



18 September, 2006

Bill Strongman, P. Eng.  
Director, Regional System Planning  
Alberta Electric System Operator  
via email: bill.strongman@aeso.ca

Dear Bill,

**Re: Comments on 10-Year Transmission System Plan Initial Stakeholder Consultation Meeting**

ATCO Power appreciates the opportunity to provide the following comments on the 10-Year Transmission System Plan ("10-Year Plan").

1. A scenario should be included that reflects PPA units continuing to operate past their PPA life.
2. The MATL line and associated supply should be included as a scenario in the 10-Year Plan.
3. The actual generation capabilities of the units should be reflected in the plan rather than the MCR values provided on the CSD web page (eg. the CSD page shows Calpine's Calgary Energy Centre as a 250 MW facility but it is capable of producing up to 286 MW).
4. Consider environmental, economic, and social components of transmission routes to ascertain whether transmission can be built on a timely basis. Some of the complexities around these components are currently evidenced through landowner issues over the 500 kV North-South route.
5. Industrial or utility corridors should be considered as a way of maximizing new right-of-ways.

ATCO Power appreciated the opportunity to comment and looks forward to further discussions to assist the AESO in its 10-Year Plan endeavor.

Sincerely,

A handwritten signature in black ink, appearing to read "Dave Johnson".

Dave Johnson  
Manager, Power Marketing

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September 15, 2006

Mr. Jeff Nish  
Director, Resource Adequacy  
Alberta Electric System Operator  
2500, 330 5<sup>th</sup> Ave S.W.

Dear Mr. Nish,

**RE: EPCOR response to AESO Proposed 10 Year Transmission System Plan 2007-2016**

EPCOR Utilities Inc. ("EPCOR") would like to commend the AESO on the time and effort, to date, put into the development of the AESO's 10-Year Transmission System Plan ("Plan"). EPCOR attended the AESO's September 7, 2006, presentation on the Plan ("September 7 presentation") and is pleased to provide the following comments.

EPCOR has also reviewed the AMEC Americas Limited draft report entitled "Alberta 10 Year Generation Outlook" (AMEC Draft Report). EPCOR understands this report forms the basis for the Generation Scenarios discussion section of the September 7 presentation and is intended to stimulate further stakeholder discussion. As such, this letter includes combined comments on the September 7 presentation and the AMEC Draft Report.

As a major generator and participant in the Alberta market, EPCOR has concerns about the impact that transmission planning might have on future adequacy issues in Alberta. EPCOR, therefore, recognizes the importance of the AESO's process to develop a Plan that will minimize any negative impacts from insufficient transmission capacity or transmission congestion on long-term adequacy. EPCOR, however, is also cognizant of the limitations on the AESO to plan long-term transmission given the energy-only market structure in Alberta. EPCOR believes it is important that the AESO recognize these limitations and restrict any planning activities to the transmission system, and not to any mechanisms that might be intended to ensure adequate future generation capacity.

EPCOR provides the following specific comments.

Load Forecasting

EPCOR understands that the AESO has put significant effort into the development of the load forecast, including producing forecasts for specific areas in the province, i.e. the north-east area. EPCOR, however, believes that as part of this forecasting exercise, the AESO should set out the assumptions inherent in the forecast load results. For example, what are the assumed electricity prices, oil prices, natural gas prices and provincial economic growth rates used to determine the load forecast? The inclusion of these factors in the forecast is important for the internal consistency of the load forecast itself and for consistency when comparing the load forecast with possible generation scenarios.

Further, the AESO has performed a sensitivity analysis of the load forecast using a proxy of +/-300MW in 2006 and +/-500MW in 2016. In EPCOR's view, more specific sensitivity analyses should be performed that make explicit what the different assumptions, including electricity, oil and natural gas prices and economic growth rates, are in each of the scenarios. In addition, EPCOR believes that

additional development and explanation of the behind-the-fence assumptions is needed, including sensitivity analyses to deal with the possibility of behind-the-fence generation not meeting its load. Further, any additional load forecast sensitivities, with changes to price or economic growth assumptions must include load growth sensitivity for behind-the-fence load also.

When comparing the load forecast to the different generation scenarios, it is crucial that the forecast and scenario being compared share common and consistent assumptions. Further discussion of assumptions in generation scenario development is in the Generation Scenarios section of this letter, below.

EPCOR would also like to understand what assumptions the AESO has made with respect to industrial load and, specifically if the AESO considered the potential for reduced industrial load in its forecast, particularly in the Fort Saskatchewan area. For instance, EPCOR understands that Dow has recently decided to close two of seven processes and there is the possibility of further load reduction in the Fort Saskatchewan area in the future. Has the AESO included, or has the AESO considered the possibility of, any other industrial load reductions in its load forecast?

#### Reserve margin

One of the key assumptions in the Generation Scenarios section of the September 7 presentation and the AMEC Draft Report is that investment in new generation will respond to an effective capacity reserve margin metric of 7.5%. While EPCOR understands that it is the AESO's intention to allow this reserve margin metric to be a simplified proxy for market price signals, EPCOR cautions the AESO that this approach has limitations and may not be appropriate.

EPCOR understands the AESO's assumption to be that new investment in generation will occur when the reserve margin falls to an arbitrarily chosen level of 7.5%. EPCOR notes that the assumption that investment in generation will respond to a reserve margin signal is of limited value. While the reserve margin metric may be of some informational value to the market, incremental generation investment decisions are based on investor forecasts of energy prices (including electricity, natural gas and coal) and general market conditions and growth expectations, not on a reserve margin metric published by the AESO. Investment response to price signals is a key feature of Alberta's energy only market.

While it is not inappropriate for the AESO to calculate and publish a reserve margin metric, it is inappropriate and outside the AESO's mandate, to determine an "appropriate" reserve margin level. Please confirm that the AESO's intention in setting a reserve margin threshold is to estimate how much generation capacity is likely to be required and where the AESO expects incremental generation to happen, in order to plan and build a reliable transmission system. Please confirm that it is not the AESO's intention to set a reserve margin in order to influence market price signals and/or generation investment decisions.

EPCOR wishes to reiterate that the AESO's mandate is to ensure a safe and reliable transmission system and facilitate open and competitive markets. This precludes the AESO from any role in determining appropriate generation levels or from making efforts to ensure incremental investment in generation occurs. In Alberta's energy only market, these roles fall to the market, and the market only.

The 7.5% effective capacity reserve margin threshold excludes tie-line capacity. While there may be some merit to this assumption, EPCOR is concerned that excluding the tie-lines will not provide an accurate reflection of price, particularly given the assumption that the introduction of the Quick Hits will alleviate the imports offer requirements at \$0. Excluding the inter-ties has the impact of lowering prices, which is a negative trend from the perspective of incenting investment in new generation. Further, expansion of inter-tie Available Transfer Capability (ATC) is expected within the forecast period and there is the

possibility of the Montana Alberta Tie Ltd (MATL) project proceeding, providing additional incremental ATC into Alberta.

### Generation Scenarios

Similar to the discussion regarding load forecasting, above, EPCOR believes it is important that the AESO include price assumptions in its generation scenario forecasts. EPCOR believes that incorporating price assumptions in generation scenario development is crucial because investment in generation responds to forecast price signals (electricity, natural gas and coal), as well as forecasts of economic growth and market conditions. As with load forecasting, sensitivity analyses to changes in these assumptions should be undertaken. As mentioned above, these assumptions should be consistent when comparing any specific load forecast scenario to any generation scenario.

Further, given the AESO's forecast generation additions, both base (all scenarios) and specific scenarios, and the unit cost analysis in Table 3.1 of the AMEC report, it is crucial that the AESO include and disclose the price and economic assumptions inherent in its base scenario and in the specific scenarios. These price forecast assumptions will provide an indication of whether or not incremental generation, based on Table 3.1, is economic. For example, the AESO has included significant wind generation additions in its base scenario. Given the unit cost analysis data in Table 3.1, it is clear that such additions will require sufficiently high prices. This further underlines the need for the AESO to include specific price and economic assumptions in both generation scenario development and load forecasting.

EPCOR has some observations and comments regarding specific assumptions in the generation scenarios:

- With respect to the inclusion of the Bow City project in the generation scenarios, has the AESO considered any sensitivities surrounding the timing of this project?
- The description of existing hydro generation in the AMEC Draft Report does not include several small hydro plants. EPCOR notes the following plants are not included: Dickson Dam (15.6 MW summer, 4.5 MW winter); Belly River (2.86 MW summer, 0 WM winter); Waterton Dam (2.77 MW summer, 1 MW winter) and St. Mary's Dam (2.38 MW summer, 2 MW).
- The Sundance upgrades, assumed by the AESO, appear inconsistent with public information Transalta has previously submitted to the EUB.
- Has the AESO considered the existence of some surplus dormant behind-the-fence cogeneration capacity in the Fort McMurray area and the possibility that this additional generation could be sold into the grid in the future?
- With respect to the Battle River retirement assumptions, has the AESO considered extending the life of the Battle River plants beyond the expiration of the PPAs? Are there other assumptions, economic, environmental, or otherwise, that support the AESO's assumption that the plants will be retired when the PPAs expire?

In all generation scenarios, the AESO has included an incremental 100 MW of simple cycle gas generation by 2006, with a further 100 MW by 2016. EPCOR notes that these incremental additions do not take into account the planned simple cycle gas additions at our Cloverbar site, let alone any other potential gas peaker plants that might be built during the forecast period. For information purposes, EPCOR has submitted an application to the EUB for the Cloverbar project and the projected timelines for incremental generation capacity are: 43MW in Q4 2007; 100MW in Q4 2008; and 100MW in Q4 2010. EPCOR notes that this would result in an incremental 243MW of generation capacity from simple cycle gas plants by 2011, independent of any other potential additions in the forecast timeframe. EPCOR believes that the AESO should include, at a minimum, the full impact of EPCOR's Cloverbar project, based on the above timelines, in its planning, when making assumptions regarding simple cycle gas generation additions.

In summary, EPCOR understands the challenges facing the AESO in preparing a ten year transmission system plan. EPCOR believes that, in preparing the load forecasts and generation scenarios necessary to create the plan, it is essential that the AESO make explicit and consistent assumptions with respect to energy prices and economic growth. Further, EPCOR stresses that, while planning an adequate and reliable transmission system is an integral part of the AESO's mandate, the AESO has no role in determining or planning appropriate generation. In Alberta's energy only market, the decision to invest in incremental generation capacity should only be made based on unbiased and clear market price signals.

EPCOR appreciates the opportunity to provide comments on the September 7 presentation and the AMEC Draft Report. Should you have any questions, please contact me at (780) 412-3940

Sincerely,

*<original signed by>*

Sian Barraclough  
Manager, Regulatory Affairs  
EPCOR Utilities Inc.



September 18, 2006

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## **Re: 10 Year Transmission System Plan – TransCanada Comments**

Dear Bill,

TransCanada appreciates the opportunity to provide feedback to the AESO on their recent stakeholder communications with respect to the upcoming 10 Year Transmission System Plan and the Draft Alberta 10 Year Generation Outlook prepared by AMEC Americas. It is helpful to have input from a major engineering firm with resources to set out energy balances for processes and create meaningful cost estimates. It is also helpful that the AESO has made provision for interested readers to reflect carefully upon, and comment on, the engineering consultant's draft.

TransCanada has the following concerns with these documents:

1. Lack of consistency with “Alberta’s Integrated Energy Vision”
2. Load forecast not reflecting Calgary growth and export capability
3. Assumptions made in setting the Reserve Margin
4. The lack of a Fort McMurray cogeneration scenario

### **1. Alberta’s Integrated Energy Vision**

While AESO transmission system plans must comply with legislative and regulatory requirements, they should also focus on facilitating and supporting the government directions and priorities reflected in current transmission and energy policy. In particular, the AESO needs to ensure that there is sufficient transmission for all participants to fully develop economically credible generation resources. “Alberta’s Integrated Energy Vision”, published August 25, 2006 (page 8-9), states:

Energy integration is fundamental to Alberta’s future energy development and marks a significant shift in direction. Integration means that energy projects and commodities are no longer treated on a stand-alone basis but as part of a larger energy system.

An integrated systems approach that realizes economic synergies in upgrading, refining, processing, and secondary manufacturing in Alberta using our energy resources, increases value-added opportunities for Albertans and ensures that we capture the best value and, best use for our resources.

Coordination of energy development activity with other resource development industries to ensure future access to resources while minimizing the environmental footprint of energy operations, as well as using opportunities created by other industries, is an equally important element of the Integrated Energy Vision.

Some examples serve to illustrate the opportunities presented by an integrated energy industry through multiple uses of the hydrocarbons and their by-products:

- a new energy efficient bitumen extraction and upgrading technology, in combination with gasification, uses asphaltene residue to produce virtually all the fuel gas and hydrogen required to fuel a commercial scale Steam Assisted Gravity Drainage operation, a related cogeneration facility and the upgrading components; (underlining added)
- one of the by-products of bitumen upgrading and refining is carbon dioxide that can be injected underground. It has a part to play in enhanced oil recovery;
- Ethane, a component of natural gas, is currently used as a feedstock for the petrochemical industry. Ethane from natural gas can be utilized to produce pellets that are used to make plastics products, and directly add value to gas resources; and
- oil sands plants burn natural gas to produce electricity, steam and heat. The electricity is used for oil sands process needs while any excess power may be made available to the larger Alberta electricity grid as part of the total electricity supply for the province. (underlining added)

An integrated approach to energy development will also be important to the future of the electricity industry in Alberta. An important element of the Integrated Energy Vision will be to ensure that Albertans have continued access to secure and reliable electricity through a competitive and effectively functioning electricity marketplace. The Integrated Energy Vision will continue to foster a diversity of fuel sources for electricity generation.

Alberta has a vast supply of high quality coal to generate electricity throughout this century. Ongoing research and development will continue to explore environmentally friendly means to use coal to generate power. Cogeneration from Alberta's oil sands plants has delivered efficient, environmentally friendly power. Oil sands production processes generate steam and heat as by products, which are harnessed to produce electricity with any surplus made available to the electricity market. (underlining added)

On page 14 of the Integrated Energy Vision, it states that the third key transmission priority for the future is the “expansion of transmission in the Edmonton-Fort McMurray area which is experiencing phenomenal growth. Additional transmission capacity will provide assured and long-term electricity supply to Albertans, as well as increase market reach for energy imports and exports.” (underlining added)

This raises the concern as to whether the AESO and AMEC are addressing transmission requirements to meet Alberta domestic loads or are also examining transmission requirements for Alberta supply opportunities in the context of Pacific NW markets.

The AMEC report (page 18) states that oil sands developers are “generally sizing power facilities to meet only their own behind the fence needs” and “Plans submitted by developers to the AESO show an overall balance of their loads and their behind the fence generation.” To conclude that this recent trend can be taken as highly indicative of the future is likely flawed and even contradicts the AESO's recently

published Draft of the Northeast Alberta Service Requirements Forecast that shows 747 MW of excess average generation above average load in 2016 (Table C4.2).

These comments are provided in support of our view that without a further scenario that reflects Fort McMurray generation developments, the 10 year plan may significantly understate future transmission needs. More details on this concern are set out in a later section on Fort McMurray cogeneration.

## **2. Load Forecast**

While little detail has been provided on the load forecasting methods and assumptions, TransCanada has the following concerns:

- Recently, the Calgary market has had above normal population, economic and load growth. This type of localized regional growth needs to be forecast and modeled by the AESO to appropriately plan for transmission in and around Calgary as well as impacting the balance of the AIES. Simply applying Conference Board of Canada growth projections broadly across the province will not suffice and could lead to inaccurate models and plans.
- The AESO forecast does not model for exports from Alberta to other markets. In the 2007 AESO GTA, the AESO is currently proposing new firm Export tariffs which, when approved, will allow participants to schedule firm exports as well as opportunity exports. “Alberta’s Integrated Energy Vision”, proposes increasing the market reach for energy exports and recognizes that the US will continue to be the major market for Alberta’s energy into the future. Joint efforts by the AESO, AltaLink and industry have significantly increased the amount of export capacity on the BC Alberta Tie Line. All of these factors taken together would suggest significant increases in exports for the next several years from the depressed levels experienced in the last 18 months. Ignoring exports in the load forecast will present an inaccurate picture of the actual load that will be on the transmission system in the future and particularly in southern Alberta.

## **3. Reserve Margin**

In developing the reserve margin that in the AESO analysis underpins the amount of generation forecast to be developed in the province, the AESO has apparently made some unstated yet fundamental assumptions. TransCanada disagrees with these assumptions and require clarification:

- No additional tie lines are built to other jurisdictions
- There is no relatively low cost transmission path from Alberta to or from the Pacific Northwest
- NorthernLights does not proceed
- There is no large scale generation development in Fort McMurray or elsewhere in Alberta for export
- There are no provincial government initiatives to incent syngas cogeneration, to enhance royalties from natural gas, to increase property taxes from a gasification plant, to increase output of value-added products in gasification processes, to encourage more valuable use of waste products or to achieve the efficiency benefits of syngas or gas fired cogeneration plants.

As well, the methods and determinations applied to set the reserve margin at the installed capacity of 22% leading to an effective capacity of 7.5% require explanation and evidence. It is not apparent why this number has been selected and not some other number. The AMEC report (page 10) indicates that the

market will respond to price signals when the difference between firm capacity and peak load falls to 7.5%. The 22% reserve margin seems to be based on the market currently sitting at an installed capacity reserve margin of 22% but this number has been lower and higher in recent years and in the AESO's Reserve Margin forecast (April 17, 2006) is forecast to be 16% in 2009. TransCanada would be interested to know the foundation for this important assumption and whether it allows for the time delays in constructing new generation or will reserve margins need to fall even further before new generation is initiated.

#### **4. Fort McMurray Cogeneration**

As TransCanada has advised before, we believe there is substantial potential for major syngas cogeneration opportunities in the Fort McMurray area far in excess of the local and behind-the-fence loads. TransCanada is continuing development of the NorthernLights project from Fort McMurray to the Pacific Northwest to capitalize on this potential and believes that the AESO should consider a scenario with major new Fort McMurray generation.

The AMEC report contains helpful information; however it is somewhat unbalanced in that it includes a wealth of information from AMEC's coal work but little information from its work with cogeneration systems. It seems to develop conclusions based on choices that the majority of institutions are making rather than dealing with issues from basic principles.

1. Page 17, Section 2.3.2, Cogeneration: The report provides considerable discussion of coal sources, coal plants and expected improvements in the efficiencies of coal fired systems. The description of cogeneration technology is not as complete. Energy Policy makers, environmental groups, regulators, corporate planners and suppliers to the industry who are looking to this report for an analysis of how cogeneration compares to other generating processes need more information than the amount provided.

We understand that AMEC is well informed on cogeneration technology and economics from its feasibility studies that led to the development of two cogeneration plants operating in Alberta.

AMEC states that the reason for not providing more information is that few developers are overbuilding their power plants to supply the grid. It is well recognized that if developers build their cogeneration systems to only supply their on-site loads they are choosing a generation configuration that is substantially suboptimal. This means that there are very low incremental costs to overbuild for export to the Alberta grid or for export markets outside of Alberta. Furthermore, should the industry view the long-term price of gas to be a barrier, there is the opportunity to develop gasification capacity and effectively cap the input costs at the cost of the gasification process plus a low cost fuel such as Coke or Bitumen. TransCanada concludes that if there was sufficient transmission out of the Ft. McMurray area to markets, that cogeneration for domestic and export purposes is a credible alternative that the AESO should be considering. Failure to do so will result in the perception that the AESO will not provide more transmission capacity out of Ft. McMurray and therefore new cogeneration for export out of Ft. McMurray will not be built.

2. Page 18 section 2.4, 3<sup>rd</sup> paragraph: Some of the stated reasons why oil sands by-products will not be gasified are not clear and would benefit from clarification with additional text:

*“A major gasification plant will cost \$2 billion, making power generation with syngas more capital intensive and placing greater demands on scarce resources than installing natural gas*

turbines”. The capital intensive nature of the process would be seen as an advantage to firms that are not capital constrained. The capital investment locks-in the cost of the fuel (as it does with a hydro project) but the price of natural gas, a resource that is likely to be more scarce than capital, would escalate, probably in real terms. This prospect of locking in fuel prices will have greatest appeal to developers in the scenario with natural gas prices at \$7 per GJ that AMEC has selected as a base case. Developers who are capital constrained could buy syngas from utilities who are not.

*“When gasifiers are installed and syngas is produced, hydrogen for the production of transportation and petrochemicals has highest value in the hierarchy of uses and power generation is among the lowest.”* Use of the hydrogen component in syngas production does not preclude the use of the carbon monoxide component of the syngas for power production. The economics of selecting between using carbon monoxide to produce more hydrogen versus burning carbon monoxide in a cogeneration facility needs to be evaluated.

*“Upgraders that produce and gasify asphaltenes... expect to, with the exception of OPTI Nexen, either use the syngas internally or sell it as a feedstock.”* On this and other occasions in the report, AMEC observes that the industry as a whole has adopted a specific design philosophy and that OPTI Nexen alone has selected a different option. The inference each time is that OPTI Nexen’s choice is not relevant. TransCanada understands that other oil sands developers are monitoring the OPTI Nexen gasification project closely to guide their own decisions on this matter. The correct choices will become evident over time as history plays itself out. It would be more helpful to base conclusions on cost estimates and economic principles rather than a survey of current industry choices.

3. Pages 23 and 24, Table 3.1:

- We are missing asphaltenes as a fuel and we are missing cogeneration as an option under the coke and asphaltenes cases.
- It would be helpful to have separate columns under cogeneration for SAGD and mining operations since the SAGD operations are particularly efficient and the impact of this is lost when SAGD and mining operations are lumped together.
- Since AMEC has stated that the developers will build cogeneration for on-site loads it will be informative to show the incremental costs of overbuilding for the grid or for the export market.
- The unit cost of \$1000 per kW for cogeneration plants seems high in relation to combined cycle units. It may be that the cost of the heat recovery steam generator is being included in error with the cost of generation in the cogeneration case or, alternatively, that the cogeneration case is not being credited with the cost of gas-fired boilers.
- An AMEC comment on the basis for expected lives of the gas-fired systems would be helpful. AMEC uses 20 years. The Northwest Power Planning and Conservation Council, in its carefully considered 5<sup>th</sup> Development Plan, uses 30 years for projects of this type.

TransCanada encourages AESO planners to acquire information on future activity in cogeneration from business development executives in oil sands development companies and generation development companies, not just the operators of oil sands facilities. Generation developers, who are in a position to propose investment in incremental increases in the sizing of cogeneration plants at oil sands plants, are hesitant to do so if there is an apparent reluctance from the AESO to plan for adequate transmission capacity to viable markets inside and outside of Alberta.

TransCanada believes that AESO stakeholders would benefit significantly if AMEC were provided with more time and resources to address these comments (and comments of others as appropriate). As noted above, the AESO should develop another scenario reflecting cogeneration in the Fort McMurray region fueled by either syngas or natural gas at a relatively low price and which exceeds incremental “behind the fence” load and thus results in surplus energy available.

#### **Other Points**

1. Page 10, Section 1.3.2: With higher export capability and lower export losses, there is the prospect that export opportunities will incent low-cost producers to build early for export. It would be helpful to have an analysis setting out the cost of power required at the bus bar in Alberta to compete with plants in export markets.
2. Page 12, Section 2.1.2: It is reasonable to assume, as AMEC has, that the Slave or Dunvegan projects would not be commissioned by the end of 2016. This section raises an interesting question though. If the Slave or Dunvegan projects were expected to be commissioned shortly after the end of the study period, would the system be developed differently in the decade preceding their commissioning?
3. Page 11, Section 2.1.1: Dickson Dam (15 MW) is missing from the small hydro table. (It doesn't appear on the AESO's Current Supply and Demand web page but does appear in other AESO reports.)

TransCanada is very concerned about these issues and interested in working with the AESO and industry to further address them. I can be reached at (403) 920-2092.

Yours sincerely,

#### ***Original Signed***

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Director, Market Services

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September 15, 2005

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Dear Jeff,

We would like to thank the AESO for holding the September 7, 2006 stakeholder consultation to review the load and generation assumptions that will form the foundation of the 10-Year Transmission Plan. These consultations provide a useful means for the AESO to disclose its methodology and for stakeholders to provide constructive comments. Our comments here will focus on the generation assumptions.

To set the context of these comments it is instructive to recall the AESO's obligations under section 4 and 8 of the Transmission Regulation. These require that the AESO plan the transmission system so that transmission is not a constraint in locating and operating generation. Importantly, these requirements apply universally to all types of generation and therefore it is important that any transmission plan is sufficiently flexible to accommodate changing market conditions and the associated range of generation mix this is plausible over the next 10-plus years.

The current generation assumptions are not aligned with the requirements of section 4 and 8 because they are significantly flavoured in two key areas. First, in the AMEC Outlook document generation additions are driven by a need to maintain a fixed 7.5% (effective capacity) reserve margin. The presumption here is that such a level of reserve margin reflects the level of supply that keeps the market in equilibrium. Unfortunately, generation procurement in the Alberta market is not keyed to a 7.5% reserve margin and instead will develop from the myriad of forces driving the market. Moreover, because the reserve margin

calculation is based solely on an examination of the “effective capacity” at time of system peak it presumes that load and generation focus their purchasing or selling decisions solely on the basis of system peak or “effective capacity” at time of system peak. While firm capacity is undoubtedly one aspect of the decision to build new generation, it is not the sole consideration. In effect, this approach ignores the other considerations with the net result of discounting and trivializing generation technologies that are prized for their low energy costs even while having less certain firm capacity at time of system peak, such as wind or run-of-river hydro.

Second, the generation assumptions rely predominantly on a number of predictive forecasts that may easily be incorrect. In particular, the assumed generation additions (both base level and scenario variations) are predicated on current views of capital costs, environmental requirements, fuel prices and AESO market rules. In each instance there are legitimate and reasonable alternatives. For instance, the capital cost of projects are heavily influenced by construction costs and therefore large scale projects could experience significant cost inflation, due to ever rising labour and construction costs from an over heated Alberta economy; the success of the petroleum sector to find more gas, coupled with a softening US economy could lead to reduced gas prices and lower operating costs for gas-fired generation; legislative changes could place further restrictions on air, water and waste emissions and therefore favour cleaner technologies; the AESO may be instructed to modify the market rules including lifting the price cap to a higher level thereby altering the economics for peaking generation facilities. Lastly, the AESO or stakeholders could resolve the operational issues associated with wind cost effectively resulting in significantly more interconnections.

The vulnerability of relying on predictive forecast is clearly illustrated in the recent article reported in the Brooks Weekender paper, (August 25, 2006, See attached Article.) There it was reported that the Bow City coal project has been placed on hold indefinitely due to “higher costs than anticipated”. This raises serious doubts about the correctness of the predictive assumptions used by AMEC and provided to AESO. Given the presence of either of the 500 MW generation units (1000 MW total) in all AMEC models and their timing of supply to the market this is a crucial assumption in all scenarios through 2016.

In our view, the 10-Year Transmission plan should focus on assuring that the transmission system is capable of accommodating plausible levels of generation, throughout all regions of the grid. To this extent the AESO should focus on the potential of each generation type and less so on attempting to predict the outcome of the market. In this respect the 10-Year Plan would be better served by testing alternative transmission plans against generation scenarios that are a function of varying levels of regional generation and varying mixes of generation technologies in each of these regions. As well, the suggestion of a transparent queue (where both load and generation projects that have applied for connection

regionally are publicly disclosed) would serve to support plausible discussions in the AESO Transmission Plan. Since the AESO is not the agency to pick and choose who will connect, this additional market information would serve to provide up to date information to market participants as to the progress of load and generation projects planning to connect to the AES. An example of the value of this information is the inclusion by AMEC of Table 2.1 *Upgraders and Gasifiers in Alberta* as support for the prognostications related to the role of by-products from oilsands, as a fuel source for electrical generation. Those projects wishing to connect would be detailed in a published queue to provide the market with their intent to connect and their progress by achieving milestones. (see West Windeau comments posted to AESO website April 9 2006).

As well, the assumptions of the costs related to generation type need to be examined. Recent articles published in the USA on the costs associated with IGCC facilities and carbon sequestration is not in line with the AMEC examples provided in Table 3.1. The above announcement by Luscar would reinforce that the 10 year outlook as presently written is not accurately predicting the forward price of power supplied from clean coal, asphaltine or coke technologies. Costs associated with IGCC construction, operation and carbon capture and CO<sup>2</sup> transport and sequestration are in the range of **7.1 cents US** not 5.1 cents. (Scientific American, Sept 2006, volume 295). This is without the added cost of construction in Alberta. As such, more stable cost technologies like wind becomes pivotal in future supply scenarios that are currently only based on firm capacity.

Also, references related to the seasonal capacity of wind and hydro are simple and may mislead the reader. The writer of the AMEC report has not followed the example of other jurisdictions in examining the role of renewables in the formation of an integrated supply plan. The synergistic relationship of renewables to one another and to the existing thermal base has not been examined thoroughly enough. The carte blanche de-rating of both water and wind in capacity does not mirror the more complex modelling results of New York, Quebec and Ontario where the seasonal capacity value for wind can provide the market with additional systems benefit such as enhancement of some water power (through storage) and thermal (through the hedging of gas during winter price peaks). A more appropriate scenario would be to determine the actual wind resource that Alberta has and to model the benefits of geographic diversity and then establish (as other ISO's have) the merits of additional wind energy in the generation portfolio. A study of this nature conducted by a firm with experience in this area, such as GE, could be based on some of the existing work that has been done by the AESO in its variability studies. The study could be done in time to include the results in the 10-Year Plan and add merit to the scenarios.

Finally, the generation scenarios lack any consideration of the impact and influence of external markets. Clearly, different levels of imports and exports will affect the willingness (or not) to build generation facilities in Alberta and to this

extent the generation scenarios underpinning the 10-Year Plan should examine the impact of varying levels of inter-jurisdictional transfers.

We trust that these comments will be useful to the development of the 10-Year Plan. If you have any questions about the issues raised herein or wish to discuss these issues further please contact myself.

Regards,

A handwritten signature in black ink, appearing to be 'CM', with a stylized flourish at the end.

Claude Mindorff

President

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Attachment: Article on Suspension of Bow City Project, Brooks Weekender  
August 25 2006