June 15, 2015

Alberta Utilities Commission
Fifth Avenue Place
425-1st Street SW
Calgary, Alberta T2P 3L8

Attention: John Petch, Commission Counsel

Dear Sir:

Re: **Proceeding 3167**
Decision 2013-135
Alberta Utilities Commission Direction No. 3

Please find enclosed the Alberta Electric System Operator's ("AESO") Annual Report in accordance with Direction No. 3 in Decision 2013-135, directing the AESO to "monitor and report the cost of using the TCM Rule on at least an annual basis."[1]

Sincerely,

"original signed by"

Heidi Kirrmaier
Vice President, Regulatory

[1] Decision 2013-135, ATCO Power Ltd. and ENMAX Energy Corporation, *Complaints by ATCO Power Ltd. and Enmax Corporation regarding ISO rule Section 302.1: Real time Transmission Constraint Management* (April 5, 2013) at para. 197(3).

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Alberta Electric System Operator
AUC Decision 2013-135
Direction No. 3 Annual Report

Date:	June 15, 2015
Prepared by:	Alberta Electric System Operator
Prepared for:	Alberta Utilities Commission

635321 v1

Contents

1 Background

Direction No. 3 of Commission Decision 2013-135 directs the Alberta Electric System Operator (AESO) to monitor and report on the cost of using the TCM Rule to the Commission on at least an annual basis.[1] In June 2014, the AESO submitted its initial report in compliance with that direction.[2] In its letter to the AESO dated September 24, 2014, the Commission directed the AESO "to continue to provide, as a minimum, volume and cost figures calculated using the Long-term Transmission Plan (LTP) Theoretical methodology (Method 1) in any subsequent reports filed in accordance with Direction No. (3) of AUC Decision 2013-135."[3] The AESO files this report in compliance with these directions.

2. Costs of the TCM Rule

2.1 Determination of Constrained Down Generation

In the AESO's June 16, 2014 Direction No. 3 Annual Report the following methodologies were used to estimate the annual cost of Constrained Down Generation (CDG).

Method 1 - LTP Theoretical	The cost of "Nominal CDG"[4] is simulated using a distribution of price impacts from a variety of dispatch levels.
Method 2 - Ex Post based on "Nominal CDG"	Calculation of CDG using actual event merit orders and "nominal CDG". An "unconstrained SMP" value is estimated by assuming "nominal CDG" is not in place. Another SMP value is calculated assuming CDG exists. The difference in those SMP values is multiplied by AIES demand to estimate the cost of CDG.
Method 3 – Ex Post based on Estimated CDG	The same as Method 2 above, however a further step is added in order to refine the estimate. Rather than using a "nominal CDG" value, it considers the amount of in-merit CDG assets in the area where CDG takes place.

[1] Decision 2013-135, ATCO Power Ltd. and ENMAX Energy Corporation, *Complaints by ATCO Power Ltd. and Enmax Corporation regarding ISO rule Section 302.1: Real time Transmission Constraint Management* (April 5, 2013) at para. 197(3).

[2] 0003.02.AESO-3167.

[3] 0004.01.AUC-3167.

[4] Nominal CDG refers to the constraint limit size without consideration of energy that would be in merit. For the duration of a constraint, that level is used as a proxy for the volume of CDG.

Method 2 will no longer be used by the AESO to estimate the costs of CDG, as that method is less representative of market outcomes than Method 3. Method 3 is more refined than Method 2 as it estimates the amount of in-merit CDG volume of assets located within the area where CDG events take place. The AESO will continue to use Methods 1[5] and 3 to estimate costs.

Table 1 below summarizes annual CDG volume and estimated costs for the years 2008 through 2014.

Table 1: CDG Volume and Cost Estimate

Year	CDG Volume (GWh)		Cost (Million Dollars)		
	Nominal	Estimated*	Method 1	Method 2	Method 3
2008	295	N/A	827	N/A	N/A
2009	55	N/A	76	N/A	N/A
2010	700	N/A	691	N/A	N/A
2011	142	108	264	171	111
2012	164	84	238	200	105
2013	126	103	199	305	264
2014	169	149	90	-	58

*Estimated CDG volume is only available for 2011 onwards due to data availability.

CDG volumes in 2014 are generally in line with prior year estimates, with estimated CDG volume being higher than previous years due in part to outages on a KEG-area transmission line. Estimated costs of CDG were lower in 2014, likely due to lower pool prices.

2.2 Transmission Must Run

Table 2 below summarizes transmission must run costs for the years 2011 through 2014.

Table 2: TMR Costs (Million Dollars)

Year	Contracted TMR Costs	Conscripted TMR	Total TMR Costs
2011	$28.3	$5.8[6]	$34.1
2012	$3.7	$24.0	$27.7
2013	$2.7	$8.6[3]	$11.3
2014	$0.5	$4.9	$5.4

[5] Method 1 involves simulating the cost of “nominal CDG” based on a distribution of price impacts derived from a variety of dispatch levels in random merit orders.

[6] The cost of TMR for the years 2011 and 2013 have been adjusted as settlement has been completed and actuals are now available. For 2011, values have been adjusted downward from $6.4M to $5.8M. For 2013, values have been adjusted upward from $8.1M to $8.6M.

Note that the AESO's June 16, 2014 Direction No. 3 Annual Report reflected the contracted TMR costs associated with the use of TMR to relieve in-flow constraints, in the northwest of the province. Given the AESO's consideration of dispatching a generating asset to restore the balance on the interconnected electric system, the 2014 value for contracted TMR costs now also includes the cost of dispatch of the Location Based Credits Standing Offer (LBCSO) units. As this cost will be included in future reported contracted TMR costs, the values for the years 2011 through 2013 have been revised above to reflect this change.

2.3 Total Costs of Using the TCM Rule

Table 3 below summarizes the total cost of using the TCM Rule for the years 2011 through 2014.Totals are calculated by summing the CDG cost estimate included in Table 1 and Total TMR costs included in Table 2.

Year	Method 1	Method 3
2011	$298	$145
2012	$266	$133
2013	$210	$275
2014	$95	$63

Results indicate that the cost of using the TCM Rule in 2014 was significantly lower than in previous years.

3 Increased Use of TMR/DDS

The AESO continues to evaluate how to best differentiate among TMR-related costs resulting from: a requirement to serve load during inflow constraint events; efforts to mitigate outflow constraints; or increased use of TMR to help restore the balance on the interconnected electric system in order to avoid potential price distortion. The AESO is also continuing to develop processes and tools to enable the use of TMR to restore the balance on the interconnected electric system. However, other than the continued increased use of the synchronous condense mode on the Poplar Hill unit, the nature and timing of constraints did not present the AESO with the opportunity to make use of TMR for purposes of restoring the energy balance on the interconnected electric system. Completion of system changes associated with implementation of Transmission Constraint Rebalancing will improve the AESO's visibility of real-time CDG by enabling the AESO to take into account changes to load levels, merit order offers and other information. This will improve the AESO's ability to determine the volume and timing of CDG, and the associated required TMR dispatch volume requirements.