Q2/2016 Quarterly Report

April – June 2016

July 29, 2016

Taking action to promote effective competition and a culture of compliance and accountability in Alberta's electricity and retail natural gas markets

www.albertamsa.ca

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Wholesale Market

Summary

The pool price for the quarter averaged $15.00/MWh ($12.76/MWh ext. off-peak, $16.12/MWh ext. on-peak). Average prices were 74% lower than the same period last year, the lowest quarterly average since 2001. Since Q3 2015, each quarter set successively lower average prices. The first six months of 2016 have averaged $16.55/MWh, almost 75% lower than the January-June average over the last 15 years.

Table 1: Summary Statistics

		2015	2016	Change
Pool Price ($/MWh)	April	20.52	13.63	*-34%*
	May	53.93	15.89	*-71%*
	June	97.31	15.44	*-84%*
	Q2	**57.22**	**15.00**	***-74%***
Supply Cushion (MW)	April	1,996	2,478	*+24%*
	May	1,912	1,966	*+3%*
	June	1,885	2,585	*+37%*
	Q2	**1,931**	**2,339**	***+21%***
Gas Price ($/GJ)	April	2.42	1.09	*-55%*
	May	2.65	1.16	*-56%*
	June	2.48	1.79	*-28%*
	Q2	**2.52**	**1.34**	***-47%***
Demand (AIL, MW)	April	8,711	8,475	*-3%*
	May	8,378	7,855	*-6%*
	June	8,783	8,369	*-5%*
	Q2	**8,621**	**8,229**	***-5%***
Wind (Avg MW)	April	523	477	*-9%*
	May	302	405	*+34%*
	June	227	523	*+130%*
	Q2	**350**	**468**	***+34%***

Market conditions remain similar to Q1, with a low natural gas price, relatively high supply cushion, and the absence of any significant volume of economic withholding. Demand also fell by 5% compared to Q2 2015, in part due to the Fort McMurray wildfire which reduced electricity consumption at industrial facilities.

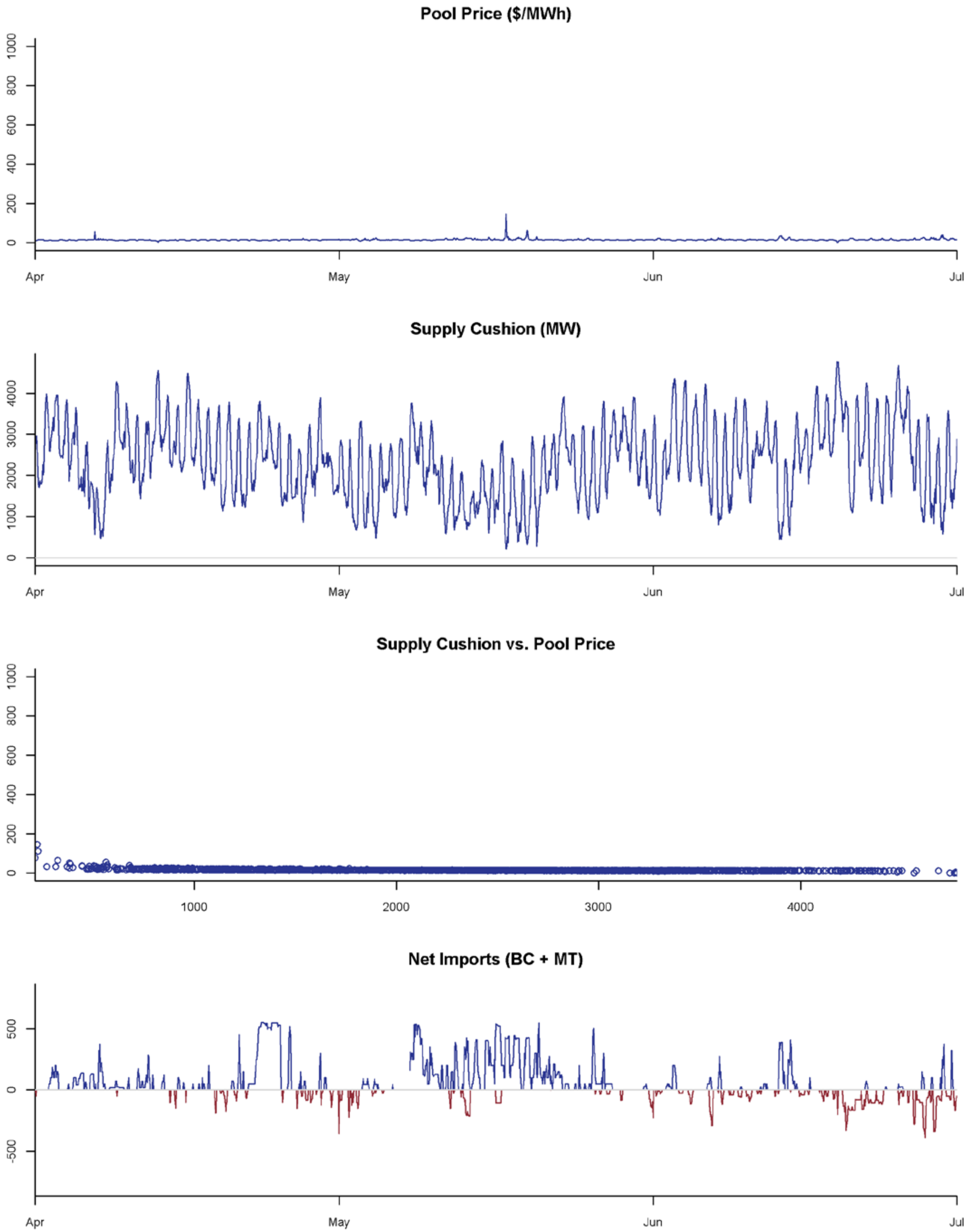
Impact of Fort McMurray Wildfire

The Fort McMurray wildfire, starting in May 2016, was the largest fire evacuation in Alberta's history and one of the most significant events of Q2 2016. However, despite presenting unique challenges to operations, the wildfire had limited impact on the broader Alberta electricity market.

Most electricity consumption in the Fort McMurray area is industrial and is typically supplied by generation on-site (behind-the-fence generation). The net electricity flow can go either way depending on the on-site needs. The result is that while there could be 2,000 MW of industrial consumption, only 10% of it might come from the wider electricity system; conversely, despite a significant volume of generation, only a small fraction may be exported to the grid. Figure 1 shows a significant drop in cogeneration at the start of the Fort McMurray wildfire. This drop in volume corresponds with a drop in electricity usage at these facilities.

Figure 1: Daily Total Metered Volumes at Cogeneration Assets

Figure 2: Summary Graphs

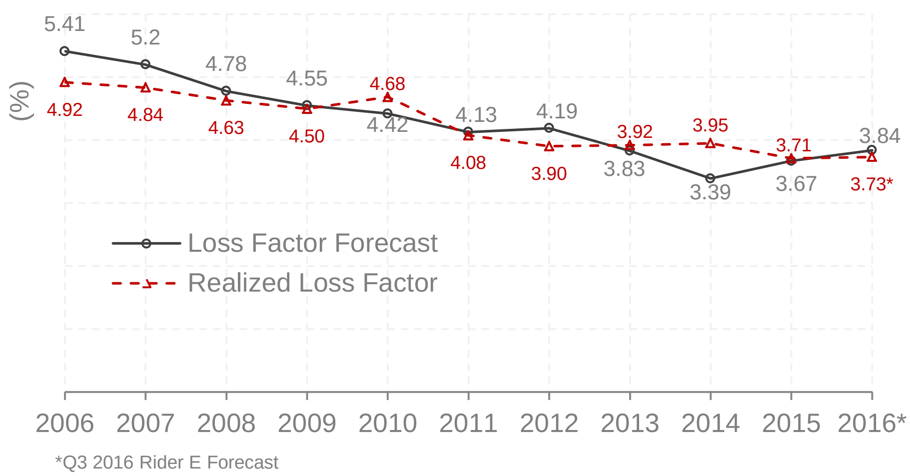


Transmission System Losses and HVDC Transmission Reinforcement

Not all generated electricity makes it to a consumer. Usually three to six percent of electricity is lost to resistance in the transmission process, an amount that would be worth over $1.5 billion[1] in the past decade. However, system losses have generally been in decline since 2006, in part due to upgrades to transmission.

In November 2015, the AESO forecast the system average losses to be 3.84% in 2016. Realized losses during the first-half of 2016 have resulted in a system average loss factor of 3.73%.[2] Annual location-specific loss factors for services to market participants are finalized in advance of each year for tariff purposes, such that they are "anticipated to result in the reasonable recovery of transmission line losses."[3] Realized losses are reported on a quarterly basis in "Rider E" estimates and are used to calibrate future forecasts. The relationship between the forecast system average loss factors and actual losses are shown in Figure 3. It shows that while the forecast loss factors increased since 2014, realized loss factors do not follow that trend.

Figure 3: System Average Loss Factors (%)



The AESO's Q3 2016 Rider E[4] estimate for 2016 total system losses decreased from 2.43 TWh to 2.32 TWh, after actual losses up to April 2016 were factored into the estimates. For the first four months of 2016, losses were 3.53% of customer volume, compared to 3.76% in the first four months of 2015. For the balance of 2016, system average losses are now forecast to be 3.73%, roughly equivalent to 2015.

While a wide variety of factors influence overall system losses, there are two main recent changes that have reduced system losses: the addition of generation capacity near Calgary (a large load center); and the addition of two low-loss HVDC lines. The addition of generation near

[1] Alberta Electric System Operator, Q3 2016 Rider E Estimate (June 28, 2016). http://www.aeso.ca/transmission/33033.html
[2] Alberta Electric System Operator, Current Loss Factors (November 2015). http://www.aeso.ca/transmission/33056.html
[3] Alberta Regulation 86/2007, *Transmission Regulation*, Section 31(1)(c). http://www.qp.alberta.ca/documents/Regs/2007_086.pdf
[4] Alberta Electric System Operator, Q3 2016 Rider E Estimate (June 28, 2016). http://www.aeso.ca/transmission/33033.html

Calgary reduces the amount of electricity that must be transmitted over large distances (increasing losses) and the HVDC lines reduce losses from transmitting electricity when required.

The two HVDC lines, the Western Alberta Transmission Line (WATL) and Eastern Alberta Transmission Line (EATL), reinforced transmission between Edmonton and Calgary. With over 4,500 MW of generation located west of Edmonton in the Wabumun area, typical flows on transmission lines are from north to south to the Calgary area load centre. In total, 0.9 net TWh flowed from north to south in the first six months of 2016, mostly on WATL. For scale, total load in the province (excluding behind-the-fence) was approximately 30 TWh.

As shown in Table 2, both lines were in service simultaneously about 81% of the time. When both lines are in service, the typical configurations are shown in Table 3. As might be expected, both lines flow from north to south most (59%) of the time. The second most common configuration is WATL flowing from north to south, and EATL flowing south to north (31%).

Table 2: WATL/EATL Percentage of time in service (first half of 2016)

		EATL Status		
		In Service	Out Of Service	Total
WATL Status	In Service	81%	7%	88%
	Out Of Service	10%	2%	12%
	Total	92%	8%	100%

Table 3: Percentage of time by direction of line flow (when both in service, first half 2016)

		EATL Direction		
		North-South	South-North	Total
WATL Direction	North-South	59%	31%	89%
	South-North	3%	8%	11%
	Total	61%	39%	100%

The reasons for a particular configuration can be varied, but the HVDC lines are first used to mitigate any potential reliability concerns or contingencies, congestion, and are otherwise set at flows calculated to minimize system losses given the current system conditions. Losses and reliability are not always trade-offs, as a particular configuration may both address reliability concerns while also reducing system losses relative to the lines being out of service. The value of avoided congestion or decreased losses due to the HVDC lines has not been directly quantified.

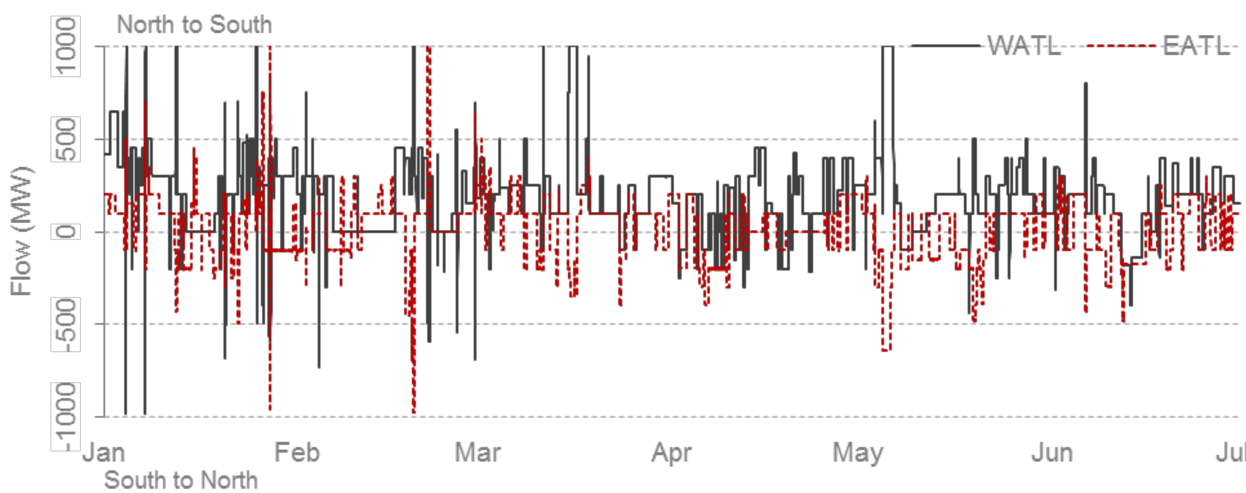
The HVDC lines having countervailing flows may not be intuitive. However, as shown in Table 4, system conditions are common (27%) where flowing WATL from north to south and EATL in the opposite direction would be estimated to minimize losses. Overall both lines matched their loss minimizing direction of flow roughly 70% of the time. Table 4 only includes periods when both lines are in service and where loss optimizing calculations are available to the MSA.

Figure 4 shows all flows on the WATL and EATL in the first half of 2016. The relatively high volatility in the first two months of 2016 is mostly due to testing.

Table 4: Loss Optimizing Flow Directions (when both in service, first half of 2016)

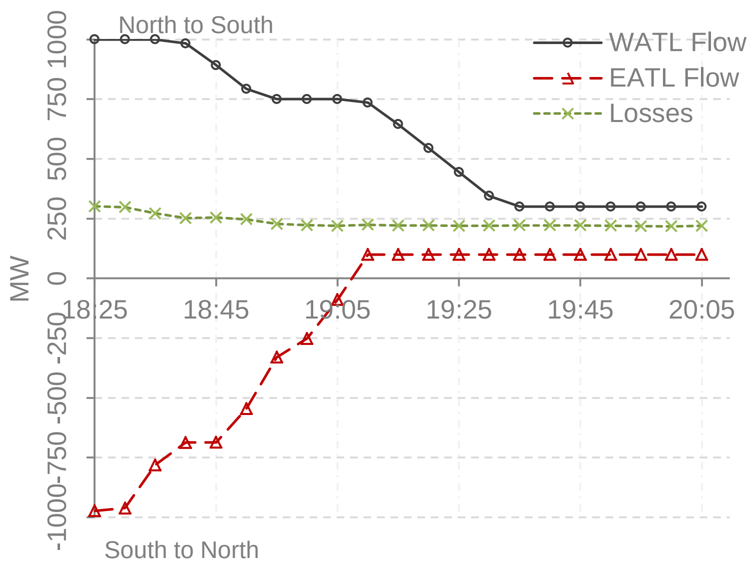
		EATL Loss Optimized Direction		
		North-South	South-North	Total
WATL	North-South	61%	27%	88%
	South-North	1%	11%	12%
	Total	62%	38%	100%

Figure 4: Flow on WATL and EATL (2016)



The flows on the HVDC lines have been observed in real time to have an impact on losses. As an example to provide a sense of scale, Figure 5 shows the conclusion of a testing period on February 19, 2016. Over one hour, the change from a testing configuration to loss configuration reduces losses roughly 80 MW.

Figure 5: Impact on Losses from change to HVDC flows



Forward Market

Overall forward market trading volume this quarter was lower than in the first quarter, being driven by large decreases in the volume of yearly contracts that were traded. However, second quarter volumes are comparable to volumes observed in 2015.

Table 5: Trade Volumes by Contract Term (TWh)

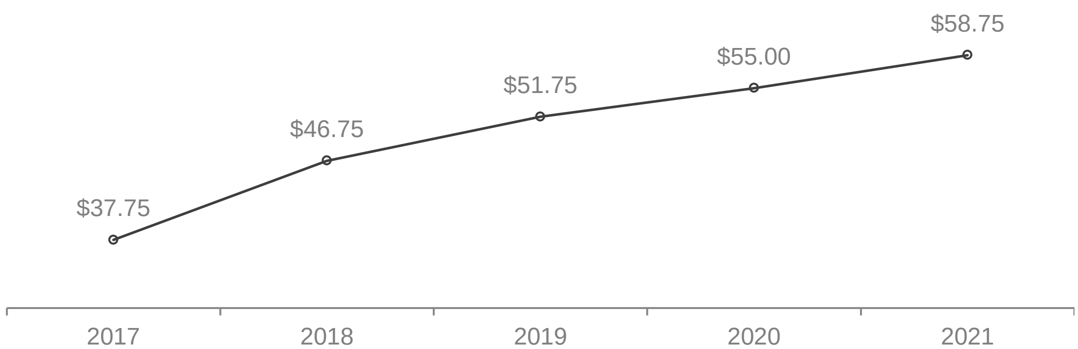
		Daily	Monthly	Quarterly	Yearly	Other	Total
2015	**Q1**	0.10	9.96	0.84	4.17	0.76	15.84
	Q2	0.20	10.46	1.14	16.71	0.66	29.18
	Q3	0.06	6.25	0.50	4.40	0.29	11.51
	Q4	0.06	5.87	0.98	5.74	0.03	12.68
	Year	0.42	32.54	3.46	31.03	1.74	69.20
2016	**Q1**	0.22	9.36	1.78	12.37	3.01	26.73
	Q2	0.19	8.25	0.59	4.50	1.08	14.61

As of June 30, all monthly flat forward contracts were trading at $42.00/MWh, or below, with prices rising modestly since the first quarter as shown in Figure 6. In most months in 2016, forward prices are observed to decline as we near the beginning of a month as uncertainty is reduced. In this quarter, the last trade for monthly contracts prior to the start of a given month, averaged about $22.50/MWh, about $7.50 (50%) higher than the spot prices. It is not unexpected to see a forward premium as participants may be reluctant to speculate that prices will continue to be low as a small number of high priced events can significantly affect a monthly average spot price. In addition, generators have little incentive to sell into the forward market close to marginal cost, thereby giving up any potential upside in the spot market. The MSA is monitoring the forward premium to assess whether it is being influenced by other factors.

Figure 6: Monthly Flat Forward Curve as of June 30, 2016

The annual forward curve has also increased modestly since the first quarter; however it remains at or below $55.00/MWh through 2020.

Figure 7: Annual Flat Forward Curve as of June 30, 2016



Retail Market

Dual Fuel Contracts

Early in 2016 the MSA contacted competitive retailers to gather information on the different types of contracts that their customers purchased. This is a repeat of what was done in the previous two years. As shown in Table 6, the total number of competitive retail energy contracts for all consumer types increased 0.1%, from 654,804[5] in 2014 to 655,667 in 2015.

Under these contracts consumers buy either one fuel (i.e. electricity or natural gas) or both fuels. As reported in Table 6, 76% of competitive retail energy contracts cover both electricity and natural gas, while 24% cover a single fuel. This is unchanged from 2014.

Table 6: Count of Competitive Contracts

	Single Fuel	Dual Fuel	Total
2013	132,697	464,775	597,472
2014	155,338	499,466	654,804
2015	155,062	500,605	655,667

The options for electricity consumers to green their energy consumption are detailed in the next section. However, the total number of green contracts (which may be single or dual fuel) has declined over the past three years, from 3.8% of all competitive contracts in 2013, to 3.3% in 2015. This would not include greening options that are separated from an electricity retailer.

Table 7: Green Contracts / Total

2013	3.8%
2014	3.4%
2015	3.3%

The total number of contracts by load serving entity (LSE) region is shown in Table 8.

Table 8: 2015 Competitive Contracts by LSE

LSE	# Contracts	% Total
ENMAX	268,721	41%
FortisAB	152,272	23%
EPCOR	101,477	15%
ATCO	85,140	13%
Red Deer	22,996	4%
Lethbridge	19,999	3%
Other	5,062	1%
Total	655,667	100%

[5] This number is a correction from 654,787 as published in the 2015 Retail Market Update

Green Energy Options

Many competitive energy retailers in Alberta give consumers the option to green their electricity and/or natural gas consumption. When a consumer opts for the green natural gas rate, the retailer may purchase greenhouse gas offsets or inject natural gas obtained from a renewable source (biomethane) into the system. If offsets are purchased, they may be procured from a gas-related project or other offset project. When a consumer opts for the green electricity rate, the retailer purchases and retires renewable energy certificates (RECs) on behalf of the consumer. One REC is created when one megawatt of electricity is produced by a solar, wind, hydro or biomass facility. The REC signifies ownership of the renewable attributes of the electricity. If a consumer purchases RECs sufficient to cover her consumption it can be said that she is consuming green energy.

RECs are purchased by retailers and retired on behalf of consumers when green energy is purchased. Retiring RECs means that the REC is entered into a database and marked as consumed to ensure that the renewable energy cannot be counted twice. In Canada, most RECs are certified under the EcoLogo standard.[6] To comply with the standard, retailers and producers must undergo annual third party audits to ensure RECs are properly produced and retired. EcoLogo certifies facilities as producing "new renewable low-impact" electricity if the facility is less than 15 years old. EcoLogo also certifies facilities older than 15 years old in a separate category. Some RECs are registered in the Western Renewable Energy Generation Information System (WREGIS)[7], which helps ensure RECs are retired properly.

In Table 9 below, we have provided a list of retailers that provide green electricity options in Alberta. The products vary by: percentage of energy greened; price; type, age and location of the renewable generation facility; and certification. Table 10 provides similar information for green natural gas options.

[6] http://www.comm-2000.com/ProductDetail.aspx?UniqueKey=27261
[7] https://www.wecc.biz/WREGIS/Pages/Default.aspx

Table 9: Retail Green Electricity Options

Retailer	Percentage greened	Price / kW of REC[8]	Source	Certification
Alberta Cooperative Energy (ACE)	100%	$0.02	Alberta small scale solar and wind	No certification
ATCO Energy	25% or 100%	$0.02	Alberta-based sources	EcoLogo
Bullfrog Power (does not sell electricity)[9]	100% of estimated electricity consumption	$0.025	Alberta wind and hydro	EcoLogo
ENCOR	15%, 50% or 100%	$0.03 (15%) $0.025 (50%) $0.02 (100%)	Taylor Hydro, Alberta	EcoLogo
Just Energy	60% or 100%	$0.025	Alberta-based	EcoLogo
UTILITYnet Group[10]	0 to 100%	$0.0166	Alberta and B.C. based biomass	EcoLogo

Table 10: Retail Green Natural Gas Options

Retailer	Percentage greened	Price / GJ[11]	Type of product	Source	Certification
Bullfrog Power (does not sell natural gas)[12]	100% of estimated natural gas consumption	$3.93	Renewable natural gas injected into national pipeline system	Biomethane facility, Quebec	ICF International
ENCOR	15%, 50% or 100%	$2.00 (15%) $1.75 (50%) $1.50 (100%)	Carbon offsets	Niagara Landfill Gas Project, Ontario	ISO
Just Energy	60% or 100%	$1.25	Carbon offsets	Not specified	Not specified

[8] Price when 100% of electricity consumption is greened. If a lower percentage is greened, the prorated price is the same unless otherwise noted.
[9] Bullfrog Power offers to green electricity consumption by retiring RECs, but is not a retailer of electricity.
[10] Includes: Aboriginal Power, Adagio Energy, Bow Valley Power, Brighter Futures, Burst Energy, Camrose Energy, Choice Energy, Echo Energy, E NRG Power, Get Energy, SolarMax Power, Link Energy Flex, Merit Energy & Power, Milner Power, Mountain View Power, NewGen Energy, Park Power, Peace Power, Relay Energy, Spot Power, Vector Energy, Wainwright Energy, and Spot Power.
[11] Price when 100% of natural gas consumption is greened. If a lower percentage is greened, the prorated price is the same unless otherwise noted.
[12] Bullfrog offers to green natural gas consumption by purchasing the environmental attributes from a biomethane facility, but is not a retailer of natural gas.

Operating Reserves

Market Summary

Total operating reserve cost decreased 67% in Q2 2016 compared to Q2 2015. The decrease in operating reserve cost was seen across most operating reserve products. However, the procurement cost of standby regulating reserve increased 110% quarter-over-quarter while the total volume of standby regulating reserve procured remained the same.

Comparing Q2 2015 and Q2 2016, the total operating reserve volume procured decreased by 5%. The amount of active and standby operating reserve procured decreased by 4% and 5%, respectively. The amount of standby reserves activated decreased by 26%.

Table 11: Operating Reserve Statistics

Total Cost ($ Millions)			
	Q2 2015	**Q2 2016**	***% Change***
Active Procured	**58.6**	**18.2**	***-69.0***
RR	16.0	10.1	*-36.6*
SR	23.6	5.7	*-75.6*
SUP	19.1	2.3	*-87.9*
Standby Procured	**5.9**	**6.3**	***7.1***
RR	2.0	4.2	*109.8*
SR	2.9	1.8	*-38.7*
SUP	1.0	0.3	*-66.7*
Standby Activated	**11.1**	**0.9**	***-92.1***
RR	0.1	0.0	*-77.1*
SR	7.5	0.6	*-91.3*
SUP	3.6	0.2	*-94.2*
Total	**75.7**	**25.4**	***-66.5***
Total Volume (GWh)			
	Q2 2015	**Q2 2016**	***% Change***
Active Procured	**1,279.5**	**1,230.5**	***-3.8***
RR	340.2	339.8	*-0.1*
SR	469.5	445.1	*-5.2*
SUP	469.8	445.6	*-5.1*
Standby Procured	**548.8**	**521.1**	***-5.0***
RR	217.2	217.0	*-0.1*
SR	241.5	228.0	*-5.6*
SUP	90.1	76.0	*-15.6*
Standby Activated	**50.4**	**37.5**	***-25.5***
RR	2.3	1.4	*-41.6*
SR	33.0	25.3	*-23.2*
SUP	15.1	10.8	*-28.0*
Total	**1,878.7**	**1,789.1**	***-4.8***
Average Cost ($/MWh)			
	Q2 2015	**Q2 2016**	***% Change***
Active Procured	**45.8**	**14.8**	***-67.8***
RR	46.9	29.8	*-36.5*
SR	50.2	12.9	*-74.3*
SUP	40.6	5.2	*-87.3*
Standby Procured	**10.8**	**12.1**	***12.8***
RR	9.2	19.4	*109.9*
SR	12.0	7.8	*-35.1*
SUP	11.0	4.4	*-60.5*
Standby Activated	**221.2**	**23.5**	***-89.4***
RR	52.5	20.6	*-60.7*
SR	226.0	25.6	*-88.7*
SUP	236.6	19.0	*-92.0*
Total	**40.3**	**14.2**	***-64.8***

Standby Regulating Reserve cost analysis

As summarized above, the volume of standby regulating reserve procured rarely changes from day-to-day.[13] Providers are paid as bid per MWh and the costs of procuring and activating standby reserves can vary quite significantly across providers and across days. Moreover, between 2013 and 2015, the AESO only activated 1% of the standby regulating reserves procured each year on average. There is no WECC requirement governing how much regulating reserve (active or standby) that the AESO needs to procure. Thus, it appears that standby costs for regulating reserve could be decreased without negatively impacting reliability. In terms of active regulating reserve, the AESO buys sufficient volume to cover the normal moment to moment bumps in

[13] The AESO procures 100 MW of standby regulating reserve daily.

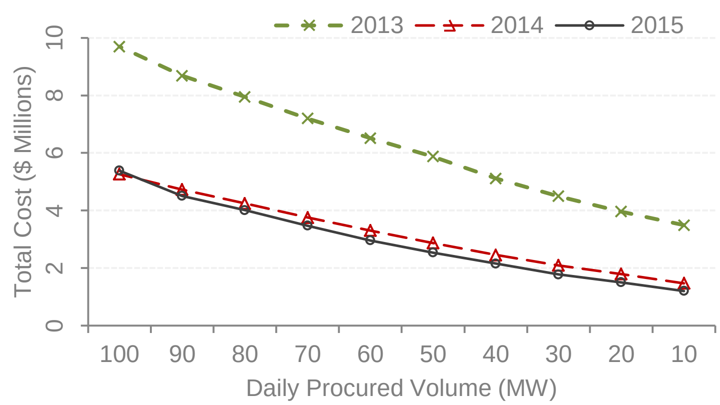
load as well as expected load ramps. In the case of standby reserves, the AESO can either pre-purchase or conscript as necessary.

The MSA used standby regulating reserve market clearing and activation data from 2013 to 2015 to construct counterfactual standby regulating reserve costs by incrementally decreasing the volumes of standby regulating reserve procured. The following assumptions were made for this analysis:

1. The standby market clears as it currently does, from lowest to highest based on the blended price until the required volume is met.[14] Standby regulating reserve is activated from lowest to highest based on the activation price. Providers are paid as bid per MWh.
2. If the amount of standby procured is not enough to meet the amount that was needed to be activated based on historical activations, then the AESO will conscript units to provide the reserve. The cost of conscripting regulating reserve is added to the total cost.
3. The conscription cost is calculated as the greater of the active payment or the highest combined premium and activation price for the hour as per section 11(3)(a) of the ISO Tariff. For the purposes of this analysis, section 11(3)(b) of the ISO Tariff, relating to verifiable net opportunity costs of providing the reserve, was ignored.
4. All of the volume that was in the day-ahead operating reserves market would be available for conscription in each hour of the effective date.

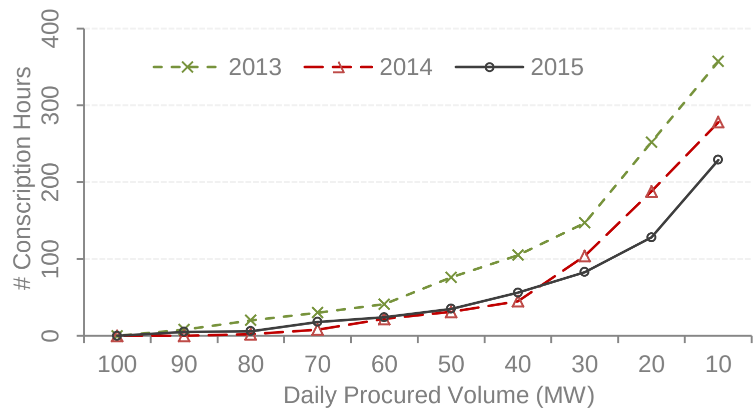
Figure 8 shows the total cost of standby regulating reserve steadily decreases as the daily volume procured decreases. On the other hand, the number of hours where the AESO would have to conscript increases as shown in Figure 9. The number of conscription hours increases sharply when the amount of standby regulating reserve procured daily is less than 40 MW.

Figure 8: Standby Regulating Reserve Costs



[14] *Blended price = premium price + (activation percentage x activation price)* where the activation percentage is equal to 1% for on peak periods and 3% for off peak periods.

Figure 9: Regulating Reserve Conscriptions



There are some caveats to the results of this analysis. The analysis used actual offers for standby regulating reserve in the period. Thus, it does not take into account changes in market participant behaviour or market structure that would result from decreasing the procurement volume. For example, if the procurement volume was decreased significantly and the incidents of conscription became more frequent, the terms set out in the ISO Tariff for conscription may change. Also, the cost of conscription calculated is an estimation based on section 11(3)(a) of the ISO Tariff. It does not take into account the opportunity cost for providing reserve, as contemplated in section 11(3)(b) of the ISO Tariff. Further, it assumes that the AESO will conscript if the amount of standby procured is less than the amount of standby activated in actuality, while the AESO may choose to not conscript reserve.

The MSA is not advocating that the AESO proceed down a path leading to high levels of conscription of service based on the existing tariff. Nevertheless, the analysis shows that for small decreases in procurement volumes the AESO could realize savings on the total cost of procuring standby regulating reserve while maintaining low rates of conscription.

The MSA is continuing to analyze participation and results in the operating reserves markets, with the aim of reporting on the state of competition in future reports.

Regulatory

Investigation Procedures and Stakeholder Consultation Process

The MSA is undertaking a consultation to update its Investigation Procedures and Stakeholder Consultation Process. Information related to this process can be found on the MSA's website.

Regulating reserves over the Alberta-BC interconnection

Further to a written request from the AESO in July 2015, the MSA extended forbearance to the AESO regarding ISO rule section 205.4 for the period from August 15, 2015 to December 31, 2015. Both the AESO request and the MSA's response were posted to the MSA website. The purpose of the AESO request was to conduct testing of whether regulating reserves could be provided via the Alberta-BC interconnection. Forbearance was sought on the basis that under the current ISO rule section 205.4, regulating reserves may only be provided by pool assets located in the balancing authority area of the ISO. The basis for forbearance was that the initiative was consistent with promoting a competitive market for regulating reserves. Ultimately the AESO did not to proceed with the testing during or since the noted period and given that the AESO did not request any extension of the prior forbearance, MSA considers this matter to be closed.

Compliance

From January 1 to June 30, 2016, the MSA closed 201 ISO rules compliance files and issued 18 notices of specified penalty. The total financial amount of the notices of specified penalty was $41,750. The MSA noticed that many compliance files pertaining to ISO rule section 203.4 received in 2016 related to unit ramping towards a dispatch level prior to the effective time of an advanced dispatch. We encourage participants to review their procedures regarding advanced dispatches with their staff.

In the same period, the MSA closed 48 Alberta Reliability Standards compliance files and issued 4 notices of specified penalty. The total financial amount of the notices of specified penalty was $15,000. Two of the files remained open at the end of the quarter as the penalty due date for the notices of specified penalty was in Q3 2016. In addition, three of the files closed this year were notices of specified penalty issued in the fourth quarter of 2015 which remained open at the end of 2015 pending mitigation plan completion. The files were closed upon completion of the mitigation plans and the total financial amount of those notices of specified penalty was $18,750.

Figure 10: ISO Rules Compliance

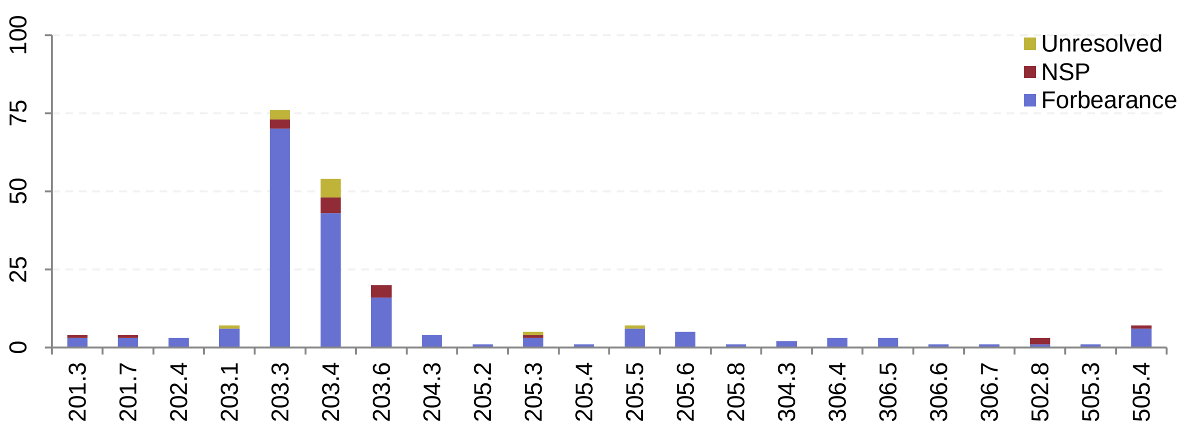
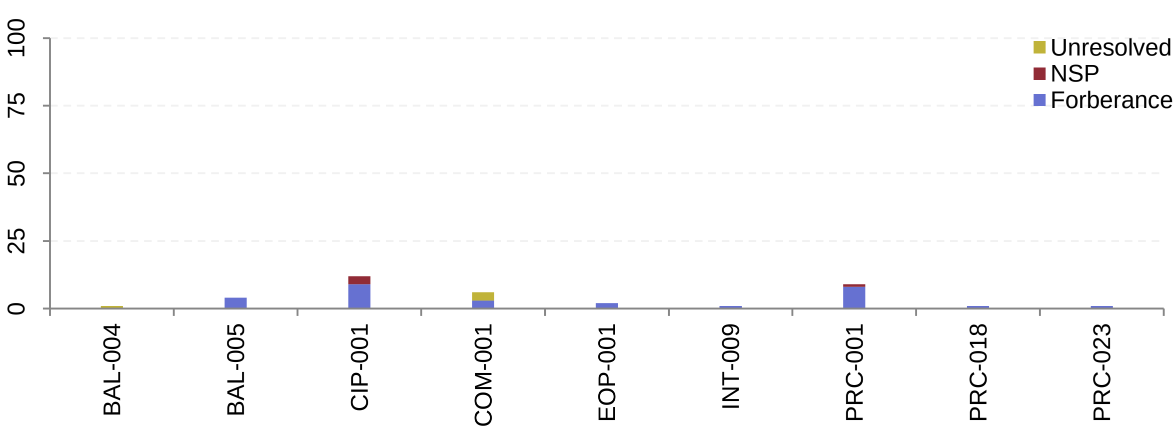


Figure 11: Reliability Standards Compiance



MSA Releases

- Notice re MSA Response and Updated Drafts of Investigation Procedures and Stakeholder Consultation Process (2016-07-15)
- Market Share Offer Control 2016 (2016-07-13)
- Notice re Stakeholder Consultation Process and Investigation Procedures - Stakeholder Comments (2016-07-12)
- Notice re Stakeholder Consultation Process and Investigation Procedures Review (2016-06-27)
- Notice re Publication of Retail Market Statistics - Feedback Requested (2016-06-08)
- MSA 2016 First Quarter Report (2016-04-29)
- MSA Annual Report to the Minister (2016-04-20)
- Notice re MSA Staff Changes (2016-04-13)
- Notice re Revocation of Feedback and Guideline Notices (2016-04-11)