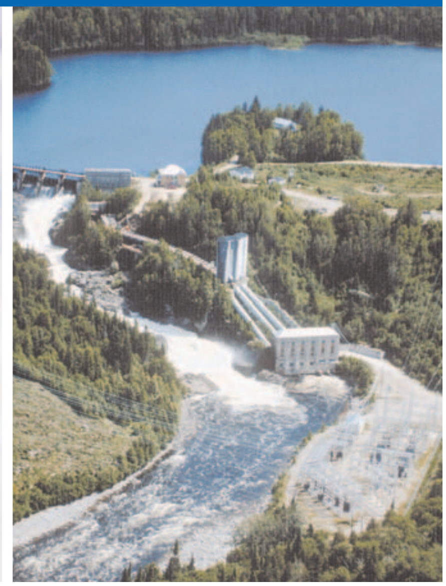




Power for the Future

Towards a Sustainable Electricity System for Ontario



Pembina Institute
for Appropriate Development

Canadian Environmental Law Association

Energy for the Future cataloguing information

ISBN 0-921719-59-0

CELA CATALOGUE NUMBERS: 471A - Full Report, 471B - Summary

MAY 2004

Power for the Future

Towards a Sustainable Electricity System for Ontario

Mark S. Winfield, Ph.D.
Matt Horne, M.R.M.
Theresa McClenaghan, LL.B., LL.M.
Roger Peters, P.Eng, M.Eng

Pembina Institute for Appropriate Development

Canadian Environmental Law Association

Acknowledgements

The Pembina Institute for Appropriate Development and the Canadian Environmental Law Association would like to thank the EJLB Foundation, Toronto Atmospheric Fund TORONTO Atmospheric Fund and the Richard Ivey Foundation for their financial support of this project.

The authors also benefited from an excellent team of external reviewers and advisors, including Jack Gibbons, Peter Love, Dave Martin, Kai Millyard, and Keith Stewart.

We would like to thank Fe deLeon of the Canadian Environmental Law Association and Lori Chamberland of the Pembina Institute for their assistance and support with many aspects of this project.

Finally, we would like to thank Green Living Communications for their invaluable contributions to the design and production of this report.

Any errors and omissions remain the responsibility of the authors.

About the authors

Mark S. Winfield, Ph.D.

Mark Winfield is Director of the Pembina Institute's Environmental Governance Program. Prior to joining Pembina he was Director of Research with the Canadian Institute for Environmental Law and Policy. Dr. Winfield holds a Ph.D. in Political Science from the University of Toronto, and has published reports and articles on a wide range of environmental policy issues. He is also an Adjunct Professor with the University of Toronto's Institute for Environmental Studies and Division of the Environment.

Matt Horne, M.R.M.

Matt Horne is an analyst in Pembina's Sustainable Communities Group. His focuses include provincial and municipal policy work relating to renewable energy and energy efficiency, and community energy planning with First Nation communities. Prior to joining the Pembina Institute, he worked extensively with the CIMS and MARKAL energy-economy models on projects attempting to estimate the costs of greenhouse gas emission reductions for the Canadian economy. The work with the CIMS model at Simon Fraser University was particularly helpful when analyzing results for this project. Mr. Horne has a Bachelor of Engineering degree from Dalhousie University and a Master of Resource Management degree from Simon Fraser University.

Theresa McClenaghan, LL.B., LL.M.

Theresa McClenaghan holds an LL.B. from the University of Western Ontario (1984), an LL.M. (constitutional law) from Osgoode Law School (York University, 1999) and a diploma in Environmental Health from McMaster University (1999). She is a member of the Bars of Manitoba and Ontario. Theresa has practised public interest environmental law for seventeen years, both in private practice and since joining the Canadian Environmental Law Association as counsel in May 1998. Theresa has appeared before all of the Courts of Ontario, the Federal Trial Division and Court of Appeal, the Supreme Court of Canada and numerous provincial and federal tribunals including the Ontario Energy Board and the National Energy Board.

Roger Peters, P.Eng, M.Eng

Roger Peters is Director of the Sustainable Communities Group at the Pembina Institute and an advisor on energy efficiency and renewable energy policy. Roger is a chemical and environmental engineer with over 20 years experience in the energy efficiency and renewable energy fields. He was a founding partner in Marbek Resource Consultants – a major energy efficiency consulting firm in the 1980s, and participated in previous energy efficiency potential studies in Ontario in the 1990s. From 1993 to 1996 Roger served as Director of Technical Services at the Saskatchewan Energy Conservation Authority. Roger has significant international experience in Asia and Africa, working on energy efficiency and rural energy projects funded by the World Bank, Global Environmental Facility and the Canadian International Development Agency (CIDA).

About the Pembina Institute

The Pembina Institute is an independent, not-for-profit environmental policy research and education organization specializing in the fields of sustainable energy, community sustainability, climate change and corporate environmental management. Founded in 1985 in Drayton Valley Alberta, the Institute now has offices in Calgary, Edmonton, Vancouver, Ottawa and Toronto.

For more information on the Institute's work, please visit our website at www.pembina.org.

About the Canadian Environmental Law Association

The Canadian Environmental Law Association (CELA) is a public interest law group founded in 1970 for the purpose of using and improving laws to protect the environment and public health and safety. Funded as a legal aid clinic specializing in environmental law, CELA lawyers represent individuals and citizens' groups in the courts and before tribunals on a wide variety of environmental protection and resource management matters. In addition, CELA staff members are involved in a range of initiatives related to law reform, public education and community organization.

Towards a Sustainable Electricity System for Ontario

Executive Summary

May 2004

1. Introduction

The past five years have been a period of extraordinary change and upheaval in Ontario's institutions and policies related to electricity. More changes have occurred in the electricity sector since 1998 than over the preceding nine decades following the creation of the Ontario Hydro-Electric Power Commission (HEPC) in 1906.

The Energy Competition Act of 1998 divided the HEPC's successor, Ontario Hydro, into four separate entities: Ontario Power Generation (OPG), Hydro One, the Ontario Electricity Financial Corporation (OEFC), and the Electrical Safety Authority. In addition, under the legislation, competitive retail and wholesale electricity markets were introduced in May 2002, supervised by the Ontario Energy Board (OEB) and an Independent Market Operator (IMO). However, the government terminated the competitive retail electricity market six months later in the context of high and unstable electricity prices.

In the meantime, from 1997 onwards, a significant portion of the province's nuclear generating facilities were taken out of service for safety and maintenance overhauls. This, in turn, led to an increased reliance on coal-fired generation to meet the province's electricity needs, a situation that has significantly exacerbated the severe air quality problems regularly experienced in southern Ontario.

The new provincial government, elected in October 2003, has made a strong commitment to the phase out of OPG's coal-fired plants by 2007 due to the severe environmental and health impacts of their operation. This state of affairs is further complicated by the consideration that all of the province's existing nuclear generating facilities, which currently account for 28% of the province's generating capacity, will reach the end of their projected operational lifetimes by 2018. The resulting situation was summarized by the province's Electricity Conservation and Supply Task force in its January 2004 report in the following figure:

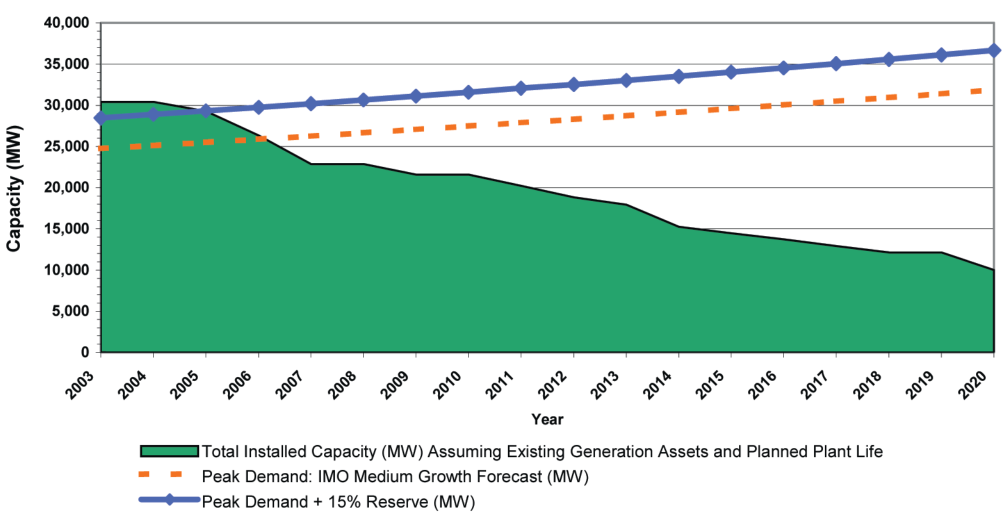


Figure E1: Existing Generation vs. Peak Demand

The combination of the projected end of life of the province's existing coal-fired and nuclear generating stations, and predictions of growing electricity demand have prompted a major debate over the province's future electricity needs, and how those needs might be met. The options that have been proposed to the province range from ambitious energy efficiency programs accompanied by major investments in low-impact renewable energy sources, such as wind and small-scale hydro, to the construction of a series of new nuclear generating facilities.

2. The Pembina Institute/ Canadian Environmental Law Association Sustainable Electricity Project

In this context of change and uncertainty, the Pembina Institute and the Canadian Environmental Law Association undertook a study to answer four key questions regarding Ontario's future electricity path. These questions were as follows:

1. How much might future electricity demand in Ontario be realistically reduced through the adoption of energy efficient technologies, fuel switching, cogeneration, and demand response measures?
2. How much future supply might be realistically obtained from low-impact renewable energy sources, such as wind, the upgrading of existing hydroelectric facilities, and the development of new small-scale hydro plants, solar, and biomass?
3. How should the remaining grid demand, if any, be met once the technically and economically feasible contributions from energy efficiency, fuel switching, cogeneration, demand response measures, and low-impact renewable energy sources have been maximized?
4. What public policies and institutional arrangements should the province adopt to ensure the maximization of the contributions from energy efficiency and other demand side measures, low-impact renewable energy sources, and the most environmentally and economically sustainable supply mix to meet remaining future grid demand?

3. Assessing the Potential Impact of Energy Efficiency on Future Electricity Demand

In order to answer the first question, regarding the potential impact of energy efficiency programs, a series of generic policy measures was proposed to promote the adoption of energy efficient technologies, cogeneration in the industrial and commercial sectors, and fuel switching from electricity to natural gas, where this is the most efficient option.

The Canadian Integrated Modeling System (CIMS) computer model, developed by the Energy and Materials Research Group at Simon Fraser University, was then used to estimate the reduction in electricity consumption that could be achieved between the present and 2020 through the implementation of these policies; the incremental investment associated with achieving the 2020 energy savings; the resulting changes in natural gas demand from the adoption of energy efficient technologies and practices; and the net cost per kWh saved through energy efficiency measures.

Three types of policy intervention were simulated through the CIMS model:

1. The provision of financial incentives in the form of grants, sales tax removal, or tax credits for the adoption of the most efficient technologies and industrial processes.
2. The provision of innovative financing programs for high-efficiency technologies and industrial processes to facilitate the faster payback of investments in these technologies and processes through energy savings.
3. The removal of barriers to cogeneration in the industrial and commercial sectors, through mechanisms such as net metering and power purchasing agreements.

The CIMS electricity consumption forecast by sector assuming no change in parameters (business as usual) is shown in **Table E1**.

Table E1: CIMS Electricity Consumption Forecast by Sector—Business as Usual, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	36,674	38,430	40,535
Commercial/Institutional		55,279	64,885	76,226	89,489
Industrial	Process	12,709	12,749	12,912	13,049
	Auxiliary	33,440	33,950	36,072	38,269
	Cogeneration	(464)	(497)	(535)	(567)
TOTAL		138,890	147,761	163,105	180,775

The CIMS electricity consumption forecast by sector with all of the three policy changes in place is shown in **Table E2**.

Table E2: CIMS Electricity Consumption Forecast by Sector—Impact of Policy Changes, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	30,542	27,277	26,494
Commercial/Institutional		55,279	47,623	40,874	39,201
Industrial	Process	12,709	11,952	10,863	10,058
	Auxiliary	33,440	32,060	33,263	34,570
	Cogeneration	(464)	(1,282)	(2,173)	(3,047)
TOTAL		138,890	120,895	110,104	107,276

The CIMS results show that with the policy assumptions built in to the model for each sector, energy users would significantly change their purchasing habits with respect to energy-using equipment and processes. These changes would reduce business-as-usual electricity consumption by 73,500 GWh/yr (from 180,775 to 107,276 GWh/yr) by 2020. This amounts to a 40% reduction against the business-as-usual forecast.

The electricity savings would result from three types of technological and behavioural changes:

1. The adoption of the most energy efficient technologies instead of conventional products in all sectors
2. The expansion of cogeneration in the industrial and commercial/institutional sectors as energy consumers take advantage of the efficiencies offered by combined heat and power, and generating power through cogeneration and micro-turbines instead of buying from the grid
3. A shift from electricity to natural gas for heating in the residential and commercial/institutional sectors

These changes would be achieved as energy users would take advantage of financial incentives that reduce the capital cost of energy efficient or non-electric technologies, and innovative financing that would allow them to make purchasing decisions more on a life-cycle cost rather than a first-cost basis.

The study finds that capital investments of $18.2 billion by energy consumers over the 2005–2020 period would be required to achieve these savings through energy efficiency, fuel switching, and cogeneration. However, 96% of these costs would be recovered by consumers through their savings in energy consumption resulting from these investments. Ontario's natural gas consumption would increase by 12% over business-as-usual projections by 2020 as a result of the technological and behavioural changes flowing from the measures tested through CIMS.

The study also considers the potential impact of demand response measures that encourage consumers to not use power at peak periods. This is done through pricing mechanisms designed to encourage consumers to delay or manage power-using activities on an hourly or daily basis at critical peak periods. Estimates developed for the IMO suggest that up to 10% of Ontario's peak demand could be shifted through demand response measures. Consideration is also given to the potential contribution of an on-site solar rooftop program to help address summer peak demand.

The total impact of the modelled energy efficiency measures and potential contribution of demand response programs and on-site solar generation on net grid peak demand are shown in **Table E3**.

As Table E3 shows, net summer peak demand could be reduce by nearly 50% against the business-as-usual projections through the adoption of more energy efficient technologies, fuel switching, cogeneration, demand response measures, and on-site generation.

Table E3: Estimated Peak Demand Reduction and Net Grid Peak Demand 2010–2020

	2010 Peak (MW)		2015 Peak (MW)		2020 Peak (MW)	
	Winter	Summer	Winter	Summer	Winter	Summer
IMO Forecast for Peak Demand	26,000	27,800	26,500	28,700	28,000	30,000
Peak Demand Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(4,500)	(8,900)	(8,900)	(12,300)	(12,300)
Demand Response Measures	(2,330)	(2,330)	(1,980)	(1,980)	(1,770)	(1,770)
On-Site Generation		(250)		(500)		(750)
Net Grid Peak Demand	19,170	20,700	15,620	17,320	13,930	15,180

4. Meeting Remaining Grid Demand

The second and third questions are examined in section 5 of the study. The analysis concludes that it would be reasonable to expect significant contributions to Ontario's electricity supply from low-impact renewable energy sources, such as small-scale hydro, wind, and biomass by 2020 as shown in **Table E4**.

The study finds that, assuming the province maximizes the potential contributions from energy efficiency measures and low-impact renewable energy sources, and phases out the province's coal-fired generating facilities no later than 2010, and given the projected end of life of the province's existing nuclear generating facilities, 4,500 MW of new base load generating capacity will be needed to meet the balance of the province's electricity needs by 2020.

On the basis of costs, environmental and health impacts, speed of construction, and reliability, the study finds that this remaining base load requirement would be best met through combined cycle natural gas generating facilities. However, in light of the concern in the very long term regarding natural gas supplies in North America, these facilities should be seen as an interim measure towards a system that relies on more advanced renewable energy sources in the future.

Table E4: Potential Renewable Energy Supply, 2010–2020

	2010			2015			2020		
Source	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
Wind	7,884	1,317	3,000	12,208	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4205	281	600	5,606	375	800
TOTAL	15,768	2,151	4,500	22,983	3,377	7,100	32,762	4,649	9,800

The final estimated grid demand and supply mix is outlined in **Table E5**.

Table E5: Final Estimated Grid Demand and Supply Mix, 2010–2020

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
New CCNG Base Load	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

The study compares the financial, economic, and social implications of the supply options available to the province to meet its future electricity needs. Under the business-as-usual scenario, assuming that existing hydro and peaking gas and oil-fired (assumed to be replaced by gas) generating capacity are retained, demand response programs are pursued, and that renewable energy sources are maximized, but if aggressive efficiency programs and new combined cycle natural gas baseload supply are not pursued, a peak supply gap of nearly 15,000MW would emerge by 2020. Meeting this gap through new nuclear generation would carry a capital cost of over $39 billion.

The capital costs of addressing the same gap through a combination of energy efficiency measures, fuel switching, cogeneration, and new combined cycle natural gas generation as outlined in this study, by comparison, would be in the range of $23 billion. In addition to avoiding certain capital costs, a supply strategy focused on improving energy efficiency rather than creating new generation would carry with it other benefits: the avoided costs of producing the electricity and gas saved as a result of energy efficiency measures, and the environmental, health, safety, and security co-benefits associated with avoiding the need to construct and operate new generating capacity that would be required under business-as-usual scenarios. There would also be overall improvements in housing quality and the competitiveness of Ontario industry as a result of investments in more modern and energy efficient technologies.

5. Implementing a Sustainable Electricity System in Ontario

Achieving the potential reduction in electricity demand identified in this study by 2020 will not be easy or without risk. However, the study notes that other jurisdictions in North America are implementing the types of program that will be needed in Ontario to achieve this target. California, for example, has reduced peak power demand by 20%, or 10,000 MW over the past 20 years, with a combination of utility demand side management (DSM) programs, and building and appliance standards.

The study concludes that with an appropriate regulatory foundation in the form of minimum energy efficiency standards and labelling, Ontario Energy Board (OEB) incentive mechanisms for utilities, and improved grid access for cogenerators, major reductions in electricity consumption can be achieved without excessive costs to government or energy consumers, or by penalizing low-income members of Ontario society.

The specific measures recommended to the province in the study are as follows:

1. The Government of Ontario should adopt minimum energy efficiency standards under the Energy Efficiency Act equivalent to the energy efficiency levels required for Energy Star labelling for all major electricity-using devices and equipment when the market share for new or replacement energy efficient models surpasses 50%, and not later than 2010 for all devices. The province should develop its own energy efficiency standards for equipment not covered by Energy Star.

2. The provincial Building Code should be amended to require R2000, Canadian Building Improvement Program (CBIP), or equivalent energy efficiency performance for all new buildings and building renovations by 2010.

3. The Planning Act should be amended to permit municipalities to make energy efficiency design requirements a condition of planning and site approvals for new developments.

4. The most energy efficient technologies in all sectors and end-uses should be labelled through the Energy Star program or, if not included in Energy Star, through a provincial labelling system.

5. The OEB performance-based rate setting and DSM incentive mechanism model currently applied to Enbridge Gas Distribution should be extended to Hydro One and all of Ontario's electrical distribution utilities. All distribution utilities should be required to set targets for energy efficiency gains and be allowed to then share in the benefits of DSM programs. The incentive mechanisms should allow utilities without DSM capabilities to meet their targets by contracting the delivery of DSM programs to other electrical and gas utilities, the energy service industry, or specialized non-profit agencies.

6. The Government of Ontario should expand its current net metering policy to include all industrial, commercial/institutional, and residential users, and develop grid inter-tie specifications and training programs for utility staff. A series of annual special RFPs or feed-in tariffs should be issued to encourage smaller industries and large commercial and institutional facilities to develop their cogeneration potential.

7. The Government of Ontario should establish a partnership with utilities, financial institutions, energy service companies, municipalities, and other stakeholders to offer a series of financing mechanisms to assist electricity consumers in all sectors to finance the adoption of energy efficient products and technologies and measures out of the savings they will achieve through these investments.

8. The Government of Ontario should enter into an agreement with the federal government under the auspices of the federal government's Kyoto Protocol implementation plan to share the costs of providing the following financial incentives for the adoption of energy efficient technologies:
   - Grants for high efficiency home energy retrofits and new R2000 homes
   - Grants towards the additional cost of new high-efficiency commercial buildings, and commercial building retrofits
   - Sales tax rebates for all Energy Star products in all sectors and small-scale renewable energy power sources
   - Business tax credits for industrial energy efficiency equipment and cogeneration systems.

These incentives should focus initially on technologies where the largest reductions can be achieved at the lowest cost, such as commercial HVAC and lighting, and industrial drive power. The incentives should be in effect only until the market share of the efficient technology reaches 50%.

9. Mechanisms to ensure the delivery of programs to low-income consumers should be incorporated into the DSM mandates and incentives provided to energy and electrical distribution utilities. A specific portion of DSM spending should be set aside for this purpose, including revenues from the Public Benefits Charge proposed in Recommendation 11.

10. The Government of Ontario should adopt legislation creating a new agency, the Ontario Sustainable Energy Authority, reporting to the Minister of Energy, to lead and coordinate the province's energy efficiency efforts. The agency's functions should include:

- The coordination and oversight of the development and implementation of provincial energy efficiency standards and labelling programs
- Ensuring the consideration of energy efficiency in the policies and programs of provincial government agencies
- The ongoing assessment of the effectiveness of energy efficiency programs being delivered by utilities and provincial agencies, including low-income programs and the provision of recommendations for their improvement to the provincial government and the OEB
- The forecasting of province's future electricity needs
- Research, development, and education and information dissemination on energy efficient technologies and practices.

The proposed Ontario Power Authority, responsible for issuing requests for proposals for the construction of new generating capacity, should be a division of the new agency.

11. A PBC of 0.3 cents/kWh should be applied on all electricity sales to finance energy efficiency and low-income assistance programs.

12. The Government of Ontario should implement the following demand response policies:

- The OEB should be directed to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market.
- The Government of Ontario should assess the infrastructure needed to encourage and facilitate demand response in the Ontario market. A portion of the revenues generated by the PBC proposed in Recommendation 11 should be used to meet the costs of providing the required infrastructure.
- All electricity consumers should be able to participate in demand response programs, and should not be capped in terms of the level of their participation.

13. The Government of Ontario should undertake a design and costing study for a 200,000 unit solar PV roof program modelled on those undertaken in Europe and the United States, and implement this program using a feed-in tariff funding mechanism.

14. The Government of Ontario should issue, through the IMO or proposed Ontario Electricity Authority, RFPs for supply from wind, upgraded existing or new small scale hydro, solar, the use of waste-generated methane from municipal, agricultural, industrial sources and other low-impact renewable energy sources. The initial RFPs should seek to have 4,500 MW capacity in place by 2010, followed by additional calls for supply up to 7,100 MW by 2015 and 9,800 MW by 2020.

15. The Government of Ontario should undertake, on an urgent basis, a complete up-to-date assessment of the potential contributions from onshore and offshore wind generation, small scale hydro, and the use of waste digestion-generated methane, to the province's future energy supply. This effort should include primary research as required, including detailed wind potential mapping.

16. The Government of Ontario should initiate a research and development program on renewable energy technologies funded through the PBC proposed in Recommendation 11. This should include both technology development and the resolution of grid integration issues.

17. The IMO should adopt management practices designed to forecast power outputs from wind power capacity and run-of-river hydro (and solar PV systems), and be prepared to dispatch hydro storage and existing natural gas facilities as needed to provide base load capacity.

18. The Government of Ontario should establish and expedite the completion of a consultative process to develop land-use guidelines for the siting of renewable energy generating facilities.

19. The Government of Ontario should develop guidelines, in conjunction with the federal government, for the approval of offshore wind power generation facilities.

20. The Government of Ontario should issue, through the IMO or the proposed Ontario Electricity Authority, a request for proposals for long-term base load supply, meeting the construction time, cost, reliability, and environmental, health, and safety performance of combined cycle natural gas generating facilities. The call for proposals should seek to have 4,200 MW of new base load supply in place by 2007 and 4,500 MW in place by 2020.

The study concludes that Ontario is now at a critical juncture in terms of its future energy path, and that the decisions made about electricity policy over the next year will set the province's course for the next 20 or 30 years. The choices the province makes will have major implications for the health, environment, safety, and security of Ontario residents, and the competitiveness of Ontario's businesses and industries for decades to come.

The study shows that the choice faced by the province is clear. The province can take the path of making a massive investment in a generation technology, namely nuclear power, that has never lived up to its promise and is in large measure responsible for the environmental, reliability, and financial crises now facing Ontario's electricity system, and which carries with it enormous environmental and economic risks and costs to present and future generations of Ontarians.

In the alternative, the province can choose the path, as laid out in the study, of setting a policy framework that will result in the widespread adoption of proven energy efficient technologies and practices that will reduce consumers' energy bills, improve air quality, protect the health and safety of Ontario residents, and result in a more, safe, secure, and reliable electricity system.

The study consists of a main report and four appendixes:

- A report by Mark Jaccard and Associates on the CIMS modelling
- A report on the history and estimated timelines and refurbishment costs of Ontario's nuclear generating facilities
- A review of recent energy efficiency initiatives in North America, prepared by the Pembina Institute
- A review of combustion technologies for electricity generation, prepared by the Pembina Institute

All of the project materials are available on the websites of the Pembina Institute for Appropriate Development (**www.pembina.org**) and the Canadian Environmental Law Association (**www.cela.ca**).

Power for the Future

Towards a Sustainable Electricity System for Ontario

May, 2004

1. Ontario's Emerging Electricity Challenge

The past five years have been a period of extraordinary change and upheaval in Ontario's institutions and policies related to electricity. More changes have occurred in the electricity sector since 1998 than over the preceding nine decades following the creation of the Ontario Hydro-Electric Power Commission (HEPC) in 1906.[1]

1.1. The *Energy Competition Act*, 1998

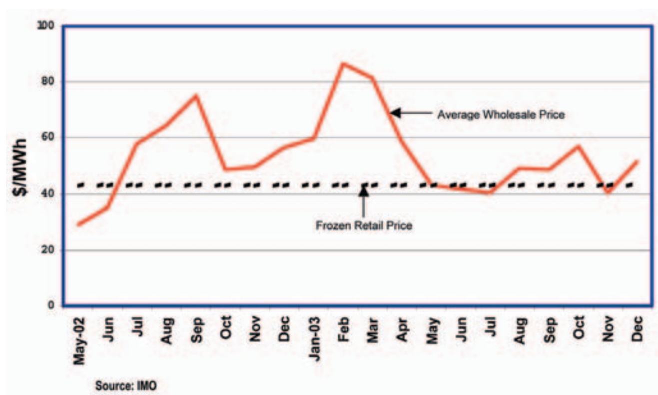
Under the *Energy Competition Act*, adopted in 1998, the HEPC's successor, Ontario Hydro, established as a Crown corporation in 1973,[2] was broken up into a number of entities. These included three separate companies owned by the province: Ontario Power Generation (OPG), which assumed Ontario Hydro's existing generating assets; Hydro One, responsible for transmission and distribution infrastructure; and the Ontario Electricity Financial Corporation (OEFC), which assumed $22 billion of Ontario Hydro's accumulated debt.[3] A fourth entity, the Electrical Safety Authority (ESA), was created to assume the utility's electrical safety inspection functions. [4]

The second key theme of the legislation was the introduction of competitive retail and wholesale electricity markets in Ontario, conferring new powers on the Ontario Energy Board (OEB) to regulate the market and creating an Independent Market Operator (IMO) to operate the technical aspects of the new markets. In the past the province had relied on Ontario Hydro, subject to some limited oversight by the OEB and the Ministry of Energy, to plan for and establish electricity-generating capacity to meet the province's electricity needs. This approach was to be replaced by competitive markets, which would rely on the private sector to plan for and develop electricity supply in response to the province's needs, under a regulatory regime administered by an expanded OEB.[5] To ensure a competitive market, OPG was required to reduce its share of the province's electricity supply from over 85% to 35% by 2010.[6]

1.2. The Electricity Market Opens (and Closes)

Following a series of delays, competitive markets were opened in May 2002. However, this was followed by a period of rising electricity prices, as shown in **Figure 1.1** below. [7]

Figure 1.1:
Ontario Wholesale Electricity Spot Prices
(May 2002–December 2003)[8]



In response to public concerns over the sudden increases in electricity prices, the government terminated the competitive retail electricity market in November 2002. At that time, the provincial government adopted a fixed electricity price of 4.3 cents per kWh, retroactive to May 1, 2002, and stated that this price would stay in place for the following six years. Rebates of $75 to electricity consumers for the cost of electricity while the competitive market was in place were also announced, at a total cost of $335 million. The cost of the difference between the fixed retail electricity price and wholesale electricity price was to be covered via OPG revenues from electricity sales. In practice, as of February 2004, revenues had fallen $852 million short of wholesale electricity costs,[9] with the difference being added to the debt administered by the OEFC.[10]

The announcement of the termination of the competitive retail market was accompanied by some modest initiatives related to renewable energy and efficiency. These included: [11]

- A commitment that the government reduce its electricity consumption by 10% and source 20% of its own energy needs from renewable sources;
- The provision of tax incentives for the purchase of energy efficiency equipment by industry and sales tax rebates for consumers for the purchase of high-efficiency appliances; and
- A 10-year corporate income tax holiday for new suppliers of electricity from clean, alternative, or renewable sources.

In addition, in July 2003, the government announced that it would introduce a requirement that the amount of electricity provided in Ontario from renewable sources (defined as hydro, wind, and biomass) would, starting in 2006, increase by 1% per year over eight years, to total 3,000 MW by 2014.[12] No legislation or regulations to actually implement the renewable energy standard were announced or implemented prior to the 2003 provincial election.

1.3. The NAOP and Coal-Fired Generation

In the meantime, in July 1997 an external review raised major concerns regarding the maintenance and safety of Ontario's nuclear generating assets.[13] In response, Ontario Hydro adopted a Nuclear Asset Optimization Plan (NAOP). Under the plan, seven generating units[14] were taken out of service for repair and overhaul. Investments of between $5 billion and $8 billion over four years in the refurbishment of Ontario Hydro's nuclear generating facilities were announced.[15]

As part of the NAOP, Ontario Hydro announced its intention to rely on its coal-fired generating facilities (Lakeview [Mississauga]; Nanticoke; Lambton; Thunder Bay; and Atikokan) to replace the power supplies lost as a result of the taking out of service of the seven nuclear generating units. This lead to major increases in emissions of smog and acid rain precursors, heavy metals, and greenhouse gases from these facilities. Between 1995 and 2001, their greenhouse gas emissions increased by a factor of 2.3, and emissions of the smog and acid rain precursors sulphur dioxide (SO_2) and nitrogen oxide (NOx) had doubled and increased by a factor of 1.7, respectively.[16]

As a result, in 2001 OPG's coal-fired plants accounted for the following:[17]

- 27% of Ontario's SO_2 emissions
- 20% of Ontario's greenhouse gas emissions
- 14% of Ontario's NOx emissions
- 67% of Ontario's chromium emissions
- 34% of Ontario's airborne mercury emissions

The increased emissions from the Lambton, Nanticoke, and Lakeview facilities in particular have significantly exacerbated the severe air quality problems regularly experienced in southern Ontario[18] and emerged as a major political issue in the province. In light of the health and environmental impacts of their operation, all three major political parties committed to a phase out of the coal-fired plants during the October 2003 election campaign.

OPG encountered significant challenges in the implementation of the NAOP, with the first of the four laid-up Pickering "A" units only coming back into service in September 2003. The cost of this return to service was $1.25 billion. The original budget for the return to service of all four units had been $780 million, with the first unit expected to return to service in June 2000.[19] Two of the Bruce units were brought back in service in October 2003 and January 2004, respectively.[20] Both were significantly over budget and behind schedule as well.[21]

1.4. Projections of Rising Demand and Falling Supply

The overall situation flowing from this extended period of policy instability is one of growing concern regarding the security and reliability of the province's electricity supply. Delays in return to service of nuclear generating facilities have resulted in significant growth in reliance on imports of power during periods of high demand.[22] At the same time, most of the new generation facilities that were being considered by non-OPG proponents in anticipation of a competitive electricity market have been placed on hold[23] due to the unstable policy environment, the fixed electricity price adopted in November 2002, and the continued provincial financing of the refurbishment of OPG's nuclear generating facilities.

In the meantime, Ontario Hydro and its successor OPG had not developed any major new generating capacity since the completion of the Darlington plant in 1993. The reasons for this included a focus on energy efficiency and demand side management in the early 1990s, and, after 1995, anticipation of the establishment of a competitive market and need to reduce OPG's market share. Ontario Hydro also began to wind down its efficiency and demand side management programs from 1993 onwards as part of the restructuring undertaken by then Chairman Maurice Strong[24] and as a consequence of an oversupply situation following the commissioning of the Darlington facility. The remaining energy efficiency programs initiated by the Ministry of Environment and Energy and other provincial agencies in the early 1990s were abandoned following the 1995 election.[25]

The new provincial government, elected in October 2003, has made a strong commitment to the phase out of OPG's coal-fired plants by 2007 due to the severe environmental and health impacts of their operation.[26] As shown in **Table 1.1**, these plants currently account for 23% of Ontario's electricity supply. In addition, in November 2003 the government announced the abandonment of the fixed electricity price of 4.3 cents per kWh as of April 1, 2004, going to 4.7 cents per kWh for the first 750 kWh consumed and 5.5 cents per kWh for consumption beyond that level. This step reflected the government's view that the fixed price approach was not financially sustainable.[27]

Table 1.1: Ontario Electricity Supply, 2003[28]

Source	GWh	%	Peak (MW)	%	Capacity (MW)
Coal	35,098	23	5,865	23	7,285
Nuclear	61,040	40	7,140	28	10,720
Hydro	33,572	22	6,375	25	7,665
Peaking Gas and Oil	12,208	8	3,060	12	4,645
Imports	10,682	7	3,060	12	
Total Demand	152,600		25,500		30,315

This state of affairs is further complicated by the consideration that all of the province's existing nuclear generating facilities,[29] which currently account for 28% of the province's generating capacity, will reach the end of their projected operational lifetimes by 2018. This is shown in **Tables 1.2** and **1.3**.[30]

Table 1.2: Ontario Power Generation CANDU Reactors: "A" Plant Phase-Out Schedule[31]

Station Capacity	Unit	Comm'l Oper'n[32]	First Shutdown	Second Shutdown	Life
Pickering "A" 4 x 515 MWe (net)	1	07/1971	12/1983–09/1987	12/1997–SD[33]	?
	2	12/1971	08/1983–11/1988	12/1997–SD	?
	3	06/1972	06/1989–08/1991	12/1997–SD	?
	4	06/1973	08/1991–03/1993	12/1997–09/2003	13 yrs–2016
Bruce "A" 4 x 769 MWe (net)	1	09/1977	01/1998–SD		?
	2	09/1977	10/1995–SD		?
	3	01/1978	01/1998–02/2004		8 yrs–2012
	4	01/1979	01/1998–10/2003		13 yrs–2016

Table 1.3: Ontario Power Generation CANDU Reactors: "B" Plant Phase-Out Schedule[34]

Station Capacity	Unit	Commercial Operation	25 years
Pickering "B" 4 x 516 MWe (net)	5	05/1983	2008
	6	02/1984	2009
	7	01/1985	2010
	8	01/1986	2011
Bruce "B" 4 x 860 MWe (net)	5	03/1985	2010
	6	09/1984	2009
	7	04/1986	2011
	8	05/1987	2012
Darlington 4 x 881 MWe (net)	1	11/1992	2017
	2	10/1990	2015
	3	02/1993	2018
	4	06/1993	2018

As a result, there is growing concern among the public, energy consumers, and the government over both the province's short-term ability to meet peak electricity demand,[35] and its longer-term electricity supply.[36] Public concerns about the security of the province's future electricity supply were further reinforced by the August 2003 blackout.

The overall situation with respect to the province's electricity supply and demand over the next 15 years, assuming no significant efforts to reduce electricity demand, the phase out of the coal-fired plants, and the run-down of existing nuclear generating facilities, was summarized by the province's Electricity Conservation and Supply Task Force in its January 2004 report as shown in **Figure 1.2**[37].

In developing its estimate, the Electricity Conservation and Supply Task Force extrapolated the IMO's 2003–2013 forecast of electricity consumption and peak demand from 2005 to 2020 as shown in **Table 1.4**.[39]

The implication of these trends is that Ontario will need to make major decisions about long-term electricity policy in the relatively near future. These include questions on the shape of future demand and

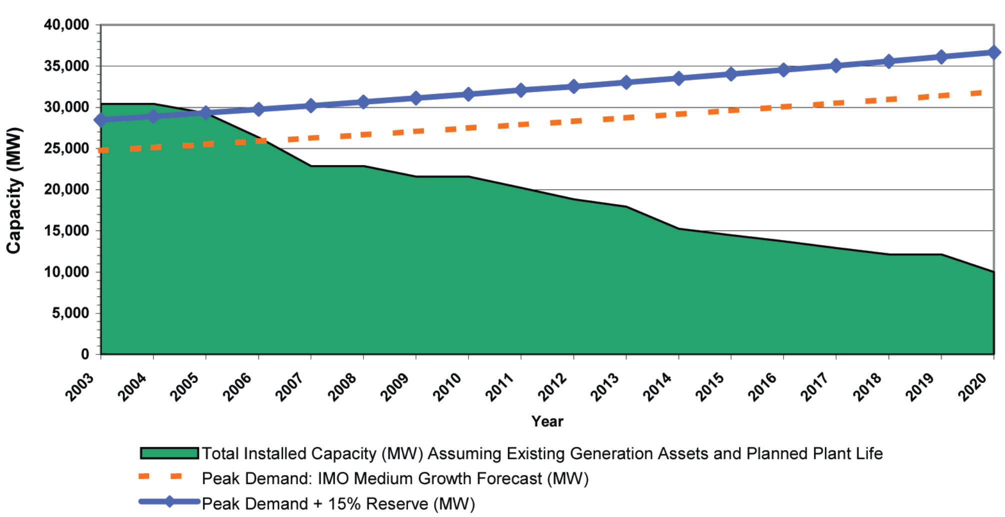


Figure 1.2: Existing Generation vs. Peak Demand[38]

Table 1.4: Forecast Electricity Consumption and Peak Demand, 2005–2020

	2005	2010	2015	2020
Consumption (GWh/yr)	153,000	164,000	172,000	180,000
Peak Demand[40] (MW)	25,500	27,800	28,700	32,000

supply. The business-as-usual projections from the Task Force and the IMO, for example, do not consider the potential reduction in future demand that programs and policies adopted by the provincial government to promote energy efficiency might provide.

Even if energy efficiency programs were to be successfully adopted, consideration also needs to be given to how the remaining demand for electricity might be met. The options range from investing in the refurbishment of the existing nuclear generating facilities to extend their projected lifetimes, or even in the development of new nuclear generating facilities, to meeting the province's needs though low-impact renewable energy sources, such as wind and small-scale hydro.

In the case of both energy efficiency programs and new supply options, decisions on the path forward will need to be made in the relatively near future, as most available options are associated with potentially long lead times to full implementation. Equipment such as industrial motors and residential appliances have lives of 10 to 15 years. It could therefore take that long to replace all of the existing equipment with more efficient units. Buildings are renovated infrequently, and there may be similar delays in the adoption of more energy efficient technologies and practices.

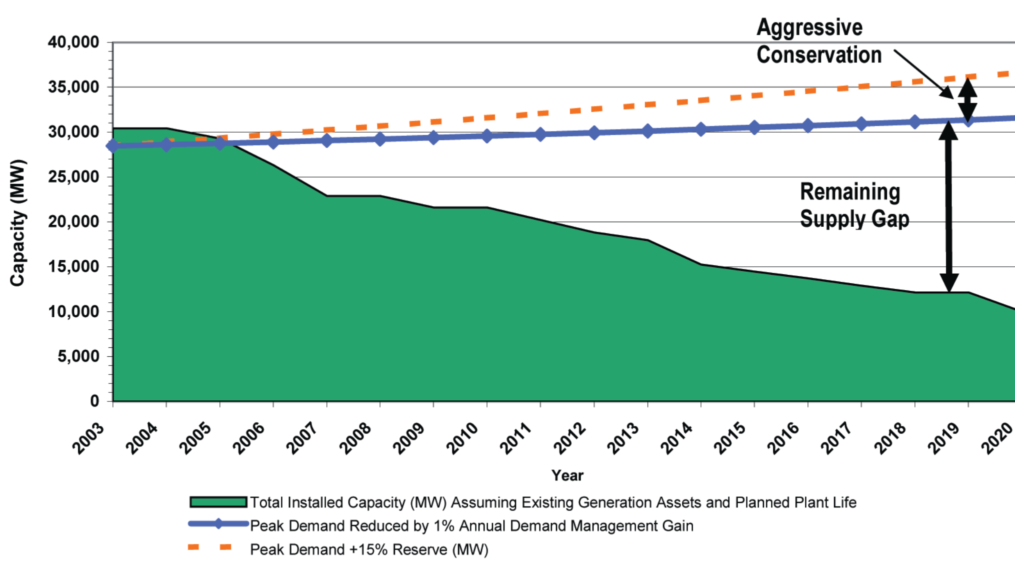
1.5. The Debate over Energy Efficiency and the Future Shape of Ontario's Electricity System

A number of recent reports have examined the questions of the future shape of Ontario's electricity system in considerable detail. Among the most prominent of these have been the work of the province's Electricity Conservation and Supply Task Force, completed in January 2004[41] and a July 2003 report completed by Torrie Smith Associates for the Campaign for Nuclear Phase-Out.[42]

Both studies are in overall agreement on the direction of rising future electricity demand in the absence of efforts to improve energy efficiency and reduce demand. They are also in agreement on the wind down of the province's existing nuclear and coal plants for technological as well as policy reasons. However, the studies disagree strongly on the potential contributions from energy efficiency measures to meeting the province's future energy needs, and, by implication, the levels and types of new supply that will be needed to meet future electricity demand.

The Electricity Supply and Conservation Task Force, for its part, only projected a modest reduction in electricity demand of approximately 5,000 MW,

Figure 1.3: Future Demand/Supply Balance[43]



consisting of the government target of 5% plus an additional 700 MW of peak demand reduction through "demand response" measures such as innovative pricing and smart metering. The Task Force called this reduction "aggressive conservation," although the peak demand by 2020 was still projected to be higher than in 2003, as is shown in the Task Force's **Figure 1.3**.

As shown in **Figure 1.4**, this continued growth in demand, in combination with the expected closure of coal-fired generating facilities and the run down of existing nuclear generating facilities by 2018, resulted in a projection by the Task Force for the need for 12,700 MW of new generating capacity, over and above what can be achieved through the "aggressive" pursuit of renewable options, such as wind, hydro, and biomass.[44] The Task Force's report implied that this need would have to be met through new natural gas-fired generation or new and refurbished nuclear generation capacity.

The March 2004 report of the Ontario Power Generation Review Committee[46] reached similar conclusions, stating that "renewable energy sources, conservation and co-generation are all important, but cannot fully bridge the supply gap."[47] The committee did not give estimates of how much these sources might be able to contribute, but projected a potential supply shortage of between 5,000 and 7,000 MW by 2007.[48]

The July 2003 Torrie Smith Associates[49] study reached very different conclusions. As shown in **Figure 1.5**, it found that grid power consumption could be reduced significantly against current levels of demand by 2020 through the following:

- The replacement of all electricity-using equipment with the most energy efficient commercially available equipment today
- The maximization of industrial and commercial sector cogeneration and other on-site power sources
- The elimination of the use of electricity for space and water heating

The remaining electricity demand could be filled through a combination of existing hydro facilities and new wind, biomass, small-scale hydro, and solar, eliminating the need for nuclear or fossil fuel-fired generation. However, 3,000 MW of imported power from Quebec and Manitoba would be required to meet peak demand.

The conclusions of these studies present the provincial government with a number of dilemmas in terms of its future electricity policies. The wide variations in their findings regarding the potential contributions from energy efficiency, for example, leave the province with questions about the appropriate level of effort to put into energy efficiency programs, the scale of the province's future supply needs, and the best supply options to meet those needs.

Figure 1.4:
Electricity Supply and Conservation Task Force Projection of Generation vs. Peak Demand—With Renewables[45]

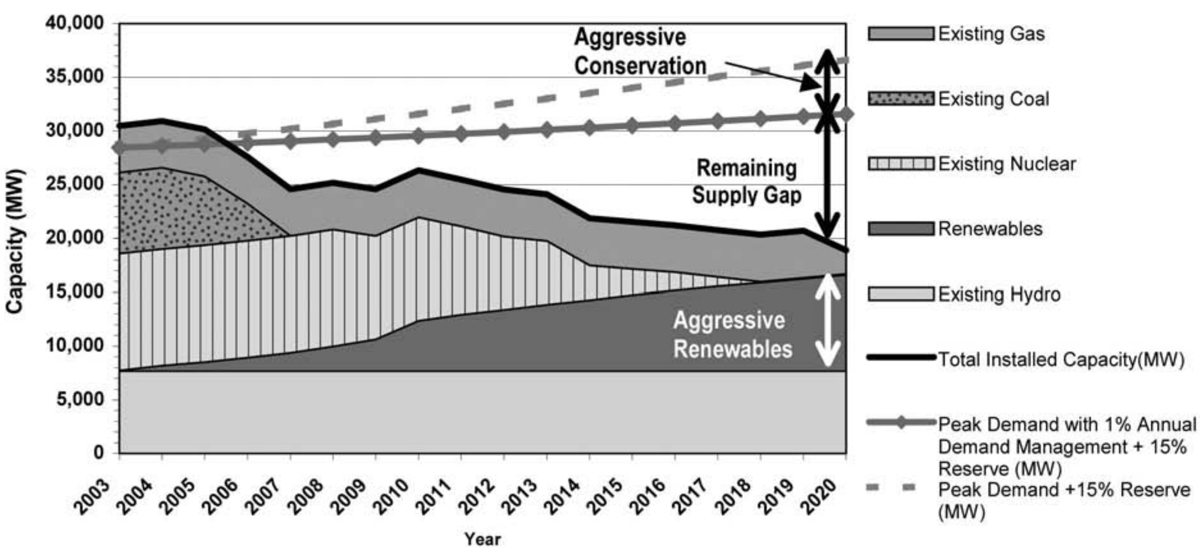
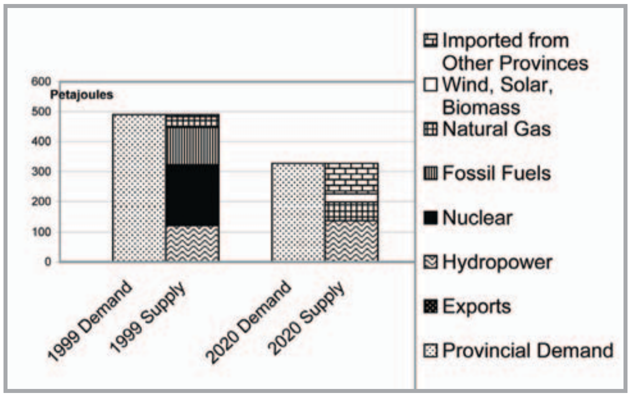


Figure 1.5:
Torrie Smith Associates Projection of Electricity in Ontario 1999 and 2020—Nuclear/Coal Phase-Out[50]



1.6. Project Overview

In light of this period of extraordinary change and upheaval in Ontario's electricity institutions and policies, and the debate over the future shape of Ontario's electricity needs and supply, this study seeks to build on the work of both the Electricity Supply and Conservation Task Force and Torrie Smith Associates, and to answer four key questions regarding the province's future electricity path. These questions are as follows:

1. How much might future electricity demand in Ontario be realistically reduced through the adoption of energy efficient technologies, fuel switching, cogeneration, and demand response measures?
2. How much future supply might be realistically obtained from low-impact renewable energy sources, such as wind, the upgrading of existing hydroelectric facilities, and the development of new small-scale hydro plants, solar, and biomass?
3. How should the remaining grid demand, if any, be met once the technically and economically feasible contributions from energy efficiency, fuel switching, cogeneration, demand response measures, and low-impact renewable energy sources have been maximized?
4. What public policies and institutional arrangements should the province adopt to ensure the maximization of the contributions from energy efficiency and other demand side measures, low-impact renewable energy sources, and the most environmentally and economically sustainable supply mix to meet remaining future grid demand?

The overall structure of this study is as follows:

Section 1 provides the overall context and rationale for the study.

Section 2 outlines the definition of an environmentally and economically sustainable electricity system that provides the normative framework for the study. This section also describes the study's methodological approach.

Section 3 describes the energy efficiency policies tested using computer modelling and the outcomes of the modelling in terms of impact on electricity demand, natural gas consumption, and societal and program costs.

Section 4 develops an estimate of remaining grid demand, once energy efficiency policies have been implemented, also considering the potential impact of demand response and other peak reduction measures.

Section 5 examines electricity supply options for meeting the remaining grid demand, including low-impact renewable energy sources, and refurbished or new nuclear and fossil-fuel sources.

Section 6 summarizes the study's overall findings with respect to the four research questions. It also provides policy recommendations for the province to maximize the contributions from efficiency, fuel switching, and cogeneration in the most efficient way possible, and to ensure an environmentally and economically sustainable supply to meet the province's remaining electricity demand.

2. Project Goals and Methodology

2.1. Guiding Principles for a Sustainable Electricity System

A sustainable energy path for Ontario's electricity supply and demand is defined, for the purposes of this study, as one that minimizes the impact of electricity supply and demand on the environment and human health, uses only environmentally and economically sustainable sources of energy, and provides the reliable energy services that Ontario's citizens and businesses need at a reasonable cost.

The specific features of a sustainable energy path for Ontario's electricity supply and demand would include the following:

- Using electricity as efficiently as possible and with as even a load curve as possible
- Using electricity only for services for which there is no sustainable alternative
- Producing power at the consumer's site, wherever possible, to make best use of efficiencies such as combined heat and power, and local renewable energy sources
- Using a wide variety of grid power sources in a distributed fashion to maintain the reliability and resilience in the grid
- Using only renewable energy sources to generate electricity
- Phasing out energy sources that are not environmentally or economically sustainable, such as fossil fuels and nuclear energy
- Using lower impact non-renewable fuels such as natural gas as bridging fuels to a situation where the electricity system can rely on renewable energy sources to meet demand
- Ensuring that the price of electricity reflects the full costs of its generation, including externalized life-cycle environmental, economic, and social costs
- Ensuring that all members of society have access to electricity to meet their basic needs and have the opportunity to benefit from energy efficiency programs, regardless of their incomes

An electricity system constructed on the basis of these principles would seek to maximize energy efficiency, and then employ low-impact renewable energy sources as its option of first resort to meeting remaining electricity demand. Lower-impact non-renewable fuels would then be used to address any remaining demand requirements.

This report examines the feasibility of implementing an electricity system in Ontario that reflects these principles over the next 15 years. In particular, it examines the economic and technical achievability of such a system, and seeks to identify specific policy measures needed to bring about its implementation.

2.2. Methodology

This report approaches the exploration of possibilities for a sustainable electricity system for Ontario through five steps:

1. An examination of the extent to which grid demand might be reduced through a series of policies that encourage households, and commercial/institutional and industrial facilities to adopt the most energy efficient technologies currently available; increased industrial and commercial/institutional cogeneration; and the elimination of electric heating. This examination is undertaken through the following:
   - The proposition of a series of generic policy measures to promote the adoption of energy efficient technologies, cogeneration in the industrial and commercial/institutional sectors, and fuel switching from electricity to natural gas where this is the most efficient option
   - The use of the Canadian Integrated Modeling System (CIMS) computer model developed by the Energy and Materials Research Group at Simon Fraser University to estimate the following: the reduction in electricity consumption that could be achieved from the present to 2020

through the implementation of energy efficiency policies; the incremental investment associated with achieving the 2020 energy savings; the resulting changes in natural gas demand from the adoption of energy efficient technologies and practices; and the net cost per kWh saved through energy efficiency measures

2. The development of an estimate of the reduction in peak electricity demand that would result from the reduction in consumption identified through the CIMS model, and other measures that could be used to shift or reduce 2020 summer and winter peak demand. Load factors are used to estimate the peak demand impacts of the CIMS results. The load-shifting potential of demand response measures such as time-of-day pricing are also considered, along with the peak demand reductions that could be achieved through the use of on-site renewable energy technologies.
3. The review of the potential contributions in terms of power production, peaking potential, and cost of low-impact renewable energy technologies, including existing and new small-scale hydro, wind, and biomass, to meeting the remaining 2020 grid demand. A mix of low-impact renewable energy sources that appears technologically and economically feasible is identified to contribute to meeting this demand.
4. The consideration of the economic, environmental, and social aspects of options to address any remaining grid demand after the optimization of energy efficiency, cogeneration, fuel switching, and the introduction of low-impact renewable energy generation. This may include such options as imports from neighbouring provinces, new or refurbished nuclear generating facilities, combined cycle natural gas, and other new technologies.
5. On the basis of these steps, an overall policy framework for the province is proposed to maximize the adoption of energy efficient technologies, cogeneration, fuel switching, and the use of low-impact renewable energy sources, and to address any remaining supply gaps. This framework considers such factors as financing mechanisms, institutional arrangements, and costs to government of program delivery and administration.

3. Reducing Electricity Consumption

Energy efficient technologies in commercial use today would allow Ontario industry, commercial and institutional establishments, and households to use electricity much more efficiently than is currently the case. The widespread adoption of these technologies in Ontario is essential to meeting the province's future electricity needs in an environmentally and economically sustainable manner, and to ensuring the future competitiveness of the Ontario economy.

The maximization of energy efficiency before considering the construction of new sources of supply offers a series of advantages that make it the option of first choice in the design of Ontario's future electricity system. The provincial government,[51] the Electricity Conservation and Supply Task Force, and others have recognized these advantages, which include the following:

- The ongoing reductions in energy costs for energy consumers. This is particularly important in the context of energy prices that are likely to rise in the future. Investments in energy efficiency can pay for themselves in savings to energy consumers over time.
- The avoided capital costs associated with the construction of new sources of supply and electricity.
- The avoided environmental and health impacts that would otherwise flow from the construction and operation of new sources of supply of electricity. The life-cycle environmental and health impacts of fuel production for non-renewable energy sources, such as fossil fuels and nuclear would be avoided as well.
- The avoided security risks associated with conventional sources of supply, particularly nuclear energy.
- The avoided political risks associated with dependency on fuel sources or energy imports from other jurisdictions.
- The permanent and reliable character of the savings achieved through increased energy efficiency.
- The reduced losses of energy through transmission and distribution systems.
- The improved reliability of the electricity system by lightening the load at the end of the supply/delivery chain, thereby enhancing the reliability of each link in the entire chain.[52]
- The employment benefits flowing from investments in energy efficiency initiatives as opposed to new generation.[53]

A strategy based on the maximization of energy efficiency does carry with it some risks. Energy consumers may not adopt more efficient technologies and practices for a variety of reasons. These include a lack of information about the availability of better options, their costs over conventional technologies, and concerns over the payback times in terms of energy savings against the additional initial investment cost.

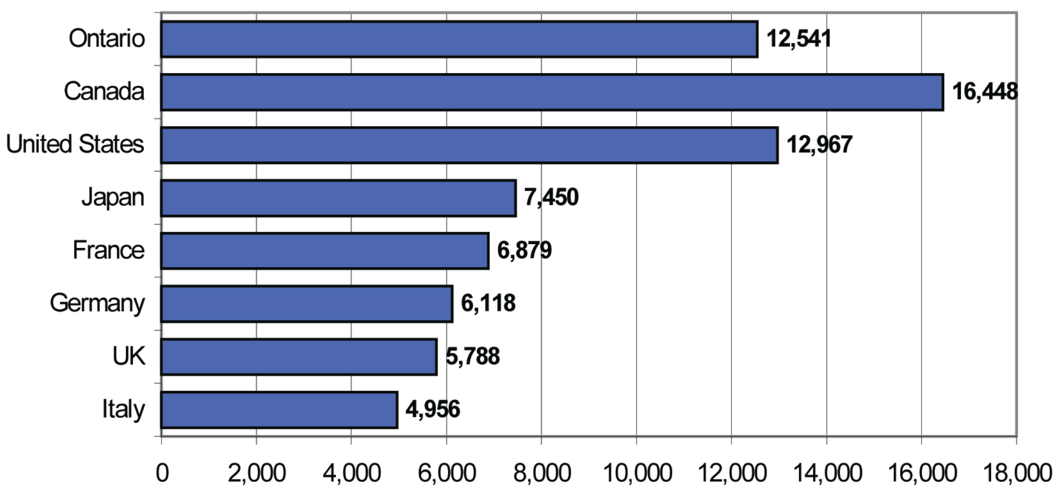
However, the alternative strategy of simply attempting to build supply to meet whatever demand emerges as a result of population and economic growth would result in much higher energy costs to consumers. Consumers would have to pay down those capital costs through their energy bills, and may have to forgo the opportunity to make investments to reduce their own consumption in order to do so. This would have serious adverse implications for many sectors of society, including the competitiveness of Ontario industry in relation to other jurisdictions, and the ability of low-income households to meet their basic energy needs.

If the same capital that would need to be invested in the construction of new generating facilities is invested in energy efficiency measures, energy consumers are provided with a means of reducing their energy costs, even in the context of rising energy prices. Major investments in energy efficiency could also form the foundation of a wider technological renewal of the Ontario economy, through which the province's competitiveness could be enhanced.

The first question explored in this study is that of how much future electricity demand might be reduced through the adoption of energy efficient technologies and practices. The key to answering this question is examining how Ontario households and businesses can be persuaded to adopt the more energy efficient technologies and practices that are available, and thereby reduce the underlying risks associated with relying on efficiency improvements to meet demand. Other jurisdictions in North America are facing the same challenges, and a number of lessons from their experiences are applied in the following discussion.[54] California, for example, has reduced peak power demand by 20%, or 10,000 MW over the past 20 years, with a combination of utility demand side management programs, and building and appliance standards.[55]

It is also important to note that while Ontario's levels of consumption of electricity are typical for North America, as shown in **Figure 3.1**, they are very high relative to advanced economies outside North America. Even allowing for differences in geography and economic structure, this suggests that these countries are much more efficient in their use of electricity than is Ontario. This is not surprising, given that many of these jurisdictions have pursued energy efficiency as a central component of their economic strategies for many decades.[56]

Figure 3.1:
Net Electricity Consumption per Capita (KWh), 2000[57]



Source: US Energy Information Administration and UN World Population Prospects, Population in 1999 & 2000.

("Net consumption" is defined as generation, plus imports, minus exports, minus transmission and distribution loss.)

3.1. Approaches to Reducing Electricity Demand

The following approaches are available to reduce electricity consumption on the demand side of the electricity meter.

3.1.1. The Adoption of Energy Efficient Technologies

Many of the most energy efficient technologies or measures available today in each sector of the economy are up to 50% more efficient than those currently in use or those with the highest market share.[58] In most cases, the cost of these technologies is higher than conventional ones, but this incremental cost can be recovered from energy and operating savings in a number of years.

Consumers do not adopt more energy efficient products and technologies or improve the efficiency of their homes and buildings for a number of reasons. These include a preference for lowest first cost rather than lowest life-cycle cost and a preference for familiar products over new ones. Energy efficient technologies can also be harder to find in the marketplace than conventional alternatives.

3.1.2. Cogeneration

New technologies, such as micro-turbines, are making combined heat and power production a feasible option for commercial and institutional buildings as well as industrial facilities at an overall power and heat efficiency of more than 75%.[59] This makes cogeneration an extremely efficient way of using and producing energy.

Producing electricity in this way close to where it is used offers a number of other key advantages:

- The reduction of stress on electricity transmission and distribution systems, while potentially avoiding the need to build expensive new transmission lines.
- The protection of sensitive systems against power disruptions through distributed generation systems so that even if there is a problem with the electricity grid (as on August 14, 2003), customers served by distributed generation sources will still have power.
- Allowing the size of generation systems to be scaled to the power needs of the consumer.
- The provision of shorter project lead-times and easier site approvals.

The main barriers preventing increased use of cogeneration are a shortage of investment capital, the unfamiliarity of cogeneration technologies to potential users, and the lack of net metering that would allow users to buy and sell power to the grid at the same price, as discussed in section 3.2.4.

3.1.3. Eliminating the Use of Electricity for Heating

Efficient gas furnaces and water heaters can now provide space heating at up to 96% and water heating at 80% efficiency, and on a life-cycle basis provide these services at a lower cost than electricity. Eliminating the use of electricity for heat is therefore a very effective and efficient way of reducing the demand for electricity. The main barriers to such a transition in Ontario are a combination of lack of access to natural gas supply in some, particularly rural, areas and the lower initial cost of electric heating systems. This is a particularly serious barrier to low-income households.

3.2. Policy Options to Reduce Grid Consumption

The following types of policies have been used in other jurisdictions to eliminate the barriers that prevent consumers from choosing the most energy efficient technology available each time they replace an existing product or purchase a new one, and to encourage fuel switching and cogeneration.

3.2.1. Minimum Efficiency Codes, Standards, and Labelling of Energy Efficient Technologies

Once an energy efficient technology has gained a significant market share in the new product market, its incremental cost comes down; and there is little penalty to either the energy consumer or manufacturer from regulations that eliminate less-efficient products from the market. This approach has been used successfully to reduce the annual energy consumption of domestic refrigerators by 35% between 1990 and 2000.[60] Energy efficiency codes for buildings in Ontario have also been successful in maintaining a minimum level of comfort and efficiency in housing. The use of codes and standards is a risk-free strategy as the savings are guaranteed.

Labelling high-efficiency products is effective in providing consumers with information on energy performance that helps them make sound buying decisions. Labelling is also effective in helping provide a level playing field for new high-efficiency products that come onto the market.

3.2.2. Financial Incentives for the Most Energy Efficient Technologies and Industrial Processes

When a new more energy efficient product is introduced, and sales are low, there is normally a capital cost barrier that prevents fast user uptake. Financial incentives, like the Ontario sales tax rebate on appliances, help to kick start transformation of the market by temporarily lowering the incremental cost of energy efficient technologies over less-efficient options. Financial incentives lower the payback period on new energy efficient products for energy consumers during the important first phase of market transformation. As sales of new energy efficient technologies increase, the price differential between efficient products and conventional products decreases and often disappears, so that incentives can be phased out. More energy efficient T8 fluorescent lamps, for example, now cost almost the same as less-efficient T12 lamps.

3.2.3. Innovative Financing Programs for High-Efficiency Technologies and Practices

Many potential users of higher efficiency technologies are unwilling or unable to accept the length to time needed for the cumulative savings to cover off the initial additional cost of these technologies over conventional options. These barriers can be overcome through programs that allow customers to purchase energy efficient technologies on a life-cycle basis and pay for the additional cost out of the savings achieved over time. Successful examples of such programs include prime rate loan programs used by utilities such as SaskEnergy to help customers purchase high-efficiency gas furnaces. Innovative new approaches to financing being proposed include the use of Local Improvement Charges to pay for energy efficiency upgrades to buildings, allowing the cost of long payback improvements to be shared by current and future owners of the property.

3.2.4. Net Metering and Power Purchasing Agreements for Cogeneration

Industrial plants and larger commercial and institutional facilities have few incentives to generate their own heat and power and to sell any excess electricity that they might be able to generate to the grid. These barriers include:[62]

- The lack of grid access for firms with the potential to sell excess electricity. This includes the lack of physical grid connections and the absence of regulatory structures that permit retail customers to sell back to the grid. The lack of net metering also limits the viability of small-scale cogeneration.
- The lack of interconnection standards for electricity projects.
- The discrepancy between the cost of back-up power and the price paid for electricity sold, which reduces the financial viability of cogeneration projects. In some jurisdictions, the cost of connecting to the grid and receiving back-up power from the grid is very high compared with the expected revenue from electricity sales.
- The setting of transmission tariffs on the average cost of transmitting electricity, meaning that the rate doesn't change regardless of how far the electricity is being distributed. This unnecessarily burdens cogeneration projects that are sited close to their electricity customers.
- The hesitancy of plant managers to move away from their core business and begin selling electricity as well. The uncertainty surrounding cogeneration costs can be high for firms unfamiliar with the technology, thereby discouraging investment.

These barriers can be removed by introducing grid access standards and a net metering regime under which power is sold to the grid at the same price or higher than the power purchased by the facility in recognition of the efficient use of natural gas use in cogeneration plants. Long-term power purchase agreements for cogenerators can provide the long-term financial stability needed to justify cogeneration investments in larger facilities.

3.3. Using the CIMS Model to Evaluate Demand Side Policy Options

To test the impact of power consumption reduction policies, and to get a firmer idea of the incremental cost of efficiency improvements to government and consumers, some typical policy scenarios were tested using the Canadian Integrated Modelling System (CIMS) model developed by the Energy and Materials Research Group (EMRG) at Simon Fraser University. The CIMS model provides a forecast of energy use by technology, end-use, and sector in five-year increments, together with the end-use equipment investment associated with each forecast.

The results allow the analyst to test different policy scenarios and estimate the energy savings that each might produce over the long term. The associated costs allow efficiency "supply curves" of cost-per-unit savings against size of savings to be derived from the CIMS model results. These supply curves illustrate the most cost effective end-uses and allow comparison with supply side costs.

3.3.1. The CIMS Model

The CIMS model estimates future energy demand by simulating the addition and replacement of energy using "stock"—industrial process equipment, electric motors, commercial lighting equipment, residential appliances, etc. The addition of new stock is linked to forecasts of macroeconomic parameters such as industrial production, commercial floor space, and housing starts. Stock replacement is determined by the life of the piece of equipment, or its availability. CIMS also simulates a "competition" among technologies that can meet the demand for new or replaced stock. The distribution among the competing technologies depends on its capital cost, operating cost, and various parameters representing consumer preference.[63]

Energy demand is then estimated by multiplying the stock number of each technology installed at any time by their energy use per unit. CIMS also aggregates the investment in the stock. The model allows the analyst to modify parameters to simulate policies that add or remove technologies, change energy prices, or manage consumer choice. By running a base case (business as usual) forecast followed by a forecast with the policy parameters changed, the analyst can estimate the reduction in energy use resulting from the policy change as well as the additional investment required to achieve these savings.

Because CIMS treats each energy end-use separately, the analyst can also construct a "supply" curve of energy efficiency measures showing which groups of measures are the most cost effective.

3.3.2. How the CIMS Model Was Used to Simulate Energy Efficiency Policies

The CIMS model has been used for several other studies in Ontario, and has been calibrated to 2000 electricity use as reported by Statistics Canada. Capital costs, operating costs, and energy use per unit have been incorporated into the model for most technologies currently in use today. User preference parameters in the form of perceived discount rate have been set to simulate today's user choices of lowest first cost. Cogeneration is constrained to provide power only within industrial plants (i.e., power is not sold to the grid).

The CIMS model uses the forecasts for electricity and gas prices for Ontario prepared by Natural Resources Canada (see **Tables 3.1** and **3.2**) to compute the life-cycle costs of competing technologies.

Table 3.1: Ontario Electricity Price Forecast (¢/kWh), 2000–2020[64]

	2000	2005	2010	2015	2020
Commercial	8.30	8.50	9.22	9.98	10.79
Industrial	6.30	5.38	5.83	6.31	6.82
Residential	10.00	10.24	11.11	12.03	13.00

Table 3.2: Ontario Natural Gas Price Forecast ($/GJ), 2000–2020[65]

	2000	2005	2010	2015	2020
Commercial	5.25	5.79	6.41	6.97	7.61
Industrial	3.61	3.97	4.40	4.76	5.18
Residential	6.37	7.01	7.76	8.46	9.25

The prices in Tables 3.1 and 3.2 are considered reasonable expectations in Ontario. While until April 1, 2004, the residential tariff was 4.3 cents per kWh, once other fixed and variable charges were added, the Ontario consumer was effectively paying in the range of 10 cents per kWh.[66]

To simulate the types of electricity reduction policies described earlier in this section, changes were made to the CIMS model parameters:

1. To simulate **net metering for cogeneration**, the constraints that CIMS uses to restrict cogeneration were removed. This allowed generation of power up to levels matching the steam demand of the industry, with the excess electricity being supplied to the grid.
2. To simulate **financial incentives** (such as the removal of sales taxes), the capital cost of the most energy efficient technology used for each energy end-use, high-efficiency gas heating systems, and cogeneration systems in CIMS were all reduced by 8%.[67] CIMS includes most of the high-efficiency technologies and cogeneration systems available on the market today, and these were designated as the "target" technologies for this policy.[68] In effect, the simulation reduced the effective payback period for energy efficiency, cogeneration, and fuel switching investments for the user by reducing their first costs.
3. Under normal circumstances, energy consumers will give preference to technologies with the lowest first cost, and only invest in energy efficiency if the paybacks are very short. CIMS simulates this behaviour by using high user discount rates, which minimize the importance of fuel and operating costs in any decision. To simulate market transformation programs that remove these barriers through **innovative financing** and other means, the user perceived discount rates in CIMS for the targeted

technologies were reduced to the financial "hurdle" rate[69] in each sector. These hurdle rates were set at 12% for the industrial sector, and 8% for the residential and commercial sectors. In effect, the reduction of discount rates simulates a situation where potential users of an energy efficient technology are provided the means to pay for the technology as they achieve the savings. This leads to users investing in measures with longer payback periods than they normally would.

4. Minimum standards were not explicitly simulated, but the model results were used to identify the year when each of the targeted technologies gained a significant market share (>50%) and therefore determine when a standard could be imposed without penalizing consumers or industry.

The forecast electricity consumption by sector assuming no change in CIMS parameters (business as usual) was estimated as shown in **Table 3.3**.

Table 3.3: CIMS Electricity Consumption Forecast by Sector—Business as Usual, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	36,674	38,430	40,535
Commercial/Institutional		55,279	64,885	76,226	89,489
Industrial	Process	12,709	12,749	12,912	13,049
	Auxiliary	33,440	33,950	36,072	38,269
	Cogeneration	(464)	(497)	(535)	(567)
TOTAL		138,890	147,761	163,105	180,775

There are some discrepancies between the CIMS forecasts, which are based on 2000 Statistics Canada figures and Natural Resources Canada forecasts, and those of the IMO and Electricity Conservation and Supply Task Force (see **Table 1.4**). These discrepancies are particularly evident in the early years of the forecast. This is due to differences in data reported to the two different sources by Ontario energy users, and in the assumptions of macroeconomic parameters over the next 15 years. However, the differences are not large enough to affect the results of this analysis.

3.4. The CIMS Results

Four CIMS simulations were carried out with the following policy assumptions:

Simulation 1: The removal of barriers to cogeneration

Simulation 2: The provision of financial incentives + the removal of barriers to cogeneration

Simulation 3: The reduction of discount rates (simulating the impact of innovative financing programs) + the removal of barriers to cogeneration

Simulation 4: The provision of financial incentives + the reduction of discount rates + the removal of barriers to cogeneration

The individual runs showed that lowering discount rates resulted in the largest reduction in electricity consumption, followed by cogeneration and financial incentives. This appears to be a reasonable result since the lack of means to finance the higher cost of energy efficient technologies out of the savings applies to all sectors and end-uses. Financial incentives alone provide a benefit only if they bring the cost of the energy efficient technology close to that of conventional technologies. Cogeneration only applies to industry and larger commercial and institutional buildings. The three measures are not additive, but each tends to improve the chances of the others being successful. A small financial incentive program, for example, will increase the likelihood of a consumer taking advantage of a financing program.

The following analysis considers the consumption reduction associated with the combined policies. Full details of the CIMS model simulations and results are provided in a separate report by M. K. Jaccard and Associates in Appendix 1.

3.4.1. The Impact of Modelled Policies on Electricity Consumption

The CIMS electricity consumption forecast by sector with all of the three policy changes in place is shown in **Table 3.4**.

Table 3.4: CIMS Electricity Consumption Forecast by Sector—Impact of Policy Changes, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential		37,926	30,542	27,277	26,494
Commercial/Institutional		55,279	47,623	40,874	39,201
Industrial	Process	12,709	11,952	10,863	10,058
	Auxiliary	33,440	32,060	33,263	34,570
	Cogeneration	(464)	(1,282)	(2,173)	(3,047)
TOTAL		138,890	120,895	110,104	107,276

Energy savings achieved with the policy changes in place in each sector relative to the business-as-usual forecast are shown in **Table 3.5**.

Table 3.5: CIMS Energy Savings Forecast by Sector—Impact of Policy Changes, 2005–2020

Sector		GWh/Yr			
		2005	2010	2015	2020
Residential			6,132	11,153	14,041
Commercial/Institutional*			17,262	35,352	50,288
Industrial	Process		797	2,050	2,991
	Auxiliary		1,890	2,809	3,699
	Cogeneration		786	1,638	2,480
TOTAL			26,867	53,002	73,499

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

The CIMS results show that with the policy assumptions built in to the model for each sector, energy users would significantly change their purchasing habits with respect to energy-using equipment and processes. These changes would reduce business-as-usual electricity consumption by 73,500 GWh/yr (from 180,775 to 107,276 GWh/yr) by 2020. This amounts to a 40% reduction against the business-as-usual consumption forecast.

The electricity savings result from three types of technological and behavioural changes:

1. The adoption of the most energy efficient technologies instead of conventional products in all sectors
2. The expansion of cogeneration in the industrial and commercial/institutional sectors as energy consumers take advantage of the efficiencies offered by combined heat and power, and generating power through cogeneration and micro-turbines instead of buying from the grid
3. A shift from electricity to natural gas for heating in the residential and commercial/institutional sectors

These changes would be achieved as energy users take advantage of financial incentives that reduce the capital cost of energy efficient or non-electric technologies, and innovative financing that would allow them to make purchasing decisions more on a life-cycle cost rather than a first-cost basis.

The overall results provided by the CIMS model should be viewed as an example of what could be achieved using the types of policies simulated. Actual strategies that might be used to obtain these savings are outlined in section 6 of this report.

The CIMS results are conservative in nature. Many of the savings and cost advantages of new innovative approaches to energy efficient building design, such as integrated design, high-efficiency lighting management, and radiant cooling have yet to be built into the CIMS model.

3.4.2. The Impact of Energy Efficiency, Increased Cogeneration, and Fuel Switching on Natural Gas Consumption

One of the major issues that has emerged in the debates over future electricity supply in Ontario is the question of the impact of different energy efficiency and supply options on natural gas consumption.[70] The CIMS estimates of the net changes in natural gas consumption resulting from fuel switching and cogeneration, less the efficiency gains from using more energy efficient gas-using products are shown in **Table 3.6**.

Table 3.6: CIMS Forecast of the Impact of Simulated Policies on Natural Gas Consumption, 2005–2020

Sector		Increases in Natural Gas Use—PJ			
		2005	2010	2015	2020
Residential			(23)	(38)	(45)
Commercial/Institutional*			52	118	176
Industrial	Process		2	4	6
	Auxiliary		0	0	1
	Cogeneration		(3)	(5)	(8)
TOTAL			28	79	130

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

The CIMS results show that natural gas use in the residential sector would be significantly reduced by the policy changes. While there would be a switch by energy consumers to natural gas for heating, many of the measures that improve electricity efficiency also improve gas efficiency. The same thing happens in the industrial sector, where there would be an increase in the amount of cogeneration, but this would be more than offset by using more gas-efficient cogeneration technologies. In the commercial/institutional sector, the increase in cogeneration would not be fully offset by increases in efficiency, with the result that there would be a net increase in gas use in the sector.

The net increase in gas consumption over business-as-usual by 2020 would be 130 PJ for a total of about 1,210 PJ per year. This is an increase of 43% over Ontario's 2001 natural gas consumption of 842 PJ. However, only about 12% of this increase is attributable to the impact of fuel switching, increased cogeneration, and other technological and behavioural changes flowing from the policy measures tested through the CIMS simulations.

3.4.3. The Costs of Energy Efficiency Improvements

Total undiscounted additional investments required to achieve savings identified through the CIMS analysis between 2005 and 2020 are shown in **Table 3.7**. The figures reflect the additional (undiscounted) investment costs (i.e., incremental investments over business-as-usual) resulting from stock changes in targeted technologies and their direct competitors.

Table 3.7: CIMS Forecast of Total Incremental Investments Needed to Achieve Projected Electricity Savings

Sector		Total Incremental Investments 2005–2020
		In millions of dollars (undiscounted)
Residential		6,633
Commercial/Institutional*		13,494
Industrial	Process	770
	Auxiliary	225
	Cogeneration	365
TOTAL		21,487 = $21.5 billion

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

The figures in Table 3.7 show the additional investment by both energy users and government (through financial incentives) in new more-efficient equipment and cogeneration over the 15-year period covered by the CIMS analysis.

However, it is critical that the costs be considered in the context of the reduced electricity costs that consumers will enjoy as a result of investing in higher efficiency technologies. In some cases, the investments will result in reduced gas consumption and lower maintenance costs as well.

This is illustrated in **Table 3.8**, produced directly from the CIMS model results. Table 3.8 provides a comparison of the incremental investment in energy efficient technologies and practices, the reduction in operation and maintenance costs resulting from these investments, and the net savings in energy costs assuming the energy prices given in Tables 3.1 and 3.2.

Table 3.8: Forecast Incremental Costs Associated with Achieving 2020 Energy Savings (discounted to 2004)

Sector	Incremental Costs Associated with Achieving 2020 Savings In millions of dollars (discounted to 2004)			
	Investment	Operation and Maintenance	Energy	Total
Industrial	829	273	(1,255)	(153)
Residential	7,220	(45)	(6,174)	1,001
Commercial/Institutional*	10,211	1,345	(11,782)	(226)
TOTAL	18,260	1,573	(19,211)	622

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

As Table 3.8 shows, the savings flowing from reduced energy consumption almost pay for the additional cost of the adoption of higher efficiency equipment. In fact, there are net benefits to commercial/institutional and industrial energy consumers.

Table 3.8 also shows a cost to residential consumers of energy efficiency investments of approximately $1 billion. This cost would amount to just over $90 per resident, spread over a 15-year period, or approximately $6 per person per year. However, in addition to energy savings, investments in the residential sector would carry with them significant co-benefits in terms of improvements in overall housing quality.

In essence, the savings in energy costs resulting from reduction in energy consumption will pay for more than 96% of the capital costs of the adoption of more energy efficient technologies over the long term. The net effect would be that even in the context of rising electricity and gas prices, the electricity costs to households and businesses would remain roughly the same as they are now, provided that consumers make the necessary investments in more energy efficient technologies and practices.

It is also important to note that the estimates of the savings resulting from investments in energy efficiency only consider the direct cost savings resulting from reduced energy use. They do not consider the economic, health, environmental, and social co-benefits that would flow from these investments. These co-benefits include the avoided environmental and health impacts of the construction and operation of generating facilities, improved housing quality, and the increased competitiveness of businesses and industries resulting from their more efficient use of energy resources.

In the case of health and environmental benefits, for example, the Ontario Medical Association has estimated that the total annual health costs associated with poor air quality in Ontario, to which, as described in section 1.3 of this report, the current electricity supply mix is a major contributor, at $9.9 billion per year.[71] The reductions in these costs that would flow from the avoided impacts of electricity generation arising from investments in energy efficiency measures would therefore be substantial.

A more detailed discussion of the costs of individual types of energy efficiency measures is provided in section 3.4.5.

3.4.4. Stock Turnover and Minimum Energy Efficiency Standards

Table 3.9 shows the market share of new stock of each of the targeted energy efficient technologies under the policy regime simulated through the CIMS analysis and the market share of total installed stock in 2010 and 2020.

The table shows that by 2010, significant fuel switching, uptake of the targeted energy efficient technologies, and cogeneration has taken place. This would allow minimum energy efficiency standards and codes to be raised to the levels of these technologies soon after 2010 without penalizing manufacturers or consumers. This would have the effect of allowing natural stock turnover to achieve complete market transformation to energy efficient technologies by 2020. As soon as the energy efficiency standards are in place, the financial incentives can be discontinued or shifted to newer and even more energy efficient technologies. This would not change the total incremental investment needed, but greatly reduce the government share of the cost once market transformation has begun.

3.4.5. The Most Cost-Effective Ways to Reduce Electricity Use

It is also interesting to consider the relative contribution and cost of some of the individual technologies contributing to reduced electricity use. **Table 3.10** was generated from the CIMS results and provides the estimated cost per kWh saved[72] for each technology end-use and the GWh/yr saved in that end-use over the 15-year period 2005–2020. The table illustrates how the "supply" cost of most energy efficient technologies lies at between 0 and 7 cents per kWh saved. The table also shows how some energy efficient technologies are more cost effective than others and where the greatest impact can be obtained from energy efficiency programs.

It is important to note that all of the different end-uses are not independent of each other, and the costs and savings generated by one group of technologies is often contingent on another group. The results show that residential appliances and fuel switching, commercial/institutional building shell and heating, ventilation and air conditioning, and lighting, and industrial drive powers should receive priority attention. The costs of saved energy found in this analysis compare well with other recent studies of conservation/demand side options.[73] In section 5, we compare these costs per kWh with the costs of supply options.

The high cost of new single family home space heating improvements reflects the fact that the these improvements have the effect of reducing natural gas consumption significantly, but have a limited impact on electricity use.

Table 3.9: CIMS Forecast of Market Share of Targeted Energy Efficient Technologies, 2010–2020

Technology End-use or Sub-Sector	Market Share of Targeted Energy Efficient Technologies		
	New Market Share in 2010	Total Market Share in 2010	Total Market Share in 2020
Residential			
Clothes Washers	100%	53%	100%
Dishwashers	89%	45%	89%
Other Hot Water Use	77%	61%	70%
Clothes Dryers	100%	43%	97%
Ranges	100%	33%	91%
Freezers	99%	32%	90%
Lighting	100%	100%	100%
Refrigerators	100%	41%	97%
Air Conditioners	100%	17%	44%
New Homes	65%	34%	52%
Existing Home Retrofits	10%	3%	11%
Furnace Air Fans	100%	63%	100%
Water Heaters	86%	58%	76%
Commercial/Institutional			
Office Equipment (Plug Load)	43%	20%	43%
Hot Water	100%	76%	100%
Cooking	100%	71%	100%
Refrigeration	97%	45%	97%
Lighting	99%	52%	81%
Large Retail—New	8%	4%	6%
Hospitals/Nursing Homes—New	73%	27%	59%
Hotels/Motels—New	95%	35%	75%
HVAC Systems/Cogeneration	100%	27% to 41%	71% to 84%
Industrial			
Motor Drives	35%	34%	36%
Fans and Blowers	77%	23%	50%
Conveyors	34%	29%	34%
Compressors	76%	55%	74%
General Pumping	91%	86%	91%
Slurry/Stock Pumping	100%	92%	100%
Precision Pumping	98%	90%	98%
Shaft Drive Motors	58%	36%	47%
Lighting	96%	49%	74%
Space Heating	84%	47%	67%

Table 3.10: Estimated Cost per kWh Saved by End-Use

Technology End-use	Incremental Capital Cost of Efficiency ($/kWh saved)	Cost of Additional Natural Gas ($/kWh saved)	Electricity Saved through Efficiency, Fuel Switching and Cogeneration (GWh/yr)
Residential			
Lighting	$(0.006)		832
Furnace Air Fans	$(0.004)		359
Post-1960 Single Family Homes—Space Heating	$0.001	$(0.079)	373
Pre-1960 Single Family Homes—Space Heating	$0.003	$0.007	971
Apartments—Space Heating	$0.016	$0.021	1,540
Ranges	$0.022	$(0.014)	1,702
Hot Water Heating	$0.032	$(0.038)	4,738
Freezers	$0.053		385
Other Housing—Space Heating	$0.057	$(0.279)	352
Clothes Dryers	$0.061	$(0.031)	338
Clothes Washers	$0.065		660
Dishwashers	$0.081		746
Air Conditioners	$0.104		246
Other Appliances	$0.142		0
Refrigerators	$0.156		622
New Single Family Homes—Space Heating	$0.663	$(0.624)	176
Commercial/Institutional			
Hot Water	$(0.000)	$0.035	4,945
Cooking	$(0.000)	$0.093	1,088
Shell and HVAC	$0.024	$0.042	30,040
Lighting	$0.024		9,970
Refrigeration	$0.097		1,419
Office Equipment (Plug Load)	$0.375		361
Industry—Auxiliary			
Lighting	$(0.006)		22
Space Heating	$(0.000)	$0.060	61
Conveyors	$0.000		145
Direct Drive	$0.000		1,356
Pumps	$0.004		554
Fans and Blowers	$0.005		219
Compressors	$0.013		1,341
Industry—Process			
Chemicals	$0.002		238
Metals	$0.002	$0.008	239
Pulp and Paper	$0.024		1,777
Petroleum Refining	$0.028		127
Iron and Steel	$0.046	$0.063	488

3.5. Estimating Peak Demand Reduction from Efficiency Improvements, Increased Cogeneration, and Fuel Switching

The reduction in peak demand associated with the efficiency gains forecast through the CIMS analysis in section 3.4 were estimated using load factors.

The system peak load factor may be defined as average demand divided by peak demand.

Average demand (MW) = Total consumption (GWh) x 1,000/Hrs per year
Peak Demand = Average Demand/Peak Load Factor

Applying this formula to the IMO forecasts of electricity consumption and peak demand,[74] the average system summer peak load factor for the Ontario grid is about 68%. Applying this factor to the 73,400 GWh of electricity savings realized across all sectors shown in Table 3.5 through the proposed policies produces a peak demand reduction of 12,300 MW by 2020. As shown in **Table 3.11**, this would reduce expected summer peak demand in 2020 from 30,000 MW to 17,700 MW. This estimate is conservative, as the majority of the GWh savings would be achieved in the residential and commercial/institutional sectors where the peak loads are the highest.

Determining the separate effects of the efficiency savings on individual summer and winter peaks would require a more detailed analysis of each end-use. For this analysis it is assumed that the estimated peak demand reduction would apply to both summer and winter.

No additional policies would be required to achieve these reductions. The phasing out of electric heat in favour of gas will have a very positive effect on the winter peak. Priority could also be given under the electricity efficiency strategy described in section 6.4 to those technologies identified in Table 3.9 that would achieve the highest peak demand reduction, such as commercial/institutional building HVAC and water heating systems, and household ranges.

Table 3.11: Estimated Reduction in Summer Peak Demand from Efficiency, Fuel Switching, and Cogeneration

	2010 Peak (MW)	2015 Peak (MW)	2020 Peak (MW)
IMO Forecast for Summer Peak Demand	27,800	28,700	30,000
Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(8,900)	(12,300)
Remaining Summer Peak Demand	23,300	19,800	17,700

4. Demand Response and Peak Load Shaving

This section assesses the additional reduction in peak demand that could be achieved through demand response measures, such as time-of-day pricing and smart metering. The additional reduction that could be achieved through special demonstration programs specifically designed to shave peak demand, such as a 1,000 MW solar photovoltaic (PV) roof program, are also considered.

4.1. Demand Response Measures

Demand response measures are those in which power users are encouraged to not use power at peak periods. This is done through pricing mechanisms designed to encourage customers to delay or manage power-using activities on an hourly or daily basis at critical peak periods. It can also be carried out through interruptible or ripple supply rates, where users agree to have non-key loads such as water heaters and battery charging shut off or supplied intermittently during peak periods.

Demand response measures should not be confused with measures that encourage power consumption and load reduction through improved equipment efficiency as described in section 3.

The April 2003 "Blueprint for Demand Response in Ontario," prepared by Navigant Consulting for the IMO, indicates that up to 10% of Ontario's peak demand could be shifted through demand response measures.[75] The recommended measures include widespread use of "interval" meters for all types of customer throughout the province that would allow customers to choose a fixed price for power or modify their electricity use in response to price signals from their utilities.

Assuming that efficiency measures, fuel switching, and cogeneration reduced 2020 peak grid demand by 12,300 MW (from 30,000 MW to 17,700 MW) as discussed in section 3.5, demand response measures could reduce this figure by an additional 1,770 MW as shown in **Table 4.1**.

4.2. Load Shaving through On-site Generation

Several jurisdictions in the United States and Europe have implemented programs that encourage the use of on-site grid-connected solar PV systems incorporated into the roofs of existing and new buildings, or buildings that otherwise provide a portion of their own power from renewable energy sources. In Europe, feed-in tariffs and other innovative means are used to finance solar PV programs so that the cost is internalized within the grid system (paid for by all customers) rather than through a direct subsidy.[76] Countries such as Germany have supplemented these measures with major solar PV programs. A German 100,000 Roof Photovoltaic Programme was introduced in 1999 and is administered by the German Credit Institution for Reconstruction (*Kreditanstalt für Wiederaufbau* [KFW]). The program supports the installation or extension of photovoltaic systems with a peak nominal power of at least 1 kWp. The program offers a special zero-interest loan with a repayment period of 10 years and up to two starting years without credit repayment.[77]

These solar PV programs have many key benefits. These include:

- Providing reductions in summer peak demand. Air conditioning loads that drive summer peaks reach their highest levels during the day when solar radiation is high and solar PV systems deliver their maximum output.
- Providing a jump-start to the solar PV industry so that economies of scale can be achieved, thereby reducing costs.
- Providing greater visibility for renewable energy.
- Allowing energy users who wish to generate their own power to do so.
- Providing end-of-line stability to power distribution systems to maintain power quality.

Ontario's summer peak appears to be rising faster than the winter peak due to the increasing air conditioning load.[78] However, Ontario also has a very good summer solar resource, and there should be sufficient roof space in major cities like Toronto to mount large numbers of solar PV systems. The cost of solar PV systems is still high, but the potential is very large. A 1,000 MW solar roof program involving up to 200,000 buildings in Ontario, coupled with the improved grid access policies described in section 6.4 would lay the foundation for cost reduction and a major contribution from solar electricity beyond 2015. A solar roofs program would provide the much needed peak demand reduction as the summer peak grows in the province as well as providing the other benefits listed above.

One kW of PV capacity will provide one kW output at full-sun conditions at noon. If it is assumed that average summer conditions during the summer peak are equivalent to 75% full sun, 1,000 MW of solar PV could be expected to reduce peak demand by about 750 MW and produce about 2,500 GWh/yr of power.

4.3. Estimating Remaining Grid Peak Demand

Section 3 of this study demonstrates that it is reasonable to assume that electricity consumption from the grid in Ontario could be reduced by 73,500 GWh/yr against business-as-usual forecasts by 2020 through a combination of the adoption of existing energy efficient technologies, cogeneration, and fuel switching. As discussed in section 3.5, this translates into a reduction in peak demand of 12,300 MW.

Demand response measures are estimated to be able to reduce peak demand by a further 10%, or approximately 1,770 MW, by 2020. An on-site generation solar roof program could reduce summer peak demand by a further 750 MW by 2020. The total estimated peak demand reduction and resulting net grid peak demand are shown in Table 4.1.

Table 4.1: Estimated Peak Demand Reduction and Net Grid Peak Demand 2010–2020

	2010 Peak (MW)		2015 Peak (MW)		2020 Peak (MW)	
	Winter	Summer	Winter	Summer	Winter	Summer
IMO Forecast for Peak Demand	26,000	27,800	26,500	28,700	28,000	30,000
Peak Demand Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(4,500)	(8,900)	(8,900)	(12,300)	(12,300)
Demand Response Measures	(2,330)	(2,330)	(1,980)	(1,980)	(1,770)	(1,770)
On-Site Generation		(250)		(500)		(750)
Net Grid Peak Demand	19,170	20,700	15,620	17,320	13,930	15,180

As Table 4.1 shows, net summer peak demand could be reduced by nearly 50% against the business-as-usual projections through the adoption of more energy efficient technologies, fuel switching, cogeneration, demand response measures, and on-site generation.

5. Meeting Residual Grid Demand

5.1. Remaining Grid Demand

Table 5.1 summarizes the remaining grid requirements in Ontario assuming the reductions in demand outlined in sections 3 and 4.

Table 5.1: Net Grid Requirements, 2005–2020

	GWh/yr	Winter Peak (MW)	Summer Peak (MW)
2005	153,000	25,500	26,300
2010	136,000	19,200	20,700
2015	117,000	15,600	17,400
2020	104,000	13,900	15,200

These figures indicate that there would be a need to provide a reliable base load of approximately 13,000 MW and additional capacity to meet another 2,000 MW of mid-load and peak demand by 2020.

Ontario has a range of potential supply options to meet this remaining grid demand. In addition to the province's existing hydroelectric facilities, these include traditional non-renewable energy sources, such as nuclear power, and fossil fuels, such as coal and natural gas. New renewable sources of supply, including wind, hydroelectric power, and the use of methane from municipal landfills and the anaerobic digestion of municipal, agricultural, and industrial wastes (biomass) will also be available.

5.2. Renewable Supply Options

In accordance with the sustainable energy path laid out in section 2, renewable energy sources, such as wind, hydro, and biomass, are examined as the supply options of first resort for the purposes of this study. This reflects the following features of these sources:

- Their low environmental and health externalities relative to conventional sources. Wind energy, for example, generates no emissions other than those associated with the manufacturing of generating equipment.[79]
- Their low operating costs relative to conventional supply, given that the underlying energy sources, such as wind, run-of-river water, and municipal and agricultural wastes are available at little or no cost.
- Renewable sources do not require the import of fuels or electricity from outside of Ontario. Therefore, they provide a higher security of supply than conventional supply options. Renewable energy sources are also unaffected by the shifts in the costs of conventional fuels, such as coal and natural gas, that may occur due to international demand or market conditions that are beyond the control of the Government of Ontario.
- Their low security risks relative to some types of conventional supply, particularly nuclear energy.
- The distribution of supply among a larger number of technologically and geographically diversified sources reduces the risks and impacts associated with the failure of particular technologies, or upsets and breakdowns at individual large, centralized generating facilities.

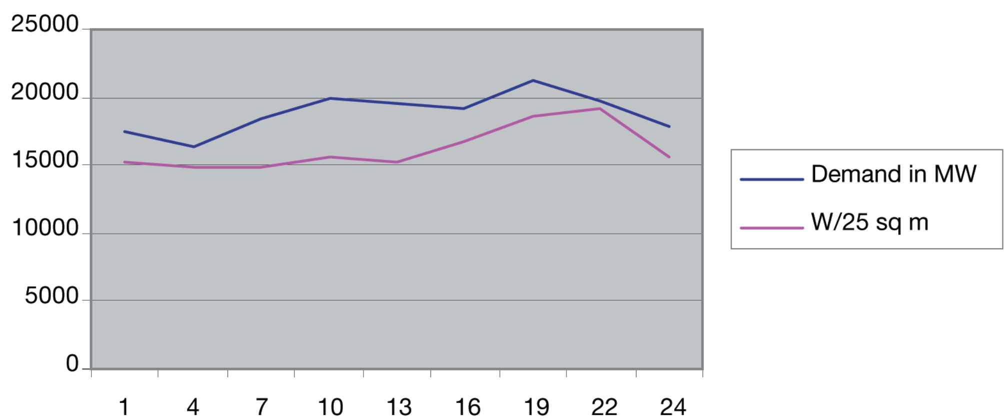
The following analysis of renewable energy options reviews wind, hydro, and biomass power sources and their potential contribution to annual electricity supply and meeting peak demand. The analysis is based on the best currently available information sources on renewable energy in Ontario.[80] It is important to note that the overall state of the estimates of the potential contributions from low-impact renewable energy sources in Ontario is poor, as only very limited work has been done in this area since the time of the Ontario Hydro Demand Supply Strategy in the early 1990s. Some of the available technologies, particularly wind, have undergone major advancements since then.

5.2.1. The Ability of Renewable Energy Sources to Meet Peak Demand

Some renewable energy sources have limited dispatch capability (e.g. run-of river hydro). Others, such as wind, are intermittent but match peaks in demand quite. There is a good correlation, for example, between Ontario's peak electricity demand and the characteristics of Ontario wind speeds, as shown in **Figures 5.1** and **5.2**. Hydro with storage capacity can be used for both base load and peaking, although it is associated with potentially higher environmental impacts. Finally, modern electronic control and power regulation equipment, and accurate weather forecasting allow grid dispatchers to forecast power outputs from renewable energy sources (such as solar, wind, and run-of-river hydro) and dispatch hydro storage and natural gas capacity as needed. With an effective integration and dispatch strategy in place, therefore, much higher percentages of supply from renewable sources are possible.

Figure 5.1: Ontario Electricity Demand vs. Wind Supply for July 18, 2001[81]

Figure 5.2: Ontario Electricity Demand vs. Wind Supply for January 18, 2001[82]



5.2.2. Hydroelectric Power Generation

Current hydroelectric capacity in Ontario is 7,665 MW, mostly located on the Niagara, St. Lawrence, and Ottawa rivers, and in northern Ontario. Some locations are run-of-river, while in other locations there is significant storage capacity. Power can be dispatched from those facilities with storage capacity in response to demand within certain reservoir level limits.[83]

Ontario Hydro/Ontario Power Generation (OPG) have proposed the addition of diversion tunnels and a new underground generating station with a capacity of 600 MW to the existing generating facilities at Niagara Falls.[84] As shown in **Table 5.2**, the Ontario Waterpower Association has estimated that there is a total of between 1,200 MW and 4,000 MW of additional waterpower resources in Ontario that could be developed at between 6 and 8 cents per kWh.[85]

Table 5.2: Ontario Waterpower Potential for Development[86]

Source	Capacity (MW)	Energy (GWh)
Known Developable Sites	200 to 300	1,000 to 1,500
Re-developments at Existing Facilities	600 to 1,300 (equivalent)	2,000 to 3,000
Upgrades—Re-powering and Efficiency Improvements	200 to 400	1,000 to 1,500
Additional Development Potential	200 to 2,000	1,000 to 10,000
TOTAL	1,200 to 4,000	5,000 to 16,000

On this basis, it is reasonable to assume that a total of 2,000 MW of new hydroelectric supply could be brought on line by 2020, bringing total capacity, considering the 7,665 MW already in place, to 9,665 MW. A certain portion of this capacity could be dedicated to providing back-up power for provincial wind capacity. It was assumed that the capacity factor for any new hydro facilities would be approximately the same as existing facilities.87 However, the contribution to peak supply would be slightly lower than existing plants, due to the high portion of run-of-river facilities assumed to be in the new capacity.

5.2.3. Large-Scale Wind Power Generation

The technologies for generating electricity through wind power have undergone an enormous transformation over the past decade, resulting in a dramatic reduction in the costs of wind-generated electricity.[88] Large-scale installations of wind power generation units are becoming more common in Europe and the United States. The total installed and forecast wind power generating capacity in selected leading countries is shown in **Table 5.3**.

Table 5.3: Installed and Forecast Wind Power Generating Capacity, Selected Countries[89]

Country	Installed Capacity (MW) 2000	Forecast Capacity (MW) 2005
Germany	6,107	14,307
Spain	2,836	11,236
Denmark	2,341	3,841
United States	2,610	7,360

Wind farms in Ontario must be located close to the grid. This implies locations in southern Ontario and parts of northern Ontario where grid access will be feasible. The grid-accessible portion of the province is estimated to have a geographic area of over 300,000 sq. km. This is approximately the same land area as Germany, where there is 7,500 MW of installed wind power generating capacity.[90] Ontario has abundant wind resources, and in its 2001 report, the Ontario Wind Power Task Force (OWPTF) estimated potential onshore wind capacity on Crown land in Ontario at between 2,000 and 7,500 MW.[91] Most of this capacity is on the shores of the Great Lakes where wind regimes are high enough to make wind a commercially viable power option at current wind turbine costs of approximately $1.5 million per megawatt. [92]

Private developers have indicated that in the early stages of Ontario's wind energy development, the net present realized cost of wind energy from a viable site is 8 to 10 cents/kWh.[93] The factors that have the largest impact on price are the wind regime, which in Ontario is good, but not as good as on Canada's coasts or on the prairies, and the foreign exchange needed to purchase most of the turbine equipment.[94] The establishment of a wind equipment manufacturing industry in the province would reduce the latter costs.[95]

The prices of wind power systems themselves have been falling steadily over the past 20 years. Recent modular installations of 1 MW units in the North Sea off the UK and Denmark show that even lower costs can probably be achieved.[96] The OWPTF did not explicitly estimate the offshore potential in the Great Lakes, but states that it would be "significantly greater" than the 7,500 MW of onshore potential.[97] It would seem plausible therefore that 7,000 MW of wind power could be installed onshore and offshore in Ontario by 2020. The minimum capacity factor for wind systems expected in Ontario is 30%[98] so that 7,000 MW would generate 18,396 GWh/yr of electricity.

The OWPTF also showed that wind generator output could be expected to match both daily and seasonal peak demand.[99] Wind speeds increase in the afternoon in both summer and winter, coinciding with the evening peak. Wind speeds also increase with lower temperatures and match the higher loads that occur during colder weather.[100] Conservatively, therefore, 7,000 MW of wind power capacity should be able to contribute at least 3,000 MW during periods of peak demand.

Even though the match between peak demand and wind speed is good, there will still be some occasions when wind power generator output will need to be supplemented by dispatchable sources, such as hydro with storage or natural gas turbine peaking units. There will be a need to designate a certain proportion of the hydro capacity in Ontario as a complementary source to wind, integrating outputs from the two sources to provide an equivalent base load source. This coordination should be made easier through advances in wind forecasting, which will allow the outputs from wind farms to be predicted several days ahead. Diversifying the location of wind power farms throughout the Great Lakes will also reduce the percentage of time that wind power will need to be supplemented with hydro.

5.2.4. Landfill, Sewage, and Anaerobic Waste Digestion Gas Capture and Generation (Biomass)

Methane generated in landfills, and from the anaerobic digestion of sewage sludge, and municipal and agricultural wastes can be collected and burned as fuel to generate electricity.

It has been estimated that over 100 MW of generating capacity could be provided through landfill gas recovery and combustion in Ontario.[101] The largest installed generating capacity in Canada is 30 MW at the City of Toronto's former Keele Valley landfill.[102] Large, new, or expanding Ontario municipal waste landfills have been required to install landfill gas recovery facilities since 1998. [103]

The OWPTF estimated that a total of between 200 MW and 500 MW of capacity might be provided through the use of methane from the anaerobic digestion of various waste streams, at a cost of between 6 and 9 cents/kWh.[104] Some additional supply may be provided through industrial cogeneration using materials such as wood or agricultural wastes as fuel as well.

On this basis, it is estimated that 800 MW of capacity from landfill and waste digestion generated gas combustion and agricultural and wood waste combustion might be installed by 2020. These sources are assumed to have quite a high capacity factor, and deliver at least 50% of capacity at peak times. Therefore, 800 MW of capacity was assumed to deliver 5,600 GWh/yr and 375 MW at peak periods.

5.3. Summary of Renewable Energy Potential and Remaining Demand

Table 5.4 provides a possible demand and supply mix in which coal is phased out by 2010 and nuclear power by 2020, incorporating the estimated contributions available from renewable energy sources outlined in section 5.2.

Table 5.4: 2010–2020 Demand and Supply Mix with Efficiency and Low-Impact Renewable Energy Sources[105]

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/ Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
Remaining Base Load Requirement	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

5.4. Supply Options to Meet Remaining Grid Demand

Table 5.4 shows that even with the contributions from efficiency programs and low-impact renewable sources of supply, approximately 4,200 MW of new base load capacity would be needed by 2010, and 4,500 MW of new base load capacity would be needed by 2020. As a result, of the contributions from energy efficiency, cogeneration, demand response, and new renewable energy sources, this requirement is substantially less than the full replacement of OPG's current coal-fired generating capacity.[106]

Given that demand side efficiency policies take time to fully implement, and that the capacity to make a large investment in renewable energy sources such as wind power takes time to develop, this new base load capacity should be added on an as needed basis. However, this capacity need not exceed the 4,500 MW shortfall in total base load capacity otherwise projected by 2020.

A number of options are available to the province to meet remaining grid demand, including imports of electricity, new or refurbished nuclear generating facilities, "clean" coal, and combined cycle natural gas-fired generation. These options are discussed in the following sections.

5.4.1. Imports of Electricity from Other Jurisdictions

The Torrie Smith Associates study suggested reliance on imports of up to 3,000 MW during periods of peak demand from Manitoba and Quebec to address the shortfall in Ontario generating capacity that may remain following the implementation of aggressive energy efficiency, cogeneration, and fuel switching initiatives.[107]

However, according to the IMO, the existing interconnection capacity between Ontario and neighbouring jurisdictions is 4,000 MW. Perhaps more importantly, the IMO estimates that only 1,400 MW of supply would likely be available for import during peak periods, as the available supply is largely from US jurisdictions subject to the same weather conditions as southern Ontario.[108]

The option of reliance on imports carries with it significant political, environmental, and social risks. The development of new large-scale hydro facilities in northern Manitoba, for example, would raise significant environmental concerns, and may also raise issues with First Nations in the region. Power losses from the long-distance transmission of electricity from northern Manitoba to markets in southern Ontario would be significant. Reliance on imports effectively externalizes the environmental and social costs associated with meeting Ontario's electricity demand onto other jurisdictions.

In the case of imports from the United States, Ontario is downwind of the coal-fired facilities in the US Midwest that would provide the bulk of the available supply. Reliance on these supplies would therefore defeat the air quality goals associated with the phase out of the province's existing coal-fired generating facilities.

All of these factors make reliance on imports to meet the province's electricity requirements an unattractive proposition, and one that should be reserved for use in emergency situations rather than meeting routine peaks in demand.

5.4.2. New or Refurbished Nuclear Generating Facilities

The refurbishment (principally the "retubing" of reactor cores) of OPG and Bruce Power's existing nuclear generating facilities to extend their projected lifetimes is an option under consideration by the province.[109] The Ontario Power Generation Review Committee, chaired by former federal Minister of Finance John Manley, recommended in its March 2004 report that OPG proceed with the refurbishment of Pickering Unit 1, and consider the refurbishment of the remaining units at Pickering "A" on the basis of the outcome of that effort.[110] Atomic Energy of Canada Ltd. (AECL), for its part, has raised the possibility of the construction of up to eight new 700 MW nuclear generating units to meet the province's future electricity needs, at a total cost of $12 billion.[111]

As noted by the province's Electricity Conservation and Supply Task Force, either nuclear option is associated with high and unpredictable capital costs.[112] In the case of new facilities, this problem is illustrated by the experience of the construction of the Darlington generating facility, whose costs rose from an original estimate of $3.95 billion in 1978 to a final actual cost of $14.4 billion.[113] The cost overruns associated with the efforts to bring the laid-up Pickering "A" units on line under the auspices of the Nuclear Asset Optimization Plan (NAOP)[114] highlight the same problems with refurbishment projects.[115]

AECL has suggested that price guarantees could be provided for the construction of new nuclear generating facilities.[116] However, such guarantees would ultimately depend upon the federal government's willingness to absorb any cost overruns. The federal government's willingness to do so has not been established. In addition, an attempt to site new nuclear generating facilities would likely prompt serious local resistance. New facilities would also require an extensive approval process through the Canadian Nuclear Safety Commission (CNSC) and federal and provincial environmental assessment legislation.

The Electricity Conservation and Supply Task Force suggested a minimum lead-time of seven years to bring new nuclear generation capacity on line for these reasons,[117] meaning that new supply would become available in 2011 at the earliest. Approvals involving technologies other than AECL CANDU-type reactors—those, therefore, unfamiliar to the CNSC —a possibility suggested by the OPG Review Committee,[118] would likely take even longer.

Estimates of the costs of refurbishing existing nuclear generating facilities in Ontario were developed for this study on the basis of past experience.[119] These estimates are presented in **Table 5.5**.

Table 5.5: Estimated Refurbishment Costs for Ontario Nuclear Generating Facilities (Current Dollars)

Station	Refurbishment Cost Range
Bruce 3 & 4	$720 million
Bruce 1 & 2	$1.5 to $2.5 billion
Pickering A	$3 to $4 billion
Pickering B	$3 to $4 billion
Bruce B	$3 to $4 billion
Darlington	$3 to $4 billion
Total	$14.2 to $19.2 billion
Midpoint	$16.7 billion

In addition to the up-front capital costs, it is unclear how long retubed reactors would be able to operate. Estimates, based on the performance of previously retubed reactors, range from eight to fourteen years.[120]

Reflecting the costs and uncertainties regarding retubing projects, in September 2002, the New Brunswick Public Utilities Board reached the following conclusion regarding a proposal by New Brunswick Power and AECL to refurbish the utility's Point Lepreau nuclear generating station:

> The Board, as a result of its review of the evidence in relation to the capacity factor and the cost of capital, finds that there is no significant economic advantage to the proposed refurbishment project. In addition, the Board considers that there are other significant aspects of the refurbishment option for which the economic impact is uncertain. These aspects create additional economic risk, which leads the Board to conclude that the refurbishment of Point Lepreau, as outlined in the evidence, is not in the public interest. The Board, therefore, will recommend to the Board of Directors of NB Power that it not proceed with the refurbishment of Point Lepreau. [121]

Beyond these concerns regarding capital costs and the length of time retubing would extend facility lifetimes, there are ongoing concerns regarding the overall reliability of nuclear generating facilities in Ontario. The annual capacity factor[122] for reactors in Ontario in 2003 was less than 50%.[123]

In addition to these immediate operational and reliability issues with respect to nuclear generation, there are ongoing concerns regarding safety in relation to major accidents, the health impacts of low-level releases of radioactive material from nuclear generating facilities, the unresolved question of long-term waste management,[124] undermined decommissioning costs, and the environmental and social costs associated with the mining and production of nuclear fuel.[125]

The most recent available production cost figure for nuclear energy in Ontario is 7.7 cents/kWh.[126] However, this figure likely underestimates long-term waste management costs, decommissioning costs, and does not include the costs of direct and indirect subsidies, such as those provided through the *Nuclear Liability Act*, and environmental and social externalities associated with nuclear fuel production.

This combination of factors makes the options of either the refurbishment of the province's existing nuclear generating facilities or the construction of new facilities an extremely high-cost and high-risk energy supply option for Ontario.

5.4.3. "Clean" Coal

The Pembina Institute examined a range of "clean" coal technologies in detail as part of its work on proposals for additional coal-fired generation in Alberta in 2001.[127] The technologies reviewed included subcritical and supercritical pulverized coal combustion (PCC), atmospheric pressurized fluidized bed combustion (AFBC and PFCB), and integrated gasification combined cycle (IGCC).

The only "clean coal" option found to have the potential to meet the Ontario government's air quality goals related to the phase-out of OPG's existing coal-fired plants is IGCC.[128]

In IGCC plants, coal is not burned in a traditional boiler but is converted into hydrocarbon vapour (syngas) in a gasifier. The syngas is then cleaned, stripped of impurities, and used as fuel instead of natural gas in a conventional combined cycle plant. The result is high system efficiencies and emissions of smog precursors and heavy metals comparable to combined cycle natural gas facilities. IGCC plants are operating commercially in the United States and have demonstrated high levels of reliability.[129]

The capital costs of IGCC are higher than other coal or natural gas-fired options. However, the operating costs of IGCC are relatively low, which means its overall levelized cost to produce electricity is comparable to that of combined cycle natural gas facilities.[130]

The use of coal as the source of fuel in these plants addresses the gas supply issues associated with natural gas-fired plants. However, the greenhouse gas emissions associated with IGCC plants are only 25% lower than those of conventional coal-fired facilities. This present a weakness in terms of the achievement of the province's air quality goals associated with the coal phase-out, and the fulfillment of Canada's wider greenhouse gas emission reduction obligations under the Kyoto Protocol.

5.4.4. Combined Cycle Natural Gas-Fired Generation (CCNG)

Commercial grade natural gas burns more cleanly than other fossil fuels as it consists mostly of methane and has already been cleaned of sulphur. In combined cycle natural gas-fired generation (CCNG) plants, natural gas is used as fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the host exhaust gas from the turbine is then used to generate steam in a waste heat recovery unit. The steam is then used to produce more electricity in a steam turbine generator system. The output from both the gas turbine and the steam turbine electricity systems is combined to produce electricity very efficiently.[131]

CCNG plants produce low emissions of smog precursors, 60% of the greenhouse gas emissions associated with coal-fired options, and virtually no emissions of heavy metals.[132]

While natural gas is a much cleaner fuel than coal and makes an ideal bridging fuel to a sustainable future, it is not inexhaustible. The provision of the equivalent of 25,000 GWh of electricity through combined cycle natural gas-fired generation would increase the province's annual natural gas requirements by approximately 176 PJ.[133] In combination with the impact of the energy efficiency, cogeneration, and fuel switching measures outlined in section 3, this would increase total natural gas consumption by 2020 against current levels as outlined in **Table 5.6**.

Natural gas consumption at the projected 2020 level may exceed current pipeline capacity from western Canada.[134] However, the capacity of the TransCanada and Alliance/Vector pipeline systems may be increased substantially through the installation of additional compressors and by looping sections.[135] This would not require the construction of a new pipeline from western Canada.

Questions have been raised regarding the availability of long-term gas supplies to meet the additional demand flowing from the impact of increased reliance on CCNG for base load power supply in Ontario, particularly as production from conventional supplies in Alberta begin to decline.[136]

A 2001 study by the Canadian Gas Potential Committee suggested a 40-year supply of gas is available at 1998 production levels (233 Tcf) mostly in the Western Canadian Sedimentary Basin (WCSB) and Mackenzie Valley. This estimate did not include coal bed methane, estimated at an additional 74 Tcf in the WCSB.[137] The National Energy Board has suggested that the WCSB gas resource potential is 30 to 38 times greater than total production in 2001.[138] Total reserves have been estimated to be 68 to 76 times 2001 production on this basis.[139]

Concerns have also been raised with respect to the impact on electricity costs of natural gas prices in both the short and long term if the province becomes heavily reliant on gas-fired generation.[140] Natural gas prices can be subject to short-term peaks. This has been particularly true over the past few years in North America. These price shifts have been due to the limited ability of consumers to reduce their consumption in the short term, and of suppliers to increase short-term supply in situations where demand is high. Although medium and long-term projections for gas prices vary, they tend to forecast natural gas prices that are below current price levels.[141] The findings of a study on future Alberta natural gas prices completed for the Alberta Clean Air Strategic Alliance (CASA) are presented below.[142]

Table 5.6: Forecast Natural Gas Consumption (PJ), 2001 vs. 2020

2001 Total Consumption	842
CIMS Forecast of Increased Consumption in High Efficiency, High Cogeneration Scenario by 2020	370
CCNG Base Load Fuel Requirement, 2020	176
2020 Total Consumption	1,388

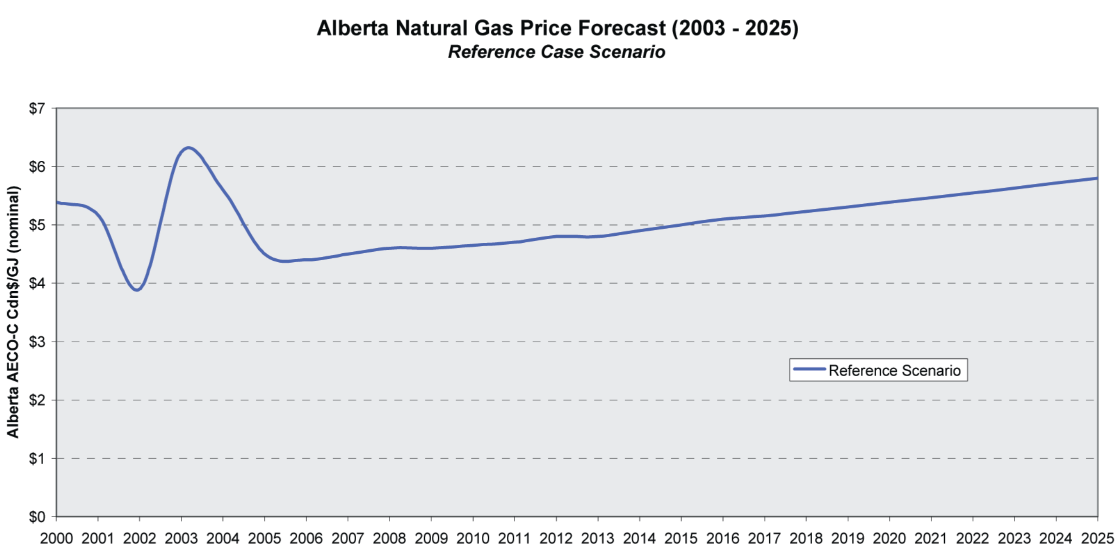


Figure 5.3: Alberta Natural Gas Price Forecast, 2000–2025 (Developed for CASA)

5.5. Supply Options Summary and Conclusions

The supply options available to meet the remaining base load requirements need to be assessed in light of the sustainability criteria outlined in section 2, as well as the costs for electricity delivered to consumers, their capital costs, and, in light of the province's emerging short-term electricity needs, the time within which they can be approved and brought into service.

Table 5.7 compares the electricity costs of the demand reduction and supply options examined in this study.

Table 5.7: Electricity Costs of Demand Reduction and Supply Options

Energy Efficiency Options	0–7 cents/kWh [143]
Cogeneration	3–5 cents/kWh [144]
Wind	8–10 cents/kWh [145]
Hydro	Heritage: 1.098 cents/kWh [146] New: 6–8 cents/kWh [147]
Biomass	6–9 cents/kWh [148]
Combined Cycle Natural Gas	5.18 cents/kWh [149]
Nuclear	7.8 cents/kWh [150]
Coal Integrated Gasification Combined Cycle	4.6–5.1 cents/kWh [151]

Table 5.8 provides estimates of the capital costs of different supply options.

Table 5.8: Estimated Capital Costs of Supply Options

Energy Efficiency Options	\$1.36 million/MW [152]
Cogeneration	Not available but likely comparable to CCNG [153]
Wind	\$1.5 million/MW [154]
Hydro	Not available. Depends on site and nature of project
Biomass	Not available but likely comparable to CCNG
Combined Cycle Natural Gas (CCNG)	\$1 million/MW [155]
Nuclear	Refurbished: \$1.125 million to 1.52 million/MW [156] New: \$2.1 million/MW [157]
Coal Integrated Gasification Combined Cycle	\$1.8 million/MW [158]

Table 5.9 provides estimates of the amount of time needed to bring different supply options into service, considering approval and construction times.

Table 5.9: Estimated Time to Service of Supply Options

Energy Efficiency Options	Transition to higher efficiency technologies largely complete by 2010 [159]
Cogeneration	2 years [160]
Wind	6 months to 1 year following approvals [161]
Hydro	Niagara tunnel: 5 years New small scale: dependant on nature of project
Biomass	2 years [162]
Combined Cycle Natural Gas	2 years [163]
Nuclear	Refurbished: 3–6 years [164] New: minimum 7 years [165]
Coal Integrated Gasification Combined Cycle	2–3 years [166]

In terms of costs per kWh of electricity efficiency measures, combined cycle natural gas generation and integrated gasification combined cycle generation are the lowest cost electricity supply options available to Ontario. This reinforces the importance of an emphasis on conservation as the option of first choice in the province's overall electricity strategy.

All of the non-nuclear supply alternatives offer the advantages of relatively short and well-established construction times. New nuclear generating facilities would have the highest capital costs, even assuming that there are no cost overruns. Such overruns have always been a feature of nuclear construction in the past in Ontario. Refurbished nuclear generating facilities would have higher construction costs than CCNG, and also carry with them a high degree of uncertainty. The uncertainty regarding the likely lifetime and reliability of refurbished reactors has to be taken into account as well.

Integrated gasification and combined cycle natural gas generation both offer the advantages of being well-established technologies with known capital costs, construction timelines, and high reliability. However, IGCC does not fully address the need to reduce the greenhouse gas emissions associated with electricity generation. At the same time, increases in gas consumption flowing from the replacement of electric heat with natural gas and significant increase in cogeneration outlined in Table 5.6 imply that natural gas should be used sparingly as a supply source and as efficiently as possible. In addition, CCNG is subject to short-term cost concerns due to the potential short-term volatility of natural gas prices, although this may be mitigated through long-term supply contracts with fixed prices. All of these factors suggest a role for CCNG as an option once efficiency and sustainable supply options have been maximized.

It is important to consider the costs associated with nuclear generation that are not accounted for in the figure in Table 5.7. These include such things as decommissioning, long-term waste management, servicing offloaded stranded debt associated with construction and refurbishment of nuclear generating facilities, and the environmental and social externalities associated with the production of nuclear fuel. This implies that the figure in Table 5.7, provided by OPG, significantly underestimates the actual cost of nuclear generation.

In addition, the high externalized environmental and social costs of the production of nuclear fuel relative to the very low externalities of new renewable energy sources [167] must be considered. There are also security and safety risks associated with nuclear generating facilities that are low or virtually non-existent with renewable energy sources. The improved reliability, lower system risks, and avoided grid upgrading costs from distributed generation from multiple technologies relative to a centralized generation system reliant on single technology must be factored in as well.

In the context of these considerations, the preferred approach to meeting remaining grid demand, having maximized contributions from energy efficiency, cogeneration, fuel switching, and demand response measures, is to maximize the contribution from low-impact renewable energy sources. On the basis of cost, reliability, safety, security, and lowest environmental impact, combined cycle natural gas generation should be used to meet the remaining base load demand.

The final proposed supply mix is presented in **Table 5.10**.

Table 5.10: Final Estimated Grid Demand and Supply Mix, 2010–2020

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
New CCNG Base Load	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

6. Conclusions and Recommendations

This study was undertaken in the context of growing concern over the future direction of Ontario's electricity system. The combination of the projected end of life of the province's existing coal-fired and nuclear generating stations, and predictions of growing electricity demand have prompted a major debate over the province's future electricity needs, and how those needs might be met.

In this context, this study sought to answer four key questions regarding future electricity supply and demand in Ontario:

1. How much might future electricity demand in Ontario be realistically reduced through the adoption of energy efficient technologies, fuel switching, cogeneration, and demand response measures?
2. How much future supply might be realistically obtained from low-impact renewable energy sources, such as wind, the upgrading of existing hydroelectric facilities, and the development of new small-scale hydro plants, solar, and biomass?
3. How should the remaining grid demand, if any, be met once the technically and economically feasible contributions from energy efficiency, fuel switching, cogeneration, demand response measures, and low-impact renewable energy sources have been maximized?
4. What public policies and institutional arrangements should the province adopt to ensure the maximization of the contributions from energy efficiency and other demand side measures, low-impact renewable energy sources, and the most environmentally and economically sustainable supply mix to meet remaining future grid demand?

6.1. Energy Efficiency Potential and Remaining Grid Demand

The first question was explored in sections 3 and 4 of the study. The study concludes that through the combination of a number of policies intended to prompt the adoption of energy efficient technologies, industrial and commercial/institutional sector cogeneration, fuel switching from electricity to natural gas, and demand response measures, total grid demand could be reduced against business-as-usual projections as shown in **Table 4.1**, reproduced below.

Table 4.1: Estimated Peak Demand Reduction and Net Grid Peak Demand 2010–2020

	2010 Peak (MW)		2015 Peak (MW)		2020 Peak (MW)	
	Winter	Summer	Winter	Summer	Winter	Summer
IMO Forecast for Peak Demand	26,000	27,800	26,500	28,700	28,000	30,000
Peak Demand Reduction from Energy Efficiency, Fuel Switching, and Cogeneration	(4,500)	(4,500)	(8,900)	(8,900)	(12,300)	(12,300)
Demand Response Measures	(2,330)	(2,330)	(1,980)	(1,980)	(1,770)	(1,770)
On-Site Generation		(250)		(500)		(750)
Net Grid Peak Demand	19,170	20,700	15,620	17,320	13,930	15,180

As Table 4.1 shows, net summer peak demand could be reduced by nearly 50% against the business-as-usual projections through the adoption of more energy efficient technologies, fuel switching, cogeneration, demand response measures, and on-site generation.

The study finds that capital investments of $18.2 billion over the 2005–2020 period would be required to achieve these savings through energy efficiency, fuel switching, and cogeneration. However, 96% of these costs would be recovered by consumers through their savings in energy consumption resulting from these investments. Ontario's natural gas consumption would increase by 12% over business-as-usual projections by 2020 as a result of the energy efficient technological and behavioural changes flowing from these measures.

6.2. Meeting Remaining Grid Demand

The second and third questions were explored in section 5 of the study. The analysis presented there concluded that it would be reasonable to expect that the contributions to Ontario's electricity supply from new hydro, wind, and biomass by 2020 could be as shown in **Table 6.1**.

Table 6.1: Potential Renewable Energy Supply, 2010–2020

	2010			2015			2020		
Source	**GWh**	**Peak (MW)**	**Capacity (MW)**	**GWh**	**Peak (MW)**	**Capacity (MW)**	**GWh**	**Peak (MW)**	**Capacity (MW)**
Wind	7,884	1,317	3,000	12,208	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4205	281	600	5,606	375	800
TOTAL	15,768	2,151	4,500	22,983	3,377	7,100	32,762	4,649	9,800

As shown in Table 5.4 the province will also require 4,500 MW of new base load generating capacity to meet the balance of the province's electricity needs by 2020. This table assumes that the province maximizes the technologically and economically feasible contributions from energy efficiency measures and low-impact renewable energy sources. The projected date for the phase-out of the province's coal-fired generating facilities is no later than 2010, and the projected end of the operating lives of the province's existing nuclear generating facilities is 2018.

The study concludes that on the basis of costs, environmental and health impacts, speed of construction, and reliability, the remaining base load requirement would be best met through combined cycle natural gas generating facilities. However, in light of the concern in the very long term regarding natural gas supplies in North America, these facilities should be seen as an interim measure towards a system that relies on more advanced renewable energy sources in the future.

The final estimated grid demand and proposed supply mix was outlined in **Table 5.10**, reproduced on the next page.

Table 5.10: Final Estimated Grid Demand and Supply Mix, 2010–2020

	2010			2015			2020		
	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)	GWh	Peak (MW)	Capacity (MW)
IMO Forecast	164,000	27,800		172,000	28,742		180,000	30,079	
Demand Reductions—Efficiency/ Cogeneration	(26,867)	(4,510)		(53,002)	(8,898)		(73,499)	(12,339)	
Additional Load Shifting		(2,329)			(1,984)			(1,774)	
On-Site Solar Roofs Program	(876)	(250)	330	(1752)	(500)	670	(2,628)	(750)	1,000
Grid Demand	136,257	20,711		117,246	17,360		103,873	15,216	
Existing Nuclear	51,246	5,994	9,000	22,776	2,664	4,000			
Existing Hydro	33,572	6,375	7,665	33,572	6,375	7,665	33,572	6,375	7,665
Existing Peaking Gas and Replaced Oil	12,208	3,060	4,645	12,208	3,060	4,645	12,208	3,060	4,645
Wind	7,884	1,317	3,000	13,140	2,196	5,000	18,396	3,074	7,000
New Hydro	4,380	600	1,000	6,570	900	1,500	8,760	1,200	2,000
Biomass	3,504	234	500	4,205	281	600	5,606	375	800
New CCNG Base Load	23,915	3,570	4,200	25,054	3,740	4,400	25,623	3,825	4,500
Total Supply	136,709	21,150	30,010	117,525	19,216	27,810	104,165	17,909	26,610
Contingency	452	440		278	1,856		292	2,693	

It is important to compare the financial, economic, and social implications of the supply options available to the province to meet its future electricity needs. Under the business-as-usual scenario, assuming that existing hydro and peaking gas and replaced oil-fired generating capacity are retained, demand response programs are pursued, and that renewable energy sources are maximized as suggested by the Electricity Conservation and Supply Task Force, but aggressive efficiency programs and new combined cycle natural gas baseload supply are not pursued, a peak supply gap of nearly 15,000MW[168] would emerge by 2020. Meeting this gap through new nuclear generation would carry a capital cost of over $39 billion.[169]

The capital costs of addressing the same gap through a combination of energy efficiency measures, fuel switching, cogeneration, and new combined cycle natural gas generation as outlined in this study, by comparison, would be in the range of $23 billion.[170] In addition to these avoided capital costs, a supply strategy focused on improving energy efficiency rather than creating new generation would carry with it other benefits: the avoided costs of producing the electricity and gas saved as a result of energy efficiency measures, and the environmental, health, safety, and security co-benefits associated with avoiding the need to construct and operate new generating capacity that would be required under business-as-usual scenarios. There would also be overall improvements in housing quality and the competitiveness of Ontario industry as a result of investments in more modern and energy efficient technologies.

6.3. Implementing a Sustainable Electricity System

6.3.1. Maximizing the Efficient Use of Electricity

Achieving the potential reduction in electricity demand identified in this study by 2020 will not be easy or without risk. However, other jurisdictions in North America are implementing the types of program that will be needed in Ontario to achieve this target.[171] With the appropriate regulatory foundation in the form of minimum energy efficiency standards and labelling, the Ontario Energy Board (OEB) incentive mechanisms for utilities, and improved grid access for cogenerators, major reductions in electricity consumption can be achieved without excessive costs to government or energy consumers, or by penalizing low-income members of Ontario society.

This section begins with a series of foundation policies that would be needed for an energy efficiency strategy to succeed. This is followed by a discussion of provincial energy efficiency programs to supplement the foundation measures. Finally, the questions of the coordination and management of an efficiency strategy and cost sharing are discussed.

6.3.1.1. Foundation Policies

Minimum Energy Efficiency Standards

The CIMS results show that a combination of financial incentives and innovative financing could transform the market for new and replacement energy efficient technologies and fuel switching by 2010. Policies to remove the barriers to cogeneration would also produce a rapid uptake of this option in the industrial and commercial/institutional sectors. If this market transformation could be maintained, the CIMS results show that simple stock turnover could be used to reduce electricity consumption in Ontario to 121,000 GWh/yr by 2010 and 107,000 GWh/yr by 2020.

The simplest and lowest administrative cost way of ensuring that the transformation continues is to raise minimum energy efficiency standards for electricity-using products and energy codes for buildings to the energy efficiency levels of the CIMS targeted technologies. Once a significant market transformation has occurred, this could be done without disruption of these markets.

California, for example, has reduced peak power demand by 20%, or 10,000 MW, over the past 20 years, with a combination of utility demand side management programs, and building and appliance standards.[172]

> **Recommendation 1:** The Government of Ontario should adopt minimum energy efficiency standards under the **Energy Efficiency Act** equivalent to the energy efficiency levels required for Energy Star labelling for all major electricity-using devices and equipment when the market share for new or replacement energy efficient models surpasses 50%, and not later than 2010 for all devices. The province should develop its own energy] efficiency standards for equipment not covered by Energy Star.

> **Recommendation 2:** The provincial Building Code should be amended to require R2000, Canadian Building Improvement Program (CBIP), or equivalent energy efficiency performance for all new buildings and building renovations by 2010.

> **Recommendation 3:** The **Planning Act** should be amended to permit municipalities to make energy efficiency design requirements a condition of site approvals for buildings.

Labelling of Energy Efficient Products

The United States Environmental Protection Agency's Energy Star program, which provides for the labelling of products with the highest energy efficiency, is now used internationally to identify efficient lighting, appliances, computers, motors, and many other products. It has recently been introduced into Canada and has been successfully used in Ontario as the basis for its energy efficient appliance sales tax rebate program. As part of BC Hydro's Power Smart programs, Energy Star labelling increased the market share of efficient appliances by several percentage points.[173]

> **Recommendation 4:** The most energy efficient technologies in all sectors and end-uses should be labelled through the Energy Star program or, if not included in Energy Star, through a provincial labelling system.

Utility Regulation and Demand Side Management Incentive Mechanisms

In order to develop and maintain a culture of energy efficiency in Ontario, the benefits of efficiency need to be embedded within the utility regulatory system. It must always be financially beneficial for electrical distribution utilities to undertake demand side management (DSM) programs. Without this being made a permanent feature of the utility regulatory system, energy consumers will not have the stable environment necessary to make the required efficient investments.

The current shared savings DSM incentive mechanisms applied to Enbridge Gas Distribution in Ontario have been successful in creating an energy efficient culture within the utility, where efficiency targets are set and DSM programs are delivered on an ongoing basis. The utility shares in the financial savings from the DSM programs through incentive mechanisms.[174]

Extending this concept to Ontario's electricity distribution utilities will present challenges. However, a significant reduction in energy demand has been achieved through DSM programs encouraged by government incentive structures in California.[175]

Utilities could also be allowed to meet energy efficiency targets by contracting among themselves or to energy service companies to deliver DSM programs. All utilities could be regulated in this fashion, even if they do not have the internal expertise in DSM.

The small size of some distribution utilities should not prevent them from being included in the DSM incentive mechanisms. Aquila Networks, a small electric utility serving the Kootenay and Okanagan regions of British Columbia, for example, has successfully used a DSM incentive mechanism for nearly 10 years under a performance-based rate setting regime regulated by the BC Utilities Commission.[176]

While a DSM incentive mechanism for electrical utilities in Ontario will not in itself be sufficient to bring about the energy efficiency improvements shown to be possible in the CIMS analysis, it is an essential requirement if other efficiency measures are to succeed. Utilities must be major, permanent partners in improving energy efficiency, and offer DSM programs over the long term. Without an incentive mechanism, utilities benefit from higher electricity sales, and therefore have strong incentives not to pursue DSM activities.

> **Recommendation 5:** The OEB performance-based rate setting and DSM incentive mechanism model currently applied to Enbridge Gas Distribution should be extended to Hydro One and all of Ontario's electrical distribution utilities. All distribution utilities should be required to set targets for energy efficiency gains and be allowed to then share in the benefits of DSM programs. The incentive mechanisms should allow utilities without DSM capabilities to meet their targets by contracting the delivery of DSM programs to other electrical and gas utilities, the energy service industry, or specialized non-profit agencies.

Improved Grid Access for Cogenerators

In order to make it worthwhile for industrial and commercial/institutional facilities to increase their cogeneration of heat and power and to sell the excess power to the grid, a regime needs to be put in place that both makes it financially worthwhile and technically simple177 for them to do so.

The key measure needed to encourage more cogeneration and renewable energy on-site power generation is net metering—effectively paying the same price for power produced as for power used. In addition, practical and safe specifications for power quality, metering, switching, inverters, and other technical matters are needed for grid inter-ties. Inspectors, meter readers, and other utility staff need to be provided with information and training on the integration of local power sources. These specifications should reflect an assumption that local power sources are commonplace rather than the exception.

Grid inter-ties and net metering should also be designed such that power supplied to the grid is measured separately from the amount taken from the grid.[178] This would allow policies to be implemented where higher prices are paid for excess power supplied to the grid than the purchase price. Special requests for proposals (RFPs) or feed-in tariffs[179] could be used to encourage industries and large commercial and institutional users to develop cogeneration potential.

> **Recommendation 6:** The Government of Ontario should expand its current net metering policy to include all industrial, commercial/institutional, and residential users, and develop grid inter-tie specifications and training programs for utility staff. A series of annual special RFPs or feed-in tariffs should be issued to encourage smaller industries and large commercial and institutional facilities to develop their cogeneration potential.

6.3.1.2. Provincial Energy Efficiency Programs

In addition to the adoption of these foundational policies, the Government of Ontario should implement a series of energy efficiency programs that would accelerate the transition to energy efficient products and technologies and increase the market share of energy efficient technologies to a level where minimum energy efficiency standards and codes can be raised without significant adverse economic impacts.

A Partnership to Deliver Innovative Financing Programs

The individual CIMS runs showed that lowering of user-perceived discount rates[180] had the largest impact on electricity consumption, followed by cogeneration and financial incentives to reduce the up-front capital costs of more energy efficient equipment. The most effective way of reducing the perceived discount rate is through financing mechanisms that allow electricity consumers in all sectors to finance the higher cost of energy efficient technologies out of the savings obtained as these savings occur.

The province should form partnerships with electric and gas utilities, energy service companies, and financial institutions to provide a suite of programs to provide financing for energy efficient technologies and measures. One example is the Better Buildings Partnership model conceived in Toronto that uses a revolving fund to finance energy efficiency improvements in buildings managed by energy service companies.[181] Another example of a model for financing the purchase of higher efficiency energy using products is the SaskEnergy prime rate financing for Energy Star furnaces.[182] Given the longer payback for permanent energy efficiency improvements to buildings, innovative new financing approaches such as using local improvement charges to pay back the cost of retrofits—attaching the cost and benefits to the building property instead of the owner—are being developed.[183] Many of the programs could be delivered by distribution utilities under a DSM incentive mechanism.

Recommendation 7: The Government of Ontario should establish a partnership with utilities, financial institutions, energy service companies, municipalities, and other stakeholders to offer a series of financing mechanisms to assist electricity consumers in all sectors to finance the adoption of energy efficient products and technologies and measures out of the savings they will achieve through these investments.

Financial Incentives

The CIMS results showed that on their own, financial incentives that reduce the first cost of energy efficient technologies would have only a modest impact on the adoption of more energy efficient technologies. However, a small financial incentive increases the likelihood of a consumer taking advantage of a financing program, particularly in the early stages of a program, when an energy efficient product may be less available and more expensive. Incentives like the current Ontario sales tax removal for Energy Star appliances and the federal grants for home energy retrofits would have the "pump priming" effect needed to start market transformation. Through the Office of Energy Efficiency, the federal government is offering grants to support making new and existing commercial buildings[184] more energy efficient.

The Government of Ontario should pursue an agreement with the federal government to share the costs of an expanded sales tax rebate system and extend similar incentives to a set of priority energy end-uses not covered by federal incentives, particularly lighting, hot water heating, industrial drive power, and household appliances. This could be done under a federal-provincial agreement to reduce Ontario's greenhouse gas emissions as part of Canada's Kyoto Protocol commitments.

However, incentive programs should only be kept in place for a period of five years. After that point, other policies and programs should start to consolidate the market transformation, and minimum energy efficiency standards could be put in place to complete the process.

Recommendation 8: The Government of Ontario should enter into an agreement with the federal government under the auspices of the federal government's Kyoto Protocol implementation plan to share the costs of providing the following financial incentives for the adoption of energy efficient technologies:

- Grants for high efficiency home energy retrofits and new R2000 homes
- Grants towards the additional cost of new high-efficiency commercial buildings, and commercial building retrofits
- Sales tax rebates for all Energy Star products in all sectors and small-scale renewable energy power sources
- Business tax credits for industrial energy efficiency equipment and cogeneration systems.

These incentives should focus initially on technologies where the largest reductions can be achieved at the lowest cost, such as commercial HVAC and lighting, and industrial drive power. The incentives should be in effect only until the market share of the efficient technology reaches 50%.

Special Assistance for Low-Income Households

Even with innovative financing programs and financial incentives, higher energy efficient technologies are often beyond the reach of low-income consumers. They may rent their accommodation and appliances, or may lack access to the capital needed to buy new appliances. For those that do own homes, the needed improvements may go well beyond energy efficiency upgrades. Low-income consumers therefore face the double problem of rising power prices and not being able to reduce their energy use. Several US states and countries like the UK have set up special programs to deliver energy efficiency programs to low-income housing, focusing on comprehensive building improvements and ways that make high-efficiency lighting, appliances, and heating systems more affordable.[185]

Recommendation 9: Mechanisms to ensure the delivery of programs to low-income consumers should be incorporated into the DSM mandates and incentives provided to energy and electrical distribution utilities. A specific portion of DSM spending should be set aside for this purpose, including revenues from the Public Benefits Charge proposed in Recommendation 11.

6.3.1.3. Provincial Leadership and Coordination of Energy Efficiency Programs

The foundation policies and programs outlined in Recommendations 1 to 9 would form the basis for an integrated 15-year strategy designed to reduce electricity demand in Ontario by 30% below 2003 levels by 2020. While responsibility for direct implementation of energy efficiency programs would be in the hands of electricity and natural gas distribution utilities' strong leadership, support and oversight would need to be provided by the provincial government.

The Minister of Energy has recently proposed the creation of an Ontario Power Authority with responsibility for carrying out planning functions and issuing calls for proposals to the private sector for new generation.[186] This approach runs a significant risk of placing an overwhelming and unnecessary emphasis on the construction of new supply, unless the authority is placed within a broader institutional structure that strongly emphasizes overall energy sustainability.

Recommendation 10: The Government of Ontario should adopt legislation creating a new agency, the Ontario Sustainable Energy Authority, reporting to the Minister of Energy, to lead and coordinate the province's energy efficiency and electricity planning efforts.[187]
The agency's functions should include:

- The coordination and oversight of the development and implementation of provincial energy efficiency standards and labelling programs
- Ensuring the consideration of energy efficiency in the policies and programs of provincial government agencies
- The ongoing assessment of the effectiveness of energy efficiency programs being delivered by utilities and provincial agencies, including low-income programs and the provision of recommendations for their improvement to the provincial government and the OEB
- The forecasting of the province's future electricity needs
- Research, development, education, and information dissemination on energy efficient technologies and practices

The proposed Ontario Power Authority, responsible for issuing requests for proposals for the construction of new generating capacity, should be a division of the new agency.

6.3.1.4. Costs and Cost Sharing

The bulk of the costs of DSM programs delivered by regulated utilities in Ontario could be recovered through the performance rate setting process and DSM incentive mechanism governed by the OEB.

However, the province would be faced with the costs of its share of the financial incentives outlined in Recommendation 8. A reasonable estimate of this cost, assuming that it reflects the removal of the provincial sales tax on energy efficient equipment and appliances, would be 8% of the investment in energy efficient technologies from 2005 to 2010. Under the federal-provincial Kyoto Protocol implementation agreement proposed in Recommendation 8, the federal government could be asked to contribute 50% of these costs.

In addition, there would be administrative costs associated with the development and implementation of minimum energy efficiency standards and labelling programs, and overall program coordination.

Many US states that have restructured their electrical utilities have introduced small public benefits charges (PBC) on each kWh of electricity sold to finance energy efficiency programs.[188] The use of the funds raised varies from state to state, but the basic objectives are to compensate for the fact that the new utility structure removes incentives for utilities to carry out DSM programs, and to make the financing of energy efficiency programs more revenue neutral.[189] Many US states[190] and the United Kingdom[191] have used PBCs to finance programs specifically targeted at helping low-income consumers improve the quality of their housing and adopt more efficient electricity-using appliances.

Recommendation 11: A PBC of 0.3 cents/kWh should be applied on all electricity sales to finance energy efficiency and low-income assistance programs.[192]

The PBC would be levied on all electricity sales and be revenue neutral in that it would go back to consumers who receive the financial incentives or to low-income consumers. Consumers who do not purchase targeted technologies, or take advantage of DSM programs offered by utilities, will lose their contribution to the PBC and also have to pay higher tariffs.[193]

Table 6.3 shows the revenues that could be generated through a PBC, and potential uses of these revenues.

Table 6.3: PBC Funding Distribution for Energy Efficiency Programs (5-Year Increments)

	2005–2010	2010–2015	2015–2020
Income from a 0.3 cent/kWh PBC Levied on All Power Sales[194]	$2,040 million	$1,755 million	$1,557 million
Cost of Incentives (8% of Targeted Technologies)	$627 million		
Assumed Ontario Share (50%)	$313 million		
Program Capitalization, Low-Income Program Delivery, Research and Development of Energy Efficiency and Renewable Energy Technologies, Program Administration, including Development and Administration of Standards and Labelling Programs	$1,727 million	$1,755 million	$1,557 million

The CIMS results show that the net cost (revenue) of the possible energy efficiency gains to Ontario consumers, assuming that all incremental costs are paid by electricity consumers, is shown in **Table 3.8** (reproduced from section 3).

Table 3.8: Forecast Incremental Costs Associated with Achieving 2020 Energy Savings (discounted to 2004)

Sector	Incremental Costs Associated with Achieving 2020 Savings In millions of dollars (discounted to 2004)			
	Investment	Operation and Maintenance	Energy	Total
Industrial	829	273	(1,255)	(153)
Residential	7,220	(45)	(6,174)	1,001
Commercial/Institutional*	10,211	1,345	(11,782)	(226)
TOTAL	18,260	1,573	(19,211)	622

* Includes small-scale on-site cogeneration as well as electricity efficiency and fuel switching

Only the residential sector shows a net cost, and, as shown in section 3, this is equivalent to approximately $6 per person per year. This cost would be further reduced by the incentives paid during the first five years, and increased very slightly by the PBC.

6.3.1.5. Demand Response Measures

As outlined in section 4.1, it is estimated that peak electricity demand could be reduced by up to 10% through demand response measures.

Recommendation 12: The Government of Ontario should implement the following demand response policies:

- The OEB should be directed to undertake a generic proceeding on demand response to consider the various issues impeding demand response and develop appropriate policies and codes to encourage greater demand response in the Ontario market.
- The Government of Ontario should assess the infrastructure needed to encourage and facilitate demand response in the Ontario market. A portion of the revenues generated by the PBC proposed in Recommendation 11 should be used to meet the costs of providing the required infrastructure.
- All electricity consumers should be able to participate in demand response programs, and should not be capped in terms of the level of their participation.[195]

In addition, the 1,000 MW solar roof program outlined in section 4.2 could provide a significant reduction in summer peak demand.

Recommendation 13: The Government of Ontario should undertake a design and costing study for a 200,000 unit solar PV roof program modelled on those undertaken in Europe and the United States, and implement this program using a feed-in tariff funding mechanism.

6.3.2. Achieving a Sustainable Supply Mix

Section 5 concluded that following the maximization of the potential contributions from energy efficiency, cogeneration, fuel switching, and demand response measures, the province should seek to maximize the contributions from low-impact renewable energy sources. These include the upgrading of existing hydro facilities, the development of new small-scale hydro plants, large scale wind generation, and the use of landfill, sewage, and anaerobic waste digestion gas capture and generation.

A number of steps are needed to ensure that the potential contributions from these sources are maximized.

6.3.2.1. Renewable Portfolio Standard/Requests for Proposals

The Ontario Wind Power Task Force has highlighted the point that renewable energy sources suffer price disadvantages relative to conventional energy sources, due to the unaccounted externalized environmental and health costs of fossil fuels.[196] Renewable energy sources may also face barriers in entering markets in which conventional energy suppliers are well established. Although further reductions in the costs of wind power generation technology are expected in the future, many jurisdictions in the United States and Europe have adopted mechanisms to accelerate the development of renewable energy sources, particularly through the adoption of renewable portfolio standards (RPS) for renewable energy sources.[197]

An RPS effectively guarantees a portion of the electricity market to renewable energy sources, either through direct calls for a certain amount of supply, or by requiring that all RFPs for new supply include a certain portion from renewable energy sources. This has the effect of enabling potential renewable energy suppliers to obtain financing to develop their projects, by ensuring that there will be a market for their energy if they proceed with development.

In Ontario, an RPS would need to be sufficiently large to signal that demand for equipment, especially wind power generation technologies, will be high enough to justify the establishment of a manufacturing industry in Canada. The development of such an industry would carry with it significant employment benefits, and also reduce the industry's vulnerability to changes in capital costs due to shifts in foreign exchange rates affecting equipment prices.

The RFPs should be competitive, and decisions should be based on price, certainty of delivery, and reliability.

Recommendation 14: The Government of Ontario should issue, through the IMO, RFPs for supply from wind, upgraded existing or new small scale hydro, solar, the use of waste-generated methane from municipal, agricultural, industrial sources and other low-impact renewable energy sources. The initial RFPs should seek to have 4,500 MW capacity in place by 2010, followed by additional calls for supply up to 7,100 MW by 2015 and 9,800 MW by 2020.

6.3.2.2. Renewable Energy Potential Assessment

Section 5 of this study highlighted the poor state of the available estimates of the potential contributions to the province's electricity supply from renewable energy sources. These are incomplete, often out of date, and do not reflect current technologies. Experience in other jurisdictions, such as Germany, confirm that contributions on the scale of Ontario's existing conventional sources of supply, such as coal, are possible.[198] However, much more precise estimates of the potential contributions from renewable energy sources are needed to facilitate long-term planning and policy development.

> **Recommendation 15:** The Government of Ontario should undertake, on an urgent basis, a complete up-to-date assessment of the potential contributions from onshore and offshore wind generation, small scale hydro, and the use of waste digestion-generated methane, to the province's future energy supply. This effort should include primary research as required, including detailed wind potential mapping.

> **Recommendation 16:** The Government of Ontario should initiate a research and development program on renewable energy technologies funded through the PBC proposed in Recommendation 11. This should include both technology development and the resolution of grid integration issues.

6.3.2.3. System Integration Improvements for Renewable Energy

Some renewable energy sources have limited dispatch capability (e.g. run-of river hydro). Other sources, such as wind, are intermittent, but match peaks in demand quite well. Hydro with storage capacity can be used for both base load and peaking, although it can be associated with higher environmental impacts. Electronic control and power regulation equipment and accurate weather forecasting can allow grid dispatchers to forecast power outputs from renewable energy sources such as solar, wind, and run-of-river hydro, and dispatch hydro storage and natural gas peaking facilities as needed, allowing the potential contributions from renewable energy sources to be maximized.

> **Recommendation 17:** The IMO should adopt management practices designed to forecast power outputs from wind power capacity and run-of-river hydro (and solar PV systems), and be prepared to dispatch hydro storage and existing natural gas facilities as needed to provide base load capacity.

6.2.3.4. Resolution of Land-Use Planning and Site Approval Issues for Low-Impact Renewable Energy Sources

Siting conflicts are emerging as a significant barrier to the establishment of new renewable energy generating capacity, particularly with respect to wind installations. In response, some elements of the wind industry have pressed for exemptions from land-use planning and environmental assessment requirements for wind power generating facilities. [199]

This may not be the best approach to these issues, and may actually have the effect of exacerbating local land-use conflicts over new renewable energy generating facilities. A better strategy may be to develop land-use guidelines and policies related to renewable energy sources, particularly wind, with a range of affected constituencies. This strategy may place some attractive locations associated with important natural heritage or biodiversity functions off-limits to development, but will ease the industry's development more generally in the long term.

> **Recommendation 18:** The Government of Ontario should establish and expedite the completion of a consultative process to develop land-use guidelines for the siting of renewable energy generating facilities.

Offshore wind power generation technology is well developed and in widespread use in Europe. Offshore installations would avoid many of the land-use conflicts that have been associated with land-based facilities. Federal approvals may be needed under the *Fisheries Act* and the *Navigable Waters Protection Act* for offshore facilities.

> **Recommendation 19:** The Government of Ontario should develop guidelines, in conjunction with the federal government, for the approval of offshore wind power generation facilities.

6.3.2.5. Long-term Supply Contracts for Required Base Load

A number of supply options were examined in section 5.4 of this study to meet the remaining 4,500 MW of base load generating capacity that this study projects that the province would need by 2020, even with the maximization of energy efficiency, and the contributions from renewable energy sources.

These supply options included imports of electricity from other provinces, new or refurbished nuclear generating facilities, "clean" coal technologies, and combined cycle natural gas fired generation. On the basis of considerations of cost, safety, security, reliability, construction time and environmental and health impacts, the study concluded that the best option to meet this base load need is new combined cycle natural gas generating facilities.

The RFPs for new base load supply should be competitive, and decisions should be based on price, ability to meet environmental, health, safety, reliability criteria, and certainty of delivery and timeliness of development.

> **Recommendation 20:** The Government of Ontario should issue, through the IMO, a request for proposals for long-term base load supply, meeting the construction time, cost, reliability, and environmental, health, and safety performance of combined cycle natural gas generating facilities.
> The call for proposals should seek to have 4,200 MW of new base load supply in place by 2007 and 4,500 MW in place by 2020.

6.4. Implementation Plan

An overall implementation plan for the elements embodied in Recommendations 1 to 20 is presented in **Table 6.4**.

6.5. Conclusions

Ontario is now at a critical juncture in terms of its future energy path. The decisions made about electricity policy over the next year will set the province's course for the next 20 or 30 years. The choices the province makes will have major implications for the health, environment, safety, and security of Ontario residents, and the competitiveness of Ontario's businesses and industries for decades to come.

This study has shown that the choice faced by the province is clear. The province can take the path of making a massive investment in a generation technology, namely nuclear power, that has never lived up to its promise, is in large measure responsible for the environmental, reliability, and financial crises now facing Ontario's electricity system, and which carries with it enormous environmental and economic risks and costs to present and future generations of Ontarians.

In the alternative, the province can choose the path, as laid out in this study, of setting a policy framework that will result in the widespread adoption of proven energy efficient technologies and practices that will reduce consumers' energy bills, improve air quality, protect the health and safety of Ontario residents, and result in a more, safe, secure, and reliable electricity system.

The decision on what path to take now rests with the current Government of Ontario. The health, safety, and well being of future generations of Ontario residents rests on whether it chooses wisely.

Table 6.4: Implementation Plan for Recommendations

Activity	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Nuclear Facility End of Life					■	■	■	■	■	■	■	■	■	■	■		
Coal Facility Phase-Out		■	■	■	■												
Minimum Efficiency Standards and Building Code Revisions Development and Adoption		■	■	■	■	■	■										
Labelling Program Development and Implementation		■	■	■	■	■	■										
Utility DSM Incentive Mechanisms in Place		■	■	■													
Net Metering and Grid Access Implementation		■	■	■													
Energy Efficiency Partnership Financing Mechanisms Established		■	■	■	■	■	■	■	■	■	■	■					
Financial Incentive Implementation	■	■	■	■	■	■											
Low-Income Household Assistance		■	■	■	■	■	■										
Provincial Coordinating Agency Establishment		■															
PBC Implementation		■															
Demand Response Implementation		■	■	■													
Solar Roofs Program Design and Implementation			■	■	■	■	■	■	■	■	■						
Renewable Energy Potential Assessment	■	■															
Renewable RPS Implementation: Phase 1	■	■	■	■	■	■	■										
Phase 2							■	■	■	■	■	■					
Phase 3												■	■	■	■	■	■
Renewable Energy Dispatch Management Mechanism Implementation		■	■	■	■	■	■										
Renewable Energy Onshore and Offshore Siting Guidelines Development	■	■															
New Base Load RFPs and Construction	■	■	■	■	■												

Endnotes

1 On the creation of the HEPC see N. B. Freeman, *The Politics of Power: Ontario Hydro and Its Government 1906–1995* (Toronto: University of Toronto Press, 1996), Chapter 2.

2 See Freeman, *The Politics of Power*, Chapter 6, on the establishment of Ontario Hydro.

3 Ontario Hydro's total debt at the time of the coming into force of the legislation was $38 billion.

4 On the Electrical Safety Authority, see M. Winfield and H. Benefides, "Drinking Water Protection in Ontario: A Comparison of Direct and Alternative Service Delivery Options" (Ottawa: The Pembina Institute, 2001), Appendix 4.

5 The design of the new system flowed from the 1996 report of the Advisory Committee on Competition in Ontario's Electricity System. See Advisory Committee on Competition in Ontario's Electricity System, " A Framework for Competition" (Toronto: Queen's Printer for Ontario, 1996).

6 This was to be achieved through a "Market Power Mitigation Agreement," negotiated between OPG and the provincial government. See Market Design Committee, "Third Interim Report" (October 8, 1998), 1–5.

7 Electricity Conservation and Supply Task Force, "Tough Choices: Final Report to the Minister" (Toronto: January 2004), Figure 3.A. Under the market system, the hourly electricity price was determined on the basis of the price of the last amount dispatched into the market (i.e., the "spot" market price).

8 Electricity Conservation and Supply Task Force, "Tough Choices: Final Report to the Minister" (Toronto: January 2004), Figure 3.A.

9 The Hon. D. Duncan, Minister of Energy, Notes for Remarks to the Canadian Energy Efficiency Alliance, February 17, 2004.

10 See R. Mackie, "McGuinty government raises price cap on hydro," *Globe and Mail*, November 26, 2003.

11 See Government of Ontario, "Eves Government Takes Action to Promote Green Energy, Alternative Fuels and Conservation" (news release, November 13, 2002).

12 Ministry of Energy, "Ernie Eves Government Introduces Standard to Increase Green Energy," (news release, July 3, 2003).

13 Ontario Hydro, "Report to Management IIPA/SSFI Evaluation Findings and Recommendations" (Toronto: Ontario Hydro, July 1997).

14 This refers to four units at Pickering "A" and three units at Bruce "A"; Bruce Unit 2 had been shut down in October 1995.

15 Ontario Hydro, "Ontario Hydro Moving Ahead on Major Overhaul of Production Facilities" (news release, August 13, 1997).

16 J. Gibbons, "Countdown Coal: How Ontario can improve air quality by phasing out coal-fired electricity generation" (Toronto: Ontario Clean Air Alliance, February 2003), Appendix C.

17 Ontario Clean Air Alliance, "Countdown Coal" 2.

18 See, for example, Toronto Public Health, "Air Pollution Burden of Illness in Toronto: Summary Report" (Toronto: City of Toronto, May 2000).

19 See Pickering Review Panel, "Report of the Pickering 'A' Review Panel" (Toronto: Ministry of Energy, December 2003), 3. The estimates available to the panel for the return to service of the remaining three units were $3–$4 billion, with return to service between October 2006 and August 2008.

20 "Bruce unit 3 resumes electricity production" *Toronto Star*, January 10, 2004. The Bruce "A" and "B" facilities were leased to British Energy in May 2001. Following the bankruptcy of British Energy, the lease was transferred to Bruce Power Inc., a consortium of Cameco, TransCanada Pipelines, OMERS, the Power Workers Union, and the Society of Energy Professionals.

21 See Appendix 2 "Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs" for a detailed discussion of the refurbishment of the Bruce "A" units.

22 Imports accounted for 3% of supply in 1997 and 7% in 2003. Maximum current import capacity for Ontario is 4,000 MW. The IMO estimates that the maximum amount of power available for import during peak months is 1,400 MW. See IMO, "18 Month Outlook: An Assessment of the Reliability of the Ontario Electricity System from July 2003 to December 2004" (Toronto: IMO, June 2003).

23 IMO, "10-Year Outlook: An Assessment of the Adequacy of Generation and Transmission Facilities to Meet Future Electricity Needs in Ontario from January 2004 to December 2012" (Toronto: IMO, March 2003).

24 See Freeman, *The Politics of Power*, 171–179.

25 See M. Winfield and G. Jenish, "Ontario's Environment and the 'Common Sense Revolution': A Four Year Report" (Toronto: Canadian Institute for Environmental Law and Policy, 1999), 3–47.

26 Ministry of Energy, "Energy Minister Announces Plan to Address First Third of Coal Commitment," (news release, January 20, 2004). The retirement dates for the coal-fired facilities without the coal phase-out would be as follows: Nanticoke 2015; Lambton 2010–2020; Thunder Bay 2021; Atikokan 2025. (pers. comm., Jack Gibbons, Ontario Clean Air Alliance, November 18, 2003, [based on OPG information]).

27 See Ministry of Energy, "Ontario Government Takes Responsible Action On Electricity Pricing," (news release, November 25, 2003); R. Mackie, "McGuinty government raises price cap on hydro," *Globe and Mail*, November 26, 2003.

28 Figures are estimated from Electricity Conservation and Supply Task Force, "Tough Choices: Final Report to the Minister" (Toronto: Ministry of Energy, January 2004)

29 This includes the facilities not included in the NAOP: Pickering "B"; Bruce "B"; and Darlington, totalling 12 units and 8,728 MW in generating capacity.

30 See Appendix 2 of this report for details of estimates. Tables assume a 25-year lifetime for units, and an 8–13 year lifetime for refurbished units.

31 Nuclear Engineering International, "2003 World Nuclear Industry Handbook," 126, 127; Ontario Hydro, Quarterly Technical Reports for Pickering Nuclear Generating Station, 1983 to 1993.

32 Comm'l Oper'n: Date of Commercial Operation (commercial operation follows the date of criticality and the date of first power).

33 SD: Shut Down. Pickering Units 1, 2, and 3, and Bruce Units 1 and 2 remain shut down at this time, although Ontario Power Generation describes them as being "laid up," which presumably indicates that they do not consider them to be *permanently* shut down. However, these units are listed as "shut down" by Nuclear Engineering International.

34 Nuclear Engineering International, "2003 World Nuclear Industry Handbook," 126, 127.

35 IMO's June 2003 assessment of system reliability concluded that "reserve margins are forecast to be negative" for most of the July 2003 to December 2004 period. See IMO "18-Month Reliability Forecast."

36 Under business-as-usual models, the IMO projects that Ontario will require about 6,400 MW of additional generating resources over the 2004 to 2013 period. See IMO, "Ontario Demand Forecast from January 2004 to December 2013" (Toronto: IMO, March 2003).

37 This overall picture is consistent with those provided by other sources. See for example, R. D. Torrie and R. Parfett, "Phasing Out Nuclear Power in Canada: Towards Sustainable Energy Futures" (Ottawa: Campaign for Nuclear Phaseout/Torrie Smith Associates, July 2003); see also IMO, "Ontario Demand Forecast from January 2004 to December 2013."

38 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 2.C.

39 Electricity Conservation and Supply Task Force, "Tough Choices," 20.

40 The IMO forecasts that the summer and winter peak demands will be similar with the summer peak slightly higher by 2,000 MW. The summer peak has been used in this table.

41 Electricity Conservation and Supply Task Force, "Tough Choices."

42 Torrie and Parfett, "Phasing Out Nuclear Power in Canada."

43 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 2.D.

44 Electricity Conservation and Supply Task Force, "Tough Choices," 51.

45 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 5.C.

46 OPG Review Committee, "Transforming Ontario's Power Generation Company" (Toronto: March 2004). Also known as the Manley Committee, after its chair the Hon. John Manley, former federal Minister of Finance.

47 OPG Review Committee, "Transforming Ontario's Power Generation Company," 20.

48 OPG Review Committee, "Transforming Ontario's Power Generation Company," 3.

49 Torrie and Parfett, "Phasing Out Nuclear Power in Canada."

50 Torrie and Parfett, "Phasing Out Nuclear Power in Canada," Figure 11.

51 The Hon. D. Duncan, Minister of Energy, Notes for Remarks to the Canadian Energy Efficiency Alliance, February 17, 2004.

52 See R. H. Cowart et. al., "Efficient Reliability: The Critical Role of Demand-Side Resources in Power Systems and Markets" (Montpelier, VT: The Regulatory Assistance Project, June 2001).

53 Recent research by the Pembina Institute suggests that on average, investments in energy efficiency create over 35 person years of employment per $1 million invested. This is approximately four times the employment created by the same amount of investment in energy supply. See B. Campbell, L. Dufay, and R. Macintosh, "Comparative Analysis Employment from Air Emission Reduction Measures" (Drayton Valley: The Pembina Institute, January 1997).

54 For an overview of selected recent energy efficiency initiatives in North America, see Appendix 3 of this report.

55 The Energy Foundation Utility Energy Efficiency Fact Sheet, http://www.ef.org/national/FactSheetUtility.cfm

56 See, for example, C. Moore and A. Miller, *Green Gold: Japan, Germany, the United States and the Race for Environmental Technology* (Boston: Beacon Press, 1994).

57 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 2.B.

58 See the Energy Star website, http://oee.nrcan.gc.ca/energystar/english/consumers/index.cfm

59 See http://rncan.gc.ca/es/etb/cetc/pdfs/the_power_of_new_technology_microturbines_e.pdf

60 See Office of Energy Efficiency, "Improving Energy Performance in Canada—Report to Parliament Under the Energy Efficiency Act 2001–2002" (Ottawa: Natural Resources Canada, 2003), Figure 4-13.

61 See Appendix 3: "Energy Efficiency Program Case Studies."

62 C. Strickland and J. Nyboer, "Cogeneration in Canada" (Canada Industrial Energy End-Use Data and Analysis Centre, 2002). Report prepared for Natural Resources Canada.

63 For example, consumers are more likely to choose a familiar technology over a new one, even if the cost is the same. Consumers will also favour products with the lowest capital cost, even though their operating cost may be significantly higher.

64 Analysis and Modelling Group, "Canada's Emissions Outlook: An Update" (Ottawa:National Climate Change Process, 2000).

65 Analysis and Modelling Group, "Canada's Emissions Outlook: An Update."

66 When such factors as customer charges, distribution charges, transmission charges, wholesale operations charges, and debt retirement charges are considered, a typical average bill in the City of Toronto works out to 11.7 cents/kWh. In November 2003, the government announced the abandonment of the fixed electricity price of 4.3 cents/kWh as of April 1, 2004, going to 4.7 cents/kWh for the first 750 kWh consumed and 5.5 cents/kWh for consumption beyond that level.

67 In the case of residential retrofit, costs were reduced by 20% to reflect the federal EnerGuide for Homes grants that pay up to 20% of the cost of an energy efficiency retrofit based on EnerGuide audit recommendations.

68 See Appendix 1 of this report for a list of targeted technologies.

69 A hurdle rate is usually defined as the interest rate above which consumers will consider investing in options other than financial institutions.

70 See, for example, Electricity Conservation and Supply Task Force, "Tough Choices," 59.

71 Ontario Medical Association, "The Illness Costs of Air Pollution in Ontario: A Summary of Findings" (Toronto: Ontario Medical Association, June 2000), updated via pers. comm., John Wellner, Environmental Program Director, Ontario Medical Association, January 25, 2003.

72 The cost per kWh saved is equal to the annualized investment cost ($/yr) divided by the annual savings (kWh/yr). The annualized cost of a technology is its capital cost expressed as a series of equal annual payments over its useful life. Using this methodology allows the direct comparison of supply and demand side options for meeting increasing consumption of electricity.

73 BC Hydro, "Conservation Potential Review" (Vancouver: BC Hydro, 2003).

74 IMO, "Ontario Demand Forecast from January 2004 to December 2013, " March 2003.

75 For more information on demand response measures and their potential impact on peak demand, see Navigant Consulting, "Blueprint for Demand Response in Ontario" (Toronto: April 2003), prepared for the IMO.

76 "Effective Green Power Policies," *REFocus*, January/February 2003, 30.

77 "ALTENER Programme—The ENER-IURE Project 'RES Legislation in Germany'" (Forum für Zukunftsenergien: November 1999).

78 See IMO, "Ontario Demand Forecast from January 2004 to December 2013."

79 Large-scale hydro can have major environmental and social impacts. However, development of additional large-scale hydro projects in Ontario seems unlikely, given that most economic large-scale sites have already been developed.

80 The analysis draws significantly on the efforts of the Ontario Wind Power Task Force in its "Industry Report and Recommendations" (September 2001).

81 Ontario Wind Power Task Force, "Industry Report and Recommendations," 16.

82 Ontario Wind Power Task Force, "Industry Report and Recommendations," 17.

83 For an overview of existing OPG hydroelectric facilities in Ontario, see http://www.opg.com/ops/H_locations.asp

84 Ontario Hydro, "Niagara River Hydroelectric Development Project Outline" (Toronto: Ontario Hydro, December 1994). An Adam Beck 3 Project, consisting of an additional tunnel and a few 600–900 MW generating stations is also under consideration, although it is considered to have higher capital costs. Pers.comm., Rick Jennings, Ontario Ministry of Energy, March 16, 2004.

85 Ontario Wind Power Task Force, "Industry Report and Recommendations" (Toronto: The Task Force, September 2001), 75.

86 Figures were provided by e-mail, Paul Norris, President, Ontario Waterpower Association, February 17, 2004.

87 In Ontario this is currently approximately 50%.

88 In the United States, the average cost per KWh of wind-powered electricity fell from 38 cents in 1982 to 4.5 cents in 2001. L. R. Brown, "Eco-Economy: Building an Economy for Earth" (New York: W.W. Norton and Earth Policy Institute, 2001), Figure 5-2.

89 Adapted from Ontario Wind Power Task Force, "Industry Report and Recommendations," 4.

90 Ontario Wind Power Task Force, "Industry Report and Recommendations," 37.

91 Ontario Wind Power Task Force, "Industry Report and Recommendations," 38.

92 Ontario Wind Power Task Force, "Industry Report and Recommendations," 45.

93 Ontario Wind Power Task Force, "Industry Report and Recommendations," 75.

94 Pers. comm., Jason Edgeworthy, Vision Quest Inc., March 10, 2004.

95 The development of Canada's first manufacturing facility, in the Gaspé region, was announced in March 2004. See Canadian Association for Renewable Energies, "Turbine Manufacturer to Invest $7 Million in Gaspesie" (news release, March 3, 2004).

96 See W. Rowley, A. Westwood, and D. Westwood, "Offshore Wind Energy: The Age-Old Renewable Fuel: Global Prospects," *REFocus*, May/June 2003.

97 Ontario Wind Power Task Force, "Industry Report and Recommendations," 37–38.

98 Ontario Wind Power Task Force, "Industry Report and Recommendations," 37.

99 Ontario Wind Power Task Force, "Industry Report and Recommendations," 16–20.

100 Even if electricity is not used directly for heating, higher use of circulation fans and other HVAC equipment occurs during colder periods.

101 S. Elton, "Toward and New Energy Strategy" (Toronto: Canadian Institute for Environmental Law and Policy and the Ontario Environment Network, 1999), citing Ministry of Energy estimates.

102 Environment Canada "Six successful landfill gas utilization projects demonstrate early actions to reduce greenhouse gases" (news release, March 9, 1999).

103 See Ontario Regulation 232/98.

104 Ontario Wind Power Task Force, "Report and Recommendations," 74.

105 The capacity factors used in this table are as follows: coal 55%; nuclear 65%; existing peaking gas and replaced oil 30%; new and existing hydro 50%; wind 30%; solar PV 30%; landfill/waste generated gas 55%; remaining base load requirement 65%.

106 4,500 MW and 25,000 GWh rather than 7,285 MW and 35,000 GWh.

107 Torrie and Parfett, "Phasing Out Nuclear Power in Canada," 24.

108 IMO, "18 Month Outlook."

109 R. Mackie, "Liberals mull Pickering options," *Globe and Mail*, December 6, 2003.

110 OPG Review Committee, "Transforming Ontario's Power Generation Company," Recommendations V.1 and V.3.

111 J. Spears, "8 Nuclear reactors urged for Ontario," *Toronto Star*, December 31, 2003. AECL has suggested that the operating costs of the reactors would be 4.4 cents per KWh.

112 Electricity Conservation and Supply Task Force, "Tough Choices," Figure 5.B, 49.

113 See Appendix 1 of this report.

114 Pickering Review Panel, "Report of the Pickering 'A' Review Panel." The Task Force concluded that the estimated cost of the retubing of Pickering Unit 4 was $500 million, while the action cost of bringing the unit back into service was $1.25 billion.

115 For a detailed discussion of the impact of the NAOP efforts on OPG's overall financial position see KPMG, "Ontario Power Generation Inc. Financial Review of Operations" (Toronto: KPMG, March 2004).

116 Spears, "8 Nuclear reactors urged for Ontario."

117 Electricity Conservation and Supply Task Force, "Tough Choices," 57.

118 OPG Review Committee, "Transforming Ontario's Power Generation Company," 21.

119 See Appendix 2 in this report for a detailed discussion of the basis of these estimates.

120 See Appendix 2 in this report for a detailed discussion of this issue. The OPG Review Committee estimated a lifetime of 8–14 years for Pickering reactor Unit 1 after refurbishment. See OPG Review Committee, "Transforming Ontario's Power Generation Company," 19.

121 New Brunswick Board of Commissioners of Public Utilities, "Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau Nuclear Generating Facility" (September 24, 2002), 16.

122 The portion of time reactors were available to produce power.

123 See Table 4 "CANDU Performance at Ontario Hydro/Ontario Power Generation 1997–2003" in Appendix 2 of this report. This estimate includes all Ontario units.

124 The *Nuclear Waste Management Act*, 2002, requires that OPG begin to set aside $500 million initially, and $100 million per year for the Nuclear Waste Management Organization (NWMO) created through the act, but the NWMO has yet to make a recommendation regarding a long-term solution to the fuel waste issue.

125 For information on the social, health, and environmental impacts of uranium mining and processing, see Canadian Coalition for Nuclear Responsibility, http://www.ccnr.org/#uranium

126 Ontario Hydro, "Final Annual Report: January 1998–March 1999" (Toronto: Ontario Hydro, 1999), 67.

127 See Appendix 4 "A Comparison of Combustion Technologies for Electricity Generation." Originally published by the Pembina Institute, July 2001.

128 Appendix 4, 6–7.

129 Appendix 4, 2–3.

130 Appendix 4, 7.

131 Appendix 4, 3.

132 Appendix 4, 6.

133 Based on OCAA estimate of 142 GWh per PJ. See Gibbons, "Moving to a Coal-Free Future: Viability of Natural Gas as a Fuel for a Coal Phase-Out" (Toronto: Ontario Clean Air Alliance, September 2003), 4.

134 The Ontario Clean Air Alliance estimates that there is currently 416 PJ in additional capacity available through the TransCanada pipeline system. See Gibbons, "Moving to a Coal-Free Future," 8–9.

135 Gibbons, "Moving to a Coal-Free Future," 9.

136 J. Spears "Big chill ahead for Ontario energy," *Toronto Star*, February 24, 2004.

137 Cited in "Backgrounder: No price break for Albertans from 'cheap' coal fired power" (Drayton Valley: The Pembina Institute, November 2001).

138 "Canada's Energy Future" (Ottawa: National Energy Board, 2003), Appendix A, Table A6.1.

139 Gibbons, "Moving to a Coal-Free Future," 8.

140 Electricity Conservation and Supply Task Force, "Tough Choices," 53.

141 See for example, Gibbons, "Moving to a Coal-Free Future," 10, citing NYMEX Natural Gas Spot and Futures Prices January 2002–August 2009.

142 EDC Associates, "Electricity Price, Energy Production and Emissions Impact Evaluating proposed management scenarios for reducing air emissions of 5 priority substances from electricity generation facilities in Alberta: Optimized Scenario and Sensitivity Results prepared for CASA" (Edmonton: EDC Associates, November 2003), 24, Figure 1.

143 Data is from CIMS analyses presented in section 3.4. of this report.

144 No recent levelized cost information could be found for industrial and commercial cogeneration in Ontario. These estimates are from "Evaluation and Recommendations for Saskatchewan's Electric Options 2003–2020" (Saskatchewan Energy Conservation and Development Authority, July 1994), adjusted for inflation.

145 Ontario Wind Power Task Force, "Industry Report and Recommendations," 75.

146 Ontario Hydro, "Final Annual Report: January 1998–March 1999," 67.

147 Ontario Wind Power Task Force, "Industry Report and Recommendations," 75.

148 Ontario Wind Power Task Force, "Industry Report and Recommendations," 74.

149 "New Energy Directions: A Low-Cost, Low-Risk Electricity Supply Strategy for Ontario" (Toronto: distributed by the Ontario Clean Air Alliance, March 2004), Appendix B. This estimate is based on the U.S. Department of Energy 's January 2004 forecast that the wellhead price of natural gas in 2010 will be $3.40 per thousand cubic feed (2002 US$). Note that the PIAD estimate for Alberta 2001 of the overall levelized cost to produce electricity was 4.9 cents/kWh.

150 Ontario Hydro "Final Annual Report: January 1998–March 1999," 67. This cost estimate does not include nuclear waste management costs, decommissioning costs, direct and indirect subsidies, and life-cycle externalities of uranium production, or commercial return on capital. The provisions of the federal *Nuclear Waste Management Act*, 2002, require that OPG set aside $500 million initially plus $100 million per year for waste management costs. This would add approximately 0.2 cents per kWh to the cost of nuclear energy. However, this level of funding is inadequate to address long-term waste management. The estimated cost of AECL's long-term deep geological proposal for high-level waste presented to the Nuclear Fuel Waste Management and Disposal Concept Environmental Assessment Panel was $17–$19 billion.

151 Appendix 4, 7.

152 From section 3. Note that this is the required incremental investment, not net societal cost. Energy savings resulting from the investment would permit energy consumers to recover over 96% of their investment over the study period.

153 On the costs and potential for cogeneration in Ontario see Hagler Baily Canada et. al., "Potential for Cogeneration in Ontario: Final Report" prepared for the Ontario Ministry of Energy, Science and Technology, March 2000.

154 Ontario Wind Power Task Force, "Industry Report and Recommendations," 45.

155 Appendix 4, 7.

156 Based on refurbishment of total nuclear capacity 12,626 MWe (net) at a cost of $14.2–$19.2 billion

157 Based on AECL proposal for eight 700 MW units at a total cost of $12 billion.

158 Appendix 4, 7.

159 See the discussion of CIMS results in section 3.4.

160 This is an estimate, assuming construction time would be similar to that for CCNG.

161 Electricity Conservation and Supply Task Force, "Tough Choices," 50.

162 Estimate, assuming construction time similar to CCNG.

163 Construction time following approval. Approvals are already in place for some CCNG facilities in Ontario.

164 Based on Pickering Unit 4 experience and OPG Review Committee, "Transforming Ontario's Power Generation Company," 50.

165 Electricity Conservation and Supply Task Force, "Tough Choices," 57. This is based on an assumption of 2 years for approvals.

166 Same as CCNG, plus time for construction of gasification facility.

167 Assuming no new large-scale hydro.

168 Assuming a capacity factor of 80%, this would require 15,306 MW of nuclear generating capacity.

169 15,306 MW of capacity assuming AECL's proposal for new nuclear at $2.1million/MW as per Table 5.8.

170 This assumes the $18.2 billion investment in energy efficiency measures described in Table 3.8, and $4.5 billion in new CCNG at $1 million/MW as described in Table 5.8.

171 See Appendix 3 "Energy Efficiency Program Case Studies."

172 The Energy Foundation Utility Energy Efficiency Fact Sheet http://www.ef.org/national/FactSheetUtility.cfm

173 "Internal Evaluation of Energy Star Appliance Program." BC Hydro Power Smart, May 2002.

174 On the impact of these programs in Ontario, see Pollution Probe "Pollution Probe's Submissions with Respect to the January 23, 2004, OEB Staff Report on Demand-Side Management and Demand Response," February 9, 2004.

175 Smart Communities Network 2004, http://www.sustainable. doe.gov/municipal/commdsm.shtml

176 Aquila uses a Shared Savings Mechanism approach based on the power savings and the resource benefits flowing from those savings. The benefits are calculated over the lifetimes of the DSM measures put in place. Aquila receives a share of the total net present value of these life-cycle benefits in the form of rate adjustment.

177 The same applies to power consumers who wish to install their own renewable energy-based power sources such as solar PV systems and sell excess power to the grid. As discussed in section 4, solar PV can play a significant role in shaving summer peak demand. Removing grid connection barriers now will pave the way for solar PV to play a major role in managing power demand in the post-2010 era.

178 Conventional meters run backwards when power is supplied to the grid. This is acceptable when buying and selling tariffs are the same, but not if the tariffs are different.

179 A feed-in tariff is a fixed price paid for power from a designated source (e.g., gas cogeneration of solar PV)—usually higher than the price paid for conventional power. It has been successfully used in Germany and other European countries to kick start the renewable energy industry.

180 That is, the length of payback period a consumer is prepared to tolerate to recover the additional capital cost of more energy efficient equipment through energy savings.

181 See http://www.city.toronto.on.ca/wes/techservices/bbp/

182 See Appendix 3 in this report.

183 The Pembina Institute is current working on a position paper on this policy option.

184 See http://www.oee.ncan.gc.ca

185 See IndEco Strategic Consulting Ltd., "DSM for low-income consumers in Ontario" (Toronto: IndEco, November 2003), prepared for the Canadian Environmental Law Association.

186 Notes for remarks, The Hon. D. Duncan, Minister of Energy, "Choose what works for a change," the Empire Club, Toronto, April 15, 2004.

187 In order to ensure effectiveness and accountability, the agency should be subject to oversight and evaluation by the Provincial Auditor and Environmental Commissioner, and subject to the *Freedom of Information Act* and *Protection of Privacy Act*.

188 American Council For An Energy-Efficient Economy has published several reports on US state approaches to DSM regulation, including M. Kushler and M. Suozzo, "Regulating Electric Distribution Utilities As If Efficiency Mattered" (Washington, DC: American Council For An Energy-Efficient Economy, 1999).

189 On these programs, see Appendix 3 of this report. See also IndEco, "DSM for low-income consumers in Ontario."

190 IndEco, "DSM for low-income consumers in Ontario."

191 The Energy Savings Trust in the UK is financed by a PBC and delivers energy efficiency programs to low-income consumers. See http://www.est.org.uk

192 Distribution of the funds could be managed through a board of trustees reflecting the membership of the energy efficiency partnership proposed in Recommendation 7, including consumer, environmental non-governmental organization, and low-income representatives.

193 Under performance-based rate setting and DSM incentives, a utility is allowed to recover the costs of DSM in its rates.

194 Power sales are to be equal to the reduced demand after energy efficiency gains, fuel switching, and cogeneration.

195 For a detailed discussion of the IMO's recently proposed demand response program see J. Gibbons, "Memo to: IMO re: Achieving significant demand response in Ontario" Pollution Probe, March 17, 2004.

196 Ontario Wind Power Task Force, "Industry Report and Recommendations," 28–29.

197 See W. R. Moomaw, "Assessing Barriers and Opportunities for Renewable Energy in North America," *Environmental Challenges and Opportunities of the Evolving North American Electricity Market Background Paper 9* (Montreal: North American Commission for Environmental Cooperation, June 2002).

198 Germany currently has 7,500 MW of installed wind power capacity.

199 Ontario Wind Power Task Force, "Industry Report and Recommendations."

Appendix 1
Potential Impact of Improved Energy Efficiency on Electricity Demand in Ontario

Potential Impact of Improved Energy Efficiency on Electricity Demand in Ontario

Final Report to

The Pembina Institute for Appropriate Development

M.K. Jaccard and Associates Inc.

New Westminster, BC

Bryn Sadownik

John Nyboer

Rose Murphy

Alison Laurin

April 27, 2004

Table of Contents

Table of Tables

1 Introduction

1.1 Background

The Pembina Institute for Appropriate Development (PIAD) has undertaken an analysis of the electricity sector in Ontario. Their work is motivated by a need to move the province towards a more environmentally and economically sustainable electricity system.

Ontario relies heavily on nuclear and coal-fired generation. In addition to the environmental and health concerns associated with this current generation mix, all of the province's existing nuclear generating facilities will reach the end of their expected operational lives over the next 15 years. In addition, the provincial government has committed to the phase-out of coal fired generation by 2007. A major debate is emerging over the appropriate direction of the province's future electricity investments. There are disagreements about the degree to which energy efficiency programs can be expected to reduce future electricity demand, and by implication the province's future new generation capacity needs.

Given that the current situation provides an opportunity to advance major changes in the province's electricity policy framework, PIAD has undertaken an investigation of the potential impact of increasing investments in efficiency measures, as part of its broader electricity policy study. M.K. Jaccard and Associates (MKJA) agreed to assist PIAD in their analysis by using the CIMS energy-economic model to investigate the potential impact on electricity demand of a generic set of efficiency policy measures, as described in the following section.

1.2 Specific Terms of Reference

CIMS was used to simulate four policy scenarios which represent efforts to substantially increase the penetration of energy-efficient end-use technologies, encourage fuel switching (away from electricity) in the same technologies, and remove institutional constraints to cogeneration. These scenarios were constructed by combining the following three modifications to CIMS in various ways.

Modification 1 reduced the user-perceived private discount rate (on investment decisions) for targeted energy-efficient and fuel switch end use technologies to 8% for technologies in commercial and residential sectors, and 12% for technologies in the industrial sector, including cogeneration. This was done to suggest the impact of a variety of policies such as loan programs and tax measures that would increase the attractiveness of these investments. A list of targeted technologies is provided in Appendix A.

Modification 2 reduced the capital cost of the targeted technologies (except residential retrofit) by 8% to emulate a sales tax reduction or grant towards the cost of the technology. Residential retrofit costs were reduced by 20% to reflect the newly announced Federal grant program for this end-use.

Modification 3 removed restrictions that prevent the penetration of cogeneration in the industrial and commercial sectors so that these users could adopt cogeneration where it was cost effective to do so, up to the limitations provided by the local steam load. It was assumed that in effect, cogeneration operators received the same price for power supplied to the grid and for power purchased.

Results were provided for five runs using the demand-side CIMS sub-models for Ontario. The five runs include 1) a Business-as-Usual (BAU) run, 2) a run in which cogeneration in the model is not constrained, 3) a run incorporating the reduced discount rate scenario, 4) a run incorporating the reduced capital cost scenario, and 5) a run incorporating both reduced discount rates and reduced capital costs. Financial costs and energy consumption were summarized by sub-sector (Residential, Commercial, Iron & Steel, Mining, etc.) for the province of Ontario for each run. New technology acquisition for specific energy-efficient technologies targeted under the different policy simulations were also summarized.

1.3 Report Outline

The methods section that follows describes the CIMS model and explains in some detail how policy simulations were applied in the model. It also explains how the costs associated with the policy scenarios were evaluated and reported. The third section presents and discusses financial costs and energy demand impacts for the policy simulations. Finally, we offer some key caveats and conclusions. Detailed reporting of new technology acquisition for the specific energy-efficient technologies targeted is not included in this report, but was provided directly to PIAD as a spreadsheet file.

2 Method

2.1 The CIMS Model

CIMS simulates energy and GHG emissions in the Canadian economy based on a detailed representation of regional economic sectors and technologies in over 50 unique sub-models. The disaggregated energy picture is calibrated to energy and GHG emissions for 2000.[1] The sub-models are then run using forecasts of

[1] Calibration is principally to Statistics Canada's publication *Quarterly Report on Energy Supply and Demand*, 57-003, and Environment Canada's *Greenhouse Gas Inventory*. Exceptions are energy data for Mining (Annual Survey of Mines Data) and Petroleum Refining (Canadian Industrial Energy Enduse Data and Analysis Centre, Petroleum Refining Survey Data).

industry and sectoral growth based on estimates of economic output growth in *Canada's Emissions Outlook: An Update* (CEOU)[2] to give a BAU forecast of energy and emissions.

CIMS provides a dynamic forecasting picture of sectoral energy use, which includes trends in energy efficiency (for instance from the acquisition of more energy efficient technologies), GHG intensities (for instance from fuel switching) and structural production shifts (for instance, the trend towards electric arc furnaces in steel production, relative to integrated mills). The model bases its choice of new technologies – needed to meet production output growth and the retirement of existing capital stock – on the behaviour of consumers, managers and other decision makers based not only on the lifecycle financial cost of competing technologies, but also on risk, market variance (i.e., the degree to which purchasers face different prices for the same technology) and intangible factors (for instance, performance preferences).[3]

CIMS covers the entire Canadian economy and can connect to an aggregated representation of the US economy. It currently models six provinces and an aggregation of the Atlantic provinces. While the model is simple in operation, it can appear complex because it is technologically explicit and covers the whole economy. This means that all technologies (refrigerators, cars, lamps, industrial motors, steel furnaces, buildings, power plants, etc.) must be represented in the model, including their inter-linkages. Because of the great diversity of technologies in industry, the model is especially large for that sector. Appendix B lists the technologies in the sectors being targeted by this research.

In simulating the effects of a technology-specific action, CIMS also simulates the indirect effects of that action within that sector. For example, by specifying in the model that more efficient motors will be required in the industrial sector, changes in the cost of motor-driven service demand may have an effect on the type of process equipment chosen, and subsequently on other energy service demands in the sector (for example, for steam).

A CIMS simulation involves six basic steps. Steps 4 and 5 were not activated for this project.

1. Assessment of demand
2. Retirement
3. New technology competition / retrofitting
4. Energy supply and demand equilibrium

---

[2] Analysis and Modelling Group, 1999.

[3] Discount rates are intended to reflect the rate of return that companies and consumers expect from energy investments, one of the model's reflections of behaviour. External limits are used to reflect portions of the market that would not be eligible for certain technologies due to size or technical limitations. Non-cost parameters are used to simulate market barriers that reduce the penetration of a technology below what would be considered economic.

5. Macro-economic equilibrium
6. Output

1. *Assessment of demand:* Technologies are represented in the model in terms of the quantity of service they provide. This could be, for example, vehicle kilometres travelled, tonnes of paper, or m^2 of floor space heated and cooled. A forecast is then provided of growth in energy service demand.[4] This forecast drives the model simulation, usually in five year increments (e.g., 2005, 2010, 2015, etc.).

2. *Retirement*: In each future period, a portion of the initial-year's stock of technologies is retired. Retirement depends only on age.[5] The residual technology stocks in each period are subtracted from the forecast energy service demand and this difference determines the amount of new technology stocks in which to invest.

3. *New technology competition / retrofitting*: Prospective technologies compete for this new investment so that the outcome approximates what would happen in the real world. Hence while the engine for the competition is the minimization of annualized life cycle costs, these costs are substantially adjusted to reflect market research of past and prospective firm and household behaviour.[6] Thus, technology costs depend not only on recognised financial costs, but also on identified differences in non-financial preferences (differences in the quality of lighting from different light bulbs) and failure risks (one technology is seen as more likely to fail than another). Even the determination of financial costs is not straightforward, as time preferences (discount rates) can differ depending on the decision maker (household vs. firm) and the type of decision (non-discretionary vs. discretionary). The model allocates market shares among technologies probabilistically.[7]

   In each time period, a similar competition occurs with residual technology stocks to simulate retrofitting prior to the new technology stock competition.[8] The same financial and non-financial information is required, except that the capital costs of residual technology stocks are excluded, having been spent earlier when the residual technology stock was originally acquired.

---

[4] The growth in energy service demand (e.g., tonnes of steel) must sometimes be derived from a forecast provided in economic terms (e.g., dollar value of output from the steel sector).

[5] There is considerable evidence that the pace of technology replacement depends on the economic cycle, but over a longer term, as simulated by CIMS, age is the most important and predictable factor.

[6] With existing technologies there is often available data on consumer behaviour. However, with emerging technologies (especially the heterogeneous technologies in industry) firms and households need to be surveyed (formally or informally) on their likely preferences. These latter are referred to as stated preferences whereas preferences derived from historic data are referred to as revealed preferences.

[7] In contrast, the optimizing MARKAL model will tend to produce outcomes in which a single technology gains 100% market share of the new stocks.

[8] Where warranted, retrofit can be simulated as equivalent to complete replacement of residual technology stocks with new technology stocks.

CIMS has additional levers that allow the user to constrain in various ways the simulation of equipment acquisition decisions. For instance, *maximum market shares* and *minimum market shares* are set for certain technologies or groups of technologies. Of particular importance to this project are maximum market shares, which have been set for cogeneration technologies. These constrain the share of steam demand that can be met by this technology. This constraint represents institutional barriers to cogeneration regarding grid connection, metering, electricity purchase rates, and grid access to third parties.[9]

4. *Equilibrium of energy supply and demand*: Once the demand model has chosen technologies based on the base case and policy case energy prices, the resulting demands for energy are sent to the energy supply models. These models then choose the appropriate supply technologies, assess the change in the cost of producing energy, and if it is significant send the new energy prices back to the demand models. This cycle goes back and forth until energy prices and energy demand have stabilised at an equilibrium.[10]. As noted above, in the current study, this feature of the model was not used, and a set of fixed energy prices were provided to the demand model (see below).
5. *Equilibrium of energy service demand*: Once the energy supply and demand cycle has stablized, the final demand feedback cycle is invoked (if turned on), which adjusts demand for energy services according to their change in overall price, based on price elasticities. If this adjustment is significant, the whole system is re-run from Step 1 with the new demands. This feature was also not used in the current study.
6. *Output*: Since each technology has net energy use, net energy emissions and costs associated with it, the simulation ends with a summing up of these.

2.1.1 Modeling the Policy Simulation

We used the CIMS model to generate the Business as Usual forecast, and for all policy simulations. Only the sub-models in Ontario that could be targeted with specific electricity efficiency and/or cogeneration technologies were run. The sub-models are: Chemical Product Manufacturing, Commercial, Electricity Generation, Industrial Minerals, Iron and Steel, Metal Smelting and Refining, Mining, Other Manufacturing, Petroleum Crude Extraction, Petroleum Refining, Pulp and Paper, and Residential. All CIMS simulations start in 2000. It is not possible to change the policy emulating parameters used in this analysis from one time period to another. Some adjustments were therefore necessary to ensure that the impacts of the policy changes did not take effect

---

[9] For a more complete discussion of institutional barriers to cogeneration, see: M.K. Jaccard & Associates, *Cogeneration Potential in Canada, Phase 2*, Prepared for Natural Resources Canada, April 2002 (available on-line at www.cieedac.sfu.ca).

[10] This convergence procedure, modelled after the NEMS model of the US government, stops the iteration once changes in energy demand and energy prices fall below a threshold value. In contrast, the MARKAL model does not need this kind of convergence procedure; iterating to equilibrium is intrinsic to its design.

until 2005. To do this we ran CIMS with the policy simulation applied at the beginning of 2000, and then adjusted the 2005 stock, costs and energy values to be the same as the 2005 BAU values. The same limitations meant that the policy changes had to be maintained through to 2020 even when they may not be needed.

PIAD and MKJA agreed on the efficient technologies to be targeted in the policy scenarios, choosing the top performing technology for each end use.[11] The list of targeted technologies is shown in Appendix A. The same technologies are targeted with the lowered discount rate and the capital cost adjustment. By lowering the discount rate, we are representing an increase in the attractiveness of more energy efficient and less electricity reliant technologies.[12]

We simulated support for more cogeneration in the industrial and commercial models by removing restrictions that limited the penetration of cogeneration (to reflect current institutional barriers). Cogeneration is adopted within a sector sub-model according to that model's competition algorithm for steam and/or heat demand. Cogeneration technologies are also targeted as part of the targeted discount rate reduction and capital cost reduction.

2.2 Method for reporting costs

The costs reported in this study are the differences between the total amount spent on capital, operating, maintenance, and energy under the policy and under the BAU over the life of the technologies. All costs are reported in 1995 dollars with future costs discounted to 2004 using a 10% discount rate. We refer to these costs as 'financial costs'. They represent the anticipated financial costs of firms and households adapting to policy change.[13] The financial costs and benefits of a policy simulation are the differences between the total amount spent on capital, operating, maintenance, and energy under the policy and under the BAU over the life of the technologies. Capital costs of technologies purchased during the modelling period are included, but if the technology life extends beyond 2020, the capital cost only includes the costs occurring up to 2020 (based on the annualised cost of capital using a 10% discount rate). All

[11] Except when this technology was a custom product not widely available on the market. Then the next most efficient model was targeted

[12] Research during the past thirty years has shown that consumers and firms forego apparently cost-effective investments in energy efficiency -- future savings of energy-efficiency investments are discounted at rates well in excess of market rates for borrowing or saving. (For example see A. Jaffe and R. Stavins, "The Energy-Efficiency Gap: What Does it Mean?" *Energy Policy* 22, 10 (1994): 804-810; J. Scheraga, "Energy and the Environment: Something New under the Sun?" *Energy Policy* 22, 10 (1994): 811-818; R. Sutherland, "The Economics of Energy Conservation Policy," *Energy Policy* 24, 4 (1996): 361-370.) This behaviour is captured in the CIMS technology-choice algorithm. By lowering the discount rates, this simulation represents investment decisions if energy-efficiency investments are evaluated at the market rate for borrowing or saving.

[13] We refer to the anticipated financial cost as an *ex ante* financial costs in other studies. See: M. Jaccard, J. Nyboer, C. Bataille and B. Sadownik, "Modeling the Cost of Climate Policy: Distinguishing Between Alternative Cost Definitions and Long-Run Cost Dynamics," *The Energy Journal* 21, 1 (2003): 49-73.

costs are reported in $1995 with future costs discounted to 2004 using a 10% discount rate.

2.3 CIMS Electricity and Natural Gas Price Forecasts

Business-as-usual electricity and natural gas price forecasts used in the CIMS simulations are shown in Tables 1 and 2 below. These prices are based on the forecasts provided by Natural Resources Canada as part of the CEOU.

Table 1 Electricity Price Forecasts used in the CIMS Ontario model (¢/kWh)

	2000	2005	2010	2015	2020
Commercial	8.30	8.50	9.22	9.98	10.79
Industrial	6.30	5.38	5.83	6.31	6.82
Residential	10.00	10.24	11.11	12.03	13.00

Prices are in 2004 dollars.

Table 2 Natural Gas Price Forecasts used in the CIMS Ontario model ($/GJ)

	2000	2005	2010	2015	2020
Commercial	5.25	5.79	6.41	6.97	7.61
Industrial	3.61	3.97	4.40	4.76	5.18
Residential	6.37	7.01	7.76	8.46	9.25

Prices are in 2004 dollars.

3 Results

Electricity demand, natural gas consumption and financial cost results from the CIMS simulations are summarized in Tables 3, 4 and 5. We discuss each of these five simulations in more detail in the sections below.

Table 3 Summary of CIMS Simulations, Electricity Demand, 2000-2020

Simulation	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Baseline	490.26	500.00	531.94	587.18	650.79
1. Unconstrained Cogeneration Competition	490.26	500.00	520.52	562.12	612.76
2. Unconstrained Cogeneration Competition + Discount Rate Reduction	490.26	500.00	437.51	400.69	391.88
3. Unconstrained Cogeneration Competition + Capital Cost Reduction	490.26	500.00	511.94	546.06	591.62

4. Unconstrained Cogeneration Competition + Discount Rate Reduction + Capital Cost Reduction	490.26	500.00	435.22	396.37	386.20

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration).

Table 4 Summary of CIMS Simulations, Natural Gas Consumption, 2000-2020

Simulation	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Baseline	880.11	933.27	964.72	1,019.18	1,077.49
1. Unconstrained Cogeneration Competition	880.11	933.27	980.58	1,054.32	1,130.77
2. Unconstrained Cogeneration Competition + Discount Rate Reduction	880.11	933.27	1,000.05	1,111.90	1,226.56
3. Unconstrained Cogeneration Competition + Capital Cost Reduction	880.11	933.27	978.62	1,052.91	1,130.44
4. Unconstrained Cogeneration Competition + Discount Rate Reduction + Capital Cost Reduction	880.11	933.27	992.92	1,097.81	1,207.63

Table 5 Summary of CIMS Simulations, Financial Costs ($ million)

Simulation	Net Cost	Individual Cost		
		Investment	O/M	Energy
1. Unconstrained Cogeneration Competition	-995.90	522.61	578.65	-2,097.16
2. Unconstrained Cogeneration Competition + Discount Rate Reduction	432.61	17,227.90	1,485.04	-18,280.33
3. Unconstrained Cogeneration Competition + Capital Cost Reduction	-1,213.98	1,482.13	696.89	-3,393.00
4. Unconstrained Cogeneration Competition + Discount Rate Reduction + Capital Cost Reduction	622.31	18,260.39	1,572.77	-19,210.84

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.1 Business-as-Usual

The business-as-usual (BAU) electricity demand forecast was generated based on parameters and assumptions in CIMS (for instance, production, housing and commercial floor space growth forecasts, energy price forecasts, assumptions about structural change), and is not calibrated to any other forecast.[14] In the base year (2000), the models are calibrated to Statistics Canada energy consumption data, and total electricity demand in Ontario is within 2% of that reported by Statistics Canada.[15] Table 6 describes total electricity demand for all sectors in Ontario between 2000 and 2020, while Table 7 provides a detailed breakdown of the BAU for those sectors targeted in the policy simulations. In these tables, electricity demand refers to the electricity demand met by the electricity supply sector model in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration). Table 8 describes natural gas consumption for the same time period.

Table 6 Business-as-Usual Electricity Demand (all sectors), Ontario (2000-2020)

Unit	2000	2005	2010	2015	2020
PJ	493.3	503	535	591	655
GWh	137,028	139,722	148,611	164,167	181,944

Table 7 Electricity Demand by Sector, Business-as-Usual, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	166.33	174.42	182.70
Metal Smelting and Refining	7.78	8.05	8.53	9.39	10.38
Pulp & Paper	35.76	35.41	34.94	37.19	39.54
Other Manufacturing	64.59	64.29	64.07	65.24	66.51
Mining	6.52	6.83	7.30	8.11	8.86
Iron & Steel	21.04	22.63	24.36	26.11	27.53
Industrial Minerals	3.70	3.85	4.03	4.44	5.03
Chemicals	17.41	18.48	20.62	23.40	26.16
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.44	0.49	-1.33
Residential Sector	153.70	136.53	132.03	138.35	145.93
Commercial Sector	172.70	199.00	233.59	274.41	322.16
Total -- All Sectors	490.26	500.00	531.94	587.18	650.79

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

---

[14] CIMS estimation of future demand and supply can be calibrated to other forecasts (e.g., in its federal government climate policy analysis), however this step was not included in this analysis.
[15] Statistics Canada, *Quarterly Report on Energy Supply-Demand in Canada 2000 – IV* (Ottawa: Ministry of Industry, 2001), p. 76.

Table 8 Natural Gas Consumption by Sector, Business-as-Usual, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	384.98	405.56	426.33
Metal Smelting and Refining	11.47	13.25	14.52	15.85	17.36
Pulp & Paper	42.63	46.85	50.22	53.73	57.22
Other Manufacturing	169.20	175.83	176.84	177.45	178.75
Mining	1.47	2.80	3.34	3.90	4.43
Iron & Steel	60.01	61.99	64.04	66.17	68.24
Industrial Minerals	6.46	6.33	6.23	6.64	7.50
Chemicals	35.77	40.06	45.05	51.12	57.07
Petroleum Extraction	0.01	0.01	0.01	0.01	0.01
Petroleum Refining	12.29	19.68	24.72	30.70	35.77
Residential Sector	320.30	350.14	367.54	391.21	418.06
Commercial Sector	220.50	216.33	212.20	222.40	233.10
Total -- All Sectors	880.11	933.27	964.72	1,019.18	1,077.49

3.2 Unconstrained Cogeneration

In this simulation, constraints to cogeneration in CIMS were removed (noted in section 2.1), and cogeneration technologies were allowed to compete equally with boilers to meet steam demand. Relative to the BAU, the greatest increases in cogeneration occur in the Commercial, Petroleum Refining and Other Manufacturing. The Chemicals Manufacturing, Iron and Steel, and Pulp and Paper industry sectors already meet a significant portion of their steam and electricity demand by cogeneration in the BAU, which remains unchanged in the unconstrained cogeneration simulation (this does change with technology specific targeting in the policy scenarios). Cogeneration is not available (in the CIMS model) to the Residential, Petroleum Extraction and Mining sub-models.

The simulation results in a 6% drop overall in (utility) electricity demand in the targeted demand sectors. Table 9 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 10 describes natural gas consumption for the same time period.

A detailed breakdown of costs is shown in Table 11. The net discounted financial cost for the simulation period is -$1 billion ($1995) – i.e. a net financial benefit to the users of cogeneration.

The results here are generally consistent with an earlier study conducted by MKJA, which examined the potential of cogeneration in Canada.[16]

---

[16] Though provincial results were not reported in the study's report, the contractor reviewed output files to ensure that the simulation runs were set up in a similar fashion to that study's 'unconstrained case' and that found that the Ontario reports from the CIMS model were fairly consistent. Changes to the CIMS model has occurred in the intervening years, so results cannot be exactly the same. M.K. Jaccard & Associates, *Cogeneration Potential in Canada, Phase 2* Prepared for Natural Resources Canada, April 2002.

Table 9 Electricity Demand by Sector, Unconstrained Cogeneration, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	166.02	173.75	181.70
Metal Smelting and Refining	7.78	8.05	8.53	9.39	10.38
Pulp & Paper	35.76	35.41	34.94	37.19	39.54
Other Manufacturing	64.59	64.29	64.05	65.22	66.47
Mining	6.52	6.83	7.30	8.11	8.86
Iron & Steel	21.04	22.63	24.36	26.11	27.53
Industrial Minerals	3.70	3.85	4.03	4.44	5.03
Chemicals	17.41	18.48	20.62	23.40	26.16
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.14	-0.15	-2.30
Residential Sector	153.70	136.53	132.03	138.35	145.93
Commercial Sector	172.70	199.00	222.47	250.02	285.12
Total -- All Sectors	490.26	500.00	520.52	562.12	612.76

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration).
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 10 Natural Gas Consumption by Sector, Unconstrained Cogeneration, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	383.97	403.41	422.89
Metal Smelting and Refining	11.47	13.25	14.52	15.85	17.36
Pulp & Paper	42.63	46.85	50.22	53.73	57.22
Other Manufacturing	169.20	175.83	176.86	177.49	178.82
Mining	1.47	2.80	3.34	3.90	4.43
Iron & Steel	60.01	61.99	64.04	66.17	68.24
Industrial Minerals	6.46	6.33	6.23	6.64	7.50
Chemicals	35.77	40.06	45.05	51.12	57.07
Petroleum Extraction	0.01	0.01	0.01	0.01	0.01
Petroleum Refining	12.29	19.68	23.69	28.50	32.25
Residential Sector	320.30	350.14	367.54	391.21	418.06
Commercial Sector	220.50	216.33	229.07	259.70	289.83
Total -- All Sectors	880.11	933.27	980.58	1,054.32	1,130.77

Table 11 Financial Costs, Unconstrained Cogeneration ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-20.14	9.86	4.11	-34.11
Metal Smelting and Refining	0.36	0.00	-0.04	0.40
Pulp & Paper	0.08	0.05	0.02	0.01
Other Manufacturing	0.63	1.22	0.42	-1.01
Mining	0.00	0.00	0.00	0.00
Iron & Steel	0.00	0.00	0.00	0.00
Industrial Minerals	0.00	0.01	0.00	-0.01
Chemicals	0.00	0.00	0.00	0.00
Petroleum Extraction	0.00	0.00	0.00	0.00
Petroleum Refining	-21.21	8.58	3.70	-33.50
Residential Sector	0.00	0.00	0.00	0.00
Commercial Sector	-975.76	512.75	574.54	-2,063.05
Total -- All Sectors	-995.90	522.61	578.65	-2,097.16

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.3 Unconstrained Cogeneration + Discount Rate Adjustments

In this scenario, the discount rate applied to targeted energy-efficient, cogeneration and fuel switch end use technologies was reduced to 8% for technologies in commercial and residential sectors, and 12% for technologies in the industrial sector. This scenario is intended to simulate a variety of policies such as loan programs and tax measures that would remove the user perceived barriers that discourage investment in these alternatives. Also, the constraints to cogeneration continued to be removed in CIMS.

Table 12 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 13 describes natural gas consumption for the same time period.

This scenario results in a 40% drop in electricity demand relative to the BAU scenario. The Pulp & Paper, Commercial, Residential, and Petroleum Refining sectors experience significant reductions. Most of the aggregate savings in 2020 occur due to reductions in the Commercial sector, followed by the Residential and Industrial sectors. A detailed breakdown of costs is shown in Table 13. The net discounted financial cost for the simulation period is $433 million ($1995). However, the Commercial sector and several industrial sectors show a net benefit from the scenario. Only in the Residential sector and in five industries is there a net cost.

Table 12 Electricity Demand by Sector, Unconstrained Cogeneration + Discount Rate Adjustments, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	154.41	152.07	151.14
Metal Smelting and Refining	7.78	8.05	8.14	8.62	9.23
Pulp & Paper	35.76	35.41	29.46	25.99	23.30
Other Manufacturing	64.59	64.29	62.15	62.21	62.49
Mining	6.52	6.83	6.86	7.24	7.59
Iron & Steel	21.04	22.63	23.40	24.28	24.91
Industrial Minerals	3.70	3.85	3.81	3.98	4.30
Chemicals	17.41	18.48	18.40	19.85	21.53
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.14	-0.14	-2.27
Residential Sector	153.70	136.53	111.37	100.90	98.91
Commercial Sector	172.70	199.00	171.73	147.73	141.82
Total -- All Sectors	490.26	500.00	437.51	400.69	391.88

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 13 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Discount Rate Adjustments, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	384.89	406.21	426.86
Metal Smelting and Refining	11.47	13.25	14.69	16.17	17.84
Pulp & Paper	42.63	46.85	50.15	53.87	57.49
Other Manufacturing	169.20	175.83	175.58	174.91	175.07
Mining	1.47	2.80	3.95	5.57	7.11
Iron & Steel	60.01	61.99	66.05	70.40	73.80
Industrial Minerals	6.46	6.33	6.61	7.49	8.87
Chemicals	35.77	40.06	45.04	51.29	57.43
Petroleum Extraction	0.01	0.01	0.02	0.02	0.03
Petroleum Refining	12.29	19.68	22.79	26.48	29.22
Residential Sector	320.30	350.14	350.61	363.68	387.43
Commercial Sector	220.50	216.33	264.55	342.01	412.27
Total -- All Sectors	880.11	933.27	1,000.05	1,111.90	1,226.56

Table 14 Financial Costs, Unconstrained Cogeneration + Discount Rate Adjustments ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-155.94	779.06	257.42	-1,192.42
Metal Smelting and Refining	-40.40	-0.95	-0.81	-38.64
Pulp & Paper	-52.42	414.73	149.04	-616.19
Other Manufacturing	61.87	188.02	79.65	-205.80
Mining	2.95	-8.53	-4.05	15.53
Iron & Steel	52.37	114.66	-15.99	-46.31
Industrial Minerals	-6.47	23.39	-2.06	-27.79
Chemicals	-203.56	17.18	8.89	-229.62
Petroleum Extraction	0.30	0.00	0.00	0.30
Petroleum Refining	29.42	30.57	42.75	-43.90
Residential Sector	855.10	6,312.97	-40.01	-5,417.86
Commercial Sector	-266.55	10,135.87	1,267.63	-11,670.05
Total -- All Sectors	432.61	17,227.90	1,485.04	-18,280.33

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.4 Unconstrained Cogeneration + Reduced Capital Costs

In this scenario the capital cost of targeted energy efficiency and fuel switch technologies and cogeneration technologies were reduced by 8% to emulate a sales tax reduction or grant towards the cost of the technology. Residential retrofit costs were reduced by 20% to reflect the newly announced Federal grant program for this end-use. Also, the constraints to cogeneration continue to be removed in CIMS.

Table 15 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 16 describes natural gas consumption for the same time period.

This scenario results in a 9% drop overall in electricity demand relative to the BAU scenario. This is significantly less than the first policy scenario, but provides a net financial benefit (see below). Most of the aggregate savings in 2020 occur due to reductions in the commercial sector and residential sectors, while industrial sectors only contribute minimally to demand savings. A detailed breakdown of cost is shown in Table 17. The net discounted financial benefit for the simulation period is $1.2 billion ($1995) – all sectors with the exception of three industries show net benefits.

Table 15 Electricity Demand by Sector, Unconstrained Cogeneration + Reduced Capital Costs, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	165.00	171.91	179.14
Metal Smelting and Refining	7.78	8.05	8.41	9.15	10.01
Pulp & Paper	35.76	35.41	34.66	36.69	38.82
Other Manufacturing	64.59	64.29	63.82	64.91	66.11
Mining	6.52	6.83	7.19	7.89	8.54
Iron & Steel	21.04	22.63	24.25	25.94	27.32
Industrial Minerals	3.70	3.85	4.00	4.39	4.95
Chemicals	17.41	18.48	20.51	23.12	25.74
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	2.11	-0.23	-2.41
Residential Sector	153.70	136.53	129.22	133.32	139.69
Commercial Sector	172.70	199.00	217.71	240.82	272.79
Total -- All Sectors	490.26	500.00	511.94	546.06	591.62

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 16 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Reduced Capital Costs, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	383.94	403.52	423.06
Metal Smelting and Refining	11.47	13.25	14.56	15.94	17.49
Pulp & Paper	42.63	46.85	50.23	53.73	57.23
Other Manufacturing	169.20	175.83	176.88	177.52	178.85
Mining	1.47	2.80	3.46	4.24	4.98
Iron & Steel	60.01	61.99	64.20	66.50	68.66
Industrial Minerals	6.46	6.33	6.21	6.58	7.40
Chemicals	35.77	40.06	44.95	51.05	57.03
Petroleum Extraction	0.01	0.01	0.01	0.01	0.01
Petroleum Refining	12.29	19.68	23.44	27.95	31.42
Residential Sector	320.30	350.14	362.85	383.37	408.89
Commercial Sector	220.50	216.33	231.82	266.02	298.48
Total -- All Sectors	880.11	933.27	978.62	1,052.91	1,130.44

Table 17 Financial Costs, Unconstrained Cogeneration + Reduced Capital Costs ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-73.85	22.06	22.10	-118.02
Metal Smelting and Refining	-14.17	-1.52	-0.28	-12.37
Pulp & Paper	-22.11	9.01	2.66	-33.77
Other Manufacturing	-21.06	0.07	0.35	-21.48
Mining	4.63	-4.56	-1.35	10.54
Iron & Steel	-10.18	2.89	-7.64	-5.43
Industrial Minerals	24.31	3.77	18.86	1.68
Chemicals	-16.96	0.76	-0.20	-17.52
Petroleum Extraction	0.03	0.00	0.00	0.02
Petroleum Refining	-18.33	11.64	9.72	-39.69
Residential Sector	-343.71	563.56	-4.63	-902.64
Commercial Sector	-796.43	896.51	679.41	-2,372.34
Total -- All Sectors	-1,213.98	1,482.13	696.89	-3,393.00

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

3.5 Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios

In this scenario:

1. the capital cost of targeted energy-efficient and fuel switch end use technologies and cogeneration technologies were reduced by 8%;
2. residential retrofit costs were reduced by 20% to reflect the newly announced Federal grant program for this end-use;
3. the constraints to cogeneration were removed in CIMS;
4. the discount rate applied to targeted energy-efficient and fuel switch end use technologies and cogeneration technologies was reduced (8% for commercial and residential; 12% for industrial).

This scenario results in a 41% drop in electricity demand relative to the BAU scenario, showing that the combined scenarios are not additive. Most additional reductions from adding the capital cost reduction occur in the residential sector.

Table 18 describes electricity demand by sector between 2000 and 2020 for those sectors targeted in this policy simulation. Table 19 describes natural gas consumption for the same time period.

A detailed breakdown of costs is shown in Table 20. The net discounted financial cost for the simulation period is $622 million ($1995). However, the commercial and industrial sectors show a net benefit. Only the residential sector shows a net cost of $1,001 million ($1995).

Table 18 Electricity Demand by Sector, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, 2000-2020 (PJ)

Sector	Electricity Demand (PJ)				
	2000	2005	2010	2015	2020
Industry	163.86	164.47	153.83	151.03	149.69
Metal Smelting and Refining	7.78	8.05	8.13	8.62	9.22
Pulp & Paper	35.76	35.41	29.40	25.87	23.14
Other Manufacturing	64.59	64.29	62.10	62.13	62.39
Mining	6.52	6.83	6.85	7.23	7.58
Iron & Steel	21.04	22.63	23.34	24.17	24.73
Industrial Minerals	3.70	3.85	3.78	3.92	4.21
Chemicals	17.41	18.48	18.18	19.52	21.11
Petroleum Extraction	0.07	0.06	0.05	0.05	0.04
Petroleum Refining	7.07	4.87	1.99	-0.47	-2.74
Residential Sector	153.70	136.53	109.95	98.20	95.38
Commercial Sector	172.70	199.00	171.44	147.14	141.13
Total -- All Sectors	490.26	500.00	435.22	396.37	386.20

Note: Electricity demand refers to the electricity demand met by the electricity supply sector in CIMS, and is equal to: (electricity consumption in the demand sectors) - (electricity supplied by cogeneration)
A negative demand value indicates that electricity provided by cogeneration exceeds that used by that particular industry.

Table 19 Natural Gas Consumption by Sector, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, 2000-2020 (PJ)

Sector	Natural Gas Consumption (PJ)				
	2000	2005	2010	2015	2020
Industry	339.31	366.80	384.20	404.87	424.92
Metal Smelting and Refining	11.47	13.25	14.69	16.18	17.85
Pulp & Paper	42.63	46.85	49.41	52.37	55.28
Other Manufacturing	169.20	175.83	175.39	174.51	174.49
Mining	1.47	2.80	3.95	5.58	7.11
Iron & Steel	60.01	61.99	66.19	70.70	74.20
Industrial Minerals	6.46	6.33	6.75	7.81	9.39
Chemicals	35.77	40.06	45.02	51.24	57.37
Petroleum Extraction	0.01	0.01	0.02	0.02	0.03
Petroleum Refining	12.29	19.68	22.79	26.47	29.21
Residential Sector	320.30	350.14	345.00	352.80	373.37
Commercial Sector	220.50	216.33	263.72	340.14	409.34
Total -- All Sectors	880.11	933.27	992.92	1,097.81	1,207.63

Table 20 Financial Costs, Unconstrained Cogeneration + Combined Effect of Technology-Specific Scenarios, ($ million)

SECTOR	Net Cost	Individual Cost		
		Investment	O/M	Energy
Industry	-153.24	828.61	272.72	-1,254.57
Metal Smelting and Refining	-41.20	-1.67	-0.93	-38.60
Pulp & Paper	-35.15	459.03	140.57	-634.75
Other Manufacturing	49.98	184.39	77.21	-211.62
Mining	1.06	-9.94	-4.05	15.06
Iron & Steel	62.09	121.75	-10.45	-49.21
Industrial Minerals	20.02	26.11	17.88	-23.97
Chemicals	-228.51	14.88	8.15	-251.54
Petroleum Extraction	0.32	0.02	0.00	0.30
Petroleum Refining	18.14	34.04	44.33	-60.23
Residential Sector	1,000.81	7,220.33	-45.07	-6,174.44
Commercial Sector	-225.26	10,211.45	1,345.12	-11,781.83
Total -- All Sectors	622.31	18,260.39	1,572.77	-19,210.84

Note: All costs are reported in $1995 with future costs (2004-2020) discounted to 2004 using a 10% discount rate.

4 Conclusions

The four generic policy scenarios modelled in the study result in significant reductions in electricity demand, particularly in the second and fourth scenario simulations in which the discount rate applied to targeted energy-efficient, cogeneration and fuel switch end use technologies was reduced to 8% for technologies in the commercial and residential sector, and 12% for industrial. The second scenario, intended to simulate a variety of policies such as loan programs and tax measures that would remove the user perceived barriers that discourage investment in these alternatives, results in a 40% reduction in electricity demand in 2020.

The third scenario, in which the capital costs of the same targeted technologies were reduced by 8% (20% for residential retrofits), resulted in a 9% reduction in electricity consumption. This particular simulation reflects only the competition response to the lower capital costs and does not reflect an 'announcement effect' of a program of this nature which could increase its effectiveness particularly early in a market transformation program.

In scenario four, where the discount rates and capital costs are lowered, and cogeneration is unconstrained, electricity consumption is reduced by 41%. The results show that the electricity savings produced by the individual policy scenarios are not additive. The exact nature of this overlap and interaction between individual scenarios has not been explored in this analysis.

The results provided in this report do not predict the impact of individual policies and programs nor do they endorse specific government policies. They are illustrative of changes to the capital costs and discount rates in the CIMS model, made to represent the potential impact of policies designed to encourage the adoption of energy efficient technologies and fuel switching away from electricity.

5 Key Caveats

Important caveats are noted below.

Cogeneration simplifications. CIMS' representation of cogeneration does not include the establishment of dedicated generation capacity to supply power to an open electricity market beyond that which would match the current steam or heating load of an industry or commercial building. Also, CIMS does not account for the cyclical and seasonal nature of thermal demand in the commercial sector which results in cogeneration systems being sized for the base thermal load rather than the average assumed by CIMS. The effect of this limitation is to overestimate the amount of cogeneration that is economical. However, CIMS does not include hot water loads in cogeneration simulations. This would smooth out seasonal thermal demand and increase cogeneration potential.

Community energy management not considered. The analysis conducted using CIMS focused on technology and building-specific energy efficiency actions. It did not include potential electricity savings from changes to urban form, industrial siting, and the provision of infrastructure. For instance, the potential of Community Energy Systems (district cooling using lake water, other district energy systems which use waste heat) were not examined. These effects lead to underestimation of the potential savings in the residential and commercial sectors.

HVAC & lighting interactions in commercial. In the commercial sector there are significant interactive effects between energy end-uses and energy efficiency measures that are not modeled in CIMS. For example, the energy demanded by a commercial building's cooling system is affected by the efficiency of the lighting system, the use of office equipment and the building shell. More efficient lighting and office equipment produce less waste heat and thereby lower the load on the cooling system, and more efficient building shells reduce the infiltration of outside weather conditions. Detailed engineering models exist that calculate these interactions for specific building types, but this type of analysis is beyond the scope of the commercial sub-model in CIMS. Electricity savings in the commercial sector are likely to be underestimated for this reason.

CIMS also does not simulate the efficiency gains that could be achieved in new buildings from use of integrated building design and designation process such as Leadership in Energy and Environmental Design (LEED). Savings in heating, cooling and lighting in new commercial buildings are therefore underestimated.

No technology use actions. This study focused on the acquisition (and retrofitting) of technologies over time, and did not examine technology use actions that influence how current technologies can be operated or maintained to maximize energy efficiency, or behavioural actions to conserve electricity.

Declining capital costs for new technologies. Over a 15 year time horizon, new energy-efficient technologies are likely to have significantly lower capital cost with economies of scale in manufacture and movement up the design learning curve for producers. This could represent a decrease in costs for targeted technologies in future time periods that would enhance the uptake of energy-efficient technologies. CIMS has a function to simulate this relationship, but the projected declining cost curves were not available for most targeted technologies in the sectors covered in this analysis. Including these more extensively would lower the financial costs reported in all policy scenarios, and energy demand in the capital cost reduction scenarios where market penetration was lower.

Social (or welfare) costs of policies have not been assessed. The financial costs reported for this project do not represent the social costs of pursuing these policies. The factors contributing to these social costs are:

> *The financial costs in CIMS do not represent the actual financial costs paid by consumers*
>
> The financial costs reported here do not include estimates of failure risk, and are based on single point estimates of the financial cost differences of technologies. Realized financial costs could be higher because they would include costs associated with the following. First, the risk of premature failure can be higher for new and emerging technologies, which would result in replacement costs sooner than expected.[17] However, most of the technologies targeted in this work are well established alternatives (Energy Star appliances for example), for which the risk is minimal. Second, energy efficient technologies commonly have long payback periods due to higher capital costs, and consumers who choose them loose the option of pursuing a different options in the future.[18] Third, the acquisition, installation, and operating costs faced by consumers will vary across Ontario.[19] This market heterogeneity is captured by a parameter in CIMS, but if consumers faced with higher costs are forced (as opposed to encouraged) to purchase a specific technology, their realized financial costs will be higher than if they had not been forced to make a decision. The potential for this happening is minimal because consumers have been allowed to choose between technologies freely in this work.

---

[17] J. Scheraga, "Energy and the Environment: Something New under the Sun?" *Energy Policy* 22, 10 (1994): 811-818.

[18] R. Pindyck, "Irreversibility, Uncertainty and Investment," *Journal of Economic Literature* 29, 3 (1991): 1110-1152.

[19] See A. Jaffe and R. Stavins, "The Energy-Efficiency Gap: What Does it Mean?" *Energy Policy* 22, 10 (1994): 804-810.

Only a partial equilibrium response to policies is provided

Because the CIMS simulation did not incorporate energy supply and demand price feedbacks or macro-economic feedbacks (steps 4 and 5 of the CIMS simulation) only a partial equilibrium portrayal of the response to the policies is provided in the results. Aggregate, macro-economic effects include trade and structural repercussions resulting from changes in energy prices, and in turn the prices of other intermediate and final products.

Where energy efficient technologies achieve substantial market penetration, and there is a lower cost of energy services, a *rebound effect* in consumer demand can occur where consumers reinvest their savings in alternative forms of consumption, which could also entail energy use. The magnitude and nature of this effect is contentious.[20] This effect is not included in these results.

All administrative and program costs are not provided

Estimated government costs for increased personnel, facilities, subsidies and other expenditures (advertising, information brochures, labelling, etc.) to develop and implement the specific programs and policies needed to achieve the modeled savings are not included.

No estimates of changes to consumers' surplus are made

Where there is an indication that particular technologies confer extra value to consumers above their financial costs, compared to their competitors, changing away from those technologies will confer a loss of consumers' surplus. No cost estimate is provided. The magnitude of these costs would be greatest when the new technologies are substantially different from those being replaced. For example, although buses and cars both move people from point A to B, they do so in a substantially different manner. When the existing and replacement technologies are very similar, energy efficient versus standard refrigerators for example, the change in consumers' surplus is negligible.

Externality costs are not included

Externality costs, such as pollution damages, should be included in social cost estimates unless options are being compared in terms of their relative cost-effectiveness in achieving a particular externality reduction target.

Uncertainty about baseline market shares of technologies. The availability and quality of data to inform the current and forecasted market share of technologies vary by sub-sector. The parameters in CIMS reflect best available information; more uncertainty exists in the industrial sectors.

---

[20] Schipper, ed., "On the Rebound: The Interaction of Energy Efficiency, Energy Use and Economic Activity," *Energy Policy* 28, 6-7(2000): 351-354.

Uncertainty about technology preferences. While there is some good market information in some cases, we still face considerable uncertainty in our knowledge of the technology-specific, non-cost preferences of firms and households when deciding upon which technology to acquire to satisfy an energy service.

Appendix A - Targeted Technologies

Technologies targeted by the discount rate and capital cost reductions are described in the tables below. Appendix B provides a picture of how these technologies are competed in the CIMS model. The targetted technologies were selected to represent the top-rated technology option for reducing electricity consumption, without increasing use of either coal or oil.[21] In some end-uses, technologies that specifically promote fuel switching (with no energy efficiency gains) were targeted

Table A-1 Targeted Industrial Technologies

Energy End Use	Technology
Auxiliary Services (all Industry)	Direct Drive with Motor Speed Controller, Variable Speed Drive and Direct Coupling
	High Efficiency Airfoil Fan
	High Efficiency Belt Conveyor
	High Efficiency Centrifugal Compressor
	High Efficiency Centrifugal Pump System with Variable Speed Drive
	High Efficiency Rotary Pump System with Variable Speed Drive
	High Efficiency Reciprocating Pump System with Variable Speed Drive
	Efficient Alternating Current Induction Motors
	Synchronous Alternating Current Induction Motors
	Natural Gas Steam Cogeneration Systems
Lighting (all Industry)	Fluorescent Lamps
	Low Pressure Sodium Lamps
Space Conditioning (all Industry)	Space Heating Natural Gas, Efficient
	Space Cooling Electric, Efficient
Chemicals Manufacturing	Production of Hydrogen Peroxide via Oxidization of Liquid Isopropyl Alcohol
	Production of Sodium Chlorate via Electrolysis using Metal Anode Cells
Industrial Minerals	Clinker Finish Grinding using Roller mills with High Efficiency Separation
	Cement Rotary Long Dry Kiln with Waste Heat Recovery and Cogeneration
	Dry Raw Clinker Grinding, Roller Mill
Iron & Steel	Hot Dip Steel Galvanizing using Natural Gas as a Fuel
	Ladle Reheating using Natural Gas as a Fuel
	Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls, Oxygen Lance and Preheated Scrap
	Direct Smelting (ELRED)
	Steel Finishing Mill with Computer Controls
	Steel Roughing Mill with Computer Controls

[21] The electricity use of each technology was evaluated in terms of both electricity used directly at that service node and electricity consumed indirectly (for instance, through auxiliary motor systems that an industrial process technology may employ).

Table A-1 continued.

Energy End Use	Technology
Metal Smelting and Refining	Carbonylation Refining (Nickel Production) Top Blown Rotary Converter (Nickel Smelting, Copper Smelting) Fluidized Bed Roasting (Nickel Smelting) Oxygen Reverbatory Furnace (Nickel Smelting) Refining Furnace with Oxygen Injection (Copper Refining) Flash Furnace For Roasting and Smelting using Natural gas and Petroleum Coke (Copper Smelting) Tank Agitation Leaching and Electrolytic Precipitation (Zinc Smelting) Flash Roaster to Oxidize Zinc Sulphate (Zinc Smelting) Fire Refining with Fractional Distillation (Magnesium Refining) Flash Furnace for Smelting Magnesium Oxide (Magnesium Smelting) Flash Roaster to Calcine Magnesium Oxide (Magnesium Smelting) New Air Compression and Distillation, Cryogenics
Mining	Diesel-Powered Tailing Disposal Fine Grinding of Metal Ores using Computer Control Diesel-Truck Transfer of Metal Ores Diesel-Powered Metal Ores Extraction
Petroleum Refining	Efficient Fluidized Catalytic Cracking Unit using New Catalysts Efficient Vacuum Unit (Mechanical Vacuum System) Hydrogen Production via Increased Efficiency Natural Gas Steam Reformation
Pulp & Paper	Recycled Pulping using Explosion De-inking Mechanical Pulping using Thermopulp® Biodegradable Debarker/Cutter Efficient Disc Refining and Screening Efficient Paper Forming Tomlinson Recovery Furnace Black Liquor Gasification, Computer Control & Cogeneration (Low Odour Configuration, High Solids Firing)

Table A-2 Targetted Commercial / Institutional Technologies

Energy End Use	Technology
Hot Water	High Efficiency Natural Gas Hot Water Tank Reduced Hot Water Use - Low Flow Devices
Building Shell	Windows with High Performance Glazing Roof Insulation Upgrade Wall Insulation Upgrade
Lighting	Energy Efficient Lighting (T12 Fluorescent Lamps, Compact Fluorescent Lamps, 2-Photon lamps) Lighting Redesign
HVAC	High Efficiency Air Condioning Equipment

(Heating Ventilation & Air Conditioning)	Improved HVAC System Control (via Building Automated System (BAS), Facility Management System (FMS), Energy Monitoring and Control System (EMCS)) Variable Air Volume (VAV) System Variable Speed Drive (VSD/VFD) Improved Boiler Controls Temperature Setback High Efficiency Natural Gas Boiler Ground Source Heat Pump (GSHP)
	Natural Gas Cogeneration
Other End-uses	Natural Gas Cooking Equipment High Efficiency Refrigeration Improved Plug Load Efficiency

Table A-3 Targetted Residential Technologies

Energy End Use	Technology
Appliances	Clothes Washer, Top-rated Energy Star Electric Dryer, Top-rated Energy Star Electric Cooking Range, Top-rated Energy Star Freezer, Top-rated Energy Star Dishwasher, top rated Energy Star Refrigerator, top rated Energy Star
Lighting	Compact Fluorescent Lamps
Air Conditioning	High Efficiency Air Conditioning
Hot Water Use	Reduced Hot Water Consumption – Low flow showerhead Reduced Hot Water Consumptions - Tap Aerator
Building Shells and Domestic Heating Systems	Enhanced R-2000 home – new single family home Retrofitted Shell - existing single family home Integrated Natural Gas Furnace and Domestic Hot Water Tank High Efficiency Natural Gas Furnace High Efficiency Electric Intermittent Fan Improved Apartment Shell Improved Other Building Shell
Water Heating	High Efficiency Natural Gas Water Heater High Efficiency Electric Water Heater Solar Water Heating
Other	Photovoltaic Panels

Appendix B – Technologies in CIMS

The groupings below indicate technologies that compete for a given energy service (a service node) in CIMS in which actions are targetted in this analysis. Service nodes that do not offer options that reduce electricity consumption, or which do not represent services in Ontario are not described.

The name of the technology option targetted by the discount rate and capital cost reductions (in Appendix A) may not appear exactly in the tables below. In CIMS the technology option may be competed in more than one energy service competition. For instance, because CIMS models a variety of motor sizes, alternating current induction motors are targetted at each motor size service node). Also, depending on sub-model (sector) structure, more than one technology can be grouped together as a 'package technology'. Targetted CIMS technologies are indicated in italic font in the tables below.

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC

Service/ Process	Technology Option
Direct Drive	Motor Speed Controller V-Belt
	Motor Speed Controller, Variable Speed Drive + Direct Coupling
Fans and Blowers	Low Efficiency Backward Inclined Fan
	High Efficiency Backward Inclined Fan
	Low Efficiency Radial Fan
	High Efficiency Radial Fan
	Low Efficiency Airfoil Fan
	High Efficiency Airfoil Fan
	Low Efficiency Vane Axial/Tube Axial Fan
	High Efficiency Vane Axial/Tube Axial Fan
	Medium Efficiency Airfoil Fan
	Medium Efficiency Vane Axial/Tube Axial Fan
Conveyors	Low Efficiency Belt Conveyor
	High Efficiency Belt Conveyor
	Low Efficiency Screw Conveyor
	High Efficiency Screw Conveyor
	Low Efficiency Apron Conveyor
	High Efficiency Apron Conveyor
	Low Efficiency Chain Conveyor
	High Efficiency Chain Conveyor
	Medium Efficiency Belt Conveyor
	Medium Efficiency Plus Belt Conveyor
	Medium Efficiency Screw Conveyor
	Medium Efficiency Plus Screw Conveyor

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC, continued

Service/ Process	Technology Option
Compression Size 1	Low Efficiency Centrifugal Compressor, Size 1-3 ***High Efficiency Centrifugal Compressor, Size 1-3*** Low Efficiency Double Acting Reciprocating Compressor, Size 1-3 High Efficiency Double Acting Reciprocating Compressor, Size 1-3 Low Efficiency Rotary Compressor, Size 1-3 High Efficiency Rotary Compressor, Size 1-3 Low Efficiency Single Acting Reciprocating Compressor, Size 1-3 High Efficiency Single Acting Reciprocating Compressor, Size 1-3 Medium Efficiency Centrifugal Compressor, Size 1-3 Medium Efficiency Double Acting Reciprocating Compressor, Size 1-3 Medium Efficiency Rotary Compressor, Size 1-3 Medium Efficiency Single Acting Reciprocating Compressor, Size 1-3
Compression Size 2	Low Efficiency Centrifugal Compressor, Size 4-6 ***High Efficiency Centrifugal Compressor, Size 4-6*** Low Efficiency Double Acting Reciprocating Compressor, Size 4-6 High Efficiency Double Acting Reciprocating Compressor, Size 4-6 Low Efficiency Rotary Compressor, Size 4-6 High Efficiency Rotary Compressor, Size 4-6 Low Efficiency Single Acting Reciprocating Compressor, Size 4-6 High Efficiency Single Acting Reciprocating Compressor, Size 4-6 Medium Efficiency Centrifugal Compressor, Size 4-6 Medium Efficiency Double Acting Reciprocating Compressor, Size 4-6 Medium Efficiency Rotary Compressor, Size 4-6 Medium Efficiency Single Acting Reciprocating Compressor, Size 4-6
General Pumping Size 1	Inefficient Centrifugal Pump System, Size 1-3 Inefficient Centrifugal Pump w/ VSD, Size 1-3 ***High Efficiency Centrifugal Pump System w/ Variable Speed Drive, Size 1-3*** Medium Efficiency Centrifugal Pump System, Size 1-3
General Pumping Size 2	Inefficient Centrifugal Pump System, Size 4-6 Inefficient Centrifugal Pump w/ VSD, Size 4-6 ***High Efficiency Centrifugal Pump System w/ Variable Speed Drive, Size 4-6*** Medium Efficiency Centrifugal Pump System, Size 4-6
Slurry / Stock Pumping Size 1	Low Efficiency Rotary Pump System, Size 1-3 ***High Efficiency Rotary Pump w/ Variable Speed Drive, Size 1-3*** Medium Efficiency Rotary Pump System, Size 1-3 Sub- High Efficiency Rotary Pump, Size 1-3
Slurry / Stock Pumping Size 2	Low Efficiency Rotary Pump System, Size 4-6 ***High Efficiency Rotary Pump w/ Variable Speed Drive, Size 4-6*** Medium Efficiency Rotary Pump System, Size 4-6 Sub- High Efficiency Rotary Pump, Size 4-6

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC, ,continued

Service/ Process	Technology Option
Precision Pumping Size 1	Inefficient Reciprocating Pump System, Size 1-3
	High Efficiency Reciprocating Pump System w/ Variable Speed Drive, Size 1-3
	Medium Efficiency Reciprocating Pump System, Size 1-3
	Sub- High Efficiency Reciprocating Pump System, Size 1-3
Precision Pumping Size 2	Inefficient Reciprocating Pump System, Size 4-6
	High Efficiency Reciprocating Pump System w/ Variable Speed Drive, Size 4-6
	Medium Efficiency Reciprocating Pump System, Size 4-6
	Sub- High Efficiency Reciprocating Pump System, Size 4-6
Shaft Drive Size 1	Standard Alternating Current (AC) Induction Motor 1-5 Hp, Meets 1997 Minimum Standard
	Efficiency Efficient AC Induction Motor 1-5 Hp
Shaft Drive Size 2	Standard AC Induction Motor 6-25 Hp, Meets 1997 Minimum Standard
	Efficient Motor 6-25 Hp
Shaft Drive Size 3	Standard AC Induction Motor 26-100 Hp, Meets 1997 Minimum Standard
	Efficient AC Induction Motor 26-100 Hp
Shaft Drive Size 4	Standard AC Induction Motor 101-200 Hp, Meets 1997 Minimum Standard
	Efficient AC Induction Motor 101-200 Hp
Shaft Drive Size 5	Standard AC Induction Motor 201-500 Hp
	Efficient AC Induction Motor 201-500 Hp
	Synchronous AC Induction Motor 201-500 Hp
	Direct Current Motor Generator Electric Motor 201-500 Hp
	Direct Current Solid State Electric Motor 201-500 Hp
	Steam Driven Motor 201-500 Hp
Shaft Drive Size 6	Standard AC Induction Motor >500 Hp
	Efficient AC Induction Motor >500 Hp
	Synchronous AC Induction Motor >500 Hp
	Direct Current Motor Generator Electric Motor >500 Hp
	Direct Current Solid State Electric Motor >500 Hp
	Standard Steam Drive Motor >500 Hp
Lighting	Incandescent Lamps
	Fluorescent Lamps
	Mercury Vapour Lamps
	Low Pressure Sodium Lamps
	High Pressure Sodium Lamps
	Metal Halide Lamps
Space Heating	Space Heating Electric, Efficient
	Space Heating Heavy Fuel Oil
	Space Heating Steam, Efficient
	Space Heating Oil, Efficient
	Oil Storage Heating Fired by Natural Gas

Table B-1 Cross-cutting Industrial Technologies in CIMS: Motor Systems, Lighting, HVAC ,continued

Service/ Process	Technology Option
Space Heating	***Space Heating Natural Gas, Efficient***
	Oil Storage Heating Supplied by Steam
	Space Heating Natural Gas
	Space Heating Electric
	Space Heating Steam
	Space Heating Oil
	Space Heating Heavy Fuel Oil
Space Cooling	Space Cooling Electric
	Space Cooling Electric, Efficient

Note: These technologies are modelled uniquely for all industrial sector models in CIMS. The exact representation of technologies relate to the specifications of each industry.

Table B-2 Cross-cutting Industrial Technologies in CIMS: Steam Provision

Service/ Process	Technology Option
Steam	Boiler @ 600 psig using iron process gas
Boilers	Boiler coal @ 600 psig with heat recovery and regenerative burners
	Boiler coal @ 600 psig, mid-size
	Boiler low sulfur residual @ 600 psig with heat recovery
	Boiler low sulfur residual @ 600 psig with heat recovery and regenerative burners
	Boiler low sulfur residual @ 600 psig with regenerative burners
	Boiler low sulfur residual @ 600 psig, mid-size
	Boiler natural gas @ 600 psig
	Boiler natural gas @ 600 psig with heat recovery
	Boiler natural gas @ 600 psig with heat recovery and regenerative burners
	Boiler natural gas @ 600 psig with regenerative burners
	Coke-fired boiler, high efficiency, mid-size, petroleum refining technology
	Heavy fuel oil-fired boiler, high efficiency, mid-size, petroleum refining technology
	Heavy fuel oil-fired boiler, mid-size, petroleum refining technology
	Light fuel oil-fired boiler, high efficiency, mid-sized, petroleum refining technology
	Light fuel oil-fired boiler, mid-sized, petroleum refining technology
	Liquefied petroleum gas-fired boiler, high efficiency, mid-sized, petroleum refining technology
	Liquefied petroleum gas-fired boiler, mid-size, petroleum refining technology
	Natural gas-fired boiler, mid-sized, petroleum refining technology
	Natural gas-fired high efficiency boiler, mid-sized, petroleum refining technology
	Standard coke-fired boiler, mid-sized, petroleum refining technology
	Still gas-fired boiler
	Still gas-fired high efficient boiler

Table B-2 Cross-cutting Industrial: Steam Provision in CIMS, continued

Service/ Process	
Steam Cogeneration	***Cogenerator @ 900 psig using iron process gas*** ***Cogenerator coal steam turbine @ 900 psig with regenerative burners*** ***Cogenerator coal steam turbine @ 900 psig, mid-size*** ***Cogenerator coal steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Cogenerator high sulfur residual steam turbine @ 900 psig*** ***Cogenerator hog fuel steam turbine @ 900 psig, mid-size*** ***Cogenerator hog fuel steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Cogenerator low sulfur residual steam turbine @ 900 psig with regenerative burners*** ***Cogenerator low sulfur residual steam turbine @ 900 psig, mid-size*** ***Cogenerator low sulfur residual steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Cogenerator natural gas steam turbine @ 900 psig with regenerative burners*** ***Cogenerator natural gas steam turbine @ 900 psig, mid-size*** ***Cogenerator natural gas steam turbine @ 900 psig, with regenerative burners, mid-size*** ***Coke-fired cogeneration, high efficiency, mid-sized, petroleum refining technology*** ***Heavy fuel oil-fired cogeneration, mid-sized, petroleum refining technology*** ***Light fuel oil-fired cogeneration, mid-sized, petroleum refining technology*** ***Liquid petroleum gas-fired cogeneration, mid-sized, petroleum refining technology*** ***Natural gas-fired cogeneration, mid-sized, petroleum refining technology*** ***New cogenerator natural gas steam turbine @ 600 psig, large*** ***New cogenerator natural gas steam turbine @ 600 psig, small*** ***Standard coke-fired cogeneration, mid-sized, petroleum refining technology*** ***Still gas top cycle turbine cogeneration***

Note: These technologies are modelled uniquely for all applicable industrial sector models in CIMS. The exact representation of technologies relate to the specifications of each industry. For instance, hog fuel boilers are only available in the pulp and paper sector.

Table B-3 Chemical Products – Process Technologies in CIMS

Service/ Process	Description
Hydrogen Peroxide Electrolysis	Hydrogen Peroxide Process – Anthraquinone ***Production of Hydrogen Peroxide via Oxidization of Liquid Isopropyl Alcohol***
Sodium Chlorate Electrolysis	Production of Hydrogen Peroxide via Electrolysis using Graphite Electrode Cell ***Production of Hydrogen Peroxide via Electrolysis using Metal Anode Cell*** Sodium Chlorate Production with Bipolar Membrane, Caustic By-product

Table B-4 Commercial / Institutional Technologies in CIMS

Service/ Process	Description
Plug Load	Standard Plug Load Efficiency ***Improved Plug Load Efficiency***
Hot Water	Average Efficiency Electric Hot Water Systems Average Efficiency Electric Hot Water Tank with Service Load Reduction Improved Efficiency Electric Hot Water Tank Improved Efficiency Electric Hot Water Tank with Service Load Reduction ***Average Efficiency Electric Hot Water Tank with Solar Heating*** Average Efficiency Natural Gas Hot Water Systems Average Efficiency Natural Gas Hot Water Tank with Service Load Reduction Improved Efficiency Natural Gas Hot Water Tank ***Improved Efficiency Natural Gas Hot Water Tank with Service Load Reduction*** ***Average Efficiency Natural Gas Hot Water Tank with Solar Heating*** Average Efficiency Oil Hot Water Systems
Cooking	Electric Cooking Equipment *Natural Gas Cooking Equipment* Propane Cooking Equipment
Refrigeration	Refrigeration in New Buildings ***High Efficiency Refrigeration***
Building Shell These options are modelled uniquely for specific building segments. Shell efficiency actions are targetted only in building segments in which the action does not result in an increase electricity consumption due to a greater cooling load (Hotel/Motels, Hospitals/Nursing homes, Warehouses, and Miscellaneous)	Existing Shell Existing Shell, Wall Retrofit New Shell New Shell, Roof Upgrade New Shell, Wall Insulation Upgrade New Shell, Windows Upgrade New Shell, Use of Temperature Setback[22] New Shell, Roof and Wall Upgrade New Shell, Windows and Wall Upgrade New Shell, Roof and Windows Upgrade New Shell, Roof, Windows and Wall Upgrade ***New Shell, Roof, Windows and Wall Upgrade; Temperature Setback***

[22] Temperature setback is included here because like the shell options it reduces the heat load.

Table B-4 Commercial / Institutional Technologies in CIMS, continued

Service/ Process	Description
HVAC Systems HVAC efficiency and cogeneration options are modelled as packages for specific building segments: Large retail Small retail Large office Small office Schools/ Universities Hotel/Motels Hospitals/Nursing homes. Not all options are available for each segment. A simplified set of technologies are modelled for Warehouses and Miscellaneous building segments.	Existing HVAC Systems - Electric Heating New HVAC Systems - Electric Heating New HVAC - Electric Heating with More Efficient A/C New HVAC - Electric Heating, Improved HVAC/Ventilation Control (using BAS/FMS/EMCS and VSD/VFD) New HVAC – GSHP New HVAC - GSHP, Improved A/C Efficiency New HVAC - GSHP, and BAS/FMS/EMCS and VSD/VFD ***New HVAC - GSHP, Improved A/C, Improved HVAC System Control (BAS/FMS/EMCS) and VSD/VFD*** New HVAC - Electric Heating, Improved A/C, and BAS/FMS/EMCS
	Existing HVAC Systems - Natural Gas Heating New HVAC Systems - Natural Gas Heating New HVAC - Natural Gas Heating with More Efficient A/C New HVAC - Improved Natural Gas Heating Efficiency (90%) New HVAC - Natural Gas Heating, Improved HVAC/Ventilation Control (using BAS/FMS/EMCS, VSD/VFD and VAV) ***New HVAC - Natural Gas Cogeneration*** New HVAC - Natural Gas Heating, Solar Heating New HVAC - Improved Natural Gas Heating Efficiency (90%), Boiler Controls, Improved A/C Efficiency ***New HVAC - Improved Natural Gas Heating Efficiency (90%), Boiler Controls, BAS/FMS/EMCS, VAV and VSD/VFD*** New HVAC - Improved Natural Gas Heating Efficiency (90%), Boiler Controls, Improved A/C, BAS/FMS/EMCS, VSD/VFD, VAV *New HVAC - Natural Gas Cogeneration, Improved A/C Efficiency* ***New HVAC - Natural Gas Cogeneration, BAS/FMS/EMCS, VSD/VFD VAV*** ***New HVAC - Natural Gas Cogeneration, Improved A/C, BAS/FMS/EMCS, VSD/VFD, VAV*** New HVAC - Natural Gas Heating, Improved A/C, BAS/FMS/EMCS, VSD/VFD and VAV Existing HVAC Systems - Propane Heating New HVAC Systems - Propane Heating Existing HVAC Systems - Oil Heating New HVAC Systems - Oil Heating
High Bay Lighting	New Service / Hallide Lamps ***Upgrade to 2-Photon Lamps***
Service Lighting	New Building Service Area Lighting (T12 fluorescent lamps, Incandescent Lamps) ***New Building Service Area Lighting: T8 Lamps and Compact Fluorescent Lamps***

Table B-4 Commercial / Institutional Technologies in CIMS, continued

Service/ Process	Description
General Area Lighting	Existing Building General Area Lighting New Building General Area Lighting (T12 fluorescent lamps, Incandescent Lamps) New Building General Area Lighting (T12 fluorescent lamps, Incandescent Lamps), Lighting Redesign to Lower lux ***New Building General Area Lighting, T8 Lamps, Compact Fluorescent Lamps***

Notes:

GSHP: Ground Source Heat Pump
VAV: Variable Air Volume
BAS: Building Automated System
FMS: Facility Management System
EMCS: Energy Monitoring and Control System
VSD/VFD: Variable Speed Drive

Table B-5 Industrial Minerals -- Process Technologies

Service/ Process	Description
Finish Grinding	Clinker Finish Grinding using Ball mills Clinker Finish Grinding using Ball mills with High Efficiency Separation Clinker Finish Grinding using Roller mills ***Clinker Finish Grinding using Roller mills with High Efficiency Separation***
Dry Process Kilns (Cement)	Cement Rotary Kiln, Long Dry Standard Process Cement Rotary Kiln, Long Dry Standard Process with High Efficient Cooler Cement Rotary Kiln, Long Dry Preheating Process Cement Rotary Kiln, Long Dry Preheating with Efficient Cooler Cement Rotary Kiln, Long Dry Preheating and Precalcine Cement Rotary Kiln, Long Dry Preheating and Precalcine with Efficient Cooler ***Cement Rotary Kiln, Long Dry Standard Process with Waste Heat Recovery Cogeneration*** Cement Rotary Kiln Long Dry Process with Preheating and Precalcining and Computer Control Cement Rotary Kiln New Dry Preheating Process with High Efficient Cooler Cement Rotary Kiln New Dry Preheating and Precalcine Process with Efficient Cooler)
Dry Raw Grinding	Dry Raw Clinker Grinding Ball Mill ***Dry Raw Clinker Grinding, Roller Mill***

Table B-6 Iron & Steel -- Process Technologies

Service/ Process	Description
Galvanizing	Electro Galvanizing using Natural Gas as Fuel Electro Galvanizing using Oil as Fuel ***Hot Dip Galvanizing using natural gas as fuel*** Hot Dip Galvanizing using oil as fuel
Ladle Preheat	***Ladle Reheating using Natural Gas as Fuel*** Electric Ladle Reheating
Electric Arc Steel	Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls and Preheated Scrap Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls, Oxygen Lance ***Ultra High Power Electric Arc Furnace, Gas with Water-cooled Walls, Oxygen Lance and Preheated Scrap***
BOF Steel	Blast/Coke Furnace; Basic Oxygen Furnace (Gas) Blast/Coke Furnace; Basic Oxygen Furnace (Oil) Blast Furnace with Plasma Torch; Basic Oxygen Furnace (Gas) Blast Furnace with Plasma Torch; Basic Oxygen Furnace (Oil) ***Direct Smelting (ELRED); Blast Oxygen Furnace (Gas)*** Direct Smelting; Blast Oxygen Furnace (Oil) HIsmelt Process - Direct Reduced Iron; Blast Oxygen Furnace (Gas) HIsmelt Process - Direct Reduced Iron; Blast Oxygen Furnace (Oil) Corex Process - Direct Smelted Iron; Basic Oxygen Furnace (Gas) Corex Process - Direct Smelted Iron; Basic Oxygen Furnace (Oil) Blast/Coke Furnace; Basic Oxygen Furnace (Gas) Gas recovery Blast/Coke Furnace; Basic Oxygen Furnace (Oil) Gas recovery Blast Furnace with Plasma Torch; Basic Oxygen Furnace (Oil) Gas Recovery Blast Furnace with Plasma Torch; Basic Oxygen Furnace (gas) Gas Recovery
Finishing Mills	Steel Finishing Mill without Computer Controls ***Steel Finishing Mill with Computer Controls***
Roughing Mills	Steel Roughing Mill without Computer Controls ***Steel Roughing Mill without Computer Controls***

Table B-7 Non-ferrous Metal Smelting and Refining -- Process Technologies

Service/ Process	Description
Nickel Refining	***Nickel Carbonylation Refining***
	Nickel Roasting and Retort Refining
	Nickel Electrolytic High Voltage Cell with Matte Anodes
	Nickel Electrolytic Low Voltage Cell with Metal Anodes
Nickel Conversion	***Nickel Top Blown Rotary Converter***
	Nickel Pierce Smith Converter
Nickel Roasting & Smelting	Nickel Flash Furnace Roasting and Smelting - Natural Gas

Table B-7 Non-ferrous Metal Smelting and Refining -- Process Technologies, continued.

Service/ Process	Description
	Nickel Flash Furnace Roasting and Smelting – Oil
	Nickel Flash Furnace Roasting and Smelting - Natural Gas
	Nickel Hearth Roasting and Oxygen Reverbatory Smelting Furnace
	Nickel Fluidized Bed Roasting and Reverbatory Furnace Smelting
	Nickel Fluidized Bed Roasting and Oxygen Reverbatory Furnace Smelting
	Nickel Sinter Roasting and Reverbatory Furnace Smelting
	Nickel Sinter Roasting and Electric Arc Furnace Smelting
	Nickel Fluidized Bed Roasting and Electric Arc Furnace Smelting
	Nickel Hearth Roasting and Electric Arc Furnace Smelting
Copper Refining	Copper Electrolytic Refining Cell with Anode Furnace
	Copper Refining Furnace with Oxygen
Copper Conversion	***Copper Top Blown Rotary Converter***
	Copper Pierce Smith Converter
Copper Smelting	Copper Flash Furnace For Roasting and Smelting - Coal
	Copper Flash Furnace For Roasting and Smelting - Oil
	Copper Hearth Roasting and Electric Arc Furnace Smelting
	Copper Fluidized-Bed Roasting and Electric Arc Furnace Smelting
	Copper Flash Furnace For Roasting and Smelting - Natural Gas, Petroleum Coke
Zinc Hydro Metallurgy	***Zinc Tank Agitation Leaching and Electrolytic Precipitation***
	Zinc Pressure Leaching with Electrolytic Precipitation
	Zinc Pressure Leaching with Electrolytic Precipitation
Zinc Roasting	Fluidized Bed Roaster To Oxidize Zinc Sulphate
	Flash Roaster To Oxidize Zinc Sulphate
Magnesium Refining	***Magnesium Fire Refining with Fractional Distillation***
	Magnesium Electrolytic Refining with New Electrolysis Cell
	Magnesium Electrolytic Refining with Old Electrolysis Cell
Magnesium Smelting	Electro thermal Furnace For Magnesium Oxide

	Vertical Retort Smelter For Magnesium Oxide Blast Furnace Smelter For Magnesium Oxide ***Flash Furnace For Smelting Magnesium Oxide***
Magnesium Roasting	Hearth Roaster To Calcine Magnesium Oxide Fluidized Bed Roaster To Calcine Magnesium Oxide ***Flash Roaster To Calcine Magnesium Oxide***
Cryogenics	Air Compression and Distillation, Cryogenics ***New Air Compression and Distillation, Cryogenics***

Many of the targeted technologies in this sub-sector were selected for fuel switching and do not necessarily represent 'state-of the-art' technologies.

Table B-8 Mining -- Process Technologies

Service/ Process	Description
Underground Mining Tailing Disposal	***Underground Metal Tailings Disposal, Diesel Powered*** Underground Metal Tailings Disposal, Electric Powered
Underground Mining Primary Milling	Fine Grinding of Underground Metal Ores ***Fine Grinding of Underground Metal Ores with Computer Control***
Underground Mining Transportation	Conveyance Transfer of Underground Metal Ores, Electric Conveyors ***Diesel Truck Transfer of Underground Metal Ores***
Underground Mining Extraction	Extraction of Underground Metal Ores, Electric Powered ***Extraction of Underground Metal Ores, Diesel Powered*** Extraction of Underground Metal Ores, Liquefied Petroleum Gas and Diesel Powered Extraction of Underground Metal Ores, Liquefied Petroleum Gas and Electric Powered
Open Pit Mining Tailing Disposal	***Open Pit Metal Tailings Disposal, Diesel Powered*** Open Pit Metal Tailings Disposal, Electric Powered
Open Pit Mining Secondary Crushing	Fine Grinding of Open Pit Metal Ores ***Fine Grinding of Open Pit Metal Ores with Computer Control***
Open Pit Mining Transportation	Conveyance Transfer of Open Pit Metal Ores ***Diesel Truck Transfer of Open Pit Metal Ores***
Open Pit Mining Extraction	Extraction of Open Pit Metal Ores, Diesel ***Extraction of Open Pit Metal Ores, Electric***

Many of the targeted technologies in this sub-sector were selected for fuel switching and do not necessarily represent 'state-of the-art' technologies.

Table B-9 Petroleum Refining -- Process Technologies

Service/ Process	**Description**
Catalytic Cracking	Standard Fluidized Catalytic Cracking Unit Fluidized Catalytic Cracking with Turbine Power Recovery Train ***Efficient Fluidized Catalytic Cracking Unit using new Catalysts***
Vacuum Distillation	Standard Vacuum Distillation Units - Mechanical Vacuum Pumps ***Efficient Vacuum Unit (Mechanical Vacuum System)*** Low API Feedstock; Efficient Unit
Hydrogen Production	Hydrogen Via Natural Gas Steam Reformation ***Hydrogen via increase efficiency Natural Gas Steam Reformation***

Table B-10 Pulp & Paper -- Process Technologies

Service/ Process	Description
Pulping (Recycled)	Recycled Pulp with Washing Deinking Recycled Pulp with Flotation Deinking ***Recycled Pulp with Explosion Deinking***
Pulping (Mechanical)	Refiner Mechanical Pulper Size two Thermomechanical pulp (TMP) refiner Size two Thermomechanical pulp (TMP) refiner with high speed refiner Size two Thermomechanical pulp (TMP) refiner with large electric vapour recompression Size two Thermomechanical pulp (TMP) refiner with electric vapour recompression and high speed refiner ***Thermopulp*** Chemi-mechanical , Chemi-thermo-mechanical and bleached Chemi-thermo-mechanical pulp
Debark	Ring Style Mechanical Debarker/Cutter Rosser-Head Mechanical Debarker/Cutter ***Biodegradable Debarker/Cutter***
Tissue Stock Prep	Tissue paper conical refining and screening ***Efficient tissue paper disc refining and screening***
Tissue Forming, Pressing & Finishing	Tissue form, press, finish ***Tissue efficient form, press, finish***
Coated Paper Stock Prep	Coated Paper woodfree conical refining and screening ***Efficient coated Paper woodfree disc refining and screening***
Coated Paper Forming, Pressing & Finishing	Woodfree form, press, finish Woodfree form, extended nip press, finish ***Woodfree efficient form, press, finish*** Woodfree efficient form, extended nip press, finish

Uncoated Paper Stock Prep	Uncoated Paper woodfree conical refining and screening ***Efficient uncoated Paper woodfree disc refining and screening***
Uncoated Paper Forming, Pressing & Finishing	Woodfree form, press, finish Woodfree form, extended nip press, finish ***Woodfree efficient form, press, finish*** Woodfree efficient form, extended nip press, finish
Linerboard Stock Prep	Linerboard conical refining and screening ***Efficient linerboard disc refining and screening***

Table B-10 Pulp & Paper -- Process Technologies, continued

Service/ Process	Description
Linerboard Forming, Pressing & Finishing	Linerboard Form, Press, Finish Linerboard Form, Extended Nip Press, Finish ***Linerboard Efficient Form, Press, Finish*** Linerboard Efficient Form, Extended Nip Press, Finish
Newsprint Prep, Form, Press & Finish	Newspaper refine/screen, form, press & finish Newspaper refine/screen, form, press & induction heat finish Newspaper refine/screen, form, extended nip press & finish Newspaper refine/screen form, extended nip press & induction heat finish ***Newspaper refine/screen, efficient form, press & finish*** Newspaper refine/screen, efficient form, press & induction heat finish Newspaper refine/screen, efficient form, extended nip press & finish Newspaper refine/screen, efficient form, extended nip press & induction heat finish
Recovery Furnace	Tomlinson recovery furnace with direct contact evaporator Tomlinson recovery furnace in a low odour configuration Tomlinson recovery furnace with low odour configuration and computer control Tomlinson recovery furnace with low odour configuration, high solids firing and computer control Tomlinson recovery furnace with computer control & cogeneration, 600 psig with low odour configuration and high solids firing Tomlinson recovery furnace with computer control & cogeneration, 750 psig with low odour configuration and high solids firing Tomlinson recovery furnace with computer control & cogeneration, 900 psig with low odour configuration and high solids firing Tomlinson recovery furnace with computer control & cogeneration, 1200 psig with low odour configuration and high solids firing ***Tomlinson recovery furnace black liquor gasification, computer control & cogeneration,1200 PSIG (low odour configuration, high solids firing)*** Tomlinson recovery furnace with direct contact evaporator, Retrofit to Optimized Operation, 5% Greater Steam Production

In Mechanical Pulping, Stone Groundwood Pulping and Explosion Pulping are not included. The first technology is because the technology is outdated, the second because it is not yet seen to be viable.

Table B-11, Residential Technologies

Service/ Process	Description
Other Appliances	Minor Appliances ***Minor Appliances, Photovoltaic Panels***
Clothes Washers	Clothes Washer, Standard Model Clothes Washer, More Efficient ***Clothes Washer, Top-rated Energy Star***
Clothes Dryers	Electric Dryer, Standard Model Electric Dryer, More Efficient ***Electric Dryer, Top-rated Energy Star***
Ranges	Cooking Range, Gas Cooking Range, Electric, Standard Model Cooking Range, Electric, More Efficient ***Cooking Range, Electric, Top-rated Energy Star***
Freezers	Freezer, Standard Model Freezer, More Efficient ***Freezer, Top-rated Energy Star***
Lighting	Incandescent Lamps Krypton Lamps ***Compact Fluorescent Lamps***
Other Non-Appliance Hot Water	Non-Appliance Hot Water ***Non-Appliance, Reduced Hot Water Consumption, Low Flow Showerhead***
Non Machine Dishwasher	Non-Machine Dishwasher, Hot Water Use ***Non-Machine Dishwasher, Reduced Hot Water Use - Tap Aerator***
Dishwasher	Dishwasher Standard Model Dishwasher, More Efficient ***Dishwasher, Top-rated Energy Star***
Refrigeration	Refrigerator, Standard Model Refrigerator More Efficient ***Refrigerator Top-rated Energy Star*** Refrigerator Most Efficient, Custom Made
New Single Family Homes, Shell Options The shell options noted	***Enhanced R-2000*** Enhanced MNECH Standard Shell

are modelled in conjunction with the various heating technology options below	

Table B-11, Residential Technologies, continued

Service/ Process	**Description**
Existing Single Family Homes, Shell Options This is modelled for two vintages of homes. They are also modelled in conjunction with the various heating technology options below	Existing Shell (non-retrofit) ***Retrofitted Shell***
Single Family Homes, Heating Options	***Electric Heat Pump, 145% efficiency*** Electric Baseboard, 100% efficiency ***Integrated Natural Gas Furnace and Domestic Hot Water*** Natural Gas Furnace, 78% efficiency ***Natural Gas Furnace, 92% efficiency*** Oil Furnace, 68% efficiency
Furnace Air	Electric Intermittent Fan - System Efficiency of 14% ***Electric Intermittent Fan - System Efficiency of 34%***
Space Heating – Apartments	Space Heat Apartment Electric Baseboards 100% Efficiency Space Heat Apartment Natural Gas 65% Efficiency Space Heat Apartment Natural Gas 78% Efficiency Space Heat Apartment Oil 68% Efficiency Space Heat Apartment Better Shell Electric Baseboards 100% Efficiency Space Heat Apartment Better Shell Integrated Furnace and DHW Natural Gas Space Heat Apartment Better Shell, Natural Gas Heating, 78% Efficiency ***Space Heat Apartment Better Shell, Natural Gas Heating, 92% Efficiency*** Space Heat Apartment Better Shell Oil 68% Efficiency
Space Heating -- Other Buildings	Space Heat Other Natural Gas 78% Efficiency Space Heat Other Oil 68% Efficiency Space Heat Other Better Shell Electric Baseboards 100% Efficiency Space Heat Other Better Shell Integrated Furnace and DHW Natural Gas Space Heat Other Better Shell Natural Gas 78% Efficiency ***Space Heat Other Better Shell Natural Gas 92% Efficiency*** Space Heat Other Better Shell Oil 68% Efficiency Space Heat Other Baseboards 100% Efficiency

	Space Heat Other Natural Gas 68% Efficiency
Hot Water Heating This is modelled for apartments and non-apartments separately	Water Heater Oil Natural Gas Baseline Water Heating Natural Gas EF=0.72 Water Heater Electric Generation 0 EF=0.78 ***High Efficiency Natural Gas Water Heater, EF=0.85*** Solar Water Heating

Appendix 2
Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs

Appendix 2: Ontario's Nuclear Generating Facilities: A History and Estimate of Unit Lifetimes and Refurbishment Costs

Contents

Tables

Figures

Figure 1
Ontario Nuclear Capacity
(Actual 1971-2003, Projected 2004-2019

Figure 2
Lifetime Performance Vs. Age for Ontario Nuclear Power Plants

Figure 3
Average Cumulative Availability Vs. Reactor Age for Ontario Nuclear Program

Figure 4
Annual Energy from Ontario Nuclear Program
(Actual 1971-2001, Projected 2002-2020)

1. Background

CANDU is a registered trademark of Atomic Energy of Canada Limited (AECL) which stands for **CAN**adian **D**euterium **U**ranium reactor. Its generic name is Pressurized Heavy Water Reactor (PHWR), and it uses heavy water (deuterium oxide) as both moderator and coolant. CANDU reactors need about one metric tonne of heavy water for every megawatt of capacity. Heavy water is very expensive to manufacture, making CANDU reactors more expensive than other reactor designs.

The CANDU core is a cylindrical reactor vessel called a calandria, which encloses hundreds of horizontal fuel channels. Each fuel channel consists of a pressure tube inside a calandria tube. Heavy water coolant under pressure runs through the pressure tubes containing the fuel bundles to remove the heat. The heavy water moderator is in the calandria outside of the calandria tubes. Light Water Reactors (both Pressurized Water Reactors and Boiling Water Reactors) require enriched uranium fuel and use a relatively poor moderator (ordinary 'light' water); whereas CANDU reactors use un-enriched uranium, but have a more effective moderator (heavy water) to slow down neutrons and sustain a chain reaction.

CANDU reactors can remain operating while spent fuel bundles are pushed out of a fuel channel on one side of the reactor, and new fuel bundles are loaded in the other. After ten to twenty years, the fuel channels face an increasing risk of catastrophic failure leading to a major Loss of Coolant Accident (LOCA). This occurred in 1983 in a pressure tube of Reactor #2 at the Pickering station in Ontario, when a meter-long rupture forced the shutdown and retubing of all four reactors at Pickering A over a period of ten years.

A prototype CANDU reactor, the Nuclear Power Demonstration (NPD), built at Rolphton, Ontario, began operation in 1962. It was followed by the 220 MW Douglas Point reactor at the Bruce site on Lake Huron. Douglas Point was intended to be the first commercial nuclear plant, when it began operation in 1968, but it was a technological and financial failure that was permanently shut down in 1984, having had a lifetime capacity factor of only about 50% over a lifetime of less than 18 years[1]. In addition to the NPD and Douglas Point reactors, 20 large reactors came into commercial operation in Ontario between 1971 and 1993 (see Tables 1 and 2). As of March 2004, 15 of these reactors were operating (see Table 3). The five other reactors have been shut down for seven years or more

[1] International Atomic Energy Agency, *Operating Experience with Nuclear Power Stations in Member States in 1984*, Vienna, 1986, p. 67.

Table 1.
Ontario Power Generation CANDU Reactors:
"A" Plant Phaseout Schedule

STATION CAPACITY	UNIT	COMM'L OPER'N	FIRST SHUTDOWN	SECOND SHUTDOWN	LIFE
Pickering "A" 4 X 515 MWe (net)	1	07 / 1971	12 / 1983 – 09 / 1987	12 / 1997 - SD	?
	2	12 / 1971	08 / 1983 – 11 / 1988	12 / 1997 - SD	?
	3	06 / 1972	06 / 1989 – 08 / 1991	12 / 1997 - SD	?
	4	06 / 1973	08 / 1991 – 03 / 1993	12 / 1997 - 09 / 2003	13yrs-2016
Bruce "A" 4 X 769 MWe (net)	1	09 / 1977	01 / 1998 - SD		?
	2	09 / 1977	10 / 1995 - SD		?
	3	01 / 1978	01 / 1998 – 02 / 2004		8yrs-2012
	4	01 / 1979	01 / 1998 – 10 / 2003		13yrs-2016

COMM'L OPER'N = date of Commercial Operation (Commercial Operation follows the date of Criticality and the date of First Power)

SD = Shut Down. Pickering units 1,2, and 3, and Bruce units 1 and 2 remain shut down at this time, although Ontario Power Generation describes them as being "laid up",which presumably indicates that they do not consider them to be *permanently* shut down. However, these units are listed as "shut down" by Nuclear Engineering International.

Sources:
Nuclear Engineering International, *2003 World Nuclear Industry Handbook*, pp. 126 & 127.
Ontario Hydro, *Quarterly Technical Reports Pickering Nuclear Generating Station, 1983 to 1993.*
Bruce Power, *Bruce A Restart Project: Environmental Assessment Study Report*, August 2002, Executive Summary, p. 2.

Table 2.
Ontario Power Generation CANDU Reactors:
"B" Plant Phaseout Schedule

STATION CAPACITY	UNIT	COMMERCIAL OPERATION	25 YEARS
Pickering "B" 4 X 516 MWe (net)	5	05 / 1983	2008
	6	02 / 1984	2009
	7	01 / 1985	2010
	8	01 / 1986	2011
Bruce "B" 4 X 860 MWe (net)	5	03 / 1985	2010
	6	09 / 1984	2009
	7	04 / 1986	2011
	8	05 / 1987	2012
Darlington 4 X 881 MWe (net)	1	11 / 1992	2017
	2	10 / 1990	2015
	3	02 / 1993	2018
	4	06 / 1993	2018

COMM'L OPER'N = date of Commercial Operation (Commercial Operation follows the date of Criticality and the date of First Power)

Source: Nuclear Engineering International, *2003 World Nuclear Industry Handbook*, pp. 126 & 127.

Table 3.
Ontario Power Generation Nuclear Capacity
(March 2004*)

Station	Reactors	Total Capacity
Pickering "A"	1 X 515 MWe(net)	515 MWe(net)
Bruce "A"	2 X 769 MWe(net)	1538 MWe(net)
Pickering "B"	4 X 516 MWe(net)	2064 MWe(net)
Bruce "B"	4 X 860 MWe(net)	3440 MWe(net)
Darlington	4 X 881 MWe(net)	3524 MWe(net)
Ontario Power Generation		11081 MWe(net)

* Re-start of the three Pickering A reactors that have remained shut down since December 1997 would add 1545 MWe(net), raising total nuclear capacity to 12626 MWe(net).

1.1. The Pickering Nuclear Stations

In August 1964, AECL and Ontario Hydro reached an agreement to build two 500 MW CANDU reactors at Pickering, Ontario, just east of Toronto on Lake Ontario.[2] This was Canada's first large-scale nuclear power plant. Ontario Hydro chose to build nuclear stations with four reactors each, in order to reduce costs by sharing safety systems and other infrastructure. AECL and Ontario Hydro were engaging in technological leap-frogging, as the Douglas Point reactor did not even reach criticality until November 1966. Many of the mistakes made at Douglas Point had to be corrected while construction was underway at Pickering.

The federal and Ontario governments not only provided most of the financing for Pickering reactors 1 and 2, but also provided Ontario Hydro with what amounted to a performance guarantee. The total cost of the two Pickering reactors (to both the federal government and Ontario Hydro) was reported at $393 to $420 million (dollars of the year).[3] Ontario Hydro has reported that the release estimate for all four reactors in 1965 was $508 million (dollars of the year)[4], and that the total cost for all four Pickering A units was $716 million (dollars of the year).[5]

The four Pickering A reactors maintained reasonable performance until August 1983, when a disastrous pressure tube rupture occurred in Pickering Reactor 2, and all four reactors were shut down in succession to have their pressure tubes replaced. The retubing of the four reactors cost about $1 billion (dollars of the year)[6] -- more than their original capital cost. The shutdown of the four Pickering A reactors was staggered over a ten-year period 1983-1993 (see Table 1, "First Shutdown").

In 1974, construction started on the four Pickering B reactors immediately beside Pickering A. All eight reactors eventually shared common safety systems, including containment and vacuum building, as well as the emergency core cooling system, resulting in a higher risk of accident than at other facilities. The 1974 release estimate for the four Pickering B reactors was $1.585 billion, and the final cost in 1986 was $3.846 billion.[7]

~~~~~~~~~~~~~~~~~~~~~~~~~~~

[2]Wilfrid Eggleston, *Canada's Nuclear Story*, Clarke Irwin, Toronto, 1965, p. 340.

[3]Robin Ann Cantor, *An Analysis of Public Costs and Risks in the Canadian Nuclear Industry*, PhD Dissertation, Department of Economics, Duke University, 1985, p. 69.

[4]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, p. 1.

[5]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p.2.

[6]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p.2.

[7]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, Attachment 1, p. 1-1.
~~~~~~~~~~~~~~~~~~~~~~~~~~~

Safety Issues at the Pickering "A" Nuclear Station

The Pickering A nuclear station should be shut down permanently for safety reasons alone. Due to its age, the Pickering A station is the only nuclear plant in the western world that has only one emergency shutdown system. All other nuclear plants in Canada and abroad have two complete emergency shutdown systems for back-up. Ontario Power Generation (Ontario Hydro) installed a cheaper alternative in order to save $300 million.[8] The Pickering station is also closer to larger numbers of people than any other nuclear plant in the world. For that reason, regulatory authorities would not allow a new plant to be built at Pickering today.

The Pickering reactors also have a greater risk of accident because the containment and Emergency Core Cooling System are shared between all 8 reactors at the A and B stations. The Bruce and Darlington stations share safety systems between only 4 reactors.

The consequences of an accident at Pickering "A" are potentially much more serious because of its proximity to the Greater Toronto Area. The Pickering "A" reactors have experienced a number of serious accidents, including the following...

August 1, 1983 - Pickering reactor 2 had a major "loss of coolant accident" (LOCA), after a pressure tube had a metre-long rupture. All four reactors at Pickering eventually had to be shut down over a ten-year period to be retubed at a cost of about $1 billion — more than the original capital cost of the station.

November 22, 1988 - Power was increased in Pickering reactor 1 resulting in damage to 36 fuel bundles. The cooling system was contaminated with radioactive iodine, which was released into the community over several weeks following the accident.

September 25, 1990 - Pickering reactor 2 had a "severe flux tilt" - a loss of reactor control with large power shifts in the core. Staff spent two days trying to stabilize the reactor, and the regulator later said it should have been shut down immediately.

August 2, 1992 - Pickering reactor 1 had a heavy water leak from a heat exchanger that resulted in a leak of 2300 trillion becquerels of radioactive tritium into Lake Ontario. This was Canada's worst-ever tritium release, resulting in increased levels of tritium in Toronto drinking water and along the Lake Ontario shoreline from Whitby to Burlington.

December 10, 1994 - Pickering reactor 2 had a major Loss of Coolant Accident (LOCA). A pipe break resulted in a spill of 185 tonnes of heavy water. For the first time in history at a CANDU, the Emergency Core Cooling System was used to prevent a meltdown, and about 200 workers were needed to clean up the radioactive mess.

July 21, 1995 - Two technicians carried out work on the wrong reactor (5 instead of 6),disabling the second fast shutdown system on reactor 5, which was operating at full power at the time.

February 19, 1996 - 500 tonnes of water spilled into the reactor 5 building due to worker error. Safety equipment could have failed due to water damage The accident blew a 30 kg valve component 3 meters in the air and shot water to the reactor building dome.

[8] Irene Kock, *Nuclear Hazard Report 1991-1992*, Nuclear Awareness Project, 1994, p. 4.

April 15, 1996 - Pickering reactor 4 had a heavy water leak from a heat exchanger that released 50 trillion becquerels of tritium into Lake Ontario. The level of tritium in local drinking water peaked at about 100 times the usual level.

October 11, 1996 - Drug paraphernalia were found in the operating islands at the both Pickering nuclear stations. This was one of 5 significant event reports relating to illicit drug and alcohol use at Pickering in 1996.

May 17, 1997 - It was disclosed that Ontario Hydro failed to report the dumping of more than 1000 tonnes of copper, zinc and other metals into Lake Ontario, due to corrosion of brass steam condensers.

1.2. The Bruce Nuclear Stations

Prior to the operation of Pickering Units 1 & 2, Ontario Hydro and Atomic Energy of Canada Limited (AECL) were negotiating construction of larger reactors at the Bruce site, adjacent to the Douglas Point reactor. AECL agreed to finance and construct a heavy water plant at the site, and Ontario Hydro was to be responsible for the nuclear plants.[9] The 1969 release estimate when construction began on the four Bruce A reactors was $930 million (dollars of the year).[10] The final cost was $1.8 billion (dollars of the year).[11] Performance was reasonable until the late 1980s when problems with steam generators and 'fretting' of pressure tubes by fuel bundles began to occur.[12] By 1993, Bruce A performance had decayed to an abysmal load factor of less than 40%.

Unlike the Pickering A and B stations, the four reactors at the Bruce B station are totally separate from Bruce A. The initial release estimate for Bruce B in 1976 was $3.929 billion and the final cost was $5.994 billion (dollars of the year).[13]

1.3. Darlington Nuclear Station

The Darlington nuclear station, with four 881 MWe(net) reactors, is located in the municipality of Clarington, east of Oshawa. Shortly after work began on Darlington in 1978, the partial meltdown at Three Mile Island occurred in 1979. For the first time in Ontario, construction of a nuclear station prompted large protests and construction of the nuclear plant remained highly controversial during the 1980s and early 1990s. Darlington is infamous

[9]Robin Ann Cantor, *An Analysis of Public Costs and Risks in the Canadian Nuclear Industry*, PhD Dissertation, Department of Economics, Duke University, 1985, p. 71.

[10]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, p. 1.

[11]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p. 4.

[12]*Canada Enters the Nuclear Age: A Technical History of Atomic Energy of Canada Limited*, AECL, 1997, pp. 201-202.

[13]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991, Attachment 2, p. 2-1.

for its massive capital cost overruns. An early cost estimate for Darlington in 1973 was $2.5 billion,[14] and the initial release estimate in 1978 was $3.950 billion.[15] The final cost in 1993 escalated to $14.4 billion (dollars of the year).

Darlington experienced serious technical problems in its early years. Start-up was initially delayed by problems with the validation of the shutdown system software. In 1990, reactor 2 experienced a three- month delay when a crack in the rotor of the generator was discovered. In 1991, fuel damage and pressure tube damage was discovered which caused major delays. It was eventually determined that this was caused by excessive vibrations from the main heat transport pumps on all four reactors, which were modified.[16]

1.4. Ontario's Demand-Supply Plan Hearing

In December 1989, Ontario Hydro released its Demand Supply Plan, which identified options for the 25-year period 1990-2014.[17] The plan called for construction of up to 15 reactors at four stations, and cost estimates for the plan, including additional fossil and hydro-electric generating stations, ranged from $61 billion to $200 billion.[18] The plan unraveled under scrutiny at environmental assessment hearings and was withdrawn by Ontario Hydro in January 1993.

1.5. The 1997 Nuclear Asset Optimization Plan

On August 13, 1997, Ontario Hydro announced that it would temporarily shut down its oldest seven reactors. The oldest four reactors at Pickering A were shut down at the end of 1997.[19] The three remaining Bruce A reactors were shut down on March 31, 1998. Bruce reactor 2 had already been closed in October 1995. It was the largest single shutdown in the international history of nuclear power -- over 5,000 MW of nuclear capacity. Ontario Hydro's Nuclear Asset Optimization Plan (NAOP) called for the "phased recovery" of its nuclear reactors, including first, "extensive upgrades" to the operating stations: Pickering B, Bruce B, and Darlington. Next, it would bring back into operation the four Pickering A reactors, and

---

[14]Brief by J. McCredie, Project Manager Darlington Generating Station, *Demand Supply Plan Hearing Exhibit 539*, March 20, 1992, p. 1.

[15]Ontario Hydro, *Demand Supply Plan Hearing Interrogatory No. 9.7.62.*, February 1991.

[16]Brief by J. McCredie, Project Manager Darlington Generating Station, *Demand Supply Plan Hearing Exhibit 539*, March 20, 1992, p. 3.

[17]Ontario Hydro, *Providing the Balance of Power*, 1989. The report contained four main sections: *Overview*; *Demand Supply Plan Report*; *Plan Analysis*; and *Environmental Analysis*.

[18]"Ontario Hydro Wants up to 15 Nukes", *Nuclear Awareness News*, Winter 1989/1990, pp. 1-4.

[19]"Ontario Hydro Moving Ahead on Major Overhaul of its Production Facilities", *Ontario Hydro News Release*, August 13, 1997. See also: "Results of the Nuclear Performance Advisory Group's Independent Integrated Performance Assessment and their recommended Nuclear Asset Optimization Strategy", *Ontario Hydro Advice of Decision of Board of Directors*, August 12, 1997.

then the four reactors at Bruce A. This was also called the "12/16/20 Plan" after the number of reactors sequentially in operation.

1.6. Nuclear Power & Electricity Sector Restructuring in Ontario

In October 1998 the Conservative government of former Premier Mike Harris passed the *Energy Competition Act* splitting Ontario Hydro into five publicly owned entities. The government's plan was to restructure the electricity sector, eliminating Ontario Hydro's historic monopoly, and introducing competition at both the wholesale and retail levels. Ontario Hydro ceased operation on April 1, 1999, and Ontario Power Generation (OPG), which owns all of the nuclear, fossil and hydraulic generating stations, began operation. The transmission grid and Ontario Hydro's rural retail division were transferred to Hydro One.

At the time of its dissolution, Ontario Hydro had $38.1 billion in debt and liabilities -- largely debt for nuclear projects, including $2.3 billion in nuclear liabilities for decommissioning and radioactive waste management. It was generally recognized that with this debt and its huge burden of expensive and poorly performing nuclear capacity, OPG would go bankrupt in the competitive electricity market. Thus the nuclear plants were said to be 'stranded' assets, and the debt incurred for their construction and rehabilitation was said to be 'stranded' debt. The Ontario government relieved Ontario Hydro's successor companies of most of this stranded debt. OPG was assigned a value of $8.5 billion and a debt of only $3.4 billion. Ontario Hydro negotiated a very high level of stranded debt ($20.9 billion)[20] to improve its position going into competition. This was in effect the world's biggest nuclear bailout, subsidizing the rehabilitation of Ontario Hydro's ailing nuclear fleet, and facilitating re-start of the eight Pickering A and Bruce A reactors.

As part of the restructuring process in Ontario, the government recognized that the effective monopoly of OPG (85% of the market in 2000) was a major impediment to the introduction of competition. Therefore a 'Market Power Mitigation Agreement' was negotiated, which specified that OPG would "within ten years of market opening, [...] reduce its market share of total generating capacity servicing Ontario demand to no more than 35 percent".[21]

However this did not necessarily imply divestiture. On July 11, 2000, OPG announced that it had entered a "leasing agreement" with Bruce Power Partnership for the Bruce A and Bruce B nuclear stations. At the time, Bruce Power was owned 80% by British Energy plc, 15% by Cameco Corporation (a Canadian company mainly conducting uranium mining and refining) and 5% by the unions at the stations.[22] The lease agreement runs until 2018, with an option to extend for 25 years. The detailed terms of the agreement have not been made public, however, it has been stated that OPG will receive an initial payment of $625 million with supplementary payments for the management of high level radioactive waste (spent

---

[20] Ontario Ministry of Finance, *Stranded Debt Fact Sheet* , April 1, 1999.

[21] Market Design Committee, *Third Interim Report*, October 8, 1998, p. 1-5.

[22] *Bruce Power: About Us*, downloaded February 27, 2001, http://www.brucepower.com/aboutus.htm

fuel), and a share of net revenue.[23] A major concern is that Bruce Power will not bear the full cost of long-term liabilities for decommissioning and radioactive waste management. These liabilities will rest with Ontario Power Generation and ultimately the Government of Ontario and provincial taxpayers.

After repeated delays, the Ontario government finally opened the Ontario electricity market on May 1, 2002. However, faced with volatile and rising electricity prices under the competitive market, the Ontario Government retreated from its commitment to electricity sector competition. It passed the *Electricity Pricing, Conservation and Supply Act* in December 2002, which capped electricity prices at 4.3 cents per kilowatt hour for consumers using up to 250,000 kWh annually. Large customers remained in the competitive market and received rebates under the Market Power Mitigation Agreement for the 12 months ending April 30, 2003. As of May 1, 2003, rebates to the large customers were fixed at 50% of the amount by which the average spot market price exceeded 3.8 cents per kilowatt hour.

Following their election in October 2003, the Liberal government of Premier Dalton McGuinty passed the *Ontario Energy Board Amendment Act* in December 2003. As of April 1, 2004, the fixed price of 4.3 cents/kWh rose to 4.7 cents for the first 750 kWh consumed each month. Above 750 kWh each month, the price rises to5.5 cents. The rules were not amended for customers above 250,000 kWh/yr.

While electricity has been subsidized by capping rates, the reason for high electricity costs has undoubtedly been nuclear power. When Ontario Hydro last publicly acknowledged the price of nuclear power in 1999, it cost 7.721 cents per kilowatt hour.[24] At the time, the cost of hydroelectric electricity was 1.098 cents per kilowatt hour, and the price of fossil-generated electricity was 4.293 cents per kilowatt hour. Since that time, the cost of nuclear power has unquestionably risen.

2. CANDU Nuclear Performance in Ontario

In 2003, the 20 operable reactors owned by Ontario Power Generation ran at an average net capacity factor of 48.69% (See: Table 4). Capacity factor is actual electricity production expressed as a percentage of 100% perfect output. When the Ontario Hydro Board of Directors approved the Nuclear Asset Optimization Plan in 1997, it was assumed that shutdown of the 8 Pickering A and Bruce A reactors would allow Ontario Hydro to concentrate on the restoration of the remaining reactors in the nuclear fleet to a capacity factor of 86%. However, as can be seen in Table 4, instead of improving, nuclear performance has stagnated at historically low levels, below 50% average capacity factor, despite a massive investment of funds for refurbishment.

[23]Ontario Power Generation & Bruce Power, "Ontario Power Generation and Bruce Power Announce Agreement at Bruce Nuclear", *News Release*, July 11, 2001.

[24]*Ontario Hydro Final Annual Report January 1998-March 1999*, p. 67.

Table 4.
CANDU Performance at Ontario Hydro / Ontario Power Generation
1997 - 2003
(Capacity Factor)

Station	Unit	1997	1998	1999	2000	2001	2002	2003
Pickering A	1	87.97	0	0	0	0	0	0
	2	64.23	0	0	0	0	0	0
	3	65.34	0	0	0	0	0	0
	4	0	0	0	0	0	0	18.88
Bruce A	1	20.57	0	0	0	0	0	0
	2	0	0	0	0	0	0	0
	3	57.24	85.6	0	0	0	0	0
	4	39.99	0	0	0	0	0	13.83
Pickering B	5	87.54	76.9	56.26	58.74	66.57	59.38	69.13
	6	75.27	69.0	74.97	61.48	58.45	88.95	73.01
	7	65.44	67.9	98.77	46.90	89.71	94.68	40.03
	8	8.28	77.0	78.19	60.32	78.06	80.45	87.62
Bruce B	5	83.34	81.6	69.74	91.46	65.18	79.53	76.60
	6	63.83	67.5	91.15	62.03	90.85	48.78	97.57
	7	81.96	72.1	84.18	70.63	93.31	63.96	97.25
	8	84.71	59.6	54.86	86.67	72.05	88.50	71.50
Darlington	1	63.15	83.0	93.80	81.86	91.28	85.35	85.67
	2	62.44	80.4	84.53	89.68	76.13	94.93	79.37
	3	53.33	93.8	73.74	84.97	85.99	83.20	89.07
	4	67.03	84.2	81.13	90.78	89.18	97.20	74.36
OH / OPG		56.58	49.93	47.07	44.28	47.84	48.25	48.69

Sources: *Nucleonics Week* and Ontario Power Generation

Figure 2 shows the pattern of performance for each nuclear station in Ontario over time (the multiple reactors at each station are averaged). Typically there is some improvement in performance in the first ten years of operation, but this is followed by a period of extended decline.[25] The performance of the Pickering station is particularly interesting, since there is a modest improvement of performance about year 20, reflecting the retubing of the four reactors 1983-1993. However, the performance decline continues after a relatively short

[25] Charles Komanoff, *Performance Reliability of Ontario Hydro CANDU Plants: What Should be Expected in Future (Revised)*, Coalition of Environmental Groups, November 1992.

period despite the billion-dollar investment. The pattern of nuclear performance decline can be seen more clearly on the composite graph in Figure 3, which averages all nuclear performance in Ontario over time.

It should be noted that good CANDU performance is not guaranteed even during the early years of operation. Ontario Power Generation's newest reactors at the Darlington Nuclear Generating Station experienced severe performance problems during their early years of operation. Reactors 2 (which was started first) had a three-year average capacity (load) factor of 11%, while the first year capacity factor of reactor 1 was 33%. Initial problems included the cracking of the generator rotors. All original rotors had to be replaced with a new design.[26] These first two reactors at the four unit station were also kept closed for extended periods because of unexplained fuel bundle damage in the reactor core.[27] The fuel damage problem, known as "shake and break" was eventually traced to the design of the primary heat transport pumps in relation to the size and shape of the fuel channels at Darlington. The particular equipment chosen resulted in vibrations inside the fuel channels which caused rapid breakdown of the fuel bundles and damage to the pressure tubes. The design of the heat transport pumps had to be changed to stop the resonance of the fuel channels.[28]

CANDU performance world-wide compares poorly to dominant world types of power reactors. According to *Nucleonics Week*,[29] a nuclear industry trade journal, the 2003 average capacity (load) factors for the major competitive reactor types were as follows: Pressurized Water Reactors (259 PWRs) = 82.62%; Boiling Water Reactors (92 BWRs) = 70.23; Pressurized Heavy Water Reactors [30] (41 PHWRs) = 63.28%. While CANDU performance has declined over the last 20 years, nuclear reactors in the United States have been steadily improving from an average capability factor of 62.7% in 1980 to an average of 88.7% in 1999.[31]

While aging is the broad factor associated with declining CANDU performance over time, there are a few specific technical problems that have contributed to worsening performance. The single greatest problem relates to fuel channels — the calandria and pressure tubes that are a unique feature of the CANDU reactor. After only 12 years of operation, Pickering reactor 2 was shut down in 1983 following a rupture in one of its 390 pressure tubes. Reactor 1 was shut down shortly after and reactors 3 and 4 were eventually shut down as well (see "First Shutdown", Table 1). The rupture was due to embrittlement caused by hydrogen absorption in the tube alloy. Although the outage time for each subsequent retubing was reduced through experience at the four Pickering reactors from 5 years to just under two

[26]Atomic Energy Control Board, *AECB Annual Staff Report for 1992*, AECB BMD 93-138, July 27, 1993.

[27]Atomic Energy Control Board, *AECB Annual Staff Report for 1991*, AECB BMD 92-145, July 28, 1992.

[28]Irene Kock, *Nuclear Hazard Report 1991-1992*, Nuclear Awareness Project, 1994, p. 9.

[29]"Gross Generation by Reactor Type and Vendor", *Nucleonics Week*, February 12, 2004, pp. 6-7.

[30]Pressurized Heavy Water Reactor , PHWR, is te generic name for the CANDU reactor design. Not all of these reactors were built by Ontario Hydro/OPG, or AECL. However, the Ontario Hydro/OPG/AECL 2003 average Capacity Factor of 62.11 was even lower than the overall PHWR average of 63.28%.

[31]"Nuclear power in the U.S. stays on improvement track", *Nuclear News*, May 2000, p. 27.

years, this still represents a major performance problem. The problem has not been limited to Pickering A. In 1986 there was tube rupture in Bruce A reactor 2, and other tubes at Bruce A have leaked, causing shutdowns for replacement. The Bruce reactors, however, have not been completely retubed. Although some technical solutions have allowed continued operation without Large Scale Fuel Channel Replacement, the issue of whether reactors should be completely retubed remains a primary factor in the performance, cost effectiveness and safety of all CANDU reactors.

Steam generator problems are the second most serious contributor to performance problems, although these problems are not unique to CANDU reactors. Fouling, corrosion, pitting, and fretting due to vibration are the major causes of tube failure in steam generators. These problems necessitate various expensive and technically difficult remedial programs, and will likely require the eventual replacement of some steam generators. Remedial programs include: improved chemistry control of feedwater; high pressure water jet cleaning; chemical cleaning; increased monitoring of tubes; and computer prediction and modeling of problems. The Bruce A station has had the most steam generator problems, including leaks caused by corrosion fatigue cracking and stress corrosion cracking. The steam generators of Bruce reactor 2 are in the worst condition. [32]

In order of priority, other causes of CANDU performance problems have been identified as turbines, reactors controls, primary heat transport, moderators, fuel handling, containment, emergency cooling, feed water systems, pump motor sets, and a mixture of problems associated with the balance of plant.[33]

3. Expected CANDU Lifetimes

Traditionally, Ontario Hydro and Ontario Power Generation have depreciated nuclear power plants assuming that their life expectancy was 40 years.[34] However, because of the demonstrated need for retubing and major rehabilitation at much earlier dates, this study has assumed that a reasonable estimate of CANDU lifetime is no more than 25 years, in the absence of major rehabilitation expenditures (see Tables 1 and 2). This estimate is consistent with the position of the Canadian Nuclear Association, which has stated...

> It is [...] assumed that all [CANDU] nuclear power plants will have to undergo one major rehabilitation program after 25 years in service to get to the full 40 years. Hence the forecast on availability depends on whether or not a decision is made to rehabilitate a nuclear plant after 25 years in service.[35]

[32]Dave Turner, "Pulling CANDUs Back from the Brink", *Nuclear Engineering International*, May 1994, pp. 40-41.

[33]Ontario Hydro, Demand-Supply Plan Hearing, *Response to Interrogatory 9.7.148 from the Coalition of Environmental Groups*, October 31, 1991.

[34]See for example: *Ontario Hydro Final Annual Report January 1988-March 1999*, pp. 44-45.

[35]Canadian Nuclear Association, *The Value of Nuclear Power to Canada's CO2 emissions trading system*, October 2003, p. 12.

Ontario Hydro has also estimated periods shorter than 40 years, when major rehabilitation of nuclear plants would be needed for removal and replacement of fuel channels and steam generators. Thus, it can be seen from Table 5 that these dates were also typically close to 25 years after the initial date of first commercial operation.

Table 5.
Fuel Channel & Steam Generator Replacement times
(March 31, 1999)

Station	Time Period	Years past Commercial Operation
Bruce A Reactors 3 & 4	2001-2008	23-29
Pickering B	2008-2012	25-26
Bruce B	2010-2013	26-26
Darlington	2016-2019	26-26

Source: *Ontario Hydro Final Annual Report January 1988-March 1999*, p. 56.

There is a secondary question as to the period of time that reactors can be expected to operate *after* they have undergone retubing and/or rehabilitation. The only evidence in this regard is the experience of the Pickering A station that was retubed 1983-1993. After being retubed, Pickering reactor 1 lasted 10 years 3 months before being shutdown at the end of 1997; Pickering reactor 2 lasted 9 years 1 month; Pickering reactor 3 lasted 6 years 4 months; and Pickering reactor 4 lasted 4 years 9 months (see Table 1).

After being shut down December 31, 1997, Pickering reactor 4 was restarted in October 2003, but OPG has not said how long it expects the reactor to operate. However, in 1997, as part of the Nuclear Asset Optimization Plan, Ontario Hydro suggested that Pickering reactor 4 would require pressure tube replacement in March 2017.[36] This study has therefore assumed that the most recent rehabilitation of Pickering 4 will give a life expectancy of 13 years to the reactor, i.e. until 2016. This estimate is consistent with the estimate of Torrie Smith Associates.[37] This is also consistent with the position of the Ontario Power Generation Review Committee, which estimated a lifetime of 8-14 years for Pickering reactor 1 after refurbishment.[38]

The OPG Review Committee has suggested that the Pickering B plant may last longer.[39] It have suggested that the rehabilitation dates for the Pickering reactors are 2012 to 2016, or 29

[36]Rick Machon, "Option Selection Basis", *Nuclear Asset Optimization Plan (NAOP) Development & Recommendation*, August 11, 1997, p. 16.

[37]Ralph Torrie and Richard Parfett, Torrie Smith Associates, *Phasing out Nuclear Power in Canada: Toward Sustainable Electricity Futures*, Campaign for Nuclear Phaseout, July 2003, p. i.

[38]OPG Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 50.

[39]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 19.

to 30 years after the start of commercial operation. The committee's estimates for Bruce B and Darlington are not inconsistent with the estimates of this study. The OPG Review Committee suggests that rehabilitation dates for Bruce B are 2009-2017 (24 to 30 years post-commercial operation); and for Darlington are 2013-2020 (21 to 27 years post-commercial operation).

Two other reactors have undergone major rehabilitation — Bruce A reactors 3 and 4. Bruce Power has stated that it expects Bruce reactor 3 to operate for 8 years — until 2012, and that Bruce 4 will operate for 13 years, until 2016.[40]

4. CANDU Rehabilitation Risks

As CANDU reactors in Ontario have aged, they have experienced increasing technical problems and poor performance -- typically worsening dramatically after about ten years of operation. Although it was originally assumed that CANDU reactors would last for forty years, they are experiencing serious operational problems much earlier. Ontario Hydro's decision in August 1997 to temporarily shut down its oldest seven reactors was dramatic proof that the early aging of CANDU reactors leads to poor performance and safety problems.[41]

The four Bruce "A" reactors lasted less than half of their expected 40-year lifetimes, before being shut down for long-term repair work. The Pickering "A" reactors lasted only 25 years, despite having been re-tubed 1983-1993.

4.1. The Pickering "A" Refurbishment

In August 1983 a disastrous pressure tube rupture occurred in Pickering Reactor 2, and all four reactors at the Pickering A station were shut down. The pressure tubes of each reactor were replaced in succession over a ten year period. The retubing of the four reactors cost about $1 billion (dollars of the year)[42] -- more than their original capital cost. As noted above, despite this enormous investment, the reactors were shut down just a few years later at the end of 1997 because of technical and performance problems.

The second major refurbishment of the four Pickering reactors began shortly after they were shut down at the end of 1997. This began even while a screening level environmental assessment on the restart project was being conducted by the Canadian Nuclear Safety Commission from 1999-2000. That environmental assessment was widely condemned by environmental and community groups for failing to deal with vital issues such as the possibility of severe accidents, the need for restart, and financial cost.

[40] Bruce Power, *Bruce A Restart Project: Environmental Assessment Study Report*, August 2002, Executive Summary, p. 2.

[41] Ontario Hydro, "Ontario Hydro moving ahead on major overhaul of its production facilities", *News Release*, August 13, 1997.

[42] Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p.2.

The Pickering A restart project had experienced significant delays. When the four old Pickering A reactors were first shut down on December 31, 1997, the first reactor (Unit 4) was supposed to restart in June 2000,[43] with the remaining three to be restarted at six month intervals (to be completely operational by June 2002). After repeated delays, reactor 4 only restarted commercial operation in October 2003 — three years and 4 months late. No public commitment has been made for the restart of reactors 1, 2, and 3. If they are restarted at all, it has been suggested that reactors 1, 2, and 3 would be restarted at one-year intervals.[44]

The cost of the Pickering A restart was estimated in 1999 at $780 million for all 4 reactors.[45] However, by September 2002, Ontario Power Generation reported that costs for the project had escalated to $1.025 billion.[46] At that time, OPG estimated that the start-up of Reactor 4 would cost another $230 million, and the other three reactors would cost an additional $300 to $400 million each.[47] Thus the cost for restarting reactor 4 alone was then estimated to be $1.255 billion, with a likely additional $1.2 billion for the other three reactors, totaling $2.455 billion -- three times the original cost estimate.

On May 30, 2003, the Ontario government of former Premier Ernie Eves announced the creation of a review panel on the refurbishment of the Pickering "A" nuclear station. The Sierra Club of Canada labeled the review a "whitewash" because it was had pro-nuclear leadership and because the terms of reference were restricted to determining the conditions for restarting the four reactors, rather than comparing the cost of energy alternatives and the risks of restarting the reactors.[48] The review was headed by a former federal energy minister under the Mulroney government, Jake Epp, well known for his support of nuclear power. The second member of the review was Robin Jeffrey, a nuclear industry insider, formerly head of British Energy in Norther America (British Energy is the British company that created the American nuclear company Amergen and the Canadian nuclear company Bruce Power).

The Epp review panel released its report on December 4, 2003. The panel focused blame on management practices at Ontario Power Generation, almost completely ignoring the antiquated Pickering nuclear technology.[49]

The review stated that $1.25 billion had been spent in order restart reactor 4 by September 2003. Astoundingly, OPG had failed to provide a hard estimate of the cost of completion.

---

[43]Ontario Hydro, *1998-200 Ontario Hydro Corporate Business Plan*, February 17 1998, p. 22.

[44]Richard Brennan, "Shake-up at hand over nuclear plant", *Toronto Star*, November 27, 2002, p. A8.

[45]KPMG, *Ontario Power Generation Inc. Financial Review of Operations*, March 15 2004, p. 20.

[46]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002, p. 12.

[47]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002.

[48]Sierra Club of Canada, "Eves Government Pickering Nuclear Review: A One-sided Whitewash", *News Release,* June 3, 2003.

[49]Pickering Review Panel, *Report of the Pickering "A" Review Panel*, December 4, 2003. The three panel members were Jake Epp, Chair, Peter Barnes and Dr. Robin Jeffrey.

The Epp panel guessed that the total cost would be $3 to $4 billion — an incremental amount of $1.75 to $2.75 billion to restart reactors 1, 2, and 3.[50] More than anything else, the $1 billion range of uncertainty about the final cost indicated the enormity and high risk of the Pickering restart project.

The report identified 11 increases of the cost estimate between August 1999 and May 2003, 13 revisions of the return-to-service date in the same period.[51] Little or nothing had changed in management practices at the plant since disastrous problems had been identified in 1997. All of the final recommendations of the panel related to improving corporate governance and managerial practices.

Only one sentence in the entire report, entitled "Complexity of the Project" mentioned the role that the technology might play...

> It should be recognized that the return of the remaining units remains a large, complex project with corresponding cost involving the reconditioning , rebuilding, replacing or adding of equipment at a 30-year-old station.[52]

The Epp panel implicitly supported the continued refurbishment of the other three reactors at Pickering A. However the government of Premier McGuinty was not prepared to make an immediate decision. On December 16, 2003, another panel, known as the Ontario Power Generation Review Committee, was mandated to examine the role, structure and governance of OPG, as well as the proposed restart of reactors 1, 2, and 3 at the Pickering "A" nuclear station. The Committee was headed by former federal Finance Minister John Manley, and again recruited Jake Epp. The third member of the tribunal was Peter Godsoe, Chairman and former CEO of Scotiabank. No energy or environmental experts were appointed to the committee.

The OPG Review Committee released its report on March 18 2004. Similar to the Pickering "A" Review Panel, the OPG review committee placed blame for the problems at OPG's nuclear facilities on management practices. Despite the obvious financial, performance and safety problems of the last 30 years, they found no fault with the nuclear power technology itself.

In the case of the restart of Pickering A reactors 1, 2, and 3, Manley supported the restart project strongly, suggesting that the project be done sequentially, with approval dependent on whether "OPG will be able to succeed at the Unit 1 project".[53] Manley did not even stipulate that OPG should finish the Unit 1 project *on budget*.

---

[50] *Report of the Pickering "A" Review Panel*, December 4, 2003, p. 4.

[51] *Report of the Pickering "A" Review Panel*, December 4, 2003, pp. 11 - 12.

[52] *Report of the Pickering "A" Review Panel*, December 4, 2003, p. 15.

[53] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 47.

Manley argued that the Pickering restart project would be cheaper than a Combined Cycle Gas Turbine fired by natural gas. However, the full details of this plan have not been revealed, and the economic analysis of the business case is extremely narrow and limited in a number of respects…

- The comparison of nuclear power is against a Combined Cycle Gas Turbine fired by natural gas. There is no comparison of a CCGT in a Combined Heat and Power (cogeneration) application, in which efficiency could be doubled and costs reduced dramatically.

- The Manley study compares nuclear costs against a gas-fired CCGT, but does not compare costs against a range of conservation/efficiency measures, or renewable energy sources. These green energy alternatives were the basis of the McGuinty government's election promises for the electricity sector.

- There is no discussion about the risk the refurbishment project taking longer than the expected 20 months. Restart of the Pickering 4 reactor was three years and four months late. Late restart will push up the base cost, as well as increasing replacement power costs.

- The sensitivity analysis for plant life does not take into account the risk of much worse performance than the 75 to 90% capacity factor suggested. As noted in Table 4, average performance of the nuclear fleet in 2003 was 49%.

- The study makes no mention of replacement generating costs while the Pickering reactors and others have outages for refurbishment. These costs will likely be extremely large.

- The sensitivity analysis in the business case for plant life after refurbishment does not take into account the risk that lifetimes may be far less than the 8 to 14 years suggested in the analysis.

- The cost of natural gas is condemned as "high and volatile" but absolutely no analysis is provided on natural gas prices, forecasts or possible resource strategies.

- The study does not take into account the possibility that Operation, Maintenance and Administration (OM&A) costs will be much more than the $77 to $108 million per year budgeted.

The Manley Committee not only supported the restart of the Pickering A reactors, but strongly recommended that nuclear power be supported and expanded in Ontario…

> …we have concluded that Ontario must begin planning now to supplement and ultimately replace its ageing nuclear assets with new and better generations of nuclear technology.[54]

[54]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, pp. 19-20.

This recommendation was based on no analysis -- only a number of incorrect, meaningless, unjustified and/or implausible claims...

> "nuclear plants can be a cost-effective source of base-load generation"[55]
>
> > In fact, nuclear power in Ontario has been spectacularly expensive, and NOT cost-effective. This was confirmed by OPG's own auditors on March 16, 2004.
>
> "the price of power they [nuclear plants] generate is stable over time."[56]
>
> > In fact, the only reliable aspect of the price of nuclear generated electricity in Ontario has been its dramatic increase over time as nuclear performance plummeted and nuclear costs skyrocketed.
>
> "Relying heavily on gas to provide base load would push up the level of Ontario's electricity prices and make them unstable."[57]
>
> > The major source of volatility in the electricity market has without question come from nuclear plants that on today and gone tomorrow. The shutdown of 8 reactors (5000 MW) from 1995 to 1998 was an unprecedented example of volatility and unreliability.
>
> "Renewable energy sources, conservation and co-generation are all important, but cannot fully bridge the supply gap."[58]
>
> > Manley provided absolutely no evidence to this effect. Evidence provided by intervenors, demonstrated conclusively just the opposite.
>
> "Nuclear power does not contribute to air emissions the way coal and gas do, and does not involve the complex watershed management issues of hydro projects."[59]
>
> > Nuclear power plants release a variety of radiologically and chemically toxic chemicals into the air and water. Notable amongst these emissions is radioactive tritium, which is released in large quantities by the CANDU reactor and is known to cause cancer and birth defects.
>
> "While safe long-term disposal of spent fuel is vital, there is a cooperative process under way between the federal and provincial governments to ensure this will be done."[60]

---

[55] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[56] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[57] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[58] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[59] Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

OPG's reactors had produced about 35,000 tonnes of high level radioactive waste (about 1.5 million spent fuel bundles) by the end of 2002. If these reactors are refurbished and allowed to operate for 40 years, this amount will roughly double. OPG has assessed the cost of disposing of this waste and decommissioning its reactors at $18.2 billion. Independent observers believe that this amount may be significantly underestimated. The Nuclear Waste Management Organization has been mandated to provide a recommendation on long-term management of high-level radioactive waste by November 2005. Because this organization is dominated and governed by the nuclear industry, its ability to make a credible or objective decision has been challenged.

4.2. The Bruce A Restart

In May 2001, Ontario Power Generation (OPG) finalized a deal with Bruce Power (then a subsidiary of British Energy, a nuclear power plant operator in the United Kingdom) for an eighteen-year lease to operate the Bruce nuclear complex on the shore of Lake Huron in Ontario.[61] The details of the agreement were kept secret, but it was clearly a sweetheart deal for Bruce Power.[62] Among other things, Bruce Power had no long-term responsibility for radioactive waste management and reactor decommissioning, responsibility for which remained with OPG, and ultimately with OPG's sole shareholder, the Government of Ontario. Costs for radioactive waste management and decommissioning have yet to be demonstrated, however, Ontario Power Generation has estimated that it will cost about $18.2 billion and take until 2070. About $10 billion of this amount is for radioactive waste management, assuming that deep geological disposal is used, and about $7.4 billion is for decommissioning of the 20 OPG owned reactors (including Bruce A and B).[63] OPG set aside $6.2 billion in 2003, and plans to increase that amount to $8 billion in 2007 and $10 billion by 2010. Yves Giroux, a member of the Canadian Nuclear Safety Commission has expressed doubt about whether the amounts set aside by OPG will be adequate.[64]

The agreement between Bruce Power and OPG was a cash cow for British Energy, earning $120 million profit in its first year of operation.[65] The Bruce complex includes four 769 MW (net) reactors at the Bruce A station and four 860 MW (net) reactors at the Bruce B station.

---

[60]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 20.

[61]Ontario Power Generation, Bruce Power, "Ontario Power Generation and Bruce Power Complete Lease Agreement for Bruce Nuclear Stations", *News Release*, May 12, 2001.

[62]Sierra Club of Canada, "Bruce Deal a Disaster for Ontario", *News Release*, April 17, 2001.

[63]Ontario Power Generation, *Application by OPG & Bruce Power to amend the operating licences for the Class 1 nuclear facilities to include conditions on decommissioning plans and related financial guarantees*, CNSC CMD 03-H11.1A, April 10, 2003.

[64]Peter Calamai, "Nuclear cleanup to cost billions", *Toronto Star*, April 11, 2003, p. A6.

[65]Peter Calamai, "Nuclear panel gives Bruce Power reprieve", *Toronto Star*, September 13, 2002, pp. E1 & E11.

While the four Bruce B reactors continued to operate, reactor 2 at the Bruce A nuclear station was shut down in October 1995, and reactors 1, 3 and 4 were shut down in early 1998 because of technical problems and poor performance.

In November 2000, Bruce Power selected AECL as the general contractor to lead an internal "inspection and condition assessment" of 70 fuel channels[66] as well as steam generators for Bruce A reactors 3 and 4. The assessment cost $30 million and was intended to determine if the re-commissioning of the reactors was economically justified.[67] With the guaranteed profit from the Bruce B station through its lease agreement with OPG, there was little doubt that Bruce Power would have ready cash to proceed with the Bruce A restart project. On April 6, 2001, Bruce Power announced that it intended to restart reactors 3 and 4 at the Bruce A station. At that time, Bruce Power expected that the reactors would be restarted in the summer of 2003 at a total cost of about $340 million (CDN).[68] The schedule was subsequently speeded up to restart reactor 4 in April 2003, and reactor 3 shortly afterwards.[69] However, there were repeated problems and delays and reactor 4 did not start up until October 2003. Reactor 3 did not restart until February 2004. The cost of refurbishing the two reactors also more than doubled to $720 million.[70]

[66]There are 480 fuel channels in each Bruce A reactor, so AECL is making a safety judgement based on an examination of only 7% of the 960 channels in reactors 3 and 4.

[67]Bruce Power, "Bruce A Re-start Evaluation in the Works", *Open Line*, Issue 9, November 24, 2000. Http://www.brucepower.com/whatsnew/pdfs/Issue_9.pdf

[68]Bruce Power, "Bruce Power Forges Ahead on Bruce A Restart", *News Release*, April 6, 2001.

[69]Pearl Marshall, "Bruce Power said to be planning return of final Bruce A units", *Nucleonics Week*, October 24, 2003, pp. 1, 14-15.

[70]John Spears, "Nuclear power key to future: Bruce chief", *Toronto Star*, January 30, 2004, p. A4.

CANDU Fuel Channel Problems

Problems with fuel channels in CANDU reactors have historically been the single largest cause of outages at CANDU reactors. The 480 fuel channels in each Bruce reactor core are prone to age-related problems due to the weight of the fuel bundles, as well as high temperatures, pressures and radiation fields in the reactor cores. Fuel channels in CANDU reactors consist of an outer calandria tube, and an inner pressure tube. The inner pressure tube holds uranium fuel bundles, and heavy water coolant is pumped through at high pressure to draw off the heat released by the fission process. Pressure tube problems include ‘creep’ and ‘sag’, where the metal thins out over time and the tubes become wider and longer, bending under the strain. Various design changes were made in later stations to try to accommodate this problem, but eventual tube replacement (‘retubing’) is anticipated on a schedule dictated by the extent of the problem in each reactor core.

When the pressure tubes sag they can come into contact with the outer ‘calandria tube’. This increases the chance of pressure tube rupture caused by ‘embrittlement’, where the metal becomes brittle due to absorption of hydrogen. This ‘metal hydriding’ process happens faster where the sagging pressure tubes make contact with the cooler calandria tubes. The space or annulus between the calandria and pressure tubes is maintained by spacers or ‘garter springs’. However, at Bruce reactors 3 and 4 (as well as at Pickering reactors 5 and 6), the garter springs are not locked into place and have to be periodically checked and moved back into position to keep the two tubes from touching.

AECL has argued that pressure tubes will always leak before rupturing, allowing time to shut the reactor down before a loss of coolant accident occurs -- an assumption they call ‘leak before break’. However, there have been at least two cases of catastrophic pressure tube ruptures in Ontario reactors: August 1983 at Pickering 2 and March 1986 at Bruce 2. All fuel channels at the Pickering A station reactors were subsequently replaced. Bruce reactors 1 and 2 will likely require complete retubing if they are ever to be restarted. Some individual tubes at Bruce reactors have been replaced in the past, but Bruce Power is taking a calculated risk, trading off safety against profit by arguing that complete replacement of fuel channels is not necessary at Bruce reactors 3 and 4. Bruce Power has taken this controversial position despite having inspected only 7% of tubes. Complete retubing of the reactors would likely more than double the estimated $720 million restart cost of reactors 3 and 4 as well as extending the outage time.

After the four Pickering A reactors, the Bruce A nuclear station has the oldest commercial reactors in Canada. In addition to pressure tube problems , there are other serious ongoing problems at Bruce. On June 11, 2002, an electrical arc burned a hole through a pressure tube and calandria tube during maintenance at Reactor 6 of the Bruce B station. This resulted in the reactor being shut down until early September. Bruce Power said only that a pressure tube had been “slightly damaged” and “the operational impact is not expected to be significant”.[71] The incident was kept secret on the basis that public knowledge of the shutdown of the reactor would have commercial implications for British Energy. Because of concerns about nuclear safety and the public’s right-to-know, secrecy about nuclear shutdowns has prompted public protest.[72]

[71]John Spears, “Shutdown hits Bruce reactor while Ontario had heat wave”, *Toronto Star*, September 26, 2002, pp. A1 & A21.

[72]See: “Secrecy at Bruce”, *Toronto Star Editorial*, September 27, 2002, p. A26.

Problems with steam generators have been the second largest cause of outages at CANDU reactors. All of the Bruce steam generators have been identified as being "high risk".[73] Past problems with steam generators have included clogging due to mineral deposits, 'fretting' or breakage of the internal pipes due to excessive vibration, and stress corrosion cracking of the metal. Steam generators incorporate thin-walled pipes where coolant from the reactor core circulates to transfer heat to the turbine side of the station. The steam generators at Bruce reactor 2 were damaged beyond repair after a lead shielding blanket was left inside the system during a maintenance procedure years earlier. Bruce reactor 2 was subsequently closed in 1995.

The Canadian Nuclear Safety Commission (CNSC) conducted a screening level environmental assessment on the restart of the Bruce A reactors 3 and 4. This was a low-level environmental assessment, and the CNSC maintained control over the process by ignoring public requests to ask the federal Environment Minister to appoint an independent assessment panel. As the "Responsible Authority" for federal nuclear matters, CNSC is in charge of all lower level environmental assessments (Screenings and Comprehensive Studies) unless it refers an assessment to the Minister of Environment for a hearing by an independent panel. A panel is more independent, since its members would be specially appointed by the Minister, and funding would be provided for intervenors.

On April 12, 2002, the CNSC approved the *Environmental Assessment Guidelines* for the screening assessment. Bruce Power issued its Environmental Study Assessment Report in August 2002, and CNSC released its screening report in October 2002.[74] On December 12, 2002, the CNSC held a hearing on the environmental assessment screening report for the return to service of Units 3 & 4 of the Bruce Nuclear Generating Station (NGS) 'A'. The Board ignored the concerns of environmental groups, and decided that the Screening Report had met all of the requirements of the Canadian Environmental Assessment Act.[75] Citizens for Renewable Energy (CFRE) and other groups had expressed concern about: the limited scope of the hearing; the CNSC's failure to request a bump up of the assessment to a full panel review; poor management of the assessment process; the need to expand the study area boundaries; delegation of technical environmental assessment studies to the proponent; and the failure of the CNSC to select a realistic range of severe accidents and malfunctions for consideration. The Chippewas of Nawash First Nation raised many concerns about the impacts of the reactor restart project on their fishing business near the nuclear plant.

---

[73]Ontario Hydro, Rick Machon, *Nuclear Asset Optimization Plan: Development & Recommendation*, "Option Selection Basis", p. 16.

[74]Canadian Nuclear Safety Commission, *Screening Report on Environmental Assessment of the Proposed Restart of Units 3 and 4 Bruce A Nuclear Generating Station, Kincardine, Ontario*, October 2002.

[75]CNSC, *Record of Proceedings, Including Reasons for Decision, In the Matter of Applicant: Bruce Power Inc,., Subject: "Environmental Assessment Screening Report for the Return to Service of Units 3 & 4 of the Bruce Nuclear Generating Station (NGS) 'A'", January 6, 2003*.

On January 6, 2003, the CNSC allowed Bruce Power to load fuel into reactors three and four in advance of the actual reactor start-up, delegating actual approval to CNSC staff without any need for a public hearing review.[76]

Bruce Power has also announced that it is conducing a feasibility study on the restart of the Bruce A reactors 1 and 2.[77] As part of its feasibility study, Bruce Power is also looking at a major refurbishment of the Bruce B reactors. In the absence of a large-scale refurbishment project, this study estimates that Bruce B will be forced to shut down after 25 years of operation, i.e. between 2010 and 2012 (see Table 2). The Bruce Power feasibility study and a corporate decision on these matters are expected before the end of 2004.[78] Because reactors 1 and 2 are in far worse shape than reactors 3 and 4, it is expected that the cost of their refurbishment could be more than double the $720 million cost of restarting reactors 3 and 4. This study estimates a range of $1.5 to $2.5 billion as the possible cost of the refurbishment project (see Table 6).

Bruce Power has also raised the possibility of building one or two new reactors that have yet to be designed by Atomic Energy of Canada Limited, known as the Advanced CANDU Reactor (ACR). Construction of a demonstration reactor for an untested design would be extremely risky. Bruce Power has undoubtedly been buoyed by windfall profits under its agreement with the Government of Ontario. In 2003, Bruce Power's profit increased to $286 million, compared to $106 million in 2002.[79]

Following a financial crisis at British Energy in the fall of 2002, it was announced on December 24, 2002, that a new Canadian group would purchase Bruce Power. The group consisted of Cameco Corporation, TransCanada Pipelines Ltd., and BPC Generation Income Trust, part of the OMERS pension fund. The three major partners held 31.6%, while the Power Workers Union had 4% and the Society of Energy Professionals 1.2%.

4.3. The Estimated Costs of Nuclear Refurbishment

Refurbishment of nuclear plants can involve a wide range of potential work, but in CANDU reactors, the most serious aspect of refurbishment is replacement of all the fuel channels in the reactor (see above: "CANDU Fuel Channel Problems"). This is known a Large Scale Fuel Channel Replacement (LSFCR), and has been characterized as 'heart transplant' for a CANDU reactor -- essentially the reactor core is re-built, requiring an extended outage of at least two years for the plant, at an extremely high cost.

---

[76] CNSC, *Record of Proceedings, Including Reasons for Decision, In the Matter of Applicant: Bruce Power Inc,., Subject: "Referral to a CNSC Designated Officer - Application to load fuel at Bruce 'A' NGS unit 3 and 4 reactors", January 6, 2003*.

[77] Bruce Power, "Bruce Power to explore restart of Bruce A Units 1 and 2", *News Release*, January 29, 2004.

[78] "Bruce Power Ponders Additional Nuke Restarts", *Electricity Daily*, February 6, 2004.

[79] John Spears, "Bruce Power profit more than doubles; idle reactors powered up", *Toronto Star*, January 24, 2004, p. C3.

Table 6.
Estimated Refurbishment Costs for Ontario Nuclear Power Plants
(Current Dollars)

Station	Cost Range
Bruce 3 & 4	$720 million*
Bruce 1 & 2	$1.5 to $2.5 billion
Pickering A	$3 to $4 billion
Pickering B	$3 to $4 billion
Bruce B	$3 to $4 billion
Darlington	$3 to $4 billion
Total	$14.2 to $19.2 billion
Midpoint	$16.7 billion

*Actual cost. Source: John Spears, "Nuclear power key to future: Bruce chief", *Toronto Star*, January 30, 2004, p. A4.

This study estimates that the cost of refurbishment for all 20 Ontario Power Generation Reactors will be in the range of $14.2 billion to $19.2 billion, with a midpoint of $16.7 billion (see Table 6). This assumes complete fuel channel replacement of all reactors except for Pickering A (which was already re-tubed 1983-1993) and Bruce reactors 3 and 4. This is consistent with other recent estimates of refurbishment costs. Torrie Smith Associates has suggested that the cost of refurbishing OPG's nuclear fleet would be "...on the order of $15 to $20 billion...".[80] The Pickering "A" review Panel has suggested that the total cost of refurbishing all four reactors and common systems at the Pickering A station ranges from $3 to $4 billion. This range is based on figures prepared by OPG for financial modeling purposes.[81]

The low end of the cost range ($14.2 billion) assumes that there will be no major surprises, and the high end of the range ($19.2 billion) assumes that there will be some significant additions to the estimated costs. Every nuclear power plant built by Ontario Hydro had significant cost overruns. This history demonstrates that there is severe economic risk in nuclear construction projects because of their technological complexity and high capital costs.

The cost estimates in Table 6 are conservative insofar as they do not make allowance for a number of significant hidden costs...

- There is major uncertainty about how long the reactors will continue to operate after refurbishment has taken place. For example, Pickering reactor 4 was shut down in 1997 less than 5 years after undergoing a complete fuel channel

[80]Ralph Torrie and Richard Parfett, Torrie Smith Associates, *Phasing out Nuclear Power in Canada: Toward Sustainable Electricity Futures*, Campaign for Nuclear Phaseout, July 2003, p. ii.

[81]Pickering Review Panel, *Report of the Pickering "A" Review Panel*, December 4, 2003, p. 4.

replacement. OPG has refused to say how long the refurbished Pickering A reactors should last.

- Replacement power costs are a major expense for the utility during the extended outages required for refurbishment (at least 18 to 20 months per reactor). This is typically not included as a cost of refurbishment.

- Nuclear utilities generally assume that plants will have excellent performance after refurbishment, for example 89% capacity factor in the case of the Point Lepreau refurbishment proposal (see below). By contrast, the capacity factor of the Pickering A nuclear station in 1997 (the year before it was shut down for the second time) was about 54%, despite having been retubed 1983-1993.

- The labour costs of utility staff working on the refurbishment project may not be counted as part of overall costs since 'they are on staff already'.

There have been several reports of refurbishment costs, but Ontario Hydro/OPG has made no rigorous reporting available to the general public, so these figures must be understood as approximate at best. The Pickering A station was retubed 1983 to 1993, following the disastrous 1983 pressure tube rupture in reactor 2. However, Ontario Hydro never provided an accurate accounting of the cost of that massive refurbishment exercise. In 1988, Hydro stated that...

> The cost of retubing units 1 and 2 [at Pickering "A"] cost $450 million (dollars of the year, 1984-1988) and work on the last two units is expected to cost about $500 million in dollars of the year, 1989-1993.[82]

As noted above, the cost of the Pickering A restart was estimated in 1999 at $780 million for all 4 reactors.[83] However, by September 2002, Ontario Power Generation reported that costs for the project had escalated to $1.025 billion.[84] At that time, OPG estimated that the start-up of Reactor 4 would cost another $230 million, and the other three reactors would cost an additional $300 to $400 million each.[85] Thus the cost for restarting reactor 4 alone was then estimated to be $1.255 billion, with a likely additional $1.2 billion for the other three reactors, totaling $2.455 billion -- three times the original cost estimate.

The OPG Review Committee confirmed on March 18, 2004, that the cost of the restart of Pickering reactor 4 had escalated to $1.25 billion at the time of its restart in October 2003. The Committee estimated that the cost of restarting reactor 1 would be $775 to $925 million, of which $325 million has already been spent.[86] It is not clear whether this $325 million is

[82]Ontario Hydro, *A Journalist's Guide to Nuclear Power*, 1988, p. 2.

[83]KPMG, *Ontario Power Generation Inc. Financial Review of Operations*, March 15 2004, p. 20.

[84]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002, p. 12.

[85]Ontario Power Generation, *Third Quarter 2002 Results*, October 28, 2002.

[86]Ontario Power Generation Review Committee, *Transforming Ontario's Power Generation Company*, March 2004, p. 51.

included in the $1.25 billion cost of reactor 4 or is in addition to it. The Committee also failed to provide any estimate of the cost of restarting reactors 2 and 3.

As we have seen above, the reported cost of the refurbishment of Bruce reactors 3 and 4 is $720 million.[87] It is not clear, however, what this cost includes. It has been suggested that the cost of refurbishing Bruce reactors 1 and 2 might be twice the cost of reactors 3 and 4. This study accepts that estimate as the low end of the range for their refurbishment.

4.4. Regulatory Opposition to Point Lepreau Refurbishment

The most publicly studied example of a proposed nuclear refurbishment project is the Point Lepreau Nuclear Generating Station. It is a single “CANDU 6" reactor (635 MWe) that began commercial operation in February 1983. The plant is owned and operated by New Brunswick Power, and was designed by AECL. Like other reactors of the period, the Point Lepreau plant was intended to run for 40 years, however, after less than twenty years, the reactor experienced serious performance and safety problems. In 1998, an NB Power consultant decided that the plant would require total replacement of all 380 fuel channels in the 2006-2008 period.[88] This schedule , however, has already slipped. According to the retube and refurbishment schedule, the work would take almost 5 years, and the plant would be shut down for 18 months.[89] The total estimated cost of the project was $845 million.[90]

On January 8, 2002, New Brunswick Power filed an application to the New Brunswick Board of Commissioners of Public Utilities (known as the Public Utilities Board or PUB) to hold a public hearing on the refurbishment of the Point Lepreau nuclear generating station. The hearing began on May 27, 2002, with final arguments in June. The PUB released its decision on September 24, 2002, noting that its review was made from an economic perspective, but with a public interest viewpoint. The decision was a stunning rejection of AECL’s refurbishment proposal as put forward by NB Power...

> The Board, as a result of its review of the evidence in relation to the capacity factor and the cost of capital, finds that there is no significant economic advantage to the proposed refurbishment project. In addition, the Board considers that there are other significant aspects of the refurbishment option for which the economic impact is uncertain. These aspects create additional economic risk which leads the Board to conclude that the refurbishment of Point Lepreau, as outlined in the evidence, is not in the public interest. The Board, therefore, will

---

[87] John Spears, “Nuclear power key to future: Bruce chief”, *Toronto Star*, January 30, 2004, p. A4.

[88] New Brunswick Power, *Road to Refurbishment at Point Lepreau Generating Station*, April 2001.

[89] NB Power, *Project Execution Plan*, Appendix A-4, February 2002, Table 4-1, p. 17.

[90] NB Power, *Project Execution Plan*, Appendix A-4, February 2002, Table 1-1. p. 1. This includes an ’overnight’ cost of $633 million with escalation and interest during construction of $211million.

recommend to the Board of Directors of NB Power that it not proceed with the refurbishment of Point Lepreau.[91]

- The PUB rejected many of the basic assumptions underlying the agreements of the proposed contractor, Atomic Energy of Canada Limited (AECL), and NB Power. The following are some of the conclusions reached by the PUB...an 80% capacity factor should be assumed for the refurbished plant instead of 89% as proposed by AECL and NB Power; [92]
- a discount rate of 9.33% should be used instead of 7.15% for the cost of capital for the project; [93]

(N.B. These two adjustments alone make the cost of Point Lepreau refurbishment approximately equal to the cost of a new natural gas-fired generating plant [94])

- the stipulated liquidated damages payable by AECL may not be sufficient; [95]
- there is a significant risk from delay of the project (a four-month delay would increase the cost by $63 million plus $5 million per month in interest charges.); [96] and
- there is a "regulatory risk" that the federal regulator, the Canadian Nuclear Safety Commission, may require significant changes to the refurbishment plan as proposed.[97]

The PUB decision was only a recommendation to the Board of Directors of NB Power, and it is not clear at this time, whether the refurbishment proposal will proceed despite the PUB decision. NB Power has attempted unsuccessfully to find a purchaser or equity partners for Point Lepreau.

---

[91] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 16.

[92] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 5.

[93] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 6.

[94] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 6.

[95] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 8.

[96] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 10.

[97] *Decision of the New Brunswick Board of Commissioners of Public Utilities on the Proposed Refurbishment of the Point Lepreau nuclear Generating Facility*, September 24, 2002, p. 13.

Figure 1
Ontario Nuclear Capacity
(Actual 1971-2003, Projected 2004-2019

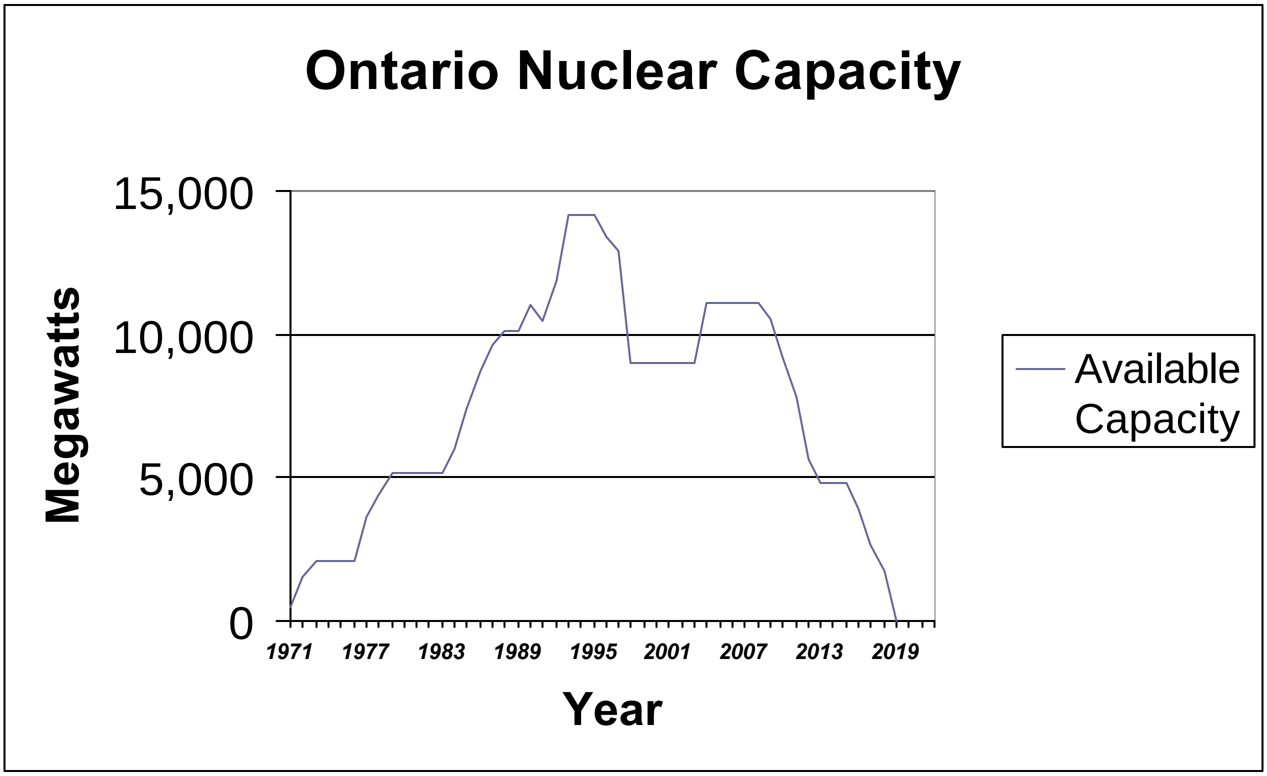


Figure 2
Lifetime Performance Vs. Age for Ontario Nuclear Power Plants

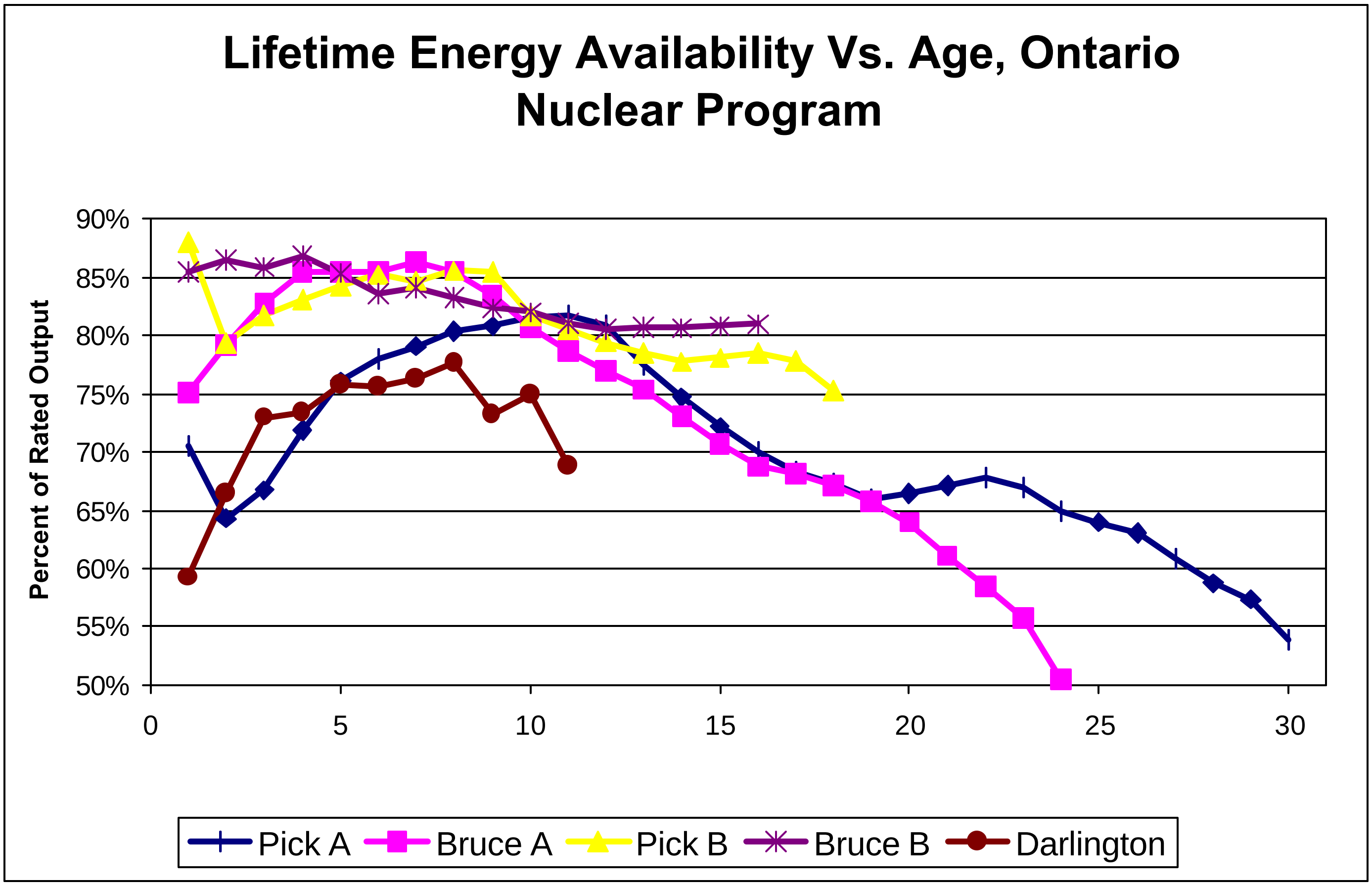


Figure 3
Average Cumulative Availability Vs. Reactor Age for Ontario Nuclear Program

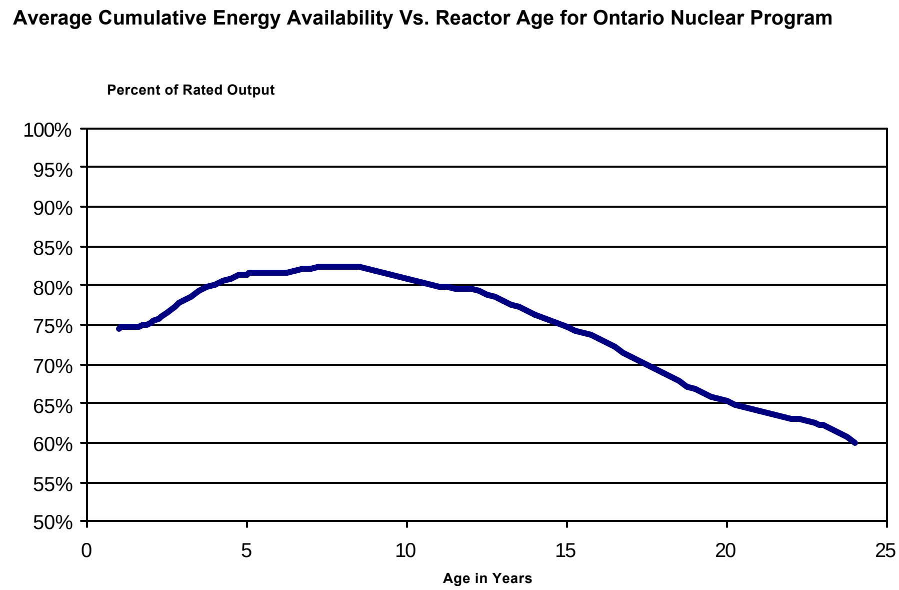
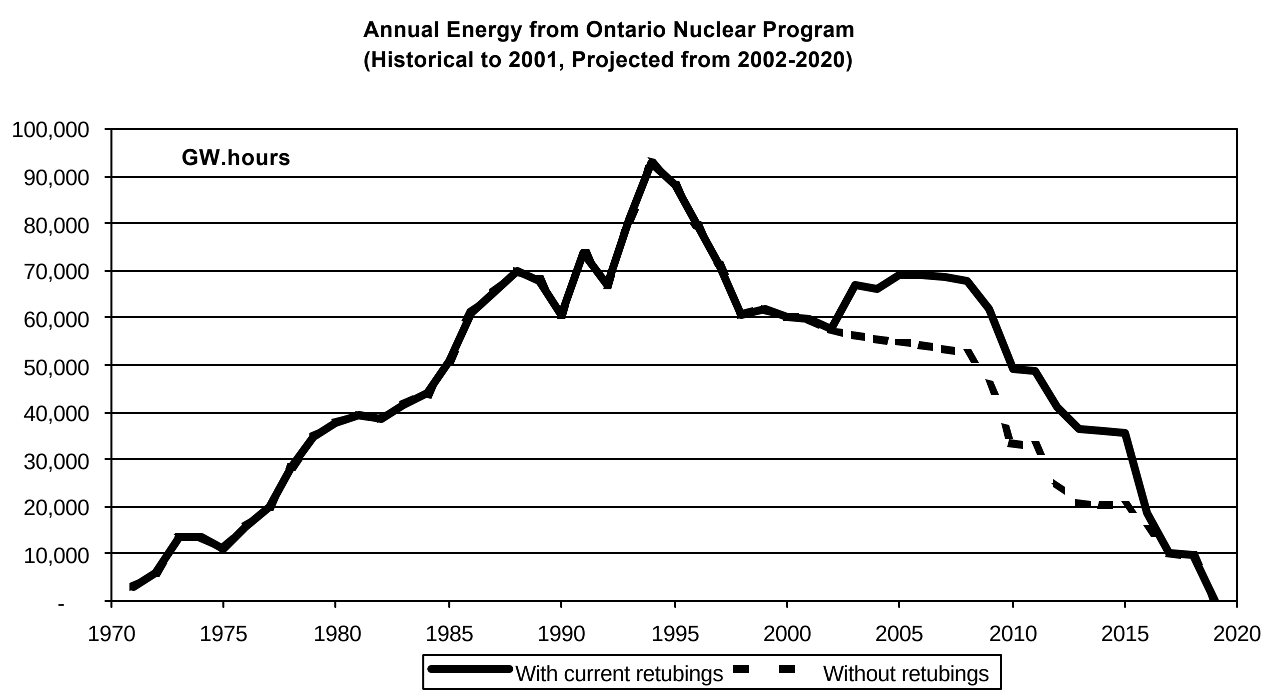


Figure 4
Annual Energy from Ontario Nuclear Program
(Actual 1971-2001, Projected 2002-2020)



Appendix 3
Energy Efficiency Program Case Studies

Appendix 3: Energy Efficiency Program Case Studies

The following program types are highlighted in this Appendix:

1. Residential Energy Efficiency Renovation Programs
2. Residential New Home Programs
3. EnergyStar Technologies Promotion and Financing Programs
4. Building Operator Training Programs
5. Commercial and Institutional Building Retrofit Programs
6. Commercial and Institutional New Building Programs
7. Multi-Purpose Efficiency Programs

A series of case studies are provided under each category, offering information on the financial, and energy saving performance of relevant established energy efficiency programs in North America.

1 Residential Energy Efficiency Renovation Programs

Case Study 1 – EnerGuide for Houses and ATCO Energy Sense

This program offers home evaluations that will assist in planning renovations, reducing drafts and increasing comfort, proper ventilation, reduce heating and cooling costs, assessing building plans, buying a house, and providing an energy efficiency rating. It provides homeowners with the facts they need to make informed decisions about energy efficiency. It applies to Canadian homeowners. This program was recently launched in Alberta through ATCO Energy Sense. It provides home energy audits for $150/home, while the Natural Resources Canada (NRCan) Office of Energy Efficiency (OEE) provides an incentive of more than $150/house to ATCO. Program participation figures for Alberta are unavailable. In the Yukon, since May 1999, more than 200 Yukon households have participated in the EnerGuide for Homes program[1].

Case Study 2 – Yukon Home Repair Program

The Yukon Housing Corporation offers low-interest loans of up to $35,000 to carry out home repairs. These are 10-year loans at a 1.9% interest rate. Additional subsidies are available for low-income families. The goal of the program is to improve the housing stock in the Yukon. Energy efficiency has been identified as one of the program's objectives. In the 2001/2002 fiscal year, 157 homeowners participated, of which 85% (133) included energy efficiency repairs. Since 1995, the Home Repair Program has assisted with improvements for over 350 Yukon households.

In the period of January through June 2001 there were 183 applications which is three times higher than the same period for the previous year. This was likely due to high energy prices at the end of 2000 and the lowering of program interest rate to half of the average 5-year bank mortgage rate.

The 2001/2002 Budget was $3.24 million with $2.862 million directed to loans. In the previous year, $1.247 million was expended.

Homeowners are responsible for implementing the actual repairs. The program requires a technical inspection before and after repairs to identify eligible repairs to get house up to current standards. Upgrades can include doors, windows, insulation, furnaces and water heater. Houses that are five years of age and older are eligible. The program will begin to use the NRCan EnerGuide auditing system for inspections in the future[2].

---

[1] References: EnerGuide for Houses contact person: Barbara Mullally-Pauly (613) 995-2945, Office of Energy Efficiency website: oee.nrcan.gc.ca/english/programs/index.cfm, EnerGuide website: oee.nrcan.gc.ca/energuide/home.cfm, ATCO EnergySense website: www.atcoenergysense.com, Yukon Energy Solutions Centre website: www.nrgsc.yk.ca

[2] References: Marc Perreault (867-393-7154) and Don Routledge (867-667-5759), Yukon Housing Corporation and Yukon Energy Solutions Centre website: http://www.nrgsc.yk.ca

Case Study 3 – Old Crow Yukon Contractor Energy Efficiency Training Initiative

The Pembina Institute implemented a project in Old Crow, Yukon in collaboration with the Yukon Housing Corporation and the Vuntut Gwitchin First Nation (VGFN) Housing Department to provide technical training for local trades people to carry out a series of renovations on residential homes that were targeted through an energy efficiency program. Funding for identifying the energy efficiency options was provided by Devon Energy Canada (formerly Anderson Exploration), while funds for training were provided by Yukon Housing Corporation and Natural Resources Canada.

A detailed four-day training workshop was delivered in the community in late April, 2002. It encompassed the following topics:

- Overview of the R-2000 housing program
- Building Science and Indoor Air Quality
- Overview of the R-2000 Building Envelope Standard
- Overview of mechanical systems – heating and domestic hot water
- Overview of mechanical systems – ventilation
- Examination of participants' learnings
- Hands on experience at the VGFN Safe House construction site

15 individuals from the community participated in the training program and 13 of them wrote and passed the exam, including several builders, the housing manager and other interested parties. As a result of the initiative, Old Crow currently has a large number of skilled energy efficiency practitioners that can proceed with housing renovations that meet high energy efficiency standards.

Case Study 4 – Massachusetts In-Home Services Program

This program aims to improve the energy efficiency of existing homes through retrofit programs (there is another program to build new homes that are 15% more energy-efficient than conventional homes). This program demonstrates effective partnerships between the Department of Energy Resources and electric utilities. Each utility offers a distinctive program and also offers consumer incentives.

The NStar Residential Conservation Service Program has energy efficiency specialists determining eligibility for a Home Energy Assessment. The assessment includes an analysis of home's energy use, advice for saving energy, and rebate offers on recommended energy improvements[3].

Massachusetts Electric Company's "Mass-Save" program offers a free home energy analysis to residential customers and installs low-cost energy and water-saving materials. They provide a report detailing the energy-saving recommendations identified by the energy advisor. For larger buildings, a Multi-family Building Audit is also available. They also sell energy efficient light bulbs at a discount[4].

---

[3] See http://www.nstaronline.com/index2.asp?lk=home

[4] See http://www.masselectric.com/res/conserv/index.htm

Case Study 5 – PowerSmart Home Information Program

Power Smart is a BC Hydro demand side management program that has invested $600 million over the last 10 years. The residential sector activities include a website and targeted initiatives in select "Power Smart Communities" including the Comox Valley, Quesnel, and all of Vancouver Island. These programs are smaller that initiatives in the early 1990's across British Columbia.

PowerSmart has budgeted $70 million for residential and commercial sector programs during the period 2003-2005. As part of the residential programs in Comox Valley and Quesnel, BC Hydro gave away over 40,000 energy saving light bulbs to community residents and picked up and recycled over 500 second refrigerators. The energy savings from the two programs combined have avoided emitting up to 1,250 tonnes of greenhouse gases into the atmosphere per year. These and several other programs helped residents save energy and money while positively impacting the environment. Other programs include access to home energy efficiency audits, and incentives for energy efficiency improvements made by certified contractors[5].

The Power Smart website for homeowners includes the following components:

- A Home Energy Profiling tool to find out what areas homeowners can target to reduce their energy consumption.
- An Appliance Calculator that calculates how much energy each homeowner's appliances use.
- Power Smart Tips, which provides advice on how to save energy around the house.
- An Energy Library, which is a comprehensive resource full of, detailed information on heating, water, lighting, appliances and more.
- A Shop Power Smart site that highlights those home products that are Power Smart certified and where to buy them.
- A section on Power Smart Homes that indicates which new housing developments have Power Smart certification and general advice on how to include maximum energy efficiency in home renovation plans.

---

[5] See http://www.bchydro.com/powersmart/ and article: "Power Smart re-launched on the Island" by Darrell Bellaart, Nanaimo News Bulletin, 7 October 2002.

2 Residential New Home Programs

Case Study 1 – Yukon Green Mortgage

The Yukon Housing Corporation Green Mortgage Program encourages building or upgrading houses to meet a high standard of energy efficiency and indoor air quality as specified by the Green Home Certification standard. It offers residential mortgages with a preferred interest rate for green homes. Once a new or existing dwelling is certified as a Green Home, the purchaser and subsequent purchasers are eligible to apply for a Green Mortgage with a preferred interest rate. The rates on Monday, January 13, 2003 were (prime rate was 4.5%):

- 3.880% for a 1 year term
- 4.580 2 yr
- 4.980 3 yr or 4yr
- 5.230 5yr

The Green Mortgage program offers a minimum down payment of 5%, no mortgage insurance fee (i.e., worth up to 4.25% of the mortgage), 1,2,3,4, and 5 year term options, a maximum borrowing amount of $200,000, and interest rate reduction based on the average interest rates posted at local banks.

Any revenues from the Green Mortgage are directed into the "Senior's Housing Fund" which will help address future housing needs of Yukon Seniors. As such, it is a revolving fund that reinvests savings into further energy efficiency and housing improvements.

The basic Green Home criteria include the following:

- Specific design standards, primarily based on the R-2000 criteria
- 75% of building materials
-
-
- n business
- Acceptable EnerGuide rating, including a pressure test

As of 2001, 17 certified Yukon Green Homes have taken advantage of the Green Mortgage Program. The program involves a partnership between contractors, the federal government (R-2000 program), local materials suppliers, and homeowners[6]. One shortcoming of the program is that it is taking mortgages away from private banks.

[6] See http://www.nrgsc.yk.ca/programs/yukon_energy_programs.php#Yukon_Housing_Programs or contact Heather Doucet. 867-667-8784 (heather.doucet@gov.yk.ca)

Case Study 2 – Texas Housing Partnership Program

This program aims to improve energy efficiency in low to moderate income housing through the establishment of partnerships among non-profit organizations, community action agencies, local governments, utility companies, public housing authorities, and social service-related organizations. The program encourages community and residential involvement in energy efficiency projects such as housing retrofits, model demonstration projects, technical training assistance, and energy education workshops and seminars. The program is a partnership between the State Energy Conservation Office (SECO) and various other bodies.

The Housing Partnership Program has 3 sub-programs.

1. Energy Efficient Housing Demonstration Project: Encourages community and residential involvement in energy efficiency projects such as housing retrofits, model demonstration projects, technical training assistance, and energy education workshops and seminars. Through a competitive bid process, several projects have demonstrated the cost-effective use of energy efficiency in residential housing since 1997. Many of the project activities and results can be replicated across Texas. The projects cover a range of activities:
    - Energy efficient design and building methods
    - Metering/monitoring of household energy consumption
    - Builder/homeowner training
    - Energy efficient appliances
    - Passive solar design/measures

2. Housing Trust Fund Program: SECO is partnering with the Texas Department of Housing and Community Affairs' Housing Trust Fund Program to increase the energy efficiency of new and existing multi- and single-family housing for low income persons and families. The Housing Trust Fund Program is the only state-authorized program dedicated to the development of affordable housing, and provides loan funds to finance, acquire, rehabilitate, and develop affordable housing for low income persons and families. SECO will provide funds to ensure that energy efficient design and appliances are incorporated in the new construction. The SECO funding will be through grants that require the housing construction to exceed a minimum standard[7].

3. Rebuild Texas - Rebuild Texas is a partnership of Rebuild America – a program sponsored by the U.S. Department of Energy (DOE) to help communities improve energy efficiency in commercial and multifamily buildings. SECO has two initiatives under this partnership:
    - Public Housing Energy Efficiency. SECO has helped develop a series of training workshops, to pass on the technical expertise from the DOE's Oak Ridge National Laboratory to promote buildings that are more energy efficient. The workshop topics range from performance contracting to local contracting; from

[7] Council of American Building Officials Model Energy Code (CABO MEC) '92 and '95.

maintenance and upkeep to resident education; and from no-cost/low-cost measures to major rehabilitation projects.

- Texas Showcase Communities. SECO is establishing partnerships to improve energy efficiency in cities which have populations ranging from 10,000 to 35,000. The aim is to implement a wide range of energy efficiency measures in local government buildings, schools, hospitals, small commercial buildings, farms and housing. The saving achieved in the local community through these measures will be used to provide additional improvements in the communities.

This program is run by the State Government agency SECO[8]. However, many programs in Texas are run by utilities following the 1999 Senate Bill 7 which restructured the state electric utilities and required each investor-owned utility to meet at least 10% of the utility's annual growth in demand through cost-effective energy efficiency measures. Most programs were offered full-scale in 2002[9].

[8] See http://www.seco.cpa.state.tx.us/Hp.htm and http://www.seco.cpa.state.tx.us/hp_eef.htm
[9] See http://www.aceee.org/new/texas.pdf

3 EnergyStar Technologies Promotion and Financing Programs

Case Study 1 – Ontario Sales Tax Exemption (8%)

All Energy Star appliances are to exempt from provincial sales tax (8%) under the new Bill 210, “Electricity Pricing, Conservation and Supply Act, 2002”. Anecdotal evidence has shown this has been a great success, partly because consumers love to save taxes.

Case Study 2 – BC Hydro PowerSmart EnergyStar Promotion

This program aims to encourage the transformation of the appliance market in British Columbia to Energy Star products using incentives for retail sales staff. BC Hydro’s Power Smart “product designation” program for products that either improve electricity efficiency (e.g., weather stripping) or have high efficiency (e.g., certain electric water heaters) has been extended to include promotion of the Energy Star labeling of refrigerators, clothes washers, and dishwashers.

There are several components to the promotion:

- Pilot projects to provide financial incentives to retail sales staff to sell Energy Star appliances – the sales person receives a bonus of $20 for each Energy Star appliance sold.
- Providing information on Energy Star on the Power Smart web site and in promotion of Power Smart products.
- Listing of all retailers in BC that carry Energy Star appliances on web site.
- Pilot projects to provide incentives to consumers to buy Energy Star appliances when an old refrigerator is removed from the home at the same time.

The pilot staff incentive program targeted a small number of retail stores. It ran for 12 months and the results show that although it has resulted in good awareness building for Energy Star among sales staff, it has not helped sales. The normal mark-up on appliances is so large that $20 is no real incentive for selective selling – maximizing volume is.

Annual energy savings for each appliance have been estimated below based on differences in performance between typical Energy Star and conventional appliances:

- Energy Star refrigerators use about 50% less electricity than a typical 10-year-old fridge and at least 10% less than the minimum federal standard.
- Energy Star clothes washers use 35-50% less hot water than a conventional washer.
- Energy Star dishwashers use 25% less electricity than the minimum federal standard.

The pilot program was run in partnership with the NRCan OEE and certain major retailers. The estimated cost of the pilot by OEE was $137,000[10]. Actual energy savings are not available.

[10] Reference: OEE 2002/2003 Business Plan

BC Hydro has had better success with consumer incentives – especially on compact fluorescent lights. The buy-one-get-one-free promotion has worked well and is liked by suppliers.

Case Study 3 – SaskEnergy High Efficiency Furnace Loans

This program aims to promote gas heating furnaces and appliances and achieve energy savings by accelerating the replacement of old heating systems with a new ones. Retailers also gain from selling and installing the new equipment.

The program is delivered through the Sask Energy Natural Gas Network – a group of independent equipment retailers and contractors across Saskatchewan. Prime interest rate loans are offered on the following new gas heating appliances:

- Furnaces
- Water Heaters
- Radiant Heaters
- Unit Heaters
- Space Heaters
- Boilers
- Fireplaces
- Clothes Dryers

The program offers a six month deferred payment option, a fixed loan rate at the prime rate (currently about 4.5%), a maximum loan per customer of $10,000, and a maximum loan period of 5 years. The program started in July 1, 2001 and has recently been extended to June 2003. Loans are arranged through local financial institutions with Sask Power paying the difference in loan interest.

No preferences are currently given for energy efficiency. The reasons given are that 1) until Energy Star there has been no simple definition of high efficiency, and 2) some rural members of the Network were not able to service condensing furnaces. However, Sask Energy plans to promote the selection of Energy Star furnaces and water heaters under the program in the spring of 2003, in cooperation with the NRCan OEE as part of their national strategy to promote Energy Star. No decision has been made yet to limit the loans to Energy Star only.

All residential and small business customers in Saskatchewan are eligible. As of December 2002, 5,882 residents had participated in the program with approved loan value of $19.8 million. The target for each year was 2,500 customers. Operating costs are estimated at $800,000 per year.

The program is operated by the Sask Energy Marketing and Sales Department and funds are allocated through the marketing budget. Sask Energy provided training and information to the members of the Network and made arrangements with financial institutions to provide the loans[11].

Case Study 4 – California Appliance Recycling Program

The Statewide Residential Retrofit Program includes an Appliance Recycling provision. The objective of the program is to encourage the removal of operable but inefficient appliances (i.e., refrigerator, freezer). In addition, the program includes a focus on second refrigerators within homes, so does not necessarily involve replacement.

Target Audience and Participation

The program had a target of removing 34,800 units in 2002, at an estimated cost of US $200 per unit. This target was exceeded in the summer of 2000, when two utility companies retired and recycled 37,000 working inefficient refrigerators and freezers.

Program Management

The California Public Utilities Commission sets out general requirements and approves or amends plans and budgets submitted by 3 major utility companies. Each utility plan may vary in terms of the number of units they propose to recycle, the budgets and consumer incentive structure. However, in 2002 companies were required to target and obtain a certain proportion of hard-to-reach customers. Companies are required to offer comprehensive toxic material recycling and disposal in accordance with California environmental laws.

Budget and Funding

The statewide program budget was nearly US $7 million for 2002, of which $6.7 million was for delivery and the remainder was for evaluation, monitoring, etc. Consumers were offered either a $35 rebate per refrigerator/freezer that was removed, or a five-pack of compact fluorescent light bulbs, worth $50.[12,13,14] The program is offered on a first come, first served basis, depending on the budget.
The program is one of many that is funded by Public Purposes Charge. This is a direct tax on electricity and natural gas that is used to fund energy efficiency programs. The charge was introduced at the same time as deregulation, to ensure the continuation of energy efficiency measures. The charge appears as part of the monthly utility bill (both electricity and natural gas). It is approximately US 0.37 cents per kWh for electricity (or

---

[11] Reference: Sask Energy Web site and Sask Energy Marketing staff. NRCan OEE staff.

[12] California Public Utilities Commission, 2002. *Interim Opinion Selecting 2002 Statewide Energy Efficiency Programs,* IV Programs Selected. Website at: http://www.cpuc.ca.gov/published/final_decision/14345-03.htm

[13] Originally the rebate was US$50. See Pacific Gas and Electric, Statewide Residential Appliance Recycling Program, Program Report October 1 to December 31, 2002, p.2. Website at: http://www.pge.com/003_save_energy/003a_res/cempe/pdf/4q02_recycling_narrative.pdf

[14] The energy efficient lamp bulbs have a retail value of $50, which provides an incentive for customers to choose the light bulb option, rather than the money, see Southern California Edison, Refrigerator and Freezer Recycling Program. Website at: http://www.sce.com/sc3/011_reb_off/011a_fyh/011a1_reb_off/011a1b_ref/011a1b2_ref_frez.htm

between 2 and 3%, though the actual amount varies, depending on the sector and company).[15]

Energy Savings

In 2002 the CPUC targeted a reduction of 72.9 million kWh per year and a reduction of overall demand by 11MW for the three utility companies[16].

To assess the actual achievements of the program, one needs to look at the reports of the individual utility companies. Southern California Edison had an initial budget of US$4 million, which resulted in 19,916 units being recycled (actual and committed), for a net saving of 34.4 million kWh and 5.5MW capacity.[17] Before the end of the year, additional funds were added which will allow a further 4512 units to be recycled, with additional energy and demand savings of 7,782 MWh and 1.2 MW.

At the end of the year, Pacific Gas and Electricity (PGE) reported spending its full budget of US$1.68 million and that additional funds were shifted to the program, increasing the total budget to US2.5 million. When the fourth quarter report was compiled, the company had recycled 10,193 appliances (actual and committed), for an energy saving of 17.4 million kWh and saving of 2.7 MW capacity.[18,19] These are preliminary figures and do not appear to account for the full, enlarged budget. The company will update the figures in their 2003 report. At the time the report was compiled only US$1.83 million of the budget had actually been spent. At PGE the energy efficient light bulbs were chosen rather than the financial rebate in exchange for more that half the appliances recycled (5460 chose light bulbs, compared with a total 10,193 appliances). As a result of the uptake of the lamp bulbs additional energy savings of 249,000 kWh were achieved (that is, 1.6% more than the program target).

Because final figures are not available, it is not possible to report the total savings accomplished in 2002.

Financial Characteristics for Consumers

The consumer would pay for a replacement appliance, where required, but could offset the cost by $35 received for recycling the old appliance.

---

[15] California Energy Commission, 2003. California Investor-Owned Utilities Retail Electricity Price Outlook 2003-2013, see also http://www.energy.ca.gov/energypolicy/documents/index.html

[16] Interim Opinion Selecting 2002 Statewide Energy Efficiency Programs, California Public Utilities Commission. IV Programs Selected. http://www.cpuc.ca.gov/published/final_decision/14345-03.htm

[17] Southern California Edison, Residential Appliance Recycling Program, October 1, 2002 thru December 31, 2002, p. 1 and 2. Website at: http://www.sce.com/NR/rdonlyres/eq27aqkd5wzpd2lt5vklnox2otzdhdlijw6mvmuybjzket4z2iienubq3tgbil4gofrxsoex4l3jj644hip37rv7iwc/EE_Filings_4Qtr_2002_Report.pdf,

[18] Pacific Gas and Electric, Statewide Residential Appliance Recycling Program, Program Report October 1 to December 31, 2002. Website at: http://www.pge.com/003_save_energy/003a_res/cempe/pdf/4q02_recycling_narrative.pdf

[19] Full details about the program implemented by Pacific Gas and Electric are available in a workbook at http://www.pge.com/003_save_energy/003a_res/cempe/xls/4q02_recycling_wkbk.xls N.B. This report may be removed from the website at the end of the first quarter, 2003.

Implementation Issues

One of the utility companies (PGE) informed the public about the refrigerator/freezer recycling through a cable TV bill insert, that was sent by direct mail to over 6 million homes in the third quarter of 2002. In addition they supplied 25,000 point-of-sale fliers to appliance retailers, issued a press release and did 30 second cable TV ads.[20]

PGE note that customers received their incentive cheques within 10 business days of pick up.

Case Study 5 – California Upstream Residential Lighting Program

The objective of this program is to continue the upstream lighting program and, in 2002 to broaden the availability of EnergyStar qualified lighting products to include lighting fixtures, ceiling fans and other lighting measures in more stores and outlets. Retailers or manufacturers receive additional incentives that are passed on to the customer. The California Public Utilities Commission sets out general requirements and approves or amends plans and budgets submitted by individual utilities. The program will also target the “hard to reach” through the addition of non-traditional delivery channels, such as grocery stores, drug stores, etc. The total program budget for 2002 was $9.3 million. The program’s energy reduction targets for the 2002 program were 293 GWh of energy savings per year and a demand reduction of 23 MW[21].

---

[20] This was reported in the third quarter report for the program. However, this report is no longer available on the website, since it has been replaced with the fourth quarter report.

[21] Reference: Interim Opinion Selecting 2002 Statewide Energy Efficiency Programs, California Public Utilities Commission. IV Programs Selected. http://www.cpuc.ca.gov/published/final_decision/14345-03.htm

4 Commercial Building Operator Training/Certification Programs

Case Study 1 – Northwest Energy Efficiency Alliance Building Operator Certification

The Regional Building Operator Certification (BOC) program aims to achieve energy efficiency through improved building operations. BOC is a professional development program that teaches facility managers, building operators, maintenance personal and others who monitor commercial building controls how to reduce energy and resource consumption in the facilities they operate. Building operators and managers who successfully complete a training series earn certification.

Studies show that electricity use in Northwest commercial and government buildings could be cut by 15 percent or more if building operators managed and maintained their structures and building systems more effectively. The program was initiated by the Northwest Energy Efficiency Alliance (NEEA) and is delivered by industry through a voluntary, competency-based certification process.

Almost 1000 students have participated since 1997, with about 250 per year. The program has trained over 10% of eligible participants. A target of 40% of operators has been made for 2010.

The program operates through a partnership between facility-oriented associations (e.g., Northwest Building Operators Association - NWBOA, Washington Association of Maintenance and Operations Administrators, Oregon Schools Facility Management Association, Operating Engineers Union, International Facility Managers Association), utilities and trade associations, and major employers in the Northwest (e.g., Boeing, U.S. Navy, Washington State Department of General Administration, University of Oregon). They develop an agreement on marketing and training responsibility through the Northwest Energy Efficiency Council in Oregon and Washington and NWBOA in Idaho and Montana.

The annual program costs include US$1.8 million for delivery, $140,000 for administration, and $233,000 for evaluation. The NEEA gets its funding from ratepayer sources sponsored by the Bonneville Power Association. They charged on average $966 per student between 1997 and 2000. The cumulative computed impact for the period 1997-2000 per student participating in the program was estimated to be 177,500 kWh (compared with an initial planning value of 25,000 kWh per year). Total annual energy savings of the whole program were estimated at 172 GWh at the end of the period between 1997 and 2000. A demand reduction of 19 MW was estimated to be achieved by 2001. The program demonstrated a benefit-cost ratio of 7.8[22].

[22] See http://www.nwalliance.org/projects/projectdetail.asp?PID=41 and http://www.nwalliance.org/resources/reports/88.pdf

5 Commercial and Institutional Retrofit Programs

Case Study 1 – NRCan OEE Energy Innovators Program

The Energy Innovators Initiative is designed to facilitate large-scale energy retrofit projects by providing funding of up to 25% of eligible costs to a maximum of $250k. Projects are selected on a competitive basis. The program will also subsidize study and feasibility costs. It requires that client commit to very strict and extensive process requirements. It unofficially relies on ESCOs to generate projects. It will pay up to $15/GJ of energy savings through funding provided by the federal government through the NRCan OEE. It is managed through an independent office[23].

Case Study 2 – New York Standard Performance Contracting Program

The New York State Energy Research and Development Authority (NYSERDA) offers a commercial and industrial performance program which aims to encourage contractors to implement cost-effective electrical efficiency improvements or summer demand reductions for eligible customers. This performance-based program offers incentive payments to contractors and ESCOs that develop projects delivering verifiable annual electric energy savings. Eligible measures include lighting (e.g., LED traffic signals and exit signs), motors, variable-speed drives, energy management systems, certain process equipment, packaged air conditioning devices and chillers (e.g., including non-electric refrigeration and chillers), and custom measures that result in electric-energy savings or demand reductions.

This program is open to facility owners or tenants who agree to pay the New York State System Benefits Charge for the duration of the standard performance contract (SPC) agreement. All classes of customers (i.e., commercial, industrial, and residential) that meet program requirements are eligible. Eligible customers are electricity distribution (i.e., default) customers of Central Hudson Gas & Electric Corp., Consolidated Edison Company of New York, Inc., New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., and Rochester Gas and Electric Corporation. The performance-based incentives are provided through an SPC between NYSERDA and the contractor. The contract between the customer and the contractor can be an energy performance contract or a fee-for-service contract. The average annual electric energy savings will be verified for up to a two-year period following project installation. There is a customer cap of $1 million and a contractor cap of $4 million. Documented Nitrogen Oxide (NOx) emission reductions achieved by energy efficiency projects receiving incentive funds are eligible to receive additional incentives.

Energy marketers are encouraged to participate and offer energy efficiency as a value-added service. There are two stages: project planning/installation which occurs prior to and just after installation of the energy efficiency measures; and project measurement and verification activities which occur after the energy-efficient equipment is installed and operating. The NYSERDA reviews profile information provided by the ESCO to determine if the measure is cost effective on a resource cost basis. Cost effective measures with long lives and higher energy and demand savings produce higher cumulative present value of savings and will receive higher incentive rates. Photovoltaics, and other renewable technologies, are sometimes eligible for

---

[23] See http://oee.nrcan.gc.ca/eii

incentives. The maximum incentive for custom measures is capped at 30 percent of its cost. The total contracted project incentive paid to an ESCO may not exceed 50% of the total project cost[24].

Cumulative funding for the program to date has been US$81 million. As of September, 2002, $33.5 million was spent. Funding for June 2002 to June 2003 period is $20 million on first come, first served basis. As of June 2002, a total of 405 projects were in various stages of completion, from project development to measurement and verification. Incentives of more than $70 million were awarded to 93 ESCOs.

As of September, 2002, annual savings of 232 GWh and a demand reduction of 51 MW were achieved. When fully implemented in 5 years, the projects are expected to reduce electricity use by 489 GWh per year, including a reduction of the summer peak demand by more than over 100 megawatts[25].

Case Study 3 – New York Energy Efficiency Services Technical Assistance

This program is a part of the New York State Energy Research and Development Authority's (NYSERDA) Business and Institutional Program. The program provides technical assistance in the following areas:

- Energy feasibility studies – to identify capital improvements
- Energy operations management – to improve electrical energy efficiency of facility operations
- Rate analysis and aggregation – to prepare customers to negotiate energy prices and services with independent marketers

Businesses, not-for-profit and private institutions, state and local governments, schools, universities, multi-family buildings, health-care facilities, and building owners are all eligible. Customers can select their own consultants or use one of NYSERDA's 36 pre-selected firms to provide help through the Flexible Technical Assistance program, which offers the same services as the standard Technical Assistance program.

---

[24] The total contracted project incentive is the sum of the energy efficiency incentive, and any small site bonus, electric chiller and A/C bonus, and NOx incentives, included in the SPC Agreement. The total contracted project incentive also includes any demand reduction incentive approved for a custom demand reduction measure. The total contracted project incentive paid to an ESCO may not exceed 50% of the total project cost. If a project includes a custom conversion measure, the incentive will be capped at 30% of the measure cost. For these purposes, total project cost includes all costs directly associated with the energy savings of the project including, but not limited to: the Detailed Energy Analysis; energy efficiency measure design, procurement and installation; measurement and verification of energy savings (where the ESCO is responsible for M&V); and ESCO overhead and profit. Where a project includes more than one customer, the 50% limit applies to each customer individually See section 3.2 Total Project Incentive at: http://www.nyserda.org/695pon.html

[25] See http://www.nyserda.org/695pon.html and http://www.nyserda.org/sbcsept2002.pdf
Technical questions should be directed to Todd Baldyga at (518) 862-1090, ext. 3354 or tab@nyserda.org
Contractual questions should be directed to Mary Sauvie at (518) 862-1090, ext. 3229 or mks@nyserda.org

Up to US$100,000 of funding is available per project for cost-shared help from energy engineers and experts. The total budget is $24.6 million of which $6.7 million has already been spent.

According to a survey of NYSERDA's clients, two-thirds of them have implemented recommendations made by Technical Assistance contractors. Each dollar spent on engineering services has resulted in $14 in capital improvements and $4 per year in energy savings. Savings of 195.5 GWh have been achieved, with a demand reduction of 52 MW. The program is targeting annual savings of 560 GWh and a demand reduction of 149 MW[26].

Case Study 4 – Texas LoanSTAR Revolving Loan Fund

This revolving loan fund was legislatively mandated to be funded at a minimum of US$95 million at all times. It aims to provide financing for energy efficiency projects to institutions of higher education, school districts, non-profit hospitals and local governments. Projects can include energy efficient lighting systems; high efficiency heating, ventilation and air conditioning systems; computerized energy management control systems; boiler efficiency improvements; energy recovery systems; and building shell improvements.

127 loans have been made to public institutions since the program started in 1989 with low interest rates that depend on money market costs and administrative costs. For the year ending August 2002, the rate was 3%. The fund is managed by the State Energy Conservation Office (SECO). Texas A&M University is responsible for monitoring and verifying the energy savings.

Between 1989 and the end of 2000, the program had achieved annual energy savings of $100 million. The program has a 20-year target of $500 million of annual energy savings. Actual energy savings have exceeded targeted savings by 5% on average[27]. The maximum load repayment period is 10 years and the fund has already revolved one complete cycle.

SECO also has a State Agency Program which provides a provision for higher education, state agencies, public school districts and local governments to enter into performance contracting agreements, under which facilities make no upfront investments but finance projects through guaranteed annual energy savings[28].

Case Study 5 – VanCity Community Foundation

The VanCity Community Foundation is a catalyst for community transformation based on social and economic justice in a sustainable environment. It supports community partners to connect their current activity to transformation.

The Foundation provides the following services:

- grants of $2,500 to $15,000
- guaranteed loans and lines of credit of $10,000 to $100,000
- low interest loans of $10,000 to $100,000

[26] See http://www.aceee.org/new/eedb.htm and http://www.nyserda.org/techasst.html and http://www.nyserda.org/sbcsept2002.pdf . Contact for the Flex Tech program: Jillina Baxter at (518) 862-1090, ext. 3279; fax (518) 862-1091; jb1@nyserda.org

[27] See http://www.seco.cpa.state.tx.us/ls.html or contact theresa.sifuentes@cpa.state.tx.us

[28] See http://www.seco.cpa.state.tx.us/sa_performcontract.htm

- technical assistance in marketing and communications, budgeting, business plan development, strategic and operational planning, board governance and others

The VanCity Credit Union provides an annual donation to the Foundation. Gifts are also provides from other donors. The general endowment has grown to more than $7.3 million in 2002. Committed community supporters have also added capacity through permanent legacies in the form of Named Fund endowments. Named Funds can be created with a gift of $1,000. The Foundation also provides matching interest for a period of time on Funds, which meet the mandate of the Foundation's grants program. The total permanent endowments are now more than eleven million dollars.

The Foundation provides grants to organizations that are involved in the following community economic development categories including:

- affordable housing
- employment development
- non-profit enterprise

Total grants and loans approved in 2001-2002 were $415,963[29]. The Foundation provides a model for financing of community based projects and could be applied to energy efficiency measures in a different context.

Case Study 6 – California Express Efficiency Program

The Express Efficiency program pays rebates to distributors and small to medium sized nonresidential customers for equipping facilities with selected EE measures, including T8 and T5 lamps, electronic ballasts, lighting controls such as photocell controllers and occupancy sensors, compact fluorescent lamps, high-efficiency motors and HVAC measures. There is an emphasis on the hard-to-reach sectors. The California Public Utilities Commission (CPUC) sets out general requirements and approves or amends plans and budgets submitted by individual utilities. The program targets small to medium sized nonresidential customers. Customers must have monthly demand of less than 500 MW and annual gas usage of less than 250,000 therms (7.3 GWh).

The total budget for the program is US$23.8 million. The program target for 2002 was savings of 284 GWh of electricity per year and 82 GWh of thermal energy savings along with an electrical demand reduction of 56 MW[30].

Case Study 7 – California Standard Performance Contract Program

The Standard Performance Contract Program provides energy efficiency incentives for comprehensive retrofit projects for large and medium businesses. Small businesses can also participate if their measures do not qualify for the Express Efficiency program. The programs include lighting, but only as part of the overall project. These programs are also coordinated by CPUC and delivered by individual utilities. Any customer paying the gas or electricity "Public Goods Charge" would be eligible, even if the customers have opted to purchase their gas or electricity from suppliers other than the default utility. The program involves a partnership between energy service companies who sponsor energy efficiency retrofit projects at utility customers' facilities. The utility companies provide general promotion and program information to customers.

---

[29] Reference: Vancity Community Foundation Annual Report 2001-2002
[30] Reference: CPUC (2002).

The program's budget was $20.7 million in 2002, of which $20.1 million for program delivery. The program has achieved savings of 73 GWh of electricity per year and 50 GWh of thermal energy savings along with an electrical demand reduction of 13 MW[31].

Case Study 8 – Massachusetts Commercial and Institution Retrofits

This program aims to improve the energy efficiency of commercial and institutional buildings through retrofit programs. The Massachusetts Division of Energy Resources (DOER) coordinates the program which involves a partnership with utilities which each have unique programs. In the year 2000 the budget for the program was US$53 million out of a total DOER budget for all energy efficiency programs of US$130 million. The benefit to cost ratio for this program and residential programs was 2.3, including post-program effects[32]. Program savings are expected at 122 million kWh per year.

The NStar utility program enables client to incorporate energy efficient lighting fixtures, controls, high-efficiency mechanical equipment, and other energy saving strategies within their current facility. Benefits of this program include: rebates up to 50% of the total project cost; cost sharing for engineering services; and design and commissioning services. NStar also has gas efficiency programs including: Small Business High-Efficiency Heating Rebate Program; Small Business High-Efficiency Water Heating Rebate Program; Infrared Heating Equipment Rebate Program; Building Operator Certification Training; and customized programs[33].

Massachusetts Electric Co. has several programs for large businesses. For small business they pay 80% of the cost of the installation of a company's energy saving improvements and finance the remaining 20%, interest free, for up to 24 months[34].

Case Study 9 – BC Hydro Power Smart Partners Program

The BC Hydro Power Smart Partners Program is designed to facilitate large scale electrical energy retrofit projects by funding electricity demand reductions on a competitive bid basis. It works with the 1000 largest electricity consumers in the province. The Bid "price" is determined by dividing funding requested by electrical energy saved. The program will also subsidize study and feasibility costs. The program reportedly has an unofficial price cap of 5 cents/kWh for savings. It is managed and funded by BC Hydro, but unofficially relies on energy service companies (ESCOs) to generate projects. Anecdotal evidence also suggests that program is overly complex for benefit realized, and may be replaced by a rate incentive program. The large required administrative and technical infrastructure is problematic[35].

---

31 Reference: CPUC (2002).
32 See http://www.state.ma.us/doer/pub_info/ee00-long.pdf p.15
33 See http://www.nstaronline.com/index2.asp?lk=buss
34 See http://www.masselectric.com/bus/effic/index.htm
35 See http://eww.bchydro.bc.ca

6 Commercial and Institutional New Building Programs

Case Study 1 – NRCan OEE Commercial Building Incentive Program

The Commercial Building Incentive Program (CBIP) pays an incentive to a building owner in proportion to the annual energy cost savings relative to a reference building roughly based on the Model National Energy Code for Buildings (MNECB). The maximum annual incentive is $60k per building. Savings must be demonstrated using software provided by the program. The objective of the program is to reduce energy consumption in new commercial construction. The program is financed and administered by NRCan's Office of Energy Efficiency using federal funds. The program is centrally managed by CBIP specific technical and administrative infrastructure. It has been in operation for 4 years. Energy and financial savings are unknown.

CBIP has already invested huge amounts in the setup and maintenance of the program. The CBIP budget unknown, but is clearly substantial. CBIP has experienced significant difficulties with all aspects of the program design and delivery. Major program revisions may be pending. However, it is likely to be an excellent fit for supporting Alberta programs because of the substantial financial investment to date in program infrastructure[36].

Case Study 2 – California Savings By Design

This program provides incentives for efficiency during the design process for non-residential buildings. This creates an incentive for designers to become engaged in energy efficiency. The California Public Utilities Commission sets out general requirements and approves or amends plans and budgets submitted by individual utilities. CPUC has directed that at least 50% of funds be used for "whole-building" oriented projects. Building architects, design teams, building owners and developers receive incentives passed on the % by which the work exceeds the "Title 24 standards" (California's building energy standard). Building owners or designers receive an incentive if work exceeds 10% above the standard, while if the work exceeds standards by 15%, the architects and design team also receive an incentive.

The total budget for the program is $23.3 million per year, of which $22.5 million is for programs and the remainder is for monitoring and administration. The program savings goals approved by CPUC for 2002 were 87.6 GWh/year of electricity and 14 GWh of thermal energy along with an electrical demand reduction of 29MW[37].

Case Study 3 – New York State New Construction Program

This program aims to save energy in buildings by providing technical and financial incentives to applicants to specify and install selected energy-efficient equipment or to erect buildings that exceed the energy efficiency of standard design practice as determined by NYSERDA and the minimum requirements of the New York State Energy Conservation Construction Code. It can also be used for substantial renovations of buildings.

Applicants may choose among incentives for pre-qualified equipment, custom measures or whole building capital costs. The program provides technical assistance incentives to applicants to assist in the evaluation of energy-saving options for each qualified project and

[36] See http://cbip.nrcan.gc.ca/cbip. Further information is available from the Manager, Pierre Geuvrement, 613-996-6722, pgeuvrem@nrcan.gc.ca.
[37] Reference: CPUC (2002).

capital cost incentives to defray a portion of the incremental capital cost to purchase and install more energy-efficient or advanced equipment. The program may cover up to 80% of the incremental costs of qualified energy-efficiency measures. All energy-efficiency measures must meet cost-effectiveness and benefit/cost criteria set by NYSERDA.

The cumulative budget of US$64 million to date will deliver anticipated savings of 238 GWh and a demand reduction of 38MW. $28 million is available for projects during the period of June 2002 to December 2003 on a first come, first served basis, with $3 million allocated to building-integrated photovoltaics.

The process starts through an application to NYSERDA which has retained several Outreach Project Consultants (OPCs) to assist applicants. These OPCs work directly with program applicants to determine eligibility, explore participation options, identify technical assistance needs, and assist in completing program applications. NYSERDA provides written pre-approval of all qualified applications for incentives under this program. This pre-approval authorizes the applicant to proceed with the purchase and installation of the specific equipment and building features outlined in the approved application. Upon completion of the approved installation, the applicant is asked to provide written certification that the equipment and building features have been installed. NYSERDA may elect to inspect any or all projects prior to final approval. All building projects with approved incentive offers over $50,000 are inspected prior to payment[38].

[38] See http://www.nyserda.org/593pon.html and http://www.nyserda.org/sbcsept2002.pdf .
Questions can be directed to Cullen O'Brien at (518) 862-1090, ext. 3414 or cmo@nyserda.org

7 Multi-Purpose Efficiency Programs

Texas Standard Offer and Market Transformation Programs

The 1999 Texas State Senate Bill 7 requires that utilities to acquire energy-efficiency savings equal to the equivalent of at least 10% of their growth in demand. The Texas Public Utility Commission (PUC) oversees the implementation. A preliminary evaluation of programs was undertaken for the "Emission Reduction Incentive Grants Report" which was prepared for the Texas Natural Resource Conservation Commission in September 2002. As most energy efficiency programs were new in 2002, there is not a lot of analysis yet on their performance.

Utilities are to obtain the required energy savings by selecting programs in the following categories:

Standard Offer Programs	**Market Transformation Programs**
Commercial and Industrial	Air Conditioning Distributor
Industrial and Small Commercial	Energy Star Homes
Load Management	Residential Energy Star Windows
Hard to Reach	Air Conditioning Installer Information and Training

These programs apply to all sectors. They aim to maximize synergies with federal programs such as EnergyStar. Programs are managed by utilities.

The budget in 2002 was US$43.8 million, according to the utility reports to the PUC. Funding comes through transmission and distribution rates that are collected by utilities in areas where retail competition has begun and through electric rates in areas where competition has not begun. Energy savings of 246 GWh per year have been achieved. By 2007 it is estimated that the program will facilitate 510 GWh/year savings.

California Energy Efficiency Programs

California energy efficiency programs are controlled by the California Public Utilities Commission (CPUC). The following table highlights the various programs that are currently offered, some of which are explained in more detail in previous sections of this report. The table highlights energy and demand reduction targets for each program and program budgets[39].

[39] See http://www.cpuc.ca.gov/published/final_decision/14345.htm

Table 3.1 – California Energy Efficiency Programs

Program	Energy Reduction Target (GWh/yr)	Demand Reduction Target (MW)	Gas demand Reduction Target (GWh/yr)	Total Budget (US$ million)
Statewide Residential Retrofit Programs				
Home EE surveys				2.1
Appliance Recycling	72	11	88	6.7
Single-Family Unit Rebates for EE Equipment	47	33	88	24.5
Multi Family EE rebates	17	7	59	8.3
Statewide Residential New Construction	9	13	12	14.0
Statewide Nonresidential Retrofit Programs				
Nonresidential SPC Programs	73	13	50	20.1
Efficiency Express Programs	283	55	82	23.1
Nonresidential Audit Programs				7.1
Building Operator Certification and Training				1.0
Emerging Technologies				1.6
Statewide Nonresidential New Construction Programs	87	29	15	22.5
Marketing and Outreach Programs				10.0
Education and Training				7.3
Codes and Standards Advocacy				2.0
Statewide Upstream Residential Lighting Program	293	23		9.3
Total				$160

Appendix 4
A Comparison of Combustion Technologies for Electricity Generation

Appendix: A Comparison of Combustion Technologies for Electricity Generation

This appendix provides additional background information to the summary entitled "Best Available Pollution Control Technologies for Coal Combustion" that accompanies a Pembina Institute media release on July 24, 2001.

With commercially available coal-fired technology, it is possible to reduce emissions to levels considerably below those required by the Alberta government. In fact, some of the proven technologies reviewed in this document can achieve much better performance than the new Alberta standards demand; most are commonly used in jurisdictions in the U.S. and Europe and are economically viable at today's prices for natural gas, electricity and coal. Consequently, the Pembina Institute believes that proponents of new or retrofitted coal-fired plants in Alberta should be required to implement options that have better environmental performance than what is specified in the latest, already outdated, Alberta regulations.

1. Overview of Technologies

All coal combustion technologies rely on the generation of high pressure steam using heat produced by burning coal. This high pressure steam then drives a turbine, and electricity is produced from an electrical generator attached to the steam turbine.

Exhaust gases from combustion of the coal are typically cleaned by a series of downstream processes. Particulates are removed by electrostatic precipitators or fabric filters (baghouses), and sulphur oxides (SO_x) are removed by one of a range of possible flue gas desulphurization (FGD) processes. Nitrogen oxide (NO_x) production can be controlled by in-furnace features such as low NO_x burners. A Selective Catalytic or Non-Catalytic Reduction process can further reduce NO_x emissions.

The combustion of coal in the boiler can be accomplished in various ways, described below. In general, the most energy-efficient plants have the lowest emissions, as they produce more electricity per unit of coal burned. However, emissions from less-efficient plants can be reduced with "add-on" pollution control options.

1.1 Subcritical and Supercritical Pulverized Coal Combustion (PCC)

Coal combustion has traditionally occurred at atmospheric pressure using subcritical steam, but today, greater efficiencies can be obtained by using higher steam pressures in the supercritical range.* Both the subcritical and supercritical processes begin with coal being ground into a fine powder. The powdered coal is blown with air into the boiler through a series of burner nozzles where combustion takes place at temperatures from 1300-1700°C, depending largely on the coal type. Combustion occurs at near-atmospheric pressure, which simplifies the burner and coal handling facilities. Subcritical PCC plants use steam in the range of 16 megapascals (MPa) pressure and 550 °C while supercritical PCC plants use steam with pressures as high as 30 MPa and 600 °C. The higher steam pressure in supercritical plants results in higher energy efficiency – 38-45%, compared with 33% for subcritical plants. While supercritical plants have higher capital costs and some added risk due to the higher pressure and temperature, they have been in commercial use for many years.

* At atmospheric pressure, water bubbles at boiling point before turning into steam; above a certain critical pressure, it enters a "supercritical" state, where it undergoes a continuous transformation directly into steam.

Most plants in Alberta currently use only low efficiency subcritical coal-fired processes. If conventional pulverized coal combustion is being considered, proponents should use supercritical steam processes to maximize efficiencies.

1.2 Atmospheric and Pressurized Fluidized Bed Combustion (AFBC and PFBC)

Fluidized bed combustion (FBC) processes are commonly used with high sulphur coal. In a FBC plant, hot air blown up through the floor of the boiler suspends or “fluidizes” powdered coal mixed with a sorbent such as powdered limestone. The combustion of the coal in the presence of the sorbent facilitates the capture of sulphur dioxide (SO_2). Conventional boilers, by contrast, simply burn the fuel on a grate in the firebox. FBC plants can remove up to 98% of the SO_2 and the coal burns more efficiently because it stays longer in the combustion chamber.

AFBC plants operate at atmospheric pressure, and NO_x generation is minimized due to lower combustion temperatures (815-875^oC) than in conventional PCC plants. In contrast to AFBC plants, PFBC plants operate at elevated pressures. PFBC plants are typically more compact than similar capacity AFBC and PCC plants due to the higher pressure. The PFBC design allows for potentially greater efficiency, reduced operating costs and less waste than the AFBC design. PFBC plants use the same process as AFBC plants to fluidize or float the coal/sorbent mixtures. In both AFBC and PFBC plants, the reacted sorbent forms a dry, granular material that is easily disposed of or used as a commercial by-product. The reacted sorbent is removed with the bed ash through the bottom of the boiler and with the fly ash that has been collected in the dust collectors at the top of the boiler stacks.

In PFBC plants, additional energy is captured when the combustion gases that leave the fluidized bed are cleaned in a gas cleanup system and then re-burned in a gas turbine. The gas turbine is connected to an electrical generator thereby improving the plant’s efficiency. The use of a steam turbine and a gas turbine improves performance by creating a highly efficient combined cycle system.

The operating temperatures of fluidized beds are between 760 and 870^0C, approximately half the temperature of a conventional boiler. This relatively low temperature is below the threshold where thermally induced NO_x forms. Thus, the fluidized bed designs have reduced SO_2 and NO_X emissions when compared with PCC designs. In addition, fluidized bed combustion can use high-ash coal whereas conventional pulverized coal units must limit ash to relatively low levels.

Given that most coal in Alberta has a low sulphur content (less than 1% and sometimes as low as 0.2%, compared with high sulphur coal, which contains up to 5%), it is unlikely that this process would be selected in Alberta.

1.3 Integrated Gasification Combined Cycle (IGCC)

IGCC plants are extremely clean and more efficient than traditional coal-fired systems. In IGCC plants, coal is not burned in a traditional boiler but is converted into a hydrocarbon vapour (syngas) in a gasifier. The syngas is then cleaned, stripped of impurities and used as fuel instead of natural gas in a conventional combined cycle plant (see description of the natural gas combined cycle plant, below). The result is an integrated gasification combined-cycle configuration that provides ultra-low pollution levels and high system efficiencies. The IGCC systems that are operating commercially have demonstrated exceptional environmental performance. Emissions of SO_2 and NO_x are less than one-tenth of those allowed under U.S. New Source Performance Standards limits. Moreover, IGCC efficiency levels can be as high as 45%.

Most of the existing IGCC plants were built on a demonstration basis with government subsidies; however, these plants are nearing full commercial operation. For example, it is reported that the Wabash River plant in Indiana had an overall reliability of 79% in 1999 and operators are now receiving a lot of interest in their technology. A mechanism is in place for repayment of loans received from the Department of the Environment.

1.4 Comparison with Natural Gas Combined Cycle

The natural gas combined cycle process (NGCC) is not a coal combustion process, but a description is included here for comparison with the various coal-fired options

Commercial-grade natural gas burns more cleanly than other fossil fuels because it consists mostly of methane and has already been cleaned of sulphur. In NGCC plants, natural gas is used as fuel in a gas turbine. Electricity is produced from the generator coupled to the gas turbine, and the hot exhaust gas from the turbine is used to generate steam in a waste heat recovery unit. The steam is then used to produce more electricity in the same way as described for the PCC options above. The output from both the gas turbine and the steam turbine electrical generators is combined to produce electricity very efficiently. NO_x control in gas turbines is proven technology and can be accomplished with relatively low cost "low NO_x burners." In addition, NO_x can be reduced still further with such "add-on" control technology as Selective Catalytic Reduction (see below). Emissions of particulate matter are also quite low, although some secondary particulate matter is produced through atmospheric chemistry reactions involving NO_x.

A variation of the NGCC is the natural gas combined heat and power cycle (NGHPC). In these plants, the waste heat recovered from the turbine exhaust gas is not used to produce steam; instead, it is used to supply heat to an adjacent facility, such as a refinery. The end result is a plant that produces both electricity and useful heat. NGHPC plants have even higher overall energy efficiencies than NGCC plants, at lower capital costs, due to the elimination of the steam cycle. Several NGHCC systems are being used in oil, gas and petrochemical industries across Canada.

2. Add-on Pollution Control Options

A number of pollution control devices are commonly added onto conventional coal-fired plants. These add-ons can enable conventional coal-fired plants to achieve very low levels of emissions and, for some pollutants, the add-on options can result in coal-fired electrical generation being nearly as clean as natural gas-fired generation.

Flue Gas Desulphurization (FGD) – FGD is a process where lime or lime-like material is added to the flue gas to absorb sulphur compounds and reduce the amount of SO_2 emissions. The process can be wet or dry, regenerable or non-regenerable. Often the recovered sulphur or reacted absorbent can be sold as an industrial process chemical. Wet FGD systems can achieve up to 95% sulphur removal, while dry systems can remove up to 70-80% of the sulphur.

Low NOx Burners (LNBs) – Low NO_x burners are used to control the combustion process to minimize the formation of NO_x. The design of LNBs for gas turbines is well proven and NO_x reduction from LNB-equipped gas turbines exceeds 90%. This level of reduction meets many of the more stringent NO_x regulations in the U.S. and Europe; however, further reductions in NO_x

can be achieved with an SCR unit added to the exhaust of a gas turbine. LNBs for sub and supercritical PCC plants is also well proven but NO_x reduction from LNB-equipped PCC plants is only 50%. This necessitates the use of additional NO_x control equipment such as selective catalytic reduction to enable PCC plants to meet the standards in many parts of the world (although not Alberta).

Selective Catalytic or Non-Catalytic Reduction (SCR or SNCR) – SCR or SNCR is a process that removes NO_x formed in the exhaust gases due to high combustion temperatures. SCR technology involves the injection of ammonia (NH_3) into the exhaust gas, which then passes through a catalyst bed where the ammonia and nitrogen oxides react to form harmless nitrogen and water vapour. SNCR involves a similar process but without the catalytic reaction. Both SCR and SNCR can reduce NO_x emissions by about 80% before ammonia slippage out of the exhaust stack becomes a problem. These technologies have been applied to both gas and coal-fired facilities to further reduce NO_x emissions.

Electrostatic Precipitators (ESPs) and Fabric Filters (Baghouses) – ESPs or baghouses are commonly added to all coal-fired power plants to remove particulate matter and flyash from the exhaust gases. ESPs use an electrostatic charge to attract small particles, whereas baghouses simply filter the particulate matter from exhaust gases using a self-cleaning fabric filter process. ESPs are more prone to upsets since they rely on an electrical charge, which is typically de-energized during a plant shutdown. Baghouses are less sensitive to upsets and are more efficient at removing most particulates. Both ESPs and baghouses are able to remove some mercury (that fraction of mercury emissions already associated with the flyash) if they are used on cooled exhaust gas. Baghouses are generally more efficient at removing mercury than ESPs.

3. Comparison of Coal Combustion Options

The following table compares coal combustion technologies. It summarizes the characteristics of the various coal-fired generating technologies and compares them with cleaner burning natural gas systems. Footnotes appear immediately following the table on page 8. All dollars are Canadian currency unless otherwise noted.

Coal Combustion Technology Comparison

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Environmental Performance [1]							
Plant Efficiency [2]	33%	38-43%	36%	42% [3]	45%	52%	~60%
Heat Rate (GJ/MWh)	10.9	9.5-8.4	10	8.6	8.0	6.9	6.0 per equiv. MWh
CO_2 (kg/MWh) [2]	1000	870-770	920	790	735	400	350
Sulphur Removal Standard	Alberta: 180 ng/J U.S.: 260 ng/J, 70-90% removal and BACT [4]						
SO_2 (kg/MWh) – no FGD	1.6 [5]	1.4 [6]	0.3 [7]	0.12 [3]	~ zero	~ zero	~ zero
SO_2 (ng/J) – no FGD	229	221	30 [8]	14	~ zero	~ zero	~ zero
S02 (ng/J) – with FGD	< 70	< 66	Not required	Not required	Not required	Not required	Not required
NO_x Removal Standard	Alberta: 125 ng/J U.S.: 65 ng/J						
NO_x (kg/MWh) – no SCR	2.1 [2]	1.8 [6]	0.5 [7, 8]	<0.7	0.25-0.45 [9] (w/ LNB)	0.12 (w/ LNB)	0.12 (w/ LNB)
NO_x (ng/J) – no SCR and w/ LNB	86-125 [5]	86-125 [5]	43	<86 [3]	31-56	18 [10]	18 [10]
NO_x (ng/J) – with SCR and LNB	43-62	43-62	SCR not required	SCR probably not required	SCR probably not required	SCR probably not required	SCR probably not required
Particulate Matter Standard	Alberta: 13 ng/J U.S.: 13 ng/J						
PM (kg/MWh) – no ESP/Baghouse	0.5	0.4 [6]	~0.4	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
PM (ng/J) – no ESP/Baghouse	46	42	~42	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
Mercury	Depends on coal source	Depends on coal source	Depends on coal source	Better than PCC but not as good as IGCC	Little or no air borne mercury	Little or no air borne mercury	Little or no air borne mercury

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Pollution Control Add-ons							
Flue Gas Desulphurization (FGD)	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[11]	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[11]	Not required	Not required	Not required	Not required	Not required
NO_x Control: Low NO_x Burners (LNB)	LNB can reduce approx. 50% NOx formation.	LNB can reduce approx. 50% NO_x formation.	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.
NO_x Control Selective Catalytic Reduction (SCR)	80% NO_x removal without ammonia slip problems. [12]	80% NO_x removal without ammonia slip problems. [12]	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.
	Note: Typically **both** LNB and SCR required in PCC plants to meet most standards.						
Baghouse or ESP	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Not Required	Not Required	Not Required
Mercury[13]	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse and FGD 60-70% removal. ESPs not as effective.	With baghouse up to 70% removal.	With baghouse up to 70% removal.	Not Required	Not Required	Not Required
CO_2 Capture	From flue gas, difficult to recover.	From flue gas, difficult to recover.	From flue gas, difficult to recover.	Recovery should be similar to IGCC.	Relative to other options, recovery is more straightforward from off-gas. [14]	From flue gas, difficult to recover.	From flue gas, difficult to recover.

Base Processes	**Subcritical Pulverized Coal Combustion (PCC)**	**Supercritical PCC**	**Atmospheric Fluidized Bed Combustion (AFBC)**	**Pressurized Fluidized Bed Combustion (PFBC)**	**Integrated Gasification Combined Cycle (IGCC)**	**Natural Gas Combined Cycle (NGCC)**	**Natural Gas Combined Heat and Power Cycle**
Operational Performance							
Currently in use at:	Genesee, Keephills, Wabamun. Many plants worldwide.	Europe, Japan, U.S. Many plants worldwide.	Pt. Aconi, NS uses Circulating Fluidized Bed (185 MW plant), first one in Canada 1993. [7] Japan, Europe. Commonly used with high sulphur coal.	Sweden, Spain, U.S., 350 MW plant under construction in Japan. [15] Commonly used with high sulphur coal.	General coal gasification well proven. IGCC used at three U.S. plants (Polk, Wabash,[16] Pinon Pine) and in The Netherlands and Spain.	Many plants worldwide.	Many plants worldwide.
Commercially Proven	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Scale	100-1000 MW	100-1000 MW	400 MW guaranteed by manufacturer. [8]	80 MW	100-300 MW	Any size in modulars	Any size in modulars
Reliability and Uptime	Good	Good	Good	Good	Good [16]	Good	Good
Economic Performance [17]							
Capital Cost – main process ($/kW)	$**1200**-1500 [15] $1283 [18] $1200 [19]	$**1275**-1575 [15] $1322 [18] $1200 [19]	$**1500**-1950 [15] $1324 [18]	$**1725**-2025 [15] $1429 [18]	$**1800**-2100 [15] $1798 [18] $1800 [20]	**$1,000**	**$940** [21]
Capital Cost – add-ons ($/kW)							
FGD	$**105**-180 [15] $158-236 [22]	$**105**-180 [15] $158-236 [22]	N/R	N/R	N/R	N/R	N/R
SCR [15]	$**60**-120	$**60**-120	N/R	N/R	N/R	N/R	N/R
LNB [15]	**$7.5**-15	**$7.5**-15	**$7.5**-15	**$7.5**-15	Std.	Std.	Std.
Total Capital Cost ($/kW)	**1373**	**1448**	**1508**	**1733**	**1800**	**1000**	**940**
(Sum of bold numbers above used in total capital cost)							
Return (%)	15%	15%	15%	15%	15%	15%	15%
Life (yrs)	35	35	35	35	35	35	35
Total Capital Cost ($/MWh)	23.68	24.97	26.01	29.89	31.06-34.94	17.25	16.22
(Note: No Tax, No Depreciation)							
Operating Cost ($/MWh)							
Labour [23]	2.08	2.08	2.32	2.77	2.77-3.12	2.08	2.08
Other (100% of labour)	2.08	2.08	2.32	2.77	2.77-3.12	1.63	2.08
Energy (GJ/MWh)	10.9	9.5	10	8.6	8.0	6.9	6
$/GJ [17 24 25]	**1.18**	**1.18**	**1.18**	**1.18**	**1.18**	**4.00**	**4.00**
Energy Cost ($/MWh)	12.86	11.21	11.80	10.15	9.44	27.60	24.00
Operating Cost – add ons ($/MWh)							
FGD [22]	2.6	2.6					
Total Operating ($/MWh)	19.62	17.97	16.44	15.69	14.98 - 15.67	31.31	28.16
Overall levelized cost to produce electricity ($/MWh)	**43.30**	**42.94**	**42.45**	**45.58**	**46.04-50.61**[26]	**48.56**	**44.38**

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Rank (1=Best, 7=Worst)							
Efficiency/GHG Ranking	**7**	**5**	**6**	**4**	**3**	**2**	**1**
Sulphur Removal Ranking	**7**	**6**	**5**	**4**	**3**	**2**	**1**
NO_x Control Ranking	**7**	**6**	**4**	**5**	**3**	**2**	**1**
PM Emission Ranking	**7**	**6**	**5**	**4**	**3**	**2**	**1**
Mercury Emission Ranking	**7**	**6**	**5**	**4**	**3**	**2**	**1**
CO_2 Sequestration Ranking	**More Difficult**	**More Difficult**	**More Difficult**	**Less Difficult**	**Less Difficult**	**More Difficult**	**More Difficult**
Capital Cost Ranking	**3**	**4**	**5**	**6**	**7**	**2**	**1**
Operating Cost Ranking	**5**	**4**	**3**	**2**	**1**	**7**	**6**
Overall Cost to Produce Ranking	**3**	**2**	**1**	**4**	**6**	**7**	**5**

Table Footnotes

[1] Environmental performance characteristics described are at the plant site only. These values do not consider any "upstream" impacts, such as from coal mining operations, natural gas production and processing.

[2] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations - Pulverized Coal Power Plant," http://www.ieagreen.org.uk/emis4.htm, 40% efficiency emits 830 kg/MWh and 43% efficiency emits 770 kg/MWh.

[3] Southern Illinois University, Coal Research Center, "Pressurized Fluidized Bed Combustion," www.siu.edu/~coalctr/presfbc.htm.

[4] Application of terms of the U.S. EPA standard would result in at least 70% removal of sulphur, or about twice what would be required with Alberta standards and Alberta's coal.

[5] From EPCOR's EIA for Genesee 3.

[6] Based on ratio of efficiencies (33% vs. 38%).

[7] See Nova Scotia Power's website: http://www.nspower.ca/OurEnvironment/EmissionControls/. Port Aconi Power Plant in Nova Scotia removes 90% of the sulphur and 60% of NO_x.

[8] Southern Illinois University, Coal Research Center, "Atmospheric Fluidized Bed Combustion," www.siu.edu/~coalctr/atmosfbc.htm.

[9] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Integrated Gasification Combined Cycle," http://www.ieagreen.org.uk/emis6.htm.

[10] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Natural Gas Combined Cycle," http://www.ieagreen.org.uk/emis5.htm based on 25 ppm (~ 18g/GJ).

[11] "Sorbent Injection Systems," www.siu.edu/%7ecoalctr/sorbinj.htm.

[12] Southern Illinois University, Coal Research Center, "Post Combustion NO_x Control Technologies: Selective Catalytic Reduction Systems," http://www.siu.edu/~coalctr/postcomb.htm.

[13] Environmental Working Group, Clean Air Network and Natural Resource Defense Council, "Mercury Falling: An Analysis of Mercury Pollution from Coal-Burning Power Plants," June 2001, Washington DC.

[14] CO_2 is recovered at the large gasification project at Great Plains, Dakota and injected into underground reservoirs for enhanced oil recovery at Weyburn, Saskatchewan. See Dakota Gasification Company website: http://www.dakotagas.com/ and http://ens.lycos.com/ens/jul2000/2000L-07-14-11.html.

[15] Energy Issues (The World Bank) No.14 August 1998, " Technologies for Reducing Emissions in Coal-Fired Power Plants" by Masaki Takahashi, http://www.worldbank.org/html/fpd/energy/enls14.pdf. Costs in $US converted to $Cdn at 1.50 exchange rate (1995$).
[16] Wabash River (one of the U.S. IGCC Demonstration Projects) has begun repaying the DOE and has also achieved 79% overall reliability in 1999, "Clean Coal Today" Newsletter of the Office of Fossil Energy, U.S. DOE, DOE/FE-0215P-39 Issue No. 39, Spring 2000.
[17] All currency in Canadian dollars.
[18] From EPCOR's EIA for Genesee 3, Vol.1, Figure 2.2.1.
[19] Calculation based on the average of Keephills and Genesee 3 expansions.
[20] This number represents the actual cost of constructing the greenfield IGCC Polk Power Plant. U.S. DOE Publication "Techline DOE Sponsored Clean Coal Project Wins Power Magazine 1997 Award," June 5, 1997, U.S. Department of Energy.
[21] Calculated from TransCanada Pipeline's Press Release for the Redwater and Carseland Cogeneration Projects.
[22] Southern Illinois University, Coal Research Center, "Dry Flue Gas Desulfurization." http://www.siu.edu/~coalctr/index.html. $US converted to $Cdn at 1.50 exchange rate (1995$).
[23] For the PCC options, cost of labour ($2.08/MWh) has been calculated using information from EPCOR's Genesee 3 Expansion EIA: 60 people, 440 MW, $120,000 per person per year and 90% load factor. This labour cost has been assumed the same for the two natural gas options. Labour for IGCC and PFBC has been determined using EPCOR's staffing model (60 people) and adding 15 more operators and 5 more maintenance/technical staff to handle the additional complexity of the IGCC and PFBC plants. Labour for AFBC assumes adding 5 more operators and 2 more maintenance/technical staff.
[24] Coal prices from the Coal Association of Canada Website 1998 Prices FOB Vancouver or see also Fording Coals 2000 Annual Report: $US 35.50/t ($Cdn 53.25/tonne), less transportation at approx. $32/tonne (Vancouver - Edmonton), 18 GJ/tonne gives $Cdn 1.18/GJ. This assumes that value of coal in Edmonton area is related to world market prices for coal.
[25] Gas price based on approximate daily AECO prices for June 28, 2001 from http://www.gasalberta.com/WebPublish/Web-Gas%20Price.htm
[26] Lower range of values for IGCC based on same reliability/uptime as for the other options. Higher range of values based on 11% worse reliability of IGCC when compared to the other options.

Glossary of Terms used in Table

AFBC - Atmospheric Fluidized Bed Combustion
BACT - Best Available Control Technology
CC - Coal Combustion
CO_2 - Carbon dioxide
ESP - Electrostatic Precipitators
FGD - Flue Gas Desulphurization
GHG - Greenhouse Gases
GJ - Giga-Joules
IGCC - Integrated Gasification Combined Cycle
kg - kilogram
LNB - Low NOx Burners
MWh - Mega-Watt per hour
NGCC - Natural Gas Combined Cycle
NO_x - Nitrogen Oxides
NR - not required
PCC - Pulverized Coal Combustion
PFBC - Pressured Fluidized Bed Combustion
PM - Particulate matter
ppm - parts per million
SCR - Selective Catalytic Reduction
SO_2 - Sulphur dioxide
SO_x - Sulphur oxides

The following summary compares the coal combustion options.

1. Efficiency and CO_2 – The coal combustion options are not as efficient as the natural gas options, and consequently all have significantly higher rates of greenhouse gas emissions. Of the coal-fired options, the IGCC process is the most efficient with the conventional subcritical PCC plants having the lowest efficiency.

2. SO_2 – Both the super and subcritical PCC options have high rates of sulphur emissions and require flue gas desulphurization to meet Alberta's standards. None of the other options require any add-on sulphur removal equipment.

3. NO_x – All coal-fired options, except perhaps IGCC, typically require both low NO_x burners and SCR/SNCR to meet a U.S. Standard for NO_x. The less-stringent standard in Alberta makes it possible for proponents to meet the Alberta standards with only low NO_x burners.† The natural gas options may not require SCR/SNCR to meet the more stringent U.S. standards if the gas turbines are properly equipped with LNBs to reduce NO_x by 90+%. If LNBs are not available to reduce NO_x to sufficiently low levels, the design may have to include a combination of LNBs and SCR/SNCR.

4. Particulate Matter – Of the coal-fired options, only the IGCC option does not require supplemental dust control measures. All other coal-fired options require either a baghouse or ESP, with the preferred option being a baghouse due to the added benefits of removing other pollutants such as mercury.

5. Mercury –With the exception of the IGCC option, all coal-fired options emit mercury from their stacks. The addition of a baghouse helps remove some mercury; however, the baghouse does not reduce the mercury down to the levels achieved in IGCC or the natural gas-fired plants.

6. CO_2 Sequestration – CO_2 must be considered in the design of all future power plants. Of all the options considered (coal and natural gas), only the IGCC option has a design that can facilitate CO_2 capture. This is because the relatively high pressure of the exhaust gases in an IGCC plant allows for easier CO_2 removal. Of course, the amount of CO_2 emitted from a natural gas-fired power plant is approximately half that emitted from a coal-fired plant.

7. Proven Technology – Both the subcritical and supercritical PCC options are well proven and are used in thousands of plants worldwide ranging in size from 100 MW to 1000 MW. AFBC plants are also well proven with hundreds in commercial operation in the 200 MW size and a few operating in Japan and France at 350 MW. PFBC plants are in commercial operation in Sweden, Japan and the U.S. with most in the smaller size (that is, less than 100 MW). A 350 MW unit is currently under construction in Japan. Most of the IGCC plants were initially built on a demonstration basis; however, all of them are now approaching a commercial level of operation in the range of 200-300 MW. The production of syngas from coal, which is the first step in an IGCC plant, has been around for many years and is a well proven technology. Both natural gas-fired options are commercially proven with thousands of installations worldwide in various sizes.

8. Capital and Operating Costs – The natural gas-fired options have the lowest capital cost, but even with their high efficiency, their operating costs are somewhat higher than coal at today's current gas prices ($4.00/GJ). Among the coal-fired options, the capital cost for the relatively basic design of the subcritical PCC option is the lowest, with progressively higher capital costs for the supercritical PCC, AFBC, PFBC and IGCC. Operating costs rank in more or less reverse order, with the AFBC and the supercritical PCC plants having the lowest operating costs.

9. Overall Levelized Cost to Produce Electricity – Comparing all options (coal- and natural gas-fired), the AFBC, super-PCC and the sub-PCC options can produce the least expensive electricity at around $43/MWh. The highest cost option is the NGCC at approximately $49/MWh at a $C4.00/GJ cost of natural gas. The IGCC system is also more expensive than other coal-fired options (generally 7-18% more, depending on the assumed reliability and other criteria used in the table), but is becoming competitive at today's electrical pool prices. At gas prices of approximately $3.25/GJ, NGCC becomes economic relative to the supercritical PCC coal-fired option. While the economics for all options is extremely sensitive to the cost of energy (coal or natural gas), all options considered have overall levelized costs within 10% of the average.

† The Two Elk Power Generation plant that was recently approved in Wyoming is designed to achieve low emissions using both low-NOx burners and Selective Catalytic Reduction. Ninety-five percent of the SO_2 will be removed using flue-gas desulphurization lime spray dryer.

4. Discussion

From an environmental standpoint, none of the coal-fired options is as favourable as the natural gas-fired options. However, among the coal-fired options, IGCC has the best environmental performance and comes very close to being as clean as the natural gas-fired options for all pollutants except CO_2. Natural gas-fired generation emits approximately half the CO_2 per amount of energy produced of any coal-fired option.

Based on the economic analysis presented in this paper, the IGCC option has an overall levelized cost of power that is within 7-18% of the supercritical PCC plant now being proposed in Alberta by EPCOR. The only area of concern with the IGCC option is its commercial viability on larger scale operations. With the number of IGCC plants moving into or already in commercial operation, this concern should be alleviated. Proponents of coal-fired plants should seriously consider IGCC, given its superior environmental performance for only a modest incremental increase in cost. The relatively high cost of today's natural gas (assumed to be $4.00/GJ) means it costs slightly more (12%) to produce electricity with the NGCC option than with the supercritical PCC option. However, at gas prices of approximately $3.25/GJ, the NGCC option has the same overall levelized cost as supercritical PCC plants. The natural gas combined heat and power cycle has very favourable economics even at today's gas prices due to its low capital cost and high efficiency.

With the deregulation of the electricity sector in Alberta, there is no longer a direct relationship between the cost of generation and the prices paid by consumers. In any hour, the price of generation is now set by the variable cost of the last unit dispatched. Even with the addition of more coal-fired capacity, consumers will typically be paying prices that are consistent with cleaner gas-fired generation. Allowing the proponents of new coal-fired generation to avoid the cost of installing more effective pollution control equipment on their plants will simply transfer the cost of the pollution onto society without providing offsetting benefits of lower cost power. While it is true that the addition of new coal-fired capacity will augment the supply of electricity in the province and lead to reductions in the market price of power in Alberta (from the average of $133/MWh in 2000), these same reductions would be realized with the addition of an equivalent amount of gas-fired capacity. The fact is that, following the addition of this new coal-fired generation, consumers will be paying prices that are consistent with the costs of cleaner gas-fired power plants but will experience comparatively higher levels of pollution from the new coal-fired facilities. The Alberta government should ensure that consumers get what they pay for – clean, highly efficient gas-fired generation. There is no need to settle for less.

5. Conclusions

This paper clearly shows that:

- Natural gas-fired generation has superior environmental performance and acceptable economic performance when compared with the coal-fired option.
- Of the coal-fired options, only the IGCC option comes close to meeting the environmental performance of the natural gas options and this is achievable with acceptable economical performance (IGCC has an overall levelized cost of power that is within 7 to 18% of the most economic options).
- All options, along with their associated pollution control add-ons, are feasible at today's gas, coal and electrical prices.
- With the pollution control add-ons, the environmental performance of the more conventional PCC coal-fired options can be drastically improved while still producing economic electricity.

All the electrical generation options reviewed in this paper can comfortably meet the new Alberta standards, in some cases without the additional pollution control equipment that would be required to meet the standards in the U.S. and certain other jurisdictions.

Alberta has clearly not adopted the approach of using Best Available Control Technology in designing the latest environmental standards. This review shows that many different, proven technologies are commercially available and could be economically included in the design of any coal-fired plant in Alberta. Unfortunately, because Alberta's standards are not as strict as in some other jurisdictions, proponents of coal-fired plants in Alberta will not be required to use these technologies.

Pembina Institute for Appropriate Development

www.pembina.org

Canadian
Environmental
Law Association

www.cela.ca