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ALBERTA 10 YEAR GENERATION OUTLOOK

Prepared for

ALBERTA ELECTRIC SYSTEM OPERATOR

By

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SUMMARY

This document presents scenarios of generation additions to the Alberta system over the next ten years to facilitate the AESO's obligation to maintain a long term transmission outlook.

The scenarios are based on the load forecast prepared by the AESO which forecasts the peak Alberta load to increase by 3280 MW from 9,580 MW in 2005 to 12,860 MW in 2016. The average growth rate over this period is 2.7% per annum and 1600 MW of 3280 MW increase is behind the fence load that is served by behind the fence generation.

Based on this load growth, the need to provide reserve capacity and the projected retirements of Wabamun Unit 4 and Battle River Units 3 and 4, it is estimated that 2,000 MW of new generation capacity will be installed by 2011 and 3,800 MW by 2016.

It is expected that new generation capacity will comprise:

- Behind the fence cogeneration additions that will meet the 1600 MW of largely oil sands behind the fence load growth, but will not make any significant contribution to meeting the growth in the grid load.
- Small additions to the grid including upgrades at existing coal fired plants, gas fired peaking units, hydro and wind which are included based on their firm capacity, and other small additions that will add 770 MW over the ten year period.

The likely candidates for providing the remaining generation, which will be approximately 500 MW in 2011 and 1500 MW by 2016, are additional coal fired units at the Keephills and Genesee plants, an Integrated Gasification Combined Cycle (IGCC) plant fired with coke that would likely be located in the Fort Saskatchewan area and a new two unit coal fired plant at Bow City near Brooks.

A Southern Development Scenario and a Northern Development Scenario are examined as shown in the tabulation below, assuming unit additions of 500 MW:

	Southern	Generation		Northern	Generation
Major Grid Additions – Base Case	2011	2016		2011	2016
New Coal Units - KH3 and GN4		500		500	1000
Coke IGCC or KH4					500
Coal at Bow City	500	1000			
Total of Major Additions	500	1500		500	1500

- In the Southern Scenario 1000 MW would be developed at Bow City and the remaining 500 MW would be met by Keephills Unit 3 which is the most advanced coal addition in the north.
- In the Northern Scenario 500 MW would be met by adding Keephills Unit 3, 500 MW by Genesee Unit 4 and the remaining 500 MW by either Keephills Unit 4 or an IGCC unit fired with coke from an oil sands upgrader in the Fort Saskatchewan area.

Sensitivity analyses are prepared for higher and lower load growth and a higher level of wind development. The results of the high and low load growth analyses are shown in the tabulation below:

	Southern	Generation		Northern	Generation
	2011	2016		2011	2016
1. Major Grid Additions – High Load					
1.1 New Coal Units - KH3 and GN4	500	1000		500	1000
1.2 Coke IGCC or KH4	0	0			500
1.3 Coal at Bow City	500	1000		500	500
1.4 Total of Major Additions - High	1000	2000		1000	2000
2. Major Grid Additions – Low Load					
2.1 New Coal Units - KH3 and GN4				500	1000
2.2 Coke IGCC or KH4	0				
2.3 Coal at Bow City	500	1000			
2.4 Total of Major Additions - Low	500	1000		500	1000

- Increasing the grid load by 300 MW by 2011 and 500 MW by 2016 results in two units, rather than the one in the Base Case, being added by 2011. In both scenarios these are the first unit at Bow City and Keephills Unit 3.
- Reducing the grid load by 300 MW by 2011 and 500 MW by 2016 does not change the Base Case in the period to 2011 – one unit is still added. In the period to 2016 only one additional unit is required.
- In the Base Case 600 MW of wind is added in the period to 2011 and a further 600 MW by 2016 which are estimated to contribute 120 MW of additional firm capacity in each five year period. The sensitivity analysis examines the impact of an additional 800 MW (160 MW firm) by 2011 and an additional 1700 MW (340 MW firm) by 2016 which brings the total installed wind capacity to 3200 MW by the end of the ten year period. These additions do not fundamentally change the need for major additions as shown in the Base Case.

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Introduction

The Transmission Regulation (174/2004) under the Electric Utilities Act requires the Alberta Electric System Operator (AESO) to “prepare” and “maintain” a “long term transmission outlook document”. A necessary input to the preparation of this document is determining the timing and location of future generation additions to the Alberta Interconnected Electric System (AIES).

This document has been prepared to meet the AESO’s requirement for a long-term conceptual outlook for generation development in Alberta. In doing so it is recognized that generation development is a non-regulated competitive business and that it is not possible to definitively describe the timing and location of generation development 10 years into the future.

The analysis in this report of the likely types and locations of new generation is based on the transmission policy and market structure that is currently in place and on the assumption that transmission is not a constraint in locating new generation. It does however anticipate further tightening of environmental standards, particularly with respect to carbon dioxide emissions.

Section 1 of the report presents an estimate of the amount of new generation that will be developed over the next 10 years based on the AESO’s load forecast and projected generating unit retirements; Section 2 presents a review of Alberta’s electric generation resources; Section 3 compares the costs of the major generation options and Section 4 develops generation scenarios to meet the expected requirements.

Disclaimer

This report has been prepared for the AESO to meet its obligations under the Act. The discussion and analysis presented herein are to provide the AESO with a range of possibilities of how generation may develop in Alberta. It should not be relied on by third parties and, in the event it is used by third parties in any way, AMEC accepts no liability.

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1. NEW GENERATION REQUIREMENTS

1.1 The Existing Alberta System

Alberta's installed generating capacity, as set out on the AESO's website, at the end of 2005 was made up of 5,840 MW of coal-fired plant, 4,170 MW of gas-fired plant, 869 MW of hydro, 251 MW of wind and 178 MW of other for a total installed capacity of 11,308 MW.

Up until the 1950s generation in Alberta was primarily from hydroelectric plants on the Bow River and from small gas and coal-fired thermal plants owned by municipalities. With the more rapid load growth after the discovery of oil at Leduc in 1947, larger steam electric plants were added to the system. From the 1960s onward these were predominantly mine mouth coal-fired plants of progressively larger size and higher efficiency. Between 1960 and 1995, 5,600 MW of coal-fired generation were added to the system. With the addition of these thermal plants, which operate as base load, the use of the hydro system changed so that it could take on a greater peaking role.

Most of the 3500 MW of additions to the system since the mid-1990s is gas-fired power plants. Technical improvements in gas turbines, lower load growth which is better met by smaller additions, low gas prices, major heat loads required for oil sands extraction and petrochemicals and the restructuring of the power sector all contributed to this choice of generation. Other recent additions to the system are the 450 MW coal-fired unit at Genesee, 250 MW of wind in the southwest and 80 MW of small hydro.

Alberta has a 500 kV transmission interconnection with British Columbia, and is part of the BC and western United States synchronous system, and has a smaller 150 MW DC tie with Saskatchewan which provides a limited connection to central and eastern North America.

The restructuring of the Alberta power sector in 1996 created a power pool for trading electric energy and provided open access for new generators. Rather than the three incumbent utilities [TransAlta Utilities Corporation, ATCO Power and Edmonton Power (EPCOR)] having to divest their generating assets, the output of their plants was sold to third parties in Power Purchase Arrangements (PPAs) with durations of up to 20 years. Of the total 5840 MW of coal-fired generation in place, 5390 MW is held as PPAs; and of the 869 MW of hydro generation,789 MW is held a PPA.

1.2 Load Forecast

The estimates of new generation requirements described in Section 1.3 are based on the AESO's 2006 load forecast titled "Future Demand and Energy Requirements".

Table 1.1 presents the actual 2005[1] and forecast 2011 and 2016 Alberta Total Peak Demand (line 1) and Alberta Grid Peak Demand (line 2) together with the behind the fence Peak Demand (line 3) which is the difference between the total and grid peak loads. The Total Peak Demand is forecast to increase at 2.7% per annum and the Grid Peak Demand is forecast to increase at 1.7% per annum.

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[1] Whereas the AESO document uses 2005/06, and the same format in subsequent years, to denote the winter peak that may ocurr near the end of 2005 or beginning of 2006; this document uses only the calender year, that is the 2005 used here corresponds to 2005/06 in the AESO report. The terms "Total", "Grid" and "behind the fence" Peak Demand are as defined in the AESO document with behind the fence load being that load that is served by behind the fence generators.

1.3 Reserve Margin and New Generation Capacity

Prior to restructuring the question of how much generation capacity was required to reliably meet the load would have been addressed using a generation planning model which simulated the operation of the system. This analysis provided a basis for determining the amount of new generation capacity that had to be added each year to meet a given Loss of Load Probability (LOLP) or Estimated Unserved Energy (EUE) criterion. The results of the LOLP and EUE

Table1.1 Alberta Peak Load and Installed Capacity (MW)

	2005	2011	2016
PEAK LOAD			
1. Alberta Total Peak Demand	9,580	11,467	12,860
2. Grid Peak Demand	8,158	8,910	9,844
3. Behind Fence Peak Demand	1,422	2,557	3,016
PEAK LOAD + RESERVE			
4. Total Peak Demand + 7.5% Reserve	10,299	12,327	13,825
GENERATION CAPACITY			
5. Total Firm Capacity in 12/2005	10,574	10,574	10,574
6. Retirements	0	279	575
7. Capacity Net of Retirements	10,574	10,295	9,999
SURPLUS (SHORTFALL)			
8. Total Surplus (Shortfall)	276	(2,032)	(3,826)
9. Increase in Behind Fence Load	0	1,135	1,594
10. Grid (Shortfall)	276	(897)	(2,232)

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analyses also provided an estimate of the amount the generation capacity needed to exceed the peak demand, known as the reserve margin.

Since the Alberta power sector has been restructured the amount of new generation built is no longer determined in a generation planning analysis but rather by many different corporate entities in response to the expected future pool prices. Since pool prices increase as reserve margins decline, the forecast reserve margin on the system will affect the amount and timing of new generation investment.

The approach in this report is first to define the firm generation capacity that is available to meet the load and then using that definition of firm capacity to select a reserve margin that is expected to occur over the longer term with Alberta's market structure.

1.3.1 Firm Capacity

The calculation of Total Firm Capacity of 10,574 MW shown in Table 1.1 for the end of 2005 is calculated by (i) starting with Total Installed Capacity on the Alberta system of 11,308 MW from the AESO website, (ii) subtracting the 209 MW capacity of the Rossdale plant which although included in the 11,308 MW is no longer available for the purposes of merit order dispatch, (iii) de-rating the hydro to the capacity that is likely to be available during the winter when the peak load occurs and (iv) de-rating the wind to take into account its low capacity factor and variable output.

This calculation is summarized in Table 1.2 and the approach to hydro and wind is described in the text below the Table.

Table 1.2 Calculation of Firm Capacity (MW)

Installed Capacity December, 2005	11,308
Less: Rossdale Capacity	-209
Small Hydro Derate	-64
PPA Hydro Derate	-260
Wind Derate	-201
Total Firm Capacity	10,574

Hydro

Alberta's hydro plants have limited storage and cannot operate at full output during winter at the time the peak load occurs. To take this into account:

- The 80 MW of small hydro is de-rated by 80 percent, or 64 MW to a net of 16 MW to take into account their limited reservoir storage and its primary use to augment the supply of water for irrigation during the summer months and;
- The 789 MW of the larger previously regulated hydro is de-rated by 260 MW or 33% to reflect their output in a peaking operation mode in December through February.

Wind

Wind generation in Alberta typically has a capacity factor in the 30% to 35% range with output being higher in the winter at the time of system peak. Although the wind generation may not

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actually be available at the time of system peak as an energy producer it does contribute to the overall reliability of the system and its impact on pool price does delay the installation of other types of generation. For the purposes of this study wind is included at a capacity value of 20%, which means that the 251 MW on the system at the end of 2005 is de-rated by 80 percent, or by 201 MW. Similarly each 100 MW of wind added to the system in the future is assumed to contribute 20 MW of firm capacity, or put differently, to displace 20 MW of other generation that would otherwise be added.

1.3.2 Reserve Margin

A reserve margin of 7.5% is selected for the purposes of estimating the firm capacity that will be installed to meet the Total Alberta Peak Load in Table 1.1. In other words it is expected that new generation will be added in response to price signals when the margin between the peak load and the firm capacity falls to approximately 7.5% as a result of load growth.

The 7.5% reserve margin used here is based on the definition of firm capacity developed above and is not directly comparable to reserve margins that are based on total installed capacity that have been used in the past in Alberta. Since installed capacity is greater than firm capacity, reserve margins based on total installed capacity are higher for a given system. The reserve margin of 7.5% used here is equivalent to a reserve margin of about 13% if the total 2005 installed, rather than firm, hydro and wind capacity is included and is equivalent to a reserve margin of about 22% if the full 2005 capacity of the BC and Saskatchewan inter-ties are also included.

The tabulation below summarizes how the “firm capacity reserve margin” of 7.5% used in this study compares to the other two definitions.

Definition	Equivalent Margins
1. Firm Capacity Reserve Margin	7.5%
2. Margin including the installed hydro and wind capacity	13 %
3. Margin including the installed hydro and wind capacity and interties	22%

1.3.3 Retirements

The firm capacities net of retirements in 2011 and 2016 are calculated by subtracting the projected retirements from the firm capacity in 2005/06. These retirements include Wabamun Unit 4, 279 MW, at its planned retirement date of 2010 and Battle River Units 3 and 4, totaling 296 MW, in 2013 consistent with the termination of their PPA.

1.3.4 Surplus and Shortfall

The Total Surplus (Shortfall) in Table 1.1 is simply the difference between the Total Firm Capacity and the Total Alberta Load plus the 7.5% Reserve. The estimated surplus in 2005 of 276 MW falls to a shortfall of 3826 MW for all of Alberta, as shown on line 8, by 2016 and to a shortfall of 2,232 MW for the grid.

The balance of this report addresses how these shortfalls will likely be met.

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2. ALBERTA ELECTRIC GENERATION RESOURCES

This discussion identifies the generation resources that are likely to be developed over the next ten years, and together with a comparison of the costs of the likely major generation additions in Section 3, provides the basis for the generation scenarios developed in Section 4.

The resources are discussed in the order that they were developed historically in Alberta– hydro, coal, gas, wind, followed by other types of resources.

2.1 Hydro

2.1.1 Existing Hydro

Of the total of 869 MW of hydro, 789 MW was developed by Calgary Power (now TransAlta) at thirteen different plants, and was commissioned between 1911 and 1972. At the time the Alberta electricity supply industry was restructured, the continuing outputs from these plants were covered under a Power Purchase Arrangement (PPA). The following table provides a breakdown of the installed capacities at the PPA hydro plants.

	Installed Capacity (MW)
Bow River Hydro (11 plants)	319
Brazeau Hydro (1 plant)	350
Bighorn Hydro (1 plant)	120
Total PPA Hydro	789

The Bow River Hydro system comprises eleven separate plants on the Bow River and several of its tributaries, located between Banff and Calgary. The Brazeau hydro plant is situated on the Brazeau River, south-west of Drayton Valley and the Bighorn hydro plant is located on the main stem of the North Saskatchewan River upstream of Nordegg.

The remaining "small" hydro capacity reported by the AESO totals 80 MW, and is located at five separate plants, as follows:

	Installed Capacity (MW)
Oldman River	32
Chin Chute	11
Irrican Hydro	7
Raymond Reservoir	18
Taylor Hydro	12
Total Small Hydro	80

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2.1.2 Potential Hydro projects

In the past 30 years, two large hydro projects in the province have been studied in some detail:

- The Dunvegan Project on the Peace River just upstream of where Highway 2 crosses the Peace River, between Grande Prairie and Fairview which was studied in the mid-1970s. The preferred layout at the time would impound a reservoir which would flood water back approximately 130 km to the Alberta/BC boundary and would have an installed capacity of some 900 MW.
- The Slave River Hydro Project on the Slave River at the boundary between Alberta and the Northwest Territories which was studied in the early 1980s. The project would flood back to the outlets of the Peace-Athabasca Delta and have an installed capacity of some 2,000 MW.

However both these projects have construction periods of 8 to 10 years which would be in addition to the time required to carry out environmental studies and get the necessary approvals, and therefore are not candidates for the ten year timeframe examined here.

The only known hydro project that is likely to come on over the next 10 years is a much smaller alternative run-of-river project at Dunvegan that Glacier Power applied to the EUB to develop in 2000. The application was rejected in March 2003, mainly because of concerns over the risk of flooding in the Town of Peace River due to ice build-up below the dam, and over restrictions to the movement of fish in the river. Glacier Power is addressing these concerns and is currently preparing its next submission.

The project, which is expected to be completed in 2012, would develop approximately 6 m of head with an installed capacity would be about 100 MW. It is assumed to contribute 50 MW of firm capacity at the time of system peak.

2.2 Coal

Currently there are seven coal-fired plants operating in Alberta of which four are located near Wabamun Lake approximately 50 km west Edmonton, two are east of Red Deer and Calgary and one is located at Grande Cache near the BC border northwest of Edmonton.

With the exception of HR Milner at Grande Cache, the coal-fired plants in Alberta are located adjacent to open pit mines that have been developed specifically to serve these power plants. The coal from these dedicated mines varies somewhat in quality but is typically ranked as sub bituminous, classified as B or C, and referred to as plains coal. The “as received” heat content ranges from approximately 16 to 20 GJ/tonne and the sulphur content ranges from about 0.2% to 0.6%. The best deposits in terms of seam thickness, strip ratios and low sulphur content are in the Wabamun Lake area where most of the generation is currently concentrated.

2.2.1 Wabamun Lake Area Plants Owned by TransAlta and EPCOR

The Wabamun plant on the north side of the lake was TransAlta’s first coal-fired plant. When completed in 1968 it comprised two 65 MW units, which were initially fired with gas and later converted to coal, a 140 MW unit and a 279 MW unit. The 140 MW unit was retired in November of 2003 and the two 65 MW units were retired at the end of 2004. The remaining 279 MW unit is scheduled to be retired in 2010. The Wabamun plant is supplied by the Whitewood Mine which is also on the north side of the lake and which has significant remaining coal reserves to the west of the area currently being mined.

The 2,018 MW Sundance plant is located on the south side of the lake and has six units that were commissioned from 1970 to 1980. The capacity of Sundance Unit 6 has subsequently

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been increased by approximately 40 MW. The 762 MW Keephills plant is located to the southeast of the Sundance plant and has two units that were commissioned in 1983 and 1984. The Sundance and Keephills plants are also both owned by TransAlta and both are supplied by the adjacent 13 million tonne per year Highvale Mine.

EPCOR's 1,218 MW Genesee plant is to the southeast of the Keephills plant. The first two units were commissioned in 1989 and 1994 and the third unit, which is the only coal-fired unit built since industry restructuring and not subject to a PPA, in March 2005.

Upgrades similar to the one completed at Sundance Unit 6 are possible for Sundance Units 3, 4 and 5 and somewhat smaller increases at Keephills and Genesee Units 1 and 2. Such upgrades typically have a cost per kW which is well below the cost per kW of a new coal-fired plant and, because part of the upgrade is in effect an efficiency improvement, the heat rate of the upgrade is better than the heat rate of the overall plant. Two more upgrades of the Sundance units of 40MW each are assumed at in the period to 2011 and a further total of 100 MW of upgrades are included in the 2012 to 2016 period.

2.2.2 ATCO Power Plants

ATCO's two major coal-fired plants are Battle River which is due east of Red Deer and Sheerness which is south of Battle River and east of Calgary.

At the time of its completion in 1981, the Battle River plant comprised five generating units with a total installed capacity of 724 MW. Units 1 and 2, each with 30 MW capacity, were commissioned in 1956 and 1964 and are now retired. Unit 3 was commissioned in 1969, Unit 4 in 1975 and Unit 5 in 1981. The PPAs for Units 3 and 4 expire in 2013 and the PPA for Unit 5 expires in 2020. For the purposes of estimating the new generation that will be built it is assumed that these units are retired when their PPAs expire.

The Sheerness plant is located approximately 30 km south of the Town of Hanna and some 200 km east of Calgary. The installed capacity of each of its two units, including the recent capacity increases, is about 390 MW each. Unit 1 was commissioned in 1986 and Unit 2 in 1990

There are sufficient coal reserves to fuel the two units for their full 40 year life but not sufficient to fuel a third unit.

The HR Milner plant is located about 20 km north of the Town of Grande Cache in west-central Alberta. The 143 MW single unit plant, commissioned in 1972, was built to use waste coal from the Smoky River Mine and more recently has used coal imported to the site

2.2.3 Major Additions

Alberta has very substantial coal resources that form a large arc from west and northwest of Edmonton to southeast of Calgary. Over the years, more than twenty individual coal properties have been investigated to some degree for the purposes of providing coal for coal-fired plants.

The lead time for bringing on a coal fired plant at a new mine will typically be about eight years and will involve a substantial investment even before all necessary regulatory approvals are obtained. Currently there are 2500MW which can be brought on in a shorter timeframe:

- Two additional units at Keephills and a fourth unit at Genesee; and
- Two units at Bow City which is south east of Calgary near Brooks.

Given that the total requirement for new grid generation is about 2200 MW over the next ten years it is likely that the portion of this that is coal fired will come from these more advanced

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properties. The costs of these are compared to other possible major additions to the system in Section 3.

2.2.4 Characteristics of New Coal-fired Plants

It is expected that the next coal-fired generation additions in Alberta will be similar to the recently completed Genesee Unit 3 which includes a super-critical steam cycle and clean air technologies to enhance operational and environmental performance.

The higher temperature and steam pressure in a super-critical boiler (implementing once - through technology), combined with a high-efficiency steam turbine result in a more efficient conversion of thermal energy to electricity. The net efficiency of a super-critical unit such as Genesee 3, based on the higher heating value of coal, is 38.4% as compared to 35% in a sub-critical unit such as Genesee 1 and 2 and the Keephills units. Genesee 3 is fitted with environmental controls which include low NO_X burners to reduce NO_X emissions, a dry flue gas desulphurization unit to reduce SO_2 emissions and fabric filters to control particulate emissions, to comply with emission regulations at the time the unit was installed.

The current “Alberta Air Emission Standards For Electricity Generation” provides emission limits for SO_2, NO_X and particulates and can be met wit[illegible]w NO_X burners, flue gas desulphurization and fabric filters similar to those installed at Genesee 3 plus selective catalytic reduction if required to further reduce NO_X emissions.

The Government of Alberta has developed a regulation that requires existing plants to reduce their Mercury emissions by 70%. This emission requirement will also apply to new plants. It is expected that the flue gas desulphurization, selective catalytic reduction and fabric filters installed to reduce emissions of SO_2, NO_X and particulates on new plants will also reduce Mercury emissions to, or close to, this level. Further reductions in Mercury can be achieved by injecting a material that absorbs mercury, such as activated carbon, upstream of the particulate collector such as a bag house or electrostatic precipitator.

The cost estimates of the coal-fired plants presented in Section 3 include environmental controls to meet the current standards for SO_2, NO_X and particulates and sufficient funds for adding an absorbent to further reduce Mercury if required.

In addition to installing environmental control equipment, owners of new coal-fired plants in Alberta have also been required to purchase CO_2 offsets for the amount that the carbon dioxide emissions of their coal-fired plant exceed those of a combined cycle plant. The cost of purchasing the CO_2 offsets is included as part of the cost comparisons presented in Section 3. Options for actually reducing CO_2 emissions are discussed in the next section.

2.2.5 Technologies to Reduce CO_2

There are several initiatives underway in Canada to address the CO_2 issue. One of the most significant is the program of the Canadian Clean Power Coalition. Their objective is “to demonstrate that coal-fired electricity generation can effectively address air quality issues projected in the future, including greenhouse gas”. Their goal is to “construct and operate a full-scale demonstration project to remove greenhouse gas and all other emissions of concern from a new coal-fired power plant by 2010 to 2012 time frame”.

The two main options for reducing CO_2 are (i) further efficiency improvements to coal fired plants that may be combined with post-combustion capture of CO_2 , and (ii) the removal of CO_2 prior to combustion.

Efficiency improvements and post-combustion capture of CO_2

As with the progression from sub-critical to super-critical coal-fired power plants, the next efficiency improvement is the advancement from the super-critical steam cycle to the ultra super-critical (USC) cycle .

USC power plants have been operational in Europe and Japan for the past decade. Published data indicate that the operating results have been good as the development into the USC concept has been a stepwise progress from well-proven super-critical systems. There have been no major problems in terms of water/steam process, pulverized fuel combustion or heat transfer. EPRI reports that USC is now the baseline state-of-the-art for power plant developments in Europe and Japan.

The estimated efficiency for an USC plant using Alberta sub bituminous coal is about 44% which further reduces CO_2 emissions. Typically the CO_2 emissions are 0.99 tonne/MWh for a sub-critical plant, 0.88 tonne/MWh for a super-critical plant and 0.75 tonne/MWh for an ultra super-critical plant.

Further reduction requires separating the CO_2 from the dilute flue gas stream, capturing and sequestering it or finding a CO_2 user such as an Enhanced Oil Recovery (EOR) facility. Advancements are being made in the technologies to achieve this but they are still very costly and require technical demonstration on a large scale.

Separation of CO_2 from the flue gases can be accomplished by absorption after contact with amine-based solvents, by adsorption on activated carbon, by passing the gas through special membranes, or by cryogenic separation.

The most advanced technology for power plant application is the amine scrubbing process. The technology has been under development for over 20 years and Fluor Daniel markets it as the ECONOMINE FG process. After cooling the flue gas in a dry contact cooler (DCC), the CO_2 is removed in an absorption tower. There is also a significant amount of ancillary equipment as the system includes an amine regeneration loop. The system has high auxiliary utility loads that reduce the overall efficiency of the plant. The regeneration loop includes a reboiler which consumes a substantial amount of steam from the power plant, flue gas fan power is increased to compensate for additional pressure drops in the system and the captured CO_2 is compressed to pipeline pressure for use/sequestration.

Once captured and compressed, the CO_2 can be utilized to enhance oil recovery by injection into a reservoir; to displace methane from coal seams, resulting in the use of the methane as a fuel for heating or electricity generation; or can be sequestered in geological formations such as depleted oil or gas reservoirs, deep and un-mineable coal formations, and deep saline aquifers.

Pre-combustion capture of CO_2

Whereas the foregoing has discussed post-combustion capture of CO_2 from the flue gas, in technologies such as the Integrated Gasification Combined Cycle (IGCC) the CO_2 can be removed prior to combustion. The IGCC technology has been applied for over two decades and several plants are in operation.

The basic components in the IGCC power plant are as follows:

- Fuel handling;
- Oxygen separation;
- Coal (fuel) gasifier;

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- Gas (syngas) coolers and syngas clean-up and wastes;
- Combined cycle unit; and
- Plant infrastructure and ancillary systems.

There are several technology vendors that can supply suitable processes for the gasification of coal and coke. These include Shell, who developed their own technology; General Electric, who purchased the Chevron Texaco technology; Conoco-Phillips, who purchased the E-Gas technology; Siemens, who purchased the Future Energy technology; and Sasol-Lurgi, who developed their own technology.

IGCC power plants provide distinct advantages in comparison to conventional coal-fired power plants. The gasification process produces a syngas comprising mainly CO and Hydrogen that can be burnt cleanly in gas turbines. This technology keeps emission levels of SO_2 and NO_X below required limits and offers the potential to significantly reduce CO_2 emissions. Shift convertors can be used to react the CO fraction of the syngas with water to produce CO_2, that can be captured, and Hydrogen which can become the fuel for the gas turbine. Gas turbines capable of being fired with Hydrogen are under development and are expected to be available for large scale commercial operation by about 2012.

Views on the future role of IGCC as a source of power generation are changing. In 2004, the Northwest Power and Conservation Council reported that “a coal gasification plant could be ordered and built today. However, relatively few demonstration plants have operated for extended periods and numerous technical difficulties have been experienced with these demonstration projects, especially during the first years of operation. This experience has led to concerns regarding plant cost and reliability, which coupled with the lack of overall plant performance warranties appear to preclude financing.”

In early 2005, the National Energy Technology Laboratory (NETL) of the U.S. Department of Energy reported positively on recent moves towards commercialization of IGCC. They indicated that, in 2004, several major energy corporations (including American Electric Power, Cinergy, First Energy, Consol, General Electric and Bechtel) had expressed strong interest in building IGCC power plants. The mounting interest in IGCC reflects a convergence of three changes in the electric utility marketplace:

- The increasing maturity of gasification technology;
- The extremely low emissions from IGCC, especially air emissions, and the potential for lower cost control of greenhouse gases than other coal-based systems; and
- The recent dramatic increase in the cost of natural gas-based power, which is viewed as a major competitor to coal-based power.

This growing confidence in IGCC plants must be tempered when considering their use in Alberta fuelled with the sub bituminous coal that is available in large quantities. Although there are instances of gasifying sub bituminous coals, the development work in the U.S. is based on much higher quality coal with heat contents that are almost double the Alberta coals. As noted in Section 2.4, the coke that is produced as a by-product of oil sands upgrading, which also has a heating value almost twice the Alberta coals, is a more likely fuel for an IGCC plant than coal.

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2.3 Natural Gas

Of the approximately 3,500 MW of new generation that has been added to the Alberta system over the past five years, some 2,500 MW is gas-fired.

The gas-fired generation additions are either combined cycle or cogeneration plants and the principal building block for both is a gas turbine. The gas turbines are linked to a heat recovery steam generator (HRSG) which drives a steam turbine in the case of the combined cycle plant and provides process steam in the case of cogeneration.

2.3.1 Combined Cycle

Equipment configuration can vary widely for a combined cycle plant. A one-on-one plant consists of a single gas turbine, HRSG and steam turbine. A two-on-one plant consists of two gas turbines, two HRSGs and a single steam turbine. Other variations of the numbers of gas turbines and steam turbines in a combined cycle configuration are also available.

A typical combined cycle merchant power plant operating in Alberta is the Calgary Energy Centre developed by Calpine. This plant has been in operation since 2003 and provides a nominal base load capacity of 250 MW.

As a combined cycle plant utilizes the waste heat from the gas turbine to produce steam which is further converted to electric power in the steam turbine generator, an overall thermal efficiency of greater than 50% can be achieved. High efficiency combined with higher proportion of Hydrogen in natural gas as compared to coal results in CO2 emissions of about 0.40 tonnes/MWh, or less than half a new pulverized coal fired plant such as Genesee 3.

2.3.2 Cogeneration

[illegible]eneration, which is simply defined as the simultaneous generation of electric power and thermal energy, is widely used in northern Alberta's oil sands. The use of the waste heat to produce steam or hot water leads to very high operating efficiencies for a cogeneration plant. Often the waste heat recovery unit is also provided with duct firing to further increase the steam or hot water output of the unit. Duct firing does not improve efficiency, however it is a means of adding thermal generating capacity at a relatively low additional capital cost.

The gas turbine unit selected for each of the various projects is dependent on the type and size of facility and the contractual arrangement under which the cogeneration is developed.

The most popular gas turbine utilized at oil sands facilities over the past decade has been the General Electric Frame 7EA, a nominal 85 MW unit. Two of these units are installed at the Syncrude Aurora Mine, two are installed at the Albian Sands Muskeg River Mine and one is planned for installation at the CNRL Horizon Project. These units have also been utilized at heavy oil and SAGD projects such as Primrose and will be used at the Long Lake Project.

The GE 7EA continues to be a favoured workhorse in the oil sands development due to its operating history and reliability, but also the fact that the amount of recoverable exhaust heat matches the demands of oil sands projects.

Some oil sands developments have also used larger gas turbines. The facility at MacKay River has a General Electric Frame [illegible]A, a nominal 172 MW unit; the Suncor Plant has two ABB Frame 11N2 units, rated at nominal 115 MW each; and the GE 7FB, and "G" class machines offered by Siemens or Mitsubishi (MHI) are being considered.

Oil sands developers such as Syncrude own and operate their cogeneration facilities and produce enough power to meet their mining and upgrading needs. Some of the other oil sands developments have arrangements with independent power producers (IPPs) for the delivery of power and heat for the oil processing operations. At Muskeg River and Primrose, ATCO Power owns and operates the cogeneration plant; at MacKay River, TransCanada Power is the IPP; and at Suncor, TransAlta owns and operates the Poplar Creek Power Plant. Each of these facilities provides electric power and thermal energy to the host facility and can also supply electric power surplus to the host's needs into the grid.

Oilsands projects that are currently under development are trending towards the oil sands developer owning and operating the cogeneration plants, as opposed to forming alignments with IPPs and, with the exception of OPTI Nexen, are generally sizing power facilities to meet only their own behind the fence needs.

2.4 Oil Sands By-products

Currently there are two instances in which oil sands by-products are being used, or are about to be used, as an energy source in Alberta:

- Suncor currently utilizes coke for the generation of high pressure steam in conventional boilers, which have been retrofitted with FGD systems to reduce the SO_X emissions, primarily to produce process steam; and
- OPTI Nexen is installing an asphaltene gasification unit as part of its Long Lake upgrader to provide hydrogen to the hydroccracker and synfuel for power and steam generation. Two GE 7EA gas turbines will provide sufficient power for facility use and have up to about 60 MW available for grid export. The term "polygeneration" has been coined for plants such as Long Lake which generate more than two useful products, that is electricity, steam and hydrogen.

Although the OPTI Nexen project, which will start production next year, might be seen to be setting a trend of gasifying asphaltene to produce power for internal use and sales to the grid, it is unlikely that others will follow this lead over the ten year timeframe of this study.

The reasons for this are as follows:

- Planned oil sands developments are constrained by limited engineering, manpower and transportation capacity. The focus of developers is on the production of oil and their approach to power is only to install sufficient generation capacity to meet their demand and to do so using well proven and readily implemented technologies.
- A major gasification plant will cost $2 billion, making power generation with syngas more capital intensive and placing greater demands on scarce resources than installing natural gas fired turbines.
- When gasifiers are installed and syngas is produced, hydrogen for the production of transportation fuels and petrochemicals has highest value in the hierarchy of uses and power generation is among the lowest.

The plans of oil sands developers bear this out:

- Plans submitted by developers to the AESO show an overall balance of their loads and their behind the fence generation.
- Upgraders that produce and gasify asphaltene, as shown in Table 2.1, expect to, with the exception of OPTI Nexen, either use the syngas internally or sell it as a feedstock.

The remaining oil sands by-product is coke. In Fort McMurray the Suncor and Syncrude plants have coke stock piles from operations to date and continue to produce coke. Syncrude

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produces a fluid coke and stores it in ponds, while Suncor produces sponge coke which is either stored on site, sold when possible or burnt in convention boilers for its own energy needs. Suncor currently produces approximately 3 million tonnes of coke per year of which about 900,000 tonnes are used to fire boilers, 300,000 tonnes are marketed and the remaining production is largely stored or used for construction projects. Suncor continue to consider greater use of coke for power and steam generation but are currently installing gas fired generation as part of their ongoing expansion.

As Table 2.1 shows, as many as four new upgraders are planned for the Fort Saskatchewan area of which the Petro Canada upgraders will be major coke producers. Use of coke for power generation at this location, or some other location given the proximity to rail and coke’s high heating value that makes transportation viable, is much more likely than in Fort McMurray. The coke from the Fort Hills upgrader alone could fuel a base load 1500 MW power plant.

The two likely technologies to be used to generate power from coke are:

- Gasification in IGCC plants as described in Section 2.2.5 which have the advantage of low NOx and SO2 emissions, capturing heavy metals in an unleachable slag, producing saleable by-products such as Sulphur and the slag that can be used for road beds, CO2 emissions of 0.82 tonnes/MWh and the potential to separate and capture CO2.
- Circulating Fluidized Bed (CFB) boilers, which are preferable to conventional boilers for the high sulphur coke that will be produced. CFB boilers are capable of using a wide range of fuels and by adding limestone with the fuel the suphur is captured in the ash. However the CFB boilers produce 30 to 40 times as much ash as IGCC technology and although their NOx and SO2 emissions can be kept within the prescribed limits they are higher than for an IGCC plant and CO2 emissions are slightly higher at 0.87 tonnes/MWh with limited potential to retrofit the plant to capture that CO2.

The costs of the two technologies are similar. The IGCC plant is likely to have a slightly higher capital cost but better heat rate, greater flexibility in that the option exists to sell some of the syngas that is produced and lower emissions. It is assumed in the cost comparisons of generation from coal, natural gas, coke and wind in Section 3 that coke will be used to fire an IGCC plant.

2.5 Wind

Southern Alberta provides an attractive regime for wind generation. Since the mid 1990s some 300 MW of new wind generation has been installed of which about MW 250 is connected to the transmission system and forms part of the 11,308 MW of existing generation listed on the AESO website.

Wind generation is sold to “green” customers wishing to purchase a renewable source of power, to coal-fired generators buying carbon dioxide offsets and directly to energy customers or into the pool. The capacity factors of new wind generators are 35% on an annual basis and higher in December and January at the time of system peak. Generators receive a subsidy from the federal government of $10/MWh during the first 10 years of operation.

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Table 2.1 Upgraders and Gasifiers in Alberta

Company Name	Project	Upgrader Location	Feedstock to upgrader	upgrading process	capacity in bbl/day	Feedstock to Gasifier	Gasification Technolgy Supplier	Gasification Products Produced	Usage	timing of first production
BA Energy	Phase 1, Heartland Upgrader	Strathona County	merchant	hydrogen addition	75,500	-	no plans announced	tbd	tbd	2008
BA Energy	Phase 2,3, Heartland Upgrader	Strathona County	merchant	hydrogen addition	157,500	-	no plans announced	tbd	tbd	after Phase 1 completed
CNRL	Horizon-Phase 1	Wood Buffalo	Horizon-Phase 1	tbd	125,000	tbd	no plans announced	tbd	tbd	proposed
CNRL	Horizon-Phase 2,3	Wood Buffalo	Horizon-Phase 2	tbd	108,000	tbd	no plans announced	tbd	tbd	2021
Husky Energy	Bitumen Upgrader	Lloydminster	Lloydminster area	delayed coking	5,000	tbd	rfp out for gasification	tbd	tbd	2010
Northwest Upgrading Inc	Northwest Upgrader-Phase 1	Ft. Saskatchewan	merchant	hydrogen addition	75,000	Resid HC residue	Lurgi	hydrogen	internal usage for upgrading	2009
Northwest Upgrading Inc	Northwest Upgrader-Phase 2	Ft. Saskatchewan	merchant	hydrogen addition	75,000	Resid HC residue	Lurgi	hydrogen	internal usage for upgrading	2010-2015
Northwest Upgrading Inc	Northwest Upgrader-Phase 3	Ft. Saskatchewan	merchant	hydrogen addition	75,000	ashphaltenes	Lurgi	hydrogen	internal usage for upgrading	2010-2016
Opti-Nexen	Long Lake-Phase 1	Ft. McMurray	SAGD	hydrogen addition	70,000	asphaltenes	Shell	Power, hydrogen and SAGD energy	internal use for upgrading, excess, excess power to the grid	2007
Opti-Nexen	Long Lake-Phase 2	Ft. McMurray	SAGD	hydrogen addition	70,000	asphaltenes	Shell	Power, hydrogen and SAGD energy	proposed	2008-2010
Peace River Oil	Blue Sky	Peace River	Merchant	slurry hydrocracking	25,000	Resid HC residue	tbd	hydrogen + power (maybe)	hydrogen for upgrading	2012
Peace River Oil	Blue Sky	Peace River	Merchant	slurry hydrocracking	eventually to 75000	Resid HC residue	tbd	hydrogen + power (maybe)	hydrogen for upgrading	proposed
Petro-Canada/Tech/UTS Energy	Sturgeon Upgrader	Sturgeon County	Fort Hills	delayed coking	50,000	petroleum coke	gasification to be considered in the future	tbd		2011
Petro-Canada/Tech/UTS Energy	Sturgeon Upgrader, Phase 2	Sturgeon County	Fort Hills	delayed coking	90,000	petroleum coke	gasification to be considered in the future	tbd		proposed
Petro-Canada	Refinery	Strathcona County	MacKay River & 3rd parties	delayed coking	135,000	petroleum coke	coke will be marketed			2008
Shell Canada	Scotford Refinery Expansion	Strathcona County	Albian Sands Energy	hydrogen addition	150,000	Resid HC/SDA residue	no plans announced			2010
Shell Canada	Scotford Refinery Expansion	Strathcona County	Albian Sands Energy	hydrogen addition	500,000	Resid HC/SDA residue	no plans announced			proposed
Suncor Energy	Voyageur Project	Ft. McMurray	Steepbank Mine and Firebag 1-4	delayed coking	235,000	delayed coke	tbd	gasifier to consume 20% of the petcoke produced		2010
Suncor Energy	Millineum Coker Unit Project	Ft. McMurray	Steepbank Mine and Firebag 1-4	delayed coking	increasing to 350,000 bpd	delayed coke	tbd			2008
Syncrude Canada Ltd.	Upgrader Expansion 2	Wood Buffalo	Aurora Mine train 3	fluid coking	180,000	fluid coke	no plans announced			2010
Synenco Phase 1	Northern Lights-Phase 1	Sturgeon County	Northern Lights-Phase 1	hydrogen addition	57,250	SDA residue	General Electric	hydrogen, syngas no power at the present time	have a MOU for a long term contract to sell hyrogen, nitrogen, sulphur and CO2 to Agrium in Ft Sask	2010
Synenco Phase 2	Northern Lights-Phase 2	Sturgeon County	Northern Lights-Phase 2	hydrogen addition	57,250	SDA residue	General Electric	hydrogen, syngas		2012

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There is considerable interest in wind development in Alberta with some 3000 MW of new generation currently at various stages of development. However, in April of 2006 the AESO established an operational threshold of 900 MW of wind under current system conditions.

For the purposes of this study it is assumed that this threshold will determine the amount of wind that is installed up to 2011 and that 600 MW will be installed in that five year period. For the second five year period it is assumed that the AESO's work with stakeholders to identify mitigation options will be successful and that the threshold will be raised and another 600 MW will be installed bringing the total installed wind capacity to 1500 MW in 2016.

In recognition of the magnitude of the wind resource and the considerable interest, a sensitivity analysis is under taken in which a total wind installation of 3200 MW by 2016 is examined.

2.6 Peaking Capacity

A power system such as that in Alberta is made up of base load, mid range and peaking plants.

Of the plants discussed above the run-of-river hydro, the wind and most of the cogeneration will offer into the pool at $0/MWh and will thus be the first units to be dispatched and the coal and coke fired plants will likely offer in at their variable fuel/operating costs which will ensure them a base load role essentially all of the time. Only the combined cycle plant will operate in a mid range role and none of the plants discussed can be considered peakers.

In June of this year EPCOR announced that it is preparing applications to the EUB to install 245 MW of peaking capacity at its Clover Bar site over the period 2007 to 2010. Others are also considering peaking capacity but there is a general concern that the pool price cap of $1000/MWh combined with a small number of hours of operation will make it very difficult for peakers to be economic.

Given this uncertainty on the economics, new peaking capacity which includes EPCOR's planned additions are projected to be 100 MW by 2011 plus an additional 100 MW by 2016.

2.7 Other

Of the 3,500 MW of new generation capacity that has been added to the system since 1996 approximately 20% is from generators that are smaller than 50 MW. These plants, which are largely gas-fired plants plus a smaller amount of biomass, have not been addressed in the foregoing discussion which has focused for the most part on plants between 100 and 500 MW.

It is expected that this phenomenon of small additions will continue in the future but, because most of it is small gas-fired plants and gas prices continue to be high, will represent a smaller portion of the total additions. It is estimated that such generation will amount to additions of 50 MW by 2011 and another 50 MW between 2011 and 2016.

2.8 Conclusions

Based on the review of the generation resources and the announced intentions of generators it is concluded that the likely small generation additions over the next ten years will be:

- One 100 MW hydro plant, probably in 2012, contributing 50 MW to firm capacity.
- Two more upgrades of Sundance units totaling 80MW in the period to 2011 and a further 100 MW of upgrades in the 2012 to 2016 period.
- Wind generation additions of 600 MW by 2011 and a further 600 MW by 2016, contributing 120 MW of additional firm capacity in each five year period, and bringing the total installed wind capacity to approximately 1500 MW by 2016.

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- Peaking generation additions, most likely at the Clover Bar site, of 100 MW by 2011 and an additional 100 MW by 2016.
- Other small generation of 50 MW by 2011 and an additional 50 MW by 2016.

These small additions, using the firm capacity of hydro and wind, add up to 350 MW by 2011 and, with an additional 420 MW between 2011 and 2016, 770 MW in the ten year period.

The conclusions of the review with respect to major additions are that:

- The likely candidates for new coal fired units are two additional units at Keephills, a fourth unit at Genesee and a new two unit plant at Bow City.
- Cogeneration additions by oil sands developers will likely only match the growth in their behind the fence loads and will likely be gas fired rather than using the oil sands by-products asphaltene and coke.
- Coke is the only oil sands by-product that is likely to significantly contribute to meeting the growth in the grid load over the next ten years.
- The other possible major contributor to serving the growth in the grid load is gas fired combined cycles.

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3. COMPARISONS OF MAJOR GENERATION OPTIONS

This section presents a cost comparison of the coal, gas and coke fired thermal plants and wind generation discussed in the previous Section. The objective in setting out the relative lifetime costs of these types of generation is to identify the likely candidates for providing major additions to meet the load growth to 2016.

Table 3.1 presents a comparison of the levelized costs of:

Coal - a super-critical pulverized coal unit (s) similar to Genesee 3

Natural Gas - a combined cycle plant that could be located almost anywhere in the province;

- cogeneration plant assumed to be installed as part of oil sands development

Coke – an IGCC plant comprising a gasifier and a combined cycle fuelled with the syngas

Wind – a typical wind farm comprised of turbines of about 2 MW each.

The top line of Table 3.1 presents estimates of prices for coal, gas and coke that will fuel the thermal power plants.

The coal price is based on information from a presentation made by TransAlta Utilities Corporation, on behalf of the Canadian Clean Power Coalition in May 2004 in Lexington, Kentucky. That presentation showed the $/GJ coal costs for a total of twenty prospective, but unnamed, sites in Alberta. The costs varied from a low of $0.75/GJ, which reflected the costs at the existing Highvale mine serving Keephills and the Genesee mine, to a high of a $1.96/GJ. Thirteen of the 20 sites had costs between $1.00 and $1.20/GJ. A cost of $1.00/GJ is selected as being generally representative of additional units at Keephills and the Genesee or a greenfield site.

AECO-C gas price forecasts prepared in mid 2006 by Sproule and Gilbert Laustsen Jung Associates Ltd. are in the range of $6.00/GJ to $7.00/GJ over the next ten years, expressed in constant 2006 dollars. A price of $7.00/GJ has been selected for the base case analysis here and sensitivity analyses are presented at $6.00 and $8.00/GJ.

As noted in Section 2, coke that is currently being produced in the province is largely being stockpiled. In the absence of an established market, a handling/limited opportunity cost of $10/tonne is selected, which is equivalent to $0.30/GJ, assuming the power plant is located near the upgrader producing the coke.

The second line in Table 3.1 presents the plants' heat rates, that is the amount of energy in the form of fuel that is required to produce a megawatt hour of electrical output. The heat rate for a super-critical coal-fired unit is 9.5 GJ/MWh.

Since the gas-fired combined cycle and cogeneration plants utilize the waste heat from the gas turbine, either to generate electricity in a steam turbine or to provide process heat, they are more efficient and have lower heat rates. The heat rates given in the Table for the combined cycle plant and cogeneration plant are considered to be representative of plants that are being installed in Alberta. In addition to variations resulting from different types of equipment, the heat rate of the combined cycle plant will vary slightly with the altitude and temperature at the site and the cogeneration heat rate will vary with the configuration of equipment and the nature of the steam host.

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Table 3.1 Comparison of Unit Costs of Coal and Gas-fired Plants

	COAL Pulverized Coal	**GAS** Combined Cycle	**GAS** Cogeneration	**COKE** IGCC	**WIND** Wind Turbine
COST ANALYSIS					
1. Cost of Fuel ($/GJ)	1.0	7	7	0.3	0
2. Heat Rate (GJ/MWh)	9.5	6.5	5	8.5	na
3. Fuel Cost per MWh ($/MWh)	10	50	39	3	0
4. 0&M ($/MWh)	6	5	4.5	7	10
5. Capital ($/kW)	2000	800	1000	2300	2000
($/MWh)	27	12	14	34	68
6. Total Cost ($/MWh)	43	67	57	43	78
7. CO_2 Offsets ($/MWh)	5	0	0	4	-4
8. Total Cost Incl. CO_2 ($/MWh)	48	67	57	47	74
SENSITIVITY ANALYSIS					
Gas Price at $6/GJ	48	60	51	47	74
Gas Price at $8/GJ	48	74	62	47	74
CO_2 Offsets at $20/tonne	53	67	57	51	70

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Each plant's fuel cost per MWh of output in line 3 is the product of the fuel price and plant's heat rate. In the case of the coal-fired plants, the fuel cost is simply the multiplication of the two values. However in the case of the gas-fired plants the fact that the gas price is quoted in terms of gas's higher heating value and the heat rates quoted by manufacturers are in terms of gas's lower heating value has to be taken into account by multiplying the product of the two by 1.1.

The operation and maintenance costs are shown in terms of $/MWh figures for each of the plants. In fact the operation and maintenance for the coal-fired plants are largely fixed, and independent of the level of output, and the operation and maintenance costs for the gas-fired plants are generally proportional to the level of output.

The fuel and operation and maintenance costs are all estimated in terms of mid-2006 dollars and are assumed to escalate at a general level of inflation of two percent per year over the life of the project.

The $/kW capital cost estimates in line 6 include the complete design, procurement, construction (direct and indirect), commissioning and Owners' costs of each plant. A high voltage substation is included, but the transmission line to the grid is excluded. The estimates are in mid-2006 dollars. Interest during construction (IDC) and escalation are not included in the $/kW costs but are taken into account in the $/MWh costs on the next line.

The capital cost of a single 450 MW super-critical pulverized coal-fired unit is estimated to be $2,000/kW. In reality an additional unit on an existing site such as Keephills or Genesee is probably slightly less than this and a green-field site could be slightly more.

The estimated capital cost for the combined cycle plant of $800/kW is for a one-on-one GE Frame 7FA installation with a nominal capacity of about 250 MW. In addition to the gas turbine the estimate includes the HRSG, steam turbine, condenser cooling system with mechanical draft cooling tower and all ancillary systems.

The $1,000/kW estimated capital cost of a cogeneration plant is for a single unit installation of a GE Frame 7FA with a nominal capacity of 170 MW. The estimate includes the gas turbine, the HRSG with duct firing, ancillary systems to support the requirements of the cogeneration system and interconnections to the process plant. Redundant steam generation capacity (auxiliary boilers) is not included.

The capital cost of a coke fired IGCC plant of $2300/kW includes the cost of the gasifier and a combined cycle plant designed for the syngas produced. The capital cost of the wind turbine of $2000/kW is considered representative of the costs of a wind farm with the turbines of about 2 MW that are typically being installed in Alberta.

The capital costs are expressed in terms of $/MWh costs using a financial model. The key input parameters to the financial model are:

- The coal-fired plant has a four year construction period, 30 year life and operates at a 90 percent capacity factor;
- The gas-fired plants have a two year construction period, 20 year life and operate at a 95 percent capacity factor;
- The coke fired IGCC plant has a four year construction period, 20 year life and operates at a 90 percent capacity factor;
- The wind turbine capital costs are incurred over a two period and the facility has a 20 year life, operates at a 35% percent capacity factor and receives a $10/MWh subsidy for the first ten years of operation which, for the purposes of the calculations here, is levelized over the life of the plant;
- All capital is financed with 60 percent debt at a cost of debt of 6% and 40 percent equity with the return on equity of 15%;
- The capital cost allowances (CCAs) are 50 percent for the cogeneration plant and wind turbine and 8 percent for the other plants and the combined federal and provincial tax rate is 31 percent; and
- Inflation, which would apply to all costs and revenues, is assumed to be two percent per year.

These parameters are used to calculate the annual capital-related costs of each plant on a cost-of-service basis over its life and then those annual costs are levelized in constant 2006 dollars.

A revenue stream equal to the levelized cost, increasing at the rate of inflation of two percent per year, times the plant's output at the load factors indicated would recover the capital costs, taxes, interest charges and provide a 15% return on equity over the lives of the plants. The use

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of a single levelized value results in a return on equity that is lower than 15% in the earlier years and higher in the latter years.

The total cost of power for each plant in line 6 is the sum of the operating and fuel costs and the levelized capital charges and is expressed in 2006 dollars.

The cost of CO_2 offsets is included in line 7 in Table 3.1. The coal-fired plants are equipped with scrubbers to reduce SO_2 emissions, low NO_X burners and SCRs to reduce oxides of nitrogen emissions, and baghouses which remove in excess of 99 percent of particulate matter. Rather than include a means to capture CO_2, which would increase the capital and operating costs substantially, the cost of buying CO_2 offsets is included as a charge to the coal and coke fired plants. The charge is based on an offset cost of $10.00/tonne of CO_2 and is applied to the coal and coke fired plants to the extent that their CO_2 emissions exceed those of the combined cycle plant. For example a super-critical coal-fired plant produces about half a tonne more CO_2 per MWh than a combined cycle so that offsets of $10/tonne increase the costs of the coal-fired plant by $5/MWh. Wind on the other hand produces no CO_2 and is given a credit.

The pulverized coal-fired units similar to Genesee 3 and the coke fired IGCC both have a total levelized lifetime costs including CO_2 offsets in the $45 to $50/MWh range that are lower than the costs of the other three options examined. The cost of gas fired cogeneration, representing the generation configuration typically installed by oil sands developers, has the next lowest cost $57/MWh, the combined cycle is next at $67/MWh and wind is the most costly at $74/MWh.

Sensitivity to Gas Prices and Higher Offset Costs

The sensitivity analysis examines the effect of using gas prices of $6 and $8/GJ and increasing the cost of CO_2 offsets from $10 to $20 per tonne. A gas price of $6/GJ reduces the difference in the costs of the combined cycle and cogeneration plants and the coal and coke plants. Conversely a gas price of $8/GJ pushes the costs of both the combined cycle and cogeneration well above the coal and coke options.

Increasing the cost of CO_2 offsets to $20 per tonne increases the costs of the coal and coke options and reduces the cost of wind generation, but does not change the ranking of the options.

Reducing CO_2 Emissions

The foregoing analysis has been based on buying CO_2 offsets since the technologies to reduce emissions of CO_2 below the levels currently being achieved are not expected to be available and commercially accepted in North America until the end of the ten year timeframe of this study.

The status of the technologies that would reduce CO_2 are summarized below:

- Ultra super-critical coal-fired plants are now in operation in certain parts of the world, and have efficiencies of about 45% and CO_2 emissions of 0.75 tonnes/MWh as compared to 1.0 tonnes/MWh for a sub-critical plant such as Keephills and 0.9 tonnes/MWh in a super-critical unit such as Genesee 3. Ultra super-critical coal-fired plants are not significantly more costly than the super-critical units such as Genesee 3 included in the cost comparison in Table 3.1 but at this time none have been installed in North America.
- Methods to capture the remaining CO_2 emissions from these coal plants, such as amine scrubbing, are at an early stage of development and the facilities required to capture and sequester of CO_2 would substantially increase the cost of power from these plants.

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Although considerable research is underway in North America and worldwide, these technologies are not expected to be commercially available until about 2012.

- Reducing CO_2 emissions from an IGCC plant will be possible once gas turbines have been developed that will burn a Hydrogen rich fuel. However, like the amine scrubbing, these units are not expected to be available until about 2012 and the power produced would be significantly more expensive.

The most likely steps to be taken with these technologies in the 10 year timeframe to reduce CO_2 emissions are the possible installation of an ultra super-critical unit towards the end of the period and/or the installation of an IGCC plant that would be designed so that it could be converted at a later date to capture the CO_2.

Conclusions

The comparison of costs of large generating plants shows that pulverized coal units similar to Genesee 3 and coke fired IGCC plants are the lowest cost options and the most likely major additions to the system over the next ten years. Gas fired cogeneration ranks next in costs and, as noted in Section 2, is the likely source of generation to meet the behind the fence loads.

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4. GENERATION SCENARIOS

This section presents scenarios of the likely timing and location of the major generation additions expected to be added over the next ten years. Table 4.1 presents those additions to the system in terms of those to be added by 2011 and for the full ten years to 2016.

Table 4.1 starts with the 2,032 MW of new generation that is estimated to be needed by 2011, as developed in Table 1.1, and the 3,826 MW needed by 2016. Subtracting the increases in behind the fence generation from these totals results in grid shortfalls of 897 MW in 2011 and of 2,232 MW in 2016.

The remaining steps in developing the scenarios of major additions are to:

- Deduct the contribution to firm capacity that will be made by the smaller additions to the grid; and then
- Develop two scenarios of major additions that could meet the remaining generation shortfall.

In addition sensitivity analysis to higher and lower load growth and a high level of new wind are examined.

4.1 Smaller Grid Additions

As set out at the end of Section 2 the likely smaller grid additions comprise:

- One 100 MW hydro plant, probably in 2012, contributing 50 MW to firm capacity.
- Two more upgrades of Sundance units totaling 80MW in the period to 2011 and a further 100 MW of upgrades in the 2012 to 2016 period.
- Wind generation additions of 600 MW by 2011 and a further 600 MW by 2016, contributing 120 MW of additional firm capacity in each five year period, and bringing the total installed wind capacity to approximately 1500 MW by 2016.
- Peaking generation additions, most likely at the Clover Bar site, of 100 MW by 2011 and an additional 100 MW by 2016.
- Other small generation of 50 MW by 2011 and an additional 50 MW by 2016.

These small additions, using the firm capacity of hydro and wind, add up to 350 MW by 2011 and, with an additional 420 MW between 2011 and 2016, 770 MW in the ten year period. As shown in the bottom half of Table 4.1, subtracting these levels of smaller additions from the grid requirements leave 547 MW to be met by major additions in 2011 and 1442 MW by 2016.

4.2 Scenarios of Major Additions

As noted at the end of Section 3 the major additions are likely to be pulverized coal units similar to Genesee 3 and coke fired IGCC plants. Assuming that the unit sizes will be 500 MW each, one unit is required by 2011 and a total of three units by 2016.

Two scenarios of major additions are developed:

- Scenario 1 - Southern Generation in which the Bow City units are added first (on the bottom left side of Table 4.1); and
- Scenario 2 - Northern Generation in which Keephills and Genesee units and a coke fired IGCC plants are added first (on the bottom right side of Table 4.1).

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Table 4.1 Generation Scenarios (MW)

	2011	2016			
1. Total New Generation	2032	3826			
2. Cogeneration Serving Behind	-1,135	-1,594			
the Fence Load					
3. New Grid Generation	897	2232			
4. Less Smaller Additions to Grid					
4.2 Small Hydro (@50%)		-50			
4.3 Upgrades at Coal Plants	-80	-180			
4.1 Wind (@20%)	-120	-240			
4.4 Peaking	-100	-200			
4.5 Other	-50	-100			
4.6 Total Smaller Additions	-350	-770			
5. To be Met Major Grid Additions	547	1462			
6. Scenarios of Major Additions	Scenario 1			Scenario 2	
	Southern	Generation		Northern	Generation
	2011	2016		2011	2016
6.1 New Coal Units - KH3 and GN4		500		500	1000
6.2 Coke IGCC or KH4					500
6.3 Coal at Bow City	500	1000			
6.4 Total of Major Additions	500	1500		500	1500

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Based on the current status of the units it is assumed that:

- Keephills 3 and/or the first unit of the Bow City plant could be installed by 2011;
- Genesee 4 and/or the second unit of the Bow City plant could be installed between 2011 and 2016; and
- A third unit in the north could be either Keephills 4 or a coke fired IGCC plant.

Scenario 1 comprises adding the first unit at Bow City by 2011 and by 2016 the second Bow City unit and Keephills 3. In other words the Southern Generation Scenario includes two southern units and one northern unit.

Scenario 2, in which all the units are located in the north, comprises adding Keephills 3 by 2011 and by 2016 Genesee 4 and either Keephills 4 or a coke fired IGCC plant.

4.3 Sensitivity Analysis

Sensitivity analyses are carried out for variations in load growth, as shown in Table 4.2, and the amount of wind that may be installed, as shown in Table 4.3.

The load growth sensitivity analysis examines variations in the grid load of +/- 300 MW by 2011 and +/- 500 MW by 2016. These variations may be the result of the load growing either faster of slower than the base case; or the behind the fence generation either not meeting the behind the fence load, and some of that load being met by the grid, or exceeding behind the fence load, and providing surplus generation to the grid.

In the situation with the grid load being 300 MW higher in 2011 and 500 MW in 2016, two units are required by 2011. With Keephills 3 and the first unit of the Bow City plant the only units that can be installed by 2011, these become the first additions in both Scenarios.

These two units are followed by the second Bow City Unit and Genesee 4 in the Southern Scenario and by Genesee 4 and either Keephills 4 or a coke fired IGCC plant in the Northern Scenario.

The low grid load case simply removes the need for the second unit in the base case in the 2011 to 2016 period.

In the Accelerated Wind Development Scenario, as shown in Table 4.3, it is assumed that an additional 800 MW of wind are installed by 2011 and an additional 1700 MW by 2016 bringing the total wind installation to 3200 MW by the end of the 10 year period. Using the factor of 20% to calculate the firm capacity, this additional wind reduces the generation to be met by coal and coke plants by 160 MW in 2011 and 340 MW by 2016.

Using a criterion that a unit will be added when the shortfall exceeds 100 MW results in this additional wind not affecting the number of units needed in the first and second five year periods.

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Table 4.2 Generation Scenarios with High and Low Load Forecast

	Scenario 1			Scenario 2	
	Southern	Generation		Northern	Generation
	2011	2016		2011	2016
Base Case Load	547	1462		547	1462
1. Major Grid Additions - High					
Increment to Base Case Load	300	500		300	500
Total High Load	847	1962		847	1962
1.1 New Coal Units - KH3 and GN4	500	1000		500	1000
1.2 Coke IGCC or KH4	0	0			500
1.3 Coal at Bow City	500	1000		500	500
1.4 Total of Major Additions - High	1000	2000		1000	2000
2. Major Grid Additions - Low					
Decrement to Base Case Load	300	500		300	500
Total Low Load	247	962		247	962
2.1 New Coal Units - KH3 and GN4				500	1000
2.2 Coke IGCC or KH4	0				
2.3 Coal at Bow City	500	1000			
2.4 Total of Major Additions - Low	500	1000		500	1000

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Table 4.3 Northern Generation Scenario with Accelerated Wind

	Scenario 2	
	Northern	Generation
	2011	2016
Base Case Load to be Met by Major Additions	547	1462
Less:		
Additional 800 MW of Wind by 2011 & 1700 MW by 2016 (@20%)	160	340
To be met Coal & Coke Additions	387	1122
2.1 New Coal Units - KH3 and GN4	500	1000
2.2 Coke IGCC or KH4		500
2.3 Total Coal and Coke Additions	500	1500

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