Q3/17 Quarterly Report

July – September 2017

November 3, 2017

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

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Wholesale Market

Summary

Pool price in Q3 2017 averaged $24.57/MWh ($18.22/MWh ext. off peak, $27.75/MWh ext. on peak). This is a 37% increase in pool price compared to the same period last year. While the pool price increased quarter-over-quarter, the quarterly average pool price is still relatively low compared to historical quarterly averages before 2016.

In Q3 2017, total demand increased 4% year-over-year compared to a 1% decline in load year-over-year in Q3 2016. This is lower than the 7% growth in demand seen year-over-year in Q2.

Due to a prolonged period of hot weather throughout the province, Alberta consecutively set new summer peak loads during several hours on July 6, 7, and 27. Alberta's new summer peak load is 10,852 MW set in hour ending (HE) 17 on July 27. The corresponding pool price in the hour was $33.45/MWh. The previous summer peak load was set in HE 17 on July 9, 2015 at 10,520 MW the pool price in the hour was $33.15/MWh.

Table 1: Market Summary

		2016	2017	*Change*
Average Pool Price ($/MWh)	July	18.21	26.96	*48%*
	August	17.9	24.57	*37%*
	September	17.7	22.11	*25%*
	Q3	**17.94**	**24.57**	***37%***
Average Gas Price (AECO-C, $/GJ)	July	2.27	1.57	*-31%*
	August	1.85	1.65	*-11%*
	September	2.52	0.88	*-65%*
	Q3	**2.21**	**1.37**	***-38%***
Total Demand (GWh)	July	6,580	6,972	*6%*
	August	6,678	6,937	*4%*
	September	6,294	6,495	*3%*
	Q3	**19,551**	**20,404**	***4%***
Average Supply Cushion (MW)	July	2,220	2,081	*-6%*
	August	2,185	1,578	*-28%*
	September	2,195	1,729	*-21%*
	Q3	**2,200**	**1,797**	***-18%***
Total Wind (GWh)	July	228	256	*12%*
	August	232	225	*-3%*
	September	364	257	*-29%*
	Q3	**825**	**737**	***-11%***
Net Imports (GWh)	July	-103.6	-69.1	*33%*
	August	-230.3	-156.5	*32%*
	September	-204.4	-144.5	*29%*
	Q3	**-538.3**	**-370.1**	***31%***

Figure 1: Average Quarterly Pool Price

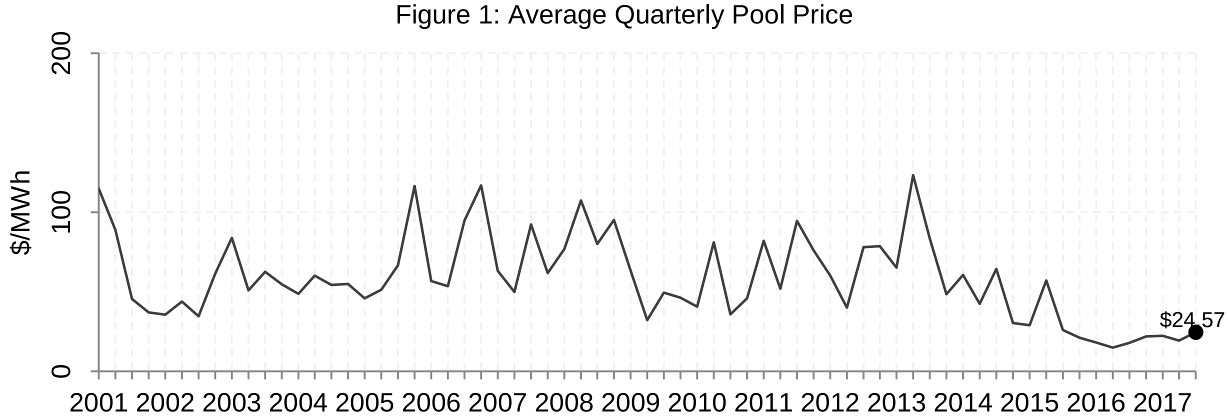


Figure 2: Average Quarterly Alberta Internal Load

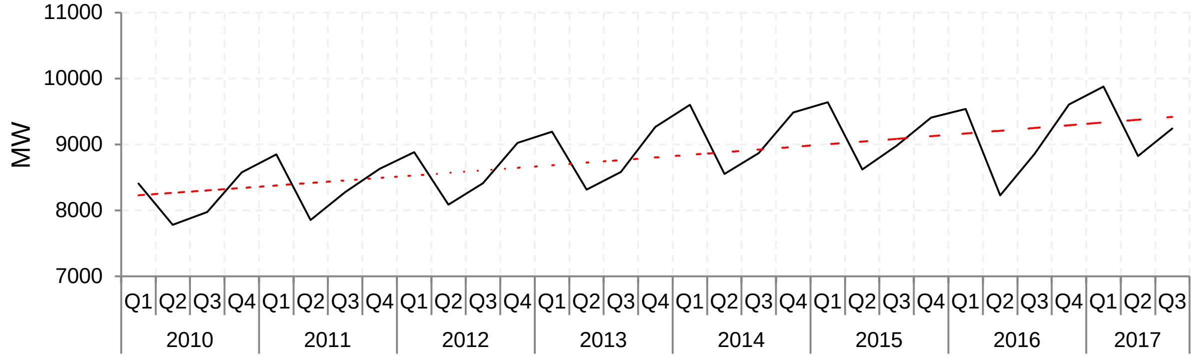
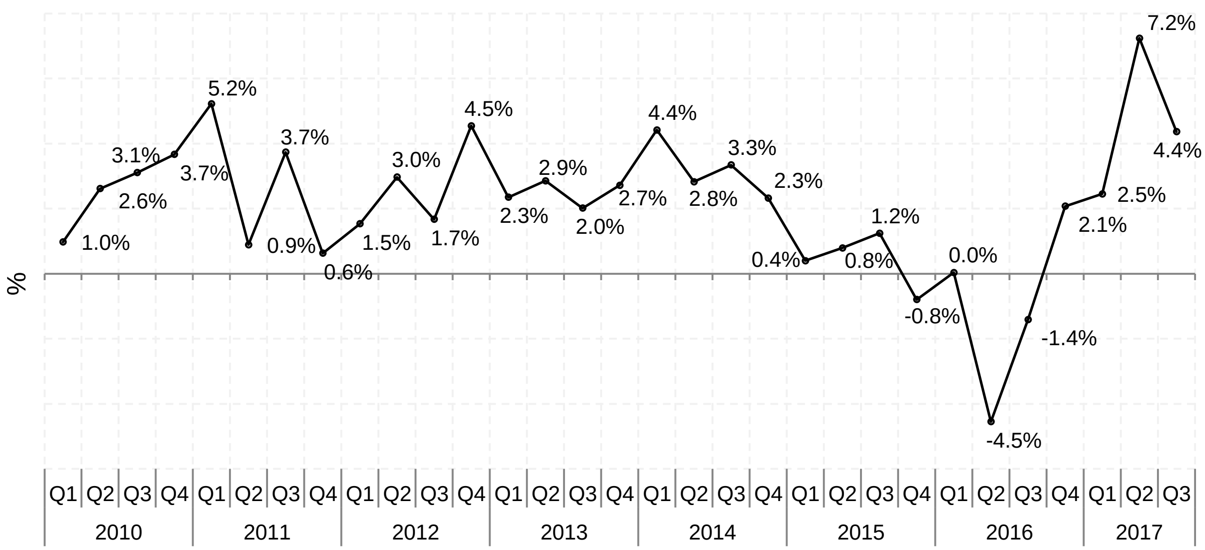


Figure 3: Growth in Total Alberta Internal Load (% Year-over-Year)



Average supply cushion, adjusted for export reductions and import availability, decreased 18% compared to the same time last year. In Q3 2017, the supply cushion fell below 1,000 MW in 4% of the hours. In Q3 2016, the supply cushion remained above 1,000 MW in all hours. Thus, there were more occasions where there was low supply in Q3 2017 compared to Q3 2016. This, along with the increase in demand, contributed to the increase in pool price and led to several pool price spikes during the quarter.

Figure 4: Adjusted Supply Cushion Duration Curves

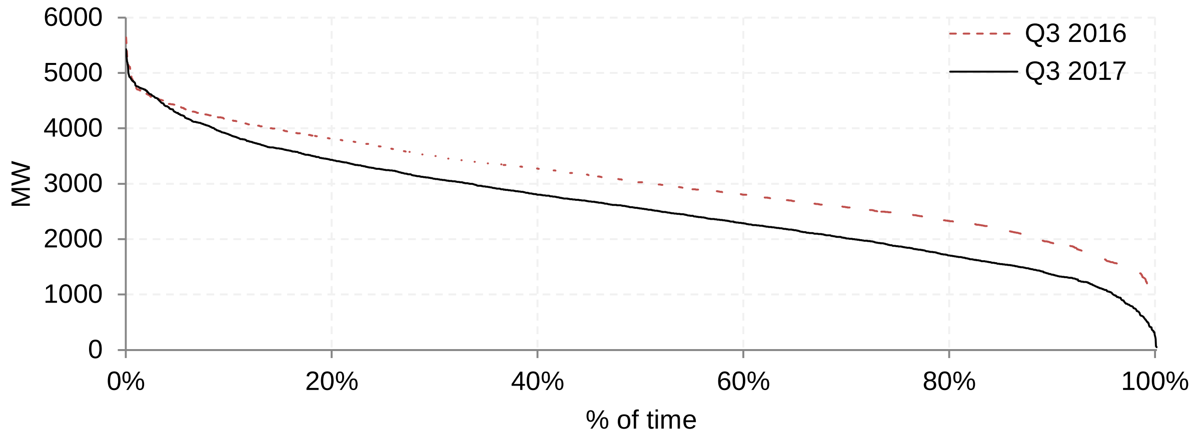
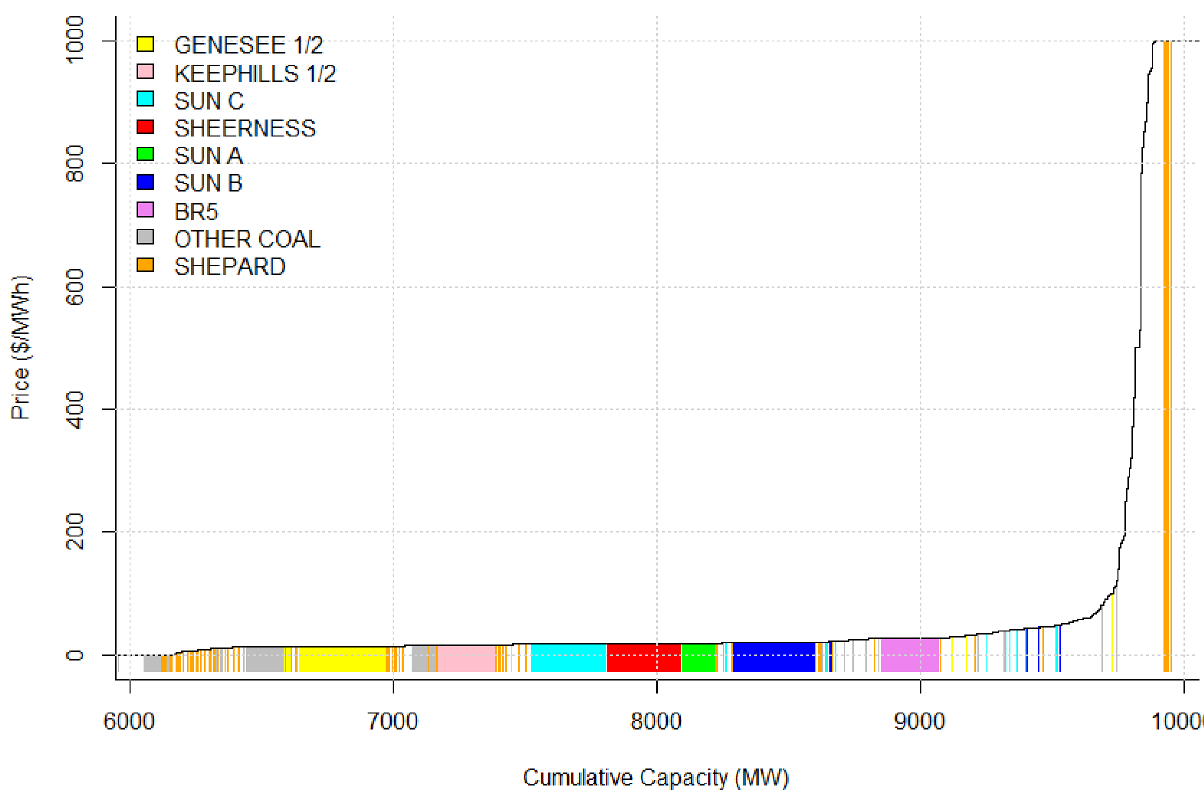


Figure 5: Q3 2017 Aggregate Merit Order



High Priced Hours

In the past, a few high priced hours would result in relatively high average pool prices in a quarter. Since early 2016, pool prices have remained low with relatively few price spikes. In Q3 2017, the hourly pool price settled above $100/MWh in 18 hours over nine days between July 25 and September 26. These 18 hours contributed to an increase in the average quarterly pool price by $6.63/MWh quarter-over-quarter.

Coal supply issues at Keephills and Sundance led to derates at both facilities throughout most of the quarter. These coal derates contributed to the scarcity conditions which led to higher prices in most of the high-priced hours during July and August.

These events are summarized below.

July 25, 2017

On July 25 HE 16, the hourly pool price settled at $340.44/MWh with the system marginal price (SMP) hitting $999.30/MWh for a brief period. While total system load was moderate (approximately 10,200 MW), outages at three coal plants (HRM, SD1, and SD2) and derates at several other facilities caused prices to rise. Total wind generation was 12 MW with the interties exporting around 170 MW during the period. Pool price settled at $49.22/MWh during HE 17, but spiked again to $192.68/MWh in HE 18 with the curtailment of 75 MW of imports from Saskatchewan as a contributing factor.

July 26, 2017

On July 26, pool price spiked to $203.42/MWh during HE16, $999.99/MWh from HE 17 to 19, and $131.41/MWh during HE 20. These high priced hours resulted from outages (HRM, KH2, SD1, SD2, and SD6) and derates at numerous Alberta's coal plants coupled with high loads and low wind generation. Wind generation remained mostly below 100 MW while total provincial imports were greater than 500 MW throughout the course of the event. The AESO armed between 0 MW and 102 MW of LSSi over the five hours to enable the high level of imports. During the first four hours of this event, the contingency reserve requirement increased due to increased imports into Alberta resulting in some standby contingency reserves to be activated to cover the need for additional contingency reserves.

Combined with higher loads due to hot weather, the supply cushion fell to 0 MW during the highest priced hours. At the beginning of HE 17, the AESO declared an Energy Emergency Alert (EEA) 1 followed by an EEA2 in the same hour. This EEA2 remained in effect until the beginning of HE 20.

July 28, 2017

On July 28 HE 17, the hourly pool price settled at $491.67/MWh with the SMP reaching $899.00/MWh for 28 minutes due to six coal plants (GN1, HRM, KH2, SD1, SD2, and SD6) being offline coupled with a high summer load of 10,400 MW due to hot temperatures throughout the province. Total wind generation was less than 100 MW while net system imports were approximately 460 MW during the hour. To allow for more imports into the province, the AESO armed approximately 55 MW of LSSi during the hour.

August 8, 2017

On August 8 HE 16, the hourly pool price settled at $102.87/MWh. The SMP was $307.61/MWh for approximately 15 minutes during the latter part of the hour. Low wind (10 MW) coupled with higher system loads (10,150 MW) and exports (470 MW) resulted in tighter supply which led to higher prices. Aside from HRM, there were no coal outages at the time of the event; however, there were coal derates due to coal supply issues.

August 9, 2017

On August 9 HE 19, the hourly pool price settled at $116.81/MWh. Due to a transmission constraint, the unconstrained SMP hit $860/MWh while the constrained SMP hit $989.65/MWh during the first six minutes of the hour. The high SMP resulted from tighter supply due to moderate system load (10,100 MW) coupled with higher exports (570 MW) and low wind (50 MW). Aside from HRM, there were no coal outages at the time of the event; however, there were coal derates due to coal supply issues. The estimated cost of the transmission constraint totaled $117.96.

August 22, 2017

On August 22, the hourly pool price settled at $337.84/MWh in HE 15 and $302.47/MWh for HE 16. For 26 minutes between HE 15 and HE 16, SMP hit $999.00/MWh with supply cushion falling to 111 MW during HE 16. This event was caused as a result of a trip at SD6 coupled with high demand (10,500 MW), low wind (15 MW), and moderate exports (300 MW) during the period. HRM was on outage during the event.

August 27, 2017

On August 27, the hourly pool price settled at $100.01/MWh in HE 14 and $210.45/MWh in HE 18. SMP hit $999.00/MWh during HE 18 for a brief period. Supply cushion was approximately 100 MW for both hours with coal outages at four coal plants (GN1, HRM, SD1, and SD6) over the period. Wind generation increased over the period, but remained below 250 MW. Net exports were below 250 MW for both hours.

September 25, 2017

On September 25, the hourly pool price settled at $277.01/MWh in HE 12 with SMP hitting $529.00/MWh for 25 minutes. At the time, there were 100 MW of scheduled exports through the Saskatchewan intertie and wind generation was decreasing with an average of 49 MW. In addition to HRM, there were coal outages at KH3 and SD6 during the hour.

In HE 14, the hourly pool price settled at $263.92/MWh with SMP hitting $999.10/MWh for approximately 15 minutes. Average wind generation decreased to 37 MW and there were 50 MW of exports on the Saskatchewan intertie. In addition to HRM, there was an outage at KH3 during the hour. There were outages on the BC and Montana interties in both hours with supply cushion averaging 122 MW.

September 26, 2017

In HE 14, the hourly pool price settled at $630.47/MWh due to SMP hitting $999.99/MWh for the last half of the hour. Due to derates at SH1 and SH2. The supply cushion was 0 MW during the hour which resulted in the AESO declaring an EEA1. This alert persisted until HE 15. There were 76 MW of exports to Saskatchewan and large coal outages at KH2 and KH3.

In HE 15, the hourly pool price settled at $296.57/MWh. Exports to Saskatchewan increased to 147 MW and the amount of derates decreased. In both hours, the BC and Montana interties were on outage.

Imports and Exports

In Q3 2017, 370 GWh of net exports flowed out of Alberta. This is a 31% decrease in net exports compared to Q3 2016 where Alberta's total net exports were 538 GWh. During Q3 2017, Alberta was a net exporter for all hours on average during the quarter. This is a reversal of import/export behaviour seen in Q2 2017 where Alberta was a net importer of power from the interties. In Q2 2017, Alberta imported 836 GWh net of power due to greater than average hydropower generation in British Columbia and the Pacific Northwest. In Q3 2017, higher average hourly prices in Mid-Columbia created an arbitrage advantage to export contributing to higher net exports compared to Q2 2017.

Figure 6: Average Net Imports by Hour Ending

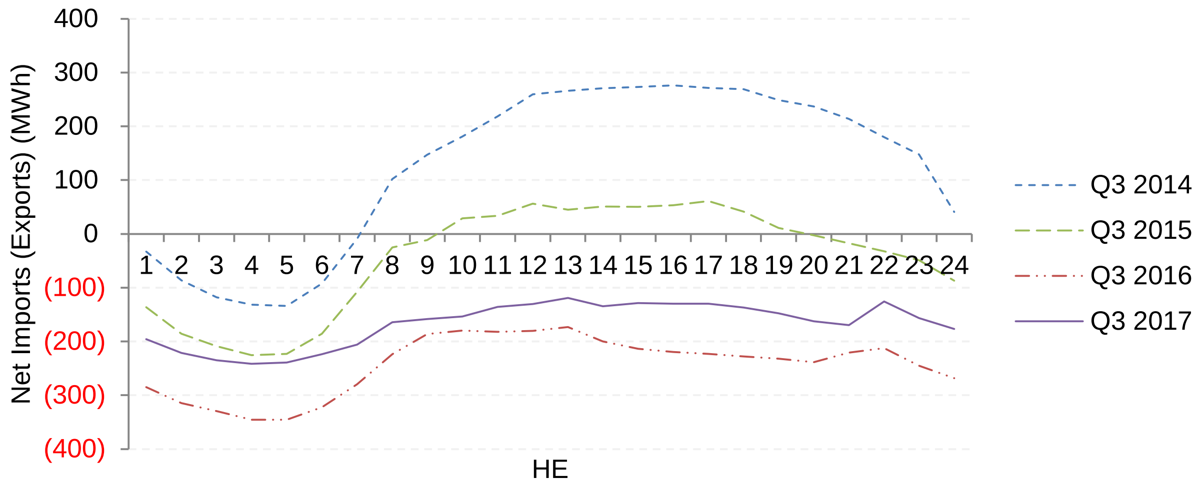


Figure 7: Average Q3 2017 Pool Prices in Alberta and Mid-Columbia by Hour Ending

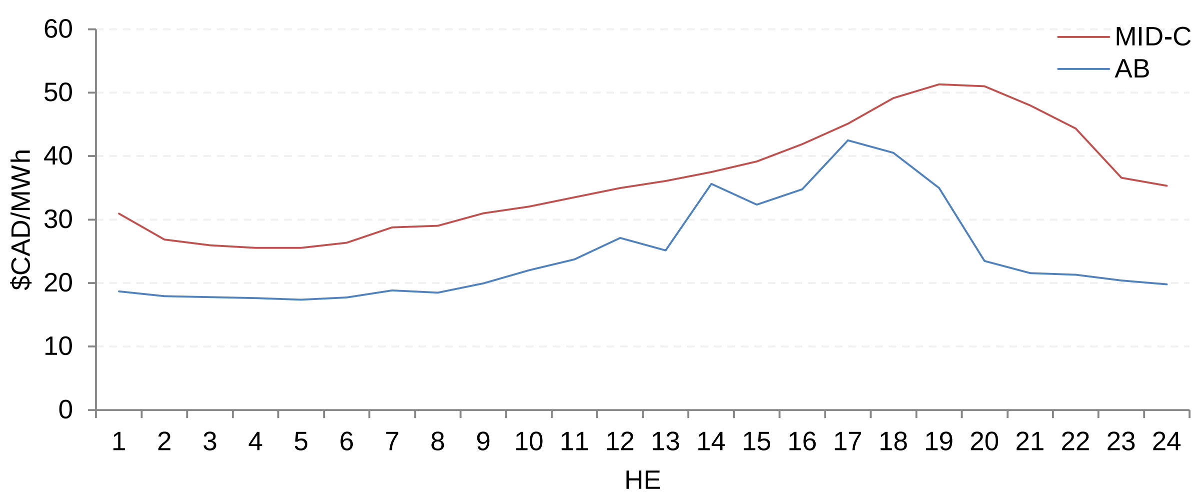
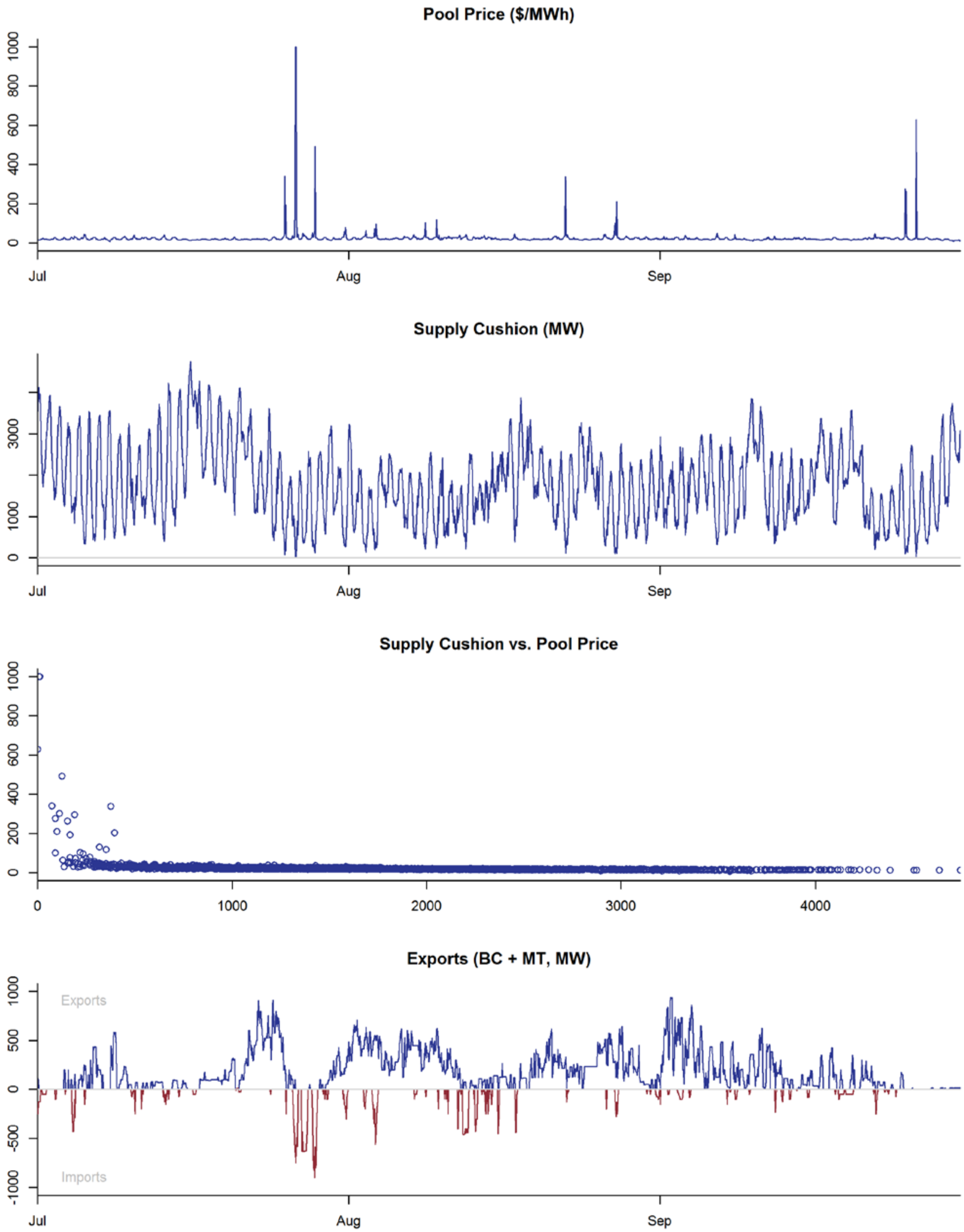


Figure 8: Q3 2017 Summary Graphs



Ancillary Services

Operating Reserve

Total operating reserve costs increased 43% compared to Q3 last year. This is mostly due to increases in the cost of active contingency reserve, the cost of activating standby contingency reserve, and to a lesser degree due to increases in the cost of procuring standby spinning reserve.

Table 2: Operating Reserve Summary

Total Cost ($ Millions)			
	Q3 2016	**Q3 2017**	***Change***
Active Procured	**11.5**	**17.9**	***55%***
RR	7.3	7.0	*-5%*
SR	2.8	7.3	*166%*
SUP	1.4	3.6	*150%*
Standby Procured	**2.5**	**1.9**	***-23%***
RR	1.8	0.7	*-59%*
SR	0.6	1.0	*85%*
SUP	0.2	0.2	*9%*
Standby Activated	**0.4**	**0.9**	***138%***
RR	0.1	0.0	*-96%*
SR	0.2	0.6	*240%*
SUP	0.1	0.2	*291%*
Total	**14.4**	**20.7**	***43%***
Total Volume (GWh)			
	Q3 2016	**Q3 2017**	***Change***
Active Procured	**1,306**	**1,330**	***2%***
RR	348	348	*0%*
SR	479	491	*2%*
SUP	479	491	*2%*
Standby Procured	**519**	**483**	***-7%***
RR	212	176	*-17%*
SR	231	231	*0%*
SUP	77	77	*0%*
Standby Activated	**18**	**25**	***34%***
RR	4	0	*-96%*
SR	10	15	*51%*
SUP	5	9	*106%*
Total	**1,844**	**1,837**	***0%***
Average Cost ($/MWh)			
	Q3 2016	**Q3 2017**	***Change***
Active Procured	**8.82**	**13.43**	***52%***
RR	21.12	20.05	*-5%*
SR	5.74	14.92	*160%*
SUP	2.97	7.24	*144%*
Standby Procured	**4.86**	**4.02**	***-17%***
RR	8.51	4.17	*-51%*
SR	2.43	4.50	*85%*
SUP	2.05	2.24	*9%*
Standby Activated	**20.18**	**35.74**	***77%***
RR	32.27	30.42	*-6%*
SR	18.55	41.71	*125%*
SUP	13.74	26.07	*90%*
Total	**7.82**	**11.26**	***44%***

The AESO procured an additional 12 GWh of active spinning reserve and an additional 12 GWh of active supplemental reserve in Q3 2017 compared to the same quarter last year. This is primarily due to a change in the amount of on-peak contingency reserve procured with an average increase of 7 MW of spinning reserve and 7 MW of supplemental reserve procured per day. The increase in procurement volumes along with higher pool prices in Q3 2017 resulted in higher costs to procuring active contingency reserve over the quarter.

The cost of procuring standby spinning reserve and activating standby contingency reserve also increased. The increase in the cost of procuring standby spinning reserve was likely due to an increase in offered premium prices for standby spinning reserve as the volume procured for the product remained unchanged quarter-over-quarter.

There was an increase in the amount of standby contingency reserve activated in Q3 2017 compared to the same quarter last year leading to higher total costs for the products. This is a continuation of a trend seen over the past year of higher standby contingency reserve activations compared to the previous year. In 24 hours from July 26 to 28, standby contingency reserves were activated to enable imports. High demand exceeding 9,750 MW was characteristic of those hours where imports were higher and import enablement through standby activations occurred.

Load Shed Service for Import (LSSi)

LSSi is an ancillary service procured by the AESO to facilitate imports into Alberta as contemplated under section 16 of the *Transmission Regulation*. LSSi allows the AESO to increase the available transfer capability of the BC and Montana interties by contracting with loads to trip power consumption in the event that system frequency decreases due to the intertie tripping offline at the increased capability.

LSSi is procured through contracts. The current contracts are expiring in June 2018. The current contract structure involves: an availability payment, an arming payment, and trip payments. LSSi providers may also receive a minimum arming guarantee payment of 50 hours multiplied by the arming price. The availability payment is made to LSSi providers for the amount of LSSi that is offered to be armed. This payment is set at $5/MWh. The arming payment is made when the AESO arms an LSSi provider to potentially trip if frequency drops. The arming payment differs depending on the LSSi provider. The trip payment is set at $1,000/MWh and is paid to the LSSi provider in the event that they are tripped to arrest the drop in frequency.

Table 3: Annual LSSi Costs ($000's)

	Availability Payment	Arming Payment	Trip Payment	Minimum Arming Guarantee Payment	Total
2012	7,716	14,150	119	1,975	23,960
2013	8,626	9,192	170	3,021	21,009
2014	9,969	11,538	0	2,956	24,464
2015	9,336	1,235	122	6,812	17,505
2016	10,294	0	0	8,000	18,294
2017 YTD	7,842	6,224	0	4,211	18,277

The total year-to-date cost of LSSi for 2017 is approximately $18 million. This is equivalent to the total cost of LSSi in 2016. However, the cost of LSSi in 2017 is expected to increase through the remainder of the year. Unlike in 2016, LSSi was armed to enable imports in 2017, resulting in total arming payments of approximately $6 million year-to-date. In total, 5,254 MWh of LSSi was armed year-to-date with 1,263 MWh of LSSi armed in Q3 2017. The LSSi was armed in Q3 during days with supply scarcity and high load conditions between July 26 and 28.

Despite not arming LSSi in 2016, the total cost of the service last year was higher than the total cost in 2015 and roughly equivalent to the total cost of LSSi in the first nine months of 2017. The cost of LSSi in 2016 was made up of availability and minimum arming guarantee payments. The costs associates with these payments were highest in 2016 compared to all other years from 2012 to 2017 year-to-date even though the AESO was not using the service during the year.

The MSA made a recommendation in the Q4 2016 report suggesting the AESO should examine the three-part pricing structure of the LSSi contracts prior to the expiry of the existing contracts. Based on the total cost of LSSi over the last five years, the MSA remains of the view that changing the current payment structure to one where LSSi payments would only go towards actual services provided would be beneficial.

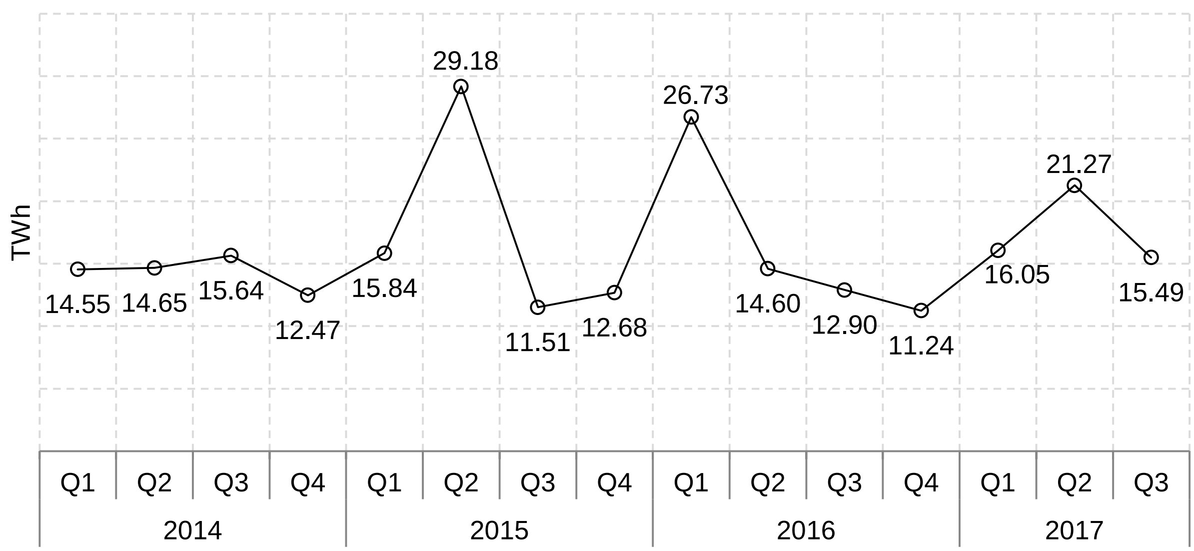
Forward Market

Forward market liquidity in Q3 2017 was down 28% compared to Q2, but was 20% higher than liquidity in Q3 2016. The decrease in trade volumes compared to Q2 was primarily due to a decrease in the volume of annual contracts traded.

Table 4: Trade Volumes by Contract Term (TWh)

		Daily	Monthly	Quarterly	Annual	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	0.58	4.50	1.08	14.60
	Q3	0.07	6.80	1.23	4.56	0.25	12.90
	Q4	0.09	5.44	1.46	3.78	0.47	11.24
	Year	0.57	29.85	5.05	25.20	4.81	65.47
2017	**Q1**	0.06	6.53	3.03	4.57	1.86	16.05
	Q2	0.13	6.87	2.31	11.13	0.84	21.27
	Q3	0.18	6.61	2.13	5.42	1.15	15.49
	YTD	0.37	20.00	7.47	21.12	3.85	52.81

Figure 9: Total Trade Volumes over Time



Effect of PPA Termination Announcements on the Forward Market

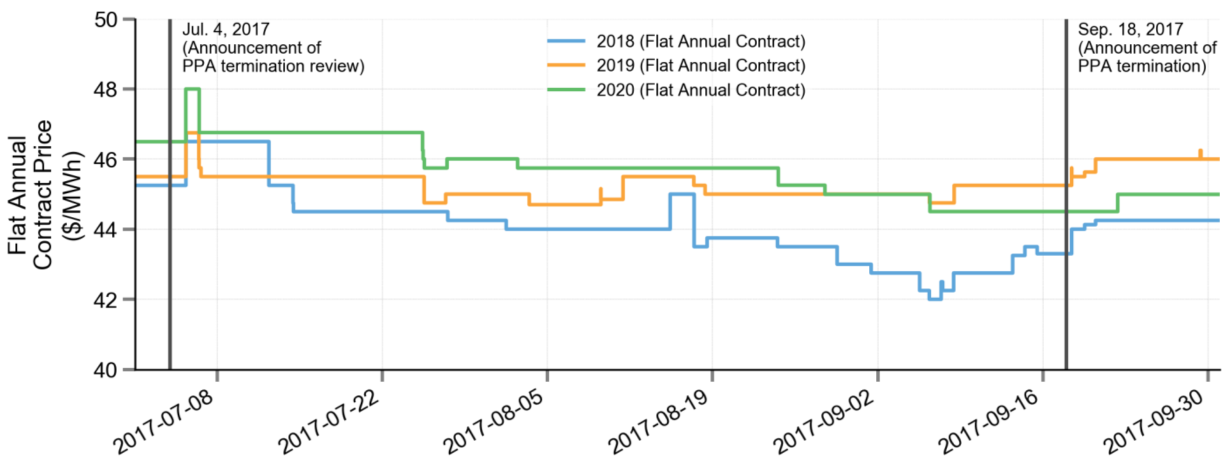
On July 4, 2017 the Balancing Pool initiated a consultation process with representatives of consumers regarding the reasonableness of terminating the Sundance A, Sundance B, and Sundance C Power Purchase Arrangements (PPAs). The Sundance A PPA is set to expire on December 31, 2017. However, it was included in the consultation process should the Balancing Pool terminate all of the Sundance PPAs prior to the end of 2017.[1]

On April 19, 2017, TransAlta Corporation announced the retirement of Sundance 1 and the mothballing of Sundance 2, the two generating units making up the Sundance A PPA, effective January 1, 2018.[2] At the same time, TransAlta Corporation also announced their intent to convert the units comprising Sundance B and C from coal to gas fired generators between 2021 and 2023. The effect on the forward market from this announcement was discussed in the MSA's Q2 2017 Quarterly Report.[3]

On September 18, 2017, the Balancing Pool announced that it provided notice to TransAlta Generation Partnership that the Sundance B and C Power Purchase Arrangements (PPAs) would be terminated no later than March 31, 2018. The combined capacity of the respective PPAs is 1,416 MW.

In the days following both announcements, the MSA observed slight overall increases in forward market prices for 2018-2020 flat annual contacts.

Figure 10: Evolution of Flat Annual Forward Price Curve

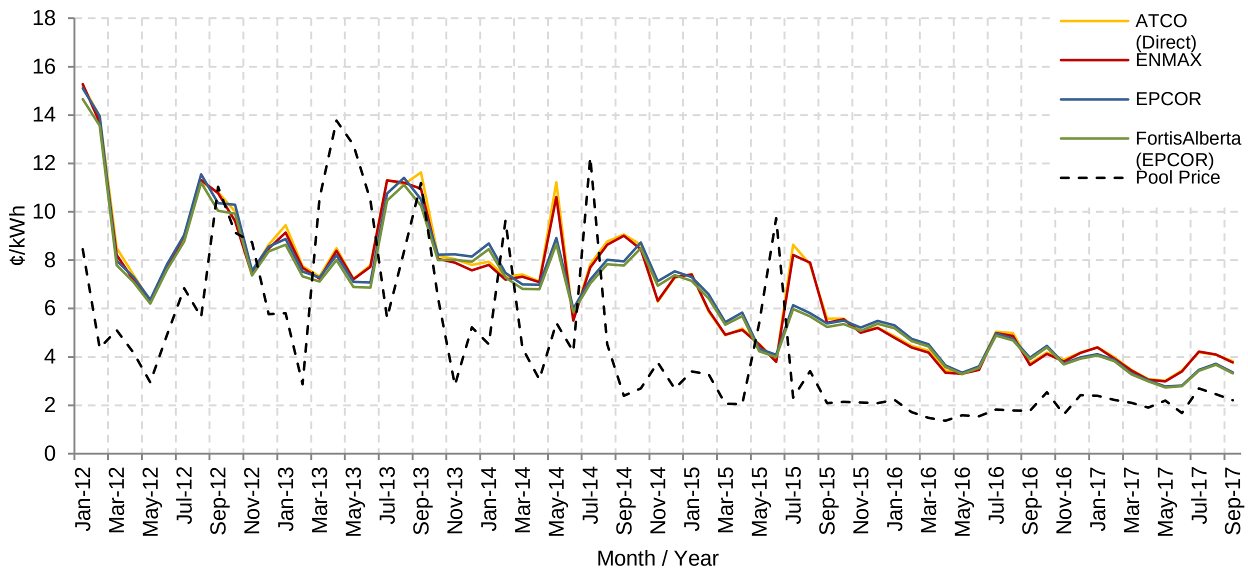


1 Balancing Pool, PPA Termination Customer Information Package, July 4, 2017, pages 10 - 11
2 TransAlta Board Approves Plan for Accelerating Transition to Clean Power in Alberta, April 19, 2017
3 Q2/2017 Quarterly Report, page 17

Retail Market

Regulated Rate Option (RRO) Rates decreased over the course of the quarter slightly compared to the general trend observed earlier in 2017. Rates in the ATCO (Direct) and ENMAX areas were slightly higher than those in the EPCOR and FortisAlberta areas. Over the past two years, pool prices in the wholesale market have been low. Over this period, RRO prices have gradually decreased and are now more consistent with the prices in the underlying wholesale electricity market.

Figure 11: Residential RRO Rates and Monthly Average Pool Price



Rate Cap Regulation for Board or Council Approved Regulated Rate Tariffs

The *An Act to Cap Regulated Electricity Rates* provides price protection to RRO customers. The associated *Rate Cap (Board or Counsel Approved Regulated Rate Tariffs) Regulation* (Regulation) provides a role for the MSA in approving claims for relief by certain RRO providers. These are the entities whose RRO rates are approved either by city/municipal counsel or, in the case of REAs, by their Board of Directors. The MSA issued a notice proposing an approval process for Deferral Account Statements (DAS) on August 16, 2017 and issued a notice with stakeholder comments and the final adopted process on October 3, 2017.

The time lines for submission of claims to the MSA and then subsequently passing on approved claims to the Minister of Energy for payment are specified in the Regulation. The time lines are tight in the case where a claim is made for a new month. In such cases, the new RRO rates have just been established and RRO consumption volumes must be based on forecasts. However, claimants do have the option to wait until final load settlement takes place before submitting the necessary paperwork to the MSA.

The final process adopted by the MSA for the approval of the DAS is:

1. Within five business days of the start of the month the Owner must provide the MSA, by email to deferralsubmission@albertamsa.ca, with:
    a. the actual consumption in kWh of regulated rate customers in each rate class determined through the final load settlement calculations for the most recent six months for which that information is available [Regulation s.5(2)(a)]. This information should be provided in an excel file with row headings of Date (month-year), Rate Class, and Consumption (kWh); and
    b. a completed DAS for the applicable calendar months, in the form prescribed by the Minister, for the MSA's approval [Regulation s.5(2(b)]. The Owner must provide the MSA with the DAS by email in the electronic fillable form provided by the Minister and updated by the MSA to include pre-set formulas for the calculation of applicable rates. The MSA will not accept a DAS in any other form or by any other method.
2. On receipt of the above information, the MSA will confirm the calculation of the amounts in the DAS.
    a. If the MSA determines an error has been made in the calculation of the amounts, it will require the Owner to provide a corrected DAS [Regulation s.6(4)(a)].
    b. If the Owner determines there is a material error in a previously submitted DAS or there has been a material change in information set out in a DAS, it shall submit a corrected DAS for the MSA's approval [Regulation s.6(4)(b)].
3. If the MSA confirms that the calculations are correct, it will approve the DAS by signing the DAS and posting the DAS publically on its website within ten business days of the start of the month [Regulation s.6(5)].
4. If the information outlined in section 1 of the process is not provided within five business days of the start of the month, the MSA will not approve a DAS for that month.
    a. The Owner may submit a DAS that includes the missed month's information in a following month if the deferral account information was based on final load settlement calculations, as outlined in s. 5(4)(b) of the Regulation.
    b. If the deferral account information was based on forecast consumption, as outlined in 5(4)(a) of the Regulation, the Owner may submit the missed month once the final load settlement data is available.

No action is required under this process until the reference price exceeds 6.8 cents/kWh. The MSA, however, will work with Owners to test the process later in 2017 and will be contacting affected Owners shortly to outline the testing process.

Compliance

Through enforcement of ISO rules and Alberta Reliability Standards the MSA contributes to the reliability and competitiveness of the Alberta electric system and promotes a culture of compliance and accountability among market participants.

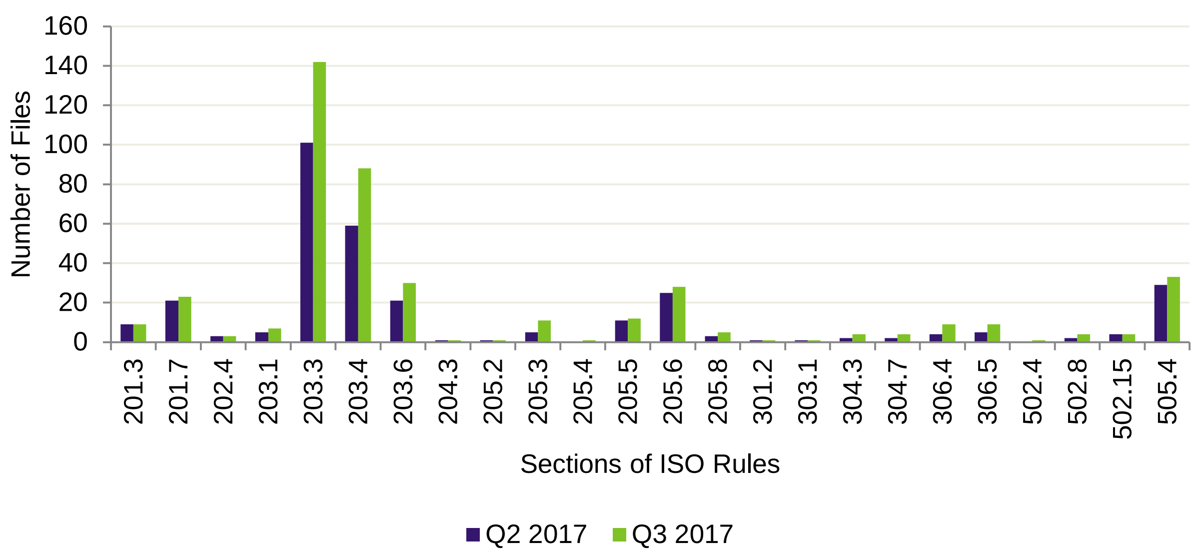
ISO Rules

The purpose of ISO rules is to promote orderly and predictable actions on the part of market participants and to support the role of the AESO in coordinating those actions. In Q3 2017, the MSA opened 116 new ISO rules compliance matters. Between January 1 and September 30, 2017, 401 files were addressed compared to the 308 files addressed in the first two quarters of 2017.[4] The difference between the two aforementioned reporting periods represents the number of files that were addressed in Q3 2017. Correspondingly, 93 files were addressed in Q3 2017 while 30 files were carried over to Q4 2017.

Of the 401 addressed matters year-to-date, 57 resulted in notices of specified penalty (NSP) totalling $85,250 in financial penalties (an increase of $26,250 since the last quarterly report). In Q3 2017, penalties ranged in value from $250 to $5,000.

Figure 12 shows the cumulative number of files dealt with in Q2 2017 and Q3 2017 and includes addressed and unresolved files (or files that were received and/or resolved in 2017). Figure 13 provides more detail on the outcomes of each file dealt with between January 1 and September 30, 2017.

Figure 12: ISO Rules Self-report and Referral Files Dealt with between January 1, 2017 and the end of Q2 2017 and Q3 2017

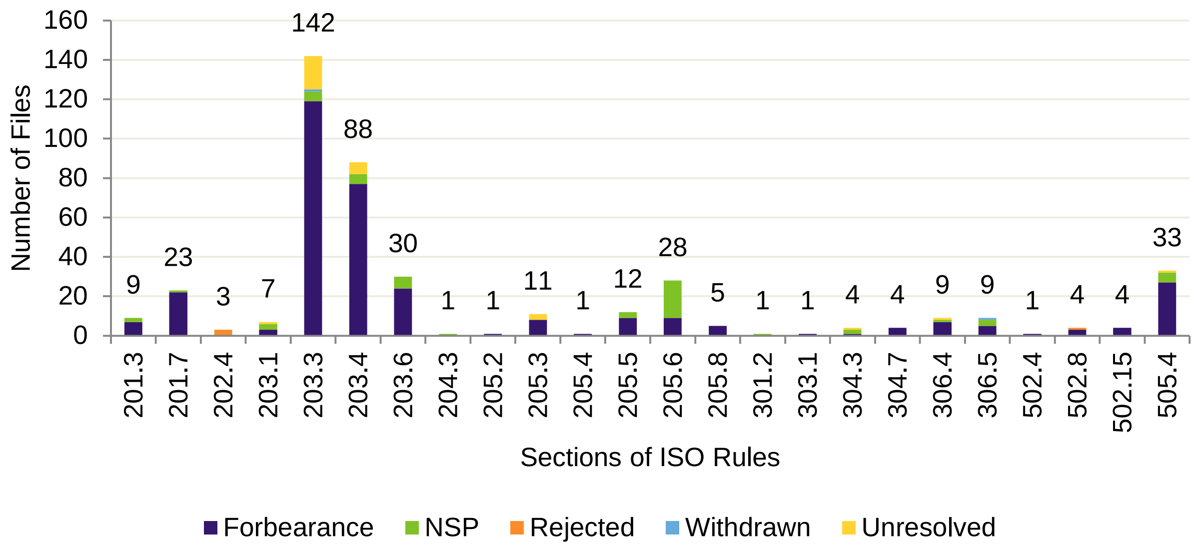


[4] Addressed means that a forbearance letter or notice of specified penalty (NSP) was issued; or files were rejected or withdrawn.

The sections of ISO rules listed in Figure 12 and Figure 13 fall into the following categories:

201	General
202	Dispatching the Markets
203	Energy Market
204	Dispatch Down Service Market
205	Ancillary Services Market
301	General (ISO Directives)
303	Interties
304	Routine Operations
306	Outages and Disturbances
502	Technical Requirements
505	Legal Owners of Generating Facilities (Testing)

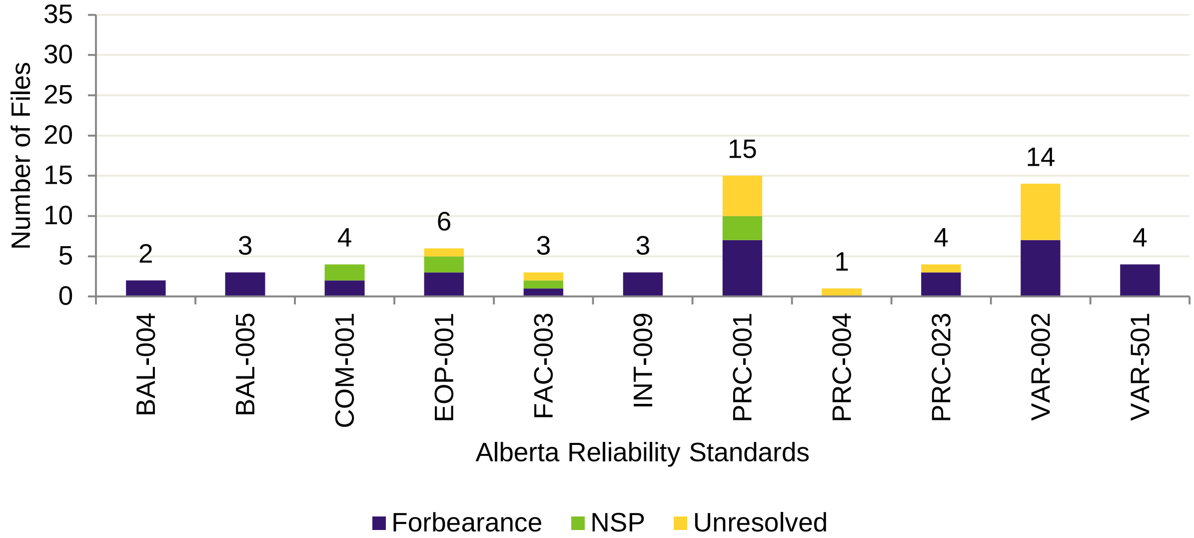
Figure 13: ISO Rules Self-report and Referral Files Dealt with in 2017 (period ending September 30, 2017)



Alberta Reliability Standards

The purpose of Alberta Reliability Standards is to ensure the various entities involved in grid operations (generators, transmission operators, and the AESO) are doing their part by way of procedures, communication, coordination, training, and maintenance, among other practices, to support the reliability of the interconnected electric system. For Alberta Reliability Standards, the MSA opened 18 new files in Q3 2017. The MSA has addressed 43 matters since the start of 2017, while 16 remained unresolved at the end of Q3 2017. Five of the matters closed during this quarter were addressed with a notice of specified penalty, totalling $28,500 in financial penalties (compared to the $7,500 reported in the Q2 2017 report). In Q3 2017, penalties ranged in value from $2,250 to $18,750.

Figure 14: Alberta Reliability Standards Self-report and Referral Files Dealt with in 2017 (period ending September 30, 2017)



The Alberta Reliability Standards listed in Figure 14 fall into the following categories:

BAL	Resource and Demand Balancing
COM	Communications
EOP	Emergency Preparedness and Operations
FAC	Facilities Design, Connections and Maintenance
INT	Interchange Scheduling and Coordination
PRC	Protection and Control
VAR	Voltage and Reactive

Other Activities

Mitigation in Electricity Markets Report

On August 30, 2017 the MSA released a report it prepared titled *Mitigation in Electricity Markets*.

Electricity markets typically feature rules that mitigate market prices so as to ensure competitive market outcomes. The methods for doing so vary across electricity markets and feature quite prominently in most jurisdictions with capacity markets. The MSA undertook some work to understand the different mitigation methods used in a number of US markets and has shared that work with stakeholders. The report does not make recommendations about which methods are most appropriate for Alberta. Instead it stresses the importance of understanding why mitigation is required; what needs to be mitigated; and if mitigation is required, how and when that mitigation is applied.

Code of Conduct Investigation Report

The MSA received a complaint regarding the conduct of a distribution service provider (DSP) that is a Rural Electrification Association (REA) associated with the transfer of an REA member's distribution service to another DSP that operates in the same service area. The complaint related specifically to the REA's refusal to transfer the member's distribution service to the new DSP until termination costs associated with the customer's fixed rate contract for retail electricity services (Fixed Rate Contract) with the REA had been paid.

The REA is subject to the *Code of Conduct Regulation* (Code). One of the main purposes of the Code is to prevent any undue competitive advantage being accrued by affiliated retailers of the DSP. The REA, by choice, offered its members a Fixed Rate Contract in addition to the Regulated Rate Option (RRO) that it is required to provide.

Following careful analysis, the MSA came to the view that denying the transfer of distribution service until termination costs associated with the fixed price contract were paid amounted to the provision of an unfair competitive advantage. The REA has ceased this practice going forward. On September 6, 2017, the MSA communicated to stakeholders that it had concluded an investigation into the conduct. For more information please follow the link to the MSA website.

The MSA considered a similar issue in 2016, where an RRO provider attempted to recover the (purchased) bad debt that had been incurred by the RRO provider's affiliated retailer. In that case the MSA advised the RRO provider of its concern and the practice of the RRO provider collecting the affiliate's debt ceased.[5]

[5] Q1/2016 Quarterly Report, pages 11-12.

Recommendations

Over the years the MSA has made many recommendations in its quarterly reports, mostly focused on the wholesale electricity market. The table below is a summary of recommendations made or referenced in 2015, 2016, and 2017 quarterly reports. The table also tracks developments since the recommendation was made and the conclusion of the issue. New changes to the recommendation are bolded. When the recommendation has been concluded it will be removed from the table after the year-end report.

Table 5: Current Status of MSA Recommendations

First Report	Subject	Recommendation	Developments Since First Recommendation	Conclusion
2013 Q2	Natural Gas Generation Outage Reporting by the AESO	Public outage information used for generator outage coordination or forming future price views is inaccurate until close to real time. The MSA recommends disaggregating natural gas outages by simple cycle, combined cycle, and cogeneration in the outage reports. [Q1 2017]	The initial analysis was revisited in Q4/15, and subsequent discussions with the AESO informed the analysis and recommendation presented in the 2017 Q1 report.	Unresolved
2015 Q2	Import Enablement via Additional Operating Reserves	In real time AESO will activate standby contingency reserves if required and if available. However, on many occasions the standby reserves are generators that are already running and providing energy to the system. As they are activated from standby they withdraw from the energy market. Paying to withdraw from the energy market to enable imports also requiring payment does not seem like an efficient outcome. Therefore, given the current structure of Alberta's operating reserves market, the MSA does not recommend the use of active operating reserve (or standby activations) as a mechanism of enabling imports.	A further example outlining the MSA's concern over this practice was described in the 2017 Q1 report.	Unresolved

First Report	Subject	Recommendation	Developments Since First Recommendation	Conclusion
2015 Q2	Activation Prices of Standby Reserves	A pay as bid activation price for standby reserve appears to be inefficient, particularly in periods of price volatility. The MSA recommends setting the activation price for standby at that of the active reserves and standby sellers then compete based on the premium they require.	No developments since first recommendation.	Unresolved
2016 Q2	Standby Regulating Reserve Volumes	The AESO rarely used all of the standby regulating reserves procured. The MSA recommended reducing the buy volume of standby regulating reserve as it appeared reductions in procurement would not increase conscription rates. [2016 Q2]	The AESO reduced the buy volume by 20 MWs in September 14, 2016. The MSA estimates the reduction in procurement costs is approximately $1m from September 14, 2016 to the end of Q1 2017. This in turn reduces the amount that needs to be charged to consumers through Rate DTS of the ISO tariff.	Resolved
2016 Q4	LSSi contract structure	In 2016 $10 million was spent on availability payments for LSSi, but there were no armings. With the aim to change the payments structure such that LSSi payments were for actual services provided, the MSA recommends the AESO re-examine the three part pricing structure of LSSi contracts prior to the expiry in 2018.	**As of Q3 2017, $18 million was spent on LSSi year-to-date. The MSA reiterated their recommendation in the Q4 2016 report for the AESO to re-examine the three part pricing structure of the LSSi contracts prior to their expiry in June 2018. [Q3 2017]**	Unresolved

First Report	Subject	Recommendation	Developments Since First Recommendation	Conclusion
2017 Q1	Micro Gen Regulation	To avoid uncertainty of how the Micro-Generation Regulation is interpreted, the MSA believes that there exists an opportunity to clarify what “name plate” capacity means in relation to AC/DC ratings of solar generators. The MSA recommends the Alberta Utilities Commission create such clarity by incorporating the appropriate AC/DC language into either Rule 24 or the Micro-Generator Application Process & Guidelines.	Complete. AUC has issued a new Rule 24 which became effective July 4, 2017. In Form A of Rule 024, there is a requirement to state nameplate capacity in terms of AC capability.	Resolved
2017 Q2	Entering outages in ETS past expiry of agency agreement	The MSA believes that the AESO’s systems should accommodate the entry of outage information by either the principal, or where applicable an agent, even if the outage information extends beyond the term of the agency arrangement.	No developments since first recommendation.	Unresolved