

TCM: Rule 9.4 AUC Re-Filing Proposal Paper  
Stakeholder Comment Matrix  
July 20, 2010

**1. Executive Summary**

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	<p>This proposal has the potential to be very costly to consumers through higher pool prices. The ADC requests a formal review on a quarterly basis by a third party such as the MSA of the outcome of implementing the rule and changes to bidding behavior in response to anticipated constraints. If it is determined that the cost of this practice becomes consistently greater than what is currently in place would yield, then the AESO needs an off ramp to suspend the rule and return to current practice.</p>	<p>The AESO does not expect implementation of the Transmission Constraints Management (TCM) protocol to result in high pool prices. The AESO currently manages, and will continue to manage, congestion effectively by using practices and procedures such as the connection process, regional operating procedures and remedial action schemes. These measures optimize the use of the system and lead to less frequent and shorter duration congestion events on the system. Without them congestion would be worse. Recent analysis indicates that the frequency and duration of future constraints should be primarily contingency related and accommodated within the normal operation of the market without significant price impacts until planned transmission enhancements are in place.</p> <p>The AESO has recently published its annual system assessment entitled "24-Month Reliability Outlook". The assessment provides details on the few regional constraint events that have occurred in the last few years. The study showed that historically constraint events are very infrequent. The constraint events are considered to form part of the "abnormal operating conditions" contemplated in the Transmission Regulation.</p>

		<p>In response to stakeholder requests for information on future congestion, the AESO has prepared a regional Alberta outlook regarding future congestion which is attached as Appendix A to this matrix. The study forecast the occurrence of congestion prior to the regional planned transmission upgrades and the data indicates that the AESO will continue to be able to use temporary measures to manage near term future congestion as such congestion will be infrequent, of short duration. The detailed assumptions, data and analysis used by the AESO to reach its conclusions are provided in Appendix A.</p> <p>The AESO has performed analysis on the regional areas that have historically experienced congestion and is providing congestion estimates from simulated South of Keg (SOK) and Fort McMurray path flows under specific scenarios for future years. There is also a qualitative discussion of the future congestion in the South West and North West parts of the province.</p> <p>As noted, regional congestion is likely to be infrequent and of short duration in the near term under system normal conditions. That being said, the South of Keg (SOK) is forecast to fail to meet congestion requirements of Alberta's Transmission Regulation (AR 86/2007) on a limited basis under the generation scenarios studied potentially as early as 2011. Without the planned transmission enhancements, SOK</p>
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		<p>congestion increases significantly post 2015. Similarly, the Fort McMurray path is forecast to be congested in 2015 which could result in load curtailments or a directive for Transmission Must Run services in the scenario studied if new planned facilities are not in place.</p> <p>However, with planned transmission enhancements, the AESO believes that the constraints should be primarily contingency related and should be accommodated within the normal operation of the market without significant price impacts and at minimal cost relative to the unconstrained alternative.</p> <p>The AESO has a duty to ensure that its rules promote the fair, efficient and openly competitive operation of the market and will monitor the impact of the TCM protocol in that regard. With respect to reporting on constraints, the AESO regularly monitors the impact of transmission constraints on the market and undertakes annual stakeholder reviews to discuss regional constraint issues. Furthermore, the AESO is currently in the process updating the Long Term Transmission Plan and intends to incorporate regional forecasts of congestion on the system as part of that future study.</p> <p>The AESO would also note that the proposed TCM protocol is in many respects the current protocol except for the use of RMO for constraining down generation and the changes related to transmission rights (trigger</p>
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		<p>participants). The current OPP 521 SOK- 240 Operation (SOK) that has been in effect since August, 2007 contains most elements of the proposed TCM protocol.</p>
<p>ATCO</p>	<p>The AESO Discussion Paper on Rule 9.4 reads more like a notification paper than a consultation document. It has no discussion of principles (both planning and operating) and no objectives (i.e. minimize disruption). A lack of discussion related to principles in the operational phase (real time) of transmission constraint management should not prejudice any future discussion on the rules or business practices for transmission constraint management in the planning phase.</p> <p>Our high level concerns with the proposed rule remain:</p> <ul style="list-style-type: none"> <li>• Pool price is being unnecessarily distorted;</li> <li>• DDS in its current form does not work; and</li> <li>• The proposed rule will cause market distortions.</li> </ul> <p>Transmission constraint management procedures need to be robust enough that the market will not need to be suspended. Market suspension due to transmission constraints is unacceptable as a solution to congestion.</p> <p>We believe the AUC Decision on Rule 9.4 was permissive on many of its findings. This affords the AESO the opportunity to find a more optimal solution to real time constraints.</p>	<p>The AESO has been working on TCM with industry since the transmission regulation became law in 2004. During those discussions, the AESO has been guided by the principals and recommendations of both the Transmission Development Policy (TDP) and the Electricity Policy Framework. (See TDP page 3 for principals and for conclusions see TDP page 7; particularly point 4 on timely transmission and page 8 point 6 on 95% congestion rule which is also in the Transmission Regulation 86/2007)</p> <p>The AESO notes that transmission constraints impact the market supply and demand balance and the proposed TCM protocol works effectively within the current market design to restore that balance while having a minimal impact on pool price. Please refer to the AESO response to ADC in the Executive Summary section regarding future constraints and their price impacts.</p> <p>The AESO points out that Dispatch Down Service (DDS) does not play a role in the management of transmission constraints. It is a price reconstitution mechanism that is intended to remove the impact that Transmission Must Run (TMR) units have on pool price. The AESO continues to monitor the impact and effectiveness of the DDS rules on the market and believes that the DDS market is operating as expected.</p>

		<p>Market suspension does not play a role in the management of transmission constraints. The AESO believes that market suspension must only be used as a last resort. If a reasonable approximation of the market is still attainable over a reasonable period of time, the market should remain operational and competitive. Whenever possible, market outcomes should be decided by the actions of market participants participating in the market. The AESO is also of the view that the TCM protocol is robust enough to manage any transmission constraints unless there has been a catastrophic event on the transmission system.</p> <p>The AESO continues to believe that the TCM protocol is the best available solution to real time constraints. The TCM protocol minimizes the price impact and level of distortion, is effective, practical and works within the current market framework for all constraints and encourages fair, efficient and openly competitive behaviors.</p>
ENMAX	<p>ENMAX's comments with respect to the following Executive Summary statements are provided below:</p> <ul style="list-style-type: none"> <li>• <i>The AESO does not recommend using any pay as bid protocol;</i></li> <li>• <i>Severe market distortions are not constraint management issues and should be dealt with using other appropriate actions;</i></li> <li>• <i>The definition of "local load pocket."</i></li> </ul>	Please refer to the AESO response to ENMAX in section 5.3 and 5.2.
Capital Power	<p><b>Summary</b></p> <p>Decision 2009-042 is rooted in an understanding on the part of the Alberta Utilities Commission that transmission congestion-related events requiring the application of Rule 9.4 will be infrequent and transient. However, the available evidence suggests that the problem will be much</p>	The AESO forecast suggests that constraint events will be primarily contingency related and will be infrequent and of short duration. Please

more prevalent and serious than the Commission was led to believe by the AESO. If that is the case, then the revised Rule 9.4 does not satisfy the requirements of the Commission as expressed in its Decision.

In the circumstances, the AESO must either move urgently to provide reasonable and credible evidence to substantiate its assurances to the AUC regarding the infrequency and brevity of transmission congestion-related events or rewrite Rule 9.4 so as to incorporate either a dispatch down service, or a *pro rata* approach to curtailing generators upstream of transmission constraints.

### Discussion

It is abundantly clear from Decision 2009-042 that the Commission was prepared to allow the AESO to employ EMMO/RMO as the approach to curtailing upstream generators *only*. . . provided that EMMO/RMO is used infrequently and for periods of congestion of short-duration . . .". Indeed, there can be no doubt that the assurances from the AESO that it expected congestion to be "infrequent and transient" formed the foundation of the AUC decision. With respect, this makes it all the more unfortunate that the AESO has provided little information, either before the Rule 9.4 hearing or since, to substantiate those assurances. In fact, the available evidence is to the contrary.

The AESO testimony during the Rule 9.4 hearing was that congestion on the north/south corridor would be ". . . a very good example of something that we would see to be infrequent and typically very short in duration" and that ". . . the only congestion events that I'm aware of on the north/south system, either historic or even on a forecasted basis over the next several years, are related to forced outages or contingency-type situations".

However, in the *Edmonton-Calgary 500kV Transmission Development Need Application* (May 7, 2004), the AESO indicated that ". . . based on the generation development scenario assumed, i.e. upgrades of Genesee 1 and 2, and Sundance 3, 4 and 5 by 2008; and the addition of Keephills Unit 3 in 2009 . . . [c]ongestion on the Edmonton to Calgary transmission path in 2009 was estimated to be about 32% of the time in the 'summer'

refer to the AESO response to ADC in the Executive Summary section for the latest information regarding future constraints anticipated on the Edmonton to Calgary path.

The AESO has published its annual system assessment entitled "24-Month Reliability Outlook". The assessment provides details on the few regional constraint events that have occurred in the last few years. The AESO would point out that the bulk of the Southern congestion events are due to the connection of a wind farm which was known to result in constraints under N-0 conditions at the time of connection. Constraint events are very infrequent but at times necessary as the AESO plans and expands the system to meet future needs. They are considered to form part of the "abnormal operating conditions" contemplated in the Transmission Regulation.

The AESO has continued to update its studies based on the best available economic and technical information. In addition, the AESO has continued its consultation efforts on the Long-term Transmission System Plan and the projects outlined therein.

With respect to information on the KEG area projects, the AESO is committed to open, timely and transparent communication on the project with all stakeholders. The interconnection of the new Keephills 3 generator and the related upgrades to Edmonton area 240 kV transmission

<p>months, and 21% of the time in the 'winter' months". Conditions are now rapidly converging toward those predicted circumstances.</p> <p>For example, when Keephills 3 comes on-stream in 2011, Keephills-Genesee generation will be 86 MW higher (i.e., 2,496 MW vs. 2,410 MW) than in the generation capacity scenario contemplated in the 2004 Need Application. Similarly, forecast demand in 2010 is expected to surpass the levels associated with the highest congestion predicted in that document.</p> <p>So far as Capital Power is aware, the AESO has provided no new public estimates of the probability of congestion on the Edmonton to Calgary transmission path. The AESO did, however, recently indicate to Capital Power (in a letter dated December 17, 2009), a copy of which is attached, that it anticipates that from the latter half of 2011 (when Keephills 3 is scheduled to be added) to 2014 (when the West Edmonton-Calgary 500 kV HVDC transmission line is expected to be in service) there will be ". . . an increased probability of transmission constraints and possible generation curtailment of Keephills, Genesee and Sundance units during periods of high north to south flows." As much as it might like to, Capital Power finds it is difficult to reconcile this information (i.e., the 2004 Need Application, the 2008-2028 Demand and Energy Outlook, 24-Month Reliability Outlook (2009-2011) and the recent letter from the AESO) with assurances that transmission congestion-related events of the nature that would attract the application of Rule 9.4 will be either infrequent or insignificant.</p> <p>The requirement for the AESO to provide reasonable and credible evidence to substantiate its assurances is urgent. Moreover, in the absence of such substantiation, the fundamental proviso in Decision 2009-042 cannot be satisfied and Rule 9.4 must be rewritten to eliminate EMMO/RMO re-dispatch. If that were not to happen then, in light of Decision 2009-042, the AUC would be obliged to reject Rule 9.4 as being contrary to the public interest and failing to support the fair, efficient and openly competitive operation of the Alberta electricity market.</p> <p>Capital Power is appreciative of the opportunity to provide these</p>	<p>lines will require a sequence of line outages over the approximate 18 month construction period of the projects.</p> <p>Due to the complexity of the project construction schedule and the inherent dependencies within the schedule, the AESO will continue to provide regular, timely project updates to stakeholders on our website including information regarding transmission line outages and impacts to system operations.</p> <p>The AESO has a duty to ensure that its rules promote the fair, efficient and openly competitive operation of the market and will monitor the impact of the TCM protocol in that regard.</p>
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	<p>comments and would welcome the opportunity to work with the AESO to achieve a mutually satisfactory outcome. We hope that the AESO will provide information about the potential triggers of future congestion (e.g. line outages, generation outages in the south or central regions, etc), the predicted frequency of congestion in the KEG area up until the first Edmonton-Calgary 500 kV line is built, information of when the congestion is more likely to occur (on peak or off peak percentages and summer or winter), and the magnitude of curtailment expected for KEG generating units as a result of delayed upgrades in the KEG area and those related to the delayed Edmonton-Calgary 500 kV line.</p>	
<p>Industrial Power Consumers Association of Alberta (IPCAA)</p>	<p><i>“The AESO will continue its current practice of TMR procurement and usage”</i> – Why did the AESO decide not to have the new TCM rule alter TMR?</p> <p><i>“The AESO does not recommend using any pay as bid protocol within the TCM Rule.”</i> – The AESO should re-consider pay as bid if it results in more efficient (and cost effective) dispatch. By dispatching at a higher price due to a transmission constraint – generators enjoy windfall returns that are largely caused by their desire to run during periods of transmission congestion – the AESO needs to distinguish between congestion caused by generators and congestion caused by domestic Alberta loads – to expect loads to pay a higher price while some generators are constrained from exporting energy seems to be highly unfair to loads.</p> <p>TCM is only required when the AESO has not contracted for adequate TMR in advance of a potential constraint – When TMR is run it does not affect the hourly price – logically then TCM should not affect the market price when required.</p> <p>As loads pay for all transmission costs then the cost of TMR and TCM is a transmission cost – not an energy cost – and should have no impact on the hourly “unconstrained price.” To pay a higher energy cost during periods of congestion means that generators receive a wind-fall benefit due to congestion, and loads pay more than that necessary to offset the transmission constraint. Stated in the reverse manner – if the transmission constraint did not exist as adequate transmission was</p>	<p>The AESO believes that the TCM protocol provides the most efficient method of balancing supply and demand in real time.</p> <p>TMR is a temporary non-wires solution to a transmission constraint which the AESO must plan to eliminate under regulation. The TCM protocol appropriately incorporates the use of TMR within the protocol. Please refer to AESO response to ENMAX in section 5.2 for a description of the AESO’s use of TMR.</p> <p>Constraints do not always stem from a lack of transmission and all systems will experience transmission outages causing constraints. The AESO believes that the pool price has an essential role of providing a real time supply and demand balancing signal. Loss of supply due to a transmission outage impacts supply in the same manner as the loss of supply due to a generation outage and the price signal to the market should reflect the supply situation so that the appropriate market response can occur. Load benefits from having this important balancing function and, as</p>

	<p>available, loads would only pay the added cost of the incremental transmission and no additional compensation to generators. The constraint should not provide windfall benefits to any generators.</p> <p><i>“The AESO does not see a need to modify the TCM rule with respect to DDS dispatch.”</i> – Where possible, the AESO should work to enable loads to supply a DDS-like product.</p> <p><i>“The AESO will modify 9.4.4 b) rule language to provide additional clarity surrounding the conditions under which the SC will exercise its discretion in deviating from the protocol in an area.”</i> – In the event that the SC deviates from protocol, reports should be produced after-the-fact to allow the market to understand what occurred. Transparency is extremely important to the market.</p>	<p>in most electricity market designs, the costs are appropriately charged to load.</p> <p>The TCM protocol generates the appropriate price signal to downstream generation and imports. The pay as bid protocol mutes the price signal and may lead to perverse behaviors including promoting a race to the top in offers provided by downstream generators when constraint events can be anticipated and the offers are not transparent until the end of the month. Under the TCM protocol, downstream generators offer behavior must recognize the competitive response of imports and other generators even if the constraint event can be anticipated two hours out.</p> <p>TCM protocol is generic and works for all forms of congestion performing the important balancing function. Effective exports are curtailed before upstream generators are constrained down and downstream generators are dispatched on so exports do not cause loads to pay higher prices.</p> <p>TMR is a non-wires solution dealing with a foreseen reliability issue in an area and is not always effective in dealing with constraints such as constraints that arise from having too much generation in an area.</p> <p>All systems experience constraints caused by abnormal operating conditions (e.g. credible contingencies) which do not require wires solutions or TMR to resolve.</p>
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IPPSA	<p>IPPSA remains opposed to the AESO's approach to congestion management. We believe the AESO's approach is not consistent with policy, or the goals of a FEOC market. We believe that a TMR/DDS approach would be far preferable.</p>	<p>The AESO believes that the proposed TCM protocol is an effective, in-market solution compatible with the current market design that incorporates appropriate use of TMR/DDS and is preferable to all other alternatives particularly a constraint management approach that exclusively uses TMR/DDS. The AESO believes that TMR/DDS is not required when the probability of events is low (either in occurrence or duration) and/or the event cannot be foreseen. Further, TMR/DDS may be more costly and is not effective because there is often not a contestable market and therefore a generator may intentionally price its energy out-of-merit if the constraint is foreseeable and systemic. The</p>

		AESO notes that the Commission found that the TCM protocol does not offend the FEOC operation of the market because it does not use a TMR/DDS only approach.
MEG	<p>MEG has reviewed the AUC Decision 2009 – 042 – “Objections to ISO Rule 9.4 Transmission Constraints Management” and is of the view that the AUC directed the AESO to:</p> <ul style="list-style-type: none"> <li>• Identify, use, and fully define fundamental concepts and terms that would impart a common understanding of the application of the TCM rule;</li> <li>• Clarify the process steps that will be followed to manage congestion; specifically to clarify the use of TMR to manage TCM, address what appears to be a missing step under subsection 9.4.4(a) with respect to re-dispatching DDS and add clarity to when a system controller may exercise discretion under subsection 9.4.4 (b) of the TCM rule.</li> <li>• Clarify the scope of the rule; specifically to advise whether the TCM rule is applicable to the planning stage elements related to congestion and to real time congestion or just the latter.</li> <li>• If the scope of the TCM rule includes the planning stage elements, provide a description of how the RAS will be administered within the TCM rule.</li> <li>• Clarify, at a high level, when in real time, the AESO would move from the use of the TCM rule to the use of TMR.</li> <li>• Explore the merits of the ENMAX pay-as-bid protocol.</li> </ul> <p>Furthermore, the AUC advised that it is of the view that:</p> <ul style="list-style-type: none"> <li>• The use of EMMO dispatch and RMO curtailment does not offend subsections 17(b) and 17(c) of the EUA when the TCM rule is applied for unforeseen congestion that is infrequent and of short duration. However if real time congestion overly distorts market prices or allows the undue exercise of market power, the AUC supports the use of TMR.</li> <li>• The TCM rule, by impacting the pool price through economic dispatch and perverse incentives, by failing to provide compensation to constrained down generators, failing to recognize transmission “rights” for generators and failing to use a</li> </ul>	

	<p>TMR/DDS only approach, does not offend the FEOC operation of the market.</p> <ul style="list-style-type: none"> <li>• The MPOs did not demonstrate that the TCM rule is not in the public interest.</li> </ul> <p>The AESO's proposal will provide additional clarity through definition of terms used in the TCM rule, will continue the current practice of TMR procurement and usage, will make no modifications with respect to DDS dispatch and will provide additional clarity surrounding the conditions under which the SC will exercise discretion in deviating from the protocol in an area. Furthermore, the AESO will revise the TCM rule to clarify that the rule applies only to congestion in real time. The AESO has considered the ENMAX proposal to employ a pay-as-bid protocol and does not recommend such.</p> <p>MEG notes that TCM is essentially supply surplus on a regional basis and encourages the AESO to ensure consistency of both definitions, and of principles for management, under TCM and supply surplus.</p>	<p>While it makes sense to use similar approaches in TCM and supply surplus there are differences between the two issues, the main one being that there is no transmission constraint involved in supply surplus. The AESO has modeled the supply surplus approach after the approach we have taken to manage supply shortfall. Please refer to the AESO responses on the AUC directions in sections 5.1 thru 5.5.</p>
TransAlta	<p>The AESO is currently consulting with Stakeholders regarding market models for pricing and dispatching during transmission congestion events (AESO Discussion Paper Transmission Congestion Management: Rule 9.4 Re-Filing Proposal). It is difficult for stakeholders to understand the impacts of these different models without information about past or future events. The frequency and duration of congestion events has an impact on which model is workable and best for Alberta. Understanding the likelihood and type of congestion events will help ensure that stakeholders are fully informed, and therefore, able to provide more meaningful comments in the consultation process. We appreciate the AESO providing information in the Seasonal Reliability Outlook. This information moves us in the right direction. However further information is still required. Specifically the historical information still needs duration attached to it to help put it in context.</p> <p>More important would be future load flow studies that provide stakeholders with an indication of which lines will experience constraints and the size, frequency and duration of these events. We appreciate what</p>	<p>The AESO is of the belief that constraint events will be primarily contingency related and will be infrequent and of short duration.</p> <p>Please refer to the AESO response to ADC in the Executive Summary section for the latest information regarding future constraints anticipated on the Edmonton to Calgary path.</p>

	<p>is provided in the seasonal reliability outlook but it is very limited in terms of future projections for congestion. As part of such analysis TransAlta would request that the congested hours in terms of frequency, duration and time related to our facilities be provided confidentially to us.</p> <p>Undertaking this type of work is very expensive for each individual stakeholders. It would be more reasonable for the AESO to share its information with all stakeholders as they are in the best position to undertake this analysis and it is required as part of a robust stakeholder consultation process.</p>	
TransCanada	<p>TransCanada welcomes the opportunity to further contribute to the development of procedures to be used in times of real-time transmission congestion.</p> <p>TransCanada agrees that the Commission “supported the recommended rule design” but notes that it did so on the basis that congestion will be infrequent and of short duration. TransCanada would welcome analysis from the AESO regarding the anticipated frequency and duration of congestion events.</p> <p>TransCanada’s view is that the existing transmission policy, as well as the <i>Electric Utilities Act</i> and <i>Transmission Regulation</i> are premised on an unconstrained transmission system. Should chronic congestion occur, a re-evaluation of the policy, legislation and the way in which congestion is managed will be required.</p> <p>TransCanada is confused by the AESO’s statement that “[s]evere market distortions are not constraint management issues and should be dealt with using other appropriate actions” (pg 1). The Alberta electric system has experienced a few instances of congestion that caused severe market distortions and regularly experiences moderate distortions during moderate congestion. TransCanada believes the Commission also saw a correlation between market distortions and congestion as it stated that it expected the AESO to “minimize disruption of market prices as much as possible” [para. 116] when managing congestion. TransCanada is concerned that the AESO is proposing to resort to tools outside the TCM Rule to manage congestion under certain circumstances.</p>	<p>The AESO is of the belief that constraint events will be primarily contingency related and will be infrequent and of short duration.</p> <p>Please refer to the AESO response to ADC in the Executive Summary section for the latest information regarding future constraints anticipated on the Edmonton to Calgary path.</p> <p>The AESO has recently published its annual system assessment entitled “24-Month Reliability Outlook”. The assessment provides details on the few regional constraint events that have occurred in the last few years. The AESO does not consider any of these events to be severe market distortions.</p> <p>The AESO’s statement is referring to severe and sustained market distortions which the TCM rule is not intended to manage such as Category D system events. <b>Category D</b> represents a wide variety of extreme, rare and unpredictable events, which may result in the loss of customer demand (firm load) and generation in widespread areas. The system may not be able to reach a</p>

		<p>new stable state. Such events will not be caused by any credible forecast transmission constraints or by the method the AESO proposes to manage constraints. Rather, such events will be the result of a catastrophic failure of the transmission system or a breakdown in market fundamentals. These events need to be evaluated for risk and consequences. WECC has created the “Extreme Contingency Guide” to provide additional guidance around this class of event. As these events are impossible to predict, they will be managed by the appropriate rules and operating procedures, the AESO, the Market Surveillance Administrator (MSA) or other appropriate entity as the circumstances dictate.</p> <p>The AESO has a duty to ensure that its rules promote the fair, efficient and openly competitive operation of the market and will monitor the impact of the TCM protocol in that regard.</p>
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## 2. Introduction

Stakeholder	Stakeholder Comment	AESO Response
ATCO	<p>The AESO Discussion Paper on RAS is not a comprehensive picture of the planning stage. It also contains no principles. The two documents do not provide participants with a clear indication of how the AESO will manage congestion.</p>	<p>The Electric Utilities Act (EUA) and the Transmission Regulation outline the AESO duties to plan the system and provide system access. The AESO has also been guided by the principals and recommendations of both the TDP and the Electricity Policy Framework.</p> <p>AESO business practices have been well established over time. The Remedial Action Scheme (RAS) consultation is ongoing and the AESO believes that it will provide clear indication of how the AESO manages connection RAS in the planning stage. The AESO will also be consulting on revisions to the AESO reliability criteria and on new reliability standards which involve further discussions on the use of RAS in the planning domain and will ultimately help create improved well documented comprehensive RAS rules and business practices.</p>

### 3.0 Background

Stakeholder	Stakeholder Comment	AESO Response
MEG	MEG would find it useful to understand the AESO's target date for filing the TCM rule revision with the AUC.	The AESO will follow the usual rule consultation process with respect to the TCM rule and has published revised rule language for stakeholder comment. Upon reviewing stakeholder comments on the revised rule, the AESO expects to proceed with final rule language which will be re-submitted to the Commission in 2010.
ATCO	All constraints ultimately occur in real time. Therefore, the AESO needs to consider the planning phase in order to have system controller procedures that appropriately manage all the constraints that arise in real time whether they are foreseen or unforeseen.	The System Controller (SC) must be prepared for constraints that occur in real time given the actual configuration of the system and any known changes that are expected to occur over the very short term (usually the next few hours). In the planning stage, system planners study the system as it may be configured in the planning horizon and look at options and alternatives to alleviate constraints that may arise that cannot be managed appropriately in real-time by the system controller. These are two distinct and different activities in that system planners can promote system solutions such as new transmission facilities before constraints actually arise while operations planners must look for solutions that can manage constraints under the existing system configuration and conditions. Non-wires solutions such as a RAS may be required if it provides a bridge that maintains reliable system operation in real time and provides an orderly transition for the system controller to the use of the real-time TCM protocol. The AESO has established processes

		to coordinate these activities and encourage appropriate communication between the system planners and operations.
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## 4. Recap of Commission Findings in the TCM Decision

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	<p>The ADC agrees that this rule should only be applicable to real-time events and that generators should receive no payments for being constrained down. Further, if the constraint is a North-South constraint, all exports should be constrained offline before any merit order action is taken. It seems entirely inappropriate to let the pool price rise to facilitate exports because of a transmission constraint.</p>	<p>Acknowledged.</p>
ENMAX	<p><i>[T]he AESO believes that it would be useful to review the Commission findings related to objections on the grounds of public interest and FEOC... to put the discussion of Commission directions in context.</i></p> <p>According to s. 8(9)(a) of the <i>Electric Utilities Act</i>, a member of the Independent System Operator must act honestly, in good faith, and in the public interest. In ENMAX's view, the requirement to act in the public interest implies that the AESO must give significant weight to cost minimization in developing the constraints management rules. Loads pay the bills at the end of the day, and the economic welfare of the public is an important component of the public interest. The public interest should generally receive more weight than other considerations, such as administrative simplicity or a desire to preserve a single price for all generators (provided, of course, that there are FEOC-preserving alternative rules that meet Alberta's legislative requirements).</p> <p><i>In the AESO view, the ruling supported the recommended rule design related to TCM as a real time protocol, relying mainly on economic dispatch of the merit order following the dispatch of TMR, and did not see a requirement for compensation for constrained down generation under regulation.</i></p> <p>ENMAX agrees with the AESO's interpretations that TCM is a real-time protocol and that constrained-down payments are not required, but notes that there are viable alternatives to the AESO's proposals around economic dispatch of the merit order in the presence of</p>	<p>The AESO has many duties prescribed under Act all of which must be carried out in the public interest. The AESO must act on the directions provided in legislation and is guided by government policy principals and recommendations while meeting its mandate to operate the system in a safe, reliable and economic manner and to operate the market in a fair, efficient and openly competitive manner. The AESO makes decisions giving due consideration to all relevant factors within the existing market framework. The AESO acknowledges that administration simplicity is desirable but not the only factor in evaluating alternatives that are consistent with the market design.</p> <p>Please refer to the AESO response to ENMAX in section 5.3.</p>

	congestion, as discussed in section 6.3 below.	
TransAlta	The AESO, in discussing those AUC findings where the AUC determined what the AESO was proposing is not technically deficient or not contrary to a FEOC market, is tending to interpret the AUC findings as endorsing what the AESO is proposing. However, TranAlta's believes the AUC's findings generally cannot be stretched to say that what the AESO is proposing is what the legislation specifically sets out or that the AESO's proposals are the only possible solutions that comply with legislation. In most cases, the AUC has merely determined that what the AESO was proposing is permitted by legislation.	In preparing the TCM paper, the AESO asked for feedback on its interpretation of the AUC findings. The AESO agrees that at a minimum, the AUC findings did determine that what the AESO is proposing with the TCM rule is permitted by legislation. Through the course of extensive consultation on the topic the AESO has considered other approaches included the pay as bid approach that was reviewed in the AESO proposal paper.
TransCanada	Please refer to comments above. (in Executive Summary)	Please refer to the AESO response to TransCanada in the Executive Summary section.

## 4.1 i) Economic Dispatch

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	Any anticipated constraint should be managed with TMR. The circumstance to use this rule should be infrequent. The AESO should report on the frequency of using this rule provision and the resulting cost impact to the market.	<p>The AESO does not believe that TMR should be or can be used to manage all constraints. The Transmission Regulation and government policy directs the AESO to effectively eliminate TMR and use wires solutions to deal with foreseen congestion on the system except in specific and limited exceptional cases. The AESO will continue its current practice of TMR procurement and usage.</p> <p>The AESO has published its annual system assessment entitled "24-Month Reliability Outlook". The assessment provides details on the few regional constraint events that have occurred in the last few years. The AESO will continue to report on regional constraint events and will take into account the cost impact of constraints when performing its duty to plan timely system expansions and enhancements.</p>
ATCO	Just because congestion is foreseen does not change that it is congestion. The operating policies and procedures (OPPs) contain many instances of congestion that are not infrequent and not of a short duration.	<p>The AESO notes that foreseen constraints are defined to be constraints that may occur two or more years in the future and the AESO has a duty to plan the system so that constraints are eliminated under normal operating conditions. To the extent that foreseen constraints cannot be dealt with through timely system upgrades or new transmission, the AESO may consider alternative ways to manage the constraints including contracting for TMR.</p> <p>The AESO's historical data on an area by area</p>

		<p>basis indicates that many instances of constraints were of short duration and infrequent. The fact that an Operating Policy and Procedure (OPP) exists does not necessarily imply that it is needed often as most constraints are a result of contingencies on the system.</p>
<p>ENMAX</p>	<p><i>The Commission ruling on this item clearly permits the use of reverse merit order to dispatch upstream generation as consistent with and permitted under regulation.</i></p> <p>ENMAX agrees that the merit order should determine dispatch, subject of course to reliability requirements. “Reverse” merit order is nothing more than dispatching down the merit order, as the AESO does during every demand down-ramp.</p> <p>ENMAX has no objection to the use of generator-funded DDS as an alternative to RMO assuming DDS payments are very small, but cautions that in many cases DDS actually constitutes a second subsidy from downstream generators to upstream ones. (The first subsidy arises from the downstream generators’ loss of competitive advantage on the <u>delivered</u> cost of energy [energy + transmission], which results from the fact that generators make no material contribution to bulk transmission costs.) Generators located where their output helps alleviate transmission constraints contribute to DDS payments to generators located where their output would exacerbate congestion but for those payments. DDS payments therefore constitute a perverse incentive (albeit a small one so far) to locate generation in the wrong place. DDS would be fairer and would send a better price signal if upstream generators were required to pay for it.</p> <p>ENMAX notes that, if the pool price is established by the intersection of the unconstrained merit order and the demand curve, as discussed in greater detail below, “price reconstitution” becomes unnecessary because TMR will not affect the market price. Consequently, DDS could (at least in theory) be eliminated. Should generators wish to continue to use DDS to manage their risk of being constrained down, it would make sense to have it paid for by generators located upstream of binding</p>	<p>The AESO agrees with ENMAX’s interpretation of “reverse merit order”. The AESO notes that Reverse Merit Order (RMO) usage is supported by government policy and is expected to be effective in constraining upstream generation in a fair, efficient and openly competitive manner</p> <p>The AESO also agrees that there are perverse incentives related to the use of DDS to manage transmission constraints. DDS was designed to mitigate the price impact that TMR has on the market. No matter what the pricing mechanism is, a TMR dispatch for reliability reasons will usually result in constraining a downstream generator or at least not dispatching one because of the constraint. Under the current market design, the DDS rules provide a mechanism for price reconstitution as intended.</p>

	constraints.	
Industrial Power Consumers Association of Alberta (IPCAA)	<p>The AESO needs to consider other options here. Another solution is constraining down downstream load that has contracted for a demand response program.</p> <p>If there are loads that are willing to be compensated by DR payments for curtailing their consumption to alleviate a congestion problem, this should be allowed and encouraged. Load pays for all transmission costs, and as such should be part of the solution to managing temporary lack of transmission. Generators should not receive extra compensation (via increased market prices) due to congestion when they do not pay for transmission. Loads already have Critical Transmission Infrastructure costs looming. Adding to the pool price due to a temporary transmission constraint is unfair, inefficient, and far from open and competitive.</p> <p>There is the possibility of perverse price signals. For example, if there is a constraint between Area A and Area B, and the market price is allowed to rise, bringing on more expensive generation in Area B, while constraining off some generation in Area A, there will be some perverse signals for loads. If a price-sensitive load in Area A sees the higher price, it may curtail and exacerbate the problem. It would be better to treat real-time congestion management the way transmission is treated, as a separate issue. This way, there could be competition from a series of resources, including Demand Response, to meet these temporary needs. If generators want transmission rights they should pay for some transmission costs.</p> <p>More analysis should be done on when these transmission congestion periods occur. If generators who are exporting are being disadvantaged by congestion constraints, than they should pay. Alberta customers should not have to pay higher market prices to allow exporters to profit from congestion issues.</p> <p>If the merit order is to be effectively reconstituted upwards due to congestion, why do we not reconstitute the merit order downwards due to the congestion on the interties preventing imports from entering the province? According to the AESO's logic for in-market solutions, price reconstitution to compensate loads for the delays in procuring import</p>	<p>The AESO released a Demand Response Discussion Paper in October 2009 that developed principles for Demand Response products. Any Demand Response products will be evaluated for consistency with this framework. Paying a downstream load to reduce consumption within the context of the real-time market was identified in the discussion paper as inconsistent with the Alberta market design because a load would be incented to curtail via an ISO rule or program, even if it valued the electricity at a higher price than the market price. This would influence prices, and it is not the AESO's mandate to influence market prices, but rather to ensure price fidelity .</p> <p>The AESO is open to allowing loads to compete for any TMR requirements that are identified.</p> <p>Constraints do not always stem from a lack of transmission and all systems will experience planned or unplanned transmission outages causing constraints. The AESO believes that the pool price has an essential role of providing a real time supply and demand balancing signal. Loss of supply due to a transmission outage impacts supply in the same manner as the loss of supply due to a generation outage and the price signal to the market should reflect the supply situation so that the appropriate market response can occur. Load benefits from having this important balancing function and, as in most electricity market designs, the costs are appropriately charged to load.</p>

	<p>support products to restore the intertie with BC should be made a priority as well.</p> <p>The AESO’s logic for dispatching up the merit order as an “in-market” solution is perverse. If we apply the same logic to the current artificial constraints on imports, as the AESO is unwilling to contract for LSSI, then whenever the hourly price results in import opportunities that are constrained by the absence of LSSI, we should cap the price at whatever the level would have been with unconstrained imports and direct generators to run at these prices – contracting for LSSI is the same as contracting for TMR – and the failure of the AESO to procure these contracts should not result in loads having to pay higher prices – the same as a failure to contract for adequate TMR should not result in higher prices by use of the proposed TCM rule of dispatching up the merit order.</p>	<p>The AESO notes that even in the absence of payments to loads to curtail in transmission constraints situations the pool price provides an incentive to do so. In the example provided by IPCAA the proper signals are sent in most circumstances. Downstream loads are incented to curtail as the prices rises and in most existing constraint areas price sensitive loads are located downstream of the constraint. Generators on both sides of the constraint are incented to generate although the generators in area A are not allowed to increase their generation. In addition, any imports in Area B would also be incented to flow. Furthermore, as generation is restricted due to the transmission constraint the market moves closer to a supply shortfall event. A higher price signals to the market that this is occurring. Without this signal the situation that occurred (using a different protocol than the one proposed) during the SOK transmission constrained event of May 2007 can develop. In that situation the energy market was nearing supply shortfall while the price remained low and there was consequently no competitive response to the diminishing supply.</p> <p>The AESO notes that in the proposed approach to constraints management does not allow exports to flow if their curtailment is effective in managing the constraint.</p> <p>The AESO has committed to pursuing a Load Shed Service for Intertie (LSSi) product to restore import Available Transmission Capability (ATC)</p>
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		and this program is a priority for the AESO. While there are differences between interties and intra-Alberta transmission it should be noted that TMR is required for reliability reasons to prevent load curtailment. While LSSi increases the potential for imports to occur by increasing ATC, there is available generation within Alberta to meet demand. Consistent with the current market design, the existence of greater potential imports does not in and of itself mean that Alberta prices will be lower as imports must expect to receive a price that is competitive with other available markets outside Alberta.
IPPSA	<p>The AESO cites the Commission decision in stating, “The Commission ruling on this item clearly permits the use of reverse merit order to dispatch upstream generation as consistent with and permitted under regulation.”</p> <p>We trust this statement does not obviate our understanding of the AESO’s approach in real time, which is to employ Reverse Merit Order (RMO) within the T-2 period, but then to manage upstream congestion by a pro-rata mechanism after that. We believe this understanding needs to be clearly communicated within any revised rule, as it is in the existing rule.</p> <p>It is also our understanding that the rule will only lead to upstream curtailment after the TMR and DDS steps (step 9.4.4. a) vi) are employed. We believe dispatching TMR in the constrained region and employing DDS in the unconstrained region will effectively resolve all constraints issues, in a matter not at all disruptive to market prices.</p>	<p>When re-submitting the proposed TCM rule, the AESO will ensure that the transmission constraint procedure is clearly communicated and that the use of pro rata after T-2 is currently intended be a proposed part of the rule.</p> <p>The AESO intends to use contracted TMR to manage a constraint when it is effective to do so as outlined in the TCM protocol. The AESO contracts for TMR to deal with specific foreseen regional reliability issues and would use such TMR when those foreseen conditions occur. To be clear, the AESO would not expect to use Calgary area contracted TMR to manage a supply constraint in the Cold Lake or Fort McMurray area and would dispatch up the energy merit order to replace such lost supply.</p>
MEG	MEG seeks confirmation that Economic Dispatch will form the basis for curtailment under relevant OPPs post approval of the TCM Rule	When re-filing a proposed TCM rule, the AESO will ensure that the upstream constrain down procedure is clearly communicated.
Suncor	Indifferent	Acknowledged.

TransAlta	<p><i>1. Economic Dispatch – use of merit order for dispatch instructions aligned with regulations</i></p> <p>The AESO suggests the AUC determined the AESO’s proposal to be “aligned with regulations”. TransAlta believes that it can only be said that the AUC determined that the AESO’s proposal on economic dispatch satisfies the requirements of the legislation.</p>	<p>When re-submitting the proposed TCM rule, the AESO will ensure that the transmission constraint procedure is clearly communicated and that the use of merit order dispatch will be a proposed part of the rule.</p>
TransCanada	<p>Please refer to comments above. (in Executive Summary)</p>	<p>Please refer to the AESO response to TransCanada in the Executive Summary section.</p>

## 4.1 ii) Pool Price Impact

Stakeholder	Stakeholder Comment	AESO Response
AltaLink	<p>In para 117 of AUC Decision 2009-042, in addition to the statement quoted in the AESO's Proposal Paper, AUC also made the following finding "However, the price impact must be monitored and TMR used to prevent or address undue market distortion or the exercise of undue market power". In Alberta's single price energy only market the price impact resulting from transmission congestion is a critical piece of information for market participants to understand the price signals and the cost of insufficient transmission. AltaLink suggests that the AESO provide such information in a timely and transparent fashion by either estimating the hourly price impact and publishing it, or providing information such as stacking order data, number of congestion events, duration, MW volume congested, and others as deemed necessary to allow market participants to perform their own calculation to estimate the price impact resulting from transmission congestion.</p>	<p>With respect to reporting on constraints, the AESO regularly monitors the impact of transmission constraints on the market and has recently published regional transmission constraint data in its annual 24 Month Reliability Outlook. The AESO is currently reviewing the available data and will be enhancing the information provided with more specific metrics where practical.</p>
Alberta Direct Connect Consumers Association (ADC)	<p>By allowing the market price to rise in this event, the signal to load is to interrupt. If the interruptible load is physically located upstream of the constraint, the generators upstream of the constraint will be more severely impacted as there will be less local load to serve. For example in the event of a North-South constraint:</p> <ul style="list-style-type: none"> <li>• northern generators are constrained down, southern generators are dispatched on and the market price rises to the downstream offer price.</li> <li>• With the rising price, northern Alberta load responds by curtailing production (up to 200 MW).</li> <li>• Reduced northern load results in a further constraint of northern generators.</li> <li>• Instead of the pool price responding to the load reduction, it continues to rise as the real time constraint problem increases.</li> </ul> <p>A solution in this circumstance would be to pay northern Alberta price</p>	<p>Please refer to AESO response to ADC regarding the anticipated frequency of Edmonton to Calgary constraints and to IPPCCA in section 4.1i regarding the impact on demand response.</p>

	<p>responsive load to stay running.</p> <p>In response to increased imports, this is only possible with a functioning LSSi product. The timing for rule implementation should be consistent with the intertie operating at full capacity.</p> <p>Further, if TCM is implemented as described in the absence of LSSi, it is logical that anytime imports are constrained down, that the pool price should clear at the marginal unit that would be dispatched if there were no import constraint. i.e. at a lower price.</p>	
ATCO	<p><b>The AESO should strive to minimize the disruption of market prices. We're concerned the AESO has not minimized the impact to pool prices and find the alternative of market suspension as a fall back mechanism unacceptable.</b></p>	<p>The AESO believes the proposed TCM protocol will balance supply and demand in real time in almost all instances with a minimal impact on pool price.</p> <p>Market suspension does not play a role in the management of transmission constraints. The AESO believes that market suspension must only be used as a last resort. If a reasonable approximation of the market is still attainable over a reasonable period of time, the market should remain operational and competitive. Whenever possible, market outcomes should be decided by the actions of market participants participating in the market. The AESO is also of the view that the TCM protocol is robust enough to manage any transmission constraints unless there has been a catastrophic event on the transmission system.</p>
ENMAX	<p><i>The AESO notes the Commission recognizes that the TCM Rule use of the energy market merit order to constrain downstream generation impacts the market price and such impact is expected and is acceptable so long as the AESO strives to minimize the price impact.</i></p> <p>It should be noted that congestion necessarily affects the total cost of providing energy (though congestion-related costs are often less than the cost of the additional wires that would be needed to relieve it), but it</p>	<p>The Alberta electricity market needs a balancing mechanism which can effectively create market responses to increase supply or reduce demand in real time. The Alberta market design utilizes the energy market merit order and a single pool price to perform this function. The AESO is of the view that the loss of supply or load caused by</p>

	<p>need not affect the “market price.” Indeed, the <i>Transmission Development Policy</i> dated December 22, 2003 states (p.15) that, “In principle, real-time congestion or constraints should not alter or distort market prices.” Since methods of resolving congestion are available that do not alter the “market price” at all and that result in lower congestion costs than the AESO’s currently proposed TCM approach, those alternative methods should be favoured over the AESO’s currently proposed TCM approach.</p> <p><i>The AESO interprets the Commission findings to mean that the price impact of the TCM Rule is reasonable under current and anticipated market conditions.</i></p> <p>Stakeholders have too little information about “anticipated market conditions” in the context of transmission congestion to evaluate whether this statement is valid or not.</p>	<p>constraints under “abnormal market conditions” as defined in the Transmission Regulation should be reflected in the price signal so that an appropriate market response can occur. The resulting pool price reflects both the transmission constraint costs and the supply adequacy situation.</p> <p>The alternatives solutions that utilize an “uncongested price“ are not effective or practical in providing the short term balancing function and have other disadvantages as discussed in the AESO response in section 5.2 below.</p> <p>Please refer to the AESO response to ADC in the Executive Summary section regarding the AESO’s view on anticipated market conditions.</p>
<p>Industrial Power Consumers Association of Alberta (IPCAA)</p>	<p><i>“Provided that the EMMO/RMO approach is used infrequently and for periods of congestion of short-duration, the Commission finds that the price impact of the TCM Rule does not, in and of itself, offend the FEOC operation of the market.”</i></p> <p>The AESO should clarify this statement prior to moving forward. There needs to be a clear definition of “infrequently”. Does this mean that centrally procured DR that would be used to manage congestion would be acceptable and not offend FEOC if it were used “infrequently”?</p> <p>How frequent is too frequent?</p>	<p>With respect to the frequency of constraints, the AESO is guided by the Transmission Regulation also allows for a system plan which is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in merit energy can occur when operating under abnormal operating conditions. The AESO notes that the existing system has accommodated over 99% of in-merit energy in the last few years and expects to be well within the 95% limit over the next several years. Please also refer to the AESO response to ADC in the Executive Summary section regarding the AESO’s view on the future frequency of constraints.</p> <p>Please also refer to the AESO response to IPCAA in section 4.1 i) regarding the AESO’s view on centrally procured Demand Response.</p>

<p>IPPSA</p>	<p>The AESO states, “the AESO notes the Commission recognized that the TCM Rule use of the energy market merit order to constrain downstream generation impacts the market price and such impact is expected and is acceptable so long as the AESO strives to minimize this price impact.”</p> <p>How will the “AESO strive to minimize the price impact?” We are concerned about the market operator having a role in its own market; either to maximize or to minimize a price impact. Can the AESO please clarify what this means?</p>	<p>The AESO does not have a role in directly managing the market price; however, the AESO has a duty to ensure that the market operates in accordance with market rules. Constraints require the AESO to take out of market actions and the AESO strives to minimize the price impact of those actions by proposing a rule that is fair, efficient and openly competitive in nature. The AESO believes that the current TCM rule proposal does just that and is the best option, with the least price impact, for managing transmission constraints. The AESO, in looking at the various options that could be used to manage the constraint, is seeking a solution that is an “in market” solution. That is the solution relies on a market response to a price signal and is consistent with the current market design.</p>
<p>MEG</p>	<p>MEG accepts that the AUC found that the use of RMO to constrain upstream generation and the use of EMMO to dispatch downstream generation acceptable on the provision that the AESO strives to minimize the pool price impact. MEG seeks AESO direction as to the metrics to measure the minimization of the pool price impact.</p> <p>MEG suggests that an RMO directive should not cause a participant to be in violation of its environmental permits (e.g. NOx permit) nor cause a material adverse impact on its processes (e.g loss of bitumen production). MEG requests that the AESO confirm these principles in the dispatch of RMO and confirm that these same principles will form the basis of addressing supply surplus.</p>	<p>The AESO regularly monitors the energy market to determine the impact of changes to market rules. In addition the AESO will analyze significant transmission or market events to determine their impact.</p> <p>Generators that are constrained down based upon RMO will be directed to do so. Please refer to the definition of “directive” in the ISO Rules for clarity regarding environmental considerations when under a directive.</p> <p>As all market participants with generators have processes or operational concerns or both, that are as diversified as they are numerous, the ISO Rules cannot contemplate them all. It is recognized that many of the generators on the</p>

		<p>system would not be participating in the wholesale electricity market if it were not for secondary processes but the ISO rules must be fair and create a level playing field for all market participants. So while consideration is given and measures are taken within the rules to accommodate generator operational needs that are not directly related, in general the rules focus on the wholesale electricity market and do not take into account other processes that do not directly relate to competing in that market. It is primarily the responsibility of the participant to manage those processes within the context of competing in the electricity market.</p>
Suncor	See section 4.1 and 4.2 for related comments	Please refer to AESO response to Suncor in section 4.1 and 4.2.
TransAlta	<p><i>2. Pool Price Impact – recognition of transmission constraint impact on market</i></p> <p>The AUC recognized “that it may be impractical or even impossible to resolve transmission constraints without impacting the pool price” but that the AESO should “strive to minimize disruption of market prices as much as possible”. While the AUC recognized there will likely be an impact, this doesn’t mean that any solution that impacts prices is acceptable – the AESO still needs to strive to minimize impact.</p>	The AESO is of the view that the current TCM proposal causes a minimal amount of price impact. The AUC also directed the AESO to consider the legislative framework, the market design in Alberta and the underlying policy elements when reconsidering and revising the TCM rule.(206) The price impact has been considered in that context.
TransCanada	<p>TransCanada wishes to emphasize the following quote referred to by the AESO: “While the Commission recognizes that it may be impractical or even impossible to resolve transmission constraints without impacting the pool price, it expects the AESO to strive to <u>minimize</u> disruption of market prices <u>as much as possible</u>” (para 116) [emphasis added]. In TransCanada’s view this statement obligates the selection of the solution that disrupts the market the least. In this way, price fidelity is the paramount consideration when weighed against other considerations, such as convenience or simplicity.</p>	Please refer to AESO response to TransAlta in this section.

### 4.1 iii) Compensation

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	The ADC agrees that there should be no constrained down compensation for generators.	Acknowledged.
ATCO	<p>ATCO Power acknowledges the AUC decision does not require the AESO to provide compensation. The decision also does not preclude compensation. ATCO Power supports DDS compensation because it results in voluntary action. Reliance on involuntary command and control will distort the market and exacerbate congestion and the potential that the AESO will initiate market suspension. The AESO should consider compensation because it can work.</p>	<p>The AESO points out that DDS does not play a role in the management of transmission constraints. It is a price reconstitution mechanism that is intended to remove the impact that TMR units have on pool price. Used to manage transmission constraints it would introduce perverse incentives including market power issues.</p> <p>The AESO believes that constraining upstream generation using RMO and pro-rata is also a voluntary action as market participants voluntarily provide offers into the energy market which are used in the RMO and pro-rata allocation of curtailment. The TCM protocol uses an in market solution that will not create market distortions when used as anticipated.</p>
Industrial Power Consumers Association of Alberta (IPCAA)	<p><i>“Constrained down payments will not be paid to generators.” This is consistent with the 2003 Alberta Transmission Development Policy paper:</i></p> <p><i>“The real-time congestion scheme should use a reverse merit order to dispatch down units in a congested area, with units not in merit order being paid as bid so that congestion costs are not reflected in the system marginal price. In our market model, it is critical in the relatively few cases where transmission constraints are not removed, real time congestion arrangements should not set or distort market prices. Where generators are paid out of merit to alleviate a transmission constraint,</i></p>	<p>The AESO is directed by regulation and guided by government policy. The Transmission Regulation and government policy directs the AESO to effectively eliminate TMR and use wires solutions to deal with foreseen congestion on the system except in specific and limited exceptional cases. The AESO must also plan the system to accommodate 100% of in merit energy under normal operating conditions. The AESO believes the proposed TCM protocol is the most effective,</p>

	<p><i>the costs of the out of merit payments will be a transmission payment and not a form of uplift in the wholesale energy price. These costs should be allocated in the same manner as other “wires” costs.”</i></p> <p>This same policy document reference indicates that the “EMMO approach” – going up the merit order to alleviate transmission congestion – is not accepted. Out-of-merit generation should be dealt with as “wired costs”.</p> <p>The 2003 transmission policy paper is the same originating document that resulted in loads paying 100% of transmission costs in Alberta. The perception is that this applies only to payments to TFOs – but in cases of congestion the paper rightly points out that a payment for energy upstream of a transmission constraint is merely another payment for transmission – and should not set a new energy price. This appears to be government policy and we are uncertain as to how or why the AESO has chosen to ignore this policy</p>	<p>practical method of providing the required supply demand balancing function during abnormal market conditions.</p> <p>The AESO has not ignored the policy but when considering the implementation of it discovered several issues that were at odds with the energy only market design currently in place in Alberta. Please refer to the AESO response to IPCAA in the Executive Summary section and to the AESO response to ENMAX in section 5.3 for further discussion on this approach.</p> <p>The proposed TCM protocol will be able to manage constraints within the current market design without significant price impacts and at minimal cost</p>
IPPSA	<p>The AESO states, “the AESO interprets the above compensation statements to mean that constrained down payments are not required or even contemplated under regulation.”</p> <p>We trust this statement does not mean that the AESO is reconsidering Dispatch Down Service (DDS), which can be considered a constrained down payment? DDS has been agreed upon by stakeholders as a means to achieve price integrity within the Quick Hits market solutions. DDS is employed to offset the volumes of directed TMR and to restore the market price to where it would have been. Can the AESO please clarify how it will interpret the Commission’s language when it comes to DDS?</p>	<p>DDS is a price reconstitution mechanism designed to offset the impact of TMR on the pool price. Payments are made from one group of generators to another, not by load and as such DDS is not considered to be a constrained down payment. The AESO does not see a need to change the operation of the DDS market at this time and notes that as the need for TMR is eliminated over the next few years so will the need to have DDS be eliminated.</p>
Suncor	See section 4.1 and 4.2 for related comments	Please refer to AESO response to Suncor in section 4.1 and 4.2.
TransAlta	<p><i>3. Compensation – Constrained Down payments inconsistent with regulation</i></p> <p>This is a clear mischaracterization of the AUC findings. The AUC said that “there is no legislative requirement for the AESO to pay compensation to generators who are constrained down”. This cannot be</p>	The AESO agrees that the AUC said that constrained down payments are not required or contemplated under legislation. The AESO is also guided by government policy which prohibits

	<p>said to mean constrained payments are not permitted by legislation; it can only be said to mean that the AESO is not obligated to pay constrained down payments. Thus, the question of whether there are circumstances in which constrained down payments would be appropriate is still open – for example, if constrained down payments were need to ensure a FEOC market then authority to make such payments might be implied by the legislation.</p>	<p>making constrained down payments when there is a constraint except in specific and limited situations where a non-wires solution (TMR) is required.</p>
<p>TransCanada</p>	<p>As the AESO notes, the Commission found that the regulation did not require payment for constrained down generation; however, it did not rule that no payments could be made to generators who are constrained down as a result of congestion. Indeed, as noted by the AESO, the Commission supported the corresponding use of TMR and DDS in applicable but not all constraint events.</p> <p>The AESO has emphasized the following statement of the Commission: “unlike an ancillary service, the generators that are constrained down cannot physically be dispatched up to provide support to the AIES”.</p> <p>TransCanada is concerned about the potential narrowing of the definition of ancillary services from that stated in the <i>Electric Utilities Act</i>, should this statement be relied upon out of context. TransCanada notes that dispatch routinely occurs behind constraints and that ancillary services do not need to involve MW changes to support the AIES.</p>	<p>The AESO is not intending to change or alter the definition of Ancillary Services (AS). Please refer to AESO response to TransAlta in this section regarding the AESO view on constrained down payments.</p>

### 4.1 iv) Transmission “rights”

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	The ADC agrees with the AESO’s interpretation of no transmission rights for generators. Load contracts for DTS firm capacity and pays for transmission access and is still not guaranteed 100% uptime of service. If transmission service is unavailable, load is not compensated for their production loss.	Acknowledged.
ATCO	<b>The AESO should consider constrained down payments.</b>	The AESO has considered constrain down payments and do not consider them to be appropriate to manage transmission constraints. Please refer to AESO response to TransAlta in section 4.1 iii.
Industrial Power Consumers Association of Alberta (IPCAA)	IPCAA agrees with the AESO and AUC positions that generators have no ‘rights to access’ – that was the quid pro quo when loads assumed 100% responsibility for transmission costs – if generators want to have access to export markets then the merchant transmission option remains as the alternative.	The AESO acknowledges IPCAA support of its position on transmission rights and notes that with regard to access to export markets, the AESO must under regulation restore the existing interties to their rated capacity for imports and exports.
IPPSA	<p>The AESO has not commented on, or sought to define, the injection and withdrawal rights described in policy.</p> <p>The Transmission Development Policy states at page 8, in its completeness, <i>“The open access transmission structure in Alberta consists of an implicit system of injection and withdrawal rights for generators and loads. There are no explicit transmission rights. Given this structure, the transmission system must be relatively congestion free or the underlying market model will not function effectively.”</i></p> <p>It may be beyond the AESO’s mandate to define what an injection and withdrawal right is, but the AESO should acknowledge that these rights are conferred in policy, even if not conferred in legislation.</p> <p>It may be worthwhile for the AESO and stakeholders to work with policy-makers to ensure a complete understanding of transmission</p>	The AESO has a duty to provide reasonable system access, operate a FEOC market and a safe and reliable system. The AESO interprets the government reference to an injection right or a withdrawal right to refer to the duty of the AESO to provide generators and load the ability to exchange energy in the power pool through system access service. The supply of electrical energy onto the system is determined by dispatch according to relative economic merit as required under the EUA 17 (c). A generator is entitled to compensation at the pool price for electrical energy actually delivered on the system when it has received a dispatch to do so from the AESO but there is no guarantee that in any minute of any day the AESO

	<p>rights in Alberta. And to design a congestion management regime that best meets the intent of policy and legislation.</p> <p>Our interpretation of an injection right is that when a unit is in merit, it has a right to be compensated for the volume of energy it is offering at the price it is offering it, bound only by any RAS scheme it has accepted, or any transmission emergencies defined in T-Reg S. 15(1)e)ii).</p>	<p>will be able to accept an offer and issue an energy dispatch. Energy dispatch is determined according to the ISO rules and the actual dispatch ordering and timing may be impacted by many factors including, current supply demand balance, inflexible offer blocks, ramp rates, TMR requirements, system frequency and voltage levels, minimum stable generation levels and other system reliability issues.</p>
Suncor	<p>Suncor agrees that while not desirable, the application of RAS is an acceptable short term solution to address real time transmission constraints to allow system recovery, with no financial compensation expected by the owner / generator. However, in no case should the application of a RAS be considered an acceptable AESO response to a transmission deficiency in the long term. It is a reasonable expectation that the AESO implement system upgrades to relieve constraints on the transmission system within three years of a new facility coming into service. It is therefore Suncor's position that the application of a RAS should never exceed three years in duration from the date in which the generator or load has been energized. All cost savings / cost avoidances and the benefits gained by the AIES in not building the required system to alleviate the RAS, should be transferred to the affected customer. In this case, the customer would be entitled to compensation like DDS or have the RAS eliminated.</p>	<p>The AESO does not intend to use system RAS as an alternative to major system upgrades or key transmission paths.</p> <p>Regarding the temporary nature of RAS, the AESO is responsible for preparing and submitting needs identification documents to the Commission which include an estimate of the timing for completion of the required facilities. The AESO notes that there are many factors which are beyond the AESO's control which may alter the timing for completion of the requested facilities. Any customer connection project timeline may impact or be impacted by other customer connection projects and system projects, and their respective timelines. As a result, RAS requirements may change. The AESO regards connection RAS to be a temporary measure but can only provide an estimate as to when the RAS will no longer be required. The Customer can choose to accept the conditions of the RAS before connecting or can choose to wait until the facilities are in fact in place.</p>
TransAlta	<p><i>4. Transmission "rights" – Regulations provide for reasonable system access</i></p> <p>The AUC determined that the legislation requires the AESO to provide system access service, and that the provisions of the T-Reg does not suggest that incumbent generators have any preferential opportunities</p>	<p>Acknowledged.</p>

	to access the AIES.	
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## 4.1 v) Use of TMR/DDS

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	<p>The AESO needs to review the impact of this rule on frequent intervals to ensure that the lowest cost solution is meeting the requirements. If the events are more frequent than anticipated, then TMR should be used to manage the constraint.</p> <p>The AESO should also look at the possibility of a demand response product as an alternative solution. The cost to load of a rising pool price is significant. Paying a downstream load to get off the system ensures that the right load responds and gets compensated for the value they provide to the system.</p>	<p>Please refer to the AESO response to ADC in the Executive Summary section regarding the anticipated frequency of constraint events.</p> <p>The AESO released a Demand Response Discussion Paper in October 2009 that developed principles for Demand Response products. Any Demand Response products will be evaluated for consistency with this framework. Paying a downstream load to reduce consumption within the context of the real-time market was identified as inconsistent with the Alberta market design because a load would be incented to curtail via an ISO rule or program, even if it valued the electricity at a higher price than the market price. This would influence prices, and it is not the AESO's mandate to influence market prices, but rather to ensure price fidelity.</p>
Industrial Power Consumers Association of Alberta (IPCAA)	It is disconcerting that TMR and DDS appear to be referenced as similar products – TMR arises as a result of the need for temporary or lower cost solutions to building transmission – DDS is a service operated by the AESO (with the operating costs attributed to ratepayers) strictly for generators. It is interesting that the AESO is reluctant to provide a similar service for loads as part of a DR program – but provides this “free” service for generators.	The AESO does not regard TMR and DDS to be similar products. Each is designed to address a specific issue and has been supported by stakeholders. As mentioned, TMR is a non-wires alternative used to address reliability issues. DDS is a price reconstitution mechanism designed to offset the impact of TMR on the pool price.
IPPSA	We continue to believe that a TMR/DDS approach is preferable to the AESO's approach. It is less disruptive to the market and is consistent with policy and our market design.	Please refer to the AESO response to IPPSA in the Executive Summary section.
Suncor	Suncor supports the AESO's position on using TMR and DDS to reduce/eliminate transmission constraints in the short term. However Suncor's opinion is that system upgrades are required to eliminate	The AESO has a duty to plan the system such that 100% of in-merit energy can access the system under normal market conditions and is presently

	transmission constraints for the long term.	advancing critical transmission projects. Please refer to the AESO response to IPPSA in this section regarding the appropriate use of TMR/DSS.
TransCanada	It appears that the use of DDS may be expanded as a result of the TCM Rule. As a result, the import of the current DDS rule, and the problems that exist with it should be addressed, including: 1) distortion of pool price by the reference price; 2) the requirement that generators pay for DDS (while also incurring lost opportunity costs from the congestion); and 3) the potential for generators that would otherwise be out of merit to receive DDS.	The AESO does expect that the use of DDS will be expanded as a result of the TCM rule but rather the AESO expects that the use of DDS will decrease in the future as the requirement for TMR on the system is eliminated.

## 4.2 i) Long term investment impact

Stakeholder	Stakeholder Comment	AESO Response
ATCO	<p>There is a big difference between bulk and local congestion. We are concerned with local congestion. Any constraint in a local system could be in place for a long period of time until facilities are built and the situation is corrected. This will have an impact on investment.</p>	<p>The AESO recognizes that constraints have an impact on investment, however, the AESO expects that most local constraint issues are contingency related which are anticipated to be infrequent and of short duration and notes that the Alberta Utilities Commission (the Commission) was not of the view that there would be an adverse impact on the long term investment climate as a result.</p>
Industrial Power Consumers Association of Alberta (IPCAA)	<p>“The short term nature of the TCM rule is not an impediment to long term investment.”</p> <p>IPCAA agrees that AESO proposed TCM rule is not an impediment to long-term investment by generators – but then neither is the ‘pay-as-bid.’ In fact, pay as bid with price disclosure of the constrained dispatch prices may be an incentive to new investment in constrained areas either from generators or loads with DR capabilities.</p>	<p>Please refer to the AESO response to ENMAX in section 5.3 regarding the pay as bid discussion.</p>
MEG	<p>MEG notes that the AESO Proposal erroneously references the AUC findings as paragraph 187; the correct reference is paragraph 186.</p> <p>MEG would find it helpful if the AESO provided information on the frequency and duration that the AESO has utilized EMMO/RMO within the TCM rule in the past three years. This information would help validate the AESO’s assertion that the use of such is expected to be infrequent and of short duration.</p> <p>MEG seeks clarification as to whether the AESO currently has all the tools required to dispatch based on EMMO/RMO for the management of TCM.</p>	<p>Please refer to the AESO response to ADC in Executive Summary section regarding constraints information.</p> <p>The AESO will follow the usual rule consultation process with respect to the TCM rule and has published revised rule language for stakeholder comment. Upon reviewing stakeholder comments on the revised rule, the AESO expects to proceed with final rule language which will be re-submitted to the Commission in 2010.</p>
Suncor	<p>Although Suncor agrees that the application of “the TCM Rule is expected to be infrequent and of short duration”, given the AESO’s current estimates (approximately five years) to construct new major transmission</p>	<p>Please refer to the AESO response to ADC in Executive Summary section regarding constraints</p>

	<p>facilities in the Fort McMurray region, it is our expectation that the TCM Rule will be invoked more frequently and will lead to generators delaying or not developing in the Fort McMurray region. Based on first hand experience, Suncor recently went through an extensive planning review of generation development in the region and due to constraints on the system, almost decided to delay generation by several years. The only impact on changing this decision was the promise of a staged development under the recently-passed Bill 50.</p>	<p>information.</p>
<p>TransAlta</p>	<p><i>1. Long term investment impact – no long term impact expected</i>  The AUC stated that assuming the use of the TCM Rule is infrequent and of short duration, then it is “not convinced that there would be an adverse affect on the long term investment climate to the detriment of the public interest”. The AUC did not say there was no long term impact expected, just that it was not convinced there would be. This leaves it open to argue in future that there is a long term impact, or to argue this point if the TCM Rule is used more than “infrequent and of short duration”.</p>	<p>Acknowledged.</p>

## 4.2 ii) Use of business practices

Stakeholder	Stakeholder Comment	AESO Response
Industrial Power Consumers Association of Alberta (IPCAA)	<p>“This part of the ruling provides AESO some discretion on the use of business practices to meet its duties under the EUA.”</p> <p>As long as there is transparency to the market.</p>	Acknowledged.
MEG	<p>MEG notes that the AESO Proposal erroneously references the AUC findings as paragraph 188; the correct reference is paragraph 187.</p> <p>MEG is of the view that the Commission did not find the use of business practices to be contrary to the public interest, but did reiterate its support for the AESO undertaking the same consultation process for business practices as it does for the AESO rules. MEG requests the AESO confirm its intent to employ the same consultation processes for the development of an ISO rule as for a ISO business practice.</p>	<p>The AESO is currently consulting with industry on the AESO consultation process and the Transition of Authoritative Documents (TOAD) project. The AESO expects in the future Authoritative Documents (ADs or rules) will follow a prescribed consultation process while Information Documents (IDs) may be consulted upon but would not require approval from the AUC.</p>
ATCO	<b>We want adequate consultation that is principled and transparent.</b>	Acknowledged.

## 5 Discussion of Commission Directions in the TCM Decision

Stakeholder	Stakeholder Comment	AESO Response
Industrial Power Consumers Association of Alberta (IPCAA)	IPCAA does not agree with all of the AESO's interpretations of the AUC directions.	Acknowledged.

## 5.1 Clarify the Scope of the TCM Rule

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	The rule should be restricted to real time as it creates an opportunity for gaming. The MSA should also be monitoring down stream bidding behavior to determine if it increases in anticipation of a “real time” constraint.	The AESO has a duty to ensure that its rules promote the fair, efficient and openly competitive operation of the market and will monitor the impact of the TCM protocol in that regard. The rule is intended to manage transmission constraints in real time.
ATCO	<b>Principles need to be aligned. If planning principles are not discussed during the operational phase (real time), it should be done for the planning phase and nothing should be prejudiced by rules that were approached without principles.</b>	The AESO has duties under regulation and has established business practices for transmission planning and system operations. RAS consultation is ongoing and the AESO believes that it will provide clear indication of how the AESO manages connection RAS in the planning stage. The AESO will also be consulting on revisions to the AESO reliability criteria and on new reliability standards which involve further discussions on the use of RAS in the planning domain and will ultimately help create improved well documented comprehensive RAS rules and business practices. The AESO is also guided by the TDP principles with respect to transmission planning.
ENMAX	ENMAX agrees with having one rule for real time and a separate rule for the planning stage. Clearly, the real-time rule must account for whatever congestion management mechanisms are arranged at the planning stage.	The AESO has established business practices which provide for the appropriate transition of information on operating the system from the planning study stage to real-time operations. RAS consultation is ongoing and the AESO believes that it will provide clear indication of how the AESO manages connection RAS in the planning stage.
Industrial Power Consumers Association of	As indicated earlier, TCM is the consequence of not having adequate TMR in an area – and TMR is the interim or permanent solution to ‘just sufficient’ transmission capacity. An unconstrained transmission system does not mean that we require an overbuild of transmission to	The AESO notes that the Transmission Regulation only allows the AESO to use non-wires solutions like TMR in specific and limited exceptions. (Sec

Alberta (IPCAA)	the magnitude that constraints will never occur – TMR as a substitute for transmission wires can be, and often is, a lower cost solution than building wires.	15(2))The AESO is also guided by the TDP which states as a main conclusion that transmission development should eliminate the need for most TMR contracts and remove most congestion areas in the long run and that temporary congestion may occur in abnormal line configurations or in isolated instances of long-term limited growth, or other extraordinary circumstances. (Page 8 Conclusion 7)
IPPSA	<p>We support the AESO’s recommendation to confine its TCM rule to real time congestion circumstances.</p> <p>We also support the AESO’s recommendation to ‘create an information document or flowchart that outlines the AESO’s comprehensive approach to TCM both in the planning stage and in real time.’”</p>	The AESO intends to provide additional information on its approach to identifying constraints in the planning stage as part of the response to the AUC directions regarding rule 9.4.
MEG	<p>MEG supports AESO’s proposal to revise the TCM Rule to clarify that it applies to congestion in real time and as such to formulate separate RAS rules and guidelines and to create an information document or flowchart that outlines the AESO’s comprehensive approach to TCM both in the planning stage and in real time.</p> <p>MEG requests the AESO clarify at which point in the planning stage interconnecting participants will be advised that RAS is a prerequisite of interconnection or that the interconnecting participant will be included in OPPs. MEG believes the AESO has an obligation to provide such notification to interconnecting participants in a timely manner. Notification should be provided such that the requirement for RAS, or the requirement to participate in an OPP, can be incorporated into the interconnecting participant’s investment decision process.</p> <p>MEG seeks clarification if there is a reasonable time period for which a generator (load) that has accepted interconnection RAS will no longer have its interconnection RAS activated prior to the use of the 10 sequential steps listed in section 9.4.4 Given the AESO’s planning horizon, would it be reasonable to expect interconnection RAS will no longer be activated prior to the 10 sequential steps listed in 9.4.4 after a period of 5 years, or 7 years?</p>	<p>The AESO is currently consulting on its existing business practices regarding the use of connection RAS in the planning stage. A discussion paper entitled, “Transmission Constraints Management: RAS in the planning Stage” was issued in July 2009 and we published stakeholder comments on the paper and the AESO response to those comments in December 2009.</p> <p>The AESO believes that the discussion and documentation of RAS business practices will provide clarity to stakeholders regarding constraint management principles used in the planning domain. Such business practices will be integrated into and be consistent with the AESO connection process which is also currently being redesigned and consulted upon. The latest information regarding connection process redesign developments may be found in the customer connection section of the AESO website.</p>

	<p>MEG seeks clarification on the use of generation and load RAS in real time. If a generator (load) accepts RAS in the planning stage and installs RAS prior to interconnection, how is RAS on either of a generator or load activated relative to the 10 steps towards transmission constraint mitigation listed in section 9.4.4? Has the RAS on the generator (load) been activated thereby reducing MWs prior to ISO mitigating the transmission constraint?</p> <p>MEG seeks clarification on how many of the more than 70 RAS schemes currently in place are expected to be resolved through wires solutions in the next 5 years?</p> <p>MEG suggests that the AESO's proposed information document or flowchart also incorporate the interrelationships, and consistency, between TCM and supply surplus. TCM is a subset of supply surplus on a regional basis.</p>	<p>The AESO is intending to use connection RAS only until required facilities are in place and the time period will vary depending on the location and nature of the needed facilities. The AESO is responsible for preparing and submitting needs identification documents to the Commission which include an estimate of the timing for completion of the required facilities. The AESO notes that there are many factors which are beyond the AESO's control which may alter the timing for completion of the requested facilities. Any customer connection project timeline may impact or be impacted by other customer connection projects and system projects, and their respective timelines. As a result, RAS requirements may change. The AESO regards connection RAS to be a temporary measure but can only provide an estimate as to when the RAS will no longer be required. The Customer can choose to accept the conditions of the RAS before interconnecting or can choose to wait until the facilities are in place.</p> <p>Regarding the use of RAS in real time, a RAS is designed to provide automatic protection of system facilities and can activate before or during the TCM protocol procedures if the condition being monitored requires immediate action to resolve. The activation of a RAS in combination with other SC actions will have managed the constraint issue and once the SC determines that the system is under control, the TCM protocol will be applied and generation levels will be restored as appropriate respecting system operating limits.</p>
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		<p>The AESO is developing criteria for classifying the RAS currently listed in OPP 704 into different categories and will identify the existing temporary RAS. Please refer to the AESO TCM Update letter that was published at the same time as this comment matrix for more information on the various TCM initiatives including ongoing work related to OPP 704.</p> <p>TCM is fundamentally different from supply surplus. Supply surplus is the point at which there are multiple \$0 offers at the price floor (\$0) within the energy market merit order, when supply exceeds demand. A supply surplus condition affects the entire market as this energy can be supplied to the market. TCM is a regional constraint in which constrained energy within a local area cannot be supplied to the market.</p> <p>While it makes sense to use similar approaches in TCM and supply surplus there are differences between the two issues, the main one being that there is no transmission constraint involved in supply surplus. The AESO has modeled the supply surplus approach after the approach we have taken to manage supply shortfall.</p>
Suncor	<p>While Suncor supports the real time “only” implementation of the TCM rule, it is unclear how long a “real time” duration lasts. If there are situations where pro-rata has to be applied to generators in a given region for a longer duration (3+ hours), how will generators be compensated or, alternatively, and even more important, what immediate steps will be taken by the AESO / TFO to mitigate the constraint? We require more clarity on this in the TCM Rule.</p>	<p>The TCM protocol is intended to guide the SC in operating the system in real time and is expected to be robust enough to manage constraints that last several hours or if necessary several days. There is no time limit.</p> <p>The AESO has a duty to provide reasonable system access to market participants and the</p>

		current AESO policy is to not compensate generation or load who are constrained down.
TransAlta	Planning TCM. We believe the relevant point in time to determine whether a facility needs a RAS is when the facilities approval is complete. After that point, any RAS scheme should be a system RAS that is paid for by the system, rather than payment by the individual generator who is constrained down due to a system RAS scheme.	The need for a connection RAS is typically determined early in the connection process. However, circumstances can change at any point in the process and if a connection RAS is subsequently determined to be required, the customer must either accept the RAS or choose to wait until required facilities are in place before connecting.

## 5.2 Clarify the TCM/TMR Rule Relationship

Stakeholder	Stakeholder Comment	AESO Response
ENMAX	<p><i>Contracted TMR is used when it is available and effective in managing the constraint. ... Use of TMR is either foreseeable or unforeseeable ... Use of directed TMR is unforeseeable ... The AESO considers foreseeable TMR to be TMR that is required to meet forecast reliability criteria...</i></p> <p>ENMAX suggests that the rules employ the terms “contracted TMR” and “uncontracted TMR.” The main question associated with TMR types in the TCM context is, “Which providers will be dispatched first?” and the answer is that contracted TMR should always be used before uncontracted TMR. The terms “foreseeable” and “unforeseeable” are less clear because the AESO may foresee a need for TMR but in an unpredictable set of hours, or may foresee a need for TMR too short a time in advance to negotiate a contract.</p> <p><i>A local load pocket refers to a load that is somewhat isolated from the rest the system in that it is better served by local generation.</i></p> <p>Can the definition of “local load pocket” be made more explicit? This definition appears to be subjective and somewhat situation-dependent.</p>	<p>The AESO notes that step vi of the TCM protocol specifies that effective downstream contracted TMR would be dispatched if available to manage the constraint. As an example, constrains on energy flows into the Rainbow area could result in the SC dispatching contracted TMR units in that area for reliability reasons. The need for TMR contracts was foreseeable and contracts were put in place in a timely manner to manage the reliability concerns.</p> <p>Step vi of the TCM protocol also contemplates the use of directed (uncontracted) TMR in circumstances where either the constraint that occurs in real time has not been studied or the potential problem was identified but contracted TMR was not yet in place to resolve the reliability issue (an unforeseeable constraint). These are rare events and are usually the result of multiple contingencies.</p> <p>The AESO has eliminated the local load pocket definition and has modified the rule language to directly refer to directing TMR to be in compliance with reliability standards and reliability criteria. A local load pocket type constraint would potentially be one such situation where serving this load from the rest of the system would likely put the load at risk and violate reliability criteria. A local load pocket would be situation-dependent as we would</p>

		not normally plan the system in a manner that creates them.
IPPSA	<p>The AESO's proposal pertaining to use of directed TMR is not clear. The AESO states, "Directed TMR is used only after a risk assessment is undertaken, either in the near term or in real time, and it is determined that there is an unacceptable risk to load or a risk of cascading."</p> <p>We would appreciate answers to the following questions of clarification:</p> <ul style="list-style-type: none"> <li>i) What does the AESO mean by "risk to load" and "risk of cascading"?</li> <li>ii) What are the variables that the AESO needs to consider in making this calculation?</li> <li>iii) How is it possible for the AESO to make this calculation in real time?</li> <li>iv) Surely IPPSA's proposal - of directing-on a unit for TMR in the constrained region and directing off a DDS unit in the unconstrained region - is far simpler and far less risky than taking the time to evaluate whether the AESO's own methodology will work in a given circumstance, and then, if it doesn't, to go about directing TMR and DDS?</li> </ul> <p>The time and subjectivity associated with assessing whether the AESO's own methodology would work in a given circumstance raises further questions of the workability of the AESO's methodology. We would suggest that the AESO's rule needs to be clear to participants about what will happen during congestion in real time and be free of real time decisions and "risk assessments."</p>	<p>The terms risk to load and risk of cascading are terms used in operational engineering when applying technical judgment. The risk is probability of an event, such as an outage, combined with the consequence to create a risk. The risk to load can represent an outage to a large volume of load or poor power quality such as extremely low voltages. Cascading is an uncontrolled successive loss of system elements triggered by an event and results in widespread outages.</p> <p>The variables considered include actual load levels (area or system), generation dispatch levels, equipment condition (transmission, generation, control systems, telecommunications), contingencies (outages) and weather.</p> <p>Operating the system has challenges when the circumstances that create a situation are unforeseen but they are manageable. The AESO has created tools and established procedures including voltage stability studies to guide the SC when performing the required assessments. The AESO currently has a manageable process for assessing the need to direct TMR when required by reliability criteria and the process would continue to be workable under the proposed TCM protocol.</p> <p>Please refer to the AESO response to IPPSA in the Executive Summary section regarding the issues with using a TMR/DDS approach.</p>

<p>MEG</p>	<p>MEG requests the AESO:</p> <ul style="list-style-type: none"> <li>• Clarify the definition of foreseeable TMR. Is it applicable to only those constraints that can be forecast in the period between one and two years away? Does it apply to a forecast period 3 years in the future? Are all TMR requirements forecast within the next 12 months defined as unforeseeable TMR? The AESO's reference for foreseeable is not consistent with that provided in 6.4 – Define Key TCM Rule Terms.</li> <li>• Provide information on the frequency and duration of unforeseeable congestion in the past 3 years as well as the steps taken to mitigate each occurrence and the financial impact on the market.</li> <li>• Identify the local load pockets within Alberta for which TMR has been procured.</li> <li>•</li> </ul>	<p>The AESO considers foreseeable TMR to be TMR that is required to meet forecast reliability criteria under expected operating conditions and planned transmission outages in an area. The need for this TMR must be forecast typically one to two years in advance so that TMR contracts can be reasonably procured. Foreseeable TMR may be identified more than two years ahead of time; however the AESO transmission planning process is intended to eliminate the need for TMR in the longer term and TMR would not be considered an option in the AESO's mandatory ten year plans.</p> <p>TMR requirements that are identified within the next 12 months would be considered unforeseeable as it would be unlikely that the AESO be able to study the constraint, define the technical requirements, issue an RFP and execute TMR contracted in time to manage the anticipated constraint. In these unforeseeable cases, the AESO could use directed (uncontracted) TMR to deal with the reliability issue if directed TMR is necessary and effective in managing the constraint in real time until new TMR contracts became available.</p> <p>The AESO has used directed TMR only five times during the 2006 to 2010 period. The SOK event in May 2007 was the most significant occurrence involving seven generation units and costing some \$5 million. The other events involved only a single generation unit and the total cost for all four was less than \$1 million.</p> <p>The current AESO use of contracted TMR is documented in the 500 Series Transmission OPP's. The OPP's that would be associated with constraints similar to that described as a local load pocket situation would be OPP 501 Northwest Area</p>
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		Operation, OPP 510 Calgary Area Operation and OPP 513 LBC SO Generator Utilization for Transmission Reliability.
Suncor	Suncor supports the use of TMR in TCM applications.	Acknowledged.

### 5.3 Consider ENMAX Pay as Bid Approach

Stakeholder	Stakeholder Comment	AESO Response
ATCO	Aggravates market power concerns and distorts price in constrained market situations.	Acknowledged.
ENMAX	<p>Before providing comments on section 6.3 of the TCM paper, ENMAX will provide a simple example of the pay-as-bid approach. We will also provide a slightly modified approach that addresses some of the concerns the AESO raised about the pay-as-bid approach; this modified approach still meets the requirements of the Commission’s TCM decision and of Alberta’s overall regulatory framework. ENMAX will also present its views on the resulting allocation of costs between energy and transmission. The examples make use of the following diagram, which shows generators and loads in western and eastern regions connected by a transmission path.</p> <div style="text-align: center; margin: 10px 0;"> <p>The diagram illustrates two interconnected power systems. On the left, three generators labeled G1, G2, and G3 are connected to a common bus. A load labeled L1 is also connected to this bus. On the right, two generators labeled Ga and Gb are connected to another common bus. A load labeled La is connected to this bus. A horizontal transmission line connects the bus between G3 and Ga, representing a transmission path between the western and eastern regions.</p> </div> <p>For the remainder of ENMAX’s comments, the pay as bid approach will be referred to as “PAB,” the modified approach will be referred to as “DCP” (for “downstream clearing price”), and the AESO’s proposed protocol will be referred to as “TCM” (not to be confused with the more generic “transmission constraints management.”)</p> <p>Under all constraint management approaches, the merit order and generation dispatch for the entire system in the unconstrained case is as follows:</p>	

ENTIRE SYSTEM	G1	G2	Ga	G3	Gb	L1	La
Unconstrained MW	1000	500	500	50	0	1050	1000
Offer/Bid	0	25	50	60	80		
Max MW	1000	500	500	300	200		

The total load is 2050 MW, the west-to-east flow on the transmission path is 500 MW, and the pool price is \$60/MWh as set by the marginal generator (G3). Under the PAB approach, \$60/MWh is the pool price *regardless of what adjustments are required to alleviate any congestion that may arise*. The total cost to consumers for this hour, excluding wires costs, is \$60/MWh × 2050 MW = \$123,000.

Now assume that the transmission path is constrained to 400 MW, so that 100 MW of upstream generation must be curtailed and 100 MW of downstream generation must be constrained on (there is no change in demand). At this point the generation dispatch changes to that shown in the next two tables, which deal with the upstream (west) and downstream (east) regions, respectively. The X in the “upstream merit order” is the export from the region, while the I in the “downstream merit order” is the import into that region; both are shown simply to demonstrate supply/demand balance in each region.

UPSTREAM SIDE	G1	G2	G3	L1	X
Constrained MW	1000	450	0	1050	400
Offer/Bid	0	25	60		
Max MW	1000	500	300		

DOWNSTREAM SIDE	Ga	Gb	I	La
Constrained MW	500	100	400	1000
Offer/Bid	50	80		
Max MW	500	200		

On the upstream side, regional supply and demand balance with G2 as the marginal generator, so in isolation the region would have an energy

price of \$25/MWh. However, because Alberta has a single-price market, under PAB both G1 and G2 would still receive the unconstrained price of \$60/MWh. From a price perspective, therefore, the upstream generators in the same position they would have been had the transmission system been unconstrained. From a volume perspective, G2 and G3 produce less than they otherwise would have, but as noted in the Commission’s congestion management decision, Alberta’s regulatory framework provides generators with a reasonable opportunity, not an unconstrained opportunity, to access the transmission system. Note that nothing in the PAB model would preclude the use of (1a) DDS to assign the constraints among upstream generators.

At the other end of the transmission path, the “downstream” merit order is used to dispatch generators on (taking account of any TMR contracts that may exist). This is exactly the process proposed by the AESO in its TCM protocol, since it amounts to nothing more than moving up the whole-system merit order and dispatching only those generators that are able to relieve the constraint.

One possible approach to paying downstream generators is “pay as bid,” under which generators would receive the higher of pool price or their offer price. In this example, Ga would get the pool price of \$60/MWh (which, as noted previously, is determined by the intersection of the whole-system demand and unconstrained-supply curves), while Gb would get its offer price of \$80/MWh. In another approach, all downstream generators would receive the “downstream clearing price” (“DCP”) of \$80/MWh. In either case, ENMAX suggests that all payments to generators that occur above the unconstrained pool price be added to the transmission tariff as congestion charges. Doing so avoids any change to the pool price and correctly allocates costs between energy and transmission.

Under the PAB approach, the total cost to consumers (excluding wire costs) would be  $\$60/\text{MWh} \times 1450 \text{ MW} = \$87,000$  for the upstream generators, plus  $\$60/\text{MWh} \times 500 \text{ MW} = \$30,000$  for Ga, plus  $\$80/\text{MWh} \times 100 \text{ MW} = \$8,000$  for Gb, for a total of \$125,000. Since the energy charge does not change from the unconstrained case (it remains, by

1a) The AESO agrees that the PAB model deals only with dispatching up downstream generation and does not speak to the issue of constraining down upstream generation. The AESO notes that DDS is a price reconstitution mechanism designed to offset the impact of TMR on the pool price. A DDS market approach is not effective or practical for managing most constraints on the system.

	<p>definition, at <math>\\$60/\text{MWh} \times 2050 \text{ MW} = \\$123,000</math>), the <math>\\$2,000</math> difference gets treated as a congestion charge and gets recovered through transmission rates.</p> <p>Under the DCP approach, the total cost to consumers would be <math>\\$87,000</math> for the upstream generators (as before), plus <math>\\$80/\text{MWh} \times 600 \text{ MW} = \\$48,000</math> for <i>all</i> downstream generators, for a total of <math>\\$135,000</math>. In this case the difference between the actual cost and the unconstrained cost is <math>\\$135,000 - \\$123,000 = \\$12,000</math>, which amount would be added to the transmission tariff as a congestion charge.</p> <p>Note that under the AESO's proposed TCM approach, the total cost to consumers would be <math>\\$80/\text{MWh} \times 2050 \text{ MW} = \\$164,000</math>.</p> <p>Despite some similarities, neither PAB nor DCP constitute locational marginal pricing ("LMP"). Under LMP, the upstream generators would receive <math>\\$25/\text{MWh}</math>, the clearing price established by the upstream supply and demand curves, as opposed to the <math>\\$60/\text{MWh}</math> they would receive under either PAB or DCP. (In effect, the unconstrained price becomes the <i>floor price</i> for generators.) Also, under LMP the upstream loads would pay <math>\\$25/\text{MWh}</math> and the downstream loads would pay <math>\\$80/\text{MWh}</math>, rather than both paying <math>\\$60/\text{MWh}</math> under PAB and DCP, in accordance with Alberta's single-price model.</p> <p>1b) It should be noted that demand response could also be used to eliminate the congestion. Since the benefits of demand response could include the deferral or elimination of the need for a new transmission line costing millions or billions of dollars, ENMAX submits that that deferral value should be reflected in prices paid for demand response.</p>	<p>1b) The AESO released a Demand Response Discussion Paper in October 2009 that developed principles for Demand Response products. Any Demand Response products will be evaluated for consistency with this framework. Paying a downstream load to reduce consumption within the context of the real-time market was identified as inconsistent with the Alberta market design because a load would be incented to curtail via an ISO rule or program, even if it valued the electricity at a higher price than the market price. This would influence prices, and it is not the AESO's mandate to influence market prices, but rather to ensure price fidelity.</p>
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<p>2) In summary, under PAB or DCP:</p> <ul style="list-style-type: none"> <li>• the pool price (or more correctly the system marginal price) is set by the intersection of the total system supply and total system demand curves;</li> <li>• the resulting generation dispatch is the same as it would be under the AESO's TCM protocol;</li> <li>• upstream generators would receive pool price for their actual production, but would not be compensated (other than possibly through DDS payments) for being constrained down;</li> <li>• downstream generators would receive either: (a) the higher of pool price or their offer price [the PAB model]; or (b) the "downstream clearing price" [the DCP model];</li> <li>• the energy cost for the hour would be <i>pool price x total system demand</i>;</li> <li>• all generation costs in excess of the energy cost [i.e., the sum, over all constrained-on generators, of (<i>actual output</i>) x (<i>generator price – pool price</i>)] are allocated to transmission as a congestion charge.</li> </ul> <p>Having provided the example, we will now return to commenting on the AESO's constraints management document.</p> <p><i>The energy market design depends upon a single clearing price which reflects market conditions including supply and demand on the entire system, supply scarcity and congestion.</i></p> <p>PAB and DCP both result in a single clearing price that reflects supply and demand on the entire system. Scarcity costs—which are <i>transmission</i> scarcity costs, not generation scarcity costs—are correctly reflected in transmission charges. The pool price is not affected by congestion (as required by the <i>Transmission Development Policy</i>), and the correct energy and transmission price signals are sent. In the TCM approach, transmission scarcity masquerades as supply scarcity.</p>	<p>2) In the Alberta design, the pool price provides both the long term price signal for investment and the short term balancing signal for market response in real time. In Alberta's market design to the extent possible, the pool price should reflect all the market factors influencing real time supply and demand. Loss of supply from a transmission system unplanned outage (contingency) needs to be dealt with in the same way as an unplanned generation outage from a market balancing point of view. That is, the price signal should be used to elicit the appropriate market response from generation, load, imports and exports in real time. The price signal should be completely visible and subject to market forces as occurs with the TCM protocol. The Pay As Bid (PAB) and Downstream Clearing Price (DCP) models both create a clearing price that does not reflect the real time balancing needs of the market and in addition they create a price add-on for load which cannot be traded upon and which is only known at the end of the month. PAB and DCP also is at odds with the current market design as they create multiple prices for generators downstream of the constraint, not a single clearing price. Under PAB and DCP, imports are excluded from competing to replace constrained down supply because under the current market there is no mechanism for them to provide non-zero offers. Under current rules imports would receive the unconstrained price under PAB (\$60/MWh in the ENMAX example and not the \$80/ MWh ) and would therefore not be incented to offer to relieve a constraint.</p>
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	<p><i>The Transmission Development Policy recognizes that a congestion free transmission system is a necessary part of the current market design. However, it also recognizes that congestion will occur and that a congestion management plan is necessary. Under regulation, some congestion is anticipated to be part of a normally functioning “unconstrained” electricity market.</i></p> <p>3) ENMAX fully agrees that congestion is part of a normally functioning market, and notes that it is only when congestion costs exceed wires costs that new lines should be contemplated.</p>	<p>In taking this position of having transmission constraints reflected in the market, the AESO is guided by the TDP which indicates that some constraints on the system are to be expected and the Transmission Regulation in fact explicitly allows for constraints under abnormal market conditions. The TDP also recognized that transmission build may at times lag generation and load creating the potential for constraints as well. The AESO does not see a need in regulation or in the market design to distinguish between types of scarcity so long as the cause of the scarcity falls within the expected operation of the market. All causes of scarcity are real and need to be managed efficiently within the market design. The AESO also notes that government policy set out in the DOE Electricity Policy Framework recommends that the present energy only market be maintained and only incremental changes were necessary. (page 22 &amp; page 3) The AESO has implemented many of the recommended incremental changes since that time. The AESO notes that only one of the recommended changes called for a change to the calculation of pool price and that related to removing the impact of TMR on the pool price which lead to the creation of the DDS rules to achieve the recommended price reconstitution.</p> <p>3) The AESO notes that the Transmission Regulation requires the AESO to plan the system such that 100% of in-merit energy can access the system under normal operating conditions (TR sec 15) which would result in no actual congestion</p>
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	<p><i>The proposed TCM protocol manages constraints seamlessly within the current market framework. Any solution must work within the current framework of a single clearing price for the market and common transmission price for the province. While no method being considered is perfect, this method is effective because it:</i></p> <ul style="list-style-type: none"> <li>• <i>causes the least market distortion</i></li> <li>• <i>encourages the proper market responses in most cases, e.g., encourages action by imports and price responsive load and discourages exports through the market price signal</i></li> <li>• <i>discourages generation in the constrained area through volumetric curtailments, and</i></li> <li>• <i>minimizes the AESO’s direct involvement in the market while allowing participants to respond to the price signal.</i></li> </ul> <p>7) As noted above, the AESO’s proposed approach actually causes the maximal market distortion. While raising the system-wide price in a downstream region may encourage the proper market response, raising the price in the upstream region exacerbates the problem by bringing more upstream generation into merit and possibly causing upstream load to get off the system. Under PAB and DCP, the upstream price does not change but the downstream price still encourages the correct market response. No AESO involvement in the market, other than dispatching from the appropriate merit orders, is required.</p>	<p>on energy market bids and offers, however only the TCM protocol maximizes real time market competition from all sources including imports when a constraint occurs. While the AESO acknowledges that PAB and DCP will create real time prices that will tend to be lower than the TCM single market clearing price, the AESO notes that the potential for perverse offer behavior in known constraint areas may result in the total costs to load being similar particularly when there are only a few generators downstream of the constraint. In those cases where there are many potential in-merit downstream generators such as in the Ft. MacMurray area, the difference between the TCM pool price and the all in costs of the PAB protocol will be minimal and the DCP protocol result will be even closer but both will create transparency issues in the balancing market. Further, the AESO’s approach results in downward price pressure through increased competition where as the PAB approach produces increased price pressure through perverse incentives such as the “race to the top” incentive.</p> <p>7) The AESO notes that for most current and anticipated constraints, Alberta’s existing demand response market participants would be located downstream of the constraint and the proper response would be elicited if required. (Ft. Mac, Cold Lake, etc.) With respect to SOK constraints, the AESO anticipates that the TCM protocol will be used infrequently, as indicated in our future congestion study referenced above and will most often not increase the price sufficiently to cause</p>
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<p><i>The proposed TCM protocol provides the best price signal. The use of EMMO provides the most appropriate directional price signal to market participants in all existing congestion circumstances. The price will be set by dispatching the merit order and, where competition exists, the highest priced dispatched offer or bid will set the price. It is possible that lower priced imports will displace higher priced Alberta generation and this is an appropriate outcome. The AESO does not view the pool price as being artificially elevated. It is appropriate for the pool price to rise since less supply is available to the market during congestion. Participants that can relieve the congestion will respond to the price signal and participants that cannot are constrained.</i></p> <p>8) ENMAX believes that it is more appropriate, in the case of a shortage of transmission, that transmission congestion costs rise. Higher congestion costs, rather than higher energy costs, provide a more direct signal that investment in wires <i>may</i> be appropriate.</p> <p><i>The proposed TCM protocol is aligned with policy. The AESO notes that the Transmission Policy stipulates that real time congestion shall not alter or distort prices. The AESO believes that the proposed TCM protocol will result in the least amount of price distortion and the most practical application given the alternatives and is most in line with policy intent.</i></p> <p>9) ENMAX does not believe that a protocol that results in maximal pool price impact is in keeping with policy. Both PAB and DCP produce zero change in pool price from the unconstrained case.</p> <p><i>The proposed TCM protocol is practical and effective. The TCM protocol makes practical, effective use of the energy market merit order and participant offers to the market. Effective upstream generation is dispatched off in reverse merit order and effective downstream generation is dispatched on according to relative economic merit. This establishes the real time market clearing price in a transparent manner. Downstream dispatch is undertaken in a manner which is consistent with the anticipated price impact of congestion events on demand and imports.</i></p>	<p>the upstream price sensitive load to respond to exacerbate the problem. Furthermore, since SOK information is publicly available in real time, upstream price sensitive load will be able to assess the situation and make appropriate consumption decisions.</p> <p>The AESO involvement in the market actually increases significantly under PAB and DCP. In order to accurately and properly dispatch the market, the SC would need to be making determinations on an ongoing basis as to the causes of scarcity. For example, if a transmission constraint does not actually constrain in-merit generation or it occurs during a planned generation outage, does the price need to be reconstituted for the potential loss of supply? There are also situations where the loss of load may be transmission or distribution related or both. The AESO would need to monitor and distinguish the exact cause and reconstitute the price for the potential load that might have occurred and guess how much load and for how long that load might have consumed. If PCB and DCP only measure transmission constraints that impact generation then they do not achieve the stated benefit of capturing all transmission scarcity costs.</p> <p>8) The AESO has a duty to plan the system, determine the need for facilities to alleviate constraints and prepare needs identification documents for AUC approval which includes an economic comparison of options. (TR 11(3)g) The</p>
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<p>10) PAB and DCP will result in the same generation dispatch but much lower costs for consumers. Under PAB, the downstream price is no lower than it would have been absent congestion, and if higher prices are needed to attract additional downstream supply, they are available. The same is true under DCP, the only difference being that all—rather than some—of the downstream resources have access to the higher price.</p> <p><i>The proposed TCM protocol is an in-market solution. The market can provide for a price that reflects the “scarcity” created by transmission congestion – there is no need to go out of market. Scarcity pricing also leads to loads facing the full price of transmission congestion since the cost of congestion is reflected in prices.</i></p> <p>11) Both PAB and DCP are in-market since they make use of the energy market merit order, and they reflect the true cost of congestion through transmission charges.</p> <p><i>The AESO would prefer to use “in market” solutions first before going to “out of market” solutions. As an example, the AESO considers dispatching the merit order and using it to set SMP to be an “in market” solution. ... The pay as bid protocol is an administrative, non-transparent, “out of market” solution. This is at odds with the current market design which centers on a single pool price.</i></p> <p>12) Both PAB and DCP use the same dispatch process as TCM, they just set the pool price and generator payments differently. Neither uses “out of market” solutions and both result in a single pool price.</p> <p><i>A form of this pay as bid approach was implemented in a the previous version of OPP 521 and during a May 2007 constraint event resulted in setting posted prices which failed to signal the need for economic imports and downstream demand response despite the fact that the SC was close to initiating supply shortfall procedures under OPP 801. ... An analysis of the static merit order for the hour indicated that an hourly</i></p>	<p>AESO does not see a need to create a separate administrative calculation of side payments as proposed in the PAB and DCP to fulfill this duty.</p> <p>9) In the Alberta market design, real time supply demand balancing is facilitated by the price signal which elicits the appropriate real time market response to changes in supply and demand regardless of their cause. PAB and DCP do not provide an appropriate market signal for balancing purposes and create after the fact non-transparent side payments that are at odds with the single clearing price model we have in Alberta. The AESO believes that the TCM protocol will provide a real time balancing function with a minimal amount of price impact under anticipated future market conditions</p> <p>10) The generation dispatch would in fact likely be quite different under PAB and DCP because of the potential lack of response by key market participants. PAB and DCP do not provide any real time signal to imports, exports or price responsive load to adjust to changes in real time supply and demand. The AESO believes that the TCM protocol will provide a real time balancing function with a minimal amount of price impact under anticipated future market conditions.</p> <p>11) PAB and DCP are only partially market based because demand and import response is muted. The AESO has a duty to plan the system, determine the need for facilities to alleviate constraints and prepare needs identification</p>
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<p><i>price of \$17.06 / MWh would have been the unconstrained price absent the congestion. Imports did not respond given the Mid C price at the time of \$55 /MWh, probably would not have responded to the “unconstrained” price either.</i></p> <p>13) Under both PAB and DCP, the price paid for energy in the downstream region rises above the unconstrained price. The difference between the price actually paid to generators and the pool price shows up as a congestion charge. There is nothing to prevent the price paid from rising to signal the need for additional supply in the downstream region.</p> <p><i>The AESO would note however that our analysis of more recent SOK events indicate that the payments to “constrained on” generators under a pay as bid model would result in similar hourly payments as the TCM protocol in all but the highest priced hours.</i></p> <p>14) It is mathematically impossible for payments under PAB or DCP to exceed those under TCM. Admittedly, under some circumstances, they may be close. Often, however, PAB and DCP payments would be much less than TCM payments.</p> <p><i>In the May 2007 example, imports may have responded to the higher price signal because the mid-C price at the time was \$55 /MWh. Using a \$10 /MWh transportation cost for delivery to Alberta, the delivery price of \$65 may have been attractive enough for imports to be scheduled placing downward pressure on market price.</i></p> <p>15) Nothing in PAB or DCP would prevent such a response.</p>	<p>documents for AUC approval which includes an economic comparison of options. (TR 11(3)g) The AESO does not see a need to create a separate administrative calculation of side payments as proposed in the PAB and DCP to fulfill this duty.</p> <p>12) The dispatch process may be the same but because PAB and DCP are only partially market based, the generation dispatch will likely be different because demand and import response is muted. The AESO notes that for most current and anticipated constraints, Alberta’s existing demand response market participants would be located downstream of the constraint and the proper response would be elicited. (Ft. Mac, Cold Lake, etc.) Import and export levels may also vary under PAB and DCP. Furthermore, PAB and DCP do not provide an appropriate market signal for balancing purposes and create after the fact non-transparent side payments that are at odds with the single clearing price model we have in Alberta.</p> <p>13) Under PAB and DCP, the unconstrained price does not signal the use of available supply to alleviate the constraint. If 300 MW of Ft. MacMurray supply is temporarily lost due to a line outage, the unconstrained price under PAB will remain unchanged and the market will not know that 300 MW of downstream in-merit generation is dispatched and imports, exports or price responsive load will not receive any signal to respond to the loss of supply. The unconstrained price will move with a subsequent increase in load and the price will rise to reflect the next highest</p>
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*The pay as bid protocol could lead to further out of market responses or market suspension. The proposed unconstrained pool price does not send the appropriate real time price signal to market participants to reflect changed market conditions.*

16) Neither PAB nor DCP are “out of market.” Both send real-time transmission price signals and have no greater risk of leading to market suspension than TCM. A real-time price signal can be sent quite easily because the AESO could post the real-time “downstream” price as well as the real-time SMP and hourly pool price. (In fact, the real-time ancillary services price could be added to the list.) The real-time downstream price is easily derivable from the energy market merit order and the real-time dispatch.

*The pay as bid protocol is unfair and may encourage a race to the top. Consider a situation where two identical and adjacent downstream generators are both dispatched to full. Generator A offered its energy below the unconstrained price and therefore receives the unconstrained price while Generator B offers above the unconstrained price and receives its offer price. The two generators receive different payments for their energy, and Generator A is encouraged to offer its energy at a higher price above the unconstrained price. The result is that the price increases with the potential for perverse offer behavior in addition to the side payments. To avoid a race to the top, additional rules mitigating this perverse offer behavior may be needed, such as locking down offers at the end of the T-2 period. This may result in other potential undesirable market impacts.*

17) ENMAX does not agree that PAB is any more unfair than paying certain generators TMR-related prices under contracts or Article 11. With respect to a “race to the top,” it would work in congested hours only, and would certainly attract the attention of the MSA. Using DCP instead of PAB would eliminate this concern altogether.

*Transmission constraints may occur when new generation is added to the system, until new transmission facilities are built. Under the pay as bid protocol, the unconstrained merit order produces a lower market*

offer, however there will still be no competitive response to the existing real time loss of supply due to the constraint.

14) For most constraints, such as in the Ft. MacMurray, KEG and Crossfield areas, there are many potential in-merit downstream generators. Due to the competitive offers from those downstream generators in the existing merit order, the AESO estimates that in the majority of cases the difference between the TCM pool price and the all in costs of the PAB protocol will be minimally higher and the DCP protocol result will be even closer but both will create transparency issues in the balancing market.

15) PAB and DCP are only partially market based as they do not provide any real time signal to imports, exports or price responsive load to adjust to changes in real time supply and demand to alleviate the constraint and then the price signal given is muted and does not reflect the balancing need.

16) PAB and DCP are only partially market based and could increase the likelihood of market suspension by creating the potential for a “race to the top” among downstream generators. The AESO notes that anytime new rules and practices are introduced into the operation of the market, there is a risk of creating unintended consequences. Forms of the proposed TCM protocol have been in place for several years now. The PAB and DCP approach effectively changes

<p><i>price since it assumes that all new generation is unconstrained and available to be dispatched. The same situation would occur in a supply area like KEG when transmission lines are down for planned maintenance. In both these cases there is less incentive for load to accelerate transmission build or to minimize planned outages. Load already receives the benefit of unconstrained transmission through the lower market price under the pay as bid protocol.</i></p> <p>18) PAB and DCP would start with the same merit order that TCM would use. Thus, any generator that is unavailable for acceptable operational reasons—such as being at the end of a line that is down for maintenance—would be unavailable under TCM, PAB, and DCP. Since this loss of supply results in a higher price in all cases, loads <i>do</i> have an incentive to ensure the timely construction and maintenance of transmission lines that connect generators whose presence lowers the <i>delivered</i> cost of energy.</p> <p><i>Transmission constraints may occur during outages at cogeneration facilities even though the transmission system was not designed nor intended to handle these facilities at full output. Constrained cogeneration supply would lower the market price generated from the unconstrained merit order even though a transmission solution was not warranted or appropriate. There are cases where cogeneration facilities built to primarily serve local load will offer their full electrical output to the AIES during unplanned periods of reduced onsite oil production. This increase in availability may result in a constraint. In this case, the market price would be impacted under the pay as bid proposal.</i></p> <p>19) ENMAX agrees that the existing market design can lead to situations in which there are signals to build even when a transmission solution is neither warranted nor appropriate. The simplest (partial) resolution under the current rules is to use DCP. Consider the following simple example. A single generating unit—either a new unit or the cogen unit that is temporarily producing excess energy—is at the upstream end of a constrained path, while the “rest of the system” is at the downstream end. While the upstream generator would receive the unconstrained price, the rest of the generators would receive the downstream clearing price, which is equal to the price that would have</p>	<p>the current market design since it moves away from having a single market clearing price.</p> <p>17) TMR, whether contracted or directed and paid under Article 11, is used to address reliability issues where there are typically only a few generators that can provide the service and a market based approach is not practical or workable. PAB creates side payments when potentially most of the available generation can provide the service and a market based approach such as the TCM protocol uses provides a more fair, competitive in-market solution compensating all generation equally.</p> <p>18) Under PAB and DCP, the loss of a transmission element whether planned or unplanned results in a constraint and the pool price would be set at the unconstrained level determined before the constraint as if the generation were available. The loss of supply due to a transmission outage would therefore not cause price to rise and not serve as an incentive to load to ensure timely construction and maintenance of transmission lines. The side payments made to generators under PAB may provide some incentive to load in this regard as would the higher price signal under the TCM protocol.</p> <p>19) The AESO concern is not that the existing market design is sending inappropriate signals to build. The concern is that even if a the transmission plan properly accommodates the</p>
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<p>arisen had the upstream generator not existed; this is the outcome one would expect. The difference between the downstream price and the unconstrained price, times the downstream volume, would show up as a congestion charge, which it should since it provides an accurate reflection of the cost of congestion in that hour. Given that this situation would arise in a small number of hours and that the impact of a single generator should be small enough that the “whole system” and “downstream” supply curves should not be materially different, the total congestion charge in respect of the line would be far less than the cost of an upgrade. Thus, there would be no (economic) signal to build where none is warranted. If the congestion cost in respect of a new generator remains below the cost of a transmission upgrade, it means that the generator is poorly located and actually provides a negative benefit to loads.</p> <p><i>In order to avoid such situations under the pay as bid protocol, criteria would have to be developed to distinguish these temporary or permanent situations from more “normal” constraints so that the market price is not unduly impacted. The more exceptions that there are to a protocol, the more difficult it is to understand and implement.</i></p> <p>20) ENMAX sees no greater need for exceptions to PAB or DCP than to TCM.</p> <p><i>Pay as bid has operational implementation issues...</i></p> <p>21) Any congestion management rule will have operational implications. The AESO’s paper cited a case in which the TCM protocol would have cost \$2.3 million compared to \$0.1 million for PAB, which suggests that some expenditures on operational issues is warranted. In any case, PAB and DCP send better price signals with respect to both energy and transmission, so that whatever incremental operational impact there is over TCM (and ENMAX does not expect it to be large) is worth addressing. ENMAX notes again that generation dispatch should be the same under PAB, DCP, and TCM.</p> <p><i>...Requires multiple merit orders (new systems) which distinguish different types of dispatch (energy, pay as bid, TMR, DDS)</i></p>	<p>needs of cogeneration facilities with on site load under normal operating conditions, the PAB protocol could result in an inappropriately lower unconstrained pool price during operational upsets that cause transmission constraints at cogeneration facilities.</p> <p>In ENMAX’s example, the “whole system” price under DCP would be effectively the same as under the TCM protocol. The AESO does not believe that it is appropriate under the current market design to pay upstream generators a lower price for the energy that they are able to deliver into the market. The AESO also notes that it would be a difficult, theoretical exercise to determine what the unconstrained price should be as conditions change during the constraint event.</p> <p>20) The TCM protocol does not require any exceptions for constraints that can be managed by the system controller in real time. PAB and DCP require the clear classification and tracking over time of transmission constraints from other types of constraints to properly determine the unconstrained price. The AESO believes that this requirement will lead to exceptions and additional clarifying practices and procedures in implementing PAB and DCP.</p> <p>21) Forms of the proposed TCM protocol have been in place for several years now without operational issues. Full implementation of the TCM protocol will primarily involve system</p>
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	<p>22) There is no change in dispatch between TCM, PAB, and DCP; only the resulting prices and payments change.</p> <p><i>...Need to determine whether downstream demand opportunity service (DOS) gets curtailed before you begin to dispatch downstream generation on a pay as bid basis.</i></p> <p>23) ENMAX believes that, regardless of what the congestion management rules are, the handling of DOS must be addressed. Further, as an <i>opportunity</i> service, it should only be available when there is sufficient transmission capacity to support it, so it should be curtailed before any transmission congestion costs are incurred.</p> <p><i>...Multiple constraints may not be easily or accurately handled.</i></p> <p>24) ENMAX sees no reason why multiple constraints should be difficult to handle. If the SC can figure out which generators contribute to or alleviate constraints—as clearly he must do to dispatch generation—then the tools necessary to handle multiple constraints can be developed. As noted previously, the proposed TCM protocol produces the maximal cost impact for loads, so expending the resources to get this right is well worth the investment.</p>	<p>changes to more easily handle the reverse merit order and pro-rata curtailment calculations required. The AESO expects that it will be much more difficult to properly incorporate the PAB protocol within its systems. Please also refer to the AESO response to ENMAX below. (reply 22)</p> <p>22) Economic dispatch includes the determination of SMP and Pool Price. Dispatch instructs generators to their required output level. In order to determine a pool price on the unconstrained merit order the dispatch system would need to also set a virtual dispatch level for each generator as if the constraint did not exist. This virtual merit order (reflecting the virtual dispatch levels) and the ability to set SMP based on it do not exist in the system today.</p> <p>23) Demand Opportunity Service (DOS) is directly addressed with TCM protocol and is appropriately and consistently managed today. PAB and DCP require the clear classification and tracking over time of transmission constraints from other types of constraints to properly determine the unconstrained price and will lead to different treatment of DOS depending on the classification methodology used.</p> <p>24) Multiple constraints will be difficult to handle because, even though the SC knows which generation units contribute to or alleviate constraints, the SC dispatches the merit order until a supply demand balance is reached. There may be many reasons why the actual energy that is</p>
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<p><i>...Potential for an artificial price cap below \$1000 being created during a supply shortfall if transmission constraints are also present.</i></p> <p>25) As discussed, prices in constrained regions are allowed to rise sufficiently to allow supply to meet demand. There is no artificial price cap.</p> <p><i>...Incompatible with current TMR and DDS systems and procedures</i></p> <p>26) Please see the above comments on implementation issues.</p> <p><i>... Separation of dispatch from SMP could cause transparency issues for market participants.</i></p> <p>27) Dispatch under PAB and DCP will be the same as under TCM, but the former provide better energy market and congestion price signals.</p> <p><i>...Imports are [a] significant portion of peak supply and can be scheduled hourly to address extended constraint events. AESO is not a participant in the market and therefore does not have a mechanism to procure imports for the market in the absence of the proper price signal. Most market participants including loads can procure and schedule imports if there is an appropriate price signal in the market.</i></p> <p>28) PAB and (particularly) DCP allow prices to rise as needed to attract imports. The AESO need not act as a market participant.</p> <p><i>The AESO believes the price signal is the appropriate method of attracting supply to the market and encouraging fair, efficient, and openly competitive behaviors. Out-of-market actions should be avoided whenever possible and their impacts minimized when they are necessary. The pay as bid protocol creates out of market payments and may lead to perverse offer behavior.</i></p> <p>29) Energy prices affected by congestion costs do not provide a good method of attracting supply to the market because it can be difficult to determine what prices will be once certain transmission constraints are relieved. As noted previously, neither PAB nor DCP are “out of market.”</p>	<p>delivered onto the system is different that merely the sum of the energy dispatches. In essence the SC monitors actual total energy that is supplied on to the grid and maintains the supply and demand balance by issuing dispatches on an incremental basis from that balance point with those incremental dispatches setting the minute to minute SMP. In the PAB protocol, the SC would have to create tools and processes to monitor multiple actual energy balance points within the multiple constraint areas and compare that to the balance point for the system as a whole in order to accurately calculate the unconstrained price. The AESO does not currently have this capability and expects that this capability would not be easy to accurately attain.</p> <p>25) The energy market merit order typically has only a limited amount of energy priced between \$300 and \$1000 per MW. During a supply shortfall event, if several hundred MW of available supply are being paid as bid due to a transmission constraint, the unconstrained price may end up being set considerably below the \$1000 level. While supply shortfall events are very infrequent, this price cap issue does not occur under the TCM protocol.</p> <p>26) Please refer to the AESO response to ENMAX on operational issues in this section above.</p> <p>27) The generation dispatch would in fact likely be quite different under PAB and DCP because of the potential lack of response by key market</p>
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<p><i>The AESO believes that the adopted protocol should be effective, practical and work within the current market framework. The TCM Rule is compatible with OPP 801 Supply Shortfall in that the pool price rises as undispached and available supply diminishes and the top of the energy market merit order is reached. Once this happens out of market actions are used as set out in OPP 801. OPP 801 has provision for acquiring imports and other supply along with various steps to mitigate supply shortfall. All transmission limits and requirements are respected to ensure the transmission system is not placed at risk. The pay as bid proposal fails to signal scarcity conditions during supply shortfall events which could lead to further out of market actions.</i></p> <p>30) ENMAX is not aware of anything in PAB or DCP that would preclude the use of OPP 801 if it's needed. The price in the constrained area is allowed to rise sufficiently to avoid supply shortfall events (provided, of course, that supply is physically available), so no more out-of-market actions are required with PAB or DCP than with TCM. Since PAB and DCP use the same dispatch as TCM, the transmission system would not be placed at risk.</p> <p><i>The AESO believes that a single protocol to deal with congestion is appropriate. Congestion may occur for many reasons such as planned maintenance or forced outages of transmission facilities or critical generation units or inadequate transmission. The pay as bid protocol is not appropriate in all instances of transmission constraints and has implementation issues.</i></p> <p>31) ENMAX agrees that a single protocol to deal with congestion is appropriate. Because TCM creates the maximal cost impact for consumers, it is not appropriate to deal with large or long-duration congestion events. ENMAX agrees that there <i>may</i> be circumstances in which special rules are required, though it does not see this as any more likely with PAB or DCP than with TCM. Please see ENMAX's previous comments on addressing planned maintenance or forced outages of transmission facilities.</p> <p><i>It is the AESO view that the TCM protocol minimizes the price impact and the level of market distortion:</i></p>	<p>participants. Further, dispatch and price are delinked during constraint events and generators will not know why they are being dispatched until after the fact. PAB and DCP do not provide any real time signal to imports, exports or price responsive load to adjust to changes in real time supply and demand. The AESO believes that the TCM protocol will provide a real time balancing function with a minimal amount of price impact under anticipated future market conditions.</p> <p>28) PAB maintains an unconstrained price and no price signal to imports to alleviate the constraint. The AESO may have to act as a market participant if there is no market response. DCP would provide a better price signal than PAB but it would still be muted compared to TCM protocol price. The AESO would also need to publish an estimated DCP price as well as the unconstrained price in real time. The estimated DCP in most instances would be reasonably close to the price under the TCM protocol and, being an estimate, may not elicit the desired market response from imports because the importer would not know for sure what price they would actually receive until some time later when a final DCP is determined. This would considerably dilute the benefits the DCP sought to obtain.</p> <p>29) Please refer to the AESO response to ENMAX on PAB and DCP being out of market (reply 2) and on the AESO's planning duties (reply 11) in this section above.</p>
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<ul style="list-style-type: none"> <li>• <i>Prices are allowed to reflect market economics for other system congestion cases wherein a market response is appropriate.</i></li> <li>• <i>While allowing prices to rise may in some instances be more costly than the pay as bid model, the resulting price is a result of market economics and sends correct signals. The AESO has looked in detail at a past SOK event and determined that the cost to load of using the TCM protocol would actually have [been] comparable to using the pay as bid approach.</i></li> <li>• <i>Pay as bid mechanisms create out of market payments to specific generators which has the effect of unnecessarily distorting the price signal which is contrary to government policy.</i></li> </ul> <p>32) ENMAX submits that PAB and DCP create a lower cost impact than TCM, more appropriately reflect (energy and transmission) economics, and do not rely on out-of-market payments.</p> <p><i>The AESO notes that any TCM protocol should be robust enough to manage any constraint regardless of duration or size and allow the normal functioning of market fundamentals to occur in a manner consistent with market design. The TCM protocol is not intended to deal with situations where the constrained event leads to market distortions which prevent the market price from reflecting underlying market fundamentals. These situations, should they arise, will be dealt with appropriately through other means.</i></p> <p>33) ENMAX submits that PAB and DCP are superior to TCM because they accomplish the same thing at lower overall cost.</p> <p><i>Severe market distortions are not constraints management issues and should there be a need these situations will be dealt with appropriately through other means.</i></p> <p>34) ENMAX agrees that severe market distortions that arise through anticompetitive behaviour must be appropriately dealt with through other means, but severe market distortions introduced by constraints management rules must be dealt with by the AESO at the rule-making stage.</p>	<p>30) Please refer to the AESO response to ENMAX on PAB and DCP being out of market (reply 2), on dispatch differences (reply 27) and on supply shortfall issues (reply 25) in this section above.</p> <p>31) The AESO does not expect implementation of the Transmission Constraints Management (TCM) protocol to result in high pool prices. Recent analysis indicates that the frequency and duration of future constraints should be primarily contingency related and accommodated within the normal operation of the market without significant price impacts. Please refer to the AESO response to ENMAX on PAB and DCP requiring exceptions and special processes (reply 20) in this section above.</p> <p>32) PAB is an out of market payment for energy delivery inconsistent with the current market design. Please also refer to the AESO response to ENMAX on PAB and DCP being out of market (reply 2), on total cost differences between protocols (reply 6) and on transmission costs (reply 11) in this section above.</p> <p>33) Please refer to the AESO response to ENMAX on PAB and DCP not performing the balancing function as effectively (reply 2), on dispatch differences (reply 27) and on total cost differences between protocols (reply 6) in this section above.</p> <p>34) The TCM protocol will not introduce severe market distortions but will manage the system reliably if they occur. Recent analysis indicates</p>
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		<p>that the frequency and duration of future constraints should be primarily contingency related and accommodated within the normal operation of the market without significant price impacts.</p>
<p>Industrial Power Consumers Association of Alberta (IPCAA)</p>	<p>1) First of all, the AESO should acknowledge that statements such as “The pay as bid protocol removes the impact of a constraint from the pool price and, in ENMAX’s view, is consistent with government policy that congestion arrangements should not set or distort market prices” are misleading and prompt stakeholders to believe that the AESO is marginalizing ENMAX. The <i>2003 Alberta Transmission Development Policy</i> paper states that:</p> <p>“The real-time congestion program should use a reverse merit order to dispatch down units in a congested area, with units not in merit order being paid as bid so that congestion costs are not reflected in the system marginal price. In principle, real-time congestion or constraints should not alter or distort market prices.”</p> <p>Thus it is not ENMAX’s view only, but a correct statement of the Government of Alberta’s view as well.</p> <p>“The proposed TCM protocol is an in-market solution. The market can provide for a price that reflects the “scarcity” created by transmission congestion – there is no need to go out of market. Scarcity pricing also leads to loads facing the full price of transmission congestion since the cost of congestion is reflected in prices.”</p> <p>2) This is likely the most capricious statement in the entire TCM document. To suggest that somehow a congestion event is an energy scarcity and therefore all loads should pay generators a windfall scarcity premium in energy price causes loads to wonder whether the AESO is being objective and unbiased – and then to attempt to justify this as being ‘in-market’ simply adds salt to the wound. ‘In-market’ from whose perspective? Certainly loads do not see dispatching up the merit order as a result of some generators being constrained from exports as being</p>	<p>1) The AESO is of the view that the current TCM proposal causes a minimal amount of price impact. The AUC also directed the AESO to consider the legislative framework, the market design in Alberta and the underlying policy elements when reconsidering and revising the TCM rule.(206) The price impact has been considered in that context. The TCM rule incorporates a market alternative that aligns with the current market design.</p> <p>2) Constraints do not always stem from a lack of transmission and all systems will experience transmission outages causing constraints. The AESO believes that the pool price has an essential role of providing a real time supply and demand balancing signal. Loss of supply due to a transmission outage impacts supply in the same manner as the loss of supply due to a generation outage and the price signal to the market should reflect the supply situation so that the appropriate market response can occur. Load benefits from having this important balancing function and, as in most electricity market designs, the costs are appropriately charged to load. Effective exports are curtailed before upstream generators are constrained down and downstream generators are dispatched on so exports do not cause loads to pay higher prices.</p>

<p>'in-market' with respect to the energy price in Alberta.</p> <p>3) Transmission congestion should not be considered a scarcity event. Transmission issues should be dealt with outside of the energy market.</p> <p>Loads are already paying for ALL transmission. If congestion is to be managed through the energy market, why is there TMR outside of the energy market? Why not move to locational marginal pricing? Why is the AESO picking and choosing which aspects of transmission fall in the "energy" pot, and which fall in the "transmission" pot? This is not at all fair to loads because it artificially distorts the price signal.</p> <p>"The AESO would prefer to use "in market" solutions first before going to "out of market" solutions. As an example, the AESO considers dispatching the merit order and using it to set SMP to be an "in market" solution."</p> <p>4) The AESO should recognize that it is actually reconstituting the merit order upwards, not being neutral to the marketplace. Reconstituting the price is an out-of market solution.</p> <p>As mentioned earlier the same logic could be applied to constrained imports due to lack of LSSI – and the price would be capped at the level of the constrained imports – with generators dispatched at the constrained price – or at their 'bid' price but only paid to that generator. This would seem to be a totally 'in-market' solution according to the AESO concept of "in" and "out" of market solutions based on constrained resources – a constrained inter-tie then would have the same impact as a constrained transmission line.</p> <p>"The pay as bid protocol is an administrative, non-transparent, "out of market" solution."</p> <p>5) The pay-as-bid solution has been used effectively in other jurisdictions and is no more "out-of-market" than the AESO's administrative, non-transparent solution of solving a transmission issue by reconstituting the merit order upwards.</p>	<p>3) In the Alberta design, the pool price provides both the long term price signal for investment and the short term balancing signal for market response in real time. The AESO believes that it is important in our market design that to the extent possible, the pool price should reflect all the market factors influencing real time supply and demand. Loss of supply from a transmission system unplanned outage (contingency) needs to be dealt with in the same way as an unplanned generation outage from a market balancing point of view. That is, the price signal should be used to elicit the appropriate market response from generation, load, imports and exports in real time.</p> <p>TMR is an "out of market" non-wires alternative which is not aligned with the current market design and the AESO has a duty under the transmission regulation to eliminate the use of TMR with only specific and limited exceptions.</p> <p>The AESO notes that Electricity Policy Framework recommends that the present energy only market be maintained and therefore consideration of other market design is not an option at this time.</p> <p>4) The proposed TCM protocol is an effective, in-market solution compatible with the current market design in that the impact of a constraint is managed through dispatch of the existing merit order and the pool price transparently as occurs in an unconstrained market. The constraint requires a corrective action and the TCM protocol uses the existing market design to provide that action in a</p>
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	<p>The AESO already uses this mechanism for payments to generators that are not dispatched for a full hour, and then recovers the costs through an uplift charge. In this instance the recovery would be through a transmission surcharge similar to TMR payments – the inability of the AESO systems to accommodate a fair solution should not be an excuse to ‘not do the right thing’.</p> <p>“The pay as bid protocol is not appropriate for all types of constraint situations and may create perverse incentives”</p> <p>6) Perverse incentives are created by raising the entire market price for a transmission issue.</p> <p>The examples used by the AESO as ‘perverse incentives’ are a bit faulty in their logic – in that even though the payments to constrained generators may be higher – it is only for the volume that they generate – and the rest of the generators are paid the lower price – proper analysis would indicate that the total cost to loads would be lower under all circumstances for a ‘pay-as bid’ model.</p> <p>“While allowing prices to rise may in some instances be more costly than the pay as bid model, the resulting price is a result of market economics and sends correct signals.”</p> <p>7) IPCAA strongly disagrees with this statement. The AESO is effectively deciding that a higher price is better. How does this send a proper price signal to the marketplace? Are generators going to relocate their plants to better suit a temporary transmission constraint? Are loads nowhere near the constraint going to fix the problem by curtailing their demand? This is a transmission issue that should not be dealt with in the energy market. The price signal feedback loop will never encourage market participants to effectively alleviate the congestion problem. This will only create perverse incentives.</p>	<p>competitive in-market manner. Please refer to the AESO response to IPCAA in section 4.1 i) regarding the AESO approach to LSSi.</p> <p>5) The AESO regards pay as bid as being out of market in the sense that the administration payments are made after the fact and do not elicit any market response in real time to balance supply and demand. The TCM protocol is compatible with the current market design all generators are paid equally for supplied energy at a single, transparent price. Other jurisdictions who use PAB have different market designs with more than one price setting mechanism.</p> <p>Payments to Suppliers on the Margin (PSM) rules were intended to address the discrepancy between the dispatch and settlement intervals giving generators a greater opportunity to receive payments based on their actual offer price and were intended to improve price fidelity. The AESO agrees that system challenges should not be an excuse to not do the right thing but believes that issues such as AESO system costs and challenges need to be considered in any market change.</p> <p>6) The AESO believes that the TCM protocol will provide a real time balancing function with a minimal amount of price impact under anticipated future market conditions. The TCM protocol provides a real time signal to imports, exports and price responsive load to adjust to changes in real time supply and demand which will work to reduce</p>
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		<p>the price impact of the constraint.</p> <p>7) Constraints are generally contingency related and a responsive price signal is the best means of eliciting a competitive real time response from generation and load to deal with the temporary constraint issue. The AESO is required under regulation to alleviate longer term congestion issues by forecasting load and generation while planning the system to meet established reliability criteria. The TCM protocol will not impact the long term market price and the planning process any more than the alternative approaches considered. Please also refer to the AESO response to ENMAX in section 5.3 regarding transmission build signals (replies 18&amp;19) and capturing congestion costs (reply 8 &amp; 11) and to IPCAA above in this section regarding the balancing function of the TCM protocol (reply 6).</p>
<p>IPPSA</p>	<p>1) We do not support the AESO’s view that “the energy market design depends upon a single clearing price which reflects market conditions including supply and demand on the entire system, supply scarcity and <i>congestion.</i>” (italics added)</p> <p>Where is this view of the market defined for the AESO in legislation or even policy? Quite the opposite, the TDP states on page 15, “<i>In principle, real-time congestion or constraints should not alter or distort market prices.</i>”</p> <p>The AESO further states, “The Transmission Development Policy recognizes that a congestion free transmission system is a necessary part of the current market design. However, policy also recognizes that congestion will occur and that a congestion management plan is necessary...” To be fair to stakeholders, the AESO should also communicate that the TDP warns against creating a congestion management scheme like the one the AESO has proposed.</p>	<p>1) The AESO has many duties prescribed under Act all of which must be carried out in the public interest. The AESO must act on the directions provided in legislation and is guided by government policy principals and recommendations. The AESO has a duty to operate the system in a safe, reliable and economic manner and to operate the market in a fair, efficient and openly competitive manner and makes decisions giving due consideration to all relevant factors within the existing market framework. The AESO is fully aware of the references in the TDP noted by IPPSA and is guided by the intent of</p>

	<p>We draw the attention of the AESO and other stakeholders to the appendix of the TDP, which states, “...congestion costs are not (to be) reflected in the system marginal price.” (bolding and parentheses added.) And, as noted above, “In principle, real-time congestion or constraints should not alter or distort market prices.”</p> <p>While the AESO makes repeated references to the TDP in justifying its methodology, the AESO does not communicate to stakeholders that the TDP endorses the pay-as-bid model. At page 15, the TDP states, “The distortion in the system marginal price may be avoided if generators dispatched out of merit are paid their offer price less the system marginal price to relieve the congestion. The system marginal price therefore remains at a level it would have been at without congestion and generators dispatched out of merit are “kept whole” and are provided their offer price less the Pool Price for the energy provided.”</p> <p>In its “case for the proposed TCM protocol”, the AESO states, “The proposed TCM protocol manages constraints seamlessly within the current market framework. Any solution must work within the current framework of a single clearing price for the market and common transmission price for the province.” And that “The proposed TCM protocol is aligned with policy.” This is simply untrue as noted by the quotes provided from the TDP above.</p> <p>2) In its “Issues with the TCM protocol” the AESO states, “In the unlikely event that a market distortion occurs such that the price is not reflective of market fundamentals such a distortion is not a constraint management issue and will need to be dealt with appropriately through other means.” Can the AESO please clarify what this means?</p> <p>Contrast this statement to the AESO’s plan in section 6.2 of this discussion paper as noted above. In section 6.2, the AESO confirms that it will only proceed with its methodology after an internal, real time risk assessment. However, if participants act in a manner consistent with the AESO’s rule, it seems entirely inappropriate for participants to face “other means”, should the AESO’s rule lead to ‘market distortions’. And who determines these distortions?</p>	<p>that policy. In the AESO’s view, the proposed TCM protocol is aligned with government policy in that it minimizes the price impact and the level of market distortion compared to alternative approaches and is compatible with the current market design. Please also refer to the AESO response to ENMAX in this section regarding the issues with a pay as bid approach to managing constraints.</p> <p>2) The AESO believes the proposed TCM protocol will balance supply and demand in real time in almost all instances with a minimal impact on pool price. Please refer to the AESO response to TransCanada in the Executive Summary section regarding the AESO identification and approach to severe and sustained market distortions. Also see the AESO response to ATCO in that same section regarding the AESO approach to market suspension.</p>
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MEG	<p>MEG supports the AESO's recommendation not to implement the pay-as-bid protocol as it is an administrative, non-transparent and "out-of-market" solution.</p> <p>When a similar approach was employed during the period December 2000 to December 2001 (Pool Price Deficiency Regulation), it provided perverse incentives for import supply to "race to the top".</p>	Acknowledged.
Suncor	Suncor does not support the pay as bid approach.	Acknowledged.
TransAlta	Can the AESO define what is meant by a severe market distortion	Please refer to the AESO response to IPCAA and TransCanada in the Executive Summary.
TransCanada	TransCanada does not support the pay as bid approach as it risks distorting the market in both the short and long term.	Acknowledged.

## 5.4 Define Key TCM Rule Terms

Stakeholder	Stakeholder Comment	AESO Response
ENMAX	<p><i>Real time:</i> Is there merit in defining “real time” to be the period within the T-2 window?</p>	<p>In carrying out its duty to operate the system in a safe, reliable and economic manner, the AESO must take action in time frames that range from fractions of a second, minutes, ten or twenty minute intervals, within the settlement interval or twenty minutes before the start of the settlement interval all of which are stipulated in various reliability standards, reliability criteria, system operating limits, OPP’s and WECC agreements. The AESO’s proposed definition for real time refers to the actual time during which a process or events occurs is broad enough to cover the timeframes involved in the various SC activities contemplated by the TCM rule. The AESO prefers a more general definition as that used by NERC.</p>
Industrial Power Consumers Association of Alberta (IPCAA)	<p>The AESO needs to consider what the term “in-market solution” means. There appears to be a significant difference between an “in-market solution” from a generator perspective than from a load perspective. Loads pay a delivered cost of energy to their facility or home – this cost includes distribution, transmission, reliability payments (ancillary services) and energy. When Alberta moved to a 100% transmission cost to loads, the relevant energy price is the price at the generators facility – all other costs are one of the other three components. None of those three (transmission, distribution, or reliability) should be a factor in determining this unconstrained price of energy. This is a consequence of the transmission policy adopted in Alberta, and until it is changed the AESO and AUC must treat generators as energy originators at their facilities, with no windfall benefits from any of the other cost factors.</p>	<p>In any market design, there must be a mechanism which balances supply and demand on a minute by minute basis. In the Alberta market design, the real time dispatch performs this function through the pool price signal and that same pool price which is ultimately charged to loads that consume in the hour and paid to generators who produce electricity in the hour. The AESO rules are designed to ensure that the pool price is determined in a FEOC manner with no discrimination or windfall gains to market participants.</p> <p>The AESO refers to in-market solutions as being those solutions which are derived from market or competitive actions. An in-market solution is designed to allow generation and load to compete</p>

		to provide the service required. The AESO may be responsible for creating the framework for the competition but is not directly involved in the determination of the final result.
IPPSA	<p>On the definition of “foreseen and unforeseen”, for clarity we would suggest the following: “The AESO considers foreseeable TMR to be TMR that is required to meet forecast reliability criteria <u>in the period beyond the delivery hour and</u> two years in the future under expected operating conditions and planned transmission outages in the area.”</p> <p>The AESO continues, “The AESO uses directed TMR in unforeseeable circumstances, that is, the need for TMR is not planned for within the two year planning criteria.” Just to be clear, we believe the AESO is able to direct TMR in real time. We’re not sure if the above language communicates that. The AESO could also contract for TMR on short notice (hours), or for longer notice (days) via the TMR procurement protocol. Failing either approach, it can direct TMR via its tariff.</p>	<p>The AESO will consider IPPSA’s suggested clarifying amendment to the foreseeable TMR definition.</p> <p>As noted by IPPSA, the AESO does have the authority to direct TMR as required on any required timeframe if needed. Article 11 of the AESO tariff outlines the compensation required for such directed TMR. The AESO also has established procedures for TMR procurement. Whether TMR is directed or contracted, the AESO intends to continue with its current practice of TMR procurement and usage for reliability purposes.</p>
MEG	<p>MEG offers the following comments:</p> <ul style="list-style-type: none"> <li>• Real-time – The AESO suggests that real time is measured in minutes or at most several hours. Clarification is required regarding the maximum period that would be considered real-time.</li> <li>• Foreseeable – Clarification is required regarding the applicable time period. Does the AESO intend foreseeable to refer to the period beginning at two years in the future and extending indefinitely beyond?</li> <li>• Local load pocket – Clarification would be aided by a list of regions currently deemed to be a local load pocket.</li> <li>• Effective – MEG has no comment on this definition</li> <li>• Planned – the AESO has not defined this term.</li> </ul>	<p>Please refer to the AESO response to ENMAX in this section 5.4 regarding the real time definition and the AESO response to MEG in section 5.2 regarding the foreseeable time period and examples of local load pockets.</p> <p>The AESO would point out that there is a difference between operations planning which deals with the system as it exists or is expected to exist in the very near term and transmission planning which deals with all the future required additions and upgrades to the system necessary to operate the system reliably in the future. The AESO does not see a need to define the term planned as the common dictionary meaning is appropriate and sufficient.</p>

<p>Suncor</p>	<p>The protocol defined as “effective factor” is a newer concept being discussed in relation to the development and application of the TCM rule. Suncor is suggesting that this protocol be further vetted with stakeholders and undergo the appropriate review and input process.</p> <p>Clarity is required on how the “effective factor” protocol affects RAS design and implementation.</p>	<p>The AESO practice of determining effective factors when studying constraints is an existing business practice. The use of effective factors within the TCM protocol has been a part of stakeholder discussions since consultation began after the 2004 Transmission Regulation.</p> <p>Effective factors are not part of a protocol per se. They are determined through load flow studies for each specific constrained area and are used to evaluate the generators and load that is most effective in managing a constraint. Once a generator or load is determined to be effective, they are included in the TCM procedure dealing with the constraint. All generators or load deemed to be effective within the TCM procedures are treated equally regardless of their specific effective factor. If an OPP is required to document the TCM procedure, the OPP will list the effective generators or load included as being effective in managing the constraint. The OPP and the choice of effective generators or load will be consulted within the normal ISO rules process.</p> <p>The AESO business practice for assigning connection RAS does not normally require the calculation of effective factors. If a market participant connection causes a constraint that cannot be managed by the SC in real time using the TCM protocol, the market participant is given the choice of connecting with a RAS to manage the constraint or to wait until required system facilities are in place to manage constraints without a RAS.</p>
<p>TransAlta</p>	<p>The definition of Effectiveness Factor may need to be revised depending on how the factor may be applied. See our comments under 5.5 below.</p>	<p>Please refer to the AESO response to TransAlta in section 5.5 below.</p>

## 5.5 Clarify TCM Rule Process Steps

Stakeholder	Stakeholder Comment	AESO Response
Industrial Power Consumers Association of Alberta (IPCAA)	<p>The AESO needs to consider what situations this process would NOT be used for – such as major outages? At what timespan does this “real-time” policy become invalid?</p>	<p>Please refer to the AESO response to TransCanada in the Executive Summary section regarding the AESO approach to severe and sustained market distortions.</p>
IPPSA	<p>We appreciate the clarification that DDS will be employed whenever TMR is employed.</p> <p>We would suggest that as the AESO curtails downstream DDS, it should dispatch off upstream DDS to ensure price integrity. In other words, as the AESO cancels one DDS dispatch, prices will fall due to the presence of \$0 TMR volumes. So the AESO will need to Dispatch Down some volumes elsewhere to ensure price integrity.</p> <p>Also, we want to be sure that when the AESO directs TMR on in the downstream, it is dispatching down a unit upstream to ensure price integrity. We’re not sure if these steps are clear in the second bullet of “Missing DDS Step”</p>	<p>The AESO will be considering revisions to the TCM protocol language to provide clarity regarding the use of DDS. The AESO notes that the current ISO rules are intended to ensure price integrity as suggested by MEG and do provide for the use of DDS whenever TMR is used with some restrictions. Generators in a constrained area (upstream of the constraint) cannot provide DDS and DDS is not used if it would result in more TMR being required. The amount of DDS procured is reduced by the amount of constrained generation on the system such that the AESO may not need to dispatch any DDS to provide the price reconstitution result related to the TMR dispatch.</p>
MEG	<p>MEG offers the following comments:</p> <ul style="list-style-type: none"> <li>• Use of TMR – MEG has no comments on this section.</li> <li>• Missing DDS Step – Rule 9.4.4.iii addresses DDS providers downstream of the constraint receiving a DDS dispatched off direction, the Proposal suggests that DDS providers downstream of the constraint will receive a DDS dispatch on; as such the first bullet in this section in the Proposal is unclear.</li> <li>• MEG suggests that it would facilitate clarification to provide an information document or flowchart that outlines the approach to TCM as embodied in the rules/OPPs relating to TCM, supply surplus, TMR, RAS and DDS.</li> </ul>	<p>The AESO will be considering revisions to the TCM protocol language to provide clarity regarding the use of DDS.</p> <p>The AESO intends to ensure that there is a comprehensive consideration of overall TCM and will consider the need for additional information documents throughout that process.</p> <p>Please refer to AESO response to MEG in section 4.1 ii) regarding the minimum stable generation</p>

	<p>System Controller discretion – MEG reiterates its earlier comments that consistency among definitions, and principles, used in both the TCM context and the supply surplus context must be achieved. In particular, the definition, and application, of “Minimum Stable Generation” must be the same for both protocols and in this regard MEG continues to urge the AESO to consider such factors as violation of environmental permits and disproportionate economic hardship in terms of impact on the primary business of bitumen production resulting from curtailment of a cogeneration unit in defining “Minimum Stable Generation”.</p>	<p>comments.</p>
<p>TransAlta</p>	<p>TransAlta does not consider that an Effectiveness Factor is appropriate for real-time congestion management. The factor based on load flows is determined from a simulation model in which the scenario may or may not match real-time conditions in terms of the assumed mix of generation and mix of loads. The upstream generation units the model predicted as effective may be wrong. As in real-time, certain generation may not be operating or may be operating at an output different than modeled. As well, upstream loads will be different than modeled. While a load flow model may be appropriate in a planning process, it is not appropriate in real-time. TransAlta would suggest that all generation upstream of a cut plane be considered equally effective and as necessary be curtailed prorata.</p> <p>At best if the AESO decides to proceed with using an Effectiveness Factor then it should be in wide bands of equal effectiveness where, for example, considering 20% wide bands a calculated number of 0.9 would be the same as 0.8 or 0.93 and so on. A band approach would recognize the inaccuracy of the calculation to predict real-time values.</p> <p>Also given that reverse merit order would be used then the use of an Effectiveness Factor would appear to only be applicable when the bid prices are identical and the Effectiveness Factor could then be used to break the tie as to which bid block would be curtailed first and so on. The extreme case would be identical \$0 bid blocks.</p>	<p>Please refer to AESO response to Suncor in section 5.4.</p> <p>The AESO notes that effectiveness factors are intended to be used in the development of OPP’s for real time constraint management. Operations planning will perform studies on the system as it exists or will exist in the very near term. This is a practice that has been in place for many years and has proved to be reliable as far as inclusion of the correct parties in the constraints management protocol. Such modeling establishes boundary conditions under credible operating states. The studies determine a range of effective factors for any particular generator or load under various operating conditions. The study results provide the AESO with sufficient information on relative generation and load effectiveness to select the specific generators and load to be used for the purpose of managing constraints in an area. As TransAlta suggests, once selected as an effective generator or load, the TCM rule or OPP would be applied ensuring that all selected are treated on a fair and equitable basis.</p>

TransCanada	TransCanada believes that the “missing DDS step” should be included in the TCM Rule. This is required for clarity and consistency, as well as to ensure that this step continues to be part of the TCM protocol should changes be made to the DDS rules contained elsewhere.	The AESO will be considering revisions to the TCM protocol language to provide clarity regarding the use of DDS.
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## 6 Next Steps

Stakeholder	Stakeholder Comment	AESO Response
Alberta Direct Connect Consumers Association (ADC)	There are clearly unintended consequences of this or any other solution. It may be time to revisit the transmission policy to determine if the market objectives and fairness issues originally contemplated are being achieved.	The AESO must act on the directions provided in current legislation and is guided by government existing policy principals and recommendations. The AESO believes that the market objectives and fairness issues that gave rise to the current legislation are being appropriately addressed within the proposed TCM protocol.
ATCO	<b>ATCO Power would appreciate the AESO providing the information document or flowchart that outlines the AESO's comprehensive approach to TCM in the planning stage and in real time.</b>	The AESO intends to provide additional information on its approach to identifying constraints in the planning stage as part of the response to the AUC directions regarding rule 9.4.
ENMAX	ENMAX appreciates the opportunity to provide comments on this subject.	Acknowledged.
Industrial Power Consumers Association of Alberta (IPCAA)	IPCAA would be happy to meet with the AESO to review this feedback in advance of any refilling.  IPCAA believes that the AESO has several key issues to consider and stakeholder prior to determining that this policy is complete or comprehensive.	Acknowledged.
IPPSA	We hope the AESO can provide some further clarity and answers to the questions we have posed. Thank you for the opportunity to comment.	Acknowledged.
MEG	MEG requests the AESO to advise a target date for filing the TCM rule revision with the AUC.	The AESO has given due consideration to the comments provided by market participants on the TCM paper and is prepared to move forward with rule development. The AESO will follow the usual rule consultation process and has published revised rule language for stakeholder comment. Upon reviewing stakeholder comments on the revised rule, the AESO expects to proceed with final rule language which will be re-submitted to the Commission in 2010.

Suncor	<p>When developing further TCM rules, the AESO needs to recognize that customers who hold Industrial Systems Designations (ISD) are limited in their ability to change their net load or supply requirements in order to comply to some TCM Rules, especially concerning RAS or the application of the effective factor protocol. These protocols normally target a specific generator or load. Within an ISD, a RAS or effective factor protocol is very difficult to implement as industrial process requirements vary day to day. The application of the effective factor protocol is further complicated by the fact that Suncor, and other large ISD generators, are all connected at the Ruth Lake interconnection point, making it difficult to pin point which generators would be considered in the effective factor application. More clarity is required with respect to this rule and how it and RAS would be applied to generators at the Ruth Lake interconnection point.</p>	<p>The AESO does recognize the challenge facing ISD's, however, constraints must still be managed even in an area that is predominately supplied by ISD's or we risk damage to transmission facilities. Please also refer to the AESO response to Suncor in section 5.4 and TransAlta in section 5.5.</p>
TransAlta	<p>TransAlta is still concerned about how often congestion could occur. And to date we have very little information as to what this will look like in the future.</p> <p>Given this concern TransAlta would propose that the AESO consider revisiting the TCM rule if the events are not infrequent and of short duration. We are concerned that if the events become more frequent the distortions to FEOC will be great and many market participants could suffer large economic losses. Thus a trigger point where constraints are no longer considered of short duration and infrequent should be developed and incentives should be put in place beyond this point not to use uncompensated constrained down directives to generators to alleviate the problem.</p> <p>In keeping with the above, TransAlta would ask the AESO to consider defining what is meant by the term infrequent and of short duration, and developing metrics to represent this. Further development of a monitoring tool that is updated each quarter in terms of historical and forecast congestion in identified areas is recommended.</p> <p>This would go a long way in helping stakeholders understand the current and ongoing state of the congestion program and ensure future and current actions are appropriate.</p>	<p>Please refer to the AESO response to ADC in the Executive Summary section regarding constraint event information.</p>
TransCanada	<p>TransCanada would appreciate the opportunity to provide comments upon the final draft of the TCM Rule prior to re-filing with the Commission.</p>	<p>The AESO has published revised rule language for stakeholder comment. Market participants are encouraged to submit comments on final rule</p>

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## **Appendix A: Congestion Information**

### **Planned transmission upgrades are required.**

Alberta's transmission system is currently running at capacity which requires the AESO to actively manage congestion on transmission lines across the province. Upgrades to the system are needed:

- To preserve the overall long term reliability of the system. As you push the transmission system closer to its limits for longer periods of time the possibility of system disturbances increases.
- To meet the regulation requirements (AR 86/2007 section 15 and 16) to plan for an uncongested system and restore inertie capability.
- To preserve Alberta's quality of life and economic well being through the timely addition of transmission infrastructure. Transmission upgrades on average take anywhere from 3 to 5 years to build once the need has been identified.
- To support long term load growth on the system over the long term.
- To connect generation required over the next 20 years to keep up with load growth and replace retiring generation units.
- To integrate renewable and low-emission sources of electricity such as wind, hydro, biomass and gasification to the grid.

Until transmission upgrades are in service the AESO will continue to take appropriate temporary measures to maintain system reliability, optimize the use of existing transmission and manage congestion.

### **Prior to planned transmission upgrades, congestion will be infrequent and of short duration.**

In response to stakeholder requests for information, the AESO has prepared this regional Alberta outlook regarding future congestion. The AESO currently manages, and will continue to manage, congestion effectively by using practices and procedures such as the connection process, regional operating procedures and remedial action schemes. These measures lead to less frequent and shorter duration congestion events on the system and without them congestion would be worse. The AESO notes that the amount of future regional congestion will grow and increase the generator and load restrictions associated with meeting the reliability criteria unless planned regional transmission upgrades are in place. Prior to transmission upgrades, the AESO expects to continue to be able to use temporary measures to manage near term future congestion as such congestion will be infrequent, of short duration and manageable using the proposed transmission constraint management rules.

This document is intended to provide stakeholders with data regarding the amount of congestion that could occur on the system in the future under selected scenarios before planned transmission reinforcements are in place. The AESO regularly monitors the impact of transmission constraints on the market and has recently published historical

regional transmission constraint data in its annual 24 Month Reliability Outlook. The AESO has performed analysis on the areas that have historically experienced congestion and is providing congestion estimates from simulated South of Keg (SOK) and Fort McMurray path flows under specific scenarios for future years in this report. There is also a qualitative discussion of the future congestion in the South West and North West parts of the province. The AESO also notes that it is currently in the process of updating the Long Term Transmission Plan and intends to incorporate regional forecasts of congestion on the system as part of that future study.

## **Part One: Simulated SOK & Fort McMurray Cutplane Flows & Congestion**

**Summary:** This section provides congestion estimations from simulated South of Keg (SOK) & Fort McMurray (FM) cutplane flows one, two, five and ten years out. The analysis is based on the Future Demand and Energy Outlook 2008-2028 and the generation scenarios presented in the AESO Long Term Transmission System Plan. For each of the cutplanes the generation scenario that most stressed the path is used in the simulation. SOK path congestion is based on Generation Scenario A2 which forecasts the addition of coal and cogeneration in Northern Alberta. The Fort McMurray path congestion is based on Generation Scenario B4 which forecasts the addition of cogeneration and combined cycle in Southern Alberta. The transfer limits used in the analysis refers to the operation limits as defined in OPP 521 and OPP 505.

The congestion statistics presented in the tables which follow are based on system normal transfer limits under specifically chosen scenarios. The South of Keg (SOK) is forecast to fail to meet congestion requirements of Alberta's Transmission Regulation (AR 86/2007) under the generation scenarios studied potentially as early as 2011. Without the planned transmission enhancements, SOK congestion increases significantly post 2015. Currently real time constraints are infrequent and of short duration and are managed effectively by the AESO using its practices and procedures. Similarly, the Fort McMurray path is forecast to be congested in 2015 which could result in load curtailments or a directive for Transmission Must Run services in the scenario studied if new planned facilities are not in place.

In addition to that estimated in the tables further congestion may occur during abnormal operating conditions. Outages to a 240kV circuit affecting transfer capability (as described in OPP 521 and OPP 505) are certain to occur for a significant number of hours each year and occur due to planned and forced conditions. Planned outages are usually for maintenance and upgrades while forced outages are unplanned and are often weather related (ice, wind, lightning). The SOK-240 transfer capability is reduced by an average of between 300 to 400 MW depending on the season during line outages. The Fort McMurray capability limitation is directional with transfer in limits being reduced by 140 MW and transfer out limits being reduced by 230 during line outages. As shown in the figures in this report, the possibility of congestion increases when the transfer capability

is reduced. Any increased congestion due to line outages is not captured in the statistic summary tables provided in this document.

Future congestion is not the only factor considered when assessing the need for transmission reinforcements. Avoiding reliability issues for customers, improving the efficiency of the transmission system and restoring the capacity of the existing interties are also taken into account when determining required transmission reinforcements. The South of Keg (SOK) and Fort McMurray paths are expected to fall short of meeting reliability criteria. Failure to meet reliability criteria means that the risks from line outages are greater than levels accepted in the industry and requires action to be taken to reduce the risk to accepted levels <sup>1</sup>.

**Analysis and Results:** The results of the AESO regional analysis is represented below in graphical and tabular format for the years 2011, 2012, 2015 and 2019.

Figure 1: 2011 seasonal SOK flow duration curves based on generation scenario A2

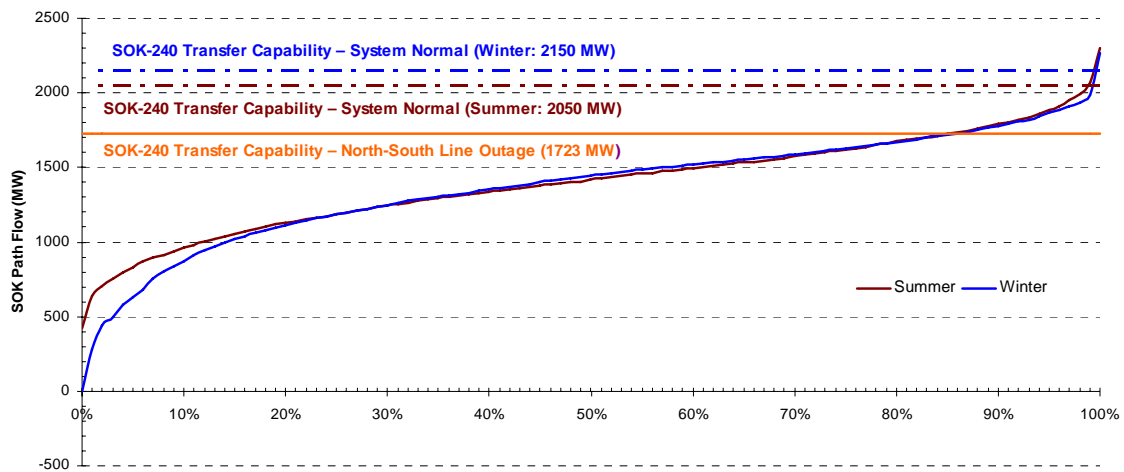


Table 1: 2011 SOK flow congestion based on generation scenario A2

	Summer	Winter	Total
<b>Average Flow (MW)</b>	1,397	1,375	1,391
<b>Number of Congested Hours</b>	53	4	57
<b>Max SOK Flow (MW)</b>	2,301	2,268	2,301
<b>Maximum Congestion (MW)</b>	251	118	251
<b>Total Congestion (MWh)</b>	5,332	205	5,537
<b>% of Flow Congested</b>	1.20%	0.09%	0.65%
<b>Average Congestion (MW)</b>	101	51	97

<sup>1</sup> Failure to meet reliability criteria is not confirmation that power outages will occur.

Figure 2: 2012 seasonal SOK flow duration curves based on generation scenario A2

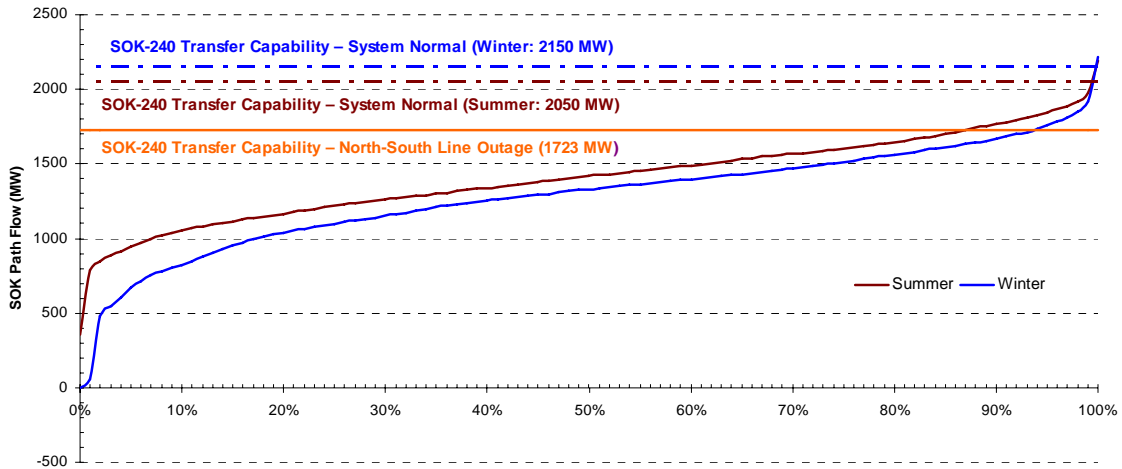


Table 2: 2012 SOK flow congestion based on generation scenario A2

	Summer	Winter	Total
Average Flow (MW)	1,409	1,276	1,348
Number of Congested Hours	26	1	27
Max SOK Flow (MW)	2,189	2,221	2,221
Maximum Congestion (MW)	139	71	139
Total Congestion (MWh)	1,664	71	1,735
% of Flow Congested	0.59%	0.02%	0.31%
Average Congestion (MW)	64	71	64

Figure 3: 2015 seasonal SOK flow duration curves based on generation scenario A2

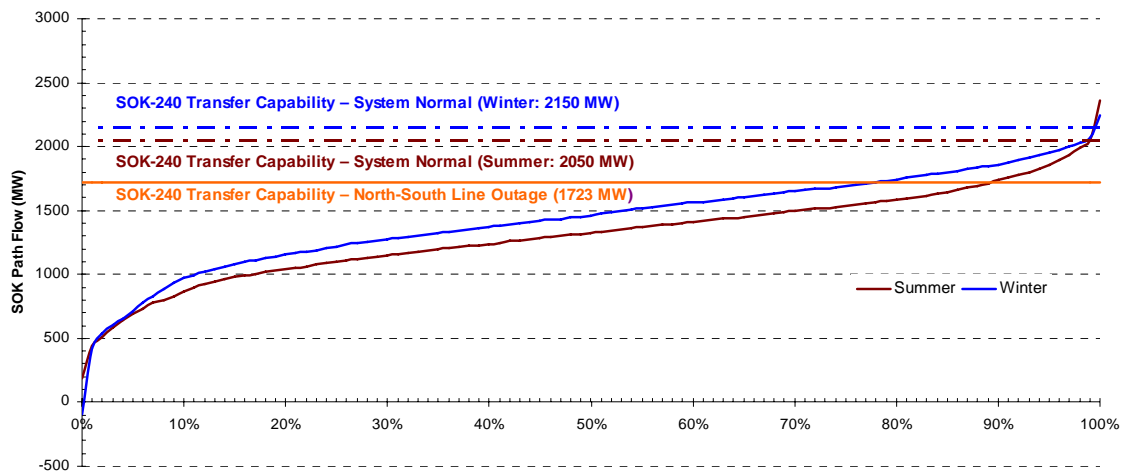


Table 3: 2015 SOK flow congestion based on generation scenario A2

	Summer	Winter	Total
Average Flow (MW)	1,311	1,422	1,370
Number of Congested Hours	52	11	63
Max SOK Flow (MW)	2,361	2,249	2,361
Maximum Congestion (MW)	311	99	311
Total Congestion (MWh)	2,779	432	3,211
% of Flow Congested	1.18%	0.25%	0.72%
Average Congestion (MW)	53	39	51

Figure 4: 2019 seasonal SOK flow duration curves based on generation scenario A2

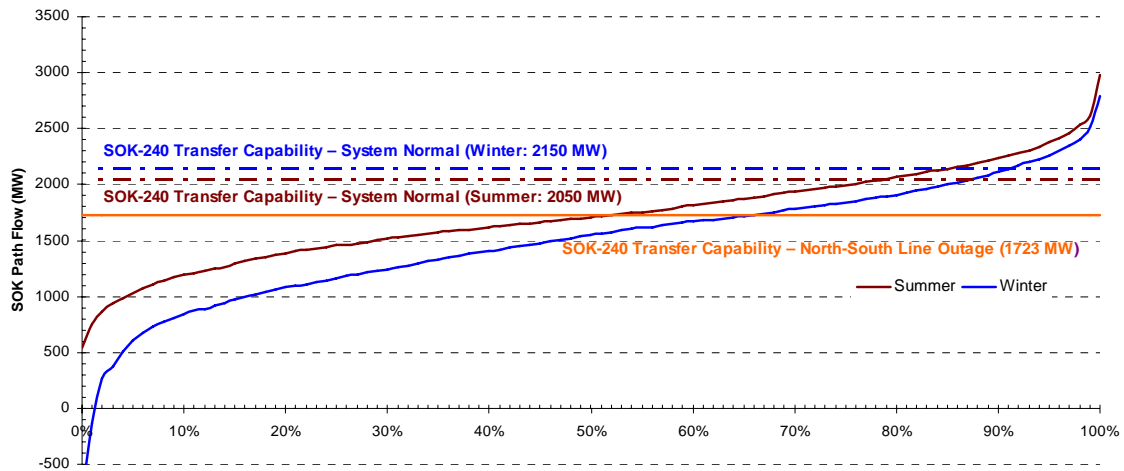


Table 4: 2019 SOK flow congestion based on generation scenario A2

	Summer	Winter	Total
Average Flow (MW)	1,716	1,480	1,601
Number of Congested Hours	942	379	1,321
Max SOK Flow (MW)	2,979	2,787	2,979
Maximum Congestion (MW)	929	637	929
Total Congestion (MWh)	201,654	65,882	267,536
% of Flow Congested	21.33%	8.68%	15.04%
Average Congestion (MW)	214	174	203

Figure 5: 2011 Fort McMurray flow duration curve based on generation scenario B4

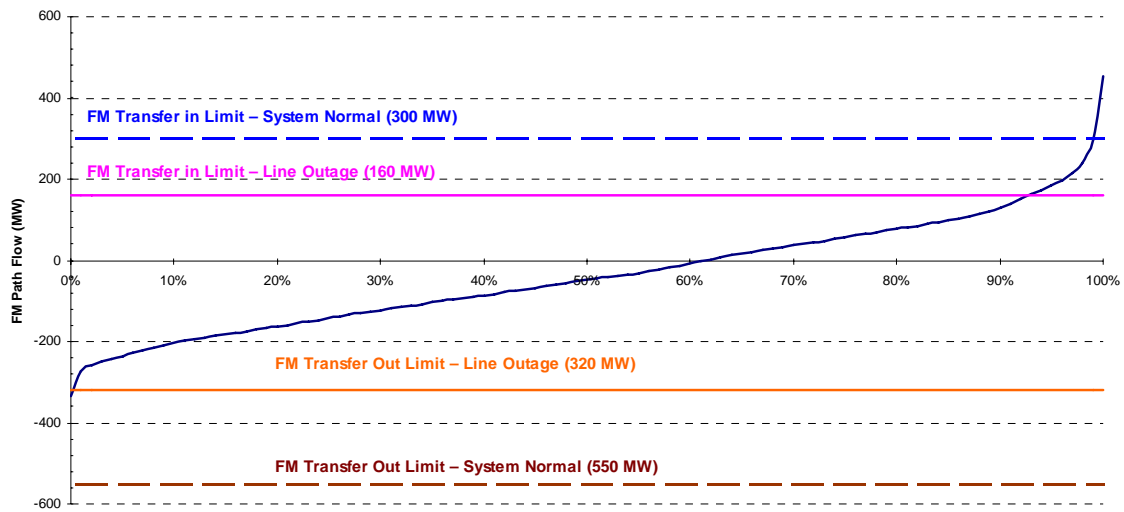


Table 5: 2011 Fort McMurray flow congestion based on generation scenario B4

	Import	Export
Average Flow (MW)	97	124
Number of Congested Hours	86	0
Max FM Flow (MW)	453	334
Maximum Congestion (MW)	153	0
Total Congestion (MWh)	4,269	0
% of Flow Congested	3%	0%
Average Congestion (MW)	50	0

Figure 6: 2012 Fort McMurray flow duration curve based on generation scenario B4

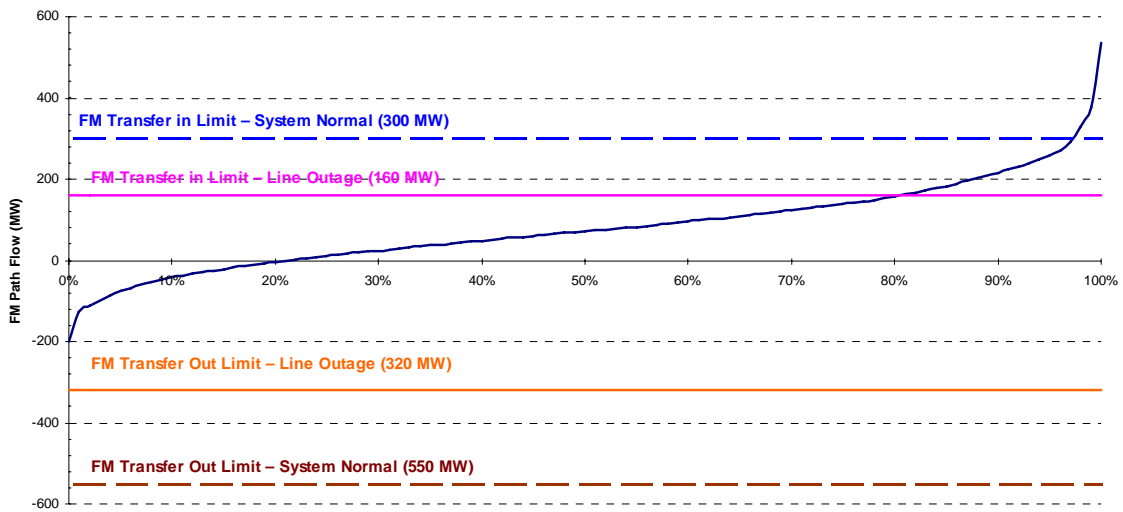


Table 6: 2012 Fort McMurray flow congestion based on generation scenario B4

	Import	Export
Average Flow (MW)	115	49
Number of Congested Hours	244	0
Max FM Flow (MW)	537	199
Maximum Congestion (MW)	237	0
Total Congestion (MWh)	15,765	0
% of Flow Congested	4%	0%
Average Congestion (MW)	65	0

Figure 7: 2015 Fort McMurray flow duration curve based on generation scenario B4

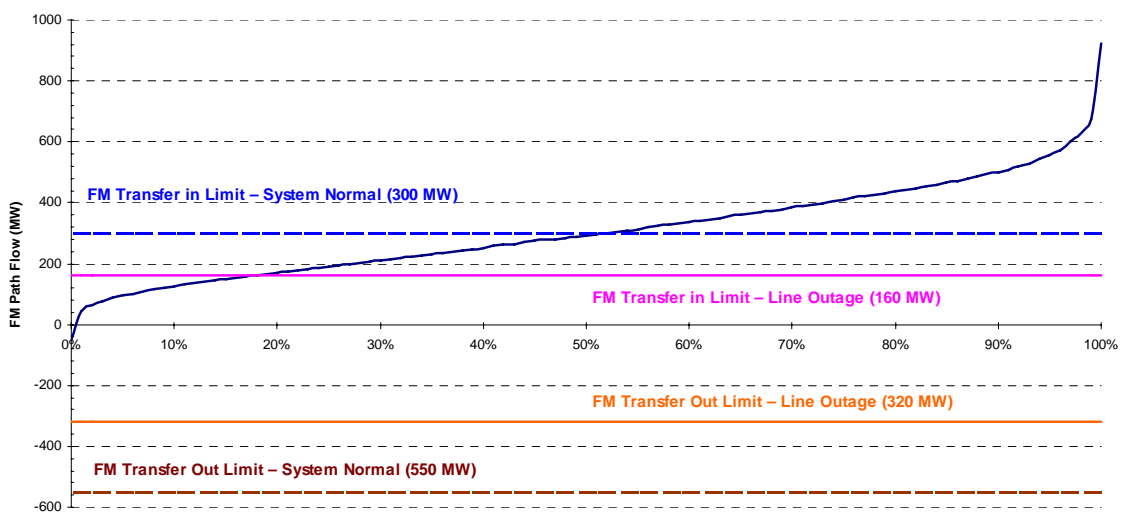


Table 7: 2015 Fort McMurray flow congestion based on generation scenario B4

	Import	Export
Average Flow (MW)	305	19
Number of Congested Hours	4,257	0
Max FM Flow (MW)	922	49
Maximum Congestion (MW)	622	0
Total Congestion (MWh)	552,609	0
% of Flow Congested	49%	0%
Average Congestion (MW)	130	0

Figure 8: 2019 Fort McMurray flow duration curve based on generation scenario B4

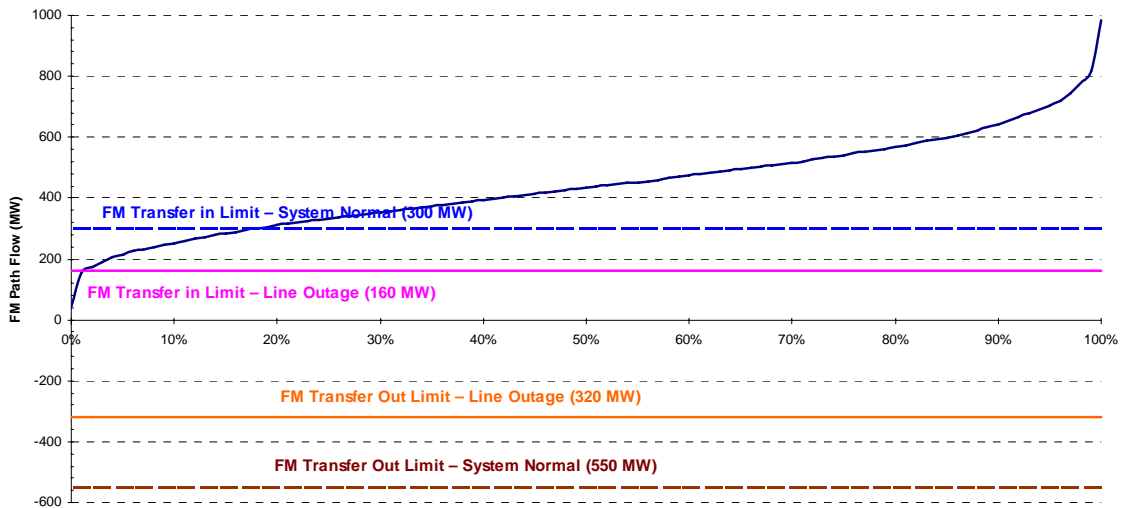


Table 8: 2019 Fort McMurray flow congestion based on generation scenario B4

	Import	Export
Average Flow (MW)	440	0
Number of Congested Hours	7,206	0
Max FM Flow (MW)	985	0
Maximum Congestion (MW)	685	0
Total Congestion (MWh)	1,344,604	0
% of Flow Congested	82%	0%
Average Congestion (MW)	187	0

## Part Two: South West Congestion Discussion

Presently there is more wind generation capacity in the Southwest area than transmission capacity can manage resulting in congestion when the wind generation operates at high levels. In the next 5 years, more wind generation plans to connect and more transmission facilities are required to accommodate the additional generation.

The plans for transmission upgrades in the Southwest include new 240kv transmission lines, reconfiguring 138kv transmission lines, new substations including transformer capacity upgrades and a phase shifting transformer.

In the Pincher Creek area, limited transmission capacity causes some wind generation congestion with all transmission elements in service. Planned and forced outages to transmission elements greatly increase the wind generation congestion. The total congestion is currently running at less than 100 hours per month on average.

A new 240 kV transmission line into the Pincher Creek area is scheduled to be in service before the end of 2010. The integration of the new line will eliminate congestion with all transmission facilities in service and greatly reduce the congestion under planned and forced outages. Further wind generation additions over the next five are expected to be concurrent with further transmission development and wind generation congestion should be negligible.

### **Part Three: North West Congestion Discussion**

Over the next 5 years transmission facilities are planned to be upgraded and the contracted TMR requirement is planned to be eliminated. The transmission facility upgrades consist of new 240 kV and 144kV transmission lines and voltage support devices including static VAr compensators and capacitor banks.

Congestion occurs in load areas that cannot be served by in-merit energy market generation from outside of the area. Alberta's Northwest is such a load area. Generators in the area are often not in-merit during high load periods. To meet reliability performance requirements the AESO contracts with generators for transmission must run service. The Northwest transmission system is weak due mainly to the distances between load and major generation centers. The transmission must run requirement varies with the area load and area in-merit generation.

At present, there are a total of seven generating units in the Northwest that provide contracted TMR service. Four generators are located in the Rainbow Lake/Fort Nelson area and three generators are located in the Grand Prairie area.