Potential for Cogeneration in Ontario

- Final Report -

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TABLE OF CONTENTS

TABLE OF CONTENTS

1. INTRODUCTION

Cogeneration (the combined production of heat and power, where both products are utilized) can get the highest utilization of the energy available from a fuel, making it the most efficient way to generate electricity using fossil fuels. Substituting cogeneration for generation from more intensive emitting sources can reduce both greenhouse gases (GHGs) and other pollutants. Ontario is the third largest producer in Canada of electricity from coal, which is the most intense GHG emitter of the fuels used for electricity production.

This project is intended to address the future prospects for cogeneration in the context of a restructured electricity market in Ontario. Its estimates of economic potential and its identification of the key factors affecting implementation will provide the Ontario government, and others, with information to use in tracking performance. Its identification of barriers will help the government to plan policies that can affect that performance.

The electricity supply industry in Ontario is being restructured from monopoly-based to competitive. The Ontario government has indicated that restructuring should not degrade the industry's environmental performance; its White Paper listed "Enhanced safety, reliability and environmental protection" as goals of electricity restructuring.[1]

One of the most important environmental impacts of electricity generation is the result of air emissions. Coal-fired electric stations are major emitters of SO_2, NO, mercury, and CO_2 as well as particulate matter and other air toxics. In 1995, Ontario Hydro's five coal-fired stations accounted for between 10% and 18% of Ontario's emissions of these four key pollutants. In a restructured market, owners will have profit motivations to increase utilization of these plants, possibly resulting in even higher emission levels.

At the same time, industry restructuring presents a unique opportunity to reduce the impact of this sector on the environment. This can be accomplished if Ontario's new electricity system incorporates energy efficiency and greater utilization of low environmental impact generation systems, including cogeneration.

Also currently in progress is the National Climate Change Process. It is a multi-stakeholder consultation process aimed at providing guidance on the least-cost ways for Canada to meet its commitments for GHG reductions under the Kyoto Protocol. If Canada signs the Kyoto Protocol, it will be required to reduce its GHG emissions to 6% below their 1990 levels by the 2008-2012 time period. Several of the consultation tables of the Climate Change Process have identified cogeneration as a potentially cost-effective way to reduce GHG emissions.

1 Government of Ontario, "Direction for Change: Charting a Course for Competitive Electricity and Jobs in Ontario," pg. 10.

The timing and purpose of this project, therefore, relate to the need to understand both the opportunities and challenges for cogeneration in the restructured Ontario electricity market and the opportunities for reducing GHG emissions through cogeneration.

1.1 Process for the Project

This project has two related elements: the estimation of economic cogeneration potential in Ontario, and the description of barriers which might prevent the realization of the potential. The first task is essentially analytical, requiring quantification of the total possible size of the market, the costs of cogeneration, and the costs of the alternatives. The second task is essentially a description of those factors which can present barriers.

For the analytical portion of the project, the methodology and data sources are described in later sections of this report. The economic potential is limited by two factors: the cost of the electricity and heat produced by cogeneration compared to its cost from alternative sources, and the existence of locations with a simultaneous demand for heat and electricity. The project used available data from various sources to assess the size of the total possible market. It used engineering cost data to analyze the cost of cogeneration. It used the best available forecasts for natural gas and electricity prices. These results were then combined to produce an estimate of the total economic potential.

For the barriers portion, the project combined the expertise of the project team with information obtained from industry participants. This information came from two Workshops with wide industry participation. The Workshops identified and verified the information on barriers. They also helped verify the technical data, especially cost data, from the analytical work.

1.2 Contents of the Report

The ultimate end of the report is to estimate the amount of economic potential for cogeneration in Ontario and to describe barriers which might prevent its realization.

The next three sections of this report present the methodologies and results of the three steps in the analytical task of estimation of economic potential. The next section estimates the cost of cogeneration. Section 3 contains information on the total technical potential, and Section 4 estimates economic potential and the GHG implications of installing that much cogeneration.

Section 5 describes the barriers which may prevent the full economic cogeneration potential from being realized without some change in policy or the electricity market in Ontario.

Appendix A contains a report on the forecast used for the study of natural gas prices. Appendices B and C are reports from the first and second workshops.

2. ESTIMATES OF COST OF COGENERATION IN ONTARIO

Several different technologies and fuels can be used for cogeneration. The choice of technology is often related to the size of the application and to the nature of the steam host. Large-scale applications primarily use gas turbines. Smaller applications can use a variety of technologies. Costs in this study are estimated separately for these larger and smaller scale technologies.

Some industries, notably the forest products industries, generate waste materials which can be used as fuel. Some applications, like district heating, have widely dispersed customers for the heat output; others have single heat customers. These applications have differing cost characteristics.

The estimates of the cost of cogeneration in Ontario are built up from assumptions about the cost components: fuel, operating, and capital. Cost estimates were made separately for two size classes of cogeneration. AGRA Monenco, Inc estimated costs for the medium and large cogeneration applications (those above 10 MW of electricity generation capacity). Hagler Bailly estimated costs of smaller cogeneration facilities.

Costs for each cogeneration technology are expressed as levelized unit energy costs (LUEC). LUEC is the present value of the cost of the electricity over the lifetime of the investment divided by the present value of the total of electricity produced over the lifetime. LUECs are used in this study because they allow direct cost comparisons between generation resources using different fuels and having different lifetimes and different time patterns of cash inflows and outflows.

In deciding on cogeneration installations, decision-makers do not typically refer to LUECs. The decision will be based on the projected energy costs for the total operation, including costs of fuels (gas, electricity, and other fuels), other energy operating costs, and capital costs. LUECs are used here because they allow comparison of costs across different technologies.

However, since the actual decision is based on total cost for the installation, in many specific cases a cogeneration project is economic even though it uses a technology whose LUEC is above the market price of electricity. For example, if a steam host has a boiler that requires replacement, the incremental cost of the cogeneration can be reduced by the cost of the boiler, if the cogeneration facility can eliminate the need for it. Section 4 of this report discusses such cases in more detail.

Electricity generation cost estimates have three major components: capital cost, fuel cost, and operating and maintenance (O&M) costs. Capital costs reflect the fully installed cost for the technology. Fuel costs depend on fuel prices and conversion efficiency of the technology. O&M

costs are sometimes estimated as a function of initial capital costs. Sources of data for these costs will be detailed with the assumptions below.
Costs are presented for three time periods: 2000, 2005, and 2010. All costs are presented in Canadian dollars, using a constant value for the year 2000. All costs are therefore in real terms. Forecast assumptions are also in real terms. Values are presented in real terms to avoid the need to inflate future costs and then discount by an interest rate adjusted for expected future inflation.

2.1 Assumptions

Table 2-1 Forecast Gas Prices

FORECAST GAS PRICES
Alberta Border

(All prices in $2000/Mcf)

	LOW CASE		BASE CASE		HIGH CASE	
YEAR	$	5 yr AAGR	$	5 yr AAGR	$	5 yr AAGR
2000	3.00		3.00		3.00	
2005	2.51	-3.50%	3.15	1.00%	3.49	3.10%
2010	2.10	-3.50%	3.43	1.70%	4.07	3.10%
2015	2.34	2.20%	3.86	2.40%	4.65	2.70%
2020	2.61	2.20%	4.35	2.40%	5.31	2.70%

2.1.1 Gas Prices

All the cost estimations used the same assumptions about the delivered price of natural gas, which fuels many of the potential applications. The forecast price of natural gas is the subject of a separate report, which is attached as Appendix A of this report. Forecasts are for delivered gas prices in three scenarios: a base case, with high and low cases.

Forecast gas prices are projected to 2020 for all three cases. Forecast prices were presented at the first Workshop. The gas prices used for this report are presented in Table 2-1.

2.1.2 Large and Medium Technologies

Capital costs for current installations rely on information from the AGRA Monenco generation cost model. These data represent current costs as obtained from previous confidential studies by AGRA Monenco and from recent manufacturer information.
Fuel costs were determined by the heat rate and the cost of gas. Heat rates are from the same source as the capital costs, and for the base year, they represent the expected performance of currently available technologies.

O&M costs are derived from a fixed and variable component. The fixed component represents such fixed expenses as insurance and local taxes, if any. The variable component represents the variable cost of operating the cogeneration facility.

Given these costs, the next step is to calculate the cost of power. To determine the cost of power produced by the large and medium cogeneration technologies, AGRA Monenco developed an income statement proforma financial model. This level of modeling was needed to allow analysis of the impacts of taxes on the cogeneration costs. The financial model was used to calculate the LUEC of each of the different plant capacities.

The assumptions used for the AGRA Monenco model were

- Debt rate 6%
- Debt term 20 years
- Debt/equity 75/25
- Hurdle rate (IRR) 13%
- Steam value ($/1000 lb) $7.51
- Capacity factor 93%

The debt rate represents a real interest rate for borrowing for projects of this kind. The IRR hurdle rate is a real rate that typical developers would require for a cogeneration project.

The steam value is based on the commodity value of the gas displaced assuming 80% conversion efficiency for the gas, which is the value suggested by participants in the Workshops. For the early year cases, it is assumed that the cogeneration is being added to an existing facility. The steam is therefore given no credit for reductions in O&M or capital costs.

2.1.3 Small Technologies

Cost calculations for the smaller technologies were taken from the cost section of the PHB Hagler Bailly model DISGEN, which is used to calculate potential for (small-scale) distributed generation of all kinds including cogeneration. The DISGEN model bases decisions on total energy cost for the site. It therefore does not use LUECs directly; they were calculated for this project to allow comparison with the LUECs for the medium and large technologies.

These assumptions were consistent where possible with those for the larger technologies. Capital costs come from similar sources: previous confidential PHB Hagler Bailly projects, feedback from Workshop participants and other market sources in Ontario; information from manufacturers, and information from standard published industry cost sources. These sources also provide the information on the technical performance of the equipment, including heat rates and capacity factors. O&M costs were derived from the capital costs. For these cost estimates, all of the technologies are assumed to run at a 90% capacity factor.

Gas costs were taken from the gas price forecast.

The LUECs were calculated assuming a 7-year payback period, spreading the capital costs equally over that period. This assumption reflects the small scale nature of these technologies and the likely approach of its owners.

The heat value was calculated by assuming that the heat requirement would otherwise be met by burning gas at 85% conversion efficiency. For this calculation, no credit is given for reductions in O&M or capital costs, because such savings are specific to particular applications.

A key variable in evaluating these technologies is the ratio of electricity to thermal output. That ratio varies significantly between applications, depending on the nature of the heat demand and the technology. For this study, the electricity/thermal ratios vary from 0.5 to 4.0. All the fuel cell technologies have ratios above 1.2; among the other technologies, only the reciprocating engines have ratios that high. All the other thermal technologies have ratios well below one. These differences reflect the differences in the technologies. The fuel cells produce very little heat, giving much of their energy to electricity generation. The thermal technologies have much more waste heat available because they produce exhaust heat.

2.2 Cost Estimates

2.2.1 Large and Medium Technologies

The current cost estimates for these technologies are based on actual costs or current planning costs of actual plants.

AGRA Monenco used its power project database to identify the cost of generating electricity and recovered thermal energy. The database is continuously updated with new supplier and market information. A number of sizes of cogeneration plants were selected based on actual configurations of cogeneration technologies[2]. The following candidate plants were analyzed:

Combined cycle cogeneration: 250, 150, 100 and 50 MW

Simple cycle cogeneration: 250, 40, 26 and 10 MW

[2] Plant sizes in MW are for the electricity output. Heat output is in addition to the electricity.

Combined cycle cogeneration plants include a gas turbine, a steam turbine and a heat recovery steam generator (HRSG). A simple cycle cogeneration plant includes only a gas turbine and an HRSG. The significance of this difference is that a combined cycle plant typically transfers a greater proportion of the energy from input gas to electricity. In a simple cycle plant, a greater proportion of the energy of the input gas is applied to displacing thermal energy for space heating or industrial processes.

For all of these plants, estimates were developed for total capital cost, variable operating costs, and fixed operating costs. Other operational cost estimates include expected plant life, plant availability, gas consumption, plant heat rate (without thermal sale), plant heat rate (with thermal sale) and steam output. All these parameters were quantified using AGRA Monenco's cogeneration cost date base.

The model was used to calculate levelized unit energy costs for six parameters including O&M, fuel cost, income tax, power price without thermal credit and power price with thermal credit (Table 2-2.) All calculations are in real (constant dollar) terms.

The levelized unit energy cost of electricity ($/kWh) for each plant capacity was calculated as follows:

$$\frac{\text{NPV of electricity revenue over 20 years}}{\text{NPV of power output over 20 years (kWh)}}$$

Of all the cost components of gas fired cogeneration, the price of natural gas has the most significant impact on the levelized unit energy cost. The year one burner tip cost of gas ranges from $4.40/Mcf for large plants over 50 Mw to $6.73/Mcf for small units less than 500 kW. Long-term high, medium and low gas price forecasts developed by Hagler Bailly were applied to all gas fuelled plants.

The 13% IRR hurdle rate represents the expectation of a typical developer, as estimated by AGRA Monenco.

Using Table 2-2 for illustration, the following significant results are apparent. The capital cost per kW increases significantly as plant capacity decreases due to loss of economies of scale. Costs per kW range from a low of $774/kW for a 250 MW combined cycle plant to $2,039/kW for a 10 MW simple cycle plant. The results show the same relationship between plant size and the levelized cost of O&M.

While levelized fuel cost increases as plant capacity decreases, the impact of the combined versus simple cycle plant configuration is also apparent. Using the 250 MW plants for purposes of illustration, the combined cycle plant has a lower fuel cost because a portion of the waste heat recovered is used to generate additional electricity through a steam turbine.

Heat rates are a measure of the plant's power generating efficiency. The total heat rates (without thermal credit) also show the influence of the steam turbine on reducing plant heat rates by increasing electricity output. The thermal credit heat rate incorporates the thermal sale into the plant's overall efficiency. The formula for thermal credit heat rate is:

$$\frac{\text{Total input energy (Btu)}}{\text{Total electricity output (kWh)} + \text{Total thermal energy recovered (kWh)}}$$

For purposes of the study, the volume of thermal energy recovered was quantified differently in the case of the combined cycle and simple cycle plants. The volume of thermal energy recovered in the simple cycle plants was defined by that volume of waste heat rejected via the exhaust of the gas turbine that could normally be recovered for thermal sale using a state of the art HRSG. The results show that, with full heat recovery, simple cycle plants can achieve efficiencies of up to 80%.

For combined cycle plants, the amount of electricity generation depends on the volume of steam diverted from the steam turbine to the heat application. For this analysis, the volume of steam diverted to use the thermal energy from the combined cycle plants was set at a level just sufficiently high to allow the plant to qualify for accelerated depreciation under the Class 43.1 efficiency provisions.

The levelized tax cost represents only corporate income tax paid after deduction of the class 43.1 accelerated capital cost allowance. Other taxes, including federal and provincial capital taxes, sales tax and municipal taxes are not included.

The levelized unit energy cost (LUEC) is shown both with and without the addition of thermal sales revenue (Thermal Credit). Again, the large proportion of thermal energy recovered for thermal sale in the case of the simple cycle plants is apparent. The Levelized Thermal Credit is substantially greater for the simple cycle plants than for the combined cycle plants.

It is important to note that the approach used in the study for quantifying thermal sale does not necessarily reflect the approach that would be taken in the field. In cases where power prices are relatively high, an investor may choose to minimize the use of waste heat for thermal sale. On the other hand, in cases where the site has a large heat demand, the investor might choose to divert a larger proportion of recovered heat to thermal sale. The limiting factor for heat recovery is the purchased energy load of the thermal host, proximate to the site of the generating plant.

Under the base case gas price assumptions, Table 2-2 shows that, even with credit for the thermal sales, most of the cogeneration plants analyzed in this study will have LUECs above the 3.8¢/kWh revenue cap set for most of the output of Ontario Power Generation, Inc. under the Market Power Mitigation Agreement. Only the 250 MW simple cycle plant with maximum thermal sale achieves electricity prices low enough to compete with 3.8¢/kWh electricity. The implications of this result for future economic potential for cogeneration in Ontario will be analyzed in Section 4 of this report.

Resulting cost estimates are presented in Table 2-2 for the base case gas prices.

The cost estimates clearly show that there are economies of scale in cogeneration installations. The smaller installations have higher costs than the larger ones. This result is consistent with other studies. The degree of economies of scale in electricity generation have declined with the development of gas turbine technology. However, the larger cogeneration facilities considered here are about at the size that has been cited as the minimum size to achieve efficient scale.

The results also show that, for cogeneration applications, simple cycle gas turbines have lower costs than combined cycle turbines. This result is also not surprising. If the only output is electricity, combined cycle generators have lower costs because they can achieve higher overall conversion efficiencies by using the heat in the turbine's exhaust gases to generate more electricity. A cogeneration application gets higher conversion efficiencies by direct use of the heat in the exhaust gases. The overall conversion efficiency for simple cycle turbines cogenerators is therefore typically higher than that of the CCGT, while the capital cost is usually lower because the steam turbine is not needed. This produces the result that simple cycle gas turbines are likely to be preferred for cogeneration applications, especially those with a high steam load relative to electricity load.

Table 2-2 Large and Medium Cogeneration Technologies

Cogeneration Potential in Ontario

Estimated Total Costs of Electricity Generated

Base Case Gas Prices

Type of Unit	Rated Output (MW)	Fuel	Capital Cost[1] (Cdn$/kW)	Levelized O&M Cost (Cdn$/MWh)	Levelized Fuel Cost (Cdn$/MWh)	Plant Heat Rate[2] (Btu/kWh)	Thermal Credit Heat Rate (Btu/kWh)	Availability	Levelized Tax[3] (Cdn$/MWh)	LUEC without Thermal Credit [4] (Cdn$/MWh)	Levelized Thermal Credit (Cdn$/MWh)	LUEC with Thermal Credit [5] (Cdn$/MWh)
Cogeneration[6]												
Gas Turbine Plants	CCC 250	Gas	774	4.96	34.73	6,705	< 6,000	93.0%	1.27	50.82	4.21	46.72
	SCC 250	Gas	814	4.97	54.41	10,506	4,330	93.0%	1.52	70.62	32.69	38.80
	CCC 150	Gas	813	6.25	39.95	7,715	< 6,000	93.0%	1.36	57.80	9.33	48.71
	CCC 100	Gas	1,131	9.36	38.94	7,519	< 6,000	93.0%	2.10	64.88	8.65	56.46
	CCC 50	Gas	1,626	18.61	37.61	7,262	< 6,000	93.0%	3.25	80.55	6.98	73.76
	SCC 40	Gas	1,290	17.29	44.81	8,652	4,350	93.0%	2.65	81.00	24.78	56.88
	SCC 26	Gas	1,563	20.37	56.01	10,815	4,840	93.0%	3.29	99.23	36.40	63.80
	SCC 10	Gas	1,600	22.50	62.50	11,124	4,780	93.0%	4.37	116.05	39.35	78.50

Note:
[1] Excludes Interest during Construction
[2] Include 3% Degradation.
[3] Tax cost includes Income Tax only. Capital taxes, GST and municipal taxes are not included.
[4] LUEC is based on the sales value of steam equal to zero Cdn$/klb
[5] LUEC is based on the sale value of steam equal to 7.51 Cdn$/klb
[6] Thermal recovery of CCC plants is designed to just meet the Class 43 heat rate of 6000 Btu/kWh.

Legend:
CCC250 - 250MW Combined Cycle Cogeneration* SCC250 - 250MW Simple Cycle Cogeneration*
CCC150 - 150MW Combined Cycle Cogeneration* SCC40 - 40MW Simple Cycle Cogeneration*
CCC100 - 100MW Combined Cycle Cogeneration* SCC26 - 26MW Simple Cycle Cogeneration*
CCC50 - 50 MW Combined Cycle Cogeneration* SCC10 - 10MW Simple Cycle Cogeneration*

* Class 43.1 eligible

2.2.2 Estimated Costs for Small Cogeneration

Tables 2–3 and 2–4 show the derivation and results of the calculation of LUECs for smaller generation. Four technology types have been analyzed, with a selection of sizes for each type:

- Microturbines
- Fuel Cells
- Reciprocating Engines
- Aero Derivative Turbines.

Of these, two (reciprocating engines and aero derivative turbines) are established technologies with well-known cost and performance characteristics, while one type (microturbines) is being installed in some applications. The fourth type, fuel cells, has had fewer actual applications and is continuing to develop rapidly. The cost estimates for each type are subject to appropriate levels of uncertainty associated with their degree of development and actual application.

The cost and performance data for the cogeneration technologies are taken from the PHB Hagler Bailly DISGEN model, modified by inputs from Ontario industry participants. This model is used to estimate the potential for distributed electricity generation of all kinds.

The cost data for DISGEN are regularly updated with information on actual installed cost of distributed generation facilities and on the current best engineering estimates of costs for generation technologies still in development. The assumptions for this analysis are intended to be compatible with that for the larger technologies. The 7-year payback period produces a rate of return similar to that of a 13% IRR.

The 90% capacity factor assumed for these cost tables was chosen to show cogeneration favorably. It is assumed that an actual installation will be optimized for the sizes of the heat and electricity loads. Typically, heat loads are higher than electricity loads, so the electricity generation runs essentially to meet the electricity baseload plus as much of the heat load as that electricity generation will provide. Optimization considers the thermal/electricity ratios shown in Table 2-3 and how well they match the energy and heat requirements for the specific installation.

Several results are apparent in Table 2-4. First, as for the larger technologies, there are clear economies of scale. Within each technology, the larger the application, the lower the LUEC. These reflect the fixed costs of preparation of the installation as well as the lower cost per unit of capacity as the size of the application increases.

Second, the Table shows that none of the small technologies would be competitive against electricity at a wholesale price of $0.038 per kWh, the price set under the Market Power Mitigation Agreement as a revenue cap for most of OPG's generation. OPG will be required to pay rebates to all Ontario consumers should the average revenue for its generation capacity exceed this cap. Generation prices will be determined competitively and could be significantly above OPG's revenue cap, although the revenue cap is expected to have an influence on prices.

Table 2-3 Indicative Performance Attributes of Small Cogeneration Systems

Indicative Performance Attributes of Small Cogeneration Systems
(Estimated Data for 2001) ($ figures in CD$ except where noted)

Size (kW)	Technology	Fuel	Assumed Capacity Factor (%)	Heat Rate (Btu/kWh)	Heat Rate (GJ/kWh)	Electric-to Thermal (E/T) Ratio	Output Electricity (GJ/h)	Output Thermal (GJ/h)	Total Conversion Efficiency (%)	Total Heat (Annual GJ)	Total Electricity (Annual GJ)
75	microturbine	gas	90%	12,186	0.013	0.6	0.27	0.45	75%	3,548	2,129
100	microturbine	gas	90%	11,373	0.012	0.6	0.36	0.60	80%	4,730	2,838
	Fuel cells:										
200	Phosphoric Acid	gas	90%	8,530	0.009	1.3	0.72	0.55	71%	4,367	5,676
300	Solid Oxide-Atmospheric	gas	90%	7,582	0.008	1.5	1.08	0.72	75%	5,676	8,515
600	Solid Oxide-Atmospheric	gas	90%	7,417	0.008	1.6	2.16	1.35	75%	10,643	17,029
450	Solid Oxide-Atmos. Hybrid	gas	90%	6,824	0.007	2.0	1.62	0.81	75%	6,386	12,772
900	Solid Oxide-Atmos. Hybrid	gas	90%	6,824	0.007	2.0	3.24	1.62	75%	12,772	25,544
220	Solid Oxide-Press. Hybrid	gas	90%	5,687	0.006	4.0	0.79	0.20	75%	1,561	6,244
920	Solid Oxide-Press. Hybrid	gas	90%	5,687	0.006	4.0	3.31	0.83	75%	6,528	26,112
300	Molten Carbonate	gas	90%	7,000	0.007	2.0	1.08	0.54	73%	4,257	8,515
1200	Molten Carbonate	gas	90%	6,700	0.007	2.0	4.32	2.16	76%	17,029	34,059
250	PEM	gas	90%	8,530	0.009	1.2	0.90	0.75	73%	5,913	7,096
300	Reciprocating engines	gas	90%	9,222	0.010	0.8	1.08	1.35	83%	10,643	8,515
1000	Reciprocating engines	gas	90%	8,124	0.009	1.0	3.60	3.60	84%	28,382	28,382
2500	Reciprocating engines	gas	90%	7,935	0.008	1.1	9.00	8.18	82%	64,505	70,956
5000	Reciprocating engines	diesel	90%	7,417	0.008	1.2	18.00	15.00	84%	118,260	141,912
1500	Aeroderivative turbines	gas	90%	12,186	0.013	0.5	5.40	10.80	84%	85,147	42,574
3000	Aeroderivative turbines	gas	90%	10,339	0.011	0.6	10.80	18.00	88%	141,912	85,147
6000	Aeroderivative turbines	gas	90%	9,749	0.010	0.6	21.60	36.00	93%	283,824	170,294

Table 2-4 Indicative Cost Attributes of Small Cogeneration Systems

Indicative Cost Attributes of Small Cogeneration Systems
(Estimated Data for 2001) ($ figures in CD$ except where noted)

Size (kW)	Technology	Fuel	Installed Capital Cost ($/kW) (1)	O&M Cost ($/MWh) (2)	Fuel Cost ($/MWh)	Heat Rate (Btu/kWh)	Availability (%)	Taxes	LUEC ($/MWh)	Thermal Credit ($/MWh)(3)	Adjusted LUEC ($/MWh)
75	Microturbine	gas	1575	18.42	68.55	12,186	92%		115.51	37.64	77.87
100	Microturbine	gas	1350	15.04	63.97	11,373	92%		103.48	37.64	65.84
	Fuel cells:										
200	Phosphoric Acid	gas	3000	17.64	47.98	8,530	98%		119.98	17.37	102.61
300	Solid Oxide-Atmospheric	gas	3150	8.94	42.65	7,582	96%		108.67	15.05	93.61
600	Solid Oxide-Atmospheric	gas	2850	5.84	41.72	7,417	95%		99.20	14.11	85.09
450	Solid Oxide-Atmos. Hybrid	gas	2400	13.43	38.39	6,824	93%		95.30	11.29	84.01
900	Solid Oxide-Atmos. Hybrid	gas	2250	13.43	38.39	6,824	93%		92.59	11.29	81.30
220	Solid Oxide-Press. Hybrid	gas	2700	17.17	31.99	5,687	92%		98.08	5.65	92.44
920	Solid Oxide-Press. Hybrid	gas	2250	8.31	31.99	5,687	92%		81.06	5.65	75.42
300	Molten Carbonate	gas	3000	18.39	39.38	7,000	92%		112.12	11.29	100.83
1200	Molten Carbonate	gas	2850	13.34	37.69	6,700	92%		102.67	11.29	91.38
250	PEM	gas	3000	13.61	47.98	8,530	93%		115.95	18.82	97.13
300	Reciprocating engines	gas	1650	23.89	51.87	9,222	92%		105.66	28.23	77.43
1000	Reciprocating engines	gas	1463	14.86	45.70	8,124	92%		87.06	22.58	64.48
2500	Reciprocating engines	gas	1350	11.25	44.63	7,935	92%		80.34	20.53	59.81
5000	Reciprocating engines	diesel	900	20.08	66.75	7,417	95%		103.14	30.11	73.03
1500	Aeroderivative turbines	gas	2200	10.57	68.55	12,186	92%		118.98	45.16	73.81
3000	Aeroderivative turbines	gas	1900	8.05	58.16	10,339	92%		100.64	37.64	63.00
6000	Aeroderivative turbines	gas	1850	7.50	54.838	9,749	92%		95.854	37.64	58.22

(1) Including gas compression and moderate emission controls
(2) With fixed O&M converted at assumed capacity factor
(3) Most small cogen systems limited to lower temperature applications -- exception small gas turbines

Assumptions					
Capacity Factor	90%				
Gas Price	5.625	$/MMBtu	Diesel Price	9	$/MMBtu
	5.33	$/GJ		8.53	$/GJ
Boiler Efficiency	85%		Capital Reco	7	years

Exchange Rate Conversion 1.5 CD$/US$

All of the technologies except for the fuel cells are competitive against a delivered electricity price of $0.072 per kWh. That is the average delivered price expected to result from an average generation price of $0. 038. The pricing of transmission and distribution services is therefore important to the financial viability of the smaller cogeneration technologies. This impact will be discussed more fully in Section 4 of this report.

Table 2-5 shows the forecast of cogeneration costs for some of the smaller size applications. The forecasts use the forecast of gas prices for this project along with forecasts of the capital costs and efficiencies of the smaller cogeneration technologies. The table shows the future costs falling. Costs fall because capital costs per kW decrease by 1-6% per year for these technologies. The more established technologies have the lower rates of capital price decrease. Efficiency is forecast to improve for all the technologies in the table, at rates from 0.2-1.1% per year.

Table 2-5 LUEC Cost Forecast for Small Cogeneration Technologies

Small
Cogeneration Technologies
LUEC Cost Forecast

Type	Size (kW)	Cost ($/MWh) 2000	2005	2010
Microturbine	100	65.84	55.04	51.02
Solid Oxide-Atmospheric fuel cell	600	85.09	72.36	67.97
Solid Oxide-Press. Hybrid fuel cell	920	75.42	67.68	60.15
Reciprocating engines	300	77.43	74.18	69.34
Reciprocating engines	2500	59.81	57.01	52.58
Aeroderivative turbines	1500	73.81	66.50	59.37
Aeroderivative turbines	3000	63.00	56.03	49.34
Aeroderivative turbines	6000	58.22	49.49	46.41

2.3 *Electricity Prices*

In the regulated electricity market, electricity prices were relatively easy to forecast. They were set to recover the full cost of the monopoly generator, Ontario Hydro. In a competitive electricity market, electricity prices are much more difficult to predict. Experience in other jurisdictions has shown that, after the introduction of competition, electricity prices become much more volatile.

PHB Hagler Bailly has recently completed a study for Ontario Power Generation (OPG) to determine the cost to the province of premature retirement of the coal-fired generation in the OPG fleet. As part of that study, PHB Hagler Bailly modelled the competitive electricity market for the years 2005-2012. The results of that model form the basis for a reasonable wholesale electricity price forecast for the Ontario market.

The forecast in Table 2-6 is based on the model results. For the first three years of the competitive market, the forecast assumes that the $38 per MWh revenue cap for OPG under the Market Power Mitigation Agreement (MPMA) effectively operates as both a cap and a floor. After the expiration of the revenue cap, the models indicate a small decrease in price. They then show electricity price in Ontario rising until the system requires new gas CCGT generation in 2012. From there, the market price remains that of the full cost of new CCGT generation, which is taken to be constant in real terms. Although the real price of gas is rising in the forecast, assumed continued improvements in the efficiency of generation offset the consequent cost increase.

Table 2-6 Forecast of Electricity Prices in Ontario

Forecast of Electricity Prices in Ontario Annual Averages	
Year	Price ($/MWh)
2001	38
2005	37
2010	43
2015	47
2020	47

3. TECHNICAL POTENTIAL FOR COGENERATION IN ONTARIO

The technical potential for cogeneration in Ontario is a function of the ability of the cogeneration technology to fulfill demands for simultaneous generation of heat and electricity, and of the number of applications which have demand matching the technology's ability. Estimating the technical potential therefore requires information on both the demand and the technical ability.

The number of potential applications is finite for all the technologies. However, the larger the application, the smaller the number of potential sites. Where there are few potential sites, they can more readily be counted and the technical potential added up. Where there are very many sites, the economics of each cannot be analyzed in detail. For large applications, therefore, estimating technical potential is best done by counting potential sites. For smaller applications, an analytical or modelling technique is required to estimate the fraction of the total potential sites or of the total energy demand that can be met by cogeneration.

Most of the large-scale (above 50 MW) applications of cogeneration relate to industrial steam hosts. Only a few industries are large enough and need enough process steam or heat to create a possibility of applications on this scale. Examples include forest products, iron and steel making, chemicals, and refineries. For this scale of application, the counting method works well.

For medium scale applications, the steam hosts could be much more varied. They could include smaller firms with steam-intensive processes, or larger industries with less steam-intensive processes but large total needs. Examples include food processing or automobile and auto parts manufacturing. Some commercial enterprises can also support cogeneration installations of between 10 and 50 MW. Examples include hospitals, larger office buildings, and such other large institutions as universities. To estimate potential in these applications, a mix of counting methods and analytical techniques is used.

In the analysis, the large and medium size cogeneration applications are identified as industrial, while the smaller ones are identified as commercial. For both sizes, technical potential is estimated both with analytical techniques and by adding up potential sites. Analytical techniques are required for analysis of potential more than five years in the future, since the sites of future industrial or commercial developments are not known.

3.1 Methodology and Data Sources

3.1.1 Large and Medium Cogeneration

Analytical Techniques

The analytical technique uses aggregate data on energy use by industry. Such data are available for total commercial and industrial users in Ontario, including forecast data, from the NRCan publication *Canada's Energy Outlook, 1996-2020*.[3] That publication identifies total energy demand by sector for each province.

Data have also been obtained from the Office of Energy Efficiency of NRCan. For the industrial sector, these data cover energy demand by fuel by industry group.

The analytical techniques used for each sector are described in the next section.

Identified Sites

Using identified sites is a counting method, gathering data on sites which have been identified as potentially developable. This method is expected to produce a lower estimate than an analytical technique would, since identified sites have been selected as those with greatest economic potential. This method is important to the analysis here, since it will provide information on how much cogeneration can be expected to be installed in Ontario in the near term.

The estimates for large and medium cogeneration sites are an update of the estimates made by AGRA Monenco for Ontario Hydro Services Company in the summer of 1999[4]. Those estimates were largely based on an inventory of potential sites for medium and large-scale cogeneration applications.

The estimates have been expanded using information on additional potential new cogeneration locations in Ontario. This information comes from inventories of potential cogeneration sites obtained from other stakeholders in the industry, including suppliers of equipment and fuel for potential new applications. The data also include new information on forest products industry operations, chiefly in northern Ontario.

3 Natural Resources Canada, Energy Forecasting Division, Energy Policy Branch, Energy Sector, "Canada's Energy Outlook 1996-2020", April 1997.

4 AGRA Monenco, Inc., "Final report: Quantification of Transmission Infrastructure Bypass", August 1999. Filed with Ontario Energy Board in RP-1999-0044, Exhibit D, Tab S, Schedule 3.

3.1.2 Small Cogeneration Applications

The estimate of technical potential for small and medium applications uses an analytic and modelling approach to the available data. For the PHB Hagler Bailly DISGEN model, the data base includes information on the number of buildings in the commercial sector by building type. In addition, NRCan's Office of Energy Efficiency (OEE) has provided data on energy end use in the commercial sector. The data are broken out by nine building types and six end uses. These data allow an analysis of the total potential for simultaneous use of heat and electricity in the commercial sector.

This analysis can indicate how much cogeneration could be supported if a given fraction of the total heat and electricity load in the province were met with cogeneration. These estimates then form the top of a range of possible cogeneration, or the total technical potential.

3.2 Estimates of Technical Cogeneration Potential

3.2.1 Estimates for Industrial Applications

Identified Sites

Table 3-1 shows the estimates of the total technical potential for cogeneration applications in Ontario in the industrial sector, using the identified sites methodology. These estimates relate to large-scale applications as described above.

The total technical potential for cogeneration in large and medium applications is shown as 4,146 MW.

Table 3-1 Industrial Cogeneration Potential in Ontario, February, 2000

Project Location	Market Segment	Electrical Capacity (MW)	Probability of Proceeding
Identified 10-40 MW			
GTA	nug	10	H
N. Ont.	ind	20	M
Central Ont.	nug	20	M
GTA	inst	15	M
GTA	nug	20	M
GTA	ind	11	M
GTA	nug	25	M
Totals	**10**	**121**	
Identified 40-100 MW			
GTA	ind	40	M
East. Ont.	ind	40	M
East. Ont.	nug	50	M
GTA	nug	50	M
GTA	ind	40	M
East. Ont.	nug	90	L
NW Ont. Pulp & Paper	nug	65	M
Totals	**8**	**375**	
Identified 100-250 MW			
Ottaw a/Carlton Pulp & Paper	nug	153	L
East Ont.	ind	110	M
GTA	nug	150	M
GTA	nug	100	M
East. Ont. Pulp & Paper	nug	180	M
N. Ont.	nug	120	L
GTA	nug	100	L
GTA	nug	100	L
NW Ont. Pulp & Paper	nug	165	L
NW Ont.Pulp & Paper	nug	180	L
Totals	**10**	**1,358**	
Identified 250 MW and larger			
GTA Pulp & paper	ind	250	H
Niag. Penn Pulp & Paper	ind	350	M
West. Ont.	nug	550	H
Niag. Penn.	nug	350	M
Totals	**4**	**1,500**	
Total	**32**	**3,354**	
Plus 20% unidentified		**688**	
Total potential		**4,146**	

The estimates above are from AGRA Monenco. The list of all cogeneration projects identified from data sources is updated from the list published in the AGRA Monenco report cited in the footnote above. The list used here identified three market segments: industrial, commercial, and institutional. If the project is to be sponsored by a non-utility generator, the segment is listed as NUG. In the table above, commercial and institutional projects have been removed to avoid double counting with the calculation of commercial potential in the next section of this report.

In the table, the probability of proceeding reflects the opinion of the data source at the time the project was identified. It does not necessarily refer to economic viability. The additional technical potential of 20% in unidentified projects is based on an estimate by AGRA Monenco. The project capacity refers to proposed size; the projects are not necessarily sized by embedded electrical or thermal loads

An approximate check is available on these estimates. The report "Opportunities for Increased Cogeneration in the Pulp and Paper Industry" was completed in March, 1999 by Neill and Gunther (Nova Scotia) Limited, for the Canadian Forest Service of NRCan.[5] The report estimated total potential based on the existing and projected uses of energy in the pulp and paper industry. This estimate came from a technical analysis of the total energy used in the industry and its sources. The report estimated the potential as a total for all provinces using fossil fuel for electricity generation and pulp and paper operations.

Assigning Ontario its share of the cogeneration potential equal to its share of total energy used nationally would probably underestimate total forest products cogeneration potential, since Ontario has a higher concentration on forest products than the average. Using this approximation, the estimate is for 906 MW of cogeneration potential in the Ontario pulp and paper industry. Table 3.1 identifies 1343 MW of pulp and paper projects, approximately 50% more than this estimate. Given the expectation that the 906 MW is an underestimate, this result is consistent with the Neill and Gunther study.

Analytical Technique

The analytical technique used information from both the OEE data base and the NRCan Report. The OEE provided historical data on the total electricity demand by major industry group in Ontario. Totals from these data were compared to the industrial electricity demand shown in the 2020 Report, and they were compatible. The OEE data are available by industry. The analysis assumed all electricity demand in the pulp and paper, smelting and refining, petroleum refining, chemicals, iron and steel, and 25% in the "Other" category, could be met by cogeneration.

Forecasts of future demand were obtained by applying the growth rate of industrial electricity demand from the NRCan Report to the base year load obtained from the OEE data.

5 Neill and Gunther (Nova Scotia) Limited, "Opportunities for Increased Cogeneration in the Pulp and Paper Industry", prepared for Industry Economics and Programs Branch, Canadian Forest Service, NRCan, March 1999.

In the industrial sector, the total energy supplied by natural gas is about twice that supplied by electricity. The maximum technical potential, therefore, would occur if the cogeneration is sized to meet the heat load, with the heat from the cogeneration displacing the natural gas. The cogenerators would then have excess electricity to sell in the market. For this analysis, it was assumed that half of the total gas used in the industries which can support cogeneration could be displaced by the heat product. This analysis produced a much higher estimate of the technical cogeneration potential than did an analysis assuming that the cogeneration would be sized to the electricity, not the heat, load.

Table 3-2 shows the resulting potential estimates. These estimates are significantly higher than those obtained by counting up identified industrial sites. In 2000, the estimate from this analytical technique is over 11,000 MW of technical potential, as compared to under 5,000 MW from the AGRA Monenco data.

It should be noted that this estimate probably does represent an extreme value. If all the estimated technical potential were realized, industrial cogeneration would account for at least a third of the total electricity generation capacity in the province.

Table 3-2 Industrial Cogeneration Potential in Ontario

INDUSTRIAL COGENERATION POTENTIAL IN ONTARIO
Analytical Method

	MW	TWh.
2000	11214	28.43
2005	11966	31.06
2010	12676	33.09
2015	13371	34.96
2020	14037	36.44

3.2.2 Technical Cogeneration Potential in Commercial and Institutional Applications

Table 3-4 has an estimate of the technical potential for cogeneration for the commercial customer class in Ontario, which includes commercial and institutional customers. This estimate is an approximation.

The underlying data for this estimate come from the Office of Energy Efficiency (OEE) of NRCan. They provided historical data on energy end uses for nine building types for six end uses and six fuels. The data were for the years 1981-1997, inclusive. Table 3-3 shows the data for 1997 for electricity and heat load for those building types which were analyzed for cogeneration potential. The table also shows the assumptions made for the analysis.

Table 3-3 Data for Estimation of Technical Cogeneration Potential (Commercial Sector)

Data for Estimation of Technical Cogeneration Potential
Commercial Sector
Ontario

	Historical Data				Assumptions		
	Energy Use 1997		Average Annual Growth Rate **1981-97**		Average Annual Growth Rate **2000-20**		Fraction of Electricity in Large Buildings
Sector	Electricity PJ	Heat PJ	Electricity	Heat	Electricity	Heat	
Offices	46.34	52.44	4.35%	1.14%	2.60%	1.07%	46%
Health	9.78	41.79	0.28%	-2.50%	0.11%	-1.87%	40%
Schools	9.31	34.91	0.36%	-2.64%	0.37%	-2.00%	27%
Hotels	14.82	12.04	1.50%	0.65%	0.33%	0.43%	10%
Retail	55.05	33.16	1.74%	-0.89%	0.43%	-0.50%	10%
Other	20.26	35.29	1.99%	-1.35%	1.09%	-0.50%	5%

Data Source: Office of Energy Efficiency, NRCan

The table shows the average annual growth rates over the entire historical period and the forecast average growth rates. For most building types, demand for both electricity and heat showed decelerating growth. The forecast continued that deceleration, making the forecast growth rate lower than the historical growth rate. For some building types, heating load had been falling; the forecast is for a continued, but slightly slower, decline.

For each building type, an assumption was made about the fraction of total electricity and energy use which occurred in larger buildings, capable of supporting the kind of cogeneration facility analyzed in the previous chapter. These estimates depend on that assumption which is shown in the last column of Table 3-3. If the assumed fraction in large buildings rises, the estimated cogeneration potential will rise with it.

Data to support this assumption were available for two building types. An Ontario Hydro survey in the 1980s found that 46% of energy use in the office sector came in buildings with more than 200,000 square feet. The analysis assumed that such buildings would be candidates for cogeneration, so the fraction for office buildings is taken at 46%.

The Ontario Association of Physical Plant Administrators indicated that its 17 schools used a total of 12 PJ of energy. That is about 27% of the total energy estimated for the schools sector for 1998. The analysis assumed that such institutions have large buildings or groups of buildings which can host cogeneration applications (as several already do.) The fraction for schools buildings is taken at 27%.

Estimates for the amount of cogeneration which could be sustained in each of these building types are shown in Table 3-4.

In actual cogeneration applications, the technology will be chosen to meet the specific heat and electricity characteristics of the site. This analysis of technical potential requires some broad assumptions about technologies and relative heat and electricity demand. Where the energy requirement for heat is greater than that for electricity, a technology with a low electricity to thermal ratio is chosen. That could still produce electricity in excess of that required by the host. For this analysis of technical (not economic) potential, it is assumed that all such electricity could be sold into the grid.

As Table 3-3 shows, for four of the six building types analyzed, the total energy required for heat is significantly greater than that required for electricity. For these building types, the cogeneration potential is that amount of cogeneration which would be required to meet the total heat load in the large buildings.

In the other two building types, electricity demand is higher than heat demand. A cogeneration system which met the full electricity demand might produce much more heat than the buildings could use. For these types, a technology was selected with an appropriate size and electricity to heat ratio, and the technical potential estimate is for the electricity load.

Table 3-4 shows the technical potential in the commercial sector as roughly constant over time. While heat demand in some building types is forecast to grow, the growth is offset by declines in other building types.

Table 3-4 Commercial Sector Cogeneration Potential

Estimated Technical Cogeneration Potential
Commercial Sector
Ontario

Sector	2000	2005	2010 MW	2015	2020
Offices	1144	1227	1308	1389	1467
Health	857	755	683	617	572
Schools	241	212	192	174	161
Hotels	55	55	56	57	60
Retail	148	144	137	131	134
Other	92	90	85	81	83
Totals	2537	2483	2461	2448	2477

3.2.3 District Heating

District heating is an application of cogeneration where the heat from the generator is used for space heating, water heating, and other uses in a group of buildings. The buildings need to be close to each other because the heat is distributed to them from the central source through pipes. District heating systems are economic when the buildings are dense enough to support the application.

The above analysis implicitly includes the technical potential for district heating in the commercial sector. The methodology starts with the total amount of energy used in heating and electricity generation, and estimates technical potential by building type according to estimates of building size. Since the technical potential estimate depends on the share of the building type that is large enough to consider cogeneration, the possibility of district heating is implicitly included. In effect, district heating is a specific way to implement the cogeneration which is calculated as being included in the technical potential.

3.2.4 Technical Cogeneration Potential in the Residential Sector

Cogeneration facilities in individual residences would be small, given the size of a typical household load. According to the OEE data, total non-electric energy used for space and water heating in the residential sector is about 2 ½ times as great as total electricity demand. The limiting factor in developing residential cogeneration facilities would therefore be electricity demand. This would be especially true for fuel cells, which as the table in Section 2 showed, have very high electricity/thermal output ratios (they have a low fraction of total energy available as heat.)

Current cogeneration technologies are not yet effective for the residential sector. It is difficult to make a quantitative estimate of the cogeneration potential when the technologies are still undergoing such rapid development.

3.3 Total Technical Potential

The total technical potential estimated for the industrial and commercial sectors is estimated to grow from about 14,000 MW in 2000 to over 16,000 MW by 2020. The total in 2000 is over half the expected annual peak load in that year. As already noted, these estimates represent extremes which are only possible if a very large fraction of the current natural gas use in the province, especially in the industrial sector, is replaced by cogeneration.

Table 3-5 Total Cogeneration Potential in Ontario

TOTAL COGENERATION POTENTIAL IN ONTARIO			
		MW	
	Industrial	Commercial	Total
2000	11214	2537	13750
2005	11966	2483	14449
2010	12676	2461	15138
2015	13371	2448	15819
2020	14037	2477	16514

4. ECONOMIC POTENTIAL FOR COGENERATION IN ONTARIO

The economic potential for cogeneration is the total amount of cogeneration which can make an economic return on its investment. That is defined as cogeneration which, after paying all of its costs, produces heat and electricity together more cheaply than they can be obtained from alternative sources.

Economic potential is defined at a point in time. Realization of the potential takes place over time. When cost conditions first make a 250 MW cogeneration facility economic, it cannot be installed immediately. This study is intended to quantify the amount of cogeneration likely to be installed, given the assumed cost conditions and in the absence of barriers. The estimate uses different methodologies for large and small applications.

4.1 Methodology

Quantifying economic potential uses the cost and technical potential estimates of Sections 2 and 3 of this report. The analysis indicates which technologies have the potential to be economic, and what the total technical potential is. Then the economic potential is the application of economic technologies in locations where the technical potential exists.

4.1.1 Large and Medium Scale

For large and medium scale generation, estimating economic potential at any time essentially amounts to an analysis of how many of the identified projects will be economic under the specific assumptions about their costs. The cost estimates of Section 2 showed that there are economies of scale for cogeneration projects. Therefore, larger projects may be economic when smaller ones are not. To determine which projects are economic, this methodology simply compares the avoided electricity cost to the LUEC of the technology which would be used. Thus, if the avoided electricity cost is above the LUEC of, say, a 100 MW project but below that of a 50 MW project, than all projects of at least 100 MW will be considered economic. This methodology assumes that most projects which could be economic in the short run have been identified.

To translate this estimate of current economic potential into an estimate of the amount of cogeneration which would be likely to be installed in each year, the study has distributed the current potential over the following six years. It has followed a similar methodology to estimate the amount of economic potential identified in the future. To do this, economic potential is projected as a fraction of the total technical potential. The fraction is inferred from the fractions in the short run and the expected trend of cogeneration costs and electricity prices.

4.1.2 Small Scale Generation

To analyze the smaller projects, PHB Hagler Bailly used its DISGEN model. That model considers the total energy cost of candidate applications, and installs cogeneration when it is economic. The results from the application of the DISGEN model were not consistent with information from stakeholders and market participants on the actual amounts of cogeneration currently being installed in Ontario. Investigation of the causes for the discrepancy revealed several factors leading to cogeneration installation which the DISGEN model cannot consider.

These factors are discussed in Section 4.2. That section also shows how the DISGEN model was adjusted to account for these factors. The forecast for cogeneration in the short term is derived from the market information combined with the DISGEN runs. The forecast for the longer term is inferred as a fraction of the estimated long-run potential.

4.2 Market Considerations

4.2.1 Electricity Prices

The price of electricity is a key variable in determining the economic potential. In the past, electricity prices could be predicted with some reasonable assurance. Electricity prices to consumers were set to recover the historical cost of the entire electricity supply system. Since most of those costs are known in advance, the price can also be known in advance with relatively little variance.

With the restructuring of the Ontario electricity market, however, forecasting prices has become more difficult. The wholesale price will be set by market forces. The wholesale electricity price forecast shown in Section 2.3 is the Hagler Bailly forecast derived from an earlier project. The wholesale market price is an annual average. This forecast does not address two important factors that determine the economic potential for cogeneration. The first of these factors is an input to the DISGEN model; the second cannot be.

The first factor is whether the electricity from the cogeneration facility is competing with the wholesale market price or the delivered price. The cost estimates of Chapter 2 showed that most cogeneration applications are not economic if they have to compete against a wholesale price at the level shown in Section 2.3. However, many of them are economic if they compete against the delivered retail price of electricity, since the delivered retail price is likely to be about twice the wholesale price.

The difference between the wholesale price and the delivered price will have several components: transmission charges, distribution charges, the IMO uplift, and a competition transition charge. In turn, each of these charges can have several components. The question of whether self-generation installations pay these charges has only been partly settled. The Ontario Energy Board (OEB) has ruled that distributors containing new self-generators do not have to pay the network portion of Hydro One's transmission tariff on the new self-generation capacity. Distributors containing self-generators below 1 MW capacity will not have to pay any transmission tariff on that capacity[6].

The IMO Technical Panel is currently discussing the rules which implement this decision, as well as the question of whether self-generators are responsible for all or some of the IMO's charges. The issue of billing of new self-generators is therefore not yet fully resolved. However, the wording of the OEB's decision indicated that it favored the establishment of new generation in the province.

For this report, the cogeneration potential estimates will consider two extremes of the resolution of the pricing issue: potential if the cogeneration must compete with the wholesale electricity price, and potential if the cogeneration competes with the delivered retail price. The DISGEN model explicitly includes prices against which the cogeneration competes, as well as prices it gets for outside sales. The delivered vs. wholesale price factor can therefore be considered directly in the model.

The second factor is price volatility. Because electricity will be sold on an hourly market, there is likely to be more attention to the hourly changes in market-clearing prices. Periods of shortage can create "price spikes," when the price rises to well above (an order of magnitude or more) its average level. If the Ontario market does move to Locational Marginal Pricing, the spikes are likely to be more pronounced in some local areas.

Potential generation entrants will expect to take advantage of the price volatility. If their systems are flexible enough, they can operate only during those hours when the spot electricity wholesale price is above their cost of production. Even though their costs are above the average price, such generators can earn economic returns by keeping their average received price above their average total costs.[7] This strategy is more difficult to follow for many potential cogeneration operators than for operators of merchant combined cycle or simple combustion turbine plants. Cogenerators must able to meet the steam or heat loads of their thermal hosts, which could preclude shutting down when prices are low.

Load following capability is a factor cited by cogeneration owners as making some new investments economic. It is applicable in installations where a backup steam or heat system is available for use when the cogeneration facility is shut down. The effect of this factor on cogeneration potential is difficult to consider in the DISGEN model because it is so specific to individual sites and agreements between thermal hosts and electricity providers. For the runs for

6 Ontario Energy Board, "Decision with Reasons". RP-1999-0044.

7 Since such operations likely imply a lower capacity factor than for full-time operation, the fixed costs must be spread over fewer operating hours. The LUEC is therefore raised by this operating philosophy.

this project, this factor was approximated by increasing the penetration rate of cogeneration when it had a small cost advantage or disadvantage.

4.2.2 Capital Costs

Capital costs for large, medium and small cogeneration applications were quantified in Section 2 of this report. These costs are for new cogeneration applications using the best available equipment for each of the applications listed.

Stakeholders indicated that the actual capital costs for specific applications might be lower than those indicated. For example, where a facility has a boiler that has reached the end of its life, the cost of the cogeneration is only the incremental cost of adding electricity generation to the boiler cost. For a new installation which needs both steam and electricity, the cost of cogeneration is again only the incremental cost of the cogeneration over the cost of the boiler that would be needed anyway.

Since these effects are so specific to particular applications, they cannot be taken into account either in the large applications cases or in the DISGEN model. They have been considered in the revised DISGEN model runs by reducing capital costs by an arbitrary amount.

4.2.3 Fuel Costs

Fuel costs were discussed in Section 2. Stakeholders did not indicate that specific potential cogeneration applications would have any fuel cost advantage that was not considered in the analysis or the DISGEN model.

4.2.4 Other Factors

Other considerations may lead owners or developers to install cogeneration in sites where the economics are only marginally positive or even marginally negative.

In some uses, cogeneration is a more reliable electricity source than power from the local distribution company. Most power outages are caused by the distribution system. The next most likely source of an outage is the transmission system. Many customers with a need for highly reliable electricity supply install self generation. When such customers also have a suitable heat load, they might install cogeneration instead of backup generation. This factor can lower the effective capital costs for cogeneration, because the capital cost would be only the differential between the cost of the cogeneration and the cost of the simple backup.

Cogeneration also increases reliability, because it provides a source of power that is available even when the transmission or distribution system fails. For some companies, the value of the increased reliability may make cogeneration economic even if its monetary cost is higher than that of central supply.

For the runs in the DISGEN model, these factors are represented by both the reduction in capital costs and in the increased penetration of marginally economic or marginally uneconomic cogeneration.

Another factor which could lead to installation of cogeneration which is not economic in the market sense is the fact that cogeneration generally makes more efficient use of the primary energy supply than do non-cogeneration applications. It can therefore be seen as less environmentally harmful. Some users may prefer lower impact modes of electricity generation. This factor is considered in the model by adjusting the penetration rate of marginally economic or marginally uneconomic cogeneration.

4.2.5 Sensitivity Analysis

Several factors crucial to the economics of cogeneration have been identified in this study. These include the price of natural gas, the capital cost of the equipment, and the price of the displaced electricity. The cost sensitivities for some of these factors are shown in Table 4-1. The analysis will show the sensitivity results for the high and low natural gas prices.

The economic potential for large and medium scale cogeneration was assessed by undertaking sensitivity analysis on those variables which can impact the economic viability of cogeneration and which are most likely to move in a direction that improves the economic viability. The parameters tested include market electricity sales rates of $38, $45 and $50 per MWh, heat rate improvements of 5 and 10% and capital cost re installed kW reductions of 5 and 10%. The results of the analysis are shown on Table 4.1.

Table 4-1 Sensitivity Analysis of Cogeneration Costs

Cogeneration Potential in Ontario

Sensitivity Analysis based on 250MW Combined Cycle Cogeneration Case (CCC250)

Parameter Changed	Changed	LUEC without Thermal Credit [1] (Cdn$/MWh)	LUEC with Thermal Credit [2] (Cdn$/MWh)	IRR (%)
Base Case	46.72 Cdn$/MWh	50.82	46.72	13.00
Electricity Rate	38.00 Cdn$/MWh	-	-	N/A [3]
	45.00 Cdn$/MWh	-	-	0.74
	50.00 Cdn$/MWh	-	-	25.47
Heat Rate	-5%	49.13	45.03	13.00
	-10%	47.44	43.34	13.00
Capital Cost	-5%	50.21	46.12	13.00
	-10%	49.61	45.52	13.00

Note:
[1] LUEC is based on the cost of steam equal to zero Cdn$/klb
[2] LUEC is based on the cost of steam equal to 7.51 Cdn$/klb
[3] IRR in this case is not available since all the net cash flows along the study period are negative.

The economic potential for cogeneration in Ontario will be estimated in this study for three cases, a base case and high and low scenarios. Much of the differential between these will be based on the difference between assumptions.

4.3 Cogeneration Potential: Base Case

4.3.1 Economic Potential for Large and Medium Scale

Table 4.2 shows which cogeneration technologies are economic under the base electricity price case. The electricity price of $50 per MWh is about the expected market price of $38 per MWh plus the credit for the network transmission charge.

Table 4-2 Return to Cogeneration: Large and Medium Scale

Returns at $50 per MWh. Large and Medium Scale		
Type of Unit	Rated Output (MW)	IRR (%)
Cogeneration		
Gas Turbine	CCC 250	25.47
	SCC 250	43.57
	CCC 150	18.62
	CCC 100	N/A
	CCC 50	N/A
	SCC 40	N/A
	SCC 26	N/A
	SCC 10	N/A

IRR = Internal Rate of Return
IRR computed with electricity rate
at 50.00 Cdn$/MWh

Only large-scale cogeneration would be economic under this price regime. Table 4-3 below shows all those projects from the list in Table 3-1 which are above 150 MW and would therefore be economic competing with an average electricity price of $50 per MWh.

Table 4-3 Estimated Economic Potential: Large/Medium Scale

Economic Potential at $50/MWh Electricity Price			
Project Location	**Market Segment**	**Electrical Capacity (MW)**	**Probability of Proceeding**
Identified 100-250 MW			
Ottawa/Carlton Pulp & Paper	nug	153	L
GTA	nug	150	M
East. Ont. Pulp & Paper	nug	180	M
NW Ont. Pulp & Paper	nug	165	L
NW Ont.Pulp & Paper	nug	180	L
Totals	**5**	**828**	
Identified :250 MW and larger			
GTA Pulp & paper	ind	250	H
Niag. Penn Pulp & Paper	ind	350	M
West. Ont.	nug	550	H
Niag. Penn.	nug	350	M
Totals	**4**	**1,500**	
Total economic potential		**2,328**	

Table 4-3 shows the amount of large and medium scale cogeneration estimated to be economic at this time. To estimate how much cogeneration will be installed over time, this study uses an S-curve for the penetration of the potential. It spreads the installation of this potential out over six years, with the peak coming in the third and fourth years. This timing accounts for both decision and construction periods.

In addition, the amount of economic cogeneration will increase over time as both the technology becomes cheaper and as the Ontario industrial sector expands. Table 3-5 showed an estimate of the total technical potential for the next 20 years. Using that estimate, the current economic potential is about 23% of technical potential. In the base case, the fraction of total technical potential that is economic was assumed to increase by about 0.5% per year to 2008, and by 1% per year from then to 2010. The proportion of economic cogeneration is expected to increase due to lower costs of cogeneration and increasing electricity prices.

The estimate of future installations applied the same S-curve to the amount of increased economic potential created in each year. Economic potential grows because technical potential grows and the proportion that is economic increases, under the assumptions used here.

As with the results for small scale cogeneration, the totals in Table 4-3 do not include several announced or prospective projects in the 40-60 MW range which appear likely to proceed. Some of the same considerations leading to an underestimate for the small scale cogeneration projects likely apply in this case. Therefore, in deriving the annual installation rates, the current amount of economic potential was increased by 5% over the amount shown in Table 4-3.

The resulting estimates of installed large and medium scale cogeneration are shown in Table 4-4.

Table 4-4 Economic Cogeneration Installed: Large and Medium Scale

Estimated Economic Cogeneration Installed Annually
Large and Medium Scale Applications
Base Case

	MW Installed in Year										
	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Cumulative Total
Potential	73	493	634	657	558	210	89	90	94	104	3002

4.3.2 Economic Potential for Small Scale Cogeneration

The potential for small-scale cogeneration was estimated with the DISGEN model. In the first years, the DISGEN model produces low totals. These totals disagree with the strong feedback received from industry participants in Ontario. The reasons for this discrepancy were analyzed in Section 4.2 of this report.

Several basic parameters in the DISGEN model were altered in an attempt to produce results that reflected this feedback. The most important changes were a reduction in the price of capital and an increase in the market penetration rates. These changes produced higher installation rates, but were in the early years still below the levels indicated by the industry feedback.

The results shown in Table 4-5 below, therefore, represent a blend of two sources: in the first years, they reflect the information received from industry participants; in the later years, they are the results from the DISGEN model runs with the base case assumptions.

Table 4-5 Economic Cogeneration Installed: Small (0.25-10 MW)

Estimated Economic Cogeneration Installed Annually
Small Scale Applications
Base Case

MW Installed in Year

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Cumulative Total
Potential	50	55	60	65	72	88	119	122	123	125	879

4.3.3 Total Economic Cogeneration Installed Annually: Base Case

The total cogeneration installed annually is the sum of the large and small scale applications. It is shown below in Table 4-6.

Table 4-6 Total Economic Cogeneration Installed Annually: Base Case

Estimated Economic Cogeneration Installed Annually
Base Case

MW Installed in Year

Scale	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Cumulative Total
Large/Medium	73	493	634	657	558	210	89	90	94	104	3002
Small	50	55	60	65	72	88	119	122	123	125	879
TOTAL	**123**	**548**	**694**	**722**	**630**	**298**	**208**	**212**	**217**	**229**	**3881**

4.4 Cogeneration Potential: Alternate Cases

The amount of economic cogeneration is determined by many variable factors, most of which have been discussed in this report. The estimates of installed cogeneration given above are derived from a single set of assumptions about the values of these variables. Given the uncertainty about these factors, it is useful to provide some information on the results under different assumptions.

Estimates of the amount of cogeneration installed per year were made for the two alternative gas price cases. The prices for the alternative cases are shown in Table 2-1 and a more detailed explanation is provided in Appendix A.

To estimate the amount of large and medium scale cogeneration which would be installed, the same methodology was used as for the base case. AGRA Monenco provided estimates of the LUECs of the available technologies. With the information on currently identified projects, this produced an estimate of the amount of such cogeneration which would be economic now. This estimated amount was then installed over a six-year period, using an S-curve for installation.

Changes in the gas price will not change the amount of technical cogeneration potential, so the high and low cases assumed that the initial fraction of total potential grew faster or slower than it did in the base case. For the high gas price case, the fraction of the technical potential that is economic grows by 0.4% per year until 2008, and at 0.75% per year after that. For the low gas price case, the fraction grows by 1% per year until 2008, and 1.5% per year after that.

Table 4-7 shows the results for the high and low cases.

Table 4-7 Estimated Economic Cogeneration Installed Annually: High and Low Cases

Estimated Economic Cogeneration Installed Annually
High and Low Cases

MW Installed in Year

HIGH CASE (Low gas prices)	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Cumulative Total
Large/Medium	90	458	639	679	869	452	304	156	161	173	3982
Small	65	72	78	85	100	133	132	137	158	177	1136
TOTAL	**155**	**529**	**717**	**763**	**969**	**585**	**436**	**293**	**319**	**350**	**5118**
LOW CASE High gas prices)											
Large/Medium	47	239	330	345	439	215	137	59	62	71	1944
Small	34	37	40	44	48	51	65	75	90	105	588
TOTAL	**81**	**276**	**370**	**388**	**487**	**266**	**202**	**134**	**152**	**176**	**2532**

The study also explored sensitivity to transmission pricing for new cogeneration. Under the Hydro One tariff as approved by the Ontario Energy Board, embedded generators will not pay network transmission charges. Since many of the cogeneration applications are likely to be embedded in a distribution company's territory, while others are not, the sensitivity of the amount of cogeneration installed, relative to the transmission charges, was explored.

The exploration was done with the DISGEN model, which only considered small scale cogeneration applications. According to the DISGEN model, removing transmission charges from applications of between 1 and 10 MW would roughly double the amount of small scale cogeneration which would be installed over the period up to 2010.

4.5 GHG Reductions Associated with Cogeneration

GHG reductions associated with cogeneration depend on the emissions rates of the cogeneration facilities and the emissions rates of the facilities they displace.

Emissions rates for the cogeneration facilities can be inferred from their heat rates. The heat rates give the number of Btus per kWh for the cogeneration. Assuming that all the input heat energy comes from natural gas, emissions rates are readily available to convert the energy content of the natural gas into CO2 emissions.[8]

The heat rates for the large and medium technologies are close to each other. To estimate the GHG emissions, a weighted average of the heat rates was constructed.

For the small technologies, the heat rates can vary significantly across technologies. Heat rates were derived as a weighted average of the heat rates of the technologies. The weights assumed that most of the electricity would be provided by gas turbines, with some contribution from both gas and diesel reciprocating engines. Fuel cell contributions were assumed to increase over time.

Cogeneration displaces electricity generation and steam or other heat generation.

To estimate GHG emissions from electricity generation requires knowing what the fuel source would have been. For this study, an assumption is made that the displaced fuel source would be coal. Emission rates for coal-fired plants in Ontario are available from a report by Acres Management Consulting for Ontario Power Generation, Inc.[9] The Acres report indicates that the emissions rates vary by plant, with over 10% difference between the highest and the lowest. However, the plants most likely to be displaced by cogeneration in southern Ontario (Nanticoke, Lambton, and Lakeview) have very similar CO_2 emission rates. This estimation used a weighted average of the existing OPG coal-fired station emission rates.

8 Natural Resources Canada, Canada's Energy Outlook, 1996-2020, Appendix D, Table 2, page D-2.
9 Acres Management Consulting with Diener Consulting, Inc., Replacing Coal-fired Generation with Gas: Financial Costs and Environmental Benefits, Toronto, March 6, 2000. Table B5a, pg. 33.

Cogeneration also avoids the use of natural gas or other fuels to generate heat or steam. For this estimate, it was assumed that the avoided fuel would be natural gas. The natural gas would have been used to generate steam at the average efficiency rate of the boilers, which is assumed at 80%. Avoided GHG emissions from the steam generation are therefore computed assuming that the equivalent amount of end-use heat would have been produced by steam boilers operating at 80% efficiency.

The emissions from each type of cogeneration are readily available from the heat rates for the equipment. The heat rates translate directly to quantities of natural gas consumed.

Table 4-8 below shows the GHG emissions of the cogeneration and the emissions avoided by the use of cogeneration. Cogeneration using gas produces only about 1/3 the emissions for equivalent electricity and heat use from coal-fired and natural gas sources.

Table 4-8 Net Reduction in GHG Emissions from Cogeneration

GHG EMISSION SAVINGS FROM COGENERATION
BASE CASE

Mtons CO2

	2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	Cumulative Totals
Emissions from Cogeneration											
Large Applications	0.2	1.7	3.6	5.6	7.3	8.7	9.0	9.3	9.6	10.0	65.1
Small Applications	0.1	0.3	0.5	0.8	1.2	1.6	2.0	2.5	2.9	3.4	15.3
TOTAL EMISSIONS	0.3	2.0	4.1	6.4	8.5	10.3	11.0	11.8	12.6	13.4	80.3
Avoided Emissions											
Electricity Generation	0.8	5.1	10.6	16.5	21.8	24.3	25.9	27.6	29.3	31.2	193.1
Heat Production	0.2	0.8	1.6	2.5	3.3	4.7	5.3	5.8	5.5	6.0	35.6
TOTAL AVOIDED	1.0	5.9	12.2	19.0	25.1	29.0	31.2	33.4	34.8	37.2	228.8
NET EMISSION REDUCTION	0.6	3.9	8.1	12.6	16.7	18.7	20.2	21.6	22.2	23.8	**148.4**

5. ANALYSIS OF BARRIERS TO COGENERATION

At this time, there remains a great deal of uncertainty regarding the regulatory treatment of cogeneration facilities. This uncertainty includes questions surrounding the regulatory treatment of transmission and distribution tariffs for cogeneration and environmental approvals requirements. Stakeholders noted that major investments are unlikely to be made until the content of these regulations becomes clear.

This uncertainty is a short-term concern that will be rectified in the near future as the required regulations are developed and introduced. Some of these uncertainties have already been reduced by regulatory decisions or government policy measures.

This section of the report analyses some of the barriers to the installation of economic cogeneration projects. In this context, barriers are defined as factors that could prevent or slow the use of cogeneration in applications where it is otherwise economic. This analysis is based on the barriers that were identified and discussed at this project's two Stakeholders Workshops, a review of previous studies on such barriers, and the study team's understanding of these barriers.

The description and characterization of the barriers in this section is primarily from the point of view of the stakeholders, as expressed in the Workshops. Reports from the Workshops are attached as Appendices B and C.

In order to be most useful, the focus of this analysis of barriers is on those for which potentially viable solutions can be identified. Those barriers for which such solutions could not be identified are discussed separately.

This analysis consists of a description of the barriers, how they impact the potential for cogeneration and the identification of possible solutions. The identified barriers have been classified into three categories: market barriers, institutional barriers and regulatory barriers. Where appropriate and possible, closely related barriers have been analyzed together.

The scope of this project does not include an assessment of the cost/benefits of these possible solutions or their potential impact on the future utilization of cogeneration.

5.1 Market Barriers

5.1.1 Low Price for Electricity

A low price for electricity is likely the most significant of the many barriers analyzed in this chapter. Some stakeholders characterized prices as artificially low.

Several factors have been identified that have resulted, in the view of stakeholders, in artificially low prices for electricity, particularly nuclear-generated electricity, and will continue to do so unless rectified. Heavy public capital contributions, including the writedown of the stranded debt, are seen as having allowed this highly capital-intensive form of electricity generation to become competitive. Other factors include the concern by many that the full costs associated with the decommissioning of nuclear plants at the end of their useful life and the long-term costs to store spent nuclear fuel are currently not included in the costs of nuclear power. The billions of dollars that were invested by the government over the past forty years in the research and development of CANDU reactors are also not included in the current cost of nuclear power in Ontario.

Another important factor that, in the view of stakeholders, has led to artificially low prices for electricity in Ontario is the failure of the current pricing system to include the full environmental costs associated with generating electricity from coal and oil-fired plants. These externalities include, but are not limited to, the cost of the impact on human health and the environment of emissions such as SO_2, NO_X, CO_2, mercury and other toxics.

The decision of the Ontario government to freeze electricity rates in 1994 has also produced what some stakeholders see as artificially low electricity prices in Ontario. Average electricity rates were frozen due to concerns that, without such measures, high rates could jeopardize the competitiveness of Ontario's industrial and commercial sectors. The last electricity price increase in the province was seven years ago. The move to a competitive electricity supply market can be expected to remove any "price freeze" barrier.

The range of government actions suggested by stakeholders which can address this barrier include the following:

- Full or at least partial exemption from the Debt Retirement Charge (DRC) for newer, cleaner means of electricity generation, such as cogeneration.
- Ensure that OPG or any subsequent owner of Ontario's nuclear assets allocates sufficient funds for the decommissioning of nuclear plants at the end of their useful and the long-term costs to store spent nuclear fuel.
- Environmental policies which impose costs for atmospheric emissions, especially of NO and SO_2.

5.1.2 Artificially Low Cost to Reactivate 5 GW Nuclear Capacity

The Pickering and Bruce Nuclear stations have a total of about 5 GW of potential generation capacity that is not in service. Although the cost to bring these units back into production is not publicly known, some stakeholders expressed a concern that these costs may not take into account the full costs to eventually decommission these units and the long-term cost to store the spent nuclear fuel. The reactivation of these units may also benefit from financing rates that could be significantly less than those rates available to developers of new cogeneration facilities.

As discussed in the previous section, a possible government action to address this barrier is to ensure that the costs to bring these units back into production include the full costs associated with the long-term cost of storing spent nuclear fuel.

5.1.3 Market Power of OPG

Although the *Electricity Competition Act* and the Market Power Mitigation Agreement (MPMA) seek to reduce the market power of OPG, the company could retain a dominant position in the electricity market for a number of years after the market opens. This presents a potential barrier to the future utilization of cogeneration in a number of ways.

The MPMA itself has been seen by some as a barrier to entry. It sets a revenue cap of $38 per MWh on 90% of OPG's capacity. It also explicitly allows OPG to take actions to ensure that the market price comes up to this cap. It is possible that the cap will also become a floor, as OPG uses its market power to prevent the price from rising above the cap on average. As the results of this project show, many potential cogeneration projects cannot achieve a LUEC below $38 per MWh. Setting this price as the wholesale market price, therefore, may preclude these projects from entering the market.

On the other trend, it is possible that market prices will be higher than $38/MWh. Prices in the US mid-West, which averaged $55 Cdn/MWh in 1999, could exert upward pressure on the Ontario price and bring the competitive generation price well above $38 per MWh, although Ontario consumers will benefit from rebates on about 75% of their energy use.

There is also some concern on the part of stakeholders that OPG may offer heavily discounted rates to owners of potential large cogeneration facilities to ensure that OPG retains them as customers and keeps their resulting load base.

One way to address this barrier is to instruct the Market Surveillance Panel of the IMO to monitor OPG for entry-preventing behavior like that described above.

5.1.4 Market Rules

Although the Market Design Committee was careful to try to ensure that all potential competitors would be treated fairly, stakeholders expressed concern that some aspects of the Market Rules could act to the detriment of small generators, including cogenerators.

One example is the amount and frequency of information that generators are required to provide to the IMO. To offer supply in the market, they must place offers for the entire day ahead, in hourly intervals, with updates several times a day. Smaller generators may find this information burden onerous.

Under the Market Rules as currently proposed, very small generators (under 1 MW) do not have to meet these information requirements.

5.1.5 Standard Supply Service Code

The Ontario Energy Board's Standard Supply Services Code (SSSC) effectively places restrictions on the sources from which monopoly distributors can buy electricity for their standard service[10] customers. They are allowed to buy only from the spot market or from contract suppliers after an open bidding procedure. Provisions for SSSC are important because it is expected that, especially in the period just after market opening, a large fraction of the total electricity sold to consumers will be under standard service supply.

At the time of the Workshops, the SSSC was understood to allow only spot market purchases. Stakeholders noted that a projected cogeneration plant with electricity in excess of its host's needs will want to sell the electricity as merchant power. Many developers would prefer to have forward contracts for the some or all of that power, both to reduce their risk and to help in their financing. Stakeholders were concerned that one of the most natural markets for such power was removed.

These concerns may have been mitigated by the ability of the distributors to conduct open bidding for supply contracts.

5.1.6 Cost of Cogeneration Technology

Although advances continue to be made in cogeneration technology that result in lower costs per unit of power produced and/or increased efficiency, the cost remains too high for some applications. Future efficiency improvements can result in lower costs per kWh of electricity that is generated.

10 Sometimes called "default" customers. This refers to customers who do not choose an alternative supplier of commodity electricity.

As with most technologies, stakeholders expected that this barrier will be reduced if the market demand for cogeneration technology increases in the future. This increased demand will lead to further investments in R&D and larger, more efficient production facilities which, in turn, would lead to higher operating efficiencies and lower cost for the equipment.

This is not a market barrier, as we have defined it here. It is a true cost factor which affects the economics of cogeneration projects. Governments can reduce costs through tax or other policies.

5.1.7 Undervaluing of System Reliability

Cogeneration represents a distributed generation approach to power generation and distribution that is inherently more reliable than a small number of very large plants that depend on a large transmission system to transport the power to where it is required. Stakeholders noted that at the present time, there is no recognition in the pricing system for this increased reliability.

A remedy for this barrier would be to have locational pricing for electricity. Then generation located inside areas formed by transmission constraints would receive a locational premium. The Market Design Committee recommended that the IMO track locational prices in the first 18 months of the competitive market, and recommend a form of locational marginal pricing after that time. Following that recommendation would remove this barrier.

5.1.8 Cost of Back-up Electricity

In order to maximize system reliability and meet peak demand, most facilities operating cogeneration systems will also want at least the ability to purchase electricity from an external supplier. While the actual cost of the additional electricity would presumably be at a competitive rate for the amount purchased, stakeholders are concerned that the transmission and distribution charges could be set so high that they prohibit investment in the cogeneration facility.

5.2 Institutional Barriers

Several institutional barriers relate to information and contracting costs.

5.2.1 Reluctance to Make Long-Term Commitments

Stakeholders felt that senior management of owners of many of the most attractive potential cogeneration sites with a sufficiently high steam and electricity demand are reluctant to make the long-term commitment required to construct a cogeneration plant. This reluctance is particularly large at this time as the electricity market has not yet opened, the new market rules are still under development and the future price of electricity that can be purchased on the open market is unknown.

This barrier will be partly overcome as fair and equitable market rules are developed and after the market has been operating for a few years.

5.2.2 Competition for Limited Funds and Senior Management Attention

Stakeholders noted that senior managers compare the returns/pay back period of potential cogeneration facilities against other potential capital projects. Other projects may have high potential returns and fast payback periods compared to the construction and operation of a cogeneration facility. Related to this issue is the senior management time that is required for any major capital investment.

The solution to these barriers lies in the fact that if cogeneration is or becomes more cost effective than the current power supply options, those companies that do begin to employ it will derive financial savings compared to their competitors and thus gain a competitive advantage.

5.2.3 Attitudes of Senior Management

Related to the first two institutional barriers are attitudes of senior management of the most attractive potential cogeneration sites. Stakeholders suggested that these attitudes are based on the fact that power supply has not been a part of their core business, electricity has been provided in the past by one utility, and that power supply has not typically been viewed as being as important as other factors impacting the company.

This barrier will never be completely overcome, as power supply will typically not become a core component of most business. In the longer term, if energy prices rise and economic alternatives such as cogeneration become more wide spread, it can be expected that the relative importance of power supply might increase.

5.2.4 Lack of Information, Understanding and Confidence

Although not a new technology, stakeholders noted that there is generally a lack of information, understanding and confidence in cogeneration technologies both by potential users as well as investors. This barrier results in the need by both potential customers and investors to spend the time and cost to inform themselves about this technology. Similar information costs are not incurred if power is simply purchased from an independent third party.

Information costs may be one of the most important institutional barriers. All three of the above barriers effectively relate to information costs. For many potential cogeneration hosts, energy is a relatively small fraction of their total costs, overshadowed by materials or labor costs, for example. To understand the cogeneration opportunity, each firm's management must spend time developing expertise.

Well-functioning markets can mitigate this barrier. In a functioning market, if there is an opportunity to save money cost-effectively, the opportunity will be taken. In this case, the information each firm would need is similar. Even if it is not cost-effective for the management of each potential host firm to acquire this information itself, it probably will be cost-effective for a specialist firm to acquire the information and sell it to the host firms. The specialist firms could readily go further than providing information in advance on costs; they could operate the cogeneration facility as well, keeping within themselves the information and management capability that they can apply in several places, while the host company might only apply it once.

An effective way to overcome these information cost barriers may be to promote (or ease) the formation or entry into Ontario of specialist energy information and operation firms.

5.2.5 Early Stage in Development of Industry of Facility Owner/Operators

There are currently relatively few owner/operators of cogeneration facilities in Ontario. These are the specialist firms referred to in section 5.2.4. Stakeholders feel a more mature industry will be required in order to realize the full potential for cogeneration in Ontario.

The development and maturing of this industry will proceed as this technology becomes more widely spread.

5.2.6 Local Resistance to Siting of New Facilities

Although the siting of cogeneration facilities does not seem to have been a major barrier so far, stakeholders feel it remains an issue that should be closely monitored. It is important to note that local opposition is much less likely for a cogeneration facility than for a merchant plant built to generate electricity exclusively as the cogeneration plan is typically located where there is an existing steam demand and thus an existing boiler. The cogeneration facility is thus merely replacing an existing boiler.

Any local concerns that may arise should be overcome, as residents become more familiar with the technology. It may also be useful to ensure that environmental groups with a provincial overview of the electricity system can provide their perspective on the relative merits of cogeneration.

5.2.7 Transmission Infrastructure

In choosing a location for a new generating facility, investors in merchant plants are free to go anywhere they can acquire land and an adequate fuel supply. Cogeneration investors are limited to locating at the sites where there is simultaneous demand for heat and power.

Stakeholders emphasized that the design of any cogeneration installation is very specific to the characteristics of the site: the size of the electricity load, the size of the heat load, and the time patterns of their usage (the load durations). In many cases, a cogeneration facility which can meet the heat load efficiently will produce more electricity than the steam host requires. For the cogeneration application to maximize value, and perhaps even to be economic, it requires access to the electricity market for the surplus power. Access to the market will be provided in the coming competitive environment.

However, some potential cogeneration projects may be located within an area defined by transmission congestion, potentially limiting excess power sales or reducing their value.

5.2.8 Interconnection Requirements and Costs

Stakeholders reported that some local utilities, particularly the smaller ones, have in the past imposed unnecessarily high technical requirements that a cogeneration facility would have to meet to sell them their surplus electricity or to connect for backup power. Such requirements may severely impact the economic feasibility of those cogeneration facilities which generate electricity that exceeds their own requirements or which require back up from local distribution companies.

This barrier can be addressed by setting a province-wide interconnection standard, or through regulatory challenge of the requirements.

5.2.9 Lags in Equipment Availability

World demand for new electricity generation facilities is currently quite high. As a result of past experience with cycles of high and low demand, producers of generation equipment have been reluctant to ramp up output sharply. Therefore, the lag between order and delivery of new generation equipment, particularly large turbines, has lengthened.

This barrier will only be overcome as more production capacity for the manufacture of this equipment is introduced and the required equipment become more readily available.

5.3 Regulatory Barriers

5.3.1 Transmission and Distribution Pricing

Stakeholders were concerned that the transmission pricing tariff proposed by Ontario Hydro Networks Company could create a significant barrier for some potential cogeneration projects. This concern has been reduced by the Ontario Energy Board's recent decision in the transmission pricing case. It rejected the OHSC proposal to bill new embedded generators for the full transmission tariff. Instead, new embedded generators will pay only for the fixed connection and transformation charges of the system, not for the cost of network operations.

In addition, the Board accepted that generators below 1 MW not be subject to load billing for any component of the transmission charge.

5.3.2 Environmental Assessment and Approval

As a relatively low emission technology, stakeholders stressed that it will be important to ensure that potential cogeneration projects are reviewed efficiently and promptly, particularly the smaller sized plants.

The Ministry of the Environment's new proposed environmental assessment requirements identifies three categories of projects: 1) those that require an individual environmental assessment; 2) those that would require a screening process; and 3) those that that would not require approval under the *Environmental Assessment Act*. The Ministry is in the process of seeking stakeholder views on what types of projects should be placed in each category and appropriate threshold levels.

5.3.3 Assets Included in Class 43

The federal government allows preferential tax treatment for certain assets that are part of a cogeneration facility. These assets are defined under Class 43. Stakeholders noted that they currently do not include all the assets associated with a cogeneration facility and require a heat rate that may be hard for smaller cogeneration units to attain.

5.3.4 Proposed Power Engineers Regulations

In the summer of 1999, new regulations were drafted to replace the sections of the *Operating Engineers Act* that stipulate the conditions under which a full-time, licensed operator was required for stationery boilers. The proposals in the new *Power Engineers Regulations* would require these operators for all steam turbines over 75 kw. The *Operating Engineers Act* did not include requirements for steam turbines and required an operator for steam boilers over 13,000 lb/hr or about twice the size of the 75 kw proposed in the new regulations.

Stakeholders were concerned that this requirement, if adopted, would have a very detrimental impact on the cost effectiveness of smaller cogeneration plants in the 75-150 kw size range.

Meetings between the concerned stakeholders and those responsible for the Act could move this problem towards a reasonable solution.

5.4 Barriers With No Apparent Policy Approaches

5.4.1 Uncertain Future Natural Gas and Electricity Prices

One of the features of a competitive market is that prices are not controlled and thus future prices will remain uncertain. This barrier has recently been exacerbated by the "North Americanization" of the gas market. Due to the large increase in gas transmission capacity coming on stream in late 2000, a larger volume of natural gas from Canada's western sedimentary basin will have full access to US gas markets. This and other factors resulted in gas price increases in 1999. It is not yet clear how much of these gas price increases are a result of fundamental market changes and how much are a result of short-term factors such as weather and storage levels or medium-term factors such as low levels of exploration and development activity.

As the physical and market infrastructure for gas matures, gas price volatility may decline. On the other hand, a more actively traded market could become more volatile, especially over short periods of time.

This barrier is related to the informational barriers and to the familiarity of management with management of market risk of various kinds. Installing cogeneration can reduce a company's exposure to gas prices or raise it, depending on how fuel supply contracts are handled and on what the non-cogeneration electricity supply options are. It can also reduce a company's exposures to extremes of electricity market prices. As managements become more sophisticated in managing risk, this factor will become another part of the market consideration.

5.4.2 Availability of Steam/Low Grade Heat Hosts

Whereas access to electricity markets had been the prime barrier to cogeneration projects in the past, the availability of steam/low grade heat hosts is now a barrier to greater utilization of this technology.

APPENDIX A

GAS PRICE REPORT

Delivered Natural Gas Price Forecast for Ontario

Current Prices

Current Delivered Prices in Ontario

Current delivered prices for system gas in Ontario reflect contracts made some time ago. Delivered prices are lower for higher delivery volumes due to lower distribution costs. In October 1999, Firm Service Delivered Prices were as given in the table below.

	500 GJ/Month	5000 GJ/Month
Toronto	$5.73 per Mcf	$5.57 per Mcf
Sudbury	$5.01 per Mcf	$4.13 per Mcf
Sarnia	$5.70 per Mcf	$5.40 per Mcf

(Source: Canadian Gas Price Reporter)

Current Border Prices

The October average price at Empress for a 1-year contract is $3.44 per Mcf. This price is well above a comparable price from a year ago. The August field price in Alberta was up by almost $1.00 per Mcf from the previous year.

Recent Price History

The Alberta border price has more than doubled since 1995. The average 1995 Alberta border price was C$1.21 per MMBtu; the average price for the first ten months of 1999 was C$2.89 per MMBtu. The trend has been steadily upward from July to October, which is consistent with usual seasonal patterns, but the growth has been more rapid than in past years.

This price increase has been due to two factors: an increase in the price of gas in North American markets generally and a narrowing of the differential between gas prices in Canada and gas prices in the United States. The average differential in 1995 between the NYMEX price and the Alberta border price was over C$1; in 1999 to date, the average differential was C$0.40.

Gas prices have been increasing in the United States and Canada since the spring of 1999. After strong growth from May of 1999, Canadian prices peaked in September and fell noticeably in October. Monthly gas prices can be volatile. In the twelve months to October, 1999, monthly average prices ranged from C$2.32 to C$3.61 per MMBtu.

Canadian domestic demand has grown, but not by enough to account for the price increase. Improved transportation facilities have brought the Canadian gas prices closer to US prices.

Transmission Tolls

The current firm transmission toll for TCPL is about C$.99 per Mcf from the Alberta border the Toronto City gate.

Distribution Tolls

The current lowest charge on the Enbridge Consumers' Gas system for large users in the off peak periods is about $2.15, including charges for storage and balancing. They estimate that a generation plant of 100 MW or more, operating on a gas load factor of about 80%, would pay about $0.40 per Mcf for distribution, including charges for transportation and some storage and balancing. This rate is significantly below the $0.55 per Mcf rate, not including storage and balancing, for their largest industrial customers. It represents an attempt by Enbridge to keep generators from bypassing the distribution system.

Delivered Price Forecast – Base Case

Alberta Border Price

Recent price forecasts are available from several sources, including the US Energy Information Agency (EIA) and the National Energy Board (NEB)[11]. However, most of these forecasts did not anticipate the sharp upward movement in gas prices in the second and third quarters of 1999, so they are already out of date. For example, the NEB has two forecast cases. The Alberta gas prices are $1.82 and $2.50 per Mcf., and the US prices are C$3.00 and C$3.75, in 2010. The highest of these prices are below current prices in both countries.

The question for this price forecast is whether recent prices imply consistently higher prices in the future, whether they are normal variance around an unchanged trend, or whether they represent an earlier move to the forecasted level. The base forecast assumes that the current prices are a temporary upward swing, but that swing is relative to a higher future base price level.

For the base case forecast, the year 2000 price is derived from current market information as received from the Canadian Gas Reporter and from conversations with energy analysts in Alberta and Ontario. The forecast growth rates are based on a consensus forecast growth rate from four sources: the EIA, Gas Research Institute (GRI), Standard and Poor's/McGraw Hill, and WEFA.

Current forward Empress prices are about at the level forecast above for 2010. It is expected that prices will fall in 2000, as more supply comes on stream, and then rise gradually as increased demand, especially from new gas-fired generation in the United States, takes the supply up. The forecast is therefore based on an Alberta border price of $3.00 per Mcf in 2000, escalating at 1% per year for the next five years and 1.7% per year for the following five years.

[11] National Energy Board, *Canadian Energy: Supply and Demand to 2025*, National Energy Board, 1999.

After 2010, the rate of price increase continues to accelerate. It is set at 2.4% per year. This is the average price growth rate of Case 1 and Case 2 of the NEB Report. Using these growth rates, the price of Empress gas reaches $4.35 per Mcf in 2020. This price is about $0.90 above the current price, and represents overall an average growth rate over the entire period of about 1.2% per year from current levels.

The pattern of price growth in the NEB forecast is opposite to that in the EIA forecast. in the NEB forecast, prices grow more slowly in the early years, accelerating to a rate of over 2% p9er year in the later second decade of the forecast. in the EIA forecast, prices grow more rapidly in the early years, decelerating to 1% per year or less for the second decade of the forecast for all of the forecast cases (except one case for one five-year period.)

Transmission Toll Forecast

There is currently excess gas transmission capacity, resulting from recent TCPL capacity expansions. The excess is expected to increase, with the completion of the Alliance pipeline to Chicago and the probably construction of the Vector line from Chicago to Dawn, Ontario. These will create competitive downward pressures on TCPL rates, until increased gas shipments take up the capacity.

Beyond this immediate period, it is expected that there will continue to be competitive pressure on pipeline tolls. Given the more open environment for new pipeline investments, response to actual or impending transmission capacity shortages seems to be robust. Further, the monopoly pipeline activities are likely to come under some form of Performance Based Regulation (PBR), which will put increased downward pressure on their costs and rates.

PBR is becoming the first choice of regulators for utilities in restructured competitive markets in North America. It provides better incentives to regulated utilities to reduce costs. While PBR has not yet been applied to gas transmission pipelines in Canada, the expectation is that it will be adopted within the next 5 years.

The combination of competitive pressures on price and PBR pressures on cost lead to the forecast of falling transmission tolls. The forecast gas transmission toll declines steadily, at a rate of just under 1.4% per year for the first 10 years, to arrive at a level of C$.85 per Mcf by 2010. For the following 10 years of the forecast, pipeline tolls fall at a somewhat slower rate, 0.5% per year.

Distribution Toll Forecast

The forecast varies for large and small customers. The current rates for large customers represent significant price discrimination in favor of large users. The discrimination is based at least in part on the potential ability of large users to bypass the distribution system and connect directly to gas transmission. While such discrimination is expected to continue, the forecast shows a mild degree of reduction in its extent.

For the large users, as for large potential cogeneration plants, the forecast assumes that distribution rates will stay constant in real terms, implying gradual increases in nominal terms. The forecast differentiates between rates for large plants and medium sized one. The toll for large users, plants above about 50 MW, is forecast to remain constant at a rate of $0.40 per Mcf. For smaller plants, around 10 MW, the forecast has a distribution rate above that for the large users, but well below that for smaller commercial users. The distribution rate assumed here is $0.80 per Mcf.

Much smaller cogeneration installations would be expected to pay the residential rate. A generator below 1 MW, for example, might not even qualify for the commercial rate. The current trend in residential consumption of natural gas is downward, as a result of significant increases in average efficiencies of home heating systems. With the resulting excess capacity, there will be little upward pressure on distribution rates due to the need for new investment. On the other side, there will be continuous downward pressure from PBR. These rates, therefore, are expected to move downward steadily. The rate of downward movement reflects the potential for productivity improvements. For the first ten years, the distribution rates trend down by about 2.2% per year; for the succeeding 10 years, they fall by about 1.5% per year.

Upper and Lower Case Forecasts

The upper and lower cases are derived entirely from alternative forecasts of Alberta border prices for gas. The transmission and distribution tolls do not vary between cases. The focus of this study is on the impact of gas prices on the potential for cogeneration in Ontario. Varying gas prices allows enough price spread for this analysis.

The cases are based on the two cases of the recent National Energy Board forecast. That forecast analyzes two cases. In that forecast, Case 1 represents a combination of low cost supply and current demand trends, to produce a higher quantity of energy demanded. Case 2 represents a combination of current supply trends and accelerated demand efficiency, to produce a lower quantity of energy demanded. Case 1 can generally be expected to produce lower prices and Case 2 to produce higher prices. However, the NEB chose them for their impact on demand, not price; the highest price would be produced by a combination of current supply trends with current demand trends, and the lowest by a combination of lower cost supply and more efficient demand. For the purpose of this forecast, therefore, the two cases allow a reasonable test of the assumptions, without creating extremes.

The National Energy Board report predates the natural gas price increases of later in 1999. Using it therefore requires some assumptions about how to match its forecasts to later events.

Low Price Case

The low price case assumes that the price history since the publication of the NEB report represents normal variance around the prices in the case. For this case, the gas price in 2010 is taken as the 2010 price from the NEB Case 1. That price is significantly below the assumed 2000 price. To reach the predicted level, the price is forecast to fall for the first ten years. Although the price probably will not fall smoothly over that period, the low price case smoothes the drop, in order to avoid the need to predict a specific dynamic pattern. The rate of decrease was calculated as the rate needed to reach the NEB forecast price by 2010; it is a real decline of 3.5% per year.

After 2010, the low price case forecast uses the NEB's forecast growth rate from 2010 to 2025 for the period from 2010 to 2020.

High Price Case

The high price case is also based on the NEB forecast, but it assumes that the forecast price in 2000 forms a new basis for price increases. The case is therefore derived by applying the forecast price growth rates from NEB's Case 2 to the assumed price in 2000. This produces prices that are notably higher than those in the base case. The growth rates are those for the Alberta border price in two ten-year blocks: from 200 to 2010, and from 2020 to 2020.

The two cases are not symmetrical. The low price case is farther below the base case than the high price case is above it. This is in keeping with the current sentiment among gas price forecasters, who generally believe that the risk in gas prices, at least for the next five years or so, is downward. Higher oil and gas prices have stimulated exploration and development activity in Canada, which is expected to increase supply and bring current prices down.

FORECAST GAS PRICES
Alberta Border

(All prices in $2000/Mcf)

	LOW CASE		BASE CASE		HIGH CASE	
		5 yr		5 yr		5 yr
YEAR	$	AAGR	$	AAGR	$	AAGR
2000	3.00		3.00		3.00	
2001	2.90		3.03		3.09	
2002	2.79		3.06		3.19	
2003	2.70		3.09		3.29	
2004	2.60		3.12		3.39	
2005	2.51	-3.50%	3.15	1.00%	3.49	3.10%
2006	2.42		3.21		3.60	
2007	2.34		3.26		3.71	
2008	2.26		3.32		3.83	
2009	2.18		3.37		3.95	
2010	2.10	-3.50%	3.43	1.70%	4.07	3.10%
2011	2.15		3.51		4.18	
2012	2.19		3.60		4.29	
2013	2.24		3.68		4.41	
2014	2.29		3.77		4.53	
2015	2.34	2.20%	3.86	2.40%	4.65	2.70%
2016	2.39		3.95		4.78	
2017	2.45		4.05		4.91	
2018	2.50		4.15		5.04	
2019	2.56		4.25		5.17	
2020	2.61	2.20%	4.35	2.40%	5.31	2.70%

DISTRIBUTION AND TRANSMISSION CHARGES

(All prices in $2000/Mcf)

		Distribution Tariffs for Cogeneration					
	Transmission	>50 MW		10 MW		<500 kW	
YEAR	Tolls	Sudbury	Toronto	Sudbury	Toronto	Sudbury	Toronto
2000	0.98	0.40	0.40	0.80	0.80	2.50	2.75
2001	0.97	0.40	0.40	0.80	0.80	2.44	2.69
2002	0.95	0.40	0.40	0.80	0.80	2.39	2.63
2003	0.94	0.40	0.40	0.80	0.80	2.34	2.57
2004	0.93	0.40	0.40	0.80	0.80	2.29	2.52
2005	0.91	0.40	0.40	0.80	0.80	2.24	2.46
2006	0.90	0.40	0.40	0.80	0.80	2.19	2.41
2007	0.89	0.40	0.40	0.80	0.80	2.14	2.35
2008	0.87	0.40	0.40	0.80	0.80	2.09	2.30
2009	0.86	0.40	0.40	0.80	0.80	2.05	2.25
2010	0.85	0.40	0.40	0.80	0.80	2.00	2.20
2011	0.84	0.40	0.40	0.80	0.80	1.97	2.17
2012	0.83	0.40	0.40	0.80	0.80	1.94	2.13
2013	0.82	0.40	0.40	0.80	0.80	1.91	2.10
2014	0.82	0.40	0.40	0.80	0.80	1.88	2.07
2015	0.81	0.40	0.40	0.80	0.80	1.85	2.04
2016	0.80	0.40	0.40	0.80	0.80	1.83	2.01
2017	0.79	0.40	0.40	0.80	0.80	1.80	1.98
2018	0.78	0.40	0.40	0.80	0.80	1.77	1.95
2019	0.78	0.40	0.40	0.80	0.80	1.75	1.92
2020	0.77	0.40	0.40	0.80	0.80	1.72	1.89

DELIVERED PRICES FOR GAS FOR COGENERATION
LOW, BASE AND HIGH CASES
(All prices in $2000/Mcf)

							<500 kW					
	>50 MW			10 MW			Sudbury			Toronto		
YEAR	Low	Base	High	Low	Base	High	Low	Base	High	Low	Base	High
2000	4.38	4.38	4.38	4.78	4.78	4.78	6.48	6.48	6.48	6.73	6.73	6.73
2001	4.26	4.40	4.46	4.66	4.80	4.86	6.31	6.44	6.50	6.55	6.69	6.75
2002	4.15	4.41	4.54	4.55	4.81	4.94	6.14	6.40	6.53	6.38	6.64	6.77
2003	4.03	4.43	4.63	4.43	4.83	5.03	5.97	6.37	6.56	6.21	6.60	6.80
2004	3.93	4.45	4.72	4.33	4.85	5.12	5.81	6.33	6.60	6.04	6.56	6.83
2005	3.82	4.47	4.81	4.22	4.87	5.21	5.66	6.30	6.64	5.88	6.53	6.87
2006	3.72	4.51	4.90	4.12	4.91	5.30	5.51	6.29	6.69	5.73	6.51	6.91
2007	3.62	4.55	5.00	4.02	4.95	5.40	5.36	6.29	6.74	5.58	6.50	6.95
2008	3.53	4.59	5.10	3.93	4.99	5.50	5.22	6.28	6.80	5.43	6.49	7.00
2009	3.44	4.64	5.21	3.84	5.04	5.61	5.08	6.28	6.86	5.29	6.48	7.06
2010	3.35	4.68	5.32	3.75	5.08	5.72	4.95	6.28	6.92	5.15	6.48	7.12
2011	3.39	4.75	5.42	3.79	5.15	5.82	4.96	6.32	6.99	5.16	6.52	7.19
2012	3.43	4.83	5.53	3.83	5.23	5.93	4.97	6.37	7.07	5.16	6.56	7.26
2013	3.47	4.91	5.63	3.87	5.31	6.03	4.98	6.42	7.15	5.17	6.61	7.34
2014	3.51	4.99	5.75	3.91	5.39	6.15	4.99	6.47	7.23	5.18	6.66	7.42
2015	3.55	5.07	5.86	3.95	5.47	6.26	5.01	6.52	7.31	5.19	6.71	7.50
2016	3.59	5.16	5.98	3.99	5.56	6.38	5.02	6.58	7.40	5.20	6.76	7.59
2017	3.64	5.24	6.10	4.04	5.64	6.50	5.04	6.64	7.50	5.22	6.82	7.68
2018	3.68	5.33	6.22	4.08	5.73	6.62	5.06	6.70	7.59	5.23	6.88	7.77
2019	3.73	5.42	6.35	4.13	5.82	6.75	5.08	6.77	7.70	5.25	6.94	7.87
2020	3.78	5.52	6.48	4.18	5.92	6.88	5.10	6.84	7.80	5.27	7.01	7.97

APPENDIX B

FIRST WORKSHOP REPORT

POTENTIAL FOR COGENERATION IN ONTARIO:
NOTES FROM DECEMBER 9, 1999 STAKEHOLDERS WORKSHOP

Prepared for
Energy Policy Branch
Ontario Ministry of Energy, Science & Technology

By
Hagler Bailly
In association with
AGRA Monenco
And
Lourie & Love Environmental Management Consulting

January 31, 2000

1. INTRODUCTION

The main purpose of this report is to summarize the discussions that took place during the half day Stakeholders Workshop that was organized December 9, 1999. It also includes copies of the material distributed at this workshop so that it can be sent to those who were not able to attend but expressed interest in being kept informed.

The purpose of the Workshop was to seek the views of selected stakeholders on the opportunities for cogeneration applications in Ontario and on the major barriers that may prevent wider utilization. This workshop was part of a project that the Ministry of energy, Science and Technology is currently undertaking, in cooperation with the Ministry of Natural resources and the Ministry of Economic Development and Trade, to evaluate the potential for cogeneration in Ontario.

A list of 32 potential participants were identified, representing the following five major categories:

Current cogeneration plant operators
Potential operators/developers
Equipment manufacturers
Financial consultants
Environmental non-government organizations

The list of invitees to this workshop is included in Section 5 of this Appendix.

2. SUMMARY OF PLENARY SESSION

Doug MacCallum of the Ministry of Energy, Science & Technology began the workshop by welcoming all participants. He noted that this project was part of the Ontario government's response to the challenge of reducing Ontario's greenhouse gas emissions. He also noted that a number of the recently published federal "Issue Tables" that had assessed a wide range of opportunities to reduce CO_2 emissions had referred to cogeneration as one of the technologies that offer the potential for significant emission reductions.

Peter Love of Lourie and Love began by noting how pleased he was to see such a good turn-out for this workshop, particularly in light of the relatively short notice and the time of year. He also noted that the participants represented a broad range of interests and felt that this would be very useful during the discussions. He then briefly reviewed the Agenda for the workshop (included in Section 5), noting that the project team planned the event to maximize the time that participants could spend discussing the key issues in three breakout groups.

He then summarized the workshop objectives, which were:

To seek views of representatives from major stakeholders on:
Most attractive cogeneration applications in Ontario
Major barriers that may prevent wider utilization

He also noted that the focus of the workshop would be on seeking views of participants during the breakout group discussions. He suggested that in addition to discussing the two above-noted issues, these breakout groups might also want to address the key question "What would it take for your organization to consider proceeding with a cogeneration project". Based on a brief discussion of this question statement, it was generally agreed that many organizations are already "considering" such projects and that a better phrasing of this question might be:

What will it take for your organization to proceed with a cogeneration project?

Scott Stevens of Energy Ventures Group, representing AGRA Monenco, then briefly summarized the initial cost estimates of alternative cogeneration technologies that had been developed for this project. The capital, O&M, fuel, levelized tax and resulting Levelized Unit Electricity Cost (LUEC) before and after the steam thermal credit for 8 medium-large units (>10 MW) and 19 small units (<10MW) were summarized on two tables; these tables are included in Appendix B of this report. The delivered prices for natural gas to 2020 for three categories of plant sizes (>50 MW, 10 MW and < 500 kW) under three scenarios (Low, Base and High), in $2000/Mcf were also presented and are included in Appendix A of this report.

Workshop participants who had comments on these assumed costs were asked to contact Scott directly after the workshop as it was felt that such discussions would be better conducted on a one-on-one basis.

Mitch Rothman from Hagler Bailly, who is the Project Manager for this project, began by thanking participants for taking the time to provide the study team with their thoughts and insights on the issues associated with cogeneration. He then briefly reviewed an initial list of fourteen potential barriers to cogeneration; this list is included in Section 5. He emphasized that this list was intended to start the discussion on barriers, was not intended to be comprehensive and that they were not presented in any order of importance.

There followed a general discussion of the barriers to cogeneration; the following were the main points that were raised during this discussion:

1. Limited number of suppliers
2. Uncertainty of prices significant—gas, electricity
3. Uncertainty of supply
4. Uncertainty of nuclear power input
5. Size of project & barriers to small projects
6. Lack of district heating limits steam host opportunities
7. Environmental approval regulations—these require harmonization
8. Access to equipment

9. Market in environmental emission credits; will overcome the environmental externality barrier in favour of cogeneration
10. Ability of financial people to convince CEO's of benefits / risks
11. Cost of back-up power – will penalize cogeneration
12. Need to treat very small plants inside the meter as a demand management measure; gross vs. net billing
13. Barriers can be divided into short and long term issues
14. Issue of taxation incentives must also be addressed
15. Need to look at emission trading potential and the role that this can play in maintaining a market for CO_2 and NOx etc., which may be reduced through cogeneration
16. How to look at a whole suite of pollutants instead of a few?

3. NOTES FROM BREAKOUT GROUPS

The following three sections summarize the main points that were discussed during each of the breakout sessions, as recorded by the facilitators and presented to the workshop when the groups reconvened.

3.1 Group A

FACILITATOR: PETER LOVE, LOURIE & LOVE

Greg Allen	Green Energy Coalition
David Bond	Ministry of Economic Development & Trade
Frank Dixon	Westcoast Power
Harry Goldgut	Great Lakes Power
Finn Greflund	TransCanada Energy
Susan Olynyk	Dofasco
John Welch	General Electric
Aqeel Zaidi	Union Gas

This group appeared to spend more time discussing the first issue (most attractive cogeneration opportunities) than the other two groups.

Breakout members first briefly introducing themselves, noting their interests in cogeneration. During this opening discussion, the following barriers to cogeneration were noted, many of which relate to the future electricity pricing by OPG:

- Uncertainty of future power prices and concern that OPG will do whatever possible to retain their current load

- Artificially low electricity prices as OPG has been allowed to write-off much of its debt
- The real avoided cost of power in Ontario is likely $0.06/kWh, $0.10 for nuclear

- No technology can compete with nuclear if capital costs are written off and there is insufficient provision for decommissioning of plants

- Lack of information regarding cogeneration

- Companies are slow to make major investment decisions in an uncertain environment and require detailed risk analysis before proceeding

- Senior management do not see cogeneration as “a big deal”

- Large industries are not in the business of making power themselves and thus might prefer to contract to third party

- Financing of cogeneration projects currently requires more equity and thus higher returns as amount of debt financing is limited

- Load factor could be a critical issue, particularly if Bruce A units come back into production

- There is currently no capacity shortage in Ontario but there is a capacity market in New York

- Availability of a sufficient steam demand will be critical for future facilities; availability of electricity demand was primary limitation previously

Most Attractive Opportunities

The group then discussed the ideal opportunities for cogeneration. It was generally agreed that the larger plants (>200 MW) that offered significant economies of scale would be the most attractive. As it was generally agreed that a large steam demand was required, the following were identified as the most attractive potential applications:

- ♦ Integrated iron & steel mills - 4 in Ontario

- ♦ Forest products industries
  - 32 pulp & paper mills in Ontario
  - some are Forest products industries
  - beginning to use less natural gas due to process changes (TMP mills primarily electricity and steam demand)
  - most inexpensive biomass is already being recovered
  - new MNR regulations preventing landfilling may result in additional sources of biomass
  - some older plants are looking at major capital equipment replacement projects
  - no developers seem interested in this market at this time
  - study of biomass potential by Union Gas available upon request

- Petro-Chemical plants (Sarnia)

- Institutions (eg hospitals)
  - major advantage is that they would get to keep resulting costs savings
  - (not the case with most commercial buildings where costs passed onto tenants)

- Municipalities (sewage treatment, district heating/cooling, municipal waste)

- Commercial buildings – only when they are grouped together as clusters

Future Electricity Pricing

The future prices for electricity was identified as a key issue. Although the pricing shortly after market opening may be difficult to predict, **this group agreed unanimously that in the longer term (2 years), industrial electricity prices in Ontario would be higher than they are now**. It also agreed that this will come as a rude awakening to many large electricity consumers who have been actively advocating an open, competitive electricity system in Ontario as they believed that this would lead to lower electricity prices. This will represent a major opportunity for cogeneration.

Major Threats to Cogeneration

The return of up to 5 GW of currently idle nuclear capacity in Ontario was seen as the largest threat to cogeneration.

This threat could be reduced if the operators of these facilities were forced to include the full costs of decommissioning and liability associated with long-term storage of nuclear wastes

Most Important Controllable Barriers

- Net billing, locational pricing and uneconomic by-pass

- Emission reduction credits, particularly in non-attainment zones, for NO_X and perhaps CO_2

- Harmonization of permitting between Canada and the US

- Confidence, experience and financial information on cogeneration projects

- Trust/comfort level between consultants, developers and end-users
- Clarification of transmission charges to alleviate congestion and encourage more generation where needed (eg Alberta's locational credit system)

- Competition transition Charge – how much is it? How will it be applied? Gross/net basis? At consumption or generation level?

Uncontrollable Barriers

- Market uncertainty re nuclear facilities

- Potential for export sales to US (higher in summer, lower in winter as US utilities are summer peaking

- Lower prices in Quebec and Manitoba (limited by current interconnections)

3.2 Group B

FACILITATOR: MITCH ROTHMAN, HAGLER BAILLY

Peter Heffernan	Rolls-Royce
Ed Kress	Great Lakes Power
Doug MacCallum	Ministry of Energy, Science and Technology
Robert McLeese	Access Capital
Scott Stevens	Energy Ventures Consulting
Dale Struthers	O&Y Enterprise
Ian Stewart	O&Y Enterprise
Paul Vyrostko	Northland Power
Henry Wegiel	Dofasco

This session first considered a number of overall categories of barriers to cogeneration. We elaborated on the sources of those barriers, and then tried to identify which of them were likely to be long-term influences. We also tried to identify a list of major short-term issues.

The categories of barriers that were identified were:
- Inability of host to commit
- Commercial and regulatory risk
- Transmission rates
- CTC
- Regulatory policy
- Information
- Tax policy
- Electricity price uncertainty

In the list below, each of these categories is headed in bold. Those that were identified as long-term issues have the abbreviation LT in the right side of the listing.

Inability of host to commit

WHY?

- No long-term PPAs
- No gas price certainty **LT**
- No price history for the revenue stream
- Customer inability to commit long-term
- Uncertainty of spark spread **LT**
- Discomfort with energy as a long-term investment area for a manufacturing company "This is not our core business" **LT**
- Lack of board-level focus on energy/electricity
- High hurdle rates for core business
- Reluctance to take risk in a non-core area

Commercial Risk vs. Regulatory Risk

- Manage commercial finance issues (eliminate regulatory risk, can negotiate commercial risk)
- Can't manage regulatory risk **LT**
- Regulatory risk may/may not go away (lessen)

Transmission Rates

- Gross billing
- Some matters are policy, not regulatory **LT**
- E.g. "Customers pay for costs they incur"
- Penalties for cogen
- complexity of proposed rate structure
- congestion pricing
- why is OHSC apparently against new generation?

CTC **LT**

- How collected?
- What basis?
- Who Pays?
- How will generation affect it?
- (Should interruptible customers pay it?)
- Will CTC be applied equally to all competitors?

Regulatory Policy

- Firm government commitment to a market reduces risk **LT**
- Do proposals promote objectives of the act?
- Cost imposition for transmission system expansions **LT**
  - Beneficiaries?
  - All system users?
- Uncertainty of market access for merchant components
- Uncertainty of emissions rules

- Uncertainty of environmental assessment process
- Uncertainty on cross-border policy harmonization (trading, labelling)
- Uncertainty of impacts of environment and other cross-border regulation

Information

- Unequal access to historical information
- Withdrawal of previously available information

Tax Policy

- Class 43 lack of credit for by-product fuels **LT**
- Municipal tax (uncertainty about treatment of hydro)
- Low value of Class 43 tax treatment

Electricity price uncertainty

- Restrictions on existing NUGs
- Impact of MPMA **LT**
  - OPGI bidding strategy
  - Speed of divestiture
  - Restrictions (or lack) on OPGI behaviour
- Is $38/MWh a cap or floor?
- Nuclear performance **LT**
  - Who pays rehab costs?
  - Default supply (SSSC)

Big Short-Term Issues

- Gross vs. Net
- Standby charges
- CTC
- IMO uplift issues
- Lack of market experience/MPMA
- Asymmetry of market information
- High operating cost of cogen compared to price cap

3.3 Group C

FACILITATOR: BRUCE LOURIE, LOURIE & LOVE

Bruce Ander	Toromont Power
Frank Bajc	ACTO/CU Power
Rick Greenwood	Ministry of Natural Resources
Mike Kuriychuk	Bowater
James Perry	Ontario Power Generation
Todd Wilcox	Toronto Hydro
Adam White	TransAlta
Phil Wood	Enbridge Consumers Gas

This group focused primarily on discussing the barriers to cogeneration; any possible solutions that were discussed are written in italics.

Three Major Barriers

1) Gross Billing Decision
2) CTC
3) Environmental Regulations

Divide the barriers into:
1) Policy, including market rules
2) Market / Technology

Policy / Market Rules

Big Issues:

- Stranded debt – CTC
- Fundamental conflict in government; as owner, generator, regulator and consumer
- High CTC protects old plants

Possible Solution:

- *Need to look at the level, duration and exemptions from the CTC for highly efficient new plants, as an incentive for developing new technologies and reducing air pollution.*

Gross Transmission Billing; a barrier:

- Not based on transmission use

Possible Solution:

- *Allow for net billing—giving fair treatment*

Back up power:

- Uncertainty / high costs of connection; leads to monopoly control
- Negotiating technical interconnection
- Role of OEB arbitration is uncertain

Possible Solution:

- *Interconnect standards / ruling to overcome this barrier*

Imbedded Generation is being treated unfairly; this limits cost choice.

Possible Solution:

- *Overcome this barrier by providing equal treatment / level playing field for imbedded generation*

Barrier aggregating thermal load, district-energy, role of municipalities

Timing and extent of locational pricing

Uncertainty re: scheduling of small projects through IMO

Environmental / Climate Change Drivers

- No teeth in climate change policy
- Uncertainty in government response to climate change
- Uncertainty re: emission caps (timing) and trading rules
- Costs / allocation of credits
- Present standards based on point of impingement, not heat rate; this penalizes efficiency

Possible Solution:

- *Overcome by setting / clarifying standards that encourage efficient generation*
- *Favourable tax treatment for high efficiency / low emission*
- *Common emission standards for new and existing plants*

Environmental Approvals:

- Lack of updated process
- Lack of "Green Energy" certification standard

Market / Technology

Time / Cost barrier for smaller plants / projects

Technology / Information

- Focus on development information NOT technical information except fuel cells etc.
- Time / cost barrier
- Local resistance negligible

4. CONCLUDING COMMENTS

The main features of the discussions in each breakout group were summarized by the facilitators. No attempt was made to summarize the many common themes that emerged from these presentations but it was noted that the three groups approached the issues in different ways. Group A spent most of their time discussing the most attractive potential cogeneration applications and divided the barriers into controllable and uncontrollable. Group B focused on discussing short term vs. long term barriers. Group C identified three major barriers and identified the major issues and possible solutions.

During the ensuing discussion, reference was once again made to the fact that future electricity prices will be critical to the success of new cogeneration projects. The Ministry of Energy, Science and Technology was asked to provide participants with the government's best estimate of future electricity prices. Subsequent to this workshop, the Ministry of Energy, Science & Technology informed the study team that there was no official price forecast. The Ministry suggested that the project team use three electricity generation price levels in the projections: $38, $45, and $50 per MWh.

At the end of the workshop, Doug MacCallum once again thanked all participants for their time and cooperation. He added that all participants (as well as those who were interested but could not attend) would be invited to the next Stakeholders Workshop. This will be held:

Tuesday February 15, 2000

Participants at this workshop will be sent a draft copy of the consultant's report on the potential for cogeneration in Ontario for their review prior to this workshop.

5. LIST OF INVITEES, INVITATION, AGENDA AND INITIAL LIST OF POTENTIAL BARRIERS

5.1 List of Invitees

ABB Alstom Power	Martin Lenzin	(403) 278-7111
Access Capital	Robert McLeese	(416) 366-4820
AMPCO (Association of Major Power Consumers of Ontario)	Ken Snelson	(416) 769-8880
ACTO/CU Power	Frank Bajc	(416) 620-1992
BOMA (Building Owners and Manufacturers Association)	Ian Stewart	(416) 862-6005
Boralax	Yves Rheault	(514) 363-5130
Bowater	Catherine Cobden	(819) 643-7200
Canadian Pulp and Paper Assoc.	Lucy Veilleux	(514) 866-6621
Dofasco	Tom McGuire	(905) 544-3761
Enbridge Consumers Gas	Phil Wood	(416) 495-8350
GE Power Systems	Glen Kennedy	(416) 858-5314
Great Lakes Power	Harry Goldgut	(416) 956-5139

Green Energy Coalition/Sierra Club	Greg Allen	(416) 488-4425
Hospital for Sick Children	Gregory Dick	(416) 813-5171
IPPSO (Independent Power Producers Society of Ontario	Jake Brooks	(416) 322-6549
Northland Power	John Brace	(416) 962-6262
Ontario Clean Air Alliance	Jack Gibbons	(416) 923-3529
Ontario Lumber Manufacturers	Agnus Rocha	(416) 367-9717
Ontario Power Generation	James Perry	(416) 592-5318
Pollution Probe	John Welner	(416) 926-1907
Pratt & Whitney	Ted Traynor	(905) 564-4135
Probyn & Company	Stephen Probyn	(416) 777-2800
Rolls-Royce	Peter Heffernan	(905) 201-0724
Sudbury District Energy Corporation	Brund Pozza	(705) 673-9133
Toromont Power	Bruce Ander	(416) 667-5724
Toronto Hospital	Mike Horn	(416) 340-4800
Toronto Hydro	Todd Wilcox	(416) 542-2588
TransAlta	Barry Chuddy	(905) 869-2162
TransCanada Energy	Finn Greflund	(416) 829-7246
Union Gas	Dave Simpson	(519) 436-4651
University of Toronto	Harvey Krueger	(416) 978-6650
Westcoast Power	Frank Dixon	(416) 499-3676

5.2 Invitation to Workshop

Ministry of Energy, Science & Technology Letterhead)

November 26, 1999

Dear Cogeneration Stakeholder:

I would like to invite you to participate in a half day Stakeholders Workshop on Thursday December 9 from 9:00 to 1:30 at the Sheraton Centre, 123 Queen St. West, Toronto.

The purpose of this Workshop is to seek your views on the most attractive opportunities for cogeneration applications in Ontario and on the major barriers that may prevent wider utilization. The is part of a project the Ministry of Energy, Science and Technology is currently undertaking, in cooperation with the Ministry of Natural Resources and the Ministry of Economic Development and Trade, to evaluate the potential for cogeneration in Ontario.

The restructuring of the electricity market currently underway in Ontario is expected to remove one of the major barriers to cogeneration projects by allowing access to electricity markets. There are several remaining factors that will be critical in evaluating the likely uptake of cogeneration. We would ask that in preparation for this workshop, you begin to identify what you consider to be the major barriers to wider utilization of cogeneration.

It is our intention to distribute the Notes from this Workshop to all participants. The Ministry's consultants on this project (Hagler Bailly, AGRA Monenco and Lourie & Love) also plan to facilitate a second workshop in February to review their draft report that will incorporate the discussion at this December 9 Workshop.

Please find attached to this invitation the Agenda for this Workshop and a Confirmation Form. If you have not already confirmed your attendance by phone, please fax back the attached Confirmation Form by December 2 or email your confirmation (plove@lourielove.com). If you are unable to attend, please let us know if there is another representative from your organization that would be able to participate.

We hope that you will be able to participate at this Workshop and thank you for your time and consideration.

Yours truly,

Doug MacCallum
Team Leader, Energy Economics
Energy Policy Branch

5.3 Agenda

COGENERATION STAKEHOLDERS WORKSHOP

Thursday December 9, 1999
9:00 – 1:30
Simcoe/Dufferin Room, Sheraton Centre
123 Queen St. West, Toronto

8:30 Registration, Coffee

9:00 Welcoming Remarks

9:10 Review of Workshop Objectives and Agenda

9:15 Outline of Objectives of "Potential for Cogeneration in Ontario" Project

9:25 Presentation of Initial Cost Estimates of Cogeneration Technologies

9:35 Summary of Initial Identification of Barriers to Wider Utilization

9:45 Questions/Comments

10:00 Bio Break

10:15 Reconvene into Three Breakout Groups
Each to discuss most attractive applications, major barriers to wider utilization and other issues of interest

11:45 Reports from Breakout Groups

12:15 Questions/Comments/Observations

12:30 Working Lunch/Further Discussions

1:15 Conclusions/Next Steps

5.4 Initial List of Potential Barriers to Cogeneration

The list below is intended to start the discussion on barriers to cogeneration in Ontario. The list is not intended to be comprehensive, nor is it in any particular order of importance. The purpose of the Workshop is to develop a list of factors that the stakeholders see as barriers, in order to allow further analysis of them as the project proceeds.

- User unfamiliarity with cogeneration technologies
- High information costs for energy purchasers to find out about cogeneration
- Arbitrarily short payback periods or high hurdle rates by potential cogeneration hosts
- Difficulty of financing merchant portion of projects
- Local resistance to specific sites
- Uncertainty about transmission regulatory treatment
- Uncertainty about distribution regulatory treatment
- Inability of cogeneration to get payments for contributions to system reliability
- Low commodity prices for electricity
- Scarcity of locations which can use steam or low-grade heat
- Uncertainty of future gas prices
- Uncertainty of future electricity/gas (“spark”) price spreads
- Cost of cogeneration technology

APPENDIX C

SECOND WORKSHOP REPORT

POTENTIAL FOR COGENERATION IN ONTARIO:
NOTES FROM FEBRUARY 15, 2000 STAKEHOLDERS WORKSHOP

Prepared for
Energy Policy Branch
Ontario Ministry of Energy, Science & Technology

By
Hagler Bailly
In association with
AGRA Monenco
And
Lourie & Love Environmental Management Consulting

March 31, 2000

1. INTRODUCTION

The main purpose of this Workshop was to discuss the draft copy of the project report that had been sent out to workshop participants for their review. A list of the invitees to the workshop and the letter inviting them to participate is included in Section 3.

As with the previous December 15 Workshop, Doug MacCallum of the Ministry of Energy, Science and Technology welcomed participants to the workshop and thanked them for their cooperation.

Peter Love then briefly summarized the objectives of the Workshop and the proposed agenda (copy included in Section 3). He then asked for any comments on the Report of the December 15 workshop which had been sent out to participants; no major changes or revisions were suggested.

Mitchell Rothman, the Project Manager, then summarized the main features associated with the estimated potential for cogeneration in Ontario and there followed a discussion on a variety of points. As these points were further discussed in the breakout groups, they are not summarized here.

Peter Love then summarized the major barriers that had been identified and were discussed in the draft report. Workshop participants were encouraged to review and expand on these barriers in their breakout groups.

Based on the interests of the participants at the Workshop, it was agreed that there would be three breakout groups that would discuss and review the draft report from three perspectives:

Large Plants (>10 MW)

Small Plants (< 10 MW)

Pulp & Paper Industry

2. NOTES FROM BREAKOUT GROUPS

The following sections summarize the main points that were discussed during each of the breakout sessions, as recorded by the facilitators and presented to the workshop when the groups reconvened. The fourth section, prepared by the consultants after the workshop, summarizes the major conclusions and next steps.

2.1 Large Plants

Facilitator: **Peter Love**
Technical Resource: **Scott Stevens**

Terry Vaughan	Access Capital
Frank Bajc	CU Power International
John Welsh	GE Power Systems
Ed Kress	Great Lakes power
Bob Porter	TransCanada Energy
Richard Chan	Union Gas

1. Economic Assumptions

Debt Rate	2 of 6 preferred working in nominal rates (i.e. 8% including inflation) other 4 were indifferent current rate based on risk free rate (6%) plus risk premium (1.8-2%)
Term	25 year term assumed is OK current tendency is now to shorter term natural gas contracts (3-5 years) high premium for 10 year gas contracts
Debt/Equity	50/50 for merchant plants smaller plants will tend to be financed with balance sheet financing ratio will depend on structure of the project/coverage rates group suggested running sensitivity using 60/40
IRR	13% a little high; 12% more reasonable assumes no residual value
Steam	some contracts currently for as low as $2.45 will come down as efficiency assumed in evaluations is increased could be 0 to get some projects to qualify for Class 43 could be based on the highest value for steam could also be based on real avoided cost approach group suggested that a sensitivity analysis be run using $5.00
Capacity	would certainly be lower for merchant plants, especially peaking plants for co-gen, will only proceed if it can be run at high capacity no sensitivity runs required steam reliability is key concern for all industrial users might involve leaving existing boilers in place and/or multiple units assumed that the required reliability was already incorporated into costs
Other Issues	cost of back-up electricity

What was assumed in this project?

2. Potential

Group felt strongly that systems <150MW should not be ruled out
- costs should be compared to delivered cost (including CTC, T/D, etc.)
- delivered cost of electricity could be even higher for smaller users

Group suggested a price/potential chart be developed

Generally agreed that technical potential should start with inventory of boilers
- Hydro study and Acres report for MOE about 83/84 were suggested

Guess is that the number of locations >10MW steam demand is multiple hundreds

District Energy Potential
- Cdn District Energy Assoc – identified 23 projects across Canada
- Note: avoid double accounting potential with potential for small plants

3. Barriers

Additional barriers that were identified by the group:

Cost of backup electricity
Low subsidized cost of existing district heating projects
Required transmission infrastructure may not be in place in all potential locations
Inexpensive hydro in N. Ontario
Environmental regulatory approvals (subject of MOE workshops)
If caps on other industries in future, should be on net, not gross, emissions
Environmental controls should be no more stringent than on existing units
    (e.g. requirement for emissions monitoring on units >25MW)
First nations issues, including use of "traditional" lands, becoming very important
Discussion of distribution issues should be added to Transmission pricing section of draft report
Federal government should be encouraged to expand asset coverage of Class 43
    (e.g. more of the infrastructure required for hydro projects)
For smaller plants (<1MW), connection specs by local utilities may be onerous
Note was made of a CERI project currently underway on barriers to district energy

4. Potential Drivers to Increased Co-gen

The group also identified the following drivers which will tend to encourage greater utilization of co-gen:

NIMBY leads to inability to site future large generation plants or transmission
Economies of scale favour distributed generation
Emerging market for emission credits could become significant

2.2 Small Applications

Facilitator:	**Mitchell Rothman**
Andrew Amiri	Cummings Ontario
Masoud Almassi	Enbridge Consumers Gas
Bernard Jones	ONGA
Paul Vyrostko	Northland Power
Mike Horn	Toronto General Hospital
Derek Macartney	Trigen Canada
Helmut Krueger	University of Toronto
Frank Dixon	Westcoast Power

The group discussed an agenda, which was then organized into three broad topic areas: Definitions, Drivers, and Barriers.

Definitions

1. There may be a more important break between installations over and under 5 MW than between those over and under 10 MW.

2. Fuel cells for house-size applications are clearly small. But they would still have to meet safety and performance standards.

3. In the market for small cogeneration, the owner can choose the appropriate technology for installation; in the larger applications, the technology is inevitably gas turbine.

Drivers

1. Capital Costs
   - Costs are very site-specific
   - Are installation costs included in the costs as displayed? What other costs are included, for example, chillers?
   - Installed cost of $1200-2000 per kW for reciprocating engine technology is reasonable.
   - $1650 per kW is reasonable for a small reciprocating engine.

- But the larger units may not decline in cost as much as is shown, because of quality upgrades.

2. Operating Costs
   - Operating costs for reciprocating engine technologies are usually underestimated. Need to get feedback on that from operators.
   - $20/MW is not unreasonable for O&M costs for reciprocating engine technologies.
   - $15/MW (as shown in the table) is the top of the range for O&M costs for reciprocating engine technologies.
   - Are the O&M costs for small turbines underestimated?

3. Electricity vs. Heat Output
   - There is no game without heat
   - Or: There is no game without both heat and electricity
   - Electricity sales need peaking rates

4. The Business from the Investor's Point of View
   - The investor has equipment to operate
   - Its returns (electricity price) are uncertain
   - Its costs (gas price) are uncertain

Barriers

1. Operating Engineers Act
   - Proposed change requires on-site engineer for even small turbines
   - Does not recognize technology (automatic shut offs)

2. Connection Codes
   - Can bring installed cost up to 3x capital costs
   - Example: $300 K connection cost for 2x333kW project; killed project
   - To protect the small generator from the grid costs $5 K; to protect the grid from the generator costs $300 K; does this make sense?
   - Utilities may use codes or stall/delay approvals if they do not want generation
   - But most MEUs not the barrier; extent of MEU barrier depends on their regulation and incentives
   - Manufacturers can get around this with a pre-engineered package
   - No province-wide standard for interconnection; should be set by neutral third party

3. Standards for Installation
   - Noise suppression (especially for gas compression)

4. Class 43 Criteria
   - Small installations may not be able to attain Class 43 heat rates

5. Emissions Credits

- OPG has a head start on trading emission credits
- How do new generators get credit when they are moving to self-generation from buying electricity?

6. Information Barriers
   - Host companies do not want to become utilities
   - Need to develop a more mature industry of owner-operators
   - Lag in equipment availability

2.3 Pulp & Paper Industry

Facilitator:	**Bruce Lourie**
Recorder:	**Leah Hagreen**
Mike Kuriychuk	Bowater
Dennis Foran	Domtar
Peter Heffernan	Rolls-Royce
Paul Marier	Spruce Falls
Gerry Murray	Strathcona Paper
Susan Shaw	Trigen Canada
Aqeel Zaidi	Union Gas

Assumptions

1. Boiler efficiency assumption too low @ 70%, should be ~80% (for industrial, left on at all times; may be low if facility is turned on and off)
   → this will change steam cost #'s; in reality steam value ~$5

2. Efficiency #'s for turbine need to indicate whether lower heating value or higher heating value

3. Electricity pricing needs to show:
   - on-peak
   - off-peak
   - delivered

4. Similar to gas tables should be sensitivity table for delivered electricity price (value not cost)

5. Suggestion to look at price forecasts in region (US)

6. Need an electricity price forecast with assumptions **

7. Need to see gas assumptions behind forecast
8. Technology assumptions suggest minimum steam use as heat → misses the most likely configuration of combined cycle with non-condensing turbine; this should be included

9. Note that report needs to be clear that focus is gas cogen not steam cogen
   →define cogen clearly**

10. Need to consider a variety of commercial operations and clarify what is and what is not included

11. Importance of biomass***
    - The importance of biomass for cogen must not be overlooked for the pulp/forest sector; this should be included or qualified, as it has important greenhouse gas implications (being the start to this whole process)

12. Is the focus cogen or generation → peaking is not cogen

13. What is the discount rate for NPV analysis? Does not look like NPV actually considered. Prefer constant $.

14. Need to see all assumptions in financial analysis
    - Interest rates
    - Discount
    - Tax rates
    - Before / after tax assumptions
    - Cash flow

15. Report assumes non – by-passable transmission costs (i.e. third party)and is limited by 3.8cent constraint

16. Actual availability for aero-plants >90% (~95%)

Technical Potential

1. 1987 Acres report is the best source of technical potential in Ontario; should be used as a good cross-check
2. clarify definition of technical potential; the report does not use true "technical" potential, but one that has an economic screen
3. who's "probability" assessment, how was it derived, how was it assigned, what are the implications?
4. There is a large potential for microturbines in sawmills → has this potential been included? It looks like non; this misses important greenhouse gas emission reduction potential
5. Missing important potential in the <10MW industrial category → back-up systems for large buildings
6. Look at small scale technology; this has been proven in Scandinavia in the forest product sector – this type of technology must be examined for this sector
7. The role of black liquor gasification for Kraft mills is not in the report – this is a highly energetic fuel, with lots of potential for the forestry sector in cogen, and has implications for greenhouse gasses

8. Other technology to look at – coke oven gas in steel mills
9. Look at fuels other than natural gas (the report now only sees one fuel as being a potential, this is a serious drawback)**
10. Look at the technical potential beyond single plant, especially distinct energy (chilling and heating)**

Economic Potential

Lack of analysis of chilling potential and benefits of this; need to build into the economic assumptions
Will see more price volatility in the market, especially summer providing opportunity for absorption chilling
Economic factor in paper industry is age of boilers

Barriers

1. Market place dynamics haven't begun; this may create opportunities, change the potential for development of cogen
2. Net vs. gross is still an issue
3. Stranded debt
4. Cost of local interconnect – this is a huge issue for small companies especially
5. Back-up rates
6. Economic assumptions neglect positive value of market services in new market
   - Grid stability
   - Congestion pricing
   - Environmental benefits
7. Foreign exchange rate (US) will impact the projects
8. Smaller the plant, the higher the costs

General Comments

1. Report should focus on barriers, potential is more "academic"
2. Class 43.1 rules miss the point that less efficient plants may have greater market & environmental benefits
3. Lack of caps on other sectors is a barrier
4. Uncertainty in emission trading market
5. Labelling of power could be a barrier
6. Need to ensure that certain assets aren't favoured (i.e. trans over cogen)

2.4 Notes and Next Steps from Workshop

The Workshop was very productive. It allowed the project team to get good feedback from the stakeholder community. The feedback included suggestions of gaps in the analysis, gaps in the information given about assumptions, and some new information.

The next steps can be broken down into a few categories: assumptions, methodology, runs, reporting, and barriers.

Assumptions

Electricity Prices

The Workshop clearly noted the lack of a clear forecast of electricity prices or any rationale for the forecast that was used. In fact, the tables presented to the Workshop used different electricity price forecasts. The tables from AGRA Monenco used the Ministry's very rough forecast. The tables from Hagler Bailly used a more elaborate forecast, which was close to be not identical to that used by AGRA Monenco. Workshop participants also identified a need to specify generation prices and transmission and distribution tariffs separately.

Several tasks flow from this observation:
- Generate an electricity price forecast and rationale for it.
- The electricity price forecast should identify transmission and distribution rates.
- Communicate the forecast to all team members
- Run the models using the electricity forecast.

Project List for Technical Potential

The Workshop also noted that the existing list of potential cogeneration projects for the large and medium scale could not really be called a list of technical potential. That list already had significant implicit screening for economic feasibility, since it contained only projects that had actually been considered for implementation. A more complete list would include all locations in the province with a steam boiler. The list of sites also need not be screened for compatibility of steam and electricity load, since the open electricity market can be expected to absorb any excess electricity generation. This discussion led to additional tasks:

- Get the steam boiler inventory prepared for Ontario Hydro in 1988/89, for the Demand/Supply Plan.
- Look for other inventories of steam boilers.

Because of the focus on identified projects, the amount of technical potential is seriously underestimated, according to Workshop participants. With new information on boilers, it should be possible to make a new estimate of technical potential.

Interest/Discount Rates and IRR

Several Workshop participants had comments on interest rates and payback periods. These comments were on both sides. Some participants suggested that a 7-year payback period and a 13% IRR are both too stringent. Others thought that a 13% IRR was too high. Given this lack of consensus among participants, there is no need to change the assumptions in the runs.

Capital Costs

Workshop participants also commented on the capital costs in the tables. One question was whether the capital costs as stated include all the costs of integration of the generation into the grid or distribution system. It is assumed that the costs are for a complete installation.

For the reciprocating engine technologies, there were comments that the capital costs were too low, as well as comments that the capital costs were about right.

Actions from this

- Capital costs continue to be inconsistent. AGRA Monenco and Hagler Bailly need to agree on consistent capital cost assumptions, including clarity on whether they include full installation costs or only equipment costs.

Steam Values

One comment noted that the value of steam was too high, at $7.51 per thousand pounds. One participant noted that they can buy steam for as low as $2.45 per thousand pounds. This value is related to the conversion efficiency of the boiler providing the steam.

Most participants said that the assumed efficiency of the steam boiler was too low. For an industrial boiler that is run constantly, 80% efficiency is a minimum, not the 70% assumed in the analysis. A 70% efficiency would be relevant for a boiler that was used in a commercial application, where it was cycled on and off to meet the steam or heat demand.

The action from this comment is to increase the efficiency of the steam boiler being replaced to 80%.

Methodology

Technical Potential

Some participants questioned whether the calculation of technical potential is relevant. The project should be more about barriers than about calculation of potential.

Economic Potential

The Workshop was also critical of the methodology for determining economic potential for the large and medium scale. Several participants felt that a simple cutoff based on price did not reflect what actually happens in the market. Others noted that they know of actual installations of a size that would be cut off under the suggested criterion, and they are doing very well.

Part of the problem in this discussion relates back to the question of whether the economic potential is to be measured against the wholesale market price of electricity or against the delivered price. It is clear that there will be some variance in this rule, depending on the size of the application, but the rule is not clear yet.

The actions from this comment are

- Make an assumption about the prices (net or gross) which the cogeneration would have to compete against
- Consider the methodology for selecting from the list of potential projects.

Runs

Once the assumptions are compatible, we will need a set of compatible runs of the models. The runs will start from the same set of assumptions.

The runs have to be for more extended time frames. The DISGEN model is already being run for the years up to 2010. Given the proposal, the analysis needs to be extended to 2020. Results for 2015 and 2020 will be sufficient.

The AGRA Monenco model is currently being run only for the immediate year, which is assumed to be 2000. Again, the project needs runs representing the years 2005, and 2010. The data needed for those years are costs and economic potential.

We also need sensitivities for the runs. At the least, we are committed to running different gas prices. The Workshop noted that the gas price sensitivities should be coordinated with the electricity price ones, so that we are not running very low gas prices with very high electricity prices, for example.

The actions are

- Determine the base case inputs for the cost runs
- Run the costs
- Run DISGEN and the AGRA Monenco models to get economic potential
- Run sensitivities as ***Reporting***

The report needs more detail on the assumptions, especially on the electricity price.

The report will also need to reflect the additional information.

The workshop suggested that there could be some use of graphs to present information in the report.

Barriers

The Workshop identified several barriers which are not in the report. The two most clearly identified are more relevant only to smaller generation technologies. These are the requirement that even small boilers have a full time operator, and the possible connection costs for small embedded generation

The action for this item is to verify these barriers and include them in the report.

3. LIST OF INVITEES, INVITATION AND AGENDA

3.1 List of Invitees

ABB Alstom Power	Martin Lenzin	(403) 278-7111
Access Capital	Robert McLeese	(416) 366-4820x225
AMPCO (Association of Major Power Consumers of Ontario)	Ken Snelson	(416) 769-8880
ACTO/CU Power	Frank Bajc	(416) 620-1992
BOMA (Building Owners and Manufacturers Association)	Ian Stewart Dale Struthers	(416) 862-6005 (416) 862-6062x8685
Boralax	Yves Rheault	(514) 363-5130
Bowater	Catherine Cobden Mike Kuriychuk	(819) 643-7200x7515 (807) 475-2432
Canadian Pulp and Paper Assoc.	Lucy Veilleux	(514) 866-6621
Dofasco	Tom McGuire Henry Wegiel Susan Olynyk	(905) 544-3761 (905) 548-4037 (905) 548-7200x6107
Enbridge Consumers Gas	Phil Wood	(416) 495-8350
GE Power Systems	Glen Kennedy John Welch	(416) 858-5314 (416) 858-5314
Great Lakes Power	Harry Goldgut Ed Kress	(416) 956-5139 (416) 956-5140
Green Energy Coalition/Sierra Club	Greg Allen	(416) 488-4425
Hospital for Sick Children	Gregory Dick	(416) 813-5171
IPPSO (Independent Power Producers Society of Ontario)	Allen Barnstaple Jake Brooks	(416) 224-9569 (416) 322-6549
Northland Power	John Brace Paul Vyrostko	(416) 962-6262 (416) 962-6262
Ontario Clean Air Alliance	Jack Gibbons	(416) 923-3529
Ontario Forest Industries Association	Craig Gammie	(416) 368-2842
Ontario Lumber Manufacturers	Agnus Rocha	(416) 367-9717
Ontario Power Generation	James Perry	(416)
Pollution Probe	John Welner	(416) 926-1907x236

Pratt & Whitney	Ted Traynor	(905) 564-4135
Probyn & Company	Stephen Probyn	(416) 777-2800x224
Rolls-Royce	Peter Heffernan	(905) 201-0724
Ryerson Polytechnic University	Ian Hamilton	(416) 979-5000x6272
Strathcona Paper	Gerry Murray	(416) 236-4415
Sudbury District Energy Corporation	Brund Pozza	(705) 673-9133
Toromont Power	Bruce Ander	(416) 667-5724
Toronto Hospital	Mike Horn	(416) 340-3073
Toronto Hydro	Todd Wilcox	(416) 542-2588
TransAlta	Barry Chuddy Adam White	(905) 829-7246 (905) 829-7232
TransCanada Energy	Finn Greflund	(416) 869-2162
Trigen Canada	Susan Shaw	(519) 434-9194x222
Union Gas	Dave Simpson Aqeel Zaidi Craig Lemon	(519) 436-4651 (519) 496-5221 (519) 436-4651
University of Toronto	Harvey Krueger	(416) 978-6650
Westcoast Power	Frank Dixon	(416) 499-3676

3.2 Invitation

(MEST Letterhead)

January 28, 2000

Dear Cogeneration Stakeholder:

I would like to invite you to participate in a half day Stakeholders Workshop on Tuesday February 15 from 9:00 am to 1:30 pm, in the Ottawa Room of the MacDonald Block, 900 Bay Street, Toronto.

The purpose of this Workshop is to seek your comments on a project that we have undertaken to identify the potential for cogeneration applications in Ontario and on the major barriers preventing wider utilization. This project is being undertaken by the Ministry of Energy, Science and Technology in cooperation with the Ministry of Natural Resources and the Ministry of Economic Development and Trade.

The restructuring of the electricity market currently underway in Ontario is expected to remove one of the major barriers to cogeneration projects by allowing access to electricity markets. There are several remaining factors that will be critical in evaluating the likely uptake of cogeneration.

Many of you participated in a December 9 Workshop where we had preliminary discussions on some of these issues and we thank you for your time and ideas. The consultants on this project

(Hagler Bailly, AGRA Monenco Incorporated and Lourie & Love) are currently preparing a draft report on this project, based on the analysis they have undertaken during this project, including the barriers to wider utilization that were discussed at the December 9 Workshop. The draft report will be presented for discussion at the February 15 Workshop.

Please find attached to this invitation the Agenda for this Workshop and a Confirmation Form. Please fax back the attached Confirmation Form to Peter Love by February 8 or email your confirmation (plove@lourielove.com). If you are unable to attend, another representative from your organization would be welcome. Please indicate if you would like the notes from that December 9 Workshop as well as the draft of the project report emailed to you for your review prior to the February 15 Workshop. It is the Ministry's intention to distribute the Notes from this Workshop and the Final Report to all participants.

We hope that you will be able to participate at this Workshop and thank you for your time and consideration.

Yours truly,

Doug MacCallum
Team Leader, Energy Economics
Energy Policy Branch

3.3 Agenda

COGENERATION STAKEHOLDERS WORKSHOP

Tuesday February 15, 2000
9:00 – 1:30
Ottawa Room, 2nd floor, MacDonald Block
900 Bay Street (at Wellesley), Toronto

8:30	Registration, *Coffee*
9:00	Welcoming Remarks
9:05	Review of Workshop Objectives and Agenda
9:10	Outline of Objectives of "Potential for Cogeneration in Ontario" Project
9:15	Review and Discussion of Notes from December 9 Stakeholders Workshop
9:30	Summary of Draft Report "Cogeneration in Ontario"
10:00	Questions/Comments
10:15	Bio *Break*
10:30	Reconvene into Three Breakout Groups Each to discuss detailed comments on Draft Report and other related issues
12:00	Reports from Breakout Groups
12:30	Questions/Comments/Observations
1:00	*Working Lunch*/Further Discussions
1:30	Conclusions/Next Steps