ALBERTA ELECTRIC SYSTEM OPERATOR

2003 TARIFF

RATE SCHEDULES

Issued - January 9, 2004

EUB Decision	Effective Date
Decision 2003-077 (November 4, 2003)	December 1, 2003
Amendments as per Decision 2003-099 (December 16, 2003)	January 1, 2004

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Rate Schedule – Demand Transmission Service (DTS)

Applicable to: Demand Customers

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

The Interconnection Charge equals:

$1,248.62 /MW/month of Billing Capacity in the Billing Period, plus
$1.75/MWh of Metered Energy during the Billing Period.

Billing Capacity shall be the highest of:
(i) The highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) The Ratchet Level; or
(iii) 90% of the Contract Capacity.

where "Ratchet Level" is defined as the highest of the following:

(i) 90% of the highest Metered Demand in the past 12 months;
(ii) 85% of the highest Metered Demand in the past 24 months;
(iii) 80% of the highest Metered Demand in the past 36 months;
(iv) 75% of the highest Metered Demand in the past 48 months;
(v) 70% of the highest Metered Demand in the past 60 months.

The Operating Reserve Charge equals:

Metered Energy in each hour X **4.22%** X Pool Price.

The Other System Support Services Charge equals:

$20.53/MW/month of highest Metered Demand in the Billing Period, plus a charge (where Power Factor is less than 90%) of **$400/MVA** applied to the difference between the highest metered Apparent Power and 111% of the highest Metered Demand during the same Billing Period.

Terms: The rate is separately applicable at each POD.

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 paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.
Rate Riders A&B apply to these customers when invoked by the AESO.

Rate Schedule – Demand Opportunity Service (DOS 7 Minutes)

Applicable to: Qualified Opportunity Service Customers who are recallable within 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.

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

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

(a)

(i) **$3.00/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 x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the AESO for each Point of Delivery.

(b) A minimum charge equal to:

Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x $3.00/MWh.

Plus

(2) Transaction Fee: **$500** per Billing Period.

Terms: The rate is separately applicable at each POD.

A Customers pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The maximum term for a System Access Services Agreement for Demand Opportunity Service will be one (1) calendar month.

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.

In the event that a Customer's service is recalled, 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.

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 paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Demand Opportunity Service (DOS 1 Hour)

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.

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

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

(a)

(i) **$5.00/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 x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the AESO for each Point of Delivery.

(b) A minimum charge equal to:

Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x $5.00/MWh.

Plus

(2) Transaction Fee: **$500** per Billing Period.

Terms: The rate is separately applicable at each POD.

A Customers pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The maximum term for a System Access Services Agreement for Demand Opportunity Service will be one (1) calendar month.

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.

In the event that a Customer's service is recalled, 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.

The amount of Metered Energy attributable to service under this Rate Schedule shall be determined in accordance with paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Demand Opportunity Service (DOS Term)

Applicable to: Qualified Opportunity Service Customers

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.

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

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

(a)

(i) **$20.00/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 x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the AESO for each Point of Delivery.

(b) A minimum charge equal to:

Opportunity Capacity under this Rate Schedule x number of hours in total transactions in the Billing Period x 75% x $20.00/MWh.

Plus

(2) Transaction Fee: **$500** per Billing Period.

Terms: The rate is separately applicable at each POD.

A Customers pre-qualified eligibility for Demand Opportunity Service will be available for a maximum of one (1) year. The maximum term for a System Access Services Agreement for Demand Opportunity Service will be one (1) calendar month.

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.

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 paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Export Service (ES)

Applicable to: Customers exporting electric energy from the AIES.

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

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

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

(a)

(i) **$2.35/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 x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the AESO for each Point of Exchange.

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

75% x capacity scheduled for Customer for the transaction x hours in the transaction x ($2.35/MWh + Incremental Losses Charge / Energy Transfer in 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** per Billing Period.

Terms: System Access Service provided pursuant to this Rate Schedule is recallable on one (1) hour's notice. The rate is separately applicable at each Point of Exchange.

The Terms and Conditions form part of this Rate Schedule.

Rate Schedule – Demand Under-frequency Load Shedding Credit (UFS)

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 POD's 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 UFS Capacity for each relay setting. The AESO provides no assurance as to the number or duration of any future outages.

UFS Capacity shall be the peak demand (expressed in MW) for each setting for which the Customer has agreed to be shed as set out in the System Access Service Agreement.

Relay Trip Setting	**Credit ($/kW of UFS Capacity/month)**
59.1 Hz	$0.065
58.9 Hz	$0.060
58.7 Hz	$0.055
58.5 Hz	$0.050
58.3 Hz	$0.045
58.1 Hz	$0.040
58.0 Hz	$0.035

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

Rate Schedule – Customer-Owned Substation Credit (COS)

Purpose: The Customer-Owned Substation Credit is to compensate customers who own their own substation, the cost of which are not included in the AESO's revenue requirements.

Available to: DTS Customers who own their transmission station which steps the voltage down from transmission voltage to 25 kV or less, provided that the transmission station is fully operational and none of the costs of the transmission station are included in the AESO's revenue requirements.

Rate: **$700/MW/month** of Billing Capacity in the Billing Period.

Terms: The Terms and Conditions form part of this Rate Schedule. The full Customer contribution pursuant to Article 9 is applicable to Customers eligible for this credit.

Rate Schedule – Supply Transmission Service (STS)

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 sum of the Interconnection Charge, the Losses Charge, and the Operating Reserve Charge, where:

The Interconnection Charge equals:

$2.35/MWh of Metered Energy during the Billing Period.

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

The Losses Charge equals:

Metered Energy in each hour X location specific loss factor X Pool Price

Where "location specific loss factor" is determined by the AESO for each Customer.

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

Operating Reserves Charge equals:

Metered Energy in each hour X **4.0%** X Pool Price.

Regulated Generating Unit Connection Costs:

An additional charge of **$348/MW** per month for each MW of unit MCR applicable only to regulated generating units, as that term is defined in the Act, as outlined in Appendix B of the rate schedules.

Terms: The rate is separately applicable at each POS.

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 paragraphs 6.2 and 6.3 of the Terms and Conditions.

The Terms and Conditions form part of this Rate Schedule.
Rate Riders A&B apply to these customers when invoked by the AESO.

Rate Schedule – Import Service (IS)

Applicable to: Customers importing electric energy into the AIES.

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

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

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

(a)

(i) **$2.35/MWh** of Energy Transfer during the Billing Period;

(ii) Incremental Losses Charge, calculated as the sum, over all transaction hours in the Billing Period of the following:

Energy Transfer in hour x location specific loss factor x Pool Price for the hour, where the location specific loss factor is an incremental factor determined by the AESO for each Point of Exchange.

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

75% x capacity scheduled for Customer for the transaction x hours in the transaction x ($2.35/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** per Billing Period.

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

The rate is separately applicable at each Point of Exchange.

The Terms and Conditions form part of this Rate Schedule.

APPENDIX "A"
RATE RIDERS

Rate Rider A1

Transmission Duplication Avoidance Adjustment

Dow Chemical Canada Inc. / Dow Hydrocarbons / ASU2

Applicable to: TransAlta Utilities Corporation / Aquila Canada Corp.

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.

Rate Rider A1
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

Rate Rider A2

Transmission Duplication Avoidance Adjustment

NOVA Chemical 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[1]

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 80MVA. 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[2]

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

[1] Application, Section 2.5: Terms for the Duplication Avoidance Tariff; Section 2.5.1: Metering and Totalizing

[2] Application, Appendix C: Example of Totalizing0

	Time Interval 1	Time Interval 2
535S Point of Demand (A)	+65 MW	+ 130
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 -300MW, 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.

Rider A2 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 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

Rate Rider A3

Transmission Duplication Avoidance Rate A3

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

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 & 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.

Rider A3 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 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

Rate Rider A4

Transmission Duplication Avoidance Adjustment

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, plus any expansions to this Industrial System as may be approved by the AEUB, for System Access Service to Imperial Oil at the 715S transmission station Point of Demand and Point of Supply and the 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 AESO's June 22, 2001 Application for a Duplication Avoidance Tariff for Imperial Oil Resources Limited Cold Lake Site. Charges under Rate DTS and Rate STS will be calculated using the totalized Metered Demand and the totalized Metered Energy. The meters at the 837S transmission station to be totalized are 5L408, 5L409, and 5L410. The meters at the 715S transmission station to be totalized are 5L242, 5L335, 5L367, 5L395, and the future metering point for Imperial Oil's Cogeneration Facility.

Imperial Oil shall make the following payments to the AESO:

1. Capital Charge:
   A lump-sum payment of $5,968,800 to be made immediately 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 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.

The amount of load included in the totalizing calculation will be limited to 115 MW, which is the maximum amount of load that the Duplicate Facilities would be able to serve, based on the deemed capacity 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 115 MW 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.

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 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%

Rider A4 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

Rate Rider B

Working Capital Deficiency/Surplus Rider

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

Applicable to: Customers receiving service under the following Rate Schedules:

DTS
STS

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.

Rate Rider C

Deferral Account Adjustment Rider

Purpose: To recover or refund all accumulated deferral account balances.

Applicable to: Customers receiving service under the following Rate Schedules:

DTS
STS

Effective: The rider is effective for all billing periods, **effective January 1, 2004.**

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
- Other Ancillary Services Revenue Category

STS Rate Schedule
- Interconnection Revenue Category
- Operating Reserve Revenue Category
- Transmission Losses 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.

Rate Rider D

AESO Tariff Deficiency Correction Regulation Rider

Purpose: To recover the amounts set out in the AESO Tariff Deficiency Correction Regulation.

Applicable to: Customers receiving service under the following Rate Schedules:

DTS
STS

Effective: The rider is effective from January 1, 2003 to May 31, 2003 inclusive.

Rate: Charges for STS customers in any one Billing Period shall be,

$0.095/MWh of Metered Energy during the Billing Period.

Charges for DTS customers in any one Billing Period shall be,
$38.95/MW/month of Billing Capacity in the Billing Period, plus
$0.054/MWh of Metered Energy during the Billing Period.

Billing Capacity shall be the highest of:
(i) The highest fifteen (15) minute Metered Demand in the Billing Period;
(ii) The Ratchet Level; or
(iii) 90% of the Contract Capacity.

where "Ratchet Level" is defined as the highest of the following:

(i) 90% of the highest Metered Demand in the past 12 months;
(ii) 85% of the highest Metered Demand in the past 24 months;
(iii) 80% of the highest Metered Demand in the past 36 months;
(iv) 75% of the highest Metered Demand in the past 48 months;
(v) 70% of the highest Metered Demand in the past 60 months.

Terms: The rate is separately applicable at each POS and POD.

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 paragraphs 6.2 and 6.3 of the Terms and Conditions

The Terms and Conditions form part of this Rate Schedule.

APPENDIX B

Maximum Continuous Rating Values for Regulated Generation Units under Rate STS

GENERATING UNIT	UNIT MCR(MW)	POINT OF SUPPLY TOTAL
ATCO Battle River 1		
ATCO Battle River 2		
ATCO Battle River 3	147.3	
ATCO Battle River 4	147.3	
ATCO Battle River 5	368.2	
ATCO Battle River		662.8
ATCO H. R. Milner	144.3	144.3
ATCO Rainbow 1	25.9	
ATCO Rainbow 2	39.8	
ATCO Rainbow 3	21.4	
ATCO Rainbow		87.1
ATCO Sheerness 1	189.1 **ATCO**/189.1 **TAU**	
ATCO Sheerness 2	189.1 **ATCO**/189.1 **TAU**	
ATCO Sheerness		756.4
EPI Clover Bar 1	157.2	
EPI Clover Bar 2	157.2	
EPI Clover Bar 3	157.2	
EPI Clover Bar 4	157.2	
EPI Clover Bar		628.8
EPI Genesee 1	384.1	
EPI Genesee 2	384.1	
EPI Genesee		768.2
EPI Rossdale 8	66.7	
EPI Rossdale 9	70.6	
EPI Rossdale 10	70.6	
EPI Rossdale		207.9
TAU Hydro	791.4	791.4
TAU Sundance 1	278.6	
TAU Sundance 2	278.6	
TAU Sundance 3	353.2	
TAU Sundance 4	353.2	
TAU Sundance 5	353.2	
TAU Sundance 6	364.2	
TAU Sundance		1981.0
TAU Wabamun 1	63.7	
TAU Wabamun 2	63.7	
TAU Wabamun 3	139.3	
TAU Wabamun 4	278.6	
TAU Wabamun		545.3
TAU Keephills 1	381.1	
TAU Keephills 2	381.1	
TAU Keephills		**762.2**
TOTAL		**7335.4**