AESO Recommendation Paper

Congestion Management Plan

August 30, 2007

CONGESTION MANAGEMENT PLAN

Executive Summary

The Department of Energy (DOE) policy intent is clear that the transmission system needs to be built to effectively operate congestion free. The ISO must proactively plan a transmission system that "is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy … can occur when all transmission elements are in service, and is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in-merit electric energy … can occur when operating under abnormal conditions." [1]The DOE does recognize, however, that congestion may occur under abnormal operating conditions, when there is a lag between transmission build and generation development or in local load pockets.

DOE regulations[2] and policies such as the Transmission Development Policy (TDP) of 2003 provide a specific framework for congestion management (CM) rules development. To ensure better alignment of the congestion management rules with DOE policies and regulations, the AESO conducted a review of the CM protocol proposed in December 2006 and the complete set of relevant operating procedures and has recommended a consistent approach for all congestion management events. The most significant changes are the reliance on economic merit order dispatch and the elimination of the trigger participant designation. The recommended approach is effective in terms of both system and wholesale market operation.

This paper outlines where the conflicts exist between the December CM plan and policy, and introduces a standard approach to real-time congestion management.

[1] Alberta Regulation 86/2007, Transmission Regulation Section 15(1)(e)
[2] This paper is aligned with the TDP and the April 2007 transmission regulation.

1.0 Background[3]

The Department of Energy (DOE) recognized the importance of eliminating congestion given Alberta's single pool price market design and directed the ISO to plan a transmission system that "is sufficiently robust so that 100% of the time, transmission of all anticipated in-merit electric energy … can occur when all transmission elements are in service, and is adequate so that, on an annual basis, and at least 95% of the time, transmission of all anticipated in-merit electric energy … can occur when operating under abnormal conditions." [4] In setting this target, the DOE recognized that congestion may occur even after the next phase of planned transmission development.

A congestion management (CM) plan is required for any electrical system to manage congestion that is identified or develops – either in the system planning stage or in Real Time (RT). CM rules are required to address congestion that may occur under abnormal operating conditions, when there is a lag between transmission build and generation development, or in local load pockets. The DOE regulations[5] and policies such as the Transmission Development Policy (TDP) of 2003 provide a specific framework for CM rules development. The ISO is also "responsible for ensuring open and non-discriminatory access to the transmission system …"[6] Transmission rights are not a feature of the market framework in Alberta

To meet the policy direction of the DOE, the ISO must manage constraints without any discriminatory access to one set of participants over another. In other words there will be no transmission rights and no preferential treatment to incumbents. In addition, the ISO is "to determine, according to relative economic merit, the order of dispatch of electric energy"[7] and the TDP states that "real time congestion will be resolved by merit order re-dispatch, followed, if necessary, by pro rata curtailment …"[8]

The AESO worked with industry through 2006 to develop a congestion management plan. However, upon further examination it was noted that amendments to the CM plan proposed in December 2006 would provide better alignment to government policy in several areas. For example, using the Supply Transmission Service (STS) contract levels as outlined in the December CM plan, infers that incumbent generators have effectively been assigned "transmission rights" in line with that contract level and accordingly this creates a barrier to entry for new participants. This is inconsistent with a non-discriminatory, open-access transmission policy. Further, curtailing "trigger participants" before incumbents to address any constraints in the delivery hour also implied transmission rights. In addition, the December CM plan did not reflect the direction

[3] The new Transmission Regulation has some minor wording changes that need to be incorporated for accuracy. The following footnotes refer to the 2004 regulation.
[4] Alberta Regulation 86/2007, Transmission Regulation Section 15(1)(e)
[5] This paper is aligned with the TDP and the new transmission regulation of 2007.
[6] Alberta Transmission Development Policy; December 2003; page 4
[7] Electric Utilities Act; Statutes of Alberta, 2003; Section 17(c)
[8] Alberta Transmission Development Policy; December 2003; page 8

provided in the DOE policy to use "reverse merit order mechanisms" or "orderly market dispatch" to address real-time congestion.

In this paper, the December CM plan is re-examined and several changes are recommended to bring the plan into better alignment with policy and regulation (the 2007 CM protocol).

2.0 Recommended 2007 CM Protocol

To ensure better alignment of the congestion management rules with DOE policies and regulations, the AESO recommends a number of changes to the original December CM plan. The most significant changes are the reliance on economic merit order dispatches and the elimination of the trigger participant designation in real time. While congestion may occur during abnormal operating conditions or due to the lag in transmission enhancements for new generation additions, no participant will be given prioritized access to the transmission system (rights). Instead, economic offers will be used in concert with physical system modeling to address congestion in real time.

When the AIES becomes congested in real time, the System Controller will determine which units to curtail or dispatch based on their effectiveness in relieving a constraint and their position in the merit order. This process will occur in an orderly fashion and be reflected in the associated OPPs for any particular congestion event. The proposed reverse merit order (RMO) approach complies with government policy, has the easiest practical application and, in most cases, causes the least distortion to the pool price while sending correct price signals to most market participants. In addition, incorporating Transmission Must Run (TMR) dispatches into the early stages of the protocol allows effective TMR to be used to relieve a constraint in a local load pocket or downstream of a constraint instead of causing unnecessary curtailment.

The practical steps the AESO proposes to follow in its congestion management protocol are outlined below.

The System Controller will implement the following steps in order as required to the extent they are effective in relieving the constraint:

- Determine the effective generation and load able to relieve the constraint.
- Cancel directives to upstream[9] generators, i.e., generators that generate into the constraint, to generate above their Maximum Capacity.
- Curtail opportunity services: curtail upstream IOS, downstream EOS and downstream DOS.

[9]The term "upstream" refers to generator output that must flow through the constraint or to a load whose electric energy is not delivered to them through the constraint. The term "downstream" refers to a generator whose output does not contribute to the constraint or to a load that could receive electric energy through the constraint from an upstream generator.

- Dispatch downstream contracted TMR or constrain on TMR in areas of local load pockets.
- Constrain off upstream energy using reverse merit order or pro rata when offer prices are equivalent, then dispatch up downstream generation using the energy market merit order.
- Curtail downstream DTS using prorata allocation.

The steps of the protocol are consistently applied in all congestion situations in that TMR is dispatched if contracted or if required before further steps are taken. Contracted TMR is dispatched in situations like Rainbow Lake where there is a local load that cannot be served by the system generation, only the local generation. A situation may also exist where contracted TMR can relieve a constraint instead of having to dispatch any other unit down, like in an SOK event. The steps are also consistent with policy in that an RMO approach is used followed by pro rata curtailment as required. Finally, the 2007 CM protocol is standardized in that a constraint is addressed by "Constraining Down (units upstream of the constrained path), then Dispatching Up (units that are downstream of the constraint)". This CDDU methodology alleviates constraints in an effective and practical fashion while ensuring that the resulting market price signal suffers the least amount of distortion.

In summary, the 2007 CM protocol establishes a consistent approach to real-time congestion management resulting in practical operational and wholesale market outcomes. Table 1 below summarizes the adjustments required to the December CM plan to incorporate the recommended approach.

Table 1: Congestion Management Recommendation – Adjustments to Protocol Steps

December CM Plan	**2007 CM Protocol**	**Comments**
1. Determine the effective generation and load able to relieve the constraint	Step maintained – used to create effective TMR and system merit orders	
2. Curtail upstream generators to STS levels	Directives to generators to generate above their MC cancelled. No STS curtailment.	
3. Curtail upstream IOS and downstream EOS	Step maintained – import/export opportunity service cut before load (DTS)	
4. Curtail downstream DOS	Step maintained – demand opportunity service cut before load (DTS)	
5. Curtail upstream generator trigger volume	Step eliminated – no transmission access guarantee	

December CM Plan	2007 CM Protocol	Comments
6. Dispatch downstream contracted TMR	Step modified – Effective contracted TMR dispatched on first, then in-merit energy dispatched off.	TMR contracted/directed in areas of local load pockets, to provide generation access; to provide voltage support. This step is first if contracted, or as required to address system issues[10]. Price impacts mitigated by competitively procured DDS.
7. Curtail downstream demand trigger volume	Step eliminated – no transmission access guarantee	
8. Curtail upstream generation using prorata allocation	Step modified – upstream energy constrained off using RMO followed by pro rata allocation, then downstream generation dispatched up using energy market merit order. No constrained down payments to generators.	Standard protocol to be applied in all cases, following or in concert with TMR directives to address local load pockets or voltage constraints. "Constrained Down, Dispatch Up" or "CDDU" results in correct system price signal when competitive supply options exist. Protocol can be adapted to potential FEOC outcomes.
9. Direct downstream uncontracted TMR	Step eliminated – merit order dispatch always utilized. TMR dispatched as required for system.	
10. Curtail downstream DTS using prorata allocation	Step modified – curtail using RMO, then prorata.	The protocol escalates to OPP 801 if a supply adequacy situation results.

3.0 Congestion Management Alignment with DOE Policy and Regulations

The 2007 CM protocol aligns with the DOE policy as outlined in the 2003 Transmission Development Policy (TDP) and subsequent regulation. The TDP specifically states that:

[10]In unusual or unforeseen circumstances the SC may still direct uncontracted TMR but this will not be a normal step in CM.

- "the ISO will be required to develop.... a system for managing real time congestion that may occur during abnormal conditions."
- "real time congestion should be resolved by merit order re-dispatch, followed if necessary by pro rata curtailment of parties with equivalent offers or bids."
- "... 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.
- "… real-time congestion arrangements should not alter or distort market prices."
- "Constrained down payments will not be paid to generators"
- "the costs of the out of merit payments will be a transmission payment and not a form of uplift in the wholesale energy price."

In developing the 2007 CM protocol the focus was on three key areas: the use of trigger participant; the use of STS contract levels, and the use of an economic merit order approach. The December CM plan was aligned with government policy regarding use of TMR and treatment of opportunity service. The adjustments that were made to ensure policy consistency are discussed further below.

3.1 Transmission Access- STS and Trigger Volume

The Transmission Regulation and TDP very clearly state that generators have no transmission rights[11] and, correspondingly, have no cost obligations for the transmission system.[12] The regulation and the ISO tariff apply to both existing and new generation (except selected PPA units in the STS tariff who pay an additional historical connection charge which is intended to put all generators on an equal interconnection cost basis). The STS rate only reflects a variable charge (losses) with any initial system contribution costs being fully refundable.

The Transmission Regulation further contemplates equality between existing and new generation when it requires generator interconnection costs to be shared among all users at an interconnection and refund existing users if a new customer is added. The refund would similarly have the effect of putting new and existing users on an equal cost sharing footing.[13] [14]

The Transmission Regulation again considers equal access among all generators when it states that existing generator interconnection owners may not prohibit interconnection or access to the interconnection facilities by other market participants.[15] This is consistent with the EUA which similarly directs the ISO to ensure all market participants wishing to participate in the energy market are given a reasonable opportunity to do so. [16]

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[11] Alberta Transmission Development Policy; December 2003; page 8
[12] Alberta Regulation 174/2004, Transmission Regulation Section 30(a)
[13] Alberta Regulation 174/2004, Transmission Regulation Section 16(4)
[14] AESO 2006 Tariff Terms and Conditions; Section 9.10
[15] Alberta Regulation 174/2004, Transmission Regulation Section 16(3)
[16] Electric Utilities Act; Statutes of Alberta, 2003; Section 17(b) and 29

Accordingly, the concept of an existing participant or an STS contract holder having preferential transmission rights is not supported in regulation or policy and therefore should not be considered in a congestion management plan.

3.2 Reverse Merit Order

The use of reverse merit order in congestion management, while not stipulated in regulation, was directly contemplated in the TDP.[17] The DOE was specific in directing that in principal, real-time congestion or constraints should not alter or distort market prices and it identified reverse merit order as a mechanism that enabled the orderly curtailment of generation from highest cost to lowest cost.[18] The DOE position is consistent with the Act which asks the ISO to determine, according to relative economic merit, the order of dispatch and to direct the economic operation of the system.[19]

With the implementation of rules related to "must offer/must comply" (MOMC) and offers submitted and binding two hours before delivery (T-2), the development of a practical, effective RMO proposal will be even more successful.

3.3 Use of Transmission Must Run (TMR)

Proactive transmission planning is intended to significantly reduce the occurrence of congestion; however, the TDP gave the ISO some flexibility to enter into TMR contracts where they are a superior economic alternative and a shorter lead time solution.[20] The DOE policies and regulations provided guidance on the application of TMR on a number of fronts. These include:

- The Transmission Regulation directs the ISO to make rules regarding TMR unit operation and to recover TMR costs in the ISO tariff and thereby not have those costs or operating rules set or distort pool price.[21]
- The TDP further contemplates RT congestion management when TMR exists, stating that "real time congestion management use reverse merit order to dispatch down units in a congested area, with units not in merit being paid as bid."[22]

The December CM plan and use of TMR is consistent with DOE policy in that TMR is treated as an effective economic alternative to wires at the time of a constraint. The 2007 CM protocol contemplates the ISO dispatching or directing TMR units on as required and proposes that timely use of effective TMR can prevent the need for further steps. This is consistent with policy as such TMR dispatches are a superior economic alternative to wires at the time of dispatch.

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[17] Alberta Transmission Development Policy; December 2003; page 8
[18] Alberta Transmission Development Policy; December 2003; Appendix 6.2
[19] Electric Utilities Act; Statutes of Alberta, 2003; Section 17(c) and 17(h)
[20] Alberta Regulation 174/2004, Transmission Regulation Section 8(4)
[21] Alberta Regulation 174/2004, Transmission Regulation Section 8(5) and 23
[22] Alberta Transmission Development Policy; December 2003; page 8

To address the potential price impact due to a TMR dispatch, Dispatch Down Service (DDS) will be introduced to establish a product to manage constraints while allowing the Pool Price to be set in an unconstrained fashion. Further, to ensure that price distortion does not unnecessarily occur, the standardized 2007 CM protocol provides for economic dispatch when there are competitive options for supply.

3.4 Imports and Exports

The DOE policies provide direction on two main fronts regarding interties: (1) the treatment of interties vis a vis Alberta generators, and (2) the priority of intertie service. Each of these is addressed in the CM protocol.

It is clear that imports are to be treated as intra Alberta generators. This is reflected in among other things the DOE request that import variable charges be removed coincident with the discontinuation of the STS variable charge for generators and having losses apply to both.[23] However, during congestion events interconnection standards and Total Transfer Capability (TTC) methodology come into play when imports are involved. In most cases an import curtailment is the result of an import TTC reduction which is necessary to comply with reliability standards. These situations are commonly intertie specific and the reduced TTC level must be followed.

When TTC levels are not a limiting factor, the treatment of imports in the CM protocol will be considered as would other intra-Alberta generation – if dispatching an import is effective in relieving a constraint or to meet system need without creating a further congestion issue, an import will be dispatched in an orderly economic fashion following the merit order.

In terms of service priority, Demand Transmission Service (DTS) has priority being a firm service and accordingly opportunity services including Export Opportunity Service (EOS) should be curtailed before DTS.

The relationship between EOS and Demand Opportunity Service (DOS) seems also relatively clear. The DOE confirmed the opportunity export tariff should continue to recover a portion of the embedded cost of transmission wires, losses and ancillary services. The AESO has complied with the regulation and has incorporated a more equitable treatment between EOS and DOS in the 2007 approved Tariff Rates. However, the 2007 DOS variable tariff is greater than the EOS variable tariff which implies that DOS pays a higher relative share of transmission costs and should receive priority of service in the congestion protocol. The December CM protocol which curtails EOS before DOS is consistent with policy and ISO tariff treatment. If the AESO adopts new transmission services that create different levels of curtailment priority for exports the CM protocol would need to be amended to include these priorities but the basic approach would remain the same.

[23] Alberta Transmission Development Policy; December 2003; page 10

3.5 System Planning versus Real Time Congestion Management

While the TDP and associated regulations direct the use of an RMO approach and preclude the use of trigger participants in dealing with real time congestion, the TDP does not prohibit the designation of a RAS (Remedial Action Scheme) participant during the planning stage. In the planning stage, reliability issues such as voltage stability and thermal overloads may require the installation of remedial action schemes (RAS). Assigning RAS requirements to an interconnecting participant in the planning phase allows the AESO to add new assets to the system while meeting the intent of the DOE policy given that the real time CM protocol does not manage congestion through use of any identified trigger participant. The RAS requirements would be identified in the planning stage of a new interconnection. Since there is no practical way of procuring this service competitively and because such schemes are unit specific by nature, the RAS requirement would be assigned to a new participant until appropriate transmission infrastructure can be provided. Alternatively, the new participant would not be able to be connected to the system.

A RAS would not be used to manage congestion when a real time operational approach, as described herein, could be used. Consistent with the intent of the DOE policy, a RAS would normally be used to mitigate the effects of a contingency. As the transmission system is built to accommodate new generation, the RAS schemes can be removed. Costs associated with installing a RAS would be allocated in the same manner as other interconnection costs.

3.6 Summary of Consistency with DOE Policy

The 2007 CM protocol is consistent with the DOE policy on all fronts. A summary of the overview and consistency is outlined in Table 2 below.

Table 2: Congestion Management Recommendation – Overview and Consistency with Policy

DOE Policy	2007 CM Protocol	Comments
No transmission access guarantee	Eliminate Trigger participant and STS curtailment Opportunity service cut before firm (IOS, EOS, DOS)	Incremental generation may require RAS schemes to connect in the short term; however, this is not used in the CM protocol.
If appropriate, TMR allowed	TMR dispatched/directed in areas of local load pockets, to provide generation access; to provide voltage support. This step is first if contracted, or as required to address system issues.	

DOE Policy	2007 CM Protocol	Comments
Reverse Merit Order (RMO)	RMO protocol is utilized in all circumstances followed by prorata curtailment of effective units.	
No constrained down payments to generators	Merit order determines dispatch and marginal price for settlement.	
Congestion should not alter or distort prices	All options have price impacts. Unconstrained pool price is optimal. TMR is dispatched/directed and DDS is used to reconstitute price. In system constraints, merit order is dispatched up following curtailment upstream of constraint to ensure orderly dispatch and effective price signals.	Standard protocol sequence to be applied in all cases using dispatch of effective units and minimizing market price distortion. Protocol can be adapted to potential FEOC outcomes.

4.0 2007 CM Protocol Implementation

To implement the 2007 CM protocol, ISO Rule number 9.4.4 requires amendment. Rule language has been drafted to reflect the 2007 CM protocol and an abridged version is outlined in appendix 3 (a similarly abridged version of the December CM plan rule language is provided in appendix 2 for comparison.)

Following consultation on the protocol and the associated rule language, the relevant operating policies and procedures (OPPs) will be amended to reflect this standardized approach to congestion management. OPP 521 regarding congestion management in the event of a North – South contingency (referred to as South of Keg or SOK) has already been drafted for interim approval. To ensure alignment with the revised procedure, rule amendment may be required in part or in whole to OPP 501, 502, 505, 510, 515, 517, 521 and possibly 503, 508, and 522. Some of these procedures already reflect the current protocol in part but may still require minor amendments.

As required, these procedures may need to be adjusted to reflect “residual supply calculations” consistent with Section 6 results.

Finally, it should be noted that some of the procedures for CM are more complex than others. Accordingly, from an implementation perspective, some software development

may be required to automate the effective merit orders to provide the System Controller with enhanced decision support tools and to align with the Quick Hit market rule changes.

5.0 Conclusions

It is clear that the DOE market policy envisions a transmission system without constraints. Nonetheless, the AESO needs to take steps to ensure that a proper congestion management protocol exists, is consistent with DOE policy and provides for effective management of congestion that does occur. This paper summarizes the recommended CM protocol.

The AESO 2007 CM protocol is consistent with DOE policy as it relies on effective dispatches of TMR and the energy merit order to address congestion in real time. The recommended 2007 CM protocol is also practical and efficient in that the System Controller is armed with an orderly, effective set of steps to address congestion as it occurs. Finally, the 2007 CM protocol is designed to ensure that the impact on the market is as neutral as possible and that the resulting price signals are directionally correct.

The AESO welcomes Participant comments on this paper and the 2007 CM protocol.

Appendix 1 contains Congestion Management related excerpts from DOE Policy and Regulations.

Appendix 2 contains an abridged version of the December CM plan draft rules and Appendix 3 contains a similarly abridged version of the recommended 2007 CM protocol rules.

Appendix 1–Congestion Management and DOE Policy and Regulations

i) The Electric Utilities Act

The Electric Utilities Act (EUA) enacted in June 2003 sets out the powers and duties of the Independent System Operator (ISO) and any congestion management plan must be consistent with the policy direction provided in the EUA. Section 17 of the EUA specifically directs the ISO:

(b) to facilitate the operation of markets for electric energy in a manner that is fair and open and that **gives all market participants wishing to participate in those markets and to exchange electric energy a reasonable opportunity to do so**;

(c) **to determine, according to relative economic merit, the order of dispatch** of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric systems outside Alberta, to satisfy the requirements for electricity in Alberta;

(h) to direct the safe, reliable and **economic** operation of the interconnected electric system;

In Section 29, the EUA further requires that "the ISO must provide system access service on the transmission system **in a manner that gives all market participants wishing to exchange electric energy and ancillary services a reasonable opportunity to do so**."

The congestion management policy must be in line with the provisions of the EUA.

ii) The Transmission Regulation

In August 2004, the Government of Alberta recognized the need for a formal congestion management rule/practice when it issued the Transmission Regulation under the EUA. Section 9 of the Transmission Regulation on "Managing Transmission Constraints" stipulates that:

9(1) The ISO must make rules and adopt practices respecting the operation of the transmission system and the management of transmission constraints that may occur from time to time.

Section 9 establishes the need for formal congestion management rules.

The Transmission Regulation provides some indications of the direction congestion management policy should take by stipulating that:

16(3) The owner of a generating unit that interconnects with the transmission system, and who has paid local interconnection costs, **may not prohibit interconnection or access to the interconnection facilities by other market participants**.

30(a) ensure (i) the just and reasonable **costs of the transmission system are wholly charged to owners of electric distribution systems**, customers who are industrial systems and persons who have made an arrangement under section 101(2) of the Act, **and exporters**, to the extent required by the ISO tariff and

30(b) ensure owners of generating units are charged local interconnection costs to connect their generating unit to the system, and are charged a financial contribution towards transmission system upgrades and for **location-based losses**

16(4) If another person makes use of the facilities for which a local interconnection cost has been paid,

(a) the cost of the use of those facilities by that other person or persons must be allocated to all users in accordance with the ISO tariff, and

(a) **the original local interconnection cost, or a portion of it, must be refunded** to the person who paid it in accordance with the ISO tariff.

8(5) The ISO must **make rules respecting the operation of a generating unit necessary to alleviate a transmission system constraint** and include in the ISO tariff the recovery of those costs.

23(3) The ISO must **make rules regarding transmission must-run generating units** and the determination of pool price so that the pool price will be determined using the last in-merit generating unit(s) actually dispatched.

Taken together, the above quoted sections of the Transmission Regulation provide some clear direction on who pays for transmission, how equality among generators will be maintained and the use of TMR to relieve congestion. By inference, the quotes provide indications of the relative treatment appropriate for generators, imports, exports and TMR in managing congestion.

iii) The Transmission Policy

Before the Transmission Regulation came into force, Alberta Energy provided a detailed summary of intended policy direction through a paper entitled, "Transmission Development The Right Path for Alberta A Policy Paper". In that November 2003 paper, Alberta Energy states:

"The open access transmission structure in Alberta consists of an implicit system of injection and withdrawals rights for generators and loads. **There are no explicit transmission rights.**" (TDP p8)

"In general terms, **real-time congestion will be resolved by merit order re-dispatch, followed, if necessary, by pro-rata curtailment of parties with equivalent offers or bids**." The TDP further contemplates a RT congestion management protocol when TMR exists, that is that "real time congestion management use reverse merit order to dispatch down units in a congested area, **with units not in merit 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, 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." (TDP p8)

"**In principal**, real-time congestion or constraints should not alter or distort market prices." (TDP Appendix 6.2 p15)

"The current practice of charging exporters who use non-firm transmission service (i.e. opportunity service) is appropriate. The **opportunity export tariff will continue to**

recover a portion of the embedded cost of transmission wires, losses and ancillary services, while respecting the established practices for inter-regional electricity trade. Such non-firm transmission service should be **priced at a discount from the firm transmission service rate**." (TDP p10)

"Alberta Energy also confirms that **import variable charges be removed coincident with discontinuation of the STS variable energy charge for generators**." (TDP p10)

The Transmission Policy Paper provides clear policy direction with respect to transmission rights and protocol while also giving guidance to the treatment of imports and exports.

iv) Alberta Energy and Utilities Board (EUB) Policy

The EUA, Transmission Regulation and TDP supersede the policy direction provided by EUB Decision 2002-099 released in November 2002 which, among other things, provided direction on real-time congestion management. Change was, in fact, anticipated in this decision as the **EUB recognized the need to revisit the proposed congestion management principles "in the event of major structural changes in the marketplace**… or substantial changes in the circumstances giving rise to this Decision." (EUB 2002-099 p226)

Changes to the fundamental market structure were formally acknowledged in EUB Decision 2005-096 on the AESO 2005/2006 General Tariff Application. In Section 8.1 Disposition of Outstanding Board Directives, the EUB stated that "the Board considers, at this time, that the AESO should generally start with a "clean slate"." This "clean slate" approach overrides the Board congestion management directives in Decision 2002-099.

Appendix 2 –December CM Plan

The December CM plan developed in 2006 contained the following steps to be implemented in the noted sequence (some minor editing has been performed on the original rules for ease of reading purposes). For clarity, this proposed December CM plan is recommended to be replaced by the 2007 CM protocol summarized in this paper and further detailed in Appendix 3.

1.1.1 9.4.2 Determining a Transmission Constraint

The **ISO** may determine that a **transmission constraint** exists by one or more of the following means:

a) By assessing an market participant application pursuant to the **ISO tariff** for system access service or requesting an increase to the peak demand or supply capability and applying **reliability criteria** to the specifications of the application;

b) By performing operations planning analysis based on the Operating Criteria, Part III of the **reliability criteria** from time to time to assess if such criteria is met; or

c) By the **system controller** observing a thermal or voltage limit excursion or predicting a thermal or voltage limit excursion after performing a contingency analysis.

1.1.2 9.4.3 Notification to Market Participant

a) In the event the **ISO** has determined pursuant to the foregoing rule 9.4.2 a) that a **transmission constraint** exists, the **ISO** must do the following:

i) Notify the **market participant** that the requested increase must be a **trigger service** and the associated **trigger volume**;

ii) Provide to the **market participant** a description of the **transmission facilities** that will be required to relieve the **transmission constraint** and the estimated date of **energization** of such **transmission facilities;**

iii) Prior to the date of **energization** of the service, develop an **ISO** OPP that identifies the final **trigger volume** and describes how the **ISO** will operate to manage the **transmission constraint**; and

iv) When the **transmission facilities** required to relieve the **transmission constraint** have been commissioned, notify the

market participant that the requested increase in service is not a **trigger volume**.

b) In the event the **ISO** has determined pursuant to the foregoing **rule** 9.4.2 b) that a **transmission constraint** exists, the **ISO** must develop and approve an **ISO** OPP to describe how the **ISO** will operate to manage the **transmission constraint.**

1.1.3 9.4.4 Transmission Constraint Mitigation

a) Subject to rule 9.4.4 b), the **ISO** must follow the following steps sequentially in mitigating a **transmission constraint**:

i) Using the **effective factor** as a guideline, determine the **assets** which are **loads**, **generating units** and **interconnections** to be included.

ii) Issue **directive**s to **generating units** that are **upstream** of the **transmission constraint** directing them to curtail to their **supply transmission service** levels.

iii) Curtail opportunity **export services downstream** of the **transmission constraint** and curtail opportunity **import services upstream** of the **transmission constraint.**

iv) Curtail **demand opportunity service loads downstream** of the **transmission constraint**.

v) Curtail each **generating unit's trigger volume** that is **upstream** of the **transmission constraint**.

vi) **Dispatch generating units downstream** of the **transmission constraint** which are contracted with the **ISO** to provide **TMR** to increase their **energy production**.

vii) Curtail each **demand customer**'s **trigger volume** that is **downstream** of the **transmission constraint**.

viii) Curtail **generating units upstream** of the **transmission constraint.** If there is more than one **generating unit upstream** of the **transmission constraint,** the curtailment to each **generating unit** will be allocated on a pro-rata basis.

ix) Issue **directives** to **generating units downstream** of the **transmission constraint** to increase **energy production** or to begin **energy production**, if so required by the **reliability criteria**.

x) Curtail **demand transmission service** loads **downstream** of the **transmission constraint**, if so required by the **reliability criteria**. If there is more than one **demand customer downstream** of the **transmission constraint**, the curtailment to each **demand customer** will be allocated on a pro-rata basis.

In all of the above steps that involve generation or load curtailments, where the generator or load is supplying both reserve service and energy, then reserve service will be curtailed first, before energy.

Appendix 3 – 2007 CM Protocol consistent with Policy
The recommended 2007 CM protocol contains the following steps to be implemented in this sequence:

1.1.4 9.4.2 Determining a Transmission Constraint

The **ISO** may determine that a **transmission constraint** exists by one or more of the following means:

a) By assessing an market participant application pursuant to the **ISO tariff** for system access service or requesting an increase to the peak demand or supply capability and applying **reliability criteria** to the specifications of the application;

b) By performing operations planning analysis based on the Operating Criteria, Part III of the **reliability criteria** from time to time to assess if such criteria is met; or

c) By the **system controller** observing a thermal or voltage limit excursion or predicting a thermal or voltage limit excursion after performing a contingency analysis.

1.1.5 9.4.3 Notification to Market Participants

a) In the event the **ISO** has determined pursuant to the foregoing rule 9.4.2 a) that a **transmission constraint** exists, the **ISO** must do the following:

i) Notify all **market participants** that a requested STS increase may cause a potential congestion condition

v) Provide to **market participants** a description of the **transmission facilities** that will be required to relieve the **transmission constraint** and the estimated date of **energization** of such **transmission facilities;**

vi) Prior to the date of **energization** of the service, develop an **ISO** OPP that identifies and describes how the **ISO** will operate to manage the **transmission constraint**; and

vii) When the **transmission facilities** required to relieve the **transmission constraint** have been commissioned, notify **market participants** that the potential congestion condition has been relieved.

b) In the event the **ISO** has determined pursuant to the foregoing **rule** 9.4.2 b) that a **transmission constraint** exists, the **ISO** must develop and approve an **ISO** OPP to describe how the **ISO** will operate to manage the **transmission constraint.**

1.1.6 9.4.4 Transmission Constraint Mitigation

a) Subject to rule 9.4.4 b), the **ISO** must follow the following steps sequentially in mitigating a **transmission constraint**:

i) Using the **effective factor** as a guideline, determine the **assets** which are **loads**, **generating units** and **interconnections** to be included.

ii) Cancel **directive**s, if appropriate, to **generating units** that are generating above their **Maximum Capacity** which would have the effect of curtailing them to their **Maximum Capacity** levels.

iii) Re-dispatch Dec Down Service (DDS) merit order to curtail DDS services that are **downstream** of the **transmission constraint**.

iv) Curtail opportunity **export services downstream** of the **transmission constraint** and curtail opportunity **import services upstream** of the **transmission constraint.**

v) Curtail **demand opportunity service loads downstream** of the **transmission constraint**.

vi) **Dispatch effective generating units downstream** of the **transmission constraint** which are contracted with the **ISO** to provide **TMR** to increase their **energy production.**

vii) Curtail **generating units upstream** of the **transmission constraint.** If there is more than one **generating unit upstream** of the **transmission constraint,** the curtailment to each **generating unit** will be allocated on the basis of reverse merit order. If there are equivalent priced offers in the merit order, then curtailment will be allocated on a pro-rata basis as required or practical.

viii) Dispatch generating **units downstream** of the **transmission constraint** to increase **energy production** or to begin **energy production**..

ix) Curtail **demand transmission service** loads **downstream** of the **transmission constraint**, if so required by the **reliability criteria**. If there is more than one **demand customer downstream** of the **transmission constraint**, the curtailment to each **demand customer** will be allocated on the basis of reverse merit order. If there are equivalent priced bids in the merit order, then curtailment will be allocated on a pro-rata basis as required or practical. If the constraint is still present after reaching the lowest cost bid in the merit order capable of effectively relieving the constraint, then curtailment will be allocated on a pro-rata basis.

In all of the above steps that involve generation or load curtailments, where the generator or load is supplying both reserve service and energy, then reserve service will be curtailed first, before energy.