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
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Rate Appendix
Regulated Generating Units

Terms and Conditions of Service

DTS **Demand Transmission Service**

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**

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,

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

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)** 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 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.

DOS Term **Demand Opportunity Service (Term)** 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.

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)** Page 2 of 2

(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)** Page 1 of 2

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.

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

(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**

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** Page 1 of 2
Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2

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.

Rider A2 **Transmission Duplication Avoidance Adjustment** Page 3 of 5
NOVA Chemicals Corporation — Joffre Industrial System

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** **Shell Canada Corporation — Scotford Industrial System** Page 1 of 5

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** Page 2 of 5
Shell Canada Corporation — Scotford Industrial System

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 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** **Shell Canada Corporation — Scotford Industrial System** Page 5 of 5

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

Rider A4 **Transmission Duplication Avoidance Adjustment** Page 2 of 5
Imperial Oil Resources Limited — Cold Lake Industrial System

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 April 1, 2009 until such time as it is replaced by a rate approved by the Commission in the AESO's next GTA.

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) Page 2 of 3

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	