

# ISO Tariff – Rider A3

## Transmission Duplication Avoidance Adjustment

### Shell Canada Corporation – Scotford Industrial System



## Applicability

**1** Rider A3 applies to **system access service** provided to Shell Canada Corporation (Shell Canada) at the 409S transmission station **point of delivery** and **point of supply** at Shell Canada's Scotford industrial system, as designated by Alberta Energy and Utilities Board Order No. HE U2000-109.

## Rate

**2(1)** For each metering time interval, the **metered demand** and **metered energy** for each **point of delivery** and **point of supply** (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 settlement under the **ISO tariff**. Charges under the **ISO tariff** will be calculated using the totalized **metered demand** and **metered energy**.

**(2)** Shell Canada will make the following payments to the **ISO**:

(a) Capital Charge: A payment of \$2,907,800 is due immediately upon implementation of this rider.

(b) Incremental Losses Charge:

(i) 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 subsection 6 below. If the **metered demand** in a metering interval is between two levels in subsection 6 below, 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.

(ii) For each **settlement 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 subsection 6 below that corresponds with the totalized **metered energy** for the hour; and

(c) Other Expenses Charge: The other expenses charge is shown in subsection 7 below.

**(3)** Shell Canada will receive a primary service credit in respect of the duplicate facilities as is provided to other Rate DTS customers of the **ISO** who provide their own transmission station, pending the decision of the Alberta Energy and Utilities Board on the **ISO's** 2002 tariff application.

## Terms

**3** All terms and conditions in the **ISO 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 **ISO** 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 **ISO** 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 twenty-four (24) years of the term of the Duplication Avoidance Tariff. At the end of twenty-four (24) years, the undepreciated value would be zero. The termination notice period, for both the **ISO** and Shell Canada, will be twenty-four (24) **months**.

### Metering and Totalizing

**4(1)** Totalization should proceed on the basis of economic indifference to Shell Canada between the Duplication Avoidance Tariff 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.

**(2)** 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 **ISO** compared to construction of duplicate facilities.

**(3)** 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 delivery** and **point of supply** for the purpose of totalizing **metered demand** and **metered energy**.

**(4)** During the term of the Duplication Avoidance Tariff, the **ISO** 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 **ISO** under the **ISO tariff** are equivalent to the costs that Shell Canada would have incurred had they built the duplicate facilities.

**(5)** 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

**5(1)** 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 <b>point of delivery</b> (A)	+60 MW	+60 MW
409S <b>point of supply</b> and <b>point of delivery</b> (B)	-70 MW	+20 MW
Totalized <b>metered demand</b> and <b>metered energy</b> (C)	-10 MW	+80 MW

**(2)** 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 **interconnected electric system** 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 **interconnected electric system** would be 10 MW. This energy balance is simulated through the proposed totalizing procedure. Combining the **point of delivery** (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 **interconnected electric system**.

(3) In time interval 2, the load served from **point of delivery** (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 **interconnected electric system** to Shell Canada. Thus (B) is also a **point of delivery**. If Shell Canada built the duplicate facilities, the level of energy delivered from the **interconnected electric system** 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 **interconnected electric system** to Shell Canada.

### Schedule 1 — Incremental Loss Factors

6	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%

### Schedule 2 — Other Expenses Charge

7	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

12-Month Period	Monthly Payment
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

12-Month Period	Monthly Payment
Jan. 1, 2035 – Dec. 31, 2035	\$ 2,432
Jan. 1, 2036 – Dec. 31, 2036	\$ 2,761

### Revision History

Effective	Description
2011-07-01	Revised and reformatted all subsections, as approved in <b>Commission</b> Decision 2011-275 issued on June 24, 2011.