NAVIGANT CONSULTING

Avoided Cost Analysis for the Evaluation of CDM Measures

Presented to

Hydro One Networks Inc.

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INTRODUCTION

Navigant Consulting Ltd. (Navigant Consulting) was retained by Hydro One Networks Inc. (Hydro One or HONI) to develop avoided cost estimates that can be used by HONI and other Ontario local distribution companies (LDCs) in their assessment of conservation and demand management (CDM) measures. The Ontario Energy Board (OEB) has asked HONI to develop an estimate of avoided costs that can be used to estimate the value of savings from these CDM measures.[1]

This report presents Navigant Consulting's analysis of the avoided energy, generation capacity, and transmission costs for the period from 2006 through 2025 and describes the major economic and energy market assumptions and inputs for the forecasts that were used to develop these avoided cost estimates. Also presented is an analysis of the environmental externalities from electricity generation.

The avoided cost estimates presented are forecasts of future costs and capital expenditures. As a forecast, they are "best estimates" of costs that are inherently uncertain. Throughout this report we outline these uncertainties and where appropriate estimate the range of possible outcomes and values. When evaluating these avoided cost estimates one should recognize that there are uncertainties associated with both the value of the avoided costs and with the savings provided by the CDM measures. These uncertainties should be evaluated and considered separately. Navigant Consulting believes that it is not appropriate to discount the avoided cost estimates to account for the uncertainty associated with the CDM savings estimates. The uncertainty of these savings estimates should be addressed through due diligence, review, and proper selection of measure load shape impacts and lives, and the application of effective measurement and verification protocols.

There are a wide range of analytical approaches and methodologies that can be used to estimate avoided costs for CDM measures. Navigant Consulting has employed approaches that we believe offer an appropriate level of analytical precision – recognizing the uncertainty associated with many of the underlying determinants of these avoided costs – and allow the avoided cost estimates to be readily applied to the evaluation of CDM measures. These methodologies and analytical methods must conform to how the avoided cost estimates will be used. Given the large number of parties that will be using these estimates and the wide range of measures to which they will be applied, particular consideration needs to be given to ensuring that they can be readily and consistently applied.

[1] http://www.oeb.gov.on.ca/html/en/hearingsanddecisions/decisionsandreports.htm, February 22, 2005.

Navigant Consulting Qualifications

Navigant Consulting has provided Ontario wholesale market assessment services, which include Ontario wholesale electricity market price forecasts and reviews of the wholesale market performance and anticipated impacts of future market design initiatives to more than 30 clients. Our Ontario electricity price forecasts have been used by the OEB to assist in establishing prices for the Regulated Price Plan and to evaluate and support billions of dollars of generation investment. We regularly use IESO market data to benchmark our price forecasts and use generator disclosure reports to evaluate the offer strategies for various Ontario generators and fine-tune our Ontario model specification. We have defended these market price forecasts before regulators in adjudicatory proceedings and lenders and investors in project financings.

Contents of This Report

This report contains four chapters. The first is this Introduction. The second reviews the analysis methodologies and sources of assumptions that were used to develop the avoided cost estimates for energy, generation capacity, transmission capacity and environmental externalities. The third chapter reviews the avoided cost analysis results. The final chapter summarizes these results and reviews important considerations with respect to the application of these avoided costs. Note that the information and results presented in the third chapter are provided primarily for transparency and are not suitable for application to actual CDM programs. We advise that readers refer to the information and data presented in the final chapter for the actual application of these avoided costs.

ANALYSIS METHODOLOGY

Overview

This chapter reviews the analytical methods that Navigant Consulting used to develop estimates of avoided costs for energy, generation capacity, transmission capacity and environmental externalities. The avoided energy cost analysis focuses on the Independent Electricity System Operator's (IESO's) administered spot market. The approach used to estimate avoided generation capacity costs is consistent with the contract structure used by the Ministry of Energy in its 2,500 MW RFP,[2] with these capacity costs representing a "top-up" payment to cover the generators' fixed operating and capital costs. Recognizing that there will be demand response measures that reduce peak demand but provide little, if any, energy savings we also developed an avoided generation capacity cost estimate based on the installed costs of simple cycle gas turbine (SCGT) generators which are generally used to provide capacity and given their high operating costs typically provide little energy. This approach ensures that the avoided energy and capacity cost estimates are consistent. Our avoided transmission investment analysis is based on HONI's current transmission expansion plan as reflected in its 10-Year Transmission Plan (*Transmission Solutions*) and reflects the investment costs of the transmission facilities that could be avoided by CDM investments. Environmental externalities are estimated based on damage cost estimates.

Note that since the level of operating reserve required is based on system contingencies related to the underlying generation fleet, not the marginal generating unit, and that CDM will not affect the underlying generation fleet, Navigant Consulting does not expect that CDM will have any impact on magnitude of operating reserve required for system reliability.

In the final chapter we adjust these estimates to ensure that transmission losses (for energy and environmental externalities) and system reserve margin (for generation capacity) are properly reflected in avoided costs to be applied for economic analysis of CDM programs.

Avoided Energy Cost

Navigant Consulting has developed an avoided energy forecast that can be used to evaluate the avoided costs achieved through CDM measures. This forecast reflects the real-time cost of energy and generally represents the marginal operating costs of the generating unit that clears the spot electricity market. This pricing behaviour is promoted by the Clean Energy Supply contract which incents generators to offer into the real-time market at their marginal operating costs. With a spot

[2] Request for Proposals For 2,500 MW of New Clean Generation and Demand-Side Projects (2,500 MW RFP)

market where generator offer strategies are reflective of a unit's marginal operating costs, avoided energy costs are reflected by market prices.[3]

The avoided energy forecast was developed using the ProSym market simulation model. Navigant Consulting's Ontario ProSym database reflects the Ontario hourly load shape, all committed new entrant generation and additional generation as required to achieve an 18% reserve margin, best available information regarding the operating profile of OPG's hydroelectric fleet (baseload and peaking resources), and operating characteristics and fuel prices for OPG's fossil fleet. The sources of our assumptions are discussed after ProSym is reviewed.

ProSym is a detailed chronological model that simulates hourly operation of generation and transmission resources. It dispatches generating resources to match hourly electricity demand recognizing unit operating constraints, dispatching the cheapest available generation first. The choice of generation is determined by the generator's offer to the market operator, by technical factors such as ramp rates (for fossil resources) or water availability (for hydraulic resources) and by transmission constraints. This dispatch establishes market-clearing prices that each generator located within the same market area receives for its energy output, regardless of its actual offer price.

Our ProSym model specification includes the entire Eastern Interconnect, so it captures trade between Ontario and its interconnected markets.

A more detailed explanation of how this model works can be found in *Appendix A – Detailed Avoided Energy Forecasting Methodology*. The time horizon for the forecast is twenty years, with every year modelled from 2006 through 2015, and with 2020 and 2025 simulated as well. The prices between 2015 and 2020 and between 2020 and 2025 were then interpolated. The specific assumptions used in specifying the model are discussed below.

Market Modelling Assumptions

The sources of the primary modeling assumptions as well as the key assumptions are reviewed below. Broadly, four classes of primary assumptions underpin our price forecast:

[3] In a system without such a market, one would need to dispatch the system with and without the assumed level of CDM impact to determine the avoided energy cost. While we could have performed our analysis by assuming a specific level of CDM impact, e.g., 100 MW to reflect the average impact from an assumed CDM impact of 200 MW, this was not believed to have a material impact on the analysis results and there was no basis upon which to estimate the likely level of CDM impact. When this analysis is updated we expect that better information will be available regarding likely levels of CDM impacts.

1. Demand forecast
    a. Peak demand
    b. Energy
    c. Price responsive load
2. Supply forecast
    a. Coal phase out
    b. Nuclear return
    c. Renewable generation
    d. Cogeneration
    e. Natural gas-fired generation
3. Transmission capabilities and constraints
4. Fuels
    a. Natural gas & oil prices
    b. Coal prices

Relevant but less important is the US-Canadian currency exchange rate.[4] The following sections present our data sources and judgment for each of the primary assumptions.

Demand Forecast

The demand forecast was based upon IESO forecasts of 2005 peak demand and energy, and an actual Ontario load shape (from a single year which represents normal weather). The "Expected Seasonal Peak Demand" value for 2005 was taken from the IESO's most current *18-Month Outlook: Ontario Demand Forecast From April 2005 to September 2006* (March 23, 2005). The 2005 energy forecast was based on the "Median Growth Scenario" in the IESO's *10-Year Outlook: Ontario Demand Forecast From January 2005 to December 2014* (March 31, 2004). The 2005 energy and peak demand values were then escalated annually by the growth rates predicted in the IESO's *10-Year Outlook: Ontario Demand Forecast From January 2005 to December 2014* (March 31, 2004). For energy, the median growth rate of 0.9% was used, and for peak demand, the normal weather summer peak demand growth rate of 1.1% was used. Table 1 presents the annual energy consumption and peak demand forecasts that we used.

[4] The avoided energy cost forecast is based on an exchange rate of $1.00 CAD to $0.80 USD.

Table 1: Forecast Annual Energy Consumption and Peak Demand

Year	Annual Energy Pre-Conservation (TWh)	Annual Peak Demand (MW) Pre-conservation and DR
2005	155.5	25,551
2006	156.9	25,832
2007	158.3	26,116
2008	159.7	26,403
2009	161.2	26,694
2010	162.6	26,988
2011	164.1	27,284
2012	165.6	27,585
2013	167.1	27,888
2014	168.6	28,195
2015	170.1	28,505
2016	171.6	28,818
2017	173.2	29,135
2018	174.7	29,456
2019	176.3	29,780
2020	177.9	30,108
2021	179.5	30,439
2022	181.1	30,774
2023	182.7	31,112
2024	184.4	31,454
2025	186.0	31,800
CAGR, 2005	0.9%	1.1%

Source: IESO

Price Responsive Load

Our assumptions regarding the amount of price responsive load reflect the forecast provided by the IESO in the "Planned Resource Scenario" of their *18-Month Outlook.* The 2006 value of 655 MW was then kept constant throughout the forecast period and was the same for all three scenarios. Because the purpose of this analysis was to estimate the value of load reductions achieved through CDM measures we did not increase this amount of price responsive load or assume any additional CDM beyond this price responsive load.

Supply Assumptions

Three supply scenarios were developed to reflect the uncertainty regarding future supply and provide a range of likely market prices. The most significant areas of uncertainty relate to the policy decisions of phasing out Ontario's coal-fired generation, and returning to service the remaining laid-up nuclear units.

The base case (Scenario 1) includes full phasing out of the coal units by the end of 2007, in accordance with the Government's objective, and the return to service, and later refurbishment when required, of all nuclear units. Scenario 2 – Low Nuclear also phases out all coal by 2007, but does not include the return to service of Pickering 2 & 3, or the refurbishment of any Pickering units when required. Rather, these units are allowed to retire at that time. Scenario 3 – Coal Phase-Out by 2010, includes the return of all nuclear units, but each of the two Bruce A units is delayed by one year. This delay is one of the reasons why this scenario has a delayed coal phase-out schedule, with all coal phased out by the end of 2010. The details of the scenarios are laid out below.

Coal Phase-Out Schedule

All three scenarios assume full coal phase-out, although the timing differs. Scenarios 1 and 2 assume that the phase-out of all coal is achieved by the end of 2007, whereas Scenario 3 assumes a delayed coal phase-out schedule with full phase out occurring by the end of 2010. The detailed coal phase-out schedule for each scenario is given in Table 2. In Scenario 3 where coal is retained until 2010, the cleanest and lowest cost coal-fired generation is the last to be retired.[5]

Table 2: Coal Phase-out Schedule

Scenario 1 - Base Case and Scenario 2 - Low Nuclear	Scenario 3 - Coal phase-out by 2010
Lambton	**Lambton**
All units retire on December 31, 2007	Units 1 and 2 retire December 31, 2007
	Unit 3 and 4 retire December 31, 2010
Nanticoke	**Nanticoke**
Units 5 and 6 on December 31, 2006	Units 5 and 6 on December 31, 2006
Units 1,2,3,4,7 and 8 on December 31, 2007	Units 1, 2, 3 and 4 on December 31, 2007
	Units 7 and 8 on December 31, 2009
Atikokan	**Atikokan**
December 31, 2007	December 31, 2007
Thunder Bay	**Thunder Bay**
December 31, 2006	December 31, 2006

Source: Navigant Consulting

[5] Lambton Units 3 and 4 have FGDs and SCRs to reduce SO_2 and NOx emissions, causing them to be the Ontario coal-fired units with the lowest SO_2 and NOx emissions. The FGDs allow the units to burn high sulfur coal which also causes them to be the lowest cost coal units.

Nuclear Return Schedule

Given the announcement that the Government and Bruce Power have completed negotiations for the restart of Bruce units 1 & 2, all three scenarios include the return to service of these units. All three scenarios also include the return of Pickering 1, which is expected later this year. Pickering units 2 & 3 are included in Scenarios 1 and 3, but not in Scenario 2. The assumptions regarding the return of this nuclear capacity is based in part on analyses that Navigant Consulting has performed which indicates that the refurbishment of this nuclear capacity is cost-effective assuming Ontario's coal-fired generation is phased-out and if these refurbishments can be completed within the budgets proposed.

The detailed nuclear return schedule is provided in Table 3.

Table 3: Nuclear Return Schedule

Scenario 1 - Base Case		Scenario 2 - Low Nuclear		Scenario 3 - Coal Phase out by 2010	
Pickering A	**Returns**	**Pickering A**	**Returns**	**Pickering A**	**Returns**
Unit 1	Sep-05	Unit 1	Sep-05	Unit 1	Sep-05
Unit 2	Apr-07	Unit 2	Does not return	Unit 2	Apr-07
Unit 3	Apr-08	Unit 3	Does not return	Unit 3	Apr-08
Bruce A	**Returns**	**Bruce A**	**Returns**	**Bruce A**	**Returns**
Unit 1	Jan-08	Unit 1	Jan-08	Unit 1	Jan-09
Unit 2	Jan-09	Unit 2	Jan-09	Unit 2	Jan-10

Source: Navigant Consulting

Renewable Generation

All three scenarios have the same assumptions regarding renewable capacity additions. We have assumed that the targets of 1,350 MW of renewable capacity by the end of 2007 and 2,700 MW by the end of 2010 will be met. We have included all of the projects that have signed RES contracts with the Government from the first Renewables RFP, and have assumed an additional 1,000 MW of capacity will be contracted for through the current Renewables RFP and subsequent tranches (i.e., a second renewables RFP in 2005 for up to 200 MW from projects less than 20 MW) and will be in-service by the end of 2007. We have then assumed an additional 450 MW of renewable capacity coming into service each of the following three years to meet the 2010 commitment. Approximately 80% of this capacity is assumed to be wind power based on the results of the first Renewables RFP,[6] with the remaining portion made up of small hydro and biomass projects.

[6] In the first Renewables RFP 90% of the capacity was from wind projects. Subsequent to this RFP the Federal Government has implemented additional incentives for non-wind renewable projects which are expected to increase the proportion of these projects in these Renewable RFPs.

Cogeneration

The three scenarios have the same assumptions regarding the addition of cogeneration capacity. The first of the units brought into service will be the GTAA Cogen project that recently signed a Clean Energy Supply (CES) contract with the Government. This project is expected to come into service in 2006. We then assume an additional 600 MW of cogeneration development by 2014, spurred by the appointment of an industrial cogeneration facilitator, and any policies that the facilitator may put in place.

Natural Gas-Fired Generation

In each scenario, the projects that have signed CES contracts were included, along with any generic natural gas units needed in each year to maintain a reserve margin in Ontario of approximately 18%. Given the different nuclear and coal capacity assumptions, the amount and timing of new gas-fired generation will differ from one scenario to the next.

Table 4 shows the demand-supply balance that underlies the base case forecast. Existing Capacity values reflect the effects of the coal phase-out and the return and refurbishment of nuclear capacity. Included in cumulative new entry for 2008 is 2,155 MW from the 2,500 MW RFP and an additional 400 MW is assumed to enter service by 2009. Also included in cumulative new entry is the 2,700 MW of renewable capacity based on the Government's Renewable Portfolio Standard.[7] After this new gas-fired capacity (combined cycle gas turbine or simple cycle gas turbine whichever has the lowest overall cost given the identified need for capacity) is added to maintain an 18% reserve margin.

7 Wind and new run-of-river hydro projects are de-rated from their nameplate capacity in the demand-supply balance table to reflect actual capability factors.

Table 4: Base Case Demand-Supply Balance

Total Resources (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020	2025
Existing Capacity	28,927	28,152	24,521	25,290	24,521	25,290	24,409	23,893	23,893	22,488	24,775	25,290
Cumulative Retirements	(1,140)	(2,430)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)
Non-Utility Generation	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690
Cumulative New Entry	342	621	3,046	3,738	4,730	4,922	5,667	6,517	6,867	8,167	8,367	9,767
Total Resources (MW)	30,959	30,463	29,257	30,718	30,941	31,902	31,766	32,100	32,450	32,345	34,832	36,747
Total Requirements (MW)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**	**2025**
Net Energy (TWh)	156.9	158.3	159.7	161.2	162.6	164.1	165.6	167.1	168.6	170.1	177.9	186.0
Projected Peak Demand	25,832	26,116	26,403	26,694	26,988	27,284	27,585	27,888	28,195	28,505	30,108	31,800
Less: Conservation Impact												
Demand Response	655	655	655	655	655	655	655	655	655	655	655	655
Conservation												
Revised Peak Demand	25,177	25,461	25,748	26,039	26,333	26,629	26,930	27,233	27,540	27,850	29,453	31,145
Plus: Reserve Req. @18%	4,532	4,583	4,635	4,687	4,740	4,793	4,847	4,902	4,957	5,013	5,301	5,606
Total Requirements (MW)	29,709	30,044	30,383	30,726	31,072	31,423	31,777	32,135	32,497	32,863	34,754	36,751
Surplus/(Deficiency) (MW)	1,250	419	(1,126)	(8)	(131)	480	(11)	(35)	(47)	(518)	78	(4)
Reserve Margin (%)	23.0%	19.6%	13.6%	18.0%	17.5%	19.8%	18.0%	17.9%	17.8%	16.1%	18.3%	18.0%

Source: Navigant Consulting

Transmission Capabilities and Constraints

Given that the HOEP is based on a uniform price which does not reflect transmission congestion within Ontario, we do not reflect internal Ontario transmission constraints in this model specification. The transfer capabilities of transmission interconnections with adjacent markets are from the IESO *10-Year Outlook* (dated March 31, 2004), differentiated by season and direction of flow. Table 5 indicates the assumed ratings of Ontario's interconnections with adjacent markets based on the information presented in the IESO's *10-Year Outlook*.

Table 5: Ontario Interconnection Limits

Interconnection	Flows Out of Ontario (MW)	Flows Into Ontario (MW)
Manitoba		
Summer	262	330
Winter	274	342
Minnesota	140	90
Michigan		
Summer	1,900	1,200
Winter	2,000	1,450
New York East	400	400
New York West		
Summer	1,250	1,150
Winter	1,500	1,350
Quebec South		
Summer	740	1,410
Winter	760	1,410
Quebec North		
Summer	95	65
Winter	110	84

Source: IMO, 10-Year Outlook, March 31, 2005. Where a range of values was given, the mid-point has been shown here.

Fuel Prices

Given the uncertainty associated with fuel price forecasts, Navigant Consulting typically relies on liquid financial and physical markets to specify the underlying fuel forecasts we use in power market modeling, unless our clients derive their own forecasts. Since we forecast prices in US dollars, we specify fuel prices within the model in US dollars.

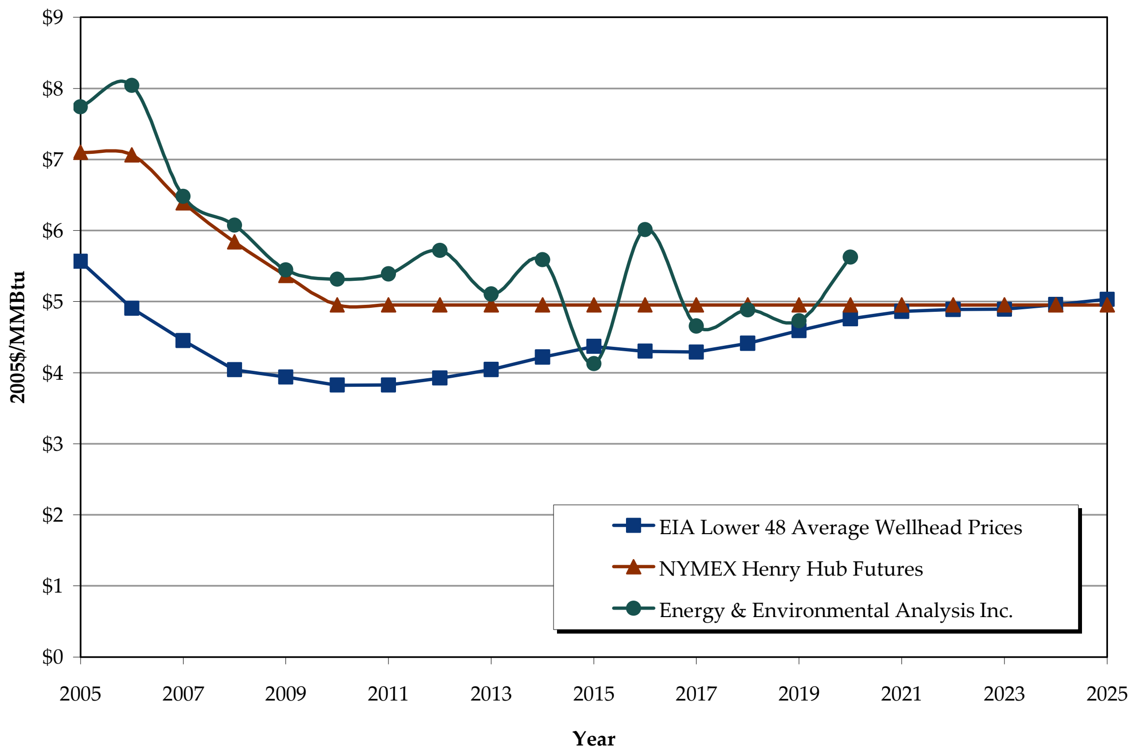
Natural Gas

For this forecast we used the futures prices as reported publicly on the NYMEX website in US$/MMBtu. We elected to use these futures prices since they reflect the prices at which buyers and sellers are willing to transact and represent transparent pricing information. With recent increases, natural gas prices are at historic highs. Given the uncertainty regarding natural gas prices, we performed a sensitivity analysis where we evaluated natural gas prices which were ± 20% relative to the Henry Hub price used in the base case.

Figure 1 contrasts the Henry Hub futures natural gas prices that we have used as the basis for our natural gas price forecast with other natural gas price forecasts including the US Energy Information Administration (*Annual Energy Outlook*) and a natural gas price forecast that was developed by

Energy & Environmental Analysis Inc. for the American Gas Association (*Natural Gas Outlook to 2020*, February 2005.)

Figure 1: Industry Natural Gas Price Forecasts



Source: Energy Information Administration, NYMEX, and Energy & Environmental Analysis Inc.

NYMEX futures prices are only available through 2010, so we have escalated the 2010 prices by inflation for subsequent years. To these futures prices, we apply a basis differential. For natural gas this basis differential is from Henry Hub to the Union Dawn trading hub in southwestern Ontario. This basis differential is based on the historical relationship between futures prices for delivery at Henry Hub and Dawn. Finally, we apply a local delivery charge to represent costs paid to the gas utility to deliver the gas from Dawn to individual generator locations.

For residual and distillate oil we also add a basis differential from New York Harbour to Kingston to reflect delivery at Lennox. Since Lennox operates as a dual-fuel facility, and we believe it has an environmental constraint on the number of oil-fired hours, we use a blend of natural gas and residual oil price. Natural gas and fuel oil price assumptions are presented in Table 6 below.

Table 6: Natural Gas and Fuel Oil Prices (2005 USD$)

Year	Natural Gas @ Southern Ontario - Low Case ($USD/MMBtu)	Natural Gas @ Southern Ontario - Base Case ($USD/MMBtu)	Natural Gas @ Southern Ontario - High Case ($USD/MMBtu)	#2 Fuel Oil @ Southern Ontario ($USD/MMBtu)	#6 Residual Oil @ Southern Ontario ($USD/MMBtu)
2006	6.22	7.78	9.33	9.91	5.78
2007	5.67	7.09	8.51	9.24	5.42
2008	5.20	6.49	7.79	8.60	5.07
2009	4.78	5.98	7.17	8.26	4.88
2010	4.44	5.55	6.66	7.97	4.72
2011	4.44	5.55	6.66	7.74	4.59
2012	4.44	5.55	6.65	7.74	4.59
2013	4.43	5.54	6.65	7.74	4.59
2014	4.43	5.54	6.65	7.74	4.59
2015	4.43	5.54	6.64	7.74	4.59
2016	4.43	5.53	6.64	7.74	4.59
2017	4.42	5.53	6.63	7.74	4.59
2018	4.42	5.53	6.63	7.74	4.59
2019	4.42	5.52	6.63	7.74	4.59
2020	4.42	5.52	6.62	7.74	4.59
2021	4.41	5.52	6.62	7.74	4.59
2022	4.41	5.51	6.62	7.74	4.59
2023	4.41	5.51	6.61	7.74	4.59
2024	4.41	5.51	6.61	7.74	4.59
2025	4.40	5.50	6.60	7.74	4.59

Source: Navigant Consulting

Coal

Our forecast of coal prices was based on the NYMEX futures coal price (Central Appalachian), with transportation charges added. The transportation charges were derived from Energy Information Administration (EIA) data. Table 7 presents the coal price forecast used in the model. Note that prices are only shown through 2010 since all coal-fired generation has been phased out after that.

Table 7: Coal Prices (2005 USD$)

Year	Low Sulfur Bituminous - Lakeview	High Sulfur Bituminous - Lambton 3 & 4	Low Sulfur Bituminous - Lambton 1 & 2	Nanticoke (Blend of low sulfur bituminous and Powder River Basin coal)	Low Sulfur Lignite - Atikokan	Low Sulfur Lignite - Thunder Bay
2006	$2.91	$1.80	$2.84	$2.38	$1.19	$1.34
2007	$2.60	$1.61	$2.54	$2.16	$1.07	$1.20
2008	$2.47	$1.52	$2.41	$2.06	$1.01	$1.14
2009	$2.47	$1.52	$2.41	$2.06	$1.01	$1.14
2010	$2.47	$1.52	$2.41	$2.06	$1.01	$1.14

Source: Navigant Consulting

Avoided Generation Capacity Costs

Our avoided capacity cost estimates are based on the contracting framework employed by the Ontario Ministry of Energy in its 2,500 MW RFP for conservation measures and the costs of a SCGT for demand response programs that provide peak demand reductions but limited energy savings. Specifically under the CES Contract generators receive supplemental payments from the Ontario Power Authority (OPA) when deemed net margins earned from their participation in the energy market are less than their fixed operating and capital costs as specified in their proposal submitted in response to the 2,500 MW RFP. Natural gas-fired generators also specify a project heat rate and a variable operation and maintenance (VOM) cost. This heat rate is applied to the daily Dawn natural gas price to determine the project's deemed fuel cost. This deemed fuel cost and VOM cost establish the project's deemed marginal operating costs. Whenever the HOEP is greater than the project's deemed marginal operating cost it is assumed to be operating, subject to various operating and scheduling constraints. The deemed net margins earned when operating are the difference between the HOEP and the deemed marginal operating costs. These deemed net margins are then subtracted from the Net Revenue Requirements (NRR) submitted by the Proponent to determine the "top-up" payment or Contingent Support Payment (CSP) as it is referred to in the CES Contract. The NRR is anticipated to represent the fixed operating and capital costs of the project less any supplemental revenue that the Proponent expects to earn outside the energy market, e.g., from operating reserve revenues.

The framework that we have established for estimating avoided capacity costs is consistent with that established by the CES Contract. We estimate each project's NRR, heat rate and VOM and based on these estimates determine the CSPs for each year of the analysis period. Our analysis implicitly assumes that this contracting framework will be employed by the OPA when contracting for capacity in the future.[8] The OPA has indicated in the Request for Expressions of Interest it is administering for generation and demand response capacity in the York Region that it will use a contract form consistent with the CES contract and that it expects generators to maximize their revenues from sources other than the OPA.

Consistent with the results of the 2,500 MW RFP and analyses that we have performed, combined cycle gas turbines (CCGTs) are assumed to be the least cost source of significant new capacity The higher capital costs of a CCGT relative to a SCGT, or peaker, are more than offset by the additional energy market revenues earned by the CCGT. Therefore, our analysis of avoided capacity costs for conservation measures evaluates the "top-up" payments for CCGTs.

[8] However, the results of our analysis are generally consistent with those that would be achieved if Ontario had a capacity market similar to the Resource Adequacy Market that has been evaluated by the IESO, or the installed capacity markets that have been implemented in U.S. Northeast markets.

The assumptions used for the NRR estimate are presented in Table 8 below. The source for the cost and operating performance assumptions is the US Energy Information Administration's *2005 Annual Energy Outlook*. US dollars were converted to Canadian dollars at $1.00 CAN to $0.80 US exchange rate. The natural gas transportation charges reflect a Union Gas delivery charge from Dawn to Parkway.[9] We have embedded in the NRR the additional cost of natural gas transportation charges and subtracted from it the anticipated revenues from operating reserve. The financing assumptions are appropriate given the risks borne by the Supplier in the CES contract.

Table 8: Assumptions for Net Revenue Requirement Calculation

Assumption	CCGT	SCGT	Source
Capital Cost (CAD$/kW)	802	559	Energy Information Administration[1]
Total Capital Cost (CAD$/kW)[2]	889	624	
Fixed O&M (CAD$/kW-year)	16	15	Energy Information Administration
Natural Gas Delivery Charge (CAD$/kW-year)	8	8	Based on Union Gas Rate C1 for transportation between Dawn and Parkway
Operating Reserve Revenue (CAD$/kW-year)	(4)	(5)	Navigant Consulting forecast
Percent Debt	60%	60%	Navigant Consulting judgement
Percent Equity	40%	40%	Navigant Consulting judgement
Cost of Debt	7.5%	7.5%	Navigant Consulting judgement
Return on Equity	14%	14%	Navigant Consulting judgement

Notes:
1. EIA 2005 Annual Energy Outlook and related assumptions can be found at: http://www.eia.doe.gov/oiaf/aeo/. The costs presented above have been escalated from EIA assumptions, which are given in 2002 dollars.
2. Total Capital Cost includes the cost of operational spares and the cost of construction financing both of which are not included the EIA's capital cost assumption.

Using the assumptions noted above and a 20-year cash flow valuation model, Navigant Consulting has estimated a NRR for the CCGT of $12.82/kW-month. The NRR for the SCGT is $10.23/kW-month. The NRR calculation for the CCGT assumes a 20 percent NRR Indexing Factor. That is, 20 percent of the NRR, which is the maximum permitted under the CES contract, will be escalated annually according to the inflation rate. We have not applied a NRR Indexing Factor to the calculation of the NRR for the SCGT.

Avoided Transmission Investment Costs

The focus of this analysis is to determine the impact of CDM-driven peak demand reductions on the timing of transmission system investments. The starting point was to determine what transmission investments can be avoided or deferred by CDM measures. Transmission investment can be avoided only if the CDM programs are able to defer the need date of the investment, i.e., to reduce load so that it is needed at least one year later. There are a number of transmission system investments which are not driven by load growth or conversely cannot be deferred by reductions in

9 The majority of natural gas-fired capacity contracted under the 2,500 MW RFP was located at Dawn. We assume that any subsequent RFPs will limit the amount of capacity located in this area given the potential for transmission constraints.

load growth from CDM measures. These include: (1) asset sustainment which are the capital and OM&A costs for existing facilities; (2) interconnection upgrades; (3) transmission congestion relief; and (4) supply reliability improvements. The one major form of transmission system investment that can be avoided is system upgrades for local area load growth. Hydro One has indicated that for 2006 these system upgrades for local area load growth had a capital budget of approximately $60 million compared to a total capital budget for this period for the transmission business of $400 million.

To estimate these avoided transmission investment costs we obtained from Hydro One an estimate of the cost of the system upgrades for local area load growth reflected in its 10-Year Transmission Plan.

The cumulative CDM impact is critical in determining the number of years the transmission investment could be deferred. For example, if the average deferral period for a range of projects under an assumed 0.1% annual reduction in load from CDM (ie, 25 MW in 2007, plus an additional 25 MW in 2008 and so on) was estimated to be one year, the average deferral period would increase with higher CDM impacts (say 0.2% or 0.3% annual reduction in load).[10] In addition, the necessary lead times vary from investment to investment. Given the nature of transmission system planning and with the understanding that investment decisions will be based on forecasts of CDM activity, the actual ability to defer investment is dependant on the reasonableness of the CDM impact assumptions and the existing evidence of their effectiveness.

The avoided transmission costs were estimated based on the magnitude of capital expenditures deferred, the deferral period, the cost of capital, and avoided operations and maintenance (O&M) costs. Hydro One indicates that annual O&M costs are approximately 1% of the capital costs. Hydro One's current pre-tax cost of capital of 9.3% was used in the analysis. This is based on a capital structure comprised of: 60% debt at 5.6%[11]; 4% preferred shares with a yield of 5.5%; and 36% equity with a 9.88% after-tax cost of equity. Based on a 36% tax rate, the pre-tax cost of the preferred shares is 8.6% and the pre-tax cost of common equity is 15.4%.

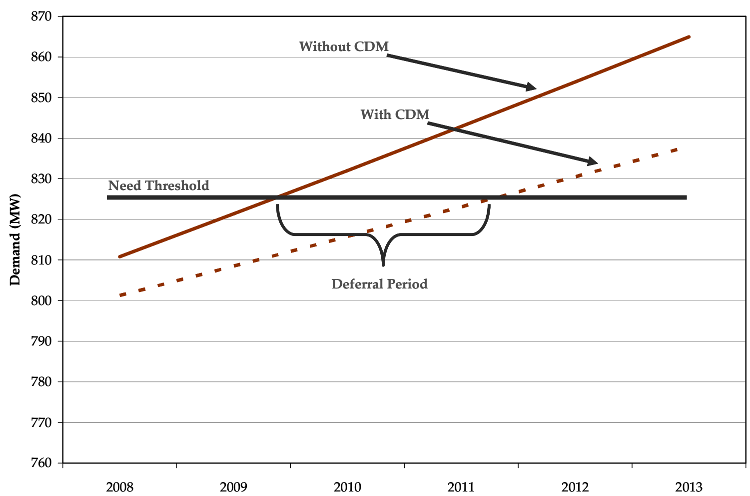
The nominal capital costs provided in 2005 dollars by HONI were escalated at a 2.5% inflation rate up to the need date to account for the increase in project costs over time. As CDM activity further defers the need for investment, further escalation is applied. O&M costs are also escalated at the same inflation rate.

[10] The second critical determinant of the deferral period is the load growth in that area. It is the relationship between the load impact from the CDM and the period over which the CDM impacts are experienced (determining the cumulative impact) versus the forecast load that determines length of the deferral period.

[11] The 5.6% interest rate is the declared long-term debt interest rate as released in the Hydro One "*Notes To Consolidated Financial Statements*".

An example of the transmission investment avoided cost analysis is presented in Figure 2 and Table 9. Figure 2 shows illustratively the impact of a CDM measure on load growth, and the resulting ability to defer the need date of an investment. Over the deferral period, avoided capital carrying charges and O&M expenditures are accrued, providing cost benefit for the CDM measure.

Figure 2: Illustrative Example of Deferred Transmission Investment



In this illustrative example, the initial investment of $11.31 million has been deferred by two years. The localized CDM impacts are driven by assumed province-wide CDM impacts of 0.4% annually, prorated to the load that will be served by the transmission upgrade. The escalation in capital costs over the deferral period amounts to $570 thousand and is realized as an additional cost in the year the project is initiated. Leading up to the new need date, the avoided capital carrying charges are $1.05 million per year and the benefit of avoided O&M is $113 thousand during the deferral period. The bottom row of Table 9 represents the total avoided cost associated with the deferral of this particular transmission project.

Table 9: Transmission Avoided Costs Analysis Model

Category	2008	2009	2010	2011	2012	2013	2014	2015
Load (MW)	801.3	808.5	815.7	823.1	830.5	838.0	845.5	853.1
CDM Impact (MW)	9.6	12.9	16.3	19.8	23.3	26.9	30.6	34.4
New Need Date					X			
Original Need Date			X					
Cost	$ -	$ -	$ -	$ -	$ 11.89	$ -	$ -	$ -
Original Cost	-	-	11.31	-	-	-	-	-
Avoided Capital Expenditures	-	-	11.31	11.31	(0.57)	-	-	-
Avoided Capital Carrying Charges	-	-	1.05	1.05	(0.57)	-	-	-
O&M	-	-	-	-	-	0.119	0.122	0.125
Original O&M	-	-	-	0.113	0.116	0.119	0.122	0.125
Avoided O&M Costs	-	-	-	0.113	0.116	-	-	-
Total Avoided Cost Benefit	**$ -**	**$ -**	**$ 1.05**	**$ 1.16**	**$ (0.46)**	**$ -**	**$ -**	**$ -**

Source: Navigant Consulting

The avoided costs associated with the deferral of each project are then aggregated. This figure is divided by the cumulative province-wide load reduction impact from the CDM programs to derive a $/kW estimate. This $/kW estimate is then levelized to yield a $/kW-year estimate. The levelized avoided costs across the period take into account the time value of money and redistribute the payments equally over the term. All payments and credits are discounted back to a present value and then redistributed using an equal payment method. The HONI corporate cost of capital (9.3%) was used as the discount rate.

Avoided Transmission and Distribution Losses

The forecast of avoided energy costs developed by Navigant Consulting is a forecast of the cost of electricity at the point of generation, and not necessarily the cost of electricity that is consumed at the ultimate delivery point. The actual avoided energy cost must be adjusted to reflect the impact of transmission and distribution losses that would have been incurred between the generation and consumption points.

Navigant Consulting understands that distribution losses will be evaluated and applied by LDCs prior to applying the avoided energy cost framework.

On average, transmission losses amount to less than three percent of the electricity transmitted through the system[12]. The magnitude of these losses varies throughout the day and by season, losses generally increase as load on the system increases. In addition, marginal losses, the change in losses due to an incremental unit of power injected into the grid, can be significantly greater. These

[12] Navigant Consulting analysis of information provided by the IESO.

marginal losses, which are of obvious importance in an avoided energy cost analysis, can reach up to four times the average[13].

Based on hourly transmission losses from May 1, 2002 provided by the IESO, we have calculated average and marginal losses by seasonal time-of-use periods, which are shown in Table 10.

Table 10: Transmission Losses by Season and Time-of-use Period

Since Market Opening May 1, 2002	Time of Use Periods										
	Winter				Summer				Shoulder		
	December - March				June - September				April, May, October & November		
	On Peak	Mid-Peak	Off Peak	Average	On Peak	Mid-Peak	Off Peak	Average	Mid-Peak	Off Peak	Average
	7 - 11 am, 5 - 8 pm	11 am - 5 pm, 8 - 10 pm	10 pm - 7 am		11 am - 5 pm	7 - 11 am, 5 - 10 pm	10 pm - 7 am		7 am - 10 pm	10 pm - 7 am	
Average Losses	2.6%	2.6%	2.5%	2.5%	2.8%	2.7%	2.4%	2.5%	2.7%	2.4%	2.6%
Marginal Losses	9.9%	7.4%	5.7%	7.0%	8.6%	5.7%	5.3%	6.0%	12.3%	4.6%	8.0%
(MW)	21,489	21,013	18,457	19,702	20,803	19,740	16,315	18,031	18,869	15,862	17,205

Source: Navigant Consulting analysis

Avoided Environmental Costs

Electricity generation, like all economic activities, affects the environment in ways that impose costs on society. Such costs represent real damages to people and property, even if they are not paid by consumers. These costs are avoided when electricity is not generated. To include them in total avoided costs on the same basis as other avoided costs, their dollar value must be estimated (that is, they must be monetized).

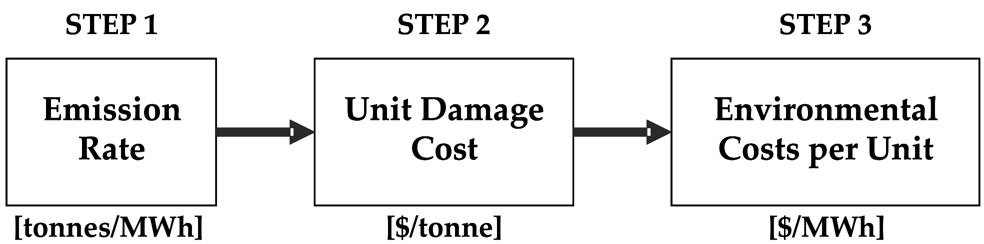
The essential framework for the monetization of the costs is given in Figure 3 below. The basic model is that electricity generation causes environmental impacts through emissions of pollutants, which affect people, animals, vegetation, and buildings. The environmental costs of pollution are the costs to the society of these impacts.

Figure 3 shows that the estimated money costs per unit of output for any environmental damage from any given pollutant are the product of the rate of emission of the pollutant and the unit damage costs for the pollutant. Total damage costs from that pollutant are then the unit damage costs times the total output.

[13] Navigant Consulting analysis of information provided by IESO. In discussion with the IESO, it was suggested that the higher marginal losses for the mid-peak period of the shoulder months are attributable to the increased output from the hydroelectric units in the north of the Province. The longer the distance that energy has to travel, the larger the overall losses. The increase in output from the hydroelectric units in the shoulder months is largely due to spring freshet, and the increased number of maintenance outages taken during this period by the thermal units.

To be consistent with the financial cost analysis, environmental costs will be estimated for each year of the study and for each of the eight time periods in the year.

Figure 3: Diagram of Environmental Cost Estimation



This framework is applied for each pollutant for each category of environmental damage which it causes. It produces a dollar amount per unit of electricity for the avoided damage costs for each pollutant, which are then summed for all pollutants to produce a total avoided damage cost per unit.

The amount of each pollutant emitted per MWh depends on the generation source. As for the other avoided cost calculations, the reduction in generation due to CDM measures is from the resources on the margin. That is, when a CDM measure reduces demand by one MWh, the analysis assumes that the reduction comes from the generation source that is the last to be scheduled.

Generation on the margin changes with changing supply and demand conditions. The electricity supply system is designed to respond to demand as it fluctuates in the short term (hours to months). In the long term, the supply system itself changes as old plants retire and new ones are commissioned. In Ontario, the source of the generation on the margin is expected to change significantly as coal-fired plants are phased out and new generation is brought on-line.

These changes in what generation is on the margin change the environmental benefits of the reduction in demand. Since the environmental benefits of reducing demand change over time, the analysis must be done separately for each time frame. For this report, the environmental cost analysis uses the same time frames as the production cost analysis: winter and summer on-peak, mid-peak, and off peak periods, and shoulder season mid-peak and off-peak periods. Each of these periods is analyzed separately.

The incremental environmental costs are estimated in three separate categories and added together to obtain total incremental environmental costs:

- Health damage costs are the costs of damages to human health caused by the impact of pollution on the population in the pollution deposition zone.
- Damage costs from effects on agriculture and property

- Climate change costs are the costs of climate change attributable to the emissions.

In determining the avoided cost for electricity not generated, all of these costs can be estimated in money terms, or monetized. Monetized environmental damage costs can then be used for decision making along with financial and other money costs.

Some major pollutants resulting from electricity generation and their impacts are

- Carbon Dioxide (CO_2): causes climate change,
- Total Particulate Matter (TPM), measured by size (PM_{10} – particulate matter less than 10 microns in diameter— and $PM_{2.5}$): causes health damage to humans,
- SO_2: causes damage to human health due to conversion to PM through photochemical reactions and damage to vegetation and materials
- NO_x: causes damage to human health due to conversion to PM and ground-level ozone through photochemical reactions.

Electricity generation can emit many other pollutants, some of them (such as mercury), toxic. This analysis looks only at the effect of emissions for which monetary values are available for Ontario. It therefore focuses on the pollutants listed.

Monetizing these costs requires numerical estimates for all of the factors in Figure 3. This requires several separate estimates, each of which is subject to some uncertainty and in some instances methodological challenges. The resulting monetary estimates are therefore subject to considerable uncertainty. However, with significant research on these issues there is considerable consensus on the appropriate methodologies, and the results generally fall within a recognizable range. The discussion below indicates some of these issues and the choices which are made for this study.

Step 1 in Figure 3 represents data on the emission rates for the avoided generation. These are the emissions of the pollutants whose impacts will be evaluated, and depend on the kind of generation being avoided.

Step 2 in Figure 3 is the most problematic to estimate. Unit damage cost estimates are the result of several steps which are analyzed separately.

The first part of Step 2 is to determine how the emissions affect the quality of the air. The effect is concentration of contaminants in an area subject to the effects of the emissions. The concentration of contaminants is a result of the location of the emitters and the prevailing winds. Estimates of contaminant concentration come from models which take into account both air flow and photochemical effects of the mix of pollutants. An example of a contaminant concentration would be an increase of PM_{10} of, say, 1 $\mu g/m^3$ (micrograms per cubic metre) of ambient air.

The next part of Step 2 is to determine the response of the exposed population to the increased concentration of the pollutant. These are measured in concentration-response functions. Concentration-response functions are the result of epidemiological studies which correlate health effects with levels of pollutant concentration. The resulting functions give the increase in risk of health impacts for a given increase in concentration. For example, a concentration-response function for mortality due to $PM_{2.5}$ exposure could say that the mortality risk increases by 2.14×10^{-5} for an increase in concentration of 1 $\mu g/m^3$. Other such functions would give the increase in risk of hospital admissions, emergency room visits, etc.

The last part of Step 2 is to determine the cost of the environmental damage by evaluating the damages in money terms. These costs come in the three categories already identified: costs of damage to human health, costs of damage to property and crops, and costs of climate change.

Damage to human health is further analyzed as mortality (increased risk of death) and morbidity (increased risk of illness).

For human health damages, several methodologies can be used to arrive at monetary values. One commonly accepted methodology is called contingent valuation. It uses sophisticated questionnaire and survey techniques to infer the amounts that individuals would be willing to pay for various benefits. For example, one benefit of reduced pollution is a reduction in the risk of the health impacts. A willingness to pay study could infer from individual's preferences as stated in a series of complex questions that the individual would be willing to pay $1,000 to avoid an increase in mortality risk from 1 chance in 10,000 to 1 chance in 5,000. From this conclusion, the implied value of life is $5,000,000. The value ascribed to the mortality risk is called the Value of a Statistical Life, or VSL.

For morbidity effects, both willingness to pay to avoid morbidity risks and direct costs of the morbidity effects (costs of medical treatment, etc.) can be used to arrive at monetary valuations for the damages.

The analysis of avoided environmental costs for CDM measures requires a further step. The intent of the analysis is to determine the environmental cost of the electricity generation on the margin; that is, the environmental cost of the electricity that would be displaced by a successful CDM program. Since the type of generation which is on the margin changes over time, the costs for each form of generation that creates environmental costs must be weighted by their probability of being on the margin in order to get marginal avoided costs. This is necessary because, for example, if the

MWh saved would otherwise have been provided by activating a demand response program, no emissions would be avoided.[14]

To obtain the marginal environmental cost, therefore, the marginal cost for the sources of electricity that generate air emissions (basically, all fossil-fueled sources) is weighted for each time period by the fraction of time that this electricity is on the margin.

In practice, all of the parts of Step 2 in Figure 3 above are difficult to estimate. Ideally, both the impact of pollution on an affected population and its value should be estimated for each population, because of the differences across populations. However, given the difficulty and cost of such studies, results from one jurisdiction are often applied to populations in another, where the two are chosen to be similar. A robust literature of impact and cost estimations is becoming available, allowing reasonable choice.

A recent study for the Ontario Ministry of Energy[15] has specifically reported on estimated environmental costs from electricity generation for Ontario. We will use these estimated environmental costs as the basis for the monetization of the avoided environmental cost due to CDM.

The CBA Study presented two levels of environmental costs for each of four scenarios:

- Production of 26.6 TWh per year entirely from the existing coal-fired fleet
- Equal production entirely from new gas-fired generation (CCGTs)
- Equal production from a mix of gas-fired and nuclear generation
- Equal production from the existing coal-fired units equipped with emissions controls.

The two levels of environmental cost were those considering mortality impacts as estimated by studies looking at exposed populations over a long period of time and those considering mortality impacts as estimated by studies looking at exposed populations over shorter time periods. The estimated mortality rates from the long-term functions were about seven times the estimated mortality rates from the short-term functions. The standard for environmental cost studies has been the use of the short-term mortality rates. This has been largely due to the fact that there have been few studies estimating the long-term impacts. Since the methodology requires careful matching of the populations in the studies providing the estimates with the populations where the estimates are

[14] Costs, of course, would have been avoided, in that the demand response market participant would not be paid for its response.

[15] DSS Management Consultants and RWDI Air, "Cost-Benefit Analysis: Replacing Ontario's Coal-Fired Electricity Generation", prepared for Ontario Ministry of Energy, April, 2005; hereafter "CBA Study".

applied, and given the relative lack of long-term studies, we have used only the results from short-term mortality estimates.

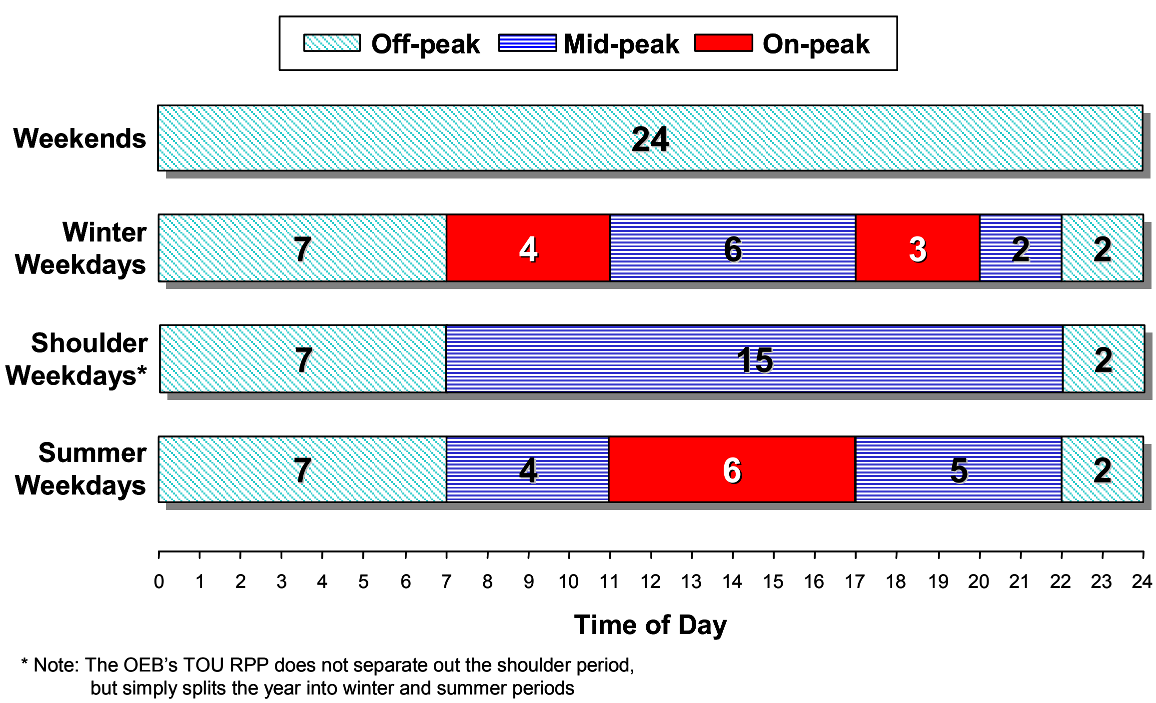
AVOIDED COST ANALYSIS RESULTS

Note that the information and results presented in this chapter are provided primarily for transparency and are not suitable for application to actual CDM programs. We advise that readers refer to the information and data presented in the final chapter for the actual application of these avoided costs.

Avoided Energy Cost

As discussed, the PROSYM model forecasts the energy costs that could be avoided by conservation and demand management. The model generated an hourly energy cost forecast that was used to develop seasonal on-peak, mid-peak and off-peak energy costs according to the Time of Use (TOU) price periods defined by the Ontario Energy Board's Regulated Price Plan (RPP). Whereas the RPP defines only two seasons, summer and winter, we have chosen to present avoided costs broken down into three seasons to provide more resolution for valuing CDM initiatives. We have defined summer to be the months from June through September, winter to be December through March, and the shoulder season to be the months of April, May, October and November. The designation of on-peak, mid-peak and off-peak was applied based on the RPP TOU price periods as shown in Figure 4 below.

Figure 4: RPP Time of Use Price Periods



For all three seasons, the off-peak period is defined as 10 PM to 7 AM every day, and all day on weekends and holidays.[16] For the summer season, on-peak is defined as 11 AM to 5 PM on weekdays, while the hours of 7 AM to 11 AM and 5 PM to 10 PM are classified as mid-peak. For the winter season, the periods of 7 AM to 11 AM and 5 PM to 8 PM are considered on-peak, with the periods of 11 AM to 5 PM and 8 PM to 10 PM designated mid-peak. Since the RPP only specifies two seasons, there was no definition for on-peak, mid-peak and off-peak hours for the shoulder period. The off-peak period has been set to be consistent with that for the other seasons. The remaining hours have all been classified as mid-peak. There are two reasons for this decision. The first reason is that shoulder months are intrinsically lower-priced months due to more moderate weather, and so the peak prices in such months will not compare with peak prices in the summer and winter. The second reason is that the difference between on-peak and mid-peak avoided energy costs would not be large enough to justify a separate category. Navigant Consulting calculated shoulder season on-peak and mid-peak avoided costs according to both the summer and winter time period designations, and found that in both cases, the difference between the on-peak price and mid-peak price was less than \$5/MWh. In contrast, for the summer and winter seasons, this difference was approximately \$30/MWh. The resulting seasonal TOU avoided energy costs for the base case forecast are provided in Table 11. These values are shown in 2005 dollars and do not reflect transmission losses.

[16] All time periods referenced are local time.

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Table 11: Base Case Seasonal Time-of-Use Avoided Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/MWh)										
	Winter				Summer				Shoulder		
	On Peak	Mid-Peak	Off Peak	Average	On Peak	Mid-Peak	Off Peak	Average	Mid-Peak	Off Peak	Average
2006	$106.2	$75.8	$41.8	$63.2	$100.7	$74.8	$43.9	$62.3	$72.0	$39.4	$53.9
2007	$106.9	$74.3	$40.6	$62.3	$97.1	$71.4	$41.3	$59.1	$67.9	$37.1	$51.1
2008	$96.6	$74.7	$42.8	$61.8	$93.9	$73.2	$44.1	$60.8	$73.6	$39.8	$54.8
2009	$91.4	$64.7	$41.7	$57.6	$86.6	$67.9	$40.8	$56.4	$68.1	$37.5	$51.0
2010	$90.4	$63.3	$43.5	$58.1	$86.5	$67.1	$40.3	$55.9	$64.7	$36.6	$49.0
2011	$85.6	$61.8	$42.8	$56.2	$81.3	$66.1	$39.6	$54.3	$63.7	$35.4	$47.8
2012	$85.2	$61.5	$42.3	$55.6	$87.0	$67.1	$40.8	$55.9	$65.3	$38.3	$50.6
2013	$92.6	$65.7	$46.4	$60.5	$87.7	$70.6	$42.0	$57.6	$66.6	$40.7	$52.5
2014	$90.7	$68.6	$47.4	$61.6	$93.7	$73.1	$43.0	$60.1	$69.4	$41.6	$54.0
2015	$89.7	$68.5	$51.3	$63.5	$108.3	$78.6	$46.2	$66.2	$70.4	$44.7	$56.0
2016	$90.4	$68.7	$50.9	$63.5	$106.3	$77.7	$46.1	$65.5	$69.8	$44.6	$55.7
2017	$91.1	$68.9	$50.6	$63.5	$104.3	$76.8	$46.0	$64.8	$69.3	$44.6	$55.5
2018	$91.7	$69.0	$50.2	$63.4	$102.4	$75.8	$45.9	$64.2	$68.7	$44.5	$55.1
2019	$92.2	$69.1	$49.8	$63.4	$100.5	$74.9	$45.7	$63.5	$68.1	$44.4	$54.8
2020	$92.6	$69.1	$49.4	$63.2	$98.7	$74.0	$45.5	$62.8	$67.5	$44.3	$54.5
2021	$92.5	$68.9	$49.5	$63.2	$96.7	$74.0	$45.6	$62.5	$67.7	$44.4	$54.7
2022	$92.3	$68.6	$49.6	$63.1	$94.9	$74.0	$45.7	$62.1	$67.9	$44.5	$54.9
2023	$92.0	$68.3	$49.6	$63.0	$93.0	$74.0	$45.7	$61.8	$68.1	$44.6	$55.0
2024	$91.7	$68.0	$49.7	$62.9	$91.2	$73.9	$45.7	$61.4	$68.2	$44.6	$55.1
2025	$91.3	$67.6	$49.6	$62.7	$89.4	$73.7	$45.7	$61.0	$68.2	$44.7	$55.2

Source: Navigant Consulting avoided cost forecast

The annual average avoided costs for the Base Case are given in Table 12 below. The nominal 2006 annual average avoided costs of $61.4/MWh (shown in the table as $59.9/MWh in 2005 dollars) lines up nicely with current 2006 forward prices for Ontario of $61.71/MWh. These avoided costs are higher than historical prices due to the high natural gas price forecast used, and the alignment of the forecast prices with forwards provides confirmation of their reasonableness.

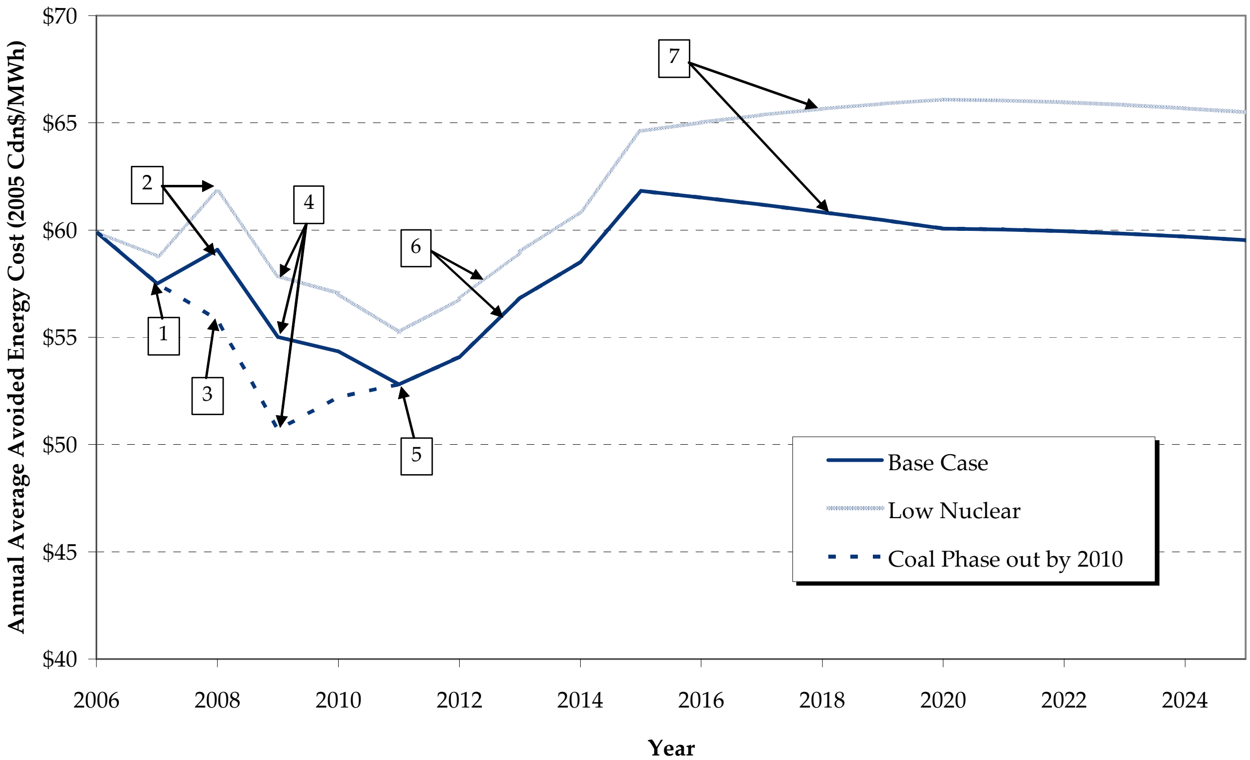
Table 12: Supply Scenario Comparison

Year	Annual Average Avoided Energy Cost (2005 CAD$/MWh)		
	Scenario 1: Base Case	Scenario 2: Low Nuclear	Scenario 3: Coal Phase out by 2010
2006	$59.9	$59.9	$59.9
2007	$57.5	$58.8	$57.5
2008	$59.1	$61.8	$55.8
2009	$55.0	$57.9	$50.7
2010	$54.3	$57.0	$52.2
2011	$52.8	$55.2	$52.8
2012	$54.1	$56.8	$54.1
2013	$56.8	$59.0	$56.8
2014	$58.5	$60.9	$58.5
2015	$61.8	$64.6	$61.8
2016	$61.5	$65.0	$61.5
2017	$61.2	$65.4	$61.2
2018	$60.8	$65.7	$60.8
2019	$60.5	$65.9	$60.5
2020	$60.1	$66.1	$60.1
2021	$60.0	$66.0	$60.0
2022	$59.9	$66.0	$59.9
2023	$59.8	$65.8	$59.8
2024	$59.7	$65.7	$59.7
2025	$59.5	$65.5	$59.5

Source: Navigant Consulting avoided cost forecast

Table 12 also displays the annual average avoided costs for our two alternate supply scenarios. These results demonstrate the general robustness of the forecast to varying supply assumptions. While Scenario 2 always has higher avoided costs than the Base Case due to less nuclear capacity, the differences are not very large until the later years of the forecast. As would be expected, the difference increases over time as more nuclear units are retired in Scenario 2 and escalating gas prices exacerbate the difference in avoided costs caused by using more natural gas capacity to replace nuclear capacity present in the Base Case. The Coal Phase-out by 2010 Scenario is identical to the Base Case except for 2008 through 2010, when the coal phase-out is delayed. In these years, the presence of some coal-fired capacity lowers avoided costs, although the difference is not very large. The annual average avoided costs for the three scenarios are shown graphically in Figure 5. This figure also provides an explanation of the factors that drive the avoided costs over time.

Figure 5: Supply Scenario Comparison

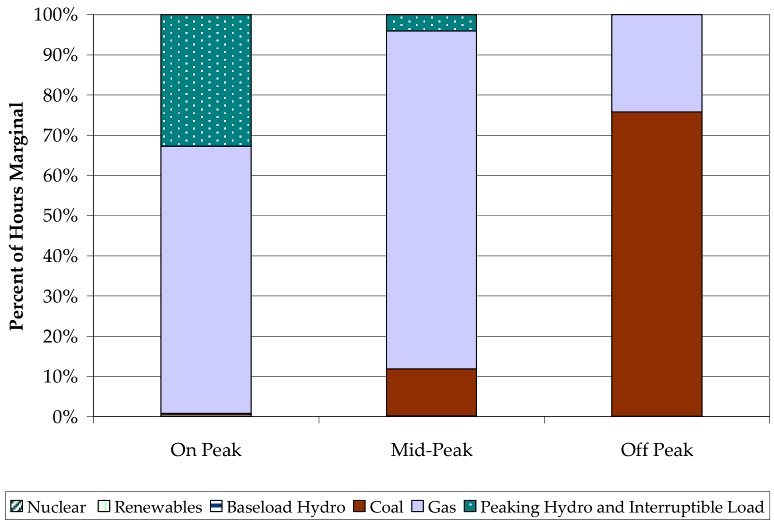


1. Declining gas prices and Pickering A returns drive avoided energy cost down
2. Coal phase-out causes jump in avoided energy cost in Base Case and Low Nuclear Scenario
3. Retention of coal and continuing decline in gas prices continues to drive avoided energy cost down in Scenario 3
4. Return of Bruce A unit and continuing declining gas prices reduce avoided energy cost further
5. Coal phase-out causes jump in avoided energy cost in Scenario 3, Coal Phase out by 2010
6. Nuclear units out for refurbishment and escalating gas prices raise avoided energy cost sharply
7. Market price increases are driven mainly by inflation, so avoided energy cost remains relatively stable

Source: Navigant Consulting

The relatively high avoided energy costs are driven by the prevalent role of gas-fired units in setting market prices. Figure 6 shows the percentage of time that each type of unit is marginal (i.e. setting the market price) in 2006. As can be seen, gas-fired generation is the marginal resource for the majority of on-peak and mid-peak hours, while "other" units, which include peaking hydro and interruptible load, establish the avoided cost for most of the other on-peak hours. Coal units play a role in establishing the avoided cost for some mid-peak hours, and are the most prevalent marginal units off-peak. The presence of the coal units as marginal for some hours moderates avoided costs in those hours, but gas prices still play a significant part in determining the avoided energy costs.

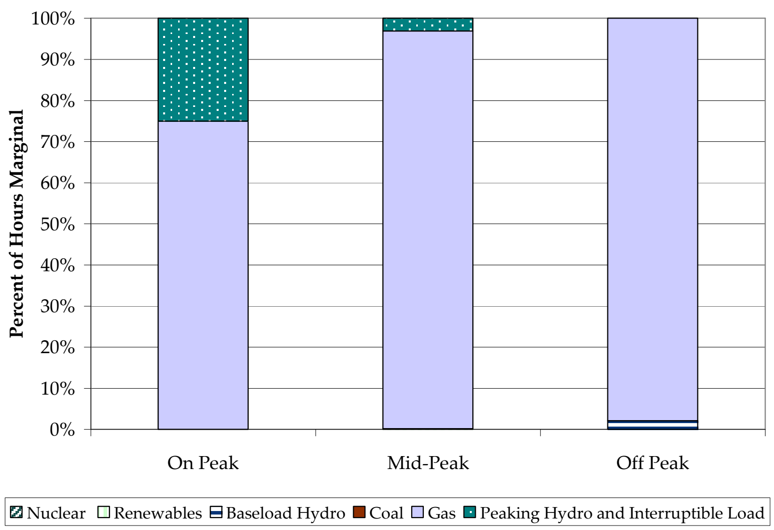
Figure 6: Marginal Units 2006



Source: Navigant Consulting

By 2010, with the retirement of the coal plants and the commissioning of additional gas-fired capacity, natural gas-fired generation is the marginal resource in an even greater number of hours. As can be seen from Figure 7: , gas-fired units establish avoided energy costs for most hours, making up for the loss of the coal fleet, and reducing the number of hours that other units are on the margin as well. The reduced role of gas-fired generation on peak reflects that increased role of storage hydro units in establishing avoided costs.

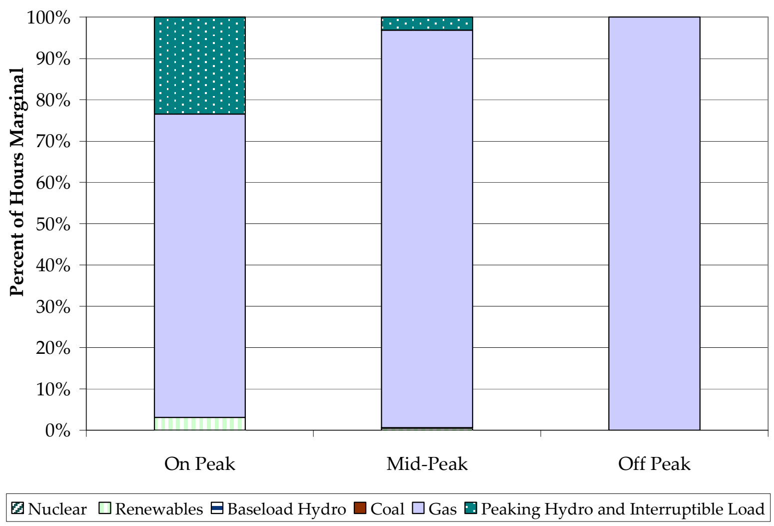
Figure 7: Marginal Units 2010



Source: Navigant Consulting

With load growth and even more gas-fired capacity by 2020, gas-fired units set the margin in almost all off-peak hours, and in the majority of on-peak hours. This explains why the off-peak energy costs rise more than the off-peak and mid-peak costs. Figure 8 depicts the percentage of hours during which each type of unit is forecast to be marginal in 2020.

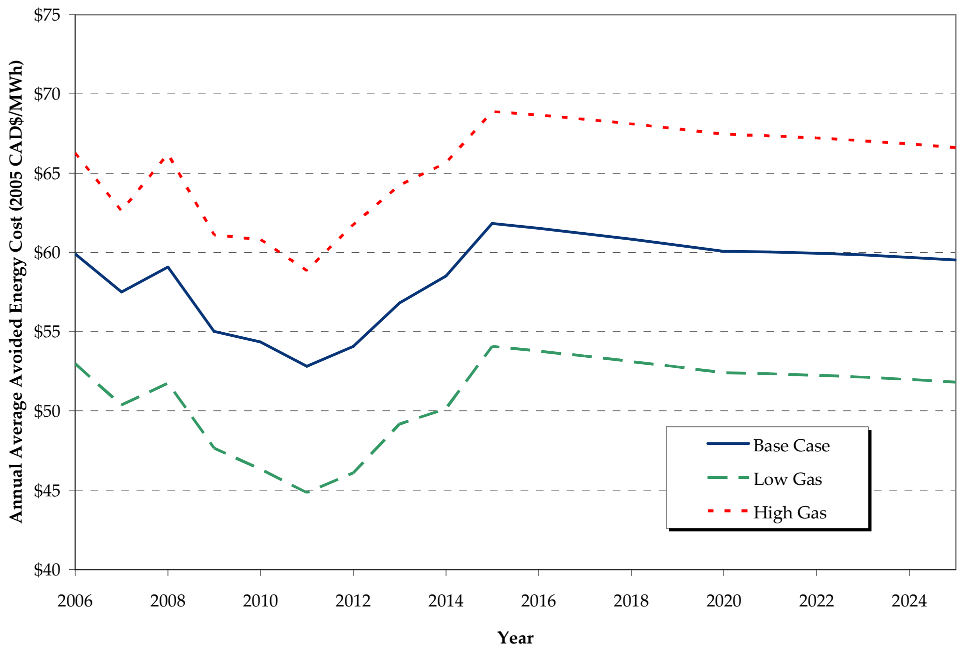
Figure 8: Marginal Units 2020



Source: Navigant Consulting

Given the role of gas-fired units as a marginal generation resource, one would expect that the avoided energy costs would be highly sensitive to natural gas prices. Figure 9: presents the results of our natural gas price sensitivity for the Base Case. As expected, the annual average avoided costs show that the forecast is sensitive to gas prices. Natural gas prices are inherently volatile and difficult to predict, and constitute the greatest uncertainty in this forecast. However, given the relatively high natural gas price forecast used in the base case, it is very unlikely that gas prices will be as high as those used in the High Gas Scenario.

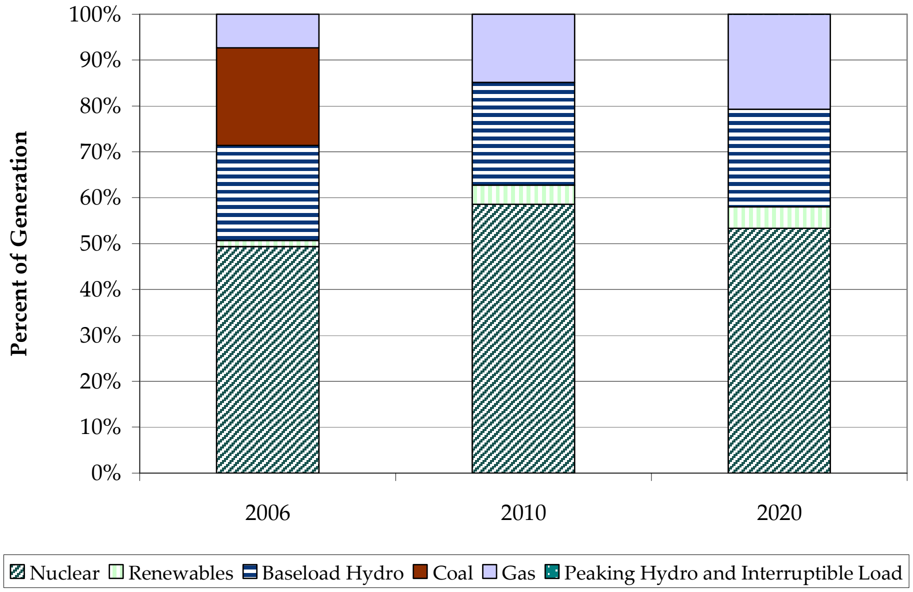
Figure 9: Natural Gas Price Sensitivity (2005 CAD$)



Source: Navigant Consulting

Finally, while natural gas-fired generation is often on the margin, the breakdown of total energy production is more varied. Figure 10: shows that nuclear units supply half of the energy required, with coal and hydro providing the bulk of the rest. Given the limited amount of gas-fired capacity in the province, gas-fired generation only makes up 7% of the total production, despite establishing the avoided energy costs in so many hours.

Figure 10: 2006, 2010 and 2020 Generation by Type



Source: Navigant Consulting

By 2010, the coal units have been phased out, and the energy they would produce is made up primarily from increases in nuclear capacity and more natural gas-fired generation.

Finally, by 2020, natural gas generation supplies a larger portion of Ontario's total energy. Since the amount of nuclear and hydro capacity does not increase significantly from 2010 to 2020, most of the growth in Ontario's energy demand must be supplied by natural gas generation. As a result, gas generators supply a greater percentage of the province's energy, leading to higher avoided energy costs, particularly off-peak.

Avoided Generation Capacity Costs

A critical determinant of the value of avoided generation capacity costs is when there is a need for this capacity. Table 13 presents a demand - supply balance similar to that found in Table 4, with the exception that only committed capacity has been included (i.e. no new additional gas-fired generation capacity has been included to maintain the 18% reserve margin).[17] The capacity deficit in 2008 indicates that CDM programs have an avoided generation capacity value as of 2008.

[17] One additional difference is the amount of cumulative new entry in 2008. Table 4 which is consistent with the ProSym model specification was specified prior to the Government announcement regarding the award of two CES contracts for 560 MW to Eastern Power. The 9 MW difference in new entry for 2008 is immaterial and would have little impact on the results presented in this report.

Table 13: The Need for Additional Capacity, Demand - Supply Balance

Total Resources (MW)	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2020
Existing Capacity	28,927	28,152	24,521	25,290	24,521	25,290	24,409	23,893	23,893	22,488	24,775
Cumulative Retirements	(1,140)	(2,430)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)	(7,561)
Non-Utility Generation	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690	1,690
Cumulative New Entry	342	621	3,055	3,247	3,439	3,631	3,631	3,631	3,631	3,631	3,631
Total Resources (MW)	30,959	30,463	29,266	30,227	29,650	30,611	29,730	29,214	29,214	27,809	30,096
Total Requirements (MW)	**2006**	**2007**	**2008**	**2009**	**2010**	**2011**	**2012**	**2013**	**2014**	**2015**	**2020**
Net Energy (TWh)	156.9	158.3	159.7	161.2	162.6	164.1	165.6	167.1	168.6	170.1	177.9
Projected Peak Demand	25,832	26,116	26,403	26,694	26,988	27,284	27,585	27,888	28,195	28,505	30,108
Less: Demand Response Impact											
Demand Response	655	655	655	655	655	655	655	655	655	655	655
Revised Peak Demand	25,177	25,461	25,748	26,039	26,333	26,629	26,930	27,233	27,540	27,850	29,453
Plus: Reserve Req. @18%	4,532	4,583	4,635	4,687	4,740	4,793	4,847	4,902	4,957	5,013	5,301
Total Requirements (MW)	29,709	30,044	30,383	30,726	31,072	31,423	31,777	32,135	32,497	32,863	34,754
Surplus/(Deficiency) (MW)	1,250	419	(1,117)	(499)	(1,423)	(812)	(2,047)	(2,921)	(3,283)	(5,054)	(4,658)
Reserve Margin (%)	23.0%	19.6%	13.7%	16.1%	12.6%	15.0%	10.4%	7.3%	6.1%	-0.1%	2.2%

Source: Navigant Consulting

In accordance with the CES contract, the avoided capacity costs reflect the difference between the estimated NRR and imputed net market revenues (this is defined as the contingent support payment or CSP in the CES contract), calculated according to the heat rate and VOM indicated in Table 14, the forecast natural gas price at Dawn and the base case avoided energy cost forecast. The avoided capacity costs shown in Table 15 should be used for CDM measures that have an impact on peak loads and provide energy savings.

Table 14: Assumptions for Imputed Net Market Revenues Calculation

Assumption	CCGT
Heat Rate (Btu/kWh)	7,100
Variable O&M (CAN$/MWh)	3.05

Source: Navigant Consulting

Given that the NRRs for individual projects will vary based on their in-service dates, we assume that the NRRs escalate by inflation. That is, the NRR for a project in-service in 2009 will be greater than the NRR for a project in-service in 2008 by inflation. The net revenues earned in the energy market are not likely to vary based on the in-service date of the CCGT.[18] To reflect the increasing NRRs we provide separate forecasts of the avoided capacity costs based on different generator in-service dates. These avoided capacity costs should be used for a consistent CDM measure in-service date.

[18] Except to the degree that new gas turbine technologies are introduced. While we expect this to occur over time, we assume that this analysis will be updated by the time that there is a new class of gas turbines that is receiving widespread application.

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Table 15 illustrates the range of avoided capacity costs in a given year resulting from differences in NRRs for each CDM measure in-service date.

Table 15: Avoided Capacity Cost by CDM Measure In-Service Date (2005 CAN$/kW-year)

CDM Measure In-Service Date	Avoided Capacity Costs (2005 CAN$/kW-year)																	
	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
2008	58.7	62.8	50.8	58.4	52.6	36.3	23.9	6.5	7.4	7.9	7.4	6.4	4.6	6.9	7.6	7.4	6.1	3.4
2009		65.6	53.5	61.0	55.2	38.8	26.4	8.9	9.8	10.1	9.7	8.6	6.8	9.0	9.6	9.3	8.0	5.3
2010			56.3	63.7	57.8	41.4	28.9	11.4	12.2	12.5	11.9	10.8	8.9	11.1	11.7	11.4	10.0	7.2
2011				66.5	60.5	44.1	31.5	13.9	14.6	14.9	14.3	13.1	11.2	13.3	13.8	13.4	12.0	9.2
2012					63.3	46.8	34.2	16.5	17.2	17.4	16.7	15.4	13.5	15.5	16.0	15.5	14.1	11.2
2013						49.6	36.9	19.1	19.7	19.9	19.2	17.9	15.8	17.8	18.2	17.7	16.2	13.3
2014							39.7	21.8	22.4	22.5	21.7	20.3	18.2	20.2	20.5	20.0	18.4	15.4
2015								24.6	25.1	25.1	24.3	22.8	20.7	22.6	22.8	22.2	20.6	17.6
2016									27.9	27.8	26.9	25.4	23.2	25.0	25.2	24.6	22.9	19.8
2017										30.6	29.6	28.1	25.8	27.6	27.7	27.0	25.3	22.1
2018											32.4	30.8	28.4	30.2	30.2	29.5	27.7	24.5
2019												33.6	31.2	32.8	32.8	32.0	30.1	26.9
2020													34.0	35.5	35.5	34.6	32.7	29.3
2021														38.3	38.2	37.2	35.3	31.9
2022															41.0	39.9	37.9	34.4
2023																42.7	40.6	37.1
2024																	43.4	39.8
2025																		42.6

Source: Navigant Consulting

As expected, the avoided capacity cost varies from year to year based on forecast net margins earned in the energy market. Higher market energy prices reduce the OPA's CSP obligation to suppliers, thereby reducing the value of the avoided capacity costs in that year. However, the larger avoided energy costs that result from higher energy prices act to counterbalance these lower avoided capacity costs.

Table 16 simplifies the application of the NRR in the calculation of the CSPs or avoided capacity costs. This approach assumes equal amounts of CDM savings are realized each year (ie, 100 MW in 2007, plus an additional 100 MW in 2008 and so on) and simply takes the average NRR in each year to calculate the CSPs. This differs from the more rigorous approach which weighs the value of the NRR for the years in which capacity was avoided. For the initial years of the analysis there is not a significant difference between the in-service dates based estimate and the average estimate.

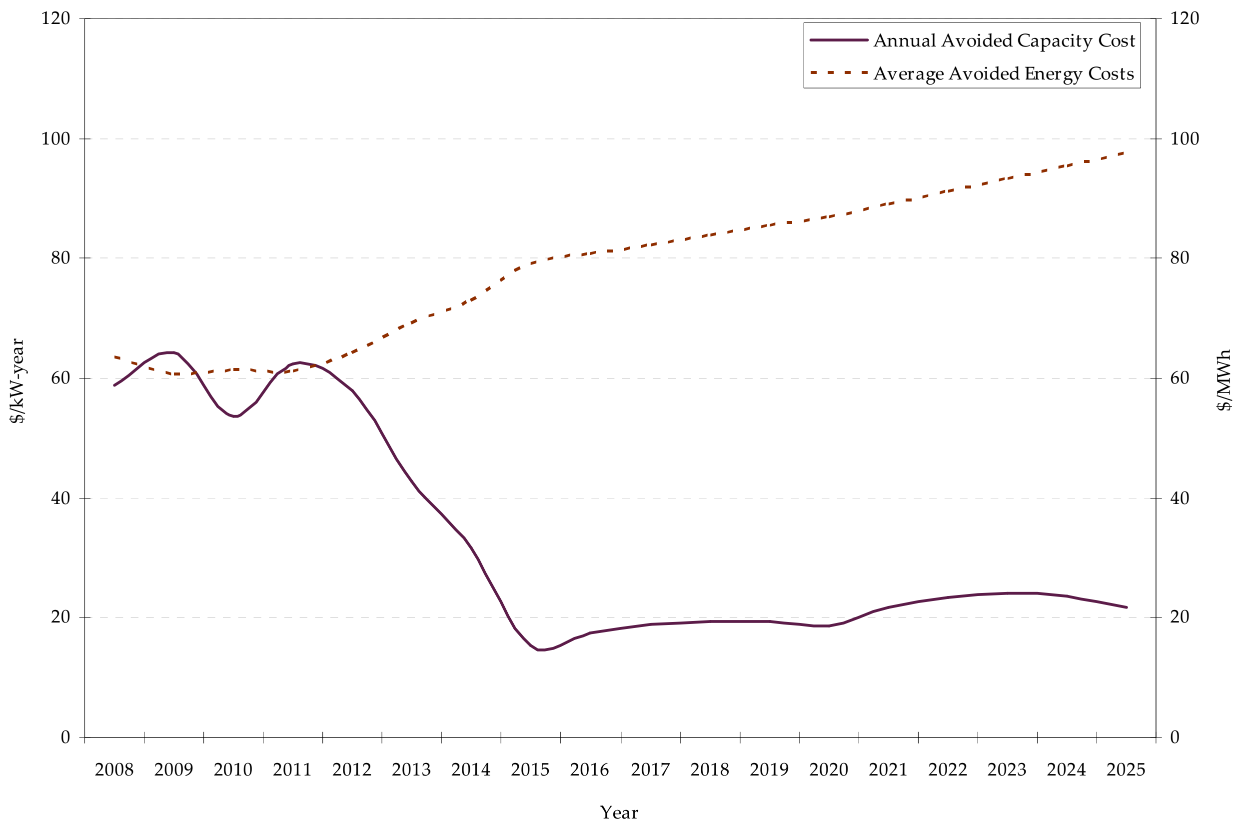
Table 16: Average Annual Avoided Generation Capacity Costs (2005 CAN$/kW-year)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Capacity Costs based on Avoided CSPs using Simplified NRR (2005$/kW-year)	58.7	64.2	53.5	62.4	57.9	42.8	31.6	15.3	17.4	18.9	19.5	19.4	18.6	21.8	23.4	24.0	23.6	21.7

Source: Navigant Consulting

Since we are presenting normalized avoided capacity costs, changing the CDM impact percentage does not have any effect on the avoided capacity per unit of CDM. Figure 11 illustrates the variability of the avoided capacity costs over the forecast period. Note that in the early years the average avoided energy cost and the avoided capacity costs are clearly inversely related, as expected. Very small changes in the average avoided energy cost result in significant changes in the annual avoided capacity costs.

Figure 11: Annual Avoided Capacity Costs and Average Avoided Energy Cost for the Base Case



Source: Navigant Consulting

Table 17 provides the avoided capacity costs for demand response measures that provide little avoided energy savings and focus primarily on peak energy savings. As previously explained, we have used the average NRR for SCGT projects to measure the value of these demand response programs in each year. Although the NRRs for new SCGT contracts increase each year for inflation, we assume that there would be an equal amount of demand response each year and average the current and previous years NRRs to evaluate the avoided capacity costs from demand response for a given year.

Table 17: Annual Avoided Capacity Costs from Peak Period Demand Response (2005 CAD$/kW-year)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025
Avoided Capacity Costs from Peak Period DR based on SCGT NRR (2005 CAD$/kW)	114.0	112.6	111.2	109.9	108.6	107.3	106.0	104.7	103.5	102.3	101.1	99.9	98.7	97.6	96.4	95.3	94.2	93.2

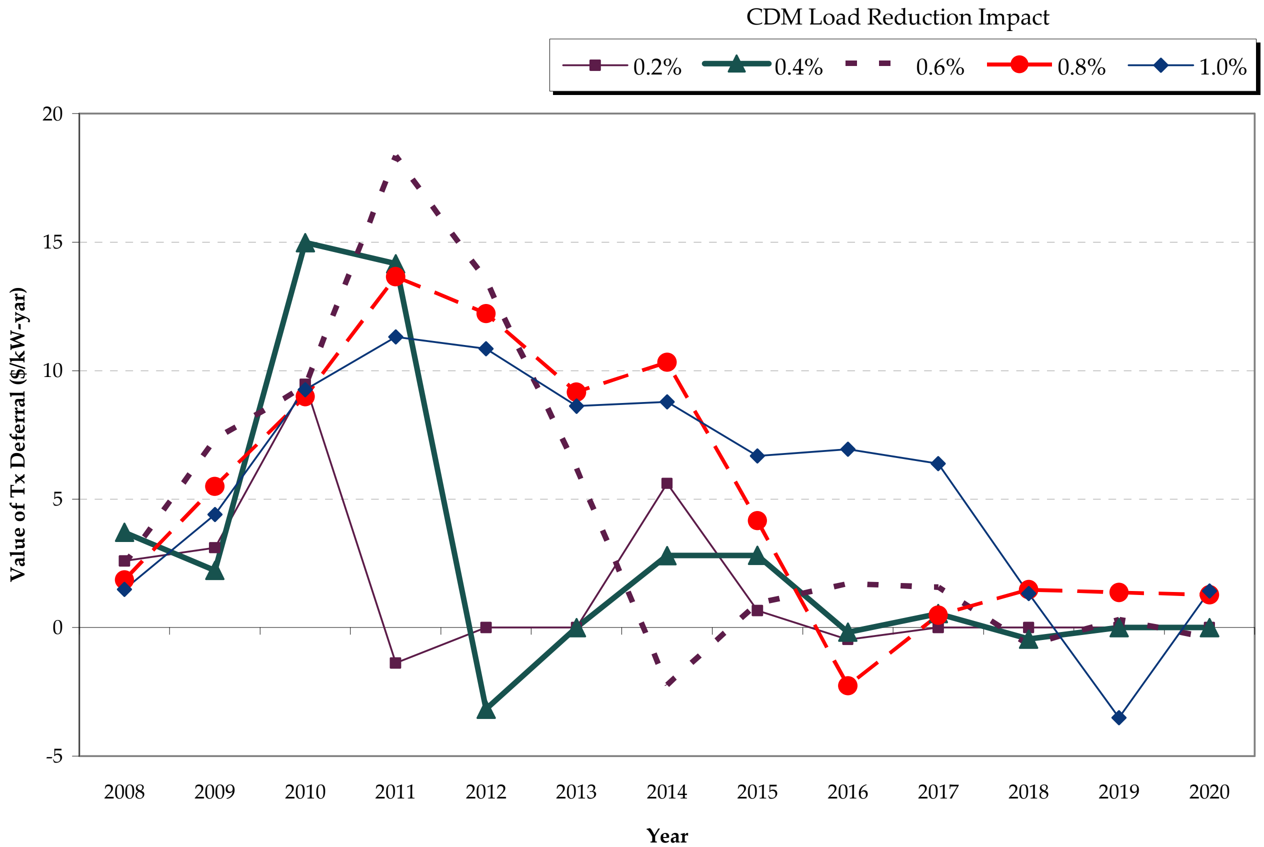
Source: Navigant Consulting

Avoided Transmission Investment Costs

The transmission investment deferral costs and benefits are calculated as a cost per kW per year ($/kW-year) and aggregated across the various transmission investments that can be deferred. Figure 12 shows the total value of transmission investment deferrals for differing levels of annual load reduction impacts.

Depending on the magnitude of the CDM impact the number of projects which can be deferred and the length of the deferral vary. On the lower end of the spectrum, the fewer the deferrals the greater the variation in savings from year to year. The result is a relatively large spike in savings in the year the project is deferred as seen in the 0.2% load reduction scenario illustrated below. The increase in cost in the following year is a result of the escalation of project capital costs (for the deferred project) combined with the lack of other project deferrals in that year. The additional deferrals at higher load reductions act as a counterbalance providing benefits in years where additional capital costs are incurred. As the magnitude of the CDM impacts increases, a larger number of projects are able to be deferred, resulting in a smoothing of the total benefit.

Figure 12: Value of Transmission Investment Deferral



Source: Navigant Consulting

By limiting this analysis to the deferral of projects currently under consideration, essentially no benefits are identified after 2020. In reality though, over time new transmission investment needs will be identified and these projects can be deferred by CDM programs. We have assumed that the costs of the projects and the ability to defer them are consistent with the projects for which HONI provided cost estimates.

The above analysis indicates that the average avoided cost across the period where deferrals are achieved is relatively consistent regardless of the magnitude of the CDM impact. That is, the levelized avoided cost across the range of years with significant deferrals (2008 – 2015) is consistent across a range of CDM impacts (0.2% - 0.6% reductions in load per year), as illustrated in Table 18.[19]

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[19] Levelized avoided costs across the period take into account the time value of money and redistribute the payments equally over the term. All payments and credits are discounted back to a present value and then redistributed using an equal payment method. The HONI corporate cost of capital (9.3%) was used as the discount rate.

Table 18: Levelized Avoided Transmission Capacity Upgrade Costs (2008 – 2015)

Annual Incremental CDM Impact	Levelized Avoided Cost Benefit 2008 - 2015	Average	2005 CAD$
0.1%	$3.52		
0.2%	$2.67		
0.3%	$6.24		
0.4%	$5.02	$5.62	$5.22
0.5%	$6.85		
0.6%	$7.31		
0.7%	$7.57		
0.8%	$7.95		
0.9%	$7.95		
1.0%	$7.32		

Source: Navigant Consulting

Given the relative uncertainty surrounding the magnitude of potential CDM impacts and the relative consistency of the levelized avoided costs for different annual incremental CDM impacts, we have chosen to use the average across the range of likely CDM impacts. The grey shaded cells in Table 18 represent Navigant Consulting's expectation for the potentially achievable range of annual incremental CDM impacts over the medium term. The resulting value of transmission investment avoided costs is $5.22/kW-yr (2005 CAD$) over the period 2008 to 2015.

Earlier investments are unavoidable given the limited time for these CDM programs to achieve a cumulative load reduction level that would defer a transmission investment. To extend this analysis beyond 2015 would require additional information on the need for future transmission investments and the costs that would be associated. Unfortunately, this information is not available. However, Navigant Consulting believes that it would be reasonable to assume that the avoided costs for the period from 2008 through 2015 would be representative of the avoided costs for the period from 2016 through 2025, assuming that a consistent level of load impact is experienced.

It is important to recognize that the results presented above were derived by taking the avoided costs associated with deferring localized transmission capacity upgrade projects and allocating the avoided costs across the province-wide CDM impacts. As such, they understate the value of CDM in those areas in need of localized transmission capacity upgrades and overstate the value of CDM in those areas that do not require localized transmission capacity upgrades.

Note that the transmission capacity upgrade projects in our analysis did not include a third supply point for Toronto, with a scheduled need date in 2010. This project, likely to cost several hundred million dollars, was excluded given the considerable uncertainty over the most cost-effective means of serving load growth in the Toronto area. We also expect that the potential value of deferring this project will be reflected in a localized resource plan which is likely to incorporate various CDM measures. Given our exclusion of this major project, the system-wide results presented are conservative in that they do not reflect a major transmission capacity upgrade project, but this approach also provides an opportunity to separately reflect the localized value of deferring the third supply point to Toronto without double-counting the benefits.

The use of "system-wide" versus localized avoided transmission upgrade costs is discussed in more detail in the following chapter.

Avoided Environmental Costs

The total environmental costs are the sum of the health damage and environmental damage costs. The CBA Study estimate of environmental damages included both damages to property (agriculture and cleaning costs for buildings) and the costs of GHG emissions.

For this study, we assumed that each MWh of coal-fired generation avoided would save environmental costs equal to those calculated for Scenario 1 of the CBA Study. That scenario had total environmental costs for the existing coal-fired fleet.

The CBA Study gave environmental costs in terms of 2004 CAD$/kWh. To be consistent with other values in this study, we escalated those values to 2005$/MWh

For gas-fired generation, we used the results of Scenario 2 of the CBA Study to give values for the environmental costs of CCGT generation. For the environmental costs of SCGT generation, we multiplied the CCGT value by a factor of 1.5, to account for of the higher emissions of SCGTs[20].

Costs in each of these two categories and total costs for coal and gas fired generation are given in Table 19 below. The CBA Study results were stated in 2004 dollars; to be consistent with values in the rest of this study, these costs have been escalated to 2005 dollars.

[20] According to the tables in the CBA Study, SCGT emissions of SO_2 and PM_{10} per kWh are about 1.5 times as high as those for CCGTs.

Table 19: Total Environmental Damage Costs

2005 $/MWh	Health Damages	Environmental Damages	Total
Coal	$18.43	$14.25	$32.69
Gas (CCGT)	$2.05	$5.42	$7.46

Source: Navigant Consulting

The costs shown in Table 19 are the average costs from the CBA Study for the environmental damages from these two sources of generation. The effect of these impacts is assumed to be linear; that is, if the emissions per MWh are halved, the costs will also be halved. The marginal environmental costs for each of these kinds of generation are therefore equal to the average costs shown in Table 19.

However, as noted earlier, these forms of generation are not always on the margin. The marginal environmental cost for the system at any given time is the environmental cost for whatever generation source is then marginal. The marginal environmental cost over a time period is the cost for the sources that were marginal over the period. The ProSym model allowed the marginal sources of generation in each of the time periods identified for this study to be estimated. For example, Figure 6 shows the marginal sources for the time periods in 2006.

For the calculation of marginal environmental costs, we have assumed that the damage cost functions continue to be linear. That is, every MWh of reduced generation is assumed to reduce environmental costs by the same amount as a reduction in MWh produced by the same generation type at any other time or from any other level of output.

The resulting environmental costs are given in Table 20 below. The costs range from about $7 per MWh, for periods when gas generation is on the margin for a relatively small fraction of the time (as in summer on-peak periods in 2014 and 2015) to values over $25 per MWh in off peak periods of 2006 and 2007, when coal-fired generation is often on the margin.

Table 20: Avoided Environmental Cost

Year	Ontario Seasonal Average Avoided Environmental Cost (2005 CAD$/MWh)										
	Winter				Summer				Shoulder		
	On Peak	Mid-Peak	Off Peak	Average	On Peak	Mid-Peak	Off Peak	Average	Mid-Peak	Off Peak	Average
2006	$6.7	$8.5	$26.2	$17.9	$7.4	$10.6	$25.8	$18.4	$13.3	$28.3	$21.6
2007	$6.4	$8.5	$25.1	$17.2	$9.7	$10.2	$23.2	$17.3	$13.0	$26.4	$20.4
2008	$7.9	$9.2	$8.2	$8.4	$10.1	$10.0	$8.1	$9.0	$8.6	$8.0	$8.2
2009	$8.6	$9.1	$8.0	$8.4	$10.5	$10.2	$8.1	$9.1	$9.5	$7.6	$8.5
2010	$8.2	$9.7	$8.2	$8.5	$9.4	$10.4	$8.2	$9.0	$9.4	$7.9	$8.6
2011	$9.4	$9.2	$7.9	$8.6	$9.9	$10.2	$8.1	$9.0	$9.0	$7.4	$8.1
2012	$10.0	$9.5	$8.0	$8.8	$9.3	$10.4	$8.2	$9.0	$9.9	$8.0	$8.9
2013	$10.0	$10.2	$8.2	$9.1	$8.2	$10.0	$8.2	$8.7	$10.1	$8.0	$9.0
2014	$10.1	$10.3	$8.2	$9.1	$6.6	$9.4	$8.2	$8.2	$10.2	$8.1	$9.0
2015	$10.5	$10.6	$8.3	$9.3	$6.8	$10.1	$8.3	$8.5	$10.6	$8.2	$9.3
2016	$10.2	$10.5	$8.3	$9.2	$7.0	$10.1	$8.3	$8.6	$10.5	$8.2	$9.2
2017	$10.0	$10.4	$8.3	$9.1	$7.2	$10.1	$8.3	$8.6	$10.4	$8.2	$9.2
2018	$9.8	$10.4	$8.2	$9.1	$7.5	$10.1	$8.3	$8.6	$10.3	$8.2	$9.1
2019	$9.5	$10.3	$8.2	$9.0	$7.7	$10.1	$8.3	$8.7	$10.2	$8.2	$9.1
2020	$9.3	$10.3	$8.2	$8.9	$7.9	$10.0	$8.3	$8.7	$10.2	$8.1	$9.0
2021	$9.2	$10.3	$8.2	$8.9	$8.0	$9.8	$8.3	$8.6	$10.2	$8.1	$9.0
2022	$9.0	$10.3	$8.2	$8.9	$8.1	$9.6	$8.3	$8.6	$10.1	$8.1	$9.0
2023	$8.9	$10.3	$8.2	$8.8	$8.2	$9.4	$8.3	$8.6	$10.1	$8.1	$9.0
2024	$8.7	$10.3	$8.2	$8.8	$8.3	$9.2	$8.3	$8.5	$10.1	$8.1	$9.0
2025	$8.6	$10.3	$8.2	$8.8	$8.4	$9.0	$8.2	$8.5	$10.1	$8.1	$9.0

Source: Navigant Consulting

These costs are from about 15% to over 60% of the financial costs shown in Table 11 on page 27. Once the coal-fired plants are retired, however, the environmental costs are at or below 20% of the financial costs, and generally range from about 8% to 17% of financial costs.

Until 2008, the environmental costs are consistently higher in the off-peak periods than they are in the on-peak periods. This is due to the fact that coal-fired generation is on the margin a higher fraction of the time in such low-demand periods, while other sources, like demand response (which has no environmental cost) are more likely to be on the margin in high-price periods.

Once coal-fired generation is no longer available, SCGTs are the generation source with the highest environmental cost. This resource is on the margin more in the on-peak and mid-peak periods. The avoided environmental cost is therefore higher in those periods than in off-peak periods.

ANALYSIS RESULTS SUMMARY

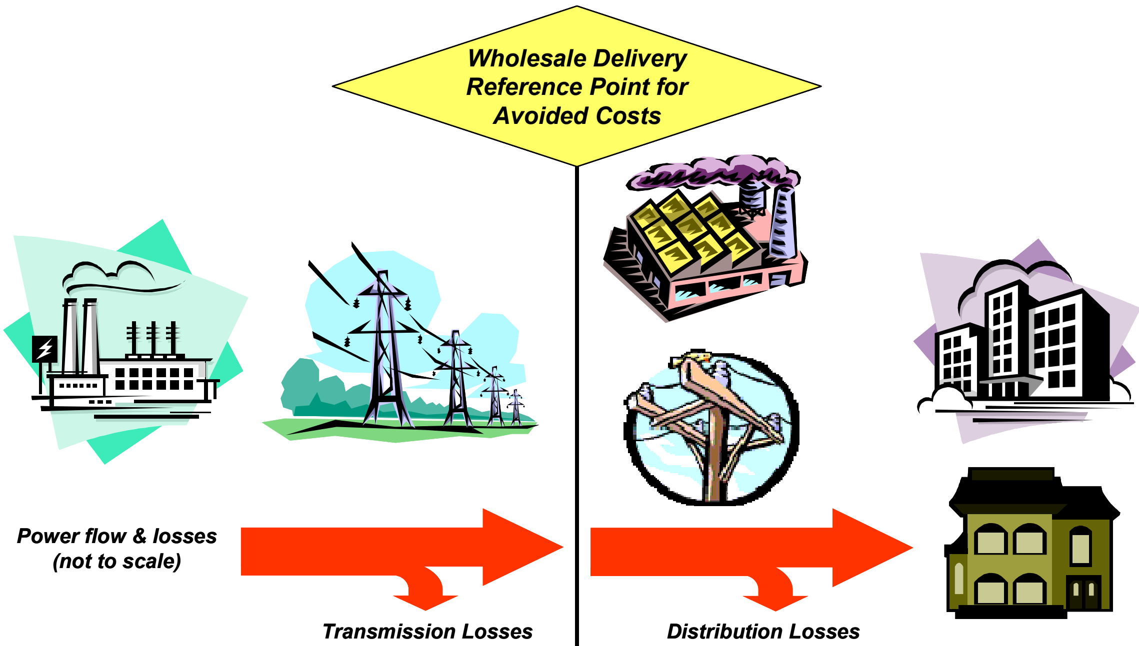
This section presents Navigant Consulting's forecast of avoided costs for energy (with and without environmental damage costs), generation capacity and transmission capacity for the period 2006 through 2025. All of the values presented are in constant 2005 CAD$.

The values presented are intended for use as "default" values for the economic analysis of CDM programs, recognizing that it may be appropriate to make adjustments to these for certain CDM programs. Navigant Consulting believes that it would be appropriate for the Ontario Energy Board to provide guidance to LDCs regarding the appropriate costs and economic analysis framework to apply in these circumstances and situations. To aid the Ontario Energy Board in providing such guidance, Navigant Consulting presents its views and discusses the implications of different approaches.

Reference Point for Avoided Costs

The avoided costs presented herein represent the costs at a wholesale delivery point – typically the interface between the transmission system and an LDC or between the transmission system and a large industrial customer. This is shown graphically in Figure 13 below. As such, Navigant Consulting has adjusted the avoided energy costs given in Table 11 on page 27 to reflect marginal transmission losses in each of the eight time periods (ie, 1 kWh provided to a wholesale delivery point requires slightly more than 1 kWh to be produced by a generator), and adjusted the avoided generation capacity costs given in Table 16 on page 35 to reflect a reserve margin of 18%. No adjustment was required for transmission capacity, since the transmission planning decisions and system capacity upgrades are based upon demand at the relevant wholesale delivery point(s).

Figure 13: Schematic Representation of Reference Point for Avoided Costs



Avoided Cost Component	***Adjustment applied (reflected in numbers provided herein)***	***Adjustments to be applied as appropriate (not reflected in numbers provided)***
Energy	Escalated to reflect transmission system losses	Local distribution losses
Generation Capacity	Escalated to reflect system reserve margin	Local distribution losses
Transmission Capacity	No adjustment	Local distribution losses

In applying the avoided cost data for CDM program analysis, LDCs and others will need to adjust estimates of customer energy savings and peak demand impacts for local distribution losses to reflect the expected impact of the CDM program at the wholesale delivery point.

Avoided Costs

Four tables summarizing the results of our analysis are presented in this section.

Table 21 provides Navigant Consulting's forecast of the avoided energy, generation capacity and transmission capacity costs at a wholesale delivery point. As discussed, energy costs have been adjusted for marginal transmission system losses in each of the eight time periods used in our analysis and generation capacity costs have been adjusted for system reserve margin. This table would be appropriate for analyzing the benefits of conservation programs without consideration of environmental damage costs. As noted, the estimated impact of the conservation program to be analyzed should reflect distribution system losses between the customer and the wholesale delivery point.

The first row of each table provides the average number of hours per year in each of the eight periods.

Table 21: Avoided Energy, Generation Capacity and Transmission Capacity Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/MWh)								Avoided Generation Capacity Costs (2005 CAD$/kW-yr)	Avoided Transmission Costs (2005 CAD$/kW-yr)
	Winter			Summer			Shoulder			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak		
Hours/Period	602	688	1,614	522	783	1,623	1,305	1,623	N/A	N/A
2006	$117.8	$81.9	$44.3	$110.2	$79.4	$46.3	$82.1	$41.3	$0.00	$0.00
2007	$118.6	$80.2	$43.0	$106.2	$75.7	$43.7	$77.5	$38.9	$0.00	$0.00
2008	$107.2	$80.6	$45.4	$102.7	$77.6	$46.6	$83.9	$41.7	$69.32	$5.22
2009	$101.4	$69.8	$44.3	$94.7	$72.0	$43.1	$77.7	$39.3	$75.71	$5.22
2010	$100.3	$68.4	$46.1	$94.6	$71.2	$42.6	$73.8	$38.4	$63.19	$5.22
2011	$95.0	$66.7	$45.4	$89.0	$70.1	$41.8	$72.6	$37.1	$73.65	$5.22
2012	$94.5	$66.4	$44.8	$95.2	$71.1	$43.1	$74.4	$40.2	$68.31	$5.22
2013	$102.7	$70.9	$49.2	$96.0	$74.9	$44.3	$75.9	$42.6	$50.55	$5.22
2014	$100.7	$74.0	$50.3	$102.4	$77.5	$45.4	$79.2	$43.6	$37.34	$5.22
2015	$99.5	$73.9	$54.4	$118.4	$83.4	$48.8	$80.3	$46.8	$18.10	$5.22
2016	$100.4	$74.2	$54.0	$116.3	$82.4	$48.7	$79.6	$46.8	$20.49	$5.22
2017	$101.1	$74.4	$53.6	$114.1	$81.4	$48.6	$79.0	$46.7	$22.26	$5.22
2018	$101.8	$74.5	$53.2	$112.0	$80.4	$48.4	$78.3	$46.6	$22.97	$5.22
2019	$102.4	$74.6	$52.8	$109.9	$79.5	$48.2	$77.6	$46.5	$22.94	$5.22
2020	$102.8	$74.6	$52.4	$107.9	$78.5	$48.0	$76.9	$46.4	$21.99	$5.22
2021	$102.6	$74.4	$52.5	$105.8	$78.5	$48.2	$77.2	$46.5	$25.78	$5.22
2022	$102.4	$74.1	$52.6	$103.8	$78.5	$48.2	$77.5	$46.7	$27.59	$5.22
2023	$102.1	$73.7	$52.6	$101.7	$78.4	$48.3	$77.6	$46.7	$28.36	$5.22
2024	$101.8	$73.4	$52.7	$99.8	$78.4	$48.3	$77.7	$46.8	$27.88	$5.22
2025	$101.4	$73.0	$52.6	$97.8	$78.2	$48.3	$77.8	$46.8	$25.64	$5.22

Source: Navigant Consulting

Table 22 provides a forecast of the environmental damage costs adjusted for marginal transmission system losses in each of the eight time periods used in our analysis. Note that these environmental damage costs represent the damage cost of the marginal unit of energy consumed at the wholesale reference point. As such, they are driven by the emissions characteristics of the marginal generation unit. This is why the damage costs in the peak and mid-peak periods in 2006 and 2007 (when natural gas is the dominant fuel source for the marginal generation) are lower than the damage costs in the off-peak period (when coal is the dominant fuel source for the marginal generation).

Table 22: Avoided Environmental Damage Costs

Year	Ontario Seasonal Average Environmental Damage Costs (2005 CAD$/MWh)							
	Winter			Summer			Shoulder	
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak
Hours/Period	602	688	1,614	522	783	1,623	1,305	1,623
2006	$7.5	$9.2	$27.8	$8.1	$11.2	$27.3	$15.2	$29.7
2007	$6.4	$8.5	$25.1	$10.6	$10.9	$24.5	$14.8	$27.7
2008	$7.9	$9.2	$8.2	$11.1	$10.6	$8.6	$9.8	$8.4
2009	$8.6	$9.1	$8.0	$11.5	$10.8	$8.6	$10.8	$8.0
2010	$8.2	$9.7	$8.2	$10.3	$11.0	$8.7	$10.8	$8.3
2011	$9.4	$9.2	$7.9	$10.9	$10.8	$8.5	$10.3	$7.7
2012	$10.0	$9.5	$8.0	$10.2	$11.1	$8.6	$11.3	$8.4
2013	$10.0	$10.2	$8.2	$9.0	$10.6	$8.6	$11.5	$8.4
2014	$10.1	$10.3	$8.2	$7.2	$10.0	$8.7	$11.6	$8.5
2015	$10.5	$10.6	$8.3	$7.5	$10.8	$8.7	$12.1	$8.6
2016	$10.2	$10.5	$8.3	$7.7	$10.7	$8.8	$12.0	$8.6
2017	$10.0	$10.4	$8.3	$7.9	$10.7	$8.8	$11.9	$8.6
2018	$9.8	$10.4	$8.2	$8.2	$10.7	$8.8	$11.8	$8.6
2019	$9.5	$10.3	$8.2	$8.4	$10.7	$8.8	$11.7	$8.5
2020	$9.3	$10.3	$8.2	$8.6	$10.7	$8.8	$11.6	$8.5
2021	$9.2	$10.3	$8.2	$8.7	$10.4	$8.7	$11.6	$8.5
2022	$9.0	$10.3	$8.2	$8.9	$10.2	$8.7	$11.6	$8.5
2023	$8.9	$10.3	$8.2	$9.0	$10.0	$8.7	$11.6	$8.5
2024	$8.7	$10.3	$8.2	$9.1	$9.8	$8.7	$11.6	$8.5
2025	$8.6	$10.3	$8.2	$9.2	$9.5	$8.7	$11.5	$8.5

Source: Navigant Consulting

Table 23 provides Navigant Consulting's forecast of the avoided energy costs incorporating environmental damage costs as well as the avoided generation capacity and transmission capacity costs at a wholesale delivery point. This table is simply a summation of the previous two tables. As with the previous tables, avoided energy and environmental damage costs have been adjusted for marginal transmission losses in each of the eight time periods used in our analysis and generation capacity costs have been adjusted for system reserve margin. This table would be appropriate for estimating the societal benefits of conservation programs reflecting consideration of environmental damage costs.

Table 23: Avoided Energy (with Environmental Damage), Generation Capacity and Transmission Capacity Costs

Year	Ontario Seasonal Average Avoided Energy Cost (2005 CAD$/MWh)								Avoided Generation Capacity Costs (2005 CAD$/kW-yr)	Avoided Transmission Costs (2005 CAD$/kW-yr)
	Winter			Summer			Shoulder			
	On Peak	Mid-Peak	Off Peak	On Peak	Mid-Peak	Off Peak	Mid-Peak	Off Peak		
Hours/Period	602	688	1,614	522	783	1,623	1,305	1,623	**N/A**	**N/A**
2006	$125.3	$91.1	$72.1	$118.3	$90.6	$73.6	$97.3	$70.9	$0.00	$0.00
2007	$125.0	$88.7	$68.1	$116.8	$86.6	$68.1	$92.3	$66.5	$0.00	$0.00
2008	$115.1	$89.8	$53.5	$113.8	$88.2	$55.2	$93.7	$50.1	$69.32	$5.22
2009	$110.0	$78.9	$52.3	$106.2	$82.8	$51.7	$88.5	$47.3	$75.71	$5.22
2010	$108.5	$78.0	$54.3	$104.9	$82.1	$51.3	$84.6	$46.6	$63.19	$5.22
2011	$104.4	$75.9	$53.4	$99.8	$80.9	$50.3	$82.9	$44.8	$73.65	$5.22
2012	$104.5	$75.9	$52.8	$105.3	$82.2	$51.7	$85.7	$48.6	$68.31	$5.22
2013	$112.7	$81.1	$57.4	$104.9	$85.5	$52.9	$87.4	$51.0	$50.55	$5.22
2014	$110.7	$84.4	$58.5	$109.6	$87.5	$54.1	$90.8	$52.1	$37.34	$5.22
2015	$110.0	$84.5	$62.7	$125.9	$94.1	$57.6	$92.3	$55.4	$18.10	$5.22
2016	$110.6	$84.7	$62.3	$124.0	$93.1	$57.5	$91.6	$55.3	$20.49	$5.22
2017	$111.1	$84.8	$61.9	$122.0	$92.1	$57.3	$90.9	$55.3	$22.26	$5.22
2018	$111.6	$84.9	$61.5	$120.2	$91.1	$57.2	$90.1	$55.2	$22.97	$5.22
2019	$111.9	$84.9	$61.0	$118.3	$90.1	$57.0	$89.3	$55.1	$22.94	$5.22
2020	$112.1	$84.9	$60.6	$116.5	$89.1	$56.8	$88.5	$54.9	$21.99	$5.22
2021	$111.8	$84.6	$60.7	$114.5	$88.9	$56.9	$88.8	$55.1	$25.78	$5.22
2022	$111.4	$84.4	$60.8	$112.6	$88.7	$57.0	$89.0	$55.2	$27.59	$5.22
2023	$111.0	$84.1	$60.9	$110.7	$88.4	$57.0	$89.2	$55.3	$28.36	$5.22
2024	$110.5	$83.7	$60.9	$108.9	$88.1	$57.0	$89.3	$55.3	$27.88	$5.22
2025	$110.0	$83.4	$60.9	$107.0	$87.7	$57.0	$89.4	$55.3	$25.64	$5.22

Source: Navigant Consulting

Finally, Table 24 presents Navigant Consulting's estimates of the avoided generation capacity costs for demand response programs that provide peak demand reductions but negligible energy savings.

Table 24: Avoided Generation Capacity Costs for Demand Response Programs

Year	Avoided Capacity Costs (2005 CAD$/kW-yr)
	SCGT Peaking Capacity
2006	$0.0
2007	$0.0
2008	$134.5
2009	$132.9
2010	$131.3
2011	$129.7
2012	$128.1
2013	$126.6
2014	$125.1
2015	$123.6
2016	$122.1
2017	$120.7
2018	$119.2
2019	$117.9
2020	$116.5
2021	$115.1
2022	$113.8
2023	$112.5
2024	$111.2
2025	$109.9

Source: Navigant Consulting

Application of Results

To assist LDCs and others in using these avoided cost estimates for CDM economic evaluation, this section describes the peak demand impacts that should be used and presents alternative approaches for generation and transmission capacity avoided costs.

CDM Demand Impact Should be Based on Diversified Demand Reduction Coincident with the Summer Peak

While Ontario was previously winter-peaking, and has lately had winter and summer peaks of roughly the same magnitude, the IESO expects that future requirements for generation will be driven by Ontario's summer peak. The IESO's most recent *10-Year Outlook* focuses on the summer peak[21]. Given this, the peak demand impact for a given CDM program or measure should reflect the expected diversified demand reduction coincident with the summer peak, which typically occurs in the mid-afternoon during the one of the hottest days of summer.

This exclusive focus on summer peak demand reduction for economic analysis purposes applies to transmission capacity avoided costs as well. Note that all of the planned transmission system capacity upgrades identified by Hydro One for the period 2006 through 2015 are in Southern Ontario.

Generation Capacity Vintage

As discussed previously, Navigant Consulting's avoided generation capacity costs for conservation programs are an average of the contingent support payments from various CES-like contracts that are expected to exist in any year. Hence, the avoided generation capacity costs for 2011 reflect CES-like contracts from 2008, 2009, 20010 and 2011. Based on our assumption that the avoided costs will be used to evaluate CDM programs that will be implemented over the next five years and which will have different penetration rates and capacity savings in each year, we suggest that use of the average generation capacity avoided costs is appropriate.

However, if greater accuracy is desired, avoided generation capacity costs for a CES-type contract starting in the year in which the generation would have otherwise been required can be used. This information is given in Table 15 on page 35. For example, if a CDM program is expected to realize a peak demand reduction of 10 MW for twenty years starting in 2009, it may be appropriate to use the avoided generation costs in the second row of the Table 15, escalated to reflect a system reserve margin of 18%. This approach would yield lower avoided generation capacity costs in the latter years of the analysis.

Note that such an approach would generate different generation capacity costs in any given year for each contract "vintage." Hence, if the example program given above was estimated to realize an additional 5 MW for twenty years starting in 2010 (incremental to the 10 MW savings forecast for 2009), the avoided generation capacity costs for this "stream" of capacity savings would be based on the third row of Table 15 (escalated to reflect a system reserve margin of 18%), and so on for expected incremental savings in future years. While this approach is more accurate, it is much more complex.

For this reason, Navigant Consulting suggests the use of the average avoided generation capacity costs would be appropriate for most applications, with more detailed analysis used when the

[21] *10-Year Outlook*, March 31, 2004. The IESO has not released its 2005 10-Year Outlook and as such this is the most recent 10-Year Outlook.

incremental complexity and effort is justified (and the timing of the program impacts is relatively certain).

Avoided Generation Capacity Costs for Demand Response

Navigant Consulting has provided two sets of avoided generation capacity costs – one set based on the forecast payments for a CCGT under a CES-type contract and the other set based on the estimated net revenue requirements for an SCGT. The latter set of values is provided for the analysis of demand response programs that focus on reducing peak demand but have very little, if any, impact on energy consumption. Such programs are more directly comparable to an SCGT peaking plant which runs infrequently, whereas conservation programs, which focus on reducing energy consumption and may or may not have an impact on peak demand, are more directly comparable to a CCGT which runs for many hours in a year.

Navigant Consulting believes that the use of two separate avoided generation capacity costs is appropriate given the wide range of CDM programs expected to be implemented. However, there will undoubtedly be questions about when one set of values should be used instead of the other.

A conservative approach would be to limit the use of avoided SCGT generation capacity costs (provided in Table 24) to demand response programs with negligible energy savings impacts, and to use the avoided CCGT generation capacity costs (provided in Table 21 and Table 23) for all other CDM programs. This approach however would generally underestimate the avoided costs for CDM measures targeted towards summer peak demand reduction that also provide some energy savings.

In developing an appropriate measure and threshold to use in determining which set of avoided generation capacity costs should be used, Navigant Consulting considered:

- The likely "load shape" of the CDM measure relative to the output profile of an SCGT (ie, when is an SCGT likely to operate)
- The range of system demand and number of hours for which the use of an NRR for an SCGT combined with the avoided energy costs provided herein would not be expected to overstate the total avoided costs for a CDM measure.

Based on these considerations and our analysis of the total avoided costs for various CDM measures, Navigant Consulting suggests that the avoided SCGT generation capacity costs should be used for all CDM measures with annual load factors (based on the CDM measure's diversified coincident summer peak demand reduction) of 5% or less. Setting the threshold higher could result in avoided costs that are overstated and setting the threshold lower than this would generally result in avoided costs that are understated.

Navigant Consulting does not suggest any adjustment to the avoided energy costs for the reasons given below. Based on Navigant Consulting's forecast, the avoided energy costs for the most expensive 5% of hours in a given year are generally higher than the summer on-peak avoided energy costs and higher than the marginal operating costs of an SCGT. However, assuming that SCGT capacity operated under a CES-type contract as described previously, the prices during the most expensive 5% of hours in a given year would generate net market revenues for the SCGT and these would reduce the avoided generation capacity costs for these generators. The degree to which the use of the avoided energy costs presented herein for summer on-peak periods understates the avoided energy cost for the most expensive 5% of hours is roughly equal to the amount by which the avoided generation capacity costs for an SCGT would be reduced under a CES-type contract based on their deemed net market revenues. Navigant Consulting feels that introducing a separate set of avoided energy costs to be used under certain circumstance would add unnecessary complexity to CDM analysis and that the use of the avoided SCGT generation capacity costs combined with the avoided energy costs provide herein will provide a reasonably accurate estimate of the value of CDM measures that satisfy the threshold defined above.

To summarize, Navigant Consulting suggests that the set of avoided SCGT generation capacity costs should be used for all CDM measures for which the load factor derived using the estimated energy savings and diversified coincident summer peak demand reduction is less than 5%. The specific equation for calculation of this load factor is:

Load Factor = Annual Energy Savings / (Diversified Summer Coincident Peak Demand Reduction x 8760[22])

Note that this definition of load factor is not the same as the traditional definition of load factor (which is based on the maximum demand in a year, not the diversified summer coincident peak demand), so it may be less confusing to simply define the threshold according to the ratio of annual energy savings divided by diversified coincident summer peak demand reduction. The 5% load factor threshold corresponds to a ratio of annual energy savings divided by diversified coincident summer peak demand reduction of 438, which could be rounded down to 400 for conservatism.

Four examples for representative CDM measures are provided below to better explain how the suggested approach would be applied:

- Strictly speaking, demand response measures do not reduce energy use, only peak demand, hence the ratio would be zero, which is below the suggested threshold of 400 indicating that the set of avoided SCGT generation capacity costs should be used.

[22] 8760 = number of hours in a normal year.

- Consider a CDM program that targets high efficiency central air conditioners and is expected to reduce energy consumption and diversified coincident summer peak demand by 20%. Assuming a standard central air conditioner uses 1000 kWh annually with has a diversified coincident summer peak demand of 2.5 kW, a 20% reduction in energy use and peak demand would yield savings of 200 kWh and 0.5 kW (ie, 2.5 kW x 20%). For this particular program, the ratio would be 400 (200 kWh / 0.5 kW = 400), indicating that the set of avoided SCGT generation capacity costs should be used. Using the suggested approach and assuming 1) 2000 customers participate in such a program (yielding 1 MW of diversified coincident summer peak demand reduction) and 2) all of the energy savings occur during the summer on-peak period, the total avoided energy costs in 2010 for this program exclusive of environmental damage costs would be roughly $38,000 (taken from Table 21 and 400 MWh summer on-peak energy savings)[23], whereas the avoided generation capacity costs in 2010 would be $131,000 (taken from Table 24). Since this example program is at the threshold of 400 and we have assumed that all of the energy savings occur during the summer on-peak period (a conservative assumption since air conditioners will operate during the summer mid-peak and off-peak periods), this example essentially represents the maximum contribution of avoided energy costs to the total avoided costs when using the avoided SCGT generation capacity costs.

- A conservation program that reduces energy by an equal amount in each hour of the year would have a ratio of 8760, which indicates that the set of avoided costs based on CCGT generation capacity costs should be used.

- A CDM program that does not provide any summer peak reduction would have a ratio of infinity, again indicating that the set of avoided costs based on CCGT generation capacity costs should be used.

Localized Transmission Capacity Deferral

The estimates of avoided transmission capacity costs given above represent the impact of CDM on several planned transmission system capacity upgrades averaged over the entire system (and levelized over time). These "system-wide" avoided costs are intended as the default for reflecting the average transmission deferral value of CDM. Hence, these estimates would be suitable for broad-based CDM programs that cover much of the province or for programs where specific transmission avoided costs are not readily available.

Analysis of CDM programs targeted to a specific region or LDC territory may benefit from more detailed consideration of the impact of CDM on specific transmission system capacity upgrade

[23] The total avoided energy costs inclusive of environmental damages for this example program would be roughly $42,000 (taken from Table 23 and 400 MWh of summer on-peak energy savings)

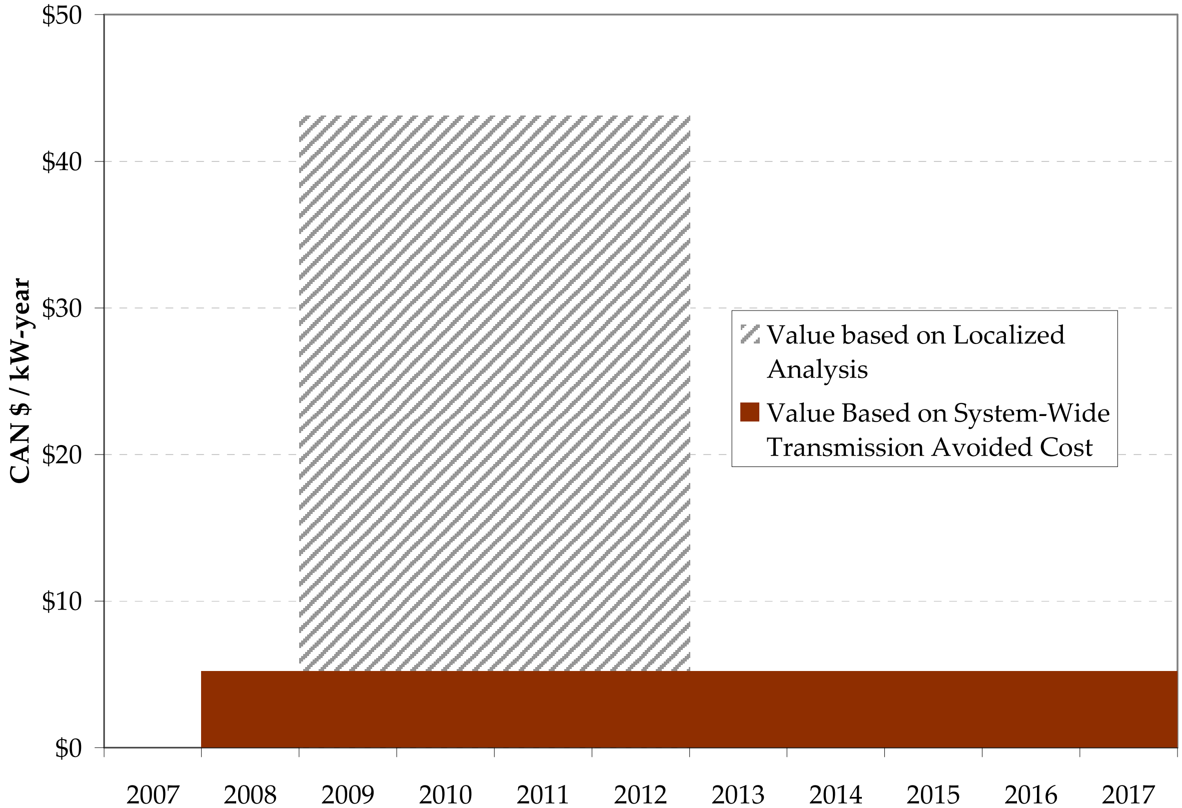
projects. We suggest that the methodology for such analysis should be similar to that described by Navigant Consulting in this report. Note that such analyses are likely to yield significantly higher avoided cost values on a $ / kW-year basis but only over the timeframe for which the transmission system capacity upgrade project can be deferred. For example, using a hypothetical project with a capital cost of 10 million dollars (2005$) and an original need date of 2009, a 5 year, 15 MW CDM program is capable of deferring the need for investment by 3 years. The levelized value of this deferral, strictly evaluated over the deferral period, is $43.13/kW-yr (2005$).

Table 25: Illustrative Example of Localized Analysis of Transmission Avoided Costs

Category	2007	2008	2009	2010	2011	2012	2013	2014	2015
Load (MW)	490.1	480.3	485.5	490.7	496.0	501.4	506.8	512.3	517.8
Original Load (MW)	490.1	495.3	500.5	505.7	511.0	516.4	521.8	527.3	532.8
CDM Impact (MW)	0.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00	15.00
New Need Date						X			
Original Need Date			X						
Cost ($M)	$ -	$ -	$ -	$ -	$ -	$ 11.89	$ -	$ -	$ -
Original Cost ($M)	-	-	11.04	-	-	-	-	-	-
Avoided Capital Expenditures ($M)	-	-	11.04	11.04	11.04	(0.85)	-	-	-
Avoided Capital Benefit ($M)	-	-	1.02	1.02	1.02	(0.85)	-	-	-
O&M ($M)	-	-	-	-	-	-	0.119	0.122	0.125
Original O&M ($M)	-	-	-	0.110	0.113	0.116	0.119	0.122	0.125
Avoided O&M Costs ($M)	-	-	-	0.110	0.113	0.116	-	-	-
Total Avoided Cost Benefit ($M)	**$ -**	**$ -**	**$ 1.02**	**$ 1.13**	**$ 1.14**	**$ (0.73)**	**$ -**	**$ -**	**$ -**
Levelized Avoided Cost Across Deferral Period ($M)			**$ 0.70**	**$ 0.70**	**$ 0.70**	**$ 0.70**			
Avoided Transmission Cost Benefit (2005$/kW-yr)			**$ 43.13**	**$ 43.13**	**$ 43.13**	**$ 43.13**			

In this example, the estimated localized transmission avoided costs are nine times larger then the system-wide attributable value. Figure 14 clearly illustrates the significant difference between the two approaches. Note that, for this illustrative example, the higher value based on the localized avoided costs would only be applied to the 15 MW of CDM that enables the localized deferral and only for the actual deferral period, whereas the lower system-wide value would be applied to all CDM across the province. Note that specific analysis should be undertaken for each transmission project to determine the potential localized avoided cost and deferral period for varying levels of CDM impacts – the numbers provided for this illustrative example should not be used.

Figure 14: Comparison of Localized versus System-wide Transmission Avoided Costs



As noted, Navigant Consulting's analysis of the system-wide avoided transmission capacity costs does not reflect the potential deferral of the third supply point to Toronto. Hence, the system-wide numbers are substantially lower than if this project was included. In essence, the exclusion of this project reduces or "discounts" the system-wide avoided transmission capacity costs by over 50% relative to what they would be if the estimated cost of the third supply point had been included. Navigant Consulting suggests that this approach provides an appropriate discount to the system-wide transmission avoided cost estimates to mitigate the potential impact of double counting assuming that Hydro One and others are given the option to use localized transmission impacts. If no discount is applied to the system-wide transmission avoided cost estimates, then reflecting localized transmission impacts in the economic analysis for certain CDM programs would likely result in double counting of avoided transmission capacity costs. On the other hand, applying a higher (ie, > 50%) discount would likely understate avoided transmission capacity costs.

Essentially, we expect that there is likely to be some transmission avoided cost for most CDM programs with relatively long-life measures, and the use of the default or system-wide transmission avoided cost estimate ensures this value is captured in the economic analysis. For CDM programs that reduce summer peak demand, the transmission avoided costs are expected to be relatively small compared to the avoided energy and generation capacity costs. Hence, applying a discount to the system-wide transmission avoided cost is not likely to materially affect the overall CDM portfolio of programs, whereas allowing the use of localized transmission avoided costs will ensure that the true value of targeted CDM programs will be reflected in the economic analysis.

APPENDIX A – DETAILED AVOIDED ENERGY FORECASTING METHODOLOGY

Within ProSym, thermal generating resources are characterized according to a range of capacity output levels. Generation costs are calculated based upon heat rate, fuel cost and other operating costs, expressed as a function of output. Physical operating limits related to expected maintenance and forced outage, start-up, unit ramping, minimum up and down time, and other characteristics are respected in the ProSym simulation.

Hydroelectric resources are also characterized in ProSym according to expected output levels, including monthly forecasts of expected energy production. Navigant Consulting has specified ProSym to reflect historical monthly output of Ontario's hydroelectric fleet. The data have been updated to reflect upgrades and capacity additions to Ontario's hydroelectric fleet. ProSym schedules run-of-river hydroelectric production based upon the minimum capacity rating of the unit. The dispatch of remaining hydroelectric energy is optimized on a weekly basis by scheduling hydro production in peak demand hours when it provides the most value to the electrical system.

Offer prices are developed for each unit and show the minimum price the unit owner is willing to accept to cause the unit to operate. For most generation resources, offer prices are composed primarily of incremental production costs. Incremental production cost is calculated as each station's fuel price multiplied by the incremental heat rate, plus variable operations and maintenance cost.

Market clearing prices reflect the offer of the last generating resource used to meet the next increment (Megawatt) of demand. Station revenues are based on these market-clearing prices within the market area in which the plant is located.

Navigant Consulting runs ProSym in a mode that establishes market-clearing prices in a specific regional market and in adjacent markets with significant intertie connections. In establishing the market-clearing price, the ProSym simulation takes into account economic import and export possibilities and sets the market-clearing price as the offer price of the marginal generator needed to serve a final increment of demand within the region.[24]

[24] The Independent Electricity System Operator's (IESO's) Import Offer Guarantee (IOG) rule prevents imports from setting the HOEP. Therefore, there is a difference between our model structure and the Ontario market rules. If the Ontario market were forecast to be in need of significant amounts of energy and capacity and relying on imports for this required energy and capacity and if the pricing for imports was significantly different than that for Ontario generation, this difference might result in meaningful differences between our cost forecast and actual market costs. However, during the term of this forecast we do not expect the Ontario market to need to rely on imports for significant amounts

Treatment of "OPG Regulated Assets" in the Model Specification

A significant portion of Ontario's generation, i.e., OPG's nuclear and major baseload hydroelectric generating units (Saunders, Beck, and DeCew Falls), have been designated as regulated assets with the price for these plants set by a cost-of-service regulatory framework administered by the OEB, and originally set under regulation by the Government. While the price for the output of these plants will be established by the OEB, their value in the Ontario market will be established by the same market dynamics that are in place currently, i.e., a bid-based pool where participating generators receive a uniform price. Specifically, the party responsible for scheduling and ensuring the dispatch of this generation would seek to ensure that this generation is available to the maximum degree possible, particularly during periods when market prices are high and the value of the generation is the greatest. Furthermore, if the scheduling and dispatch of these units does not change given that OPG's regulated assets don't establish the market-clearing price for the vast majority of hours, we expect that the treatment of these generating stations as regulated assets will not affect the HOEP.

of energy and capacity and the costs of marginal generation in Ontario and its interconnected markets are not likely to differ significantly. Therefore, we do not believe that this difference between the model structure and market rules is likely to lead to significant differences between our cost forecast and actual market costs.