



AESO 10-Year Plan (2007-2016) Initial Stakeholder Meeting – September 7, 2006
Stakeholder Questions/Comments and AESO Responses
October 26, 2006

The AESO would like to thank those stakeholders who have taken the time to ask questions and provide comments about the 10-year Transmission System Plan (2007-2016) meeting held on September 7, 2006.

The meeting was attended by stakeholders from the following organizations:

Alberta Department of Energy	ATCO Electric
Alberta Energy and Utilities Board	Balancing Pool
AltaLink	Bietz Resources Ltd.
ATCO Power	City of Lethbridge
BCTC	Constellation New Energy
BP Canada Energy Company	Current Solutions Inc.
City of Medicine Hat	Department of Energy
CRD Energy Services / CRD Management Inc.	Direct Energy
DC Energy Services Inc.	Dow Chemical Canada Inc.
Direct Energy	ENMAX
Energy Logics	Esso
EPCOR	Gale Force Energy
Gale Force Energy	Kinder Morgan Canada
Industrial Power Producer's Society of Alberta	Montana Alberta Tie Ltd.
Lawson Lundell LLP	National Energy Board
MSA	Phoenix Engineer
Phillips Partners Inc	PKS Ventures Inc.
Phoenix Engineer	SNC Lavalin T&D
RESL	Suncor Energy Products Inc.
Spirit Pine Energy	The Cogent Group Inc.
Synergia Polygen Ltd.	TransAlta
Thermal Power Western Region	Valeo Power
TransCanada	
Vision Quest	

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SUBJECT	STAKEHOLDER QUESTION / COMMENT AND AESO RESPONSE
LOAD FORECAST 2006	<p>1) STAKEHOLDER SESSION: When will the AESO’s load forecast document be posted to the website?</p> <p><i>AESO: The AESO intends to post the load forecast document in October.</i></p> <p>2) STAKEHOLDER SESSION: What is the most important output of the load forecast? Who is the “customer” within the AESO?</p> <p><i>AESO: The majority of the work is done for the Transmission Planning group to assist in the development of a Need Identification Document. Other departments that utilize the load forecast are market services with particular emphasis on the long-term adequacy initiative that is currently being brought forward.</i></p> <p>3) STAKEHOLDER SESSION: What is the variance between the actual load and the load forecast for 2005?</p> <p><i>AESO: The variance for 2005 is approximately 1.2% over the actual load at peak.</i></p> <p>4) STAKEHOLDER SESSION: At what stage will the AESO begin to include large projects in its load forecast?</p> <p><i>AESO: AESO includes large projects in its load forecast but the total is adjusted such that the additions do not exceed the economic forecast.</i></p> <p>5) STAKEHOLDER SESSION: Does the AESO factor in changing weather patterns to the load forecast?</p> <p><i>AESO: No. The AESO uses two years of historical load data which will provide a fair representation of the next 10 years.</i></p> <p>6) STAKEHOLDER SESSION: How does the AESO determine behind-the-fence load?</p> <p><i>AESO: The AESO uses SCADA data of generation as well as metered flow.</i></p> <p>7) STAKEHOLDER SESSION: What approach does the AESO use in obtaining the coincident peak for all areas of the province?</p>

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	<p><i>AESO: The AESO doesn't have data for peak by sector, so an energy forecast is developed and then the metering point load shape is applied.</i></p> <p>8) STAKEHOLDER SESSION: The energy forecast graph on slide 11 of the presentation illustrates the total load. Is the Alberta internal load (AIL) net load the driver for the forecast? What are the growth rates of the Alberta Interconnected Electric System (AIES)?</p> <p><i>AESO: Yes, the AIL is the driver for the forecast. The growth rates of the AIES are</i></p> <ul style="list-style-type: none"> • <i>Energy Growth 1.8%</i> • <i>Peak Growth 1.9%</i> <p>9) STAKEHOLDER SESSION: As the load increases on the AIES, does it lose efficiency?</p> <p><i>AESO: As the system load increases the electric losses on the lines also increase. However, as the system is upgraded to meet the increased load, either with additional lines or larger conductors on existing lines, the losses are reduced.</i></p> <p>10) STAKEHOLDER SESSION: What is the underlying premise behind the oil and gas forecast?</p> <p><i>AESO: The Conference Board of Canada economic forecast includes oil and gas price forecasts. We also used Canadian Association of Petroleum Producers' (CAPP) moderate case for oilsands production.</i></p> <p>11) STAKEHOLDER SESSION: Does the AESO run sensitivity analysis on the oil and gas forecast?</p> <p><i>AESO: No.</i></p> <p>12) STAKEHOLDER SESSION: In a Need Identification Document (NID), does the AESO account for the probability associated with the range of load growth? (i.e. Calgary grows faster than Airdrie – can you factor in this probability to an area of the province?)</p> <p><i>AESO: The Need Identification documents (NID's) take into account a range of load growth but do not account for probabilities.</i></p>

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	<p>13) ENMAX: How do you use the point- of delivery (POD) historical growth rates as an input to the load forecast? Is it just a simple linear extrapolation or do you use a weighting factor to emphasize the more recent data and account for accelerating growth?</p> <p><i>AESO: Historical growth at individual metering points is considered and grouped accordingly. Each group of metering points is given a +/- consideration for high growth or low growth areas.</i></p> <p>14) TRANSCANADA: “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.” Please respond.</p> <p><i>AESO: Please refer to the response to question 13.</i></p> <p>15) EPCOR: “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.” Please respond.</p> <p><i>AESO: Sensitivity cases were prepared to determine the impact of accelerated wind development, lower behind-the-fence generation and higher industrial loads. Please refer to the Alberta 10 Year Generation Outlook report prepared by AMEC. (please click here)</i></p> <p>16) EPCOR: “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 process, oil process, natural gas prices and provincial economic growth rates used to determine the load forecast?”</p> <p><i>AESO: AESO will include the assumptions that were used in the load forecast in the Load Forecast document that will be posted in October.</i></p> <p>17) EPCOR: “ ...additional development and explanation of the behind-the-fence assumption is needed, including the sensitivity analyses to deal with the possibility of the</p>

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	<p>behind-the-fence generation not meeting its load.” Please respond.</p> <p><i>AESO: Please refer to the response to question 15.</i></p> <p>18) EPCOR: “..any additional load forecast sensitivities, with changes to price or economic growth assumptions must include load growth sensitivity for behind-the-fence load also.” Please respond.</p> <p><i>AESO: Please refer to the response to question 15.</i></p> <p>19) EPCOR: “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.”</p> <p><i>AESO: The Provincial load forecast is based on an econometric model, the potential for specific reduced industrial load is not directly considered.</i></p> <p>20) STAKEHOLDER SESSION: Will distribution facility owner’s (DFO) forecast be factored in to the AESO’s load forecast?</p> <p><i>AESO: No. The AESO’s load forecast is independent of the Distribution Facility Owner’s forecast. However the DFO’s forecast is factored into the AESO’s forecast at the need application level.</i></p>
<p>DEVELOPMENT OF GENERATION SCENARIOS</p>	<p>21) STAKEHOLDER SESSION: Will the AESO update the generation scenarios upon the release of the National Energy Board’s report on the development of resources?</p> <p><i>AESO: The generation scenarios to be used in the 10 Year Transmission System Plan will be finalized before the next version of the National Energy Board’s report is issued. Any current, relevant reports that are available for subsequent Need Applications will be considered.</i></p> <p>22) STAKEHOLDER SESSION: Will the AESO incorporate updated information on generation when they develop a need application?</p> <p><i>AESO: Most definitely. The AESO’s 10-Year Transmission System Plan provides a “snapshot” of the transmission system for the next 10 years. The AESO will update the load and generation forecast specific to the project at the need identification stage.</i></p>

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	<p>23) STAKEHOLDER SESSION: When the AESO performs its sensitivity analysis, where will it remove the load from the system?</p> <p><i>AESO: The AESO performed a system wide sensitivity analysis without being specific as to where load was removed.</i></p> <p>24) STAKEHOLDER SESSION: Similarly, what generation did you remove, or “turn off” from the system?</p> <p><i>AESO: Again, the AESO was not specific in what generation is “removed” from the system in performing the sensitivity analysis for the generation scenarios. The generation scenarios are described in Section 4 of the Alberta 10 Year Generation Outlook report.</i></p> <p>25) STAKEHOLDER SESSION: Is the AESO only developing these scenarios in order to test the transmission system?</p> <p><i>AESO: Yes. The AESO will develop these generation scenarios in order to test the transmission system and create a high-level view or “snapshot” of the transmission system for the next 10 years.</i></p> <p>26) STAKEHOLDER SESSION: Does the AESO look at opportunities where generation might have an incentive to locate? (i.e. transmission losses?)</p> <p><i>AESO: Location based incentives were not assumed in the development of the scenarios. Location, type of generation and timing will be dictated by the market participants.</i></p> <p>27) STAKEHOLDER SESSION: Has the AESO monitored and evaluated generation that appears to be opportunistic or predatory?</p> <p><i>AESO: No. The AESO has not made a distinction in the types of generation wishing to connect to the grid. Scenarios were developed to test the transmission system over the next 10 years.</i></p> <p>28) STAKEHOLDER SESSION: Is an in-service date (ISD) of five years for a coal-fired plant reasonable?</p> <p><i>AESO: Yes, given recent experience with other projects.</i></p>

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	<p>29) TRANSCANADA: Page 1 of letter, Item 3. – Assumptions made in setting the Reserve Margin</p> <p>AESO: <i>This response is written to address the questions raised by TransCanada, EPCOR and West Windeau on the selection and use of the reserve margin. The 7.5% reserve margin used in the Draft Alberta 10 Year Generation Outlook report was based on estimating the reserve margin at which certain metrics, in the form of Loss of Load Probability and Estimated Unserved Energy, and pool prices were reached in a situation in which exports were constrained by internal limitations. That analysis has been redone based only on pool prices and without the export constraint and, based on that analysis, a reserve margin of 10% has been selected for the Final Report.</i></p> <p><i>A reserve margin is selected so that the load forecast prepared by the AESO can be translated into levels of installed capacity in 2011 and 2016. It is estimated that when the reserve margin reaches 10% pool prices will reach a level that will make new generation financially viable. The reserve margin/pool price analysis is done with the current ties in place and the full installed capacity of all units taking into account the planned and forced outage rates of the thermal plants and the expected energy output of wind and hydro.</i></p> <p><i>The resulting reserve 10% margin used in the generation outlook of is an “Effective Capacity Reserve Margin”. How that 10% compares to other definitions of reserve margin is shown below:</i></p> <table border="0"> <thead> <tr> <th data-bbox="737 976 856 1003"><u>Definition</u></th> <th data-bbox="1341 976 1570 1003"><u>Equivalent Margins</u></th> </tr> </thead> <tbody> <tr> <td data-bbox="737 1008 1150 1036"><i>Effective Capacity Reserve Margin</i></td> <td data-bbox="1520 1008 1570 1036">10%</td> </tr> <tr> <td data-bbox="737 1040 1213 1097"><i>Margin including the total installed hydro and wind capacity</i></td> <td data-bbox="1472 1068 1556 1097">15.5 %</td> </tr> <tr> <td data-bbox="737 1102 1213 1159"><i>Margin including the total installed hydro and wind capacity and inerties</i></td> <td data-bbox="1472 1130 1556 1159">24.5%</td> </tr> </tbody> </table> <p><i>The effective reserve margin was selected so as to reflect the contribution that a MW of wind and hydro capacity make relative to other forms of generation.</i></p> <p><i>The intent in selecting a reserve margin is only to obtain estimates of the likely total installed capacities in 2011 and 2016 for use in the Generation Outlook. Neither AMEC nor the AESO are suggesting this reserve should be used for any other purpose. The last comprehensive study of a reserve margin for the Alberta system was prepared in 1994 and concluded that 22.5% was appropriate based the inclusion of transmission ties and total installed capacities. (“A Filing by the</i></p>	<u>Definition</u>	<u>Equivalent Margins</u>	<i>Effective Capacity Reserve Margin</i>	10%	<i>Margin including the total installed hydro and wind capacity</i>	15.5 %	<i>Margin including the total installed hydro and wind capacity and inerties</i>	24.5%
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	<p><i>Alberta Generating Utilities on behalf of the Electric Utility Planning Council with the Energy Resources Conservation Board regarding the Reliability Criterion for Generation Planning in Alberta” January, 1994)</i></p> <p>30) STAKEHOLDER SESSION: Is the 7.5% reserve margin large enough to provide for contingencies?</p> <p>AESO: <i>The 10% (see response 29 above) is a proxy for the market signals to generation developers. It has been assumed that new generation additions will occur when the reserve margin (as defined in the AMEC report) drops below 10%. No assessment is made of the adequacy of this amount of generation.</i></p> <p>31) WESTWINDEAU: “Generation procurement in the Alberta market is not keyed to a 7.5% reserve margin and instead develop from the myriad of forces driving the market...While firm capacity is one aspect of the decision to build new generation, it is not the sole consideration.” Please explain how the AESO will address this issue in its 10-Year plan.</p> <p>AESO: <i>Please refer to the response to questions 29 and 30.</i></p> <p>32) EPCOR: “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.”</p> <p>AESO: <i>Please refer to the response to questions 29 and 30.</i></p> <p>33) EPCOR: “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.”</p> <p>AESO: <i>Please refer to the response to questions 29 and 30.</i></p> <p>34) EPCOR: “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</p>

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	<p>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.”</p> <p><i>AESO: Please refer to the response to questions 29 and 30.</i></p> <p>35) TRANSCANADA: “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:</p> <ul style="list-style-type: none"> • 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 • Northern Lights 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.” <p>Please clarify.</p> <p><i>AESO: Please refer to the response to questions 29 and 30 above and 37 below.</i></p> <p>36) TRANSCANADA: “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.” Please respond.</p> <p><i>AESO: Please refer to the response to questions 29 and 30.</i></p>

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	<p>37) TRANSCANADA: Page 1, Item 4. The lack of a Fort McMurray cogeneration scenario.</p> <p>AESO: <i>TransCanada raises a series of questions related to the amount of cogeneration in Fort McMurray including the basis of the costs of generation sources used in Table 3.1 and why the amount of cogeneration installed is based more on observed behaviour of the oil sands developers rather than on this economic comparison of generation sources.</i></p> <p><i>The cost comparison in Table 3.1 is based on a utility cost of service approach and is included to provide a guide to the relative life time costs of the options. It is relevant to a company ranking power generation options but is much less relevant to an oil sands developer who is choosing between investments in more power production or more bitumen production.</i></p> <p><i>TransCanada’s suggestions to base the capital costs of the natural gas-fired cogeneration on the incremental cost relative to raising steam in boilers in the comparison Table 3.1, and to have a Fort McMurray Cogeneration Scenario, which comprises an additional 500 MW being exported to serve the rest of the grid, are included in the Alberta 10 Year Generation Outlook Report. It is acknowledged that TransCanada see significantly more generation being developed from this source to serve an export market.</i></p> <p>38) EPCOR: “...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.”</p> <p>AESO: <i>Please refer to the response to question 37.</i></p> <p>39) TRANSCANADA: Page 18 section 2.4, 3rd 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:</p> <p>“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</p>

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	<p>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.”</p> <p>Please clarify.</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>40) TRANSCANADA: Please explain the following: “...Pages 23 and 24, Table 3.1:</p> <ul style="list-style-type: none"> • 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 5th Development Plan, uses 30 years for projects of this type. “ <p><i>AESO: Please refer to the response to question 37.</i></p> <p>41) TRANSCANADA: “TransCanada is continuing development of the Northern Lights 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.”</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>42) TRANSCANADA: “AMEC states that the reason for not providing more information is</p>

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	<p>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.” Please respond.</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>43) WESTWINDEAU: “...the generation assumptions rely predominantly on a number of predictive forecasts that may easily be incorrect.”(i.e. Bow City coal project is on hold) Please respond.</p> <p><i>AESO: The AESO recognizes the possibility of some projects not proceeding. We have adopted a scenario approach to account for this possibility.</i></p> <p>44) WESTWINDEAU: “...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.” Please respond.</p> <p><i>AESO: It is not the role of the AESO to have an integrated supply plan, also referred to as an integrated resource plan, prepared on its behalf. Renewable resources are included in the scenarios in the context of the existing competitive generation market in Alberta.</i></p> <p>45) WESTWINDEAU: “...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.” Please respond.</p> <p><i>AESO: For the 10-Year Plan, the AESO includes the generation that it is aware of at the time and factors this into the scenarios.</i></p> <p>46) STAKEHOLDER SESSION: The assumptions provided in the presentation appear to be “light” on gas-fired generation; does the AESO consider the types of generation you need to operate the transmission system reliably?</p> <p><i>AESO: The AESO believes the market will dictate where and what kind of generation is developed. The transmission system will be built to accommodate that generation. The Alberta 10 Year Generation Outlook report includes modest increases in the amount of gas-fired generation.</i></p>

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	<p>47) EPCOR: “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).”</p> <p>AESO: <i>The AESO recognizes the Current Supply and Demand web page does not include certain small hydro projects and may understate or overstate the capacities of certain projects and does not reflect the changes in the output projects with gas turbines which vary with temperature from summer to winter. On the other hand, for example, the capacity of the Calpine unit is understood. The total capacities on the website are however considered to be sufficiently accurate for the purposes of this exercise.</i></p> <p>48) TRANSCANADA: “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.)” Please respond.</p> <p>AESO: <i>Please refer to the response to question 47.</i></p> <p>49) ATCO POWER: “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)” Please respond.</p> <p>AESO: <i>Please refer to the response to question 47.</i></p> <p>50) TRANSCANADA: “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?”</p> <p>AESO: <i>The AESO also prepares a 20-Year Outlook Report as well as the 10-Year Transmission System Plan. These projects are included in the 20-Year Outlook. The 10-Year Transmission System Plan is updated every two years and, assuming there will be better information on these projects available, they will be included as appropriate.</i></p>

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	<p>51) ATCO POWER: “A scenario should be included that reflects PPA units continuing to operate past their PPA life.” Please respond.</p> <p><i>AESO: Based on current information, there is no indication that those units will continue to operate past 2010 and 2013 respectively. However, the AESO may incorporate any changes to the planned retirements at the need identification stage of the affected project.</i></p> <p>52) STAKEHOLDER SESSION: The generation scenarios include the retirement of Wabamun 4 as well as Battle River 3 and 4. Will the AESO plan for the possibility of an extension or repowerment of these units?</p> <p><i>AESO: Please refer to the response to question 51.</i></p> <p>53) EPCOR: “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?”</p> <p><i>AESO: Please refer to the response to question 51.</i></p> <p>54) STAKEHOLDER SESSION: Do the generation scenarios intended to be used for the 10-Year Transmission System Plan include the re-powered Clover Bar plant?</p> <p><i>AESO: Yes. The generation scenarios will account for the full amount of EPCOR’s announced addition of 245 MW at Clover Bar.</i></p> <p>55) EPCOR: “EPCOR believes that the AESO should include, at a minimum, the full impact of EPCOR’s Clover Bar project, based on the above timelines, in its planning, when making assumptions regarding simple cycle gas generation additions.” Please respond.</p> <p><i>AESO: Please refer to the response to question 54.</i></p> <p>56) EPCOR: “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?”</p>

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	<p><i>AESO: The timing of the Bow City project will be determined by the project proponents. However, the scenario approach the AESO is utilizing will provide for a sensitivity for this situation where Bow City generation is not developed.</i></p> <p>57) TRANSCANADA: “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.” Please respond.</p> <p><i>AESO: The AESO does canvas stakeholders including oilsands development companies and generation developers to prepare transmission plans that are adequate to meet their needs.</i></p> <p>58) EPCOR: “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?”</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>59) TRANSCANADA: “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.” Please respond.</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>60) TRANSCANADA: “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).” Please</p>

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	<p>respond.</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>61) TRANSCANADA: 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.” Please respond.</p> <p><i>AESO: Please refer to the response to question 37.</i></p> <p>62) BCTC: In the presentation, Mr. Nish stated the “tarsands upgraders that had been proposed for Ft McMurray would likely be sited in Ft Saskatchewan due to cost issues in Ft McMurray. A few questions come to mind. How likely is this shift to occur? Is the tarsands co-generation potential tied to the upgrader facilities or other facilities? Would this potential then shift to Ft Saskatchewan, or how much of it would shift (a general guess would be helpful)?”</p> <p><i>AESO: The conclusions on location are based on discussions with developers, recent public announcements as well as publications from an oilsands advisory group. The shift that occurred is illustrated both in the cogeneration surveys in 2005 and 2006 as well as page 18 and 19 of the Alberta 10 Year Generation Outlook report.</i></p> <p>63) STAKEHOLDER SESSION: Why does the AESO exclude export/import capability from the generation scenarios?</p> <p><i>AESO: Import/export issues will be dealt with in the bulk system analysis portion of the 10 Year Transmission System Plan.</i></p> <p>64) TRANSCANADA: “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</p>

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	<p>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.” Please respond.</p> <p><i>AESO: Please refer to the response to question 63.</i></p> <p>65) TRANSCANADA: “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.”</p> <p><i>AESO: The AESO believes this type of market analysis is outside the purview of the 10-Year Transmission Plan.</i></p> <p>66) WESTWINDEAU: “...the generation scenarios lack any consideration of the impact and influence of external markets.” Please explain.</p> <p><i>AESO: Please refer to the response to question 63.</i></p> <p>67) STAKEHOLDER SESSION: Will the location of interties have an impact on how the AESO plans the transmission system?</p> <p><i>AESO: The AESO will incorporate intertie capacity at the Need Identification stage of a specific project.</i></p> <p>68) MATL: During the AESO presentation on the 2007 – 2017 generation forecast, Mr. Nish stated that the tie lines account for 865 MW of Alberta capacity. What does that capacity represent in terms of the existing tie lines and the new MATL tie line? Please breakdown the AESO’s capacity figures for each of the three tie lines – BC, Saskatchewan and Montana for 2007 and 2017.</p>

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	<p><i>AESO: The AESO considers the design rating of the new MATL tie line to be 300 MW as proposed, subject to Western Electricity Coordinating Council (WECC) path rating and the operations assessment. However the total intertie capability is limited to 865 MW because the trip of the BC Interconnection will require the transfer tripping of MATL due to the size of that interconnection not being able to accommodate the resultant flow. At some lower flows, the MATL line may not need to be transfer tripped for a BC Interconnection outage. However there may be some operational issues with the continuous operation of MATL with the BC Interconnection out of service to be able to withstand the next contingency (i.e. loss of Alberta generator) which operations is assessing.</i></p> <p>69) ATCO POWER: “The MATL line and associated supply should be included as a scenario in the 10-Year Plan.” Please respond.</p> <p><i>AESO: Please refer the response to question 68.</i></p> <p>70) STAKEHOLDER SESSION: Will the AESO include the pending Montana Alberta Tie Line in the behind-the-fence generation?</p> <p><i>AESO: Please refer the response to question 68.</i></p> <p>71) WESTWINDEAU: “...the assumptions of the costs related to generation type need to be examined... costs associated with IGCC construction, operation and carbon capture and CO2 transport and sequestration are in the range of 7.1 cents US not 5.1 cents. (Scientific American, Sept 2006, volume 295).” Please respond.</p> <p><i>AESO: The costs in Table 3.1, which are revised in the Final Report, are based on buying offsets which are less costly than sequestering.</i></p> <p>72) STAKEHOLDER SESSION: Will economics be largely affected if Genesse 4 or Bow City power projects do not proceed?</p> <p><i>AESO: The AESO has developed generation scenarios that are used to identify future transmission system needs. If Genesse 4 or Bow City does not proceed, that impact would be addressed in the relevant needs identification studies. In the meantime, inclusion of the projects provides a roadmap for potential transmission development.</i></p>

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	<p>73) STAKEHOLDER SESSION: In the development of the scenarios, does the AESO consider the impact of new generation on the pool price?</p> <p><i>AESO: To the extent that reserve margin is used as a proxy for market signals (including Pool Price) to developers to build generation, there is recognition of the impact of new generation on pool price.</i></p> <p>74) STAKEHOLDER SESSION: As the timeframe in which new generation is connected to the AIES, will the price sensitive load increase?</p> <p><i>AESO: New price sensitive load was not assumed.</i></p>
<p>TRANSMISSION PLANNING PROCESS</p>	<p>75) ATCO POWER: “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.” Please respond.</p> <p><i>AESO: These issues will be addressed through the Need Identification process.</i></p> <p>76) SPIRIT PINE ENERGY: How will the AESO’s 10-Year Transmission System Plan address the present 900 MW wind threshold?</p> <p><i>AESO: The AESO is working with stakeholders to develop mitigation measures to address the threshold. The 10-Year Transmission System Plan is developed to provide a “road map” of the AIES for the next 10 years based on current information. The AESO has included a scenario that addresses the development of wind generation to 3200 MW by 2016.</i></p>