Barra Strategies Incorporated
Strategic Planning and Risk Management

# THE NUCLEAR GENERATION OPTION

Prepared for Emera Inc.

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# The Nuclear Generation Option

## 1.0 Introduction

The objective of this report is to provide a general overview of the nuclear generation option by providing an overview of the technology, a summary of the experience in Canada with nuclear generation, and generalized or indicative estimates of the costs of constructing and operating nuclear power plants. The information contained in the report is drawn from publicly available sources and while Barra Strategies Incorporated has attempted to verify the quality of the information contained in the report, it may contain inaccuracies.

In 2009, nuclear generation produced 15% of the electricity produced in Canada in 2009 and accounted for over 16.5% of the global production.

| Electricity Production by Fuel Source in TWh (2009) | | |
|---|---|---|
| **Fuel Source** | **Canada** | **World** |
| Coal and Peat | 91.6 | 8,119 |
| Oil | 8.3 | 1,027 |
| Gas | 37.5 | 4,301 |
| Biofuels | 6.5 | 217 |
| Waste | 0.2 | 2,697 |
| Hydro | 364.0 | 3,329 |
| Nuclear | 90.4 | 2,697 |
| Geothermal | 0 | 67 |
| Solar PV | 0.1 | 20 |
| Solar Thermal | 0.0 | 1 |
| Wind | 4.5 | 273 |
| Tide | <0.1 | <1 |
| Other | | 10 |
| TOTAL | 603.2 | 20,132 |

Source: International Energy Agency

## 2.0 Nuclear Generation Technologies

### 2.1 Current Reactors

There are a wide range of nuclear reactor technologies currently in service around the world. In all the designs, the heat produced by the continuous fission of atoms in the fuel is used to produce steam. The steam is used to drive conventional turbine-generators to produce electricity.

A number of elements can be used as nuclear fuel. Almost all current commercial reactors, however, are fueled with Uranium. Uranium in its natural state consists largely of two isotopes, U-235 (0.7%) and

U-238 (~99.3%). The production of energy in nuclear reactors is from the 'fission' or splitting of the U-235 atoms. The U-235 isotope is naturally unstable and spontaneously fissions. As it fissions, it releases fission products including neutrons and heat. If the neutron strikes another U-235 particle, it too will fission and under the right circumstances result in a chain reaction of neutrons striking other U-235 atoms. Chain reactions within the fuel in nuclear reactors are controlled through the use of neutron-absorbing materials (e.g., control rods).

The low concentration of U-235 occurring in nature will not sustain a chain reaction. The uranium fuel has to be, either, enriched through a separation process, or a moderator has to be used to increase the probability a neutron will strike other U-235 atoms in the fuel. Nuclear fuel enrichment typically increases the percentage of U-235 to only 3 to 5%. (This compares to the 90% or greater concentration used in nuclear weapons.)

The vast majority of reactors used to produce electricity are based on one of four main designs

- pressurized water reactors (PWRs),
- boiling water reactors (BWRs),
- pressurized heavy-water reactors (PHWRs), and
- gas-cooled reactors (GCRs).

| Reactor Type | Main Countries Deployed In | Number | GWe | Fuel | Coolant | Moderator |
|---|---|---|---|---|---|---|
| PWRs | US, France, Japan, Russia, China | 271 | 270 | Enriched $UO_2$ | Water | Water |
| BWRs | US, Japan, Sweden | 84 | 81 | Enriched $UO_2$ | Water | Water |
| PWHRs | Canada & India | 48 | 27 | Natural $UO_2$ | Heavy Water | Heavy Water |
| GCRs | United Kingdom | 17[1] | 10 | Natural U (metal), enriched $UO_2$ | $CO_2$ | Graphite |

[1]As of 4/1/12, number of GGRs is 15.

Source: Nuclear Energy Institute/ Nuclear Engineering International Handbook 2011, updated to 1/1/12.

### 2.1.1 Pressurized Water Reactors

In a pressurized water reactor, the fission reaction occurring in the fuel inside the reactor vessel generates heat which is carried by pressurized water in the primary coolant loop to a steam generator. The steam generator acts as a high-pressure heat exchanger transferring the heat from the primary coolant loop into water in a secondary cooling loop. That water is boiled and the resulting steam is dried and directed to a turbine which rotates the electrical generator. The primary coolant water is pumped back from the steam generator into the reactor core to be reheated. The steam exiting the turbine is condensed back to a liquid state in a steam condenser (a low pressure heat exchanger) and pumped back to the steam generator to be re-boiled. The heat removed in the steam condenser is discharged into an adjacent water body or into the air through a cooling tower.

The primary coolant water is circulated using electrically powered pumps. These pumps and other operating systems in the plant are usually powered by electricity generated by the reactor unit or from the connected electricity grid. In the event of a loss of power, electricity is provided by on-site diesel generators.

Control rods are used to limit the reactivity in the core and control the amount of heat being produced. A typical PWR contains 150 to 200 fuel assemblies. Spent fuel is removed from the reactor during planned fuel replacement outages.

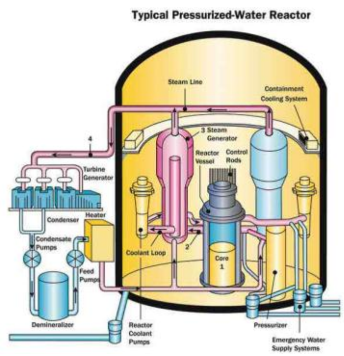



Figure by US Nuclear Regulatory Commission

### 2.1.2 Boiling Water Reactors

In a boiling-water reactor, the fission reaction occurring in the fuel in the reactor vessel's core creates heat which is absorbed in the reactor coolant. The reactor coolant becomes as steam-water mixture as it moves through the core. It exits the core and enters a two-stage moisture separator that removes water droplets from the mixture and dries the steam. The steam is then directed to the turbine which in turn rotates the generator producing electricity. The steam exiting the turbine is condensed back to a liquid state in a steam condenser (a low pressure heat exchanger) and pumped back into the reactor to be re-boiled. The heat removed in the steam condenser is discharged into an adjacent water body, or into the air through a cooling tower.

The reactor coolant water is circulated using electrically powered pumps. These pumps and other operating and safety systems in a BWR plant are usually powered by electricity generated by the reactor unit or from the connected electricity grid. In the event of a loss of power, electricity is provided by on-site diesel generators.

As in a PWR reactor, enriched uranium fuel is used to enable a fission reaction to occur. Control rods are also used to adjust the reactivity in the core and control the amount of heat being produced. A BWR reactor usually has between 370 to 800 fuel assemblies containing enriched uranium fuel. Spent fuel is replaced during planned fuel-replacement outages.

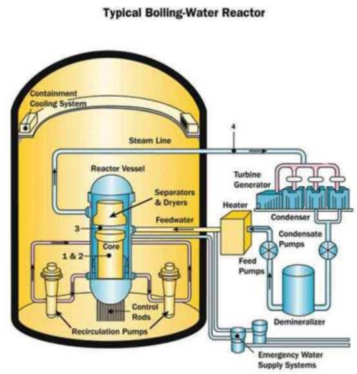



Figure by US Nuclear Regulatory Commission

### 2.1.3 Pressurized Heavy Water Reactors

A Pressurized Heavy Water Reactor is similar in concept to a PWR. The major difference is the deuterium-enriched water (aka heavy water) is used to promote the fission chain reaction by slowing down released neutrons to increase the probability they will be absorbed by other U-235 atoms. This allows PHWRs to use non-enriched fuel.

Heavy water is chemically the same as ordinary water but the hydrogen atoms replaced by deuterium isotopes ($D_2O$ rather than $H_2O$). It is found in ordinary water at a ratio of 1 molecule of D2O for 20 to 40 million molecules of H2O. Heavy water is usually produced in an ammonia based separation and concentration process.

The **CAN**ada **D**euterium **U**ranium (CANDU) is the main pressurized heavy water reactor design. The current CANDU units use heavy water to both moderate the reaction and to transfer heat away from the reactor to the steam generators.

CANDU reactors are designed to allow for spent-fuel to be replaced while the unit continues to operate thereby increasing its overall electricity production capability but avoiding fuel replacement outages. Fuel bundles, containing ceramic fuel pellets, are loaded into horizontal reactor fuel channels by a fueling machine at one reactor end and removed at the other side by another fuelling machine.

CANDU 6 Nuclear Plant

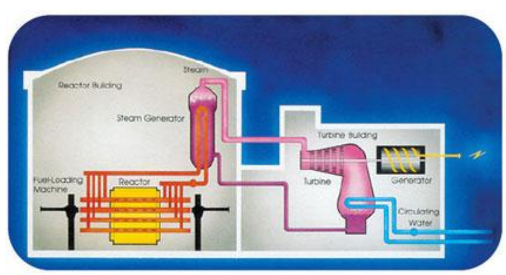



Figure by NB Power

### 2.1.4 Gas Cooled Reactors (GCRs)

A gas-cooled reactor uses graphite as its neutron moderator and carbon dioxide (or some other gas such as helium) as a coolant to take away the heat created during the fission reaction and transfer it to steam generators. Unlike the PWR and PHWR designs, the steam generators are located inside the reactor's pressure vessel. Once the steam passes though the turbines, it is condensed and recirculated back into the boilers for re-boiling. Heat captured during the condensing of the steam is discharged to an adjacent water body, or released into the air through a cooling tower. Control rods are used to control the chain reaction.

The initial commercial GCR design was named the Magnox after the Magnesium Oxide alloy used to manufacture its fuel cladding. Similar to the heavy water in a Pressurized Heavy Water Reactor, the graphite used to moderate the Magnox reactor is sufficient to facilitate a chain reaction while using non-enriched fuel. Also like CANDU reactors, the Magnox reactors were designed to allow for on-line refueling to increase its cost-effectiveness by eliminating the need for refueling outages. A total of 22 Magnox reactors were developed across 10 stations and only 1 unit remains in-service. The others are in the process of being decommissioned.

The Advanced Gas-cooled Reactor (AGR) was developed from the Magnox design. It utilizes a stainless-steel cladding to allow it to operate at higher temperatures and uses a slightly-enriched (2.5 to 3.0% U-uranium fuel (2.5 to 3.5% U-235) to compensate for the neutrons being lost by using stainless-steel fuel-cladding. The AGR reactors were also designed to allow for on-line refueling. However, fuel assembly vibration problems over the years have resulted in the AGRS being only refueled at part load or when shut down.

Fourteen AGR reactors were built in Great Britain across 7 different stations. All remain in-service.

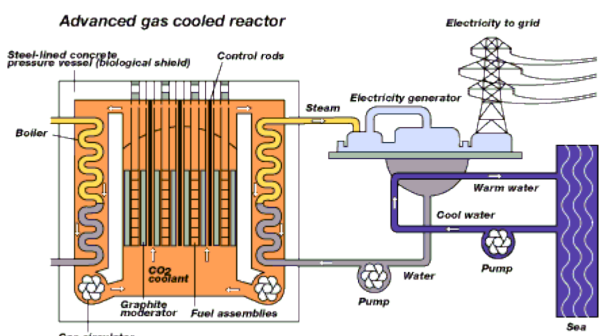



Figure by Scottish Power

## 2.2 Future Nuclear Reactors

Designs of commercial nuclear power plants continue to evolve and improve from both safety and operational perspectives. Reactor suppliers around the world have at least a dozen new designs at the advanced stages of planning.

### 2.2.1 Generation I and II Reactors

Generation I reactors were developed in the 1950-1960s and were essentially prototypes of today's power reactors. With the exception of the one Magnox reactor operating at the Wylfa Nuclear Power Plant in Wales. It is scheduled to close at the end of 2012.

The vast majority of reactors in operation today are commonly referred to as Generation II reactors. They began operating over the 1960 to 1990 period and use traditional active safety features involving electrical or mechanical operations that are initiated automatically, and in many cases, by the nuclear reactor operator. Most of the Gen II plants placed in-service are still in operation. Many have had their expected service lives extended from 40 to 60 years.

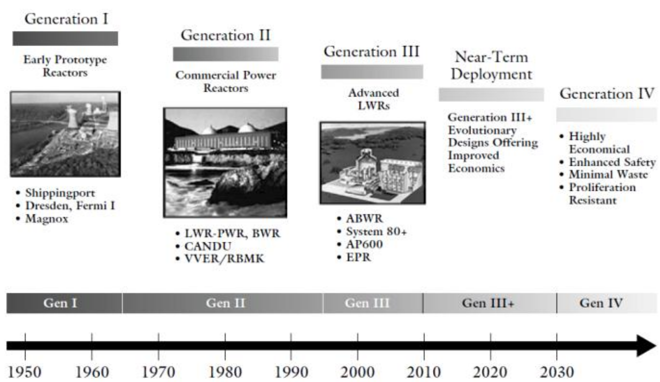



Figure by US Department of Energy, Office of Nuclear Energy, Generation IV Nuclear Energy Systems: Program Overview

### 2.2.1 Generation III and III+ Reactors

Generation III and Generation III+ reactors are essentially Generation II plants with evolutionary, state-of-the art design improvements. Generation III+ reactors offer additional safety improvements over the Generation III plants including more reliance on passive rather than active safety systems.

The Generation III and III+ improvements include:

- a simpler and more rugged design, making them easier to operate and less vulnerable to operational upsets,
- modularized construction,
- higher availability and longer operating lives (60 years),

- much smaller probabilities of accidents that could result in significant fuel damage and core melt downs,
- eliminate the need for active intervention after a plant shutdown for a significant period of time (2 to 3 days),
- resistance to serious damage that would allow radiological release from an aircraft impact,
- higher fuel burn-ups to use fuel more fully and efficiently and reduce the amount of waste, and
- greater use of burnable absorbers ("poisons") to extend fuel life.

Almost all Generation III and III+ reactors will utilize standardized designs in order to reduce design, licencing, equipment and construction costs as well as reduce construction time.

There are currently four Generation III plants in service in Japan since the late 1990s. They are all GE-Hitachi Advanced Boiler Water Reactors [ABWRs]. Other Generation III designs include Atomic Energy of Canada Limited (AECL)'s Enhanced CANDU 6 reactor (EC6), Westinghouse's 600 MW advanced PWR (AP600) and the System 80+ reactor which was originally designed by Combustion Engineering (which is now part of the Westinghouse Electric Company).

The Generation III+ reactors include AECL's Advanced CANDU Reactor (ACR) 1000, Westinghouse's AP 1000 (based on the AP 600), AREVA's European Pressurized Reactor (EPR), GE-Hitachi's Economic Simplified Boiling Water Reactor (based on the ABWR), the European ABWR (based on the ABWR with increased power output and meeting European Union safety standards), Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (APWR), and the ATMEA I PWR designed by MHI and AREVA.

### 2.3 Generation IV Reactors

Generation IV nuclear reactors are under active discussion and debate. The U.S. Department of Energy's Office of Nuclear Energy is leading governments, industry, and the research community worldwide in a wide ranging discussion on the development of Generation IV nuclear reactors. Its goal is to address the fundamental research and development issues necessary to establish the viability of next-generation nuclear energy system concepts to meet tomorrow's needs for clean and reliable electricity, and non-traditional applications of nuclear energy. Successfully addressing the fundamental R&D issues will allow Generation IV concepts to develop that excel in safety, sustainability, cost-effectiveness, and proliferation risk reduction to be considered for future commercial development and deployment by the private sector.

Generation IV reactor concepts are being developed to use advanced fuels, fashioned from recycled reactor fuel and capable of high-burn ups. The corresponding fuel cycle strategies allow for efficient utilization of domestic uranium resources while minimizing waste. Reduction of proliferation risk and improvements in physical protection are being designed into Gen IV concepts to help thwart those who would target nuclear power plants for terrorist acts or use them improperly to develop materials for nuclear weapons. Generation IV concepts will feature advances in safety and reliability to improve public confidence in nuclear energy while providing enhanced investment protection for plant owners. Competitive life-cycle costs and acceptable financial risk are being factored into Gen IV concepts with high-efficiency electricity generation systems, modular construction, and shortened development schedules before plant startup.

### 2.4 Small Nuclear Reactors

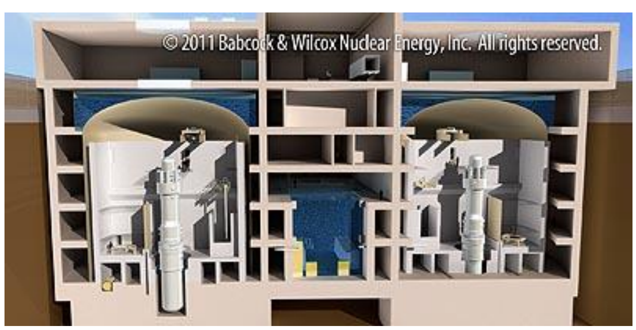
Commercial nuclear power plants have grown in significantly in size since they were first established in order to take advantage of the economies of scale in construction and operating costs. The 60 MWe reactors common in the 1950s have been surpassed by much larger units in the 1100 to 1600 MWe. The larger units can only be absorbed into very large electrical grids in order to ensure the reliability of the electrical systems they serve. Typically, a 1600 MWe unit would require another 1600 to 2400 MWe of fast-starting generation as “operating reserve” to maintain system stability in the event of a sudden reactor outage.

Interest is growing again in the development and deployment of small modular reactors as a result of the increasing capital costs of the large power reactors and as means of meeting the needs of smaller electricity system (< 4000 MW). Over the past 30 years, many hundreds of smaller power reactors have been built both for naval use (up to 190 MW thermal) and as neutron sources, yielding enormous expertise in the engineering of small units.

Generally, modern small reactors for power generation are expected to have greater simplicity of design, economy of mass production, and reduced siting costs. Most are also designed for a high level of passive or inherent safety in the event of malfunction. Smaller reactors could be built independently, or as modules in a larger complex, with capacity added incrementally as needed. The smaller units are also seen as a much more manageable investment than large scale commercial reactors.

In January 2012, the US Department of Energy (DOE) called for applications from industry to support the development of one or two US light-water small modular reactor designs, allocating $452 million over five years. Four applications were made, from Westinghouse (SMR; 225 MWe), Babcock & Wilcox (mPower; 180 MWe), Holtec (SMR -160; 160 MWe), and NuScale Power (NuScale; 45 MWe). The DOE is expected to announce its decision in late 2012.

In March 2012, the DOE also signed agreements with three companies interested in constructing demonstration SMRs at its Savannah River site in South Carolina. The three companies and reactors are: Hyperion with a 25 MWe fast reactor, Holtec with a 140 MWe PWR, and NuScale with 45 MWe PWR. OE is discussing similar arrangements with four further SMR developers, aiming to have in 10-15 years a suite of SMRs providing power for the DOE complex. The DOE is willing to provide land but will not finance the construction.




Conceptual drawing of an underground containment structure housing two B&W mPower reactor modules. Drawing from B&W Nuclear Energy, Inc.

**3.0 Nuclear Power Generation in Canada**

Canada began the development of its own nuclear power program towards the end of the World War II. The National Research Experimental Reactor (NRX) began operation in 1947 at Chalk River, Ontario and in 1952 Atomic Energy of Canada Limited (AECL) was established by the Government of Canada as a Crown Corporation with the mandate to research and develop peaceful uses of nuclear energy. The National Research Universal (NRU) reactor was built at Chalk River in 1957 and is still in operation today. It is currently expected to retire from service towards the end of 2016.

AECL, in cooperation with its Canadian industry partners - General Electric and Ontario Hydro, began developing the first **CAN**ada **D**euterium **U**ranium (CANDU) reactor in the late 1950s. A small (22 MWe) CANDU prototype went into operation in 1962 at Rolphton, Ontario, 30 km upstream from the Chalk River facilities. A larger prototype – 200 MWe – began generating power at Douglas Point, Ontario, in 1967. Douglas Point was shut down in 1984. NPD was shut down in 1987.

The first commercial CANDU reactors began operations in Pickering, Ontario in 1971. Twenty-two commercial reactors were brought into service in Canada from the early 1970s to the early 1990s. Twenty of them were located in Ontario and eighteen of those remain in-service. The remaining two units are in New Brunswick (Point Lepreau) and Quebec (Gentilly 2 in Trois-Rivières).

| Plant | Location | Owner | Operator | First In-Service | Number of Units | Unit Size |
|---|---|---|---|---|---|---|
| Pickering A | Pickering, Ontario | Ontario Power Generation | Ontario Power Generation | 1971 | Eight (6 in operation; 2 in safe shutdown state) | 515 MWe |
| Bruce A | Tiverton, Ontario | Ontario Power Generation | Bruce Power (long-term lease) | 1976 | Four (2 in operation; 2 returning to commercial service from refurbishment) | 750 MWe |
| Point Lepreau | Point Lepreau, New Brunswick | NP Power | NB Power Nuclear | 1982 | One | 635 MWe |
| Gentilly 2 | Trois-Rivières, Quebec | Hydro Quebec | Hydro Quebec | 1982 | One | 638 MWe |
| Pickering B | Pickering, Ontario | Ontario Power Generation | Ontario Power Generation | 1983 | Four | 515 MWe |
| Bruce B | Tiverton, Ontario | Ontario Power Generation | Bruce Power (long-term lease) | 1984 | Four | 822 MWe |
| Darlington | Clarington, Ontario | Ontario Power Generation | Ontario Power Generation | 1990 | Four | |

### 3.1 Ontario

Nuclear generation accounts for over half of the electricity produce in Ontario for the last two decades. Canada's first commercial reactor was put in place by Ontario Hydro in 1971 at the Pickering A Nuclear Power Plant (NPP). The last commercial reactor to be placed in service was Unit 4 at Ontario Hydro's Darlington station in 1993.

### 3.1.1 Pickering A

AECL and Ontario Hydro reached agreement in 1964 to build two 500 MW CANDU reactors at Pickering, just east of Toronto on Lake Ontario. A total for 4 units were constructed at the Pickering A plant and were placed in-service over a 23-month period from July, 1971 to June 1973. When the units first went into operation, they were consistently among the six top performing units in the world.

In 1983, Pickering A's Unit 2 experienced a pressure tube rupture – only 11 years after it had been placed in-service. Expectations at the time were that the Pickering A pressure tubes would last 15 to 20 years. This premature failure led to the retubing of all four Pickering A units much earlier than expected.

Several factors contributed to the pressure tube rupture. First, pressure tubes deform over time due to tube elongation and the spacers, or garter springs, that were supposed to keep the pressure tubes contacting the calandria tubes, had shifted out of position. This allowed the pressure tube to sag and make contact with the outer calandria tube. Second, the zirconium alloy used for the pressure tubes at Pickering 1 and 2 was also more susceptible to hydrogen absorption than expected. The hydrogen, which is produced by the effect of radiation on the heavy water coolant, formed hydrides which migrated to the cooler contact points. This in turn caused the alloy to become more brittle, form blisters and eventually crack or rupture.

Later CANDU reactors used a more hydride-resistant alloy for the pressure tubes and tighter-fitting garter springs with much less tendency to move. These later CANDUs are less susceptible to pressure tube deterioration, however, tube elongation and hydrogen absorption leading to hydride embrittlement remains a concern for all CANDU reactors – particularly as the pressure tubes reach their design life.

All four Pickering A units had their pressure tubes replaced between August 1993 and March 1993 at a total cost of close to $1 billion. The first unit's retubing took over 4 years and the last unit took 19 months. The retubed units performed well when they returned to service. Their performance began to degrade in the 1990s as maintenance backlogs began to increase. Also, following the loss-of-coolant accident on Unit 2 at the Three Mile Island Nuclear Plant in the Unites States, the Atomic Energy Board of Canada (AECB) [today the Canadian Nuclear Safety Commission] required Ontario Hydro to install secondary shut down systems on the Pickering A reactors by December 31, 1997. All four units were voluntarily removed from service and temporarily laid up by Ontario Hydro prior to that date in order to use Pickering A resources to reduce maintenance backlogs at Pickering B and Darlington as part of its Nuclear Asset Optimization Plan. Installation of the secondary shut down systems would occur prior to the units being returned to service.

When the Pickering units were laid up, Ontario Hydro expected it would start returning the units to service in late 1999 at six to eight-month intervals. The Atomic Energy Control Board (now the Canadian Nuclear Safety Commission), however, later determined returning the unit to service triggered an Environmental Assessment under the Canadian Environmental Assessment Act. This resulted in a significant delay to the physical work being done in support of restarting the units.

The August 1997 estimate to return all four units to service was in the order of $780 million and with the first unit was expected to be in-service by mid-2001 and all four units in-service by December 2002. The estimate was revised in May 1999 to $840 million to reflect increases in labour costs. By August 1999, the project cost was re-estimated to be $1.2 billion, with the costs for returning Unit 4 and the plant's common systems to service estimated at $457 million. The cost of returning each of the three other units was estimated just above $200 million. When Unit 4 was finally returned to service at the end of September 2003, the cost totaled $1.25 billion and its return to service more than two years later than the August 1999 schedule. By the time the second unit, Unit 1, was returned to commercial service in November 2005, actual project costs had increased by a further $1 billion.

In August 2005, OPG announced it has decided not to proceed with the restart of Units 2 &3 due to results of recent equipment inspections which called into question the remaining operational lives of those units. Those units were subsequently defueled and dewatered and placed in a safe shutdown state. Decommissioning of the shutdown units will take place once Units 1 & 4 have ceased operation – possibly around 2020 when Pickering B's units are potentially removed from service.

The post-restart performance of the Pickering A units has not been as good as envisioned when the restart decision was taken. OPG continues in its efforts to improve the reliability of the Pickering A units by decreasing maintenance backlogs and making modest investments in unit condition.

### 3.1.2 Bruce A

Construction of the Bruce A reactors began in 1969 before the first unit at Pickering A was placed into service. The Bruce A reactors were sized to produce sufficient steam to each generate 740 to 745 MWe of electricity and to provide process steam to the Bruce Heavy Water Plants.

The Bruce A reactors came into service over three year period starting in 1976. The reactors exhibited excellent performance when they first came into service achieving annual capacity factors in mid-80% range. Bruce A was the world's most reliable station in 1984.

In 1982, Unit 2 was shut down temporarily to repair a pressure tube leak and in 1998, a pressure tube failed while the reactor was shut down. Preparation to retube the reactors began in 1992 but was cancelled by Ontario Hydro because of an excess of generating capacity following the economic recession in the late 1980s and the coming into service of the Darlington Nuclear Generating Station over the 1990 to 1993 period. In 1986, maintenance workers accidentally left a protective lead blanket in a steam generator on Unit 2. It was not discovered until 1994 and by that time the blanket had melted and severely damaged the boiler. Unit 2 was subsequently removed from service in October 1995.

Ontario Hydro's 1997 Nuclear Asset Optimization Plan resulted in the lay-up of the remaining three Bruce A units in January 2008 to allow resources on Bruce A to be utilized elsewhere in Ontario Hydro's nuclear organization. Unlike the lay-up of the Pickering A units, the Bruce A units were laid up in a defueled and dewatered start. The timing of the future restart of the units was not specified and would be predicated on future system requirements and the economics of refurbishing the units prior to their return to service.

In 1998, the Government of Ontario began the implementation of a policy framework to establish a competitive electricity market in Ontario. Ontario Hydro was broken into five successor companies. All of its generation assets were transferred to the new Ontario Power Generation (OPG). OPG's initial Generator's Licence required it to substantially reduce its dominant position in the Ontario marketplace over a ten year period. In May 2002, Ontario Power Generation entered into a long-term lease arrangement of both the Bruce A and Bruce B nuclear plants with British Energy (operating as Bruce Power) as part of its decontrol initiatives to meet its decontrol requirements.

Bruce Power subsequently returned Units 3 &4 to service in late 2003 and early 2004. In late 2005, Bruce Power and the Ontario Power Authority entered into an agreement to support the refurbishment of Units 1 & 2. The refurbishment scope included the removal and replacement of steam generators, pressure tubes, and feeders. The original agreement called for Units 1 & 2 to be returned to service at a reported cost of $2.75 billion by mid-to-late 2009 and early 2010. The units returned to service in September and October 2012 at a cost of close to $4.8 billion.

The Bruce A units are now expected to remain operational until the mid-2030s. Planning for the refurbishment of Units 3 & 4 is said to be underway. A recent investment in Unit 3 is expected to result in an additional 10 years of service life for that unit before refurbishment is required.

### 3.1.3 Pickering B

The four units at Pickering B were placed in service over the May 1983 to January 1986 period. Each reactor is capable of producing 515 MWe (net). Pickering B and Pickering A share a common Vacuum Building as well as other common systems such as the Water Treatment Plant.

The Pickering B units operate extremely well during the 1980s and early 1990s. Performance began to deteriorate as maintenance backlogs decreased. Following the limited success in achieving the results expected by the Nuclear Asset Optimization Plan, OPG embarked on an “85/5” program in 2005 to restore the performance of the plant over a three-year period. It goal was to achieve an 85% capacity factor with a 5% Forced Loss Rate by 2007. The program was successful and the plant continues to perform well today.

In June 2006, OPG was directed by the Ontario Minister of Energy to assess the feasibility of refurbishing the Pickering B and Darlington nuclear stations, including conducting the Environmental Assessment of Pickering B’s refurbishment and continued operation. In early 2009, the CNSC accepted OPG’s Environmental Assessment, citing the refurbishment and continued operation of Pickering B is not likely to cause significant adverse environmental impacts given available mitigation. OPG also completed an in-depth Integrated Safety Review for the plant, assessing the condition of all the station’s components and systems and comparing the plant’s design against codes and standards.

In February 2010, OPG announced it would not refurbishing Pickering B but would invest approximately $300 million to continue to operate the plant for a further 10 years. The plant is now expected to operate until 2020.

### 3.1.4 Bruce B

Construction of the four units at Bruce B began in 1976. They were placed in service over the September 1984 to May 1987 period. Each unit is rated to produce 884 MWe but is limited to 822 MWe. The Bruce B units are of a similar design to Bruce A but has different steam generator and generator designs. The units have performed well during the 1980s but performance began to wane and then improved again in the 1990s - achieving life-time in-service capacity factor in the high 70 percent range. The initial release estimate for the construction of Bruce B was to $3.9 billion. The total cost by the time all the units were in-service was $5.9 billion (dollars of the year).

The Bruce B units are expected to be removed from service towards the mid to latter part of this decade. Work is currently underway to confirm the units are capable of operating for a further period of time prior to refurbishment is initiated.

**3.15 Darlington**

Construction began on the Darlington nuclear plant in 1981 just prior to the accident at Three Mile Island in the Unites States. The units came into service over the 1990 to 1993 period and are capable of producing 880 MWe.

Its initial release estimate was $3.9 billion and costs by the time all the units were in-service totaled $14.4 billion. There construction of the units was delayed as the Provincial Government reviewed the merits of continued construction of the units against declining load growth rates and Ontario Hydro's mounting debt. The Three Mile Island and Chernobyl nuclear accidents also necessitated additional safety reviews of the plant's design after construction has started. There was also a number of design issues, such as software modifications, that needed to be addressed before the units were first brought into service. Given interest rates in Canada at the time were in the range of 15 to 16%, any delay resulted in substantial increases to the plant's interest during construction costs. Several articles have suggested additional interest charges due to the delays accounted for between 50 to 70% of the increase in project costs.

The Darlington units did not perform well when they were initially placed into service. Cracks were discovered in the generator rotors which necessitated them having to be replaced by a different design. The first two units brought into service had extended outages because of unexplained fuel bundle damage in the reactor core. The fuel damage was traced to the vibrations inside the fuel channels caused by a mismatch between the primary heat transport pump design and the size and shape of the Darlington fuel channels. The design of the heat transport pumps had to be changed to prevent the fuel channel resonance.

After their initial few years of operation, the Darlington units performed well and now rank among the best CANDU plants in the world achieving life-time in service capability factors in the mid-to-high eighties range.

In 2006, the Minister of Energy directed OPG to assess the feasabilty of refurbishing the Pickering B and Darlington nulear plants. In February 2010, OPG announced it would proceed with the detailed planning required to refurbish the Dalington. It has completed the Integrated Safety Review, which assesses the condition of the plant's components and systems and compares the plant's design against current codes and standards to the CNSC. The draft Environmental Assessesment Screening Report for the plant's refurbishment and continued operation has been submitted and is in the public comment stage. The CNSC has announced it will be holding a Public Hearing on the Environmental Assessment in mid-November 2012. The CNSC's decision on the EA is expected in late 2012 or early 2013.

The Minstry of Energy has placed the expected cost of refurbishment at between $6 to $10 billion dollars. OPG will not provide a public estimate until it completes the detailed planning required to properly estimate project costs. This is expected to occur in 2015. Refurbishment of the first unit is expected to begin in the fall of 2016 and the last unit is expected to return to service in the early 2020s.

**3.2 New Brunswick**

The Point Lepreau Nuclear Plant is a one unit 635 MWe CANDU 6 plant.

It was originally envisioned as a two-unit plant sharing common infrastructure and systems. NB Power elected to proceed with the construction of only one unit while preserving the option for a second unit at a later date.

The original plan called for building two units over the 1975 to 1982 and was estimated at $854 million. The cost of building one with one unit plus common facilities was estimated at $466 million. The unit the unit came into service in 1983 at a cost of close to $1.5 billion.

The Point Lepreau Nuclear Generating Station achieved record levels of availability with a 10-year average of 93.11% for the first decade of its operations. However, numerous problems started to surface in the mid to late 1990s and performance eroded.

Point Lepreau recently returned to service following a lengthy refurbishment outage. The outage began in late March 2008 and was originally scheduled to last 18 months with the unit being returned to service in September 2009. The refurbishment outage was plagued with difficulties. The unit received permission from the CNSC to proceed to full power operation in early November 2012. The estimated refurbishment cost in 2004 was $930 million. Recent press reports suggest the final refurbishment costs will be in the range of $2.4 billion.

### 3.3 Quebec

Hydro Quebec's Gentilly II nuclear plant is a one unit CANDU 6 plant capable of producing 638 MWe of power. Construction of the unit began in 1974. The unit went into commercial service in service in October 1983.

Gentilly II's performance has been very good since the unit was placed in operation. Its lifetime in-service capacity factor is in the range of 80%.

Hydro Quebec began the assessment and planning for the refurbishment of Gentilly II in the mid-2000s. In 2008, it announced that it was proceeding with the refurbishment at a cost of $1.8 billion. Engineering and procurement work would begin in 2008 and construction activities would start in 2011. It announced in August 2010, that construction would not start until 2012.

In early October 2012, Hydro Quebec announced it would not be proceeding with the refurbishment of the plant. After several factors delayed the refurbishment project and market conditions changed since 2008, the company said it has concluded that the refurbishment project, now expected to cost C$4.3 billion, was no longer justified from a financial standpoint. The unit will cease operation at the end of 2012. The unit will then be defueled and dewatered over an 18 month period. It will then remain in a safe shutdown state until it is fully decommissioned.

### 3.4 New Generation in Canada

There has been considerable discussion over the past decade about building new nuclear plants in Ontario, New Brunswick, Alberta and Saskatchewan. No new units, however, have yet been committed and it remains unclear if any will be built in the near future.

#### 3.4.1 Ontario Power Generation

In June 2006, the Ontario Minister of Energy directed Ontario Power Generation to begin the federal approvals process for the construction of new nuclear units at OPG's Darlington site. OPG subsequently filed an Application for a Licence to Prepare a Site for the new units in August 2006 to initiate the Environmental Assessment (EA) required by the Canadian Environmental Assessment Act. The CNSC decided in 2007 that the a comprehensive Environmental Assessment was required and that it should be reviewed by a Joint Panel, consisting of individuals cross-appointed by the CNSC and the Canadian Environmental Assessment Agency, in order to streamline the regulatory approvals process. The Joint Review Panel accepted OPG's conclusion that the construction of new nuclear reactors would not have significant impact, given the available mitigation, in May 2012. The CNSC issued a site preparation licence to OPG in August 2012.

No decision has yet been made with respect to the design and timing of new units at Darlington. Infrastructure Ontario commenced procurement process for the units in 2008. News media reports suggest only one compliant bid was received from the four reactor vendors invited to participate in the procurement process and that bid was far in excess of it the expected costs. The Infrastructure Ontario procurement process was postponed in 2009. The reasons given for the postponement included the uncertainty with respect to the future of AECL. The Government of Canada announced in May 2009 that it was moving forward with the restructuring of AECL and was seeking expressions of interest in the reactor design, reactor servicing and new project portion of AECL. The organization was subsequently sold to SNC-Lavalin in June 2011 and renamed CANDU Energy.

In June 2012, OPG announced that it had signed agreements with two companies, Westinghouse and SNC-Lavalin/CANDU Energy Inc., to prepare detailed construction plans, schedules and cost estimates for two potential nuclear reactors at the Darlington site.

#### 3.4.2 Bruce Power

In August 2006, Bruce Power initiated the federal approvals process for up to 4 new nuclear units, capable of producing up to 4,000 MW, on the facilities it leases from OPG in Tiverton, Ontario. In November 2008, it initiated the approval process for up to 2 new nuclear units, capable of producing between 2,200 to 3,200 MW, on a site on Lake Erie close to the town of Port Jarvis and OPG's Nanticoke thermal generating station.

Bruce Power withdrew its applications in July 2009.

#### 3.4.3 New Brunswick

In 2007, the Government of New Brunswick commissioned two reports related to constructing a new nuclear plant in New Brunswick as part of a broader economic development strategy to establish the province as a "world class" energy hub. In one report, MZ Consulting concluded that it would be feasible to construct a first-of-a-kind ACR 1000 under certain conditions that would minimize the risk to the Province. Team CANDU (a consortium consisting of AECL, GE Canada, Hitachi Canada, Babcock &

Wilcox Canada and SNC-Lavalin Nuclear) was selected to prepare the second report - a feasibility study on constructing Canada's first ACR-1000 for the Government of New Brunswick. The Team CANDU report was accepted for review in 2008. [Team CANDU was established in 2006 to offer fixed price plants on a turnkey basis.]

AREVA signed a Letter of Intent in 2010 with the Government of New Brunswick to explore the feasibility of it financing and building a merchant plant using its AMTMEA (1100 MWe PWR) or KERENA a (formerly the SWR-1000, a 1250 MWe BWR) reactor technologies. NB Power would operate the facility while the plant would be privately-owned and financed. About half of the output would be likely to go to the northeastern USA through the NB Power's 1300 MW of interconnections. The proposal subsequently lapsed.

### 3.4.3 Alberta

In March 2008, Bruce Power applied to the CNSC for Licence to Prepare a Site to construct a new nuclear plant that would generate up to 4000 MW of electricity from two to four reactors in Cardinal Lake near Peace River in Alberta.

Bruce Power announced it was withdrawing its application in December 2011.

### 3.4.4 Saskatchewan

Bruce Power and SaskPower completed a joint feasibility study in November 2008 that concluded that nuclear power could contribute at least 1,000 MW to Saskatchewan's generation mix by 2020. The study identified the 'Prince Albert economic sub-region' as the most viable host for a nuclear facility. The study also noted that growth in electricity demand in northeastern Alberta could provide a possible export market for Saskatchewan.

In March 2009, the Government of Saskatchewan received the Uranium Development Partnership from a panel it appointed to review opportunities in the "uranium value chain" with a view to gaining greater benefit from its established uranium mining industry. The report concluded that up to 3,000 MW of nuclear power generation would be appropriate for the Province and recommended the move forward in this area. It also recommended the Province work with Alberta to consider a common power generation solution for the two provinces by pooling their power needs.

Following public consultations on the report, the Government concluded it would not support Bruce Power's proposal or any immediate addition of 1000 MWs as proposed from a single nuclear reactor. SaskPower would, however, continue to keep the nuclear generation option for the long term.

### 3.4.5 Small Modular Reactors in Canada

There is growing interest in Canada in the development and deployment of Small Modular Reactors because of their smaller size and the belief that they can be deployed more quickly because of factory fabrication and modular construction techniques. There have been no applications submitted to the CNSC to develop a Small Modular Reactor.

B&W has entered into a Pre-Licencing Reactor Vendor Design agreement with the CNSC. The Phase w review was initiated with an original completion date of late 2013. The review is currently on hold.

Licencing of Small Modular Reactors will follow the same licencing pathway as larger Power Reactors (See Appendix A). For example, a Licence to Prepare a Site will be required for each proposed development and a site specific EA will be required before that licence can be issued. Detailed design review will only be done during the Construction Licencing Phase. An SMR will very likely be required to comply with all the requirements related to safety, security, plant maintenance and plant operation, etc. that now apply to a Class I nuclear facility.

It is difficult to predict with any confidence the timeline and costs of deploying a Small Modular Reactor in Canada until the CNSC receives and dispositions the associated Licence application and a plant is actually constructed. Construction of demonstration SMRs is currently under discussion in a number of jurisdictions.

## 4.0 Costs of New Nuclear Generation

Life cycle costs for generating units are usually assessed in terms of a Levelized Energy Unit Energy Cost (LUEC) which attempts to calculate the present worth of all future expenditures associated with the amount of energy to be produced. There are a variety of methodologies used to calculate levelized costs. It is extremely important to ensure a consistent methodology, with identical economic assumptions, is used when assessing one generation option against another.

The critical assumptions in developing a LUEC include:

- the expected costs of initially constructing the facility (including interest costs during construction which can be heavily influenced by schedule assumptions)
- the costs of operating and maintaining the facility (staff, fuel, materials, taxes, etc.),
- the costs and timing of major future investments (refurbishment, large component replacements, etc.)
- the cost of decommissioning the facility and managing/disposing of wastes,
- the forecast escalation rates for labour, fuel, materials, etc., and
- the discount rate used to bring future cash flows to the present.

Discount rate selection is extremely important. In many jurisdictions, a societal, rather than a commercial/business, discount rate is used for nuclear plant investments because they are considered to be generally beneficial to society at large. It makes a significant difference to project LUECs. For example, a 2010 report published by the Organization for Economic Co-operation and Development (OECD) suggests the LUEC for a new nuclear plant in Europe ranges from 5.0-8.2 US cents/kWh using a 5% discount rate and from 8.3-13.7 US cents/kWh using a 10% discount rate. SNC-Lavalin Nuclear recently quoted a LUEC for a 2 Enhanced CANDU 6 realtors for OPG's Darlington site at between 6 to 9 CAD cents/kWh using a 5% discount, and including mid-life refurbishment and decommissioning costs.

### 4.1 Construction Costs

Experience in all industries demonstrates constructing any major capital project can be very drastically from initial estimates- particularly first of a kind projects. Estimates prepared on the basis of conceptual designs and preliminary engineering can be significantly under- or over-estimated. Comparing the costs of new projects with completed projects of a similar nature is useful in assessing the reasonableness of estimates, but need to be done with an appreciation for differing circumstances and apportionment of risks.

- The US Department of Energy in the early 2000s was suggesting overnight nuclear construction costs (no interest or escalation included) for new nuclear plants in the range of $1,200 to $1,500 per kW installed for new nuclear plants. This would put the overnight construction cost for a 1000 MW plant at $1.2 to $1.5 billion.
- A 2003 study the Massachusetts Institute of Technology suggested the costs of new nuclear was in the range of $2,000 per kW, not including interest.
- In 2007, Florida Power & Light announced overnight costs for two proposed 1100 MW units as being between $3,100 and $4,500 per kW. It also estimated the total cost of the project, including escalation and interest, as being between $5,500 and $8,000 per KW – which translates into a total project costs of between $12 and $18 billion dollars for two 1100 MW plants.

- In March 2008, Progress Energy projected two new nuclear units would cost $10.5 billion without financing. If financing were included the total costs would be in the order of $13-$14 billion.
- In 2008, Georgia Power estimated the costs of its 45% portion of two new reactors at the Vogtle site at $6.4 billion giving a total cost for two units of roughly 14 M$.
- SNC-Lavalin estimates the overnight cost for constructing 2 Enhanced CANDU 6 reators at OPG's Darlington site is between $5,000 to $7,000 CAD per MW.

Construction cost estimates can change dramatically over time as designs become more definitive and more engineering is complete. Project estimating practices continue to improve and most today include standard allowances for the amount of completed engineering and the quality of the project schedule. For example, Georgia Power reported in early 2012 that its share of the projected costs for Vogtle 3&4 was remained at $6.4 billion dollars even though the in-service dates for both units had slipped by almost 18 months.

Risk apportionment will also influence project costs significantly. If the project constructor is forced to take all the construction schedule risk, the constructor will build in a supra-normal contingency into the price – particularly if delays could result from regulatory or political interventions and other events outside the contractor's control.

### 4.2 Operating Costs

Operating costs for nuclear facilities can vary significantly depending on the design of the plant, its number of units, its installed capacity, the age of the plant, its physical condition and fuel supply/disposal costs. Operating costs are typically composed of reoccurring expenses such as staff salaries (70 to 80%) materials, purchased services, fuel, taxes, etc.

Operating costs for nuclear plants range widely. Quoted costs range from 2 to 7 cents or more per KWh of production.

- The Nuclear Energy Institute reports that production costs for nuclear plants in the Unites States in 2011 averaged 2.2 US cents/kWh including fuel. Production costs typically do not include indirect costs. Assuming indirect costs are 35% of production costs, operating costs would have been in the order of 3.0 US cents/kWh.
- Evidence provide by Ontario Power Generation to the Ontario Energy Board in 2010 suggests the operating costs for its nuclear plants are in the range of 6.5 to 7.0 CAD cents/kWh for its Pickering plants and 3.7 CAD cents/kWh at Darlington.

### 4.3 Decommissioning Costs

Decommissioning costs estimates vary widely as a result of the various assumptions used in developing them. Some of the critical variables include:

- the size of the site (number of reactors, etc.) to be decommissioned
- the duration and timing of major decommissioning activities,
- the extent of radioactivity and/or contamination on the site,
- the planned use of the site the plants post decommissioning (industrial brownfield, site for future generation, park land, etc., and

- whether there will be on-site or off-site storage/disposal of conventional and nuclear waste materials.

The Nuclear Energy Institute in the United States suggests decommissioning costs will be in the range of $500 million dollars per reactor - but will vary greatly depending on the plant size and design. The US Nuclear Regulatory Commission, the Nuclear Energy Agency, and EDF (France's nuclear operator) have suggested decommissioning costs are likely to be between 10 to 15% of a reactor's original cost.

- Exelon's current estimate for decommissioning its Zion nuclear site near Chicago, Illinois is close to $1 billion.
- New Brunswick Power's 2011 Annual Report identifies its current liability for nuclear decommissioning of its Point Lepreau facility at $907 million on an undiscounted basis.

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APPENDIX A

Nuclear Power Plant Licencing in Canada

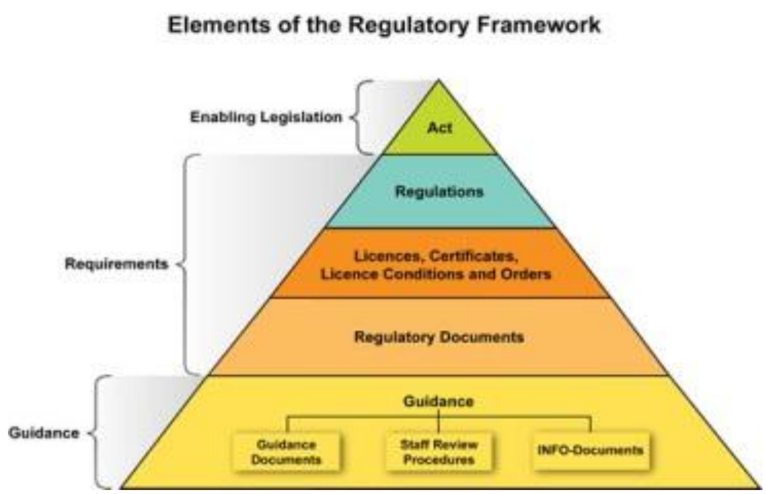
The Nuclear Safety and Control Act authorizes the Canadian Nuclear Safety Commission (CNSC) to regulate the development, production and use of nuclear energy and the production, possession and use of nuclear substances in order to

- prevent unreasonable risk, to the environment and to the health and safety of persons,
- prevent unreasonable risk to national security, and
- achieve conformity with measures of control and international obligation to which Canada has agreed.

The CNSC also administer the Nuclear Liability Act and conducts the environmental assessments related to nuclear activities required by the Canadian Environmental Assessment Act.

CNSC's Regulatory Framework

The CNSC has implemented a Regulatory Framework to ensure clear direction to industry, stakeholder and CNSC staff. It consists of laws passed by Parliament that govern the regulation of Canada's nuclear industry, and regulations, licences and documents that the CNSC uses to regulate the industry.




Source: Canadian Nuclear Safety Commission

The CNSC's regulatory framework elements fall into two categories: **Requirements** and **Guidance**.

**Requirements** are mandatory. Licensees or applicants must meet these requirements to obtain or retain a licence or certificate to use nuclear materials or operate a nuclear facility. Regulatory instruments under **Requirements** include:

- NSCA - The Act to establish the Canadian Nuclear Safety Commission, with the authority to regulate the nuclear industry.
- Regulations - Sets out statutory requirements.

- Regulatory Documents - Provide greater detail than regulations, as to what the licensees and applicants must achieve in order to meet the CNSC's regulatory requirements.

**Guidance** provides direction to licensees and applicants on meeting requirements. Regulatory tools under **Guidance** include:

- Guidance Documents - Provide practical guidance to licensees and applicants on how to meet the regulatory requirements of the CNSC.
- Staff Review Procedures - Internal working documents used by CNSC staff to conduct regulatory reviews. Staff Review Procedures ensure consistent regulatory reviews.
- Information (INFO) Documents - Plain-language publications describing nuclear-related issues and regulatory requirements and processes, for the general public and other stakeholders. INFO Documents also provide support and further information on other elements of the Regulatory Framework.

The CNSC has issue numerous regulations over the years to enable it to fulfill its nuclear energy and substances oversight role. The ones that are most applicable to development and operation of Nuclear Power Plant Developments include

- the General Nuclear Safety and Control Regulations
- the Radiation Protection Regulations
- the Class I Nuclear Facilities Regulations
- the Nuclear Substances and Radiation Devices Regulations
- the Packaging and Transport of Nuclear Substances Regulations, and
- the Nuclear Security Regulations.

Licences & Licencing

All activity related to the production and use of nuclear energy or substances must be licenced. A Nuclear Power Plant has five licences over its life cycle

- a Licence to Prepare a Site for the construction of the plant
- a Licence to Construct the plant
- a Licence to Operate the plant
- a Licence to Decommission the plant, and
- a Licence to Abandon the site.

All of the Licences are subject to the same regulatory process. An applicant must propose to carry out an activity and then the Commission reviews the application to determine

- if the Applicant's is qualified to carry on the activity and
- will, in carrying out the activity make adequate provision for the protection of the environment, the health and safety of persons and the maintenance of national security and measures required to implement international obligations to which Canada has agreed.

A Licence to Prepare a Site for a new nuclear plant can take several years. OPG received its Licence to Prepare a Site for New Nuclear Reactors at its existing Darlington Nuclear Generating facility in August 2012. It filed its application in September 2006. The CNSC is required to conduct an Environmental Assessment on the entire project under the Canadian Environmental Act before issuing a Site

Preparation Licence. This licence enables the Licencee to clear the land and make preparations to undertake construction.

No construction can begin until a Licence to Construct is provided by the CNSC. The application review includes a detailed assessment of the design of the plant and its safety parameters and how it is to be constructed and operated. There is no recent experience related to obtaining a Licence to Construct a new nuclear plant. The CNSC recently issues RD/GD 369: Licence Application Guide, Licence to Construct a Nuclear Power Plant to clearly identify the information that should be submitted to support the application. An 18 month to 24 month timeline has been suggested informally by CNSC and OPG staff with the actual time required being determined by the completeness of the information provided by the applicant and the ability of the applicant to respond to questions and concerns.

The CNSC has recently begun offering Pre-Licencing Reviews of a reactor designs to vendors. This review is not part of the Licencing process. It is an optional service offering and aims to provide early identification and resolution of potential regulatory and technical issues in the design, particularly those that could result in significant changes to the design or safety analysis. The objective of a pre-licencing review is to increase regulatory certainty while ensuring public safety. The results of the review are not binding on the CNSC.

Once the Licence to Construct is obtained, construction of the facility can begin. The length of time to construct a Nuclear Power Plant is very design and construction methodology dependent. Large NPP vendors suggest three to five year construction periods ought to be achievable. Vendors promoting Small Modular Reactors suggest one to two year construction periods ought to be achievable over time. Before the plant can be fueled and commissioned, the plant Operator must receive a Licence to Operate the Plant. The CNSC's review of this application will include detailed review of all parameters associated with operating and maintaining a nuclear power plant – its design, training and competency of its staff, its operations and maintenance procedures, etc. Licences to Operate are issued for a fixed period of time with 5 years being the current norm. Licence renewal is a formal and public process. The CNSC will review the operator's experience over the previous licence period, the current condition of the plant, the training and competency of its personnel, outstanding design and equipment condition issues, etc. before issuing its decision. There is discussion of moving towards longer operating licencing periods to align them to the completion of frequent focused in-depth assessments of the plant's safety parameters.

Modifications to existing plants could also require the operator to conduct additional environmental assessments before they are undertaken.

When an operator decides it no longer wishes to operate a facility and wishes to decommission it, it must apply for a Licence to Decommission the facility. No nuclear power plant in Canada has yet been decommissioned. Several are in safe storage state (i.e., fuel removed and moderator water drained) awaiting ultimate decommissioning. The CNSC Review will include the proposed decommissioning processes, the nuclear waste and conventional waste treatment and disposal plans, and the proposed site condition post-decommissioning. An Environmental Assessment of the plan will likely be required.

Once Decommissioning has been completed and the operator no longer wants or needs to provide oversight of the site, the operator must apply for a Licence to Abandon the Site.