COST BENEFIT ANALYSIS: REPLACING ONTARIO'S COAL-FIRED ELECTRICITY GENERATION REVISITED

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In partial fulfillment of the requirements of the M.A. Degree

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ECO 7997

December 2009

ABSTRACT

The Ontario government has announced its plan to shut down Ontario's existing coal-fired fleet. Prior to this decision, the Ontario Ministry of Energy commissioned a cost-benefit analysis of four scenarios of possible sources for electricity generation including the status quo, i.e. keep existing coal-fired generation, and a recommendation of the best-case scenario (DSS & RWDI 2005). One of the major problems with this analysis is that it assumes constant generation level. However, future generation will likely change due to several factors such as economic growth, technological improvement, changing supply mix, as well as conservation and climate change policies. The second major problem is that it does not consider the effects of uncertainty and irreversibility of investments in nuclear facilities; in other words, it excludes the option value associated with delaying these investments. This study revisits DSS & RWDI (2005) by including the effects of these two issues. This changes the total cost of generation for each of the four scenarios as well as the ranking among them.

PART 1: INTRODUCTION

The Ontario government has announced its goal to shut down all coal-fired generating stations by 2014. Since coal burning emits a large amount of pollutants, it has adverse effects on our health and the environment. Eliminating coal-fired generation will contribute greatly to a clean environment, but will likely pose significant problems as well. Additional facilities must be built or refurbished to meet the generation gap; this requires an analysis of potential options.

In 2005, the Ontario government commissioned a cost-benefit study (DSS & RWDI 2005) to analyze four possible generation scenarios as follows:

- **Scenario 1 (Status Quo[1])**: continue operating existing coal-fired plants[2]
- **Scenario 2 (All Gas)**: build new gas facilities intended only for replacing coal-fired generation[3]

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[1] In DSS & RWDI (2005), Scenario 1 is referred to as the Base Case. In this paper, it is referred to as Status Quo, to avoid confusion with one of the generation level cases, the Base Case.

[2] Ontario currently has four coal-fired facilities: Nanticoke, Lambton, Thunder Bay, and Atikokan. Lakeview was closed on April 30th, 2005. www.opg.com/power/fossil/

[3] DSS & RWDI (2005) assumes that all new gas facilities use combined cycle gas turbine (CCGT) technology.

- **Scenario 3 (Nuclear/Gas)**: a combination of new gas facilities and refurbished nuclear plants, also for replacing coal-fired generation alone[4]
- **Scenario 4 (Stringent Controls)**: keep existing coal-fired facilities but install emission control retrofits, namely Selective Catalytic Reduction, Flue Gas Desulfurization scrubbers, and enhancements to existing Electrostatic Precipitators

The study concludes that a combination of nuclear and gas-fired generation (Scenario 3) is the best alternative, all gas-fired generation (Scenario 2) is the second best, and keeping coal-fired plants but installing stringent controls (Scenario 4) is the least favorable alternative, although still preferable to the status quo.

However, the study possesses two important problems. First, it assumes a constant electricity generation level throughout the study period (2007-2026)[5]. In reality, we expect the future generation level to change due to a number of factors, including economic growth, technological improvement, expected transformation in the supply mix, as well as policies directed at conservation and climate change. These factors will affect the level of electricity demanded, either directly or indirectly through price changes, and thus, the generation level. Changes in future generation level will have an impact on total costs of generation and perhaps the ranking of the four scenarios.

The second problem is that DSS & RWDI (2005) does not include the option value of delaying nuclear investment in the total cost of nuclear generation. Since investments in nuclear power plants have high capital costs and there are great uncertainties and irreversibility

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[4] Single cycle gas turbines (SCGT) are used to meet a portion of the peak demand. Most of the base load is met using refurbished nuclear; Pickering A units 1, 2, and 3 and Bruce Units 1 and 2 are brought back on line.

[5] The forecast horizon for capital costs starts at 2005; two years are used for new building and refurbishments. For all other costs and damages as well as total present values, the forecast horizon starts at 2007.

associated with them, it may be a wiser idea to wait until some uncertainties are resolved before moving ahead. Excluding option value leads to an undervaluation of the total costs of nuclear generation and an overestimate of the net benefits if the option of delaying has value.

This study extends DSS & RWDI (2005) by addressing these two issues. Three cases of future electricity generation are considered: the Base Case, the Maximum Conservation Case, and the Minimum Conservation Case.

1. Base Case

   Capacity and generation level remain constant at 6447 MW and 26.6 TWh, respectively, for all four scenarios, as assumed in DSS & RWDI (2005).

2. Maximum Conservation Case

   This case differs from the Base Case in that it takes into account changes in future electricity generation. The factors included are economic growth, changing supply mix, policies intended to address climate change, as well as conservation policies aimed at energy savings. The conservation level is assumed to be the maximum identified potential savings estimates in Ontario Power Authority's Integrated Power System Plan (OPA 2008d).

3. Minimum Conservation Case

   This case is similar to the Maximum Conservation Case, except that the level of conservation is assumed to only meet Ontario's minimum target of 6,300 MW by 2025, approximately 65% of maximum identified potential savings. Since energy savings in this case are lower than in the Maximum Conservation Case, the annual generation level is consistently higher throughout the study period.

Due to uncertainty regarding the feasibility of different conservation options, we cannot be sure how much conservation beyond the minimum we will actually achieve. There is also a large degree of uncertainty regarding the cost-effectiveness of different supply options. However, this will become clearer with time as Ontario gains more experience in conservation and develops a better understanding of the supply options. As of now, we can only predict the probability of each case. Thus, a sensitivity analysis is conducted, using a range of different probabilities as well as the timing when uncertainties are resolved.

The results indicate that although changing generation level leads to lower total cost of generation and higher net benefit for all four scenarios, the ranking of the scenarios remains the same. In contrast, inclusion of option value has a significant impact on the ranking of the scenarios. When option value of delaying nuclear investments is added to the total cost of nuclear generation, Scenario 3 (Nuclear/Gas) becomes the least favorable scenario, although still preferable to the status quo. Scenario 2 (All Gas) becomes the best option, followed by Scenario 4 (Stringent Controls).

The paper proceeds as follows. Part 2 discusses the various policies that affect electricity demand and supply. Part 3 explains how future electricity capacity and generation are estimated. The methodology of deriving total costs of generation and net benefits is covered in Part 4. Part 5 discusses the results of the revised study. Part 6, 7, and 8 compares the Maximum Conservation Case and the Minimum Conservation Case, the Maximum Conservation Case and the Base Case, and the Minimum Conservation Case and Base Case, respectively. Part 9 discusses the methodology used to estimate the option value as well as the results. Final results of the analysis, when changes in future generation level as well as option value are included, are discussed in Part 10. Part 11 concludes.

PART 2: POLICIES AFFECTING ELECTRICITY DEMAND AND SUPPLY

Electricity generation is likely to change throughout the next couple of decades due to a number of factors. First, economic growth will lead to increasing demand. Second, technological improvement, also known as natural conservation, will alleviate some of the upward pressure on demand. Third, new conservation policies directed toward consumption habits are being planned to lessen the resource gap resulting from higher demand but lower resource availability due to coal-fired shutdowns and nuclear retirement. Fourth, changing supply resource mix in response to CFG shutdowns will affect electricity prices, which will have impacts on demand. Finally, policies to address climate change and air quality concerns will have further impacts on electricity demand through higher prices. These changes are not accounted for in DSS & RWDI (2005).

Economic Growth

The Ontario economy is predicted to continue growing throughout the study period, i.e. 2005 - 2026, thus total electricity demand will also continue growing. Three main economic drivers determine electricity demand: number of households in the residential sector, floor space in the commercial/institutional sector, and physical or financial output level in the industrial sector. A growing population (or number of households) requires higher electricity provision to the residential sector. It also leads to an expansion of commercial floor space as well as higher production level as more people participate in the labor force, thus further increasing the level of electricity demanded. Growing electricity demand implies higher electricity prices in the future as more expensive sources are required to meet additional demand. However, higher prices create incentives for consumers to practice conservation, which will decrease the rate at which electricity demand grows.

Technological Improvement (Natural Conservation)

Although electricity demand is expected to grow, largely due to economic growth, technological improvement reduces the growth rate. Technological improvement, also known as natural conservation, refers to the reduction in demand resulting from capital stock turnover with more efficient technologies, equipment, and processes replacing older ones as they reach the end of their lifespan. Natural conservation results from technology competition due to relative price changes as well as previous regulation and standards that continue to play a role in shaping consumption patterns. Taking economic growth and natural conservation effects into the forecast, OPA (2005) predicts that peak demand will increase by 1.3% per year and energy requirements will increase by 0.9% per year from 2005 to 2025.

Conservation and Demand Management (CDM)

Ontario government's mandate to shut down coal-fired plants by 2014 and the expected retirement of existing nuclear facilities between 2012 and 2020 lead to major supply issues in the medium and long run. Decrease in supply along with increase in demand means that Ontarians would face major shortages in the future, thus a sufficient level of conservation and supply resources are required to close the gap. As well, an appropriate mix of resources is necessary to ensure reliability. In response, Ontario Power Authority (OPA 2008a-f) has developed the Integrated Power System Plan (IPSP), which includes specific targets for demand reduction from conservation. In particular, the province aims to achieve demand reduction from conservation equivalent to 1,350 MW by 2010 and an additional 3,600 MW by 2025 (OPA 2008a, p6).

Conservation, the act of reducing consumption of a commodity from the normal level in response to market interventions resulting from programs or policies, falls into four categories:

1. Energy Efficiency

   Energy efficiency occurs when "customers reduce their electricity consumption but retain at least the same level of end-use service" (OPA 2008e, p2) through the adoption of more efficient technology, equipment, and production processes. On the producer side, energy efficiency measures include standards such as building codes and subsidies for R&D. On the consumer side, measures include tax credits and rebates as well as information programs.

2. Load Management (Conservation Behavior/Demand Management)

   There are two types of load management: conservation behavior and demand management. Conservation behavior occurs when "customers voluntarily reduce their electricity consumption by scaling back the activity which is powered by electricity" (OPA 2008e, p2). Demand management occurs when "customers reduce their electricity demand during peak use hours (peak clipping) or shift some of their demand to off-peak hours (peak shifting)" (OPA 2008e, P2). A reduced peak demand requires lower generation capability, thereby alleviating some pressure on acquiring sufficient supply resources to meet demand.

   Load management initiatives include smart metering and demand response programs. Smart meters track hourly or even finer intervals of electricity demand and report this information to the appropriate local distribution company. This information is useful for dynamic pricing initiatives to encourage peak demand reduction such as Time-of-Use (TOU) pricing and Critical Peak Pricing (CPP), an event-based type of TOU. Demand Response is the ability for large consumers in the wholesale market to reduce their consumption when prices are high. This is achieved through a wholesale pricing system, where price of electricity equals marginal cost of generation at any point in time. The OPA has launched several demand response initiatives, which are discussed on their website www.powerauthority.on.ca/Page.asp?PageID=1212&SiteNodeID=147. The IESO website (http://www.ieso.com/imoweb/infoCentre/ic_index.asp) indicates that most Ontarians will have moved from the tiered rate to the time-of-use rate by spring 2011 and all public sector consumers will move to a wholesale price system on Nov 1st, 2009. These pricing systems allow the price of electricity to better reflect marginal cost of generation, thus allowing consumption patterns to respond to market price signals. This will have an impact on the generation capacity required.

3. Fuel Switching

Fuel switching occurs when customers replace electricity with other energy sources for the same activity. Long-term relative electricity price increases and electricity market initiatives in favor of alternative energy can shift consumption away from electricity. Non-market initiatives to raise awareness of alternative options to electricity further facilitate the switch to environmentally friendlier energy sources. This is largely achieved through information programs and education.

4. Customer-based Generation

Customer-based generation occurs when "customers elect to install either a generator or a combined heat and power facility to meet all or a portion of their electricity consumption needs" (OPA 2008c, p2). Combined heat and power (CHP), also known as co-generation, produces heat and electricity simultaneously.

The Ontario Power Authority has initiated the Clean Energy Standard Offer Program (CESOP) aimed at encouraging contribution to clean energy supply from small electricity generators connected to a distribution system. Clean energy refers to natural gas-fired CHP, energy derived from by-product fuels, and energy from projects that generate under-utilized energy. CESOP generators are paid a price for their leftover electricity generation equal to "the cost that would otherwise have been paid if there were no CESOP, to acquire a similar amount of electricity with similar load profile and reliability characteristics" (OPA 2008h, p7).

The other major program that encourages customer-based generation is the Renewable Energy Standard Offer Program (RESOP)[6]. It helps Ontario meet its renewable target, i.e. doubling renewable generation from 7,500 MW in 2007 to 15,700 MW by 2025 (OPA, 2008g, p2), by providing a standard pricing regime and streamlined process for small renewable generators.

Changing Supply Mix

Complete shutdown of coal-fired generators, retirement of almost all existing nuclear units, and increasing demand, pose great challenges in meeting Ontario's future electricity needs. This resource gap needs to be met by new supply, which will lead to major changes in

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[6] It is replaced by the Feed-In-Tariff (FIT) Program as of Oct 1st, 2009.

the future supply mix. Electricity prices are thus expected to vary throughout the study period as production costs of these resources are incurred. Production costs include capital costs of new facilities as well as operating and maintenance costs of all supply resources. Future supply mix (after conservation) will consist of renewable sources (hydro, wind, solar and biomass), nuclear and natural gas. The Minister of Energy has set out specific minimum requirements for the supply mix, as shown in Table 2.

The costs to consumers is the sum of generation costs, conservation costs, transmission costs, wholesale charges, Debt Retirement Charge (DRC), and distribution costs. Table 3 shows the OPA's forecast of unit costs of electricity to consumers for three scenarios: Median (medium economic growth rate), Upper (high economic growth rate), and Lower Scenario (low economic growth rate). From this table, we can see that unit costs are forecast to increase to 2020 and then decline to 2025. Thus we expect demand reduction in response to higher prices until the last several years of the study period.

Table 2: IPSP's Future Resource Supply – By Type

	Conservation	Renewable	Nuclear for Base load	Replacement for Coal-fired Generation	Natural Gas
IPSP's Goal	1350MW by 2010, additional 3600 MW by 2025	10,402MW by 2010, 15,700 MW by 2025	Up to 14,000 MW	Replace all 6434 MW of coal-fired electricity by 2014	Restricted Gas[7] is used for meet peak and intermediate demand

Source: OPA 2008a, p30

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[7] Restricted Gas implies that use of gas should be restricted as much as possible to single cycle gas turbine for peak demand and combined cycle gas turbine for intermediate demand (OPA 2008a, p31-2).

Table 3: Unit Cost of Electricity to Consumer ($/MWh)

	2010	2015	2020	2025
Upper	109	121	129	124
Median	97	108	113	106
Lower	89	101	105	97

Source: OPA 2008f, p30

Climate Change Policy

In response to rising concerns about climate change, Canadian governments are striving for implementation of environmental policies targeted at emission reduction of pollutants. According to Government of Canada (2008), the federal government has committed to reducing greenhouse gas emissions by 20% in 2020 and by 60-70% in 2050 relative to the 2006 level. Actions aimed at achieving this target include future establishment of a carbon market and investments in clean energy technology.

The Government of Canada is committed to developing a North American cap-and-trade (CAT) system for greenhouse gases (GHG) and preparing Canada, ultimately, for a global trading system (Government of Canada, 2009). It intends to shift to a CAT system sometime between 2020 and 2025 from the emission-intensity targets that will come into force in 2010 (Government of Canada 2008, p10). As part of the climate change plan, the federal government is implementing the Offset System, which will "issue offset credits for eligible project-based greenhouse gas reductions or removals" (Environment Canada, 2009).

A cap-and-trade system involves setting a fixed emission level, distributing a total number of permits equal to the fixed emission level, and then allowing firms to buy and sell permits. In equilibrium, permit price equals to marginal abatement cost. NRTEE (2007) predicts that prices need to be \$190-\$240[8] per ton of CO_2e in order to reach a target of 45% reduction by 2050. Therefore to achieve the 60-70% target, prices will need to be higher. Rising production costs will be shifted onto consumers in the form of higher prices thus leading to lower consumption.

Aside from commitment to carbon pricing, the Government of Canada is also committed to investments in clean energy technologies. Within five years, starting 2009, it has committed to \$1 billion for clean energy research and demonstration projects, including \$650 million for large-scale carbon capture and storage (CCS) projects (Government of Canada, 2009a). Out of this \$1 billion, up to \$150 million is contributed towards clean energy research and \$850 million is contributed towards clean energy demonstration projects (Government of Canada, 2009b, p125). In total, Canadian governments are investing more than \$3 billion in CCS demonstration projects in the next five years (Government of Canada, 2009a). New available technology will have an impact on the types of resource used for electricity generation, thus the costs borne by generators and the price paid by consumers. This will likely change the level of electricity demanded.

PART 3: FUTURE CAPACITY AND GENERATION

To re-estimate the net benefits of the three CBA alternative scenarios, we need to estimate the level of capacity and generation required to meet the loss from coal-fired shutdowns. This involves 5 steps:

1. Forecast baseline annual peak demand and energy demand[9].

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[8] Price is in 2003 Canadian dollars.

[9] Peak demand refers to the maximum demand among all hours of the year; it is useful for estimating annual required capacity. Energy demand refers to the annual level of electricity demanded.

2. Estimate annual potential conservation savings.
3. Subtract conservation savings from baseline forecasts for each year to get total annual net demand.
4. Multiply total annual net demand by the reserve margin to get total annual capacity and generation level[10].
5. Calculate annual changes in total capacity and generation demanded. These are the additional demand that must be met by each of the four electricity resource scenarios.

Two future electricity demand scenarios (net of conservation) are used: the Maximum Conservation Case and the Minimum Conservation Case, as discussed in the introduction. The two scenarios differ in the level of conservation savings; the Maximum Conservation Case assumes that the maximum cost-effective conservation savings is fulfilled whereas the Minimum Conservation Case assumes only 65% of these savings is achieved[11].

The baseline peak demand and energy demand used for both scenarios are taken from the OPA's IPSP Load Forecast. Their respective average annual growth rates are 1.2% and 1.1%. Peak demand is derived from energy demand by applying an annual load profile. These demand forecasts are determined by economic growth, energy price changes, and availability of technology.

For the Maximum Conservation Case, conservation is assumed to achieve the maximum cost-effective reductions, referred to as the Identified Savings Potential in OPA (2008d, e).

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[10] Annual peak demand (plus reserve margin requirements) gives us the annual required capacity and annual energy demand (plus reserve margin requirements) gives us the annual required generation level.

[11] As discussed in the Introduction, the Minimum Conservation Case assumes that conservation savings is just large enough to meet Ontario's minimum conservation target of 6,300 MW by 2025, which is 65% of maximum cost-effective conservation savings.

There are four categories of conservation: energy efficiency, CDM, fuel switching, and customer-based generation.

1. Energy Efficiency

   OPA used the aggressive scenario in MKJA's Modeling and Scenario Documentation, which is based on The National Study. This scenario is the case where policy coverage is broader and more parties are involved, including all levels of government, utilities and the private sector. Policy instruments adopted are: energy efficiency subsidies, marginal cost pricing, carbon liability (\$15/ton of CO_2e)[12], energy performance standards, on-site renewable subsidies, and urban land use. OPA identified energy efficiency to contribute to 65% of total conservation savings.

2. Conservation Behavior/Demand Management (CDM)

   To estimate demand response (or DM) savings, OPA relied on its own experience as well as the 2005 Navigant Consulting study for smart metering. Since conservation behavior is achieved mostly by education and information programs and the impact is small and difficult to estimate, it is excluded from the CDM estimate. Contribution from DM to total conservation savings is estimated to be around 20% (OPA 2008d).

3. Fuel Switching

   OPA hired Marbek and ALTECH to conduct a study examining the potential effects of fuel substitution on savings. All measures that pass the Total Resource Cost (TRC) test are considered in the analysis. The TRC test is used to "determine whether

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[12] Based on a review conducted for BC Hydro in 2005, a liability of \$15/ton of CO_2e is a reasonable value in jurisdictions that currently adopt or propose a carbon liability, and it also falls below the maximum acceptable price proposed for Large Final Emitters (LFE) for 2008-2012; however, it is much lower than the cost estimates of US \$50-\$70/ton of CO_2e proposed in an American study in 2003 (MKJA 2006). A higher carbon liability implies that the cost of producing electricity would rise, thus the production level would fall.

Conservation resources included in the Plan are cost-effective for society as a whole" (OPA 2008d); cost-effectiveness implies that the Conservation measure produces a positive net benefit.

4. Customer-based Generation

The estimated potential savings from customer-based generation is based on OPA's own Bio-energy study as well as information gathered from RESOP, CESOP, and CHP programs (OPA 2008d). These programs that are underway are designed to encourage electricity generation from renewable sources and clean natural gas. Customer-based generation is estimated to contribute to 11% of total conservation savings.

To calculate required electricity capacity and generation level, the following equations are used:

Required Capacity = Peak Demand + Peak Demand * Reserve Margin, where Peak Demand = Baseline Peak Demand – Conservation Reductions

Required Generation = Energy Demand + Energy Demand * Reserve Margin, where Energy Demand = Baseline Energy Demand – Conservation Reductions

The Reserve margin is the percentage of peak demand required to meet the reserve requirement, which is the "amount of capacity in excess of forecast peak demand that is required to mitigate the reliability risks associated with various uncertainties related to planning assumptions" (OPA 2008c, p1). In the Plan, OPA has identified two types of reserves: "NPCC" Reserve and Insurance Reserve. "NPCC" Reserve is the excess level required to meet the reliability criteria set out by the Northeast Power Coordinating Council (NPCC); it is designed to address risks of changing weather, nuclear outages and unreliable wind generation. Insurance Reserve is the additional level required to mitigate reliability risks associated with Ontario's changing future supply mix. Prior to 2014, risks due to system transformation will be mitigated by coal and interconnections; after 2014, risks will be mitigated by gas and interconnections.

Table 4 shows the forecasts of required capacity and required generation from 2005 to 2026 for the Maximum Conservation Case and for the Minimum Conservation Case.[13]

Table 4: Capacity and Generation for the Maximum Conservation Case and the Minimum Conservation Case

	MAXIMUM CONSERVATION CASE		**MINIMUM CONSERVATION CASE**	
	Capacity (MW)	*Generation (TWh)*	*Capacity (MW)*	*Generation (TWh)*
2005	6447	26.6	6447	26.6
2006	4538	28.9	4548	28.9
2007	8883	26.6	8883	26.6
2008	6426	26.8	6426	26.8
2009	6289	26.4	6289	26.4
2010	6060	20.9	6060	20.9
2011	4823	20.9	5807	26.7
2012	6173	24.4	6577	25.5
2013	6023	24.4	6322	25.8
2014	6107	24.4	6326	25.5
2015	6344	25.8	6577	27.2
2016	6474	28.1	6615	28.8
2017	6394	25.9	6565	26.5
2018	6389	27.0	6563	27.7
2019	6498	27.1	6636	27.8
2020	6755	29.7	6912	30.4
2021	6750	27.4	6859	28.0
2022	6761	28.6	6868	29.1
2023	6778	28.6	6883	29.1
2024	6780	28.5	6888	29.1
2025	6821	27.8	6918	28.1
2026	6674	28.0	6830	28.9

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[13] The study period in the IPSP is 2007-2027. Forecasts for 2027 are not used in this study since the period ends at 2026. To see how I calculated capacity and generation for 2005 and 2006, please refer to Note in the Appendix.

Note: For detailed values, refer to Appendix Table 1 to Table 4.

PART 4: METHODOLOGY

In order to study the impacts of changing annual generation on the total costs of each scenario, we need to estimate the total cost of generation for all four scenarios using capacity and generation of the Maximum Conservation Case and the Minimum Conservation Case. Total cost of generation "represents the minimum average amount that society must be willing to pay for the generation of this electricity to be worthwhile" (DSS & RWDI 2005, p2). It is the sum of financial costs, health and environmental damages and is expressed in three ways: total present values, annualized values, and levelised values. The definitions of the three values are provided in the following three sub-sections.

To calculate the total cost of generation, a social discount rate of 5% is used. It is chosen in order to be consistent with the rate used to derive the best estimate values in DSS & RWDI (2005). Discounting is necessary because it allows costs incurred at different times to be compared directly. Annual costs are assumed to be incurred at the end rather than the beginning of each year, thus the exponent starts at a value of 1 instead of 0. This ensures that annual costs for the study period (i.e. 2007-2026) are properly discounted to the beginning of the starting year, which is 2007.

Present Value Costs

Total Present Value represents the "cumulative discounted value of a stream of benefits or costs over a given period of time" (DSS & RWDI 2005, p21). To calculate the new present value costs, we need to first determine what the unit costs are for all cost categories. Unit costs are the monetary costs incurred per unit of electricity production, either in megawatt or terawatt-hour terms. They are derived using the present values in the Base Case.

The steps to calculate unit costs are as follows:

1. $PVC = \sum_{i=1}^{20} \frac{C_i}{(1+r)^i}$, where r = 5%

2. $Since\ C_1 = C_2 = \cdots = C_{20}, PVC = C \times \sum_{i=1}^{20} \frac{1}{(1+r)^i}$, where C represents Annual Cost

3. $C = \frac{PVC}{\sum_{i=1}^{20} \frac{1}{(1+r)^i}}$

4. $Unit\ Cost = \frac{Annual\ Cost}{Annual\ Capacity\ or\ Generation}$

Table 5 shows the results for all cost categories. The fixed operating unit costs are in $/MW terms because they vary with the capacity level, whereas the variable operating, fuel, health, and environmental unit costs are in $/TWh terms because they vary with the generation level. DSS & RWDI (2005) shows the capital costs for gas facilities and nuclear facilities in $/KW

Table 5: Unit Costs

	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Capital ($/MW)	N/A	0.0628	0.0830	N/A
Fixed Operating (S/MW)	0.0367	0.0142	0.0154	0.0391
Variable Operating ($/TWh)	2.01	2.87	8.55	3.45
Fuel ($/TWh)	19.54	45.97	16.82	17.24
Health ($/TWh)	97.68	11.49	11.41	34.48
Environmental ($/TWh)	12.07	4.60	1.43	11.49

Source: DSS & RWDI (2005); based on its total present value costs for the four scenarios.

terms and shows the capital costs for Scenario 1 (status quo) and Scenario 4 (stringent controls) in $/unit terms. Thus unit capital costs in KW terms for Scenario 2 and Scenario 3 are calculated, since they vary with the capacity level. It is unnecessary to calculate unit capital costs for Scenario 1 and Scenario 4 since they do not vary with the capacity level; total present value capital costs for these two scenarios are taken directly from DSS & RWDI (2005).

To calculate the annual costs for each cost category, we multiply the appropriate unit cost by the annual capacity or generation level. Then we discount the annual costs using a social discount rate of 5%, as used in DSS & RWDI (2005). Finally, we add the annual discounted values together to get the present value cost. Total present value is the sum of financial, health, and environmental present values.

Annualized Values ($ Millions)

Annualized value represents the "average annual value of a stream of benefits or costs that is equal to the total present value spread evenly over the time period" (DSS & DWRI, p7). This implies that the annual value must be such that the discounted annual costs (or annual present value costs) for every year of the study period are equal. This is obtained using the average present value cost (PVC), which is equal to PVC divided by total number of years (20 in this study).

To calculate annualized values, we use the following equation:

Annualized Value = Average Annual Cost

= Sum of Annual Costs / total number of years in the study period

Where Annual Cost = Average PVC * (1.05^i); i = 1, 2 ... 20.

Levelised Values ($/MWh)

Levelised Value is the "total present value divided by the discounted total generation (MWh)" (DSS & RWDI, p7). Discounted total generation is the sum of all annual generation discounted at 5%[14]. Mathematically, this would be expressed as:

Levelised Value = Total PVC / Discounted Total Generation

Discounted Total Generation = G_1 / (1.05^1) + G_2 / (1.05^2) + ... + G_{20} / (1.05^20)

Where G_i represents the generation level for the ith year, i = 1, 2 ... 20.

Net Benefits

The Net Benefit of replacing coal with an alternative source is the reduction in estimated present value costs, which is the difference between the present values of scenario 1 and of the alternative scenario. If the present value of the alternative scenario is less than that of scenario 1 (Status Quo), then the net benefit of the alternative scenario is positive. This implies that it is reasonable to adopt that option. The scenario with the largest net benefit is the one that yields the highest return and should therefore be the one that is implemented.

PART 5: RESULTS OF THE REVISED STUDY

Maximum Conservation Case

Scenario 3 (Nuclear/Gas) yields the lowest total cost of generation and the highest net benefit, thus it is the best option among the four scenarios. Scenario 1 (Status Quo) has the highest total cost, thus it is the worst scenario. Although Scenario 2 (All Gas) is the second best option, its total cost of generation is only slightly lower than that of Scenario 4 and its net benefit is only slightly higher than that of Scenario 4 (Stringent Controls). The values between

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[14] Since total present value is the sum of discounted annual costs, therefore annual generation must also be discounted. Furthermore, they are discounted at 5% to be consistent with the discount rate used in DSS & DWRI (2005).

the two scenarios are close enough that we can conclude they are indistinguishable, given possible calculation uncertainties and measurement error.

Table 6 and Table 7 shows the costs and net benefits for the scenarios in total present value, annualized and levelised terms. The total present value costs are $46.0 billion for Scenario 1, $28.4 billion for Scenario 2, $21.4 billion for Scenario 3, and $28.5 billion for Scenario 4. The total present value net benefits are $17.6 billion for Scenario 2, $24.5 billion for Scenario 3, and $17.4 billion for Scenario 4.

Table 6: Total Cost of Generation

	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	46.0	28.4	21.4	28.5
Annualized Value ($ Millions)	3989	2465	1858	2476
Levelised Value ($ Millions)	141	87	66	88
Health and Environmental Proportion	77%	18%	19%	50%

Source: Author's own calculation

Table 7: Net Benefits

	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	17.6	24.5	17.4
Annualized Value ($ Millions)	1524	2131	1513
Levelised Value ($ Millions)	54	75	53

Source: Author's own calculation

Annualized financial costs, health damages and environmental damages for the four scenarios are shown in Table 8. From the table, we can see that Scenario 1 bears a large proportion of health damages relative to financial costs and environmental damages, whereas the alternative scenarios bear a large proportion of financial costs relative to health and environmental damages.

Table 8: Annualized Financial Costs and Health and Environmental Damages ($ Millions)

	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Financial Costs	907	2014	1498	1249
Health Damages	2743	323	320	921
Environmental Damages	339	129	40	307
Total Generation Costs	3989	2465	1858	2476

Source: Author's own calculation

Minimum Conservation Case

Scenario 3 (Nuclear/Gas) is the best scenario in this case as well; it has the lowest total cost and the highest net benefit. Scenario 2 (All Gas) has the second lowest cost and second highest net benefit, thus is the second best option. Scenario 4 (Stringent Controls) has higher cost and lower net benefit than the other two scenarios but is still better than Scenario 1 (Status Quo).

Total costs and net benefits for the scenarios are shown in Table 9 and Table 10, respectively. Total present value generation cost is $47.5 billion for Scenario 1, $29.3 billion for Scenario 2, $22.1 billion for Scenario 3, and $30.6 billion for Scenario 4. Total present value net benefit is $18.2 billion for Scenario 2, $25.5 billion for Scenario 3, and $17 billion for Scenario 4.

Table 9: Total Cost of Generation

	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	47.5	29.3	22.1	30.6
Annualized Value ($ Millions)	4127	2546	1916	2655
Levelised Value ($ Millions)	142	87	66	91
Health and Environmental Proportion	77%	18%	19%	50%

Source: Author's own calculation

Table 10: Net Benefits

	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	18.2	25.5	17
Annualized Value ($ Millions)	1581	2211	1472
Levelised Value ($ Millions)	55	76	51

Source: Author's own calculation

Table 11: Annualized Financial Costs and Health and Environmental Damages ($ Millions)

	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Financial Costs	936	2078	1543	1319
Health Damages	2841	334	332	1003
Environmental Damages	351	134	41	334
Total Generation Costs	4127	2546	1916	2655

Source: Author's own calculation

Financial costs, health damages, and environmental damages in annualized terms are shown in Table 11. Most of the total cost for Scenario 1 comes from health damages, whereas most of the costs for the alternative scenarios come from financial costs.

Expected Total Present Value and Expected Net Benefits

Since there are uncertainties regarding which case will actually take place, i.e. Maximum Conservation Case or Minimum Conservation Case, expected total present values and expected net benefits are calculated. The probability of the Maximum Conservation Case is represented as p and the probability of the Minimum Conservation Case is represented as 1-p. Table 12 and 13 present the results of a sensitivity analysis on the expected present value and expected net benefit, assuming three values of p: 0.1, 0.5 and 0.9. A more extensive sensitivity analysis is presented in the Appendix (Table 5 and 6).

Table 12: Expected Total Present Value ($ Billions)

P	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0.1	47.8	28.9	21.9	30.8
0.5	47.0	28.5	21.5	30.0
0.9	46.2	28.1	21.1	29.2

Table 13: Expected Net Benefits ($ Billions)

P	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0.1	18.9	25.9	17.0
0.5	18.5	25.5	17.0
0.9	18.1	25.1	17.0

From the above tables, we can see that expected present values of cost and expected net benefits decrease as the probability of Maximum Conservation Case, p, increases. This makes sense because generation levels are lower in the Maximum Conservation Case, due to greater conservation, compared with the Minimum Conservation Case (see Table 4). Scenario 3 yields the highest net benefit under all values of p, Scenario 2 yields the second highest, and Scenario 4 yields the lowest.

PART 6: COMPARISONS BETWEEN THE MAXIMUM CONSERVATION CASE AND THE MINIMUM CONSERVATION CASE RESULTS

Total Cost of Generation

The Minimum Conservation Case total costs are higher than the Maximum Conservation Case total costs for all four scenarios; their differences are $138 million for Scenario 1, $81 million for Scenario 2, $58 million for Scenario 3, and $179 million for Scenario 4. This result is consistent with expectation because the Minimum Conservation Case assumes lower conservation savings than the Maximum Conservation Case, which includes all potential conservation savings. Lower conservation savings implies that a higher generation level is required to meet electricity demand, thus higher costs will be incurred.

The levelised costs are the same in the Base Case and the Maximum Conservation Case for both Scenario 2 and Scenario 3. The levelised costs are only slightly different for the other two scenarios, with $1/MWh difference for Scenario 1 and $3/MWh difference for Scenario 4. Both cases have the same health and environmental proportion: 77% for Scenario 1, 18% for Scenario 2, 19% for Scenario 3, and 50% for Scenario 4.

Net Benefits

The net benefits for the Minimum Conservation Case are higher than the net benefits for the Maximum Conservation Case for Scenarios 2 and 3, but not Scenario 4. The net benefits for the Minimum Conservation Case are $57 million higher for Scenario 2, $80 million higher for Scenario 3, and $41 million lower for Scenario 4. If the proposed conservation savings are achieved, replacing coal-fired electricity generation with all gas or a combination of nuclear and gas generates higher net benefits than if the identified conservation savings are achieved. Targeting 65% of total potential conservation savings is beneficial for scenarios 2 and 3. However, targeting the full potential identified conservation savings is more beneficial if we keep Ontario's coal-fired plants but implement stringent control measures.

This study is currently the only one that studies the impact of conservation on the net benefits of alternative sources to coal for electricity generation in Ontario, thus we do not have previous studies to compare to.

PART 7: COMPARISONS BETWEEN THE BASE CASE RESULTS AND THE MAXIMUM CONSERVATION CASE RESULTS

Total Cost of Generation

Despite changing annual capacity and generation levels in this study, the results of the Maximum Conservation Case do not differ from the Base Case in terms of the ranking of the scenarios, although changes in future electricity consumption and in future supply mix will lead to slightly lower total costs of generation for all four scenarios. Scenario 3 still yields the lowest total costs and Scenario 1 still yields the highest total costs. Although Scenario 4 still yields a higher cost than Scenario 2, it is by only 4.5%, a lot smaller compared to 7.6% in the Base Case[15].

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[15] The Scenario 2 and Scenario 4 annualised generation costs in the Identified Case are $2465 million and $2476 million, respectively, thus the percentage difference is 4.5%. In the Base Case, they are $2605 million and $2802 million, thus the percentage difference is 7.6%.

For the Base Case, the respective annualized costs for Scenario 2 and Scenario 3 are $2605 million and $1942 million; for the Maximum Conservation Case, they are $2465 million and $1858 million. Although Scenario 4 (Stringent Controls) yields much higher costs than Scenario 2 and Scenario 3, they are significantly lower than those of Scenario 1 (Base Case), as expected. The Base Case annualized costs for Scenario 1 and 4 are respectively $4377 million and $2802 million; the Maximum Conservation Case annualized costs for the two scenarios are $3989 million and $2476 million.

The corresponding levelised costs for the Base Case are $164/MWh for Scenario 1, $98/MWh for Scenario 2, $72/MWh for Scenario 3, and $105/MWh for Scenario 4. The corresponding levelised costs for the Maximum Conservation Case are $141/MWh for Scenario 1, $87/MWh for Scenario 2, $66/MWh for Scenario 3, and $88/MWh for Scenario 4. Lower levelised costs due to future demand policies and changing supply mix imply lower electricity prices borne by consumers.

The Base Case costs of generation for all four scenarios are higher than the Maximum Conservation Case cost of generation. This implies that taking the effects of electricity market dynamics into the cost-benefit analysis has a positive effect on the costs that society must bear. Regardless of which option the Ontario government adopts, society will pay a lower cost for electricity generation and thus consumption. The Base Case annualized generation costs for Scenario 1, Scenario 2, Scenario 3, and Scenario 4 are $388 million, $140 million, $84 million, and $326 million, respectively.

Net Benefits

In terms of net benefits, the ranking of the scenarios remain the same; Scenario 3 has the highest values, Scenario 4 has the lowest values, and Scenario 2 has mid-range values. The Base Case annualized net benefits for Scenario 2, Scenario 3, and Scenario 4 are $1384 million, $2047 million, and $1187 million, respectively. The Maximum Conservation Case annualized net benefits for the three scenarios are $1524 million, $2131 million, and $1513 million. These net benefits are higher than the Base Case net benefits by $140 million for Scenario 2, $84 million for Scenario 3, and $326 million for Scenario 4.

Health and Environmental Proportion

The differences in the health and environmental proportions between these two cases for the four scenarios are in the range of only 0-2%. For Scenario 4, financial costs are relatively low with most of the total costs coming from health and environmental damages. It is 77% for both cases. Scenario 2 and Scenario 3 have low percentages, implying that their total costs consists of mostly financial costs rather than health and environmental damages. The percentages in the Maximum Conservation Case for Scenario 2 and Scenario 3 are 18% and 19%, respectively; they are 2% below the Base Case percentages. The health and environmental proportion for Scenario 4 is 50% for the Maximum Conservation Case and 51% for the Base Case. Financial costs and health and environmental damages contribute equally to generation costs.

Both the Base Case and the Maximum Conservation Case proportions show that replacing the status quo with any alternative scenario will generate much higher financial costs but much lower health and environmental damages. Thus coal-fired electricity generation replacement presents a trade-off between incurring higher financial costs but lower health and environmental damages and incurring higher health and environmental damages but lower financial costs. Despite this trade-off, however, the alternative scenarios still entail much lower total costs.

PART 8: COMPARISON BETWEEN THE BASE CASE RESULTS AND THE MINIMUM CONSERVATION CASE RESULTS

Total Cost of Generation

The ranking of the scenarios in the Minimum Conservation Case remains the same as in the Base Case, with Scenario 3 being the lowest costing option, Scenario 2 the second lowest, Scenario 4 the third lowest, and Scenario 1 being the highest costing option. Scenario 4 still has higher total costs of generation than Scenario 2, but by only 4.3% on annualized terms[16], which is considerably smaller than 7.6% in the Base Case.

Minimum Conservation Case costs are still lower than Base Case costs but not by as much compared to the Maximum Conservation Case. This makes sense since costs in the Minimum Conservation Case are expected to be higher than in the Maximum Conservation Case. The difference in annualized costs between the two cases is $250 million for Scenario 1, $59 million for Scenario 2, $26 million for Scenario 3, and $147 million for Scenario 4.

Levelised costs are lower in the Minimum Conservation Case than in the Base Case. The difference between the two cases is $22/MWh for Scenario 1, $11/MWh for Scenario 2, $6/MWh for Scenario 3, and $14/MWh for Scenario 4.

Net Benefits

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[16] The annualized generation costs for Scenario 2 and Scenario 4 in the Minimum Conservation Case are $2546 million and $2655 million, respectively. Their percentage difference is 4.3%.

In terms of net benefits, the ranking is the same in both cases; Scenario 3 has the highest net benefit, Scenario 4 has the lowest, and Scenario 2 stays in between. However, the Minimum Conservation Case has much higher net benefits than the Base Case; the difference in annualized values is $197 million for Scenario 2, $164 million for Scenario 3, and $285 million for Scenario 4.

Health and Environmental Proportion

Health and environmental proportions are the same as in the Maximum Conservation Case and are 0-2% higher than in the Base Case.

PART 9: OPTION VALUE

In the previous analysis, Scenario 3 (Nuclear/Gas) generates the highest net benefit; however, the option value of delaying nuclear has been excluded from the cost-benefit analysis. Although CBA is the most popular approach in evaluating policies, it is often criticized for its reliability, particularly when the project involves significant uncertainties and irreversibility. In such cases, expected net present value (NPV) may not be a good decision rule because the value of delaying the investment may be positive. In this study, we have two possible cases, the Maximum Conservation Case and the Minimum Conservation Case, which differ in conservation level. As to which case will actually take place depends on the cost-effectiveness of higher conservation as well as all supply resources, which involves great uncertainties. Since construction of nuclear plants requires a long process and huge capital costs, it may not be a wise decision to plough ahead as we may find and develop better alternatives in the future. Waiting for new information and technology may be a better decision. Thus it is necessary to estimate the option value of delaying nuclear investment.

This value depends on the probability of each case and the time at which uncertainties are resolved. In Part 5, a sensitivity analysis of PVC was presented (Table 13) reflecting different assumptions about the probabilities of the two cases. Now, in order to calculate the option value, we must also make assumptions about the length of time until the uncertainty is resolved. Let X represents this value, measured in years from 2007. For example, if X=5, then in 2012 we will learn whether the actual amount of conservation savings will correspond with the Maximum Conservation Case or with the Minimum Conservation Case. Sensitivity analysis will be conducted below using values for X of 5, 10, 15, and 20 years.

The methodology used to calculate the option value of delaying nuclear refurbishment follows the real options approach of Rothwell (2006). In that paper, Rothwell examined the risk associated with new nuclear power in Texas due to fixed-pricing, i.e. suppliers receive a fixed price for the electricity they generate, of nuclear in a deregulated and competitive environment.

Using Rothwell's notation, the net present value (NPV) is represented as the difference between the present value of net revenues and initial capital cost, i.e.

$$NPV = \frac{R}{\delta} - I,$$

where R represents the average annual value of net revenues, I represents the initial capital cost, and δ represents the capital recovery factor (or risk-adjusted discount rate). The net present value can be represented as an upward sloping straight line as a function of R.

To calculate the value of waiting, Ω, we use the following equation (Rothwell 2006, p40):

$$\Omega = B \times R^{\gamma}, \quad (1)$$

where B is a positive multiplicative constant[17] and γ reflects the capital recovery factor and the uncertainties of net revenues, R. The value of waiting as a function of R can be represented by a convex curve.

Net revenue, R, is calculated as

$$R = G_i \times (P - AVC) \qquad (2)$$

where G_i is the annual nuclear generation (68% of total annual generation in Scenario 3)[18], P is the price of electricity, and AVC is the average variable cost. Unit cost of electricity to the consumer from OPA's IPSP is used as a proxy for the price of electricity, P. The average variable cost consists of variable maintenance and operating cost and fuel cost.

The value of γ is obtained by solving the differential equation that describes the Brownian motion of net revenues (See Rothwell 2006, p41). This equation yields the solution:

$$\gamma = \frac{1}{2} \times \left\{1 + [1 + (8\delta/\sigma^2)]^{1/2}\right\} \qquad (3)$$

where σ^2 represents the variance of the net revenues, i.e.

$$\sigma^2 = \frac{\Sigma(R_i - \bar{R})^2}{n}, \text{ where n = 20.} \qquad (4)$$

Rothwell (p39, fn1) shows that

$$\delta = [e^{rT}(e^r - 1)]/(e^{rT} - 1) \quad (5)$$

The discount rate, r, is assumed to be 5% and the life of nuclear plant, T, is assumed to be 40 years.

To calculate B, note that when R=R*, i.e. define R* such that NPV=0, we are indifferent between investing and waiting. In other words, the curve representing the value of waiting and

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[17] The significance of B will be given below.

[18] The breakdown of total generation among different sources for Scenario 3 (Nuclear/Gas) can be found in Appendix A of DSS & RWDI (2005). The annual generation level in terra-watt terms for small CCGT, medium CCGT, SCGT, and nuclear is 3.2, 4.4, 1, and 18.2, respectively. Nuclear represents 68% of total generation.

the line representing the net present value must intersect. However, if R* increases, the two curves can intersect only if the value of waiting curve shifts up. This corresponds to an increase in B. Thus to calculate B, we equate the net present value and the value of waiting.

$$\left(\frac{R^*}{\delta}\right) - I = B \times R^{*\gamma} \quad (6)$$

Solving for B, we get:

$$B = [(R^*/\delta) - I]/R^{*\gamma} \qquad (7)$$

To get R*, the net revenue "trigger" value, we differentiate equation (6) with respect to R*, substitute B into the differentiated equation, then solve for R*. The solution for R* is:

$$R^* = (1/\phi) \times \delta \times I, \text{ where } \phi = (\gamma - 1)/\gamma$$

The rationale for differentiation of equation (6) with respect to R* is that the value of R* is optimal only when the two curves are tangent, thus the slope of their curves are equal. Since the slopes of the curves are represented by their respective differentiated equations, therefore differentiating equation (6) is necessary to determine the optimal R*.

The calculation of the option value (equation 1) will depend upon the assumptions about p and X. Table 14 presents the sensitivity analysis for different combinations of p and X, under the assumption that the actual conservation savings revealed at time X are those of the Maximum Conservation Case. The results indicate that an option value does indeed exist for investments in nuclear power plants. In general, option value increases as uncertainty gets resolved later into the future. The option values produced ranges from a low of $14.42 billion to a high of $16.91 billion (see Appendix Table 16). Table 14 shows the results when p takes on a value of 0.1, 0.5, and 0.9. The results of the full sensitivity analysis are found in the Appendix Table 16.

Table 14: Option Value for Maximum Conservation Case after Period X ($ Billions)

	X=5	X=10	X=15	X=20
P=0.1	14.54	16.75	16.36	16.39
P=0.5	15.05	16.82	16.53	16.54
P=0.9	15.52	15.92	15.89	15.90

Table 15 presents a sensitivity analysis under the assumption that the actual conservation savings revealed at time X are those of the Minimum Conservation Case. The results in this case also indicate positive option values of delay in nuclear investment and that option value increases as uncertainty persists further into the future. The option values range from a low of $15.37 billion to a high of $18.7 billion (see Appendix Table 17). Table 15 shows the results when p equals 0.1, 0.5, and 0.9. Results of the full sensitivity analysis are included in the Appendix Table 17.

Table 15: Option Values for Minimum Conservation Case after Period X ($ Billions)

	X=5	X=10	X=15	X=20
P=0.1	16.50	16.34	16.39	16.39
P=0.5	17.44	16.20	16.51	16.54
P=0.9	18.45	15.56	15.86	15.90

The calculation of the option value will also depend upon assumptions about the life of nuclear plants, T. Since the life of nuclear plants is typically 30 to 40 years, a sensitivity analysis for this range of values is conducted, under the assumption that p equals 0.5 and X equals 10.[19] From Table 16, we can see that option value increases with T for both cases. The option value ranges from a low of $12.98 billion to a high of $16.80 billion for the Maximum Conservation

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[19] For simplicity, the mid-point values of the entire range of values of p and X are chosen.

Case and from a low of $12.76 billion to a high of $16.18 billion for the Minimum Conservation Case.

Table 16: Option Values Depending on T ($ Billions)

T	Maximum Conservation Case	Minimum Conservation Case
30	12.98	12.76
31	13.44	13.17
32	13.88	13.57
33	14.30	13.95
34	14.70	14.31
35	15.09	14.66
36	15.46	14.99
37	15.82	15.31
38	16.16	15.61
39	16.48	15.91
40	16.80	16.18

PART 10: FINAL RESULTS INCLUDING OPTION VALUE

To determine which one of the four scenarios is the best option, we must include the option value of delaying nuclear investment in the total cost for Scenario 3 (Nuclear/Gas). When we invest in nuclear power plants, the value associated with waiting is lost, thus it can be seen as an additional cost. Including the option value of delaying nuclear investment has a significant effect on the ranking of the scenarios for the Maximum Conservation Case and the Minimum Conservation Case. The total costs of Scenario 3 increases so much that it is higher than the costs of Scenario 2 (All Gas) and Scenario 4 (Stringent Controls) for the entire range of option values. Scenario 2 now has the lowest total costs and Scenario 4 has the second lowest costs. Although Scenario 3 has higher costs than Scenario 2 and Scenario 4, it still has lower costs than Scenario 1. In terms of net benefits, Scenario 2 has the highest value, Scenario 4 has the second highest, and Scenario 3 has the lowest. When option value is included in the total costs, Scenario 3 becomes the least favorable alternative scenario. Table 17 and Table 18 show total costs and net benefits, including option value, for the Maximum Conservation Case; Table 19 and Table 20 show the final results for the Minimum Conservation Case. Since the option values do not vary significantly with X, only the option values associated with X=20 are shown in these tables.

Table 17: Total Costs Including Option Value ($ Billions) – Maximum Conservation Case

p	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Coal with Stringent Controls)
0.1	47.8	28.9	36.32 – 38.81	30.8
0.5	47	28.5	35.92 – 38.41	30
0.9	46.2	28.1	35.52 – 38.01	29.2

Table 18: Net Benefits Including Option Value ($ Billions) – Maximum Conservation Case

p	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Coal with Stringent Controls)
0.1	18.9	8.99 – 11.48	17.0
0.5	18.1	8.59 – 11.08	17.0
0.9	18.1	8.19 – 10.68	17.0

Table 19: Total Costs Including Option Value ($ Billions) – Minimum Conservation Case

p	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Coal with Stringent Controls)
0.1	47.8	28.9	37.27 – 40.6	30.8
0.5	47	28.5	36.87 – 40.2	30
0.9	46.2	28.1	36.47 – 39.8	29.2

Table 20: Net Benefits Including Option Value ($ Billions) – Minimum Conservation Case

p	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Coal with Stringent Controls)
0.1	18.9	7.2 – 10.53	17.0
0.5	18.1	6.8 – 10.13	17.0
0.9	18.1	6.4 - 9.73	17.0

To see final results for the full range of probabilities of the two cases, refer to Appendix Table 18 to Table 21. In these tables, expected total costs (including option value) for Scenario 3 are not shown for each value of X; rather, they are shown as a range of values from lowest to highest.

Although a shorter life of nuclear plant, i.e. value of T, generates a lower option value, the total cost (including option value) of Scenario 3 is still larger than the total cost of Scenario 2 and Scenario 4 for the entire range of values of T for the Maximum Conservation Case and the

Table 21: Total Costs Including Option Value for T=30 ... 40

T	Maximum Conservation Case	Minimum Conservation Case
30	34.48	34.26
31	34.94	34.67
32	35.38	35.07
33	35.80	35.45
34	36.20	35.81
35	36.59	36.16
36	36.96	36.49
37	37.32	36.81
38	37.66	37.11
39	37.98	37.41
40	38.30	37.68

Minimum Conservation Case[20]. These results for Scenario 3 are presented in Table 21. The total cost for Scenario 2 and for Scenario 4, assuming p=0.5, is $28.5 billion and $30 billion, respectively. We can see from Table 21 that the results are higher than the total cost of the other two alternative scenarios for all values of T. Thus Scenario 2 and Scenario 4 are still preferred over Scenario 3 once the option value of delaying nuclear is included.

PART 11: CONCLUSION

The analysis shows that including the option value of delaying investment in nuclear plants in the cost-benefit analysis has significant effects on the ranking of the scenarios. When it is excluded, Scenario 3 (Nuclear/Gas) is the best option for replacing coal-fired electricity generation, but when it is included, it becomes the worst option. Scenario 2 (All Gas) becomes the best option, followed by Scenario 4 (Stringent Controls). Although Scenario 2 produces a higher net benefit than Scenario 4, the difference is much smaller when we take into account changes in future electricity generation level into the analysis.

The results of this study indicate that DSS & RWDI (2005) is an incomplete analysis of the four electricity scenarios. As a result, the Government of Ontario is pursuing the wrong option by investing in new nuclear generation. The government has implemented a 20-year Energy Plan in June 2006, which insists on maintaining existing nuclear capacity of 14,000 MW (Infrastructure Ontario, 2009). Since existing nuclear stations are reaching the end of their lifespan, this will require new nuclear capacity. The next new nuclear station in Ontario is planned to be built on the Darlington nuclear site; it involves four nuclear reactors and generates up to 4,800 MW of electricity capacity (OPG, 2009). The results of this revised study

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[20] The option values assume p=0.5 and X=10.

indicate that these are not the best investments to make; a better option would be to invest in new gas-fired generation or install stringent controls in existing coal-fired facilities.

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APPENDIX

Table 1: Maximum Conservation Peak Demand (MW)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Baseline Peak			26282	26515	26749	27205	26986	27426	27648	27873	28099	28457	28820
Peak Reduction			0	251	620	1407	2576	3250	3834	4350	4863	5198	5606
Peak Demand	25823	24200	26282	26264	26129	25798	24410	24176	23814	23523	23236	23259	23214
Reserve Margin (%)	17	17	17	17	17	17	17	17	17	17	18	18	18
Total Capacity	30213	28314	30750	30729	30571	30184	28560	28286	27862	27522	27418	27446	27393
Additions	0	-1899	2436	-21	-158	-387	-1624	-274	-424	-340	-103	27	-53
Required Capacity	6447	4548	8883	6426	6289	6060	4823	6173	6023	6107	6344	6474	6394

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Baseline Peak	29187	29559	29936	30444	30960	31485	32020	32563	33115	33677
Peak Reduction	6022	6351	6664	6917	7169	7416	7671	7900	8261	8616
Peak Demand	23165	23208	23272	23527	23791	24069	24349	24663	24854	25061
Reserve Margin (%)	18	18	19	19	19	19	19	19	19	19
Total Capacity	27335	27385	27694	27997	28311	28642	28975	29349	29576	29823
Additions	-58	51	308	303	314	331	333	374	227	246
Required Capacity	6389	6498	6755	6750	6761	6778	6780	6821	6674	6693

Table 2: Maximum Conservation Energy Demand (TWh)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Baseline Energy			157	158	159	159	161	162	163	164	165	168	169
Energy Savings			0	0.8	2	6.9	13.8	16.7	19.6	22.5	25.4	27.1	28.7
Energy Demand	155	157	157	157.2	157	152.1	147.2	145.3	143.4	141.5	139.6	140.9	140.3
Reserve Margin	17	17	17	17	17	17	17	17	17	17	18	18	18
Total Generation	181.4	183.7	183.7	183.9	183.7	178.0	172.2	170.0	167.8	165.6	164.7	166.3	165.6
Additions	0	2.3	-0.01	0.234	-0.234	-5.733	-5.733	-2.223	-2.223	-2.223	-0.827	1.534	-0.708
Required Generation	26.6	28.9	26.6	26.8	26.4	20.9	20.9	24.4	24.4	24.4	25.8	28.1	25.9

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Baseline Energy	171	173	176	178	181	184	187	189	192	195
Energy Savings	30.4	32	33.6	34.9	36.2	37.5	38.9	39.9	41.7	43.5
Energy Demand	140.6	141	142.4	143.1	144.8	146.5	148.1	149.1	150.3	151.5
Reserve Margin	18	18	19	19	19	19	19	19	19	19
Total Generation	165.9	166.4	169.5	170.3	172.3	174.3	176.2	177.4	178.9	180.3
Additions	0.4	0.5	3.1	0.8	2.0	2.0	1.9	1.2	1.4	1.4
Required Generation	27.0	27.1	29.7	27.4	28.6	28.6	28.5	27.8	28.0	28.0

Table 3: Minimum Conservation Peak Demand (MW)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Baseline Peak			26282	26515	26749	27205	26986	27426	27648	27873	28099	28457	28820
Peak Reduction			0	251	620	1407	1735	2064	2393	2721	3050	3266	3529
Peak Demand	25823	24200	26282	26264	26129	25798	25251	25362	25255	25152	25049	25191	25291
Reserve Margin	17	17	17	17	17	17	17	17	17	17	18	18	18
Total Capacity	30213	28314	30750	30729	30571	30184	29544	29674	29548	29428	29558	29725	29843
Additions	0	-1899	2435.94	-21.06	-157.95	-387.27	-639.99	129.87	-125.19	-120.51	129.98	167.56	118
Required Capacity	6447	4548	8883	6426	6289	6060	5807	6579	6322	6326	6577	6615	6565

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Baseline Peak	29187	29559	29936	30444	30960	31485	32020	32563	33115	33677
Peak Reduction	3798	4010	4211	4373	4535	4694	4858	5005	5235	5462
Peak Demand	25389	25549	25725	26071	26425	26791	27162	27558	27880	28215
Reserve Margin	18	18	19	19	19	19	19	19	19	19
Total Capacity	29959	30148	30613	31024	31446	31881	32323	32794	33177	33576
Additions	116	189	465	412	421	436	441	471	383	399
Required Capacity	6563	6636	6912	6859	6868	6883	6888	6918	6830	6846

Table 4: Minimum Conservation Energy Demand (TWh)

	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Baseline Energy			157	158	159	159	161	162	163	164	165	168	169
Energy Savings			0	0.8	2	6.9	8.8	10.7	12.4	14.3	16.1	17.2	18.3
Energy Demand	155	157	157	157.2	157	152.1	152.2	151.3	150.6	149.7	148.9	150.8	150.7
Reserve Margin	17	17	17	17	17	17	17	17	17	17	18	18	18
Total Generation	181.4	183.7	183.7	183.9	183.7	178.0	178.1	177.0	176.2	175.1	175.7	177.9	177.8
Additions	0	2.3	-0.01	0.234	-0.234	-5.733	0.117	-1.053	-0.819	-1.053	0.553	2.242	-0.118
Required Generation	26.6	28.9	26.6	26.8	26.4	20.9	26.7	25.5	25.8	25.5	27.2	28.8	26.5

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027
Baseline Energy	171	173	176	178	181	184	187	189	192	195
Energy Savings	19.4	20.4	21.5	22.3	23.2	24.1	25	25.7	26.8	28
Energy Demand	151.6	152.6	154.5	155.7	157.8	159.9	162	163.3	165.2	167
Reserve Margin	18	18	19	19	19	19	19	19	19	19
Total Generation	178.9	180.1	183.9	185.3	187.8	190.3	192.8	194.3	196.6	198.7
Additions	1.1	1.2	3.8	1.4	2.5	2.5	2.5	1.5	2.3	2.1
Required Generation	27.7	27.8	30.4	28.0	29.1	29.1	29.1	28.1	28.9	28.7

Note: In 2005 (base year), peak demand and energy demand are 25823 MW and 155 TWh, respectively (OPA 2008b). In 2006, peak demand is 24200 MW and energy demand is 157 TWh (IESO 2005). Since conservation starts in 2007, there are no conservation savings for 2005 and 2006. Thus for both Maximum and Minimum Conservation Cases, total capacity and total generation are 30213 MW and 181.4 TWh for 2005; they are 28314 MW and 183.7 TWh for 2006.

Table 5: Expected Total Present Value ($ Billions)

p	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0	48.0	29.0	22.0	31.0
0.1	47.8	28.9	21.9	30.8
0.2	47.6	28.8	21.8	30.6
0.3	47.4	28.7	21.7	30.4
0.4	47.2	28.6	21.6	30.2
0.5	47.0	28.5	21.5	30.0
0.6	46.8	28.4	21.4	29.8
0.7	46.6	28.3	21.3	29.6
0.8	46.4	28.2	21.2	29.4
0.9	46.2	28.1	21.1	29.2
1	46.0	28.0	21.0	29.0

Table 6: Expected Net Benefits ($ Billions)

p	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0	19.0	26.0	17.0
0.1	18.9	25.9	17.0
0.2	18.8	25.8	17.0
0.3	18.7	25.7	17.0
0.4	18.6	25.6	17.0
0.5	18.5	25.5	17.0
0.6	18.4	25.4	17.0
0.7	18.3	25.3	17.0
0.8	18.2	25.2	17.0
0.9	18.1	25.1	17.0
1	18.0	25.0	17.0

MAXIMUM CONSERVATION CASE
VS. MINIMUM CONSERVATION CASE

TABLE 7: Total Cost of Generation

	Scenario			
	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	2	1	1	2
Annualized Costs ($ Millions)	138	81	58	179
Levelised Costs ($/MWh)	1	0	0	3
Health and Environmental Proportion	0	0	0	0

TABLE 8: Net Benefits

	Scenario		
	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	0.6	1	-0.4
Annualized Costs ($ Millions)	57	80	-41
Levelised Costs ($/MWh)	1	1	-2

TABLE 9: Annualized Financial Costs and Health and Environmental Damages ($ Millions)

	Scenario			
	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Financial Costs	29	64	45	70
Health Damages	98	11	12	82
Environmental Damages	12	5	1	27
Total Generation Costs	138	81	58	179

BASE CASE VS. MAXIMUM CONSERVATION CASE

TABLE 10: Total Cost of Generation

	Scenario			
	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	3	1	1	3
Annualized Costs ($ Millions)	388	140	84	326
Levelised Costs ($/MWh)	23	11	6	17
Health and Environmental Proportion	0%	2%	2%	1%

TABLE 11: Net Benefits

	Scenario		
	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	0	24.5	17.4
Annualized Costs ($ Millions)	140	84	326
Levelised Costs ($/MWh)	11	6	17

TABLE 12: Annualized Financial Costs and Health and Environmental Damages ($ Millions)

	Scenario			
	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Financial Costs	78	62	31	118
Health Damages	277	65	45	158
Environmental Damages	32	12	8	49
Total Generation Costs	388	140	84	326

BASE CASE VS. MINIMUM CONSERVATION CASE

TABLE 13: Total Cost of Generation

	Scenario			
	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	1	0	0	1
Annualized Costs ($ Millions)	250	59	26	147
Levelised Costs ($/MWh)	22	11	6	14
Health and Environmental Proportion	0	0.02	0.02	0.01

TABLE 14: Net Benefits

	Scenario		
	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Total Present Value ($ Billions)	0.6	1	-0.4
Annualized Costs ($ Millions)	197	164	285
Levelised Costs ($/MWh)	12	7	15

TABLE 15: Annualized Financial Costs and Health and Environmental Damages ($ Millions)

	Scenario			
	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
Financial Costs	49	-2	-14	48
Health Damages	179	54	33	76
Environmental Damages	20	7	7	22
Total Generation Costs	250	59	26	147

Table 16: Option Values for the Maximum Conservation Case ($ Billions)

p	X=5	X=10	X=15	X=20
0	14.42	16.61	16.25	16.30
0.1	14.54	16.75	16.36	16.39
0.2	14.66	16.86	16.45	16.47
0.3	14.79	16.91	16.51	16.54
0.4	14.92	16.90	16.55	16.56
0.5	15.05	16.82	16.53	16.54
0.6	15.17	16.67	16.45	16.47
0.7	15.30	16.46	16.32	16.33
0.8	15.41	16.21	16.13	16.14
0.9	15.52	15.92	15.89	15.90
1	15.62	15.62	15.62	15.62

Table 17: Option Values for Minimum Conservation Case ($ Billions)

p	X=5	X=10	X=15	X=20
0	16.30	16.30	16.30	16.30
0.1	16.50	16.34	16.39	16.39
0.2	16.72	16.35	16.46	16.47
0.3	16.95	16.34	16.52	16.54
0.4	17.19	16.28	16.54	16.56
0.5	17.44	16.20	16.51	16.54
0.6	17.69	16.07	16.42	16.47
0.7	17.95	15.92	16.29	16.33
0.8	18.20	15.75	16.10	16.14
0.9	18.45	15.56	15.86	15.90
1	18.70	15.37	15.60	15.62

MAXIMUM CONSERVATION CASE

Table 18: Expected Total Cost Including Option Value ($ Billions)

p	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0	48.0	29.0	36.42 – 38.91	31.0
0.1	47.8	28.9	36.32 – 38.81	30.8
0.2	47.6	28.8	36.22 – 38.71	30.6
0.3	47.4	28.7	36.12 – 38.61	30.4
0.4	47.2	28.6	36.02 – 38.51	30.2
0.5	47.0	28.5	35.92 – 38.41	30.0
0.6	46.8	28.4	35.82 – 38.31	29.8
0.7	46.6	28.3	35.72 – 38.21	29.6
0.8	46.4	28.2	35.62 – 38.11	29.4
0.9	46.2	28.1	35.52 – 38.01	29.2
1	46.0	28.0	35.42 – 37.91	29.0

Table 19: Expected Net Benefit Including Option Value ($ Billions)

p	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0	19.0	9.09 – 11.58	17.0
0.1	18.9	8.99 – 11.48	17.0
0.2	18.8	8.89 – 11.38	17.0
0.3	18.7	8.79 - 11.28	17.0
0.4	18.6	8.69 – 11.18	17.0
0.5	18.5	8.59 – 11.08	17.0
0.6	18.4	8.49 – 10.98	17.0
0.7	18.3	8.39 – 10.88	17.0
0.8	18.2	8.29 – 10.78	17.0
0.9	18.1	8.19 – 10.68	17.0
1.0	18.0	8.09 – 10.58	17.0

MINIMUM CONSERVATION CASE

Table 20: Expected Total Cost Including Option Value ($ Billions)

p	Scenario 1 (Status Quo)	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0	48.0	29.0	37.4 – 40.7	31.0
0.1	47.8	28.9	37.3 – 40.6	30.8
0.2	47.6	28.8	37.2 – 40.5	30.6
0.3	47.4	28.7	37.1 – 40.4	30.4
0.4	47.2	28.6	37.0 – 40.3	30.2
0.5	47.0	28.5	36.9 – 40.2	30.0
0.6	46.8	28.4	36.8 – 40.1	29.8
0.7	46.6	28.3	36.7 – 40.0	29.6
0.8	46.4	28.2	36.6 – 39.9	29.4
0.9	46.2	28.1	36.5 – 39.8	29.2
1	46.0	28.0	36.4 – 39.7	29.0

Table 21: Expected Net Benefits Including Option Value ($ Billions)

p	Scenario 2 (All Gas)	Scenario 3 (Nuclear/Gas)	Scenario 4 (Stringent Controls)
0	19.0	7.3 – 10.6	17.0
0.1	18.9	7.2 – 10.5	17.0
0.2	18.8	7.1 – 10.4	17.0
0.3	18.7	7.0 – 10.3	17.0
0.4	18.6	6.9 – 10.2	17.0
0.5	18.5	6.8 – 10.1	17.0
0.6	18.4	6.7 – 10.0	17.0
0.7	18.3	6.6 – 9.9	17.0
0.8	18.2	6.5 – 9.8	17.0
0.9	18.1	6.4 – 9.7	17.0
1.0	18.0	6.3 – 9.6	17.0