Janet L. Fraser
Director, Regulatory Affairs
Phone: 604-699-7318
Fax: 604-699-7229
E-mail: janet.fraser@bctc.com

BCTC
OPEN ACCESS TRANSMISSION TARIFF EXHIBIT B1-11

13 March 2009

Ms. Erica Hamilton
Commission Secretary
British Columbia Utilities Commission
900 Howe Street, Sixth Floor
Vancouver BC, V6Z 2N3

Dear Ms. Hamilton:

Re: British Columbia Transmission Corporation (BCTC)
Application to Amend the Open Access Transmission Tariff and a
Complaint by TransCanada Energy Ltd. (TCE) Regarding Firm Sales to Alberta
Project No. 3698539
Supplemental Evidence on TCE Complaint

Please find enclosed the Supplemental Evidence of BCTC on the TCE Complaint, filed as part of the evidentiary record in both the OATT Amendment Application and TCE Complaint proceedings. It expands on BCTC's evidence contained in the OATT Amendment Application and responses to information requests filed in the two proceedings

Sincerely,

Original signed by

Janet L. Fraser
Director, Regulatory Affairs

BC Transmission
CORPORATION

APPLICATION TO AMEND THE

OPEN ACCESS TRANSMISSION TARIFF

SUPPLEMENTAL EVIDENCE ON TCE COMPLAINT

13 March 2009

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Supplemental Evidence of BCTC

This constitutes Supplemental Evidence of BCTC on the TransCanada Energy Ltd. (TCE) Complaint, filed as part of the evidentiary record in both the Open Access Transmission Tariff (OATT) Amendment Application and TCE Complaint proceedings. It expands on BCTC's evidence contained in the OATT Amendment Application and responses to information requests filed in the two proceedings.

1.0 Alberta Market Structure

In BCTC-TCE IR 1.8.0, TCE was asked to confirm that the Alberta Electric System Operator (AESO) does not offer Firm transmission service (or any unbundled transmission service), and accordingly does not establish a long term firm ATC on the Alberta Integrated Electric System (AIES). TCE, in its response, referenced Demand Transmission Service (DTS) and Supply Transmission Service (STS), two transmission services offered by the AESO within Alberta. The AESO offers Import Opportunity Service for imports "when sufficient transmission capacity exists to accommodate the capacity scheduled for service."[1] The AESO's Terms and Conditions of Service, effective 1 August 2008, and the AESO Rate Schedules are appended as Attachment 1 to this Supplemental Evidence.

TCE also states in its response to BCTC-TCE IR 1.8.0 that "There is no ATC for the Alberta system but based on system constraints and reliability factors the AESO does set ATC for imports into Alberta." This statement is only accurate in so far as it relates to real time operations. The AESO posts an hourly ATC, but does not post a long term firm ATC. BCTC and the AESO coordinate ATC in real time pursuant to the operating orders governing the BC-AB intertie.

[1] AESO Approved Rate Schedules and Riders, p.19 of 45

2.0 Saskatchewan-Alberta Intertie

TCE's response to BCUC-TCE IR 1.8.0 references conditions on the Saskatchewan grid. The Saskatchewan-Alberta intertie differs from the Alberta-BC intertie in several respects. The connection to Saskatchewan is through a single back-to-back DC tie[2] with a rating of about 150 MW. The maximum import ATC from Saskatchewan is 153MW.

The loss of a single tie while transferring power into Alberta has the potential to put a limit on imports into Alberta to avoid excessive frequency decline after the loss of the tie and its import. However, the loss of the DC tie to Saskatchewan will actually have little impact on the AIES system frequency for two reasons. First, when the DC tie to Saskatchewan is lost, the AIES remains connected to BCTC's Transmission System and the rest of the WECC system. This interconnection provides significant support to Alberta, resulting in only a small reduction in frequency in Alberta. Second, the amount of generation shortfall is small enough (relative to the AIES connected load) that it would not significantly affect the frequency in Alberta in any event. As a result, the Alberta hourly import limit from Saskatchewan to Alberta is independent of the AIES connected load and would thus not vary hour to hour, other than for maintenance or forced outages.

Another limiting factor for imports from Saskatchewan into Alberta is the potential for line overloads on transmission from Calgary to the Southeast portion of Alberta where the DC tie to Saskatchewan is located. However, these outages are rare, primarily impacting exports from Alberta, and would not be expected to result in many limitations on imports from Saskatchewan.

[2] The back to back DC connection is a DC connection with no transmission line. It is comprised of station equipment which converts the AC supply through a converter to high voltage DC, then converts it back to AC (through another converter) and connects to an AC supply on the other side. This allows two AC systems to connect together through the DC converter equipment which isolates the two AC systems from each other and blocking loop flows, system swings, frequency excursions from flowing onto the other system.

Data posted on the AESO web site confirms that there were relatively few limitations on imports from Saskatchewan to Alberta during 2008. There were 295 hours during 2008 (3.4% of the year) for which imports were limited below the maximum ATC of 153 MW. At least 182 of those 295 hours (62%) were attributed to outages of the Converter.[3]

SaskPower's OATT is included as Attachment 2.

3.0 Customers Served by TCE That Take Service From the AESO Pool

BCTC asked TCE in BCTC-TCE IR 1.14.1 to "confirm that for the customers served by TCE that take service from the AESO pool, a curtailment of transmission service by BCTC does not result in load or service curtailment." [Emphasis added] TCE answered the question from the perspective of source customers (generators) who will "likely have unsold capacity" as a result of the curtailments, rather than answering the question from the perspective of customers "served by TCE that take service from the AESO pool". Loads in Alberta take service from the AESO pool, where generators submit offers that indicate the energy that they have for sale at the offer prices and loads submit bids that indicate their energy for purchase at the bid prices. Load in Alberta will thus continue to be served by other generators in Alberta regardless of whether imports are curtailed.

4.0 System Impact Studies

The System Impact Studies relating to the BC>AB Path of BCTC's Transmission System are attached collectively to this Supplemental Evidence as Attachment 3. These studies were posted and available to customers at the time they were prepared.

5.0 Reconciliation of AESO's Import Limits

TCE's figures for Alberta hourly import limits, as referenced in TCE's response to BCUC-TCE IR 1.3.0, were taken from the AESO's website. The AESO's website reports

[3] See previous footnote for a description of the function of a Converter.

a forecast hourly import limit. Actual hourly import limits frequently differ from forecast. BCTC’s Transmission Scheduling System (TSS) records the actual real-time import limit, as TSS is updated once the actual Alberta import limit is established by the AESO. That is, prior to the scheduling hour in real time, the Balancing Authorities (AESO and BCTC) agree to the final TTC and TRM for both sides of the BC-Alberta intertie. BCTC calculates the real time Alberta hourly import from these final values. Updates to the agreed upon hourly or real-time TTC are posted on BCTC’s OASIS.

In “Attachment 5.xls” BCTC compares the AESO’s forecasted hourly import limits to the actual hourly import limits from BCTC’s TSS in 2008. In 2008, actual import limit (BCTC TSS) was the same as the forecast import limit (AESO website) in 4,119 hours, or roughly 47 percent of the time. The forecast import limit was greater than actual import limit in 3,183 hours, or roughly 36 percent of the time. Of this amount, the forecast import limit differed by greater than or equal to 100MW approximately 9 percent of the time, differed between 50MW and 100MW approximately 9 percent of the time, and differed between 25MW and 50MW approximately 16 percent of the time. The forecast import limit was less than the actual import limit in 1,482 hours, or roughly 17 percent of the time.

6.0 BCTC’s Use of TRM

TRM is defined in BCTC's Business Practices as the amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a possible range of uncertainties in system conditions.[4] Although the power flowing on the interties closely follows a pre-defined schedule through automatic generation control, it fluctuates constantly as a result of the dynamic nature of load and generation on the power system. As such, TRM accounts for real time considerations. In the case of the BC>AB Path, TRM is put in place to reduce the probability that the actual power flowing from BC to Alberta will exceed, on a

[4] BCTC Business Practice 2.0, section 2.1

sustained basis[5], the real-time TTC that is agreed upon by the AESO and BCTC during each hour.[6] Although real-time system conditions in Alberta must inevitably factor into the determination of TRM because Alberta real-time system conditions physically affect BCTC's Transmission System, BCTC's TRM on the BC>AB Path is really directed to preserving system reliability on BCTC's own Transmission System.

For clarity, even in real-time, constraints on BCTC's Transmission System that are foreseen are managed through changes in real-time TTC, not by changing TRM. Thus, if BCTC identifies a real time constraint (for instance, a system outage that affects reliability) BCTC reduces TTC in real-time, rather than increasing TRM. BCTC and the AESO agree on TTC for the hour by taking the lower of BCTC's and the AESO's real-time TTC for that hour.

BCTC's use of TRM, and how system conditions in Alberta may be accounted for in real time, is reflected in BCTC's Business Practice 2.0. Section 2.3.1 states:

> In the Western Interconnection methodology, ATC reductions by TRM may include allowances for unscheduled flow, simultaneous limitations associated with operation under a nomogram, uncertainty in load forecast and unplanned outages (for paths in which contingencies have not already been considered in establishing the path rating).
>
> British Columbia Transmission Corporation uses TRM as a margin to ensure TTC is not exceeded in Real-time operation due to inadvertent imports and exports resulting from power system dynamics.
>
> British Columbia Transmission Corporation normally uses 50 MW TRM for the US Intertie (both directions), and normally uses 65 MW TRM for the Alberta

[5] Twenty minutes for a stability limit or thirty minutes for a thermal limit.
[6] As indicated above, in the operating timeframe (i.e. hourly and real time) the ATC on both sides of the intertie must be the same. The intertie is always operated to the lower of the BCTC or AESO TTC and reflects system conditions at the time, and BCTC and the AESO will agree hourly as to the final TTC.

> Intertie (both directions). TRM may be adjusted up or down in real time depending on the system conditions of BCTC and adjacent Balancing Authorities. [Emphasis added.][7]

Similarly, real-time system conditions in BC can physically affect the operations on the AIES. AESO Operating Policy & Procedure 304 thus states that TRM should be changed depending on certain system conditions including outages of several elements in BC. If TRM on BCTC's path to the BC-Alberta border needs to be increased because of system conditions in either BC or Alberta in the operating horizon, it is because those conditions are causing flows between Alberta and BC to deviate from the scheduled flows significantly enough to increase the risk of exceeding the agreed upon hourly or real time TTC on a sustained basis. Since the real time TTC is necessarily the same in BC as it is in Alberta (i.e. because BCTC and the AESO have agreed on the lower of the BCTC and AESO real time TTC) for the hour, both BCTC and the AESO increase TRM by the same amount to the same level.[8]

This joint coordination of TRM has allowed BCTC and the AESO to manage the real time flows from BC to Alberta reliably over many years. There has only been one reportable violation where flows from Alberta to British Columbia have exceeded the TTC on a sustained basis since reporting measures were introduced under the WECC Reliability Management System in 1998. There have been no violations of TTC for flows from British Columbia to Alberta.

As BCTC has concluded that 65MW of TRM is sufficient to address real time system conditions and prevent exceedence of the agreed upon hourly or real-time TTC,

[7] BCTC Business Practice 2.0, section 2.3.1

[8] BCTC Operating Order S.O.O. 7T-17 at p.38 addresses TRM implementation, and refers specifically to how TRM is to be addressed when 1L274/887L is opened ended and some of the BC load is fed radially from the Alberta system. It also addresses how the AESO may increase TRM on its side of the intertie to cover the increased Most Severe Single Contingency in Alberta; the Operating Order states that this TRM value will be provided to BCTC by the AESO and will also be implemented by BCTC.

65MW has been used in the planning timeframe as the TRM value.[9] This is the TRM value that is relevant to the determination of *long-term* firm ATC on BCTC's BC>AB Path. The use of a TRM value in the determination of long term firm ATC simply reflects the fact that, in real time, TRM is applied to ensure that the agreed upon hourly or real-time TTC is not exceeded. BCTC determined that 65MW was an appropriate TRM value based on iterative testing of different values. Values less than 65MW gave rise to the potential for exceedence of the agreed upon hourly or real-time TTC. Values greater than 65MW were shown to provide no additional benefits from the perspective of managing real-time system conditions, and had the effect of unduly restricting flows on the BC>AB Path.

BCTC and the AESO have always endeavoured to keep TRM to the minimum required to avoid exceeding TTC (or Operating Transfer Capability (OTC))[10] limits. The reason for limiting TRM in this manner is because TRM is subtracted from TTC (or OTC) in calculating ATC. ATC is the transmission capacity available for purchase. In BC, an increase in TRM will decrease the amount available for purchase by the same amount. This approach is consistent with the policy underlying recent FERC decisions on transparency of ATC calculations, and preventing transmission providers from using elements such as TRM as a basis to refuse transmission service requests from non-affiliates.

FERC has, consistent with the policy of reducing opportunities for discrimination, identified seven factors that a transmission provider may take into account in setting TRM. They are (1) load forecast and load distribution error; (2) variations in facility loadings; (3) uncertainty in transmission system topology; (4) loop flow impact; (5) variations in generation dispatch; (6) automatic sharing of reserves; and (7) other

[9] BCTC Business Practice 2.0, section 2.3.1

[10] OTC refers to the WECC OTC, which is the maximum amount of electric power that can be transferred reliably over a transmission path for a specific season established by the WECC OTC Study Committee. This rating is the maximum that can be demonstrated to flow under realistic and optimistic conditions within a specific season, which can be demonstrated to meet the appropriate reliability criteria. The WECC OTC cannot exceed the Path Rating.

uncertainties as identified through the NERC reliability standards development process. These seven factors were identified by TCE in its response to BCUC-TCE IR 1.25.1, and TCE suggests that BCTC ought to be using one or more of these factors to account for Alberta import limits in establishing *long term Firm ATC in the planning horizon*. None of the seven factors, even if they were mandatory, would require BCTC to limit the provision of LTF PTP transmission service on its system by increasing TRM due to import limits on an adjacent system.

A discussion of the above factors as they apply to BCTC follows.

(1) Load Forecast and Load Distribution Error

This factor is also identified in North American Electricity Reliability Corporation (NERC) standard MOD-008-01 (TRM Calculation Methodology) as components that can be used in establishing TRM.[11] Load forecast and load distribution error can lead to inadvertent exceedence of TTC on BCTC's Transmission System; however, these are issues that relate to real time operations, and not the planning horizon where LTF PTP transmission service is studied. An error between a load forecast and actual load, or an error between expected and actual load distribution can only be recognized and managed in real time.

Since Alberta is at the end of a long radial system passing through British Columbia, the AESO's load and any load forecast error contributes significantly to deviations from the scheduled flow on the intertie. The AESO’s Automatic Generation Control systems are intended to adjust generation in Alberta to match the changing conditions and maintain frequency and interchange schedules. Basically, what flows across the intertie in to Alberta is whatever the demand from Alberta requires. The AESO is responsible for load forecasting in Alberta, so BCTC cannot calculate the potential for errors in the Alberta load

[11] This standard has not been adopted in British Columbia at this time.

forecast. Changes in BC loads do not have a significant effect on the flow on the intertie with Alberta.

As referenced in BCTC's Business Practices,[12] BCTC and AESO have agreed that a fixed TRM value of 65MW is normally appropriate for managing the potential for real time errors in load forecast and load distribution. The TRM may be adjusted by both parties to account for real-time system conditions on either side of the intertie.

(2) Variations in Facility Loadings

BCTC understands this factor to be identified in NERC standard MOD-008-0 (Documentation And Content Of Regional TRM Methodology), i.e. “variations in facility loadings due to balancing of generation within a balancing authority area.” The balancing of generation to meet demand and scheduled imports or exports takes place every few seconds in the BCTC and AESO systems. Inevitably, the small mismatches between generation and demand in each system lead to deviations in power flow across the intertie. Both BCTC and the AESO have found that the existing 65 MW TRM referenced in BCTC's Business Practices has been adequate to handle these variations in facility loadings and there is no reason to increase TRM beyond 65MW in the planning timeframe where LTF PTP transmission service is analysed to account for this factor.

(3) Uncertainty in Transmission Dystem Topology

This factor is also identified in NERC standard MOD-008-01 as a component that can be used in establishing TRM. Uncertainty exists in transmission system topology because of unplanned outages. Knowing that this uncertainty exists, entities involved in planning and operating transmission systems study such outages in advance to determine the appropriate TTCs. Then when the outages

[12] BCTC Business Practice 2.0, section 2.3.1

occur, TTCs can be adjusted to reflect the new system topology. The uncertainty only exists in real-time as maintenance outages are planned for in advance. The uncertainty does exist in the long term planning timeframe as all existing and planned elements are assumed to be in service. To set long term TTCs assuming elements of the Transmission System would be out of service in the future would be imprudent. In the Western interconnection, allowances for transmission contingencies are already included in the determination of TTC such that the Transmission System is able to withstand the transition from system normal to a system with a credible outage.

(4) Loop Flow Impact

This factor is also identified in NERC standard MOD-008-01 as a component that can be used in establishing TRM. A loop flow occurs when some of the power that is scheduled to flow over one path ends up flowing over a parallel path because of the tightly meshed nature of the electrical grid. In the case of the BC to Alberta intertie, there is no parallel path. This intertie is a radial connection from BC and the rest of the WECC to Alberta. Transfers on other paths in the WECC do not affect this intertie, therefore this factor does not contribute to the determination of TRM on BCTC's path to the BC-Alberta border.

(5) Variations in Generation Dispatch

This factor is also identified in NERC standard MOD-008-01 as a component that can be used in establishing TRM. As the intertie delivers power to and from a radial system located at the end of the Western Interconnection, power flowing over the intertie from BC to Alberta is governed primarily by the net demand in Alberta. That net demand is affected by variations in the generation dispatch within Alberta. When generation in Alberta fails to keep up with load changes, the difference is delivered across the BC-AB intertie. As the AESO operates a power pool, it is very difficult to know what the dispatch pattern will be at any point in the future. As BCTC and the AESO have found the present fixed 65MW TRM is appropriate for dealing with any possible impact of real time variations in generation dispatch, there is no need to change the TRM in the long term planning timeframe.

(6) Automatic Sharing of Reserves

This factor is also identified in NERC standard MOD-008-01 as a component that can be used in establishing TRM. There is a separate reserve sharing program in place in the NorthWest, the NorthWest Power Pool Reserve Sharing Group, that accounts for transmission availability between participants for the automatic sharing of reserves. BCTC does not use TRM, nor do other members of the NorthWest Power Pool Reserve Sharing Group use TRM, to account for automatic sharing of reserves.

(7) Other Uncertainties as Identified Through the NERC Reliability Standards Development Process

BCTC is not aware of other uncertainties that have been identified through the NERC reliability standards development process.

In addition to including, where appropriate, the above factors that FERC has determined to be applicable to TRM, BCTC also follows the WECC-approved ATC methodology as described in the WECC document “Determination of Available Transfer Capability in the Western Interconnection” (Attachment 4). WECC uses this document to comply with NERC standard MOD-008-0 (Documentation and Content of Each Regional TRM Methodology).

Attachment 1

AESO 2009 Terms and Conditions of Service, and Rate Schedules

2009 TERMS AND CONDITIONS OF SERVICE

ARTICLE 1
DEFINITIONS AND INTERPRETATION

1.1 The following terms shall have the following meanings in this Tariff:

"**Act**" means the Electric Utilities Act, S.A. 2003, c. E-5.1 and regulations made thereunder, as amended from time to time.

"**AESO**" means Alberta Electric System Operator, and is a trade name under which the ISO carries on business in fulfillment of its roles, responsibilities, and duties pursuant to the Act.

"**AESO Measurement System Standard**" means the standards contained in the document titled *Alberta Electric System Operator Measurement System Standards*, made available by the AESO, which defines the accountabilities and obligations of the AESO, metering service providers, and metering data providers in respect of the provision and operation of the measurement system required for the measurement, acquisition, processing, and delivery of measurement data, as amended from time to time.

"**AESO Person**" means "Independent System Operator person" and has the meaning ascribed to it in the Act.

"**AESO Standard Facilities**" mean the least-cost interconnection facilities which meet good transmission practice including applicable reliability, protection, and operating criteria and standards, and generally consist of a single radial transmission circuit and a single transformer to supply an individual Point of Connection.

"**AESO Transmission Reliability Criteria**" means the transmission reliability criteria used by the AESO in the planning and operating of the Alberta Interconnected Electric System and which are available electronically on the AESO internet website.

"**AIES**" means Alberta's "Interconnected Electric System" and has the meaning ascribed to it in the Act.

"**Affiliate**" has the meaning ascribed to it in the Business Corporations Act (Alberta), S.A. 2000, c. B-9, as amended from time to time.

"**Ancillary Services**" has the meaning ascribed to it in the Act.

"**Apparent Power**" means the product of the volts and amperes, comprising both real and reactive power, usually expressed in kilovoltamperes ("kVA") or megavoltamperes ("MVA").

"**Application Fee**" means the refundable interconnection application fee a Customer pays to the AESO when the Customer submits a request for interconnection to the AIES. Application Fees are set out in Article 5.

"**Area Control Error**" means the instantaneous difference between actual and scheduled interchange, taking into account the effects of frequency bias (and time error or unilateral inadvertent energy, if automatic correction for either is part of the AGC).

"**AUC**" means the Alberta Utilities Commission.

"**Automatic Generation Control**" or "**AGC**" means equipment that automatically adjusts a Control Area's generation to maintain its frequency or interchange schedule plus or minus frequency bias.

"**Automatic Voltage Regulator**" or "**AVR**" means automatic control equipment that changes the Generating Unit excitation level to maintain voltage levels.

"**Billing Capacity**" has the meaning ascribed to it in Rate Schedule DTS.

"**Billing Period**" means a period of time starting on the first day of each calendar month at 00:00 hours and ending on the last day of the same calendar month at 24:00 hrs, during which a Customer is supplied with System Access Service.

"**Business Day**" means a day other than a Saturday, a Sunday, a Statutory Holiday, or a Monday when a Statutory Holiday occurs on a Saturday or Sunday and the following Monday is a day during which financial banking privileges are suspended.

"**Commercial Operation**" means the date upon which a load or Generating Unit begins to operate on the transmission system in a manner which is acceptable to the AESO and which is expected to be normal for it to so operate, after energization and Commissioning.

"**Commissioning**" means those limited activities (as approved in advance by the AESO and subject to written agreement) conducted after interconnection which are required to ensure that a facility can satisfactorily enter Commercial Operation and that a facility meets the AESO's requirements. The term of such written agreement will not extend beyond a three month period unless otherwise agreed to by the AESO.

"**Confidential Information**" means information provided to the AESO that has been specifically identified as being confidential in nature by the provider of such information and information provided pursuant to Article 8 of these Terms and Conditions of Service.

"**Constrained On**" means a condition where a Generating Unit has been dispatched on load while Out of Merit, as a result of a Dispatch Instruction by the AESO.

"**Construction Commitment Agreement**" means a financial security agreement made between the Customer and the TFO or between the Customer and the AESO prior to arrangements for new facilities required to accommodate the provision of System Access Service to the Customer or an increase thereto.

"**Contract Capacity**" means the peak demand or supply capability (expressed in MW), as set out in the System Access Service Agreement.

"**Control Area**" means a geographic area comprised of an electric system or systems, bounded by interconnection metering and telemetry, capable of controlling generation to maintain its interchange schedule with other control areas, and contributing to frequency regulation of the interconnection, such as the AIES.

"**Customer**" is an Eligible Person who takes, or applies to take, System Access Service from the AESO and satisfies the conditions provided in Article 3.1 below.

"**Customer's Facilities**" or "**Customer Facilities**" means all facilities interconnecting with the AIES on the Customer's side of the POD or POS.

"**Customer Contribution**" means the amount required to be paid by a Customer taking service under Rate Schedule DTS or Rate Schedule STS pursuant to Article 9 hereof.

"**Demand Customers**" are load customers and generation customers, the latter for the purposes of obtaining their back up supply.

"**Demand Opportunity Service Business Practices**" means the business practices contained in the Business Practices – Demand Opportunity Service (DOS) document, made available by the AESO, as may be amended from time to time in accordance with the provisions of Article 10 below.

"**Direct Loss or Damage**" has the meaning ascribed to it in the Act.

"**Dispatch Instruction**" means in respect of any Generating Unit, all dispatch instructions issued by the AESO from time to time, designating such unit to provide Ancillary Services, by changing the output or manner of operation of a unit, or by another method or procedure, and giving any necessary details as to the service to be provided.

"**Dispute**" means any dispute, claim, or difference that arises in respect of the Tariff between the AESO and the Customer.

"**Distributor**" means a party providing "Distribution Access Service".

"**Distribution Access Service**" has the meaning ascribed to it in the Act.

"**DOS**" or "**Demand Opportunity Service**" means service under Rate Schedule Demand Opportunity Service (DOS 7 Minutes), Demand Opportunity Service (DOS 1 Hour), or Demand Opportunity Service (DOS Term).

"**DTS**" or "**Demand Transmission Service**" means service under Rate Schedule Demand Transmission Service.

"**E&GI Act**" means the Electricity and Gas Inspection Act (Canada) and regulations made thereunder, as amended from time to time, or such replacement legislation as may be enacted.

"**Eligible Person**" means any of the following: the owner of a Generating Unit; the owner of an electric distribution system; an importer or exporter; the owner of an industrial system; a direct access customer, or the purchaser of a PPA.

"**Emergency**" means, as declared by the AESO, either: any abnormal system condition which requires immediate manual or automatic action to prevent abnormal system frequency deviation, abnormal voltage levels, equipment damage, or tripping of system elements which might result in cascading effects; or a state in which the AIES lacks sufficient Ancillary Services.

"**Energy Transfer**" shall mean the quantity of energy transfer attributable to a transaction for service under Export Opportunity Service Rate Schedules XOS 1 Hour and XOS 1 Month or Import Opportunity Service Rate Schedule IOS, based on the capacity at a Point of Interconnection and allocated to a Customer.

"**Force Majeure**" means: acts of God; strikes; lockouts or other industrial disturbances; vandalism; wars; riots; epidemics; landslides; lightning; earthquakes; explosions; fires; storms; intervention of federal, provincial, or local government (or from any of their agencies or boards); the order or direction of any court; inability to obtain, interruption, suspension, curtailment or other diminution of, supply of materials, utilities, or services from any supplier (including, without limitation, TFOs, Ancillary Service Providers or the AESO) and any other causes, whether of the kind herein enumerated or otherwise, not within the control of the AESO and which by the exercise of due diligence the AESO is unable to prevent or overcome. Notwithstanding the foregoing, a decision, direction, or order made by the AUC in the normal course of it exercising its authority shall not be an event of force majeure.

"**Generating Unit**" has the meaning as ascribed to it in the Act.

"**Governor**" or "**Governor System**" means automatic control equipment with speed droop characteristics to control Generating Unit speed and/or electric power output.

"**ISO**" or "**Independent System Operator**" has the meaning ascribed to it in the Act.

"**ISO Rules**" has the meaning ascribed to it in the Act.

"**Looped**" refers to transmission facilities that increase the number of electrical paths between any two POCs other than the POC that serves the Customer for whom the facilities are being or have been constructed.

"**Losses**" means the energy that is lost through the process of transmitting electric energy.

"**Maximum TMR Compensation**" means the description found in Article 11.7.

"**MCR**" or "**Maximum Continuous Rating**" is the maximum net power output that can be sustained by a generator over a long period.

"**Metered Demand**" means the rate at which electric energy is delivered to a POD, or from a POS, expressed in MW, averaged over a 15-minute, 1-minute, or other interval as deemed necessary by the AESO.

"**Metered Energy**" means the quantity of energy, expressed in MWh, reflected by the relevant Metering Equipment as having been transferred in a particular period of time.

"**Metering Equipment**" means any current transformers, potential transformers, interconnecting wiring, meters, remote metering communication facilities, and records used by the owner of the Metering Equipment in connection with these Terms and Conditions to measure Metered Demand.

"**Non-Dispensated Metering Equipment**" means Metering Equipment installed after May 31, 1998 which is not the subject of a waiver or dispensation by Industry Canada of requirements under the E&GI Act.

"**Non-Recallable Service**" means System Access Service pursuant to Rate Schedule DTS or Rate Schedule STS.

"**Opportunity Capacity**" means the incremental amount of transmission capacity that is available under a System Access Service Agreement for Demand Opportunity Service to provide capacity in addition to Contract Capacity for DTS.

"**Opportunity Service**" means System Access Service offered to any Customer who can establish to the AESO's satisfaction that it would not take System Access Service pursuant to Rate Schedule DTS and with respect to which, therefore, the service requirement presents the opportunity for incremental revenue with which the AESO can offset transmission costs.

"**Opportunity Service Customers**" means those Customers that meet the criteria for Opportunity Service, as defined.

"**Physical Capacity**" means the maximum amount of electric power that a transmission facility, as rated by a TFO, is able to transmit.

"**Planning Capacity**" means the peak demand or supply capability (expressed in MW), as requested in a Customer's application for System Access Service.

"**POC**" or "**Point of Connection**" means a point at which electric energy is transferred between the Customer's facility and the AIES. A Point of Connection may be a Point of Supply (POS), a Point of Delivery (POD), or both.

"**POD**" or "**Point of Delivery**" means the point at which electric energy is transferred from the AIES to a Customer's Facilities.

"**Point of Interconnection**" means the point at which electrical energy is transferred from the AIES to a neighbouring jurisdiction and where the electric energy so transferred is measured.

"**Pool Price**" shall have the meaning ascribed to that term in the Act, and when used in the context of a particular hour, shall mean the pool price for that hour.

"**POS**" or "**Point of Supply**" means the point which electric energy is transferred from a Customer's Facilities to the AIES.

"**Power Factor**" means the ratio of Real Power to Apparent Power.

"**PPA**" or "**Power Purchase Arrangement**" has the meaning ascribed to it in the Act.

"**PPA Effective Date**" means January 1, 2001 or such other dates as the Power Purchase Arrangement becomes effective.

"**PSC**" or "**Primary Service Credit**" means the credit set forth in Rate Schedule Primary Service Credit.

"**PSS**" means power system stabilizer.

"**Radial**" facilities are those transmission facilities that are not Looped.

"**Ratchet Level**" has the meaning ascribed to it in Rate Schedule Demand Transmission Service.

"**Rate Schedules**" means the schedules attached to and forming part of the Tariff, which set out the respective rates to be charged, and credits to be attributed, for each type of System Access Service.

"**Rated Capacity**" means the maximum amount of electric power which a transmission facility is rated by the manufacturer to be able to transmit.

"**Reactive Power**" means the portion of electricity that establishes and sustains the electric and magnetic fields of alternating current equipment, expressed in megavars ("MVAr").

"**Real Power**" means the rate of producing, transferring, or using electrical energy, expressed in megawatts ("MW").

"**Regulated Generating Unit**" is a generating unit listed in the Appendix to the Rate Schedules.

"Reliability Standards" refers to the reliability standards, agreements, criteria and directives of the WECC and the North American Reliability Council, or their successor organizations, the reliability standards, agreements, criteria or directives of any similar entity recognized by the ISO and reliability standards adopted by the ISO to supplement those standards, criteria or directives thereby adopted and enforced by the WECC or the ISO.

"**Representatives**" means the directors, officers, employees, consultants, and agents of the AESO.

"**Statutory Holiday**" means New Year's Day, Family Day, Good Friday, Victoria Day, Canada Day, Heritage Day, Labour Day, Thanksgiving Day, Remembrance Day, Christmas Day, and Boxing Day.

"**STS**" or "**Supply Transmission Service**" means the service provided under Rate Schedule Supply Transmission Service.

"**STS Capacity**" means the Contract Capacity as set out in the System Access Service Agreement for Supply Transmission Service.

"**System Access Service**" has the meaning ascribed to it in the Act.

"Substation Fraction" means the ratio of the Contract Capacity for the Point of Delivery to the sum of all Contract Capacities (for DTS and STS) at the substation at which the Point of Delivery is interconnected.

"**System Access Service Agreement**" means an agreement, in the form made available by the AESO, entered into between the AESO and a Customer for System Access Service.

"**System Contribution**" means the amount required to be paid by Customers taking service under Rate Schedule STS pursuant to Article 9.11 hereof.

"**System Security**" means the ability of the AIES to withstand events such as electric short circuits, unanticipated loss of AIES components, and switching operations without experiencing cascading loss of AIES components or uncontrolled loss of load.

"**Tariff**" means these Terms and Conditions and Appendices attached hereto and the Rate Schedules as approved by the AUC.

"**TFO**" or "**Transmission Facilities Owner**" has the meaning ascribed to it in the Act.

"**TMR**" or "**Transmission Must-Run**" means Constrained On dispatch of a Generating Unit to a specific level in accordance with a Dispatch Instruction issued to maintain System Security.

"Transmission Interconnection Requirements" means the requirements related to matters such as, but not limited to, protection, revenue metering, transmission lines, generators, loads, communications and SCADA, currently contained in the documents: Technical Requirements for Connecting to the Alberta Interconnected Transmission Grid; Part 1: Technical Requirements for Connecting Loads Rev. 1.0 (Dec. 29, 1999), Part 2: Technical Requirements for Connecting Generators to the AIES Rev. 1.0 (Dec. 29, 1999); Part 3 Technical Requirements for Connecting Transmission Facilities Rev. 1.0 (Dec. 29, 1999), AESO SCADA Standard Rev. 1.0 (Sept. 6, 2005), AESO Measurement System Standard (July 1, 2004), AIES Protection Standard Rev. 0 (Dec. 1, 2004), Phasor Measurement Unit Requirements Rev. 2.0 (July 6, 2005), Operational Voice Communication Standard Rev. 1.0 (Sept. 7, 2005), Wind Power Facility Technical Requirements Rev. 0 (Nov. 15, 2004), Transmission Modeling Data Rev. 0 (April 29, 2003), Requirements for Model Validation Reporting For Generators and Generator Control Systems Rev. 0 (November 16, 2005), all of which are prepared, published and may be amended or supplemented by the AESO from time to time.

"**Transmission Regulation**" means the Transmission Regulation, A.R. 86/2007, as amended from time to time.

"**UFLS**" or "**Under-Frequency Load Shedding Credit**" means the under-frequency load shedding provisions as set forth in Rate Schedule Demand Under-Frequency Load Shedding and the credits therefor.

"**Western Interconnection**" means the area comprising those states and provinces, or portions thereof, in Western Canada, Northern Mexico, and the Western United States in which members of the WECC operate synchronously connected transmission systems.

"**WECC**" means the Western Electricity Coordinating Council and any successor organization.

1.2 Unless otherwise expressly provided, any definition of a word or expression in the Act shall apply to the use of such word or expression in this Tariff.

ARTICLE 2
APPLICATION OF TARIFF

2.1 **Tariff Application**
This Tariff sets forth the rates and Terms and Conditions of Service under which the AESO will provide System Access Service to its Customers. By accepting service from the AESO, a Customer is deemed to have accepted this Tariff. In the event of any conflicts between the Terms and Conditions and the Rate Schedules, the Terms and Conditions govern.

2.2 **AUC Approval**
This Tariff has been approved by the AUC, defines service to be delivered by the AESO and binds all of the AESO's Customers. This Tariff defines the basic rights of the AESO and all its Customers with respect to all services provided by the AESO.

2.3 **Effective Date**
This Tariff becomes effective on the later of August 1, 2008 or the first day of the month after the AUC approves it and remains in effect until replaced or amended pursuant to Section 124 of the Act.

2.4 **Powers Under the Act**
Nothing in this Tariff shall in any way restrict or limit the powers, duties, and responsibilities of the AESO as described in the Act.

ARTICLE 3
PROVISION OF SYSTEM ACCESS SERVICE

3.1 **Provision of Service**
Subject to Article 17, the AESO agrees to provide System Access Service, up to and including the POD or POS, to all Customers who have executed a System Access Service Agreement and abide by this Tariff. The AESO will provide service up to the Customer's Contract Capacity as set out in the Customer's System Access Service Agreement contingent upon any applicable ISO Rules, OPPs or Abnormal Operating Conditions as defined in the Transmission Regulation.

3.2 **Withholding Service**
The AESO, at its sole discretion, may withhold, limit, or discontinue System Access Service if the Customer fails to abide by this Tariff. If requested by the Customer, the AESO will provide a written explanation for withholding, limiting, or discontinuing System Access Service. Any such withholding, limiting, or discontinuing will not relieve the Customer from its obligation to pay any rate, charge, or other amount that has accrued, or is accruing, to the AESO.

3.3 **Reliability Standards**
The AESO will maintain the reliability of the AIES and the Western Interconnection in accordance with the Reliability Standards.

3.4 **Reasonable Exercise of Discretion**
Where the AESO or a Customer is granted any discretion pursuant to these terms and conditions (whether with respect to granting its consent or withholding its consent to a particular matter or otherwise), the AESO, the Customer or both will, in every instance, exercise its discretion acting reasonably.

ARTICLE 4
CUSTOMER INTERCONNECTION REQUIREMENTS

4.1 **Compliance**

All Customers must comply with the Transmission Interconnection Requirements.

4.2 **Customer Facilities**

All facilities interconnecting with the AIES on the Customer's side of the POD or POS are the responsibility of the Customer and the AESO has no responsibility in respect of service provided over Customer Facilities.

4.3 **Use of Service**

No Customer or any other person may rearrange, disconnect, remove, interconnect with, or otherwise interfere with any transmission facility without the AESO's prior written consent.

4.4 **Generating Units**

Any Customer whose facilities include a Generating Unit which is operated in parallel to the electric system, whether connected at a transmission voltage or a distribution voltage, must have, for all hours in which the Generating Unit is operating, a PSS in service and an AVR operated in a voltage control mode. Any Customer that has a Generating Unit connected to the electric system without a PSS in service, or that has an AVR operating in any condition other than Voltage control, must notify the AESO of those conditions. The Customer must report to the AESO on a monthly basis, no later than the 5th Business Day of the month following the month to which the report relates, the AVR operation (voltage control or other) and PSS in-service periods for the preceding month. In the event that the AESO becomes aware of a failure to comply with this requirement, the AESO shall report the non-compliance to the WECC and any penalties assessed by the WECC that result from the non-compliance will be borne by the relevant Customer. Article 4.4 does not apply to Generating Units that are exempt from PSS requirements in accordance with WECC policy.

If the AESO requires PSS or AVR to be added to a currently regulated generator in the future, the AESO will pay any costs prudently incurred in the installation of the PSS or AVR and will recover prudently incurred costs from tariff(s) approved by the AUC. In the event the AUC determines that costs incurred by the currently regulated generators in the installation of the PSS or AVR cannot be recovered in rates charged by the AESO, then the Customer who has received the benefit of such amounts shall reimburse the AESO for such amounts. If the excitation system of an existing regulated or unregulated generator to which Article 4.4 does not apply is rebuilt or replaced, the new excitation system must be suitable for PSS, and a PSS/AVR must be installed.

4.5 **Effect of Non-Compliance**

Failure to comply with the Transmission Interconnection Requirements or Reliability Standards may result in the AESO withholding, suspending or terminating System Access Service. Where non-compliance with the Transmission Interconnection Requirements, Reliability Standards or the requirements of Article 4.4 would not have a detrimental affect on system reliability, the AESO may, in its sole discretion, waive compliance therewith for any existing Customer for whom, in the AESO's reasonable opinion, the imposition thereof would create severe hardship or unnecessary costs.

ARTICLE 5
SYSTEM ACCESS APPLICATION

5.1 **Distributor's Application for System Access Service existing POD**

(a) Subject to Article 5.4, applications for expanded System Access Service within an existing POD shall be made to the TFO. An interconnection proposal for the requested expansion is presented and reviewed by the AESO.

(b) The AESO will work cooperatively with the Distributor and the TFO to determine the most cost effective manner to facilitate System Access Service for the Distributor's request for new System Access Service or for expanded System Access Service within an existing POD.

(c) The AESO will provide the Distributor or the TFO with the necessary approvals, conditional or otherwise, and other interconnection documentation required to facilitate System Access Service.

(d) Subject to Article 5.4, if the Distributor proceeds with the recommended System Access Service solution, the Distributor is expected to provide the information and financial security required by the TFO and to enter into a Construction Commitment Agreement, if required by the TFO.

5.2 **Distributor's Application for New System Access Service**

(a) Applications for new System Access Service shall be made to the AESO and include an interconnection proposal, prepared by the Distributor and TFO.

(b) The AESO will work cooperatively with the Distributor and the TFO to determine the most cost effective manner to facilitate System Access Service for the Distributor's request for new System Access Service or for expanded System Access Service within an existing POD.

(c) The AESO will provide the Distributor or the TFO with the necessary approvals, conditional or otherwise, and other interconnection documentation required to facilitate System Access Service.

(d) Subject to Article 5.4, if the Distributor proceeds with the recommended System Access Service solution, the Distributor is expected to provide the information and financial security required by the TFO and to enter into a Construction Commitment Agreement, if required by the TFO.

5.3 **Generator, Industrial Systems, and Industrial Load Applications for Service**

Customers may apply for new System Access Service or for expanded System Access Service within an existing POC.

(a) Applications for System Access Service shall be made to the AESO and subject to the associated fee set out in sub-paragraph (c).

(b) The Customer must work with both the AESO and the TFO who will cooperatively determine the most cost effective manner to facilitate System Access Service.

(c) Where required by the AESO, the Customer must pay the following refundable system access application fee. The AESO will refund such fee to the Customer within 90 days of energization of the Customer's Facilities.

Project Size	Preliminary Assessment Fee
≤ 15 MW	$10,000
> 15 MW and ≤ 25 MW	$20,000
> 25 MW	$50,000

(d) The AESO will provide the Customer and the TFO with the necessary approvals, conditional or otherwise, and other interconnection documentation required to facilitate System Access Service.

(e) Subject to Article 5.4, if the Customer proceeds with the recommended System Access Service solution, the Customer is expected to provide the information and financial security required by the TFO and to enter into a Construction Commitment Agreement with the TFO.

5.4 **Application to the AESO**
At the sole discretion of the AESO and only in exceptional circumstances, the Customer may proceed with the application for System Access Service through the AESO and, in conjunction therewith, must provide the information, financial security, and Construction Commitment Agreement required by the AESO.

5.5 **Loss Factor Calculations and Other Studies**
A Customer or potential Customer that requests a preliminary loss factor calculation (only) must complete a loss factor calculation application form and pay the AESO a non-refundable fee of twenty-five hundred dollars ($2,500). For additional services requested by the Customer that the AESO agrees to perform, the Customer must pay the AESO's actual costs to prepare and provide the requested information. The AESO will conduct all detailed studies in the order that payment is received.

5.6 **Facility Changes**
The AESO is not liable to any Customer or potential Customer for changes to the actual or planned facilities that occur between the date upon which the TFO or the AESO, as the case may be, issues the Project Specifications and the date upon which the Customer commits, in writing, to construction of the applied-for System Access Service.

5.7 **System Application Disputes**
Disputes in respect of a Customer System Application must be referred to the AESO, in writing. The AESO will review the dispute and provide the Customer and any other affected parties with a proposed resolution within 30 Business Days of receipt thereof. In the event mutual agreement cannot be reached, any of the affected parties may then enter into the Dispute Resolution process as set out in Article 19 of this Tariff.

ARTICLE 6
SECURITY AND CUSTOMER AGREEMENTS

6.1 **Construction**
The AESO will arrange construction of new facilities only after the Customer has satisfied all necessary requirements in Article 5 and this Article 6.

6.2 **Security for New Transmission Facilities**

(a) If requested by the AESO, the Customer must provide security in an amount determined by the AESO, which amount will not exceed the estimated cost of construction. Security must be in the form of a guarantee, cash deposit, or an irrevocable letter of credit from a Canadian chartered bank, credit union, trust company, or other financial institution with a minimum A- credit rating as determined by Standard & Poor's or equivalent credit rating agency. The security must be satisfactory to the AESO, at its sole discretion, in form, substance, and amount.

(b) The AESO may request, at its sole discretion, at any time after execution of the Construction Commitment Agreement, additional or replacement security based on the AESO's estimate of the appropriate security required. Required additional or replacement security must be provided to the AESO within two business days of such request. Customers must report any event of default for borrowed funds or material adverse changes in their financial position to the AESO within two Business Days of such event.

(c) Security will not be required for transmission facilities requested by distributors regulated by the AUC.

6.3 **Effect of Non-Compliance**
If the Customer fails to provide adequate security as requested by the AESO, the AESO may immediately withhold or suspend the Customer's System Access Service pursuant to Article 3.2. Any such withholding or suspension will not relieve the Customer from its obligation to pay any rate, charge or other amount that has accrued, or is accruing, to the AESO.

6.4 **Cancellations**

(a) If new transmission facilities are no longer required for any reason after the Construction Commitment Agreement is executed, the Customer must pay to the AESO all costs incurred in the procurement and construction of facilities as of the termination date, all cancellation costs, penalties, and other related costs including those for material salvage and reclamation of the construction site. If the Customer fails to make payment on the payment due date, the AESO at its discretion may realize on any security provided by the Customer.

(b) The AESO may, but is not required to, deduct any amounts owing by the AESO to the Customer under any agreement between the AESO and the Customer on partial or full (as the case may be) satisfaction of such costs, penalties or other claims. Such amounts may include, but are not limited to, debts, liquidated demands, unliquidated demands, damages or other obligations.

6.5 **System Access Service Agreement**
Prior to Commissioning of new facilities, the Customer for whom the transmission facilities were built must execute a System Access Service Agreement for each POD or POS. The AESO will provide System Access Service during Commissioning at the Rate Schedule named in the System Access Service Agreement.

ARTICLE 7
METERING

7.1 **Metering Standards**
All Customers must provide Metering Equipment that complies with the standards defined in the AESO Measurement System Standard.

7.2 **Meter Testing**
(a) The Customer may request that the AESO arrange for any Metering Equipment testing including, at the Customer's cost, the calibration of any Non-Dispensated Metering Equipment to the System Accuracy Standard. If the Customer requests a test and the meter is subsequently found to be accurate within the System Accuracy Standard, then the Customer will pay for the cost of the testing as invoiced in its next Statement of Accounts.
(b) The AESO may require testing of Metering Equipment at any time. If the Metering Equipment meets the System Accuracy Standard, the AESO will bear the cost of such testing. Otherwise, the Customer will pay for the cost of testing and any necessary recalibration.

7.3 **Access**
The Customer must allow the AESO, including its Representatives, access to enter the Customer's premises, at any reasonable time and at the Customer's cost, to read or install Metering Equipment thereon.

7.4 **Direction to Install Metering**
The AESO may require the Customer to install Metering Equipment on the Customer's premises, at the Customer's sole cost. If the Customer fails to comply with such requirement in a timely manner, the AESO may, at the Customer's sole cost, enter and install Metering Equipment on the Customer's premises.

7.5 **Meter Data**
All Customers must provide Metering Data that complies with the standards defined in the AESO Settlement System Code and the AESO Measurement System Standard. Metering Data will be used for billing purposes, energy purchases and sales, and Ancillary Services purchases.

7.6 **Metering Signals**
Metering signals in the form of energy pulses, reactive energy pulses, and analog values of energy and reactive energy can be provided to the Customer, upon written request and at the Customer's cost. This cost will be included in the Customer's Statement of Accounts.

7.7 **Effect of Non-Compliance**

Notwithstanding Article 3.2, the AESO will not withhold, suspend or terminate System Access Service unless and until:

(a) the metering non-compliance has first been referred to the dispute resolution procedures found in Article 19,

(b) the Customer has failed to adhere to any resolution mutually achieved or the decision of an arbitrator, as the case may be, in a timely manner, and

(c) the AESO has provided the Customer with five days prior written notice of its intention to withhold, suspend, or terminate System Access Service.

ARTICLE 8
PROVISION OF INFORMATION BY CUSTOMERS

8.1 System Access Information

Customers must provide, upon request, all information that the AESO requires in order to discharge its duties and functions under the Act or in compliance with any external agency's reporting requirements. Such information includes, but is not limited to:

(a) information required by the AESO in respect of new or expanding System Access Service;
(b) technical information during construction and prior to energization (pre-commissioning information requirements can be obtained from the AESO); and
(c) Metering Equipment information outlined in Appendix A.

8.2 Forecast Information

On October 1st of each calendar year and whenever new information arises, all Customers must provide the AESO with:

(a) a copy of the Customer's operating procedures;
(b) a schedule of planned or maintenance outages for the following two calendar years; and
(c) forecast information for the following five years, including:
  (i) forecast Maximum Contract Capacity by POD or POS by month,
  (ii) the location and size of any new POD and POS required, and
  (iii) the name and location of existing POD and POS which may no longer be required.

The appropriate forms for provision of forecast and update information can be obtained from the AESO.

8.3 Effect of Non-Compliance

Failure to provide information that may have an impact on safety or system security will result in suspension, termination or delay of System Access Service until such time that the information is provided to the AESO.

The AESO is not responsible for any delay, interruption, damage or other problems caused by a delay in the provision of information required from a Customer.

ARTICLE 9
CUSTOMER AND SYSTEM CONTRIBUTION POLICY

9.1 **Service Requirements**

In considering requests to provide service to a new POC, or to increase the capacity of or improve the service to an existing POC, the AESO will determine the appropriate means of delivering the requested service.

(a) If the Customer's request primarily represents a shift of supply or demand from an existing POC, then the Customer will pay the full cost of the transmission upgrade or extension ("the project")

(b) If the AESO determines that the most economic option for providing service to a Customer is a facility other than a transmission facility (such as a distribution-level extension or isolated generation), then the customer will pay the difference in cost between the most economic option and the transmission upgrade or extension in addition to any customer contribution required under Articles 9.3 through 9.6.

Otherwise:

(c) for a Point of Delivery Customer, the Customer's contribution to project costs will be determined in accordance with Articles 9.3 through 9.6, and

(d) for a Point of Supply Customer, the Customer's contribution to project costs will be determined in accordance with Articles 9.3 through 9.6, and the Customer's System Contribution will be determined in accordance with Article 9.11.

9.2 **Payment of Contributions**

All Customer Contributions and System Contributions required under this Article 9 as determined at the time the Customer executes the necessary agreements signifying commitment as per the AESO's interconnection processes, must be paid by the Customer before the start of construction of transmission facilities to provide the requested service. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the AESO.

9.3 **Classification of System and Customer-Related Costs**

The AESO will classify project costs as either system-related costs or Customer-related costs, as follows.

(a) For a Point of Delivery Customer, subject to Article 9.3(c), Customer-related costs are those costs of a contiguous project in respect of Radial transmission extensions and enhancements at existing adjacent substations. Such costs will normally include the point of interconnection, new transmission line, communication at the point of interconnection, communication enhancements at adjacent substations, a new breaker at an existing substation if required, and other enhancements required to complete the customer's interconnection.

(b) For a Point of Supply Customer, subject to Article 9.3(c), Customer-related costs are those costs of a contiguous project in respect of Radial transmission extensions. Such costs will normally include the point of interconnection, new transmission line, communications at the point of interconnection back to the existing system, and a new breaker at an existing substation if required.

(c) System-related costs are those project costs associated with:
   (i) Looped transmission facilities;
   (ii) Radial transmission extensions if the transmission development plan (as that plan exists on the date the project is Commissioned) proposes that the Radial transmission extension becomes Looped within five years. The Customer will pay the cost of advancing that part of the project from the date established in the transmission development plan, calculated as the difference between the present values of the capital costs of the advanced and as-planned projects using the discount rate as determined under Article 9.14; and
   (iii) Where, in the sole opinion of the AESO, economics or system planning dictate that a facility larger than that required to serve the Customer is to be installed, then the AESO will classify that portion of the project deemed to be in excess of the Customer's needs as system-related costs. As the need to serve additional POCs arises, these system-related costs may be reclassified as Customer-related costs and allocated to the new Customers. The capacity between the Customer's requirements and the minimum size of facilities required to serve the Customer is not considered to be in excess of the Customer's requirements.

(d) Where the Customer requests an interconnection configuration that, in the sole opinion of the AESO, exceeds AESO Standard Facilities, the Customer must pay all customer and system costs in excess of AESO Standard Facilities.

9.4 **Operations and Maintenance**

For customers taking service under Rate DTS, an operations and maintenance charge of 12% will be added separately to the costs of:

(a) AESO Standard Facilities required to provide service to the customer where these costs are eligible for Local Investment determined in accordance with Article 9.6; and

(b) facilities which exceed the AESO Standard Facilities required to provide service to the Customer.

9.5 **Determination of Supply-Related and Demand-Related Costs**

For each Customer at a substation, Customer-related costs will be classified as either supply-related or demand-related as follows:

(a) supply-related costs shall be calculated as $STS_{customer} / (STS_{total}+DTS_{total})$, and

(b) demand-related costs shall be calculated as $DTS_{customer} / (STS_{total}+DTS_{total})$

where STS and DTS are the STS and DTS Contract Capacities, respectively, at the substation. All supply-related costs shall be paid by the Customer. The Customer's contribution to demand-related costs shall be in accordance with Article 9.6.

9.6 **Determination of Customer Contribution**

Customers may be required to contribute toward demand-related costs. The Customer's contribution to demand-related costs will be determined in accordance with this Article 9.6. Otherwise, the Customer must pay all demand-related costs.

The Customer's contribution to the demand-related costs will be calculated as follows:

Customer Contribution = Demand-related costs less the Local Investment

Where:

(a) for a Customer taking service under Rate DTS:

(i) the maximum Local Investment where the TFO provides and owns conventional transformation facilities =
- $51,400.00/year of DTS contract term for new PODs, multiplied by the Substation Fraction; plus
- $28,900.00/MW of DTS Contract Capacity/year of DTS contract term for the first (7.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $10,000.00/MW of DTS Contract Capacity/year of DTS contract term for the next (9.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $5,900.00/MW of DTS Contract Capacity/year of DTS contract term for the next (23 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $3,100.00/MW of DTS Contract Capacity/year of DTS contract term for all remaining MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD.

(ii) the maximum Local Investment where the Customer purchases, owns, and operates the Customer's own transformation facilities or is served through an unconventional interconnection such as those using metering transformers =
- $23,130.00/year of DTS contract term for new PODs, multiplied by the Substation Fraction; plus

- $13,005.00/MW of DTS Contract Capacity/year of DTS contract term for the first (7.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $4,500.00/MW of DTS Contract Capacity/year of DTS contract term for the next (9.5 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $2,655.00/MW of DTS Contract Capacity/year of DTS contract term for the next (23 multiplied by the Substation Fraction) MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD; plus
- $0.00/MW of DTS Contract Capacity/year of DTS contract term for all remaining MW of Contract Capacity for both new PODs and increases in capacity of or improvements to the service at an existing POD.

(iii) the Local Investment will not exceed the demand-related costs determined in Article 9.5(b) or, if applicable, the cost of the most economic option determined in Article 9.1(b); and

(iv) the DTS contract term = 5 to 20 years, as determined by the Customer;

and

(b) for a Customer taking service under any other rate, the maximum Local Investment = $0.

9.7 **Staged Load & Contract Capacity Increases**

(a) Where material increases or decreases in Contract Capacity are contemplated at a POC and contracted for in the original System Access Service Agreement then:

(i) Local investment for projects with expected material increases or decreases in contract load will be determined at the start of the project by taking the present value of the local investment in the incremental load for the remaining contract term;

(ii) If the material increases or decreases in contract load do not occur as expected an adjusted customer contribution may be recalculated in accordance with Article 9.9;

(iii) The discount rate used in the present value calculation of Article 9.7(a) shall be determined in accordance with Article 9.14.

(b) For increases in Contract Capacity contracted prior to the expiration of the original System Access Service Agreement which require the construction of new transmission facilities after the original interconnection then:

(i) The approved Tariff at the time the Customer executes the necessary agreements signifying commitment for the new Contract Capacity will be used in the customer contribution calculation;

(ii) Only the incremental contracted capacity will be used in the customer contribution calculation.

9.8 **Changes to Project Costs**

The cost estimate used in the calculation of project costs will be based on certain assumptions including, but not limited to, assumptions about the method of construction, the routing of facilities, and the approvals and rights of way required to serve the Customer in accordance with the Customer's requests. In the sole opinion of the AESO, where a request for service is changed by a Customer or any assumptions are changed for reasons beyond the reasonable control of the AESO or the TFO, and a variance in the cost of the required facilities over the original estimate results, then:

(a) subject to (b), where there is an increase in the Customer Contribution, this amount is immediately payable to the AESO, or

(b) if feasible, the Customer and the AESO may modify the DTS System Access Service Agreement to adjust the contract term and/or the Contract Capacity, or

(c) the Customer will have the right to cancel the request for service by paying to the AESO, and/or the TFO, all costs then incurred or required to be incurred to discharge the AESO, and/or the TFO, of all obligations and to satisfactorily cancel the request for System Access Service.

9.9 **Changes to Customer Contribution**

Certain material events may, in the AESO's sole opinion, result in an adjustment to the Customer Contribution and as appropriate, payments by the AESO to the Customer or by the Customer to the AESO. Adjustment calculations will rely on the tariff in effect at the time of the request for System Access Service (which may differ from this tariff) Either the Customer or the AESO may initiate an adjustment of the Customer Contribution at any time prior to the expiration of the twenty year refund period as set out in Article 9.10. The circumstances giving rise to contribution adjustments include, but are not limited to, those in which:

(a) a Customer materially increases its Contract Capacity or contract term prior to the expiration of its original DTS System Access Service Agreement and does not necessitate the construction of new transmission facilities;

(b) a Customer materially decreases its Contract Capacity or contract term prior to the expiration of its original DTS System Access Service Agreement;

(c) the actual Contract Capacities and/or incremental revenues turn out to be materially different, on a sustained basis, than originally projected;

(d) a facility that had been classified as system-related under Article 9.3(c) is reclassified as Customer-related due to load growth or the addition of a new POC;

(e) a material error is detected in the original calculation;

(f) there is a material difference between the estimated costs of the project and the actual costs of the project;

(g) the AESO subsequently deems that all or part of a Customer's Facilities have subsequently become system-related; or

(h) the period of advancement as set out in Article 9.3(c) is materially reduced.

9.10 **Shared Facilities**

(a) If the AESO installs facilities to serve a Customer that is required to pay a contribution, and then uses those facilities to serve other Customers within 20 years of their Commissioning, the AESO will adjust the original Customer's contribution and assess each of the new Customers a contribution, as follows:

(i) the DTS contract terms of the original and new Customers;

(ii) the Contract Capacities of the original and new Customers;

(iii) the extent of shared facilities; and

(iv) the time interval between the Commissioning of the original and new Customers.

(b) If the interval described in (a)(iv) is not greater than five years, then the original Customer is eligible for the full amount of the adjustment. If the interval is greater than five years, then for the remaining 15 years the adjustment will be determined on a straight-line, declining-balance basis.

(c) Commencing in year 11 any project whose remaining contribution adjustment is less than $50,000 shall be deemed to have an adjustment balance of zero, an no further refunds shall be due.

(d) An adjustment as described above will also apply to situations in which the AESO subsequently deems that all or part of an original Customer's facilities have become system-related.

9.11 **Determination of System Contribution**

(a) In addition to the Customer Contribution determined in Articles 9.3 through 9.6, a Customer taking service under Rate STS is required to pay a System Contribution for:

(i) new STS Capacity requirements at a new Point of Supply, and

(ii) new STS Capacity requirements at an existing Point of Supply where such additional requirements are the result of the addition of a new Generating Unit.

(b) The System Contribution is the sum of the following:

(i) $10,000/MW multiplied by the amount of new STS Contract Capacity, plus

(ii) $40,000/MW multiplied by the amount of new STS Contract Capacity multiplied by the Customer's System Contribution Factor. System Contribution Factors will be determined by the AESO for areas of the transmission system where generation exceeds load in accordance with Section 29 of the Transmission Regulation, and will be made publicly available by the AESO in advance of their effective dates.

(c) System Contributions are not required for STS Capacity requirements for which a System Access Service Agreement was signed before January 1, 2006, or for STS Capacity requirements of 1 MW or less.

9.12 **Refund of System Contribution**

(a) A Customer's System Contribution will be refunded to the Customer if the Customer's generating unit meets the ISO Rules regarding satisfactory annual performance, in accordance with the provisions of this Article 9.12.

(b) The System Contribution will be refunded in annual amounts during the "Refund Period". The Refund Period begins on January 1 following the Commercial Operation date of the Customer's generating unit and ends nine calendar years later on December 31.

(c) The annual amounts during the Refund Period will be:

(i) 5.6% of the System Contribution in each of the first through fourth calendar years in the Refund Period;

(ii) 11.2% of the System Contribution in the fifth calendar year in the Refund Period; and

(iii) 16.6% of the System Contribution in each of the sixth through ninth calendar years in the Refund Period.

(d) For each calendar year during the Refund Period in which the ISO Rules regarding satisfactory annual performance are met, the Customer will receive a refund of the annual amount determined in (c) for that year. If the ISO Rules regarding satisfactory annual performance are not met, the annual amount for that year will be forfeited.

(e) For each year of the Refund Period, the Customer must report the unit's annual performance to the AESO by January 31 of the following year.

(f) For each year of the Refund Period where the Customer has reported annual performance and where the ISO Rules regarding satisfactory annual performance are met, the AESO will pay the System Contribution refund annual amount to the Customer by February 28 of the following year.

9.13 **Limitations**

The AESO reserves the right to exercise its discretion, acting reasonably, in the application of the contribution policy. Without limiting the generality of this discretion, the AESO may:

(a) Determine costs to be system-related in certain circumstances that might, under strict application of the foregoing, have been classified as Customer-related.

(b) Determine that a refund of a Customer Contribution or a System Contribution may not be given or that a refund may be deferred pending the attainment of certain specified conditions. Upon attainment of the specified conditions, the Customer may be eligible for a full or partial refund.

(c) Determine that a refund of a Customer Contribution or a System Contribution must be returned to the AESO where it is demonstrated that an error was made or that an inappropriate refund was given.

9.14 **Discount Rate**

The discount rate applicable to payments due under this Article 9 will be determined as follows:

(a) For unassigned transmission facilities, for transmission facilities supplied to the AESO by an investor owned Transmission Facility Owner or for facilities supplied to the AESO by an income tax paying municipally owned Transmission Facility Owner:

$$[0.67 \times (GCB + 1\%)] + [(0.33 \times R) \div (1-T)]$$

where GCB is equal to the yield on 30-year Government of Canada bonds; R is equal to the AUC approved generic rate of return on common equity, as amended from time to time; and T is equal to the combined federal and provincial income tax rate for investor owned TFOs.

(b) For transmission facilities supplied to the AESO by a non income tax paying municipally owned Transmission Facility Owner:

the yield on 30-year Government of Canada bonds plus 1.9 percent.

9.15 **Miscellaneous**

(a) Where relocation of transmission facilities is required, the AESO will ensure that all reasonable costs in relocating any transmission facilities are paid for by the Customer.

(b) Where new facilities between adjacent Control Areas are required, the cost of such facilities will be shared equally between the AESO and the party responsible for costs in the other Control Area.

(c) The Customer must pay the cost of any Customer requested facilities that, in the sole opinion of the AESO, exceed the AESO Standard Facilities required to provide service to the Customer.

ARTICLE 10
DEMAND OPPORTUNITY SERVICE

10.1 **Eligibility**

To qualify for Demand Opportunity Service, the Customer must meet the commercial eligibility criteria and submit the required applications as set out in the Demand Opportunity Service Business Practices. The AESO must be satisfied that the Customer's use of the Demand Opportunity Service would not proceed on any other applicable rate. Eligibility is also contingent upon sufficient transmission capacity and suitable system operation conditions capable of accommodating the request.

10.2 **Fees**

In conjunction with the DOS Stage 2 application, which must be submitted at least 30 days prior to taking Demand Opportunity Service, the Customer must pay a non-refundable $5,000 fee to the AESO for evaluation of the Customer's commercial eligibility for DOS.

10.3 **Recallable Service**

Demand Opportunity Service is recallable:

(a) in accordance with the Rate Schedules;
(b) in accordance with the provisions of Article 17; and
(c) whenever sufficient transmission system capacity becomes temporarily or permanently unavailable.

10.4 **Metered Energy**

Any Metered Energy taken by the Customer in a Billing Period that exceeds the aggregate Metered Energy allowed under the Customer's Demand Opportunity Service System Access Service Agreements will be added to the Customer's DTS Metered Energy in the same Billing Period. Where the Customer has not executed a System Access Service Agreement for DTS services, the Customer will be deemed to have executed such an agreement effective with the beginning of the relevant Billing Period.

10.5 **Effect of Disqualification**

From time to time, the AESO may audit the Customer's eligibility for Demand Opportunity Service. If the AESO finds that the Customer no longer qualifies for Demand Opportunity Service, the Customer will be deemed to have executed an agreement for Non-Recallable Service effective on the date of disqualification and the AESO will terminate billing under a DOS Rate Schedule. The AESO may, in its sole discretion, recover retroactive amounts for the period during which such Customer did not qualify for, but was billed under, a DOS Rate Schedule.

ARTICLE 11
ANCILLARY SERVICES

11.1 General

Ancillary Services are provided by Customers when the AESO determines there is a need for such services to maintain system security and ensure the reliable operation of the Alberta Interconnected Electric System. Customers required by the AESO to provide Ancillary Services shall be directed to do so in accordance with AESO Operating Policies and Procedures and will be compensated as provided in Articles 11.2 – 11.7, as applicable.

11.2 Contracted Ancillary Services

If at the time the Customer is directed to provide Ancillary Services the Customer has an existing contract with the AESO to provide the Ancillary Services in question from the directed facility (the "Existing Contract"), then the amount to be paid to the Customer by the AESO for the Ancillary Services shall be determined according to the terms of the Existing Contract.

11.3 Directed Ancillary Services Other Than Transmission Must Run Services

If at the time the Customer is directed to provide an Ancillary Service other than TMR Service, the Customer does not have an Existing Contract, then the amount to be paid to the Customer by the AESO in respect of each Ancillary Service provided shall be the greater of the following monthly amounts. Each amount is the sum for the month of hourly compensation amounts.

(a) The product of the MW hour directed and the highest price paid in the hour to Customers providing the same Ancillary Service pursuant to Article 11.2 and that the Existing Contract was the result of a competitive process conducted in the prior 12 months; or

(b) The verifiable net opportunity cost related to foregone electricity sales incurred by the Customer to supply the directed Ancillary Service, taking into account offsetting pool energy receipts.

11.4 Transmission Must Run Services

TMR Services are Ancillary Services provided by Customers with generating units in response to a direction provided by the AESO to ensure safe and reliable electrical service for a region of the Alberta Interconnected Electric System.

TMR Services are Foreseeable if the AESO, taking into account reasonable procurement timing requirements, determines TMR Services are required to meet AESO Transmission Reliability Criteria which includes consideration of expected operating conditions and planned transmission outages. TMR Services are Unforeseeable TMR Services if they do not constitute Foreseeable TMR Services.

11.5 Arrangements and Compensation for Foreseeable TMR Services

Arrangements and compensation for Foreseeable TMR Services will be made in accordance with the Foreseeable TMR Service Procurement Procedure (Appendix C).

11.6 Compensation for Unforeseeable TMR Services

If at the time the Customer is directed to provide Unforeseeable TMR Service the Customer does not have an Existing Contract, then the amount to be paid to the Customer in the applicable Billing Period for Unforeseeable TMR Service is equal to Variable Costs plus Fixed Costs, where:

(a) Variable Costs means the hourly difference of the pool price subtracted from the Energy Price, which shall not be less than zero, multiplied by the corresponding hourly energy generated (MW.h) by the specific directed generating unit in compliance with the directive to provide Unforeseeable TMR Service, where:

(i) Energy Price ($/MW.h) is the product of the Heat Rate multiplied by the Fuel Cost, added to the sum of the Variable STS Charges and Variable O&M Charge.

(ii) Heat Rate (GJ/MW.h) is the actual heat rate of the Customer's generating unit during the period when the unit was complying with the directive.

(iii) Fuel Cost for a gas generating unit is the natural gas market price ($/GJ), being the "Daily Spot Price at AECO-C and NIT", excluding weekends, as published in the Canadian Gas Price Reporter, for natural gas on the applicable day. The Fuel Cost for a coal generating unit shall be provided by the Customer.

(iv) Variable STS Charges ($/MW.h) is the actual cost of all variable charges from Rate Schedule STS of the AESO Tariff, including the applicable loss factor charge or credit.

(v) Variable O&M Charge ($/MW.h) is the all-in cost (including major/minor overhauls), fixed at $4/MWh, of providing incremental output from the unit, excluding Fuel Costs and Variable STS charges.

(b) Fixed Costs are equal to the Average Monthly Fixed Cost multiplied by the greater of the Must Run Ratio (MRR) or the Minimum MRR, where:

(i) Average Monthly Fixed Cost is equal to one-twelfth of the sum of the annual costs in items (A) through (H) as follows:

(A) annual amortization and depreciation amounts for the Customer's investment or for the PPA acquisition cost related to the specific directed generating unit, consistent with amounts reported in the Customer's audited financial statements, and adjusted for cogeneration infrastructure not utilized for generation purposes;

(B) the product of the unamortized or undepreciated capital investment (UCI) multiplied by a deemed debt percentage of 70% and multiplied by a debt interest rate that is equal to the current 10-year Government of Canada Bond interest rate plus 0.5%, and where UCI is the greater of

(1) the Customer's initial cost of property, plant, and equipment for the specific directed generating unit, or the Customer's initial PPA acquisition cost related to the specific directed generating unit, less accumulated depreciation or amortization, as the case may be, related to the specific directed generating unit; or

(2) 25% of the Customer's initial cost of property, plant, and equipment for the specific directed generating unit, or the Customer's initial PPA acquisition cost related to the specific directed generating unit.

(C) the product of UCI, as described in (B) above, multiplied by a deemed 30% common equity percentage of capital structure multiplied by a deemed 12% rate of return on equity;

(D) if the Customer provides verifiable actual values for the items in both (B) and (C) then those will be used instead of the deemed values;

(E) the product of the tax rates multiplied by the rate of return on equity amount determined in (C), where income tax costs reflect the marginal income tax rates for both federal and provincial portions of income tax;

(F) total annual direct fixed operation and maintenance costs associated with the specific directed generating unit;

(G) total annual direct fixed fuel costs associated with the specific directed generating unit; and

(H) fixed charges from applicable PPAs associated with the specific directed generating unit.

(ii) Must Run Ratio (MRR) is the ratio of the number of hours in the month when Unforeseeable TMR Services were provided to the total number of hours in the month;

(iii) Minimum MRR is:

(A) 12% for the first or second Unforeseeable TMR Service Event within a rolling 12-month period in which TMR Service is directed by the AESO;

(B) 20% for the third Unforeseeable TMR Service Event within a rolling 12-month period in which TMR Service is directed by the AESO;

(C) 30% for the fourth Unforeseeable TMR Service Event within a rolling 12-month period in which TMR Service is directed by the AESO;

(D) 40% for the fifth Unforeseeable TMR Service Event within a rolling 12-month period in which TMR Service is directed by the AESO; or

(E) 50% for the sixth or any additional Unforeseeable TMR Service Event within a rolling 12-month period in which TMR Service is directed by the AESO.

If there is more than one Unforeseeable TMR Service Event in a Billing Period, the Minimum MRR shall be the highest applicable percentage described in (A) through (E) above.

In lieu of the Variable and Fixed Costs in (a) and (b) above, if a Customer can demonstrate foregone future energy sales due to a TMR directive, then the verifiable net opportunity cost related to foregone electricity sales incurred by the Customer to supply the directed TMR Service, taking into account offsetting pool energy receipts. This applies only to Customers that have responded to a TMR direction from using hydroelectric generation units.

11.7 **Maximum TMR Services Compensation**
The maximum monthly amount to be paid by the AESO for TMR Service results in the recovery of fixed, operating and maintenance costs, including a reasonable rate of return for the service provider, and is equal to the Average Monthly Fixed Cost plus Variable Costs as provided for in Article 11.6.

11.8 **Invoicing**
Customers that provide Unforeseeable TMR Service in response to a direction from the AESO will submit an invoice to the AESO within 15 business days after the later of (i) the end of the month in which the service was provided or (ii) the coming into effect of this Article 11. The amount of the invoice shall be determined in accordance with the method in 11.6 of this Article, and will separately itemize the values used for each component specified (Fixed and Variable Costs).

11.9 **Audit Rights**
The AESO has the right to audit Customer's invoices and source information related thereto for TMR Services, provided that any such audit is (i) conducted only on reasonable prior notice to the Customer, (ii) conducted on the Customer's premises during normal business hours, (iii) not conducted by, or the information gathered made available to, those persons at the AESO that determine Contestability for purposes of the AESO procuring TMR competitively, (iv) conducted subject to Article 20 of this Tariff, and that (v) no copies of records reviewed during the audit shall be made without the Customer's prior written consent.

ARTICLE 12
UNDER-FREQUENCY LOAD SHEDDING

12.1 **Requirement to Supply**

From and after the effective date of the Tariff, certain Customers may be eligible and required to provide under-frequency load shedding. The provisions with respect to those requirements and the credits therefore, are set out in Rate Schedule Under-Frequency Load Shedding (UFLS).

12.2 **Effect of Non-Compliance**

Failure by any Customer to whom UFLS applies to comply with the requirements thereof may cause the AESO to, at its sole discretion, withhold, limit or discontinue System Access Service to such Customer. Nothing in this paragraph affects or derogates from the right of the WECC to levy penalties or the obligation of the Customer, if any, to pay such penalties as a result of failure to provide Under-Frequency Load Shedding to the AESO.

ARTICLE 13
CONTRACT CAPACITY INCREASES & ALLOCATION

13.1 **Available Capacity**

(a) The AESO will Allocate Planning Capacity for a new or expanding POC according to available AIES capacity as of the date the AESO receives an application for System Access Service, as set out in Article 5. The AESO will inform the Customer of any AIES constraints in respect of a new or expanding POC.

(b) For the purposes of this Article 13, "Allocate Planning Capacity" means that the AESO will assign Planning Capacity to a project for planning purposes and project work priority as of the date set out in paragraph (a), above.

13.2 **Requirement of Customer to Act**

(a) The AESO, acting reasonably, may establish critical milestones with respect to project completion and may agree with the Customer on such milestones.

(b) For STS customers, milestones will include but not be limited to payment of the System Contribution determined under Article 9.11:

(i) within 90 days after EUB approval of the local interconnection facilities required to facilitate the interconnection of the STS Capacity; or

(ii) if construction of local interconnection facilities is not required to facilitate the interconnection of the STS Capacity at an existing POS, within 90 days after execution of an amended System Access Service Agreement for the POS.

(c) If the Customer fails to meet such milestones, the AESO may:

(i) cancel, and require the Customer to resubmit, the Customer's application for System Access Service;

(ii) re-Allocate the subject Planning Capacity to another applicant whose System Access Service application date is later than the Customer's application date determined in Article 13.1(a); or

(iii) proceed, with no modification to the Allocated Planning Capacity, with the Customer's original application for System Access Service on the basis of amended milestones, as agreed by the AESO.

13.3 **Limit to Contract Capacity**

The Contract Capacity for a new POS established by the AESO may not exceed the sum of the MCR of all generators connected to the AIES by the new POS less the sum of all gross loads that offset the energy delivered to the AIES from that POS under normal operating conditions.

13.4 **Increase of Contract Capacity**

In the event that a Customer desires to increase the Contract Capacity at an existing POD or POS, the Customer must execute an amended System Access Service Agreement. If new facilities or upgrades are required to provide the new service or to provide the amended service level, the requirements for a Customer Contribution and Security will apply.

13.5 **Metered Demand Limitations**

(a) Subject to paragraphs (b) and (c), the Metered Demand for a Customer taking service under Rate Schedule DTS or Rate Schedule STS shall not exceed the lesser of:

(i) the Rated Capacity of any transmission facilities comprising its interconnection; or

(ii) the Physical Capacity of any transmission facilities comprising it's interconnection.

In the event the foregoing is not complied with, the AESO shall have the right to discontinue the applicable System Access Service until the Customer installs equipment to limit its Metered Demand.

(b) A DTS Customer may temporarily exceed the level stipulated in subparagraph 13.5(a)(i) only where it has in place a System Access Service Agreement for an Opportunity Service at the applicable POD.

(c) Subject to paragraph 13.3, an STS customer may temporarily exceed the level stipulated in subparagraph 13.5(a)(i), with the AESO's consent obtained on a minimum twenty-four hours' notice, provided that the AESO determines that the transmission system can safely accommodate the proposed energy without risk of disturbance to other AESO customers.

ARTICLE 14
REDUCTIONS OR TERMINATION OF CONTRACT CAPACITY

14.1 **Eligibility**
In order to reduce the Contract Capacity at an existing POD or POS, a Customer must execute an amended System Access Service Agreement and pay any associated Customer Contribution, as determined by the AESO.

14.2 **Notice of Reduction or Termination**
In order to terminate or reduce the Contract Capacity, a Customer must provide written notice to the AESO. Terminations or reductions in Contract Capacity will be effective 5 years from the notification date.

14.3 **Excursions During the Notice Period**
The Contract Capacity immediately following the five year notice period will be the maximum of:
(a) the pre-notice Contract Capacity less the reduction of Contract Capacity requested by the Customer; or
(b) the highest Metered Demand during the five year notice period less the reduction of Contract Capacity requested by the Customer.
Customers may provide an additional notice of reduction after an excursion so Contract Capacity will be reduced to previous notice levels.

Separate written notice must be provided reductions or terminations of Contract Capacity at each respective POD and POS at a single transmission station; no net reductions will be accepted or effected.

14.4 **Payments in Lieu of Notice**
Customers reducing or terminating their System Access Service Agreements may choose to pay out the Contract Capacity as a lump sum payment.
(a) Contract Capacity reduction or termination lump sum payment charges will be based upon the present value of the System Charge as provided in the rate schedule DTS.
(b) The discount rate is as outlined in Article 9.14.
(c) The AESO may re-assess the payment if there are material differences between the requested Contract Capacity and actual capacity.

14.5 **Review of STS Contract Capacity**
At least once per year, the AESO will review the Contract Capacity of STS customers. The AESO may reduce a customer’s STS Contract Capacity to:
(a) the mean metered power delivered to the AIES in the preceding twelve (12) months; or
(b) for low capacity factor generators, the mean metered power delivered to the AIES over recurrent periods that are shorter than twelve (12) months, as determined by the AESO

if such deliveries are more than 10% below the existing Contract Capacity or as mutually agreed between the Customer and the AESO.

14.6 **Regulated Generating Units**

(a) System Access Service Agreements between the AESO and Customers who operate Regulated Generating Units will terminate on the PPA Effective Date, with the exception of Regulated Generating Units that are not sold at the PPA auction and the Regulated Hydro Generating Units outlined in the Appendix to the Rate Schedules.

(b) System Access Service Agreements with an effective date after the PPA Effective Date between the AESO and Customers who operate Regulated Generating Units or who have entered into a Power Purchase Arrangement with the owner of a Regulated Generating Unit will terminate at the end of the base life year of the Regulated Generating Unit as outlined in the Appendix to the Rate Schedules.

ARTICLE 15
FINANCIAL SECURITY, BILLING, AND PAYMENT TERMS

15.1 **Credit Requirements**

(a) The Customer must comply with the AESO's financial security requirements. Prior to receiving service, the Customer must provide the AESO with all financial information that the AESO reasonably requests in order to establish the financial security required from the Customer.

(b) If requested by the AESO, the Customer must provide financial security in an amount of up to three months' payment in advance for System Access Service. The amount of the financial security will be estimated by the AESO at its sole discretion based on the Customer's historic use or on an estimate where actual use is not available. Such security must be in a form satisfactory to the AESO including but not limited to a guarantee, cash deposit, or an irrevocable letter of credit from a Canadian Chartered Bank, credit union, trust company, or other financial institution with a minimum senior unsecured long-term debt A- credit rating or equivalent as determined by Standard & Poor's or equivalent credit rating agency.

(c) The AESO may request, at its sole discretion, at any time after initial granting of service, additional or replacement security based on the AESO's estimate of the appropriate security required. Required additional or replacement security must be provided to the AESO within two business days of such request. Customers must report any event of default for borrowed funds or material adverse changes in their financial position to the AESO within two business days of such event.

15.2 **Effect of Non-Compliance**

If the Customer fails to provide adequate security outlined in Article 15.1 then 15.2 (a), 15.2 (b), or both may apply.

(a) The AESO, at its sole discretion, may invoke a financial penalty which will be calculated at the Toronto Dominion Canadian prime rate plus 6%; until such time as the security has been provided to the AESO

(b) The AESO may immediately withhold or suspend the Customer's System Access Service.

Any such withholding or suspension will not relieve the Customer from its obligation to pay any rate, charge or other amount that has accrued, or is accruing, to the AESO

15.3 **Billing Procedures**

(a) The AESO issues Statements of Account which may include:

(i) amounts determined on an initial basis in the month following energy flow and no later than fifteen (15) Business Days after the end of the Billing Period;

(ii) amounts determined on an interim basis in the third month following energy flow; and

(iii) amounts determined on a final basis in the seventh month following energy flow.

(b) From time to time the AESO may review a Statement of Account issued in accordance with Article 15.3(a) and may issue a new Statement of Account following that review.

(c) The AESO may choose not to issue Statements of Account on an interim or final basis that result in a charge or refund of less than $1,000.

(d) The AESO may use estimated values to produce a Statement of Account when Metered Demand or Metered Energy data is not available or is incomplete, when Metering Equipment fails, or when the data is under Dispute. The AESO may also use estimated values to produce a Statement of Account if the AESO's billing and settlement system is unable to produce a Statement of Account. In the event that a Statement of Account is based on estimated values, an adjustment will be made on a subsequent Statement of Account issued in accordance with Article 15.1(a) or 15.1(b) to reflect the use of actual or more appropriate estimated values.

(e) The AESO may, but is not required to, deduct from the Statements of Account any amounts owing by the AESO to the Customer or its Affiliates.

15.4 **Totalized Billing**

Effective January 1, 2002, where a Customer is an industrial facility with multiple POCs, the AESO may totalize the POCs and produce one Statement of Account for the Customer. The AESO will base its decision to totalize on a review of the economics of providing more than one POC, reclassification of the site as an AUC designated industrial system, or the existence of a credible transmission bypass alternative.

15.5 **Adjustments**

When a Customer requests that a Statement of Account issued in accordance with Article 15.3 be recalculated and reissued forty-five (45) days or more after end of the applicable billing period as a result of:

(i) unavailable or incomplete meter data, or

(ii) inaccurate estimates of meter data,

(iii) reconciliation with updated estimates of meter data,

the AESO will recover the cost of recalculating and reissuing the affected Statement of Account from the Customer taking service from the relevant Metering Equipment. The Customer must pay to the AESO $1,000 for each recalculated and reissued Statement of Account.

15.6 **Request for Billing Data**

Data required to verify any billing information provided by the AESO may be made available to Customers during regular business hours and the Customer will be responsible to pay for all of the costs of retrieval and provision of the data.

15.7 **Payment Terms**

Notwithstanding any unresolved Dispute between the AESO and the Customer, the Customer must pay the entire amount due, as shown on the Statement of Account, no later than the twentieth Business Day after the end of the Billing Period. Payment must be made by way of electronic funds transfer or wire transfer to the bank account specified by the AESO.

15.8 **Interest and Other Charges**

In the event of non-payment under the terms of Article 15.7, interest and late payment penalties will be charged to defaulting customers.

(i) Where non-payment exists, interest charges will be calculated on the day following the applicable Transmission settlement date. The interest will be calculated at the Toronto Dominion Canadian prime rate plus 6%. Interest will be calculated from the due date to the date on which bank value is received.

(ii) In addition to the interest charge, a penalty charge will be assessed based on 2 days interest on the outstanding amount owing and calculated at the Toronto Dominion Canadian prime rate plus 6%.

The AESO will also assess the defaulting Customer for all administrative and collection costs relating to the recovery by the AESO of amounts owed. The AESO, at its sole discretion, may suspend System Access Service and realize upon any security provided by the defaulting Customer if the Customer is not in compliance with Article 15.7 in full or partial satisfaction (as the case may be) of all amounts owing to the AESO. System Access Service to the Customer will not be re-instated until the Customer has paid all amounts owing to the AESO in full and has restored or secured its credit facility in a manner satisfactory to the AESO, at the AESO's sole discretion.

ARTICLE 16
PEAK METERED DEMAND WAIVER

16.1 **Peak Metered Demand Waivers**

The AESO may, in its sole discretion, waive Metered Demand for the purposes of calculating the Billing Capacity when the Metered Demand was caused by one of the following.

(a) For all Customers:
- (i) Commissioning;
- (ii) activities required to repair and maintain transmission facilities;
- (iii) an event of Force Majeure;
- (iv) compliance with a Dispatch Instruction from the AESO during an Emergency; or
- (v) load restoration activities following an outage of transmission or distribution facilities or caused by an Emergency on the transmission system.

(b) In addition for Distributors; for pre-scheduled activities required to maintain distribution facilities. In these circumstances, the customer must provide the AESO with the information specified in the AESO's Peak Metered Demand Waiver Request form, which can be obtained by contacting the AESO. The completed form must be submitted no later than 3 business days into the billing period following the one for which the waiver is being requested.

ARTICLE 17
SERVICE INTERRUPTIONS AND FORCE MAJEURE

17.1 **Service Not Guaranteed**

Although precautions are taken to guard against System Access Service interruptions, the AESO does not guarantee uninterrupted System Access Service. For example interruptions may be caused by, but not limited to, the following:

(a) scheduled or planned facility maintenance activities;
(b) construction, commissioning and facility testing activities;
(c) unscheduled or unplanned events (such as, but not limited to, emergency equipment maintenance and Emergencies);
(d) Force Majeure;
(e) breaches of obligations owed to the AESO by its suppliers or Customers; or
(f) as otherwise expressly allowed by a Rate Schedule.

Whenever System Access Service has been interrupted, diminished or reduced for reasons other than a breach of this Tariff by the Customer, the AESO will make all reasonable efforts to ensure that service is restored as soon as practicable after the interruption, diminution or reduction.

17.2 **Interruptions for Construction, Commissioning, and Facility Testing**

The AESO will make all reasonable efforts to schedule construction, commissioning, or facility testing activities in conjunction with affected Customers planned downtime but may, upon six months written notice, interrupt Customers' System Access Service to perform such activities.

17.3 **Continued Obligations**

The Customer's obligations to pay for System Access Service, to provide information, and to maintain Transmission Interconnection Requirements are not affected during, or as the result of, any event of Force Majeure or other System Access Service interruption expressly contemplated under this Tariff.

ARTICLE 18
LIMITATION OF LIABILITY

18.1 **Limitation of Liability**

Notwithstanding anything to the contrary contained in these Terms and Conditions, no action lies against an AESO Person, and an AESO Person is not liable for any act or omission carried out or purportedly carried out in performing its obligations under this Tariff ("AESO Tariff Act") unless such AESO Tariff Act constitutes willful misconduct, negligence, breach of contract or, if the AESO Tariff Act is carried out by an AESO Person who is an individual, if such act is not carried out in good faith. If an AESO Person is liable to another person for an AESO Tariff Act, then the AESO Person is liable for only Direct Loss or Damage suffered or incurred by that other person.

ARTICLE 19
DISPUTE RESOLUTION

19.1 **Initiation of Disputes**

Disputes must be submitted, in writing, to the other party in a timely fashion, and clearly set out the subject of the Dispute including:

(a) a description of the items under dispute,
(b) the rationale for the Dispute, and
(c) the time period over which the disputed items occurred.

19.2 **Continued Obligation**

Disputes will be referred to a senior officer from each of the AESO and the relevant Customer for resolution. Pending resolution of any Dispute, the AESO and the Customer will continue to perform their respective obligations under this Tariff.

19.3 **Arbitration**

If the Dispute has not been resolved within thirty (30) days after referral to the senior officers, either the AESO or the Customer may require, by written notice, that the Dispute be resolved through arbitration. The AESO shall advise the AUC of any matter going to arbitration within thirty days of the matter being referred to arbitration. The parties shall appoint a mutually satisfactory arbitrator within ten days of the notice to resolve the Dispute through arbitration. In the event that the parties cannot agree on a single arbitrator within ten (10) days, each party shall appoint an arbitrator within ten days thereafter by written notice, and the two arbitrators shall together appoint a third arbitrator. In the event that a tribunal is required, the third arbitrator shall be appointed within twenty (20) days of written notice for arbitration. The arbitrator or tribunal shall render a decision within thirty days of the last appointment. The AESO shall advise the AUC of the results of the arbitration within thirty days of the Arbitrator's decision. The AESO shall also furnish the AUC with a list of parties potentially affected by the results of the arbitration. The arbitration shall be conducted in accordance with the Arbitration Act (Alberta), as amended from time to time. In the event of a conflict between these Terms and Conditions and the Arbitration Act, these Terms and Conditions shall prevail.

Any interested party adversely and unduly affected by the decision of an arbitrator or a tribunal is entitled to make an application to the AUC requesting a clarification or change to these Terms and Conditions.

ARTICLE 20
CONFIDENTIALITY

20.1 Use of Confidential Information

The AESO,

(a) shall not disclose the Confidential Information to any person except as permitted under this Tariff;

(b) shall only use or reproduce the Confidential Information for the purpose for which it was disclosed or another purpose contemplated in this Tariff;

(c) shall not permit unauthorized persons to have access to the Confidential Information; and

(d) shall only disclose the Confidential Information to those Representatives who need to know the information and have been informed of the confidential nature of the Confidential Information.

20.2 Exceptions

Exceptions to the AESO's confidentiality obligations stated in Article 20.1 may be made:

(a) if the relevant information is at the time generally and publicly available other than as a result of breach of confidence by the AESO;

(b) if the person or persons who provided the relevant information consents to its disclosure, use, or reproduction;

(c) to the extent the Confidential Information:

(i) must be disclosed by law to any agent, government or governmental body, authority or agency having jurisdiction over the AESO;

(ii) must be disclosed to the AESO for the purposes of the AESO fulfilling its duties under the Act; and

(iii) must be disclosed to a TFO for the purposes of the AESO fulfilling its duties under the Act. All information provided to a TFO shall be subject to the confidentiality provisions in the TFO's Terms and Conditions of service.

(d) if required in connection with legal proceedings, arbitration, or other dispute resolution mechanism relating to this Tariff;

(e) if required to protect the safety of personnel or equipment, or to protect the reliability of the AIES; or

(f) if the relevant information is an unidentifiable component of an aggregate of information.

20.3 Requests for Disclosure

In the case of a request or demand for disclosure under Article 20.2(c)(i) or Article 20.2(d), the AESO will provide notice to those affected by the request or demand as soon as reasonably practicable, so as to afford the opportunity to challenge such request or demand or seek injunctive relief or protection from the request or demand.

20.4 **Customer Obligations**

No provision of this Tariff obligates the Customer to treat its own information and agreements with the AESO as confidential.

ARTICLE 21
MISCELLANEOUS

21.1 **Binding on the ISO**
Each respective System Access Service Agreement executed by the AESO hereunder will be binding on any subsequent ISO for the length of its term.

21.2 **Assignment**
A Customer may assign its System Access Service Agreement or any rights thereunder to another Customer who is qualified for the service available under such agreement, but only with the consent of the AESO, such consent not to be unreasonably withheld. In the event an STS or DTS contract has been assigned, all rights and obligations associated with the service, including any and all retrospective adjustments due to deferral account reconciliation or any other adjustments will be applied to the account of the assignee.

21.3 **Compliance With the AESO Directives**
Customers must comply with dispatches and directives of the AESO which are required for performance of Customers' obligations hereunder in real-time, including, without limitation, those related to Transmission Interconnection Requirements and provision of Ancillary Services.

21.4 **Notifications**
All notices given or served upon the AESO in accordance with this Tariff must be in writing and marked "Important" and given by personal service, email, telefax or by registered letter addressed to:

AESO
Attention: Manager, Customer Services – Transmission
2500, 330 – 5th Avenue SW
Calgary, Alberta T2P 0L4
Fax (403) 539-2949

All notices given or served upon the Customer in accordance with this Tariff must be in writing served by personal service, registered letter or telefax and sent to the address or addresses shown for such Customer in the relevant System Access Service Agreement.

21.5 **SPRDA Generating Units**
Generating Units constructed under the Small Power Research and Development Act (Alberta) ("SPRDA") are exempt from the provisions of Rate Schedule STS to the extent the volume of energy sales are conducted under contracts specifically executed pursuant to the provisions of the SPRDA.

APPENDIX A
METERING EQUIPMENT INFORMATION

1. For each POS Meter:
    (a) Company identification
    (b) Meter type identification
    (c) Meter serial number
    (d) Date meter installed
    (e) Date meter removed
    (f) Number of elements
    (g) Manufacturer
    (h) Model
    (i) Measurement Canada approval
    (j) Past test dates
    (k) Past results (pass/fail information only)
    (l) Planned test dates

2. For each POS meter recorder:
    (a) Record identification
    (b) Recorder type
    (c) Serial number
    (d) Date installed
    (e) Date removed
    (f) Manufacturer
    (g) Model
    (h) Measurement Canada approval
    (i) Past test dates
    (j) Past results (pass/fail information only)
    (k) Planned test dates

3. For each Current Transformer associated with POS metering:
    (a) Company identification
    (b) Transformer type
    (c) Serial number
    (d) Date installed
    (e) Date removed
    (f) Phase location
    (g) Ratio
    (h) Accuracy
    (i) Manufacturer
    (j) Model
    (k) Measurement Canada approval

4. For each Potential Transformer associated with POS metering:
   (a) Company identification
   (b) Transfer type
   (c) Serial number
   (d) Date installed
   (e) Date removed
   (f) Phase location
   (g) Ratio
   (h) Accuracy
   (i) Manufacturer
   (j) Model
   (k) Measurement Canada approval

APPENDIX B
SYSTEM ACCESS SERVICE AGREEMENT PROFORMAS

Demand Transmission Service
Supply Transmission Service
Import Opportunity Service
Export Opportunity Service
Demand Opportunity Service (DOS)
Construction Commitment Agreement Proforma

SYSTEM ACCESS SERVICE AGREEMENT
DEMAND TRANSMISSION SERVICE
Date of Issue:

The following constitute the terms pursuant to which the Independent System Operator, operating as AESO shall provide System Access Service to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff).

1.0 TYPE OF SERVICE

Service under this Agreement shall be provided pursuant to Rate Schedule Demand Transmission Service (DTS).

2.0 POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

a) Point of Delivery (POD): The POD shall be **Substation Name and Number**
b) Location: **LSD: xx-xx-xx-WxM**

3.0 CONTRACT CAPACITY

xx MW Dates

4.0 COMMISSIONING PERIOD FOR NEW FACILITIES, IF ANY:

N/A

5.0 EFFECTIVE DATE
1 day of month

This agreement supercedes and replaces, as of the Effective Date, any DTS agreement for this POD at **Substation Name and Number**

6.0 CUSTOMER CONTRIBUTION
The Customer Contribution charge estimated to be $NIL. This amount has been received by the AESO.

Minimum Term 5 years. The Customer Contribution and/or Minimum Term are subject to change based on final costs.

7.0 RATES AND TERMS OF SERVICE
The supply of System Access Service pursuant to this Agreement, and the Customer's obligations with respect to connection and supply of System Support Services, shall be subject to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

8.0 NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Attention: ________________________
Address: ________________________
____
____
Tel: ________________________
Fax: ________________________
Email: ________________________

9.0 This POD is designated to provide under-frequency load shed

___ Yes ___ No

10.0 The Primary Service Credit is applicable under this Agreement

___Yes ___ No

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator, operating as AESO

Per: ________________________________ Date: ____________________

Customer Name

Per: ________________________________ Date: ____________________
Name:
Title:

Per: ________________________________ Date: ____________________
Name:
Title:

SYSTEM ACCESS SERVICE AGREEMENT
SUPPLY TRANSMISSION SERVICE

Date of Issue:

The following constitute the terms pursuant to which the Independent System Operator, operating as AESO shall provide System Access Service to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff).

1.0 TYPE OF SERVICE

Service under this Agreement shall be provided pursuant to Rate Schedule Supply Transmission Service (STS).

2.0 POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

c) Point of Delivery (POS): The POS shall be **Substation Name and Number**
d) Location: **LSD: xx-xx-xx-WxM**

3.0 CONTRACT CAPACITY

xx MW Dates

4.0 COMMISSIONING PERIOD FOR NEW FACILITIES, IF ANY:

N/A

5.0 EFFECTIVE DATE

1 day of month

This agreement supercedes and replaces, as of the Effective Date, any STS agreement for this POS at **Substation Name and Number**

6.0 CUSTOMER & SYSTEM CONTRIBUTION

The Customer Contribution charge estimated to be $NIL. This amount has been received by the AESO.

Minimum Term 5 years. The Customer Contribution and/or Minimum Term are subject to change based on final costs.

7.0 RATES AND TERMS OF SERVICE

The supply of System Access Service pursuant to this Agreement, and the Customer's obligations with respect to connection and supply of System Support Services, shall be subject to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

8.0 NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

__________ Attention: ______________________
Address: ______________________
____
____
Tel: ______________________
Fax: ______________________
Email: ______________________

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator, operating as AESO

Per: ______________________ Date: ______________

Customer Name

Per: ______________________ Date: ______________
Name:
Title:

Per: ______________________ Date: ______________
Name:
Title:

SYSTEM ACCESS SERVICE AGREEMENT
IMPORT OPPORTUNITY SERVICE

Date of Issue:

The following constitute the terms pursuant to which the Independent System Operator, operating as AESO shall provide System Access Service to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff.)

1. TYPE OF SERVICE

Service under this Agreement shall be pursuant to Rate Schedule Import Opportunity Service (IOS).

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

☐ **British Columbia Intertie** ☐ **Saskatchewan Intertie** ☐ **Montana Intertie**

3. EFFECTIVE DATE

__________ 1, 200__

4. TERM

____

5. RATES AND TERMS OF SERVICE

The supply of System Access Service under this Agreement, shall be pursuant to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

Market Access is contingent upon receipt of an executed System Access Service Agreement.

6. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Attention: ________________________
Address: ________________________
____
____
Tel: ________________________
Fax: ________________________
Email: ________________________

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator, operating as AESO

Per: ________________________________ Date: ______________________

Customer Name

Per:________________________________ Date: ______________________
Name:________________________________
Title:________________________________

Per:________________________________ Date: ______________________
Name:________________________________
Title:________________________________

SYSTEM ACCESS SERVICE AGREEMENT
EXPORT OPPORTUNITY SERVICE
Date of Issue:

The following constitute the terms pursuant to which the Independent System Operator, operating as AESO shall provide System Access Service to the Customer. (Defined terms used herein without definition shall have the meanings ascribed thereto in the Terms and Conditions of the AESO's Tariff.)

1. TYPE OF SERVICE

Service under this Agreement shall be pursuant to Rate Schedule:
☐ **Export Opportunity Service (1 Hour): XOS 1 Hour**
☐ **Export Opportunity Service (1 Month): XOS 1 Month**

2. POINT OF INTERCONNECTION WITH THE TRANSMISSION SYSTEM

☐ **British Columbia Intertie** ☐ **Saskatchewan Intertie** ☐ **Montana Intertie**

3. EFFECTIVE DATE

__________ 1, 200__

4. TERM

____

5. RATES AND TERMS OF SERVICE

The supply of System Access Service under this Agreement, shall be pursuant to the AESO's Tariff, in particular to the Rate Schedule referenced under Paragraph 1.

Market Access is contingent upon receipt of an executed System Access Service Agreement.

6. NOTICES

Notices sent to the Customer pursuant to this Agreement shall be as follows:

Attention: ________________________
Address: ________________________
____
____
Tel: ________________________
Fax: ________________________
Email: ________________________

By executing in the space below, the Customer and the AESO agree to the foregoing provisions.

Independent System Operator, operating as AESO

Per: ________________________________ Date: ______________________

Customer Name

Per:________________________________ Date: ______________________
Name:________________________________
Title:________________________________

Per:________________________________ Date: ______________________
Name:________________________________
Title:________________________________

SYSTEM ACCESS SERVICE AGREEMENT
DEMAND OPPORTUNITY SERVICE (DOS)

____________________ - ________________________

Pre-qualification Number **Request number provided by Customer**

Check this box if this Request overlaps with a previous DOS Request or DOS Transaction ☐

The Customer is to complete this document, and fax it to the System Controller to request a DOS Transaction. The Customer must follow up by phoning the SC.

Demand Opportunity Service (DOS), according to the terms herein, will be available only after the System Controller approves this DOS Request.

Identification

______________________________________ requests Opportunity Service (subject to confirmation of

Customer or Customer's Agent

available capacity) in accordance with the Pre-qualification granted by the Alberta Electric System Operator, identified by Pre-qualification Number shown above, at ____

Description of the Point of Delivery

Terms of Transaction

The requested service is (indicate one): _____ DOS Term, _____ DOS 7 Minutes, _____ DOS 1 Hour

The transaction is to begin on: _____________ at ____:_______

Start Date **Start time ***

The transaction will be completed on: _____________ at ____:_______

End Date **End time ***

A DOS Transaction must start and end at the top of an hour, and cannot start within 60 minutes of the time the DOS Request is faxed.

The minimum Term is 8 hours; End Date must occur in the same calendar month as the Start Date.

The requested Capacity is _____________ MW (cannot exceed the prequalified DOS capacity)

Applicant's Endorsement

Submitted by: __________________________________ on ___________________ at ______________________

Customer's Representative (please print) date time

Signature: ___________________________________Phone: ____________________ Fax: ________ _______________

Customer's Representative

Approval/Denial by the System Controller

Submitted by: ___________________________________ on ____________________at _____________________

System Controller's Representative (please print) date time

Signature: ___________________________________

System Controller's Representative

Approved: ☐ Denied: ☐ If denied, see System Controller Record of Transaction for comments.

AESO Record ID: _________________

Construction Commitment Agreement

THIS AGREEMENT made as of the ___ day of ____________, 200__ (the "Effective Date")

BETWEEN:

INDEPENDENT SYSTEM OPERATOR, operating as AESO,
a body corporate with offices in the City of Calgary, in the Province of Alberta ("AESO")

-and-

●
a corporation incorporated under the
laws of the Province of ● (hereinafter referred to as the "**Customer**")

WHEREAS:

A. The Customer has requested system access service from the Alberta Electric System Operator (the "**AESO**") and intends to enter into, or amend, a system access service agreement with the AESO in relation to the Customer's capacity requirements for the **[Project]**. This providing or amending of system access service will require the construction of new transmission facilities and a commitment by the Customer in relation to the expenditure of capital for such construction (the "**Proposed Project**").

B. The AESO's Tariff requires the Customer to provide security to the AESO to fund estimated cancellation costs of the Proposed Project in an amount determined by the AESO.

C. The AESO and its contractors must be held harmless from any negative financial consequences related to any cancellation of the Proposed Project. Prior to commencing the work set out in Schedule "A" hereto (the "**Project Work**"), the AESO requires that the Customer enter into this Construction Commitment Agreement ("Agreement").

NOW THEREFORE in consideration of the mutual covenants and agreements set forth herein and other good and valuable consideration, the receipt and sufficiency of which is hereby acknowledged by each of the parties, the parties hereby agree as follows:

Defined Terms

1. Capitalized terms utilized in the Agreement shall have the meanings ascribed to such terms in the preamble or body of this Agreement, and in addition the following defined terms shall have the meanings ascribed to such terms below:

“**Act**” means the *Electric Utilities Act*, S.A. 2003, c. E-5.1;

“**AESO Tariff**” means the tariff of the AESO approved by the Board;

“**Commission**” means the Alberta Utilities Commission established by the *Alberta Utilities Commission Act*;

“**Cancellation Costs**” means all the aggregate amount of costs and expenses, as well as any losses, damages, penalties or other claims the AESO or its contractors may incur or be subject to howsoever arising from the Proposed Project, and which are incurred by the AESO or its contractors relating to facilities planning and design, the competitive procurement process (if any), material and right-of-way procurements and construction of the Proposed Project (including without limitation all cancellation penalties and salvage and reclamation costs).;

“Material Adverse Change” means:

(a) a downgrade in the credit rating of the Customer or a guarantor of the Customer (“Guarantor”) by any credit rating agency; or

(b) any event, circumstance or change which results, or would reasonably be expected to result, in a material adverse change in:

i. the financial condition of the Customer or a Guarantor;

ii. the ability of the Customer or a Guarantor to perform its obligations under any Security; or

iii. the assets or business of the Customer or a Guarantor.

Term of Agreement

2. This Agreement shall take effect on the Effective Date and shall remain in full force and effect until the Proposed Project is energized and in-service, or, if upon the occurrence of a Cancellation Event (as hereafter defined) the Proposed Project is deemed cancelled and all amounts owing to the AESO hereunder have been paid in full.

AESO Tariff

3. In addition to the obligations of the Customer pursuant to this Agreement, the Customer shall remain fully subject to the AESO's Tariff in respect of the Proposed Project.

Security

4. As security for the payment and performance of all present and future debts, liabilities and obligations of the Customer to the AESO, arising pursuant to this Agreement or the Security (as hereinafter defined), the Customer agrees to provide or cause to be provided to the AESO the guarantee(s), security and other documents set forth and described in Schedule "B" attached hereto (the "**Security**"), which security shall be in an amount adequate to fund the maximum of the estimated cost of the Project Work as determined by the AESO. If the AESO determines at any time that the existing Security is inadequate to fund the maximum of the estimated cost of the Project Work, the AESO shall have the right to require the Customer or any Guarantor to provide such additional guarantee(s), security or other documents as the AESO deems necessary (which shall form part of the Security hereunder), up to the maximum of the estimated cost of the Project Work.

5. If all or part of the obligations of the Customer to the AESO pursuant hereto are unsecured, and the Customer becomes aware of any Material Adverse Change, the Customer shall provide written notice thereof to the AESO within two (2) business day of the occurrence of such Material Adverse Change. Upon the occurrence of a Material Adverse Change, the AESO shall have the right to require the Customer or any Guarantor to provide such additional guarantee(s), security or other documents as the AESO deems necessary (which shall form part of the Security hereunder), up to the maximum of the estimated cost of the Project Work as determined by the AESO.

6. In no event shall the AESO be required to proceed with or cause any Project Work to be undertaken without first receiving the Security, or such additional guarantee(s), security or other documents as the AESO deems necessary contemplated in paragraph 4 or 5, in form and substance satisfactory to the AESO.

Cancellation of Proposed Project

7. The Proposed Project shall be deemed to be cancelled upon the occurrence of any of the following events (each, a "**Cancellation Event**"):

   (a) the Customer fails to provide or cause to be provided the Security in the form set out in Schedule "B" concurrently with the execution and delivery of this Agreement, or fails to provide or cause to be provided such additional guarantee(s), security or other documents as it may be required to deliver to the AESO pursuant to the terms and conditions hereof;

(b) the Customer terminates the Proposed Project, gives notice to the AESO, or the AESO otherwise becomes aware, that the Customer is not proceeding with the Proposed Project, or the Customer otherwise takes such action or inaction to cause the AESO, acting reasonably, to believe that the Customer is not proceeding with the Proposed Project;

(c) the Board rejects or fails to approve the relevant application for the Proposed Project;

(d) the Customer fails to:

i. execute a system access service agreement (in the AESO's standard form); or

ii. enter into an amendment of its existing system access service agreement with respect to the Proposed Project (in AESO's standard form),

within 30 days after the completion of the Proposed Project;

(e) the Customer or any Guarantor breaches any term, condition, proviso, agreement or covenant under this Agreement or the Security and fails to remedy such breach within five (5) days of receipt of written notice of such breach by the AESO to the Customer;

(f) any representation or warranty made or given by the Customer in connection with this Agreement is shown to be incorrect as at the date given or ceases to be true and correct during the term of this Agreement;

(g) the Customer or any Guarantor is found to be insolvent or bankrupt by a court of competent jurisdiction or makes an authorized assignment of its assets or a compromise or arrangement for the benefit of its creditors, makes a proposal to its creditors under the *Bankruptcy and Insolvency Act* (Canada), seeks relief under the *Companies' Creditors Arrangement Act* (Canada), the *Winding Up Act* (Canada) or any other bankruptcy, insolvency or analogous law in Canada or the United States, files a petition or proposal to take advantage of any act of insolvency, consents to or acquiesces in the appointment of a trustee, receiver, receiver and manager, interim receiver, custodian or other person with similar powers over all or any substantial portion of its assets, files a petition or otherwise commences any proceeding seeking any reorganization, arrangement, composition or readjustment under any applicable bankruptcy, insolvency, moratorium, reorganization or other similar law affecting creditor's rights or consents to, or acquiesces in, the filing of such a petition; or if a petition in bankruptcy is filed or presented against the Customer or any guarantor;

(h) there is instituted by or against the Customer or any Guarantor any formal or informal proceeding for the dissolution or liquidation of, settlement of claims against, or winding up of the affairs of, the Customer or any Guarantor, or a resolution is passed for dissolution, liquidation or winding up the Customer or any Guarantor;

(i) the Customer or any Guarantor ceases or threatens to cease to carry on business or makes or agrees to make a bulk sale of assets or commits or threatens to commit an act of bankruptcy;

(j) a receiver, receiver and manager or receiver-manager of all or any part of the property, assets or undertaking of the Customer or any Guarantor is appointed;

(k) the Customer creates or permits to exist any charge, security interest, lien, encumbrance or claim against any of the collateral charged under the Security which ranks or could in any event rank in priority to or *pari passu* with the Security; or

(l) the holder of any charge, security interest, lien, encumbrance or claim against any of the collateral charged under the Security does anything to enforce or realize on such charge, security interest, lien, encumbrance or claim.

8. Upon the occurrence of a Cancellation Event, the Proposed Project shall be immediately deemed to have been cancelled, and the AESO or its agent, contractor or delegate may, without limiting or restricting other rights or remedies under contract, at law or in equity, do any one or more of the following:

(a) refuse to continue to perform any Project Work;

(b) demand immediate payment of all Cancellation Costs;

(c) demand immediate payment under any guarantee granted to the AESO;

(d) exercise its rights under all or any part of the Security, and any other security in respect of the Proposed Project provided to the AESO by the Customer under separate construction commitment agreements; and

(e) commence such legal actions or proceedings against the Customer or the Guarantor as it determines.

9. The Customer shall forthwith, upon demand having been made therefore by the AESO, pay the Cancellation Costs to the AESO. If the Customer fails to pay to the AESO the Cancellation Costs upon demand, the AESO shall be entitled to charge the Customer interest calculated at the Toronto Dominion Canadian prime rate plus 6% on all amounts due from the date of demand to the date of payment to the AESO.

10. In the event that the Customer terminates the Proposed Project prior to its completion, the AESO shall use, and shall cause its contractors to use, reasonable commercial

efforts to minimize the amount of the Cancellation Costs to the extent such is within their control.

Representations and Warranties

11. The Customer represents and warrants to the AESO as follows:

(a) the Customer is a duly incorporated or organized, validly existing and in good standing under the laws of its jurisdiction of incorporation or organization;

(b) the Security is provided to the AESO free and clear of any and all security interests, mortgages, liens, charges, and encumbrance of any nature;

(c) this Agreement has been duly authorized, executed and delivered by the Customer and constitutes a legal, valid and binding obligation of the Customer, enforceable against it in accordance with its terms, except to the extent that such enforceability may be limited by bankruptcy, insolvency, winding-up, reorganization, and similar laws affecting the enforceability of creditors' rights generally and the availability of equitable remedies such as specific performance or injunction; and

(d) the authorization, execution and performance by the Customer of this Agreement:

i. does not and will not violate any laws applicable to the Customer; and

ii. is not in contravention of its constating documents or its by-laws or the provisions of any loan agreement or other agreement to which it is a party or by which it is bound.

General

12. The Customer will pay for the AESO's legal fees (on a solicitor and his own client basis) and other costs, charges and expenses in respect of the enforcement of this Agreement and the Security by the AESO.

13. In this Agreement:

(a) any notice or communication required or permitted to be given under this Agreement will be in writing and will be considered to have been given if delivered by hand or courier, or transmitted by facsimile transmission address or facsimile transmission number of each party set out below:

if to the AESO:

Alberta Electric System Operator
2500, 330 – 5th Ave SW
Calgary, Alberta T2P 0L4
Attention: [ ]
Fax No: [ ]

if to the Customer:
•

Attention:
Fax No: •

or to such other address or facsimile transmission number as any party may designate in the manner set out above; and

(b) notice or communication will be considered to have been received if delivered by hand or courier during business hours on a business day, upon receipt by a responsible representative of the receiver, and if not delivered during business hours, upon the commencement of business on the next business day, and if sent by facsimile transmission during business hours on a business day, upon the sender receiving confirmation of the transmission, and if not transmitted during business hours, upon the commencement of business on the next business day.

14. This Agreement may not be assigned by the Customer without the prior written consent of the AESO.

15. This Agreement will enure to the benefit of and be binding upon the parties hereto and their respective successors and permitted assigns.

16. No failure or delay on the AESO's part in exercising any power or right hereunder will operate as a waiver thereof.

17. The AESO's rights and remedies hereunder are cumulative and not exclusive of any rights or remedies at law or in equity.

18. Time is of the essence of this Agreement and all documents or instruments delivered hereunder.

19. If at any time any one or more of the provisions hereof is or becomes invalid, illegal or unenforceable in any respect under any law, the validity, legality and enforceability of the remaining provisions hereof will not in any way be affected or impaired thereby to the fullest extent possible by law.

20. This Agreement will be governed by and interpreted in accordance with the laws of the Province of Alberta and the laws of Canada applicable therein. The Customer and the AESO submit to the nonexclusive jurisdiction of the Courts of the Province of Alberta and agree to be bound by any suit, action or proceeding commenced in such Courts and by any order or judgment resulting from such suit, action or proceeding, but the foregoing will in no way limit the right of the AESO to commence suits, actions or proceedings based on this Agreement in any jurisdiction it may deem appropriate.

21. This Agreement may be varied or amended only by or pursuant to an agreement in writing signed by the parties hereto.

22. All Schedules attached hereto will be deemed fully a part of this Agreement.

23. This Agreement may be signed in one or more counterparts, originally or by facsimile, each such counterpart taken together will form one and the same agreement.

THE AESO AND THE CUSTOMER have executed this Agreement as of the Effective Date:

INDEPENDENT SYSTEM OPERATOR, operating as AESO

Per: ______________________________

Per: ______________________________

(INSERT CUSTOMER'S NAME)

Per: ______________________________

Per: ______________________________

SCHEDULE "A"

To the Construction Commitment Agreement

between

INDEPENDENT SYSTEM OPERATOR, operating as AESO

and

[CUSTOMER]

dated

[DATE]

PROJECT WORK

SCHEDULE "B"

To the Construction Commitment Agreement

between

INDEPENDENT SYSTEM OPERATOR, operating as AESO and

[CUSTOMER]

dated

[DATE]

SECURITY

APPENDIX C
PROCEDURE FOR FORESEEABLE TMR SERVICE

1. This Schedule shall come into force upon the approval of the Settlement Agreement by the Board and remain in force until replaced or revised through the creation of an AESO Rule following reasonable efforts by all Parties hereto to develop same.

2. The AESO shall issue an EOI inviting eligible Customers to express interest in contracting with the AESO for the supply of TMR Service, where an Existing Contract is not in effect. (Reference #1 in below diagram)

3. Based on Customer response to the EOI, the AESO shall fairly and reasonably determine if the EOI is Contestable (Reference #2 in below diagram). The advice and direction of the Market Surveillance Administrator will be sought in all such matters and, should the subsequent determination be disputed the issue of whether the EOI is Contestable may be determined by the Board. (Reference #4 in below diagram)

4. Upon determination by the AESO that the EOI is Contestable a RFP shall be issued by the AESO (Reference #3 in below diagram). The AESO shall fairly and reasonably determine if the RFP is Contestable, again after seeking the advice and direction of the MSA. (Reference #5 in below diagram)

5. If either of the EOI or RFP is deemed by the AESO not to be Contestable the AESO shall issue written reasons in that regard and a Bilateral Negotiation Process shall commence. The Bilateral Negotiation Process:

   (a) shall be subject to the Maximum TMR Price specified by Article 11.7 of the AESO Tariff,

   (b) may include all Customers who are effective providers of the required TMR service, although preference will be given to those who responded to the EOI/RFP, and

   (c) shall not be limited by the pricing provisions of Article 11.6 of the AESO Tariff in respect of Unforeseeable TMR service.

   (Reference #6 in below diagram)

6. Any party to the Bilateral Negotiation Process may declare it unsuccessful after 30 days, at which time a Binding Arbitration Process shall commence between the AESO and the Customer (Reference #7 in below diagram). In circumstances where multiple Customers may provide TMR Services to the AESO, the AESO shall act fairly and reasonably in its selection as to the party that is subject to Binding Arbitration. The Binding Arbitration Process shall:

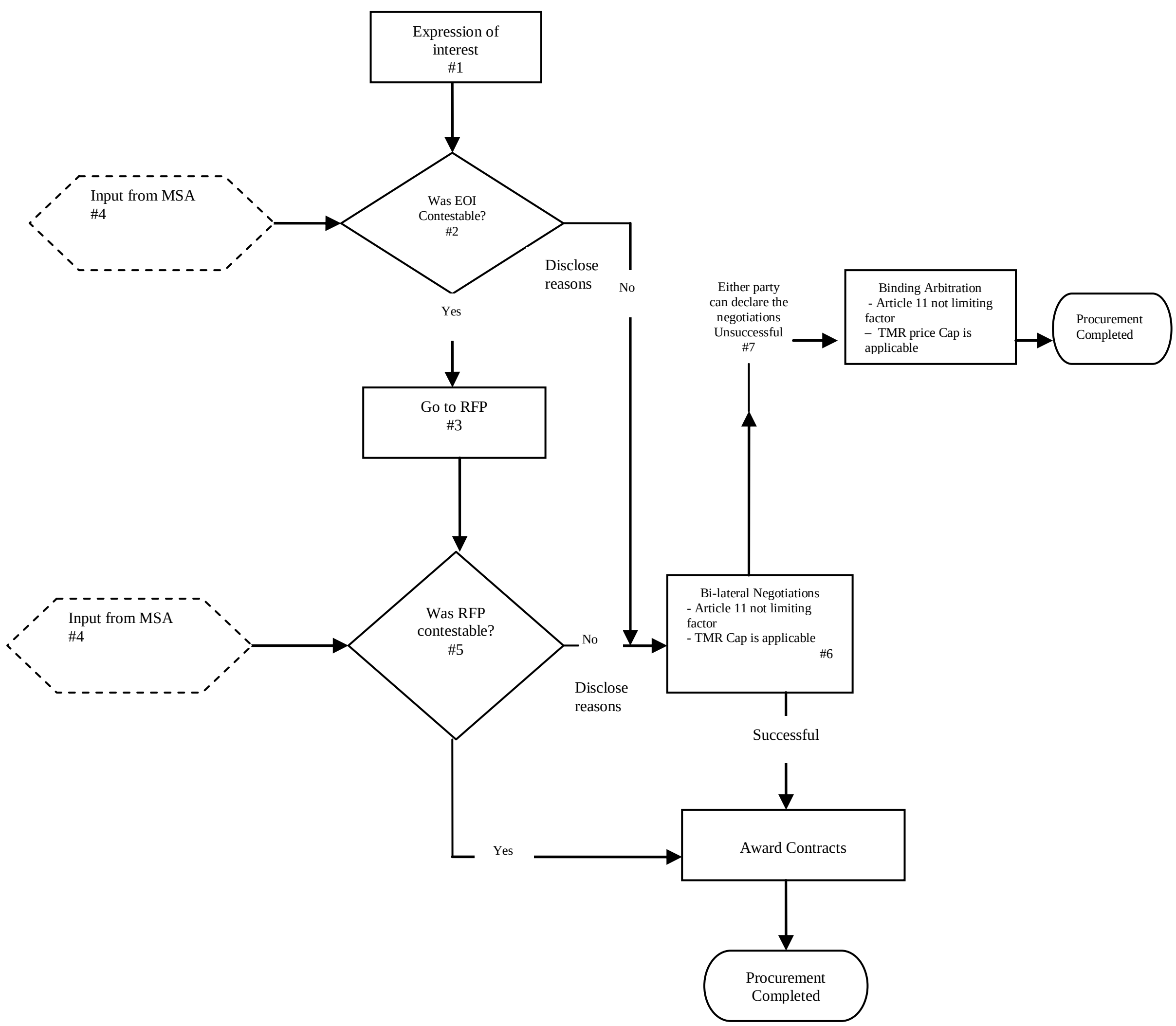
(d) be subject to the Maximum TMR Price specified by Article 11.7 of the AESO Tariff, and

(e) not be limited by the pricing provisions of Article 11.6 of the AESO Tariff in respect of Unforeseeable TMR Service.

(Reference #8 in below diagram)

7. The Binding Arbitration Process shall employ the Dispute Resolution Process established under Article 19 of the AESO Tariff and proceed directly to Arbitration as per Article 19.3 of the AESO Tariff. Any arbitrator appointed pursuant to that Dispute Resolution Process shall have an expert understanding and knowledge of the Alberta electricity marketplace. (Reference #8 in below diagram)

PROCEDURE FOR FORESEEABLE TMR SERVICE DIAGRAM



2009 RATES

Code	Description
Rate Schedules	
DTS	Demand Transmission Service
FTS	Fort Nelson Demand Transmission Service
DOS 7 Minutes	Demand Opportunity Service (7 Minutes)
DOS 1 Hour	Demand Opportunity Service (1 Hour)
DOS Term	Demand Opportunity Service (Term)
XOS 1 Hour	Export Opportunity Service (1 Hour)
XOS 1 Month	Export Opportunity Service (1 Month)
UFLS	Demand Under-Frequency Load Shedding Credits
PSC	Primary Service Credit
STS	Supply Transmission Service
IOS	Import Opportunity Service
Rate Riders	
A1	Dow Chemical Transmission Duplication Avoidance Adjustment
A2	NOVA Chemicals Transmission Duplication Avoidance Adjustment
A3	Shell Scotford Transmission Duplication Avoidance Adjustment
A4	Imperial Oil Resources Limited Transmission Duplication Avoidance Adjustment
B	Working Capital Deficiency/Surplus Rider
C	Deferral Account Adjustment Rider
E	Losses Calibration Factor Rider
F	Balancing Pool Consumer Allocation Rider
G	Bill Impact Mitigation Rider
H	Interim Refundable Fort Nelson Rider

Rate Appendix
Regulated Generating Units

Terms and Conditions of Service

DTS **Demand Transmission Service** Page 1 of 2

Applicable to: Demand Customers.

Rate: Charges for DTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge, the Voltage Control Charge, and the Other System Support Services Charge, where:

The **Interconnection Charge** equals:

(1) a **Bulk System Charge** of
- **$1,946.00/MW/month** of Coincident Metered Demand in the Billing Period, plus
- **$0.66/MWh** of Metered Energy during the Billing Period;

Plus

(2) a **Local System Charge** of
- **$577.00/MW/month** of Billing Capacity in the Billing Period, plus
- **$0.28/MWh** of Metered Energy during the Billing Period;

Plus

(3) a **Point of Delivery Charge** of

(a) **$3,291.00/MW/month** for the first (7.5 multiplied by the Substation Fraction) MW of Billing Capacity in the Billing Period, plus

(b) **$1,138.00/MW/month** for the next (9.5 multiplied by the Substation Fraction) MW of Billing Capacity in the Billing Period, plus

(c) **$667.00/MW/month** for the next (23 multiplied by the Substation Fraction) MW of Billing Capacity in the Billing Period, plus

(d) **$353.00/MW/month** for all remaining MW of Billing Capacity in the Billing Period, plus

(e) **$5,849.00/month** multiplied by the Substation Fraction in the Billing Period.

Coincident Metered Demand is the Metered Demand at the Point of Delivery averaged over the fifteen (15) minute interval in which the sum of the Metered Demands for all DTS Customers is greatest in each Billing Period.

DTS **Demand Transmission Service** Page 2 of 2

Billing Capacity shall be the highest of:
(i) the highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) 90% of the highest Metered Demand in the 24-month period including and ending with the Billing Period; or
(iii) 90% of the Contract Capacity.

The **Operating Reserve Charge** equals:
- Metered Energy in each hour × **3.33%** × **Pool Price**.

The **Voltage Control Charge** equals:
- **$0.93/MWh** of Metered Energy during the Billing Period.

The **Other System Support Services Charge** equals:
- **$77.00/MW/month** of highest Metered Demand in the Billing Period, plus
- **$400.00/MVA** of Apparent Power Difference when Power Factor is less than 90% during the interval of highest Metered Demand in the Billing Period,

where "Apparent Power Difference" is calculated during the interval of highest Metered Demand in the Billing Period as the difference between the metered Apparent Power and 111% of the Metered Demand.

Terms:

(a) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.

(b) The DTS rate is separately applicable at each POD.

(c) When invoked by the AESO, Rate Riders B and C apply to customers under this Rate Schedule.

(d) When invoked by the AESO, Rate Rider F applies to customers under this Rate Schedule with the exception of the City of Medicine Hat.

(e) The Terms and Conditions form part of this Rate Schedule.

FTS **Fort Nelson Demand Transmission Service** Page 1 of 2

Applicable to: BC Hydro for demand service to Fort Nelson, British Columbia.

Rate: Charges for FTS in any one Billing Period shall be the sum of the Interconnection Charge, the Operating Reserve Charge, the Voltage Control Charge, and the Other System Support Services Charge, where:

The **Interconnection Charge** equals:

(1) a **Bulk System Charge** of
- **$1,946.00/MW/month** of Coincident Metered Demand in the Billing Period, plus
- **$0.66/MWh** of Metered Energy during the Billing Period;

Plus

(2) a **Local System Charge** of
- **$1,531.00/MW/month** of Billing Capacity in the Billing Period, plus
- **$0.72/MWh** of Metered Energy during the Billing Period.

Coincident Metered Demand is the Metered Demand at the Point of Delivery averaged over the fifteen (15) minute interval in which the sum of the Metered Demands for all DTS Customers is greatest in each Billing Period.

Billing Capacity shall be the highest of:
(i) the highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) 90% of the highest Metered Demand in the 24-month period including and ending with the Billing Period; or
(iii) 90% of the Contract Capacity.

The **Operating Reserve Charge** equals:
- Metered Energy in each hour × **3.33%** × **Pool Price**.

The **Voltage Control Charge** equals:
- **$0.93/MWh** of Metered Energy during the Billing Period.

The **Other System Support Services Charge** equals:
- **$77.00/MW/month** of highest Metered Demand in the Billing Period, plus
- **$400.00/MVA** of Apparent Power Difference when Power Factor is less than 90% during the interval of highest Metered Demand in the Billing Period,

where "Apparent Power Difference" is calculated during the interval of highest Metered Demand in the Billing Period as the difference between the metered Apparent Power and 111% of the Metered Demand.

Terms:

(a) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.

(b) The FTS rate is separately applicable at each POD.

(c) When invoked by the AESO, Rate Riders B and C apply to customers under this Rate Schedule.

(d) The Terms and Conditions form part of this Rate Schedule.

DOS 7 Minutes **Demand Opportunity Service (7 Minutes)** Page 1 of 2

Applicable to: Qualified Opportunity Service Customers who are recallable within seven (7) minutes.

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement for Demand Opportunity Service (DOS).

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

(a) (i) **$3.23/MWh** of Metered Energy during the Billing Period; plus
(ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:
- Metered Energy in hour × location specific loss factor × Pool Price for the hour,

where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

(b) A minimum charge equal to:
- Opportunity Capacity under this Rate Schedule × number of hours in total transactions in the Billing Period × 75% × **$3.23/MWh**.

Plus

(2) Transaction Fee: **$500.00** per Billing Period.

Terms: (a) The rate is separately applicable at each POD.

(b) A Customer's pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The term for a System Access Service Agreement for Demand Opportunity Service will be:
(i) no less than a continuous eight hours from 0:00 hr midnight to 24:00 hr, or such other minimum term as the AESO may, at its discretion set; and
(ii) no greater than one (1) calendar month.

DOS 7 Minutes **Demand Opportunity Service (7 Minutes)** Page 2 of 2

(c) To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.

(d) In the event that a Customer's service is recalled, the Customer shall be required to curtail load by the amount directed by the System Controller, which can be an amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within seven (7) minutes of receiving a directive from the System Controller.

(e) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.

(f) When invoked by the AESO, Rate Rider E applies to customers under this Rate Schedule. When invoked by the AESO, Rate Rider F applies to customers under this Rate Schedule with the exceptions of the City of Medicine Hat and BC Hydro at Fort Nelson.

(g) The Terms and Conditions form part of this Rate Schedule.

DOS 1 Hour **Demand Opportunity Service (1 Hour)** Page 1 of 2

Applicable to: Qualified Opportunity Service Customers who are recallable within one (1) hour.

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement for Demand Opportunity Service (DOS).

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

(a) (i) **$5.36/MWh** of Metered Energy during the Billing Period; plus
(ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:
- Metered Energy in hour × location specific loss factor × Pool Price for the hour,

where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

(b) A minimum charge equal to:
- Opportunity Capacity under this Rate Schedule × number of hours in total transactions in the Billing Period × 75% × **$5.36/MWh**.

Plus

(2) Transaction Fee: **$500.00** per Billing Period.

Terms: (a) The rate is separately applicable at each POD.

(b) A Customer's pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The term for a System Access Service Agreement for Demand Opportunity Service will be:
(i) no less than a continuous eight hours from 0:00 hr midnight to 24:00 hr, or such other minimum term as the AESO may, at its discretion set; and
(ii) no greater than one (1) calendar month.

DOS 1 Hour **Demand Opportunity Service (1 Hour)**

(c) To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.

(d) In the event that a Customer's service is recalled, the Customer shall be required to curtail load by the amount directed by the System Controller, which can be an amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within one (1) hour of receiving a directive from the System Controller.

(e) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.

(f) When invoked by the AESO, Rate Rider E applies to customers under this Rate Schedule. When invoked by the AESO, Rate Rider F applies to customers under this Rate Schedule with the exceptions of the City of Medicine Hat and BC Hydro at Fort Nelson.

(g) The Terms and Conditions form part of this Rate Schedule.

DOS Term	**Demand Opportunity Service (Term)**	Page 1 of 2

Applicable to: Qualified Opportunity Service Customers who are recallable within seven (7) minutes.

Available: For quantities of Metered Energy taken within the Opportunity Capacity for the relevant System Access Service Agreement for Demand Opportunity Service, and when sufficient transmission capacity exists to accommodate such quantity. This service will be available a minimum of one (1) hour for Customers deemed eligible in the pre-qualification process, following the execution of a System Access Service Agreement for Demand Opportunity Service (DOS).

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

(a) (i) **$21.40/MWh** of Metered Energy during the Billing Period; plus
(ii) Incremental Losses Charge, calculated as the sum over each transaction hour of the Billing Period of the following:
- Metered Energy in hour × location specific loss factor × Pool Price for the hour,

where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

(b) A minimum charge equal to:
- Opportunity Capacity under this Rate Schedule × number of hours in total transactions in the Billing Period × 75% × **$21.40/MWh**.

Plus

(2) Transaction Fee: **$500.00** per Billing Period.

Terms: (a) The rate is separately applicable at each POD.

(b) A Customer's pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The term for a System Access Service Agreement for Demand Opportunity Service will be:
(i) no less than a continuous eight hours from 0:00 hr midnight to 24:00 hr, or such other minimum term as the AESO may, at its discretion set; and
(ii) no greater than one (1) calendar month.

(c) To the extent practicable, service for Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service for Non-Recallable Customers in an Emergency.

(d) In the event that a Customer's service is recalled, the Customer shall be required to curtail load by the amount directed by the System Controller, which can be an amount up to the Opportunity Capacity, subject to no requirement on the Customer to curtail to below the DTS Contract Capacity. Curtailment of such amount shall be achieved within seven (7) minutes of receiving a directive from the System Controller.

(e) References to Metered Energy in this Rate Schedule shall mean the amount of Metered Energy attributable to service under this Rate Schedule, which shall be determined in accordance with Article 10.4 of the Terms and Conditions.

(f) When invoked by the AESO, Rate Rider E applies to customers under this Rate Schedule. When invoked by the AESO, Rate Rider F applies to customers under this Rate Schedule with the exceptions of the City of Medicine Hat and BC Hydro at Fort Nelson.

(g) The Terms and Conditions form part of this Rate Schedule.

XOS 1 Hour **Export Opportunity Service (1 Hour)** Page 1 of 2

Applicable to: Customers exporting electric energy from the AIES.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

(a) (i) **$2.03/MWh** of Energy Transfer during the Billing Period; plus
(ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:
- Energy Transfer in hour × location specific loss factor × Pool Price for the hour,

where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

(b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity schedule is the hour-ahead scheduled amount for the transaction):
- 75% × capacity scheduled for Customer for the transaction × hours in the transaction × (**$2.03/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

Plus

(2) An Operating Reserve charge or other System Support Service charge when, in the opinion of the AESO, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

(3) Transaction Fee: **$500.00** per Billing Period.

Terms: (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour’s notice. To the extent practical, service for Export Opportunity Service Customers taking service under this Rate Schedule shall be recallable in advance of service provided under Rate XOS 1 Month in an Emergency.

(b) Rate XOS 1 Hour is separately applicable at each Point of Exchange.

XOS 1 Hour **Export Opportunity Service (1 Hour)**

(c) The minimum term for Rate XOS 1 Hour is one (1) hour. The maximum term is one (1) calendar month.

(d) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.

(e) The Terms and Conditions form part of this Rate Schedule.

XOS 1 Month **Export Opportunity Service (1 Month)**

Applicable to: Customers exporting electric energy from the AIES.

Available: Export Opportunity Service (1 Month) is available:

- after an Open Access Same-time Information System (OASIS) or similar system has been implemented by the AESO, and
- in hours when sufficient transmission capacity exists to accommodate the capacity scheduled for service.

This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Export Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The greater of (a) and (b) below:

(a) (i) **\$2.40/MWh** of Energy Transfer during the Billing Period; plus
(ii) Incremental Losses Charge, calculated as the sum over all transaction hours in the Billing Period of the following:

- Energy Transfer in hour × location specific loss factor × Pool Price for the hour,

where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

(b) A minimum charge calculated as the sum over all transactions in the Billing Period of the following (where capacity schedule is the hour-ahead scheduled amount for the transaction):

- 75% × capacity scheduled for Customer for the transaction × hours in the transaction × (**\$2.40/MWh** + Incremental Losses Charge / Energy Transfer in the Billing Period).

Plus

(2) An Operating Reserve charge or other System Support Service charge when, in the opinion of the AESO, the transaction requires the procurement of incremental System Support Services and/or Operating Reserve.

Plus

(3) Transaction Fee: **\$500.00** per Billing Period.

Terms: (a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour’s notice.

(b) Rate XOS 1 Month is separately applicable at each Point of Exchange.

(c) The minimum term for Rate XOS 1 Month is one (1) calendar month. The maximum term is one (1) calendar year.

(d) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.

(e) The Terms and Conditions form part of this Rate Schedule.

UFLS **Demand Under-Frequency Load Shedding Credit** Page 1 of 1

Purpose: The under-frequency load shedding credits compensate those Demand Customers who are connected to under-frequency load shedding devices and therefore face a higher risk of outage. In order to maintain the integrity of the AIES, the AESO shall have the right to require each Demand Customer to maintain a minimum of 50% of that Customer's aggregate load (across all PODs through which the Customer takes System Access Service) connected to an under-frequency load shedding device.

Available to: Customers served under the DTS Rate Schedule who, as directed by the AESO, install and activate an under-frequency load shed relay satisfactory to the AESO.

Rate: The credit is based on the relay setting and UFLS Capacity for each relay setting. The AESO provides no assurance as to the number or duration of any future outages.

UFLS Capacity shall be the share of the DTS Contract Capacity (expressed in MW) for each setting for which the Customer has agreed to be shed. The AESO from time to time may revise a Customer's total UFLS obligation to maintain the minimum of 50% of that Customer's aggregate load. The Customer must ensure the aggregate UFLS Capacity across all PODs through which the Customer takes System Access Service continues to meet the revised total UFLS obligation.

Relay Trip Setting	Credit ($/MW of UFLS Capacity/month)
59.1 Hz	$65.00
58.9 Hz	$60.00
58.7 Hz	$55.00
58.5 Hz	$50.00
58.3 Hz	$45.00
58.1 Hz	$40.00
58.0 Hz	$35.00

Terms: The Terms and Conditions form part of this Rate Schedule.

PSC	**Primary Service Credit**	Page 1 of 1

Purpose: The Primary Service Credit compensates customers whose interconnection does not include conventional transformation facilities owned by the TFO (including interconnections for customers who have purchased, own, and operate their transformers). The Primary Service Credit is provided in conjunction with a reduced maximum Local Investment in accordance with the Terms and Conditions of Service.

Available to: DTS Customers supplied under suitable long term contract who:

- have purchased, own, and operate their own transformation facilities to step the voltage down from transmission voltage to 25 kV or less, and associated low-voltage facilities; or
- are served through unconventional interconnections such as those using metering transformers.

The Primary Service Credit is not available for service to an isolated community as defined under the *Isolated Generating Units and Customer Choice Regulation*, A.R. 165/2003, as amended from time to time.

Rate: The **Primary Service Credit** is a credit of:

(a) **$1,810.00/MW/month** for the first (7.5 multiplied by the Substation Fraction) MW of Billing Capacity in the Billing Period, plus

(b) **$626.00/MW/month** for the next (9.5 multiplied by the Substation Fraction) MW of Billing Capacity in the Billing Period, plus

(c) **$367.00/MW/month** for the next (23 multiplied by the Substation Fraction) MW of Billing Capacity in the Billing Period, plus

(d) **$353.00/MW/month** for all remaining MW of Billing Capacity in the Billing Period, plus

(e) **$3,217.00/month** multiplied by the Substation Fraction in the Billing Period.

Billing Capacity is as defined in Rate DTS.

Terms: (a) A reduced maximum Local Investment is available to Customers receiving this credit.

(b) The Terms and Conditions form part of this Rate Schedule.

STS **Supply Transmission Service** Page 1 of 1

Applicable to: Customers who supply electrical energy to the AIES from within Alberta.

Rate: Charges for STS in any one Billing Period shall be the Losses Charge, where:

The **Losses Charge** equals:

- Metered Energy in each hour × location specific loss factor × Pool Price

where “location specific loss factor” is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

For the purpose of calculating the Losses Charge under this STS Rate Schedule, Metered Energy shall be measured on a 15-minute interval.

Regulated Generating Unit Connection Costs:
An additional charge of **$304.00/MW** per month for each MW of unit MCR applicable only to Regulated Generating Units, as identified in the Rate Appendix and only to the end of the base life year of the Regulated Generating Units as provided in the Terms and Conditions.

Terms:

(a) The STS rate is separately applicable at each POS.

(b) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.

(c) The Terms and Conditions form part of this Rate Schedule.

IOS	**Import Opportunity Service**	Page 1 of 1

Applicable to: Customers importing electric energy into the AIES.

Available: When sufficient transmission capacity exists to accommodate the capacity scheduled for service. This service shall be available a minimum of twenty-four (24) hours following execution of a System Access Service Agreement for Import Opportunity Service.

Rate: The charges for service per Billing Period shall be as follows:

(1) The **Losses Charge** equals:
- Energy Transfer in each hour × location specific loss factor × Pool Price

where "location specific loss factor" is defined in the ISO Rules and determined in accordance with ISO Rule 9.2.

For the purpose of calculating the Losses Charge under this IOS Rate Schedule, Energy Transfer shall be measured on a 15-minute interval.

Plus

(2) Transaction Fee: **$500.00** per Billing Period.

Terms:

(a) System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice.

(b) The rate is separately applicable at each Point of Exchange.

(c) When invoked by the AESO, Rate Rider E applies to customers under this rate schedule.

(d) The Terms and Conditions form part of this Rate Schedule.

Rider A1	**Transmission Duplication Avoidance Adjustment** **Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2**	Page 1 of 2

Applicable to: TransAlta Utilities Corporation / FortisAlberta

Available: At certain Points of Delivery associated with Dow's facility, as more particularly described in Board Decision U98125 (Grid Company of Alberta Inc. — Transmission Avoidance Rate — Dow Transmission Bypass).

Rate: Adjustment to otherwise applicable rates to be made in each Billing Period pursuant to the Decision.

Terms: The Terms and Conditions form part of this Rate Rider.

Transmission Duplication Avoidance Adjustment
Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2

Forecast of the benefit to the AESO arising from the customer contributions made by Dow Chemicals Canada Inc. to TransAlta Utilities Corporation.

Year	Forecast Benefit to AESO (Annual)	Forecast Benefit to AESO (Monthly)
1998	$544,093	$45,341
1999	$865,378	$72,115
2000	$836,603	$69,717
2001	$807,828	$67,319
2002	$779,053	$64,921
2003	$750,278	$62,523
2004	$721,503	$60,125
2005	$692,728	$57,727
2006	$663,953	$55,329
2007	$635,178	$52,932
2008	$606,403	$50,534
2009	$577,628	$48,136
2010	$548,853	$45,738
2011	$520,078	$43,340
2012	$491,303	$40,942
2013	$462,528	$38,544
2014	$433,754	$36,146
2015	$404,979	$33,748
2016	$376,204	$31,350
2017	$347,429	$28,952
2018	$318,654	$26,554
2019	$289,879	$24,157
2020	$261,104	$21,759
2021	$232,329	$19,361

Rider A2 **Transmission Duplication Avoidance Adjustment** Page 1 of 5
NOVA Chemicals Corporation — Joffre Industrial System

Applicable to: NOVA Chemicals Corporation (NOVA Chemicals)

Available: To NOVA Chemicals' Joffre Industrial System, as designated by the AEUB Order No. HE 9826, for System Access Service to NOVA Chemicals at the 535S transmission station Point of Demand (POD) and Point of Supply (POS).

Rate: For each metering time interval, the Metered Demand and Metered Energy for the POS and POD at the 535S transmission station will be totalized for the purpose of billing under Rate DTS and Rate STS, as described in the Totalization section below. Charges under Rate DTS and Rate STS will be calculated using the totalized Metered Demand and the totalized Metered Energy. The meters to be totalized are 330 Line-1, 330 Line-2, 298L, 297L, 535ST1, and 535ST2.

NOVA Chemicals will make the following payments to the AESO:

1. Capital Charge:
   A lump-sum payment of $2,375,000 to be made immediately upon implementation of this rate rider;

2. Incremental Losses Charge:
   Commencing on January 1, 2001, Metered Demand and Metered Energy will be adjusted through the metering balance calculation for the 535S transmission station, using the loss factors in the attached Schedule 1. If the Metered Demand in a metering interval is between two levels in Schedule 1, the applicable loss factor will be calculated by interpolating between the loss factors for the two levels of Metered Demand. If the Metered Demand in a metering interval is less than 10 MW, including 0 MW, the incremental loss will be deemed to be 0.14 MW. The meters to be compensated in the metering balancing calculation are on 298L, 297L, 535ST1, and 535ST2.

   For each billing period, commencing on the effective date of this rate rider, a payment equal to the totalized Metered Energy multiplied by the applicable loss factor and multiplied by the Pool Price, calculated on an hourly basis. The applicable loss factor for each hour will be the loss factor in the attached Schedule 1 that corresponds with the totalized Metered Energy for the hour; and

3. Other Expenses Charge:
   For each Billing Period commencing on January 1, 2001, an amount equal to the "Annual Payment" in the attached Schedule 2 for the applicable year, divided by 12.

Terms: All terms in the AESO's 23 June Application for a Duplication Avoidance Tariff for NOVA Chemicals Corporation Joffre Industrial System will be applicable.

Metering and Totalizing: See Application, Section 2.5: Terms for the Duplication Avoidance Tariff; Section 2.5.1: Metering and Totalizing.

If NOVA Chemicals were to build the Duplicate Facilities, the 535S transmission station would be a Point of Supply for metering when the Joffre Site power generation exceeds the load requirements. Likewise, it would be a Point of Demand when the Joffre Site generation does not meet the load requirements. The Duplication Avoidance Tariff will simulate this result by deeming the separate Point of Demand and Point of Supply at the 535S transmission station to be a single Point of Exchange for the purpose of totalizing Metered Demand and Metered Energy in applying the AESO's Rate DTS and Rate STS.

During the Term of the Duplication Avoidance Tariff, the AESO would totalize the metered data at the 535S transmission station for the load of NOVA Chemicals' Existing Facilities and the generation from its Cogeneration Facility. The totalized metered data would also include a debit to NOVA Chemicals to account for the deemed duplicate transformer losses. This would ensure that payments by NOVA Chemicals to the AESO under Rate DTS and Rate STS are equivalent to the costs NOVA Chemicals would have incurred had they built the Duplicate Facilities.

The amount of load of the Existing Facilities included in the totalizing calculation would be limited to the deemed capacity of the duplicate transformer in NOVA Chemicals' Duplicate Facilities design, which is 80 MVA. If the Metered Demand at the 535S transmission station for the Existing Facilities exceed this deemed capacity of 80 MVA, additional costs of upgrading the deemed duplicate transformer would be estimated and invoiced to NOVA Chemicals.

An example of the totalizing calculation follows.

Example of Totalizing:

See Application, Appendix C: Example of Totalizing
The following is an example of the totalizing calculation for Metered Demand and Metered Energy for two different metering time intervals.

	Time Interval 1	Time Interval 2
535S Point of Demand (A)	+65 MW	+130 MW
535S Point of Supply (B) (Co-generation Facility)	–365 MW	0 MW
Totalized Meter Demand and Energy (C)	–300 MW	+130 MW

In Time Interval 1, under the Duplication Avoidance Tariff, NOVA Chemicals' demand requirement is 65 MW at the 535S transmission station. At the same time, NOVA Chemicals' Cogeneration Facility is delivering 365 MW of power to the AIES at the 535S transmission station. If NOVA Chemicals built the Duplicate Facilities, the Metered Energy delivered from the AIES for NOVA Chemicals' load requirement at point A would be zero MW, and the Metered Energy received by the AIES from the generator output at point B would be 300 MW. This energy balance is simulated by the proposed totalizing procedure. Combining the Point of Demand (A) and Point of Supply (B) produces a totalized Metered Demand of –300 MW, where the negative sign signifies a net energy receipt by the AIES.

In Time Interval 2, the Cogeneration Facility is not operating, supplying zero MW of power, and NOVA Chemicals' load remains at 65 MW for the Existing Facilities and 65 MW for the new facilities. The result is a net load of +130 MW for that time interval, where the positive sign signifies a net energy delivery from the AIES.

Schedule 1 — Incremental Loss Factors

Metered Demand of Existing Facilities (MW)	Loss Factor (% of Metered Demand of Existing Facilities)
> 0 ≤ 10	1.41 %
> 10 ≤ 20	0.76 %
> 20 ≤ 30	0.57 %
> 30 ≤ 40	0.49 %
> 40 ≤ 50	0.46 %
> 50 ≤ 60	0.45 %
> 60 ≤ 70	0.45 %
> 70 ≤ 80	0.47 %

Rider A2 **Transmission Duplication Avoidance Adjustment** Page 5 of 5
NOVA Chemicals Corporation — Joffre Industrial System

Schedule 2 — Other Expenses Charge

12 Month Period	Monthly Payment
Jan. 1, 2001 – Dec. 31, 2001	$ 2,142
Jan. 1, 2002 – Dec. 31, 2002	$ 2,107
Jan. 1, 2003 – Dec. 31, 2003	$ 2,179
Jan. 1, 2004 – Dec. 31, 2004	$ 2,152
Jan. 1, 2005 – Dec. 31, 2005	$ 2,234
Jan. 1, 2006 – Dec. 31, 2006	$ 4,013
Jan. 1, 2007 – Dec. 31, 2007	$ 2,162
Jan. 1, 2008 – Dec. 31, 2008	$ 3,283
Jan. 1, 2009 – Dec. 31, 2009	$ 2,204
Jan. 1, 2010 – Dec. 31, 2010	$ 3,219
Jan. 1, 2011 – Dec. 31, 2011	$ 2,131
Jan. 1, 2012 – Dec. 31, 2012	$ 5,305
Jan. 1, 2013 – Dec. 31, 2013	$ 2,185
Jan. 1, 2014 – Dec. 31, 2014	$ 2,141
Jan. 1, 2015 – Dec. 31, 2015	$ 11,723
Jan. 1, 2016 – Dec. 31, 2016	$ 4,343
Jan. 1, 2017 – Dec. 31, 2017	$ 2,151
Jan. 1, 2018 – Dec. 31, 2018	$ 4,745
Jan. 1, 2019 – Dec. 31, 2019	$ 2,211
Jan. 1, 2020 – Dec. 31, 2020	$ 6,835
Jan. 1, 2021 – Dec. 31, 2021	$ 2,264
Jan. 1, 2022 – Dec. 31, 2022	$ 2,225
Jan. 1, 2023 – Dec. 31, 2023	$ 2,172
Jan. 1, 2024 – Dec. 31, 2024	$ 7,790
Jan. 1, 2025 – Dec. 31, 2025	$ 2,417
Jan. 1, 2026 – Dec. 31, 2026	$ 2,184
Jan. 1, 2027 – Dec. 31, 2027	$ 2,300
Jan. 1, 2028 – Dec. 31, 2028	$ 2,256
Jan. 1, 2029 – Dec. 31, 2029	$ 2,197
Jan. 1, 2030 – Dec. 31, 2030	$ 36,105
Jan. 1, 2031 – Dec. 31, 2031	$ 2,273
Jan. 1, 2032 – Dec. 31, 2032	$ 5,154
Jan. 1, 2033 – Dec. 31, 2033	$ 2,340
Jan. 1, 2034 – Dec. 31, 2034	$ 2,291
Jan. 1, 2035 – Dec. 31, 2035	$ 2,440
Jan. 1, 2036 – Dec. 31, 2036	$ 7,595
Jan. 1, 2037 – Dec. 31, 2037	$ 2,310
Jan. 1, 2038 – Dec. 31, 2038	$ 2,239
Jan. 1, 2039 – Dec. 31, 2039	$ 2,386
Jan. 1, 2040 – Dec. 31, 2040	$ 4,518

Rider A3 **Transmission Duplication Avoidance Adjustment** Page 1 of 5
Shell Canada Corporation — Scotford Industrial System

Applicable to: Shell Canada Limited (Shell Canada)

Available: To Shell Canada's Scotford Industrial System, as designated by AEUB Order No. U2000-109 for System Access Service to Shell Canada at the 409S transmission station Point of Delivery (POD) and Point of Supply (POS).

Rate: For each metering time interval, the Metered Demand and Energy for each POS and POD (409ST1, 409ST2, 337S and 746L feeders) around the 409S transmission station will be synchronized, totalized and adjusted to measure electricity at the 138 kV bus for the purpose of billing under the Transmission Tariff. Charges under the Transmission Tariff will be calculated using the totalized Metered Demand and Energy.

Shell Canada will make the following payments to the AESO:

1. Capital Charge:
   A payment of $2,907,800 is due immediately upon implementation of this rate rider.

2. Incremental Losses Charge:
   Commencing on the effective date of this rate rider, Metered Demand and Metered Energy will be adjusted through the metering balancing calculation for the 409S transmission station, using the loss factors in the attached Schedule 1. If the Metered Demand in a metering interval is between two levels in Schedule 1, the applicable loss factor will be calculated by interpolating between the loss factors for the two levels of Metered Demand. If the Metered Demand in a metering interval is less than 10 MW, including 0 MW, the incremental loss will be deemed to be 0.083 MW. The meters to be compensated in the metering balancing calculation are on 409ST1, 409ST2, 337S and 746L.

   For each billing period, commencing on the effective date of this rate rider, a payment equal to the totalized Metered Energy multiplied by the applicable loss factor and multiplied by the Pool Price, calculated on an hourly basis. The applicable loss factor for each hour will be the loss factor in the attached Schedule 1 that corresponds with the totalized Metered Energy for the hour; and

Rider A3	**Transmission Duplication Avoidance Adjustment** **Shell Canada Corporation — Scotford Industrial System**	Page 2 of 5

3. Other Expenses Charge:
   The Other Expenses Charge is shown in the attached Schedule 2.

   Shell Canada will receive a Customer-Owned Transmission Station Credit in respect of the Duplicate Facilities as is provided to other DTS customers of the AESO who provide their own Transmission Station, pending the decision of the Board on the AESO's 2002 tariff application.

Term:

All Terms and Conditions in the AESO's Tariff apply in addition to the terms in this Application for a Duplication Avoidance Tariff for Shell Canada's Scotford Industrial System. If either the AESO or Shell Canada were to terminate the Duplication Avoidance Tariff at a future date, Shell Canada would receive a partial refund of the lump sum Capital Charge payment. The amount of the partial refund would be the deemed remaining undepreciated dollar amount of the avoided Duplicate Facilities, in the year that the AESO or Shell Canada gives notice to terminate the Duplication Avoidance Tariff. The undepreciated dollar value would be calculated based on the lump sum Capital Charge payment using a straight-line depreciation over the first 24 years of the Term of the Duplication Avoidance Tariff. At the end of 24 years, the undepreciated value would be zero. The termination notice period, for both the AESO and Shell Canada, will be 24 months.

Metering and Totalizing

Totalization should proceed on the basis of economic indifference to Shell Canada between the DAT and the construction of Duplicate Facilities and a net positive benefit to other transmission customers. These principles are met by the terms proposed for the Duplication Avoidance Tariff.

There is no direct relationship between the size of 409S (sized for a prior, smaller load-only Scotford site) and the larger scale operations now reflected in the industrial system. The Duplication Avoidance Tariff for 409S is the most advantageous arrangement for the AESO compared to construction of Duplicate Facilities.

If Shell Canada were to build the Duplicate Facilities, the 409S transmission station would be a Point of Supply when the Scotford Site power generation exceeds the load requirements. Likewise, it would be a Point of Delivery when the Scotford Site generation does not meet the load requirements. The Duplication Avoidance Tariff will simulate this result by deeming the separate Point of Delivery and Point of Supply at

Rider A3 **Transmission Duplication Avoidance Adjustment**
Shell Canada Corporation — Scotford Industrial System

the 409S transmission station to be a single Point of Exchange for the purpose of totalizing Metered Demand and Metered Energy.

During the Term of the Duplication Avoidance Tariff, the AESO would totalize the metered data at the 409S transmission station for the load of Shell Canada's Load Facilities and the generation from its Cogeneration Facility. This would ensure that payments by Shell Canada to the AESO under the AESO's Tariff are equivalent to the costs that Shell Canada would have incurred had they built the Duplicate Facilities.

The level of load of the Load Facilities included in the totalization calculation would be limited to the deemed capacity of the Duplicate Facilities in Shell Canada's Duplicate Facilities design. Given that the capacity of the Duplicate Facilities would be identical to that of the 409S transmission station, if the transformer requires upgrading in order to serve additional load from the Load Facilities, Shell Canada will be responsible for the cost of the upgrade.

Example of Totalizing

The following is an example of the totalizing calculation for Metered Demand and Metered Energy for two different metering time intervals.

	Time Interval 1	**Time Interval 2**
409S Point of Demand (A)	+60 MW	+60 MW
409S Point of Supply/ Point of Demand (B)	–70 MW	+20 MW
Totalized Metered Demand and Energy (C)	–10 MW	+80 MW

In Time Interval 1, under the Duplication Avoidance Tariff, Shell Canada's load requirement is 60 MW from the 409S transmission station. At the same time, Shell Canada's Cogeneration Facility is delivering a net supply of 70 MW to the AIES at the 409S transmission station. This is net of load directly served from the Cogeneration Facility downstream of the 409S. If Shell Canada built the Duplicate Facilities, the level of energy delivered from Shell Canada to the AIES would be 10 MW. This energy balance is simulated through the proposed totalizing procedure. Combining the Point of Demand (A) and Point of Supply (B) produces a totalized Metered Demand of –10 MW, where the negative sign signifies a net energy receipt by the AEIS.

In time Interval 2, the load served from Point of Demand (A) remains at 60 MW but there is a reduced supply of energy from the Cogeneration Facility. Due to load requirements directly served from the Cogeneration Facility (net of partial load shedding), energy flows at (B) are reversed, resulting in 20 MW of energy delivered from the AIES to Shell Canada. Thus (B) is also a Point of Demand. If Shell Canada built the Duplicate Facilities, the level of energy delivered from the AIES to Shell Canada at (A) and (B) would be 80 MW. Through the proposed totalizing procedure the totalized Metered Demand would be +80 MW, where the positive sign signifies a net energy delivery from the AEIS to Shell Canada.

Schedule 1 — Incremental Loss Factors

Metered Demand of Load Facilities (MW)	Loss Factor (% of Metered Demand of Load Facilities)
> 0 ≤ 10	0.84%
> 10 ≤ 20	0.46%
> 20 ≤ 30	0.35%
> 30 ≤ 40	0.31%
> 40 ≤ 50	0.30%
> 50 ≤ 60	0.30%
> 60 ≤ 70	0.30%
> 70 ≤ 80	0.32%
> 80 ≤ 90	0.33%
> 90 ≤ 100	0.35%

Rider A3 **Transmission Duplication Avoidance Adjustment** Page 5 of 5
Shell Canada Corporation — Scotford Industrial System

Schedule 2 — Other Expenses Charge

12 Month Period	Monthly Payment
Jan. 1, 2002 – Dec. 31, 2002	$ 1,779
Jan. 1, 2003 – Dec. 31, 2003	$ 1,673
Jan. 1, 2004 – Dec. 31, 2004	$ 1,723
Jan. 1, 2005 – Dec. 31, 2005	$ 1,669
Jan. 1, 2006 – Dec. 31, 2006	$ 1,820
Jan. 1, 2007 – Dec. 31, 2007	$ 3,405
Jan. 1, 2008 – Dec. 31, 2008	$ 1,655
Jan. 1, 2009 – Dec. 31, 2009	$ 4,055
Jan. 1, 2010 – Dec. 31, 2010	$ 1,701
Jan. 1, 2011 – Dec. 31, 2011	$ 4,264
Jan. 1, 2012 – Dec. 31, 2012	$ 1,626
Jan. 1, 2013 – Dec. 31, 2013	$ 4,954
Jan. 1, 2014 – Dec. 31, 2014	$ 1,605
Jan. 1, 2015 – Dec. 31, 2015	$ 1,637
Jan. 1, 2016 – Dec. 31, 2016	$ 16,504
Jan. 1, 2017 – Dec. 31, 2017	$ 5,665
Jan. 1, 2018 – Dec. 31, 2018	$ 1,737
Jan. 1, 2019 – Dec. 31, 2019	$ 4,222
Jan. 1, 2020 – Dec. 31, 2020	$ 1,807
Jan. 1, 2021 – Dec. 31, 2021	$ 15,946
Jan. 1, 2022 – Dec. 31, 2022	$ 1,954
Jan. 1, 2023 – Dec. 31, 2023	$ 1,918
Jan. 1, 2024 – Dec. 31, 2024	$ 1,956
Jan. 1, 2025 – Dec. 31, 2025	$ 9,933
Jan. 1, 2026 – Dec. 31, 2026	$ 2,265
Jan. 1, 2027 – Dec. 31, 2027	$ 2,076
Jan. 1, 2028 – Dec. 31, 2028	$ 2,201
Jan. 1, 2029 – Dec. 31, 2029	$ 2,160
Jan. 1, 2030 – Dec. 31, 2030	$ 2,203
Jan. 1, 2031 – Dec. 31, 2031	$ 59,074
Jan. 1, 2032 – Dec. 31, 2032	$ 2,292
Jan. 1, 2033 – Dec. 31, 2033	$ 7,777
Jan. 1, 2034 – Dec. 31, 2034	$ 2,479
Jan. 1, 2035 – Dec. 31, 2035	$ 2,432
Jan. 1, 2036 – Dec. 31, 2036	$ 2,761

Rider A4 **Transmission Duplication Avoidance Adjustment** Page 1 of 5
Imperial Oil Resources Limited — Cold Lake Industrial System

Applicable to: Imperial Oil Resources Limited (Imperial Oil)

Available: To Imperial Oil's Cold Lake Industrial System, as designated by AEUB Order No. HE 9901 and expanded by U2006-207, plus any expansions to this Industrial System as may be approved by the AUC, for System Access Service to Imperial Oil at the Leming Lake-715S transmission station Point of Demand and Point of Supply and the Mahihkan-837S transmission station Point of Demand.

Rate: For each metering time interval, the Metered Demand and Metered Energy for the POS and PODs, at the 837S and 715S transmission stations, will be totalized for the purpose of billing under Rate DTS and Rate STS, as described in the Metering and Totalizing section.

Imperial Oil shall make the following payments to the AESO:

1. Capital Charge:
   A lump-sum payment of $5,968,800 collected upon implementation of this rate rider;

2. Incremental Losses Charge:
   For each billing period, commencing on the effective date of this rate rider, a payment equal to the totalized Metered Energy multiplied by the applicable loss factor and multiplied by the Pool Price, calculated on an hourly basis. The applicable loss factor for each hour will be the loss factor in the attached Schedule 1 that corresponds with the totalized Metered Energy for the hour; and

3. Other Expenses Charge:
   For each Billing Period, commencing on the effective date of this rate rider, an amount equal to the "Monthly Payment" in the attached Schedule 2 for the applicable year.

Terms: All terms in the AESO's June 22, 2001 Application for a Duplication Avoidance Tariff for Imperial Oil Resources Limited Cold Lake Site and in the AESO's 2008 Application for Amendment will be applicable.

Metering and Totalizing: If Imperial Oil were to build the Duplicate Facilities, the Leming Lake transmission station would be a Point of Supply when the Cold Lake Site power generation exceeds the load requirements, and a Point of Demand when the generation does not meet the load requirements. The Duplication Avoidance Tariff will simulate these conditions by deeming the Points of Demand at the Mahihkan and Leming Lake transmission stations, and the Point of Supply at the Leming Lake transmission station, to be a single Point of Connection for the purpose of totalizing Metered Demand and Metered Energy in applying Rates DTS and STS.

During operation of the Duplication Avoidance Tariff, the AESO will totalize the metered data for Imperial Oil's load and generation served from the Mahihkan and Leming Lake transmission stations. This will ensure that payments by Imperial Oil to the AESO under Rate DTS and Rate STS are equivalent to the costs Imperial Oil would have incurred for the Duplicate Facilities.

Charges under Rate DTS and Rate STS will be calculated using the totalized Metered Demand and the totalized Metered Energy for Imperial Oil at the Mahihkan-837S transmission station and the Leming Lake-715S transmission station. The meters to be totalized at Mahihkan-837S are 5L408, 5L409, 5L410, and 7L105. The meters to be totalized at Leming Lake-715S are 5L335, 5L408, 5L575, 5L395, 5L242, and 7L95. These meter points may change from time to time.

The amount of load included in the totalizing calculation will be limited to 157 MVA from November through April and 130 MVA from May through October, which is the maximum amount of load that the Duplicate Facilities would be able to serve, based on the deemed winter and summer capacities, respectively, of the duplicate transmission line in Imperial Oil's design. If the combined Metered Demand at the Mahihkan and Leming Lake transmission stations for the Load Facilities exceeds the 157 MVA winter or 130 MVA summer limit, the costs that would have been required to service the additional load under the Duplicate Facilities alternative will be estimated and invoiced to Imperial Oil.

Rider A4 **Transmission Duplication Avoidance Adjustment** Page 3 of 5
Imperial Oil Resources Limited — Cold Lake Industrial System

Example of Totalizing

The following is an example of the totalizing calculation for Metered Demand and Metered Energy for two different metering time intervals.

	Time Interval 1	**Time Interval 2**
Point of Demand (A) (Mahihkan)	+45 MW	+45 MW
Point of Supply / Point of Demand (B) (Leming Lake)	–100 MW	+60 MW
Totalized Metered Demand and Energy (C)	–55 MW	+105 MW

In Time Interval 1, under the Duplication Avoidance Tariff, Imperial Oil's demand requirement is 45 MW at each of the Mahihkan and Leming Lake transmission stations. At the same time, Imperial Oil's Cogeneration Facility is producing 160 MW of power, of which 15 MW is used to directly serve other load requirements. The net delivery to the AIES is 145 MW at the Leming Lake transmission station. If Imperial Oil built the Duplicate Facilities, the Metered Energy delivered by the AIES to Imperial Oil's load requirement at the Mahihkan transmission station would be zero, and the Metered Energy received by the AIES from the generator output at the Leming Lake transmission station would be 55 MW (160 MW of generation minus 105 MW of load). This energy balance is simulated by the proposed totalizing procedure. Combining the Point of Demand (A) and Point of Supply (B) produces an adjusted Metered Demand of –55 MW, where the negative sign signifies a net energy receipt by the AIES.

In Time Interval 2, the Cogeneration Facility is not operating and Imperial Oil's load remains at 105 MW (45 MW at the Mahihkan station, and 45 MW plus 15 MW at Leming Lake station). The result is a net load of +105 MW for that time interval, where the positive sign signifies a net energy delivery from the AIES.

Rider A4 **Transmission Duplication Avoidance Adjustment** Page 4 of 5
Imperial Oil Resources Limited — Cold Lake Industrial System

Schedule 1 — Incremental Loss Factors

Metered Demand of Load Facilities (MW)	Loss Factor (% of Metered Demand of Load Facilities)
> 0 ≤ 10	1.88%
> 10 ≤ 20	1.31%
> 20 ≤ 30	0.64%
> 30 ≤ 40	0.54%
> 40 ≤ 50	0.60%
> 50 ≤ 60	0.73%
> 60 ≤ 70	0.90%
> 70 ≤ 80	1.09%
> 80 ≤ 90	1.29%
> 90 ≤ 100	1.51%
> 100 ≤ 110	1.72%
> 110 ≤ 115	1.91%
> 115 ≤ 120	1.99%
> 120 ≤ 125	2.08%
> 125 ≤ 130	2.16%
> 130 ≤ 135	2.25%
> 135 ≤ 140	2.33%
> 140 ≤ 145	2.48%
> 145	2.66%

Rider A4 **Transmission Duplication Avoidance Adjustment** Page 5 of 5
Imperial Oil Resources Limited — Cold Lake Industrial System

Schedule 2 — Other Expenses Charge

12 Month Period	Monthly Payment
Jan. 1, 2003 – Dec. 31, 2003	$ 4,223
Jan. 1, 2004 – Dec. 31, 2004	$ 6,323
Jan. 1, 2005 – Dec. 31, 2005	$ 4,286
Jan. 1, 2006 – Dec. 31, 2006	$ 4,225
Jan. 1, 2007 – Dec. 31, 2007	$ 5,791
Jan. 1, 2008 – Dec. 31, 2008	$ 7,651
Jan. 1, 2009 – Dec. 31, 2009	$ 5,189
Jan. 1, 2010 – Dec. 31, 2010	$ 6,835
Jan. 1, 2011 – Dec. 31, 2011	$ 4,500
Jan. 1, 2012 – Dec. 31, 2012	$ 8,367
Jan. 1, 2013 – Dec. 31, 2013	$ 4,457
Jan. 1, 2014 – Dec. 31, 2014	$ 10,648
Jan. 1, 2015 – Dec. 31, 2015	$ 5,059
Jan. 1, 2016 – Dec. 31, 2016	$ 5,430
Jan. 1, 2017 – Dec. 31, 2017	$ 19,466
Jan. 1, 2018 – Dec. 31, 2018	$ 10,660
Jan. 1, 2019 – Dec. 31, 2019	$ 4,765
Jan. 1, 2020 – Dec. 31, 2020	$ 10,594
Jan. 1, 2021 – Dec. 31, 2021	$ 5,565
Jan. 1, 2022 – Dec. 31, 2022	$ 29,055
Jan. 1, 2023 – Dec. 31, 2023	$ 5,799
Jan. 1, 2024 – Dec. 31, 2024	$ 5,905
Jan. 1, 2025 – Dec. 31, 2025	$ 5,366
Jan. 1, 2026 – Dec. 31, 2026	$ 19,095
Jan. 1, 2027 – Dec. 31, 2027	$ 6,492
Jan. 1, 2028 – Dec. 31, 2028	$ 5,695
Jan. 1, 2029 – Dec. 31, 2029	$ 5,962
Jan. 1, 2030 – Dec. 31, 2030	$ 7,811
Jan. 1, 2031 – Dec. 31, 2031	$ 6,043

Rider B	**Working Capital Deficiency/Surplus Rider**	Page 1 of 1

Purpose: The Working Capital Deficiency/Surplus Rider is to recover unexpected increases in the AESO's working capital deficiency or to refund unexpected surpluses of working capital.

Applicable to: Customers receiving service under the following Rate Schedules:
- DTS
- FTS

Effective: The rider will be invoked for the current Billing Period when, on the last Business Day of the current Billing Period:
- the AESO's working capital balance either exceeds or falls short of the AESO's annual average forecast by an amount equal to or greater than $7.0 Million.

Rate: A percentage increase or decrease, that when invoked will restore the AESO's working capital deficiency to the AESO's annual average forecast, applied to charges under the rate schedules listed above in the current Billing Period.

Terms: The Terms and Conditions form part of this Rate Schedule.

Rider C **Deferral Account Adjustment Rider** Page 1 of 1

Purpose: To recover or refund all accumulated deferral account balances.

Applicable to: Customers receiving service under the following Rate Schedules:
- DTS
- FTS

Effective: The rider is effective for all billing periods, effective January 1, 2006.

Rate: An additional $/MWh charge or credit will be applied to each of the following:

DTS Rate Schedule
- Interconnection Revenue Category
- Operating Reserve Revenue Category
- Voltage Control Revenue Category
- Other Ancillary Services Revenue Category

FTS Rate Schedule
- Interconnection Revenue Category
- Operating Reserve Revenue Category
- Voltage Control Revenue Category
- Other Ancillary Services Revenue Category

to restore the deferral account balances to zero over the following calendar quarter or such longer period as determined by the AESO to minimize rate impact.

Terms: The Terms and Conditions form part of this Rate Schedule.

Rider E **Losses Calibration Factor Rider** Page 1 of 1

Purpose: To adjust loss factors to ensure that the actual cost of losses is reasonably recovered through charges and credits on an annual basis.

Applicable to: Customers receiving service under the following Rate Schedules:

- DOS
- XOS
- STS
- IOS

Effective: The rider is effective for all billing periods, effective January 1, 2006.

Rate: An additional calibration factor percentage (%) will be added to or subtracted from all location-specific loss factors on the DOS, XOS, STS. and IOS Rate Schedules.

Every quarter a calibration factor is determined to recover or refund all accumulated and forecast differences between the anticipated costs of transmission system losses and the actual costs of transmission system losses, on a calendar year basis. Any balance remaining at the end of a year would carry forward to be recovered or refunded in the following year.

Terms: The Terms and Conditions form part of this Rate Schedule.

Rider F **Balancing Pool Consumer Allocation Rider** Page 1 of 1

Purpose: To collect from or refund to AESO Customers an annualized amount estimated by the Balancing Pool and transferred to the AESO under section 82 of the *Electric Utilities Act*.

Applicable to: Customers receiving service under the following Rate Schedules:

- DTS, with the exception of the City of Medicine Hat
- DOS, with the exceptions of the City of Medicine Hat and BC Hydro at Fort Nelson

Effective: The rider is effective for all billing periods from January 1, 2009 to December 31, 2009.

Rate: A credit of **$6.50/MWh** of Metered Energy during the Billing Period.

Terms: The Terms and Conditions form part of this Rate Schedule.

Rider G **Bill Impact Mitigation Rider** Page 1 of 1

Purpose: To limit cost increases resulting from changes to the DTS rate, on a forecast annual basis, in accordance with Decision 2008-037 of the Alberta Utilities Commission.

Applicable to: DTS Customers at the Points of Delivery specified below.

Effective: For all billing periods from the effective date of the tariff to December 31, 2009, unless otherwise ordered by the Alberta Utilities Commission.

Rate: The **Bill Impact Mitigation Credit** per Billing Period shall be as follows:

Point of Delivery Account ID	**Credit** ($/month)
1003040	$5,101.00
100000399	$ 72.00
100000425	$2,092.00
100000426	$3,308.00
100000457	$2,541.00
100000466	$1,204.00
100000472	$3,574.00
100000475	$4,853.00
100001481	$ 682.00
100002297	$2,555.00
100010039	$1,185.00

Terms: (a) All charges in Rate Schedule DTS apply without modification.

(b) The Terms and Conditions form part of this Rate Schedule.

Rider H	**Interim Refundable Fort Nelson Rider**	Page 1 of 1

Purpose: The Interim Refundable Fort Nelson Rider H is to recover 50% of the cost of the additional transmission must-run (TMR) dispatch of a fourth generator in the Rainbow Area in support of incremental load near Fort Nelson.

Applicable to: BC Hydro for demand service to Fort Nelson in British Columbia.

Effective: The rider will be effective from January 1 to December 31, 2008, and will expire unless revoked or replaced by another approved rate or rider on or before December 31, 2008.

Rate: At the end of each billing period, the AESO will determine the incremental cost of the additional transmission must-run (TMR) dispatch of a fourth generator in the Rainbow Area, beyond the dispatch that would have been required prior to the addition of an incremental 10 MW of load near Fort Nelson in January 2008. Under this rider, 50% of the incremental cost so determined will be billed to BC Hydro.

Terms:

(a) Rider H is an incremental refundable charge in addition to amounts payable for demand and energy under Rate FTS.

(b) The Terms and Conditions form part of this Rate Schedule.

Rate Appendix Regulated Generating Units Page 1 of 3

Generating Unit	Owner	Type of Plant	MCR (MW)	Base Life
Barrier	TAU	Hydro	11.2	2020
Battle River 3	AE	Coal-fired thermal	147.3	2013
Battle River 4	AE	Coal-fired thermal	147.3	2013
Battle River 5	AE	Coal-fired thermal	368.2	2020
Battle River POS Total			662.8	
Bearspaw	TAU	Hydro	16.0	2020
Bighorn 1	TAU	Hydro	60.0	2020
Bighorn 2	TAU	Hydro	60.0	2020
Bighorn POS Total			120.0	
Brazeau 1	TAU	Hydro	160.0	2020
Brazeau 2	TAU	Hydro	190.0	2020
Brazeau POS Total			350.0	
Cascade 1	TAU	Hydro	17.0	2020
Cascade 2	TAU	Hydro	17.0	2020
Cascade POS Total			34.0	
Clover Bar 1	EPGI	Gas-fired thermal	157.2	2010
Clover Bar 2	EPGI	Gas-fired thermal	157.2	2010
Clover Bar 3	EPGI	Gas-fired thermal	157.2	2010
Clover Bar 4	EPGI	Gas-fired thermal	157.2	2010
Clover Bar POS Total			628.8	
Genesee 1	EPGI	Coal-fired thermal	384.1	2020
Genesee 2	EPGI	Coal-fired thermal	384.1	2020
Genesee POS Total			768.2	
Ghost 1	TAU	Hydro	1.0	2013
Ghost 2	TAU	Hydro	14.0	2020
Ghost 3	TAU	Hydro	14.0	2020
Ghost 4	TAU	Hydro	25.0	2020
Ghost POS Total			54.0	
H. R. Milner	AE	Coal-fired thermal	144.3	2012
Horseshoe 1	TAU	Hydro	5.0	2020
Horseshoe 2	TAU	Hydro	3.0	2020
Horseshoe 3	TAU	Hydro	3.0	2020
Horseshoe 4	TAU	Hydro	5.0	2020
Horseshoe POS Total			16.0	

Rate Appendix Regulated Generating Units (cont'd)

Generating Unit	Owner	Type of Plant	MCR (MW)	Base Life
Interlakes	TAU	Hydro	5.0	2020
Kananaskis 1	TAU	Hydro	5.0	2020
Kananaskis 2	TAU	Hydro	5.0	2020
Kananaskis 3	TAU	Hydro	9.0	2020
Kananaskis POS Total			19.0	
Keephills 1	TAU	Coal-fired thermal	381.1	2020
Keephills 2	TAU	Coal-fired thermal	381.1	2020
Keephills POS Total			762.2	
Pocaterra	TAU	Hydro	14.0	2013
Rainbow 1	AE	Gas turbine	25.9	2005
Rainbow 2	AE	Gas turbine	39.8	2005
Rainbow 3	AE	Gas turbine	21.4	2005
Rainbow POS Total			87.1	
Rossdale 10	EPGI	Gas-fired thermal	70.6	2003
Rossdale 8	EPGI	Gas-fired thermal	66.7	2003
Rossdale 9	EPGI	Gas-fired thermal	70.6	2003
Rossdale POS Total			207.9	
Rundle 1	TAU	Hydro	17.0	2020
Rundle 2	TAU	Hydro	33.0	2020
Rundle POS Total			50.0	
Sheerness 1	AE	Coal-fired thermal	378.2	2020
Sheerness 2	AE	Coal-fired thermal	378.2	2020
Sheerness POS Total			756.4	
Spray 1	TAU	Hydro	47.5	2020
Spray 2	TAU	Hydro	52.0	2020
Spray POS Total			99.5	
Sturgeon 1	AE	Gas turbine	10.0	2005
Sturgeon 2	AE	Gas turbine	8.0	2005
Sturgeon POS Total			18.0	

Rate Appendix Regulated Generating Units (cont'd) Page 3 of 3

Generating Unit	Owner	Type of Plant	MCR (MW)	Base Life
Sundance 1	TAU	Coal-fired thermal	278.6	2017
Sundance 2	TAU	Coal-fired thermal	278.6	2017
Sundance 3	TAU	Coal-fired thermal	353.2	2020
Sundance 4	TAU	Coal-fired thermal	353.2	2020
Sundance 5	TAU	Coal-fired thermal	353.2	2020
Sundance 6	TAU	Coal-fired thermal	364.2	2020
Sundance POS Total			1,981.0	
Three Sisters	TAU	Hydro	2.7	2020
Wabamun 1	TAU	Coal-fired thermal	63.7	2003
Wabamun 2	TAU	Coal-fired thermal	63.7	2003
Wabamun 3	TAU	Coal-fired thermal	139.3	2003
Wabamun 4	TAU	Coal-fired thermal	278.6	2003
Wabamun POS Total			545.3	

Attachment 2

SaskPower OATT

Effective January 1, 2006

SASKPOWER

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TRANSMISSION TARIFF

TABLE OF CONTENTS

I. COMMON SERVICE PROVISIONS

1 Definitions

1.1 Ancillary Services:

Those services that are necessary to support the transmission of capacity and energy from resources to loads while maintaining reliable operation of the Transmission Provider's Transmission System in accordance with Good Utility Practice.

1.2 Annual Transmission Costs:

The total annual cost of the Transmission System for purposes of Network Integration Transmission Service shall be the amount specified in Attachment G until amended by the Transmission Provider.

1.3 Application:

A request by an Eligible Customer for transmission service pursuant to the provisions of the Tariff.

1.4 Completed Application:

An Application that satisfies all of the information and other requirements of the Tariff, including any required deposit.

1.5 Control Area:

An electric power system or combination of electric power systems to which a common automatic generation control scheme is applied in order to:

(a) match, at all times, the power output of the generators within the electric power system(s) and capacity and energy purchased from entities outside the electric power system(s), with the load within the electric power system(s);

(b) maintain scheduled interchange with other Control Areas, within the limits of Good Utility Practice;

(c) maintain the frequency of the electric power system(s) within reasonable limits in accordance with Good Utility Practice; and

(d) provide sufficient generating capacity to maintain operating reserves in accordance with Good Utility Practice.

1.6 Curtailment:

A reduction in firm or non-firm transmission service in response to a transmission capacity shortage as a result of system reliability conditions.

1.7 Delivering Party:

The entity supplying capacity and energy to be transmitted at Point(s) of Receipt.

1.8 Designated Agent:

Any entity that performs actions or functions on behalf of the Transmission Provider, an Eligible Customer, or the Transmission Customer required under the Tariff.

1.9 Direct Assignment Facilities:

Facilities or portions of facilities that are constructed by the Transmission Provider for the sole use/benefit of a particular Transmission Customer requesting service under the Tariff. Direct Assignment Facilities shall be specified in the Service Agreement that governs service to the Transmission Customer and shall be subject to applicable regulatory approval as may be required by law.

1.10 Eligible Customer:

(i) Any electric utility including the Transmission Provider and any power marketer or US Federal power marketing agency, or any person generating electric energy for sale for resale is an Eligible Customer under the Tariff. Electric energy sold or produced by such entity may be electric energy produced in Canada, the United States, or Mexico; however, such entity is not eligible for transmission service that would be prohibited by Section 212(h)(z) of the U.S. Federal Power Act; and (ii) any retail customer taking unbundled transmission service pursuant to a statutory or regulatory requirement that the Transmission Provider offer the transmission service, or pursuant to a voluntary offer of such service by the Transmission Provider, is an Eligible Customer under the Tariff.

1.11 Facilities Study:

An engineering study conducted by the Transmission Provider to determine the required modifications to the Transmission Provider's Transmission System, including the cost and scheduled completion date for such modifications, that will be required to provide the requested transmission service.

1.12 Firm Point-To-Point Transmission Service:

Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.

1.13 Good Utility Practice:

Any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

1.14 Interruption:

A reduction in non-firm transmission service due to economic reasons pursuant to Section 14.7.

1.15 Load Ratio Share:

Ratio of a Transmission Customer's Network Load to the Transmission Provider's total load computed in accordance with Sections 34.2 and 34.3 of the Network Integration Transmission Service under Part III of the Tariff and calculated on a rolling twelve month basis.

1.16 Load Shedding:

The systematic reduction of system demand by temporarily decreasing load in response to transmission system or area capacity shortages, system instability, or voltage control considerations under Part III of the Tariff.

1.17 Long-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of one year or more.

1.18 MAPP:

The Mid-continent Area Power Pool

1.19 Domestic Load Customers:

The wholesale and retail power customers of the Transmission Provider on whose behalf the Transmission Provider, by statute, franchise, regulatory requirement, or contract, has undertaken an obligation to construct and operate the Transmission Provider's system to meet the reliable electric needs of such customers.

1.20 Network Customer:

An entity receiving transmission service pursuant to the terms of the Transmission Provider's Network Integration Transmission Service under Part III of the Tariff.

1.21 Network Integration Transmission Service:

The transmission service provided under Part III of the Tariff.

1.22 Network Load:

The load that a Network Customer designates for Network Integration Transmission Service under Part III of the Tariff. The Network Customer's Network Load shall include all load served by the output of any Network Resources designated by the Network Customer. A Network Customer may elect to designate less than its total load as Network Load but may not designate only part of the load at a discrete Point of Delivery. Where an Eligible Customer has elected not to designate a particular load at discrete points of delivery as Network Load, the Eligible Customer is responsible for making separate arrangements under Part II of the Tariff for any Point-To-Point Transmission Service that may be necessary for such non-designated load.

1.23 Network Operating Agreement:

An executed agreement that contains the terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Network Integration Transmission Service under Part III of the Tariff.

1.24 Network Operating Committee:

A group made up of representatives from the Network Customer(s) and the Transmission Provider established to coordinate operating criteria and other technical considerations required for implementation of Network Integration Transmission Service under Part III of this Tariff.

1.25 Network Resource:

Any designated generating resource or dedicated transmission equipment owned, purchased or leased by a Network Customer or by the load serving entity where the Network Customer is acting as an intermediary for the load serving entity, and used to serve the load serving entity’s load on a firm basis, under the Network Integration Transmission Service Tariff. Network Resources do not include any resource, or any portion thereof, that is committed for sale to third parties (other than the load serving entity on whose behalf the Network Customer is acting) or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis.

1.26 Network Upgrades:

Modifications or additions to transmission-related facilities that are integrated with and support the Transmission Provider's overall Transmission System for the general benefit of all users of such Transmission System.

1.27 Non-Firm Point-To-Point Transmission Service:

Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one (1) hour to six (6) months.

1.28 Open Access Same-Time Information System (OASIS):

The information system and standards of conduct contained in Part 37 of FERC regulations and all additional requirements implemented by subsequent FERC orders dealing with OASIS.

1.29 Part I:

Tariff Definitions and Common Service Provisions contained in Sections 2 through 12.

1.30 Part II:

Tariff Sections 13 through 27 pertaining to Point-To-Point Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.31 Part III:

Tariff Sections 28 through 35 pertaining to Network Integration Transmission Service in conjunction with the applicable Common Service Provisions of Part I and appropriate Schedules and Attachments.

1.32 Parties:

The Transmission Provider and the Transmission Customer receiving service under the Tariff.

1.33 Point(s) of Delivery:

Point(s) on the Transmission Provider's Transmission System where capacity and energy transmitted by the Transmission Provider will be made available to the Receiving Party under Part II of the Tariff. The Point(s) of Delivery shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.34 Point(s) of Receipt:

Point(s) of interconnection on the Transmission Provider's Transmission System where capacity and energy will be made available to the Transmission Provider by the Delivering Party under Part II of the Tariff. The Point(s) of Receipt shall be specified in the Service Agreement for Long-Term Firm Point-To-Point Transmission Service.

1.35 Point-To-Point Transmission Service:

The reservation and transmission of capacity and energy on either a firm or non-firm basis from the Point(s) of Receipt to the Point(s) of Delivery under Part II of the Tariff.

1.36 Power Purchaser:

The entity that is purchasing the capacity and energy to be transmitted under the Tariff.

1.37 Receiving Party:

The entity receiving the capacity and energy transmitted by the Transmission Provider to Point(s) of Delivery.

1.38 Regional Transmission Group (RTG):

A voluntary organization of transmission owners, transmission users and other entities formed to efficiently coordinate transmission planning (and expansion), operation and use on a regional (and interregional) basis.

1.39 Reserved Capacity:

The maximum amount of capacity and energy that the Transmission Provider agrees to transmit for the Transmission Customer over the Transmission Provider's Transmission System between the Point(s) of Receipt and the Point(s) of Delivery under Part II of the Tariff. Reserved Capacity shall be expressed in terms of whole megawatts on a sixty (60) minute interval (commencing on the clock hour) basis.

1.40 Service Agreement:

The initial agreement and any amendments or supplements thereto entered into by the Transmission Customer and the Transmission Provider for service under the Tariff.

1.41 Service Commencement Date:

The date the Transmission Provider begins to provide service pursuant to the terms of an executed Service Agreement.

1.42 Short-Term Firm Point-To-Point Transmission Service:

Firm Point-To-Point Transmission Service under Part II of the Tariff with a term of less than one year.

1.43 System Impact Study:

An assessment by the Transmission Provider of (i) the adequacy of the Transmission System to accommodate a request for either Firm Point-To-Point Transmission Service or Network Integration Transmission Service and (ii) whether any additional costs may be incurred in order to provide transmission service.

1.44 Third-Party Sale:

Any sale for resale of generation capacity or energy to a Power Purchaser that is not designated as part of Network Load under the Network Integration Transmission Service.

1.45 Transmission Customer:

Any Eligible Customer (or its Designated Agent) that (i) executes a Service Agreement, or (ii) receives service under an Umbrella Agreement. This term is used in the Part I Common Service Provisions to include customers receiving transmission service under Part II and Part III of this Tariff.

1.46 Transmission Provider:

SaskPower.

1.47 Transmission Provider's Monthly Transmission System Peak:

The maximum firm usage of the Transmission Provider's Transmission System in a calendar month.

1.48 Transmission Service:

Point-To-Point Transmission Service provided under Part II of the Tariff on a firm and non-firm basis.

1.49 Transmission System:

The facilities owned, controlled or operated by the Transmission Provider that are used to provide transmission service under Part II and Part III of the Tariff.

1.50 Umbrella Agreement:

An agreement between the Transmission Provider and an Eligible Customer which provides all the information necessary to enable such Eligible Customer to receive Short Term Firm or Non-Firm Point to Point Transmission Service under this Tariff for a maximum period of three years without the necessity of executing a Service Agreement for each Completed Application. A form of Umbrella Agreement is attached as Attachment B.

1.51 FERC:

The U.S. Federal Energy Regulatory Commission.

2 Initial Allocation and Renewal Procedures

2.1 Initial Allocation of Available Transmission Capability:

For purposes of determining whether existing capability on the Transmission Provider's Transmission System is adequate to accommodate a request for firm service under this Tariff, all Completed Applications for new firm transmission service received during the initial sixty (60) day period commencing with the effective date of the Tariff will be deemed to have been filed simultaneously. A lottery system conducted by an independent party shall be used to assign priorities for Completed Applications filed simultaneously. All Completed Applications for firm transmission service received after the initial sixty (60) day period shall be assigned a priority pursuant to Section 13.2.

2.2 Reservation Priority For Existing Firm Service Customers:

Existing firm service customers (wholesale requirements and transmission-only, with a contract term of one (1) year or more), have the right to continue to take transmission service from the Transmission Provider when the contract expires, rolls over or is renewed. This transmission reservation priority is independent of whether the existing customer continues to purchase capacity and energy from the Transmission Provider or elects to purchase capacity and energy from another supplier. If at the end of the contract term, the Transmission Provider's Transmission System cannot accommodate all of the requests for transmission service the existing firm service customer must agree to accept a contract term at least equal to a competing request by any new Eligible Customer and to pay the current Tariff for such service. This transmission reservation priority for existing firm service customers is an ongoing right that may be exercised at the end of all firm contract terms of one (1) year or longer.

3 Ancillary Services

Ancillary Services are needed with transmission service to maintain reliability within and among the Control Areas affected by the transmission service. The Transmission

Provider is required to provide and the Transmission Customer is required to purchase, the following Ancillary Services: (i) Scheduling, System Control and Dispatch, and (ii) Reactive Supply and Voltage Control from Generation Sources.

The Transmission Provider is required to offer to provide the following Ancillary Services only to the Transmission Customer serving load within the Transmission Provider's Control Area: (i) Regulation and Frequency Response; (ii) Energy Imbalance; (iii) Operating Reserve – Spinning; and (iv) Operating Reserve - Supplemental. The Transmission Customer serving load within the Transmission Provider's Control Area is required to acquire these Ancillary Services, whether from the Transmission Provider, from a third party, or by self-supply.

The Transmission Customer may not decline the Transmission Provider's offer of Ancillary Services unless it demonstrates that it has acquired the Ancillary Services from another source. The Transmission Customer must list in its Application which Ancillary Services it will purchase from the Transmission Provider.

The Transmission Provider shall specify in the applicable Rate Schedules the rate treatment and all related terms and conditions in the event of an unauthorized use of Ancillary Services by the Transmission Customer.

The specific Ancillary Services, prices and/or compensation methods are described on the Schedules that are attached to and made a part of the Tariff. Three principal requirements apply to discounts for Ancillary Services provided by the Transmission Provider in conjunction with its provision of transmission service as follows: (i) any offer of a discount made by the Transmission Provider must be announced to all Eligible

Customers solely by posting on the OASIS; (ii) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS; and (iii) once a discount is negotiated, details must be immediately posted on the OASIS. A discount agreed upon for an Ancillary Service must be offered for the same period to all Eligible Customers on the Transmission Provider's system. Sections 3.1 through 3.6 below list the six Ancillary Services.

3.1 Scheduling, System Control and Dispatch Service:

The rates and/or methodology are described in Schedule 1.

3.2 Reactive Supply and Voltage Control from Generation Sources Service:

The rates and/or methodology are described in Schedule 2.

3.3 Regulation and Frequency Response Service:

Where applicable the rates and/or methodology are described in Schedule 3.

3.4 Energy Imbalance Service:

Where applicable the rates and/or methodology are described in Schedule 4.

3.5 Operating Reserve - Spinning Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 5.

3.6 Operating Reserve - Supplemental Reserve Service:

Where applicable the rates and/or methodology are described in Schedule 6.

4 Open Access Same-Time Information System

Terms and conditions regarding Open Access Same-Time Information System and standards of conduct are set forth in 18 CFR § 37 of the FERC regulations (Open Access Same-Time Information System and Standards of Conduct for Public Utilities). The

Transmission Provider's Standards of Conduct are posted on the OASIS. In the event available transmission capability as posted on the OASIS is insufficient to accommodate a request for firm transmission service, additional studies may be required as provided by this Tariff pursuant to Sections 19 and 32.

5 Interpretation

5.1 Applicable Law:

This Tariff and any Service Agreements executed hereunder shall be governed by and construed in accordance with the laws of the Province of Saskatchewan and Canada, except where the law of the United States is specifically incorporated herein. For greater certainty, The United Nations Convention on Contracts for the International Sale of Goods as adopted by *The International Sale of Goods Act*, S.M. 1989-90, c.18, shall not apply to any Service Agreements executed hereunder.

5.2 Condition Precedent:

The Transmission Provider's obligation to provide transmission service pursuant to a Service Agreement executed under this Tariff shall be conditional upon the receipt and continued effectiveness of any regulatory or other approvals required by Canadian law in connection with transmission service hereunder.

5.3 Legislative Requirements:

The terms and conditions of this Tariff and any Service Agreements executed hereunder are subject to decisions, orders, rules and regulations of any Canadian Federal and/or Saskatchewan provincial legislative requirements in effect from time to time and this Tariff may be amended without notice in accordance with such decisions, orders, rules, regulations or requirements.

6 Reciprocity

A Transmission Customer receiving transmission service under this Tariff agrees to provide comparable transmission service that it is capable of providing to the Transmission Provider on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates. A Transmission Customer that is a member of a power pool or Regional Transmission Group also agrees to provide comparable transmission service to the members of such power pool and Regional Transmission Group on similar terms and conditions over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer and over facilities used for the transmission of electric energy owned, controlled or operated by the Transmission Customer's corporate affiliates.

This reciprocity requirement applies not only to the Transmission Customer that obtains transmission service under the Tariff, but also to all parties to a transaction that involves the use of transmission service under the Tariff, including the power seller, buyer and any intermediary, such as a power marketer. This reciprocity requirement also applies to any Eligible Customer that owns, controls or operates transmission facilities that uses an intermediary, such as a power marketer, to request transmission service under the Tariff. If the Transmission Customer does not own, control or operate transmission facilities, it must include in its Application a sworn statement of one of its duly authorized officers or other representatives that the purpose of its Application is not to assist an Eligible Customer to avoid the requirements of this provision.

The requirements of this section may be waived by the Transmission Provider.

7 Billing and Payment

7.1 Billing Procedure:

Within a reasonable time after the first day of each month, the Transmission Provider shall submit an invoice to the Transmission Customer for the charges for all services furnished under the Tariff during the preceding month. The invoice shall be paid by the Transmission Customer within twenty (20) days of receipt. All payments shall be made by wire transfer to the bank named by the Transmission Provider in Appendix 1.

7.2 Interest on Unpaid Balances

Interest on any unpaid amounts (including amounts placed in trust) shall be calculated in accordance with the methodology specified in the Transmission Provider's Business Administration Manual applicable to late payment charges. Interest on delinquent amounts shall be calculated from the due date of the bill to the date of payment.

7.3 Currency:

All rates specified in the Tariff are stated in lawful money of Canada. Unless otherwise agreed, monetary transactions, accounting and cost calculations between the Parties shall be determined and stated in lawful money of Canada. If required for any such monetary transactions, accounting or cost calculation, the rate to be used to convert from the foreign currency to that of Canada for each shall be the Bank of Canada noon spot exchange rate as published by the Royal Bank of Canada, Regina, Saskatchewan, Canada, or the last published rate if not published for such day. If any monetary transaction is for a period of time exceeding one day, the weighted average of such noon spot exchange rates for each day in the respective period of time shall be used. The weighting shall be based in proportion to the dollar value of each day's transaction.

7.4 Customer Default:

In the event the Transmission Customer fails, for any reason other than a billing dispute as described below, to make payment to the Transmission Provider on or before the due date as described above, and such failure of payment is not corrected within thirty (30) calendar days after the Transmission Provider notifies the Transmission Customer to cure such failure, a default by the Transmission Customer shall be deemed to exist. Upon the occurrence of a default, the Transmission Provider may terminate service. In the event of a billing dispute between the Transmission Provider and the Transmission Customer, the Transmission Provider will continue to provide service under the Service Agreement as long as the Transmission Customer: (i) continues to make all payments not in dispute; and (ii) pays into an independent trust account the portion of the invoice in dispute, pending resolution of such dispute. If the Transmission Customer fails to meet these two requirements for continuation of service, then the Transmission Provider may provide notice to the Transmission

Customer of its intention to suspend service in accordance with the policy of the Transmission Provider.

8 Accounting for the Transmission Provider's Use of the Tariff

The Transmission Provider shall record the following amounts, as outlined below.

8.1 Transmission Revenues:

Include in a separate transmission revenue account the revenues it receives from Transmission Service when making Third-Party Sales under Part II of the Tariff.

8.2 Study Costs and Revenues:

Include in a separate transmission general ledger expense account, costs properly chargeable to expense that are incurred to perform any System Impact Studies or Facilities Studies which the Transmission Provider conducts to determine if it must construct new transmission facilities or upgrades necessary for its own uses, including making Third-Party Sales under the Tariff; and include in a separate operating revenue account the revenues received for System Impact Studies or Facilities Studies performed when such amounts are separately stated and identified in the Transmission Customer's billing under the Tariff.

9 Tariff Amendments

Nothing contained in the Tariff or any Service Agreement shall be construed as affecting in any way the right of the Transmission Provider to unilaterally make a change in rates, terms and conditions, charges, classification of service or a Service Agreement. Prior to the effectiveness of any change not required by Section 5.3 hereof, the Transmission

Provider will provide sixty (60) days notice of such change in writing to affected Transmission Customers.

10 Force Majeure and Indemnification

10.1 Force Majeure:

An event of Force Majeure means any act of God, labor disturbance, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, any Curtailment, order, regulation or restriction imposed by governmental military or lawfully established civilian authorities, or any other cause beyond a Party’s control. A Force Majeure event does not include an act of negligence or intentional wrongdoing. Neither the Transmission Provider nor the Transmission Customer will be considered in default as to any obligation under this Tariff if prevented from fulfilling the obligation due to an event of Force Majeure. However, a Party whose performance under this Tariff is hindered by an event of Force Majeure shall make all reasonable efforts to perform its obligations under this Tariff.

10.2 Indemnification:

The Transmission Customer shall at all times indemnify, defend, and save the Transmission Provider harmless from, any and all damages, losses, claims, including claims and actions relating to injury to or death of any person or damage to property, demands, suits, recoveries, costs and expenses, court costs, attorney fees, and all other obligations by or to third parties, arising out of or resulting from the Transmission Provider's performance of its obligations under this Tariff on behalf of the Transmission Customer, except in cases of negligence or intentional wrongdoing by the Transmission Provider.

11 Creditworthiness

For the purpose of determining the ability of the Transmission Customer to meet its obligations related to service hereunder, the Transmission Provider may require reasonable credit review procedures. This review shall be made in accordance with standard commercial practices. In addition, the Transmission Provider may require the Transmission Customer to provide and maintain in effect during the term of the Service Agreement, an unconditional and irrevocable letter of credit as security to meet its responsibilities and obligations under the Tariff, or an alternative form of security proposed by the Transmission Customer and acceptable to the Transmission Provider and consistent with commercial practices established under the laws of the Province of Saskatchewan that protects the Transmission Provider against the risk of non-payment.

12 Dispute Resolution Procedures and Withdrawal of Tariff

12.1 Dispute Resolution Procedures:

Any dispute between a Transmission Customer or Eligible Customer and the Transmission Provider involving transmission service under the Tariff shall be referred to a designated senior representative of the Transmission Provider and a senior representative of the Transmission Customer or Eligible Customer, as the case may be, for resolution on an informal basis as promptly as practicable. In the event the designated representatives are unable to resolve the dispute within thirty (30) days (or such other period as the Parties may agree upon) by mutual agreement, such dispute may be submitted to arbitration and resolved in accordance with the arbitration procedures set forth below.

12.2 External Arbitration Procedures:

Any arbitration initiated under the Tariff shall be conducted before a single neutral arbitrator appointed by the Parties. If the Parties fail to agree upon a single arbitrator within ten (10) days of the referral of the dispute to arbitration, each Party shall choose one arbitrator who shall sit on a three-member arbitration panel. The two arbitrators so chosen shall within twenty (20) days select a third arbitrator to chair the arbitration panel. In either case, the arbitrators shall be knowledgeable in electric utility matters, including electric transmission and bulk power issues, and shall not have any current or past substantial business or financial relationships with any party to the arbitration (except prior arbitration). The arbitrator(s) shall conduct the arbitration in Regina, Saskatchewan and shall provide each of the Parties an opportunity to be heard and, except as otherwise provided herein, shall generally conduct the arbitration in accordance with *The Arbitration Act, 1992* of Saskatchewan.

12.3 Arbitration Decisions:

Unless otherwise agreed, the arbitrator(s) shall render a decision within

ninety (90) days of appointment and shall notify the Parties in writing of such decision and the reasons therefor. The arbitrator(s) shall be authorized only to interpret and apply the provisions of the Tariff and any Service Agreement entered into under the Tariff and shall have no power to modify or change any of the above in any manner. The decision of the arbitrator(s) shall be final and binding upon the Parties, and judgment on the award may be entered in any court having jurisdiction. The decision of the arbitrator(s) may be either appealed solely on a question of law alone or set aside. Such appeal or application to set aside shall be governed by the provisions of *The Arbitration Act, 1992* of Saskatchewan.

12.4 Costs:

Each Party shall be responsible for its own costs incurred during the arbitration process and for the following costs, if applicable:

(i) the cost of the arbitrator chosen by the Party to sit on the three member panel and one half of the cost of the third arbitrator chosen; or

(ii) one half the cost of the single arbitrator jointly chosen by the Parties.

12.5 Court Jurisdiction:

The Parties agree to the exclusive jurisdiction of the Saskatchewan Court of Queen’s Bench and the Saskatchewan Court of Appeal for the resolution of disputes which the Parties do not agree to arbitrate pursuant to Section 12.2 hereof and for the appeal, application to set aside or other reconsideration of an arbitral decision with respect to the Tariff or any Service Agreement under the Tariff.

12.6 Termination or Withdrawal of Tariff:

Notwithstanding any other provision in this Tariff, the Transmission Provider may terminate this Tariff and all Service Agreements hereunder, effective immediately and without satisfying the requirements of any other provisions of this Tariff if FERC issues an order against the Transmission Provider, for any reason, requiring modifications to this Tariff in a manner determined by the Transmission Provider to be unacceptable in its sole discretion. Further, nothing contained in this Tariff shall restrict the Transmission Provider's right to unilaterally withdraw this Tariff on notice for any other reason. Except as otherwise provided in this Section, such withdrawal shall not affect a Transmission Customer's right to receive Firm Point-to-Point Transmission Service or Network Integration Transmission Service pursuant to existing Service Agreements entered into under the Tariff. Upon such withdrawal of this Tariff, all rights to receive Non-Firm Point-to-Point Transmission Service under Umbrella Agreements shall terminate immediately, provided that the Transmission Provider shall complete Non-Firm Point-to-Point Transmission Service for specific Non-Firm Point-to-Point Transmission Service transactions scheduled prior to the date of termination of the Tariff (not to exceed service for three months). The Transmission Provider shall provide at least thirty (30) days notice of its intent to withdraw this Tariff to Transmission Customers that have entered into Umbrella Agreements for Non-Firm Point-to-Point Transmission Service.

II. POINT-TO-POINT TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service pursuant to the applicable terms and conditions of this Tariff. Point-to-Point Transmission Service is for the receipt of capacity and energy at designated Point(s) of Receipt and the transmission of such capacity and energy to designated Point(s) of Delivery.

13 Nature of Firm Point-To-Point Transmission Service

13.1 Term:

The minimum term of Firm Point-To-Point Transmission Service shall be one day and the maximum term shall be specified in the Service Agreement.

13.2 Reservation Policy:

Long-Term Firm Point-To-Point Transmission Service shall be available on a first-come, first-served basis i.e., in the chronological sequence in which each Transmission Customer has reserved service. Reservations for Short-Term Firm Point-To-Point Transmission Service will be conditional based upon the length of the requested transaction. If the Transmission System becomes oversubscribed, requests for longer term service may preempt requests for shorter term service up to the following deadlines: one day before the commencement of daily service, one week before the commencement of weekly service, and one month before the commencement of monthly service. Before the conditional reservation deadline, if available transmission capability is insufficient to satisfy all Applications, an Eligible Customer with a reservation for shorter term service has the right of first refusal to match any longer term reservation before losing its reservation priority. A longer term competing request for Short-Term Firm Point-To-Point Transmission Service will be granted if the Eligible Customer with the right of first refusal does not agree to match the competing request within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 13.8) from being notified by the Transmission Provider of a longer-term competing request for Short-Term Firm Point-To-Point Transmission Service. After the conditional reservation deadline, service will commence pursuant to the terms of Part II of the Tariff. Firm Point-To-Point Transmission Service will always have a reservation priority over Non-Firm Point-To-Point Transmission Service under the Tariff. All Long-Term Firm Point-To-Point Transmission Service will have equal reservation priority with Domestic Load Customers and Network Customers. Reservation priorities for existing firm service customers are provided in Section 2.2.

13.3 Use of Firm Transmission Service by the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under agreements executed on or after the effective date of this Tariff. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of the Point-To-Point Transmission Service to make Third-Party Sales.

13.4 Service Agreements:

The Transmission Provider shall offer a standard form Long-Term Firm Point-To-Point Transmission Service Agreement (Attachment A) to an Eligible Customer when it submits a Completed Application for Firm Point-To-Point Transmission Service. The Transmission Provider shall offer a standard form Umbrella Agreement (Attachment B), effective for a maximum term of three (3) years, to an Eligible Customer when it first submits a Completed Application for Short-Term Firm Point-To-Point Transmission Service pursuant to the Tariff. Upon expiry of an Umbrella Agreement, the Eligible Customer shall submit a new Completed Application for Short Term Firm Point-to-Point Transmission Service if the Eligible Customer wishes to reserve Short-Term Firm Point-to-Point Transmission Service, after which the Transmission Provider shall again offer a standard form Umbrella Agreement to the Eligible Customer.

13.5 Transmission Customer Obligations for Facility Additions or Redispatch Costs:

In cases where the Transmission Provider determines that the Transmission System is not capable of providing Firm Point-To-Point Transmission Service without (i) degrading or impairing the reliability of service to Domestic Load Customers, Network Customers and other Transmission Customers taking Firm Point-To-Point Transmission Service, or (ii) interfering with the Transmission Provider's ability to meet prior firm contractual commitments to others, the Transmission Provider will be obligated to expand or upgrade its Transmission System pursuant to the terms of Section 15.3. The Transmission Customer must agree to compensate the Transmission Provider for any necessary transmission facility additions pursuant to the terms of Section 27. To the extent the Transmission Provider can relieve any system constraint more economically by redispatching the Transmission Provider's resources than through constructing Network Upgrades, it shall do so, provided that the Eligible Customer agrees to compensate the Transmission Provider pursuant to the terms of Section 27. Any redispatch, Network Upgrade or Direct Assignment Facilities costs to be charged to the Transmission Customer on an incremental basis under the Tariff will be specified in the Service Agreement or specified by the Transmission Provider pursuant to the terms of an executed Umbrella Agreement prior to initiating service.

13.6 Curtailment of Firm Transmission Service:

In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, and the systems directly and indirectly interconnected with the Transmission Provider’s Transmission, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. The Transmission Provider shall implement such Curtailments pursuant to the procedures included as Attachment H hereto. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider’s

Domestic Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments.

13.7 Classification of Firm Transmission Service:

(i) The Transmission Customer taking Firm Point-To-Point Transmission Service may: (i) change its Receipt and Delivery Points to obtain service on a non-firm basis consistent with the terms of Section 22.1; or (ii) request a modification of the Points of Receipt or Delivery on a firm basis pursuant to the terms of Section 22.2.

(ii) The Transmission Customer may purchase transmission service to make sales of capacity and energy from multiple generating units that are on the Transmission Provider's Transmission System. For such a purchase of transmission service, the resources will be designated as multiple Points of

Receipt, unless the multiple generating units are at the same generating plant in which case the units would be treated as a single Point of Receipt.

(iii) The Transmission Provider shall provide firm deliveries of capacity and energy from the Point(s) of Receipt to the Point(s) of Delivery. Each Point of Receipt at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Receipt. Points of Receipt and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. Each Point of Delivery at which firm transmission capacity is reserved by the Transmission Customer shall be set forth in the Firm Point-To-Point Service Agreement for Long-Term Firm Transmission Service along with a corresponding capacity reservation associated with each Point of Delivery. Points of Delivery and corresponding capacity reservations shall be as mutually agreed upon by the Parties for Short-Term Firm Transmission. The greater of either (i) the sum of the capacity reservations at the Point(s) of Receipt, or (ii) the sum of the capacity reservations at the Point(s) of Delivery shall be the Transmission Customer's Reserved Capacity. The Transmission Customer will be billed for its Reserved Capacity under the terms of Schedule 7. The Transmission Customer may not exceed its firm capacity reserved at each Point of Receipt and each Point of Delivery except as otherwise specified in Section 22. In the event that a Transmission Customer (including Third-Party Sales by the Transmission Provider) exceeds its firm reserved capacity at any Point of Receipt or Point of Delivery, the Transmission Customer shall pay to the Transmission Provider the applicable Schedule 7 charges for the amount of capacity that exceeded the firm reserved capacity.

13.8 Scheduling of Firm Point-To-Point Transmission Service:

Schedules for the Transmission Customer's Firm Point-To-Point Transmission Service must be submitted to the Transmission Provider no later than 10:00 a.m. Central Standard Time the day prior to commencement of such service. Schedules submitted after 10:00 a.m. Central Standard Time will be accommodated, if practicable. Hour-to-hour schedules of any capacity and energy that is to be delivered must be stated in increments of 1,000 kW per hour (or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider). Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their service requests at a Common Point of Receipt into units of 1,000 kW per hour for scheduling and billing purposes. Scheduling changes will be permitted up to twenty (20) minutes (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the

Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14 Nature of Non-Firm Point-To-Point Transmission Service

14.1 Term:

Non-Firm Point-To-Point Transmission Service will be available for periods ranging from one (1) hour to six (6) months as provided in Schedule 8.

14.2 Reservation Priority:

Non-Firm Point-To-Point Transmission Service shall be available from transmission capability in excess of that needed for reliable service to Domestic Load Customers, Network Customers and other Transmission Customers taking Long-Term and Short-Term Firm Point-To-Point Transmission Service. A higher priority will be assigned to reservations with a longer duration of service. In the event the Transmission System is constrained, competing requests of equal duration will be prioritized based on the highest price offered by the Eligible Customer for the Transmission Service. Eligible Customers that have already reserved shorter term service have the right of first refusal to match any longer term reservation before being preempted. A longer term competing request for Non-Firm Point-To-Point Transmission Service will be granted if the Eligible

Customer with the right of first refusal does not agree to match the competing request: (i) immediately for hourly Non-Firm Point-To-Point Transmission Service after notification by the Transmission Provider; and, (ii) within 24 hours (or earlier if necessary to comply with the scheduling deadlines provided in section 14.6) for Non-Firm Point-To-Point Transmission Service other than hourly transactions after notification by the Transmission Provider. Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have the lowest reservation priority under the Tariff.

14.3 Use of Non-Firm Point-To-Point Transmission Service by the Transmission Provider:

The Transmission Provider will be subject to the rates, terms and conditions of Part II of the Tariff when making Third-Party Sales under agreement executed on or after the effective date of the Tariff. The Transmission Provider will maintain separate accounting, pursuant to Section 8, for any use of Non-Firm Point-To-Point Transmission Service to make Third-Party Sales.

14.4 Service Agreements:

The Transmission Provider shall offer a standard form Umbrella Agreement effective for a maximum term of three (3) years, (Attachment B) to an Eligible Customer when it first submits a Completed Application for Non-Firm Point-To-Point Transmission Service pursuant to the Tariff. Upon expiry of an Umbrella

Agreement, the Eligible Customer shall submit a new Completed Application for Non-Firm Point-to-Point Transmission Service if the Eligible Customer wishes to reserve Non-Firm Point-to-Point Transmission Service, after which the Transmission Provider shall again offer a standard form Umbrella Agreement to the Eligible Customer.

14.5 Classification of Non-Firm Point-To-Point Transmission Service:

Non-Firm Point-To-Point Transmission Service shall be offered under terms and conditions contained in Part II of the Tariff. The Transmission Provider undertakes no obligation under the Tariff to plan its Transmission System in order to have sufficient capacity for Non-Firm Point-To-Point Transmission Service. Parties requesting Non-Firm Point-To-Point Transmission Service for the transmission of firm power do so with the full realization that such service is subject to availability and to Curtailment or Interruption under the terms of the Tariff. In the event that a Transmission Customer, (including Third-Party Sales by the Transmission Provider) exceeds its non-firm capacity reservation, the Transmission Customer shall pay to the Transmission Provider the applicable Schedule 8 Charges for the amount of capacity that exceeded the Non-Firm Reserve Capacity. Non-Firm Point-To-Point Transmission Service shall include transmission of energy on an hourly basis and transmission of scheduled short-term capacity and energy on a daily, weekly or monthly basis, but not to exceed six (6) months' reservation for any one Application, under Schedule 8.

14.6 Scheduling of Non-Firm Point-To-Point Transmission Service:

Schedules for Non-Firm Point-To-Point Transmission Service, other than hourly Non-Firm Point-to-Point Transmission Service, must be submitted to the Transmission Provider no later than 10:00 a.m. Central Standard Time of the day prior to commencement of such service. Schedules submitted after 10:00 a.m. Central Standard Time will be accommodated, if practicable. Schedules of energy that is to be delivered must be stated in increments of 1,000 kW per hour (or a reasonable increment that is generally accepted in the region and is consistently adhered to by the Transmission Provider). Transmission Customers within the Transmission Provider's service area with multiple requests for Transmission Service at a Point of Receipt, each of which is under 1,000 kW per hour, may consolidate their schedules at a common Point of Receipt into units of 1,000 kW per hour. Scheduling changes will be permitted up to twenty (20) minutes (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) before the start of the next clock hour provided that the Delivering Party and Receiving Party also agree to the schedule modification. The Transmission Provider will furnish to the Delivering Party's system operator, hour-to-hour schedules equal to those furnished by the Receiving Party (unless reduced for losses) and shall deliver the capacity and energy provided by such schedules. Should the Transmission Customer, Delivering Party or Receiving Party revise or terminate any schedule, such party shall immediately notify the Transmission Provider, and the Transmission

Provider shall have the right to adjust accordingly the schedule for capacity and energy to be received and to be delivered.

14.7 Curtailment or Interruption of Service:

The Transmission Provider reserves the right to Curtail, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for reliability reasons when an emergency or other unforeseen condition threatens to impair or degrade the reliability of its Transmission System or the systems directly or indirectly interconnected with the Transmission Provider's Transmission System. The Transmission Provider shall implement such curtailments pursuant to the procedures included as Attachment H hereto. The Transmission Provider reserves the right to Interrupt, in whole or in part, Non-Firm Point-To-Point Transmission Service provided under the Tariff for economic reasons in order to accommodate: (i) a request for Firm Transmission Service; (ii) a request for Non-Firm Point-To-Point Transmission Service of greater duration; (iii) a request for Non-Firm Point-To-Point Transmission Service of equal duration with a higher price; or (iv) transmission service for Network Customers from non-designated resources. The Transmission Provider also will discontinue or reduce service to the Transmission Customer to the extent that deliveries for transmission are discontinued or reduced at the Point(s) of Receipt. Where required, Curtailments or Interruptions will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint; however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. If multiple transactions require Curtailment or

Interruption, to the extent practicable and consistent with Good Utility Practice, Curtailments or Interruptions will be made to transactions of the shortest term (e.g., hourly non-firm transactions will be Curtailed or Interrupted before daily non-firm transactions and daily non-firm transactions will be Curtailed or Interrupted before weekly non-firm transactions). Transmission service for Network Customers from resources other than designated Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. Non-Firm Point-To-Point Transmission Service over secondary Point(s) of Receipt and Point(s) of Delivery will have a lower priority than any Non-Firm Point-To-Point Transmission Service under the Tariff. The Transmission Provider will provide advance notice of Curtailment or Interruption where such notice can be provided consistent with Good Utility Practice.

15 Service Availability

15.1 General Conditions:

The Transmission Provider will provide Firm and Non-Firm Point-To-Point Transmission Service over, on or across its Transmission System to any Transmission Customer that has met the requirements of Section 16.

15.2 Determination of Available Transmission Capability:

A description of the Transmission Provider's specific methodology for assessing available transmission capability posted on the OASIS used by Transmission Provider (Section 4) is contained in Attachment C of the Tariff. In the event sufficient transmission capability may not exist to accommodate a service request, the Transmission Provider will respond by offering to perform a System Impact Study.

15.3 Obligation to Provide Transmission Service that Requires Expansion or Modification of the Transmission System:

If the Transmission Provider determines that it cannot accommodate a Completed Application for Firm Point-To-Point Transmission Service because of insufficient capability on its Transmission System, the Transmission Provider will use due diligence to expand or modify its Transmission System to provide the requested Firm Transmission Service, provided the Transmission Customer agrees to compensate the Transmission Provider for such costs pursuant to the terms of Section 27. The Transmission Provider will conform to Good Utility Practice in determining the need for new facilities and in the design and construction of such facilities. The obligation applies only to those facilities that the Transmission Provider has the right to expand or modify.

15.4 Deferral of Service:

The Transmission Provider may defer providing service until it completes construction of new transmission facilities or upgrades needed to provide Firm Point-To-Point Transmission Service whenever the Transmission Provider determines that providing the requested service would, without such new facilities or upgrades, impair or degrade reliability to any existing firm services.

15.5 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to replace Real Power Losses. The Transmission

Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are set forth in Schedule 9 of this Tariff.

16 Transmission Customer Responsibilities

16.1 Conditions Required of Transmission Customers:

Point-To-Point Transmission Service shall be provided by the Transmission Provider only if the following conditions are satisfied by the Transmission Customer:

(i) The Transmission Customer has pending a Completed Application for service;

(ii) The Transmission Customer meets the creditworthiness criteria set forth in Section 11;

(iii) The Transmission Customer will have arrangements in place for any other transmission service necessary to effect the delivery from the generating source to the Transmission Provider prior to the time service under Part II of the Tariff commences;

(iv) The Transmission Customer agrees to pay for any facilities constructed and chargeable to such Transmission Customer under Part II of the Tariff, whether or not the Transmission Customer takes service for the full term of its reservation; and

(v) The Transmission Customer has executed a Point-To-Point Service Agreement.

16.2 Transmission Customer Responsibility for Third-Party Arrangements:

Any scheduling arrangements that may be required by other electric systems shall be the responsibility of the Transmission Customer requesting service. The Transmission Customer shall provide, unless waived by the Transmission Provider, notification to the Transmission Provider identifying such systems and authorizing them to schedule the capacity and energy to be transmitted by the Transmission Provider pursuant to Part II of the Tariff on behalf of the Receiving Party at the Point of Delivery or the Delivering Party at the Point of Receipt. However, the Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in making such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice.

17 Procedures for Arranging Firm Point-To-Point Transmission Service

17.1 Application:

A request for Firm Point-To-Point Transmission Service for periods of one year or longer must be made by entering a completed Application on the OASIS used by the Transmission Provider at least sixty (60) days in advance of the calendar month in which service is to commence. The Transmission Provider will consider requests for such firm service on shorter notice when feasible. Requests for firm service for periods of less than one year shall be subject to expedited procedures that shall be negotiated between the Parties within the time constraints provided in Section 17.5. All Firm Point-To-Point Transmission Service requests should be submitted by entering the information listed below on the OASIS used by the Transmission Provider. If the OASIS used by the Transmission Provider is not functioning, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the priority of the Application.

17.2 Completed Application:

A Completed Application shall provide all of the information listed below:

(i) The identity, address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The location of the Point(s) of Receipt and Point(s) of Delivery and the identities of the Delivering Parties and the Receiving Parties;

(iv) The location of the generating facility(ies) supplying the capacity and energy and the location of the load ultimately served by the capacity and energy transmitted. The Transmission Provider will treat this information as confidential except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order, or by Canadian Law, for reliability purposes pursuant to Good Utility Practice or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with its standards of conduct;

(v) A description of the supply characteristics of the capacity and energy to be delivered;

(vi) An estimate of the capacity and energy expected to be delivered to the Receiving Party;

(vii) The Service Commencement Date and the term of the requested Transmission Service; and

(viii) The transmission capacity requested for each Point of Receipt and each Point of Delivery on the Transmission Provider's Transmission System; customers may combine their requests for service in order to satisfy the minimum transmission capacity requirement.

The Transmission Provider shall treat this information consistent with its standards of conduct.

17.3 Deposit:

A Completed Application for Firm Point-To-Point Transmission Service also shall include a deposit of either one (1) month's charge for Reserved Capacity or the full charge for Reserved Capacity for service requests of less than one (1) month. If the Application is rejected by the Transmission Provider because it does not meet the conditions for service as set forth herein, or in the case of requests for service arising in connection with losing bidders in a Request For Proposals (RFP), said deposit shall be returned less any reasonable costs incurred by the Transmission Provider in connection with the review of the losing bidder's Application. The deposit also will be returned less any reasonable costs incurred by the Transmission Provider if the Transmission Provider is unable to complete new facilities needed to provide the service. If an Application is withdrawn or the Eligible Customer decides not to enter into a Service Agreement for Firm Point-To-Point Transmission Service, the deposit shall be refunded in full, less reasonable costs incurred by the Transmission Provider to the extent such costs have not already been recovered by the Transmission Provider from the Eligible Customer. The Transmission Provider will provide to the Eligible Customer a complete accounting of all costs deducted from the refunded deposit, which the Eligible Customer may contest if there is a dispute concerning the deducted costs. Deposits associated with construction of new facilities are subject to the provisions of Section 19. If a Service Agreement for Firm Point-To-Point Transmission Service is executed, the deposit will be returned to the Transmission Customer upon expiration or termination of the Service Agreement for Firm Point-To-Point Transmission Service.

17.4 Notice of Deficient Application:

If an Application fails to meet the requirements of the Tariff, the Transmission Provider shall notify the entity requesting service within fifteen (15) days of receipt of the reasons for such failure. The Transmission Provider will attempt to remedy minor deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application, along with any deposit. Upon receipt of a new or revised Application that fully complies with the requirements of Part II of the Tariff, the Eligible Customer shall be assigned a new priority consistent with the date of the new or revised Application.

17.5 Response to a Completed Application:

Following receipt of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider shall make a determination of available transmission capability as required in Section 15.2. The Transmission Provider shall notify the Eligible Customer as soon as practicable, but not later than thirty (30) days after the date of receipt of a Completed Application either (i) if it will be able to provide service without performing a System Impact Study or (ii) if such a study is needed to evaluate the impact of the Application pursuant to Section 19.1. Responses by the Transmission Provider must be made as soon as practicable to all completed applications (including applications by its own merchant function) and the timing of such responses must be made on a non-discriminatory basis.

17.6 Execution of Service Agreement:

Whenever the Transmission Provider determines that a System Impact Study is not required and that the service can be provided, it shall notify the Eligible Customer as soon as practicable but no later than thirty (30) days after receipt of the Completed Application. Where a System Impact Study is required, the provisions of Section 19 will govern the execution of a Service Agreement. Failure of an Eligible Customer to execute and return the Service Agreement within fifteen (15) days after it is tendered by the Transmission Provider or confirm an approved request pursuant to terms of an executed Umbrella Agreement will be deemed a withdrawal and termination of the Application and any deposit submitted shall be refunded. Nothing herein limits the right of an

Eligible Customer to file another Application after such withdrawal and termination.

17.7 Extensions for Commencement of Service:

The Transmission Customer can obtain up to five (5) one-year extensions for the commencement of service. The Transmission Customer may postpone service by paying a non-refundable annual reservation fee equal to one-month's charge for Firm Transmission Service for each year or fraction thereof. If during any extension for the commencement of service an Eligible Customer submits a Completed Application for Firm Transmission Service, and such request can be satisfied only by releasing all or part of the Transmission Customer's Reserved Capacity, the original Reserved Capacity will be released unless the following condition is satisfied. Within thirty (30) days, the original Transmission Customer agrees to pay the Firm Point-To-Point transmission rate for its Reserved Capacity concurrent with the new Service Commencement Date. In the event the Transmission Customer elects to release the Reserved Capacity, the reservation fees or portions thereof previously paid will be forfeited.

18 Procedures for Arranging Non-Firm Point-To-Point Transmission Service

18.1 Application:

Eligible Customers seeking Non-Firm Point-To-Point Transmission Service must submit a Completed Application to the Transmission Provider. Applications should be submitted by entering the information listed below on the OASIS used by the Transmission Provider. If the OASIS used by the Transmission Provider is not functioning, a Completed Application may be submitted by: (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application.

18.2 Completed Application:

A Completed Application shall provide all of the information listed below:

(i) The identity, address, email address, telephone number and facsimile number of the entity requesting service;

(ii) A statement that the entity requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) The Point(s) of Receipt and the Point(s) of Delivery;

(iv) The maximum amount of capacity requested at each Point of Receipt and Point of Delivery; and

(v) The proposed dates and hours for initiating and terminating transmission service hereunder.

In addition to the information specified above, when required to properly evaluate system conditions, the Transmission Provider also may ask the Transmission Customer to provide the following:

(vi) The electrical location of the initial source of the power to be transmitted pursuant to the Transmission Customer's request for service; and

(vi) The electrical location of the ultimate load.

The Transmission Provider will treat the information in (vi) and (vii) as confidential at the request of the Transmission Customer except to the extent that disclosure of this information is required by this Tariff, by regulatory or judicial order or by Canadian Law, for reliability purposes pursuant to Good Utility Practice, or pursuant to RTG transmission information sharing agreements. The Transmission Provider shall treat this information consistent with its standards of conduct.

18.3 Reservation of Non-Firm Point-To-Point Transmission Service:

Requests for monthly service shall be submitted no earlier than one hundred twenty (120) days before service is to commence; requests for weekly service shall be submitted no earlier than sixty (60) days before service is to commence, requests for daily service shall be submitted no earlier than thirty (30) days before service is to commence, and requests for hourly service shall be submitted no earlier than 10:00 a.m. Central Standard Time the day before service is to commence. Requests for service received later than 10:00 a.m. Central Standard Time prior to the day service is scheduled to commence will be accommodated if practicable.

18.4 Determination of Available Transmission Capability:

Following receipt of a tendered schedule the Transmission Provider will make a determination on a non-discriminatory basis of available transmission capability pursuant to Section 15.2. Such determination shall be made as soon as reasonably practicable after receipt, but not later than the following time periods for the following terms of service: (i) thirty (30) minutes for hourly service; (ii) one (1) hour for daily service; (iii) four (4) hours for weekly service; and (iv) two (2) days for monthly service.

19 Additional Study Procedures for Firm Point-To-Point Transmission Service Requests

19.1 Notice of Need for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned.

19.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the

Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the requests for service, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

19.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or provide confirmation to the Transmission Provider pursuant to the terms of an executed Umbrella Agreement or the Application shall be deemed terminated and withdrawn.

19.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities Study Agreement, its application shall be deemed withdrawn and its deposit, pursuant to Section 17.3, shall be returned. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Transmission Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of: (i) the cost of Direct Assignment Facilities to be charged to the Transmission Customer; (ii) the Transmission Customer's appropriate share of the cost of any required Network Upgrades as determined pursuant to the provisions of Part II of the Tariff; and (iii) the time required to complete such construction and initiate the requested service. The Transmission Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as under the laws of the Province of Saskatchewan. The Transmission Customer shall have thirty (30) days to execute a Service Agreement or provide written confirmation to the Transmission Provider pursuant to the terms of an executed Umbrella Agreement and provide the required letter of credit or other form of security or the request will no longer be a Completed Application and shall be deemed terminated and withdrawn.

19.5 Facilities Study Modifications:

Any change in design arising from inability to site or construct facilities as proposed will require development of a revised good faith estimate. New good faith estimates also will be required in the event of new statutory or regulatory requirements that are effective before the completion of construction or other circumstances beyond the control of the Transmission Provider that significantly affect the final cost of new facilities or upgrades to be charged to the Transmission Customer pursuant to the provisions of Part II of the Tariff.

19.6 Due Diligence in Completing New Facilities:

The Transmission Provider shall use due diligence to add necessary facilities or upgrade its Transmission System within a reasonable time. The Transmission Provider will not upgrade its existing or planned Transmission System in order to provide the requested Firm Point-To- Point Transmission Service if doing so would impair system reliability or otherwise impair or degrade existing firm service.

19.7 Partial Interim Service:

If the Transmission Provider determines that it will not have adequate transmission capability to satisfy the full amount of a Completed Application for Firm Point-To-Point Transmission Service, the Transmission Provider nonetheless shall be obligated to offer and provide the portion of the requested Firm Point-To-Point Transmission Service that can be accommodated without addition of any facilities and through redispatch. However, the Transmission Provider shall not be obligated to provide the incremental amount of requested

Firm Point-To-Point Transmission Service that requires the addition of facilities or upgrades to the Transmission System until such facilities or upgrades have been placed in service.

19.8 Expedited Procedures for New Facilities:

In lieu of the procedures set forth above, the Eligible Customer shall have the option to expedite the process by requesting the Transmission Provider to tender at one time, together with the results of required studies, an "Expedited Service Agreement" pursuant to which the Eligible Customer would agree to compensate the Transmission Provider for all costs incurred pursuant to the terms of the Tariff. In order to exercise this option, the Eligible Customer shall request in writing an expedited Service Agreement covering all of the above-specified items within thirty (30) days of receiving the results of the System Impact Study identifying needed facility additions or upgrades or costs incurred in providing the requested service. While the Transmission Provider agrees to provide the Eligible Customer with its best estimate of the new facility costs and other charges that may be incurred, such estimate shall not be binding and the Eligible Customer must agree in writing to compensate the Transmission Provider for all costs incurred pursuant to the provisions of the Tariff. The Eligible Customer shall execute and return such an Expedited Service Agreement within fifteen (15) days of its receipt or the Eligible Customer's request for service will cease to be a Completed Application and will be deemed terminated and withdrawn.

20 Procedures if The Transmission Provider is Unable to Complete New Transmission Facilities for Firm Point-To-Point Transmission Service

20.1 Delays in Construction of New Facilities:

If any event occurs that will materially affect the time for completion of new facilities, or the ability to complete them, the Transmission Provider shall promptly notify the Transmission Customer. In such circumstances, the Transmission Provider shall within thirty (30) days of notifying the Transmission Customer of such delays, convene a technical meeting with the Transmission Customer to evaluate the alternatives available to the Transmission Customer. The Transmission Provider also shall make available to the Transmission Customer studies and work papers related to the delay, including all information that is in the possession of the Transmission Provider that is reasonably needed by the Transmission Customer to evaluate any alternatives.

20.2 Alternatives to the Original Facility Additions:

When the review process of Section 20.1 determines that one or more alternatives exist to the originally planned construction project, the Transmission Provider shall present such alternatives for consideration by the Transmission Customer. If, upon review of any alternatives, the Transmission Customer desires to maintain its Completed Application subject to construction of the alternative facilities, it may request the Transmission Provider to submit a revised Service Agreement for Long-Term Firm Point-To-Point Transmission Service. If the alternative approach solely involves Short-Term Firm or Non-Firm Point-To-Point Transmission Service, the Transmission Provider shall promptly tender an Umbrella Agreement for Short-Term Firm or Non-Firm Point-To-Point Transmission Service providing for the service. In the event the Transmission Provider concludes that no reasonable alternative exists and the Transmission Customer disagrees, the Transmission Customer may seek relief under the dispute resolution procedures pursuant to Section 12.

20.3 Refund Obligation for Unfinished Facility Additions:

If the Transmission Provider and the Transmission Customer mutually agree that no other reasonable alternatives exist and the requested service cannot be provided out of existing capability under the conditions of Part II of the Tariff, the obligation to provide the requested Firm Point-To-Point Transmission Service shall terminate and any deposit made by the Transmission Customer shall be returned. The Transmission Customer shall be responsible for all prudently incurred costs by the Transmission Provider through the time construction was suspended.

21 Provisions Relating to Transmission Construction and Services on the Systems of Other Utilities

21.1 Responsibility for Third-Party System Additions:

The Transmission Provider shall not be responsible for making arrangements for any necessary engineering, permitting, and construction of transmission or distribution facilities on the system(s) of any other entity or for obtaining any regulatory approval for such facilities. The Transmission Provider will undertake reasonable efforts to assist the Transmission Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other electric system pursuant to Good Utility Practice. The Transmission Customer shall reimburse the Transmission Provider for all prudently incurred costs arising from the Transmission Provider's obligation to undertake such efforts.

21.2 Coordination of Third-Party System Additions:

In circumstances where the need for transmission facilities or upgrades is identified pursuant to the provisions of Part II of the Tariff, and if such upgrades further require the addition of transmission facilities on other systems, the Transmission Provider shall have the right to coordinate construction on its own system with the construction required by others. The Transmission Provider, after consultation with the Transmission Customer and representatives of such other systems, may defer construction of its new transmission facilities, if the new transmission facilities on another system cannot be completed in a timely manner. The Transmission Provider shall notify the Transmission Customer in writing of the basis for any decision to defer construction and the specific problems which must be resolved before it will initiate or resume construction of new facilities. Within sixty (60) days of receiving written notification by the Transmission Provider of its intent to defer construction pursuant to this section, the Transmission Customer may challenge the decision in accordance with the dispute resolution procedures pursuant to Section 12.

22 Changes in Service Specifications

22.1 Modifications On a Non-Firm Basis:

The Transmission Customer taking Firm Point-To-Point Transmission Service may request the Transmission Provider to provide transmission service on a non-firm basis over Receipt and Delivery Points other than those specified in the Service Agreement or agreed on pursuant to an Umbrella Agreement ("Secondary Receipt and Delivery Points"), in amounts not to exceed its firm capacity reservation, without incurring an additional Non-Firm Point-To-Point Transmission Service charge or executing a new Service Agreement, subject to the following conditions:

(i) Service provided over Secondary Receipt and Delivery Points will be non-firm only, on an as-available basis and will not displace any firm or non-firm service reserved or scheduled by third-parties under the Tariff or by the Transmission Provider on behalf of its Domestic Load Customers.

(ii) The sum of all Firm and non-firm Point-To-Point Transmission Service provided to the Transmission Customer at any time pursuant to this section shall not exceed the Reserved Capacity in the relevant Service Agreement or agreed on pursuant to an Umbrella Agreement under which such services are provided.

(iii) The Transmission Customer shall retain its right to schedule Firm Point-To-Point Transmission Service at the Receipt and Delivery Points specified in the relevant Service Agreement or agreed on pursuant to an Umbrella Agreement in the amount of its original capacity reservation.

(iv) Service over Secondary Receipt and Delivery Points on a non-firm basis shall not require the filing of an Application for Non-Firm Point-To-Point Transmission Service under the Tariff. However, all other requirements of Part II of the Tariff (except as to transmission rates) shall apply to transmission service on a non-firm basis over Secondary Receipt and Delivery Points.

22.2 Modifications on a Firm Basis:

Any request by a Transmission Customer to modify Receipt and Delivery Points on a firm basis shall be treated as a new request for service in accordance with Section 17 hereof, except that such Transmission Customer shall not be obligated to pay any additional deposit if the capacity reservation does not exceed the amount reserved in the existing Service Agreement or agreed on pursuant to an Umbrella Agreement. While such new request is pending, the Transmission Customer shall retain its priority for service at the existing firm Receipt and Delivery Points specified in its Service Agreement.

23 Sale or Assignment of Transmission Service

23.1 Procedures for Assignment or Transfer of Service:

Subject to any legislative or regulatory approval that may be required, a Transmission Customer may sell, assign, or transfer all or a portion of its rights under its Service Agreement, but only to another Eligible Customer (the Assignee). The Transmission Customer that sells, assigns or transfers its rights under its Service Agreement is hereafter referred to as the Reseller. Compensation to the Reseller shall not exceed the higher of: (i) the original rate paid by the

Reseller; (ii) the Transmission Provider's maximum rate in effect at the time of the assignment; or (iii) the Reseller's opportunity cost capped at the Transmission Provider's cost of expansion. If the Assignee does not request any change in the Point(s) of Receipt or the Point(s) of Delivery, or a change in any other term or condition set forth in the original Service Agreement, the Assignee will receive the same services as did the Reseller and the priority of service for the Assignee will be the same as that of the Reseller. A Reseller should notify the Transmission Provider as soon as possible after any assignment or transfer of service occurs but in any event, notification must be provided prior to any provision of service to the Assignee. The Assignee will be subject to all terms and conditions of this Tariff. If the Assignee requests a change in service, the reservation priority of service will be determined by the Transmission Provider pursuant to Section 13.2.

23.2 Limitations on Assignment or Transfer of Service:

If the Assignee requests a change in the Point(s) of Receipt or Point(s) of Delivery, or a change in any other specifications set forth in the original Service Agreement, the Transmission Provider will consent to such change subject to the provisions of the Tariff, provided that the change will not impair the operation and reliability of the Transmission Provider's generation, transmission, or distribution systems. The Assignee shall compensate the Transmission Provider for performing any System Impact Study needed to evaluate the capability of the Transmission System to accommodate the proposed change and any additional costs resulting from such change. The Reseller shall remain liable for the performance of all obligations under the Service Agreement, except as specifically agreed to by the Parties through an amendment to the Service Agreement.

23.3 Information on Assignment or Transfer of Service:

In accordance with Section 4, Resellers may use the OASIS used by the Transmission Provider to post transmission capacity available for resale.

24 Metering and Power Factor Correction at Receipt and Delivery Points(s)

24.1 Transmission Customer Obligations:

Unless otherwise agreed, the Transmission Customer shall be responsible for installing and maintaining compatible metering and communications equipment to accurately account for the capacity and energy being transmitted under Part II of the Tariff and to communicate the information to the Transmission Provider. Such equipment shall remain the property of the Transmission Customer.

24.2 Transmission Provider Access to Metering Data:

The Transmission Provider shall have access to metering data, which may reasonably be required to facilitate measurements and billing under the Service Agreement.

24.3 Power Factor:

Unless otherwise agreed, the Transmission Customer is required to maintain a power factor within the same range as the Transmission Provider pursuant to Good Utility Practices. The power factor requirements are specified in the Service Agreement where applicable.

25 Compensation for Transmission Service

Rates for Firm and Non-Firm Point-To-Point Transmission Service are provided in the Schedules appended to the Tariff: Long-Term Firm Point-To-Point Transmission Service (Schedule 7); and Non-Firm Point-To-Point Transmission Service (Schedule 8). The Transmission Provider shall use Part II of the Tariff to make its Third-Party Sales. The Transmission Provider shall account for such use at the applicable Tariff rates, pursuant to Section 8.

26 Stranded Cost Recovery

The Transmission Provider may seek to recover stranded costs from the Transmission Customer pursuant to this Tariff subject to the dispute resolution provisions in section 12.

27 Compensation for New Facilities and Redispatch Costs

Whenever a System Impact Study performed by the Transmission Provider in connection with the provision of Firm Point-To-Point Transmission Service identifies the need for new facilities, the Transmission Customer shall be responsible for such costs to the extent consistent with law and policy governing the Transmission Provider. Whenever a System Impact Study performed by the Transmission Provider identifies capacity constraints that may be relieved more economically by redispatching the Transmission Provider's resources than by building new facilities or upgrading existing facilities to eliminate such constraints, the Transmission Customer shall be responsible for the redispatch costs to the extent consistent with law and/or policy governing the Transmission Provider.

III. NETWORK INTEGRATION TRANSMISSION SERVICE

Preamble

The Transmission Provider will provide Network Integration Transmission Service pursuant to the applicable terms and conditions contained in the Tariff and Service Agreement. Network Integration Transmission Service allows the Network Customer to integrate, economically dispatch and regulate its current and planned Network Resources to serve its Network Load in a manner comparable to that in which the Transmission Provider utilizes its Transmission System to serve its Domestic Load Customers. Network Integration Transmission Service also may be used by the Network Customer to deliver economy energy purchases to its Network Load from non-designated resources on an as-available basis without additional charge. Transmission service for sales to non-designated loads will be provided pursuant to the applicable terms and conditions of Part II of the Tariff.

28 Nature of Network Integration Transmission Service

28.1 Scope of Service:

Network Integration Transmission Service is a transmission service that allows Network Customers to efficiently and economically utilize their Network Resources (as well as other non-designated generation resources) to serve their Network Load located in the Transmission Provider's Control Area and any additional load that may be designated pursuant to Section 31.3 of the Tariff. The Network Customer taking Network Integration Transmission Service must obtain or provide Ancillary Services pursuant to Section 3.

28.2 Transmission Provider Responsibilities:

The Transmission Provider will plan, construct, operate and maintain its Transmission System in accordance with Good Utility Practice in order to provide the Network Customer with Network Integration Transmission Service over the Transmission Provider's Transmission System. The Transmission Provider, on behalf of its Domestic Load Customers, shall be required to designate resources and loads in the same manner as any Network Customer under Part III of this Tariff. This information must be consistent with the information used by the Transmission Provider to calculate available transmission capability. The Transmission Provider shall include the Network Customer's Network Load in its Transmission System planning and shall, consistent with Good Utility Practice, endeavor to construct and place into service sufficient transmission capacity to deliver the Network Customer's Network Resources to serve its Network Load on a basis comparable to the Transmission Provider's delivery of its own generating and purchased resources to its Domestic Load Customers.

28.3 Network Integration Transmission Service:

The Transmission Provider will provide firm transmission service over its Transmission System to the Network Customer for the delivery of capacity and energy from its designated Network Resources to service its Network Loads on a basis that is comparable to the Transmission Provider's use of the Transmission System to reliably serve its Domestic Load Customers.

28.4 Secondary Service:

The Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than

Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff.

28.5 Real Power Losses:

Real Power Losses are associated with all transmission service. The Transmission Provider is not obligated to replace Real Power Losses. The Network Customer is responsible for replacing losses associated with all transmission service as calculated by the Transmission Provider. The applicable Real Power Loss factors are set forth in Schedule 9 of this Tariff.

28.6 Restrictions on Use of Service:

The Network Customer shall not use Network Integration Transmission Service for (i) sales of capacity and energy to non-designated loads, or (ii) direct or indirect provision of transmission service by the Network Customer to third parties. All Network Customers taking Network Integration Transmission Service shall use Point-To-Point Transmission Service under Part II of the Tariff for any Third-Party Sale which requires use of the Transmission Provider's Transmission System.

29 Initiating Service

29.1 Conditions Precedent for Receiving Service:

Subject to the terms and conditions of Part III of the Tariff, the Transmission Provider will provide Network Integration Transmission Service to any Eligible Customer, provided that: (i) the Eligible Customer completes an Application for service as provided under Part III of the Tariff; (ii) the Eligible Customer and the Transmission Provider complete the technical arrangements set forth in Sections

29.3 and 29.4; (iii) the Eligible Customer executes a Service Agreement pursuant to Attachment E for service under Part III of the Tariff, and (iv) the Eligible Customer executes a Network Operating Agreement with the Transmission Provider pursuant to Attachment F.

29.2 Application Procedures:

An Eligible Customer requesting service under Part III of the Tariff must submit an Application, with a deposit approximating the charge for one month of service, to the Transmission Provider as far as possible in advance of the month in which service is to commence. Unless subject to the procedures in Section 2, Completed Applications for Network Integration Transmission Service will be assigned a priority according to the date and time the Application is received, with the earliest Application receiving the highest priority. Applications should be submitted by entering the information listed below on the OASIS used by the Transmission Provider. If the OASIS used by the Transmission Provider is not functioning, a Completed Application may be submitted by (i) transmitting the required information to the Transmission Provider by telefax, or (ii) providing the information by telephone over the Transmission Provider's time recorded telephone line. Each of these methods will provide a time-stamped record for establishing the service priority of the Application. A Completed Application shall provide all of the information listed below:

(i) The identity, address, telephone number and facsimile number of the party requesting service;

(ii) A statement that the party requesting service is, or will be upon commencement of service, an Eligible Customer under the Tariff;

(iii) A description of the Network Load at each delivery point. This description should separately identify and provide the Eligible Customer's best estimate of the total loads to be served at each transmission voltage level, and the loads to be served from each Transmission Provider substation at the same transmission voltage level. The description should include a ten (10) year forecast of summer and winter load and resource requirements beginning with the first year after the service is scheduled to commence;

(iv) The amount and location of any interruptible loads included in the Network Load. This shall include the summer and winter capacity requirements for each interruptible load (had such load not been interruptible), that portion of the load subject to interruption, the conditions under which an interruption can be implemented and any limitations on the amount and frequency of interruptions. An Eligible Customer should identify the amount of interruptible customer load (if any) included in the ten (10) year load forecast provided in response to (iii) above;

(v) A description of Network Resources (current and ten (10) year projection), which shall include, for each Network Resource:

- Unit size and amount of capacity from that unit to be designated as Network Resource
- VAr capability (both leading and lagging) of all generators
- Operating restrictions
- Any periods of restricted operations throughout the year
- Maintenance schedules

- Minimum loading level of unit
- Normal operating level of unit
- Any must-run unit designations required for system reliability or contract reasons
- Load and frequency control capability
- Dispatchability and manoeuverability
- Approximate variable generating cost ($/MWh) for redispatch computations
- Arrangements governing sale and delivery of power to third parties from generating facilities located in the Transmission Provider Control Area, where only a portion of unit output is designated as a Network Resource
- Description of purchased power designated as a Network Resource including source of supply, Control Area location, transmission arrangements and delivery point(s) to the Transmission Provider's Transmission System;

(vi) Description of Eligible Customer's transmission system:

- Load flow and stability data, such as real and reactive parts of the load, lines, transformers, reactive devices and load type, including normal and emergency ratings of all transmission equipment in formats compatible with that used by the Transmission Provider
- Operating restrictions needed for reliability
- Operating guides employed by system operators
- Contractual restrictions or committed uses of the Eligible Customer's transmission system, other than the Eligible Customer's Network Loads and Resources
- Location of Network Resources described in subsection (v) above
- ten (10) year projection of system expansions or upgrades
- Transmission System maps that include any proposed expansions or upgrades
- Thermal ratings of Eligible Customer's Control Area ties with other Control Areas; and

(vii) Service Commencement Date and the term of the requested Network Integration Transmission Service. The minimum term for Network Integration Transmission Service is one (1) year.

Unless the Parties agree to a different time frame, the Transmission Provider must acknowledge the request within ten (10) days of receipt. The acknowledgment must include a date by which a response, including a Service Agreement, will be sent to the Eligible Customer. If an Application fails to meet the requirements of this section, the Transmission Provider shall notify the Eligible Customer requesting service within fifteen (15) days of receipt and specify the reasons for such failure. Wherever possible, the Transmission Provider will attempt to remedy deficiencies in the Application through informal communications with the Eligible Customer. If such efforts are unsuccessful, the Transmission Provider shall return the Application without prejudice to the Eligible Customer filing a new or revised Application that fully complies with the requirements of this section. The Eligible Customer will be assigned a new priority consistent with the date of the new or revised Application. The Transmission Provider shall treat this information consistent with its standards of conduct.

29.3 Technical Arrangements to be Completed Prior to Commencement of Service:

Network Integration Transmission Service shall not commence until the Transmission Provider and the Network Customer, or a third party, have completed installation of all equipment specified under the Network Operating Agreement consistent with Good Utility Practice and any additional requirements reasonably and consistently imposed to ensure the reliable operation of the Transmission System. The Transmission Provider shall exercise reasonable efforts, in coordination with the Network Customer, to complete such arrangements as soon as practicable taking into consideration the Service Commencement Date.

29.4 Network Customer Facilities:

The provision of Network Integration Transmission Service shall be conditioned upon the Network Customer's constructing, maintaining and operating the facilities on its side of each delivery point or interconnection necessary to reliably deliver capacity and energy from the Transmission Provider's Transmission System to the Network Customer. The Network Customer shall be solely responsible for constructing or installing all facilities on the Network Customer's side of each such delivery point or interconnection.

30 Network Resources

30.1 Designation of Network Resources:

Network Resources shall include all generation and dedicated transmission equipment owned, purchased or leased by the Network Customer designated to serve Network Load under the Tariff. Network Resources may not include resources, or any portion thereof, that are committed for sale to non-designated third party load, or otherwise cannot be called upon to meet the Network Customer's Network Load on a non-interruptible basis. Any owned or purchased resources that were serving the Network Customer's loads under firm agreements entered into on or before the Service Commencement Date shall initially be designated as Network Resources until the Network Customer terminates the designation of such resources.

30.2 Designation of New Network Resources:

The Network Customer may designate a new Network Resource by providing the Transmission Provider with as much advance notice as practicable. A designation of a new Network Resource must be made by a request for modification of service by submitting a new Application under Section 29.

30.3 Termination of Network Resources:

The Network Customer may terminate the designation of all or part of a generating resource as a Network Resource at any time but should provide notification to the Transmission Provider as soon as reasonably practicable.

30.4 Operation of Network Resources:

The Network Customer shall not operate its designated Network Resources located in the Network Customer's or Transmission Provider's Control Area such that the output of those facilities exceeds its designated Network Load, plus non-firm sales delivered pursuant to Part II of the Tariff, plus losses. This limitation shall not apply to changes in the operation of a Transmission Customer’s Network Resources at the request of the Transmission Provider to respond to an emergency or other unforeseen condition which may impair or degrade the reliability of the Transmission System.

30.5 Network Customer Redispatch Obligation:

As a condition to receiving Network Integration Transmission Service, the Network Customer agrees to redispatch its Network Resources as requested by the Transmission Provider pursuant to Section 33.2. To the extent practical, the redispatch of resources pursuant to this section shall be on a least cost, non-discriminatory basis between all Network Customers, and the Transmission Provider.

30.6 Transmission Arrangements for Network Resources Not Physically Interconnected With The Transmission Provider:

The Network Customer shall be responsible for any arrangements necessary to deliver capacity and energy from a Network Resource not physically interconnected with the Transmission Provider's Transmission System. The Transmission Provider will undertake reasonable efforts to assist the Network Customer in obtaining such arrangements, including without limitation, providing any information or data required by such other entity pursuant to Good Utility Practice.

30.7 Limitation on Designation of Network Resources:

The Network Customer must demonstrate that it owns or has committed to purchase generation pursuant to an executed contract in order to designate a generating resource as a Network Resource. Alternatively, the Network Customer may establish that execution of a contract is contingent upon the availability of transmission service under Part III of the Tariff.

30.8 Use of Interface Capacity by the Network Customer:

There is no limitation upon a Network Customer's use of the Transmission Provider's Transmission System at any particular interface to integrate the Network Customer's Network Resources (or substitute economy purchases) with its Network Loads. However, a Network Customer's use of the Transmission Provider's total interface capacity with other transmission systems may not exceed the Network Customer's Load.

30.9 Network Customer Owned Transmission Facilities:

The Network Customer that owns existing transmission facilities that are integrated with the Transmission Provider's Transmission System may be eligible to receive consideration either through a billing credit or some other mechanism. In order to receive such consideration the Network Customer must demonstrate that its transmission facilities are integrated into the plans or operations of the Transmission Provider to serve its power and transmission customers. For facilities constructed by the Network Customer subsequent to the Service Commencement Date under Part III of the Tariff, the Network Customer shall receive credit where such facilities are jointly planned and installed in coordination with the Transmission Provider. Calculation of the credit shall be addressed in either the Network Customer's Service Agreement or any other agreement between the Parties.

31 Designation of Network Load

31.1 Network Load:

The Network Customer must designate the individual Network Loads on whose behalf the Transmission Provider will provide Network Integration Transmission Service. The Network Loads shall be specified in the Service Agreement.

31.2 New Network Loads Connected With the Transmission Provider:

The Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable of the designation of new Network Load that will be added to its Transmission System. A designation of new Network Load must be made through a modification of service pursuant to a new

Application. The Transmission Provider will use due diligence to install any transmission facilities required to interconnect a new Network Load designated by the Network Customer. The costs of new facilities required to interconnect a new Network Load shall be determined in accordance with the procedures provided in Section 32.4 and shall be charged to the Network Customer in accordance with law or policy governing the Transmission Provider.

31.3 Network Load Not Physically Interconnected with the Transmission Provider:

This section applies to both initial designation pursuant to Section 31.1 and the subsequent addition of new Network Load not physically interconnected with the Transmission Provider. To the extent that the Network Customer desires to obtain transmission service for a load outside the Transmission Provider's Transmission System, the Network Customer shall have the option of: (i) electing to include the entire load as Network Load for all purposes under Part III of the Tariff and designating Network Resources in connection with such additional Network Load; or (ii) excluding that entire load from its Network Load and purchasing Point-To-Point Transmission Service under Part II of the Tariff. To the extent that the Network Customer gives notice of its intent to add a new Network Load as part of its Network Load pursuant to this section the request must be made through a modification of service pursuant to a new Application.

31.4 New Interconnection Points:

To the extent the Network Customer desires to add a new Delivery Point or interconnection point between the Transmission Provider's Transmission System and a Network Load, the Network Customer shall provide the Transmission Provider with as much advance notice as reasonably practicable.

31.5 Changes in Service Requests:

Under no circumstances shall the Network Customer's decision to cancel or delay a requested change in Network Integration Transmission Service (e.g. the addition of a new Network Resource or designation of a new Network Load) in any way relieve the Network Customer of its obligation to pay the costs of transmission facilities constructed by the Transmission Provider and charged to the Network Customer as reflected in the Service Agreement. However, the Transmission Provider must treat any requested change in Network Integration Transmission Service in a non-discriminatory manner.

31.6 Annual Load and Resource Information Updates:

The Network Customer shall provide the Transmission Provider with annual updates of Network Load and Network Resource forecasts consistent with those included in its Application for Network Integration Transmission Service under Part III of the Tariff. The Network Customer also shall provide the Transmission Provider with timely written notice of material changes in any other information provided in its Application relating to the Network Customer's Network Load, Network Resources, its transmission system or other aspects of its facilities or operations affecting the Transmission Provider's ability to provide reliable service.

32 Additional Study Procedures For Network Integration Transmission Service Requests

32.1 Notice of Need for System Impact Study:

After receiving a request for service, the Transmission Provider shall determine on a non-discriminatory basis whether a System Impact Study is needed. A description of the Transmission Provider's methodology for completing a System Impact Study is provided in Attachment D. If the Transmission Provider determines that a System Impact Study is necessary to accommodate the requested service, it shall so inform the Eligible Customer, as soon as practicable. In such cases, the Transmission Provider shall within thirty (30) days of receipt of a Completed Application, tender a System Impact Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required System Impact Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the System Impact Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the System Impact Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned.

32.2 System Impact Study Agreement and Cost Reimbursement:

(i) The System Impact Study Agreement will clearly specify the Transmission Provider's estimate of the actual cost, and time for completion of the System Impact Study. The charge shall not exceed the actual cost of the study. In performing the System Impact Study, the

Transmission Provider shall rely, to the extent reasonably practicable, on existing transmission planning studies. The Eligible Customer will not be assessed a charge for such existing studies; however, the Eligible Customer will be responsible for charges associated with any modifications to existing planning studies that are reasonably necessary to evaluate the impact of the Eligible Customer's request for service on the Transmission System.

(ii) If in response to multiple Eligible Customers requesting service in relation to the same competitive solicitation, a single System Impact Study is sufficient for the Transmission Provider to accommodate the service requests, the costs of that study shall be pro-rated among the Eligible Customers.

(iii) For System Impact Studies that the Transmission Provider conducts on its own behalf, the Transmission Provider shall record the cost of the System Impact Studies pursuant to Section 8.

32.3 System Impact Study Procedures:

Upon receipt of an executed System Impact Study Agreement, the Transmission Provider will use due diligence to complete the required System Impact Study within a sixty (60) day period. The System Impact Study shall identify any system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. In the event that the Transmission Provider is unable to complete the required System Impact Study within such time period, it shall so notify the Eligible Customer and provide an estimated completion date along with an explanation of the reasons why additional time is required to complete the required studies. A copy of the completed System Impact Study and related work papers shall be made available to the Eligible Customer. The Transmission Provider will use the same due diligence in completing the System Impact Study for an Eligible Customer as it uses when completing studies for itself. The Transmission Provider shall notify the Eligible Customer immediately upon completion of the System Impact Study if the Transmission System will be adequate to accommodate all or part of a request for service or that no costs are likely to be incurred for new transmission facilities or upgrades. In order for a request to remain a Completed Application, within fifteen (15) days of completion of the System Impact Study the Eligible Customer must execute a Service Agreement or the Application shall be deemed terminated and withdrawn.

32.4 Facilities Study Procedures:

If a System Impact Study indicates that additions or upgrades to the Transmission System are needed to supply the Eligible Customer's service request, the Transmission Provider, within thirty (30) days of the completion of the System Impact Study, shall tender to the Eligible Customer a Facilities Study Agreement pursuant to which the Eligible Customer shall agree to reimburse the Transmission Provider for performing the required Facilities Study. For a service request to remain a Completed Application, the Eligible Customer shall execute the Facilities Study Agreement and return it to the Transmission Provider within fifteen (15) days. If the Eligible Customer elects not to execute the Facilities

Study Agreement, its Application shall be deemed withdrawn and its deposit shall be returned. Upon receipt of an executed Facilities Study Agreement, the Transmission Provider will use due diligence to complete the required Facilities Study within a sixty (60) day period. If the Transmission Provider is unable to complete the Facilities Study in the allotted time period, the Transmission Provider shall notify the Eligible Customer and provide an estimate of the time needed to reach a final determination along with an explanation of the reasons that additional time is required to complete the study. When completed, the Facilities Study will include a good faith estimate of: (i) the cost of Direct Assignment Facilities to be charged to the Eligible Customer; (ii) the Eligible Customer's appropriate share of the cost of any required Network Upgrades; and (iii) the time required to complete such construction and initiate the requested service. The Eligible Customer shall provide the Transmission Provider with a letter of credit or other reasonable form of security acceptable to the Transmission Provider equivalent to the costs of new facilities or upgrades consistent with commercial practices as established under the laws of Canada and the Province of Saskatchewan. The Eligible Customer shall have thirty (30) days to execute a Service Agreement and provide the required letter of credit or other form of security or the request no longer will be a Completed Application and shall be deemed terminated and withdrawn.

33 Load Shedding and Curtailments

33.1 Procedures:

Prior to the Service Commencement Date, the Transmission Provider and the Network Customer shall establish Load Shedding and Curtailment procedures pursuant to the Network Operating Agreement with the objective of responding to contingencies on the Transmission System or on systems directly or indirectly interconnected with the Transmission Provider’s Transmission System. The Parties will implement such programs during any period when the Transmission Provider determines that a system contingency exists and such procedures are necessary to alleviate such contingency. The Transmission Provider will notify all affected Network Customers in a timely manner of any scheduled Curtailment.

33.2 Transmission Constraints:

During any period when the Transmission Provider determines that a transmission constraint exists on the Transmission System, and such constraint may impair the reliability of the Transmission Provider's system, the Transmission Provider will take whatever actions, consistent with Good Utility Practice, that are reasonably necessary to maintain the reliability of the Transmission Provider's system. To the extent the Transmission Provider determines that the reliability of the Transmission System can be maintained by redispatching resources, the Transmission Provider will initiate procedures pursuant to the Network Operating Agreement to redispatch all Network Resources and the Transmission Provider's own resources on a least-cost basis without regard to the ownership of such resources. Any redispatch under this section may not unduly discriminate between the Transmission Provider's use of the Transmission System on behalf of its Domestic Load Customers and any Network Customer's use of the Transmission System to serve its designated Network Load.

33.3 Cost Responsibility for Relieving Transmission Constraints:

Whenever the Transmission Provider implements least-cost redispatch procedures in response to a transmission constraint, the Transmission Provider and Network Customers will each bear a proportionate share of the total redispatch cost based on their respective Load Ratio Shares.

33.4 Curtailments of Scheduled Deliveries:

If a transmission constraint on the Transmission Provider's Transmission System cannot be relieved through the implementation of least-cost redispatch procedures and the Transmission Provider determines that it is necessary to Curtail scheduled deliveries, the Parties shall Curtail such schedules in accordance with the Network Operating Agreement pursuant to the procedures specified in Attachment H hereto.

33.5 Allocation of Curtailments:

The Transmission Provider shall, on a non-discriminatory basis, Curtail the transaction(s) that effectively relieve the constraint. However, to the extent practicable and consistent with Good Utility Practice, any Curtailment will be shared by the Transmission Provider and Network Customer in proportion to their respective Load Ratio Shares. The Transmission Provider shall not direct the Network Customer to Curtail schedules to an extent greater than the Transmission

Provider would Curtail the Transmission Provider's schedules under similar circumstances.

33.6 Load Shedding:

To the extent that a system contingency exists on the Transmission Provider's Transmission System and the Transmission Provider determines that it is necessary for the Transmission Provider and the Network Customer to shed load, the Parties shall shed load in accordance with previously established procedures under the Network Operating Agreement.

33.7 System Reliability:

Notwithstanding any other provisions of this Tariff, the Transmission Provider reserves the right, consistent with Good Utility Practice and on a not unduly discriminatory basis, to Curtail Network Integration Transmission Service without liability on the Transmission Provider's part for the purpose of making necessary adjustments to, changes in, or repairs on its lines, substations and facilities, and in cases where the continuance of Network Integration Transmission Service would endanger persons or property. In the event of any adverse condition(s) or disturbance(s) on the Transmission Provider's Transmission System or on any other system(s) directly or indirectly interconnected with the Transmission Provider's Transmission System, the Transmission Provider, consistent with Good Utility Practice, also may Curtail Network Integration Transmission Service in order to (i) limit the extent or damage of the adverse condition(s) or disturbance(s), (ii) prevent damage to generating or transmission facilities, or (iii) expedite restoration of service. The

Transmission Provider will give the Network Customer as much advance notice as is practicable in the event of such Curtailment. Any Curtailment of Network Integration Transmission Service will be not unduly discriminatory relative to the Transmission Provider's use of the Transmission System on behalf of its Domestic Load Customers. The Transmission Provider shall specify the rate treatment and all related terms and conditions applicable in the event that the Network Customer fails to respond to established Load Shedding and Curtailment procedures.

34 Rates and Charges

The Network Customer shall pay the Transmission Provider for any Direct Assignment Facilities, Ancillary Services, and applicable study costs, consistent with law or policy governing the Transmission Provider along with the following:

34.1 Monthly Demand Charge:

The Network Customer shall pay a monthly Demand Charge, which shall be determined by multiplying its Load Ratio Share times one twelfth (1/12) of the Transmission Provider's Annual Transmission Revenue Requirement specified in Attachment G.

34.2 Determination of Network Customer's Monthly Network Load:

The Network Customer's monthly Network Load is its hourly load (including its designated Network Load not physically interconnected with the Transmission Provider under Section 31.3) coincident with the Transmission Provider's Monthly Transmission System Peak.

34.3 Determination of Transmission Provider's Monthly Transmission System Load:

The Transmission Provider's monthly Transmission System load is the Transmission Provider's Monthly Transmission System Peak minus the coincident peak usage of all Firm Point-to-Point Transmission Service customers pursuant to Part II of this Tariff plus the Reserved Capacity of all Firm Point-to-Point Transmission Service customers.

34.4 Redispatch Charge:

The Network Customer shall pay a Load Ratio Share of any redispatch costs allocated between the Network Customer and the Transmission Provider pursuant to Section 33. To the extent that the Transmission Provider incurs an obligation to the Network Customer for redispatch costs in accordance with Section 33, such amounts shall be credited against the Network Customer's bill for the applicable month.

34.5 Stranded Cost Recovery:

The Transmission Provider may seek to recover stranded costs from the Network Customer pursuant to this Tariff subject to the dispute resolution provisions of section 12.

35 Operating Arrangements

35.1 Operation under The Network Operating Agreement: The Network Customer shall plan, construct, operate and maintain its facilities in accordance with Good Utility Practice and in conformance with the Network Operating Agreement.

35.2 Network Operating Agreement: The terms and conditions under which the Network Customer shall operate its facilities and the technical and operational matters associated with the implementation of Part III of the Tariff shall be specified in the Network Operating Agreement. The Network Operating Agreement shall provide for the Parties to: (i) operate and maintain equipment necessary for integrating the Network Customer within the Transmission Provider's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment); (ii) transfer data between the Transmission Provider and the Network Customer (including, but not limited to, heat rates and operational characteristics of Network Resources, generation schedules for units outside the Transmission Provider's Transmission System, interchange schedules, unit outputs for redispatch required under Section 33, voltage schedules, loss factors and other real time data); (iii) use software programs required for data links and constraint dispatching; (iv) exchange data on forecasted loads and resources necessary for long-term planning; and (v) address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocols. The Network Operating Agreement will recognize that the Network Customer shall either: (i) operate as a Control Area under applicable guidelines of the North American Electric Reliability Council (NERC) and MAPP; (ii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with the Transmission Provider; or (iii) satisfy its Control Area requirements, including all necessary Ancillary Services, by contracting with another entity, consistent with Good Utility Practice, which satisfies NERC and MAPP requirements. The Transmission Provider shall not unreasonably refuse to accept contractual arrangements with another entity for Ancillary Services. The Network Operating Agreement is included in Attachment F.

35.3 Network Operating Committee: A Network Operating Committee (Committee) shall be established to coordinate operating criteria for the Parties' respective responsibilities under the Network Operating Agreement. Each Network Customer shall be entitled to have at least one representative on the Committee. The Committee shall meet from time to time as need requires, but no less than once each calendar year.

APPENDIX 1

Interbank Transfer of Funds Account

Bank Wire Transfer to:	Royal Bank of Canada 2010 11th Avenue - 8th Floor Branch 003 Transit 00008
For Credit to:	SaskPower Canadian Account No .1598440

SCHEDULE 1

Scheduling, System Control and Dispatch Service

This service is required to schedule the movement of power through, out of, within, or into a Control Area. This service can be provided only by the operator of the Control Area in which the transmission facilities used for transmission service are located. Scheduling, System Control and Dispatch Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider. The charges for Scheduling, System Control and Dispatch Service are as set forth below.

Rate: $200/MW of Reserved Capacity per month. The weekly, daily and hourly delivery charges are calculated in the same manner as in Schedule 7 and 8.

SCHEDULE 2

Reactive Supply and Voltage Control from Generation Sources Service

In order to maintain transmission voltages on the Transmission Provider's transmission facilities within acceptable limits, generation facilities under the control of the control area operator are operated to produce (or absorb) reactive power. Thus, Reactive Supply and Voltage Control from Generation Sources Service must be provided for each transaction on the Transmission Provider's transmission facilities. The amount of Reactive Supply and Voltage Control from Generation Sources Service that must be supplied with respect to the Transmission Customer's transaction will be determined based on the reactive power support necessary to maintain transmission voltages within limits that are generally accepted in the region and consistently adhered to by the Transmission Provider.

Reactive Supply and Voltage Control from Generation Sources Service is to be provided directly by the Transmission Provider. The Transmission Customer must purchase this service from the Transmission Provider. The charges for such service will be as set forth below:

Rate: $148/MW of Reserved Capacity per month. The weekly, daily and hourly delivery charges are calculated in the same manner as in Schedule 7 and 8.

SCHEDULE 3

Regulation and Frequency Response Service

Regulation and Frequency Response Service is necessary to provide for the continuous balancing of resources (generation and interchange) with load and for maintaining scheduled Interconnection frequency at sixty cycles per second (60 Hz). Regulation and Frequency Response Service is accomplished by committing on-line generation whose output is raised or lowered (predominantly through the use of automatic generating control equipment) as necessary to follow the moment-by-moment changes in load. The obligation to maintain this balance between resources and load lies with the Transmission Provider. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Regulation and Frequency Response Service obligation. Customers making alternative arrangements will be required to provide Regulation and Frequency Response Service in the amount of 1.6% of their reserved capacity for Point to Point Transmission Service or 1.6% of their Network Load responsibility for Network Integration Transmission Service. The charges for Regulation and Frequency Response Service are set forth below.

Rate: $ 128/MW of Reserved Capacity per month. The weekly, daily and hourly delivery charges are calculated in the same manner as in Schedule 7 and 8.

SCHEDULE 4

Energy Imbalance Service

Energy Imbalance Service is provided when a difference occurs between the scheduled and the actual delivery of energy to a load located within a Control Area over a single hour. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Energy Imbalance Service obligation.

The Transmission Provider shall establish a deviation band of +/- 1.5 percent (with a minimum of 2 MW) of the scheduled transaction to be applied hourly to any energy imbalance that occurs as a result of the Transmission Customer's scheduled transaction(s). Parties should attempt to eliminate energy imbalances within the limits of the deviation band within thirty (30) days or within such other reasonable period of time as is generally accepted in the region and consistently adhered to by the Transmission Provider. If an energy imbalance is not corrected within thirty (30) days or a reasonable period of time that is generally accepted in the region and consistently adhered to by the Transmission Provider, the Transmission Customer will compensate the Transmission Provider for such service. Energy imbalances outside the deviation band will be subject to charges to be specified by the Transmission Provider. The charges for Energy Imbalance Service are set forth below.

There shall be no charge for imbalances less than +/- 1.5%. Any imbalance energy within this bandwidth which occurs shall be accounted for in an imbalance energy exchange account and repaid as energy in kind between the Transmission Customer and Transmission Provider at mutually agreed times and payback amounts. Any energy imbalance on-peak or off-peak, that is not repaid in kind by the Transmission Customer within 30 days following the agreed to times and conditions stated above shall be billed at the greater of 110% of the Transmission Provider’s incremental cost at the time of occurrence or the current MAPP filed rate for Emergency Energy Interchange Service. Any energy imbalance, on-peak or off-peak, that is not repaid in kind by the Transmission Provider within 30 days following the agreed to times and conditions stated above shall be billed at 90% of the Transmission Provider’s decremental cost.

The rate for energy imbalances greater than +1.5% (Transmission Customer receives at the delivery point(s) more than it scheduled) shall be the greater of 110% of the Transmission Provider’s incremental cost at the time of occurrence or the current MAPP filed rate for Emergency Energy Interchange Service.

SCHEDULE 5

Operating Reserve - Spinning Reserve Service

Spinning Reserve Service is needed to serve load immediately in the event of a system contingency. Spinning Reserve Service may be provided by generating units that are on-line and loaded at less than maximum output. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Spinning Reserve Service obligation. Customers making alternative arrangements will be required to provide Spinning Reserve Service in the amount of 4.4% of their reserved capacity for Point to Point Transmission Service or 4.4% of their Network Load responsibility for Network Integration Transmission Service. The charges for Spinning Reserve Service are set forth below.

Rate: $298/MW of Reserved Capacity per month. The weekly, daily and hourly delivery charges are calculated in the same manner as in Schedule 7 and 8.

SCHEDULE 6

Operating Reserve - Supplemental Reserve Service

Supplemental Reserve Service is needed to serve load in the event of a system contingency; however, it is not available immediately to serve load but rather within a short period of time. Supplemental Reserve Service may be provided by generating units that are on-line but unloaded, by quick-start generation or by interruptible load. The Transmission Provider must offer this service when the transmission service is used to serve load within its Control Area. The Transmission Customer must either purchase this service from the Transmission Provider or make alternative comparable arrangements to satisfy its Supplemental Reserve Service obligation. Customers making alternative arrangements will be required to provide Supplemental Reserve Service in the amount of 6.7% of their reserved capacity for Point to Point Transmission Service or 6.7% of their Network Load responsibility for Network Integration Transmission Service. The amount of and charges for Supplemental Reserve Service are set forth below.

Rate: $409/MW of Reserved Capacity per month. The weekly, daily and hourly delivery charges are calculated in the same manner as in Schedule 7 and 8.

SCHEDULE 7

Long-Term Firm and Short-Term Firm Point-To-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider each month for Reserved Capacity at the sum of the applicable charges set forth below:

1) **Yearly Delivery**: 1/12 of the annual delivery charge of $26,532/MW of Reserved Capacity per year.

2) **Monthly Delivery:** $2,211/MW of Reserved Capacity per month (calculated as 1/12 of the annual delivery charge).

3) **Weekly Delivery**: $510/MW of Reserved Capacity per week (calculated as 1/52 of the annual delivery charge).

4) **Daily Delivery**: $102/MW of Reserved Capacity per day (calculated as 1/5 of the weekly delivery charge.)

The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the

Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Exceeded Reservation**: In the event that the Transmission Customer exceeds its firm Reserved Capacity (excluding losses) at a Point of Receipt and/or Point of Delivery, except as otherwise specified in the Tariff, the Transmission Customer shall be charged 200 per cent of the charges under Schedules 1, 2 and 7 for the maximum amount that the Transmission Customer exceeds its firm Reserved Capacity at each Point of Receipt and each Point of Delivery during the billing period.

SCHEDULE 8

Non-Firm Point-to-Point Transmission Service

The Transmission Customer shall compensate the Transmission Provider for Non-Firm Point-to-Point Transmission Service up to the sum of the applicable charges set forth below:

1) **Monthly Delivery:** $2,211/MW of Reserved Capacity per month (calculated as 1/12 of the annual delivery charge).

2) **Weekly Delivery**: $510/MW of Reserved Capacity per week (calculated as 1/52 of the annual delivery charge.)

3) **Daily Delivery**: $102/MW of Reserved Capacity per day (calculated as 1/5 of the weekly delivery charge).

   The total demand charge in any week, pursuant to a reservation for Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in megawatts of Reserved Capacity in any day during such week.

4) **Hourly Delivery**: The basic charge shall be that agreed upon by the Parties at the time this service is reserved and in no event shall exceed $6.38/MWh (1/16 of the daily delivery charge). The total demand charge in any day, pursuant to a reservation for Hourly delivery, shall not exceed the rate specified in section (3) above times the highest amount in megawatts of Reserved Capacity in any hour during such day. In addition, the total demand charge in any week, pursuant to a reservation for Hourly or Daily delivery, shall not exceed the rate specified in section (2) above times the highest amount in kilowatts of Reserved Capacity in any hour during such week.

5) **Discounts**: Three principal requirements apply to discounts for transmission service as follows: (1) any offer of a discount made by the Transmission Provider must be announced to all Eligible Customers solely by posting on the OASIS, (2) any customer-initiated requests for discounts (including requests for use by one's wholesale merchant or an affiliate's use) must occur solely by posting on the OASIS, and (3) once a discount is negotiated, details must be immediately posted on the OASIS. For any discount agreed upon for service on a path, from point(s) of receipt to point(s) of delivery, the Transmission Provider must offer the same discounted transmission service rate for the same time period to all Eligible Customers on all unconstrained transmission paths that go to the same point(s) of delivery on the Transmission System.

6) **Exceeded Reservation**: In the event that the Transmission Customer exceeds its non-firm Reserved Capacity (excluding losses) at a Point of Receipt and/or Point of Delivery, the Transmission Customer shall be charged 200 per cent of the charges under Schedules 1, 2 and 8 for the maximum amount of Non-Firm Point-to-Point Transmission Service that exceeds its non-firm Reserved Capacity during the billing period.

SCHEDULE 9

Real Power Loss Factors

For Point-to-Point service, the Transmission Provider will seasonally calculate loss factors to be used on a path-by-path basis. For each season, winter and summer, the power flow models used to calculate the losses will include peak, off-peak and shoulder hours to derive an "average" loss factor for each path. For long-term Point-to-Point service, the annual loss factor to be used for a particular path is the average of the seasonal values. The loss factors will be posted on the Transmission Provider's OASIS site.

For Network Service, the Transmission Provider will apply the "system average" loss factor of 4.4%. This factor will be reviewed annually and is subject to change annually.

The SaskPower OATT requires that Transmission Customers provide the losses associated with their service. All Transmission Customers are required to include an amount of additional capacity in their service requests sufficient to carry the losses associated with their service.

ATTACHMENT A

Form of Service Agreement For
Long-Term Firm Point-To-Point Transmission Service

1.0 This Service Agreement, dated as of _______________, is entered into, by and between Saskatchewan Power Corporation (the “Transmission Provider”) and __________________________ (the "Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to have a Completed Application for Long-Term Firm Point-To-Point Transmission Service under the SaskPower Open Access Transmission Tariff (the “Tariff”).

3.0 The Transmission Customer has provided to the Transmission Provider an Application deposit in accordance with the provisions of Section 17.3 of the Tariff.

4.0 Service under this Service Agreement shall commence on the later of (l) the requested service commencement date, or (2) the date on which construction of any Direct Assignment Facilities and/or Network Upgrades are completed. Service under this agreement shall terminate on such date as set forth in the attached specifications for Long-Term Firm Point-to-Point Transmission Service incorporated herein.

5.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Firm Point-To-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Service Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

<u>Transmission Provider</u>

Supervisor, Transmission Services
SaskPower - System Control Centre
2025 Victoria Avenue
Regina, Saskatchewan
Canada S4P 0S1
Phone: ________________________
Fax: ________________________
Email: ________________________

<u>Transmission Customer:</u>

____

____

____

7.0 No failure by the Transmission Provider or the Transmission Customer at any time or from time to time to enforce or require a strict observance of any of the provisions of this Service Agreement shall constitute a waiver of the provision or affect or impair such provisions or the right of the Transmission Provider or the Transmission Customer at any time to enforce such provisions or to avail itself of any remedy it may have.

8.0 This Service Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and any Assignees of the Transmission Customer authorized pursuant to Section 23.1 of the Tariff.

9.0 The Tariff and the attached Specifications for Long-Term Firm Point-to-Point Transmission Service are incorporated herein and made a part hereof.

10.0 Notwithstanding Paragraph 9, the Transmission Provider shall have the sole discretion and authority to offer the Transmission Customer partial service, a system impact study, or a facilities study including an estimate of the additional costs, in order to provide the Transmission Customer's right of first refusal contained in Section 2.2 of the Tariff in the event that the transmission capacity requested cannot be accommodated by the Transmission Provider due to the growth of Domestic Load. The right of first refusal contained in Section 2.2 of the Tariff is further limited for the Firm Transmission Service provided under this Service Agreement as follows:

____
____
____
____
____

11.0 Applicable taxes shall be added to all charges set forth in the Tariff.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:______________________ ______________ ______________
Name Title Date

By:______________________ ______________ ______________
Name Title Date

Transmission Customer:

By:______________________ ______________ ______________
Name Title Date

By:______________________ ______________ ______________
Name Title Date

Specifications For Long-Term Firm Point-To-Point Transmission Service
OASIS Reference Number: ________________

l.0 Term of Transaction: ____________________________________

Start Date: ____

Termination Date: _______________________________________

2.0 Description of capacity and energy to be transmitted by Transmission Provider including the electric Control Area in which the transaction originates.

____

3.0 Point(s) of Receipt:_____________________________________

Delivering Party:____

4.0 Point(s) of Delivery:____________________________________

Receiving Party:____

5.0 Maximum amount of capacity and energy to be transmitted (Reserved Capacity):_____________________________________

6.0 Designation of party(ies) subject to reciprocal service obligation:_________

7.0 Name(s) of any Intervening Systems providing transmission service:____
____

8.0 Service under this Agreement may be subject to some combination of the charges detailed below. (The appropriate charges for individual transactions will be determined in accordance with the terms and conditions of the Tariff.)

8.1 Transmission Charge:
As per **Schedule 7** of the Transmission Provider's Tariff
____

8.2 System Impact and/or Facilities Study Charge(s):
____
____

8.3 Redispatch Charge: ____________________

8.4 Network Upgrade Charge: ____________________

8.5 Direct Assignment Facilities Charge: ______________

8.6 Ancillary Services Charges:

- Scheduling, System Control and Dispatch Service as per **Schedule 1** of the Transmission Provider's Tariff
- Reactive Supply and Voltage Control from Generation Sources Service as per **Schedule 2** of the Transmission Provider's Tariff
- Regulation and Frequency Response Service as per **Schedule 3** of the Transmission Provider's Tariff
- Energy Imbalance Service as per **Schedule 4** of the Transmission Provider's Tariff
- Operating Reserve - Spinning Reserve Service as per **Schedule 5** of the Transmission Provider's Tariff
- Operating Reserve - Supplemental Reserve Service as per **Schedule 6** of the Transmission Provider's Tariff

ATTACHMENT B

Form of Umbrella Agreement for Short-Term Firm or Non-Firm Point-to-Point Transmission Service

1.0 This Umbrella Agreement, dated as of ______________________, is entered into, by and between Saskatchewan Power Corporation (the "Transmission Provider") and ________________ (the "Transmission Customer").

2.0 The Transmission Customer has been determined by the Transmission Provider to be a Transmission Customer under Part II of the SaskPower Open Access Transmission Tariff (the "Tariff") and has filed a Completed Application for Short-Term Firm or Non-Firm Point-to-Point Transmission Service in accordance with the Tariff.

3.0 This Umbrella Agreement shall come into force upon execution by both Parties. During the term of this Umbrella Agreement, the Transmission Customer shall be entitled to arrange Short-Term Firm or Non-Firm Point-to-Point Transmission Service over the OASIS used by the Transmission Provider provided that such transactions do not exceed $_______ in any calendar month. The Transmission Provider reserves the right to consent to larger monthly transactions on a case-by-case basis. The Transmission Provider may review the credit rating of the Transmission Customer at any time during the term of this Umbrella Agreement. In the event the Transmission Provider determines, acting reasonably, that the credit rating of the Transmission Customer is below the level acceptable to the Transmission Provider, the Transmission Provider may reduce the Transmission Customer's credit limit or terminate this Umbrella Agreement on thirty (30) days notice.

4.0 The Transmission Customer shall identify any affiliates that own, control or operate any transmission facilities. If there are none, the Transmission Customer shall include a sworn statement pursuant to Section 6.0 of the Tariff.

5.0 This Umbrella Agreement shall remain in effect for a period of ____ years from the date of execution.

6.0 Conditions Precedent

6.1 Unless a System Impact Study is required, service under this Umbrella Agreement shall be provided by the Transmission Provider following: a) the submission, by entry on the OASIS, of a Completed Application for Short-Term Firm or Non-Firm Point-to-Point Transmission Service by an authorized representative of the Transmission Customer; b) the Transmission Provider's signification on the OASIS that the Completed Application has been accepted; and c) confirmation by the Transmission Customer on the OASIS within the time frames specified by this Tariff and the Transmission Provider's business practices, unless the Transmission Customer designates that the transaction is pre-confirmed.

6.2 Where a System Impact Study must be performed for Short-Term Firm Point-to-Point Transmission Service and the Transmission Customer executes a System Impact Study Agreement, Transmission Service shall be provided by the Transmission Provider if, after receiving a System Impact Study which indicates that the request can be accommodated through re-dispatch and the costs of re-dispatch, the Transmission Customer provides written confirmation to the Transmission Provider that the

Transmission Customer is willing to pay for any re-dispatch costs associated with the requested service in accordance with Section 27 of the Tariff. Where re-dispatch and/or new facilities are not required, Transmission Service shall be provided upon confirmation by the Transmission Customer on the OASIS of the Transmission Provider's acceptance of the request, within the time frames specified herein, unless the Transmission Customer designates that the transaction is preconfirmed.

6.3 Where a Facilities Study must be performed for Short Term Firm Point-to-Point Transmission Service and the Transmission Customer executes a Facilities Study Agreement, Transmission Service shall be provided by the Transmission Provider if after receiving the Facilities Study, the Transmission Customer provides written confirmation to the Transmission Provider that the Transmission Customer is willing to pay for the costs of any required Network Upgrades and/or Direct Assignment Facilities and provides the necessary security in accordance with sections 19.4 and 27 of the Tariff.

7.0 The Transmission Customer agrees to supply information the Transmission Provider deems reasonably necessary in accordance with Good Utility Practice in order for the Transmission Provider to provide the requested service.

8.0 The Transmission Provider agrees to provide and the Transmission Customer agrees to take and pay for Short-Term Firm or Non-Firm Point-to-Point Transmission Service in accordance with the provisions of Part II of the Tariff and this Umbrella Agreement.

9.0 Any notice or request made to or by either Party regarding this Umbrella Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:
Transmission Tariff Supervisor
SaskPower - System Control Centre
2025 Victoria Avenue
Regina, Saskatchewan
Canada S4P 0S1
Phone: ______________________________
Fax: ______________________________
Email: ______________________________

Transmission Customer:
____
____
____
____

10.0 No failure by the Transmission Provider or the Transmission Customer at any time or from time to time to enforce or require a strict observance of any of the provisions of this Umbrella Agreement shall constitute a waiver of the provision or affect or impair such provisions or the right of the Transmission Provider or the Transmission Customer at any time to enforce such provisions or to avail itself of any remedy it may have.

11.0 This Umbrella Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and any Assignees of the Transmission Customer authorized pursuant to Section 23.1 of the Tariff.

12.0 The Tariff is incorporated herein and made a part hereof.

13.0 The Transmission Provider shall archive records of digitally transmitted information submitted pursuant to this Umbrella Agreement. Such records shall be treated as accurate records of the transactions hereunder for the purposes of admission in to evidence in any dispute resolution proceedings conducted pursuant to this Umbrella Agreement.

14.0 Applicable taxes shall be added to all charges set forth in the Tariff.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:________________________ ________________ ________________
Name Title Date

By:________________________ ________________ ________________
Name Title Date

Transmission Customer:

By:________________________ ________________ ________________
Name Title Date

By:________________________ ________________ ________________
Name Title Date

ATTACHMENT C

Methodology To Assess Available Transmission Capability

Basis of Assessment

SaskPower will assess the Available Transfer Capability (ATC) for identified constrained interfaces. The assessment will be based on the lower of the individual interface facility limits and SaskPower transmission system limits. The ATC will be posted, as required, on SaskPower's OASIS site.

Determination of ATC

ATC is a measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. Mathematically, ATC is defined as the Total Transfer Capability (TTC) less the Transmission Reliability Margin (TRM), less the sum of Existing Transmission Commitments (ETC) (which includes retail customer service), less the Capacity Benefit Margin (CBM).

Recallability is defined as the right of a transmission provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with the OATT or other contract provisions.

For non-recallable[1] transmission service, ATC is calculated using the most severe (largest) TRM required for the period of time being considered.

$$\text{NON-RECALLABLE ATC} = \text{TTC} - \text{TRM} - \text{ETC} - \text{CBM}$$

For recallable[2] transmission service, ATC is calculated by discounting the maximum TRM value by means of a coefficient (TRM_C) when system operating conditions are better than for the worst case.

$$\text{RECALLABLE ATC} = \text{TTC} - (\text{TRM}_C)\text{TRM} - \text{ETC} - \text{CBM}$$

The coefficient "TRM_C" is derived by doing a series of simulations for the interface to determine sensitivity due to variation in the pre-disturbance conditions. This range of values of transfer capability is compared to the original TTC for the interface to derive the value of "TRM_C" which satisfies the equation above that is used to post ATC values. The values of TRM_C have a range from 0 to 1.

Under commercial use of an interface, the ATC at a particular point in time can be defined as:

1 OASIS Non-recallable transmission service is equivalent to SaskPower OATT firm transmission service.
2 OASIS Recallable transmission service is equivalent to SaskPower OATT non-firm transmission service.

$$ATC = TTC – (TRM_C)TRM – ETC – RES – SCH$$

SaskPower's software uses this equation to calculate the posted ATC for the interface.

The two additional terms RES and SCH represent the ATC that has been, up to the point in time being considered, sold to a Transmission Customer(s). RES represents the sum of the unscheduled reservations on the interface and SCH represents the sum of the actual scheduled flow across the interface.

Determination of TTC

SaskPower determines the TTC of an interface based on the capability of the interface facilities and the first contingency transmission capability of the SaskPower system. To establish TTC for the interfaces, the transfer level is increased in steps. At each step, the system is studied to determine if the system meets the defined performance criteria for the critical contingencies defined. The maximum level of transfer, considering most likely load levels and probable generation patterns, becomes the TTC for the interface. The TTC for a particular interface is determined without simultaneous transfer on other interfaces.

The TTC values are derived for power flow in both directions through the interfaces. The studies are done in coordination with the respective interconnected Transmission Providers and facility owners.

Determination of TRM

TRM represents a margin that is applied to account for uncertainties and variations in system conditions and to allow for operating flexibility. The major components that are considered in the determination of TRM include:

- Probable variations in domestic load levels. SaskPower produces a high and low system peak load forecast that represents an 80% confidence interval for load growth. These load forecasts are used to account for load level and load distribution variations.
- Probable variation in SaskPower generation dispatch which is dependent on hydro conditions, fuel prices, and other applicable conditions.
- Simultaneous transfers on other interfaces. Currently, there is an interdependency between the Saskatchewan-Manitoba and the Saskatchewan-North Dakota interfaces.
- Parallel path flows. Parallel path flows, due to schedules, are not considered because all SaskPower interfaces are either directly or indirectly controlled.
- Interface control system deadbands.

For determining TRM values, probable worst case generating patterns and worst case load forecasts shall be used, for the time frame under consideration. The generation patterns shall consider high coal generation, low and high hydro conditions, with and without prior generating unit outages.

Determination of CBM

The CBM component represents a margin that reserves transmission capability on the interface to allow generating reserves, where reserve sharing agreements exist, to be imported when required. SaskPower provides its own reserves. There are currently no reserve sharing agreements; therefore, for SaskPower CBM = 0.

Determination of ETC

ETC represents the already committed (prior to the implementation of SaskPower's OATT) use of the particular path for which ATC is being calculated. For example, the existing transmission agreement that allows the transfer of power from Island Falls through the Manitoba Hydro – SaskPower 230 kV interface, would be considered an ETC.

Counter Schedules

Because the scheduled flows are physical quantities, they can be summed with respect to direction at the interface. Two equal opposing schedules will physically cancel each other and make room for a third recallable schedule to actually flow across the interface. This practice is known as counter scheduling.

The reservations represented by RES cannot be handled as counter reservations because there may not be scheduled energy associated with them and, hence, no physical net effect necessarily exists.

Frequency of ATC Determination

The frequency of ATC calculation shall be consistent with the period over which the transmission service is being offered.

ATTACHMENT D

Methodology for Completing a System Impact Study

Purpose

The purpose of the document is to describe the SaskPower study practices or methodology used for completing a system impact study under the terms of SaskPower's OATT.

Overview of the SaskPower System

The SaskPower transmission system is characterized by relatively long 230 kV and 138 kV transmission lines connecting 10 existing generating stations to sparsely distributed load supply points. The existing network resources consist of coal-fired generators, combined cycle and simple cycle gas fired generators and hydro generators. Historically, the most economic dispatch has been to use the coal generation and combined cycle generation as base load with the hydro units used to track the load shape. Simple cycle gas fired generation has been used mainly for peak shaving. The load on the SaskPower system load peaks in winter, due to increased heating and lighting requirements. The annual load factor is about 70%.

Tie lines provide three interfaces with other systems; two with the MAPP system and one with the WSCC system. These interfaces, particularly those with North Dakota and Alberta, were originally planned primarily to facilitate generation reserve sharing and seasonal diversity agreements with neighboring utilities, based on a low capacity factor. In addition to the previous reserve sharing benefits, the Manitoba interface also provides mutual system reinforcement benefits that improve stability and reduce losses. Although all the interfaces are controlled, transfer capability over the Manitoba and North Dakota interfaces are dependent on simultaneous transfers. This interdependence is due to SaskPower internal system limitations.

Saskatchewan - Manitoba Interfaces (MAPP)

The Manitoba 230 kV interface consists of the three 230 kV transmission lines, designated P52E, R25Y, and R7B, which interconnect at the SaskPower stations of E.B. Campbell, Yorkton, and Boundary Dam and the MHEB (Manitoba HydroElectric Board) stations of Rall's Island, Roblin and Reston, respectively. This interface is constrained by restrictions within Manitoba and SaskPower. The interface restrictions are not typically circuit overloads, but are generally the result of low voltage or equipment overload conditions in the SaskPower system due to the loss of generation or parallel circuits. The P52E and R7B transmission lines represent individual constrained paths that are limited by the thermal capability (sag limit) of the lines.

A second Manitoba interface consists of the two 110 kV lines from the Island Falls station in Saskatchewan to the Cliff Lake station in Manitoba. Currently, this interface is not a constrained path. The energy delivered from Island Falls into the Manitoba 115 kV interface is returned to SaskPower on the Manitoba 230 kV interface. This impact is accounted for in the participation factors and is considered an “Existing Transmission Commitment” for both interfaces.

Saskatchewan - North Dakota Interface (MAPP)

The North Dakota interface consists of the phase shifting transformer BD922T at SaskPower’s Boundary Dam station and the 230 kV line (B10T) between Boundary Dam and the Tioga station in North Dakota. This interface is constrained by the transfer capability of the BD922T phase shifting transformer and by restrictions in the U.S., as well as by SaskPower system restrictions. The SaskPower restrictions are generally the result of low voltage or equipment overload conditions in the SaskPower system due to the loss of generation or parallel circuits.

Saskatchewan - Alberta Interface (WSCC)

The Alberta interface consists of the 230 kV transmission line from Swift Current to the McNeill Converter Station, located in Alberta. This interface links the two asynchronous Eastern and Western Interconnections. This interface is constrained by the transfer capability of the McNeill back-to-back Converter Station and other restrictions in the Alberta and SaskPower systems. The SaskPower restrictions are generally the result of low voltage conditions in the SaskPower system due to the loss of generation or parallel circuits.

SaskPower Transmission System Limitations

Due to the inherent characteristics of the existing SaskPower transmission system; relatively long transmission lines, sparsely distributed load with low load factor, weak interconnections with North Dakota and Alberta and distributed generation resources, the transmission system loading and associated available transfer capability can vary significantly over a wide range of operating conditions. These limitations are usually due to high real and reactive power transmission losses that are exacerbated by contingencies, resulting in the potential for voltage instability and equipment overloads, especially in conjunction with transfers across the interfaces. To compensate for this limitation, the Coteau Creek Initiated Loadshed Scheme (CCILS) was incorporated. This scheme initiates three stages of load tripping when a contingency causes the reactive power loading at the Coteau Creek generating station to reach a predefined level. Since capacity factors for transfers across the interfaces were originally planned to be low, the risk of interrupting load was considered to be acceptable.

Also, during periods of high transmission system loading (particularly during off-peak load conditions), critical clearing times for generators and generator rotor angle stability can also become a concern.

Simulation Study Requirements

The ATC must be determined for each identified interface, based on appropriate reliability assessments. These transfer capability studies are done by the Transmission Provider, in coordination with other affected Transmission Providers.

Since SaskPower's transmission network is sparsely distributed over a large area with weak, interconnections to other transmission areas, full positive sequence AC powerflow and dynamics simulations are required for adequate reliability assessments. All simulations will be conducted using the PTI (Power Technologies Inc.) PSS/E software package, with all data provided in compatible format.

Powerflow simulations shall be conducted over the full range of probable operating scenarios within the SaskPower system. For modeling systems external to SaskPower, MAPP loadflow cases will be utilized. The powerflows are tested to determine the level of transfer that results in a constraint limited by the study criteria.

Dynamics simulations shall be conducted to confirm that the levels identified by the powerflow simulations will also meet the study criteria for dynamic system performance.

Studies shall consider simultaneous transfers on interfaces and prior scheduled equipment outages.

System Performance Criteria for Simulation Studies

The study criteria consider thermal, stability, and voltage limits. The criteria are based on meeting NERC Planning Standard IA with provision to phase out the Coteau Creek Initiated Loadshed Scheme. SaskPower applies the performance criteria as follows:

1. With normal steady state (pre-contingency) operating procedures in effect, all facility loadings shall be within SaskPower normal equipment ratings and all transmission system switching station voltages shall be within SaskPower normal limits.

2. Following contingencies, all facility loadings shall be within SaskPower emergency equipment ratings and all transmission system switching station voltages shall be within SaskPower post-contingency limits.

3. Following contingencies, transient voltages at transmission system switching stations shall meet the criteria defined in the MAPP Reliability Handbook.

4. Following contingencies, generator dynamic power angle swing damping shall meet the criteria defined in the MAPP Reliability Handbook.

5. Following contingencies and after the operation of any automatic systems, all transmission facility loadings shall be within SaskPower emergency ratings and all voltages shall be within SaskPower post-contingency limits. Automatic systems may

include capacitor or reactor insertion schemes, phase shifter tap-back or DC converter station run-back, automatic generation control or other schemes, but would not include any operator initiated system adjustments that are implemented.

Base Conditions for Simulation Studies

Powerflow models used for system impact studies are constructed from the most recent MAPP powerflow series available at the time the study is commenced. The MAPP powerflow series contains models that represent the SaskPower and MAPP systems in detail in the short, near and long-term time frame (approx. 1 to 10 years). Transfers to Alberta are currently modeled using load and/or generation at the 230 kV bus of the McNeill HVDC back-to-back converter station. A detailed model of the Alberta system (Alberta Interconnected Electric System) is not contained in the powerflow models. The Alberta system (which is part of the Western Interconnection) operates asynchronously with SaskPower (part of the Eastern Interconnection) via the converter station.

The interfaces (contract paths) for which the ATC is determined are represented by the following transmission lines in the powerflow models.

Manitoba 230 kV Interface:	P52E, Rall's Island – E.B. Campbell
	R25Y, Roblin – Yorkton
	R7B, Reston – Boundary Dam
Manitoba 115 kV Interface:	I1F/ I2F, Island Falls– Border Station
North Dakota Interface:	B10T, Boundary Dam – Tioga
Alberta Interface:	S1M, Swift Current – McNeill

ATTACHMENT E

Form of Service Agreement For Network Integration Transmission Service

1.0 This Agreement, dated as of ______________________, is entered into, by and between SaskPower (the "Transmission Provider"), and ____________________ (the "Network Customer").

2.0 The Network Customer has been determined by the Transmission Provider to have a Completed Application for Network Integration Transmission Service under the Tariff.

3.0 The Network Customer has provided to the Transmission Provider an Application deposit in the amount of $_____________, in accordance with the provisions of Section 29.2 of the Tariff.

4.0 Service under this agreement shall commence on the later of: (a) the requested Service Commencement Date; or (b) the date on which construction of all interconnection equipment, any Direct Assignment Facilities and/or Network Upgrades are completed; or (c) the date on which a Network Operating Agreement is executed and all requirements of said Agreement have been completed. Service under this agreement shall terminate on ________________________.

5.0 The Transmission Provider agrees to provide and the Network Customer agrees to take and pay for Network Integration Transmission Service in accordance with the provisions of Part III of the Tariff and this Agreement.

6.0 Any notice or request made to or by either Party regarding this Service Agreement shall be made to the representative of the other Party as indicated below.

Transmission Provider:

Transmission Tariff Supervisor
SaskPower - System Control Centre
2025 Victoria Avenue
Regina, Saskatchewan
Canada S4P 0S1
Phone: ________________________
Fax: ________________________
Email: ________________________

Network Customer:

7.0 No failure by the Transmission Provider or the Network Customer at any time or from time to time to enforce or require a strict observance of any of the provisions of this Agreement shall constitute a waiver of the provision or affect or impair such provisions or the right of the Transmission Provider or the Transmission Customer at any time to enforce such provisions or to avail itself of any remedy it may have.

8.0 (a) This Agreement shall be construed in accordance with the laws of the Province of Saskatchewan; and (b) SaskPower and the Network Customer will promptly comply with all relevant laws and regulations and the relevant orders, rules and requirements of all authorities having jurisdiction.

9.0 Nothing in this Agreement shall restrict or limit either part from establishing, altering or terminating interconnections points with any entity not a party to this Agreement or amending or entering into such agreements.

10.0 The Network Operating Agreement containing the terms and conditions under which the Network Customer will operate its facilities and the technical specifications associated with service under this Agreement are hereby incorporated and made part of this Service Agreement as Attachment F.

11.0 The Tariff, the attached Specifications for Network Integration Transmission Service, are incorporated herein and made a part hereof.

12.0 Applicable taxes shall be added to all charges set forth in the Tariff.

13.0 This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns, but shall not be assigned by either Party without the written consent of the other Party.

IN WITNESS WHEREOF, the Parties have caused this Service Agreement to be executed by their respective authorized officials.

Transmission Provider:

By:

Name	Title	Date

Network Customer:

By:

Name	Title	Date

Specifications For Network Integration Transmission Service

1.0 Term of Transaction:____
Start Date:____
Termination Date:____

2.0 Description of capacity and/or energy to be transmitted by the Transmission Provider across its Transmission System (including electric control area in which the transaction originates.)
____
____

3.0 Network Resources

(1) Network Customer Generation Owned:
Resource:________________________
Capacity:________________________
Capacity Designated as Network Resource:_______________________

(2) Network Customer Generation Purchased:
Source:________________________
Capacity:_______________________

(3) Total Network Resources : (1) + (2) = ___________________

4.0 Network Load:
Network Load Transmission Voltage Level:______________________

5.0 Points of Interconnection:_______________________________________

6.0 Points of Delivery:____
Delivering Party:____

7.0 Designation of Party subject to reciprocal service obligation:
____

8.0 Name(s) of any Intervening Systems providing transmission service:
____

ATTACHMENT F

Network Operating Agreement

This Network Operating Agreement (the "Agreement"), is made and entered into this _____ day of _______________, ____, by and between _______(Customer)______ (hereinafter referred to as the "Transmission Customer") and SaskPower. The Transmission Customer and SaskPower hereinafter are sometimes referred to individually as "Party" and collectively as "Parties", as the context suggests below.

In consideration of the promises and mutual covenants and agreements herein contained, the Parties do agree as follows:

1. Definitions

Unless otherwise specified herein, capitalized terms shall refer to terms defined in the Tariff.

2. Purpose of Agreement

SaskPower and the Transmission Customer agree that the provisions of this Agreement and the Network Service Agreement for Network Integration Service govern SaskPower's provision of Transmission Service to the Network Customer. This Agreement requires the Parties to:

2.1. Operate and maintain equipment necessary for incorporating the Transmission Customer within SaskPower's Transmission System (including, but not limited to, remote terminal units, metering, communications equipment and relaying equipment);

2.2. Transfer data (including but not limited to, heat rates, fuel costs, and operational characteristics of Network Resources, generation schedules for Network Resources, interchange schedules, unit outputs for re-dispatch required under Part III of the Tariff, voltage schedules, flows of real and reactive power, loss factors, switch status, breaker status, MW/MVAr flow on lines, bus voltages, transformer taps and other SCADA and real time data) between SaskPower Grid Control Centre and the Transmission Customer's control centre;

2.3. Use software programs required for data links and constraint dispatching;

2.4. Exchange data on forecasted load and resources necessary for planning and operation; and

2.5. Address any other technical and operational considerations required for implementation of Part III of the Tariff, including scheduling protocol.

3. Integration and Control Area Requirements

The Transmission Customer shall:

(a) Provide all Ancillary Services itself, including those necessary to operate as a control area under applicable guidelines of the North American-Electric Reliability Council (“NERC”); or

(b) Satisfy its control area requirements, including all Ancillary Services, by contracting with SaskPower; or

(c) Satisfy its control area requirements, including all Ancillary Services, by contracting with another entity which can satisfy those requirements in a manner that is consistent with Good Utility Practice and NERC standards.

The Transmission Customer shall plan, construct, operate and maintain its facilities and system in accordance with Good Utility Practice, which shall include, but not be limited to, all applicable guidelines of SaskPower and NERC, as they may be modified from time to time, and any generally accepted practices in the region. This Agreement will be revised as necessary to incorporate changes to SaskPower's guidelines and requirements.

4. Network Operating Committee

4.1. Membership - The Network Operating Committee shall be composed of representatives from the Transmission Customers taking service under Part III of the Tariff and SaskPower, or their Designated Agents.

4.2. Responsibilities - The Network Operating Committee shall:

(a) Adopt rules and procedures consistent with this Agreement and the Tariff governing operating and technical requirements necessary for implementation of the Tariff;

(b) Review Network Resources and Network Loads on an annual basis in order to assess the adequacy of the transmission network; and

(c) Obtain from SaskPower its operating policies, procedures and guidelines for network interconnection and operation.

5. Regulation and Frequency Response

The Transmission Customer shall meet its proportional share of Regulating Margin by either:

(a) Purchasing Regulation and Frequency Response Services from SaskPower pursuant to Schedule 3; or

(b) Contributing or arranging to have a third party contribute generating resources to meet the Regulating Margin requirement for the current year as follows:

Regulating Margin Requirement = Transmission Customer's maximum Network Load in the previous year x 1.7%

A Transmission Customer that meets its proportional share of Regulating Margin by alternative (b) above shall also meet the requirements of Section 16 below.

6. Operating Reserve

6.1. The Transmission Customer shall meet its share of its Control Area’s Operating Reserve requirements by either:

(a) Purchasing Operating Reserve Services from SaskPower pursuant to Schedules 5 and 6; or

(b) Providing or arranging to have a third party provide the Operating Reserve requirement.

A Transmission Customer that meets its share of its Control Area’s Operating Reserve requirement by alternative (b) above shall also meet the requirements of Section 16 below. The Operating Reserve requirement is as specified and implemented by SaskPower.

6.2. In order to facilitate the use of Operating Reserve, the Transmission Customer that meets its share of its Control Area’s Operating Reserve requirement by alternative 6.1(b) shall have available unloaded reserved Firm transmission capacity at least equal to that Operating Reserve amount. Such transmission may be loaded with interruptible energy so that, upon interruption of the energy, Transmission Service is available to replace such energy from the Operating Reserve.

In addition, the Transmission Customer shall restore Operating Reserve to the required level as promptly as practicable, but shall not exceed sixty (60) minutes from the time of the event necessitating the loading of the reserve.

7. Re-dispatch To Manage Transmission System Constraints

If SaskPower determines that the re-dispatch of Network Resources to relieve an existing or potential Transmission System constraint is the most effective way to ensure the reliable operation of the Transmission System, SaskPower will re-dispatch its and the Transmission Customer's Network Resources on a least-cost basis, without regard to the ownership of such resources. SaskPower will apprise the Transmission Customer of its re-dispatch practices and procedures, as they may be modified from time to time.

The Transmission Customer will submit verifiable incremental and decremental cost data for its Network Resources, which estimates the cost to the Transmission Customer of changing the generation output of each of its Network Resources, to SaskPower when submitting its pre-schedules. These costs will be used, along with similar data for SaskPower resources, as the basis for least-cost re-dispatch for the next day's operations (or the next day’s operations if the pre-schedule is submitted on a Friday or the day before a holiday). SaskPower's grid operation staff will keep these data confidential, including from SaskPower's marketing staff. If the Transmission Customer experiences changes to its costs during the following day, the Transmission Customer must submit those changes to SaskPower's Grid Control Centre. SaskPower will implement least-cost re-dispatch consistent with its existing contractual obligations and its current practices and procedures for its own resources. The Transmission Customer is obligated to respond immediately to requests for re-dispatch from SaskPower's Grid Control Centre. The Transmission Customer may audit particular re-dispatch events at its own expense, during normal business hours following reasonable notice to SaskPower. If such audit shows that SaskPower resources have been re-dispatched in preference to lower cost alternatives for other than emergency reasons, the cost of the audit shall be borne by SaskPower. Either the Transmission Customer or SaskPower may request an audit of the other Party's cost data by an independent agent at the requester's cost.

8. Curtailability

SaskPower reserves the right to curtail all or part of Transmission Service due to conditions which physically cause a reduction in the transmission path(s). Such conditions include, but are not limited to, forced outages of one or more elements of the transmission path, nomogram restrictions, and unscheduled loop flows. Network Integration Transmission Service will have equal status as SaskPower Domestic Load. Whenever possible and consistent with Good Utility Practice, loads will be curtailed based on load ratio share. When such conditions no longer restrict the capability of the transmission path, Network Integration Transmission Service will be resumed.

9. Maintenance of Facilities

9.1. The Network Operating Committee shall establish procedures to coordinate the maintenance schedules of the generating resources and transmission and substation facilities, to the greatest extent practical, to ensure sufficient transmission resources are available to maintain system reliability and reliability of service. By **[insert date]** of each year, the Transmission Customer shall provide to SaskPower the maintenance schedules and planned outages of each Network Resource for the next year and update the information at least thirty (30) days in advance of the date specified for the forecasted maintenance outage. Such information shall include, but not be limited to, the expected time the unit will be separated from the system and the time at which the unit is available for:

(a) Synchronizing parallel operation;

(b) Loading; and

(c) If applicable, to be put on automatic generation control.

9.2. The Transmission Customer shall obtain:

(a) Concurrence from SaskPower, at least seventy-two (72) hours before beginning any scheduled maintenance of its facilities; and

(b) Clearance from SaskPower when the Transmission Customer is ready to begin maintenance on a Network Resource, transmission line, or substation (operated at ____ kilovolt and above).

The Transmission Customer shall immediately notify SaskPower at the time when unscheduled or forced outages end. The Transmission Customer shall notify and coordinate with SaskPower prior to re-paralleling the Network Resource, transmission line, or substation.

9.3. Maintenance schedules will be posted on an electronic bulletin board.

10. Load Shedding

10.1. The Parties shall implement load shedding programs to maintain the reliability and integrity as provided in Section 29 of the Tariff. Load shedding shall include:

(a) Automatic load shedding;

(b) Manual load shedding; and

(c) Rotating interruption of customer load.

SaskPower will order load shedding to maintain the relative sizes of load served, unless otherwise required by circumstances beyond the control of SaskPower or the

Transmission Customer. Automatic load shedding devices will operate without notice. When manual load shedding or rotating interruptions are necessary, SaskPower shall notify the Transmission Customer's dispatchers or schedulers of the required action and the Transmission Customer shall comply immediately.

10.2. The Transmission Customer shall, at its own expense, provide, operate and maintain in service high-speed digital under frequency load-shedding equipment. The Transmission Customer's equipment shall be:

(a) Compatible and coordinated with SaskPower's Transmission Service Tariff load shedding equipment; and

(b) Set for the amount of load to be shed with frequency trips and tripping time consistent with SaskPower System Planning requirements.

In the event SaskPower modifies the load-shedding system, the Transmission Customer shall, at its expense, make changes to the equipment and setting of such equipment, as required by SaskPower. The Transmission Customer shall test and inspect the load-shedding equipment within 90 days of taking Long-Term Service under the Tariff and at least once each year thereafter and provide a written report to SaskPower. SaskPower may request a test of the load-shedding equipment with reasonable notice.

11. <u>Recognition of Power and Energy Flow</u>

11.1. The Parties recognize that:

(a) SaskPower's Transmission System is, and will be, directly or indirectly interconnected with Transmission Systems owned or operated by others;

(b) The flow of power and energy between such systems will be controlled by the physical and electrical characteristics of the facilities involved and the manner in which they are operated; and

(c) Part of the power and energy being delivered under this Agreement may flow through such other systems rather than through the facilities of SaskPower.

The Network Operating Committee shall, from time to time as necessary, determine methods and take reasonably appropriate action to assure maximum delivery of power and energy at the points of receipt and delivery and at such additional or alternate points of receipt and delivery as may be established by the Parties.

11.2. Each Party will at all times cooperate with other interconnected systems in establishing arrangements or mitigation measures to minimize operational impacts on each other's systems.

11.3. Each Party recognizes that a Party's proposed new interconnection or modification of an existing interconnection between that Party's system and the system of a third party, may cause adverse anticipated effects on the system of the other Party. The Party making such interconnection or modification shall minimize, or otherwise compensate for, adverse operational effects to the other Party's system.

12. Service Conditions

The Parties recognize that operating and technical problems may arise in the control of the frequency and in the flow of real and reactive power over the interconnected Transmission Systems. The Network Operating Committee may adopt operating rules and procedures as necessary to assure that, as completely as practical, the delivery and receipt of real and reactive power and energy hereunder shall be accomplished in a manner that causes the least interference with such interconnected systems.

A Transmission Customer interconnecting with SaskPower's Transmission System is obligated to follow the same practices and procedures for interconnection and operation that SaskPower uses for its own load and resources.

Where the Transmission Customer purchases Ancillary Services from third parties, the Transmission Customer shall have the responsibility to secure contractual arrangements with such third parties that are consistent with the Tariff, this Agreement and any applicable rules and procedures of the Network Operating Committee.

13. Data, Information and Reports

13.1. The Transmission Customer shall, upon request, provide SaskPower with such reports and information concerning its network operation as are reasonably necessary to enable SaskPower to operate its Transmission System adequately.

13.2. Scheduling--Hourly transactions from outside of SaskPower’s franchise area, in whole megawatts must be prescheduled by E-tag as defined in NERC Policy 3. Schedules must conform to the E-tag processing timelines. Schedules can be changed no later than 20 minutes (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) before the schedules go into effect.

The Transmission Customer shall notify SaskPower of intended imports into SaskPower’s franchise area for the next normal business day(s) by E-tag no later than 10 a.m. CST (or a reasonable time that is generally accepted in the region and is consistently adhered to by the Transmission Provider) on the day prior. Preschedules and forecasts shall include, as applicable:

(a) Each import into or export out of SaskPower’s franchise area;

(b) Each power purchase and sale from within SaskPower’s franchise area;

(c) Losses;

(d) Generation from each Network Resource;

(e) Network Load at each point designated in Section 4 of the Specifications For Network Integration Transmission Service attached to the Service Agreement;

(f) Regulation and Frequency Response requirement;

(g) Spinning or Supplemental Reserve from each Network Resource;

(h) Spinning or Supplemental Reserve purchase from SaskPower or each third party;

(i) The Transmission Customer's most severe single contingency;

(j) Available capacity from each Network Resource;

(k) Transmission Service associated with each pre-schedule and forecast;

(l) Incremental and decremental cost data for Network Resources; and

(m) Other information, as required by SaskPower.

13.3. Annual Forecast - By **[insert date]** of each year, the Transmission Customer shall update its load and resource forecast by providing SaskPower with a non-binding forecast in a format specified by SaskPower.

13.4. Monthly Forecast **– [insert number]** days before the end of the month, the Transmission Customer shall update the forecast for the following month specifying purchase, generation, maximum demand, total monthly energy and Operating Reserve Services from SaskPower or a third party.

13.5. The Transmission Customer shall telemeter to SaskPower information including but not limited to watts, VArs, generator status, generator breaker status, generator terminal voltage and high side transformer voltage, unless otherwise agreed.

13.6. The Transmission Customer shall provide generating resource characteristics to SaskPower as necessary to implement re-dispatch and constraint and reserve management.

14. Metering

14.1. Unless otherwise agreed the Transmission Customer shall be responsible for the cost of installing and maintaining revenue meters and communication equipment compatible with SaskPower's meter reading system and facility standards. Revenue quality metering equipment and meters shall be installed at the high voltage bus at each point of interconnection between the Transmission Customer's facility and SaskPower's system. The meters shall measure and record both real power (watts) and reactive power (VArs) flow and line losses, if applicable, in both directions. Meters not installed at the high voltage bus or at the point of interconnection shall be adjusted for losses.

14.2. SaskPower shall read or retrieve meter data on the first work day after the end of each billing cycle or such other date as may be required to carry out the provision of this Tariff. SaskPower shall process the meter data and determine energy imbalances, accounting and billing using such meter data.

14.3. The meter owner shall test revenue meters for power deliveries made at __kV and above at least once a year and within 10 business days after a request by the other Party. The other Party will be afforded the opportunity to be present during the meter test. For meters owned by SaskPower, the Transmission Customer may request a meter test by calling the designated customer account representative of SaskPower and shall pay for the cost of the requested test if the meter has been tested within the previous 12 months. The Parties present at the meter test shall estimate the amount of capacity and energy created during the meter test. The meter owner shall immediately repair, adjust or replace any meter or associated equipment found to be defective or inaccurate. An inaccurate meter is a meter that is found to register with an error not permitted by the *Electricity and Gas Inspection Act* (Canada) Regulations.

14.4. SaskPower shall adjust the recorded data to compensate for the effect of an inaccurate meter. Such adjustment shall be made for a maximum period of 30 days prior to the date of the test or to the period during which such inaccuracy may be determined to have existed, whichever period is shorter. No adjustment prior to the beginning of the next preceding month shall be made except by agreement of the Parties. Should any meter fail to register, SaskPower shall estimate, from the best information available, the demand created, energy flow and VAr flows during the period of the failure. SaskPower shall, as soon as possible, correct the Transmission Customer's bills affected by the inaccurate meter. That correction, when made, shall constitute full adjustment of any claim arising out of the inaccurate meter for the period of the correction.

15. <u>Communications</u>

15.1. The Transmission Customer shall, at its own expense, subscribe to a NERC certified E-tag system for scheduling.

15.2. A Transmission Customer contributing to Regulation and Frequency Response requirement and Operating Reserve requirements or securing the requirements from a third party shall, at its own expense, install and maintain telemetry equipment communicating between the generating resource and SaskPower.

16. <u>Requirements to Contribute to System Regulation and Operating Reserve</u>

The Transmission Customer who is not purchasing Regulation and Frequency Response and Operating Reserve Services from SaskPower shall operate its generating resources in a manner similar to that of SaskPower including following voltage schedules, free governor response, meeting power factor requirements at the point of interconnection with SaskPower's system, and such other criteria as may be developed by SaskPower or the Network Operating Committee. The Transmission Customer shall pay the cost of modification of SaskPower's computer hardware and software to accommodate the

Transmission Customer's contribution to Regulation and Frequency Response requirement and Operating Reserve. Any resources used by the Transmission Customer to meet its proportional share, whether the Transmission Customer's Network Resources or a third party's generating resources, shall meet the same requirements as SaskPower's generating resources used to meet the Regulation and Frequency Response requirement and Operating Reserve requirements, including but not limited to, automatic generation control capability, ramp rate, and governor response, and are subjected to random testing, and if applicable, a monthly start-up test.

17. Assignment

This Agreement shall inure to the benefit of and be binding upon the Parties hereto and their respective successors and assigns, but shall not be assigned by either Party, except to successors to all or substantially all of the electric properties and assets of such Party, without the written consent of the other Party.

18. Notice

Any notice or request made to or by either Party regarding this Agreement shall be made to the representative of the other Party as indicated in the Network Service Agreement. This agreement is attached thereto as Appendix C.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their respective authorized officials.

SASKPOWER		(TRANSMISSION CUSTOMER)	
By:	______________________	By:	______________________
Title:	______________________	Title:	______________________
Date:	______________________	Date:	______________________

ATTACHMENT G

Annual Transmission Revenue Requirement
For Network Integration Transmission Service

1. The Annual Transmission Revenue Requirement for purposes of the Network Integration Transmission Service shall be $76,484,502.

2. The amount in (1) shall be effective until amended by the Transmission Provider or modified by applicable regulatory body having jurisdiction.

ATTACHMENT H

Curtailment Procedures

When system conditions change due to such events as the loss of a transmission line or a generator, the TRM for the constrained interfaces may increase. The resulting new value of the ATC for the interface may be lower than the actual flow through the interface and a curtailment will be necessary to bring the flow down to a level that does not exceed operating limits. Curtailment is necessary to restore the operating reliability of the system so that it can withstand the next single contingency.

Curtailment is done with respect to:

1. Non-discriminatory treatment of all transmission customers including domestic load.
2. Lower priority recallable class service is curtailed ahead of non-recallable[3] class service.
3. Rank within the recallable[4] class (longer reservations out rank shorter reservations) is respected.
4. Equal rank recallable service is curtailed on a last in first out (LIFO) basis.
5. Non-recallable service is curtailed pro rata in proportion to the contribution each service is making to the security limit violation.

3 OASIS Non-recallable transmission service is equivalent to SaskPower OATT firm transmission service.
4 OASIS Recallable transmission service is equivalent to SaskPower OATT non-firm transmission service.

Attachment 3

System Impact Studies Relating to BC>AB Path

BC hydro

Impact Study for PowerEx
To Increase the Firm Transmission Capacity
to Alberta by 125 MW

Report No. NPP9915
Prepared by: Ken Poon
December, 1999

Network Performance Planning Department
T & D Engineering

Executive Summary

This System Impact Study determines the B.C. Hydro to Alberta Integrated System firm transfer capability and recommends system reinforcements needed to provide the incremental Transmission Service of 125 MW that will increase the total firm transfer capability to Alberta to 335 MW.

The study found that the existing system is not able to provide the requested incremental transmission service of 125 MW firm export to Alberta because of both stability and thermal limits.

System upgrades are needed to provide the requested transmission services. The lowest cost alternative is the addition of a 230 kV single circuit transmission line between Selkirk to Cranbrook at an estimated total cost of approximately $60M with a lead-time of about 4 years.

IMPACT STUDY FOR POWEREX WTSA FOR 125 MW EXPORT TO ALBERTA

CONTENTS

1. Introduction

On September 3, 1999 B.C. Power Exchange Corporation (PowerEx) submitted a Wholesale Transmission Service Application (WTSA) for 125 MW of Long Term Firm B.C. Hydro to Alberta Point-To-Point power transfer for the period December 1, 1999 to 29 February 2004 (Oasis Request No. 144548). There are presently a number of firm power transfer contracts on the Alberta tie totaling to 210 MW. This WTSA will bring the total B.C. Hydro to Alberta transfer requirement to 335 MW.

Pursuant to WTSA Section 19.1, B.C. Hydro determined that a System Impact Study relating to the Application is required. A System Impact Study Agreement was signed between PowerEx and B.C. Hydro.

2. Scope

This System Impact Study determines the B.C. Hydro to Alberta Integrated System firm transfer capability and recommends system reinforcements needed to provide the requested Transmission Service of 125 MW that will bring the total BC to Alberta firm transfer level to 335 MW. Cost estimates of the proposed new reinforcements are provided in this report but detailed economic analysis such as saving in losses (which is expected to be minimal) are not studied.

3. Methodology

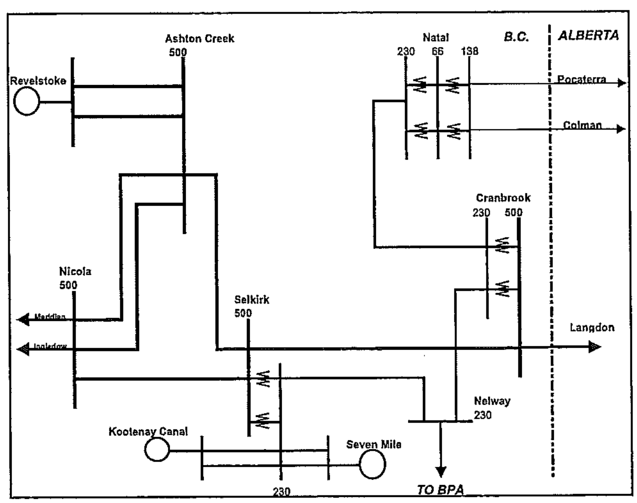
The study consists of power flow and transient stability simulations. Power flow simulations determine the thermal and voltage constraints. Stability simulations are used to evaluate the system dynamic response after a disturbance and the effectiveness of remedial action schemes if required. Constraints to the requested Transmission Service that originate within the Alberta Integrated System are not addressed in the Study.

A power flow base case representing the 2003/04 system is used (see Attachment 1). The peak local area load at Cranbrook is about 210 MW. The chosen time frame takes into consideration the lead-time required for any significant transmission reinforcement. Both the light and heavy load conditions are studied.

4. Description of the Existing System

The BC Hydro system is connected to Alberta with a 500 kV line from Cranbrook to Langdon (5L94) and two 138 kV lines from Natal to Pocaterra and Colman respectively. The transmission between Selkirk and Cranbrook consists of the 500 kV line (5L92) and the 230 kV lines 2L293 (Selkirk to Nelway) and 2L294 (Nelway to Cranbrook). Nelway is also connected to the U.S. at Boundary with a 230 kV tie. Figure 1 shows the major transmission system in the South Interior East area and the BC to Alberta interties.

Fig. 1



5. System Performance

The system with the requested transfer must be transiently stable after loss of a single element and the remaining system must be within thermal and voltage stability limits (n-1 criteria). Remedial Action Schemes (RAS) are allowed as long as there is no loss of load or, if load curtailment is allowed on a non-discriminatory basis, i.e. Firm Point-To-Point Transmission Service is treated the same as Native Loads.

5.1 Transient Stability Limit

The operating transfer limit from BC to Alberta is 800 MW. However, for transfers greater than 100 MW, remedial action schemes (RAS) are needed for a number of single contingency outages (Operating Order 7T-17).

If the 500 kV line 5L94 is tripped when the export to Alberta exceeds 100 MW, an RAS to transfer trip the Natal tie is needed to maintain system stability. This limits the single contingency firm export capability to 100 MW.

The worst single contingency for the system west of Cranbrook would be the loss of 5L92, the 500 kV Selkirk to Cranbrook line. For loss of this line when the export is more than 100 MW, an RAS to transfer trip the BC to Alberta ties is needed to maintain system stability. This again limits the single contingency firm export capability to Alberta to 100 MW. Stability case ST1 (Attachment 2) shows that without the tie tripping RAS, the system will be unstable for loss of 5L92 during the required 335 MW transfer. Direct load shedding in Alberta, as an alternative to this tie tripping RAS, can also be effective. Stability case ST7 shows that at 335 MW transfer, the amount of load shed required for loss of 5L92 will be about 125 MW.

However, the two 500 kV lines, 5L94 and 5L92, are equipped with single pole fault clearing and automatic reclose features. Previous studies have shown that even at the maximum transfer, the system will remain stable for single phase fault with successful reclose. Since most of the disturbances are single phase and temporary in nature, the probability of losing any one of these 500 kV lines due to a disturbance is considered to be low.

The BC to Alberta tie is also equipped with an undervoltage tripping scheme to provide a controlled separation due to disturbances outside the area that would otherwise result in an unstable situation. One of the disturbances that may trigger this undervoltage tie tripping would be the loss of a large generating unit in Alberta during heavy BC to Alberta transfer. However, losing a large generating unit in Alberta during the 335 MW transfer level does not cause any stability problem (stability case ST5).

No other system stability problem and no RAS are needed for a single contingency outage of BC Hydro's lines West of Selkirk (e.g. Loss of the Selkirk to Nicola line, stability cases ST2).

5.2 Thermal Limit

The 138 kV tie is limited by the Natal transformers to about 100 MW. For normal system condition, the 500 kV tie line 5L94 would carry the majority of the flow during a transfer and the flow through Natal will not exceed the thermal limits even during maximum BC to Alberta transfer. However, without the 500 kV line, the net export limit to Alberta through the 138 kV lines would be limited to 100 MW less the BC Hydro loads along the Natal to Pocaterra line which is about 40 MW. In other words, the single contingency firm transfer limit due to steady state thermal limit from BC to Alberta is only about 60 MW.

When 5L92 is not in service, the power that can be transferred to Cranbrook is limited by the thermal capability of 2L293 and 2L294. The summer and winter ratings of these 230 kV lines are 1059 A and 1277 A respectively. In this case, the net amount of BC Hydro export to Alberta will depend on the local load requirement in the Cranbrook area. Figure 2 shows that, during the peak load base case, 2L293 will exceed the thermal limit when the export to Alberta is higher than 150 MW in the Winter. However, the flow in 2L293 can be adjusted by changing the Nelway phase shifter (PST) tap setting. If the net amount of export to US on the Eastside can be limited to the flow on the Waneta – Boundary line, the PST tap can be set so that the flow in 2L293 is equal to or lower than that in 2L294 (Power Flow case PF8). The thermal rating of 2L294 is then the limiting factor. Thus, for peak load conditions, as Figure 2 shows, the transfer to Alberta is limited to about 220 MW for winter due to the thermal limit of 2L294. For summer, Figure 2 shows that if the area load were as high as the winter peak (210 MW), the export limit would be 160 MW. Assuming the summer peak is about 75% of the winter peak, the area load would be about 50 MW lower and the export would be limited to about 210 MW for summer peak loading condition. For light load condition (45%), as Figure 3 shows, the limits are 270 MW for summer and 320 MW for winter respectively.

Fig. 2

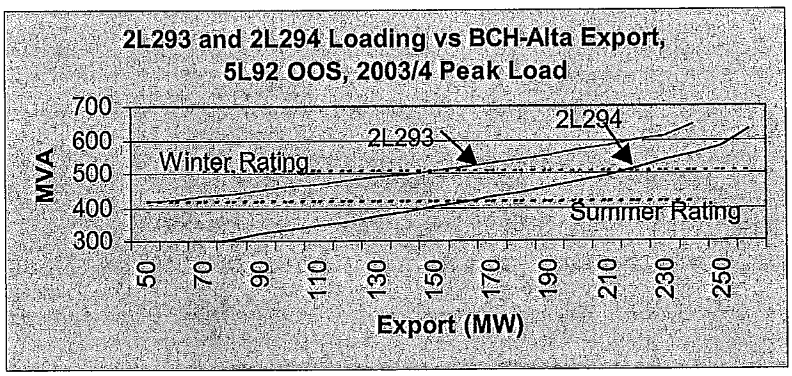
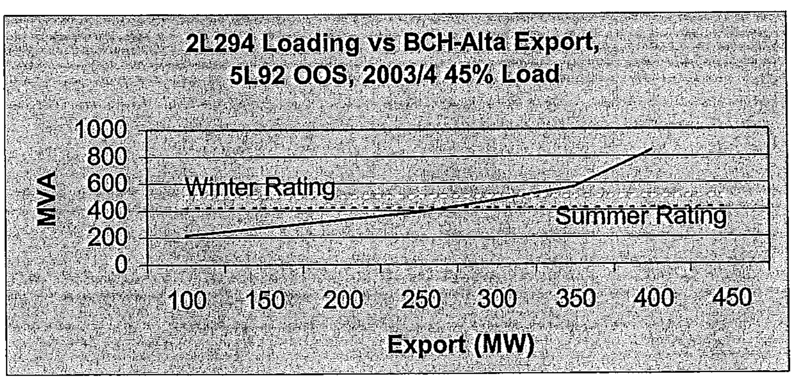


Fig. 3



5.3 Voltage Stability Limit

Figures 4 and 5 are PV curves showing the voltage stability transfer limits during peak and light load conditions without 5L92. For peak load condition the "nose point" (point of instability) of the PV curve is at an export of about 260 MW meaning the voltage will collapse if the transfer is higher than this. (If large amount of capacitor, say 300 MVAr, is added to Cranbrook, the limit can be increased to 300 MW.) For light load situation, the limit is at an export of about 400 MW.

Fig. 4

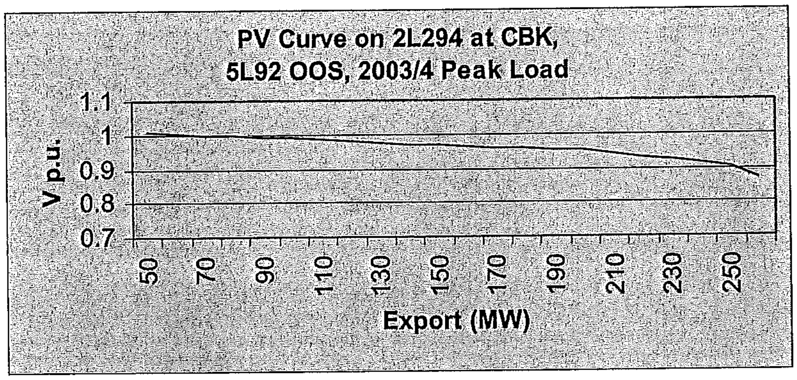
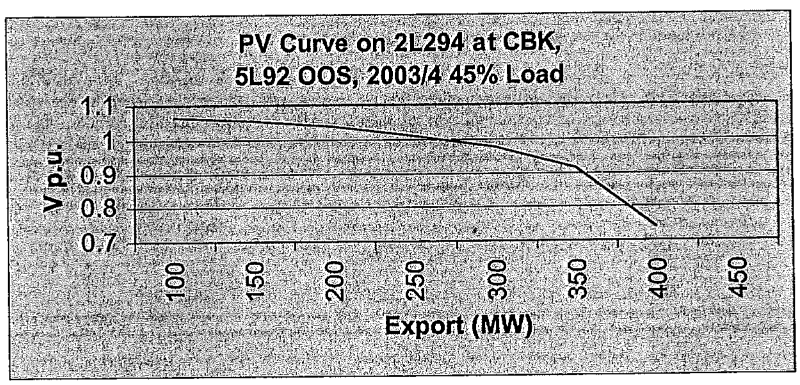


Fig. 5



The following table summarizes the various firm transfer limits of the existing system:

Stability Limit	100 MW
Summer Peak Load Thermal Limit	210 MW

Summer Light Load Thermal Limit	270 MW
Winter Peak Load Thermal Limit	220 MW
Winter Light Load Thermal Limit	320 MW
Peak Load Voltage Stability Limit	260 MW
Light Load Voltage Stability Limit	400 MW

From the above analysis, it is shown that the existing system will not support a firm BC to Alberta transfer of 335 MW without additional transmission facilities. Therefore the following options have been considered.

6. System Requirement for 335 MW Transfer

6.1 Upgrading the Cranbrook to Alberta Transmission

Unless the single contingency outage of the 500 kV tie line 5L94 is considered to be acceptable for firm transfer, upgrade will be needed to the existing ties to provide the firm transfer for loss of 5L94.

Reinforcing the transmission from Cranbrook to Natal and upgrading the Natal transformers will not be adequate. The upgrade must also cover the transmission in Alberta from Natal.

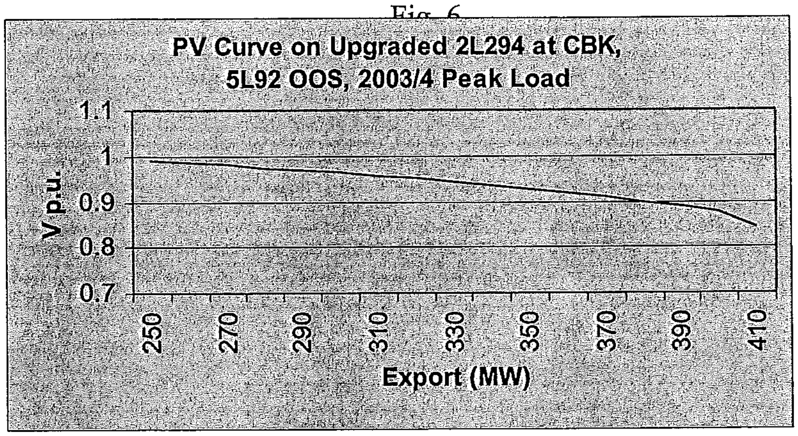
A 230 kV line from Cranbrook to Peigan Substation (Alberta) was found to be effective in increasing the transfer capability. Power flow case PF3 (Attachment 1) shows that the system will handle the 335 MW transfer for loss of the 500 kV 5L94 line. Stability case ST3 (Attachment 2) also shows that the case will be transiently stable for loss of 5L94. The length of this line will be about 180 km. Cost estimate of this line is not yet available. This line will not be required if the Firm Point-To-Point Service is curtailable for loss of the tie.

6.2 Upgrading 2L293 and 2L294

The rating of these lines of 1059 A and 1277 A for summer and winter respectively are based on an operating temperature of 91 °C. If these lines were to be re-tensioned or raised, it may be possible that the operating temperature can be increased to 150 °C (limited hours). The ratings for this operating temperature would become 1450 A and 1596 A for summer and winter respectively. However, besides the thermal limit being still insufficient, there will be no improvement to the stability limit.

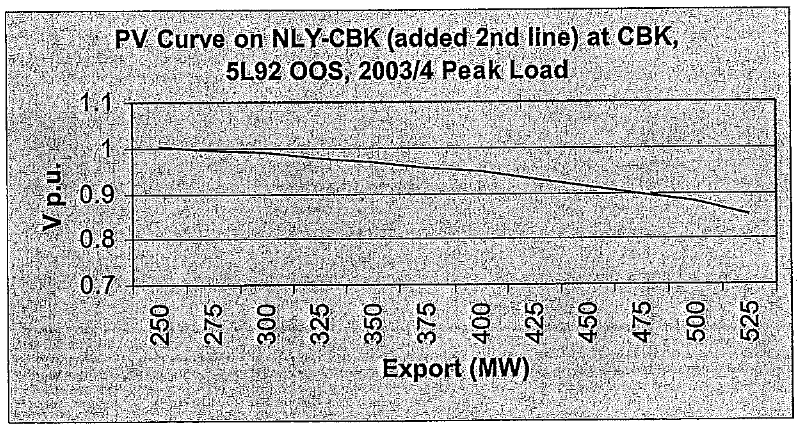
To increase both the thermal and the stability limits, it will need to replace both 2L293 and 2L294 with larger conductor or twin conductors. Power flow case PF4 and stability case ST4 shows that the system with this upgrade will be able to handle the required firm BC to Alberta transfer of 335 MW. Figure 6, a PV-curve without 5L92 in service and with this transmission upgrade, shows that the voltage stability limit (about 410 MW) is more than adequate to handle the required transfer. However, major tower upgrade or rebuild will be required for this alternative and the cost of this upgrade is estimated to be even higher than building new lines.

Fig. 6



6.3 Adding Second SEL-NLY-CBK Lines

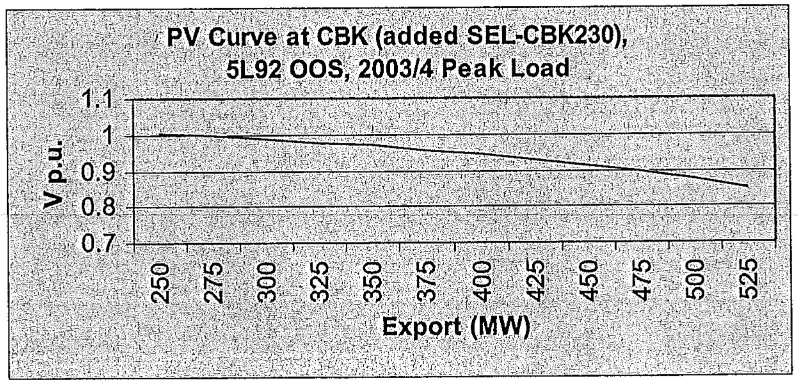
An alternative to upgrading the existing 2L293 and 2L294 circuits is to build a second line from Selkirk to Nelway and from Nelway to Cranbrook. Figure 7 is the PV curve showing the voltage stability limit without 5L92 using this transmission option. The nose point is now at 525 MW. Estimated total cost of these lines is about $65M. The construction lead-time is estimated to be about 4 years.



6.4 Adding a Selkirk to Cranbrook 230 kV Line

Another alternative to provide the required firm transfer service would be to build a new Selkirk to Cranbrook 230 kV line (wood poles) at a cost of approximately $60M which will use the existing right of way parallel to 5L92. (If this line is constructed at 500 kV but operated in 230 kV the cost would be about $110M). Technically, this option is very similar to the above option of building a second line from Selkirk to Nelway to Cranbrook as shown in the PV curve in Figure 8.

Fig.8



7. Conclusion

The existing system will not be able to provide the requested incremental transmission service for 125 MW firm export to Alberta due to both stability and thermal limits.

To provide the requested transmission service, system upgrades will be needed. The following table summarizes the various alternatives considered for increasing the Selkirk to Cranbrook transfer capability. The lowest cost alternative would be to build a new Selkirk to Cranbrook 230 kV line at a total cost of approximately $60M with a lead-time of about 4 years.

Alternatives	Export Capability Increased (MW)	Estimated Cost ($M)
Re-tension existing lines 2L293/294	<125	N.A.
Rebuild Existing lines 2L293/294 with twin conductors	>125	>65
Build second Selkirk to Nelway and Nelway to Cranbrook 230 kV lines	>125	65
Build a new Selkirk to Cranbrook 230 kV line	>125	60
Build a second Selkirk to Cranbrook 500 kV line	>125	110

Attachment 1
Load Flow Summary and 1-line Diagrams

Load Flow Summary

Case	Description
PF1	2003/4 Heavy Winter Base case, BCH load=8943 MW, Export 253 MW to WKPL, 323 MW to U.S. and 335 MW to Alberta
PF2	2003/4 Heavy Winter Peak condition, 335 MW to Alberta; CBK to Peigan 230 kV line added
PF3	Same as PF2 but with 5L94 O.O.S. (post transient outage)
PF4	2003/4 Heavy Winter Peak condition, 335 MW to Alberta; 2L293 and 2L294 upgraded to 2400 A. ratings, 5L92 O.O.S. (post transient outage)
PF5	2003/4 Heavy Winter Peak condition, 335 MW to Alberta, added second 230 kV SEL-NLY-CBK lines, 5L92 O.O.S. (post transient outage)
PF6	2003/4 Heavy Winter Peak condition, 335 MW to Alberta, added a 230 kV SEL- CBK line, 5L92 O.O.S. (post transient outage)
PF7	2003/4 Light Load (45%) condition, Export 253 MW to WKPL, 323 MW to U.S. and 335 MW to Alberta
PF8	2003/4 Heavy Winter, Export 253 MW to WKPL, 3000 MW to U.S. and 250 MW to Alberta; 5L92 O.O.S. (post transient outage)

(For copies of 1-line diagrams for the above Load Flow Cases, please contact Manager, Wholesale Transmission Contracts & Regulatory Affairs at (604) 293-5839)

Attachment 2
Stability Cases Summary and Plots

Summary of Transient Stability Cases

Case	Description	Post Transient Power Flow Case	RAS	Results
ST1	Peak load condition, 335 MW to Alberta, 3 ph fault at CBK500 and loss of SEL-CBK 500 line 5L92	n.a.	none	unstable
ST2	Peak load condition, 375 MW to Alberta, 3 ph fault at SEL500 and loss of SEL-NIC500 line 5L98	n.a.	none	stable
ST3	Peak load condition, 375 MW to Alberta with CBK- Peigan line added, 3 ph fault at CBK500 and loss of BC-Alberta 500 kV tie 5L94	PF3	none	stable
ST4	Peak load condition, 375 MW to Alberta with 2L293 & 2L294 conductors doubled, 3 ph fault at CBK500 and loss of SEL-CBK 500 line 5L92	PF4	none	stable
ST5	Peak load condition, 375 MW to Alberta, Alberta lost one 383 MW generating unit	n.a.	none	stable
ST6	Light load (45%) condition, 335 MW to Alberta and loss of SEL-CBK 500 line 5L92	n.a.	none	Stable
ST7	Peak load condition, 335 MW to Alberta, 3 ph fault at CBK500 and loss of SEL-CBK 500 line 5L92	n.a.	Shed 125 MW load in Alberta	Stable

(For copies of the plots for the above Transient Stability Cases, please contact Manager, Wholesale Transmission Contracts & Regulatory Affairs at (604) 293-5839)

BC hydro

THE POWER IS YOURS

System Impact Study for MacLaren's OASIS No. 344081, Five Year Export on the BCHA × EAL Path

Report No: NPP2001-05
May 9, 2001

Network Performance Planning Department
T&D Engineering

T&D ENGINEERING

Executive Summary

MacLaren Energy submitted an OASIS request to BC Hydro Transmission & Distribution (T&D) for Long Term Firm Point-to-Point transmission service under the Wholesale Transmission Service (WTS) tariff to export 32 MW on the BCHA × EAL Path from 1 January 2003 to 31 December 2007.

This System Impact Study identifies system constraints and redispatch options, additional Direct Assignment Facilities or Network Upgrades required to provide the requested service. The base conditions for the study are the BC Hydro native load requirements from 2003 to 2007, and prior export commitments on the BCHA × EAL path throughout the whole time period. Power flow and transient stability studies were performed to examine whether the MacLaren Energy transmission request can be accomplished in compliance with the BC Hydro, Western Systems Co-ordinating Council (WSCC), and North American Electric Reliability Council (NERC) reliability criteria. This System Impact Study only addresses the capability of the BC Hydro system and does not consider capabilities of adjacent systems.

The System Impact Study concluded that the available transfer capability (ATC) on the existing BCHA × EAL path is 0 MW. The MacLaren 32 MW transmission service request could not be accomplished without significant Network Upgrades to the system. The restriction and option for removing this restriction can be summarized as follows:

South Interior East Bulk Transmission – Thermal Limitation
This restriction will be in effect for the entire requested period. Adding a 230 kV circuit from Selkirk to Cranbrook would alleviate the thermal constraint and accommodate the total amount of the Transmission Service request.

There are no Direct Assignment Facilities associated with this request for Transmission Service, as this System Impact Study does not include an Interconnection Study.

As noted above, the full 32 MW of export request cannot be met unless a new 230 kV circuit from Selkirk to Cranbrook is placed in service. A Facilities Study would be required to consider this Network Upgrade.

Table of Contents

1. Introduction

MacLaren Energy submitted an OASIS request (No. 344081) to BC Hydro Transmission and Distribution (T&D) for Long-Term Firm Point-to-Point Transmission Service for 32 MW on the BCHA × EAL for the period 1 January 2003 to 31 December 2007.

Pursuant to the WTSA, T&D determined that a System Impact Study was required for the Application.

Power flow and transient stability studies were performed to examine whether the MacLaren Energy transmission request can be accomplished in compliance with the BC Hydro, Western Systems Co-ordinating Council (WSCC), and North American Electric Reliability Council (NERC) reliability criteria.

2. Terms of Reference

A summary of the Terms of Reference is provided below.

(a) T&D will use its existing planning and operating criteria, standards and procedures which conform with WSCC Reliability Criteria.

(b) Specifically, the following studies will be done:
- Thermal, transient, and voltage stability studies to determine the system capability to permit the 32 MW transfer.
- Identify system transmission constraints and any network upgrades.
- Identify available partial service capability, if full service is not available.

(c) The study will assess the generation reserve issues as required by the WSCC.

(d) The above technical studies will be done for the following system conditions:
- The system configuration will be based on the resource allocations from the 10 year Recommended Resource Plan, network loads, and reserved and pending Long-Term Firm Point-to-Point Transmission service for the terms of this request.
- High stress system conditions, including but not restricted to the freshet and winter peak load cases.

(e) The studies will not identify any constraints on neighbouring systems as it is the Transmission Customer's responsibility to ensure that any neighbouring utility limitations are addressed.

3. System Study Conditions

The conditions for the study are the BC Hydro native load requirements from 2003 to 2007, and prior import commitments on the BCHA × EAL path throughout the whole time period.

The system transmission upgrades identified for this transmission request are incremental to requirements for native load and existing Point to Point Service obligations. The incremental requirements are based on the additional generation resources as specified in the MacLaren Energy Application.

3.1. Resources for Transmission Request

The Point-of-Receipt (POR) for the transmission service is BC Hydro's Illecillewaet Substation. The resource is a new Independent Power Producer (IPP).

3.2. Transmission System Assumptions for Transmission Request

Transmission System assumptions for this Transmission Service request are contained in Appendix A.

4. System Requirements for Transmission Request

Planning studies were performed as per T&D's Transmission System Planning Criteria and Study Methodology.

Only those portions of BC Hydro's transmission system that require reinforcements have been addressed below.

4.1. South Interior East Bulk Transmission

When 5L92 is not in service (e.g. for maintenance), the power that can be transferred to Cranbrook (and thus to the firm local loads) is limited by the thermal capability of 2L293 and 2L294. This limitation defines the allowable firm exports on the BC to Alberta path. 0 MW long-term firm ATC exists on the BCHA × EAL path due to this thermal constraint.

A new Selkirk to Cranbrook 230 kV circuit with a lead time of 4 to 6 years would have to be built to accommodate the requested firm transfer. Redispatch was determined not to be a feasible option.

5. Conclusions

The System Impact Study concluded that the MacLaren 32 MW import request could not be accomplished without significant Network Upgrades to the system.

The full 32 MW of export request cannot be met unless a new 230 kV circuit from Selkirk to Cranbrook is placed in service. A Facilities Study is required to consider this Network Upgrade.

There are no Direct Assignment Facilities associated with this request for Transmission Service, as this System Impact Study does not include an Interconnection Study.

Appendix A.

Transmission System Assumptions for Transmission Request

A.1 Prior Uncompleted Firm Point-to-Point Requests

There are no uncompleted Firm Point-to-Point Requests on the BCHA × EAL Path.

A.2 Modifications to the Power-Flow Base Cases

The following were added in the power-flow base cases:

- All existing Transmission Service reservations were included. However, since Counter-Flow Scheduling on a bi-directional path will not increase the amount of Firm Transfer Capability on the path, transfers have been set to zero with the following exceptions:
  - The transfers for Transmission Reservation #s 141206, 311564, and 311565 are included.

Appendix B.

System Requirements for Transmission Request

B.1 South Interior East Transmission and BCHA × EAL Path

The system must be transiently stable after loss of a single element and the remaining system must be within thermal and voltage stability limits. Remedial Action Schemes (RAS) are allowed as long as there is no loss of load. Since the Path is considered radial (the transfer capabilities of the parallel 138 kV circuits are insignificant compared to the 500 kV circuit), loss of transfer is permitted for loss of a single element on the Path.

B.1.1 Thermal Limit

When 5L92 is not in service (e.g. for maintenance), the power that can be transferred to Cranbrook (and thus to the firm local loads) is limited by the thermal capability of 2L293 and 2L294. This limitation defines the allowable firm exports on the BC to Alberta path.

An alternative to provide the required firm transfer service would be to build a new Selkirk to Cranbrook 230 kV circuit with a lead time of 4 to 6 years.

B.1.2 Transient Stability Limit

Previous studies have shown that there will be no transient stability problem for the Transmission Service request.

B.1.3 Voltage Stability Limit

Previous studies have shown that there will be no voltage stability problem for the Transmission Service request.

B.2 South Interior West Bulk Transmission

The Transmission Service request is not limited by this portion of the bulk transmission network.

System Impact Study

For

The TCP 170 MW Wheel through on the BPAT - EAL Path

Report No: SPA2004-33

28 June, 2004

Performance Analysis (NI&SI)

System Performance Assessment Department (NI&SI)

Executive Summary

BCTC has conducted System Impact Studies to address the following point-to-point requests.

OASIS#	Time Stamp	Amount	Term	Customer
485180	09-Aug-02	170 MW	5 year (Jan 2003-1 Jan 2008)	TCP

Based on the study terms of reference (Section 2) and system conditions (Section 3) BCTC has determined the following transmission capabilities.

Since BCTC transmission system has an additional 270 MW transfer capability from BC to Alberta, the BCTC system has the following wheel through (US via BC to AB) capability from now until Jan 1st, 2008 (OASIS#485180) based on the already committed transfers on BPAT x BCTC path and BCTC x EAL path while taking TRM into account.

2004	2005	2006	2007	2008
226 MW	185 MW	159 MW	162 MW	158 MW

By upgrading 5L52 in 2006, BCTC can accommodate the full 170MW wheel through from US to AB.

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1. Introduction

On August 9th, 2002, TransCanada Power (TCP) submitted a Wholesale Transmission Service Application for 170 MW of Long Term Firm Point-to-Point transmission service for wheel-through on the BPAT x EAL Path for the period of January 1st, 2003 to January 1st, 2008 (Oasis Request # 485180).

BCTC and TCP have signed the System Impact Study Agreement for this request.

This report has documented the finding of the studies on the BCTC transmission system capability of accommodating the above requests.

2. Terms of Reference

This SIS is based on the following documents:

- NERC/WECC Planning Standard
- System Impact Study for Power Supply NITS 2001
- BCTC existing System Operating Order 7T-64
- BCTC Transmission Investment Plan (2004-2014)

3. System Study Conditions

The SIS conditions for OASIS request # 485180 include:

- Existing GWA transfer rights.
- Prior Long Term Firm Point-to-Point commitments on the BPAT X BCTC Path including OASIS # 257654, OASIS # 490444
- Prior Long Term Firm Point-to-Point commitments on the BCTC X EAL Path 210 MW
- Prior Long Term Firm Point-to-Point commitments on the BCTC X BPAT Path including OASIS # 72623 (230 MW) and OASIS # 254221 (500 MW)
- BC Hydro Probable Peak Load Forest including Power Smart dated on 17 November 2003.
- The generation patterns used consisted of the Network Resources from NITS Agreements #39073, #39077 and #72625 adjusted per the most recent updates and balanced with the load."
- Transmission Reliability Margin (TRM) of 50 MW on the BC-US inter-ties.

- TRM of 65 MW on the BC-Alberta inter-ties.
- New projects in BCTC Transmission Investment Plan (2004-2014)

4. Resources for Transmission Request

US generation resources are the resources for TCP 170 MW wheel through from US to Alberta (OASIS # 485180).

5. Project and Transmission Service Risks

Content of this document contains some uncertainty in the plan, reinforcement, cost, and in service dates.

6. Conclusions

Applying NERC/WECC reliability criteria and based on the above system conditions, the study was conducted on the existing 2004/2005 and the planned 2007/2008 transmission systems. The following are the conclusions.

Since BCTC transmission system has an additional 270 MW transfer capability from BC to Alberta, the BCTC system has the following wheel through (US via BC to AB) capability from now until Jan 1st, 2008 (OASIS#485180) based on the already committed transfers on BPAT x BCTC path and BCTC x EAL path while taking TRM into account.

2004	2005	2006	2007	2008
226 MW	185 MW	159 MW	162 MW	158 MW

By upgrading 5L52 in 2006, BCTC can accommodate the full 170MW wheel through from US to AB.

System Impact Study

For

Increasing Firm ATC

From BC to Alberta

and

From BC Interior to the US

Report No. SPA 2007-88

April 3, 2007

British Columbia Transmission Corporation

DISCLAIMER OF WARRANTY, LIMITATION OF LIABILITY

This report was prepared by BCTC solely for the purposes described in this report, and is based on information available to BCTC as of the date of this report. Accordingly, this report is suitable only for such purposes, and is subject to any changes arising after the date of this report. The report was conducted using BCTC's existing planning criteria, standards and procedures which conform with WECC Reliability Criteria, to determine necessary transmission system reinforcements.

Unless otherwise expressly agreed by BCTC, BCTC does not represent or warrant the accuracy, completeness or usefulness of this report, or any information contained in this report, for use or consideration by any third party, nor does BCTC accept any liability out of reliance by a third party on this report, or any information contained in this report, or for any errors or omissions in this report. Any use or reliance by third parties is at their own risk.

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Executive Summary

This report provides a high level review of Network Upgrades required for increasing Firm Point to Point (PTP) Available Transfer Capability (ATC) from BC to Alberta and from BC Interior, which includes the Northwest region, to the US. The system model used in the analysis assumes that the second Nicola-Meridian line (5L83) is not present. The study uses first contingency criteria and TTC/ATC Methodologies as stated in section 2.0 of the Business Practices (http://www.bctc.com/NR/rdonlyres/D9F43D5D-959F-458A-8549-F88D108AE357/0/022006Mar1FinalSection2.pdf), and identifies the constraints in the transmission system to be rectified in order to increase Firm PTP ATC.

Cost estimates for required reinforcements are provided. These are high level estimates, and some are based on previous studies. As such, they need to be updated once all the required reinforcement details from a Facilities Study have been identified.

Further more, this study examines BCTC transmission system only and assumes that Alberta or the US is able to accommodate the proposed transfers. As such, no contingency or operating constraints in Alberta or the US is studied.

For BC to Alberta transfers, depending on the transfer level, there are two major constraints: the 138 kV BC-Alberta ties, and the voltage support in Cranbrook area. The 138 kV constraints can be avoided by opening the 138 kV BC-Alberta tie during period of high transfer levels, thus forcing all transfers to go onto the Cranbrook Langdon 500 kV line. Reactive reinforcement in the form of switched capacitor or SVC at Cranbrook/Selkirk area is required and is expected to vary between $36M and $54M at the transfer level of between 850MW and 1200MW.

For BC Interior to the US, the constraint is on the ILM path. BCH Coastal Generation can influence the amount of ATC on the ILM path. Under certain Coastal Generation scenarios, additional Firm PTP to the US would cause 5L81 or 5L82 to be overloaded when there is a contingency on the other line. Under such situation, thermal upgrade of the emergency ratings of the capacitor banks on these lines is required to accommodate additional Firm PTP. The cost to upgrade these two lines to a rating of 3000A nominal is estimated at $27M.

Table of Content

1.0 Introduction

The purpose of this study is to determine Network Upgrades required for increasing Firm PTP ATC from BC to Alberta and from BC Interior, which includes the Northwest region, to the US. The study report provides a high level review of costs estimate and timelines for implementing these Network Upgrades. The system model used in the analysis assumes that the second Nicola-Meridian line (5L83) is not present. The study uses first contingency criteria and TTC/ATC Methodologies as stated in section 2.0 of the Business Practices (http://www.bctc.com/NR/rdonlyres/D9F43D5D-959F-458A-8549-F88D108AE357/0/022006Mar1FinalSection2.pdf), and identifies the constraints in the transmission system to be rectified in order to increase Firm PTP ATC.

2.0 Studies Performed

This study is carried out to examine only the capability of the BCTC transmission system in terms of wheeling power to Alberta or to the US. It does not study contingencies in the Alberta or the US systems but assumes that these two systems are capable of importing the transferred amount without problems within their systems.

The 2009, 2014 and 2016 Heavy Winter load flow base cases are used as the starting point for the studies. These load flow cases are the most stressed cases within the given time period. They have the most up-to-date load and resource and IPP representations. The base cases do not include the second Nicola-Meridian line (5L83) or the ILM alternative upgrades.

For the BC to AB, the base cases include existing 480 MW Firm PTP commitments plus 65 MW Transmission Reliability Margin (TRM).

For the BC to the US, the base cases include existing 230 MW Firm PTP commitments plus 50 MW TRM. The transfer on the eastern BC-US tie is set to zero to reflect third-party transmission rights. Also, AB is exporting 101MW to BC.

Finally, a combined wheeling through from the US and export from BC (1200MW) to Alberta is examined to identify the transmission upgrade requirements for utilizing the full path rating of the BCTC-AESO inter-tie.

3.0 Study Results

3.1 BC – AB Incremental Firm ATC

The system was simulated at various firm transfer levels from 545 MW to 1200 MW to identify overloads and constraints. Solutions were determined to mitigate these overloads and constraints. It was found the 138 kV ties to Alberta (1L274 and 1L275) were over loaded. However, if the 138 kV ties to Alberta are opened to force all exports to flow on the CBK-LGN 500 kV line, the overloading conditions could be avoided. The following shows the Network Upgrades and the resulting additional Firm PTP ATC with the assumptions that the 138 kV systems are operated in an open loop configuration for heavy BC to AB transfer levels:

- For 545 MW to 850 MW: no Network Upgrade is required.
- For 850 MW to 1200 MW:

  Two reinforcement options are identified to allow this level of transfer:
  Reinforcement Option 1
  - Reactive support in the form of a SVC at Cranbrook will be required. The amount of reactive power reinforcement is about 550 MVAr. The preliminary costs estimate for this option is approximately $36M, and it would take approximately 3 years to implement.
  - With reactive reinforcement at Cranbrook, a contingency on 5L91 (Selkirk-Ashton Creek) or on 5L96 (Selkirk-Vaseux) does not show any voltage violations or thermal overload problems. The system remains stable following these contingencies.

  Reinforcement Option 2
  - Series compensation on 5L94 (Cranbrook-Langdon) and 5L92 (Cranbrook-Selkirk) could be implemented to provide the same level of transfer at a cost of approximately $54M. This option will take approximately 4 years to implement.

3.2 BC – US Incremental Firm ATC

Coastal Generation was adjusted such that loss of circuit 5L81 will result in 5L82 being utilized at full capacity. An increase in Firm PTP from BC Interior to the US will result in overloading 5L82 when there is a contingency on 5L81. However, losing 5L82 will not result in overloading 5L81 for up to 85 MW additional Firm PTP. Further increase from this level will overload 5L81 when there is a contingency on 5L82. The following shows the Network Upgrades and the resulting additional Firm PTP ATC on the BC Interior to the US path:

- 0MW to 85MW:
  - Thermal upgrades of 5L82 to 3.0 kA nominal at an approximate cost of $13M. These upgrades would take 2 to 3 years to implement.

- 0MW to 170MW:
  - Thermal upgrades of 5L82 to 3.0 kA nominal
  - Thermal upgrades of 5L81 to 3.0 kA nominal

  These upgrades would cost approximately $27M and take 2 to 3 years to implement.

However, these upgrades can be avoided if re-dispatch of Coast Generation (in a ratio of 1-1 with the requested transfer) is available.

4.0 Conclusions

Not considering the limitations within Alberta system, the BCTC system is capable of delivering 1200 MW to the BC Alberta border when adequate reactive reinforcement is provided.

To provide up to 170MW of incremental export levels from BC Interior to the US, thermal upgrades of 5L81 and 5L82 will be required. However, if re-dispatch of Coast Generation is available, these upgrades can be avoided.

British Columbia Transmission CORPORATION™

Point to Point US to BC, BC to Alberta

and wheel through US to Alberta

System Impact Study

Report No. SPA 2007-85

November 2007

Transmission System Planning
British Columbia Transmission Corporation

DISCLAIMER OF WARRANTY, LIMITATION OF LIABILITY

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Unless otherwise expressly agreed by BCTC, BCTC does not represent or warrant the accuracy, completeness or usefulness of this report, or any information contained in this report, for use or consideration by any third party, nor does BCTC accept any liability out of reliance by a third party on this report, or any information contained in this report, or for any errors or omissions in this report. Any use or reliance by third parties is at their own risk.

Executive Summary

This report provides a preliminary review of requirements in responding to an aggregated firm import request for 1350 MW of power from the US Northwest (NW) into British Columbia, Canada. This report also provides a preliminary review of the requirements for delivering up to 1200MW from BCTC system to BC-Alberta border. This System Impact Study did not analyze firm transfer capability levels that require building a new tie-line. The study assumes all transmission elements are in service and uses first contingency criteria to identify the constraints in the BCTC transmission system to permit such transfers.

Cost estimates for some required reinforcements are provided. These are preliminary estimates, and some are based on previous studies. As such, they need to be updated once all the required reinforcement details from a Facility Study have been identified.

This study examines the BCTC transmission system only and assumes that the US NW is capable of sending the power into BC and that Alberta system is able to take the wheeled power without restrictions. As such, no contingency in US NW or Alberta system is studied.

BCTC has recently analyzed and confirmed the existing firm total transfer capability (FTTC) of the BPAT-BCTC Path. The analysis confirmed that the FTTC for Path 3 is 1930 MW in both directions.

Also, BCTC has recently completed a study, the System Impact Studies for Increasing Firm ATC from BC to Alberta and from BC Interior to the US. *This study indicated that the transmission facilities of BCTC-AESO Path are capable of 850 MW FTTC.*

This System Impact Study (SIS) shows that to increase the Firm TTC (FTTC) of the BPAT-BCTC Path above 1930 MW, Network Upgrades are required. The cost estimates of some of the upgrade options are shown in Section 4 of this report. When power is imported into BC from the US, it will be counter flow on the ILM path. Most of the imported power will be consumed in the Lower Mainland, and power originally designated to flow on the ILM to supply Lower Mainland load will be diverted eastward towards Alberta. Other than upgrading the BPAT-BCTC Path firm transfer capability, no major problems are anticipated in importing power from the US.

This SIS also showed that to increase FTTC of the BCTC-AESO Path from 850 MW to 1200 MW, reactive reinforcement in the Cranbrook/Selkirk area or series compensation in 5L92 and 5L94 is required

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1.0 Introduction

As of October 2007 there are 42 LTPTP transmission requests on the West to East direction of flow for paths on BPAT-BCTC, BCTC-AESO and BPAT-AESO. A total of 23 requests underwent the System Impact Study process. Out of the 23 studies, 11 participated in the Open Season hosted by BCTC from July 1 to July 31 of 2007. To efficiently meet customers' requests, BCTC combined all requests and conducted two studies to identify any system reinforcements.

BCTC has determined, in a separate study, that a firm transfer capacity of 1930MW is available without any Network Upgrades. The SIS on the BPAT-BCTC Path was conducted in steps to determine incremental firm transfer capacity by increasing thermal ratings of 5L52 to 2520 Amp, and 5L51 and 5L52 to 3000 Amp, 3400 Amp and 4000 Amp. This SIS indicated higher firm transfer capacity for this path is available by modifying:

1) thermal rating of circuit 5L52 to 2520A to provide firm transfer capacity of 2380MW;
2) thermal ratings of both 5L51 and 5L52 to 3000A to obtain 2800MW;
3) thermal ratings of 5L51 and 5L52 to 3400A to obtain 3143MW
4) thermal ratings of 5L51 and 5L52 to 4000A to provide 3663MW

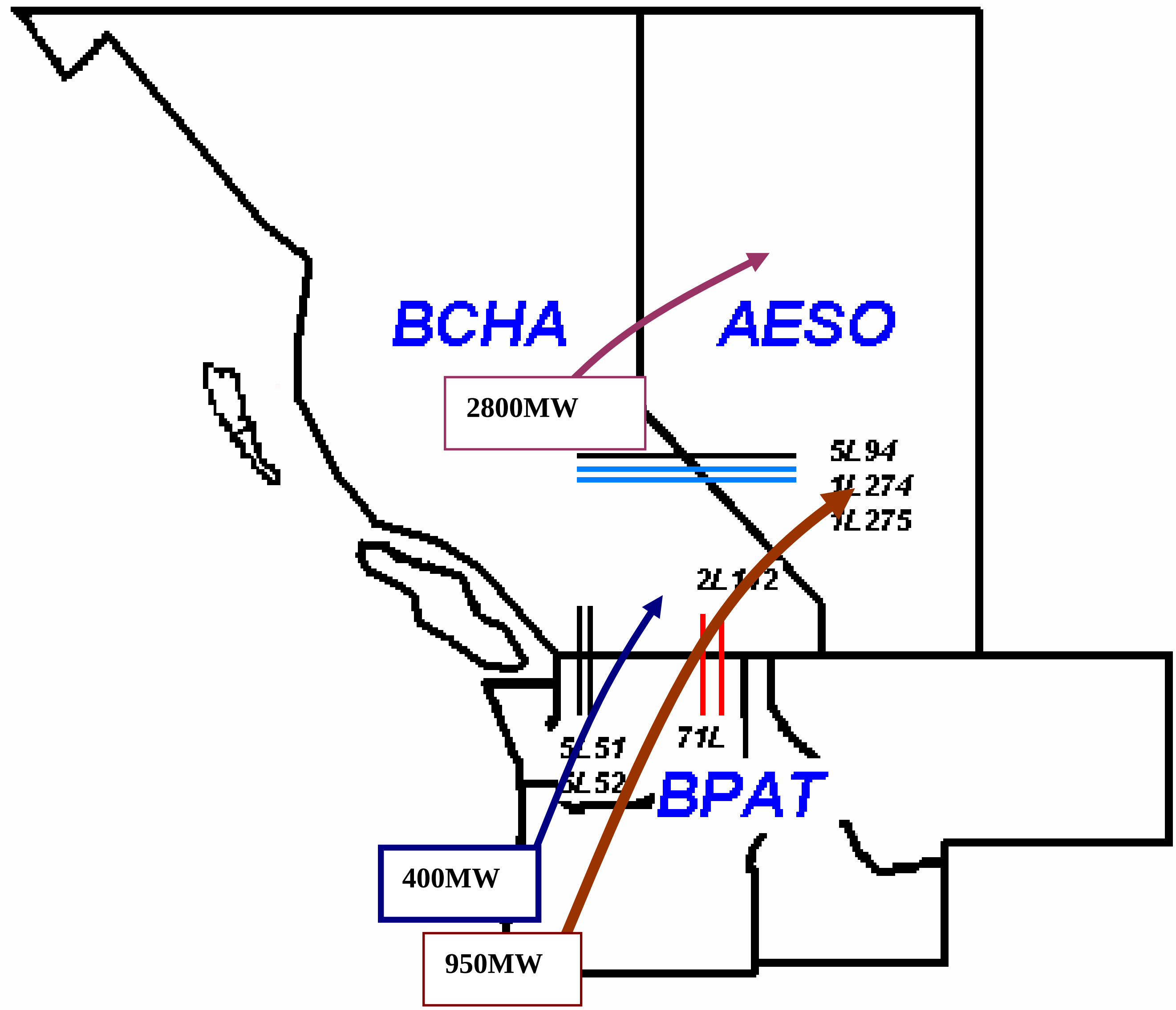
For the BCTC-AESO path, the System Impact Studies for Increasing Firm ATC from BC to Alberta and from BC Interior to the US, based on N-1 criteria shows a firm transfer capacity of 850 MW is possible without any upgrades. Increasing firm transfer capacity to 1200MW will require Network Upgrades.

The scope of this SIS is based on the pending capacity in addition to existing BCTC Long Term PTP Firm commitments. The following table shows the existing contracts and new capacity requested from year 2008 to 2011.

Existing Contracted Commitments & New Requests (MW) by path

		2008	2009	2010	2011	
A.	BPAT>BCTC					
	Contracted	1742	1844	1844	1844	
	TRM	50	50	50	50	
	New Requests	150	750	850	1350	
B.	BCTC>AESO					
	Contracted	480	100	100	100	
	TRM	65	65	65	65	
	New Requests	550	2150	2250	3750	
	BPAT>AESO					
	New Requests	150	550	650	950	(Subsets of A & B)

The following map illustrates the new capacity requested on the inter-tie.



2.0 Study Performed

This SIS is carried out to examine the capability of the BCTC transmission system in terms of importing power from US NW and wheeling part of it to Alberta. The criteria for the study are to ensure that the system can maintain proper voltages and remain stable under N-1 conditions. Transfers would have to be curtailed under multiple contingencies. It does not study contingencies in the US or Alberta systems but assumes that these two systems are capable of exporting and importing the transferred amount respectively without causing any problem within its own system.

Study Assumptions:

For the purpose of this SIS, two heavy winter load flow base cases for 2008 are used. These base cases have the BCH December 2006 load forecast, and up-to-date load, and resource and IPP data, and represent a stressed system. The following assumptions are used in the base cases:

- Because BCTC-AESO Path has a maximum rating of 1200MW, one base case has BC importing 1200MW from US and wheeling this 1200MW to Alberta.
- The second base case differs from the first base case in that it imports a total of 1350MW from US and wheels only 900MW to Alberta.
- Alberta is capable of importing 1200MW from BC.
- BPA is capable of exporting 3663MW to BC.
- Transmission Reliability Margin (TRM) for BCTC-BPAT Path is 50MW.
- TRM for BCTC-AESO Path is 65MW.
- Firm transfer capability including TRM for from US to BC is 1930 MW.
- Firm transfer capability including TRM from BC to AB is 850 MW.

3.0 Study Results

Load flow and transient stability simulations were carried out for the above base cases to investigate the performance and behavior of the transmission system. Station voltage profiles, equipment loading and system stability under N-1 conditions are monitored.

The study indicates two major reinforcements are required to support the transmission service requests. These two reinforcements are:

1. Upgrade BPAT-BCTC Path parallel 500 kV circuits (5L51 and 5L52) between Ingledow and Custer to a higher rating for a higher firm transfer capability.
2. Provide reactive reinforcement in Cranbrook area to support system voltages at system normal and maintain system stability during an N-1 contingency.

The study for the wheel through scenario can be viewed as a combination of two sub-studies. The first part consists of examining the portion from US into BC for the import, and the second part consists of the portion from BC to Alberta for the export.

US to BC

As discussed above, the existing firm transfer limit for BPAT-BCTC Path has been determined to be 1930MW. Of this 1930 MW, 1792 MW and 1894, including TRM, have been reserved by prior requests starting 2008 and 2009 respectively. To accommodate additional firm requests, BPAT-BCTC Path firm transfer capability must be upgraded. This can be achieved by upgrading the thermal ratings of circuits 5L51 and 5L52 to a higher load carrying capability. A change to the WECC path rating will be required.

BC to Alberta

Further to the System Impact Studies for Increasing Firm ATC from BC to Alberta and from BC Interior to the US, BC is connected to Alberta by a single 500kV transmission line between Cranbrook and Langdon, and two 138 kV lines between Natal–Coleman, and Fording Coal-Pocaterra. For interchanges between BC and Alberta, power flows proportionally on these three circuits. The higher the interchange, the more flow will be on the 138 kV circuits.

The following table shows the over loading condition (bold) of the Natal transformers that supply the 138kV lines as a function of the size of the BC-AB interchange:

BC to AB Transfer	Loading on Natal T1 (50MVA)	Loading on Natal T2 (50 MVA)	Loading on Green hills Tap -Fording Coal (63.3 MVA)
1200 MW	**88.7**	**87.2**	**81.5**
850 MW	**66.7**	**65.7**	**63.4**
800 MW	**64.0**	**62.9**	61.1
750 MW	**59.8**	**58.7**	57.7
650 MW	**53.8**	**52.9**	52.6
550 MW	47.9	47.1	47.5
450 MW	42.1	41.3	42.7

In order to avoid overloads on the Natal transformers, the two 138 kV ties lines to Alberta can be operated in an open-loop configuration during periods of high transfers. Therefore, all the power flows on the radial Cranbrook-Langdon 500 kV tie line.

Because of this single 500kV radial connection, it should be noted that the term 'firm transfer' means Firm Point-to-Point transmission service as defined in BCTC's Open Access Transmission Tariff.

When power is transferred from point A to point B, reactive power is required to support such transfers. For wheeling 1200MW into Alberta, a major concern for the South Interior East region is voltage support. Preliminary studies show that starting at around 850 MW of transfer from BC to AB, additional reactive support at Cranbrook is required. The other alternative is to series compensate 5L94 (Cranbrook-Langdon) and 5L92 (Cranbrook-Selkirk).

Assuming a reactive device such as a SVC is installed at Cranbrook, the following tables show at 1200MW transfer, the voltages at key stations, flows on the paths of interest, and the loading on Natal transformers:

Voltage at Key Stations @1200MW Transfer Level

	138 kV ties closed	138 kV ties open
	Voltage (pu)	Voltage (pu)
Nicola	1.054	1.054
Vaseux	1.054	1.054
Ashton Creek	1.058	1.058
Selkirk	1.044	1.045
Cranbrook	1.030	1.030
Langdon	1.029	1.013

Flows on Major Lines at 1200MW Transfer Level

	138 kV ties closed	138 kV ties open
	Flows (MW)	Flows (MW)
Selkirk-Cranbrook	1186	1180
Cranbrook-Langdon	1077	1200
Fording Coal-Pocaterra	61.9 MW	0
Natal-Coleman	63.2 MW	0

Loading on Natal Transformers @ 1200MW Transfer Level

	138 kV ties closed	138 kV ties open
Natal T1 (50 MVA)	88.7 MVA	23.2 MVA
Natal T2 (50 MVA	87.2 MVA	22.8 MVA

With an SVC modeled at Cranbrook, transient stability study shows that a contingency on 5L91 or 5L96 does not create any voltage abnormality or equipment overload and the system remains stable after this contingency.

4.0 Reinforcement Options and Cost Estimates

- Assuming that the 138 kV BC-Alberta ties are operated in an open-loop configuration during high transfer periods, the following reinforcement options are required in order to enable the 1200MW firm transfer from BC to Alberta

- Reactive support in the form of a SVC at Cranbrook is required to support the transfer. The size of the SVC should not be less than 350 MVar.
  or
  Series compensation of 5L94 (Cranbrook-Langdon) and 5L92 (Cranbrook-Selkirk)

For additional US to BC firm transfer capability at various levels from US to BC, an upgrade of the thermal rating of 5L51 and 5L52 to allow a higher firm transfer capability between Custer and Ingledow is required.

The following table shows good faith estimates of the costs of implementing the various options:

	Reinforcement	Cost Estimate	Benefit
1	Upgrade 5L52 capacity to match that of 5L51	$2.0 M 1-1.5 years to implement	Increase BPAT-BCTC Path firm transfer capability by 450 MW to 2380 MW.
2	Upgrade both 5L51 and 5L52 to a thermal rating of 3000 Amp.	$2.5M 1-2 years to implement	Increase BPAT-BCTC Path firm transfer capability by 870 MW to 2800 MW.
3	Upgrade both 5L51 and 5L52 to a thermal rating of 3400 Amp, Upgrade station equipment at Ingledow substation	(to be determined)	Increase BPAT-BCTC Path firm transfer capability by 1213 MW to 3143 MW
4	Upgrade both 5L51 and 5L52 to a thermal rating of 4000 Amp, Upgrade other network and station equipments	(to be determined)	Increase BPAT-BCTC Path firm transfer capability by 1733 MW to 3663 MW. Detailed Facilities Study needs to be performed.
5	Reactive reinforcement (i.e. SVC) at Cranbrook or Series Compensation of 5L92 and 5L94	(to be determined) or (to be determined)	Allow the transfer to go above 850 MW and up to the full path rating of 1200 MW. or Allow the transfer to go above 850 MW and up to the full path rating of 1200 MW

5.0 Conclusion:

Under single contingency criteria, the existing BCTC system can transfer up to 850MW to BC Alberta border without system upgrade. For transfers higher than 850MW, reactive reinforcement at Cranbrook area or series compensation in 5L92 and 5L94 is required.

For BC to Alberta transfers above 550MW, Natal transformers will be overloaded. Thermal upgrades in the Natal area can be avoided by operating the 138 kV ties to Alberta in an open-loop configuration to force the transfers to take place on the 500 kV circuit (5L94) between Cranbrook (BC) and Langdon (Alberta). However, it should be noted in such open-loop situation, Elk Valley Coal, Elkford, Cranbrook Regional Hospital and Fording Coal are supplied radially from Natal and their reliability will be less than when they are supplied in a looped configuration.

To meet the increased demand for firm transmission service on the BPAT-BCTC path, upgrading of the thermal ratings of 5L51 and 5L52 between Custer and Ingledow substations is required. Upgrading 5L52 to match 5L51 at 2520A will increase the firm TTC to 2380MW, resulting in an incremental increase of 450MW. Upgrading both 5L51 and 5L52 to 3000A will increase the firm TTC to 2800MW, resulting in an incremental increase of 870MW.

The present WECC Path Rating limits the total transfer on Path 3 to 2000 MW from US into BC (BPAT-BCTC Path), and 3150MW from BC to the US (BCTC-BPAT Path). A WECC path uprating process will be required to allow for the new transfers.

Attachment 4

Determination of ATC Within the Western Interconnection

Determination of Available Transfer Capability Within The Western Interconnection

June 2001

Rocky Mountain Operation and Planning Group
Northwest Regional Transmission Association
Southwest Regional Transmission Association
Western Regional Transmission Association
Western Systems Coordinating Council

CONTENTS

Determination of Available Transfer Capability Within the Western Interconnection

1. Introduction

Members of the Regional Transmission Groups (RTGs) and other entities in the Western Interconnection are obligated to provide information to their members and the public regarding Available Transfer Capability (ATC) for transmission paths, in accordance with National Electric Reliability Council (NERC) and Western Systems Coordinating Council (WSCC) standards, the Regional Transmission Group (RTG) Governing Agreements, the Federal Energy Regulatory Commission (FERC) Order 888 Open Access Tariffs, and FERC Order 889. In addition, NERC and FERC are looking for additional industry development of definitive methods for determining ATC.

Transmission Providers in the Western Interconnection will determine ATC in accordance with the NERC document "Available Transfer Capability Definitions and Determination". This Western Interconnection methodology document provides more detail and specific methodology for ATC determination based on commercial practices in the Western Interconnection. The methodology builds upon the Rated System Path based method that is used for determining Total Transfer Capability (TTC) in the Western Interconnection and is intended to fully comply with all NERC, WSCC, RTG and FERC rules regarding ATC. It provides additional details, principles, and reasonableness tests upon which a broad membership consensus has been reached. The Rated System Path Methodology is described in Appendix B of the NERC Report, "Available Transfer Capability Definitions and Determinations."

The Parties to this document acknowledge that given industry restructuring the California Independent System Operator (CaISO) and other future RTOs may have different operational protocols for calculating transmission availability. The CaISO is a non-profit public benefit corporation organized under the laws of the State of California. The CaISO is responsible for the reliable operation of a grid comprising the transmission systems of Pacific Gas & Electric Company, Southern California Edison Company and San Diego Gas & Electric Company. The CaISO, pursuant to its approved Tariff by the FERC, provides open and non-discriminatory transmission access to the market participants in its Day Ahead, Hour Ahead and Real Time Markets. Under that Tariff, CaISO follows different criteria for TTC, TRM and CBM allocations.

2. Methodology and Implementation

This document describes the Western Interconnection's regional practice and methodology for the determination of ATC. It is intended to be the Western Interconnection's standard reference document for the determination of ATC. This methodology is intended to be consistent with the requirements of NERC ATC standards. The use of ATC will be governed by the Transmission Providers' tariffs developed consistent with FERC published decisions, policies and regulations. Disputes between participants will be addressed through the process provided in the tariff or through other applicable dispute resolution processes (i.e., RTG, WSCC, other).

Each Transmission Provider's ATC methodology document shall be reviewed periodically by WSCC to ensure the procedures and practices described in their documents are consistent with the Western Interconnection ATC document and NERC standards as relates to reliability of the interconnected system. This periodic review shall not include the assessment of the Transmission

Provider's implementation of its transmission services tariff but shall verify reliability standards are observed while providing transmission services.

3. Applicability

This document and the methodology herein, apply to all members of the Parties in accordance with their governing authorities. Individual Transmission Provider variances from this methodology will be requested by the Transmission Provider and approved by the appropriate organization (FERC, Regional Transmission Association, or WSCC).

4. Scope

This document governs only the methodology for determination of ATC and required frequency for updating ATC. The obligation of participants to post ATC on an OASIS should be in accordance with FERC Orders 888 and 889 or their successor documents.

5. Purpose

The purpose of this document is to ensure consistent implementation within the Western Interconnection of the definition and determination of ATC. For the Members of these organizations, it is intended to supplement the WRTA Governing Agreement, NRTA Governing Agreement and SWRTA Bylaws (collectively, "RTG Governing Agreements"), which broadly define ATC and outline a method for requesting transmission service.

This document builds upon and supplements the rules, definitions, principles and processes delineated in the following:

- NERC Report on Available Transfer Capability Definitions and Determination (June 1996).
- NERC Report on Transmission Transfer Capability (May 1995)
- NERC Transfer Capability Margins Standard (proposed, add issue date when finalized)
- WSCC Procedures for Regional Planning Project Review and Rating Transmission Facilities (original dated March 1995)
- FERC Order 888 or successor documents (Open Access Tariffs) (original dated April 1996)
- FERC Order 889 or successor documents (Open Access Same-Time Information Systems) (original dated April 1996)
- Western Regional Transmission Association Governing Agreement (January 1995)
- Northwest Regional Transmission Association Governing Agreement (February 1995)
- Southwest Regional Transmission Association Bylaws (June 1995)
- Joint Transmission Access Principles (CCPG) (December 1991)

Summaries of any information contained in any of the documents listed above are not intended to imply any deviation from the contents of those documents.

6. Determination of ATC

The process for determining ATC for each Transmission Provider in a path should be reasonable, auditable and supportable. It consists of three steps: (1) the determination of path Total Transfer Capability (TTC), (2) the allocation of TTC among Transmission Providers, and (3) the determination of each Transmission Provider's Committed Uses. A Transmission Provider's ATC is then determined by subtracting Committed Uses from allocated TTC.

ATC = TTC (allocated) - Committed Uses

Using NERC ATC terminology,

Committed Uses = TRM + Existing Transmission Commitments (including CBM)

where TRM = Transmission Reliability Margin
CBM = Capacity Benefit Margin

For information on the determination of ATC and the related operating and planning relationships, refer to the NERC document, "Available Transfer Capability - Definitions and Determination" specifically the Sections entitled Determination of Available Transfer Capability, page 15, Commercial Components of Available Transfer Capability, pages 15 to 18, and Non-Recallable (Firm) and Recallable (Non-firm) Relationships and Priorities, pages 18 to 21.

ATC shall be calculated with the following frequencies:

- Hourly ATC for the next 168 hours: Once per day
- Daily ATC for the next 30 days: Once per week
- Monthly ATC for months 2 through 13: Once per month

Transmission Providers should use the best assumptions available for all TTC and ATC calculations. Calculations for hourly ATC within the current week should take into account the load variations during the day, any partial day outages, and best estimates of probable unscheduled flow and location of operating reserves. Daily calculations will use only peak loading for the day, and have to take into acount all partial day outages. Monthly calculations will use broader based assumptions such as monthly peak, accounting for all major outages during the month, and less specific estimates of unscheduled flow and location of operating reserves.

Generally in the Western Interconnection, netting of reservations and schedules cannot be used to increase firm ATC. There is one exception to this general rule which can be implemented on a case-by-case basis when the Transmission Provider, at its sole discretion, determines that they can do so without degrading system reliability. This exception can be invoked if there is firm load on one side of the path in question and the generation resources scheduled to serve it are on the other side of the path. Firm ATC across the path in the direction from the load to the generator can be increased by the scheduled amount from the generator to the load minus an adjustment for operating reserves and back up resources. This adjustment is determined by the location of the operating reserves and back up resources that would be deployed if the original resources serving the load were lost. Each application of this exception must be carefully analyzed based upon the specific circumstances before firm netting is employed. See Appendix I for an illustration and more details.

Parties seeking ATC on constrained paths should contact the Transmission Provider who will then work with generators on the Transmission Provider's system to assess its ability to make ATC available through redispatch and the costs associated with the redispatch, consistent with the Transmission Provider's tariff. If the constraint is related to a nomogram limitation, parties may utilize applicable nomogram market mechanism procedures.

6.1 Determination of Total Transfer Capability (TTC)

TTC represents the reliability limit of a transmission path at any specified point in time. It is a variable quantity, dependent upon operating conditions in the near term and forecasted conditions in the long term. TTC shall be calculated consistent with the requirements of FERC Orders 888 and 889 and as needed to represent system conditions, but no less frequently than seasonally. TTC cannot exceed the path rating. Within the Western Interconnection, a wide area approach is used to determine TTC on a path basis using the Rated System Path method discussed in WSCC's "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and NERC's "Report on Available Transfer Capability Definitions and Determination". The determination of TTC is required to conform with WSCC's "Procedures for Regional Planning Project Review and Rating Transmission Facilities" and WSCC's "Minimum Operating Reliability Criteria". Specific system operating conditions (system topology, load/generation patterns, simultaneous path loadings, and facility outages) may require that TTC or TRM be adjusted to maintain system reliability.

TTC may sometimes be better defined by a nomogram, a set of nomograms, or a series of equations than by a single number, particularly when determining TTC values for two or more parallel or interacting paths. Where the simultaneous transfer capabilities of paths are limited by the interactions between paths, the Transmission Provider should make this known on the OASIS. This may be done by posting non-simultaneous TTC and subtracting TRM, where TRM includes the difference between non-simultaneous and simultaneous limits. As an alternative to computing TRM, the Transmission Provider may post non-simultaneous TTC and describe on the OASIS the nomogram and associated curtailment conditions. In either case, Firm ATC should be based on the best estimate of the simultaneous capability of the path during the period posted.

The total net schedules on a Path are not to exceed the Path TTC.

6.2 Allocation of TTC

When multiple ownership of transmission rights exists on a path or parallel/interacting paths, it is necessary to reach agreement on the allocation of those transmission rights in order to determine and report ATC.[1] A single TTC number, appropriate for the actual or projected condition of the transmission system, will be agreed upon for the path and this TTC will then be allocated between the Transmission Providers, to yield each Transmission Provider's share of the path's TTC for the ATC posting period.

If the Transmission Providers can't come to an agreement amongst themselves, the WSCC and the RTGs in the Western Interconnection provide several dispute resolution forums through which path rating and allocation issues may be addressed.

[1] The allocation rules may address allocations for both normal conditions and system outage conditions.

6.3 Determination of Committed Uses

This section describes the principles, practices and methodology for the determination of Committed Uses[2] in terms of the NERC components of TRM, Existing Transmission Commitments and CBM.

6.3.1 Principles for Determination of Committed Uses

This document adopts an approach for addressing the determination of Committed Uses.

The key to the successful implementation of this approach is development of specific principles, guidelines and reasonableness tests that will be used by Transmission Providers in making their assumptions and determinations of Committed Uses and will provide guidance for dispute resolution proceedings.

Transmission Providers will be expected to:

- Use reasonable, "good-faith" assumptions, consistent with general principles outlined in this document

- Make those assumptions and the underlying justifications for those assumptions available, in accordance with NERC and WSCC standards, the RTA Governing Agreements, FERC Order 888 and FERC Order 889 or their successor documents.

- Justify such assumptions and results, if called upon to do so, in applicable dispute resolution forums, (i.e. FERC 888 tariff process and RTG, WSCC or other dispute resolution processes).

- Adopt assumptions which are consistent with documented and consistently applied reliability requirements, including WSCC Minimum Operating Reliability Criteria, WSCC Power Supply Design Criteria, WSCC Reliability Criteria for System Planning, and the transmission provider's documented and consistently applied internal reliability criteria.

- Apply all assumptions comparably, non-discriminatorily and reasonably. A Transmission Provider's assumptions and methodologies, taken as a whole, must be consistently applied in the treatment of all Transmission Customers in a comparable and non-discriminatory manner.

[2] Committed Uses, as described in the RTA Bylaws, are composed of (1) native load uses, (2) prudent reserves, (3) existing commitments for purchase/exchange/deliveries/sales, (4) existing commitments for transmission service and (5) other pending potential uses of transfer capability.

- Use assumptions and methodologies that facilitates market participation, provided that the outcome meets transmission system reliability requirements and does not impose uncompensated transmission services costs on the Transmission Provider.

- A Transmission Provider's assumptions and methodologies for determining ATC must be consistent with the assumptions used by the Transmission Provider in other aspects of its business (for example, system planning).

6.3.2 Determination of Transmission Reliability Margin (TRM)

TRM is the amount of transmission transfer capability necessary to provide a reasonable level of assurance that the interconnected transmission network will be secure under a broad range of uncertainties in system conditions. TRM accounts for the inherent uncertainty in system conditions and system modeling, and the need for operating flexibility to ensure reliable system operation as system conditions change.

The benefits of TRM extend over a large area and possibly over multiple providers. TRM results from uncertainties that cannot reasonably be mitigated unilaterally by a single provider. In accordance with the terms and conditions of the Transmission Provider's tariff, TRM may be sold on a non-firm basis providing that reliability of the system is not jeopardized. TRM should not be sold as firm.

Each Transmission Provider should make its TRM values and calculation methodology publicly available. The TRM requirement should be reviewed and appropriate updates made by the TPs at a minimum prior to each Operating Season.

In the Western Interconnection methodology, firm ATC reductions associated with TRM may include the following components. TRM may be set to zero.

- Transmission necessary for the activation of operating reserves

- unplanned transmission outages (for paths in which contingencies have not already been considered in establishing the path rating)

- simultaneous limitations associated with operation under a nomogram

- loading variations due to balancing of generation and load

- uncertainty in load distribution and/or load forecast [3]

- allowances for unscheduled flow

[3] Transmission Provider's allowances for load forecasts uncertainty may be part of TRM provided that: (1) the allowance is available as non-firm service on a comparable and non-discriminatory basis, (2) the allowance reduces the exposure to curtailments to all Transmission Customers with firm reservations on a prorata basis for unanticipated load, and (3) the allowance does not duplicate consideration of uncertainty within the load forecast itself.

Transmission capacity required to implement operating reserve sharing agreements for the period immediately following a contingency and before the market can respond (currently up to 59 minutes following the contingency) are included in TRM.

If the limitation on the use of TRM to 59 minutes would force a Transmission Provider to set aside unnecessary CBM on the same path as the TRM, that Transmission Provider may utilize the TRM beyond the 59 minutes. This would allow the Transmission Provider to maximize the ATC by not needlessly setting aside twice the amount of transmission (TRM and CBM) than is necessary for reliability.

TRM does not include allowances for planned outages and other known transmission conditions which should be included in the calculation of TTC. The Transmission Provider has the option of including the above described components of TRM in either the determination of TRM or TTC, but not in both.

Allowances for transmission contingencies should not be included in TRM for paths which have had an Accepted Rating established, since contingencies are already included in the determination of the Accepted Rating. A Transmission Customer with firm reservations which desires to reduce its risk of pro-rata curtailment must explicitly request a reservation of additional rights. Such rights cannot be reserved under the auspices of CBM or TRM. Where such reserved rights are not scheduled for use, the Transmission Provider is required to make such rights available to other transmission service requesters in accordance with FERC Order 888 rules or their successors.

Regarding nomogram operation, the purpose for applying TRM on paths which are governed by nomograms is to account for the uncertainty in capacity availability created by the existence of the nomogram. This is used to establish the amount of firm ATC the Transmission Provider can offer. The size of this TRM adjustment will vary based on specific circumstances. The Transmission Provider should consider such issues as the frequency which specific nomogram thresholds (such as loading levels on interacting paths, generation levels, ambient temperatures, etc.) are reached and the duration that those conditions exist when determining the TRM adjustment. In cases where an allocation of firm rights has been established between two paths related by a nomogram, the TRM reflects the difference between this firm allocation and the path's TTC. TRM set aside specifically for this nomogram adjustment should be offered as non-firm ATC.

Allowance for generation and load balancing and for uncertainty in load distribution and/or load forecast, should be determined through the use of power flow studies and/or historical operating experience. TRM should not include margin already afforded by the WSCC Reliability Criteria or otherwise accounted for in the determination of TTC.

Unscheduled flow may be handled in either of two ways, either of which is acceptable, provided that the methodology is applied consistently and non-discriminatorily:

- The path can be reserved up to its TTC, without factoring in any estimates of unscheduled flows. In such a case, when unscheduled flows materialize, accommodations and curtailments will be made consistent with the WSCC Unscheduled Flow Mitigation Plan.

- The path operator, using reasonable, auditable, supportable projections, may subtract sufficient transfer capability from TTC, as a component of TRM, to reduce the need to make curtailments associated with projected unscheduled flows.[4] This should be made available as Non-firm transfer capability in case unscheduled flow is less than anticipated.

One method of presenting TRM is to calculate it as a percentage of TTC. Uncertainties accounted for in TRM become more defined in the operating horizon as compared to the planning horizon. This is reflected in smaller TRM values in the operating time frame.

6.3.3 Determination of "Existing Transmission Commitments"

This section identifies those items to be included in the determination of "Existing Transmission Commitments".

- Reservations for Native Load Growth: Transmission Providers may reserve existing transfer capability needed for reasonably forecasted Native Load growth[5]. Transfer Capability reserved for Native Load growth must be made available for use by others until the time that it is actually needed by the Native Load.

- Where transmission service is reserved for a Network Resource which is a purchase by the Transmission Provider to serve Native Load customers, the reservation should reflect the terms of the purchase (if 50 MW may be scheduled in any hour, then 50 MW of transmission must be reserved for every hour). Where the reservation is made based on the Native Load reliability need, the Transmission Provider must determine the applicable hours of such reliability need based on its load and resource circumstances.

- Native Load Forecasts: ATC determination does not presume the existence of sanctioned forecasts by regulatory agencies, although a Transmission Provider may use such a sanction in arguing the reasonableness of its determination of Committed Uses. In making reservations for Native Load, adjustments may be made for near-term uncertainties (e.g. weather). Long-term forecasts may use both generic and contractually committed resources to meet native load requirements. Transmission Providers must use reasonable assumptions in determining Native Load requirements and make available those assumptions and the resulting conclusions, and be able to justify the reasonableness of those assumptions and the resulting conclusions, as well as their consistency with then-current FERC policies, in applicable dispute resolution proceedings.

- Approved Load Forecast: A publicly-approved load forecast or resource plan is one which has been approved, or reviewed and accepted, by a regulatory agency

[4] Note: the SWRTA Bylaws specifically permit the exclusion of transmission capacity needed to accommodate unscheduled flows, at levels consistent with the WSCC Unscheduled Flow Mitigation Plan. Making allowances for projected unscheduled flows based on assumptions that are appropriate for the time horizon of the ATC estimate would be consistent with making the best technical estimate of ATC, and would therefore be consistent with the NERC ATC report.

[5] See footnote 2.

that is independent of the Transmission Provider. If there is no regulatory-approved forecast/plan, the Transmission Provider may publish its own good-faith forecast/plan (for example, an official Loads & Resources plan). The Transmission Provider must also provide the assumptions, and the underlying justifications for those assumptions, used to develop the forecast/plan, in sufficient detail to permit interested parties to examine and challenge the reasonableness of the forecast/plan in an applicable dispute resolution forum.

Evidence supporting the contention that such a forecast/plan has been made in good faith includes a showing that the forecast/plan produced for the purposes of determining Committed Uses and ATC is consistent with the forecast/plan the Transmission Provider uses in its internal planning of other facilities or for processes distinct from those related to determination of Committed Uses. Where there are differences in the ATC methodology from the internal planning assumptions and criteria they must be explained and be subject to a finding of reasonableness in an applicable dispute resolution forum.

Long-term forecasts generally state a net out-of-area resource requirement, but may not break this requirement down by interconnection path/interface or by time-of-use period. The Transmission Provider may use his discretion to make this breakdown, provided the Transmission Provider uses good faith and provides the underlying justifications. Use of a Transmission Provider's own data, assumptions and contracts for service is probably the most reasonable solution that can be attained unless there is an RTG-approved or WSCC-approved area-wide resource database used by all parties posting ATC. The forecast should distinguish between committed and planned resource purchases.

- <u>Ancillary Services (required as a part of Native Load service)</u>: Transfer capability should be reserved under Native Load for those ancillary services required to serve Native Load. These include transfer capability required to supply load regulation and frequency response services. Ancillary services for Operating Reserves are covered under Section 6.3.4.

- <u>Reservations Beyond Reliability-Based Needs:</u> A Transmission Provider may reserve ATC for the import of power which is beyond the amount reserved for reliability needs of their Native Load customers, only to the extent permitted under the FERC's Order 888, or the Transmission Provider's own Open Access Transmission Tariff (OATT) and is otherwise consistent with the Federal Power Act and the FERC's applicable standards and policies then in effect.

  A Transmission Provider's merchant function may reserve transfer capability to serve the non-reliability needs of its customers; however, it is necessary to reserve such capacity pursuant to applicable Network and Point-to-Point OATT similar to any other transmission customer. The Transmission Provider may reserve ATC for the import of power which is beyond the amount reserved for the reliability needs of it's Native Load customers, only to the extent permitted under FERC's Order 888, or the Transmission Provider's own OATT, consistent with the Federal Power Act and the FERC's applicable standards and policies then in effect.[6]

Consistent with Order 888, or the Transmission Provider's own OATT, a Transmission Provider may reserve either Network or Point-to-Point transmission service for its own resources and power purchases designated to serve Network Load. A Transmission Provider may also use the point-to-point tariff to reserve Firm transmission service where it has not made a purchase commitment. It must take such Firm point-to-point transmission service for its uncommitted purchases under the same terms and conditions of the tariff as it offers to others.

- <u>Existing Commitments</u>: Committed Uses associated with existing commitments at the time of the ATC determination are permissible. Determinations for these types of Committed Uses must be made available and are subject to evaluation upon request and in applicable dispute resolution forums.

- <u>Firm Transmission Reservations for Energy Transactions</u>: Transfer capability for energy transactions that can reasonably be expected to be consummated, such as expected hydro conditions, can be a Committed Use for the Transmission Provider (including an affiliated merchant business) to the extent consistent with the reservation provisions of the approved tariff by purchasing firm point-to-point transmission service from available transfer capability. Such transfer capability can be reserved for expected energy transactions, but must be released for Non-firm uses on a scheduling basis if unused or as otherwise required in accordance with the reservation priorities provided in the Transmission Provider's tariff.

  Economy energy purchases (Non-firm purchases) by the Transmission Provider's merchant function can get service under secondary service for non-network resources on an as available basis at no additional "bookkeeping" charge (Section 28.4 of the FERC Open Access Transmission Tariff). If the Transmission Provider is using this service it should decrement Non-firm ATC for the purchase, but not Firm ATC. Firm point-to-point Transmission Service (PPTS) has reservation and curtailment priority over Secondary Service. Secondary Service has reservation and curtailment priority over Non-firm PPTS. Where the purchases are Firm and meet the requirements of a Network Resource, they qualify for a Firm transmission reservation and would be a decrement from the Firm ATC posting. To reserve Firm ATC for a Non-firm purchase or for where the Transmission Provider's merchant has not secured the purchase commitment or the purchase cannot otherwise qualify as a

[6] Order 888 provides: at page 172 when discussing Reservation of Transmission Capacity, "We conclude that public utilities may reserve existing transmission capacity needed for native load growth and network transmission customer load growth reasonably forecasted within the utilities current planning horizon:" at page 191 when discussing Use of the Tariffs by the Rights Holder, "In the case of a public utility buying or selling at wholesale, the public utility must take service under the same tariff under which other wholesale sellers and buyers take service;" at page 323 when discussing Reservation Priority for Existing Firm Service Customers, "The transmission provider may reserve in its calculation of ATC transmission capacity necessary to accommodate native load growth reasonably forecasted in its planning horizon;" and at page 342 when discussing Network and Point-to-Point Customers' Uses of the System, "However we do not require any utility to take service to integrate resources and loads. If any transmission user (including the public utility) prefers to take flexible point-to-point service, they are free to do so."

Network Resource, the Transmission Provider's merchant must make a reservation of Firm PPTS just like it was any other Transmission Customer.

- Reserving transfer capability over multiple paths to secure capacity for a future undefined resource or purchase: Transmission Providers that have uncommitted purchases or resources as part of their resource plan to serve native load can reserve transfer capability on multiple paths until the uncommitted purchase or resource is defined. In such a case, the Transmission Provider should note on the OASIS that multiple paths are being reserved. If a request for transmission service is received for which there is inadequate ATC as a result of a multiple path reservation, the Transmission Provider should have the first right of refusal for use of the path. If the Transmission Provider exercises this right on a particular path, it should release its reservation on the other (multiple) paths.

- Good Faith Requests: Capacity may be reserved as "existing transmission commitments" for "good faith requests" for transmission service received by a Transmission Provider in accordance with applicable FERC or RTG request for service policy. ATC is decremented as specified by applicable FERC or regional policy.

- Information to be Provided: The following lists the types of assumptions and data that could be used in support of the determination of Committed Uses. Transmission Providers should make available the information used in their calculation of ATC values.

  Far-Term Environment (>1 year)

  - Load forecast
  - Load forecast error (range)
  - Standard for serving load
  - Breakdown of use by path
  - Breakdown of use by Time of Use period
  - Hydro and temperature forecasts
  - DSM, interruptible load assumptions
  - Redundancy of reserved paths
  - Resource outage standards (G-1? G-2?)
  - Resource assumptions (high/low hydro...)
  - Forecasted outages
  - Unit deratings
  - Resource dispatch assumptions
  - Purchases or sales to external parties
  - Wheeling contracts, including listings of Points of Receipt, Points of Delivery, and associated transmission demands at each point.

  Near-Term Environment (<1 month)

  - Standard for probability of serving load
  - Load forecasts (range of temperatures, hydro forecast, etc.)

- Resource outage standards (G-1? G-2?)
- Forecasts of generation
- Short-term wheeling arrangements, including listings of Points of Receipt, Points of Delivery, and associated transmission demands at each point.
- Purchases and sales with external parties.

6.3.4 Determination of Capacity Benefit Margin (CBM)

CBM is the amount of firm transmission transfer capability reserved by Load Serving Entities (LSEs) on the host transmission system where their load and generation resources are located, to enable access to generation from interconnected systems to meet generation reliability requirements. CBM is a uni-directional quantity with identifiable beneficiaries, and its use is intended only for the time of emergency generation deficiencies. CBM reservations may be sold on a non-firm basis.

Reservations should be made according to the applicable Transmission Provider's tariff. The determination of CBM reservations according to this Section 6.3.4 is only for purposes of determining required transmission capacity for generation reliability and is not intended to address any payment obligations associated with such reservations.

Each Transmission Provider should make its CBM values and calculation methodology publicly available, including a description of the procedure for the use of CBM in an energy emergency. Actual usage of CBM should be posted by the Transmission Provider.

The following components and considerations should be included in the determination of CBM. CBM may be set to zero.

- Replacement Reserves :

  Transmission for restoring operating reserves following a generator contingency, generally confined to the time period extending beyond the current scheduling hour that are required above the operating reserve level and are needed to accommodate generation reserves consistent with generation reliability criteria are included in CBM. CBM is only an import quantity and is reserved to meet the Transmission Customer's own potential resource contingencies.

- Reservations of Transmission for Purposes Other than Energy Delivery:

  In certain cases, a Transmission Provider with statutory obligation to serve native load may desire to reserve transmission for purposes other than energy delivery - for example, to provide a path for the import of ancillary services (such as spinning reserves) from another control area; or to allow imports on a different path (in a case where a control area requires a certain amount of unscheduled transfer capability for stability reasons). Similar to reserve sharing arrangements, such reservations are legitimate Committed Uses by a transmission Transmission

Provider to the extent that they are associated with meeting native load reliability requirements (rather than being economics-driven).

- Reservations of additional transfer capability for resource contingencies must be based upon reasonable, publicly available assumptions subject to evaluation in applicable dispute resolution proceedings. The methodology for determining the amount of reserves must be consistent with prudent utility practice, must be clearly documented and consistently followed, must be applied in a non-discriminatory manner, and must be auditable.

- <u>Generation Patterns and Generation Outages:</u>

  Many generation patterns and forced generation outages occur in the power system. These, including the number of generator contingencies, may be considered when determining Committed Uses, to the extent that deductions from ATC associated with these uncertainties use assumptions that are consistent with the planning and service reliability criteria which the Transmission Provider (with native load requirements) uses in serving its customers.[7]

Allowance for CBM generation reliability requirements should be determined in one of two ways, namely (1) using a Loss of Load Expectation (LOLE) probability calculation, or (2) deterministic based upon the largest single contingency. An LOLE of 1 day in 10 years is recommended. This calculation is made using commonly accepted probabilistic generation reliability techniques. The calculation is performed on a monthly basis. The generation requirement is then converted to a CBM requirement for each interconnection based upon historical purchases at peak times, typical load flow patterns and an assessment of adjacent and beyond control area reserves. The generation reliability requirement is updated at least annually.

The CBM requirement should be reviewed and appropriate updates made by the TPs at a minimum prior to each Operating Season.

Individual Transmission Provider CBM Methodologies shall consider in the CBM requirement only generation directly connected to the TP's system being used to serve load directly connected to that system. Generation directly connected to the TP's system which is committed to serve load on another system or which is not committed to serve load on any system shall not be included.

Interruptible load shall be included in the determination of CBM requirements.

[7] As uncertainty in forecasts diminishes, a Transmission Provider must release transmission capacity in a manner that is consistent with prudent utility practice, clearly documented, and consistently followed, applied in a non-discriminatory manner, and auditable.

GLOSSARY

Accepted Rating: a path rating obtained through the WSCC three-phase rating process that is the recognized and protected maximum capability of the path.

Available Transfer Capability (ATC): a measure of the transfer capability remaining in the physical transmission network for further commercial activity, over and above already-committed uses.

CCPG: Colorado Coordinated Planning Group under the umbrella of the Rocky Mountain Operation and Planning Group (RMOPG).

Capacity Benefit Margin (CBM): that amount of transmission transfer capability reserved by Load-Serving Entities with generation on the system up to the purchased/owned amount of transmission, to ensure access to generation from interconnected systems to meet generation reliability requirements.

Committed Uses: Five committed uses described in the RTG Governing Agreements as described in this document.

Curtailability: the right of a Transmission Provider to interrupt all or part of a transmission service due to constraints that reduce the capability of the transmission network to provide the transmission service. Transmission service can be curtailed as per the Transmission Providers OAT or contracts.

Firm Transmission Service: transmission service which cannot be interrupted by the Transmission Provider for economic reasons, but that can be curtailed for reliability reasons. This service is known as Non-Recallable transmission service in the NERC ATC documents.

Load Serving Entity: an entity located within a Transmission Provider's system whose primary function is to provide energy to end use customers. Also known as Energy Service Providers.

Native Load: existing and reasonably-forecasted customer load for which the Transmission Provider - by statute, franchise, contract or regulatory policy - has the obligation to plan, construct or operate its system to provide reliable service. For Transmission Providers not operating in a Retail Access environment, Native Load refers to the load within a Transmission Provider's service territory, to which it is also obligated to provide energy. For Transmission Providers operating in a Retail Access environment, Native Load refers to the load within the Transmission Provider's service territory, independent of the Energy Service Provider(s) serving energy to the load.

Network Resources: Designated resources used by a Transmission Customer to provide electric service to its Native Load consistent with reliability criteria generally accepted in the region.

Non-firm Transmission Service: transmission service which a Transmission Provider has the right to interrupt in whole or in part, for any reason, including economic, that is consistent with FERC policy and the provisions of the Transmission Provider's transmission service tariffs or contract provisions. This service is known as Recallable transmission service in the NERC ATC documents, or service offered on an as-available basis where a higher priority service requester may displace a lower priority service requester under the terms and conditions of the pro-forma tariff.

NRTA: Northwest Regional Transmission Association.

Operating Season: Those seasons that WSCC requires Operating Transfer Capability Studies to be performed (winter, spring and summer).

Parties: Colorado Coordinated Planning Group, Northwest Regional Transmission Association, Southwest Regional Transmission Association; Western Regional Transmission Association, and Western Systems Coordinating Council.

Recallability: the right of a Transmission Provider to interrupt all or part of a transmission service for any reason, including economic, that is consistent with FERC policy and the provisions of the Transmission Provider's transmission service tariff or contract provisions.

RTG Governing Agreements: Northwest Regional Transmission Association Governing Agreement, Southwest Regional Transmission Association Bylaws, and the Western Regional Transmission Association Governing Agreement.

SWRTA: Southwest Regional Transmission Association.

Total Transfer Capability (TTC): the amount of electric power that can be transferred over the interconnected transmission network in a reliable manner while meeting all of a specific set of defined pre- and post- contingency system conditions.

Transmission Customer: Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. (FERC Definition – 18 CFR 37.3).

Transmission Provider: Any party that owns, controls, or operates facilities used for the transmission of electric energy in commerce.

Transmission Reliability Margin (TRM): that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

WRTA: Western Regional Transmission Association.

WSCC: Western Systems Coordinating Council

APPENDIX I

Standard for the Use of Netting for Firm ATC Calculations

In general, netting cannot be used to increase firm ATC. There is one exception to this general rule which can be done on a case-by-case basis at the Transmission Provider's discretion, provided that the criteria discussed below are adequately addressed.

If there is firm load on one side of the path in question and the generation resources scheduled to serve it are on the other side of the path, then firm ATC (and associated schedules) in the direction from the load to the generator can be increased by the scheduled amount from the generator to the load minus an adjustment for operating reserves and backup resources. This adjustment is determined by the location of the operating reserves and back up resources that would be deployed if the original resources serving the load were lost.

Any operating reserves or back up resources located on the same side of the path as the original resources maintain the firm counter-schedule, so the ATC in the direction from the load to the generator does not have to be decremented. If the operating reserves or back up resources come from the same side of the path as the load, then the counter-schedule would be lost. The ATC must then be decremented by the amount of these operating reserves and back up resources.

Each application of this exception must be analyzed carefully based upon the specific circumstances before firm netting is employed. A number of factors must be taken into consideration to determine how much of this firm netting can be reasonably allowed over any given transmission path. The factors that must be taken into account when determining the amount of load to net against include:

1. The size of the load. For firm netting, a forecast <u>minimum</u> load level that is reasonable for the time period under consideration should be used. The Transmission Provider must base the firm ATC calculations in these circumstances on a load level that can be expected to be present for the duration of any transactions that are netted against it.

2. Diversity of the load. Is the load a single large load that could be subject to interruption or is the load a diverse load area that has minimal risk of being completely blacked out?

3. Internal generation. Does the load area contain embedded generation resources?

4. Location of operating reserves and back-up resources. If the resources that are serving the load are lost, where will the operating reserves and back-up resources used to replace that generation come from? If they come from the same side of the path as load, then the counter-schedule is lost and there is the possibility that the path could be over-scheduled. Also, the reserves must be able to be deployed fast enough so that WSCC reliability standards for getting actual flows back within transfer limits are met.

Other factors may also need to be taken into account depending on the specific circumstances.

Example of Firm Netting Application:

Assume a path has a transfer capability of 1000MW in the east to west direction.
Assume that there is an actual load of 150MW on the east side of the path and 150MW of generation on the west side of the path that is used to serve it.
Firm east to west transactions of up to 1150MW can be accommodated across the path in the east to west direction since the load "nets out" 150MW due to the firm counter-schedule of the resource used to serve it in the west to east direction.

Approved at the October 25-26 WMIC meeting by WMIC.

Approved at the December 6, 2001 BOT meeting.