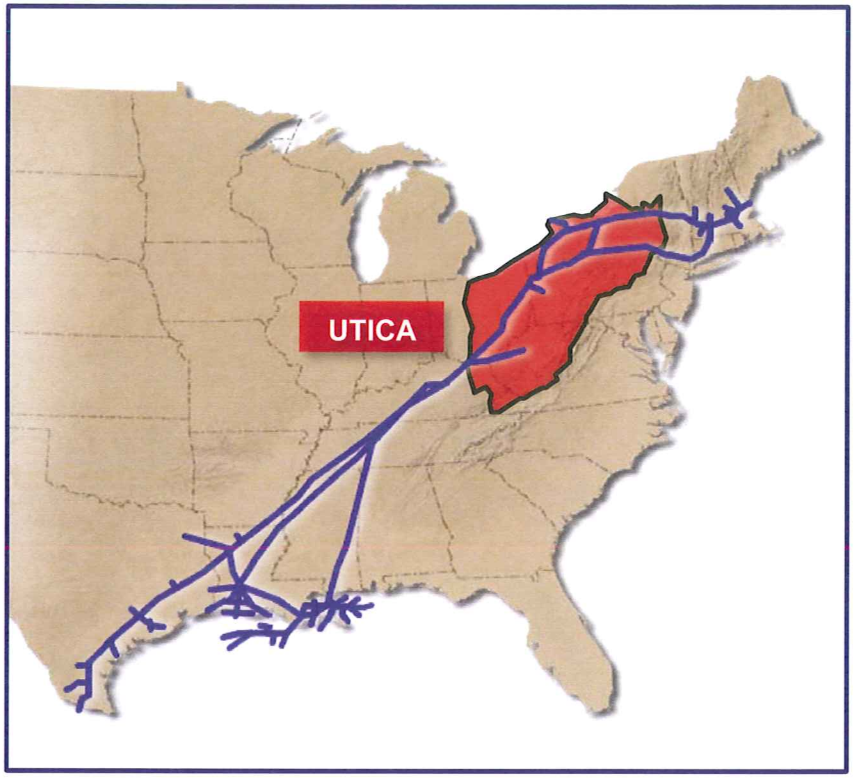
Producers Connected to TGP

- Chesapeake
- Cabot Oil & Gas
- Southwestern Energy
- Talisman Energy
- Statoil Natural Gas
- Anadarko Energy
- Chief Oil & Gas
- Enerplus Resources (USA)
- MMGS Inc (Mitsui)
- Epsilon Energy
- Hess Corporation
- EOG Resources
- EQT Energy
- Tenaska
- Cross Timbers
- SM Energy
- Stone Energy
- Ultra Resources
- SWEPI (Shell)
- Clearwater Enterprises
- Seneca

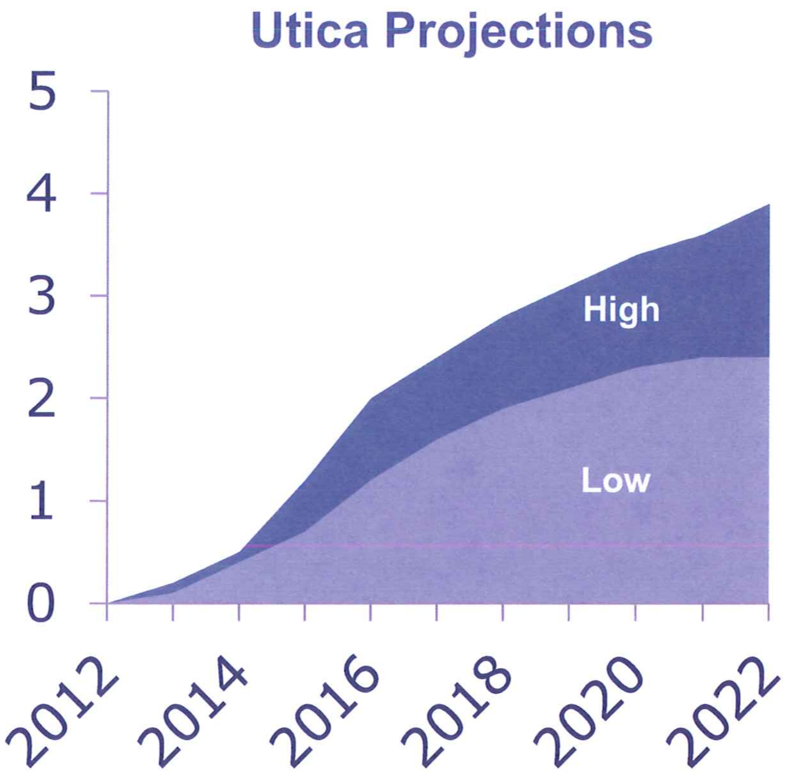
Top Shippers of Marcellus Gas

- Chesapeake
- Talisman Energy
- South Jersey Group
- Hess Corporation
- Virginia Power
- Cabot Oil & Gas
- Sequent Energy
- PSEG Energy
- Statoil Natural Gas
- BG Energy Merchants
- EQT Energy
- Repsol Energy

Tennessee In The Heart of Utica Shale



- TGP Utica development ongoing
- Multiple lines thru supply-rich area
- Direct access to liquid pooling points
- Access to growing markets
- Rich gas solutions underway



Source: Bentek

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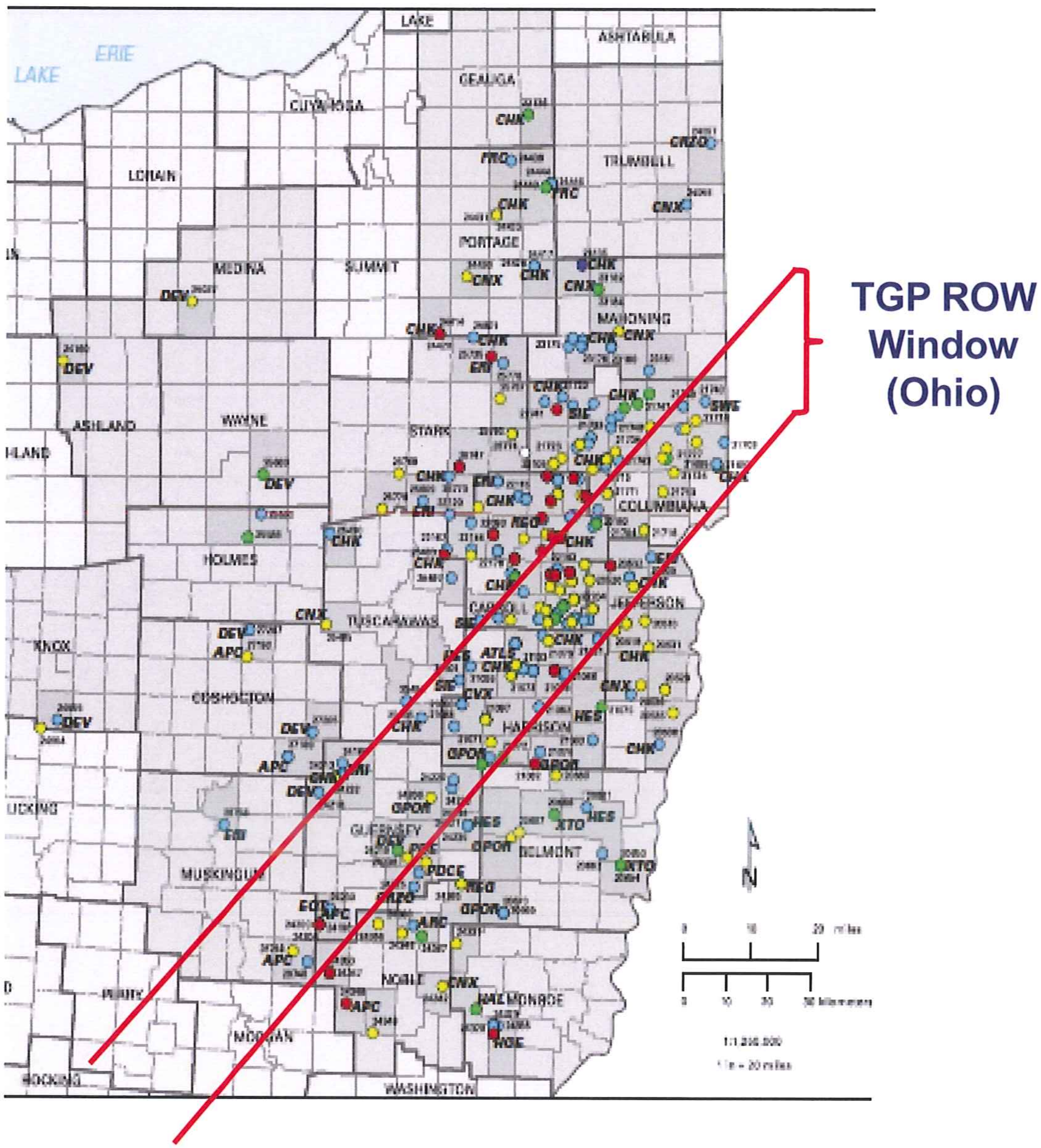
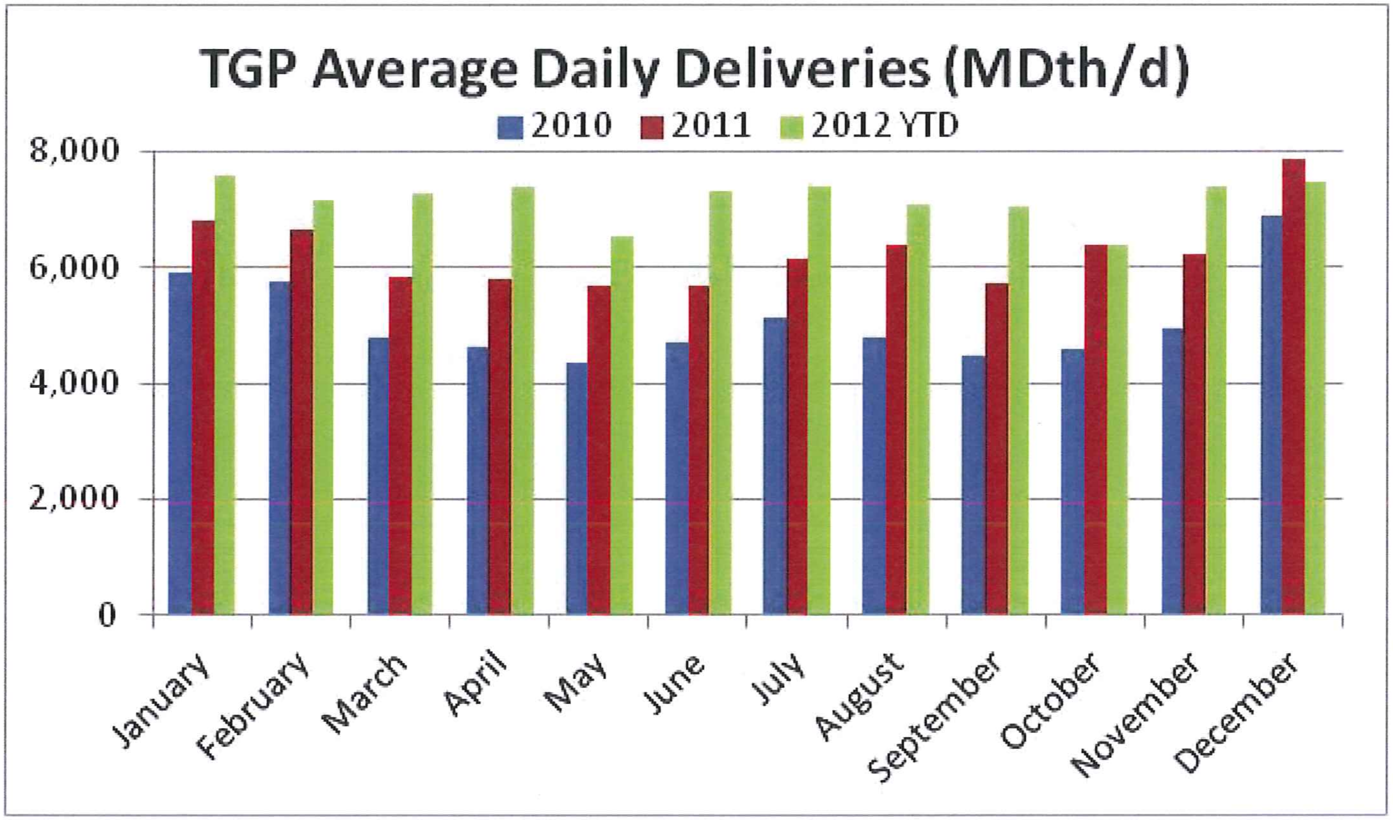
Tennessee Gas Pipeline

Utica Producer Activity



Operator	Net Acres
Chesapeake/ Total	1,300,000
Enervest	700,000
Chevron	623,000
Anadarko	390,000 (g)
Hess	200,000
Range	190,000
Halcon	140,000
Consol	100,000
Xon	90,000
BP	84,000
Rex	72,200
Gulfport	62,500
Antero	56,000
Shell	undisclosed
Hilcorp	private
Sierra	private
TOTAL	4,007,700

Demand Growth:
Increased Throughput on TGP



TGP Throughput

- Increased14.5% over 2011
- Power generation drives load growth

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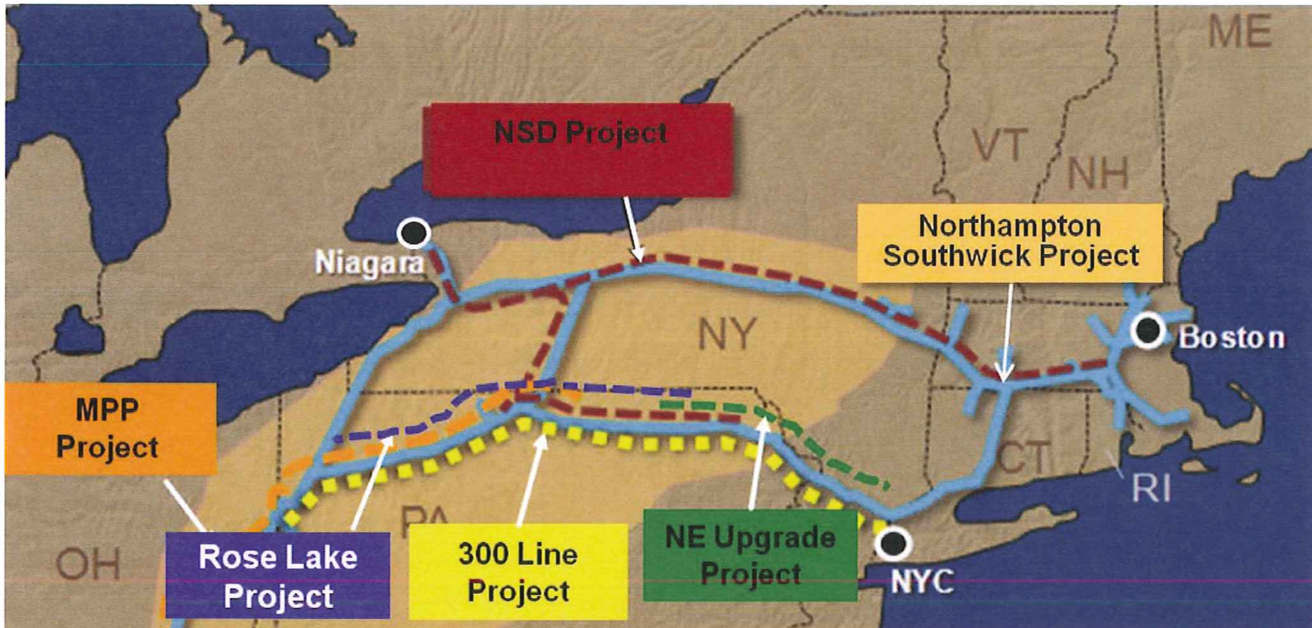
TGP – Recent Northeast Development

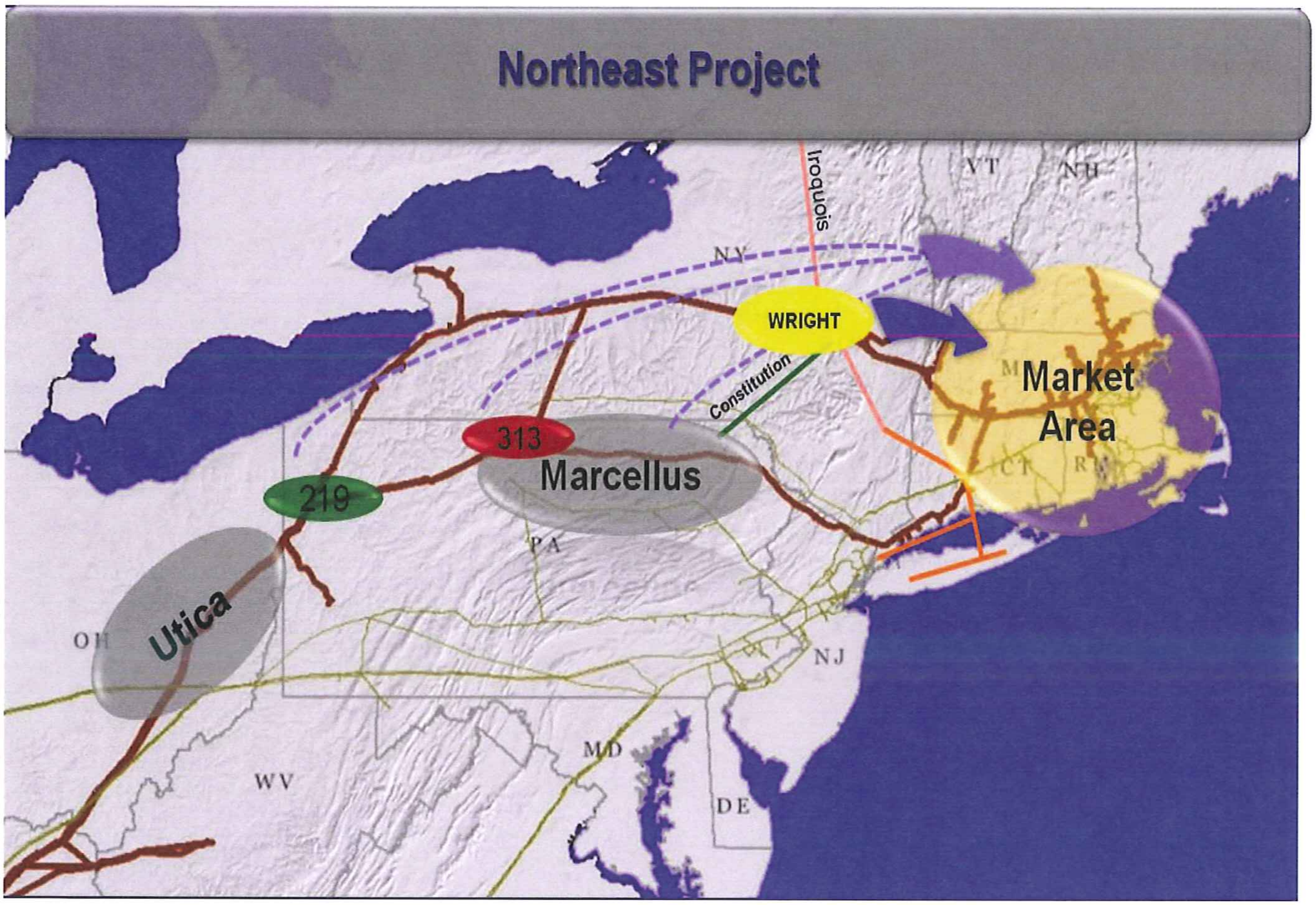


- ~ $1.3Billion Capital
- ~ Fully Subscribed
- In Service, On Time
- Development Continues

Project	Capacity (MDth/d)	Shippers	In-Service	Status
300L Project	350,000	EQT Energy	Nov 1, 2011	In Service
NSD	250,000	Cabot, Seneca, Anadarko, Mitsui	Nov 1, 2012	In Service
Northampton	10,400	Berkshire, Bay State	Nov 1, 2012	In Service
MPP Project	240,000	Chesapeake, Southwestern	Nov 1, 2013	FERC Order received , On Schedule
NE Upgrade	636,000	Chesapeake, Statoil	Nov 1, 2013	FERC Order received , On Schedule
Rose Lake	230,000	South Jersey Res., Statoil	Nov. 1. 2014	FERC Filing pending, On Schedule
Northeast Expansion	Up to 1.2 Bcf	In Active Development	TBD 2017 - 2018	In Active Development

TGP's Northeast Project

- Expansions to date have not penetrated New England market
- Need for additional capacity / new supply into the region



- **Utica and Marcellus - Liquid Supply Points**
  - Wright , NY
    - TGP
    - Constitution 650,000/d 1.1 expanded
    - Iroquois
  - Potential expansion to Pennsylvania and Ohio
- **Northeast Markets**
  - LDC's
  - Power Generation
  - Algonquin at Mendon, MA;
  - M&NE at Dracut, MA

Tenn 25 200line.

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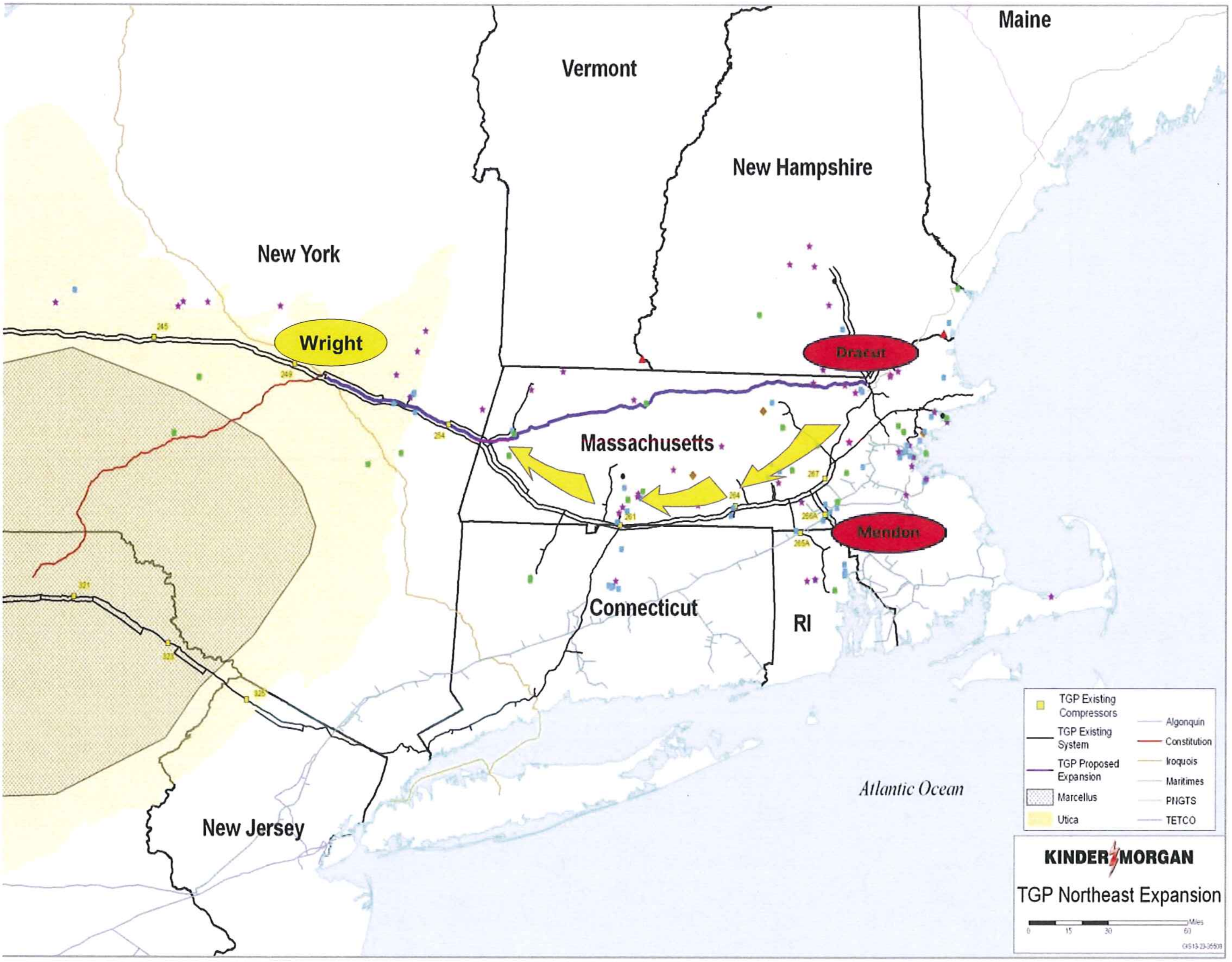
171 mile
50 mill co. located

TGP Northeast Expansion – Bullet Line



700 - 1.2 BCF
30" 36"

- 1.2 Bcf/d pipeline
- High pressure line 1440.
- Expandable to 2.2 BCF compression
- 50 miles of line in TGP's existing corridor
- Wright to Dracut plus backhaul to existing markets
- 3rd pipeline into region
  - Benefit of TGP Markets
  - Enhances existing system
- Diverse market access
  - TGP
  - Algonquin
  - M&NE and PNGTS at Dracut
- Reaches heart of New England
- New infrastructure that allows for development additional gas markets

± 75¢ @ 1.2 BCF
± 85¢ @ 700 MCF

Maritime Link CA/SBA IR-345 Attachment 1 Page 14 of 18

TGP Northeast Expansion

Key Commercial Terms	
Receipt Point	Wright, NY
Delivery Points	(1) Power Plants and LDCs on TGP's 200 line, (2) Mendon, MA (3) Maritimes & Northeast Pipeline
Supply Access	TGP, Constitution, Iroquois Gas Transmission
Volume	700 – 1,200 MDth/day
Term	15-20 years
Rate Structure	Negotiated, Fixed Rate
Indicative Rate	TBD
In-Service Date	November 2017 - 2018

Northeast Expansion Proposed Schedule

- **2013** **Project Development**
  - Q1 Identify anchor shippers / Refine project scope
  - Q2 MOU / Term Sheet for key commercial terms
  - Q3 Precedent Agreement Negotiation
  - Q4 Execute Precedent Agreements
- **Q3 2014** **Submit FERC and state agency applications**
- **Q4 2015** **Receive FERC certificate and all permits**
- **Q4 2017** **In service**

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Discussion

- **Your needs**
  - Volumes
  - Timing/Milestones
- **Next Steps**

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Commercial Contacts

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832-405-3135 (c)

Preston Troutman
Director, Business Development
preston_troutman@kindermorgan.com
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713-206-3290 (c)

Tennessee Gas Pipeline Co., L.L.C
1001 Louisiana Street
Houston, TX 77002

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Request IR-346:

With reference to CA/SBA IR-47 and Application, page 113, lines 7-9 and page 115, lines 1-3:

(a) Please provide the maximum and minimum operating capacity and the ramp rates for both regulation and load following for all other existing plants in Nova Scotia including both thermal and hydro.

(b) Please provide the maximum and minimum operating capacity and the ramp rates for both regulation and load following for each of the future gas-fired units included in the study.

Response IR-346:

(a) Please refer to Attachment 1 for maximum and minimum operating capacities for NS Power's thermal plants. Please refer to CA IR-36 Attachment 1 for ramp rates for NS Power's thermal plants. Please refer to CA IR-36 Attachment 2 for maximum and minimum capacities and ramp rates for NS Power's hydro plants.

(b) Please refer to SBA IR-47 (c) for maximum and minimum operating capacities for each of the future gas-fired units included in the study. The ramp rates were not modeled in Strategist.

Unit	Max. Capacity (MW)	Min. Capacity (MW)	AGC Max. Capacity (MW)	AGC Min. Capacity (MW)
Lingan #1	153	70	130	100
Lingan #2	153	70	130	100
Lingan #3	158	70	130	100
Lingan #4	153	70	130	100
Pt Aconi #1	171	60	n/a	n/a
Pt Tupper #2	152	65	150	70
Trenton #5	150	70	125	70
Trenton #6	157	70	142	122
Tufts Cove #1	81	45	n/a	n/a
Tufts Cove #2	93	30	91	60
Tufts Cove #3	147	40	145	55
Tufts Cove #4 / 5 / 6	150	17	49	25
Burnside #1	33	1	30	15
Burnside #2	33	1	30	15
Burnside #3	33	1	30	15
Burnside #4	33	1	30	15
Tusket #1 CT	25	1	25	15
Victoria Junction #1	33	1	30	15
Victoria Junction #2	33	1	30	15
PH Biomass	52	30	n/a	n/a

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Request IR-347:

With reference to CA/SBA IR-51 and Application, page 115, lines 9-11:

(a) Please provide all calculations, spreadsheets, reports, other work papers Strategist inputs and outputs and any other materials related to evaluation or analysis comparing additional interconnections to other jurisdictions, additional fast acting generation, the development of energy storage, or some combination of the three to support more wind beyond already committed levels for the Indigenous Wind alternative. Identify, in particular, any consideration given to combinations of the three methods.

Response IR-347:

Please refer to the following worksheets and related IR responses for supporting calculations, and working papers:

- Figure 1.1 & 4.1: Capital Investment Curve – Synapse IR-18 Attachments 1 & 2 provided the calculations behind this graph.

- Table 2.1: Inventory of Post-2001 Renewable Generation – Additional detail on historical wind generation was provided in Synapse IR-5; this is a data table only, no working papers.

- Table 2.2: Renewable Energy Needs – Please refer to Attachment 1.

- Table 2.3: Wind Capacity on NSPI System 2020-2040 – CanWEA IR-30 provided an energy version of the data in this table; this is a data table only, no working papers.

- Table 3.1: Planning Reserve Margins on NS Power System w/o ML – EAC IR-28 provided additional detail on wind capacity credits assumed in table; this table shows all calculations.

- Table 3.2: Planning Reserve Margins on NS Power System w/ ML – EAC IR-28 provided additional detail on wind capacity credits assumed in table; this table shows all calculations.

- Figure 3.2: Typical System Load Profile and Wind Generation – Seven Day Period – CA IR-35 Attachment 1 provided the data behind this graph.

- Figure 3.3: Interaction of Wind Generation and System Load – 48 Hour Period – CA IR-35 Attachment 2 provided the data behind this graph.

- Figure 3.4: One-Hour Ramp Rates – CA/SBA IR-225 Attachment 1 provided the data behind this chart.

- Figure 3.5: Multi-Hour Ramp Rates – CA/SBA IR-225 Attachment 1 provided the data behind these charts.

- Figure 3.9: Example of Net Load Falling Below Minimum Unit Commitment Level – CA/SBA IR-227 Attachment 1 provides the data behind this graph.

- Table 3.3: Daily Capacity Swings and Deployable Resources – CA IR-46 provided detail on the calculations behind this table.

- References to experiences in other jurisdiction are cited in the Bibliography of Appendix 6.02.

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Additionally, please refer to CA IRs 25 through 48 and CA/SBA IRs 220 through 229 which provided more detail on specific questions relating to Appendix 6.02.

	No ML	No ML	ML	No ML	ML
Scenario	**Low Load**	**Base Load**	**Base Load**	**Base Load**	**Base Load**
	RES 2020	**RES 2020**	**RES 2020**	**RES 2040**	**RES 2040**
NSPI Wind	253.8	253.8	253.8	253.8	253.8
Post 2011 IPPs	726.9	726.9	726.9	726.9	726.9
PH Biomass	418.0	357.0	357.0	357.0	357.0
Eligible Pre 2001 IPPS	155.5	155.5	155.5	155.5	155.5
Distribution Connected IPP's Committed	55.0	55.0	55.0	55.0	55.0
Eligible NSPI Wind & IPP Renewables (GWh)	**1609**	**1548**	**1548**	**1548**	**1548**

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Request IR-348:

With reference to CA/SBA IR-54 and Application, page 117, lines 5-7:

(a) Why it is not appropriate to evaluate alternatives on the basis of minimizing the NPV of revenue requirements for Nova Scotia customers?

Response IR-348:

The options were in fact evaluated on the basis of minimizing the NPV of revenue requirements for Nova Scotia customers, given the constraints outlined below. The response to CA/SBA IR-54 illustrates the importance of commonality that must exist amongst the alternatives in order for them to be comparable:

(i) Must satisfy the load requirements (including capacity, reserve, etc).
(ii) Must satisfy emissions limits.
(iii) Must satisfy renewable and other legislative requirements.

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Request IR-349:

With reference to CA/SBA IR-55 and Application pages 117-135, and Appendix 6.06, pages 1-3:

(a) Please provide a table or spreadsheet breaking down the differences between study period and planning period NPV costs for each alternative by type (capital and operating) and by resource (*e.g.*, 2035 250 MW CC capital recovery, 2039 425 MW wind repower capital recovery, ML capital recovery, NB Link capital recovery, energy purchases from NB, energy purchases from Nalcor, etc.)

Response IR-349:

Please refer to CA/SBA IR-291.

NON-CONFIDENTIAL

Request IR-350:

With reference to CA/SBA IR-58 and Application, pages 117-135, please have Ventyx run a "sensitivity case" against the base load and market price forecast scenarios for each of the three alternative resource plans in which the RES requirement of 40% of energy from renewable resources in 2020 is relaxed to rise 1% per year from 25% in 2020 to 35% by 2035.

Response IR-350:

Please refer to CA/SBA IR-301.