TRANSALTA UTILITIES CORPORATION

EXPANSION OF KEEPHILLS POWER PLANT

EUB Application No. 2001200

Submission on behalf of the Clean Energy Coalition
by the Pembina Institute for Appropriate Development
Mary Griffiths and Tom Marr-Laing

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Figures and Tables

Introduction

The Memorandum of Decision for the Pre-hearing meeting on the Application to expand the Keephills Power Plant indicated a number of matters that are considered relevant. This presentation will focus on socio-economic, environmental and technology issues. In particular it will examine:

1.The Alternative of Not Proceeding with the Development
2. The Need to Reduce the Emission of Air Pollutants
3. The Potential for Better Technology in the Keephills Expansion
4. The Need to Reduce Greenhouse Gas Emissions

Issues relating more specifically to air emissions and water quality will be dealt with in other papers submitted by the Clean Energy Coalition (CEC).

1 The Alternative of Not Proceeding with the Development

1.1 Meeting demand without coal-fired electricity

1. Section 2.2 of the Terms of Reference for the Application dealt with the Project Need and Alternatives. The alternatives to be reviewed were “alternatives to the Project, including but not limited to the potential alternative of not proceeding with the development.” The Environmental Impact Assessment failed to deal with this issue.[1]

2. “The alternative of not proceeding with the development” is in the best interests of the public at the present time. Current plans for new gas plants, along with investments in renewables and energy efficiency, will readily meet Alberta’s domestic demand for ten or more years (see Appendix 1). This will allow time for the possibility of major improvements in the economics of coal-fired technology with rates of emissions comparable to those from natural gas.

3. Emissions of air pollutants from natural gas are far lower than from conventional coal-fired generators (see Appendix 6). A natural gas plant has practically no primary emissions of particulate matter or SO_2, while NOx emissions are only about 15% of the Alberta standard for coal-fired power plants. Because natural gas plants use energy far more efficiently and are less carbon-intensive than coal-fired thermal power plants, the emission of greenhouse gases is also far lower. A combined cycle natural gas plant can achieve greater than 50% efficiency and greenhouse gas emissions are less than half those from a supercritical coal-fired plant. Co-generation plants can push these efficiencies to 60% or greater, by making use of waste heat from other industrial processes.

4. Alberta Energy’s estimate of the increase in supply and demand until 2005 is shown in Figure 1-1, but new proposals are adding to the estimated increase in supply. According to the Transmission Administrator, there were approximately 8,765 MW of capacity in Alberta to supply the Alberta Integrated Electricity System (AIES) on July 1, 2001.[2] A further 380 MW of capacity will be added to the system between September and the end of 2001, and approximately 4,700

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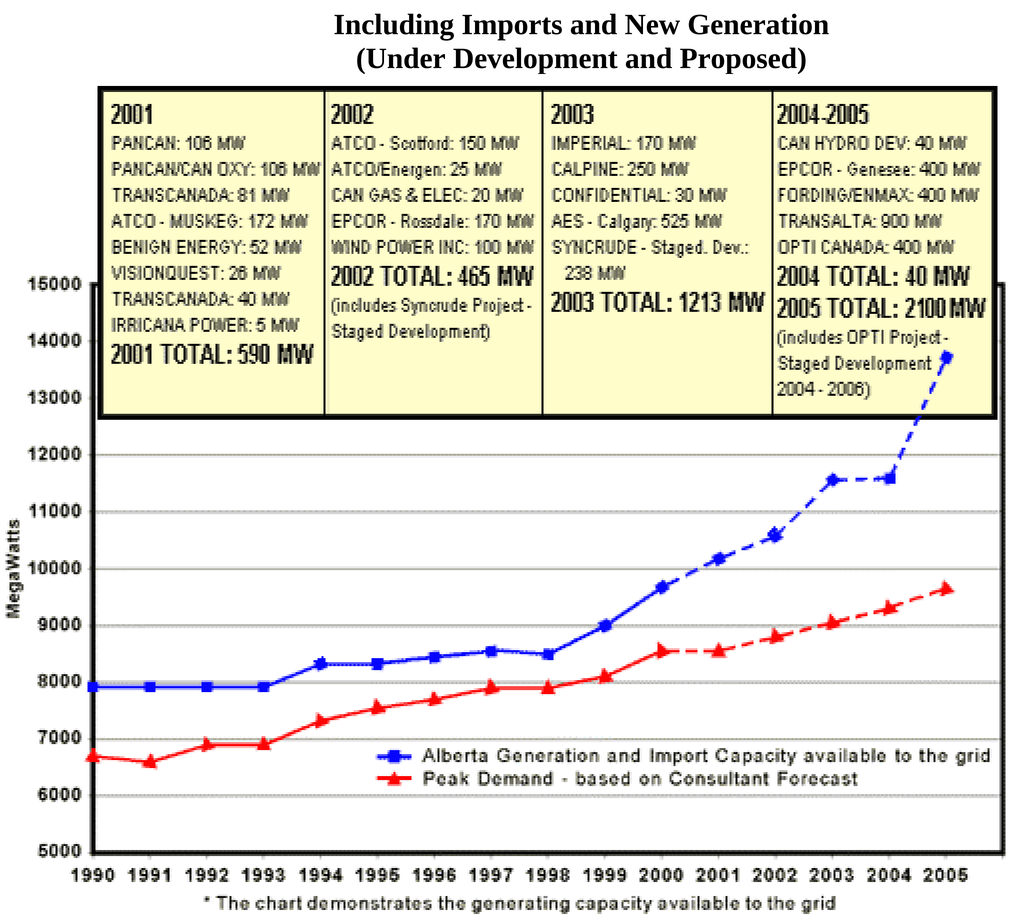
[1] The alternative of not proceeding with the project should have been handled in section 2.1.4, according to Table 1.7.2, EIA Terms of Reference, Cross Reference.
[2] ESBI Transmission Administrator, 2001. *Facilitating Major New Generation in Alberta: An Overview of the Transmission Infrastructure Requirements,* August 17, p.7; online at http://www.eal.ab.ca/tp/Facilitating_Major_New_Generation_in_Alberta.pdf

MW could be added between 2002 and 2006,[3] which would give a total of 13,845 MW by 2006, an increase of 58% compared with July 2001. This will be far in excess of the demand, which the Transmission Administrator expects to grow at about 3% per year for the next few years, declining towards the end of the decade. Indeed, supply has exceeded demand throughout 2001 and "Alberta is now a net Exporter and not Importer" of electricity .[4] It is likely that the province will remain a net exporter for many years, if all projects proceed, although the future of the export market may be uncertain given the number of new power projects being planned in the northwest U.S.

Figure 1-1. Electricity supply and demand in Alberta 1995-2005[5]



5. The Transmission Administrator indicates that with a 3% growth rate demand will be 10,500 MW by 2010. Since there could be as much as 6,800 MW of new generation capacity by 2010, this would give 4,000 MW of surplus generation during off-peak periods, even if demand grows at 3%

3 Alberta Energy, Key Numbers – Electricity, updated September 27, 2001; online at http://www.energy.gov.ab.ca/electric/general/keynumbers.htm. N.B. The figure for capacity may be a slight underestimate, as the Transmission Administrator figures are for July 1, 2001, while the new capacity listed by Alberta Energy gives plants coming on-line after September 2001.

4 Alberta Power Pool, October 2001, *Assessment of Pool Price Deficiency Regulation and Intra Day Market – Next Steps. A Discussion Paper*, p.3; online at www.powerpool.ab.ca

5 Government of Alberta, 2001, *Electricity Supply and Demand in Alberta 1995-2005*; online at http://www.albertaenergyfacts.com/media/background/elec_supply_demand.cfm

per annum.[6] At peak periods, the excess supply would be approximately 2,500 MW, after allowing reserves for maintenance shutdowns of equipment.[7] The total amount of coal-fired generation in new plants would be 2,390 MW gross, or approximately 2,200 MW net, which is about the same as the excess capacity at peak anticipated by the Transmission Administrator in 2010. It would thus be possible to meet demand from proposed developments until at least 2010 without any new coal-fired power plants, even if demand continues to increase at 3%.

6. Future demand estimates are subject to many factors and estimates vary. While a high growth rate has been used in the above calculations, the rate may be lower. Natural Resources Canada estimated a 20% increase in domestic demand in Alberta between 2000 and 2010, with a 40% increase by 2020.[8] A Canadian Energy Research Institute study estimated demand according to different growth scenarios of 2%, 2.5% and 3%, using figures from the Alberta Power Pool.[9] This suggests that a 3% rate is probably the upper end of the growth rate that can be expected. If the growth rate were 2%, demand in 2010 would be under 9,000 MW, not the 10,500 MW estimated by the Transmission Administrator. At a moderate growth rate, the increase in supply, outlined above, would be sufficient to meet demand until about 2015. Allowing a 5-year time period for the construction of a new coal-fired power plant, this suggests that the earliest a new-coal fired plant should be even considered is 2010 (i.e. operational by 2015).

7. The Pembina Institute has shown that there is considerable potential to meet demand for electricity in Alberta using renewable energy and to reduce demand through energy efficiency measures. The Alberta Energy figures on new generation capacity cited above include 340 MW from renewable energy sources, but the Pembina Institute considers 800 MW increase in renewables to be a realistic goal for 2010.[10] In addition there is potential for the generation of about 400 MW of electricity from gases that are currently flared at gas plants.[11] If all major flares are used to power microturbines, the potential is even greater. The Pembina Institute has also proposed a target of 800 MW in saving through energy efficiency (including demand side management). If one assumes that energy efficiency measures and further development of renewable energy can together add the equivalent of a further 1,200 MW of capacity by 2010 (which is below the Pembina Institute's target), it will be possible to delay a new coal-fired power

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[6] ESBI Transmission Administrator, 2001. *Facilitating Major New Generation in Alberta: An Overview of the Transmission Infrastructure Requirements,* August 17; online at http://www.eal.ab.ca/tp/Facilitating_Major_New_Generation_in_Alberta.pdf . Also update from the Transmission Administrator's office, personal communication.

[7] Transmission Administrator's office, personal communication. N.B. The total capacity available in 2010 would be over 15,500 MW (current 8,765 + 6,800 new MW). Allowing 15% of capacity for the shutdown of plants for maintenance and repair, leaves about 13,200MW to supply the grid, a surplus of 2,700 MW.

[8] Natural Resources Canada, 1999. *Canada's Emissions Outlook: 1997-2020.* Table Alta-14, shows demand increasing from 60,598 GWhr in 2000 to 72,633 GWhr in 2010 and 85817 GWhr in 2020; online at http://www.nrcan-rncan.gc.ca/inter/index_e.html

[9] Canadian Energy Research Institute, 2000, *Electricity Price Forecast*. Ch. 3, Alberta Electricity Demand. Table 3.2 estimates demand of 11,295MW in 2016 with average growth of 2.5% a year. With a slower growth of 2%, demand reaches 11,126 MW in 2020, while with strong growth of 3% demand would reach 11,438 MW in 2013, according to Power Pool of Alberta Annual Peak Demand estimates, cited in the report.

[10] Pembina Institute, 2001. *A Smart Electricity Policy for Alberta.* See Appendix 7.

[11] Statement by Alberta Energy Minister Murray Smith, with respect to the Gas Plant Efficiency Assistance Regulation, EnviroLine, Vol. 12, No. 12, No. 13 &14, p.6.

plant until at least 2014 even with a 3% growth in demand.[12] Further information on energy efficiency and renewable energy is given in Appendix 7, "A Smart Electricity Policy for Alberta."

8. One example of an economically and environmentally efficient means to meet electricity demand is through distributed generation and small scale combined heat and power (CHP) (see Appendix 8). Even with a modern coal-fired power plant, less than 40% of the coal burned is converted to electricity.[13] Further losses occur during the transmission of power, due to the heat lost in the transmission and distribution lines (with wire losses of 4.8% per 100 miles). If electricity is produced in small scale units close to demand these losses associated with centralized coal-fired power plants can be avoided. Distributed generation can be provided by low-impact renewable sources or gas-fired microturbines (and by fuel cells which are expected to be commercially available during the current decade). Not only is electricity delivered to the consumer, but heat is recovered for local use, thus reducing the heat loss to around 20%. Air pollution and greenhouse gas emissions are minimized through the high efficiency. The potential for implementing CHP in Alberta is very significant. This form of energy supply would in itself more than offset any need for additional coal-fired generation in the province.

9. The proponent may argue that Western Canada gas reserves are insufficient to supply long-term natural gas to natural gas co-generation power plants in Alberta. A recent study by the Canadian Gas Potential Committee (CGPC) suggests that sufficient natural gas is available to meet the needs of natural gas combined cycle (NGCC) power plants that are built instead of coal-fired plants. The CGPC study released in September, 2001 estimates that the Nominal Remaining Marketable Gas (discovered and undiscovered) in Canada is 233 trillion cubic feet (Tcf), which is approximately a 40-year supply at 1998 production levels – significantly longer than the operating life of any gas-fired generator built during this decade.[14] Of the 233 Tcf, the vast majority (177 Tcf) is in the Western Canadian Sedimentary Basin and the Mackenzie Valley (including the Beaufort Basin), which is potentially available to gas-fired power plants located in Alberta. In developing these estimates, the CGPC indicates that not all of this gas will be produced because of the assumptions it has used; however, as exploration technology improves and as new areas open up for development, it is reasonable to expect that a large portion of this gas will be produced. In addition, these reserves do not include the potential marketable reserves of coal bed methane, which the National Energy Board conservatively estimates to be 75 Tcf in the Western Canadian Sedimentary Basin.[15]

10. If all proposed natural gas-fired electricity generation proceeds, the consumption of gas for electricity generation in Alberta over the next 30 years (including use by current natural gas plants), would be approximately 3% of the 233 Tcf reserves.[16] Clearly, the marketable gas volumes from both conventional and unconventional sources would support Alberta based NGCC facilities for many years and have no significant impact on exports. While gas-fired generation will play a significant role in providing both base and peaking generation needs for the foreseeable

[12] With a 3% growth rate, capacity would need to increase by about 300 MW a year by 2010, based on an estimated demand of 10,500 in 2010, so the extra 1200 MW would extend the supply by 4 years.
[13] Mariah Energy Corp., 2001. *Briefing Document on Opportunities for Distributed Generation (DG) and Small-Scale Combined Heat and Power (CHP) in Alberta.*
[14] "Natural Gas Potential in Canada – 2001," September, 2001, Canadian Gas Potential Committee, http://www.canadiangaspotential.com/index.html .
[15] "Canadian Energy Supply and Demand to 2025, August 1999, National Energy Board; online at http://www.neb-one.gc.ca/energy/sd99/index.htm .
[16] Existing and proposed natural gas-fired electricity generation would use 600 million cubic feet/day. This is 0.219 Tcf/yr (600x365d/yr = 219Tcf/yr). In 30 years the plants would use approximately 7Tcf (0.219x30 = 6.57Tcf). This is 3% of the 233 Tcf reserves.

future, greater use of Alberta's minimally tapped renewable energy and energy efficiency resources would conserve natural gas reserves even further.

11. It is thus possible to meet Alberta's demand for electricity and minimize the local and global environmental impact of electricity generation without new coal-fired generation for the near and mid-term future.

12. Delaying the introduction of coal-fired generation until a later date gives time for the development of less-polluting coal burning technologies. As can be seen from Appendices 4 and 6, the coal-combustion technology that currently offers the lowest emissions is the integrated gasification combined cycle (IGCC) process. IGCC creates no sulphur dioxide or mercury emissions and has low NOx emissions. Being more efficient, the GHG emissions are lower than for other coal-burning technologies and the process has the potential to more readily permit the capture of GHG emissions. Although their construction has been supported by some public funding, several IGCC facilities are operating in the U.S. – demonstrating that such technology is viable and available. Within a few years this (or other less polluting technology) should be economically viable in a deregulated market.

13. The urgent need for less polluting technology is recognized by the Canadian Clean Power Coalition. They plan to have a new demonstration plant that meets strict environmental standards in operation by 2010.[17]

14. Of course, further improvements in low-impact energy sources (wind, solar, micro-hydro, etc.), energy efficiency and gas-fired generation may allow continued deferral of the use of less environmentally and economically competitive coal systems, particularly if pro-active, sustainable energy development policies are pursued by the private and public sectors.

1.2 Coal-fired power unnecessary to achieve lower electricity prices

15. Proponents of coal-fired generation projects have argued that the province needs more coal generated electricity to ensure Albertans will have cheap, stable electricity prices. Such claims might have been plausible under the old cost-based regulated electricity system – where consumers received lower prices in exchange for comparatively higher levels of pollution. In Alberta's deregulated electricity system, however, there is no longer a direct relationship between the cost of generation and the prices paid by consumers. As a result, as the following analysis demonstrates, consumers will receive little or no economic benefit from so-called "cheap" coal-fired generation under this new system.

16. Alberta's deregulated electrical market, while still developing, is showing signs of free market competition with suppliers and buyers entering into various types of electrical sale contracts. These contracts are generally sold through either day-to-day spot market contracts on the Alberta Power Pool or through long term over-the-counter (OTC) contracts (whether physical and/or financial).

[17] McDonald, M. and W.A. Campbell, 2001. *The Evaluation of Options for CO_2 Extractions from Existing and New Coal-fired Power Plants.* Paper presented at the Gasification Technologies 2001 Conference, San Francisco, Oct. 7-10.

17. Some portion of power from most generation projects is sold into the higher risk/return Power Pool spot market. The price paid for such power is dependent upon the relationship between supply and demand in the market at any given time.

18. Suppliers of electricity offer generation from their facilities into the electricity system by placing bids into the Power Pool. These facilities are then dispatched by the Power Pool according to a "merit order" determined by the bid prices. The price actually paid to ALL suppliers is set by the bid price of the LAST megawatt (MW) of power dispatched to the grid. Thus, the generator that produces this last MW of power is effectively the "price setter" for all power sold through the Power Pool. As such, generators with variable costs substantially lower than the marginal unit are able to realize significant operating margins. It is these margins that allow a merchant generator to recover fixed costs including profit.[18]

19. For many generators, a large portion of their output is sold through OTC supply contracts that offer relatively secure long-term arrangements for both the buyer and seller. In these contracts, the buyer receives electricity at a known price and the seller receives pre-determined revenue. Although OTC contracts lock in the price of power over a pre-established term, the price agreed to by the buyer and seller of such contracts is reflective of the parties' views of the future of the spot market value for electricity. While the buyer will enter into contracts to avoid the volatility of the spot market, they will not pay a significant premium over the expected future spot prices for their supply. Although sellers may use these contracts to backstop large capital expenditures, they will want to hedge against the downside in pool prices. As a result, forward contracts are set (or heavily influenced) by expectations of future spot prices.

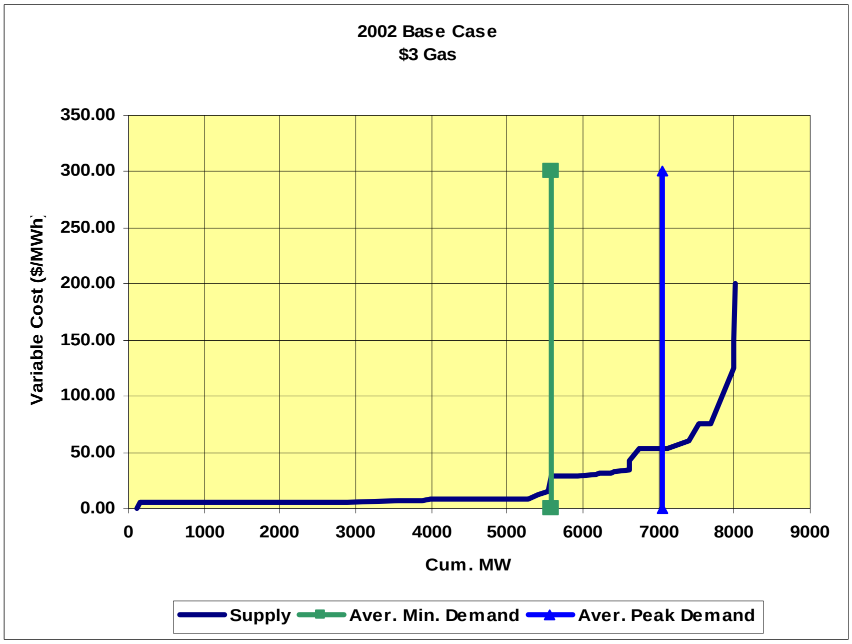
20. Given the all-important role of the Power Pool in setting electricity prices then, what role can Albertans expect from coal-plants in setting the price of power? Various consulting firms have developed sophisticated modeling tools to explore such questions. Unfortunately, access to such services was not available to the Pembina Institute because of perceived conflicts for the TransAlta Keephills project hearing. However, the Institute has prepared supply/demand price curves that will serve to illustrate the essential logic of the market's operations, and to demonstrate that it is gas that will play the dominant role in setting the overall pool price.

21. For purposes of the discussion, price curves for years 2002 and 2006 are shown using a natural gas price of $3/GJ. The impact on Power Pool prices from the addition of 900 MW of coal in late-2005 is compared with that from adding 900 MW of gas-fired generation instead. Other curves, using various gas prices and different supply scenarios are presented along with further discussion in the Appendix: *Power Pool Supply/Demand Dynamics*.

22. A Base Case variable cost curve for the year 2002 is shown in Figure 1-2. The generation supply reflected in the variable cost curve includes those natural gas plants that have recently come on-line or are expected to be on-line by early 2002.

[18] Furthermore, generators who are at or near the margin can strategically offer bids that are just below the variable cost of the NEXT generator in the merit order. Such "shadow-pricing" behavior provides marginal generators a premium above their variable costs at times when their generation sets the price and raises the overall Pool price.

Figure 1-2. Variable cost curve, base case year 2002 ($3/GJ gas price)



23. The reader will note that the variable cost of power takes a step up at the point where the cumulative supply is around 5,500 MW (the first "knee" in the curve). Generation prior to this point is supplied entirely by low variable cost coal and renewable energy sources (such as hydro and wind) – priced from $0/MWh to around $15/MWh. Generation after the 5,500 MW point is supplied by natural gas - starting at $29/MWh up to 6,700MW, then increasing in a range from $53/MWh up to $60/MWh at the 7,400MW point. The curve then takes another significant jump after 7,400 MW. Beyond this last "knee", the price of electricity climbs sharply as supply from the Rossdale plant, imports from Saskatchewan and then B.C. are brought on-line.

24. Superimposed on this curve are the forecasted minimum and peak demands for the year 2002. These values were projected from 2000 actual data and growing at 4% in 2001 and 3% in 2002. The vertical bars clearly show that all of the generation between the minimum (approximately 5,600 MW) and the peak demand (approximately 7,000 MW) will be provided by gas-fired electrical generation, with the last gas-fired unit online setting the overall pool price. At the peak end of the demand, this last plant has historically been the Clover Bar facility. The average minimum demand is not low enough for coal-fired generation to ever set the Power Pool price.[19]

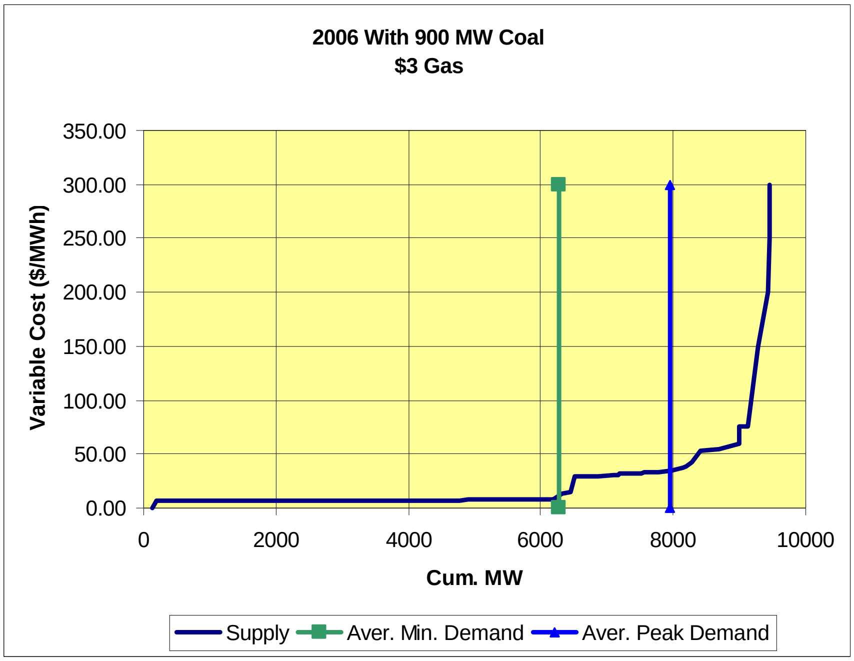
25. An analysis is now provided for the year 2006 (Figures 1-3 and 1-4). Average maximum and minimum demand is projected out from 2002 at 3% per year, rising to roughly 6,300MW and

[19] It is of interest to note that a key reason power costs have dropped from an average of $133/MWh in 2000 to around $100/MWh in 2001 (a reduction of 25%) has been the addition of new domestic supply (figure not shown). This has served to move the peak demand point away from the steep parts of the price curve (e.g. imports from B.C.) down into the flatter, lower-cost Alberta based generation supply parts of the curve. Lower natural gas prices, fewer outages, and changes to the market rules wherein import prices no longer set the overall Power Pool price have further aided in lowering the price of power.

8,000MW respectively. Five hundred and seventy-five (575) MW of new natural gas, hydro, and wind generation (all publicly announced projects) have been added into the supply mix.

26. In Figure 1-3, 900 MW of supply from new coal-fired generation has been added (coming on-line late 2005). This additional coal generation has the effect of shifting the first "knee" in the price curve to the right by approximately 900 MW (occurring at the 6,600MW point). As the minimum demand for power has also grown (moved to the right) since 2002, this minimum demand point remains close to that of the total supply available from coal.

Figure 1-3 Variable Cost Curve
900 MW Coal Year 2006
($3/GJ Gas)

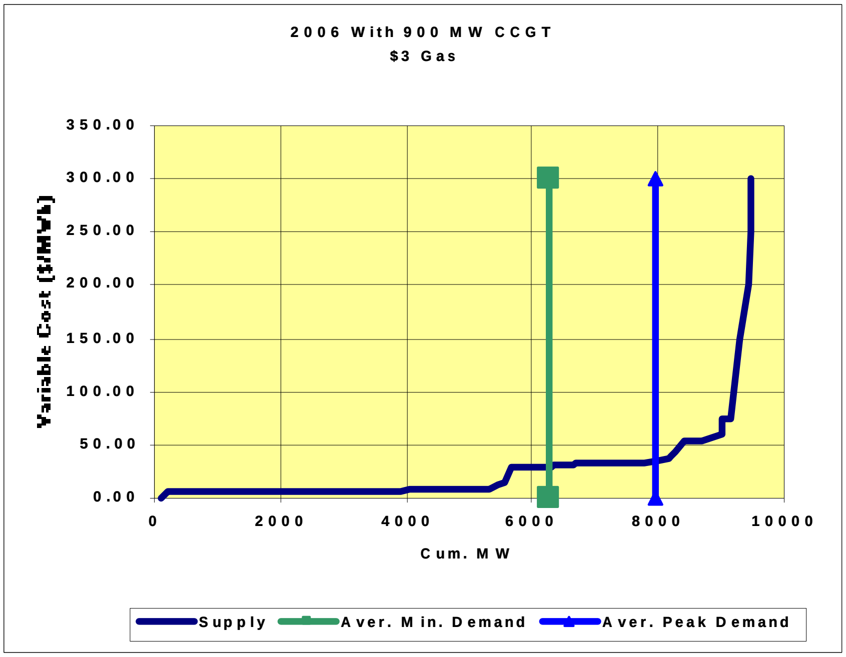


27. While the results in Figure 1-3 show the minimum demand point below the coal/gas cut-off point, gas-fired generation will still set the Pool Price 90-95% of the time. Given the opportunity for shadow-pricing (as discussed previously), even this minor benefit from low-variable cost coal is unlikely to be realized. Furthermore, with demand continuing to grow, the gap between the minimum demand line and the coal/gas cut-off point would quickly disappear – moving the entire Pool price back onto the gas curve.

28. Figure 1-3 demonstrates that even with 900 MW of new coal generation, the price of power will still be overwhelmingly set by natural gas generation. Consequently, the consumer will not receive the economic benefit of paying a price for electricity based on the low variable cost of coal generation.

29. For comparative purposes, 900 MW of combined cycle gas-fired generation is added in Figure 1-4 in place of 900 MW of coal. While the first "knee" is 900 MW further to the left of that of Figure 1-3 (occurring at the 5,700MW point), the overall Power Pool price is essentially the same in the two scenarios because demand maintains the price in the gas-part of the price curve.

Figure 1-3. Variable cost curve, 900 MW CCGT year 2006 ($3/GJ gas)



30. In both Figures 1-3 and 1-4, it is shown that the new supply has shifted peak demand away from expensive generation sources (such as the older gas-plants and imports) – offering consumers better protection from high prices. This benefit is offered equally by coal OR gas supply.

31. It is important to observe, however, that the Pool price is still sensitive to the price of natural gas for BOTH scenarios. Higher or lower gas prices will raise or lower the gas-cost part of the curve – and Power Pool prices will fluctuate accordingly. New coal generation would not protect consumers from such fluctuations. Some such scenarios are examined in the Appendix: *Power Pool Supply/Demand Dynamics*.

32. The preceding analysis shows that future spot electricity prices will continue to be set by the gas fired capacity for the majority of the hours regardless of whether new capacity additions are coal or gas fired. Going forward, average pool prices will decline (at a given gas price) for two reasons;
    - extending the supply with new, more efficient supply avoids the use of higher cost resources (such as imports from BC);
    - market heat rates will decline as new more efficient capacity is added and sets prices in a greater number of hours, thereby relegating the less efficient capacity (such as Clover Bar and Rossdale) to less frequent use.

33. The only scenario under which the Power Pool price could conceivably be significantly influenced by coal-based generation is if ALL the coal-fired projects (currently some 1,750MW) that have been announced go ahead. In this case, coal would set the pool price during much of the off-peak period.

34. However, it is highly unrealistic for this situation to occur. Given the low, flat nature of the coal-fired supply curve, these suppliers would receive little or no fixed cost recovery for their facilities.

In fact, it is in the collective interests of coal-fired generators to not allow the variable cost of coal to ever set the pool price. The fundamental dynamic of Alberta's electricity market drives suppliers to time the introduction of potential new facilities so that any new incremental addition of coal generation always lags closely behind the growth in minimum demand.

35. It is readily apparent from this analysis that adding <u>any</u> form of generation capacity will reduce the overall pool price. The addition of more generation with more efficient heat rates, regardless of fuel source, will have the effect of dropping the highest priced supplier on the merit order from being dispatched. Each time that happens, the pool price will be lowered to the next lower priced bidder. So, while it is true that the addition of new coal-fired capacity will augment the supply of electricity in the province and lead to reductions in the market price of power in Alberta, these same reductions would be realized with the addition of an equivalent amount of capacity from gas-fired, renewable, or energy efficiency options.

36. Since an ample supply of generation from new gas-fired plants and other sources are prepared to come on-line to meet the growing demand for power in Alberta (as discussed in the section 1.1), deferring consideration of new coal-fired power plants until at least the end of this decade will not have any economic implications related to the price of electricity paid by Albertans.

37. Albertans will pay similar prices for new coal-fired capacity vs. new gas-fired capacity, but will be exposed to substantially more pollution and emissions with new coal fired capacity. In other words, society will bear the cost of the environmental externality imposed by new coal fired generation but will not realize lower power prices in exchange. It is in the public interest that consumers get what they pay for – power that is as clean (or cleaner, as in the case of renewables and energy efficiency) as high-efficiency gas-fired generation.

38. Furthermore, allow a coal-fired project to proceed without requiring it to install the most effective pollution control equipment available will transfer an even higher environmental and human health liability onto society without any offsetting benefits of lower cost power (see discussion on technologies in section 3).

39. The alternative of not proceeding with development of coal-fired power plants is thus a viable alternative and the best solution at the present time, when considering the environmental, human health and economic consequences of the proposed project.

1.3 Keephills 3 and 4 present TransAlta with market dominance opportunity

40. An important objective in deregulating Alberta's electricity system was to enhance competition by encouraging a market that would attract a wide range of suppliers and purchasers. The expectation is that a fully competitive market would ensure continued reliability of low-cost electricity supply – while reducing the costs to the system from related regulatory activities.

41. A key concern about whether such a transition will be successful is the issue of "market power." Market power refers to any situation where a supplier (or group of suppliers acting in explicit or implicit collusion) could influence the market to raise prices, and/or reduce supply in a manner that would enable then to reap sustained higher profits than would otherwise be achieved in a truly competitive market. Given that provincial supply was historically concentrated in the hands of

three utilities, the task of splitting up this power, and ensuring a transition to a truly competitive market was, and continues to be, an important issue.[20]

42. Prior to the Power Purchase Agreement (PPA) auctions in 2000 (held, in part, for the purposes of splitting up the market power of Alberta's original three utilities), the provincial government established a rule that any one PPA holder would be restricted to owning less than 20% of all thermal PPA capacity. The intent of this rule was to distribute the capacity to a larger number of participants to encourage competition and to limit the risk of the abuse of market power by incumbent generators. This rule is to remain in effect until the end of 2002. There is currently a policy void after 2002 that the provincial government has not yet addressed but which is drawing increased scrutiny by market participants.

43. Most recently, a 15% holding restriction rule was applied by the Balancing Pool to the sale of the HR Milner facility in order to "contribute to the development of increased competition in the Alberta electricity market." This restriction precluded TransAlta from participating in the sale because of their expected position in the market after 2003.[21]

44. As the following table illustrates, if TransAlta is permitted to proceed with its Keephills 3&4 project and other activities planned by the corporation also proceed, then TransAlta will control more than 21% of the total generation market in 2005. This exceeds both the 15% limit applied to the HR Milner sale and the original 20% limit used for the original PPA auction and the subsequent MAP auction.

Table 1-1. TransAlta Alberta-based generation, existing and planned @ 2005

Plant Name	Capacity (MW)
TA Hydro[22]	793
Sundance Upgrades	210
Wabamum	548
Keephills 3&4	900
Dow Ft. Sask.	120
Suncor-Ft. McMurray	360
Vision Quest	23
Total at 2005	**2954**
Total System capacity[23]	13,845
TA portion of total system capacity	**21.3%**

[20] Detailed discussion of market power issues can be found in the following references: *Final Report on PPA Auction Design*, Charles River Associates, December 30, 1999, available at http://www.energy.gov.ab.ca/electric/rgeneral/index.htm. Also, *Options for Market Power Mitigation in the Alberta Power Pool, Final Report*, London Economics, January 1998, available at http://www.energy.gov.ab.ca/electric/techrfp/index.htm. These and other related documents were produced for Alberta Energy.

[21] "Appropriate holding restrictions to be placed on the pending sale of Milner and potential future sales of Balancing Pool PPA capacity," prepared for the Balancing Pool Administrator and the Power Pool Council of Alberta, London Economics, June 2001.

[22] 400 MW of this capacity is contracted for system support services (SSS) through a financial arrangement between the Transmission Administrator and TransAlta. However, TransAlta retains physical control of facilities and the discretion to determine when and how such supply is offered into the market.

[23] See Figure 1-1. Note that this assumes that all proposed projects proceed as planned. If fewer projects actually proceed, the percentage of TransAlta's market share will increase proportionately.

45. Although the market power rules for post-2002 have not yet been established, we would submit that the EUB must take market power into consideration when determining whether or not to grant a licence for TransAlta's proposed Keephills 3&4 project. Certainly, it is in the public interest to ensure that the deregulated market operates in a truly competitive manner – by precluding the opportunity for incumbent generators to benefit unfairly through abuse of market power.

46. Even if TransAlta does not proceed with construction of both Keephills units, the fact that it would have approvals in hand to construct a unit would offer it substantial influence over whether or not other proponents (particularly gas-fired generators) would be willing to enter the market.[24]

47. We would further submit that the Board should consider the significant possibility that, if granted a licence to begin construction of the Keephills project by the EUB, TransAlta could later sue the government for economic loss if it is required to divest itself (under conditions of a forced sale) of some portion of its generation portfolio in order to reduce its market share back below 20% (or other percentage limit determined necessary to ensure the long-term competitiveness of the market).

48. At a minimum, the EUB's decision on the project should be postponed until this issue is studied and policy is developed. It is our understanding that an industry review is underway by the government and we anticipate that this aspect of the market will be examined as part of the study.

[24] Not allowing the TransAlta project to proceed would likely act as a stimulus to proponents of gas-fired generators, many of whom have placed their projects on hold in anticipation of an over supplied market given the magnitude of the proposed Keephills expansion.

2 The Need to Reduce the Emission of Air Pollutants

2.1 Why air pollution is a concern

49. TransAlta states that, *"if ground-level concentrations of a pollutant are less than the pertinent guideline* value then there will be no adverse environmental effects."[25] The Alberta Ambient Air Quality Guideline values were determined to provide protection to humans from acute levels of exposure to pollutants. Other factors, such as chronic and long-term exposure of humans and ecosystems, the degree of existing environmental degradation, and cumulative effects (from both current and anticipated future sources) must be considered in order to determine the significance of an adverse environmental effect. The proponent's EIA has clearly failed to do this (as discussed in a separate submission by the CEC), thus rending the above assertion unjustified, misleading, and inaccurate.

50. The combustion of coal creates emissions of sulphur dioxide (SO_2), nitrogen oxides (NO_x), particulate matter (PM) and other air pollutants of concern, such as mercury. Sulphur dioxide contributes to acidifying emissions and to acid aerosols in fine particulate matter while NOx makes a further contribution to the acidifying emissions, secondary particulate matter and ground level ozone.

51. The emission of primary and secondary particulate matter, as well as NO_x and SO_2 gases, is of concern for human health. The federal government recently classified PM_{10} and $PM_{2.5}$ as toxic substances under the Canadian Environmental Protection Act, 1999. Recent scientific evidence indicates that there is no apparent lower threshold for the effects of PM on health, including respiratory illness and cardiovascular illness.[26] Acute exposure to high concentrations of SO_2 can lead to irritation of the upper respiratory tract and aggravate cardiac respiratory disease. Long-term exposure may increase the risk of developing chronic respiratory disease. Nitrogen dioxide (NO_2), a component of NO_x is known to irritate the lungs and increase susceptibility to respiratory infections in humans. NO_x plays an important role in the formation of ground level ozone through a complex photochemical reaction with volatile organic compounds. Unlike stratospheric ozone, which plays an important role in protecting the environment from harmful ultraviolet radiation, ground-level ozone causes adverse effects on humans, including irritation of the eyes, nose and throat, reduced lung function and the development of chronic respiratory disease.

52. These emissions will also affect the environment. Modeling work done for the Acidifying Emissions Management Implementation Team of the Clean Air Strategic Alliance, using 1995 emissions and meteorological data, indicates that acid deposition in several areas of central Alberta has reached the monitoring load and in one area exceeds the target load.[27] Ground-level ozone also reduces the productivity of agricultural crops and forests. Ground-level ozone is a major constituent of smog. The 1-hour and 24-hour guidelines for ground-level ozone are often exceeded in rural Alberta. Acid deposition, ozone and health concerns associated with regional and local air emissions, are dealt with in the submission by Dr. McDonald.

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[25] TransAlta Keephills EIA, Vol. 2, Section 5.2.9, Summary and Conclusions, p.5.2-45.

[26] Health Canada, Environment Canada, 1998. *National Ambient Air Quality Objectives for Particulate Matter, Part 1: Science Assessment Document.* A report by the CEPA/FPAC Working Group on Air Quality Objectives and Guidelines. Executive Summary.

[27] Cheng, L., V.K.K. Chung and D. Fox, 1999. *Model Assessment of Acid Deposition in Alberta,* January 24, 2001 presentation to Acidifying Emissions Management Implementation Team, Clean Air Strategic Alliance (CASA). See also *Application of Critical, Target, and Monitoring Loads for the Evaluation and Management of Acid Deposition,* CASA and Alberta Environment, 1999.

53. Mercury emissions are of concern due to their impact on wildlife and human health, especially as mercury is an acute neurotoxin. Coal-fired power plants are the main source of anthropogenic mercury in Western Canada and new Canada-Wide Standards are expected in 2002. This subject will be dealt with in detail in a companion submission.

54. There are no figures specific to Alberta, but a study in the European Union estimates that the cost of producing electricity from coal would double if the external costs such as damage to the environment and to health were taken into account.[28] These figures are supported by a recent U.S. study, that estimates the environmental and health costs of air emissions from coal-fired electricity generation at 3 to 6.5 cents per kilowatt hour (kWh, converted to Canadian $).[29] This is approximately the same as the cost of generating electricity in Alberta, which is between 4 and 5 cents per kWh.[30] Based on these figures, the total cost of coal-fired electricity is between 7 and 11.5 cents per kWh. Even if one takes the lowest estimates, it is evident that if a company generating the electricity from a coal-fired power plant had to bear the associated external environmental and health costs, the economics of coal-fired generation would change substantively.

2.2 Air pollution in Alberta

55. Alberta has high emissions of SO_2 and NO_x compared with many other regions of Canada, as can be seen from the figures in Appendix 9.

56. Figures 2-1 and 2-2 show the historic emissions of SO_2 and NO_x in Alberta and the forecast. The forecast is based on the best estimates of a multi-stakeholder group of the Clean Air Strategic Alliance, but it does not include emissions from new coal-fired power plants, so probably underestimates total emissions.[31] Although SO_2 emissions are lower than in some earlier periods they are expected to increase again. Anticipated increases in emissions from power generation sources will represent a significant component of this increase. NO_x emissions have been climbing steadily. Minimizing emissions from the power generation sector to the fullest extent possible is critical to reducing the overall rate of increase in the province.

[28] European Commission, 2001. *New research reveals the real costs of electricity in Europe.* Media release, July 20, online at http://europa.eu.int/comm/research/press/2001/pr2007en.html. These costs do not include the cost of global warming. By comparison, the external costs of electricity production from gas are less than one-third those of coal.
[29] Jacobson, M.Z. and G.M. Masters, 2001. "Exploiting Wind versus Coal," *Science*, Vol. 293, August 24, 2001. U.S. dollars in article are converted to Canadian $ at 1.50 exchange rate. We assume the costs include effects of SOx, NOx, particulate matter and GHGs.
[30] See estimated costs in Appendix 6.
[31] Figures 2.1 and 2.2 are from a presentation to the NOx/SOx Abatement Workgroup of the Clean Air Strategic Alliance's Acidifying Emissions Management Implementation Team, May 22, 2001, entitled Acidifying Emissions in Alberta – Managing the Gap. The NOx/SOx workgroup provided their best estimates for the forecast.

Figure 2-1. Sulphur dioxide emissions in Alberta

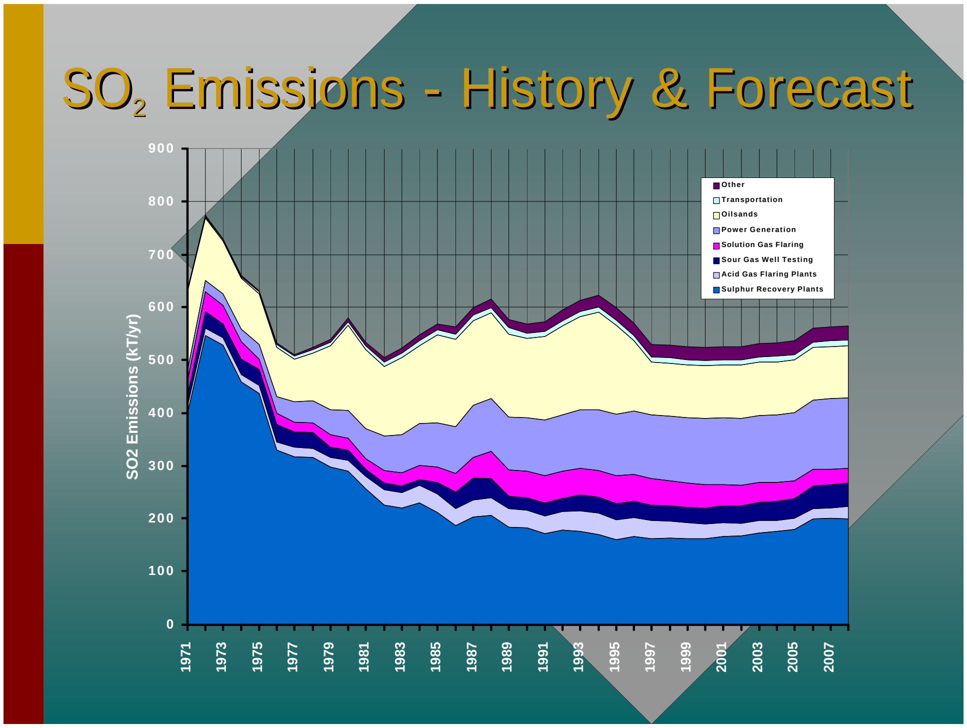
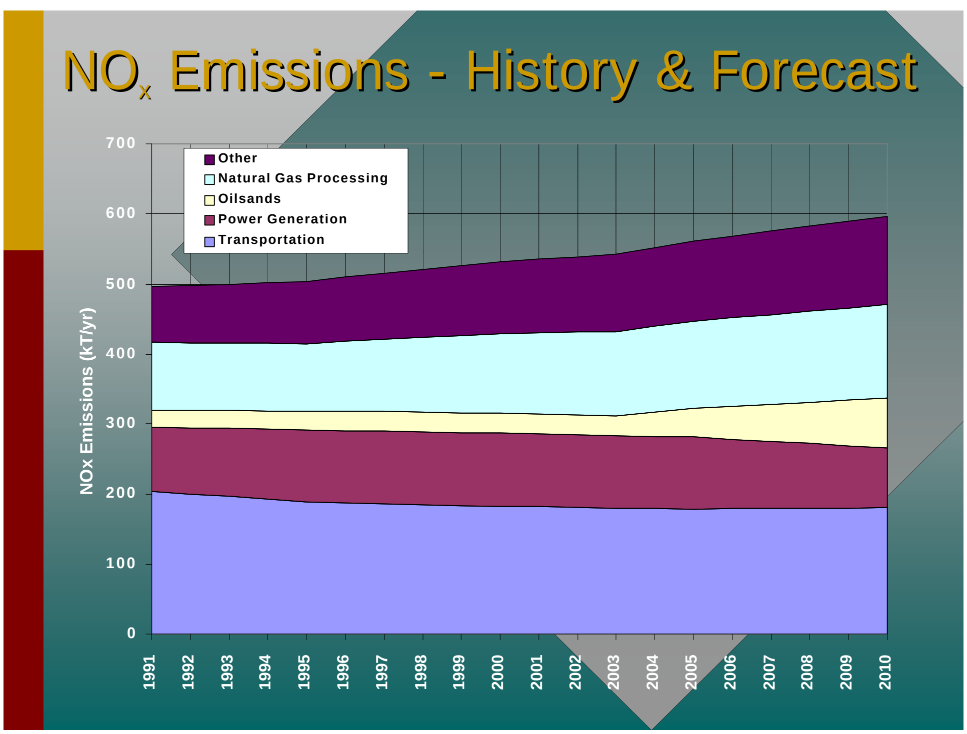


Figure 2-2. Nitrogen oxides emissions in Alberta



57. While the removal of sulphur from coal-fired power plants is not directly comparable with the removal of sulphur from gas plants, it is evident that sulphur removal requirements are much more stringent in the oil and gas sector than those required by the power generation industry. The upstream oil and gas industry currently recovers approximately 97% of its inlet sulphur (the actual percentage depending on the total daily intake of sulphur). Even the older sulphur recovery plants, that were "grandfathered" when the 1988 sulphur recovery guidelines were established are now on a regulatory track to upgrade their facilities to higher recovery standards. As well, the guidelines have been recently expanded to include refineries and heavy oil.

58. Although the new Alberta standards for coal plant emissions now require some sulphur recovery, if the new facility proceeds as proposed, little more than one-quarter of sulphur dioxide from the TransAlta's Keephills expansion will be recovered. TransAlta's Keephills expansion will emit approximately 33 tonnes of SO_2 per day, on average; the total Keephills plant will emit about 72 tonnes of SO_2 (equivalent to 36 tonnes sulphur). If the EUB oil and gas regulations were applied to the power generation industry, a facility with daily emissions of that amount of sulphur would be required to recover 96.2% of it. It is clear that the burden of sulphur recovery is not equitably distributed between industries and that coal-fired generators face a much less stringent regulatory requirement than the oil and gas sector.

59. Alberta has adopted the Canada-Wide Acid Rain Strategy for Post-2000, which means that the provincial government committed to a policy that will "Keep Clean Areas Clean." As part of that policy:

> *"Consistent with the CCME National Commitment on Pollution Prevention, jurisdictions will ensure, to the extent possible, that new sources of SO_2 and NO_x emissions in all parts of Canada use processes, practices, materials, products and energy that avoid or minimize creation of these pollutants."*[32]

60. The province has also subscribed to the policy of "Keeping Clean Areas Clean" under the Canada-Wide Standards for Particulate Matter and Ozone. This includes

> *"… ensuring that new facilities and activities incorporate the best available economically feasible technologies to reduce PM and ozone levels."*[33]

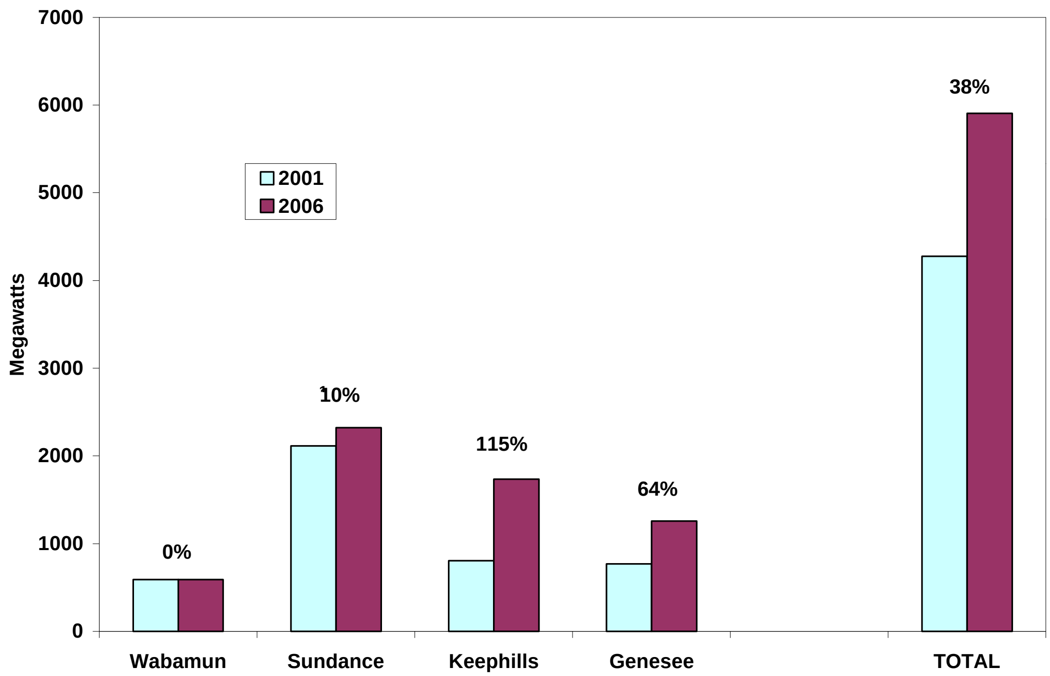
61. However, it seems that these policies are not being implemented with respect to new coal-fired power plants.

2.3 TransAlta's contribution to air pollution

62. If both the EPCOR GP3 project and the Keephills expansion are approved, the generating capacity in the region will increase by 38%, for in addition to the new plants, the Sundance upgrade will also increase capacity by 210 MW and the de-bottlenecking of the existing Keephills facility will add another 30 MW (see Figure 2-3). While not all emissions will increase proportionately, due to proposed modest improvements in emissions control at the new facilities, there will still be a significant increase in the total emissions of these substances into the area. There will also be an increase in mining activity that will further increase emissions.

[32] Canadian Council of Ministers of the Environment, 1999. *Annual Progress Report on the Canada-Wide Acid Rain Strategy for Post-2000*, p.4.
[33] Canadian Council of Ministers of the Environment, 2000. *Canada-Wide Standards for Particulate Matter and Ozone*, Annex A (b) Keeping Clean Areas Clean.

Figure 2-3. Potential increase in generation capacity from Wabamun, Sundance, Keephills and Genesee plants, 2001 and 2006

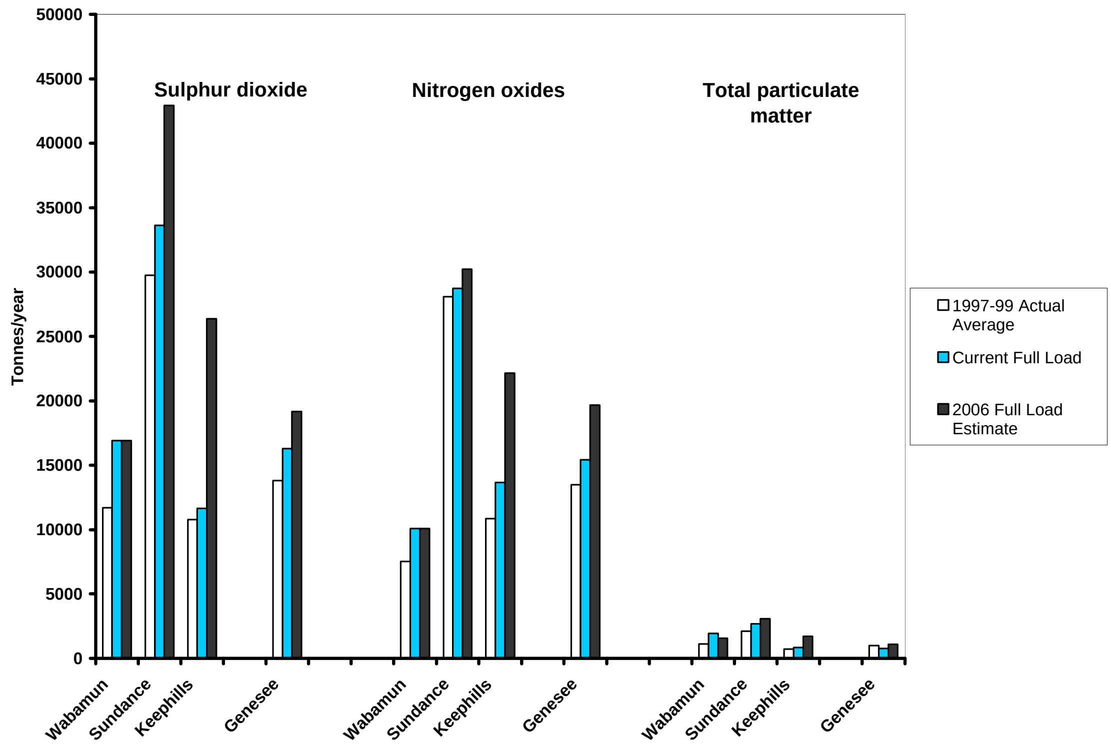


63. Figure 2-4 shows the total emissions in the region from the Wabamun, Sundance, Keephills and Genesee generating facilities. The data on which this figure is based are shown in Appendix 3. The figure shows the actual average annual emissions for the period 1997-1999 and the estimated current and future full load annual emissions (based on emissions of criteria pollutants as stated in the EIA). These emission values would be even higher if emissions of SO_2 and NO_x from the mine site were also included.

64. In the period 1997-1999 an average of 66,000 tonnes of SO_2 were emitted each year from the four facilities in the Wabamun-Genesee area.[34] Using data for criteria emission pollutants in the EIA, the average emissions in 2001 were 78,500 tonnes/year and this could increase by 34%, to nearly 105,400 tonnes a year in 2006 if all projects proceed. In addition to an increase in SO_2 emissions from the proposed Genesee and Keephills expansions, there will be a considerable increase in emissions from the Sundance Upgrade and from the de-bottlenecking of the existing Keephills facility. The 34% figure takes into account EPCOR's voluntary commitment to reduce SO_2 emissions to the equivalent of U.S. standards (of 78ng/J), without which the increase in SO_2 emissions would have been even higher.

[34] Figures derived from data supplied by Alberta Environment, October 2001.

Figure 2-4. Emissions from the Wabamun, Sundance, Keephills and Genesee plants: Actual 1997-1999 and Estimated, 2001 and 2006



65. The SO_2 emissions from Wabamun, Keephills, Sundance and Genesee account for about one half of all SO_2 emissions from the electricity generating section in Alberta (see Table 2-1; this table uses the most recent information readily available. Though not current, it is adequate for comparative purposes.) The increase in emissions from this area will increase SO_2 emissions from the electricity sector in Alberta by approximately one fifth compared with 1995 emissions.

Table 2-1. SO_x and NO_x emissions from Wabamun, Sundance, Keephills and Genesee plants, as % of provincial totals

	SO_X TONNES/ YEAR	SO_X %	NO_X TONNES/ YEAR	NO_X %
1995 Total provincial emissions[35]	608,100		653,319	
1995 Total provincial emissions from electric power generation[36]	130,471	21.5% of prov. total	90,734	13.9% of prov. total
Wabamun/Keephills/Sundance/ Genesee area average 1997-1999 (actual)[37]	66,053	50.6% of prov. total	59,919	66.0% of prov. total
Wabamun/Keephills/Sundance/ Genesee area expected increase 2001-2006[38]	26,866	21% of 1995 prov. electric power emissions	14,235	15.7% of 1995 prov. electric power emissions

66. Emissions of nitrogen oxides, that averaged nearly 60,000 tonnes per year in 1997-1999, are estimated at approximately 68,000 tonnes in 2001 (based on emissions of criteria pollutants as stated in the EIA) and will increase by about 21% between 2001 and 2006 if all projects proceed.[39] NO_x emissions in the four facilities in the Wabamun - Genesee area account for about two-thirds of all NO_x emissions from the electricity generating section in Alberta (see Table 2-1).

67. Total particulate matter will increase by 19% between 2001 and 2006 if all projects in the Wabamun/Keephills/Sundance/Genesee area proceed as planned (based on a comparison of present and future emissions of criteria pollutants), from under 6,300 tonnes in 2001 to almost 7500 tonnes in 2006.[40] This estimate of particulate matter volumes does not include the substantive volumes that are formed through "secondary" pathways from the precursor gases NO_x and SO_2.

68. TransAlta recognizes the need to reduce emissions from coal fired power plants, as is seen by their participation in the Canadian Clean Power Coalition. They have also made a commitment to upgrade technology to greatly reduce emissions from the Centralia coal-fired power plant in Washington State that they purchased in 2000. While TransAlta is receiving some financial assistance to achieve these reductions, the company has clearly indicated that the reduction of air emissions is a legitimate social and environmental concern. Yet TransAlta is not addressing these concerns in the current application in an adequate way. They do not propose to use best available demonstrated technology or to reduce emissions to the extent that is commercially feasible.

[35] Environment Canada, Criteria Air Contaminants Emission Summaries for Sulphur Oxides (SOx) and Nitrogen Oxides (NOx); online at http://www.ec.gc.ca/pdb/ape/cape_home_e.cfm
[36] Environment Canada, Criteria Air Contaminants Emission Summaries for Sulphur Oxides (SOx) and Nitrogen Oxides (NOx); online at http://www.ec.gc.ca/pdb/ape/cape_home_e.cfm
[37] Alberta Environment.
[38] Data from Appendix 3.
[39] Data from Appendix 3.
[40] Data from Appendix 3.

3 The Potential for Better Technology in the Keephills Expansion

3.1 Selection of coal combustion technology unsatisfactory

69. The proponent states that their corporate policy is to *"proactively advocate socially responsible laws and regulations."*[41] They also claim to *"Be an environmentally responsible neighbour in the communities in which the Company operates…."*[42] It would seem that one such responsible action would be to ensure that air emissions from their proposed plant will be as low as possible by using the best available control technology. Unfortunately, the configuration of technology proposed by the proponent is not representative of best available technology, nor does it even match the performance of the facility proposed by their competitor – EPCOR's Genesee 3 expansion.

70. If a coal plant is to be built, then the first action required is to select combustion technology that will generate the fewest possible emissions in the first place. Use of the highest possible combustion efficiency technology offers the direct benefit of lowering the emissions of greenhouse gases and other pollutants per unit of power produced. Subsequent decisions are then focused on selecting further "add-on" pollution control technologies to reduce the emissions leaving the stack.

71. TransAlta proposes to construct their facility using subcritical pulverized coal combustion technology. As shown in Appendix 6, this technology offers the lowest efficiency of all coal combustion technologies available. The proponent claims it will be able to operate its subcritical facility at the very aggressive efficiency rate of 37.9%.[43] How they will be able to operate at this level is unclear.

72. It is evident that higher efficiencies could be achieved if TransAlta selected any other type combustion technology. At the very least the proponent should be using a supercritical heat cycle system. In our view the use of a supercritical combustion process is now the minimum baseline standard for any new coal facility. The proposed EPCOR Genesee 3 unit will use supercritical technology and is expected to achieve 38.5% efficiency.[44] Even though the high ash content of the coal may make it difficult to get the high-end supercritical efficiency of 43% or more, the lower range of supercritical would still be an important improvement on TransAlta's proposal.

3.2 Reliance on Alberta emission standards inadequate

73. The Alberta standards should not be used as the basis for licensing a new coal-fired power plant. They do not provide a legitimate basis for determining the public interest for a number of reasons.

74. First, the Alberta government standards are weaker than other jurisdictions and are far below standards that could be achieved by "state of the art" or commercially proven technology. When the new standards were announced in June 2001 the Minister of Environment, Lorne Taylor stated that the new standards put Alberta on a par with other jurisdictions in North America.[45] In fact, as is shown in Table 3-1, U.S. standards for SO_2 and NO_x are more stringent than Alberta standards,

[41] TransAlta Keephills EIA, Vol. 1, section 3 Environmental Management, p.3-1.
[42] TransAlta Keephills EIA, Vol. 1, section 3 Environmental Management, p.3-1
[43] TransAlta Keephills EIA, Vol. 1, section 2.2.1 Detailed Plant Description, p. 2.12
[44] The Keephills expansion is expected to operate at 37.9% efficiency. EPCOR's Genesee Phase 3 supercritical plant is expected to operate at 38.5% efficiency, at the lower end of the range for supercritical operations.
[45] Government of Alberta, 2001. *Tougher Emission Standards Set for New Coal-fired Power Plants.* News release, June 15, 2001.

while the standard for particulate matter is the same.[46] Standards in B.C. are more stringent than Alberta's for SO_2 and particulate matter. The U.S. emission limits given for the U.S. in Table 3-1 (and in Appendix 5) are the U.S. New Source Performance Standards. In fact, these federal New Source Performance Standards are the least stringent standard for new U.S. coal-fired power plants. Specific emission limits are set in each plant permit and these are often more stringent (as can be seen for the individual plants in the U.S. in Appendix 5). Each state is required to have a State Implementation Plan in which they indicate how they will comply with the federal Clean Air Act. The state and U.S. Environmental Protection Agency identify areas that fail to meet the Clean Air Act standards. In these "non-attainment" areas a company is required to use technology that achieves the Lowest Achievable Emission Rates (LAER). New sources elsewhere (in "attainment" areas) are required to comply with the "Prevention of Significant Deterioration" policy and use Best Available Control Technology (BACT). Examples of permitted emission levels for some new plants in the U.S. are given in Appendix 5, to show what can be achieved. Even in clean areas, the permit standards are often stricter than the basic New Source Performance Standards. This approach ensures that emission standards can be raised as technology improves.[47]

Table 3-1. Emission standards for new coal-fired power plants

	Particulate matter	Sulphur dioxide	Nitrogen oxides
Alberta (new)	13	180	125
US EPA	13	70% - 90%removal[48]	65
British Columbia	10	90	150
Germany	18	140 or 85% removal	70
The Netherlands	7	70	70
United Kingdom	9	70-105	21-95

75. Secondly, there was no scientific basis for the new Alberta standards set and the standards do not relate to the government's commitment to policies set by the Canadian Council of Ministers of the Environment to "keep areas clean" (see section 2.2 above). The Alberta Ambient Air Quality Guidelines state that Alberta's Air Quality Management System *"is designed to ensure that emissions are minimized through the use of Best Available Demonstrated Technology (BADT) …"*[49] This was not done when the standards were set. However, the government can still require

[46] As indicated during cross-examination by the Clean Energy Coalition at the Alberta and Energy Utilities Board hearing into the EPCOR Genesee 3 application, the Alberta Environment summary entitled "Emission Guidelines for New Power Plants", incorrectly stated the U.S. emission standards for nitrogen oxide. All plants built after 1997 are required to meet a higher standard. The U.S. standard is 200 ng/J gross energy output, which converts to 65 ng/J heat input for a plant with 32.5% efficiency.
[47] US Environmental Protection Agency. *Explaining the RACT/BACT/LAER Clearinghouse*, online at www.epa.gov/ttn/catc/rblc/htm/rbxplain.html and personal communication with Natural Resources Defense Council.
[48] The U.S. has a complex standard, requiring 70% - 90% removal of sulphur depending on sulphur level of the coal, with 260 ng/J maximum. For coal used at GP3, a 70% reduction in SO_2 would be required, resulting in a standard of about 70 ng/J.
[49] Alberta Environment, February 2000, *Alberta Ambient Air Quality Guidelines.* http://www.gov.ab.ca/env/protenf/approvals/factsheets/airqualt.html

the proponent to meet emission standards that can be achieved using BADT by specifying more stringent standards in the approval, as is done in the U.S.

76. Thirdly, although the provincial government consulted with industry about the new Alberta standards for coal-fired power plants, there was no opportunity for public input. By promising public input into the new standards that are to be set in 2005, the government is clearly recognizing the right of the public to participate in the setting of such standards. However, that process will be too late to set standards for the emissions for plants that are currently proceeding with applications. In a response to a letter from the Pembina Institute concerning discussions between TransAlta and the government pertaining to the proposed Keephills expansion, Alberta standards and other issues, Minister of Energy Murray Smith stated: "The appropriate time for public input to be provided is at an Energy and Utilities Board (EUB) hearing."[50] The public have been offered a "Catch 22": they were not provided the opportunity to give input to the current standards, and are advised to provide input at a hearing; but in a hearing, the standards are then portrayed as law.

77. EPCOR has made a voluntary commitment to reduce SO_2 to meet the U.S. New Source Performance Standards. This is a clear indication that the current standards are inadequate and not consistent with BADT.

78. It is for the above reasons that we consider the current emission standards to lack legitimacy and are not to be relied upon as a basis for determining the approval of a plant.

79. Even the proponent recognizes that more stringent standards are likely to be required in the future. It is pointed out in the EIA that *"The long-term control scenario could require reduction of NO_x emissions to 64 ng/J (0.15 lb/MMBtu). In addition, reduction of SO_2 emissions by 70% and mercury emissions by 50% from current stack levels could also be required."*[51] Meeting these levels for NO_x and SO_2, which are the equivalent of the U.S. New Source Performance Standards should be the minimum requirement. There is no need to wait for the "long term"; reaching these emission standards is achievable and should be required now. As is shown in Appendix 5, new U.S. plants can be required to achieve much lower emission levels.

3.3 TransAlta could readily achieve significantly lower emissions

80. Having discussed the standards, we now outline the technology the proponent should be expected to use to achieve more appropriate emission levels. The key opportunities for TransAlta to use best available demonstrated pollution control technologies lie with controlling emissions of SO_2, NO_x and PM.

3.3.1 Sulphur dioxide

81. TransAlta only plans to reduce SO_2 emissions by about 26%, aiming at an emission of 168 ng/J, just below the Alberta standard of 180 ng/J. The U.S. standard for SO_2 is more stringent than Alberta's, with the U.S. New Source Performance Standard requiring 70% removal of sulphur for low-sulphur coals such as those mined for the Keephills facility. This would require emissions of less than 80 ng/J for the Keephills coals, or less than half the Alberta standard. This does not require different technology. These lower emission levels can be achieved using the lime spray dryer technology, which has been proposed by TransAlta, but a different scale of operation would

[50] Letter from Tom Marr-Laing, Pembina Institute to Premier Klein, June 11, 2001 and response from Minister of Energy Murray Smith, July 30, 2001.
[51] Keephills EIA, Supplementary Information, Appendix B, p.6.

be required to reduce emissions to the lower U.S. level. Doing so is clearly economically and technically feasible in Alberta, as EPCOR has already made a voluntary commitment to reduce its SO_2 emissions to meet the U.S. New Source Performance Standard from its proposed Genesee 3 plant by reducing emissions to 78 ng/J.

82. A co-benefit of removing more sulphur is that the process also removes some mercury from the emissions.[52] This was pointed out by Environment Canada in their presentation to the EUB during the hearing on the EPCOR Genesee expansion project.

83. Starting on January 1, 2003, TransAlta's Centralia plant in Washington will be required to have SO_2 emissions that will be approximately half those the company is proposing for the new Keephills units.[53] The Centralia plant is an older plant where a sulphur desulphurization unit is now required to improve local air quality. It is also instructive to note that an expansion to the plant will use gas, not coal, as fuel.

3.3.2 Nitrogen oxides

84. TransAlta proposes to achieve NO_x emissions at about 90% of the Alberta standard (giving the plant emissions of about 112.5 ng/J). It is possible to greatly reduce NO_X emissions below the Alberta standards. As was indicated by Environment Canada at the EUB hearing into the proposed EPCOR Genesee expansion, NO_x emissions can be reduced to 50 – 70 ng/J through use of such technologies as selective catalytic reduction. In the U.S. the NO_x emission standard of 65 ng/J (for a plant with 32.5% efficiency) is nearly twice as stringent as the Alberta standard of 125 ng/J.[54] For the Keephills expansion, with a claim of 37.9% efficiency, the equivalent to the U.S. standard for NO_x emissions would be 75.8 ng/J. In 1998, low NO_x burners (LNB) alone were able to reduce NO_x emissions to about 85 ng/J.[55] If LNBs are now available that can achieve a U.S. EPA standard, the proponent should be required to install such technology. If LNB alone are not able to achieve the equivalent of US EPA standards, then the proponent should install LNBs and post combustion NO_x control. Lower emission levels can be achieved using an add-on process such as selective catalytic reduction (SCR).

85. SCR is a post-combustion "add-on" technology, to complement existing NO_x reduction through low NO_x burners. It uses a catalyst and a reductant (ammonia gas) to convert the NO_x to nitrogen gas water vapour. *"The technology has been employed throughout the world to reduce emissions generated by …. low-sulphur coal-fired utility power plants."*[56] While ammonia slip has occasionally been cited as a side-effect, this is not a problem at NO_x removal levels of below 80% and in many cases the measured slip has been below the 1 ppm detection limit. Thus, ammonia slip would not be a significant issue of concern for the proposed Keephills facility.

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[52] Environmental Working Group, Clean Air Network and Natural Resources Defense Council, "Mercury Falling: an Analysis of Mercury Pollution from Coal-Burning Power Plants," June, 2001, Washington DC, p.VI-6.

[53] The Centralia permit sets maximum emissions of 10,000 tons/yr (= approximately 9,072 metric tonnes) from the 1,340 MW plant. This is about 6.77 tonnes SO_2 per MW/yr. Expected maximum SO_2 from Keephills expansion is 12,264 tonnes/yr (see Appendix 3) from 900 MW, or 13.63 tonnes per MW/yr. This comparison is approximate, due to a possible difference in the capacity factor of the two plants.

[54] The U.S. figure of 200 ng/J for gross energy output must be converted to the Canadian equivalent in terms of heat input. For a plant with 37.9% efficiency, the equivalent number is 200 ng/J x 0.379 = 75.8 ng/J of heat input.

[55] Cohen, M. *Update on SCR Operation at the Birchwood Power Facility;* online at *www.fetc.doe.gov/publications/proceedings/98/98scr/98scr_toc.html*

[56] Southern Illinois University, Coal Research Center, "Post Combustion NO_x Control Technologies: Selective Catalytic Reduction Systems," http://www.siu.edu/~coalctr/postcomb.htm.

86. SCR should also help to reduce mercury emissions when placed upstream of a flue gas desulphurization unit. A SCR system oxidizes elemental mercury, which should increase the effectiveness of the desulphurisation unit in mercury removal.[57]

3.3.3 Particulate matter

87. The proponent should also be required to reduce particulate matter emissions to lower levels. According to the Application, the proponent puts estimated annual emissions of particulate matter at 90% of the Alberta standard of 13 ng/J, based on a 90% capacity factor (thus at approximately 11.7 ng/J). It should be noted that EPCOR intends to reduce total particulate matter to 8.6 ng/J for its Genesee 3 plant, which is considerably lower. EPCOR intends to achieve this through use of a baghouse. Since the proponent also intends to use a baghouse, they should be able to commit to attaining comparable emission levels, if they are using comparable technology.

3.3.4 TransAlta not using best available demonstrated technology

88. In its Environmental Impact Assessment, the proponent declares that mitigation of soil acidification will include "using BADT for emission minimization."[58] However, TransAlta then states its intention to use the technology that will meet Alberta standards that were announced on June 15, 2001 - which they refer to in the "Alberta Guidelines." If the proponent is permitted to construct a facility that only meets the Alberta Emission Standards for Coal-fired Power Plants, it is clear from Section 3.2 that the proposed project will NOT be using the best available demonstrated technology (BADT) and that an opportunity for substantive emission reductions – using proven, economically viable technologies – will have been lost.

89. The discussion in 3.3 outlines what changes should be made in order to move the proposed Keephills facility closer towards actually using best available demonstrated technology. The regulatory authorities should require TransAlta to use these superior technologies through provisions in an approval – if permission is granted to construct a facility. The Alberta Ambient Air Quality Guidelines expect the use of BADT, and this is best achieved by writing in conditions to the individual permit, as is done in the U.S.

[57] Environmental Working Group, Clean Air Network and Natural Resources Defense Council, "Mercury Falling: an Analysis of Mercury Pollution from Coal-Burning Power Plants," June 2001, Washington, DC, p.VI-8.
[58] TransAlta Keephills EIA, Vol. 2., section 7.2.3.5, p.7.2-42.

3.4 TransAlta can afford better pollution control technology

90. The proponent may argue that, while it may have good intentions, it cannot afford to install a higher level of pollution control technology than the bare minimum required to meet current Alberta emission standards and have the project remain economically viable. However, we would submit that TransAlta has much more financial flexibility than it is prepared to acknowledge.

91. TransAlta has established for itself the following corporate financial targets:[59]

- Annual earnings per share (EPS) growth of 15 per cent;
- 15 per cent return on equity (ROE);
- 50/50 debt to equity ratio;
- maintain strong credit rating (AA-);
- take advantage of global taxation and financing opportunities;
- annual capital expenditures averaging $1.5 billion for the next three years starting 2001; and
- reduce dividend payout ratio over time by maintaining the current $1 per year dividend and growing earnings.

92. The sum of these targets demonstrates an attempt by TransAlta to maintain its historical role as a safe, low-risk utility (with low debt to equity ratios and strong credit rating) while pursuing its new vision as an aggressively growing "pure play" generator (with high EPS and ROE and rapid capital expansion).

93. It is instructive to examine the strategies of TransAlta's power generation peers. These non-utility energy companies are also committed to aggressive growth but maintain investor quality debt while incorporating higher leverage into their capital structure. For example, the debt to equity ratio for AES is 83%, Calpine: 78% and NRG: 71%.[60]

94. The total cost of Keephills 3 and 4 is projected to be $1.8 billion. The company intends to raise half this money through external debt and the other 50% from internal financial resources (equity). The net income implications of selecting different debt to equity ratios are shown in Table 3-2. It is evident that by advancing a debt to equity ratio of 75/25, typical of the capital structure employed by the major competitors in TransAlta's peer group, TransAlta could free up an additional $47 - $85 million *per annum.* Such increased cash flow could readily pay for the additional costs of expanding the facility's flue gas desulphurization (FGD) and adding on a SCR facility[61] while continuing to offer TransAlta shareholders 15-18% rates of return for their investment.

[59] TransAlta website: www.transalta.com

[60] Values reported for 2000.

[61] Based on its research of pollution control technologies (see Appendix 6), the Pembina Institute estimates the total capital cost of expanding the Keephills FGD and adding on SCR would range from $100 to $200 million (adding approximately 5-10% to the cost of the project). Annual operating costs for these facilities are estimated at $5 million/year. Applying TransAlta's investment parameters to this increased capital cost would incur a total annual *before tax* cost of between $20-35 million/year. However, if a debt to equity ratio of 75/25 were used (at rates of 7%/15%), the incremental *before tax* annual cost of these add-ons could be as low as $16- $27 million/year.

Table 3-2. Comparison of alternative Debt/Equity financing options for the Keephills 3 & 4 project

TransAlta Proposal	%	Rate	Cost
Debt (after tax; tax rate: 36%)	50%	7%	40,320,000
Equity (after tax)	50%	15%	135,000,000
Income taxes (estimated)			75,937,500
Total Annual Cost of Capital			**251,257,500**
Option A	%	Rate	Cost
Debt (after tax; tax rate: 36%)	75%	7%	60,480,000
Equity (after tax)	25%	15%	67,500,000
Income taxes (estimated)			37,968,750
Total Annual Cost of Capital			**165,948,750**
Incremental Income (Annual)			**85,308,750**
Option B	%	Rate	Cost
Debt (after tax; tax rate: 36%)	75%	9%	77,760,000
Equity (after tax)	25%	15%	67,500,000
Income taxes (estimated)			37,968,750
Total Annual Debt Service Cost			183,228,750
Incremental Income (Annual)			**68,028,750**
Option C	%	Rate	Cost
Debt (after tax; tax rate: 36%)	75%	9%	77,760,000
Equity (after tax)	25%	18%	81,000,000
Income taxes (estimated)			45,562,500
Total Annual Debt Service Cost			**204,322,500**
Incremental Income (Annual)			**46,935,000**
Keephills 3&4 Capital Cost:			**1,800,000,000**

95. It is apparent that TransAlta is attempting to "have its cake and eat it too." In order to achieve all of its financial objectives it must keep the cost of its capital investments (in terms of $ per MWh) as low as possible. The only means by which this can be done is if TransAlta selects the cheapest possible combustion processes and minimizes use of pollution control technologies. This strategy is clearly in conflict with its stated commitment to "*ecologically sustainable economic development*" and "*superior environment, health and safety performance.*"

96. TransAlta's argument that the project cannot support any additional capital investment in environmental controls is hollow. By clinging to this argument, the company is attempting to use the artificial constraints that it has imposed upon itself through an inefficient capital structure as an excuse not to develop a project that employs the best available control technology. It is suspected that once it is successful in advancing the project, the company will move to restructure its finances in order to capture this value for shareholders while continuing to pass the cost of the environmental externalities onto society.

97. The analysis in Section 1 of this submission showed that future spot electricity prices in Alberta will continue to be set by the gas fired capacity for the majority of the hours regardless of whether new capacity additions are coal or gas fired. As such, prices paid by consumers will be similar whether new capacity additions are coal or gas fired.

98. If TransAlta is allowed to build its proposed Keephills project, society will be required to bear the cost of the environmental externality imposed by new coal fired generation but will not realize lower power prices in exchange.

99. TransAlta's shareholders may appreciate the low-risk/high reward benefits of ownership in the company. Albertans, however, will receive no unique benefits from the Keephills project and, if it proceeds, they will instead be burdened with the very real environmental and human health liabilities associated with pollution from such a facility.

4 The Need to Reduce Greenhouse Gas Emissions

4.1 Greenhouse gas emissions major environmental concern for Albertans

100. Greenhouse gas emissions (GHGs) are a major environmental concern because they are implicated as a causal factor in global climate change. It is now generally accepted that rising temperatures are strongly related to the emission of GHGs from human activities. The Intergovernmental Panel on Climate Change recently concluded that "There is new and stronger evidence that most of the warming observed over the last 50 years is attributable to human activities."[62]

101. Increases in GHG emissions have significant social, environmental, and economic implications for Alberta. Computer modeling of GHG-induced climate change across Western Canada demonstrates a range of negative effects – including increased incidences of forest fires, tree dieback, drought, and disease vectors. These climatic changes will have significant impact on our Boreal and Prairie ecosystems and could impair the economic viability of our agricultural and forestry industries.[63]

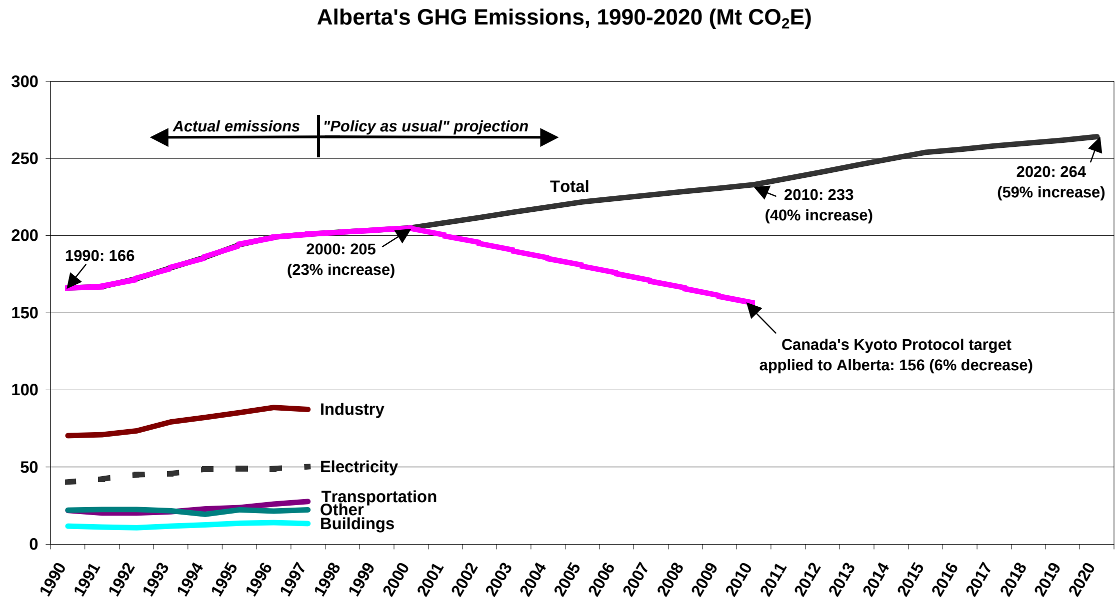
102. Our energy industries (oil, gas, fossil-fuel fired electricity) are also at significant economic risk. With the agreement reached in July 2001 in Bonn, Germany, the Canadian government has signaled its intent to ratify the Kyoto Protocol in 2002 – committing Canada to reduce its GHG emissions to 6% below 1990 levels by 2012. Although the mechanism for allocating responsibility for reducing emissions within Canada has yet to be determined, as the wealthy beneficiary of energy developments and leading contributor both to Canada's currently high per-capita GHG emissions as well as their future projected increase, Alberta is at risk of being tasked with a substantive share of this reduction requirement.

103. It is clearly in the interest of Alberta to keep GHG emissions as low as possible, to minimize future public liability for GHG emissions in this province. One estimate calculates that GHG offsets could cost the Alberta economy in the range of $600-million to $3.6-billion annually by 2010.[64]

104. The need to reduce greenhouse gas emissions in Alberta is evident from Figure 4-1. Electricity generation is responsible for approximately one quarter of total GHG emissions in the province**.** Coal-fired electricity generation creates not only more air pollution but also more GHG emissions per unit of power than any other form of large-scale power generation. In 1998, 29% of Canada's GHG emissions were emitted in Alberta, despite the province having only 9.6% of Canada's population.[65]

[62] Intergovernmental Panel on Climate Change, 2001. *Climate Change 2001, The Scientific Basis*, Summary for Policymakers, p.10.
[63] Environment Canada, 1999.The Canada Country Study, Volume III, Responding to Global Climate Change in the Prairies; online at http://www.ec.gc.ca/climate/ccs/prairie_summ.htm
[64] Climate Change Central (see Figure 2.2)
[65] Chia Ha, Greenhouse Gas Division, Pollution Data Branch, Environment Canada, personal communication; Statistics Canada for population data.

Figure 4-1. Alberta's greenhouse gas emissions[66]



105. Since Figure 4-1 was created, Alberta's Climate Change Central has made further calculations, based on the increase in energy developments in the province. Their chart is shown in Figure 4-2.

106. Figure 4-2 shows Alberta's GHG emissions in 2010 exceed the 1990 level by about 65%. However, this figure could increase to 77% if the most recently announced oilsands projects are added.[67] As shown in Appendix 2, GHGs from electricity generation are expected to increase by 75% between 1990 and 2010 and will still account for one quarter of the province's GHG emissions.

107. These higher projections are based upon the assumption all announced energy projects go ahead. Whether they all proceed is uncertain, but it is clear that the trend is towards dramatically increased emissions. Furthermore, all of the economic public policy drivers being advanced in the province are to achieve, and even exceed, this level of economic output.

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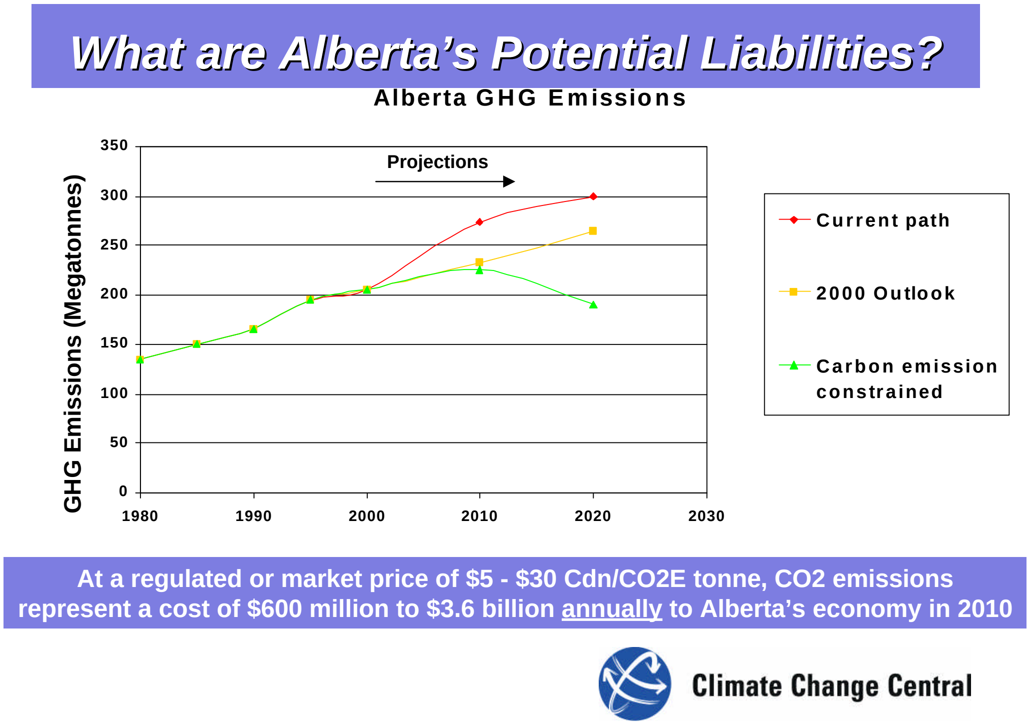
[66] Chart prepared by Matthew Bramley, Pembina Institute. Units are megatonnes of carbon dioxide equivalent (Mt CO_2E). Data sources as follows.
1990-97: F. Neitzert, K. Olsen and P. Collas (1999), Canada's greenhouse gas inventory:
1997 emissions and removals with trends, Environment Canada; and (for 1997 provincial data) Frank Neitzert, Greenhouse Gas Division, Pollution Data Branch, Environment Canada, personal communication, January 13, 1999.
2000-20: National Climate Change Process Analysis and Modeling Group (1999), Canada's Emissions Outlook, An Update. (This document projects emissions for every five years; we have interpolated for intervening years.)

[67] Update of Climate Change Central figures, carried out by Pembina Institute. The updated figures are provided in Appendix 2.

Figure 4-2. Alberta's greenhouse gas emissions - updated



GHG Emissions (Megatonnes)	1990	2000	2010	2020
Current path	166	205	272	307
Emissions outlook	166	205	233	264
Carbon Constrained	166	205	190	160

This projection:

a) includes all current publicly announced oilsands and electricity projects, and

b) does not include any increase in emissions associated with population or economic growth in the residential, commercial and transportation sectors.[68]

108. In the absence of any other regulatory mechanisms to control GHG emissions, the Alberta Energy and Utilities Board is the *de facto* regulator of GHGs from energy sources in Alberta. Any decision by the Board to allow a new facility is also a decision to permit additional emissions of GHGs, at the future expense of other developments in the province or elsewhere in Canada.

[68] Figure 4-2 is from a presentation by Climate Change Central to the Clean Air Strategic Alliance Flaring and Venting Project Team, August 2001.

4.2 What TransAlta proposes for management of its greenhouse gas emissions

109. TransAlta has proposed to offset GHGs from Keephills to the equivalent of a natural gas combined cycle (NGCC) plant. However, there will still be a large net increase in GHGs as a result of the project (6.5 Mt gross; 2.4 Mt net). Simply building a gas-fired facility rather than coal-fired would achieve the same net result – without needing to consume a portion of GHG-offsets that will become increasingly important to Alberta's economy in the near future. Its far better to avoid creating GHGs in the first place, to both keep our GHG management burden as low as possible and to reserve as many offsets as possible for helping us reach our Kyoto target.

110. Furthermore, offsetting to a NGCC level is clearly inadequate. If Alberta is to come anywhere near Canada's target of reducing GHG emissions to 6% below 1990 levels then GHG emissions from any new source, including the proposed Keephills plant will need to be FULLY offset.

111. In "Beyond Kyoto: TransAlta's Blueprint for Sustainable Thermal Power Generation," the proponent proposes a plan in which new thermal power generation facilities *"would be fully offset to ensure that the cost of GHG emissions is reflected in the market price of electricity. This will make it easier for renewables to compete in the market."* It is unfortunate that the company is not willing to set an example and implement this policy for the current project.

112. It is evident that the proponent does not yet know through what specific measures the 4.1 million CO_2E tonnes/yr reduction to partially offset the Keephills expansion will be achieved. Since accounting will be done on a corporate basis, the third-party auditor will need to verify that there are sufficient emission reductions directly associated with the Keephills project.

113. The Pembina Institute has concerns about some of TransAlta's existing offsets (p.3-13)[69]. TransAlta makes bold claims about the "high quality" (p. 3-17) of its existing offset program, claiming, for example, that it "has been recognized by leading environmental NGOs as being world class" (p. 3-16). They fail to identify the NGOs. (Likewise, who are the NGOs invoked, but not named on p. 3-19?) The Pembina Institute, in an evaluation of TransAlta's performance on climate change published in 2000,[70] criticized the lack of information provided publicly by TransAlta on baseline creation and ownership issues.

114. Notwithstanding TransAlta's claim (p. 3-16) that TransAlta's offsets will have "defined ownership", the following three examples indicate that ownership is not immediately evident.

(i) The ownership of emission reductions associated with TransAlta's renewable energy purchases under the Small Power Research and Development Act is unclear and multiple counting of these reductions has been identified. In addition, these purchases are required by law, so do not satisfy TransAlta's own criterion of *"surplus to current regulations."* (p. 3-19)

(ii) It is not clear whether TransAlta owns the emission reductions from ash sales or whether those reductions are being counted by the cement companies whose emissions are being reduced. While this may be arranged in a bilateral agreement, it is not transparent to the public.

[69] All page references in section 4.2 are to the TransAlta Keephills EIA, Vol. 1.
[70] Pembina Institute, 2000. *Corporate Action on Climate Change, An Independent Review Focusing on Canada's Electric and Natural Gas Utilities*; information about this publication is online at http://www.pembina.org/pubs/vcr98-2.htm

(iii) There appears to be a double counting problem with TransAlta's independent power projects. For example, if TransAlta establishes a natural gas power plant in Ontario that displaces coal-fired electricity in that province, presumably Ontario Power Generation's emissions will thus be reduced from what they would have otherwise been. We believe that Ontario Power and Gas is also claiming those reductions as its own.

The answers to the above points are not apparent to someone who is very experienced in reviewing Voluntary Challenge and Registry Reports.

115. To our knowledge TransAlta has not provided information to enable the public to understand how the quantified emission reductions from offsets claimed in its VCR submission and in the Centennial Project document were calculated. Indeed, TransAlta implicitly admits that to date it has not provided pertinent information to the public on its offsets portfolio (p. 3-20). It is therefore impossible to have any confidence about the quality of this portfolio. TransAlta claims that its *"offset program includes a comprehensive measurement, verification and registration program"* (p. 3-16) and that its future offsets will be subject to *"independent third party auditing of the projects and the program by competent bodies"* (p. 3-21). However, there is no indication whether there has been or will be an opportunity for scrutiny of the environmental integrity of the offsets by public interest organizations.

116. It is important to make a distinction between (i) independent third-party auditing and verification of offset projects and resulting emission reductions; and (ii) public interest input and scrutiny of the application of rules on the determination of baselines and the clear ownership of reductions. Regardless of the use or not of third-party verification, the stringency of such rules and their application is critical to ensuring the environmental integrity of the offsets, to ensure that they represent real emission reductions. TransAlta provides assurances on point (i) above, but not at all on point (ii). This omission is particularly acute given TransAlta's above-stated but unsubstantiated assertion that its program "has been recognized by leading environmental NGOs as being world class."

117. Specifically, the offset criteria outlined in table 3.2.1 (p. 3-19) do not inspire confidence that the offsets represent real emission reductions. No information is provided about what the baseline is intended to represent, its lifetime and how its profile over time is determined. If an emission reduction is to be real, the baseline must represent the best guess at what would have happened in the absence of any perceived or regulated constraints on greenhouse gas emissions. In other words, emission reductions must be truly "additional" to a business-as-usual scenario. (It should also be noted that table 3.2.1 is unclear. There are some rows in the middle of the table that do not correspond clearly to items in the left-most column.)

118. TransAlta commits to an itemized management program for its offsets (p. 3-21). A key element missing from this program is an assurance that public interest organizations will have input into, and scrutiny of the application of, baseline and ownership rules. While an audit can verify the bookkeeping process for offsets, it will not necessarily evaluate the validity of different types of offset credits. An independent review panel could determine whether the rules with respect to baselines, ownership, etc. are acceptable.

119. TransAlta states that one way it is reducing GHG emissions is through the use of advanced generation technology and increasing the efficiency of the operation compared with the existing Keephills facility. However, there are more efficient coal-burning technologies available. The company could have achieved a higher efficiency using a supercritical boiler system.

Alternatively, using coal in an integrated gasification combined cycle (IGCC) plant would give higher efficiency and lower GHG emissions compared to the proposed plant. In addition, an IGCC plant would make it easier to provide the potential to capture CO_2. Since an IGCC system may not have the necessary reliability at the current time, it would be better to delay a new coal-fired facility for a few years, to allow for the expected improvements to this technology (see Appendix 4).

120. The company mentions its work with the Canadian Clean Power Coalition (see p.3-15, section 3.2.9.7) to develop and operate a retrofit "clean coal" demonstration plant by 2007. More information on this project was provided in a recent conference paper, where it was explained that the project aims to control air emissions including CO_2[71] This is a commendable development, but it is unfortunate that TransAlta fails to make a commitment to reduce pollutants from its planned Keephills operation, since this could be achieved without any further research.

121. Although TransAlta claims that it is making *"significant investments in renewable energy"* (p.3-22) it is noteworthy that the $10-million they have spent in 2000-2001 is only 0.5% of the $1.8-billion that it will cost to construct the Keephills Centennial Project.

122. It is clear that there are significant problems with the credibility of the proponent's offer to offset some of the emissions from the proposed facility. If approval is granted to the proposed expansion, it should be conditional on TransAlta providing fully verifiable offsets for the facility's GHG emissions, including an annual report with sufficient information to provide assurance that such offsets are truly and meaningfully applied.

123. More fundamentally, it would be much more prudent for Albertans to pursue a path of simply avoiding creating these emissions in the first place. Such large increases in GHGs can be avoided while at the same time meeting our economy's demand for electricity by increasing the use of renewable energy, implementing energy efficiency measures and, as required, using fossil fuels such as natural gas that emit far fewer GHGs per unit of power.

[71] McDonald, M. and W.A. Campbell, 2001. *The Evaluation of Options for CO_2 Extractions from Existing and New Coal-fired Power Plants.* Paper presented at the Gasification Technologies 2001 Conference, San Francisco, Oct. 7-10. M. McDonald is Director, Research and Technology, TransAlta Corporation.

5 Recommendations

124. Considering environmental, social, and economic issues pertinent to TransAlta's proposed Keephills expansion, we submit that the public interest is best served by a) below; the least effective way is given in d).

a) Reject the current application, as demand for power can be met in the near future for the same or lower economic cost by adopting more energy-efficiency measures and using other, less polluting methods of generation.

b) Require the use of less polluting coal technology for generating electricity, such as the Integrated Gasification Combined Cycle process or another process with lower emissions. The proponent can decide at what point this or other technology becomes commercially viable.

c) Require the use of best available control technology (BACT) to reduce emissions from the proposed plant by as much as possible. Using BACT can reduce emissions to below U.S. New Source Performance Standards.

d) At the very least, require the proponent to meet the equivalent of New Source Performance Standards for coal-fired power plants in the United States, which are clearly achievable using the Best Available Demonstrated Technology (BADT) – a stated policy objective of the Alberta Government. This would include an adequately scaled flue gas desulphurization unit and use of low NOx burners/selective catalytic reduction to reduce SO_2 and NO_x to U.S. standards. The proponent should also be required to further reduce particulate matter, to a level comparable to that proposed by EPCOR for its Genesee 3 unit.

e) If recommendation b), c) or d) is adopted, the proponent should also be required to fully offset ALL greenhouse gas emissions from the new plant and to provide for independent third-party scrutiny of its offset program.

f) If the project is not immediately rejected, then any decision on the project should be postponed until the market power rules for post-2002 have been established.

Appendix 1. Renewable Energy and Energy Efficiency

A1.1 The potential for renewable energy and energy efficiency in Alberta

There is considerable potential to meet the demand for electricity without building a new coal fired power plant in Alberta at the present time. Demand can be reduced through energy efficiency measures. Electricity can be provided from renewable sources and by using natural gas, which is significantly less polluting than coal.

The Pembina Institute has identified a target energy efficiency savings of 800 MW of generation, or 10% of current demand, would be practicably achievable by year 2010.[72] This target was selected to match the Texas target of 10%, which is considered feasible in a state with relatively inexpensive energy.[73]

A further 800 MW of demand could be met by development of low-impact renewable energy such as wind and run-of-river hydro, according to Pembina Institute targets.[74]One study indicated that 1000 MW of wind power and 500 MW of biomass could be added by 2010.[75] This could be achieved through a low-impact renewable energy portfolio standard, net metering and a production incentive for low-impact renewable energy (until a GHG management plan recognizes the environmental benefit of renewable energy sources). At present less than 2% of Alberta's electricity supply is derived from low-impact renewably energy, including biomass wood waste plants, low-impact hydroelectric plants and wind generators. To meet the entire 800 MW capacity from wind power would require 1600 x 1.5 MW turbines, for which an area between 10 km by 10 km and 16 km by 16 km would be required.[76]

In addition, it has been estimated that the generation of electricity from flare gases that are currently burned could add at least an additional 400 MW to the Alberta grid.

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[72] Pembina Institute, 2001. *A Smart Electricity Policy for Alberta*, p.9 (see Appendix 7 of this document). The United Kingdom government has set a target of reducing demand by 30% through energy-efficiency measures.

[73] 800 MW is 10% of current capacity. Total consumption in 1999 was 60598 GWh, so 10% of demand is approximately 6000 GWh. At current rates of $0.11/kwh, the savings of 6,000 GWh of energy efficiency amount to $660-million per year.

[74] Pembina Institute, 2001. *A Smart Electricity Policy for Alberta* (see Appendix 7 of this document). This 10% target is consistent with the B.C. Hydro target of 10% of new electricity supply from renewable resources.

[75] MacRae, K.M., A. Kwaczek and A. Reinsch, 1996. *Repowering Alberta: Options for Electrical Generation Units: Economics and Emissions Impacts.* Canadian Energy Research Institute. This study showed a mix of generation, including hydro, wind, biomass and demand-side management, that would bring GHG emissions to 1990 levels by 2010 and cost no more for Alberta over 30 years than extending the life of coal-fired power plants. These measures also reduce SO_2 and NO_x emissions.

[76] It is assumed that each windmill has a capacity factor of 33%, so 2400 MW capacity is required to provide 800 MW of power. This requires 1600 x 1.5 MW turbines. At 10 to 15 turbines per sq km this would require 106 to 160 sq km or an area between 10 km and 12.6 km square. Even at the density of 6 turbines per sq km proposed by Jacobson and Masters this would require only 267 sq km, or an area 16 km by 16 km (see Jacobson, M.Z. and G.M. Masters, 2001. "Exploiting Wind versus Coal", *Science,* Vol. 293, August 24, 2001).

A1.2 Examples from the U.S.

It is instructive to examine how the U.S. attempts to reduce the impact of electricity generation on the environment. There is considerable potential to reduce demand through energy efficiency or to meet demand from renewable sources.

The potential is seen in California. It is reported that since the power shortage of 2000, demand has declined. Statewide consumption for the seven month period ending August 1,2001 was 6% lower than in the same period the previous year, when adjusted for weather.[77] Improved energy-efficiency standards have been set for new buildings and equipment and there is assistance for low-income households to enable them to benefit from improved energy efficiency. Alberta has not provided a comparable incentive to save energy and develop renewable sources. Indeed, the market signals to consumers were dampened or removed by the government's energy rebate policy implemented during Fall 2002.

Many U.S. states adopted measures that encourage energy efficiency and set renewable energy portfolio standards when they deregulated electricity supply.[78] For example, the Texas Restructuring Law, passed in 1999, requires utilities to administer energy efficiency programs to achieve savings equivalent to 10% of the annual load by 2004. The state also requires 2000 MW of new renewables by 2009.[79] In Oregon a "public purpose charge" equivalent to 3% of utility revenues, must be invested in energy efficiency and renewables. The Northeastern states are working to provide a reliable energy supply while reducing emissions through efficiency measures, use of renewable energy and strict emission standards.[80] The value of developing renewable energy technologies and improving energy efficiency were recently recognized as important elements in an effective energy policy by the Western Governors in the U.S.[81]

A federal Energy Department report, *Scenarios for a Clean Energy Future*, found that energy efficiency could reduce demand for power in the U.S. by 12% to 22% by 2020, compared with a "business as usual" scenario (depending on whether a "moderate" or "advanced" scenario is adopted).[82] Renewables could provide 13% to 18% of the supply by 2020 (with "moderate" and "advanced" scenarios, respectively). Carbon emissions would decline by up to 46%.

A recent study by Jacobson and Masters shows that wind energy is now competitive with coal.[83] The total cost of generating electricity with a large wind turbine farm (including manufacture and

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[77] Natural Resources Defense Council, 2001. *Energy Efficiency Leadership in Crisis: How California is Winning*; online at http://www.nrdc.org/air/energy/eeca/eecalinx.asp

[78] Pembina Institute, 2001. *A Smart Electricity Policy for Alberta*, p.7 (included as Appendix 7 of this document) and A. Pape, 1999. *The Role of Sustainable Electricity for Reducing GHG Emissions.* Thesis summary, available from the author through the Pembina Institute.

[79] American Council for an Energy-Efficient Economy, 2001. *Summary Table of Public Benefit Programs and Electric Utility Restructuring*; online at http://www.acee.org/briefs/mktabl.htm

[80] Northeast States for Coordinated Air Use Management, 2001. *Keeping the Lights on and the Air Clean.* Conference, July 2001; online at http://www.nescaum.org/committees/energy_conf.html

[81] Western Governors' Association, 2001. *Western States' Energy Policy Roadmap*, Policy Resolution adopted August 14; online at http://www.westgov.org/wga/policy/01/01_01.pdf

[82] Interlaboratory Working Group. 2000. *Scenarios for a Clean Energy Future* (Oak Ridge, TN: Oak Ridge National Laboratory and Berkeley, CA: Lawrence Berkeley National Laboratory), ORNL/CON-476 and LBNL-44029, November.

[83] Jacobson, M.Z. and G.M. Masters, 2001. "Exploiting Wind versus Coal", *Science*, Vol. 293, August 24, 2001. U.S. dollars in the article are converted to Canadian $ at 1.50 exchange rate.

decommissioning costs) is less than 6 cents (Canadian $) per kWh.[84] This is less than the cost of coal, when the health and environmental costs are included. According to calculations carried out by the Pembina Institute and shown in Appendix 6, the current cost of producing electricity from coal is between 4 and 5 cents per kWh. As stated in section 3.1, above, if environmental costs are included, the estimated total cost of electricity from coal is at least 7 cents, which is more expensive than using wind.[85] Jacobson and Masters estimate that the U.S. could displace 10% of coal energy at no net federal cost by investing in 36,000 to 40,000 large wind turbines and selling the electricity over 20 years, recouping all costs. At 6 turbines per square kilometre, they could be spread over an area of 80 x 80 km of farmland or ocean. An area equivalent to 16 km by 16 km would be sufficient to generate 800 MW in Alberta, which is considered a realistic target by the Pembina Institute.

[84] Even excluding the Wind Production Tax Credit (which is currently 1.7 cents U.S. per kWh) it is possible to build wind farms for less than 6 cents Canadian. Andrew Pape-Salmon, Pembina Institute, personal communication.
[85] Health and environmental costs are 3 to 6.5 cents/kWh. These figures are derived from values given by Jacobson and Masters (see above), converted to Canadian $.

Appendix 2. Greenhouse Gas Emissions

Changes to Alberta's CO_2 Emissions estimates based on recent energy sector announcements

The initial comparison of current emission projections and projections made in *Canada's Emission Outlook Update (1999)* was performed by Climate Change Central. It has been updated and amended by the Pembina Institute based on projections incorporating the most recent energy sector announcements. The revised figure shows an expected increase of 77% compared to 1990, if all projects proceed.

The following tables list oil sands and electricity projects that are ongoing or have been recently announced in Alberta.

1. Oil Sands

Oil Sands expansion to	**2010**
Suncor	425,000
Syncrude	670,000
Shell – Muskeg River (Aug. 2001 pr)	225000
SynEnCo Energy (press release Aug.23.00)	80,000
CNRL – Primrose/Wolf Lake - eia filing	120,000
Imperial – Cold Lake (pr Feb.20.01)	180,000
Truenorth- Fort Hills (pr Jan.11.01)	190,000
Japan Canada – Hangingstone (ongoing)	10,000
Gulf - Surmont	25,000
OptiCanada - LongLake	60,000
CNRL Horizon	300,000
Exxon/Mobil Kearl Lake	185,000
PanCanadian Christina Lake	85,000
PCOG MacKay River	30,000
PCOG Lewis	60,000
PCOG Meadowcreek	60,000
TOTAL bbl / day	**2,705,000**

Year		**Production**
1990		**350,000 bbl/day**
2010	Current estimate from above information	**2,705,000bbl/day**
2010	Canada's Emissions Outlook Update (Dec. '99)	**1,230,000 bbl/day**

Emissions Generation Assumptions

Oilsands

Emissions in 1990

= 350,000bbl/day x .13 t/bbbl x 365 days
= 17 Mt

- Syncrude's VCR report, October 2000, shows .138 t/bbl in 1989 and .126 in 1990

Emissions in 2010

= 2,705,000/day x **.0715** t/bbl x 365 days
= **70 Mt**

- allowing for a **45% (this is what industry is claiming)** decrease due to technology

→ Increase in CO_2 emissions between 1990-2010 is 53 Mt

2. Electricity[86]

ELECTRICITY (MW)	Coal	Nat. Gas / Cogen	Hydro	Other
Projected online 2002-2006				
Atco				
- Oldman (Energen)			32	
- Athabasca (Muskeg) (Shell)		172		
- Scotford (Shell)		150		
Glacier Power – Dunvegan			80	
TransCanada – Grand Prairie		80		
Confidential – Edmonton		30		
Calpine (Calgary energy centre)		250		
AES - Calgary		525		
Wind Power (Pincher Creek)				100
Imperial Oil (Cold Lake)		170		
Syncrude (Aurora)		238		
Epcor				
- Rossdale		170		
- Genesee	400			
Enmax/Fording - Brooks	400			
TransAlta				
- Sundance upgrades	160			
- Keephills	900			
Opti Canada (Fort McMurray)		400		
Altec Power (Fort Macleod)		40		
TOTAL - 2002-2006	**1860**	**2225**	**112**	**120**
Total online 2001	**50**	**515**		**103**
Estimated MW Total – 2001-2006	**1910**	**2740**	**112**	**223**

TOTAL 4985

2000 Production – 10,000 MW
online 2001-2006 - 4,985 MW

2010 Estimate Production – 14,985MW

[86] Source for all electricity numbers on this page: Alberta Energy – 'Key numbers on existing generation capacity and new generation – September 2001'

Annual Emissions due to power generation
(source: Canada's Emissions Outlook)
1990 = 40 Mt CO_2
2000 = 47 Mt CO_2
Technology
New efficient coal plants are not expected to be added in significant numbers until after 2010, gradually becoming economical as construction costs decline and gap between coal and natural gas prices widens. (EIA: Analysis of CC Technology Initiative, 2001)

Emissions Generation Assumptions

Electricity

CO_2 Emissions		***Plant Availability***
Coal	.9t/MWh	7000 hours / yr (80%)
Gas	.5t/MWh	8000 hours / yr (90%)

Increase Cogen/natural gas generation 2001-2010
= 2740 mW * .5 t/MWh * 8000 hrs
= 11 Mt
Increase Coal-fired generation 2001-2010
= 1910 mW * .9 t/MWh * 7000 hrs
= 12 Mt
Emissions in 2010 = 47 + 11 + 12 = 70 Mt
→ Increase in CO_2 emissions 1990 - 2010 is 30 Mt

3. Comparison

Figure 1 clearly shows a drastic increase in CO_2 emissions originating from electricity generation and oilsands development (30Mt and 53Mt respectively). Current projections for 2010 indicate that Alberta's total CO_2 emission will be 288Mt, up from 166Mt in 1990, with 25% of these emissions originating from electricity generation.

Figure 2 demonstrates a variety of scenarios facing Alberta in 2010. It is notable that in only two years, between the updating of *Canada's Emission Outlook* in 1999 and the Pembina Institute's update in 2001, the projected emissions in 2010 increased by 60Mt. The ***Canada Emissions Outlook***, updated in December 1999, indicated that Alberta would experience increases of 9 Mt from electricity generation and 15 Mt from oilsands projects to 2010 (**a 24Mt increase**). This brought their estimate of Alberta GHG emissions to 233 Mt in 2010 (from 166 Mt in 1990).

The **Current path,** based on the Pembina Institute's projections above, estimates increases of **30** Mt for electricity and **53** Mt for oilsands. This represents a total increase of **83** Mt vs the previously estimated **24** Mt (*Canada's Emission Outlook)* - a net change of **59** Mt which now takes the 2010 estimate for total GHG emissions in Alberta to **293** Mt.

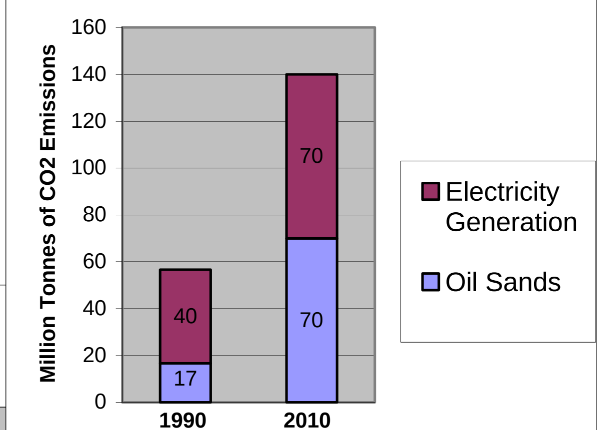

Figure 1: Change in CO2 Emissions between 1990 and 2010

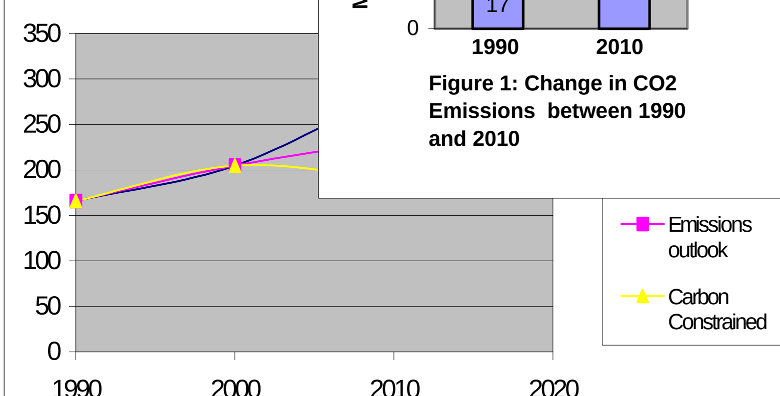

Figure 2: Alberta's emission outlook based on three different paths: 1) the projections of Canada's Emission Outlook (1999) 2) the current path as projected by the Pembina Institute and 3) projections for a carbon constrained economy

The **Carbon Constrained** line assumes substantial emission reductions.

Appendix 3. Stack Emissions

Stack Emissions from Wabamun, Sundance, Keephills and Genesee

in tonnes/year

	1997-99*	**Current**	**New**	**2006**	**%**	**Notes**
	Actual Averag	**Full Load**	**Capacity**	**Full Load**	**increase**	
		SO_2				
Wabamun	11706	16907		16907		No change in emissions
Sundance	29760	33638	Upgrade	42924		Upgrade: 4.9 t/hr x365x24 = 42924 t/y. EIA Appendix B, Table B 2.26
Keephills	10778	11651	14104			Units 1 and 2 debottlenecked - 1.61 t/hr x365x24 = 14104 t/y. EIA Vol 2, Table 5.2.11
			12264	26368		Centennial:1.40 t/h x 365x24 = 12264 t/y. EIA Vol 2, Table 5.2.11
Genesee	13809	16294	2864	19158		GP3: EPCOR commits to 78 ng/J = 0.327 t/h x365x24 = 2864 t/y at EUB hearing
Total SO_2	**66053**	**78490**		**105356**	**34**	
		NO_x				
Wabamun	7514	10074		10074		No change in emissions
Sundance	28071	28733	Upgrade	30222		Upgrade: 3.45 t/hr x325-24 = 32222 t/y. EIA Appendix B, Table B2.26
Keephills	10855	13666	8497	22163		Centennial: 0.97 t/h x365x24 = 8497 t/y. See EIA Vol 2, Table 5.2.11
Genesee	13479	15418	4249	19667		GP3: 0.485 t/h x 365 x24 = 4249 t/y. EPCOR GP3 EIA Supplementary Info. Table 10.3
Total NO_x	**59919**	**67890**		**82125**	**21**	
		Total PM				
Wabamun	1123	1953		1563		Approx. 20% decline in emissions due to planned improvements pre 2006
Sundance	2116	2681	Upgrade	3084		Upgrade: 0.306 t/h x365x24 = 3084 t/y. EIA Appendix B, Table B 2.26
Keephills	727	841	884	1725		Centennial: 0.101 t/h x 365x24 = 884 t/y. EIA Vol. 2, Table 5.2.11
Genesee	992	788	307	1095		GP3: 0.035 x365 x 24 = 307 t/y. EPCOR GP3 EIA Supplementary Info. Table 10.3
Total PM	**4958**	**6263**		**7467**	**19**	

*Source for 1997-1999 actual emissions data: Alberta Environment.

Appendix 4. Integrated Gasification Combined Cycle Generation

"One option of growing interest to coal-burning utilities is coal gasification."[87] The Integrated Gasification Combined Cycle (IGCC) process for generating electricity from coal is probably the most efficient and least polluting technology currently available. IGCC by no means presents zero emission coal technology (such technology is probably at least 15 – 20 years away), nor is it as clean as gas-fired electricity generation. However, it does release substantially fewer pollutants such as SO_2, NO_x and particulate matter than other coal technologies, and would certainly meet the current U.S. emission standards. Being more efficient, the IGCC process produces 15% fewer GHG emissions (see Appendix 6).[88] Not only does an IGCC plant produce fewer GHGs, it is the technology most suited for the capture of GHGs for carbon sequestration.

There are over 6000 MW of IGCC power generation projects that are currently in operation around the world and a further 5000 MW planned. Three of those plants in the U.S. use coal as the source fuel. The best U.S. demonstration project now achieves 85% reliability with their gasification unit and overall reliability of approximately 80%.[89]

IGCC technology has clear environmental benefits over super-critical pulverized coal combustion. More detail on these benefits is given here.

- The efficiency of IGCC is considerably better than any of the PCC options. IGCC plants are running with efficiencies of 45%, which translates into overall fewer pollutants per kW of energy produced.
- Sulphur and acid gas removal is more easily accomplished using amine absorption or other hot gas clean up processes that are part of the standard IGCC plant. IGCC can comfortably meet even the more stringent U.S. standards for SO_2.
- NO_x emissions are lower using relatively standard low NO_x burners in the gas turbines.[90] In fact, NO_x emissions from an IGCC plant are likely lower than a PCC power plant equipped with both LNB and SCR.
- No add-on pollution controls such as flue gas desulphurization (FGD), selective catalytic reduction (SCR) or baghouses are required with IGCC.
- Particulate emissions for the primary process are near zero.
- Solid wastes associated with the IGCC process are less than with conventional PCC and add-on pollution control devices such as FGD and SCR.
- Air-borne mercury emissions are much less than with PCC; there is little or no airborne mercury from an IGCC plant.
- CO_2 capture is more feasible with the IGCC process, whereas the cost of removing CO_2 from a PCC plant could be prohibitive.

[87] Armor, T., 2001. "Coal-fired Power Plants: Increasingly Lean and Green", *Power Engineering*, September; online at http://pe.pennnet.com/home.cfm

[88] Coal Association of Canada, 1990. *Canadian Clean Coal Demonstration Project: A Proposal for a Feasibility Study of an Integrated Gasification Combined Cycle Power Plant,* p.1-6, gives a figure of 15%.

[89] *Wabash River Energy Ltd., Project Update*: An Overview of the Past Year's Activities for the Wabash River Repowering Project, presented at the 2000 Gasification Technologies Conference, Richard Payonk, Global Energy Inc.; online at http://www.gasification.org/98GTC/Gtc00260.PDF

[90] Turbines supplied by General Electric for many of the IGCC plants around the world are routinely achieving <25 ppm NOx levels. See "Gas Turbine Improvements Enhance IGCC Viability," GE Power Systems, presented at the 2000 Gasification Technologies Conference, Douglas Todd, Manager Process Power Plants, GE Power Systems; online at http://www.gasification.org/98GTC/Gtc00190.pdf

The fact that there are very low or no airborne mercury emissions from an IGCC plant is an important consideration. The proponent has not provided details on how mercury emissions will be minimized from the proposed GP3 plant.

It was recognized over 10 years ago that IGCC offers a combination of advantages which no other coal based power generation system can match and *"Studies carried out in the U.S. and Canada have shown that IGCC technology will cost substantially less than alternative conventional plants when emissions are reduced to comparable levels*."[91]

Based on publicly available information, the Pembina Institute has estimated that the overall levelized costs of IGCC are within 10-20% of the most economical options available today.[92] The costs of producing electricity with IGCC are comparable to those of using natural gas at current prices ($3-$4 Can/GJ). Although IGCC may not initially be as economic as supercritical PCC, it is rapidly becoming economic especially if one looks at the potential future cost of greenhouse gas emissions. The capture of CO_2 could be especially valuable in Alberta, as was pointed out in a 1995 CANMET report. *"IGCC with partial CO_2 for enhanced oil recovery application appears to be economically feasible. This option should be seriously considered for IGCC plants near oil fields."*[93]

[91] Coal Association of Canada, 1990. *Canadian Clean Coal Demonstration Project: A Proposal for a Feasibility Study of an Integrated Gasification Combined Cycle Power Plant.*
[92] Pembina Institute, 2001, *TransAlta's Coal Plant Sub-Standard*. Media release, July 24. The full Appendix to the media release is given in Appendix 6.
[93] Canadian Centre for Mineral and Energy Technology (CANMET), Canadian Electrical Association and Alberta Office of Coal Research and Technology,1994. *IGCC Integration Assessment.* Prepared by Bechtel Canada Inc. and Nova Scotia Power Inc.

Appendix 5. Plant Emissions and Standards

Comparison between Keephills expansion and EPCOR GP3, new U.S. plants and standards in other countries

	Startup Date	Technology	Size	Total Particulates (ng/J)	Sulphur Dioxide (ng/J)	Nitrogen Oxides (ng/J)
Two Elk, Wyoming	Still in Engineering Phase	PCC	250 MW	8 -------------- (0.018 lb/MMBtu)[94]	66 -------------- (0.153 lb/MMBtu)	58 -------------- (0.135 lb/MMBtu)
Orlando Utilities, Stanton Energy Control Unit 2, Orlando FL	1997 (est.)	PCC, LNB, SCR, ESP,wet limestone FGD	430 MW 4,286 MMBtu/h	8.6 -------------- (0.02 lb/MMBtu)	107.5 -------------- (0.25 lb/MMBtu, 92% eff)	73.1 -------------- (0.17 lb/MMBtu, 70% eff)
Kansas City Power and Light, Hawthorn Station, Kansas City Missouri	May 2001	PC Tangentially Fired, SCR, dry FGD & low S coal, fabric filter	550 MW (384 tons/h)[95]	7.7 -------------- (0.018 lb/MMBtu)	51.6 -------------- (0.12 lb/MMBtu)	34.4 -------------- (0.08 lb/MMBtu, 70% eff)
SEI Birchwood Inc, Virginia	Permit issued in 1993	PC, Baghouse, FGD dry limespray drying, SCR	220 MW 2,200 MMBtu/h	TSP: 8.6 PM: 7.7 -------------- (TSP: 44 lb/hr, 99.9% eff PM10: 39.6 lb/hr, 99.9% eff)	43.0 -------------- (220 lb/hr, 94% eff)	43.0[96] -------------- (0.10 lb/MMBtu)
Kentucky Mountain Power, Knott County, Kentucky	Permit issued May, 2001	CFB, natural integrated desulphurization system, SNCR and baghouse	500 MW	6.4 ------------ (0.015 lbs/MMBtu)	55.9 -------------- (0.13 lbs/MMBtu)	34.4 ------------- (0.08 lbs/MMBtu)
Thoroughbred Generating Station, Mulenberg Cty, Kentucky,	Permit in preparation (expected limits shown)	PCC FGD, LNB, SCR, baghouse	1500 MW	8.1 ----------- (0.019 lbs/MMBtu)	71.8 ----------- (0.167 lbs/MMBtu)	38.7 ---------- (0.09 lbs/MMBtu)
EPCOR Genesee 3	2005	Super PCC, LNB, baghouse, dry limespray FGD. No SCR	450 MW	8.6	78 (voluntary commitment)	115
TransAlta Keephills expansion	2005	Subcritical PCC, LNB, baghouse, FGD, No SCR.	900 MW	11.7[97]	168[98]	112.5[99]

[94] Original units in parenthesis from US EPA Technology Transfer Network, Clean Air Technology Center, RBLC Technology Data Base Search; http://www.epa.gov/ttncatc1/rblc/htm/welcome.html , except for Kentucky plants, where information supplied by Division of Air Quality, Kentucky Dept. for Environmental Protection and Wyoming plant where information supplied by Air Quality division, Dept. of Environmental Quality, Wyoming.
Conversion as follows: 1 lb/MMBtu x 0.4536 kg/lb x 10^{-6} MMBtu/btu / 1055 J/Btu x 10^{12} ng/kg = 430ng/J.
[95] From Kansas City Power & Light Press Release June 30, 2000; online at http://www.kcpl.com/news/2000/NR6_30.htm. 2000 Annual report shows 440 MW.
[96] Ammonia slip is limited to 6.1 lb/hr. See reference in first footnote on this page.
[97] Emission rate based on 90% capacity factor. Derived from Keephills EIA, Volume 2, Table 5.2.11.
[98] Figure provided by TransAlta, personal communication.
[99] Emission rate based on 90% capacity factor. Derived from Keephills EIA, Volume 2, Table 5.2.11.

Standards						
				Total Particulates (ng/J)	**Sulphur Dioxide (ng/J)**	**Nitrogen Oxides (ng/J)**
Alberta (new)				13	180	125
US EPA				13	70% - 90% removal[100]	65
British Columbia				10	90	150
Germany				18	140 or 85% removal	70
The Netherlands				7	70	70
United Kingdom				9	70-105	21-95

Abbreviations used in the above table are explained in the endnotes following Table 6.

[100] The U.S. has a complex standard, requiring 70% - 90% removal of sulphur depending on sulphur level of the coal, with 260 ng/J maximum. For coal used at GP3, a 70% reduction in SO_2 would be required, resulting in a standard of about 70 ng/J.

Appendix 6. Comparison of Coal Combustion Options

The following table compares coal combustion technologies. It summarizes the characteristics of the various coal-fired generating technologies and compares them with cleaner burning natural gas systems. Footnotes and a glossary of abbreviations appear immediately following the table. All dollars are Canadian currency unless otherwise noted.

Base Processes	**Subcritical Pulverized Coal Combustion (PCC)**	**Supercritical PCC**	**Atmospheric Fluidized Bed Combustion (AFBC)**	**Pressurized Fluidized Bed Combustion (PFBC)**	**Integrated Gasification Combined Cycle (IGCC)**	**Natural Gas Combined Cycle (NGCC)**	**Natural Gas Combined Heat and Power Cycle**
Environmental Performance [1]							
Plant Efficiency [2]	33%	38-43%	36%	42% [3]	45%	52%	~60%
Heat Rate (GJ/MWh)	10.9	9.5-8.4	10	8.6	8.0	6.9	6.0 per equiv. MWh
CO_2 (kg/MWh) [2]	1000	870-770	920	790	735	400	350
Sulphur Removal Standard	Alberta: 180 ng/J U.S.: 260 ng/J, 70-90% removal and BACT [4]						
SO_2 (kg/MWh) – no FGD	1.6 [5]	1.4 [6]	0.3 [7]	0.12 [3]	~ zero	~ zero	~ zero
SO_2 (ng/J) – no FGD	229	221	30 [8]	14	~ zero	~ zero	~ zero
S02 (ng/J) – with FGD	< 70	< 66	Not required	Not required	Not required	Not required	Not required
NO_x Removal Standard	Alberta: 125 ng/J U.S.: 65 ng/J						
NO_x (kg/MWh) – no SCR	2.1 [2]	1.8 [6]	0.5 [7, 8]	<0.7	0.25-0.45 [9] (w/ LNB)	0.12 (w/ LNB)	0.12 (w/ LNB)
NO_x (ng/J) – no SCR and w/ LNB	86-125 [5]	86-125 [5]	43	<86 [3]	31-56	18 [10]	18 [10]
NO_x (ng/J) – with SCR and LNB	43-62	43-62	SCR not required	SCR probably not required	SCR probably not required	SCR probably not required	SCR probably not required
Particulate Matter Standard	Alberta: 13 ng/J U.S.: 13 ng/J						
PM (kg/MWh) – no ESP/Baghouse	0.5	0.4 [6]	~0.4	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
PM (ng/J) – no ESP/Baghouse	46	42	~42	Better than PCC but not as good as IGCC	~ zero	~ zero	~ zero
Mercury	Depends on coal source	Depends on coal source	Depends on coal source	Better than PCC but not as good as IGCC	Little or no air borne mercury	Little or no air borne mercury	Little or no air borne mercury

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Pollution Control Add-ons							
Flue Gas Desulphurization (FGD)	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[11]	FGD required to meet most standards. Wet FGD can achieve >95% recovery, dry can achieve up to 70-80%.[11]	Not required	Not required	Not required	Not required	Not required
NO_x Control: Low NO_x Burners (LNB)	LNB can reduce approx. 50% NOx formation.	LNB can reduce approx. 50% NO_x formation.	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.	Std equipment. Can achieve single digit ppm (better than 90%) NO_x in flue gas with LNB.
NO_x Control Selective Catalytic Reduction (SCR)	80% NO_x removal without ammonia slip problems. [12]	80% NO_x removal without ammonia slip problems. [12]	May not be required due to low combustion temperature.	May not be required due to low combustion temperature and LNB on turbine.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.	May not be required where LNBs are available to reduce NO_x by at least 90%.
	Note: Typically **both** LNB and SCR required in PCC plants to meet most standards.						
Baghouse or ESP	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Requires bag house or ESP. Baghouse more efficient and less prone to upsets.	Not Required	Not Required	Not Required
Mercury[13]	With baghouse and FGD 60- 70% removal. ESPs not as effective.	With baghouse and FGD 60-70% removal. ESPs not as effective.	With baghouse up to 70% removal.	With baghouse up to 70% removal.	Not Required	Not Required	Not Required
CO_2 Capture	From flue gas, difficult to recover.	From flue gas, difficult to recover.	From flue gas, difficult to recover.	Recovery should be similar to IGCC.	Relative to other options, recovery is more straightforward from off-gas. [14]	From flue gas, difficult to recover.	From flue gas, difficult to recover.

Base Processes	**Subcritical Pulverized Coal Combustion (PCC)**	**Supercritical PCC**	**Atmospheric Fluidized Bed Combustion (AFBC)**	**Pressurized Fluidized Bed Combustion (PFBC)**	**Integrated Gasification Combined Cycle (IGCC)**	**Natural Gas Combined Cycle (NGCC)**	**Natural Gas Combined Heat and Power Cycle**
Operational Performance							
Currently in use at:	Genesee 1& 2, Keephills, Wabamun. Many plants worldwide.	Europe, Japan, U.S. Many plants worldwide. (proposed for Genesee 3)	Pt. Aconi, NS uses Circulating Fluidized Bed (185 MW plant), first one in Canada 1993. [7] Japan, Europe. Commonly used with high sulphur coal.	Sweden, Spain, U.S., 350 MW plant under construction in Japan. [15] Commonly used with high sulphur coal.	General coal gasification well proven. IGCC used at three U.S. plants (Polk, Wabash,[16] Pinon Pine) and in The Netherlands and Spain.	Many plants worldwide.	Many plants worldwide.
Commercially Proven	Yes	Yes	Yes	Yes	Yes	Yes	Yes
Scale	100-1000 MW	100-1000 MW	400 MW guaranteed by manufacturer. [8]	80 MW	100-300 MW	Any size in modular units	Any size in modular units
Reliability and Uptime	Good	Good	Good	Good	Good [16]	Good	Good
Economic Performance [17]							
Capital Cost – main process ($/kW)	$**1200**-1500 [15] $1283 [18] $1200 [19]	$**1275**-1575 [15] $1322 [18] $1200 [19]	$**1500**-1950 [15] $1324 [18]	$**1725**-2025 [15] $1429 [18]	$**1800**-2100 [15] $1798 [18] $1800 [20]	**$1,000**	**$940** [21]
Capital Cost – add-ons ($/kW)							
FGD	$**105**-180 [15] $158-236 [22]	$**105**-180 [15] $158-236 [22]	N/R	N/R	N/R	N/R	N/R
SCR [15]	$**60**-120	$**60**-120	N/R	N/R	N/R	N/R	N/R
LNB [15]	$**7.5**-15	$**7.5**-15	$**7.5**-15	$**7.5**-15	Std.	Std.	Std.
Total Capital Cost ($/kW)	**1373**	**1448**	**1508**	**1733**	**1800**	**1000**	**940**
(Sum of bold numbers above used in total capital cost)							
Return (%)	15%	15%	15%	15%	15%	15%	15%
Life (yrs)	35	35	35	35	35	35	35
Total Capital Cost ($/MWh)	23.68	24.97	26.01	29.89	31.06-34.94	17.25	16.22
(Note: No Tax, No Depreciation)							
Operating Cost ($/MWh)							
Labour [23]	2.08	2.08	2.32	2.77	2.77-3.12	2.08	2.08
Other (100% of labour)	2.08	2.08	2.32	2.77	2.77-3.12	1.63	2.08
Energy (GJ/MWh)	10.9	9.5	10	8.6	8.0	6.9	6
$/GJ [17,24,25]	**1.18**	**1.18**	**1.18**	**1.18**	**1.18**	**4.00**	**4.00**
Energy Cost ($/MWh)	12.86	11.21	11.80	10.15	9.44	27.60	24.00
Operating Cost – add ons ($/MWh)							
FGD [22]	2.6	2.6					
Total Operating ($/MWh)	19.62	17.97	16.44	15.69	14.98 - 15.67	31.31	28.16
Overall levelized cost to produce electricity ($/MWh)	**43.30**	**42.94**	**42.45**	**45.58**	**46.04-50.61**[26]	**48.56**	**44.38**

Base Processes	Subcritical Pulverized Coal Combustion (PCC)	Supercritical PCC	Atmospheric Fluidized Bed Combustion (AFBC)	Pressurized Fluidized Bed Combustion (PFBC)	Integrated Gasification Combined Cycle (IGCC)	Natural Gas Combined Cycle (NGCC)	Natural Gas Combined Heat and Power Cycle
Rank (1=Best, 7=Worst)							
Efficiency/GHG Ranking	7	5	6	4	3	2	1
Sulphur Removal Ranking	7	6	5	4	3	2	1
NO_x Control Ranking	7	6	4	5	3	2	1
PM Emission Ranking	7	6	5	4	3	2	1
Mercury Emission Ranking	7	6	5	4	3	2	1
CO_2 Sequestration Ranking	More Difficult	More Difficult	More Difficult	Less Difficult	Less Difficult	More Difficult	More Difficult
Capital Cost Ranking	3	4	5	6	7	2	1
Operating Cost Ranking	5	4	3	2	1	7	6
Overall Cost to Produce Ranking	3	2	1	4	6	7	5

Table Footnotes

[1] Environmental performance characteristics described are at the plant site only. These values do not consider any "upstream" impacts, such as from coal mining operations, natural gas production and processing.

[2] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations - Pulverized Coal Power Plant," http://www.ieagreen.org.uk/emis4.htm, 40% efficiency emits 830 kg/MWh and 43% efficiency emits 770 kg/MWh.

[3] Southern Illinois University, Coal Research Center, "Pressurized Fluidized Bed Combustion," www.siu.edu/~coalctr/presfbc.htm.

[4] Application of terms of the U.S. EPA standard would result in at least 70% removal of sulphur, or about twice what would be required with Alberta standards and Alberta's coal.

[5] From EPCOR's EIA for Genesee 3.

[6] Based on ratio of efficiencies (33% vs. 38%).

[7] See Nova Scotia Power's website: http://www.nspower.ca/OurEnvironment/EmissionControls/. Port Aconi Power Plant in Nova Scotia removes 90% of the sulphur and 60% of NO_x.

[8] Southern Illinois University, Coal Research Center, "Atmospheric Fluidized Bed Combustion," www.siu.edu/~coalctr/atmosfbc.htm.

[9] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Integrated Gasification Combined Cycle," http://www.ieagreen.org.uk/emis6.htm.

[10] IEA Greenhouse Gas R&D Program, "Greenhouse Gas Emissions from Power Stations-Natural Gas Combined Cycle," http://www.ieagreen.org.uk/emis5.htm based on 25 ppm (~ 18g/GJ).

[11] "Sorbent Injection Systems," www.siu.edu/%7ecoalctr/sorbinj.htm.

[12] Southern Illinois University, Coal Research Center, "Post Combustion NO_x Control Technologies: Selective Catalytic Reduction Systems," http://www.siu.edu/~coalctr/postcomb.htm.

[13] Environmental Working Group, Clean Air Network and Natural Resource Defense Council, "Mercury Falling: An Analysis of Mercury Pollution from Coal-Burning Power Plants," June 2001, Washington DC.

[14] CO_2 is recovered at the large gasification project at Great Plains, Dakota and injected into underground reservoirs for enhanced oil recovery at Weyburn, Saskatchewan. See Dakota Gasification Company website: http://www.dakotagas.com/ and http://ens.lycos.com/ens/jul2000/2000L-07-14-11.html.

[15] Energy Issues (The World Bank) No.14 August 1998, " Technologies for Reducing Emissions in Coal-Fired Power Plants" by Masaki Takahashi, http://www.worldbank.org/html/fpd/energy/enls14.pdf. Costs in $US converted to $Cdn at 1.50 exchange rate (1995$).

[16] Wabash River (one of the U.S. IGCC Demonstration Projects) has begun repaying the DOE and has also achieved 79% overall reliability in 1999, "Clean Coal Today" Newsletter of the Office of Fossil Energy, U.S. DOE, DOE/FE-0215P-39 Issue No. 39, Spring 2000.

[17] All currency in Canadian dollars.

[18] From EPCOR's EIA for Genesee 3, Vol.1, Figure 2.2.1.

[19] Calculation based on the average of Keephills and Genesee 3 expansions.

[20] This number represents the actual cost of constructing the greenfield IGCC Polk Power Plant. U.S. DOE Publication "Techline DOE Sponsored Clean Coal Project Wins Power Magazine 1997 Award," June 5, 1997, U.S. Department of Energy.

[21] Calculated from TransCanada Pipeline's Press Release for the Redwater and Carseland Cogeneration Projects.

[22] Southern Illinois University, Coal Research Center, "Dry Flue Gas Desulfurization." http://www.siu.edu/%7ecoalctr/dryfluegas.htm. $US converted to $Cdn at 1.50 exchange rate (1995$).

[23] For the PCC options, cost of labour ($2.08/MWh) has been calculated using information from EPCOR's Genesee 3 Expansion EIA: 60 people, 440 MW, $120,000 per person per year and 90% load factor. This labour cost has been assumed the same for the two natural gas options. Labour for IGCC and PFBC has been determined using EPCOR's staffing model (60 people) and adding 15 more operators and 5 more maintenance/technical staff to handle the additional complexity of the IGCC and PFBC plants. Labour for AFBC assumes adding 5 more operators and 2 more maintenance/technical staff.

[24] Coal prices from the Coal Association of Canada Website 1998 Prices FOB Vancouver or see also Fording Coals 2000 Annual Report: $US 35.50/t ($Cdn 53.25/tonne), less transportation at approx. $32/tonne (Vancouver - Edmonton), 18 GJ/tonne gives $Cdn 1.18/GJ. This assumes that value of coal in Edmonton area is related to world market prices for coal.

[25] Gas price based on approximate daily AECO prices for June 28, 2001 from http://www.gasalberta.com/WebPublish/Web-Gas%20Price.htm

[26] Lower range of values for IGCC based on same reliability/uptime as for the other options. Higher range of values based on 11% worse reliability of IGCC when compared to the other options.

Glossary of Terms used in Tables 5 and 6

AFBC - Atmospheric Fluidized Bed Combustion
BACT - Best Available Control Technology
CC - Coal Combustion
CO_2 - Carbon dioxide
ESP - Electrostatic Precipitators
FGD - Flue Gas Desulphurization
GHG - Greenhouse Gases
GJ - Giga-Joules
IGCC - Integrated Gasification Combined Cycle
kg - kilogram
LNB - Low NOx Burners
MWh - Mega-Watt per hour
NGCC - Natural Gas Combined Cycle
NO_x - Nitrogen Oxides
NR - not required
PCC - Pulverized Coal Combustion
PFBC - Pressured Fluidized Bed Combustion
PM - Particulate matter
ppm - parts per million
SCR - Selective Catalytic Reduction
SO_2 - Sulphur dioxide
SO_x - Sulphur oxides

Appendix 7. Smart Electricity Policy for Alberta
Pembina Institute

Appendix 8. Briefing Document on Opportunities for Distributed Generation (DG) and Small-scale Combined Heat and Power (CHP) in Alberta, Mariah Energy Corp.

Appendix 9. Air Pollution in Alberta Compared with Canada