



# Intertie Framework

## DISCUSSION PAPER

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# 1. Executive Summary

Transmission interconnections with neighbouring jurisdictions are essential to a well functioning power market as they support reliability, market diversification, generation development and continued economic growth in Alberta. Albertans benefit from these interconnections by having the ability to import and export power as needed with physical access to diverse markets, achieving the most efficient, economic and environmentally beneficial exchange for a resource.

In 2008, the Provincial Energy Strategy (PES) stated the province's plan to adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta. As new interties are being contemplated from multiple jurisdictions, a review of the intertie framework is required to ensure it supports fair, efficient, and openly competitive (FEOC) intertie transactions. The purpose of this discussion paper is to provide a review of the intertie framework and the options available for industry dialogue.

Market based imports and exports of electricity from the Alberta market were the advent of open access transmission across North America. The interaction of Alberta's energy market with jurisdictions with different market models and trading practices has revealed seams<sup>1</sup> in operation and market design including scheduling timeframes, rights to transmission, and tariff products. Each seam requires specific attention and will be discussed in this paper.

In an uncongested system, the interties should function within the energy market merit order like internal generation and load. The opportunity is to create the conditions whereby imports and exports can submit priced offers and bids. This involves developing the capability to do real-time dispatch and real-time scheduling on the interties in order to enable importers and exporters to respond to energy market dispatches. This presents a scheduling seam whereby most transmission operators schedule hourly, only accepting real-time changes as rare late submissions.

Possible options to achieve real-time scheduling are to move to intra-hour scheduling or dynamic scheduling. Intra-hour scheduling is being explored by other markets as a means to improve flexibility on the interties. If scheduled every 5 minutes, this essentially could emulate real-time scheduling. Dynamic scheduling requires automated communications between the AESO and transmission operators from which energy is imported or exported. Dynamic scheduling is achieved when a volume of intertie capacity is held in which the power can be automatically adjusted every 4 seconds. If a unit is dynamically scheduled, it is then possible to change the schedule in real-time for dispatch, though it is a technically sophisticated means to achieve this.

An alternative to real-time scheduling (or dynamic scheduling) is to create a dispatch up/down system market product or option whereby an internal generator or load takes the dispatch for the import or export within the hour if they should fall out of merit. This has been reviewed in the past and deferred for dynamic scheduling due to the complexities of the design. Some participants have also suggested a bi-lateral market be permitted

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<sup>1</sup> Seams are differences in market design and operational practices between jurisdictions that introduce barriers to efficient economic trade.

which would allow for an importer/exporter to bi-laterally contract to take the dispatch for them. The AESO does not interpret that a bi-lateral market is within current market design policy and creates operational challenges. The AESO is seeking stakeholder feedback as to the preferred option that would permit priced bids and offers on the interties, and whether current policy permits for bi-lateral markets.

Interties will always have some form of congestion due to physical limitations on the lines themselves and/or system wide constraints. While increasing the intertie transfer capability may reduce congestion, a means to allocate the limited commercial Available Transfer Capability (ATC) is required. Due to the pending competition for ATC<sup>2</sup> between interties from different jurisdictions, a means to allocate ATC must be determined either through policy, commercial/tariff or procedural means.

Alberta is an energy only market with no transmission rights. This creates a seam with our neighbouring jurisdictions and markets where rights are sold through the Federal Energy Regulatory Commission (FERC) Open Access Transmission Tariff (OATT). Some participants have argued that existing rights bought external to Alberta should be recognized above entrants from new lines. Others have argued that merchant lines, because they have been privately financed, should be given priority rights. The AESO interprets current market policy to mean there is no commercial priority of one line over another or recognition of commercial rights to ATC. The AESO seeks stakeholder feedback on whether policy permits rights to ATC on the interties.

There has been stakeholder discussion suggesting the AESO adopt a FERC OATT or introduce new commercial or tariff products on the intertie. The FERC OATT pro-forma is principled on non-discriminatory access. The AESO's view is the tariff provides non-discriminatory access, and that opportunity service available on the interties appropriately reflects the current conditions affecting service over the intertie. While there has been stakeholder discussion on the value of a firm tariff product, the AESO is seeking stakeholder input on the objectives and the design of these products in the context of Alberta's energy only market where dispatch is based on price.

Finally, in an environment of same priced, same product offers and bids, the AESO requires a means to break the tie in order to allocate ATC between multiple interties. The identified options are last in, first out (LIFO) and pro-rata. Pro-rata is most consistent with internal practices to manage congestion and constraints on transmission lines. However, there may be some timing concerns as to when curtailments by LIFO or pro-rata should be applied. The AESO is seeking stakeholder input on how to procedurally allocate ATC as a tie breaker.

The AESO's next steps on this initiative will proceed in two parallel paths. The shorter term path will aim to resolve the rule pertaining to ATC allocation where a tiebreaker is needed due to same price, same product offers and bids. This situation can exist today with the pending restoration of the AB-Sask intertie and will need to be addressed in the short term. After consulting on this paper, the AESO will issue a draft rule for consultation that addresses a tie breaking procedure for ATC allocation. The AESO will

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<sup>2</sup> The addition of the MATL intertie does not add any transfer capability to and from Alberta. Due to system flows and constraints external and internal to Alberta, MATL and the AB-BC intertie will share import transfer capability, and MATL, the AB-BC intertie, and the AB-Sask intertie will sometimes share export transfer capability. On export today, the AB-BC and AB-Sask interties are sometimes limited by South of KEG congestion so are not always independent, but AB-Sask export ATC has been so historically low, it has not created competition. Upgrades to McNeil in 2010 will restore the AB-Sask intertie creating the competition.

target filing the rule with the Alberta Utility Commission in the summer of 2010 addressing a tie breaking procedure for ATC allocation. The longer term path will encompass consultation on the broader intertie framework, and the AESO will issue a recommendation paper in Q3 of 2010. The aim will be to implement the recommended framework within 2011.

## 2. Purpose

The purpose of this discussion paper is to provide a review of the intertie framework for industry dialogue. In order to engage industry in discussion, the paper presents options for intertie design strategy. In addition, a set of design principles for interties are outlined based on interpretation of Department of Energy policy, regulations and legislation. The AESO welcomes feedback on all areas outlined in this discussion paper. It should be noted that this paper makes no assumptions related to current or future intertie capacity and instead addresses the design to support intertie energy transactions. Clearly, restoring the current rated capacity of interties is a priority for AESO as well; however, actions to address these short term market solutions are addressed in a separate program<sup>3</sup>.

## 3. Introduction / Background

Transmission interconnections with neighbouring jurisdictions are essential to a well functioning power market as they support reliability, market diversification, generation development and continued economic growth in Alberta. Albertans benefit from these interconnections by having the ability to import and export power as needed with physical access to diverse markets, achieving the most efficient, economic and environmentally beneficial exchange for a resource.

In 2008, the Provincial Energy Strategy (*PES*) stated the province's plan to adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta. As new interties are being contemplated from multiple jurisdictions, a review of the intertie framework is required to ensure it supports fair, efficient, and openly competitive (FEOC) intertie transactions.

The Alberta electricity market currently has two major links to external systems. There is a synchronous AC intertie with BC (1200/1000 MW path rating) and a DC intertie to Saskatchewan (150 MW). The interties provide access to the North American electric grid, though not directly. The BC intertie connects to the US Pacific power markets through BCTC and to members of the Western Electric Coordinating Council (WECC). On the east side, the Saskatchewan intertie links to SaskPower and onto Manitoba Hydro and to the Mid-Continent Area Power Pool (MAPP).

Market based imports and exports of electricity from the Alberta market were the advent of open access transmission across North America. The interaction of Alberta's energy market with jurisdictions with different market models and trading practices has revealed seams in operation and market design including scheduling timeframes, rights to

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<sup>3</sup> Intertie Restoration Initiative Recommendation Paper, dated 25 March 2010

transmission, and tariff products. Each seam requires specific attention and will be discussed in this paper.

Alberta's wholesale electricity market is an energy only market, meaning that energy prices are set by the energy market dispatch based on energy bids and offers. Market participants are generally eligible to submit priced offers into the energy trading system (ETS) at T-2 hrs and the market is dispatched in real-time through the energy market merit order (EMMO). Transmission is managed in Alberta as a natural monopoly and is allocated upon dispatch based on an "injection withdrawal" transmission tariff. There are no transmission rights.

Unlike other supply or load within Alberta, an importer or exporter submits an energy transaction through a scheduling process and must secure transmission for all points of their energy transaction (including into or from Alberta). Any "offers" for imported energy or "bids" for exported energy are submitted as price takers at T-2 hours today and are as such scheduled and dispatched before the hour as "in merit"<sup>4</sup>. Over the past several years, there has been a push from industry to enable intertie offers to submit price like other source generation assets in Alberta. However, being able to submit price implies blending a real-time dispatch energy market model with a process of hourly scheduling of transmission. This paper will review options to permit priced offers and bids on the interties within the intertie framework.

The AESO manages congestion on the interties via the scheduling process. Currently, the AESO will approve all schedule submissions (known as e-tags). If the submitted volume is greater than the available transfer capability (ATC) of the intertie, the neighbouring transmission provider, the British Columbia Transmission Corporation (BCTC) or Saskatchewan Power (SaskPower), will curtail according to their priority given they sell transmission products which act as priorities or "rights". If BCTC or SaskPower do not curtail enough volume by hh:45, the AESO, as the path operator, will currently cut on a last in, first out (LIFO) basis according to the timing of e-tag approval.

With the pending development of the Montana Alberta Tie Line (MATL) and the restoration of the AB-Sask intertie, there will be competition between rate based and merchant interties from multiple jurisdictions for limited system ATC capacity where previously there has not been competition<sup>5</sup>. It will be necessary to develop a rule that allocates this capacity either through policy, tariff/commercial or procedural means. This paper will review options pertaining to ATC allocation.

Finally, all intertie participants are designated as "opportunity" service customers under the current tariff. An Alberta intertie participant may have external priority transmission product (i.e., through BC) as part of the complete transmission path for their energy transaction, thereby aligning a FERC Open Access Transmission Tariff (OATT) compatible product with opportunity service in Alberta. This paper will review whether the AESO should introduce new products on the interties to better align our market with others to ensure the value of products is not compromised.

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<sup>4</sup> "In merit" refers to an offer being priced at or below the system marginal pool price.

<sup>5</sup> The addition of the MATL intertie does not add any transfer capability to and from Alberta. Due to system flows and constraints external and internal to Alberta, MATL and the AB-BC intertie will share import transfer capability, and MATL, the AB-BC intertie, and the AB-Sask intertie will sometimes share export transfer capability. On export today, the AB-BC and AB-Sask interties are sometimes limited by South of KEG congestion so are not always independent, but AB-Sask export ATC has been so historically low, it has not created competition. Upgrades to McNeil in 2010 will restore the AB-Sask intertie creating the competition.

## 4. Policy Coherence and Principles

The Department of Energy's policies and regulations confirm that interties are part of a well functioning market and that market design that supports their integration into the wholesale market in a fair, efficient and openly competitive fashion should be explored. It is further clear that these efforts range from a priority to restore the existing interties to their rated capacity as well as to facilitate new rate base and merchant lines as envisioned by the Provincial Energy Strategy (PES). The AESO has developed the following design principles grounded in government legislation, regulations and policies to be considered with intertie market design decisions. The intent would be to use these design principles in the evaluation of different design options in consultation with industry.

1. Intertie market design should ***facilitate competition by reducing barriers while maintaining reliability***. This principle is supported by the following sections of the Electric Utilities Act (EUA):

EUA, Section 16. The Independent System Operator must exercise its powers and carry out its duties, responsibilities and functions in a timely manner that is fair and responsible to provide for the safe, reliable and economic operation of the interconnected electric system and to promote a fair, efficient and openly competitive market for electricity.

EUA, Section 17. The Independent System Operator has the following duties:

(a) to operate the power pool in a manner that promotes the fair, efficient and openly competitive exchange of electric energy;

(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;

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

EUA, Section 29. The Independent System Operator 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.

2. Intertie market design should ***facilitate restoration and expansion of intertie capacity that proves sustainable over the long term and supports efficient market processes***. This principle is supported by the following sections of the 2007 Transmission Regulation, the 2005 Electricity Policy Framework and the 2008 Provincial Energy Strategy:

Transmission Regulation, Section 16. In making rules under section 20 of the Act, and in exercising its duties under section 17 of the Act, the ISO must prepare a plan and make arrangements to restore each intertie that existed on August 12, 2004 to, or near to, its path rating.

Electricity Policy Framework, Page 32. The Transmission Policy and Regulation also provides a framework for the development of privately funded merchant transmission lines for import and export of electric energy.

Provincial Energy Strategy, Page 44. Adopt and implement a policy to build interties to other markets to ensure an adequate supply of electricity to Alberta as well as to facilitate development of additional wind generation.

3. Intertie market design should **support a level playing field for generation, imports, exports and load where possible.** This principle is supported by the following sections of the EUA and the 2005 Electricity Policy Framework:

EUA, Section 6. Market participants are to conduct themselves in a manner that supports the fair, efficient and openly competitive operation of the market.

EUA, Section 18 (1). The Independent System Operator must operate the power pool in a manner that is fair, efficient and open to all market participants exchanging or wishing to exchange electric energy through the power pool and that gives all market participants a reasonable opportunity to do so.

Electricity Policy Framework, Page 4. To the extent possible, industry suppliers with import capacity should be treated the same as intra-Alberta generators. The Department, therefore, recommends that all imports be required to offer energy and allowed to set Pool price if they are able to respond to an intra-hour energy market dispatch.

4. Intertie market design should ensure **product development is consistent with AB legislation and policy.** This principle is supported by the following sections of the 2007 Transmission Regulation and referred to in the EUB Decision 2007-106 to the AESO tariff application:

Transmission Regulation, Section 27 (4). - The cost of planning, designing, constructing, operating and interconnecting an intertie to which this section applies must be paid by

- (a) the person proposing the intertie, and
- (b) other persons to the extent that they directly benefit from the intertie, based on the use described in the needs identification document approved by the Commission, and then only to the extent permitted by the ISO tariff.

Transmission Regulation, Section 27 (6). - The ISO must include in the ISO tariff, rates and terms and conditions that include costs for use of the interconnected electric system, appropriate for the class of service provided to persons who use the intertie referred to in this section for import or export of electricity to or from Alberta.

5. Intertie market design should **manage seams between neighbouring jurisdictions and access to regulated and deregulated markets.** This

principle is supported by the following sections from the 2003 Transmission Development Policy and the 2005 Electricity Market Policy Paper:

Transmission Development Policy, Page 3. Interties are essential to a well-functioning market structure. Alberta is integrated with the electric systems of our neighbours. Transmission policy and the regulatory environment must facilitate open access to larger markets, while ensuring that Alberta's needs are met.

Electricity Policy Framework, Page 39. There are a number of seams issues with neighboring jurisdictions that have been and continue to be examined,...

6. Intertie market design should **support system dispatch through the energy market merit order**. This principle is supported by the following sections of the EUA):

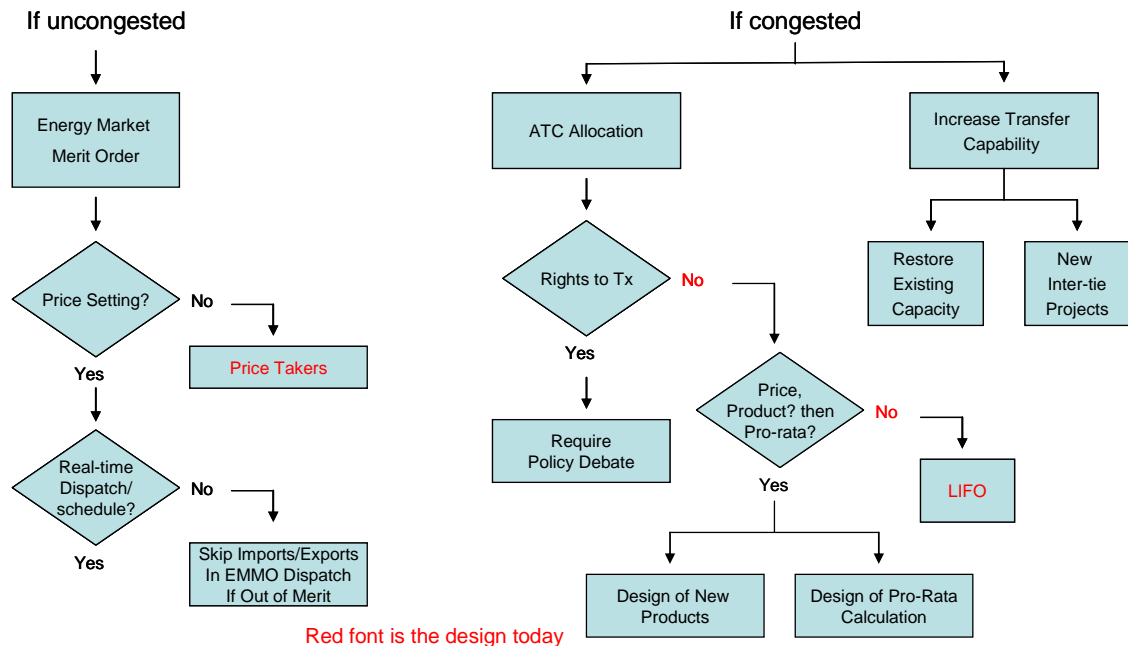
EUA, Section 17 (c). The ISO has the duty...to determine, according to relative economic merit, the order of dispatch of electric energy and ancillary services in Alberta and from scheduled exchanges of electric energy and ancillary services between the interconnected electric system in Alberta and electric system outside Alberta, to satisfy the requirements for electricity in Alberta.

EUA, Section 18 (2). All electric energy entering or leaving the interconnected electric system must be exchanged through the power pool unless regulations made under section 41, section 99 or section 142 provide otherwise.

The AESO is interested in feedback on the principles for alignment of interties into the Alberta market and larger interconnected marketplace. The AESO is also interested in the order priority that should be given to the principles given there would be likely tradeoffs between principles.

## 5. Intertie Framework

The following figure is provided to guide the discussions on interties. The left side shows how interties will fit into the Alberta energy only market without any congestion on the intertie. Importers and exporters submit bids and offers into the Energy Market Merit Order with a few market design options to consider. However, given that there may be regular or intermittent congestion on the interties, the AESO needs to develop rules to manage this congestion. There are two streams to manage this congestion shown on the right side of the framework. One stream is to increase the transfer capability in order to relieve congestion. The second stream is to manage the existing transfer capability by allocating either through policy, tariff/commercial product priority or procedural (pro-rata or LIFO) means.



The figure identifies the following as key decision points for the intertie framework to be reviewed in this paper:

- Should interties be dispatched and scheduled in real-time?
- Should there be transmission rights to ATC on the interties?
- Should product priority be used to allocate ATC?
- Should pro-rata be used to allocate ATC instead of LIFO as tie breaker?

The AESO is interested in feedback on the intertie framework and the decisions identified.

## 5.1 Real-Time Dispatch/Scheduling

Currently, importers offer at \$0 and exporters bid at \$999, thus becoming price takers. Not being able to submit price has a distorting effect on price as the offers/bids for intertie transactions may not reflect the true market value of electricity and the economics of the transactions. The AESO assumes that permitting interties to submit priced offers and bids is supported by industry (the AESO is open to feedback on this assumption). However, in order to set price, interties will have to become dispatchable in real-time like all other priced generation in the merit order so as to ensure a level playing field and compatibility with market rules<sup>6</sup>.

Prior to 2000 when imports could submit price, importers were forecasted by the system controller to be “in merit” based on their offer in comparison to system load requirements. If they were forecasted to be “in merit”; they were scheduled before the hour and dispatched accordingly, though they were allowed to continue to flow even if the offer

<sup>6</sup> 2005 Electricity Policy Framework, Page 4. To the extent possible, industry suppliers with import capacity should be treated the same as intra-Alberta generators. The Department, therefore, recommends that all imports be required to offer energy and allowed to set Pool price if they are able to respond to an intra-hour energy market dispatch.

block subsequently fell out of merit during the hour. However, due to concerns with the system controller (SC) forecasting “in merit” generation and the impact of subsequent action on other internal to Alberta generation, this procedure was stopped and imports became price takers, thereby always being “in merit”. In short, since imports were treated as “firm for the hour”, they were required to offer as such.

To avoid the issue related to SC forecasting, interties could be dispatched in real-time. However, dispatching in real-time implies also scheduling in real-time. The current industry practice in WECC is to schedule before the hour of delivery. Most transmission operators are set up to administer hourly schedule changes with intertie participants reserving transmission capacity for the hour. If Alberta was to move to real-time schedule changes, this would involve working with other transmission operators in the different markets to ensure they are willing to accept real-time schedule changes when participants respond to an AESO real-time dispatch.

To achieve real-time scheduling, there are three options. The first option involves using the current tagging and scheduling process, and developing the arrangement between multiple transmission operators to accept real-time schedule changes. This capability to change the schedule within the hour exists today, however the e-tags are considered as late submissions. It would be up to a marketer looking to source or sink energy to and from the Alberta border to work with the impacted transmission operators to accept late e-tag submissions as a norm. Further changes may be required to the scheduling timeframe to permit such tagging changes.

The second option is to move to intra-hour scheduling. Intra-hour refers to doing it every 15 minutes or 5 minutes, not necessarily in real-time. There are initiatives within WECC to explore moving from hourly schedules to intra-hour schedules to provide greater flexibility on the interconnections. Again, this would involve getting agreement from the other transmission operators in WECC in order for this to be available in Alberta.

The third option is dynamic scheduling<sup>7</sup> which is currently implemented between a few transmission operators in WECC. Dynamic scheduling would require the AESO to enter into an operational relationship with the transmission operators which energy is being sourced to or from. There is a Joint Initiative amongst WECC members to design a centrally controlled dynamic scheduling system that would permit participating members to dynamically schedule between each other. The AESO is currently not a participating member. Until such time as the AESO can dynamically schedule with a particular transmission operator, it is possible to dynamically schedule a portion of the intertie’s capacity while using the current scheduling process for the remaining portion (hourly or real-time).

Dynamic scheduling is achieved when a volume of intertie capacity is held in which the power can be automatically adjusted every 4 seconds. If a unit is dynamically scheduled, it is then possible to change the schedule in real-time for dispatch, though it is a technically sophisticated means to achieve this. This capability would also permit assets to provide Automatic Generation Control (AGC) or regulating reserves over the intertie. Dynamic scheduling may also permit transmission corridors to be set up between Alberta

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<sup>7</sup> Dynamic Schedule (NERC definition) - A telemetered reading or value that is updated in real time and used as a schedule in the AGC/ACE equation and the integrated value of which is treated as a schedule for interchange accounting purposes. Commonly used for scheduling jointly owned generation to or from another Balancing Authority Area.

and an external participant in which energy flows dynamically. This could be used to facilitate intermittent energy (like wind power) where the energy is dynamically balanced by an asset on the sink side of the intertie.

After reviewing what it takes to be able to schedule in real-time, some participants may believe that real-time dispatch and scheduling requirements would prevent them from submitting priced offers and bids due to the complexity related to risk of changes at the margin. This may be because they do not have an asset that can respond to real-time dispatch or are sourcing through a path that cannot administer a real-time schedule change. Having to submit an offer at T-2 hrs and be subject to must offer, must comply rules in Alberta may force some participants to be price takers given they have to schedule and reserve transmission capacity for the hour external to Alberta. In this case, participants may prefer an alternative option, close to what existed before 2000, where the importer or exporter is skipped over in the merit order dispatch within the hour if they go in or out of merit through a dispatch up/down service or system market product.

For example, a priced importer is scheduled and is dispatched before the hour as “in merit”. Within the hour, the load drops, and the importer falls “out of merit”. The importer is skipped and the system controller dispatches down in the merit order to account for the skipped import block. After the hour, the import is cut, the schedule is changed, and the curtailed internal block is dispatched back up. This would require an out of market settlement and/or pool price reconstitution procedure to ensure the resulting pool price reflects the energy delivered. This option and its variances have been reviewed in the past in Alberta, but have been deferred in favor of waiting for real-time scheduling capability because it does not treat an import like an internal generator and creates impacts on other generators.

The concept of a dispatch up/down service for the interties often leads to discussions of bi-lateral dispatch, whereby an importer enters into a bi-lateral contract with an internal generator or load to be able to respond to an intra-hour dispatch for the importer. This would permit the importer to maintain its schedule if dispatched off, or meet its dispatch if it does not have a schedule. This AESO views this as a form of bi-lateral dispatch. This is not considered as a viable option given the design principle to **support system dispatch through the energy market merit order** and the AESO interprets this as outside of current policy. It also complicates the operational world not knowing where the dispatch is going to physically be executed making it difficult to implement. The EMMO should include and reflect the characteristics of the offers and not rely on offsetting dispatches to resolve. Any dispatch up/down service should be managed within the EMMO and by the AESO as a system product. The AESO welcomes comments on this premise.

The AESO is interested in stakeholder comment to the following questions:

- Should the AESO adopt real-time dispatch and scheduling on the interties and what are the impacts to market participants?
- If yes, should the AESO do so through dynamic schedules, intra-hour scheduling (ex. every 5 minutes) or by using the existing scheduling process in real-time?
- Should the AESO again explore a dispatch up/down service or system market product on the interties as a substitute to real time dispatch and what are the

suggested designs?

- Do stakeholders interpret policy to permit for a bi-lateral market?

## 5.2 Transmission Rights - Policy

With the pending development of MATL and the restoration of the AB-Sask intertie, there will be competition between interties for limited ATC capacity<sup>8</sup>. MATL does not add to Alberta's ability to transfer power in and out of the province, but rather creates diversity. It will be necessary to develop a rule that allocates this capacity when there is competition between two or more interties from different jurisdictions for ATC either through policy, tariff/commercial or procedural means.

Alberta's market is an energy only market with no transmission rights. However, intertie integration provides an interesting dynamic in that they link the Alberta energy only market to markets with transmission rights. This creates a seam between the differing market places. There has been debate as to whether incumbent lines with participants who have purchased contracts for transmission rights to the Alberta border should have priority rights to ATC over new lines that do not add additional ATC. Alternatively, there has been an argument that merchant lines, which have been financed privately via the sale of transmission rights, should have priority rights to ATC.

As the Alberta market model does not recognize transmission rights, this is a policy decision detailing whether interties will be treated as part of the AIES (like internal generators and loads), or whether they will be considered as connecting to the AIES, and possibly treated differently. The AESO currently allocates ATC based on a scheduling process through the approval of e-tag volume. This may not be considered an allocated transmission right, rather an allocation for injection-withdrawal of energy like any other dispatch in the energy market merit order. However, when reviewing the injection-withdrawal method for internal energy dispatch, one of the underlying designs for this to work without transmission rights is a commitment to build an uncongested transmission system. This is not as feasible a commitment on the interties given the shared jurisdictional regulatory models. This factor may support an argument for different treatment of interties than internal generators and loads whereby rights are considered.

The British Columbia Utility Commission (BCUC) recently made a decision on the BC side of the border pertaining to transmission rights on the AB – BC intertie.<sup>9</sup> This decision related to an argument that British Columbia Transmission Corp (BCTC) oversold firm transmission capacity (785 MW) on the AB-BC intertie given the average transfer capability (480 MW), subjecting existing shippers on the line to greater pro-rata curtailments. A participant argued that this devalued the rights of current firm transmission owners on the intertie. BCTC argued that given recent system studies demonstrated the line capacity on the BC side of the border at 785 MW, that it was required to sell to this amount in order to follow the principles of its open access transmission tariff (OATT). In the end, BCTC was ordered to reduce the capacity for sale

<sup>8</sup> The addition of the MATL intertie does not add any transfer capability to and from Alberta. Due to system flows and constraints external and internal to Alberta, MATL and the AB-BC intertie will share import transfer capability, and MATL, the AB-BC intertie, and the AB-Sask intertie will sometimes share export transfer capability. On export today, the AB-BC and AB-Sask interties are sometimes limited by South of KEG congestion so are not independent, but AB-Sask export ATC has been so historically low, it has not created competition. Upgrades to McNeil in 2010 will restore the AB-Sask intertie creating the competition.

<sup>9</sup> BCTC – A Complaint by TransCanada Energy Ltd. Re BCTC Firm Transmission Sales to Alberta, September 10, 2009

under the OATT to 480 MW supporting the principle that newly bought rights should not negatively impact existing bought rights.

While this decision is recognized with its associated arguments and discussions, the AESO interprets Alberta policy to provide no preference to sales on one type of intertie transmission line over another. While the rate base line was funded by Albertans and was on the system first, this “first in” does not infer a priority over new interties. Similarly, while a merchant line is encouraged to add capacity to the system, this funded line is added because of its own economics and not to secure a higher priority transmission allocation in times of constraint.

The AESO’s interpretation of the BCUC decision as it relates to Alberta policy is that a new line should not negatively impact the physical capacity of an existing line, but that neither has a commercial right to the capacity. If a new line does impact the capacity of an existing line, a remedial action scheme (RAS) shall be added to the new line as required to ensure no negative impact. This is consistent with how Alberta manages new internal generators connecting to the Alberta Interconnected Electric System (AIES), and is also consistent with Western Electric Coordination Council (WECC) and North American Electric Reliability Council (NERC) principles. In the case of MATL, WECC has ordered that MATL will carry a RAS scheme so as to not physically impact the transfer capability of the AB-BC intertie.

However, it is important to note that there is no current mechanism to trigger transmission development for interties as exists internally through the Supply and Demand Transmission Service (STS/DTS) tariffs to effectively eliminate the need for a RAS and eliminate congested physical capacity to transmission. This raises the argument whereby physical capacity should be linked to commercial capacity on the interties. Effectively, if one merchant intertie developer who constructs a new intertie is able to substantially reduce the ATC on an existing intertie, this will be an impediment to intertie investment which is contrary to the Provincial Energy Strategy. Would this be considered contrary to the principles of FEOC?

The AESO is interested in stakeholder comment as to whether current policy permits the assignment of transmission rights to ATC and whether interties should be treated by the same rules as internal generators and loads.

### 5.3 Product Priority

Assuming there are no rights assigned to the ATC, there still needs to be a means to allocate between same priced offers or bids. This section contemplates the use of differentiated products on the interties as a form of priority.

Currently the AESO only offers import and export opportunity service (IOS/EOS) on the interties. This is considered opportunity as it is curtailed as a priority over internal STS or DTS/DOS participants within the Transmission Congestion Management (TCM) proposed rules. Opportunity service also comes with no obligation to build transmission to relieve congestion or provide access; whereas STS and DTS service implies that transmission will be built to serve the customer supply or demand. This creates an un-level playing field between intertie participants (i.e. importers/exporters) and internal generators/loads.

The product distinction also creates a seam between Alberta and other electricity markets who offer firm products such as the FERC OATT to the Alberta border. Participants may purchase a transmission right point to point to the Alberta border under a firm OATT, and be pooled into the Alberta market under a non-firm import tariff. (See Appendix A for a comparison between internal tariffs and the FERC OATT).

When considering the FERC OATT, it is important to review whether the Alberta market model is aligned with the principles behind the OATT. This is important for the sake of reciprocity whereby the requirement is summarized in the September 10, 2009, BCUC decision regarding the service access being sold on the AB-BC intertie.<sup>10</sup> The decision quoted the US Court of Appeals for the District of Columbia Circuit in *Consumers Energy Company v. FERC*, no. 03-1162 (D.C. Cir. May, 2004) at page 2 where Roberts, Circuit Judge stated, for the Court:

“FERC does not presume to tell foreign transmission owning utilities what tariffs they must file. If a marketing affiliate of such a utility wants to sell power at market based rates in the United States, however, the utility must offer transmission service *comparable* to that required of a utility in the United States. Just as a domestic transmission owning utility must allow competitors of its marketing affiliate to use its transmission services on a non discriminatory basis to compete with the marketing affiliate, so too a foreign transmission owning utility must allow companies that would compete with its marketing affiliate to use its transmission services to reach the United States market and compete on a level playing field with its marketing affiliate.”

While the AESO does not have a marketing affiliate, it is clear that for Alberta market participants to access US markets, the AESO must ensure open access to the interties. The AESO must ensure non-discriminatory access which is the fundamental principle behind the OATT. This is also a requirement of the WECC bylaws section 10<sup>11</sup>. The AESO is of the view its tariff provides non-discriminatory access, and that opportunity service appropriately reflects the current conditions affecting service over the intertie.

Even so, participants have expressed an interest in new differentiated transmission products, made available within an open auction format, in addition to the current opportunity product. They note that there is value to differentiated products over the longer term and these products may create greater alignment to current generation and load products. They argue that the lack of product differentiation has an impact upon marketing and intertie utilization between markets with rights or other market designs<sup>12</sup>. Some have indicated that intertie development and effective utilization of current or new interties relies on the development of priority term access in and out of Alberta. Without such priority products, constrained access can not be financed nor does it prove effective in reducing seams and enabling arbitrage between markets.

Others may argue that creating products will actually create more seams, increase rate pan caking and hinder access. Given that a FERC related point to point transmission

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<sup>10</sup> BCTC – A Complaint by TransCanada Energy Ltd. Re BCTC Firm Transmission Sales to Alberta, September 10, 2009, Page 5

<sup>11</sup> Bylaws of the Western Electric Coordinating Council, page 35

<sup>12</sup> With most regional US markets being day-ahead balanced markets, it is impossible to structure firm access to/from Alberta with only hourly opportunity service. Even if you were to financial hedge the price-taking portion of the Alberta transaction, the physical portion of the trade has no rights or priority hour-to-hour.

product already exists to Alberta's border, and that product is used in initial transmission allocation methods outside of Alberta, is an Alberta based product of necessity? What purpose does a firm or even differentiated non-firm transmission product provide in Alberta in an injection withdrawal no rights model where dispatch is based on a priced merit order? Does it help in resolving the larger issue discussed in section 5.2 around transmission rights and allocation of ATC?

It is recognized that as part of the AESO's 2007 tariff application, the AESO applied for a "non-recallable" export transmission service Rate XTS in addition to the export opportunity services. Rate XTS was proposed as a higher priority export service than the AESO's export opportunity rates, and was intended to be generally comparable to demand transmission service Rate DTS. The proposed rate was denied in EUB Decision 2007-106<sup>13</sup>, primarily due to concerns with respect to its compliance with legislative requirements around cost allocation principles outlined in the Transmission Regulation Sections 27 (4) and (6), quoted in the principles section of this paper.

The discussion of Rate XTS in Decision 2007-106 also included comments on the lack of available transfer capability for export in many hours during the term in which the rate was expected to be in effect. What value is a premium product on a line with limited availability? Or should a new product be developed in contemplation of restored and enhanced capacity and phased in at a later date?

The concerns that were raised in the AESO's 2007 tariff proceeding with respect to Rate XTS generally remain relevant today. In particular, available transfer capability for export remains limited in many hours, and is expected to remain so until transmission reinforcements are completed that allow restoration of the capacities of the existing interties. These factors must be considered when designing any new tariff product, however with the introduction of the MATL line and the review of the whole intertie framework, an introduction of new tariff products may be timely.

The AESO is interested to stakeholder comment to the following questions:

- What would be objectives of a new product on top of an opportunity transmission product to import and export customers?
- What would be the design options of a new product (see appendix A for assistance)?
- Should ATC priority be assigned by tariff/commercial product?
- Would an auction to different products be preferred and what would be the design of that auction methodology?

#### 5.4 ATC Allocation Tiebreaker

The above section contemplates the use of differentiated products as a form of determining priority in assigning ATC. In the event of a tie there needs to be a means in which to procedurally allocate the ATC between similarly priced offers/bids of same product. This market situation is prevalent in the current intertie framework where all imports and exports are price takers (\$0 for imports or \$999 for exports) and all are either import opportunity or export opportunity service products.

<sup>13</sup> EUB Decision 2007-106 (December 21, 2007)

The AESO currently manages congestion on the interties and ATC allocation via the scheduling process. The AESO will approve all schedule submissions (known as e-tags). If the submitted volume is greater than the available transfer capability (ATC) of the intertie, the neighbouring transmission provider, the British Columbia Transmission Corporation (BCTC) or Saskatchewan Power (SaskPower), will curtail according to their priority given they sell transmission products which act as priorities or “rights”. If BCTC or SaskPower do not curtail enough volume by hh:45 before the scheduled hour, the AESO, as the path operator, will currently cut on a last in, first out (LIFO) basis according to the timing of e-tag approval.

With the pending development of the Montana Alberta Tie Line (MATL) and the restoration of the AB-Sask intertie, there will be competition between interties from multiple jurisdictions for limited system ATC capacity<sup>14</sup>. It will be necessary to develop a rule that allocates this capacity between multiple interties where there are same price, same product offer and bids. The following outlines possible options to procedurally allocate ATC between participants using multiple interties where price and product have provided no differentiation or priority. Further design details will obviously need to follow; however there are distinctive differences in approach that warrant consideration.

1. Curtail by LIFO at xx:yy before the scheduled hour

The AESO approves all e-tag submissions. BCTC, SaskPower and MATL curtail as per their priority to their specific intertie ATC, and then the AESO curtails all remaining e-tags at xx:yy before the scheduling hour to the system ATC based on LIFO according to the timing of e-tag approval. This option may create a race for e-tag submission. Market participants could submit e-tags months in advance and then adjust just prior to T-2 to their need.

2. AESO approves e-tags as submitted up to the system ATC

The AESO approves the first e-tag submissions up to the system ATC and rejects the remainder. This is a variant on option 1 where by the AESO would no longer over approve e-tag volume and rely on curtailments first by neighbouring transmission operators to their respective intertie ATCs. This option may create a race for e-tag submission.

3. Pro-rata allocation between all scheduling participants at xx:yy before the scheduled hour

Ex: Total system import ATC shared between MATL and BC tie is 600 MW; A offers 200 MW on BC tie, B offers 400 MW on BC tie, and C offers 200 MW on MATL. Therefore, A would get 1/4 of 600 on BC tie (150 import), B would get 1/2 of 600 on BC tie (300 import), and C would get 1/4 of 600 on the MATL line (150 import). This option aligns with internal transmission congestion and constraint management protocol. To eliminate the incentive to submit exaggerated offers in order to get a greater pro-rata portion, offers on each line could be limited to the ATC maximum on each line.

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<sup>14</sup> The addition of the MATL intertie does not add any transfer capability to and from Alberta. Due to system flows and constraints external and internal to Alberta, MATL and the AB-BC intertie will share import transfer capability, and MATL, the AB-BC intertie, and the AB-Sask intertie will sometimes share export transfer capability. On export today, the AB-BC and AB-Sask interties are sometimes limited by South of KEG congestion so are not independent, but AB-Sask export ATC has been so historically low, it has not created competition. Upgrades to McNeil in 2010 will restore the AB-Sask intertie creating the competition.

#### 4. Pro-rata allocation between the lines at xx:yy

Ex: Total system import ATC shared between MATL and BC tie is 600 MW; BC-Tie ATC is 600 MW; and MATL ATC is 300 MW. A pro rata allocation between the lines would assign MATL 300/900 or 1/3 of 600 (200 for imports on MATL), and BC would be allocated 600/900 or 2/3 of 600 (400 for imports on BC tie). Once the ATC is set per line, the current practice could be implemented where our neighbours curtail to their priority with LIFO at hh:45. This option would be the most difficult to implement as it would require a change in how intertie ATC is determined and posted within AESO systems.

Today, LIFO curtailment is executed at hh:45. However, because curtailments would likely occur more often due to the competition between lines, a new timing (xx:yy) may be warranted in order to reduce the burden on participants having to change or cancel schedules.

The AESO is interested in stakeholder comment to the following questions:

- Should the AESO adopt a pro-rata solution instead of LIFO as a tie breaker?
- If pro-rata is used, how should it be calculated?
- If LIFO is used, should the AESO use LIFO at xx:yy or only approve up to the system ATC?
- What time xx:yy should be used in curtailment to maximize utilization of the ATC and provide maximum flexibility to participants and transmission operators?
- What differences in application may be required for import as opposed to export transactions?
- What other design options are there for considering ATC allocation tiebreakers?

## 6. Summary

The vision in the 2008 Provincial Energy Strategy for greater interconnection capacity to other North American markets presents a huge opportunity for Alberta. As new interties are being contemplated as a part of this vision, this paper reviewed the intertie framework to facilitate industry discussion on where changes may be required.

In an uncongested world, the interties function within the energy market merit order like internal generation and load. The opportunity is to create the conditions whereby imports and exports can submit non-zero offers and bids. This implies developing real-time dispatch and scheduling capability or a dispatch up/down system service in order to be able to respond to energy market dispatch on the interties.

Interties will always have some form of congestion due to physical limitations on the lines themselves and/or system wide constraints. While increasing the intertie transfer capability may reduce congestion, a means to allocate the limited commercial ATC between competing interties is required either through policy, commercial/tariff or procedural means.

This paper presents the various arguments and options associated with ATC allocation around transmission rights, priority tariff or commercial products and procedures. The

AESO looks forward to stakeholder input to these various options in order to develop a recommendation on a future framework.

Appendix B is offered as research detailing how ATC is allocated in South-East Europe where there are multiple interconnections from multiple jurisdictions under different regulatory rules and market models.

## 7. Next Steps

Due to the restoration of the AB-Sask intertie in 2010, and the expected in-service date of the MATL project of June 2011, the AESO will be addressing the issue identified in section 5.4, ATC allocation tiebreaker, along a shortened timeline. This contemplates the ATC allocation rule managing same price, same product offers and bids from multiple interties, which is a scenario that exists today. A determination of this rule is required sooner than the long term framework contemplated in sections 5.1-5.3 in order to be able to operate reliably and fairly.

The next steps for the AESO on the ATC allocation tiebreaker (section 5.4) are as follows.

- Consult on this discussion paper.
- Develop Draft Rule for Consultation. (May 2010)
- Consult on Draft Rule. (June 2010)
- File Rule with the AUC for approval. (Aug 2010)

The next steps for the AESO on the broader intertie framework are as follows.

- Consult on this discussion paper.
- Develop AESO recommendation paper on the intertie framework.
- Consult on recommendation paper. (Q3 – 2010)
- Implement Final Recommendation. (2011)
  - Rule Development and filings
  - Tariff Development and filings
  - IT system upgrades as required

Please provide comments following the associated comments matrix to Darren McCrank, [darren.mccrank@aeso.ca](mailto:darren.mccrank@aeso.ca) by May 28, 2010. Should you have any questions on this paper in the interim, please contact Darren McCrank at 403-539-2623 or Cheryl Terry at 403-471-3816.

The AESO is interested in stakeholder comment on the AESO's next steps.

# Appendix A

## A.1 AESO Comparison of Supply, Import, and OATT Rates

Characteristic		STS: Supply Transmission Service “Domestic Firm”	IOS: Import Opportunity Service “Intertie Opportunity”	FERC Pro Forma OATT “Typical OATT”
<b>I1 Legislated Requirements</b>				
I1a	Planning	Must plan for anticipated generation capacity [T Reg 9(a) and 10(1)(a)]	Must plan for [non-opportunity] imports [T Reg 9(a) and 10(1)(a)]	Transmission provider obligated to expand or upgrade transmission system to meet firm contractual commitments No obligation for non-firm
I1b	Recovery of connection costs	Generator pays local connection costs [T Reg 47(b)]	Cost of planning, designing, constructing, operating, and connecting an intertie must be paid by the proponent and others who benefit [T Reg 27(4)]	Transmission customer must pay for any facilities constructed for the transmission customer
I1c	Recovery of system costs	Generator pays a refundable contribution to transmission system upgrades [T Reg 29(2)] (Load customer pays all just and reasonable costs of the transmission system [T Reg 47(a)(i)])	None	Transmission customer must pay for any necessary system additions
I1d	Losses	Generator must pay location based loss charges or receive credits [T Reg 38(a)]	Opportunity service customer must pay losses or receive credits determined in a similar manner as for generators [T Reg 36(d)] plus pay losses on the intertie from the connecting bus to the border [T Reg 36(c)]	Transmission customer must pay losses determined seasonally on a path-by-path basis

# Appendix A

## A.1 AESO Comparison of Supply, Import, and OATT Rates

Characteristic	STS: Supply Transmission Service “Domestic Firm”	IOS: Import Opportunity Service “Intertie Opportunity”	FERC Pro Forma OATT “Typical OATT”
<b>I2 Currently-Approved Tariff Provisions</b>			
I2a Bulk system charge	None	None	\$/MW of reserved capacity 2 x charge above reserved capacity
I2b Local system charge	None	None	\$/MW of reserved capacity 2 x charge above reserved capacity
I2c Point of Delivery (POD) charge	None	None	None
I2d Operating reserve charge	None	None	\$/MW of reserved capacity, third party, or self-supply
I2e Losses charges	Loss factor determined under Rule 9.2 (representative of impact on average system losses)	Loss factor determined under Rule 9.2 (representative of impact on average system losses plus losses on intertie)	Annual average path loss factor (seasonal for shorter terms)
I2f Voltage control (TMR) charge	None	None	\$/MW of reserved capacity
I2g Other system support charge	None	None	\$/MW of reserved capacity, third party, or self-supply
I2h Take or pay provisions	None	None	100% of reserved capacity
I2i Transaction fees	None	\$500 per transaction per month	Deposit of 1 month’s payment for reserved capacity
I2j Construction contribution	Payment of connection costs prior to construction	Payment of connection costs prior to construction	Payment for any facilities constructed for the transmission customer
I2k Generator system contribution	\$10,000/MW to \$50,000/MW contracted Refunded within 10 years Subject to performance criteria	None	Must finance any necessary system additions Refundable with use
I2l Contract term	Minimum: 5 years Maximum: 20 years “Evergreen”	Contract: 1 year Transaction minimum: 1 hour	Minimum: 1 day Maximum firm: 3 years Maximum non-firm: 6 months

# Appendix A

## A.1 AESO Comparison of Supply, Import, and OATT Rates

Characteristic	STS: Supply Transmission Service "Domestic Firm"	IOS: Import Opportunity Service "Intertie Opportunity"	FERC Pro Forma OATT "Typical OATT"
<b>I3 Other Considerations</b>			
I3a	Conceptual basis	Network integration	Network integration
I3b	Market access	Can access market only through Alberta transmission system	Can access other markets in other jurisdictions
I3c	System planned to accommodate	Yes	No
I3d	Price offers	Can offer at price	Must offer at \$0
I3e	Market Obligations	M T-2 hrs	Must comply if scheduled
I3f	Curtailement for capacity limitations	In constrained areas and subject to congestion management	Due to ATC limits
I3g	Supply surplus conditions	Domestic \$0 offer curtailed after imports	Imports curtailed first
			Unknown

# Appendix A

## A.1 AESO Comparison of Supply, Import, and OATT Rates

Characteristic	DTS: Demand Transmission “Domestic Firm”	DOS: Demand Opportunity “Domestic Opportunity”	XOS: Export Opportunity “Intertie Opportunity”	FERC Pro Forma OATT “Typical OATT”
<b>X1 Legislated Requirements</b>				
X1a Planning	Must plan for forecast load [T Reg 9(a) and 10(1)(a)]	No obligation to plan for opportunity service	Must plan for [non-opportunity] exports [T Reg 9(a) and 10(1)(a)]	Transmission provider obligated to expand or upgrade transmission system to meet firm contractual commitments No obligation for non-firm
X1b Recovery of connection costs	In accordance with tariff Cannot be different as a result of location on the transmission system [EUA 30]	Opportunity service customer pays all connection costs	Cost of planning, designing, construction, operating, and connecting an intertie must be paid by the proponent and others who benefit [T Reg 27(4)]	Transmission customer must pay for any facilities constructed for the transmission customer
X1c Recovery of system costs	In accordance with tariff; cannot be different as a result of location on the transmission system [EUA 30]	In accordance with tariff (minimal contribution)	In accordance with tariff (minimal contribution)	Must finance any necessary system additions Refundable with use
X1d Losses	None	Opportunity service customer must pay losses or receive credits determined in a similar manner as for generators [T Reg 36(d)]	Opportunity service customer must pay losses or receive credits determined in a similar manner as for generators [T Reg 36(d)] plus pay losses on the intertie from the connecting bus to the border [T Reg 36(c)]	Transmission customer must pay losses determined seasonally on a path-by-path basis

# Appendix A

## A.1 AESO Comparison of Supply, Import, and OATT Rates

Characteristic	DTS: Demand Transmission “Domestic Firm”	DOS: Demand Opportunity “Domestic Opportunity”	XOS: Export Opportunity “Intertie Opportunity”	FERC Pro Forma OATT “Typical OATT”
<b>X2 Currently-Approved Tariff Provisions</b>				
X2a Bulk system charge	\$/MW coincident with system peak (primarily)	\$/MWh fraction of DTS charge	\$/MWh fraction of DTS charge	\$/MW of reserved capacity 2 x charge above reserved capacity
X2b Local system charge	\$/MW non-coincident peak/contract/ratchet (primarily)	\$/MWh fraction of DTS charge	\$/MWh fraction of DTS charge	\$/MW of reserved capacity 2 x charge above reserved capacity
X2c Point of Delivery (POD) charge	\$/MW non-coincident peak/contract/ratchet (primarily)	None	None	None
X2d Operating reserve charge	MWh x % x pool price	\$/MWh average DTS charge	\$/MWh fraction of DTS charge	\$/MW of reserved capacity, third party, or self-supply
X2e Losses charges	None	Loss factor determined under Rule 9.2 (representative of impact on average system losses)	Loss factor determined under Rule 9.2 (representative of impact on average system losses plus losses on intertie)	Annual average path loss factor (seasonal for shorter terms)
X2f Voltage control (TMR) charge	\$/MWh	None	None	\$/MW of reserved capacity
X2g Other system support charge	\$/MW non-coincident peak	None	None	\$/MW of reserved capacity, third party, or self-supply
X2h Take or pay provisions	90% of contracted capacity	75% of transaction capacity	75% of scheduled capacity	100% of reserved capacity
X2i Transaction fees	None	\$500 per transaction per month	\$500 per transaction per month	Deposit of 1 month’s payment for reserved capacity
X2j Interconnection cost	Must pay cost less “local investment”	Must pay cost if any (no investment)	Must pay cost (usually zero)	Must pay for any facilities constructed for transmission customer and for any necessary system additions

# Appendix A

## A.1 AESO Comparison of Supply, Import, and OATT Rates

Characteristic	DTS: Demand Transmission “Domestic Firm”	DOS: Demand Opportunity “Domestic Opportunity”	XOS: Export Opportunity “Intertie Opportunity”	FERC Pro Forma OATT “Typical OATT”
X2k Contract term	Minimum: 5 years Maximum: 20 years “Evergreen”	Contract: 1 year Transaction: 8 hours to 1 month	Contract: 1 year Transaction minimum: 1 hour	Minimum: 1 day Maximum firm: 3 years Maximum non-firm: 6 months
<b>X3 Other Considerations</b>				
X3a Conceptual basis	Network integration	Network integration	Network integration	Point-to-point
X3b Market access	Can access market only through Alberta transmission system	Can access market only through Alberta transmission system	Can access other markets in other jurisdictions	Can access other markets in other jurisdictions
X3c System planned to accommodate	Yes	No	No	Yes, for firm No, for non-firm
X3e Price bids	Can bid at price	Can bid at price	Price taker	Can bid at price (where available)
X3g Market Obligations	No obligation	No obligation	Must comply if scheduled	Must comply if scheduled
X3d Curtailment for capacity limitations	In constrained areas and subject to congestion management	In constrained areas	Due to ATC limits	Non-discriminatory with domestic to effectively relieve constraint Non-firm curtailed on price, before firm
X3f Supply shortfall conditions	Domestic firm load curtailed last	Domestic opportunity load curtailed after exports	Exports curtailed first	Unknown

# Appendix B

## Review of Allocation Methods used in other Jurisdictions

The following appendix reviews the allocation methods utilized in South-East Europe where there are multiple interconnections from multiple jurisdictions using different regulatory models. This review is provided as research into how non-FERC regulated markets allocated ATC between each other.

The references for this information come from the "Overview of Currently Applied Methods for Cross-Border Transmission Capacity Allocation in South-East Europe, Situation October 2005" and the "Coordinated Auctions in SEE Region Activity Report, May 2005". Both documents were created by the Network Access, Congestion Management and Power Flows Sub Working Group of the European Transmission System Operators.

1. Currently applied methods are explicit and implicit auctions, pro-rata rationing and priority list.
2. On the borders where there is a certain level of coordination among TSOs there is also an agreement of sharing the Net Transfer Capacity (NTC) value 50:50, and each of the neighbouring TSOs allocate its half independently.
3. Usually the same method is applied for both directions in each border.
4. The exception from 2 and 3 is the border between Austria and Hungary, where each TSO allocates its import (100% of NTC in import direction).
5. Most of the TSOs from SEE region the joint coordinated procedure of monthly network model exchange, which are then merged and used for monthly NTC calculation. Thus pretty consistent NTC values are usually obtained by the neighbouring TSOs.

The methods in bullet one are described in the following table.

Method	Description	Analysis, Observations & Financial Implications
<b>Priority List (First-Come First-Served)</b>	The marketer gets capacity in a priority order until the whole ATC is allocated. Examples of priority criteria are: chronological order, past use of capacity, etc. Transparency limited by confidentiality of trade	<ul style="list-style-type: none"><li>• Selection based on capacity used ratio and not on economic efficiency</li><li>• Not market based</li><li>• New entrants less favored (discriminated) although it can also help to mitigate market power exercise if limitations (maximum purchase) are imposed</li><li>• Absence of efficient cross-border economic signals for generation/transmission investment</li><li>• No pan European incentive for social welfare maximization and least-cost operation</li><li>• Marketers capture congestion rent and pay capacity price (usually null or low)</li><li>• Favors exporters (or importers) with a large portfolio of customers (suppliers)</li><li>• Selection based on capacity used ratio and not on economic efficiency</li></ul>

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## Review of Allocation Methods used in other Jurisdictions

<p><b>Pro-rata Rationing</b></p>	<p>Capacity is allocated in proportion to requests if they exceed the announced ATC</p>	<ul style="list-style-type: none"> <li>· Non-discriminatory</li> <li>· Not market based</li> <li>· No economic signal</li> <li>· Transparent</li> <li>· Simple implementation when compared to other mechanisms</li> <li>· The capacity is arbitrarily priced by the Regulatory authorities at a level not equal to the efficient economic value (which is the 'opportunity cost' of trading between the countries)</li> <li>· No efficient cross-border economic signals for generation/transmission investment</li> <li>· No pan European incentive for social welfare maximization and least-cost operation</li> <li>· Marketers capture congestion rent and pay capacity price (usually low)</li> <li>· Individual size of transmission right delivered inconsistent with standard trading products</li> <li>· Open to abuse by submission of excessive requests</li> <li>· Selection based in proportion to requests (if they exceed the announced ATC) and not on economic efficiency</li> </ul>
<p><b>Explicit Auctions (ATC based)</b></p>	<p>The seller (TSO) determines ex ante ATC considering security analysis, accepts bids from potential buyers and allocates the capacity to the ones that value it the most</p>	<ul style="list-style-type: none"> <li>· Economic signal</li> <li>· Non-discriminatory</li> <li>· Transparent</li> <li>· Often a joint co-ordinated mechanism between the concerned TSOs</li> <li>· Several significant implementation features: uniform clearing price vs. pay as bid</li> <li>· Different allocation products and frequencies (Y, M, D)</li> <li>· With perfect market assumption</li> <li>- price reflects cost of using capacity to the social welfare</li> <li>- internal and cross-border trade present the same profit opportunity for participants</li> <li>- efficient signals to market players for the operation and the value of the network</li> </ul>
<p><b>Implicit auctions (ATC based)</b></p>	<p>The TSO/Power Exchange (typically in import area) (TSO) determines ex ante ATC considering security analysis, accepts energy bids from potential buyers outside the area and accepts offers with lowest price for the electricity. Capacity is implicitly allocated to successful bidders.</p>	<ul style="list-style-type: none"> <li>· Economic signal</li> <li>· Non-discriminatory</li> <li>· Transparent</li> <li>· Usually requires a Power Exchange in import area</li> <li>· Applicable for day-ahead and intra-day time horizons</li> <li>· Internal and cross-border trade present the same profit opportunity for participants</li> <li>· Efficient signals to market players for the operation and the value of the network</li> <li>· No separate trade with capacity and then with electricity</li> </ul>

## Appendix B

### Review of Allocation Methods used in other Jurisdictions

Country-TSO	Involved interconnections	Method	Coordinated with other TSO	Joint with other TSO	Time frames
Albania	Greece	Priority list	No	No	Y, M
	Montenegro	Priority list	No	No	Y, M
	Serbia	Priority list	No	No	Y, M
Austria	Hungary	HU→A explicit auctions (entire A import)	Yes	No	Y, M, (D)
	Italy	Split 50:50, explicit auction (A part)	Yes	No	Y, M
	Slovenia	Split 50:50, explicit auction (A part)	Yes	No	Y, M
Bosnia-Herzegovina	Croatia	Split 50:50, pro rata (BA part)	Yes	No	Y, M
	Montenegro	No method	/	/	/
	Serbia	No method	/	/	/
Bulgaria	Greece	Priority list	No	No	M
	Romania	Split 50:50, Priority list	Yes	No	M
	Serbia	Priority list	No	No	M
	Turkey	No method	/	/	/
Croatia	Bosnia-Herzegovina	Split 50:50, missing information (HR part)	Yes	No	?
	Hungary	Split 50:50, missing information (HR part)	Yes	No	?
	Serbia	Split 50:50, missing information (HR part)	Yes	No	?
	Slovenia	missing information	No	No	?
Greece	Albania	AL,MK,BG→GR: explicit auctions (GR)	No	No	Y
	Bulgaria		No	No	Y
	FYR Macedonia		No	No	Y
	Italy	Split 50:50, explicit auction (GR part)	Yes	No	M, D
Hungary	Austria	A→HU explicit auctions (entire HU import)	Yes	No	Y, M, (D)
	Croatia	Split 50:50, explicit auction (HU part)	Yes	No	Y, M
	Romania	Split 50:50, explicit auction (HU part)	Yes	No	Y, M
	Serbia	Split 50:50, explicit auction (HU part)	Yes	No	Y, M

## Appendix B

### Review of Allocation Methods used in other Jurisdictions

Italy	Austria	Split 50:50, implicit auctions (IT part)	Yes	No	D
	Slovenia	Split 50:50, implicit auctions (IT part)	Yes	No	D
	Greece	Split 50:50, implicit auctions (IT part)	Yes	No	D
FYR Macedonia	Greece	Priority list	No	No	Y, M
	Serbia	Priority list	No	No	Y, M
Montenegro	Albania	Priority list	No	No	Y, M
	Bosnia-Herzegovina	Priority list	No	No	Y, M
	Serbia	Priority list	No	No	Y, M
Romania	Bulgaria	Split 50:50, explicit auction (RO part-testing)	Yes	No	Y, M
	Hungary	Split 50:50, explicit auction (RO part-testing)	Yes	No	Y, M
	Serbia	Split 50:50, explicit auction (RO part-testing)	Yes	No	Y, M
Serbia	Albania	Priority list	No	No	Y, M
	Bosnia-Herzegovina	Priority list	No	No	Y, M
	Bulgaria	Priority list	No	No	Y, M
	Croatia	Split 50:50, pro rata (SR part)	Yes	No	Y, M
	Hungary	Split 50:50, pro rata (SR part)	Yes	No	Y, M
	FYR Macedonia	Priority list	No	No	Y, M
	Montenegro	Priority list	No	No	Y, M
	Romania	Split 50:50, pro rata (SR part)	Yes	No	Y, M
Slovenia	Austria	Split 50:50, pro rata (SI part)	Yes	No	Y, M
	Croatia	No method	/	/	/
	Italy	Split 50:50, pro rata (SI part)	Yes	No	Y
Turkey	Bulgaria	No method	/	/	/