Quarterly Report for Q4 2021

February 11, 2022

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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THE QUARTER AT A GLANCE

- The average pool price in Q4 2021 was $107.31/MWh, bringing the average pool price for 2021 to $101.93/MWh. This is the highest annual pool price since 2008, adjusting for inflation, and a 118% increase compared to 2020. The higher pool prices in 2021 were largely the result of increased demand, more thermal generation outages, higher natural gas prices, a higher carbon price, and increased offer prices on some thermal assets.

- The average pool price in Q4 2021 was 7% higher than Q3 2021 and a 133% increase compared to Q4 2020. Higher natural gas prices were an important driver of this, particularly in October when same-day natural gas prices averaged $4.98/GJ, the highest since March 2014. In December, increased demand was a strong driver of higher pool prices as colder weather meant that demand was 4.2% higher this year. Increased thermal outages were another factor in the higher pool prices year-over-year; in November an average of 3,080 MW of thermal capacity was on outage, a 44% increase relative to November 2020.

- The conversion of coal assets to run on natural gas continued in Q4 2021. In October, the Keephills 3 asset was offline for a planned outage to convert from coal to gas-fired steam. In November, the Battle River 4 asset was fully converted to natural gas; this asset was previously able to use gas for up to 50% of its generation. In total 2,800 MW of coal capacity has been converted to natural gas so far, and by the end of 2023 Alberta's power generation is scheduled to be fully off coal.

- In the forward market, total trade volumes in 2021 were 34% higher than in 2020 but 12% below volumes in 2019. In September and October forward power prices increased materially along with natural gas futures. However, when natural gas prices declined in November, forward power prices increased slightly on the back of elevated pool prices in the energy market. The market heat rate for CAL22 increased by 27% over the quarter to close at 29 GJ/MWh on December 31. Forward prices for the January and February 2022 monthly contracts were elevated, putting upward pressure on RRO prices.

- Regulated retail energy rates and competitive variable rates increased in 2021, significantly impacting retail energy bills. Prices of competitive fixed rate offerings increased throughout the year in line with increases in near-and-long term forward prices. Short-term incentives for retail electricity customers to switch to competitive fixed rates persisted throughout 2021 despite rate increases, while the short-term switching benefit of fixed natural gas rates declined as fixed rates increased throughout the year.

- From October 1 to December 31, 2021, the MSA closed 125 ISO rules compliance matters; 17 matters were addressed with notices of specified penalty. For the same period, the MSA closed 17 Alberta Reliability Standards Operations and Planning compliance matters; four matters were addressed with notices of specified penalty. In addition, the MSA closed 80 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; 29 matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Annual summary

The average pool price in 2021 was $101.93/MWh, which represents an increase of 118% relative to 2020. This is the highest average pool price since 2008, adjusting for inflation.

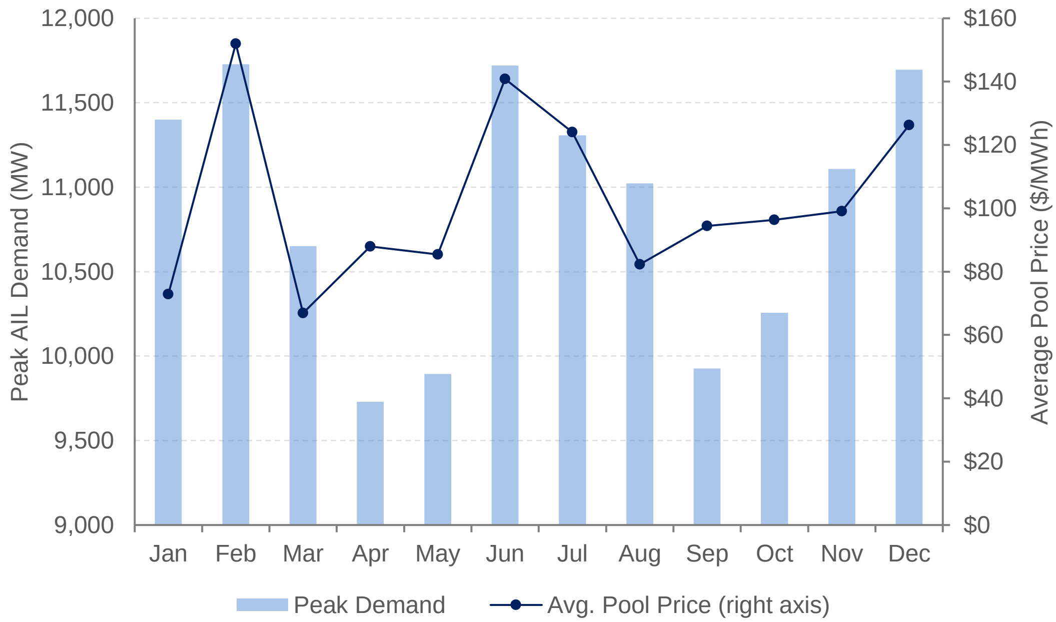
Pool prices in 2021 were driven higher as a result of increased demand, more thermal generation outages, higher natural gas prices, a higher carbon price, and increased offer prices on some thermal assets.

Average demand in 2021 was 9,728 MW, which is 2.8% higher than in 2020 but is slightly lower than the average observed in 2018 (Table 1). Demand increased relative to 2020 as a result of increased economic activity, higher oil production, and because of weather conditions in February, June, July, and December. These four months had the highest average pool prices in 2021, in part due to the extreme temperatures which increased demand (Figure 1).

Table 1: Annual market summary statistics

	2018	2019	2020	**2021**
Pool Price (Avg $/MWh)	$50.35	$54.88	$46.72	**$101.93**
Demand (AIL) (Avg MW)	9,741	9,695	9,462	**9,728**
Gas Price (2A) (Avg $/GJ)	$1.44	$1.68	$2.11	**$3.39**
Wind (Avg MW)	469	470	690	**700**
Net Imports (Avg MW)	304	174	440	**459**
Supply Cushion (Avg MW)	1,785	1,604	1,933	**1,742**

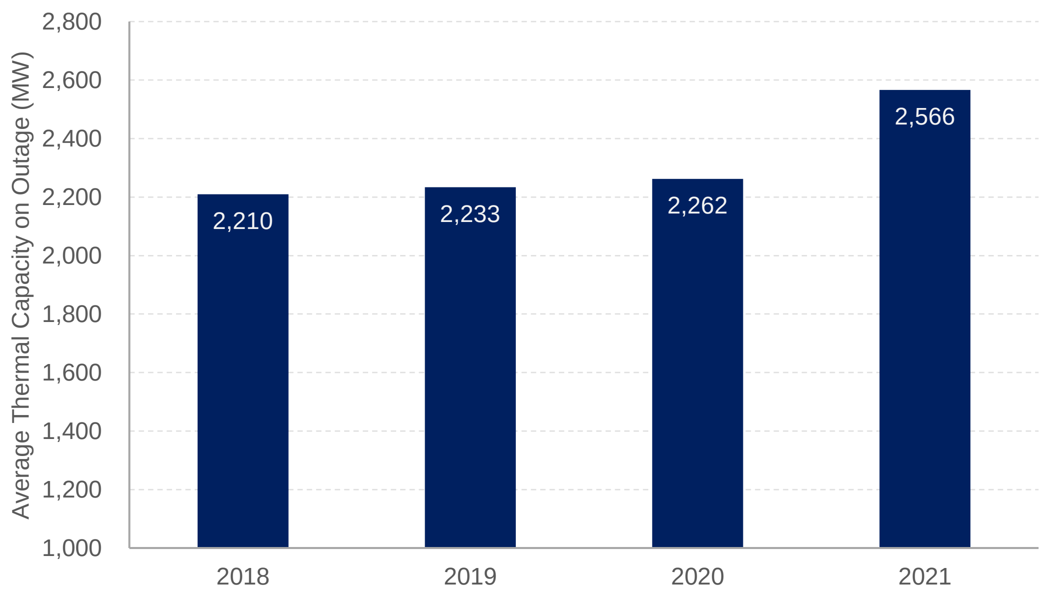
Figure 1: Peak demand and average pool price by month (January to December 2021)



Cold weather in February contributed to an hourly peak demand of 11,729 MW, a new record at the time. Towards the end of June, exceptionally high temperatures increased cooling load and a new summer demand peak of 11,721 MW was set, which is 5% higher than the previous summer record. As discussed in this report, temperatures fell significantly in the latter half of December and were an important factor in the higher pool prices observed in that month. The cold weather persisted into January 2022 when a new peak demand of 11,939 MW was set on January 3.

Thermal generator outages were higher in 2021 relative to recent years which also put upward pressure on pool prices by reducing available supply. On average, there were 2,566 MW of thermal capacity on outage or derated in 2021, which is a 304 MW increase relative to 2020 (Figure 2). This higher average was driven in part by certain major outages in 2021. For example, beginning in early April the Shepard combined-cycle asset (868 MW) was offline for around six weeks on a planned outage. In mid-July the Genesee 2 asset (400 MW) tripped offline on a forced outage and was unavailable until early December.

Figure 2: The average quantity of thermal generation capacity on outage or derated by year (2018 to 2021)[1]



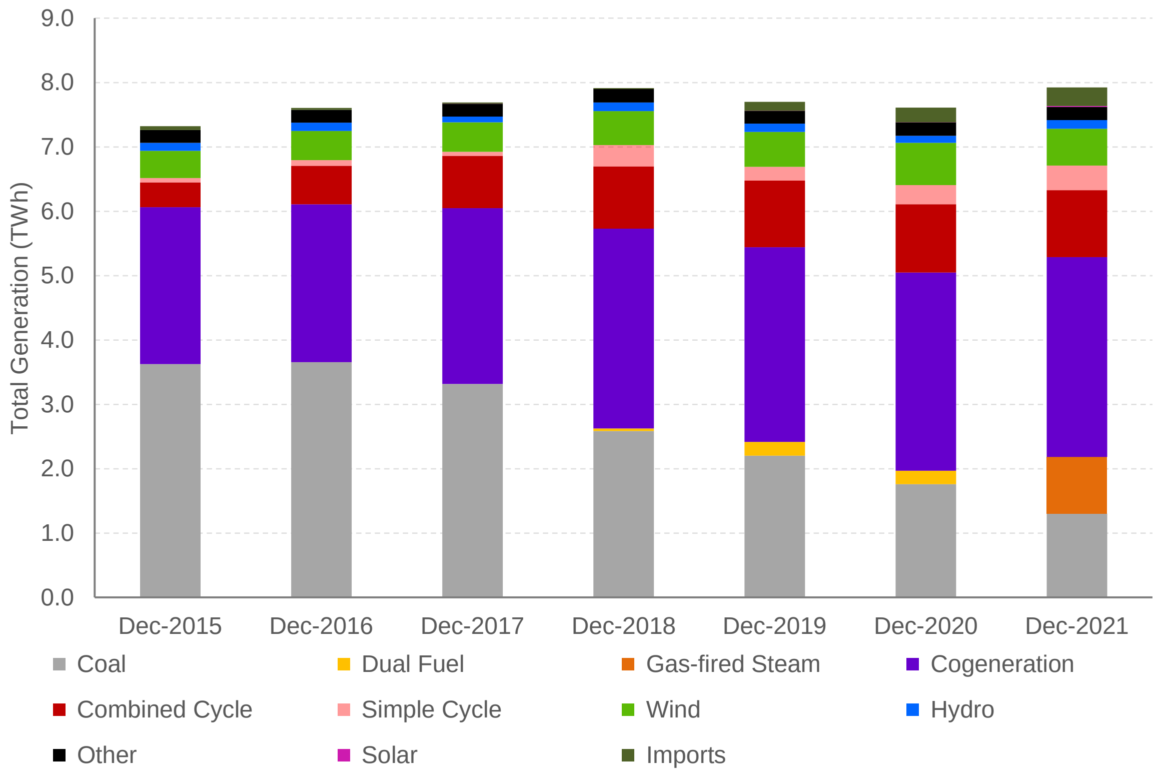
In addition, four coal-to-gas conversion outages occurred in 2021. Both Sheerness 1 (400 MW) and Keephills 2 (395 MW) were offline in the spring for conversion outages, and these were followed by the Keephills 3 (463 MW) and Battle River 4 (155 MW) conversion outages in the fall. These conversions added to previous conversions at Battle River 5 (385 MW), Sheerness 2 (400 MW), Sundance 6 (401 MW), and HR Milner, which was repowered from a 144 MW coal asset to a 208 MW simple-cycle asset. In total, 2,800 MW of capacity has been converted from coal to gas. The decline in coal-fired generation since December 2015 is illustrated in Figure 3.

[1] These outage figures do not include the Sundance 2 mothball outage which began on January 1, 2018 or the mothball outages at Sundance 3 and 5 which began on April 1, 2018. These assets were all retired after being mothballed.

Genesee 1, 2 and 3 are the remaining coal assets in Alberta. Genesee 3 (466 MW) is scheduled to be converted from coal to gas-fired steam, while Genesee 1 and 2 (800 MW in total) are expected to be repowered to 1,360 MW of combined-cycle natural gas capacity.[2] By the end of 2023 Alberta's power generation is scheduled to be completely off coal.

Converting a coal asset to a gas-fired steam asset generally reduces its carbon emissions by around 50%. This also reduces carbon costs, as carbon emissions in Alberta are benchmarked against the carbon intensity of an efficient combined-cycle asset. In 2021 the carbon price was $40/tCO2e compared to $30/tCO2e in 2020. For 2022 the carbon price is set at $50/tCO2e. Section 1.6 of this report analyzes the carbon intensity of Alberta's electricity generation over time.

Figure 3: Total generation by fuel type in December (2015 to 2021)[3]



Natural gas prices increased in 2021 to an average of $3.39/GJ, which is 60% higher than in 2020. Gas prices increased over the summer and into the fall in part due to increased power generation demand, as cooling loads increased during the summer and coal assets were converted to natural gas. In addition, higher natural gas prices were the result of increased economic activity, high gas prices in Europe and Asia, which have increased the demand for LNG

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[2] Capital Power Website: Genesee 3 and Genesee 1 and 2 Fact Sheet

[3] The generation figures in this chart include behind-the-fence generation at large industrial sites.

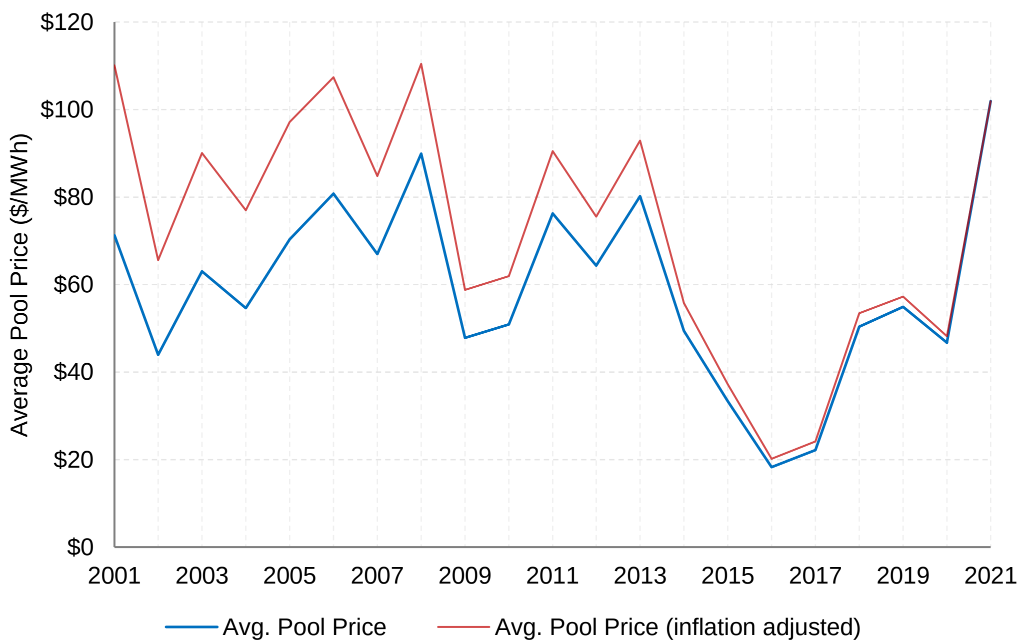
exports from North America, and the occurrence in late August of Hurricane Ida which shut down some large natural gas production sites for an extended period.[4]

The average same-day natural gas price in Alberta was $4.98/GJ during October, the highest monthly average since March 2014. Natural gas prices are an important factor in pool prices as the proportion of gas-fired assets setting the System Marginal Price (SMP) has increased with the coal-to-gas conversions. In Q4 2021, natural gas assets set the SMP 87% of the time compared to 43% in Q4 2020, and the price-setting share of coal assets fell from 54% to 10%.[5]

As discussed in the MSA Quarterly Report for Q4 2020, the expiration of the remaining thermal Power Purchase Arrangements (PPAs) at the end of 2020 transferred offer control for 2,400 MW of thermal capacity from the Balancing Pool to three suppliers with other generation assets in Alberta.[6] In addition, the Hydro PPA expired on December 31, 2020. The Hydro PPA was a financial arrangement which stipulated energy and reserve volumes on the three large hydro assets in Alberta, with a combined capacity of 790 MW.

The expiration of the PPAs resulted in more thermal capacity being offered into the energy market at higher prices, and more thermal capacity has been taken offline commercially when pool prices are elevated, both of which put upward pressure on pool prices in 2021.

Figure 4: Average annual pool prices (2001 to 2021)[7]



[4] EIA: Natural Gas Weekly Update – October 28, 2021

[5] These percentages assume that dual fuel assets exclusively used natural gas to generate electricity.

[6] Alberta MSA: Quarterly Report for Q4 2020 – February 12, 2021

[7] Inflation adjusted uses Statistics Canada: CPI annual averages for Alberta; all items, Table 18-10-0005-01

Figure 4 illustrates the average annual pool price since 2001. Accounting for inflation, the average pool price in 2021 is the highest since 2008 when the average pool price was $110/MWh in 2021 dollars.

1.2 Quarterly summary

The average pool price in Q4 was $107.31/MWh, which is 7% higher than in Q3 2021 and an increase of 133% compared to Q4 2020.[8] The higher pool prices in Q4 relative to Q4 2020 were driven by increased demand in December, higher natural gas prices, more generation outages, a higher carbon price, and higher generator offer prices.

Table 2 provides summary market statistics for Q4 compared to Q4 2020. Average demand in October and November was largely unchanged year-over-year as milder temperatures this year were offset by higher oil production. Oil production in Alberta during October set a new monthly record, increasing the demand for electricity.[9]

Table 2: Monthly market summary for Q4

		2021	**2020**	***Change***
Pool Price (Avg $/MWh)	Oct	96.35	61.26	*57%*
	Nov	99.07	38.44	*158%*
	Dec	126.27	38.44	*228%*
	Q4	**107.31**	**46.13**	***133%***
Demand (AIL) (Avg MW)	Oct	9,453	9,393	*0.6%*
	Nov	10,056	10,068	*-0.1%*
	Dec	10,670	10,241	*4.2%*
	Q4	**10,060**	**9,899**	***1.6%***
Gas Price AB-NIT (2A) (Avg $/GJ)	Oct	4.98	2.35	*112%*
	Nov	4.43	2.68	*65%*
	Dec	3.87	2.44	*58%*
	Q4	**4.42**	**2.49**	***78%***
Wind (Avg MW)	Oct	864	666	*30%*
	Nov	1,206	1,040	*16%*
	Dec	770	857	*-10%*
	Q4	**944**	**852**	***11%***
Net Imports (+) Net Exports (–) (Avg MW)	Oct	289	100	*188%*
	Nov	523	324	*61%*
	Dec	393	307	*28%*
	Q4	**400**	**243**	***65%***
Supply Cushion (Avg MW)	Oct	1,667	1,684	*-1%*
	Nov	1,611	2,051	*-21%*
	Dec	1,900	1,730	*10%*
	Q4	**1,727**	**1,819**	***-5%***

In December temperatures dropped significantly year-over-year and oil production remained high. As a result, demand increased by 4.2% year-over-year.

The AESO declared an Energy Emergency Alert level 2 (EEA2) on December 27, indicating that there was not enough supply to reliably serve demand, as the AESO was required to use operating reserves to provide energy.

The EEA2 event was caused by several factors including high demand, low wind generation, and thermal outages and derates. The daily average pool price for December 27 was $696/MWh, the highest ever recorded.

[8] Reference to Q4 means Q4 2021 unless specified otherwise. References to a month or a day in a month mean a month or day in 2021 unless specified otherwise.

[9] Alberta Government Economic Dashboard: Oil Production

Natural gas prices have a direct impact on pool prices in Alberta since gas-fired generators are the primary marginal price setters. As a result, the higher natural gas prices in Q4 had the effect of increasing generator costs and putting upward pressure on pool prices.

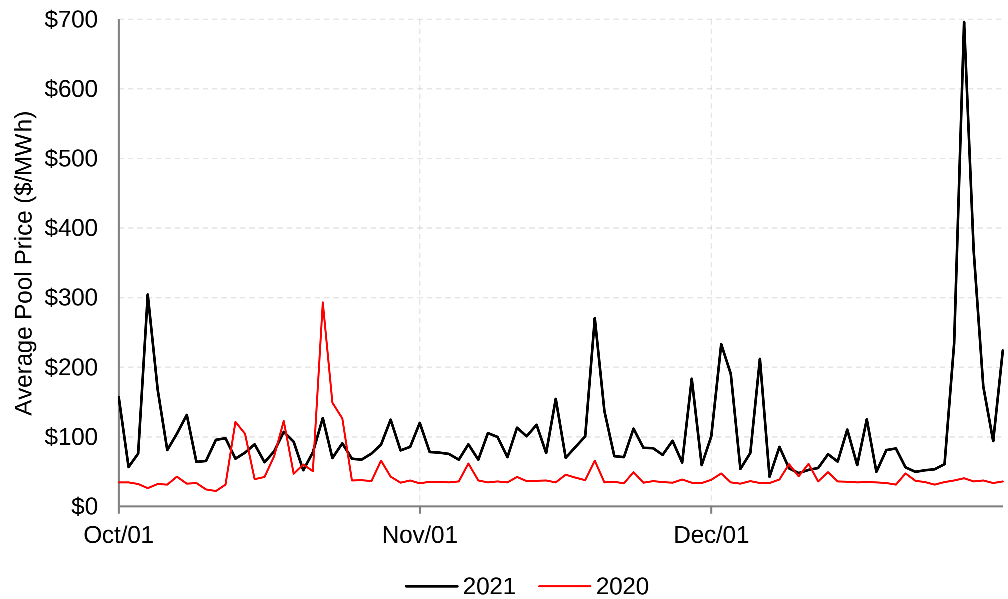
Average wind generation in November set a record of 1,208 MW, surpassing November 2020 by 167 MW due to favourable wind conditions and increased wind capacity. Average wind generation in Q4 was 944 MW, up 11% from 852 MW in Q4 2020. The increasing presence of wind generation is a driver of pool price volatility because wind generation is intermittent and highly correlated across wind assets in Alberta. In addition, wind generation tends to be lower during periods of extreme temperatures, when peak demands occur.

In response to the higher pool prices in Q4, net imports increased by 65% year-over-year to an average of 400 MW in Q4.[10] Over the course of 2021 net imports averaged 459 MW, which is a slight increase relative to 2020 and is the highest annual average on record going back to 2001. In October the BC/MATL intertie was offline for a 10-day planned outage, but the reduced import supply was offset by high wind generation and reduced thermal outages.

1.3 Market outcomes

Figure 5 illustrates the daily average pool price in Q4 2021 and Q4 2020. As shown, pool prices were typically higher in Q4 this year. On December 27 the daily average pool price increased to $696/MWh, the highest on record, with the pool prices for eight consecutive hours clearing at, or very close to, the $999.99/MWh offer price cap. The AESO declared an EEA2 at 19:29 on December 27 and this extended until 01:00 on December 28, well past the time of peak demand.

Figure 5: Daily average pool prices in Q4 (2020 and 2021)



[10] Net imports are imports less exports.

Figure 6 shows that December was an unusually cold month compared to December in recent years, with extreme cold warnings issued over multiple days. Extreme temperatures are a driver for demand and tend to be correlated with lower wind generation, which was the case in December (Figure 7). The daily average of temperatures across Calgary, Edmonton and Fort McMurray was -30°C on December 27 (Figure 6) and demand peaked at 11,508 MW in HE18. During the demand peak wind generation increased slightly to average 577 MW in HE18.

Figure 6: Daily average temperatures in Q4 (2019, 2020 and 2021)

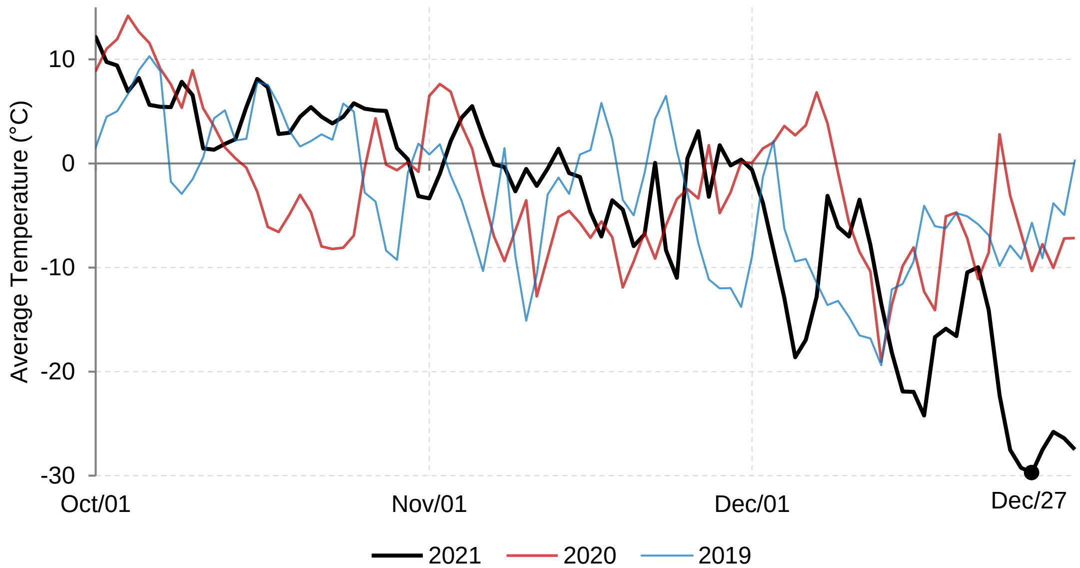
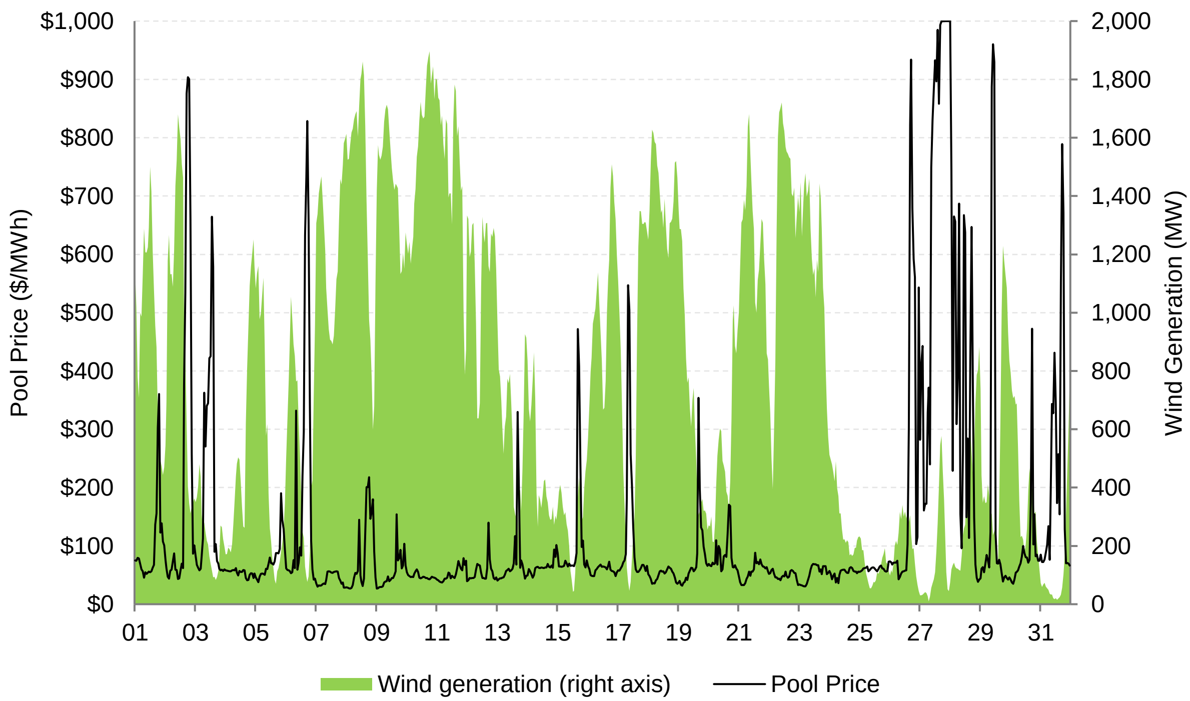


Figure 7: Pool prices and hourly average wind generation (December 2021)

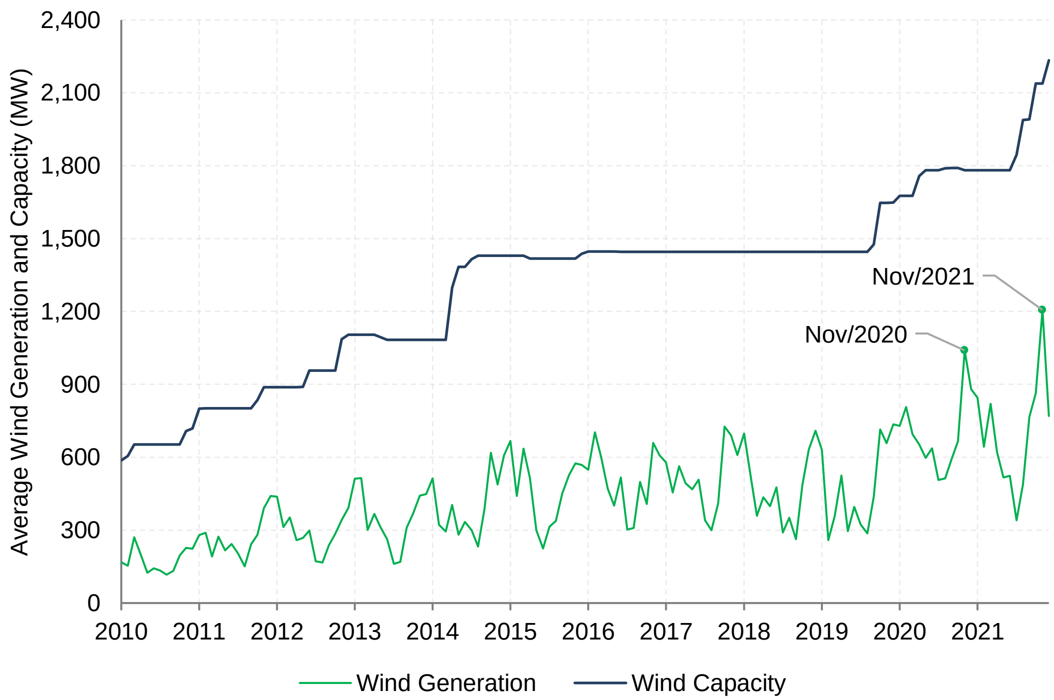


Thermal outages were a major factor in the EEA2 event on December 27. There were forced outages at two gas-fired steam assets accounting for around 800 MW of generation capacity. In addition, a number of gas-fired assets were heavily derated. These derates accounted for over 1,100 MW of capacity during some hours and contributed to the EEA2 event's extension into off-peak hours. At the same time, there were firm and interruptible gas supply constraints in the NGTL natural gas pipeline system, specifically within the North East Delivery Area (NEDA) resulting from a natural gas compressor outage. Within NEDA, delivery customers, including power generators and industrial customers, had natural gas supply reduced.[11]

Import supply from the BC/MATL intertie was also heavily constrained on December 27 due to a transmission line outage. The BC/MATL intertie was available for around 360 MW of imports during the EEA2 event, compared to around 640 MW the following day. The higher pool prices on December 27 were an important factor in the higher average pool price for December, which was $126.27/MWh.

In November the average daily pool price was $99.07/MWh despite moderate temperatures and record wind generation, as thermal outages reduced supply. On average, temperatures in November were -1.6°C, compared to -3.9°C in November 2020. The milder temperatures this year typically have the effect of lowering demand, however, increased oil production offset this and demand in November was largely flat year-over-year.

Figure 8: Average wind generation and capacity by month (January 2010 to December 2021)



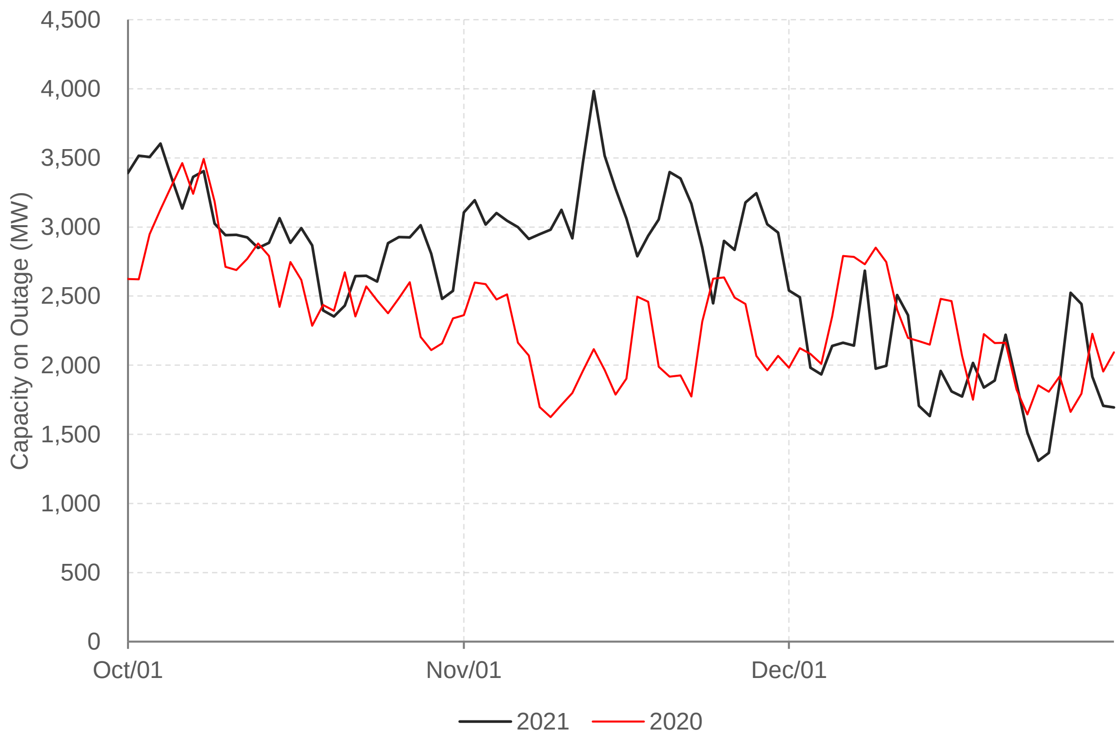
[11] NEDA IT-D and NEDA FT-D: TC Energy, Bulletins

Figure 8 shows the monthly average of total wind generation and capacity starting from January 2010. Wind capacity has been growing in recent years and 2021 saw a 27% increase from 1,781 to 2,269 MW. This trend is expected to continue, with over 1,300 MW of wind capacity currently under construction and expected to come online in the coming years.[12]

There was also an increase in solar capacity over 2021, from 107 to 336 MW, and this is also expected to keep growing with multiple projects currently under construction. Over 1,200 MW of solar capacity will be added in the next two years based on the AESO's long term adequacy report. New wind and solar projects make up just over 55% of the total capacity for projects that are currently under construction.

Thermal generation outages were an important factor in pool prices during November (Figure 9). The Genesee 2 asset (400 MW) was offline for the duration of November due to an extended forced outage, which ran from mid-July to early December. The Keephills 3 asset (463 MW) was offline or derated for much of November as the asset completed and commissioned its conversion to natural gas. The Battle River 4 asset (155 MW) took a 25-day outage in November to fully convert to natural gas. In addition, HR Milner (208 MW) was offline for a 23-day outage, there were extended forced outages at two gas peaking assets, and a large gas-turbine outage at a cogeneration facility.

Figure 9: Daily average quantity of thermal capacity on outage or derated in Q4 (2020 & 2021)



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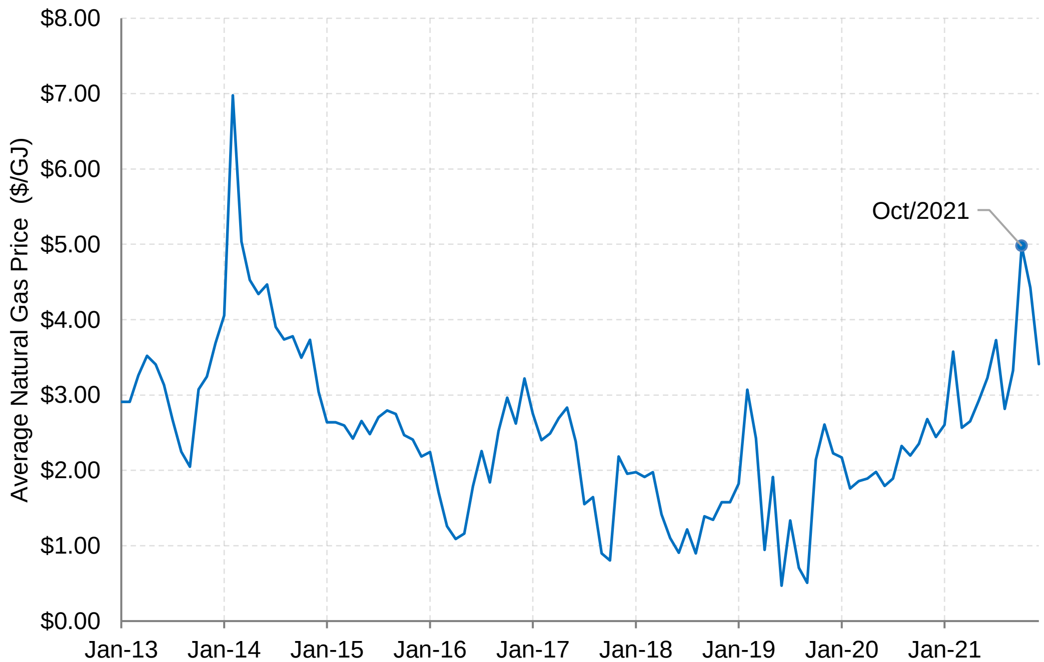
[12] AESO: Long Term Adequacy Metrics, projects under construction – February 2022

Generation outages were a significant driver of higher pool prices on the evening of Saturday, November 13. During the evening peak more than 4,600 MW of thermal capacity was offline or derated, including one gas-fired steam asset that was offline commercially. As a result of the reduced supply, the supply cushion fell to 322 MW in HE18 when demand was 10,281 MW and wind generation averaged 1,516 MW. The hourly pool price settled at $620/MWh. In this instance, the market was relying on exceptionally high wind generation to meet peak demand.

Figure 10 shows the monthly average natural gas price from 2013 to 2021. The monthly average price in 2021 peaked in October at $4.98/GJ. Natural gas prices increased due to cold weather forecasts for the winter, increased power demands, higher LNG demands from Europe and Asia, and production shut-ins along the Gulf Coast beginning in late August.

Subsequently, natural gas prices fell beginning in late October and throughout November as production increased and temperatures across much of North America were above normal in the fall, allowing for less withdrawals from storage than typically occur. Natural gas prices averaged $3.87/GJ in December, which is 58% higher than in December 2020.

Figure 10: Monthly average of same-day natural gas prices (Jan. 2013 to Dec. 2021)



Natural gas prices were a significant factor in the average pool price for October, which was $96.35/MWh compared to $61.26/MWh in October 2020. In October 2021 the market heat rate was 19 GJ/MWh, which is lower than the market heat rate in October 2020 (26 GJ/MWh) and was the lowest monthly heat rate in 2021. The heat rates illustrate that pool prices were relatively low this October, after taking the higher natural gas prices into account.

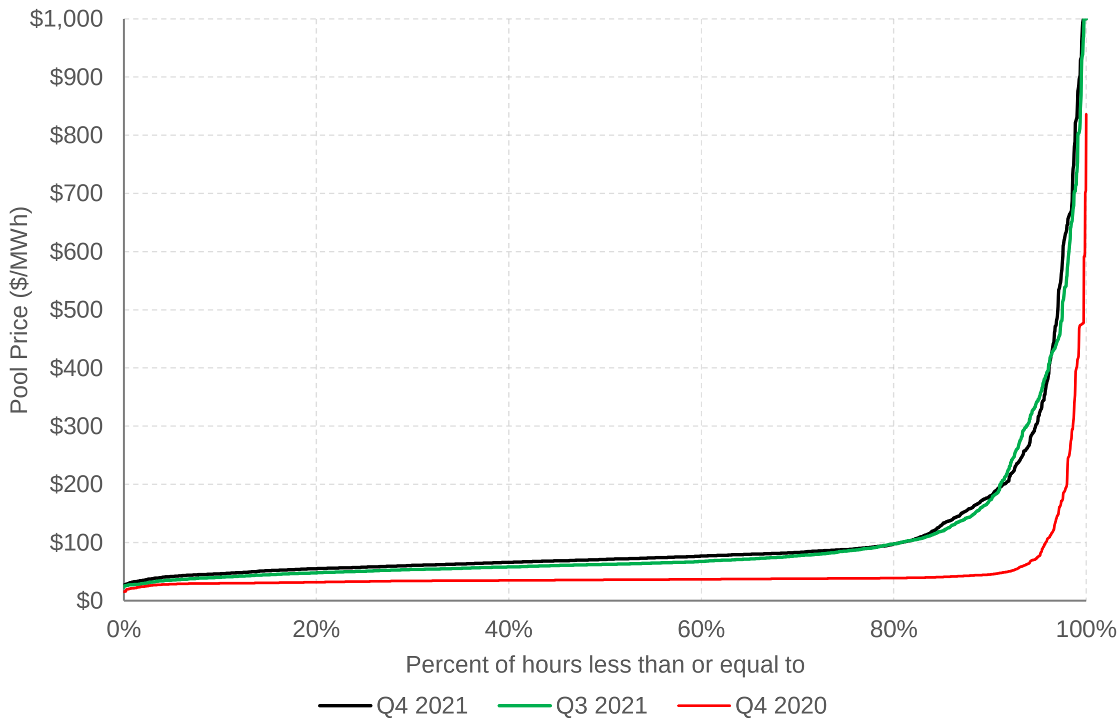
Wind generation in October was 30% higher than in October 2020. The increased wind supply helped to offset the impact of a planned BC/MATL intertie outage, which ran from October 18 to

27. During the peak hours of the intertie outage, wind generation averaged 1,010 MW. In addition, thermal outages fell around the start of the BC/MATL outage, increasing available capacity and putting downward pressure on pool prices.

1.3.1 Distribution of pool prices

Figure 11 illustrates the distribution of pool prices in Q4 compared to Q3 2021 and Q4 2020. The distribution of prices in Q4 was very similar to the distribution observed in Q3 2021. In contrast, the year-over-year comparison shows that pool prices in 2020 were lower throughout the distribution. As discussed above, pool prices in Q4 were higher than Q4 2020 for several reasons including higher natural gas prices, more thermal generator outages, and more thermal capacity being offered at higher prices. The median pool price in Q4 was $70.88/MWh, or 34% less than the average, which illustrates that some higher priced hours were a material driver of the average pool price.

Figure 11: The distribution of pool prices (Q4 2021, Q3 2021, and Q4 2020)



Beginning in HE21 of December 27 pool prices reached the offer price cap of $999.99/MWh for five consecutive hours and the AESO declared an EEA2 during this time. In Q3 2021, EEA2 events occurred on July 7 and 14, and the SMP also reached the offer price cap on June 2, 28 and 29. These events reflect a scarcity of supply relative to demand, and this market tightness is expected to put upward pressure on pool prices, incentivizing new supply.

1.3.2 Cost of transmission constraints

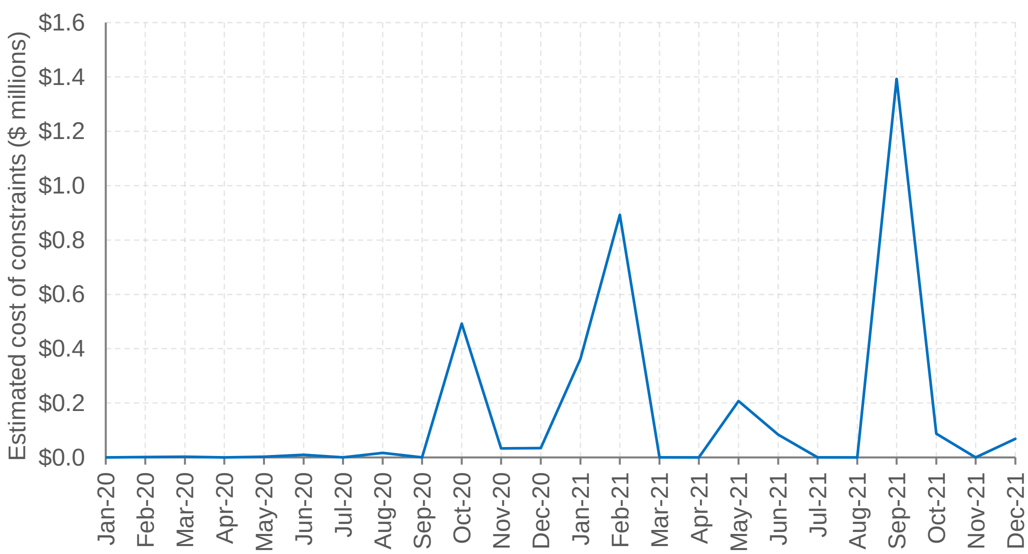
At times, Alberta's transmission system experiences constraints which may limit the supply that an in-merit generation asset(s) can provide. To continue to meet demand, the AESO may restrict the amount of generation being produced in the constrained transmission area and instead dispatch additional generation located in unconstrained areas. This results in dispatching higher-priced generation assets, increasing costs.

The estimated cost of transmission constraints increases as more generation is restricted, particularly when there is a larger price differential between the pool price and higher priced blocks that are dispatched to manage the constraint. The SMP is set at the point where supply and demand would have intersected if there were no transmission constraints at that time. The SMP is the price that is used to calculate the pool price.

The AESO purchases the out-of-merit generation outside of the market at the offer price of the dispatched operating block from source assets used to manage the constraint. The incremental cost per MWh is equal to the difference between the pool price and the offer price block(s) of these source asset(s).[13]

The total estimated cost of transmission constraints in 2021 increased to $3.1 million, which is 420% higher than in 2020 but is still low in the context of transmission costs.[14] This increase was largely driven by higher constraint costs in February and September. In February the estimated cost of constraints totalled $0.9 million, and in September it totalled $1.4 million (Figure 12).

Figure 12: Total estimated cost of constraints by month (Jan. 2020 to Dec. 2021)



[13] ISO rule 103.4, *Power Pool Financial Settlement*, section 8

[14] The AESO's reported Transmission Operating Costs budgeted for 2021 was over $2.2B as per their AESO 2021 Business Plan and Budget Proposal.

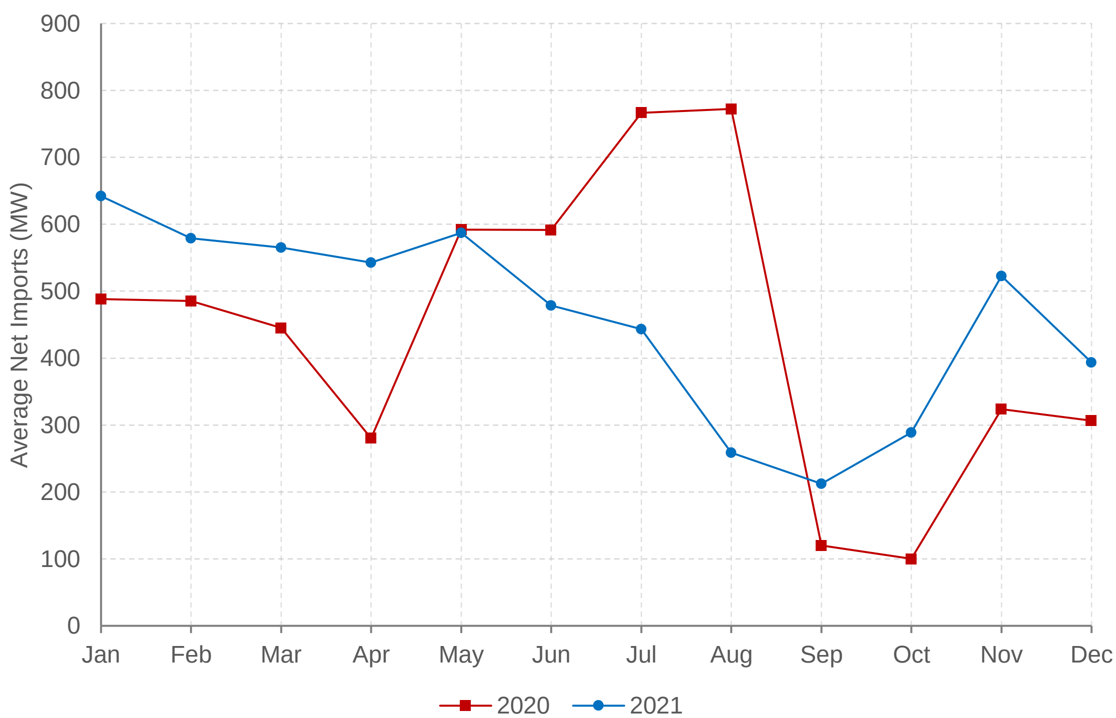
In February, the generation of a larger simple-cycle asset was constrained on multiple days when pool prices were volatile. Due to prevailing market conditions at the time, a relatively small amount of generation sometimes made a material difference in prices. As a result, the price differential between the pool price and the offer blocks of assets dispatched to manage the constraint was occasionally significant, and the estimated cost of constraints increased.

On September 12 and 13 the generation of a large combined-cycle asset was constrained due to transmission outages. Because of prevailing supply and demand conditions in the energy market, there was a material difference between the pool price and the offer blocks of assets dispatched to manage the constraint during some peak hours of September 13. The total estimated cost of constraints on September 13 was $1.1 million, and this event accounted for 83% of the total monthly costs in September.

1.4 Interties

Interties connect Alberta's electricity grid directly to those in British Columbia (BC), Saskatchewan (SK), and Montana (MATL), with the intertie to BC being the largest. For reliability purposes the AESO treat BC and MATL as one intertie (BC/MATL) because a trip on the BC intertie would also cause MATL to trip offline. Indirectly, these interties link Alberta's electricity market to US markets in Mid-Columbia (Mid-C) and California.

Figure 13: Monthly average of net imports (2020 and 2021)

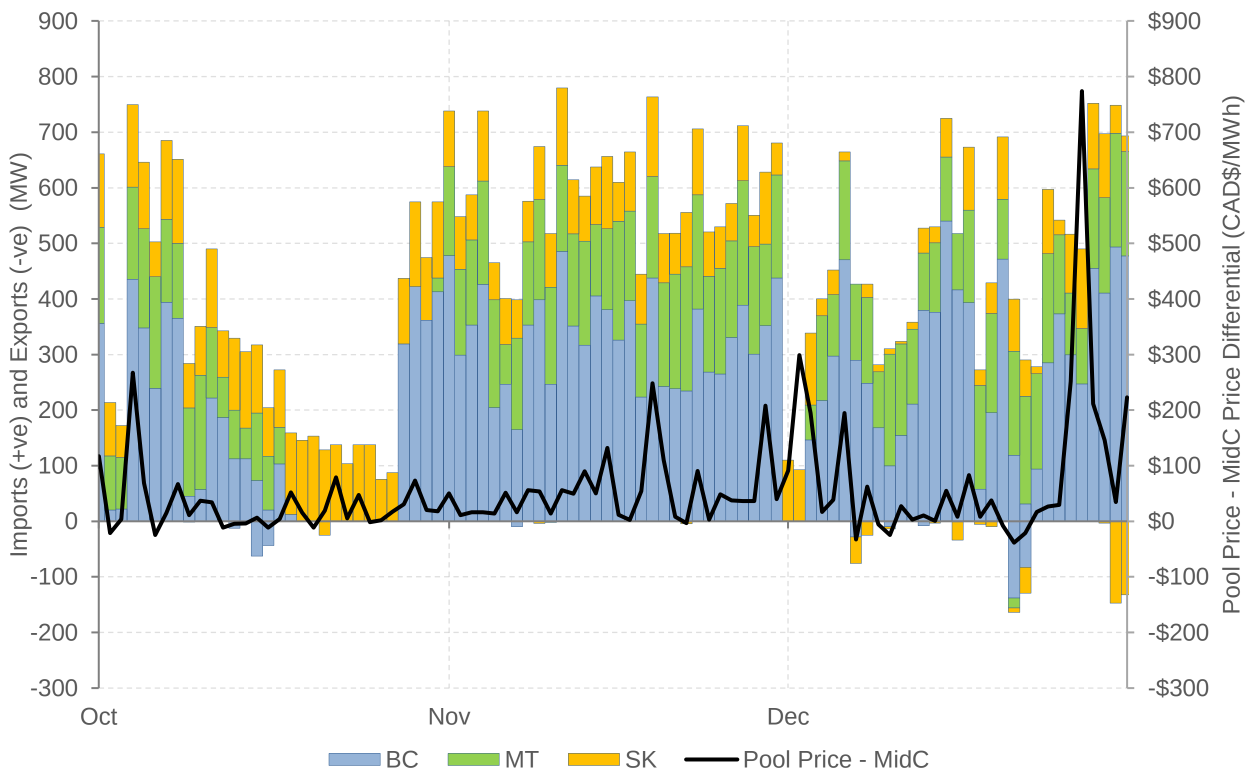


In 2021 imports into Alberta totalled 4.04 TWh or 4.7% of total AIL demand, only slightly less than the annual record of 4.8% set in 2011.[15] Average net imports in 2021 were slightly higher than last year, increasing from 440 MW to 459 MW, as lower imports during the summer of 2021 were more than offset by higher imports in other seasons (Figure 13).[16]

In response to the higher pool prices, the average volume of net imports during Q4 increased by 65% compared to Q4 2020. Figure 14 illustrates daily average import and export volumes over Q4 during peak hours (HE08 to HE23). As shown, the predominant flow of power during Q4 was imports flowing into Alberta as pool prices were often relatively high.

The BC/MATL intertie had a planned outage for transmission work in October of both 2020 and 2021. In 2021, the intertie outage ran from October 18 to 27 and this reduced import volumes significantly (Figure 14). As discussed above, pool prices during this period were moderated by increased wind generation. The average pool price during the BC/MATL intertie outage was $83.06/MWh. Thermal outages increased in November, putting upward pressure on pool prices and motivating more imports.

Figure 14: Daily average imports (+ve) and exports (-ve) and the AB - Mid-C price differential (peak hours, Q4 2021)



[15] Total imports are calculated using hourly net imports (imports - exports). Hours with net exports are set to 0 MW.

[16] Average net import volumes include negative values to reflect hours of net exports.

At around 21:24 on Tuesday, November 30 the BC intertie tripped offline due to high wind speeds, causing the MATL intertie to trip offline as well. At the time, around 300 MW of imports were flowing on the BC intertie and 200 MW on MATL. As a result of the trip, the AESO reported that grid frequency fell to 59.494 Hz before recovering and, as a result, no Under Frequency Load Shed (UFLS) thresholds were triggered. The AESO utilized no LSSi in this event because no armed LSSi was required for the 500 MW of BC/MATL imports at prevailing demand levels under the normal weather conditions table.

The SMP increased from $64.38/MWh to $79.37/MWh following the reduction in import supply. The BC/MATL intertie was offline until HE15 of December 3, and the intertie outage was a factor in some pool price volatility in the first few days of December.

As discussed above, pool prices increased significantly on Monday, December 27 as cold temperatures increased demand, two gas-fired steam assets were offline on forced outages, and a number of gas-fired assets were materially derated. In addition, imports on BC/MATL were constrained during this event to around 360 MW because of a transmission line outage. Import flows on BC/MATL during this EEA2 event made full use of the available import capacity.

1.5 Offer behaviour

As discussed in the MSA's recent Quarterly Reports, the expiration of the remaining PPAs at the end of 2020 resulted in a material change in offer behaviour in the energy market. Following the end of the PPAs, more thermal generation capacity has been offered into the market at higher prices, putting upward pressure on pool prices.

Figure 15 illustrates the percentage of available coal and converted coal capacity that was offered at or below a given price in Q4, compared to Q4 2020. In Q4, 90% (the 90^{th} percentile) of available coal and converted coal capacity was offered at or below $230/MWh and 10% was offered above $230/MWh. In Q4 2020, the 90^{th} percentile was much lower at $39/MWh as the offer prices on these assets were generally lower in Q4 last year.

The supply cushion is a summary measure of supply-demand conditions in the energy market at a particular point in time. The supply cushion shows how much available generation capacity the energy market has above that which is required to meet prevailing demand.

For a given level of supply cushion, pool prices were generally higher in Q4 relative to Q4 2020. Figure 16 illustrates the relationship between supply cushion and pool price in Q4 and Q4 2020, with the lines depicting average pool prices in 200 MW bins. At higher supply cushion levels, the higher pool prices year-over-year largely resulted from increased natural gas prices and the higher carbon price. At lower supply cushion levels, the change in offer behaviour was the primary driver of higher pool prices for a given supply cushion.

Figure 15: Duration curves of offer prices on available coal and converted coal capacity[17]

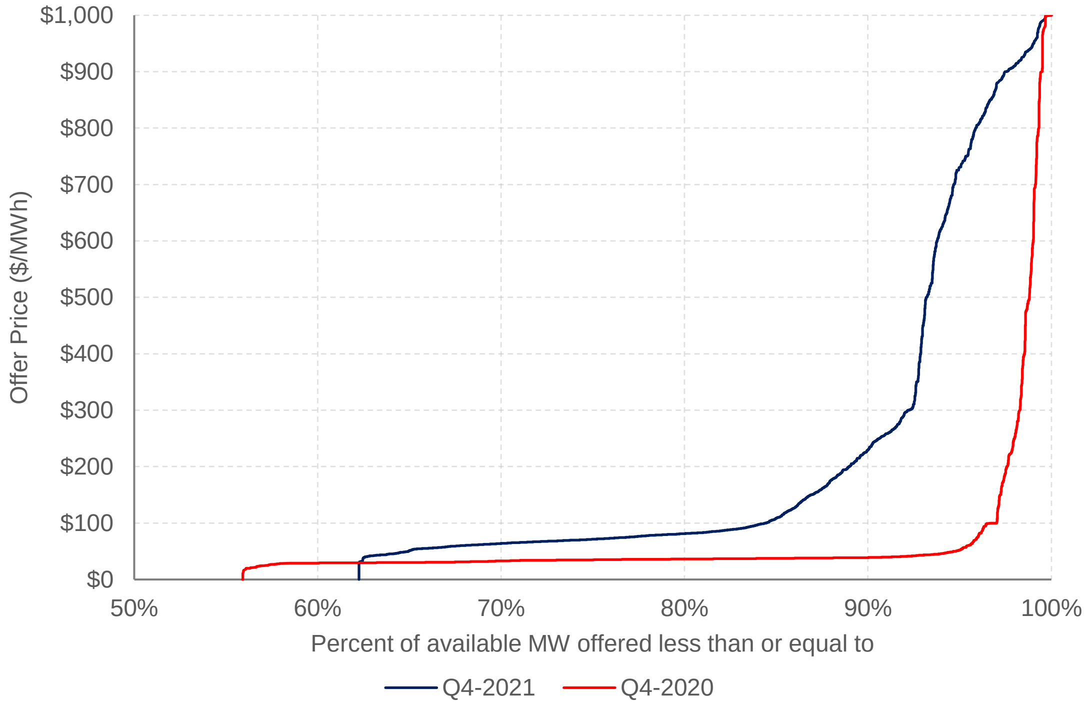
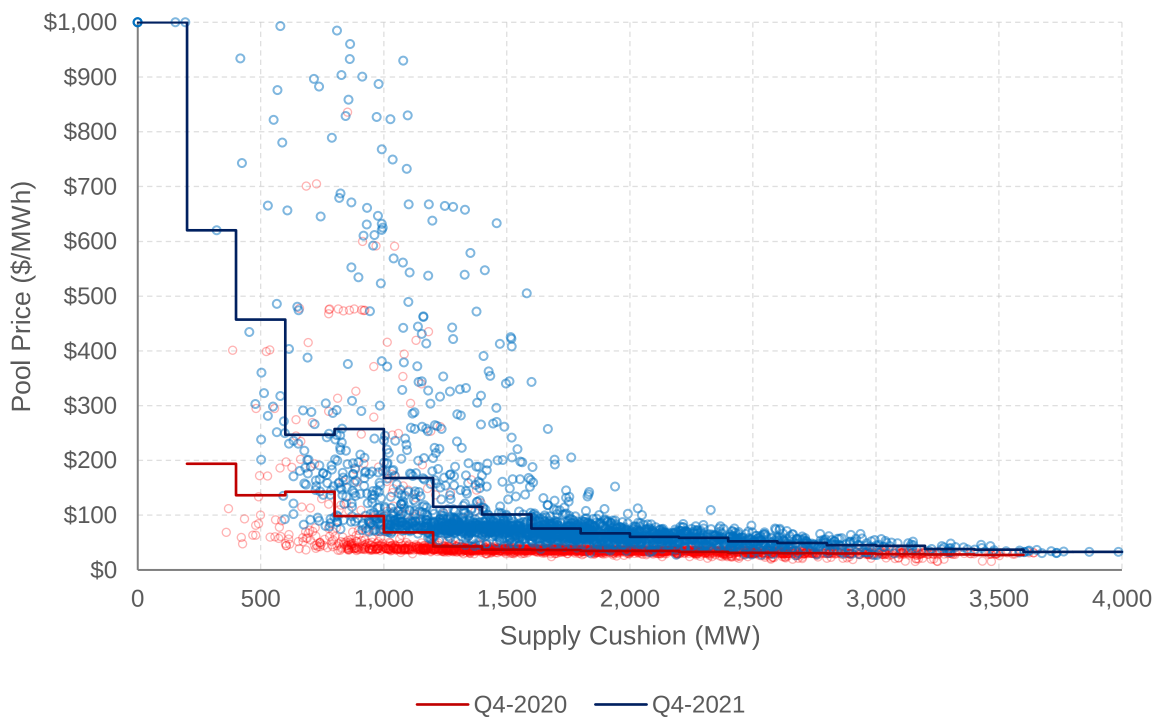


Figure 16: A scatterplot of supply cushion and pool price in Q4 (2020 and 2021)

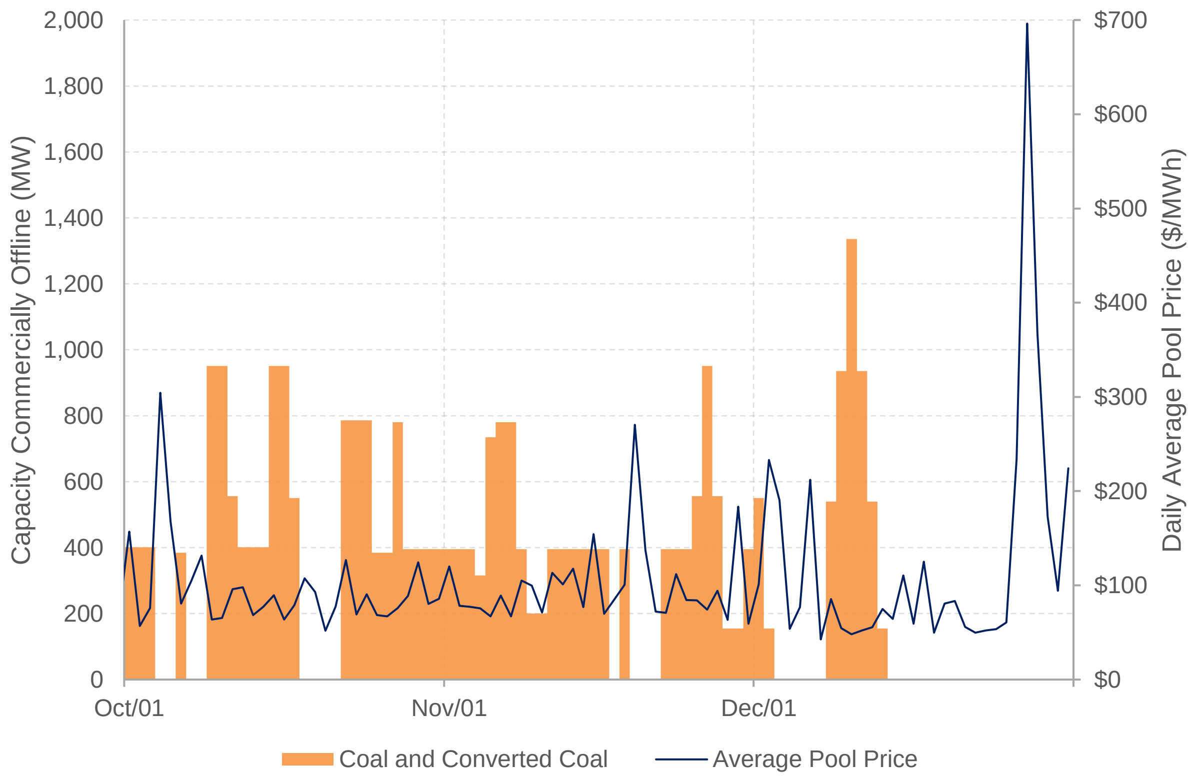


[17] The analysis includes the thermal assets at Battle River, Genesee, Keephills, Sheerness, and Sundance.

Figure 17 shows the amount of coal and converted coal capacity that was offline commercially during the daily peak in pool price over Q4. When these large thermal assets are commercially offline, they are not immediately available for dispatch by the AESO due to start-up time requirements, which are generally in the range of 8 to 24 hours. This analysis does not include mothballed capacity, and with the announced retirement of Sundance 5, there is no mothballed capacity at present.

On a few instances in Q4, converted coal assets were commercially offline when pool prices were elevated. For example, on October 1 a gas-fired steam asset was offline commercially when pool prices peaked at $569/MWh in HE17, and a gas-fired steam asset was offline commercially on December 2 when the pool price peaked at $904/MWh. However, most coal and converted coal assets were taken commercially offline when pool prices were less volatile, and no assets were commercially offline when the BC/MATL outage began in mid-October, or when low temperatures increased demand and pool prices in mid-to-late December.

Figure 17: Coal and converted coal capacity commercially offline coincident with the daily peak in pool price (Q4 2021)



1.6 Carbon emission intensity

1.6.1 Assessment

In the context of power generation, carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. Starting with this Q4 2021 report, the MSA will be publishing analysis of the carbon emission intensity of the Alberta electricity grid in its quarterly reports. The results are indicative only, in the sense that the MSA has not sought to collect the precise carbon emission intensities of assets from market participants, but rather relied on information that is publicly available.

This information includes the federal Greenhouse Gas Reporting Program (GHGRP)[18] and heat rate information for simple-cycle or combined-cycle assets, such as those publicly available from manufacturer websites or Alberta Utilities Commission (AUC) filings. The purpose of this analysis is to examine the carbon emission intensity of the grid based on asset level carbon emission intensities and hourly generation data from all assets that supply the grid.

Figure 18 provides the distribution of the hourly average emission intensity of the grid in Q4 for the past four years. Hourly average emission intensity is the volume-weighted average carbon emission intensity of the assets supplying the grid in a given hour. Figure 18 shows how many hours in a given quarter the hourly average emission intensity fell into a specified interval. For example, in Q4 2021, there were 71 hours where the average intensity was around 0.6 tCO2e/MWh and 74 hours where the average intensity was around 0.45 tCO2e/MWh.

Figure 18 illustrates a significant shift of the distribution to the left, indicating a decline in carbon emission intensity over time. In Q4 2018, an average emission intensity of 0.6 tCO2e/MWh was an hour with relatively low carbon intensity, whereas in Q4 2021 0.6 tCO2e/MWh was on the high end of the distribution. This result reflects the altered composition of Alberta’s generation mix, where the displacement of coal-fired generation with natural gas-fired generation and other low emissions resources has been the major driver. Mean and median hourly average carbon intensities are reported in Table 3.

[18] Greenhouse Gas Reporting Program (GHGRP) - Facility Greenhouse Gas (GHG) Data - Open Government Portal (canada.ca)

Figure 18: The distribution of average carbon emission intensities in Q4 (2018 to 2021)

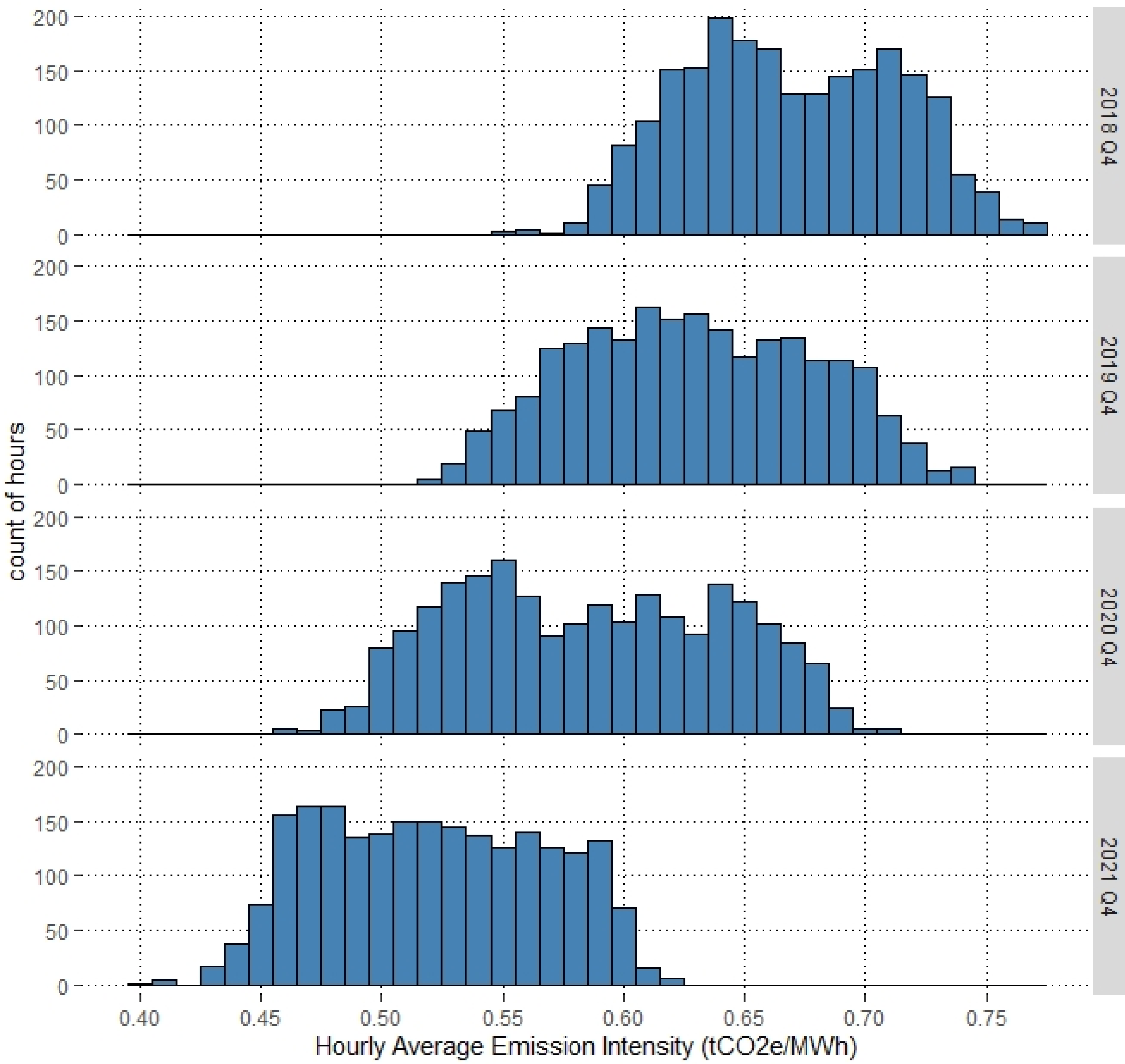


Table 3: Mean and median hourly average carbon emission intensities (tCO2e/MWh)

	Q4 2018	Q4 2019	Q4 2020	Q4 2021
Mean hourly average emission intensity	0.669	0.629	0.586	0.521
Median hourly average emission intensity	0.665	0.627	0.584	0.518

Figure 19: Carbon costs for generic coal and gas-fired steam assets

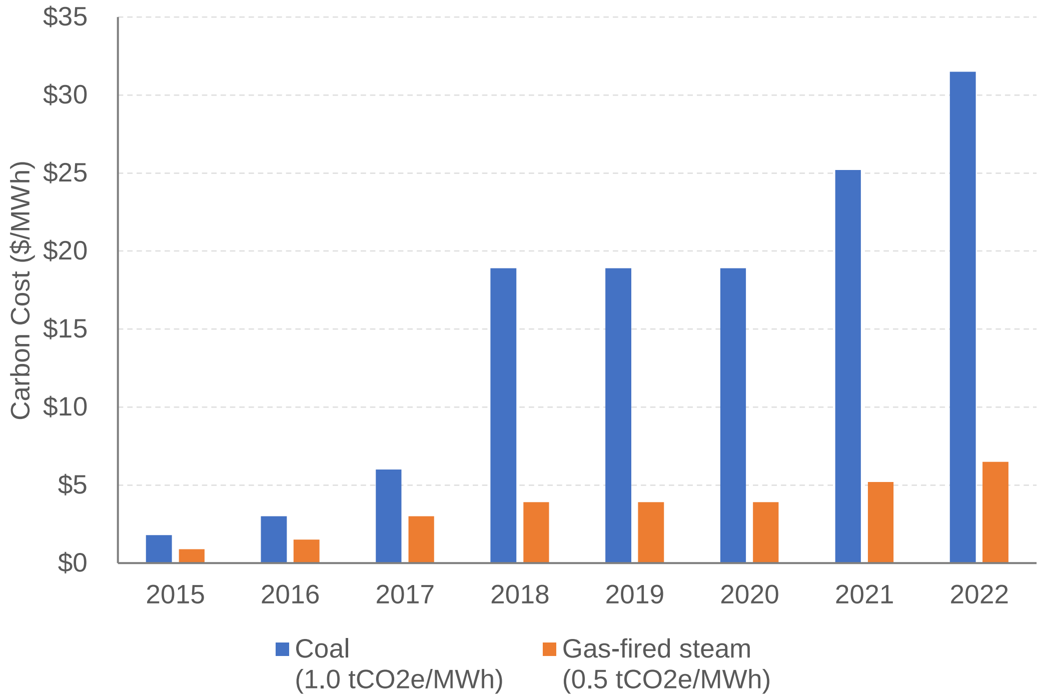


Figure 19 illustrates how carbon costs have changed over time for generic coal and gas-fired steam assets.[19] As shown, carbon costs for coal assets have increased substantially over this period because of the carbon policies. This increased cost has been a factor in coal-fired assets being offered at higher prices in the merit order, therefore being dispatched less often, and many of them have been converted to use natural gas instead of coal (reducing carbon emissions by around 50%).

Another factor that has contributed to the displacement of thermal generation in the merit order is the increase in renewable generation. Figure 20 shows how the distribution of combined wind and solar generation has changed in Q4 from 2018 to 2021. The number of zero generation hours for wind and solar decreased while the number of high generation hours increased drastically.

[19] The "clean-as-best-gas" emissions intensity standard is set to 0.37 tCO_2e/MWh. This was established by Alberta's previous *Carbon Competitiveness Incentive Regulation* (CCIR), which was replaced by the *Technology Innovation and Emission Reduction Regulation* (TIER) as of January 1, 2020. Emissions above this threshold are subject to a carbon price.

Figure 20: The distribution of wind and solar generation in Q4 (2018 to 2021)

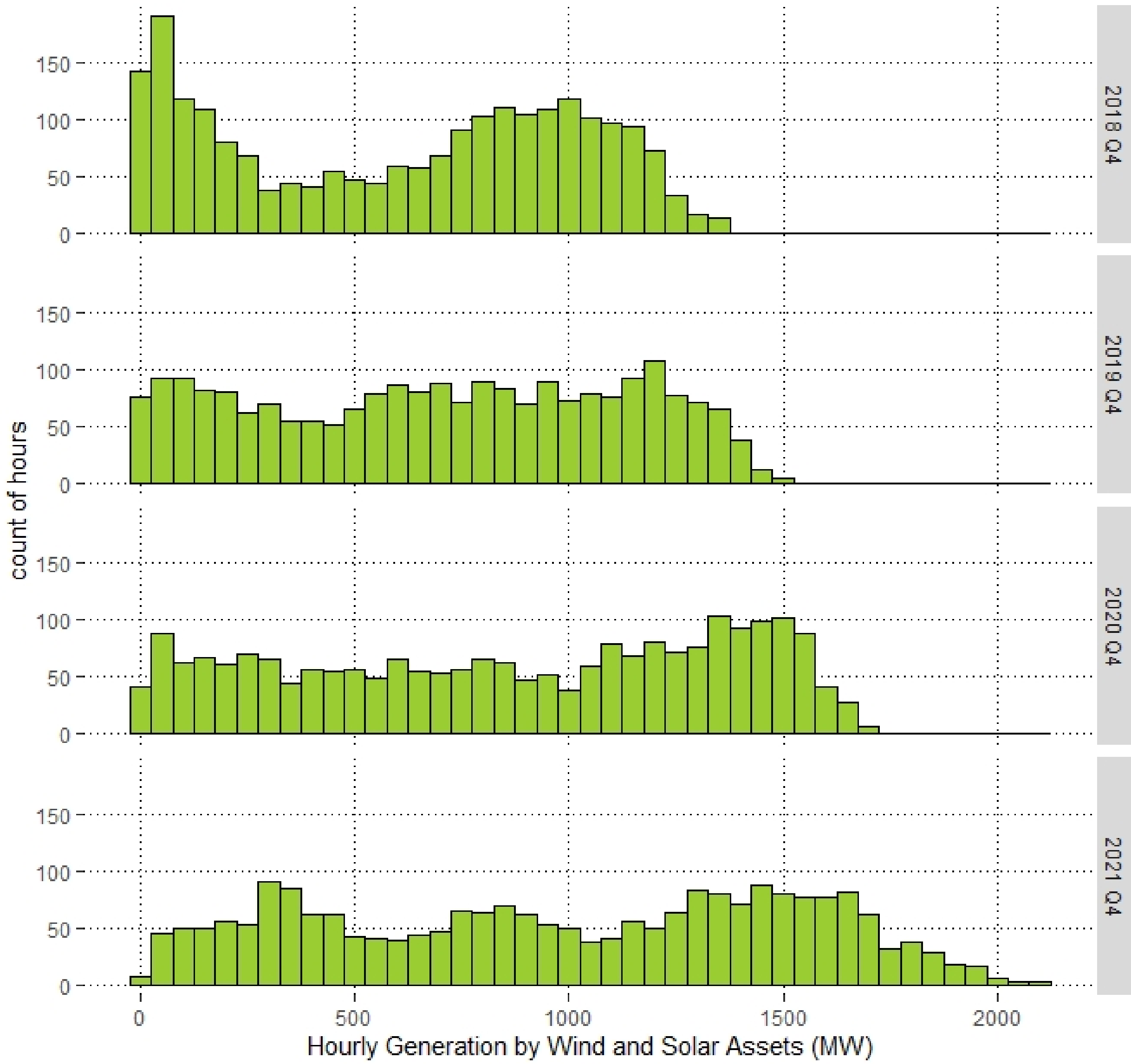
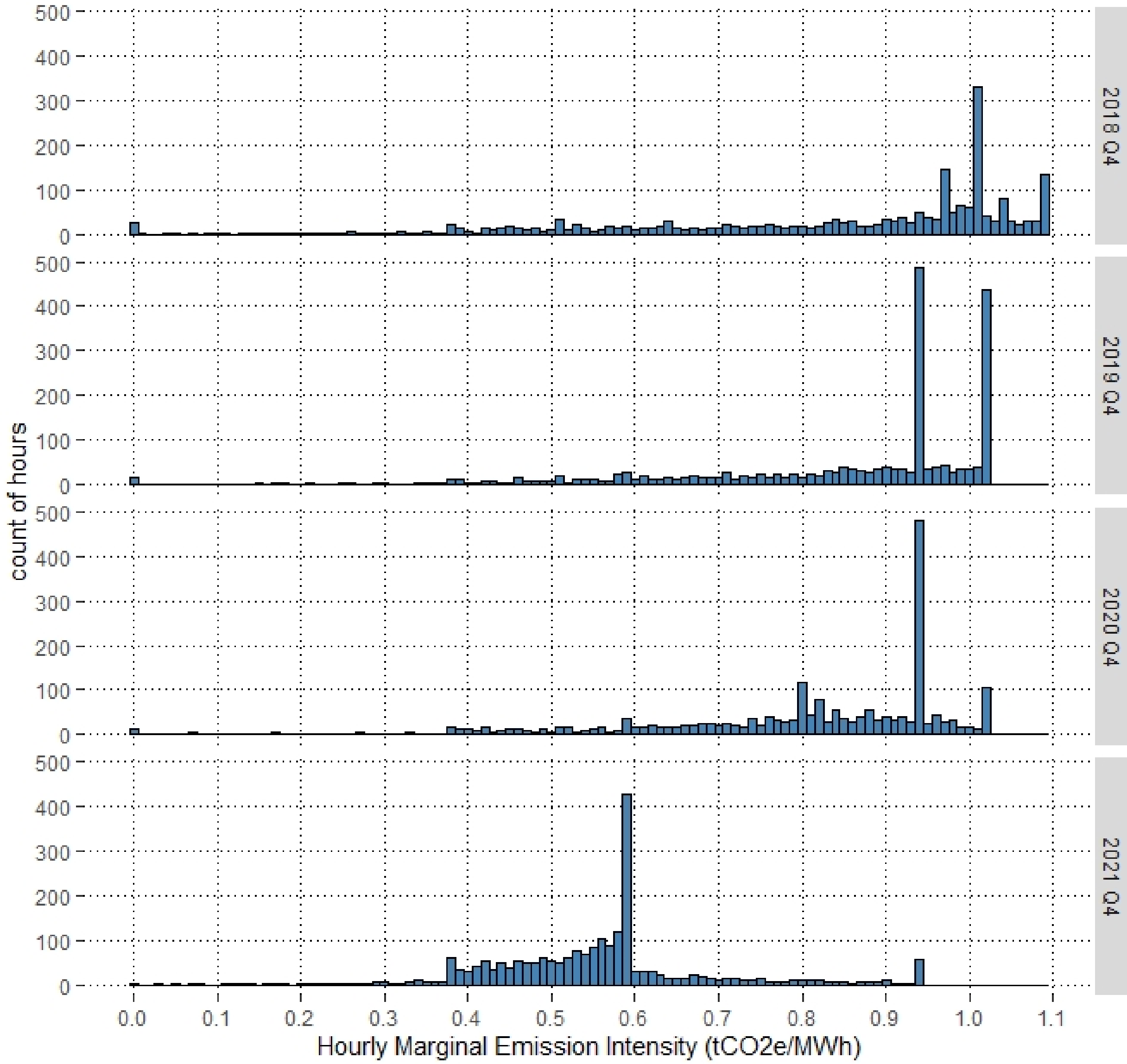


Figure 21 shows the distribution of the hourly marginal emission intensity of the grid in Q4 for the past four years. While the hourly average emission intensity of the grid presented in Figure 18 is calculated from all assets supplying the grid in a given hour, the hourly marginal emission intensity of the grid simply reflects the carbon emission intensity of the marginal asset in a given hour. In hours where there were multiple SMPs and multiple marginal assets, a time-weighted average of the carbon emission intensities of those assets is used.

Emission intensities greater than 0.8 tCO2/MWh generally reflect that coal-fired assets were on the margin in those hours. Figure 21 shows that the number of such hours declined drastically between 2018 and 2021 as a number of coal assets have been converted to use natural gas, thereby eliminating the large spikes on the high end of the distribution. The observed spike in Q4

2021 around 0.59 tCO2/MWh arises from assets with similar CEIs often being on the margin, some of which are gas-fired steam assets.

Figure 21: The distribution of marginal carbon emission intensities in Q4 (2018 to 2021)



1.6.2 Methodology

As indicated above, the underlying asset level carbon emission intensities (CEIs) used for this analysis are not perfect. Where available, CEIs were generally estimated from the GHG emissions data reported in GHGRP by dividing the total emissions by the generation volume to establish carbon emission intensity on a tCO2e/MWh basis. In cases where there is no reported GHG emission data (or where it is not desirable to use the data as addressed in items 3-5 below), the CEIs are estimated by multiplying asset heat rates (GJ/MWh) by the applicable fuel CEI (tCO2e/GJ). To address the challenges encountered in these estimations, a number of assumptions were made, which are listed below.

1. The most recent GHGRP data used for this analysis comes from 2019. This data was used for establishing GHGRP based CEIs for 2020 and 2021.

2. GHGRP data provides emission data by facility or station, rather than individual generation assets. Wherever this data source is used to establish CEIs, it is assumed that the assets that constitute the station have the same CEI as the station, except where one or more of the assets have been converted from coal to dual fuel or gas-fired steam.

3. Where there are converted assets within a station, these assets were assigned a CEI based on their heat rate. The remaining assets were assigned a CEI that is based on the historic reported station level data. This may lead to an overestimation of CEIs for assets that have not been converted within the same station, if the most carbon intensive units within a station were converted first.

4. Dual fuel assets are assumed to burn 50% coal and 50% gas.

5. Heat rate information for gas-fired assets has been collected from public resources such as manufacturer websites or AUC filings.

6. Estimating carbon emission intensities for cogeneration facilities is challenging because emissions that relate to power generation in such facilities are often not reported separately from other industrial processes. A handful of cogeneration assets, for which power generation was reported separately under the fossil-fuel electric power generation sector in GHGRP, have been used to establish an average carbon emission intensity factor, which is then applied to other cogeneration assets.

7. Where the CEIs are estimated based on asset heat rates rather than reported emissions, the heat rates (GJ/MWh) are multiplied by the CEI of natural gas (tCO2e/GJ). The analysis uses a CEI of 0.0561 tCO2e/GJ for natural gas.[20]

8. Emissions from all hydro, solar, wind, storage and biomass assets have been set to zero.

9. Imported energy has not been included in the analysis.

10. This analysis does not account for the fact that some generation assets may have different emission intensities at different operating levels.

The MSA is publishing this analysis to provide indicative results and may improve the estimations over time. The MSA welcomes any feedback and further suggestions regarding its approach from market participants.

[20] This figure comes from Table 2.4 in 2006 IPCC Guidelines for National Greenhouse Gas Inventories.

2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves (OR) that the AESO system controllers use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserves, spinning reserves, and supplemental reserves. Regulating reserves (RR) provide an instantaneous response to an imbalance of supply and demand. Spinning reserves (SR) are synchronized to the grid and provide capacity that the system controller can call upon in a short amount of time, when there is a sudden drop in supply for example. Supplemental reserves (SUP) are not required to be synchronized but must be able to synchronize quickly if called upon by the system controller.[21] These products are all bought by the AESO through day-ahead auctions.

2.1 Annual summary

In 2021, both total and average OR costs were more than double those in 2020. Total OR costs in 2021 were $339 million, compared to $148 million in 2020. Table 4 shows the year-over-year average cost changes for active OR products. As shown, the higher average costs were largely driven by higher pool prices. The general correlation between OR costs and pool price is expected because the opportunity cost of providing OR is often forgoing the sale of energy, and for active reserves prices are directly indexed to pool price.

Table 4: Average cost ($/MWh) of active OR products

Product	2021	2020	2021 less 2020
Spinning	$64.41	$22.62	$41.79
Supplemental	$42.96	$17.67	$25.29
Regulating	$64.33	$28.00	$36.33
Avg. pool price	**$101.93**	**$46.72**	**$55.22**

Although average OR costs rose substantially in 2021, these increases were significantly less than the increase in pool price. Table 4 shows that while there was a $55.22/MWh increase in average pool price, the costs of spinning, supplemental and regulating reserves increased by significantly less. This suggests that OR markets were more competitive in 2021 than in 2020.

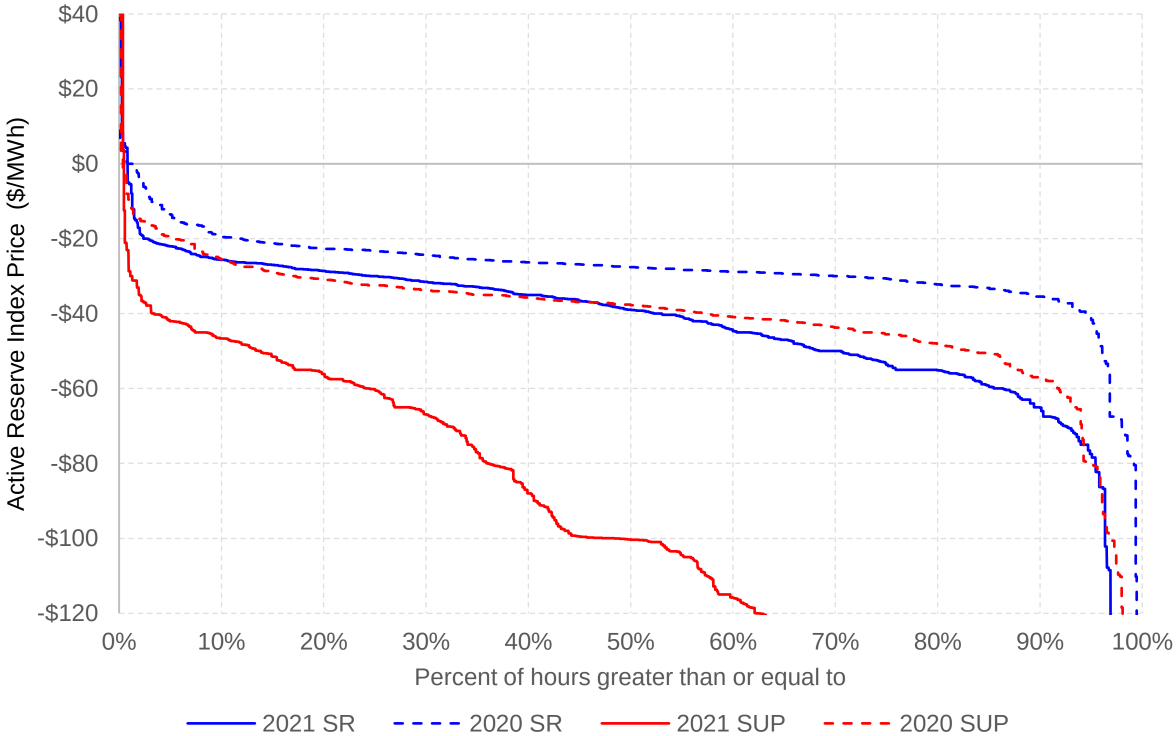
In 2021, competition in the spinning and supplemental reserve markets was driven by new OR providers offering OR at lower costs. From 2020 to 2021, the share of spinning reserve dispatches from battery resources increased from 1% to 13%. The share of supplemental reserve dispatches from load resources increased from 35% to 45%. Increased participation from battery and load resources in OR markets strenghtens competition because these resources generally offer their capacity at relatively low prices. Batteries and loads have opportunity cost profiles that are different from most generators.

[21] For more detailed information, see AESO: Operating Reserve

Figure 22 shows duration curves of the index prices (indexed to hourly pool price) for active spinning and supplemental reserves. The figure illustrates the percentage of hours the index prices for spinning and supplemental were at or above a certain price. In 2021, 50% of hours had a spinning index price greater than negative $39/MWh, compared to the 2020 median of negative $28/MWh.

The annual median supplemental index price dropped more significantly, from negative $38/MWh to negative $100/MWh. The downward shift in the index price duration curves shows that spinning and supplemental reserve markets have settled at lower index prices over the year, indicating increased competition. The supplemental index price fell more than the spinning index price, reflecting the lower opportunity cost of load resources, which cannot participate in the spinning reserve market.

Figure 22: Duration curves of index prices for active spinning and supplemental reserves, between $40 and -$120 (2020 and 2021)



2.2 Costs and volumes

Total OR costs increased in Q4 compared to both Q4 2020 and Q3 2021 as a result of higher average costs, and greater procured active volumes. Table 5 shows that the average cost of active spinning and supplement reserves was nearly four times higher in Q4 relative to Q4 2020. Figure 23 shows total OR costs by month. Total OR costs in Q4 were $76.5 million compared to $69.0 for Q3 2021 and $24.1 million for Q4 2020. The high costs in Q4 were mostly attributed to the cold weather and higher pool prices during the last week of December. This in turn led to greater intertie flows which needed to be supported by increased OR volumes.

Table 5: Average cost ($/MWh) of active OR products

Product	Q4 2021	Q4 2020	Q4 2021 less Q4 2020
Spinning	$63.32	$15.15	$48.16
Supplemental	$38.54	$9.98	$28.55
Regulating	$56.77	$24.88	$31.89
Avg. pool price	**$107.31**	**$46.13**	**$61.19**

Figure 23: Total cost of active and standby reserves and average pool price by month

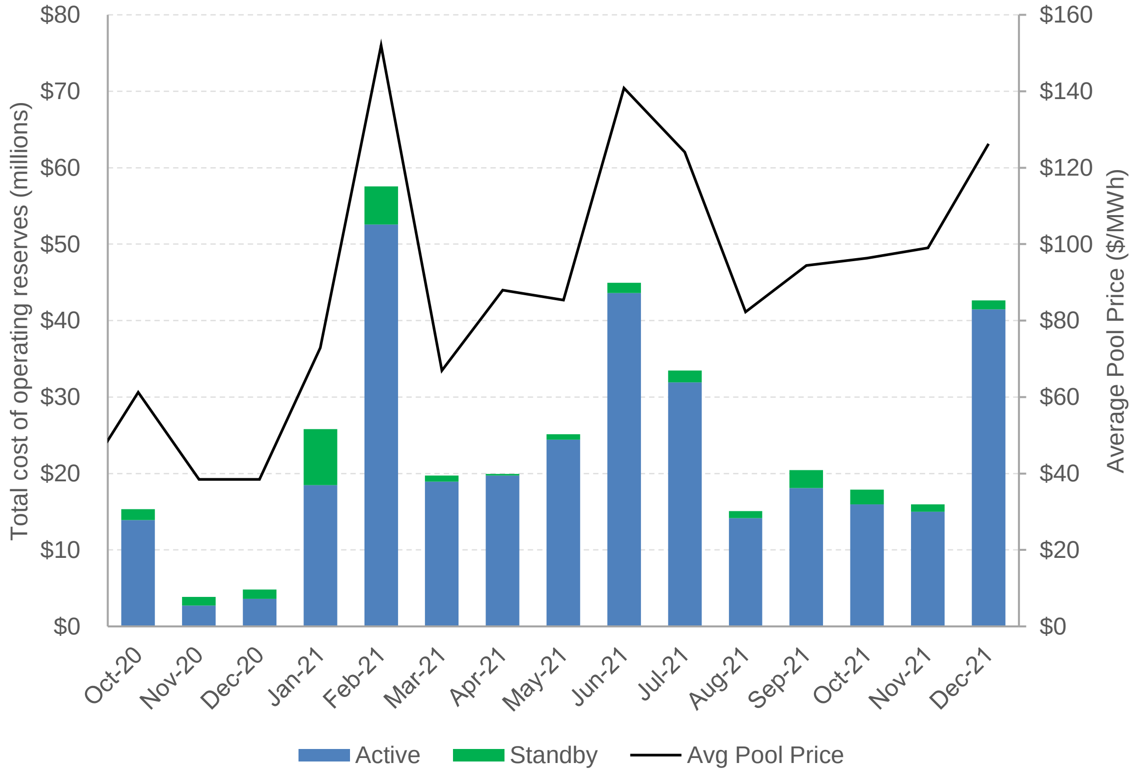


Figure 24 shows daily on-peak spinning reserve volumes from October 1, 2020 to December 31, 2021. Procured active spinning volumnes (shown in blue) increased in 2021, breaking a daily record at the end of the year, as discussed later. The volume of standby spinning reserves that were activated (shown in orange) and also by quarter in Table 6, has remained low relative to pre-February 2021 levels, when the AESO began to procure more active reserves day-ahead, as opposed to activating standby in real-time.

Figure 24: Active and standby spinning volumes, on-peak (Oct. 1, 2020 to Dec. 31, 2021)

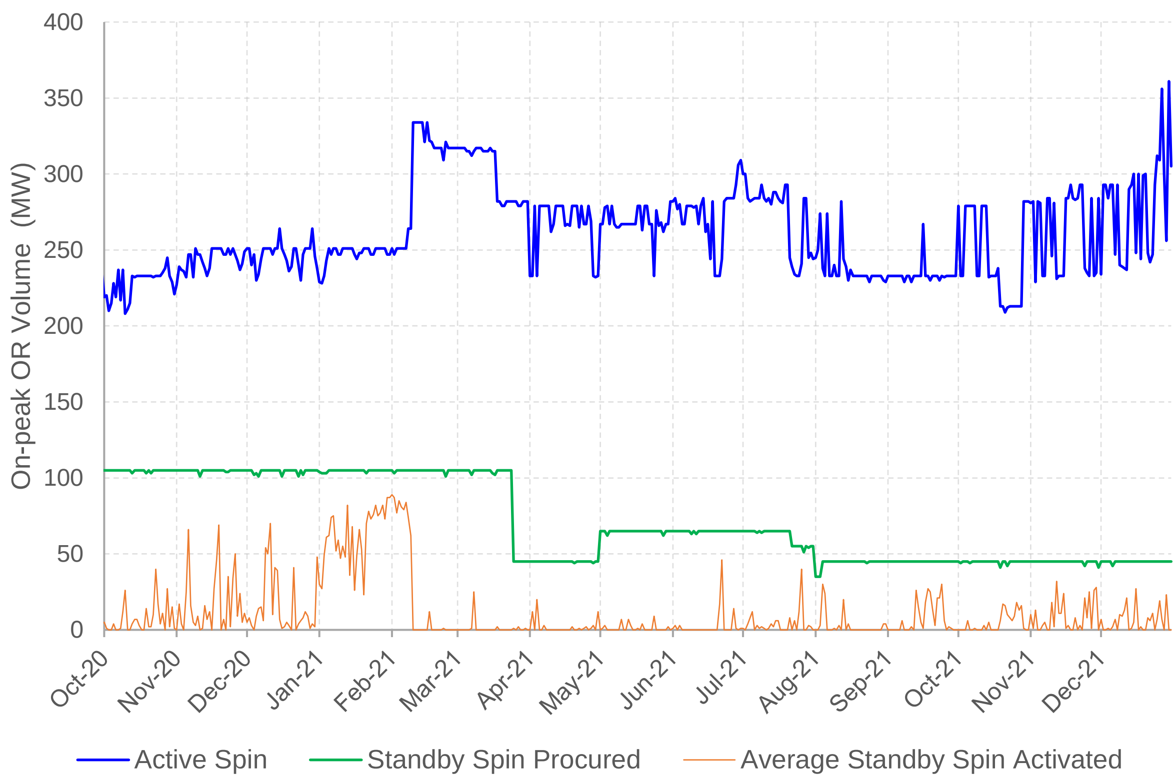


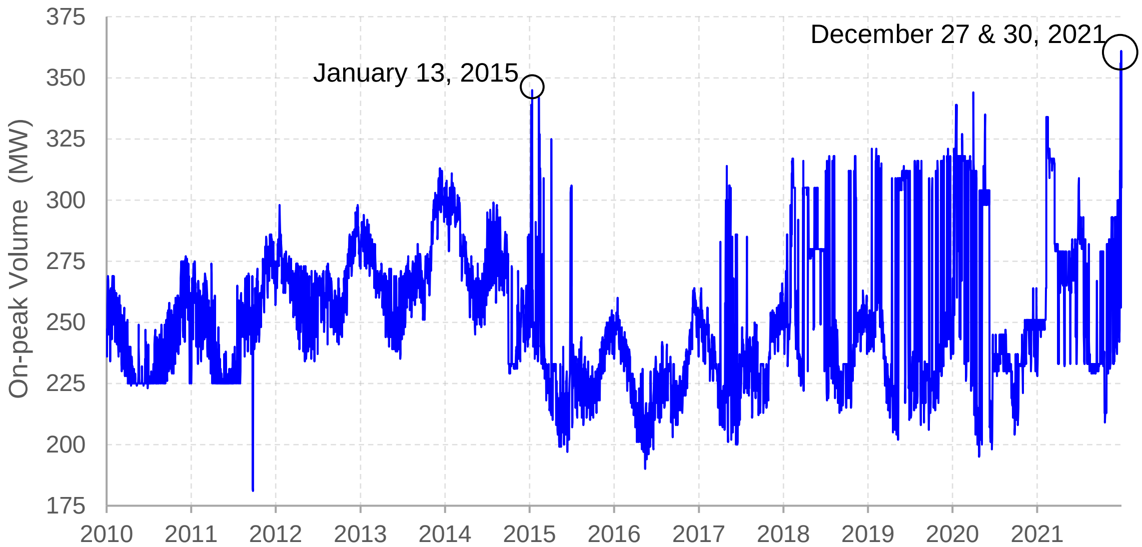
Table 6: Total spinning reserve activations by quarter (Q4 2020 to Q4 2021)

Quarter	Total SR activations (MW)
Q4 2020	21,038
Q1 2021	57,382
Q2 2021	6,611
Q3 2021	12,826
Q4 2021	14,972

Record Active OR Volumes

On December 27, the AESO procured a record volume of daily active on-peak spinning and supplemental reserves, procuring 356 MW of each. This record was broken again three days later on December 30, with 361 MW procured. This compares to the previous record of 345 MW procured for January 13, 2015. These record volumes were related to aforementioned cold weather, high demand, and high import volumes. Figure 25 shows daily active spinning reserve volumes from 2010 to 2021, highlighting the record days in 2015 and 2021.

Figure 25: Active daily spinning volumes, on-peak (2010 - 2021)



2.3 Contingency reserve directives

Contingency reserves include spinning and supplemental reserves and are used to restore the balance of supply and demand for electricity after sudden system stresses, such as the loss of a generating unit or an intertie. Contingency reserves include both supply side resources, such as generators that can quickly increase their supply, and demand side resources, such as loads that can quickly reduce their electricity consumption.

When contingency reserves are called upon to replace an unexpected loss of supply, the system controller issues a directive to contingency reserve providers. Upon receipt of a directive, a contingency reserve resource must provide a real power response, either by increasing generation or decreasing load, within ten minutes.[22] Contingency reserves are used in addition to re-dispatching energy resources to balance supply and demand.

Contingency reserves are a type of operating reserve and are bought by the AESO through day-ahead auctions. The portion of an asset's available capability that is providing active reserves cannot also provide energy. This means the MW of available capability that are providing active contingency reserve are not in the energy market merit order and directing contingency reserve resources does not directly cause a change in the dispatch level in the energy market.

Resources providing standby contingency reserve offer their available capability into the energy market, though when these standby resources are activated, the volume of activated standby MWs are removed from the energy market merit order, and the asset will receive a corresponding energy dispatch to reflect that volume of MW being used to provide reserves. All else being equal, directing contingency reserve will not increase the System Marginal Price (SMP), whereas

[22] AESO Information Document 2013-007R Contingency Reserve

dispatching additional energy can increase the SMP, as determined by offers in the energy market merit order.

In some cases, when contingency reserves are directed, the fast-ramping power is largely able to balance supply and demand. This restored balance delays the need for additional energy, thus delaying dispatching up the energy merit order, which delays an increase in SMP. The lag between a large generator trip and an increase in SMP varies case-by-case, and can be minutes to tens of minutes.

Figure 26 provides an example of how contingency reserve directives function and the dynamics between them and energy dispatches. The following sequence of events occurred on May 26, 2021:

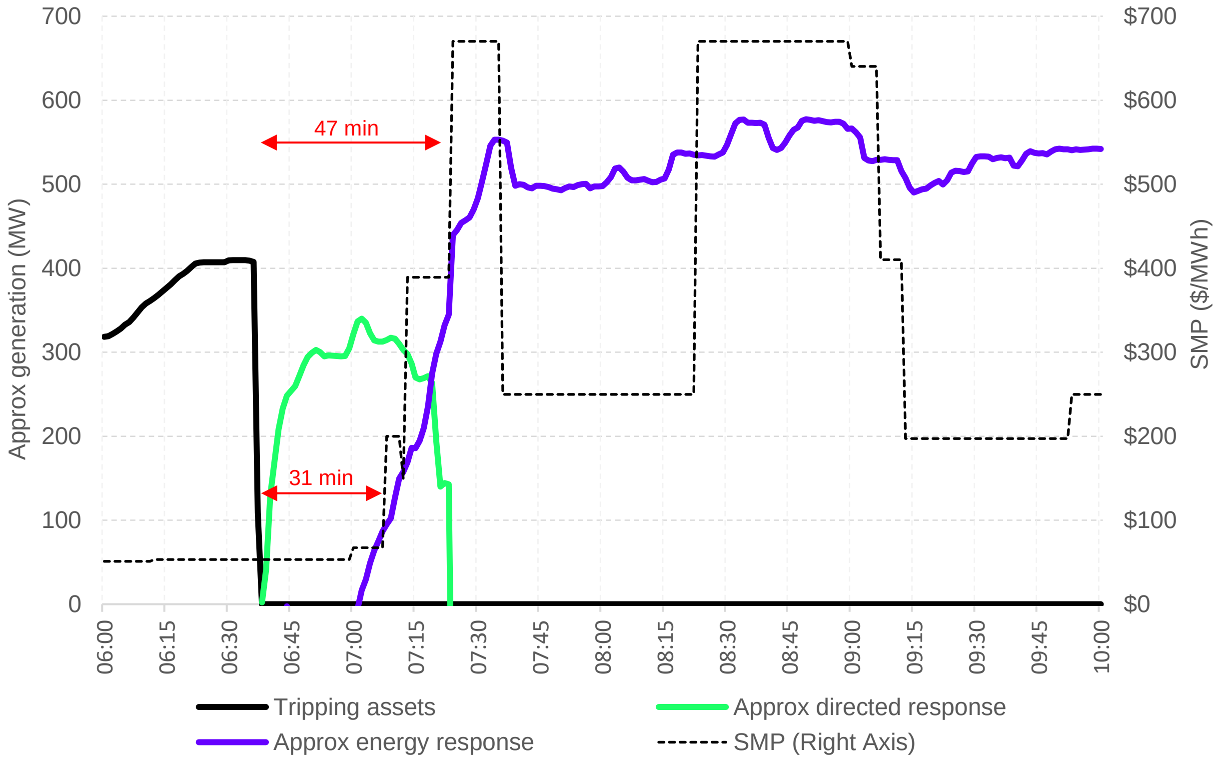
- Two generators tripped off, resulting in a loss of over 400 MW of generation at 06:37.
- Within a minute, 430 MW of contingency reserves were directed on.
- At 07:00, 23 minutes after the trip, multiple energy dispatches became effective, resulting in a slight SMP increase from $53.04/MWh to $67.12/MWh (these dispaches were issued at 06:44 to be effective at the top-of-the-hour).
- 31 minutes after the trip, a significant volume of energy dispatches became effective, from a second set of dispatches (issued at 07:05, effective at 07:08), resulting in the first large SMP increase to $200.00/MWh at 07:08.
- Approximately 47 minutes after the trip, various contingency reserve resources were directed off, additional energy resources were dispatched on, and SMP increased to $670.09/MWh at 07:24.

In Figure 26, the green and purple *approximate response* lines are the difference in generation level of select assets, from the directive or dispatch effective time, tracking the subsequent change in output. These lines illustrate the approximate sum of the responses from different assets.[23] During this event, it appears that the generation response provided by contingency reserves aided in the rebalancing of lost supply, and allowed for the delayed dispatch of energy, which delayed moving up the energy merit order to balance the trips by about half an hour. This put some downward pressure on the SMP during this time as dispatches for additional energy

[23] In this chart, the response of directed contingency reserve assets is measured in terms of gross real power response, which is the measure used to determine directive performance. The energy response may show either net-to-grid or gross response, the type depends on which measure is used to determine an asset's energy delivery compliance, and varies per asset. Thus the response lines aggregate both gross and net measurement, are only meant as approximate illustrations. Select assets were chosen to illustrate a simplified sequence of event. Larger assets with significant dispatches and directive were chosen. This chart does not illustrate the change in the MW level of regulating reserve resources, which also support system reliability during system stress.

resources were lagged, which was facilitated in part by the generation from contingency reserve resources.

Figure 26: Generation trip, directive response, and energy response event on May 26, 2021



The delay between a trip event and the issuance of energy dispatches can vary. In some events, energy dispatch instructions are issued within minutes of a unit trip and in others there may be a delay of tens of minutes before new energy dispatches are issued.

2.4 Contingency reserve directive rates

For spinning and supplemental reserves, when an asset receives a dispatch, the pool participant must ensure the asset is positioned to provide real power in the event the asset is directed to do so. When an asset receives a directive, the asset must, within ten minutes of receipt of the instruction, provide a real power response and maintain a certain level of generation in the case of generators, or reduce electricity consumption in the case of loads. Only a small percent of the dispatched volume of spinning and supplemental reserves is directed to provide real power. The following three figures illustrate how frequently contingency reserves resources were directed in 2020 and 2021. The charts show a breakdown by contingency reserve product, by resource fuel type, and by dispatch/directive size.

Figure 27 illustrates the percent of dispatched contingency reserves that were directed to provide real power by product,[24] showing spinning reserve, supplemental reserve, and the two sub-categories of supplemental reserves, generators (SUPG) and loads (SUPL). Spinning reserves were directed more frequently than supplemental reserves. Further, among resources dispatched to provide operating reserves, generators were relatively more likely to be directed to provide real power by the AESO than loads.

Figure 27: Dispatched contingency reserve directed by product type (Jan. 2020 to Dec. 2021)

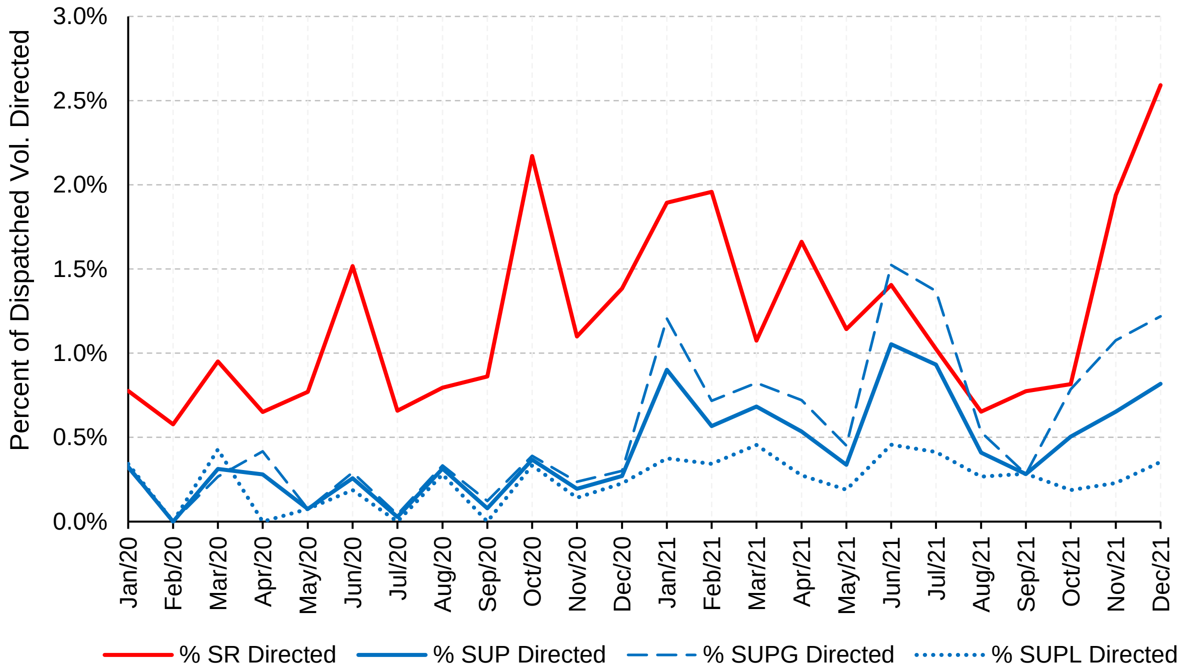


Figure 28 illustrates the percent of dispatched contingency reserves (all products) that were directed by fuel type. Hydro assets were generally directed more frequently than other fuel types, while load assets were directed less. Battery assets, which are highly responsive but generally smaller in size, were not directed with significantly higher frequency compared to other fuel types, suggesting that asset size is also important.

[24] The method of calculating directive percentages is as follows: the sum of directed volume (the numerator) is the sum of directed MW for each instance of a directive instruction. This does not describe MWh but rather MW*instructions. The sum of OR dispatches (the denominator) is the sum of dispatched active and standby, which is sold on a per hour basis and so is in MWh.

This method of counting means that if a resource is directed for 10 MW, be it for 10 minutes or 30 minutes, it will be counted as a single 10 MW directive. If a directive spans multiple settlement intervals it is still counted as a single directive. It is instances of instructions directing a resource to turn on that determines the count of directives.

Figure 28: Dispatched contingency reserve directed by fuel type and quarter (Q1 2020 to Q4 2021)

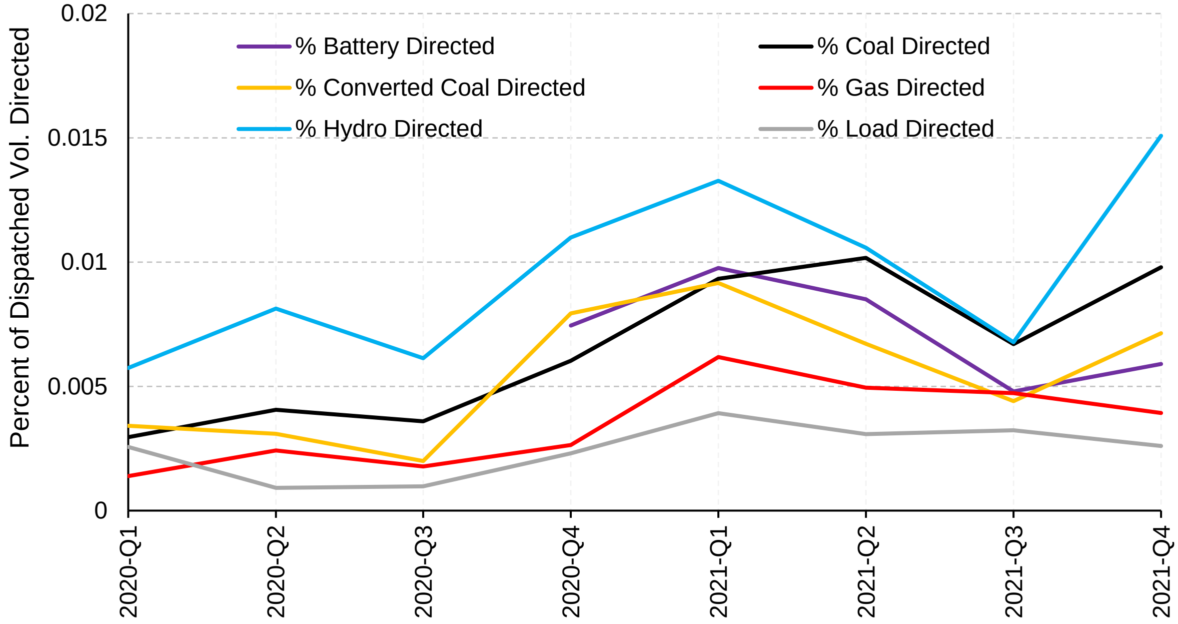
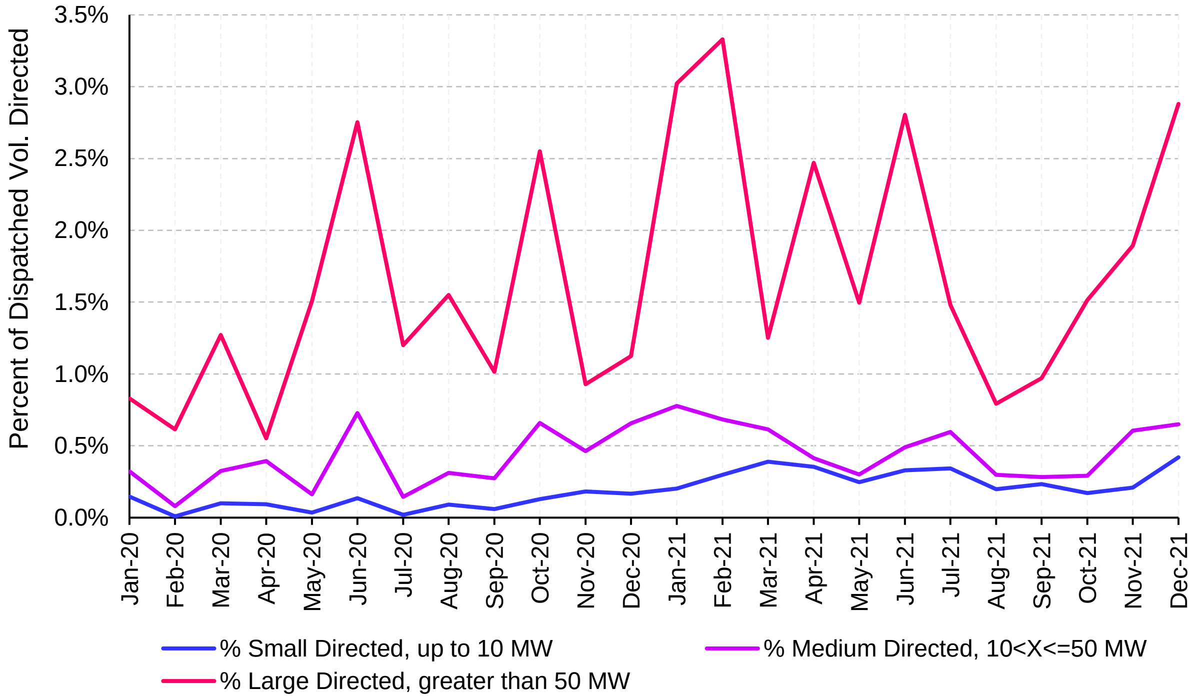


Figure 29 illustrates the percent of dispatched contingency reserves that were directed, by dispatch/directive size:

- small is from 0 to 10 MW,
- medium is from 11 to 50 MW, and
- large is greater than 50 MW.

Larger resources were directed more frequently than smaller resources. This could suggest a preference by the AESO to direct larger resources than to direct many smaller resources. There may also be an interaction between fuel type and size. Generally hydro resources are larger and are generally very responsive.

Figure 29: Dispatched contingency reserve directed by size (Jan. 2020 to Dec. 2021)



As illustrated, directives are most frequently issued to contingency reserve resources that are larger. This is especially visible for dispatches/directives over 50 MW. Resource fuel types that are more responsive or reliable also appear to be directed more often, though fuel types associated with responsiveness, such as hydro, also tend to be larger resources. Lastly, it appears that generators were directed more frequently than loads.

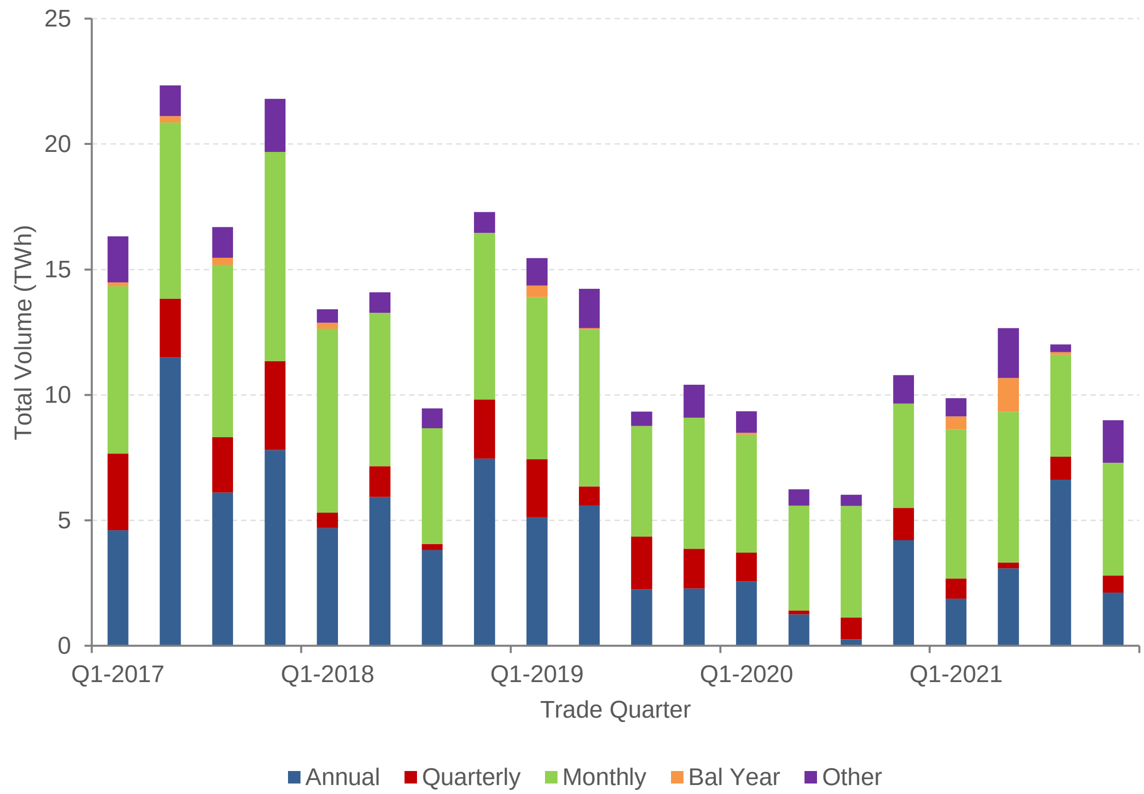
3 THE FORWARD MARKET

3.1 Forward market volumes

The financial forward market is an important component of Alberta's energy-only market design. In particular, it allows generators and larger loads to hedge themselves from pool price volatility. Hedging involves reducing exposure to pool prices by buying or selling in the forward market for a fixed price, to diversify the buy/sell price and reduce risk. Similarly, the forward market enables retailers to reduce the risks associated with selling electricity to retail customers at a fixed price, which will tend to lower the fixed prices available to retail customers.

The MSA's analysis in this section incorporates trade data from ICE NGX and Canax, an over-the-counter (OTC) broker, which are routinely collected by the MSA as part of our surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2021 are also included. These bilateral trades occur directly between two trading parties, not via ICE NGX or through a broker, and the MSA generally collects information on these transactions once a year.

Figure 30: Total trade volumes by contract term and trade quarter (Q1 2017 to Q4 2021)[25]



[25] The monthly volumes include full-load RRO trades based on the expected 4 MW traded volume.

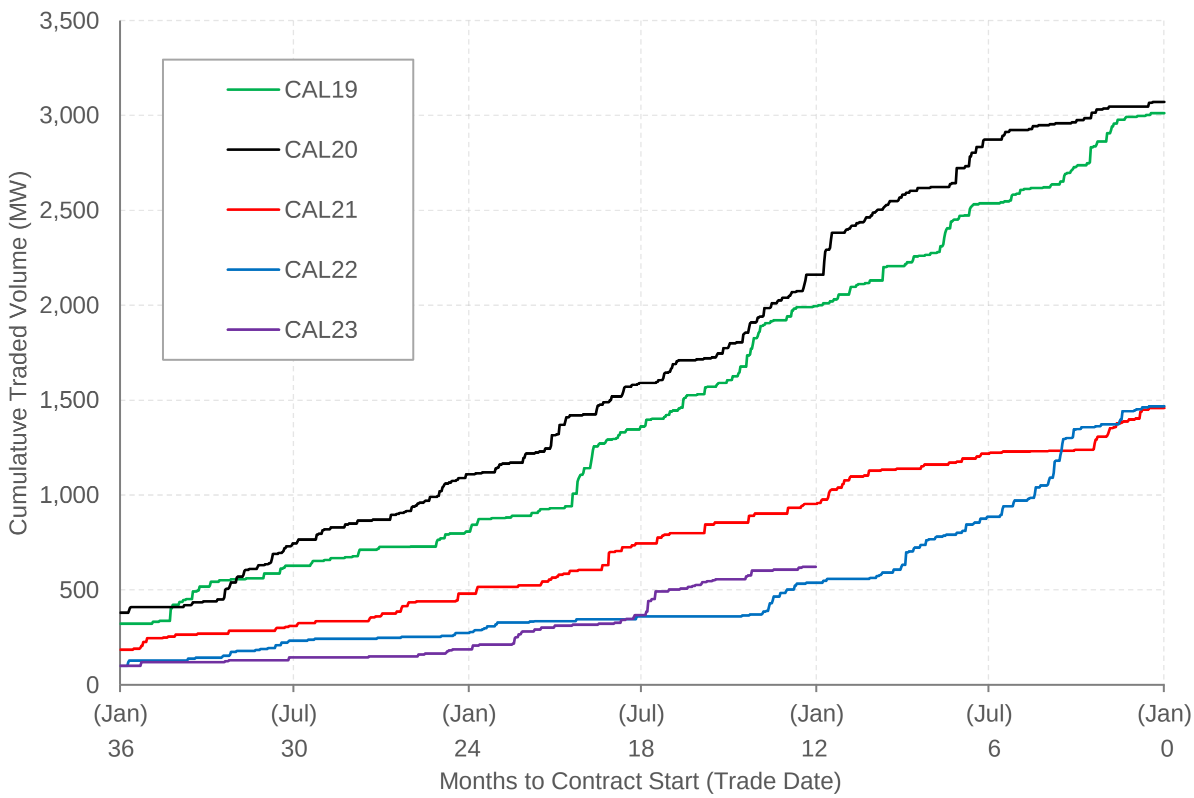
Figure 30 illustrates the total volume of trades, by the quarter in which the trades took place, from Q1 2017 to Q4 2021. The total volume is the total amount of power traded financially over the duration of a contract. The volumes are categorized based on the duration of the contract, such as annual and monthly, and these volumes include standard contract shapes, such as flat, extended peak, and off-peak, in addition to the monthly full-load RRO volumes.

Compared to Q3 2021, total volumes in Q4 2021 declined by 25%. This was mainly due to the higher volume of annual trades in Q3, which was not sustained into Q4. Total volumes in Q4 also declined by 17% compared to Q4 2020 as annual volumes were lower.

The total volume traded in 2021 was 43.5 TWh, which is 34% higher than in 2020 as total volumes declined materially in Q2 and Q3 of 2020 (Figure 30). However, the total volume traded in 2021 was 12% lower than in 2019. Direct bilateral trades accounted for 12% of total volumes in 2021, down slightly from 2020.

Figure 31 illustrates traded volumes for the CAL22 and CAL23 flat contracts relative to those of CAL19, CAL20 and CAL21.[26] Traded volume is the hourly volume of power being exchanged financially within a given transaction. As shown in the figure, traded volumes for CAL22 were similar to CAL21, and lower than the volumes for CAL19 and CAL20.

Figure 31: Cumulative traded volumes for CAL19 to CAL23 flats (up to December 31, 2021)



[26] Flat contracts cover HE01-24 for all days in the contract period and settle against the average pool price.

3.2 Trading of monthly products

Figure 32 compares monthly flat forward prices to realized pool prices for January to December 2021. As shown, monthly forward prices in 2021 generally traded at a discount to realized pool prices. For February, June, July, and December forward prices traded significantly below the realized average pool price. For December, the volume-weighted average forward price was $88.23/MWh compared to the average pool price of $126.27/MWh, a discount of 30%.

The average pool price for 2021 was $101.93/MWh but monthly forward prices have traded well below this level. Using the volume-weighted average forward price for each month yields an annual price of $72.76/MWh for 2021, a discount of 29%. For context, this implies that a 50 MW load may have saved in the region of $12.8 million by buying at monthly forward prices rather than pool prices in 2021. In general, forward prices typically trade at a risk premium to more volatile pool prices. The $29.17/MWh discount seen in 2021 not only differs from this general trend but is also substantially greater than the size of previous discounts observed in 2011 and 2013 (Table 7).

Figure 32: Monthly flat forward prices and average pool prices (Jan. to Dec. 2021)

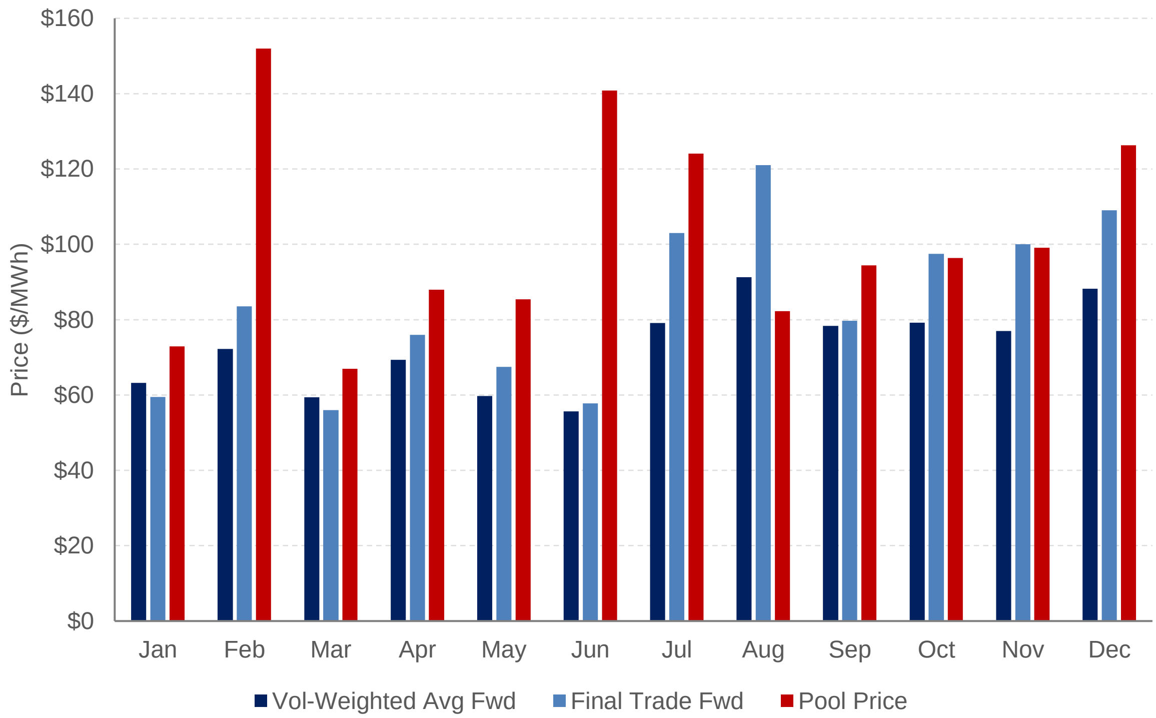


Table 7 compares monthly average forward prices and average pool prices by year from 2010 to 2021. As shown, monthly forward prices have typically traded at a premium to pool prices, and the discount in 2021 was unusually high compared to historical data. As discussed in section 1, the higher pool prices in 2021 were driven in part by extreme weather events, more thermal generator outages, higher natural gas prices, and the offer behaviour of some larger suppliers.

Table 7: Monthly average forward prices and pool prices by year[27]

Year	Monthly Forward Prices	Average Pool Price	Forward Premium (Monthly Fwd less Pool Price)
2010	$51.26	$50.88	$0.37
2011	$73.64	$76.22	-$2.57
2012	$76.15	$64.32	$11.83
2013	$65.79	$80.19	-$14.40
2014	$59.84	$49.42	$10.43
2015	$43.43	$33.34	$10.09
2016	$31.38	$18.28	$13.10
2017	$27.48	$22.19	$5.29
2018	$53.04	$50.35	$2.70
2019	$58.42	$54.88	$3.54
2020	$51.79	$46.72	$5.07
2021	**$72.76**	**$101.93**	**-$29.17**

Figure 33 illustrates the evolution of forward prices for the monthly contracts of October 2021 to March 2022. Pool price volatility, weather forecasts, and natural gas prices were the main factors influencing forward power prices over Q3 and Q4. For example, in early October forward prices increased on the back of pool price volatility and increasing natural gas futures. In mid-October, forward prices declined as pool prices came in below forward market expectations during the BC/MATL intertie outage and natural gas futures pulled back. Subsequently, increasing natural gas prices put upward pressure on power prices in late October. Between October 21 and 27 the price of natural gas for January 2022 increased by 23% from $5.02/GJ to $6.17/GJ (Figure 34).

Following this peak, natural gas prices fell throughout November and into early December as production increased and temperatures across much of North America were warmer than normal, reducing natural gas withdrawals from storage. The natural gas price for January was $3.34/GJ on December 6, 46% lower than the peak on October 27 (Figure 34).

Forward power prices fell in early November as natural gas prices were declining. However, even though natural gas prices kept falling, pool prices in the energy market remained relatively high and this put upward pressure on forward power prices in mid-to-late November. As discussed in section 1.3, the average pool price in November was $99.07/MWh despite record wind generation, falling natural gas prices, and modest demand levels.

[27] Monthly average forward prices use the volume-weighted forward price for each month to calculate an annual price.

Figure 33: Forward power prices for the October to March monthly flat contracts (5-months out)

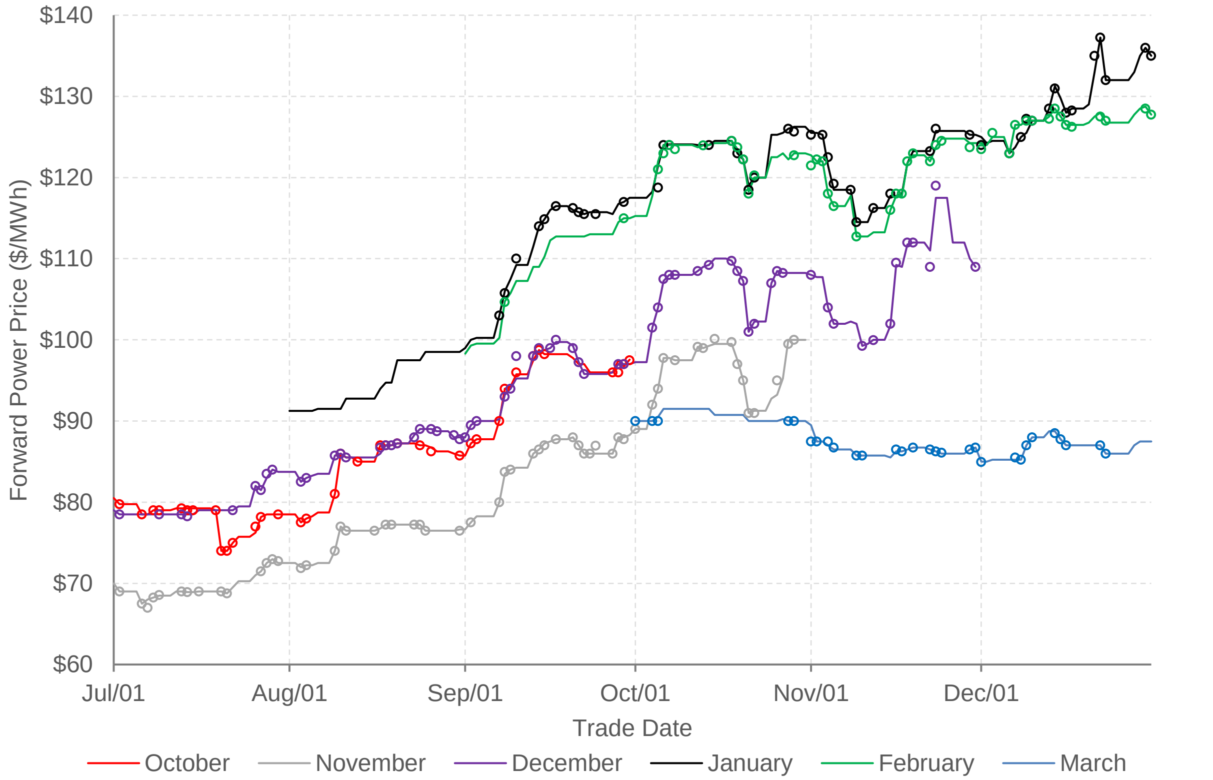
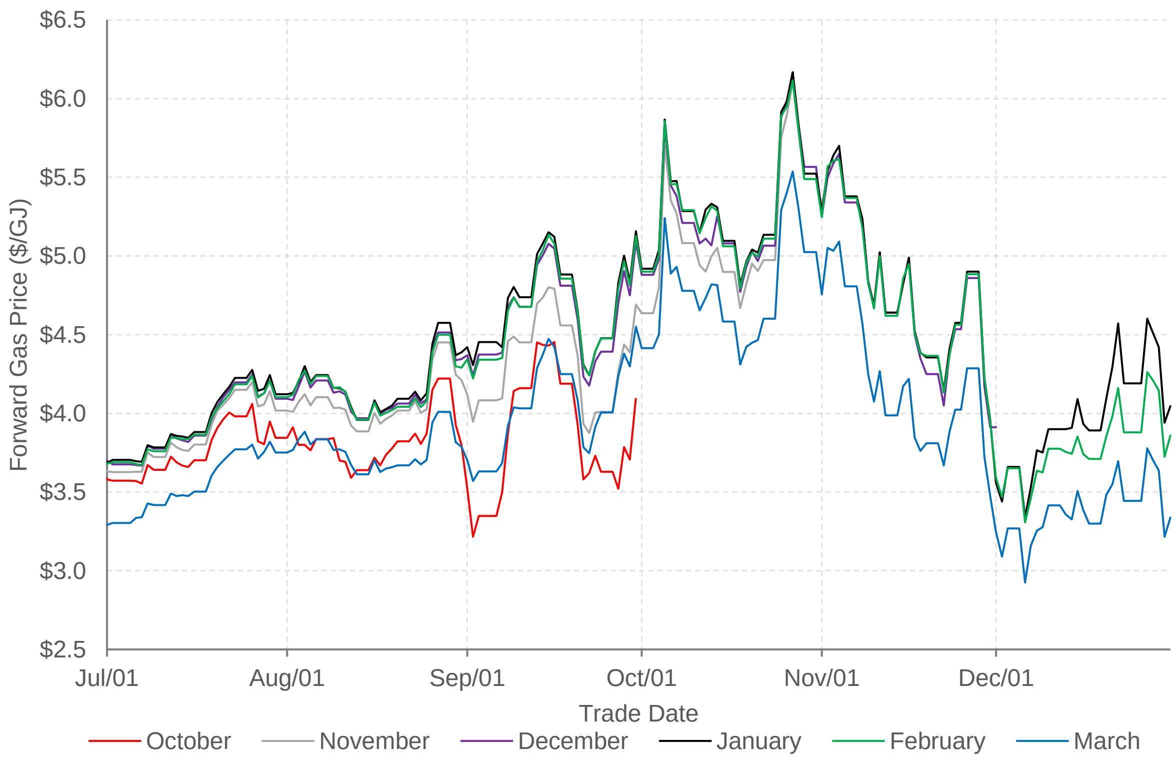


Figure 34: Forward natural gas prices for the October to March flat monthly contracts

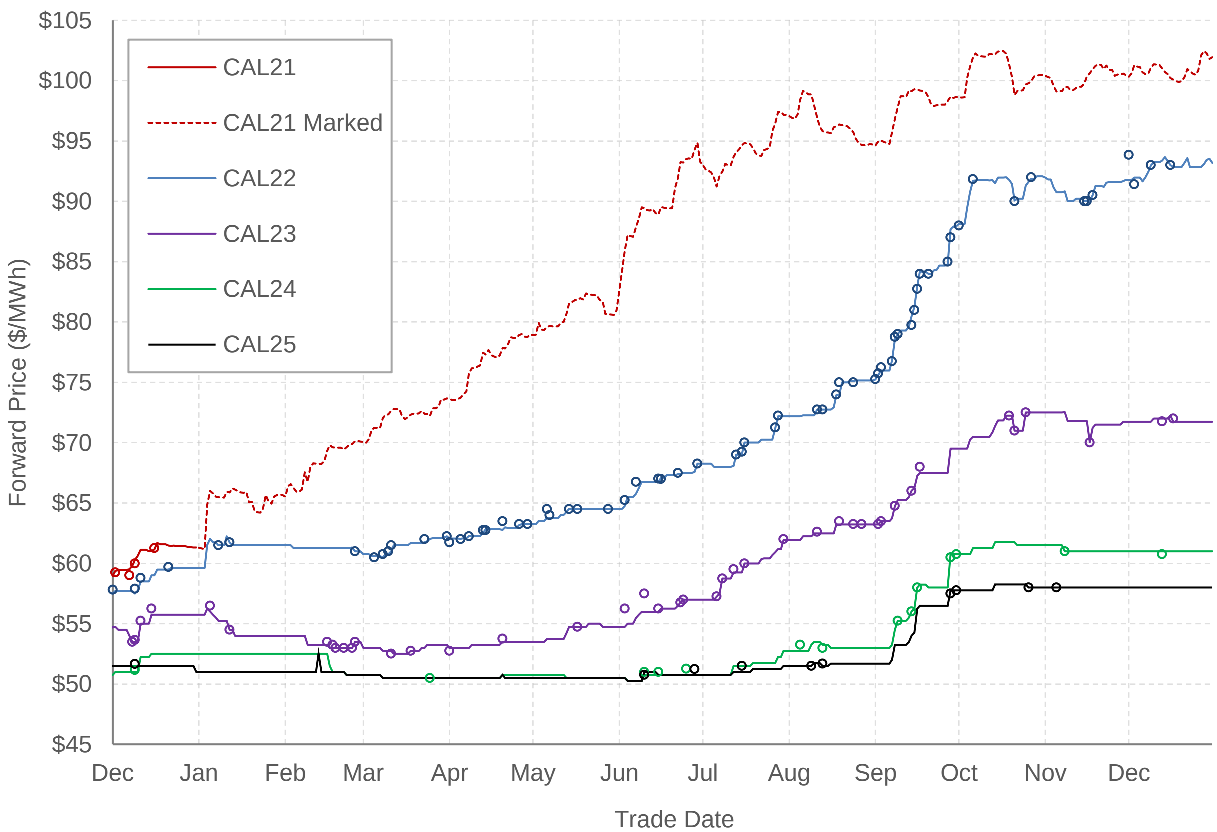


Forward prices for January and February traded at elevated levels for much of Q4 (Figure 33). These forward prices reflected an expectation of higher pool prices, with the potential for cold weather to increase demand and reduce wind generation. In addition, Keephills 1 (400 MW) retired on December 31 and the capacity of Sundance 4 was reduced from 406 MW to 113 MW, both of which reduced expected supply. Forward prices for March traded at much lower levels, mainly because there is much less potential for extreme weather.

3.3 Trading of annual products

The average pool price in 2021 was $101.93/MWh, which is well above where forward prices for CAL21 were trading. The CAL21 contract last traded for $61.25/MWh on December 16, 2020, a 40% discount relative to the average pool price (Figure 35). The marked value of CAL21 increased over 2021 as pool prices came in above forward market expectations, and as forward prices for the balance of year increased. The higher price of CAL21 put upward price pressure on other annual contracts, particularly CAL22.

Figure 35: Forward power prices for the calendar 2021 to 2025 flat contracts (over trade dates Dec. 1, 2020 to Dec. 31, 2021) [28]



[28] The marked price for CAL21 uses realized pool prices in combination with forward prices for the coming days and months to value the CAL21 contract. The solid lines in the chart illustrate daily settlement prices and the markers illustrate the latest trade price on a given day.

The price of natural gas for CAL22 peaked at $4.38/GJ on October 27, when the power contract for CAL22 traded for $92.00/MWh. Subsequently, natural gas prices declined meaningfully through November, and in early December the price of natural gas for 2022 was $3.20/GJ, a fall of 27% relative to October 27. In early November, the power price for CAL22 initially fell along with natural gas futures but in mid-November forward prices responded to pool price outcomes and began to increase slightly. As a result, the market heat rate for CAL22 increased. As of December 31, the power price for CAL22 was $93.19/MWh and the price of natural gas was $3.20/GJ, yielding a market heat rate of 29 GJ/MWh, a 32% increase relative to the heat rate of 22 GJ/MWh at the end of October.

Forward power prices are decreasing into the future (Figure 35), and this is largely the result of lower natural gas prices and expected supply increases. On December 22 a multi-year flat trade covering 2022 through 2025 cleared for a price of $71.50/MWh. Increased supply is expected as more renewable capacity is being developed and large generation projects are expected to come online including Travers Solar (465 MW), Cascade combined-cycle (900 MW), the repowering of Genesee 1 and 2 (+560 MW), and the Base Plant cogeneration project (806 MW).

3.4 Regulated Rate Option (RRO) auction prices

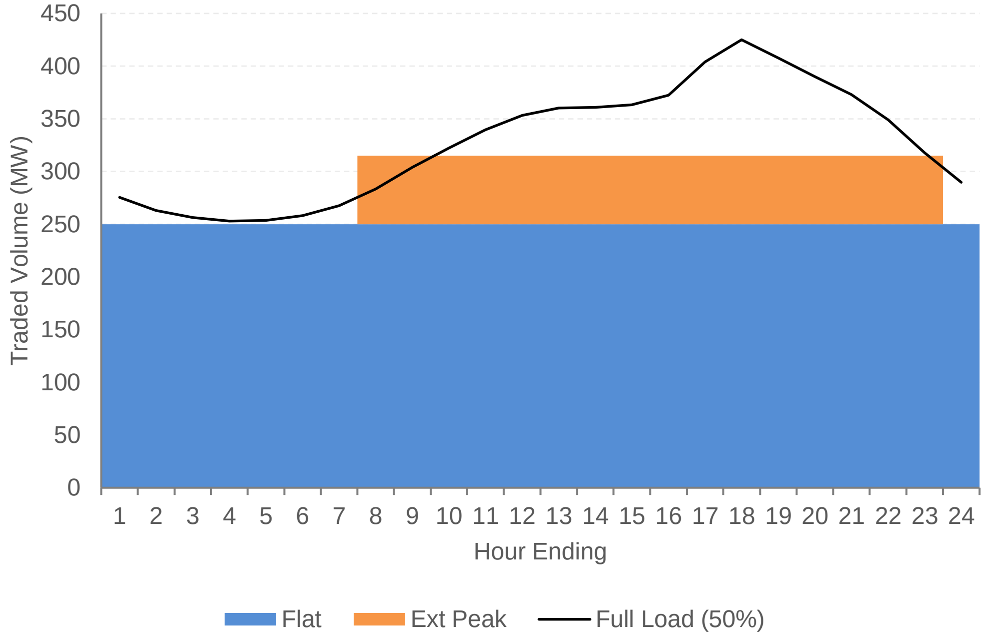
Alberta has a competitive retail electricity sector wherein retail customers can choose to buy their electricity from a number of different sources and for different lengths of time. Retail customers that consume less than 250,000 kWh annually are eligible for the RRO, a regulated electric energy rate for customers that do not sign a contract with a competitive electricity retailer. Approximately 40% of residential customers procure their electricity through an RRO provider. Retail customers that are on the RRO can choose to leave the RRO at any time, and instead sign a contract with a competitive electricity retailer.

The two largest RRO providers, EPCOR and ENMAX, serve approximately 83% of total RRO consumption. The price of electricity that is provided by the RROs in any given month is linked to the electricity prices that prevailed in the forward market in the months leading up to that RRO rate period. This is because RRO providers procure different types of monthly products in the forward market to meet their forecasted load. The process by which this procurement is structured and carried out is set out in a provider's Energy Price Setting Plan (EPSP). EPSPs are proposed by RRO providers to be effective for approximately three years and are overseen and approved in regulatory proceedings by the Alberta Utilities Commission.

Under the current EPSPs, both EPCOR and ENMAX procure a combination of flat, extended peak, and full load forward products. Flat covers all hours in the delivery period and settles against the hourly pool price, while extended peak settles against the average pool price from 07:00 to 23:00 over all days in the delivery period (Figure 36).

Full load strips differ from flat and extended peak products. While the flat and extended peak products specify a fixed quantity of electricity, full load strips instead specify a certain percentage of the actual RRO hourly load. For instance, a seller may commit to financially provide 2.5% of EPCOR's RRO load in February at a fixed price, and the volume traded will fluctuate from hour to hour as EPCOR's RRO load changes with the weather, time of day, and other factors. On average, the full load strips are each expected to result in a 4 MW volume, but the final settlement amount is not completely known until about six months after the delivery month.

Figure 36: Flat, extended peak, and full load shapes (EPCOR example)



EPCOR and ENMAX procure their RRO volumes through a series of descending clock auctions. For each delivery month, three or four auctions are held within the 120 days preceding the delivery month. In each auction, the RRO provider procures a portion of the expected volumes for the upcoming delivery month. As an example of this, Table 8 shows the RRO procurement auction dates for the December 2021 EPCOR RRO.

Table 8: EPCOR RRO auction dates for December 2021

Auction number	Auction date
1	Aug 24, 2021 (Tue)
2	Sep 21, 2021 (Tue)
3	Oct 26, 2021 (Tue)
4	Nov 16, 2021 (Tue)

For EPCOR, approximately 50% of expected load is hedged using the full load product, while the other 50% is hedged through flat and extended peak products. For ENMAX, approximately 40% is hedged using full load and 60% through flat and extended peak.

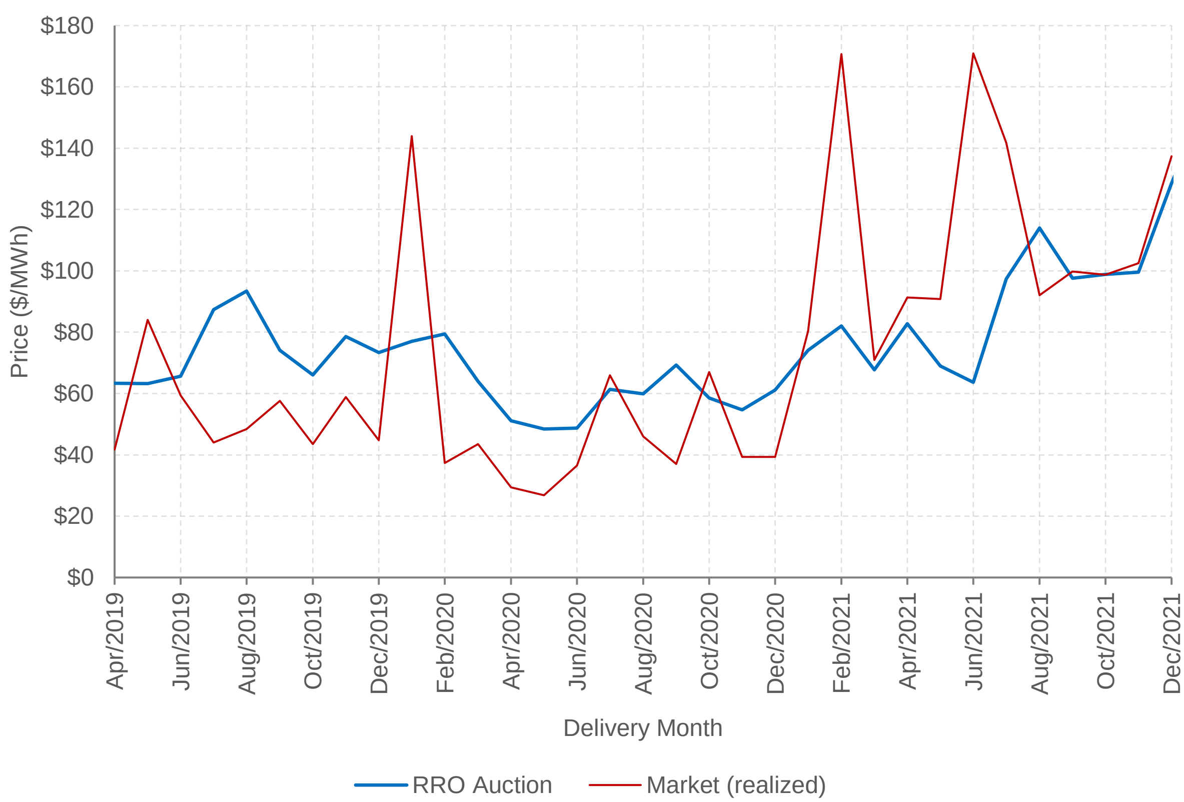
The full load product is unique to the RRO auction and acts as a means of valuing the price and quantity risk associated with supplying regulated retail electricity products. Historically, a combination of flat and extended peak forward products were procured to cover the regulated retailer's load profile. As a result, for hours where demand was higher than the procured volume, the retailer would have to buy power at pool price, and in hours where demand was lower than the procured volume, the retailer would be selling power at pool price.

The full load procurement mechanism was first proposed as part of the EPCOR 2018-2021 EPSP with April 2019 acting as the first delivery month. A similar mechanism was introduced for the December 2020 delivery month under the ENMAX 2019-2022 EPSP. Prior to the adoption of the full load procurement mechanism, price and quantity risks were administratively priced in accordance with the RRO provider's EPSP. Under the new procurement mechanism RRO rates are largely determined by the price of full load strips purchased in the auctions.

The analysis of pricing and trends in this section focus on the EPCOR RRO due to the longer period of available full load data and because EPCOR is the largest RRO provider.

Figure 37 compares the price of full load strips from EPCOR RRO procurement auctions (the blue line) with the weighted average pool price using EPCOR RRO consumption data (the red line; this is what the full load settles against). Over the entirety of this period the full load product has traded at a slight discount (0.2%) to the weighted-average pool price and has incurred much less volatility.

Figure 37: Monthly EPCOR RRO full load prices and full load weighted pool price (April 2019 to December 2021)



In 2021 the full load contract price averaged $89.80/MWh while the weighted average pool price averaged $114.22/MWh, indicating a forward discount for this specific product of 21% in the auction (Table 9). As discussed in section 3.2, monthly forward prices generally traded at a discount to pool prices in 2021.

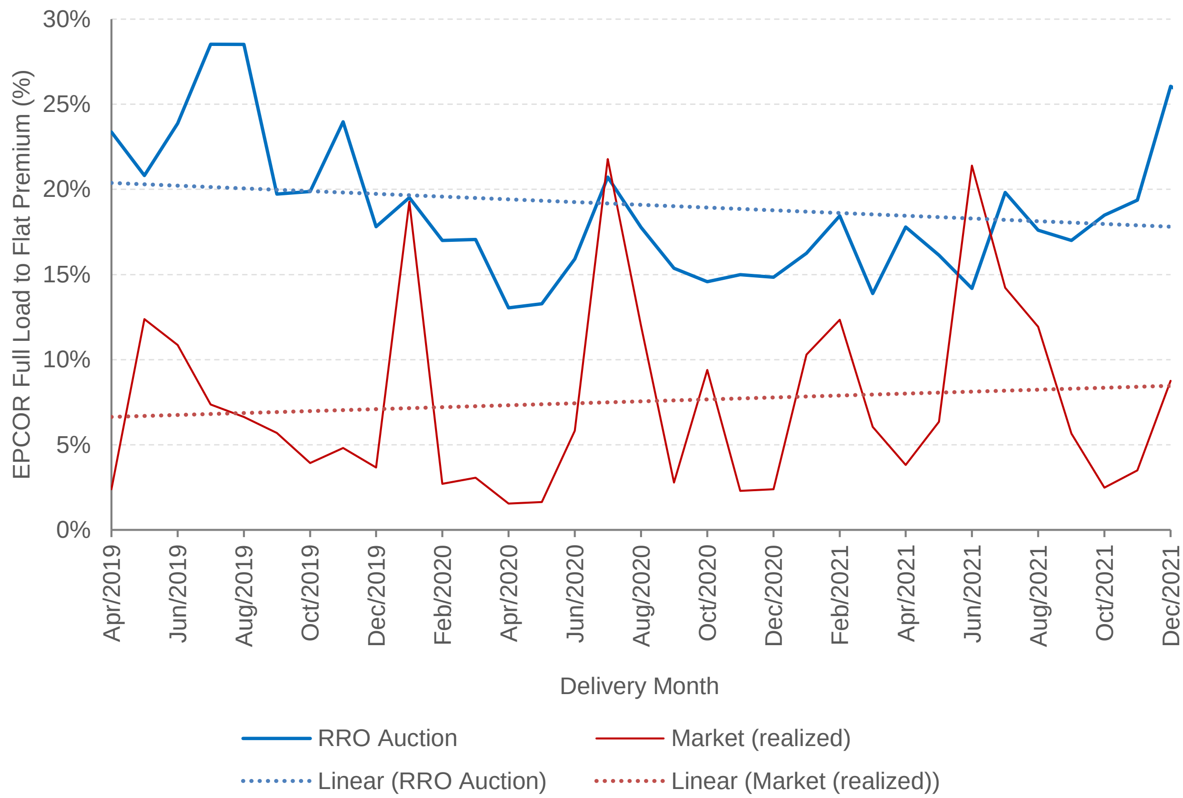
Prior to 2021, the EPCOR full load strips traded for a forward premium of 26%, which is notably high relative to 2021. Similar dynamics were observed for forward flat prices. For the contract months of April 2019 to December 2020 the flat contracts traded at a premium of 16% in the EPCOR RRO auctions, but in 2021 forward flat prices were at a discount of 26% relative to the average pool price.

Table 9: EPCOR RRO auction and realized pool prices

		RRO Auction (forward)	Realized (pool price)	RRO Auction Premium (%)
Apr-19 to Dec-20	Flat	$55.74	$48.17	16%
	Full Load	$66.93	$53.20	26%
	Full Load to Flat Premium (%)	20%	10%	10%
Jan-21 to Nov-21	Flat	$75.76	$101.93	-26%
	Full Load	$89.80	$114.22	-21%
	Full Load to Flat Premium (%)	19%	12%	6%

The full load to flat premium (“full load premium”) compares the ratio of full load prices (the weighted-average pool price) to flat prices (the average pool price). The forward full load premium serves as an indication of the expected price and quantity risks for a given month. Prior to 2021, the forward auction priced the full load premium at 20% on average. On a realized basis, the full load premium over this period was 10%. In 2021 the full load premium in the EPCOR forward auctions fell to 19%, which was 6% higher than the realized full load premium.

Figure 38: Monthly EPCOR RRO full load premium and realized full load premium (April 2019 to December 2021)



The blue line in Figure 38 shows the full load premium in the EPCOR RRO auctions by delivery month. The red line in the figure shows the realized full load premium based on actual pool prices and EPCOR consumption levels. Over this period the RRO full load premium has frequently been higher than the realized full load premium, and the magnitude is variable from month to month. Only in a small number of volatile months does the realized full load premium come close to, or slightly exceed, the premium traded in the RRO auctions.

As noted earlier, the procurement of full load strips for RRO volume procurement is a relatively recent development. As such, the period of analysis is comparatively short when considering that available for other forward products. Over time, it would be expected that the full load premium in the auctions should tend to move in a converging direction towards the realized full load premiums, as the market for full load strips continues to mature. The trend lines in Figure 38 suggest that, on average, there has been a degree of convergence that is generally directionally aligned with this expectation.

4 THE RETAIL MARKET

4.1 Competitive retail rates

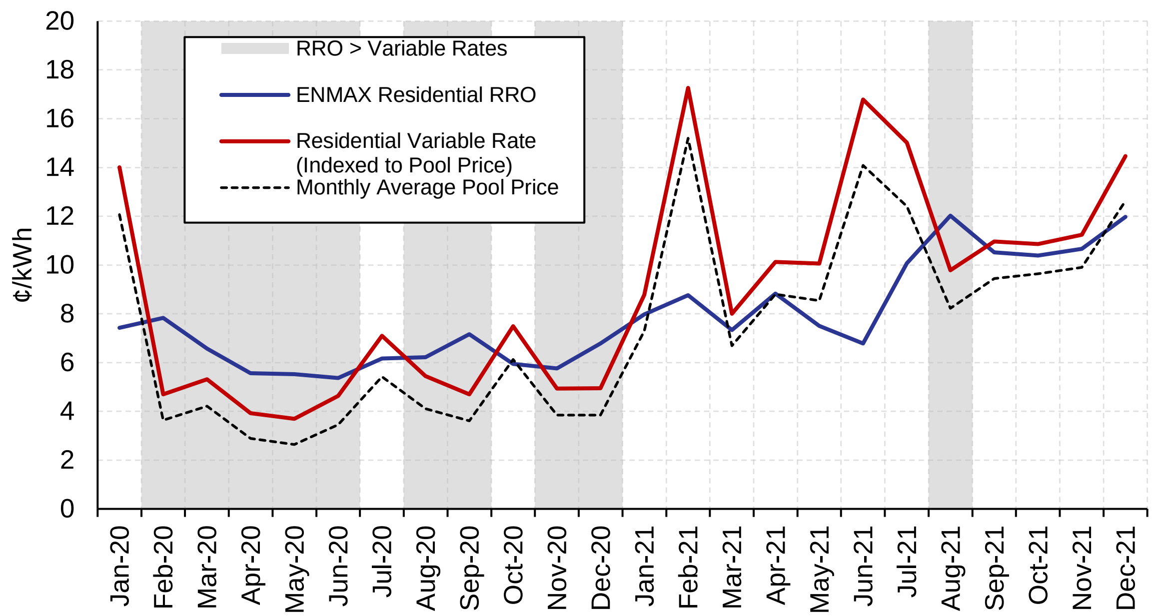
Alberta retail customers can choose to sign a contract with a competitive retailer. Competitive retailers typically offer two types of competitive energy rates to customers: fixed rates, which remain fixed over a prescribed number of years, or variable rates, which are either tied to wholesale prices or regulated rates and vary monthly.

4.1.1 Variable rates

Retail customers on variable electricity rates tied to pool price will typically not pay the monthly average pool price, but rather an average pool price weighted to account for load shape. Variable rate customers with relatively high consumption in on-peak hours, such as residential customers, typically pay more than the monthly average pool price. Variable rates tied to pool price often incorporate an adder to the energy rate, often around 1 cent/kWh.

Pool prices increased significantly in 2021, leading to significant increases in variable rates tied to pool prices (Figure 39). In the ENMAX service area, customers on variable rates tied to pool price experienced significantly higher energy rates compared to customers on the regulated rate option (RRO) in most 2021 months. This was a significant departure from 2020, which saw both significantly lower variable rates and a greater likelihood of the RRO being outperformed by variables rates tied to pool price.

Figure 39: Residential variable electricity rates vs. RRO, ENMAX service area, 2020 to 2021[29]



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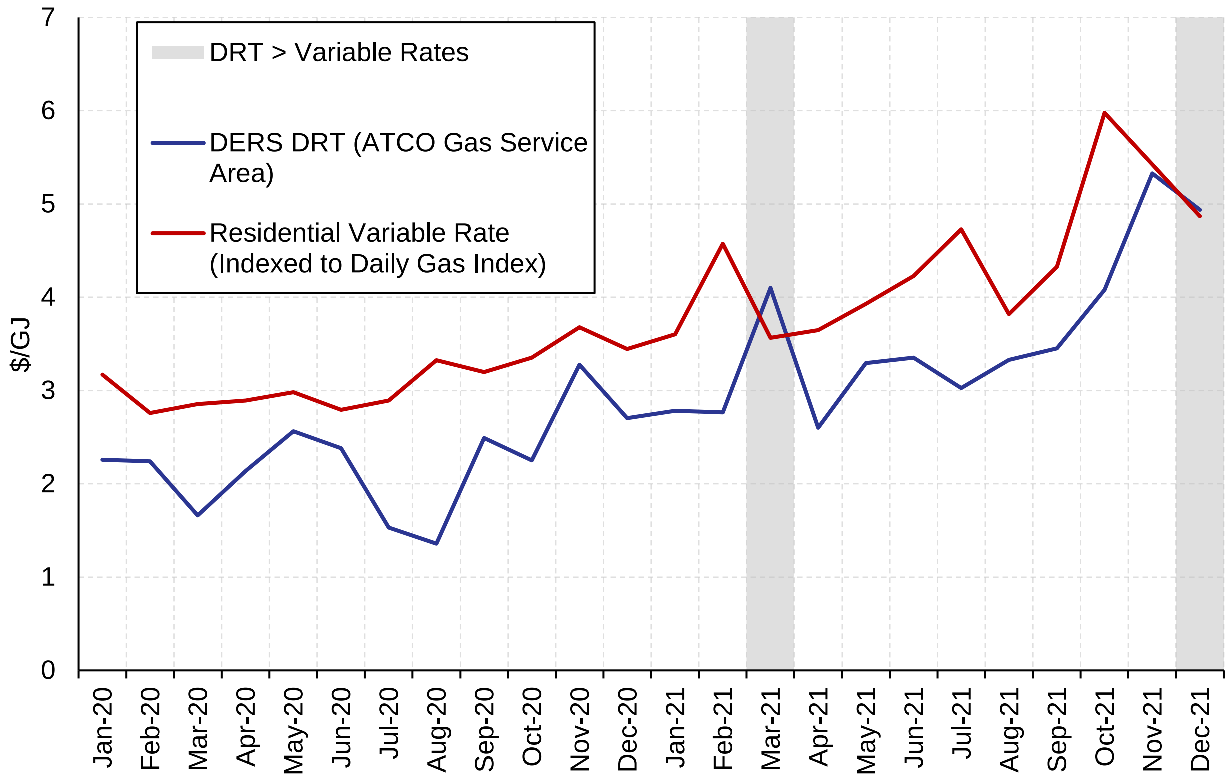
[29] Floating rates calculated using a representative residential load shape in the ENMAX service area, including a 1 ¢/kWh adder.

Both default rate tariff (DRT) rates and variable natural gas rates have increased since 2020. Unlike variable electricity rates, variable natural gas rates tied to same-day gas indices have rarely been lower than DRT rates since 2020, although this is highly dependent on the magnitude of the adder included in the variable rate (Figure 40).

Figure 40: Residential variable natural gas rates vs. DRT, ATCO Gas South service area, 2020 to 2021[30]



In response to historically high variable rates, some competitive retailers have placed price ceilings on their variable rate offerings, reducing the risk of significant month-over-month increases in variable energy rates to customers.

4.1.2 Fixed rates

When determining the price of fixed rate contracts offered to new or returning customers, retailers consider the expected cost of that customer's energy consumption over the length of the contract. Some retailers hold forward market length or generation capacity, acting as a hedge against the wholesale market cost of their retail customers' consumption. Other retailers use forward market prices to guide their pricing decisions.

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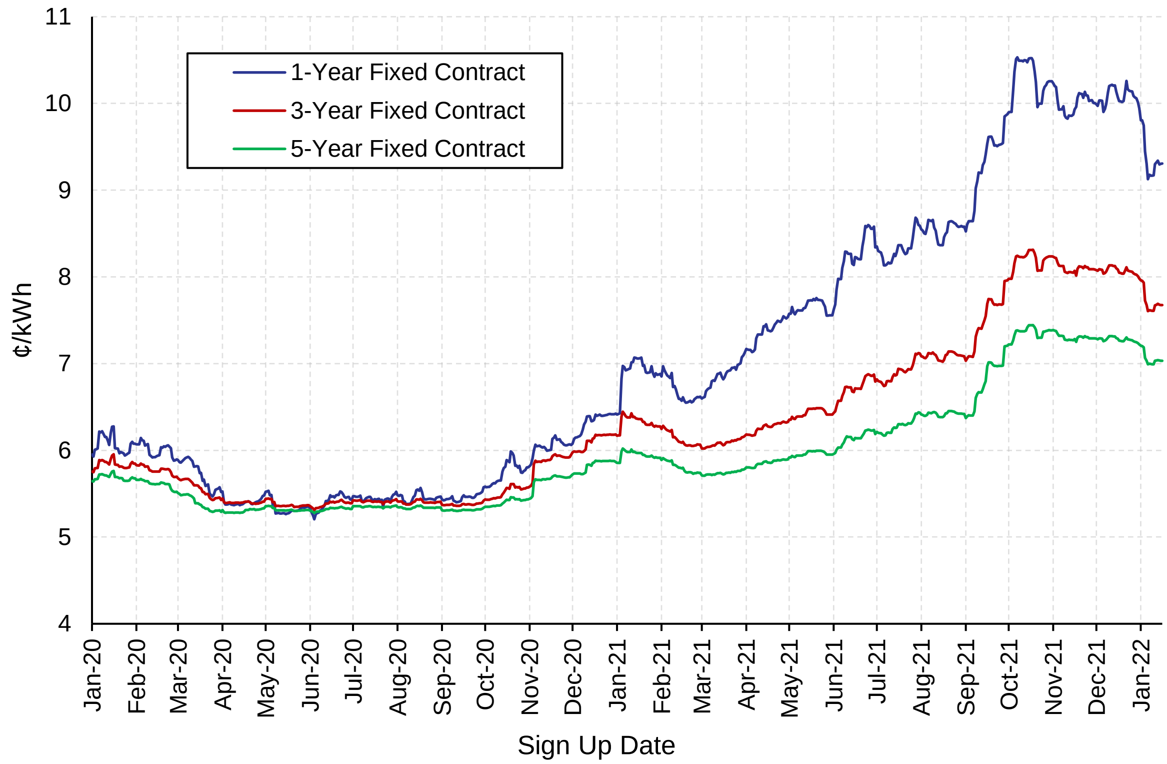
[30] Floating rates calculated using a flat load shape in the ATCO Gas South service area, including a 1 $/GJ adder. Direct Energy Regulated Services (DERS) is the DRT provider in the ATCO Gas service areas.

The 2021 increase in both near-term and long-term forward electricity and natural gas futures prices has significantly impacted retailers' expected cost (Figure 41, Figure 42). For 2020, the MSA estimates retailers expected to pay an average of approximately 5 to 6 cents/kWh for a new fixed rate residential electricity customer over the course of the customers' contract, with less than 0.5 cents/kWh difference between contracts of different lengths. Similarly, 2020 expected cost estimates for a new residential natural gas customer largely ranged from $2 to $3/GJ, with a $0.50/GJ difference in expected cost between the shortest and longest contracts.

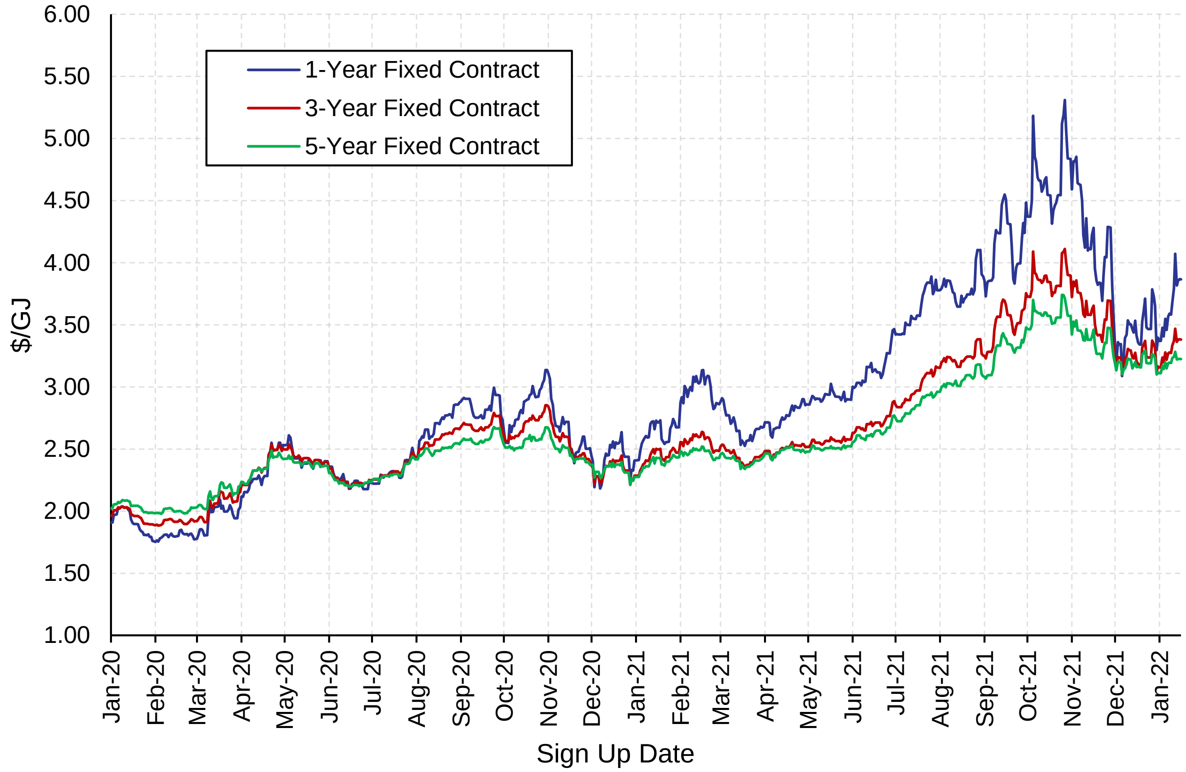
As forward prices increased throughout 2021 these expected costs increased significantly, peaking in October and gradually declining over the remainder of the quarter. Spreads between the expected costs associated with different contract lengths also increased significantly, with expected costs of 1-year and 5-year term contracts differing by as much as 3 cents/kWh and $1.50/GJ in October 2021.

Figure 41: Retailers' expected cost of a new residential electricity customer, ENMAX service area, 2020 to January 16, 2022[31]



[31] Calculated using a representative residential load shape in the ENMAX service area.

Figure 42: Retailers' expected cost of a new residential natural gas customer, ATCO Gas South service area, 2020 to January 16, 2022[32]



Competitive fixed rate electricity offerings have increased significantly as retailers' expected costs have increased (Figure 43, Figure 44). Most of the largest retailers in 2020 offered 3-year fixed electricity at rates between 6 and 7.50 cents/kWh, and natural gas at rates between 3.50 and 4.50 $/GJ. While all major retailers increased their 3-year fixed rates in 2021 as expected cost increased, retailers differed in the timing and magnitude of their response. Some retailers increased their rate offerings frequently and with little delay as expected costs increased, while other retailers did not and as result were at times offering 3-year rates at prices below expected costs. Some retailers may be more hedged to market volatility than others through physical assets and/or previous forward market trades.

By October 2021 three retailers (denoted Retailers 1, 2, 3 in the figures below) were offering 3-year fixed natural gas and electricity rates at or below expected cost. In late October, one of these retailers increased their 3-year fixed rates offerings for both electricity and natural gas. Three days later another of these retailers also increased their 3-year rate offerings, with the third retailer following with fixed-rate increases the following month.

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[32] Calculated using a representative residential load shape in the ATCO Gas South service area.

Figure 43: 3-year fixed electricity offerings, residential customers, 2020 to January 16, 2022[33]

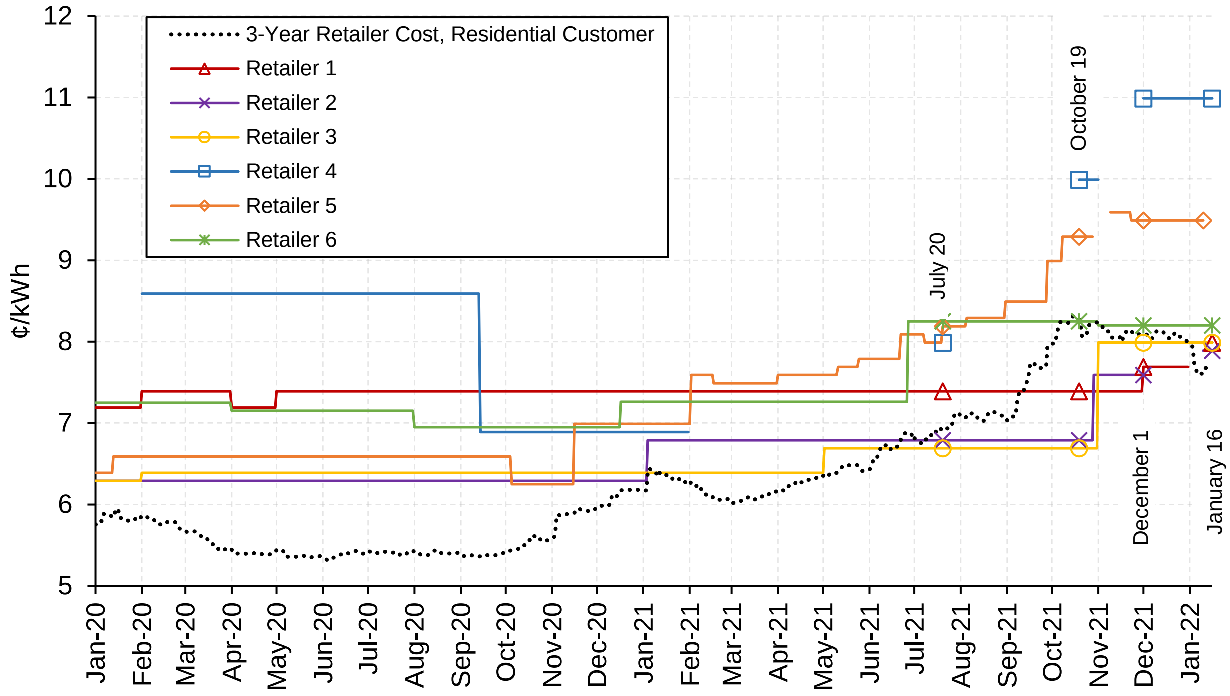
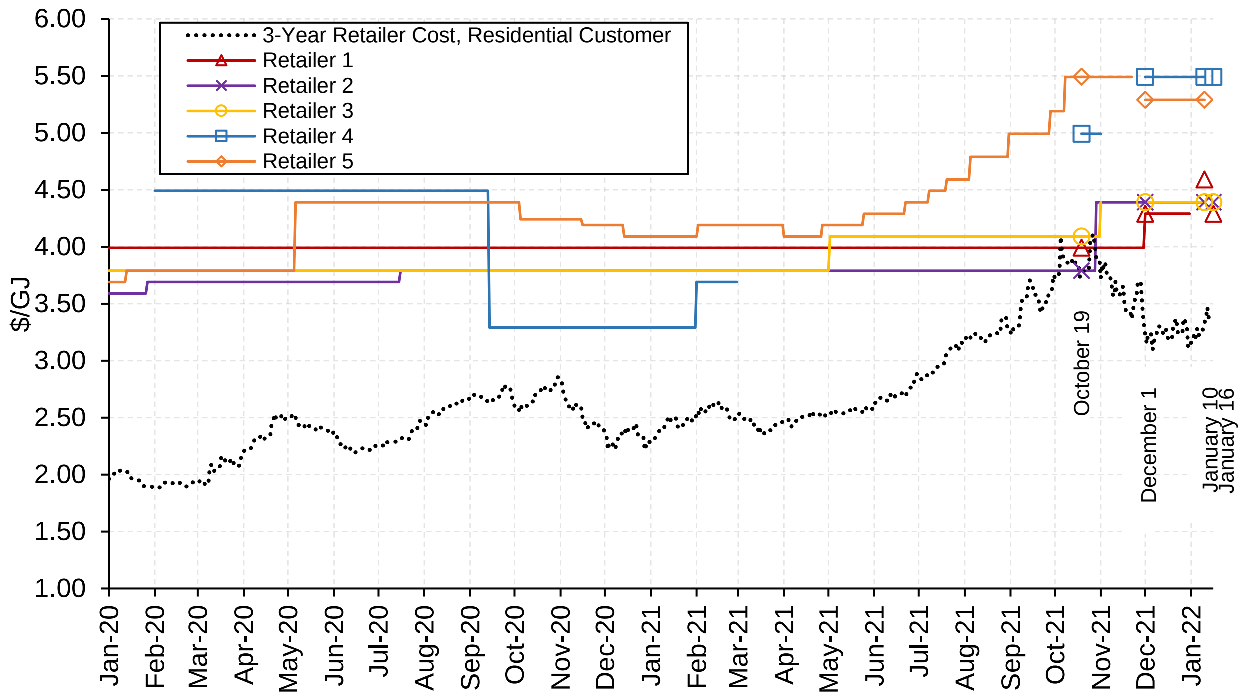


Figure 44: 3-year fixed natural gas offerings, residential customers, 2020 to January 16, 2022[34]



[33] Competitive rate data sourced from the Utilities Consumer Advocate Historic Rates Dataset.

[34] Competitive rate data sourced from the Utilities Consumer Advocate Historic Rates Dataset.

Consumer switching may have played a role in the pricing decisions of certain retailers. Regulated or competitive variable rate customers faced higher energy bills in 2021 compared to the previous year, particularly during the second half of the year. After receiving relatively high energy bills for a period or having heard public discussions relating to energy price expectations, regulated or competitive variable rate customers may have sought to fix their rates and been willing to pay higher rates than those offered earlier in the year. Competitive retailers may have increased their rates prior to such switching.

4.1.3 Competitive energy bills[35]

In 2021, competitive retail energy bills varied significantly between customers depending on: the type of energy rate they were on (fixed or variable), their energy consumption, and in the case of fixed rates, the length of the term and when they signed up for that rate.

For example, a residential customer that signed 3-year contracts with competitive retailers at the start of 2020 might have been offered fixed rates of 6.29 cents/kWh for electricity and 3.59 $/GJ for gas if they chose contracts offered by major retailers with the lowest 3-year rates at the time.

In 2020, such a customer paid similar monthly electricity bills compared to competitive variable rate customers or RRO customers (Figure 45). However, by 2021 electricity bills for both competitive variable rate and RRO customers were significantly higher and more volatile than those received by this fixed rate competitive customer.

In 2021 RRO and variable rate customers paid $200 and $400 more on their electricity bills (respectively) compared to 2020. However, fixed rate customers, such as the representative 6.29 cent/kWh customer, paid similar amounts in 2020 and 2021 (Table 10).

[35] Consumption forecasts for Q4 2021 have been used to construct billing estimates in this section.

Figure 45: Residential competitive fixed rate electricity bills vs. RRO & competitive variable rate bills, 2020 to 2021[36]

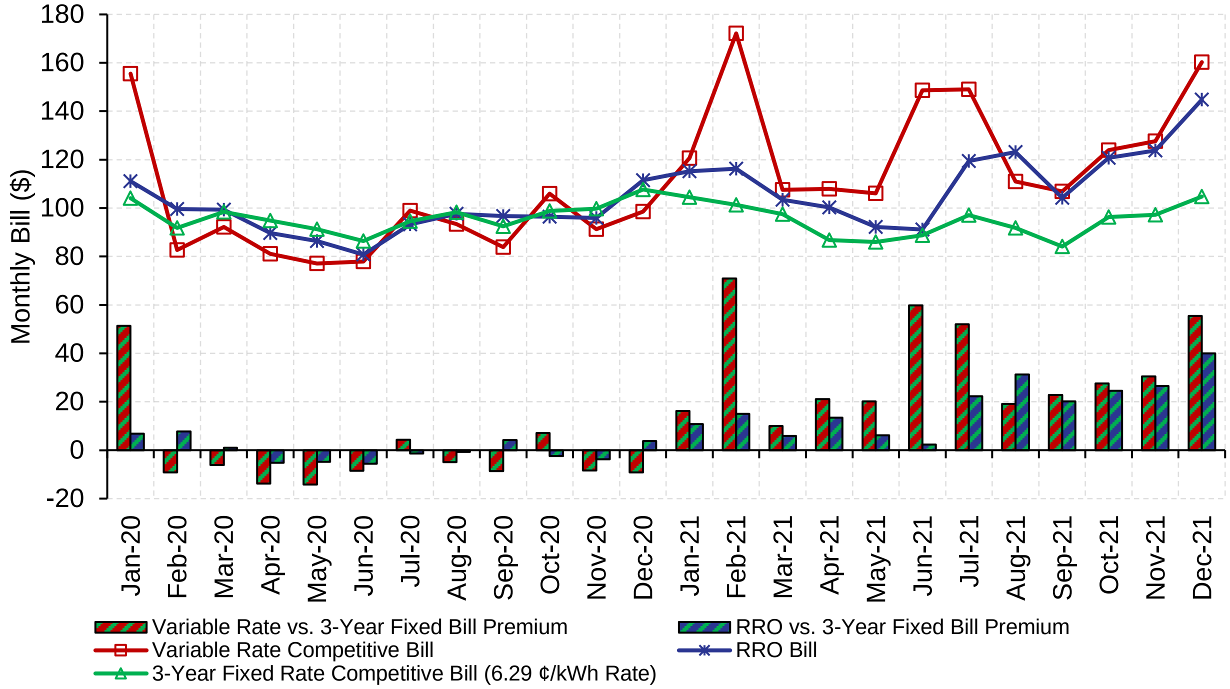


Table 10: Annual residential electricity bills ($), ENMAX service area, 2020 vs. 2021

Year	RRO	Variable Rate	Fixed Rate (6.29 ¢/kWh)
2020	1,158.33	1,138.50	1,158.75
2021	1,354.59	1,541.62	1,136.15
Difference	+ 196.26	+ 403.12	- 22.60

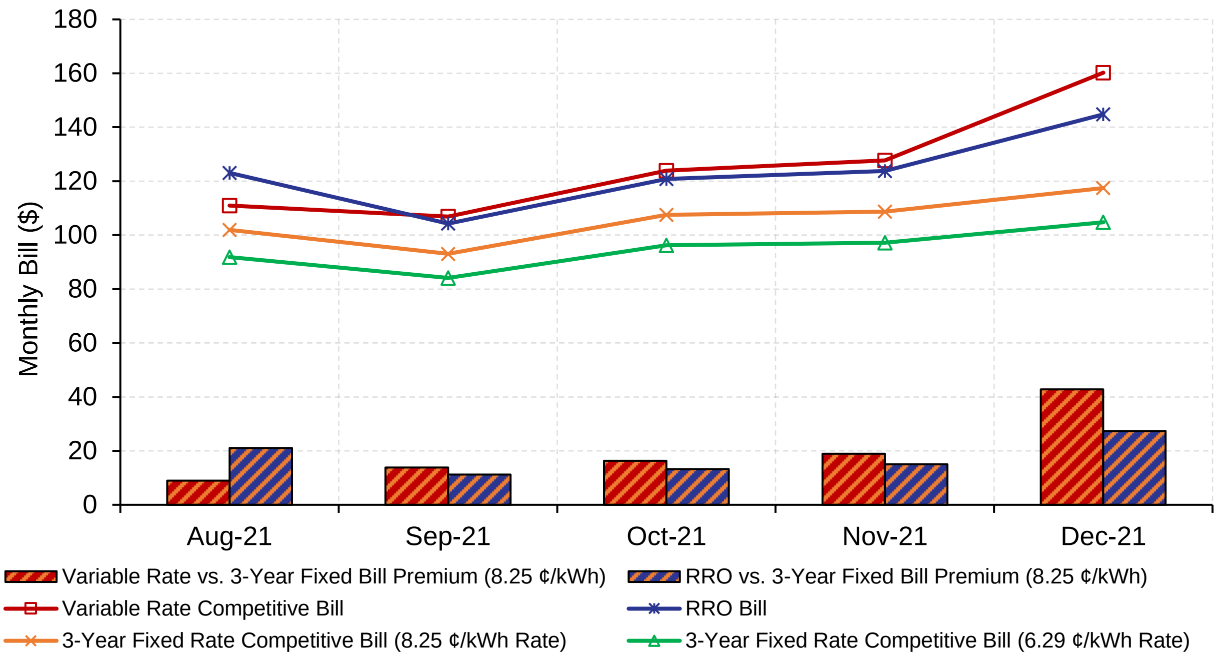
Not all competitive fixed rate customers were able to stay on the same fixed rate over 2021 and may have chosen to sign at a higher fixed rate if the term of their contract expired. In the ENMAX service area, a 1 cent/kWh increase in a residential customer's fixed rate is associated with a bill increase of approximately $6/month.

Despite increasing competitive fixed rate offerings throughout the year, short-term incentives for RRO and competitive variable rate customers to switch to competitive fixed rates persisted. For example, a residential customer switching to a 8.25 cent/kWh 3-year fixed rate prior to August

[36] Calculated using a representative residential load shape in the ENMAX service area.

2021 would have avoided significantly higher electricity bills for the remainder of 2021 than had they remained an RRO or competitive variable rate customer (Figure 46).

Figure 46: Residential competitive fixed rate electricity bills vs. RRO & competitive variable rate bills, August to December 2021[37]

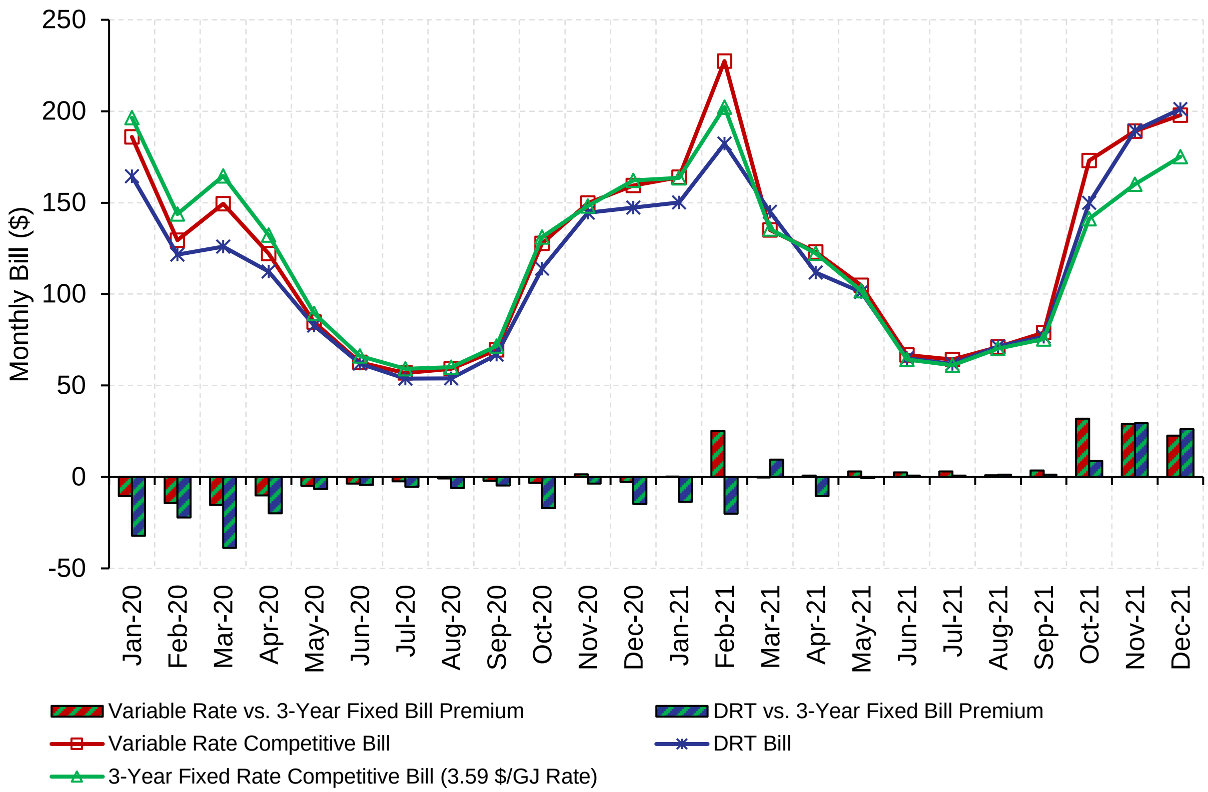


The billing impact of a customer having a competitive fixed rate for natural gas compared to being on the regulated DRT or having a competitive variable rate for natural gas is only particularly discernable during winter months, when greater volumes of natural gas are consumed by customers.

The representative customer that signed up for a 3.59 $/GJ competitive fixed rate for natural gas at the start of 2020 paid somewhat more than DRT or variable rate customers in 2020, particularly in the first quarter of that year (Figure 47). However, increases in both DRT and variable rates over 2021 resulted in this representative fixed rate customer paying lower natural gas bills over Q4 2021 than similar DRT or competitive variable rate customers.

[37] Calculated using a representative residential load shape in the ENMAX service area.

Figure 47: Residential competitive fixed rate natural gas bills vs. DRT & competitive variable rate bills, 2020 to 2021[38]



While residential DRT and competitive variable rate customers each paid around $250 more on their natural gas bills (respectively) in 2021 compared to the previous year, fixed rate customers, such as the representative 3.59 $/GJ customer, only paid around $50 more in 2021 (Table 11).

Table 11: Annual residential natural gas bills ($), ATCO Gas south service area, 2020 vs. 2021

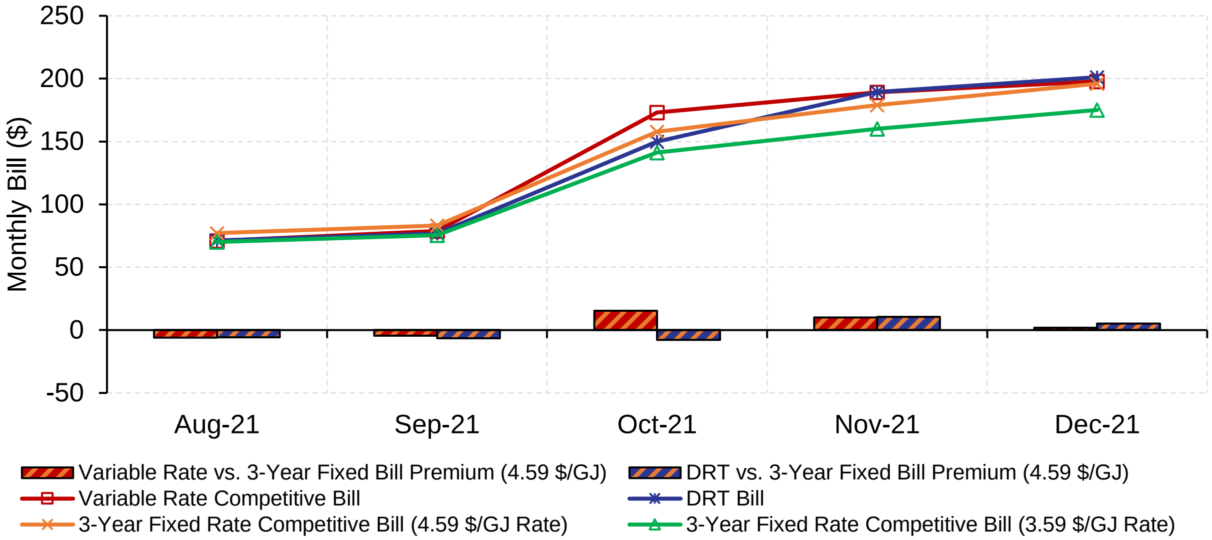
Year	DRT	Variable Rate	Fixed Rate (3.59 $/GJ)
2020	1,249.36	1,356.42	1,424.98
2021	1,505.57	1,594.81	1,472.53
Difference	+ 256.21	+ 238.39	+ 47.55

As competitive natural gas fixed rates increased throughout 2021, short-term incentives for DRT and competitive variable rate customers to switch to competitive fixed rates declined. For example, a residential competitive variable rate customer switching to a 4.50 $/GJ 3-year fixed

[38] Calculated using a representative residential load shape in the ATCO Gas South service area.

rate prior to August 2021 would have saved a total of $17 on natural gas bills over the August to December 2021 period. However, a residential DRT customer switching to such a rate in August would have paid $5 more between August and December because of switching (Figure 48).

Figure 48: Residential competitive fixed rate natural gas bills vs. DRT & competitive variable rate bills, August to December 2021[39]



4.2 Competitive retail market share and churn

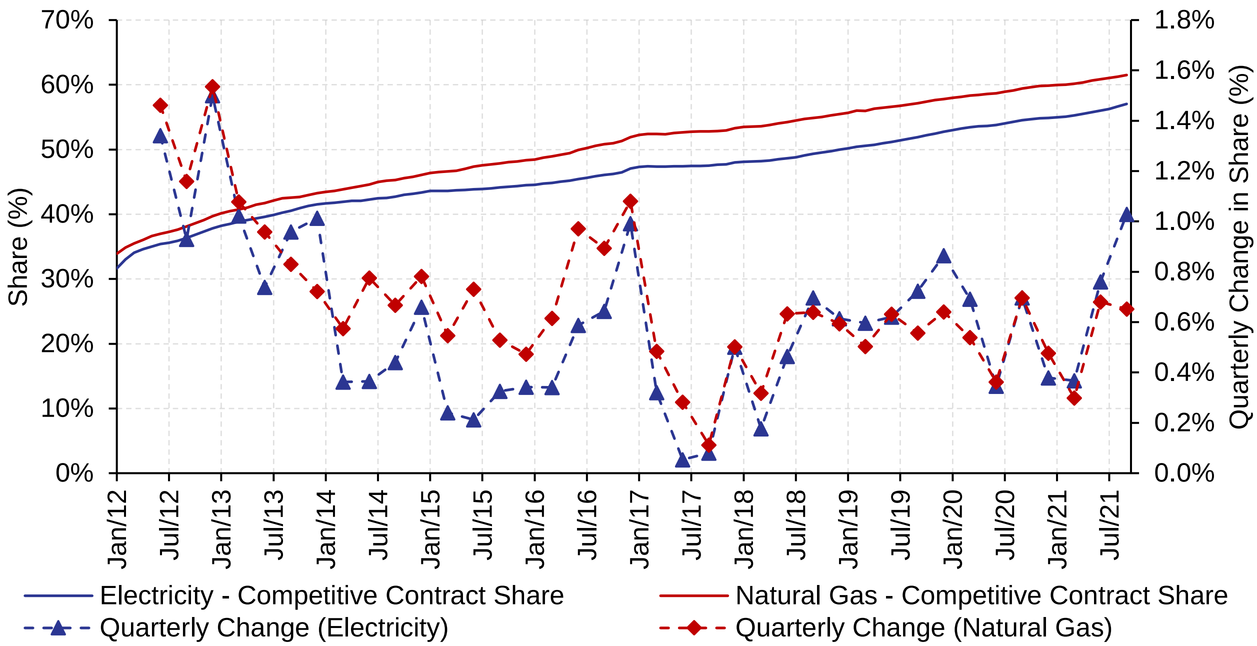
Competitive electricity market shares among residential customers increased by around 1% in Q3 2021, likely driven by regulated customers' reaction to receiving high August bills (Figure 49).[40] This quarterly increase in competitive electricity market share is historically high and comparable to that observed in Q4 2016.

Residential competitive natural gas shares did not exhibit similar increases – likely as a result of limited natural gas bill increases over the summer given low natural gas consumption despite increasing regulated natural gas rates. The MSA expects both electricity and natural gas churn to increase over Q4 2021, as regulated electricity and natural gas customers began to face higher energy bills as their energy rates and consumption increased.

[39] Calculated using a representative residential load shape in the ATCO Gas South service area.

[40] MSA Retail Statistics (2022-01-12). Data up to Q3 2021 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

Figure 49: Competitive retailer market shares, residential customers, Q1 2012 to Q3 2021

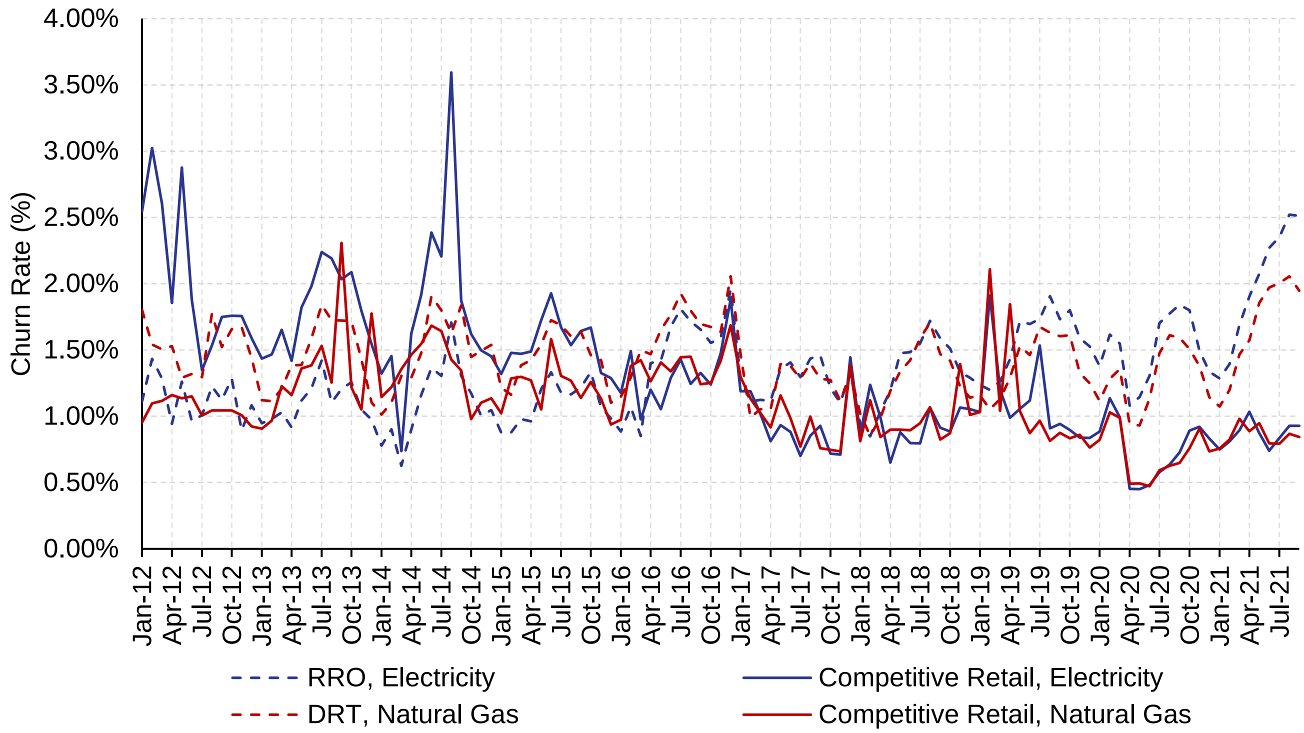


Unlike competitive retailer market share, churn represents the share of a retailers' customers that leave the retailer in any given month (Figure 50). The MSA considers retail churn to play an important role in the development of a competitive retail energy market, as high churn can enable vigorous competition to exist between retail competitors. Conversely, low churn may limit the incentive for competitive retailers to compete on price if customers are less willing to switch from their existing retailers.

Since 2019, residential customer churn among regulated retailers has exceeded that of competitive retailers. Residential regulated electricity churn continued to increase in Q3 2021, reaching historical highs of 2.5%, while regulated natural gas churn and competitive churn remained stable.[41] Combined with the 1% quarterly increase in competitive retailer market share among residential electricity customers, this 2.5% churn rate may indicate both a significant amount of switching from regulated electricity retailers to competitive retailers and a lesser degree of residential customers switching from competitive retailers back to regulated electricity retailers.

[41] MSA Retail Statistics (2022-01-12). Data up to Q3 2021 is presented here as the MSA Retail Statistics reports data using a one-quarter delay.

Figure 50: Residential churn rates, electricity and natural gas, Q1 2012 to Q3 2021



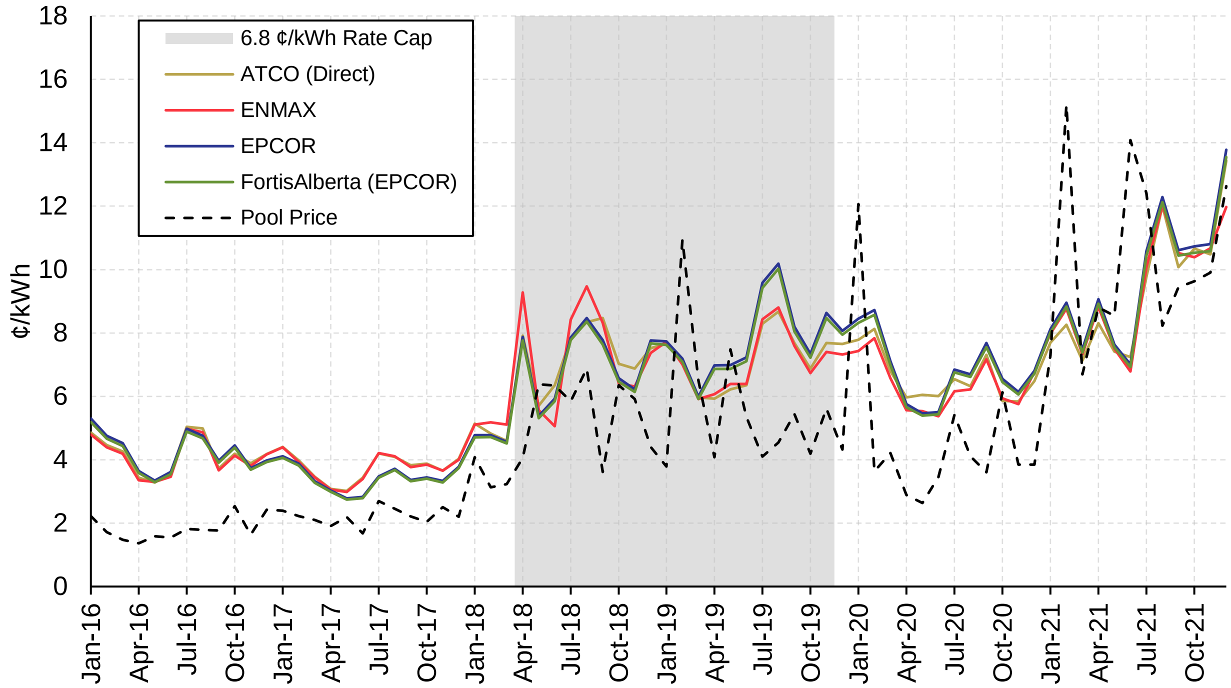
4.3 Regulated retail market

Retail customers that do not sign with a competitive retailer receive retail energy services from a regulated rate provider. Regulated electricity services are provided to most retail customers under the RRO, while regulated gas services are provided under the DRT.

4.3.1 Regulated Rate Option

Residential RRO rates continued to increase in Q4, averaging 11.5 ¢/kWh across the four largest service areas over the quarter, compared to 10.9 ¢/kWh in the previous quarter (Figure 51). In December 2021 residential RRO rates reached annual highs of over 13 ¢/kWh in most service areas, a level not seen since early 2012. Residential RRO rates averaged 9.5 ¢/kWh in 2021, a 44% increase over rates in 2020.

Figure 51: Residential RRO by service area (RRO provider), 2016 to 2021



RRO rates are primarily calculated as the volume-weighted average price of full-load strip products procured by ENMAX and EPCOR in auctions held in the 120 days preceding the start of a delivery month. The price of full-load strips for Q4 delivery months increased over the 120 days prior to delivery alongside price increases in the forward market for electricity (Figure 52).

Full-load strip purchase prices can differ in the EPCOR and ENMAX auctions as a result of differences in underlying RRO load shape or the timing of auctions. The December 2021 full-load prices in the latter half of the 120-day procurement period are notable as prices paid by EPCOR significantly exceeded prices paid by ENMAX in their respective auctions.

Residential RRO rates continued to increase in January and February 2022, averaging 16.2 cents/kWh in both months. As of January 12, the MSA has forecasted residential RRO rates to fall by March, with rates of around 11 cents/kWh expected in both March and April 2022 based on previous auction prices and historical forward market data (Table 12).

Figure 52: ENMAX and EPCOR RRO full-load strip prices, Q4 2021 delivery dates

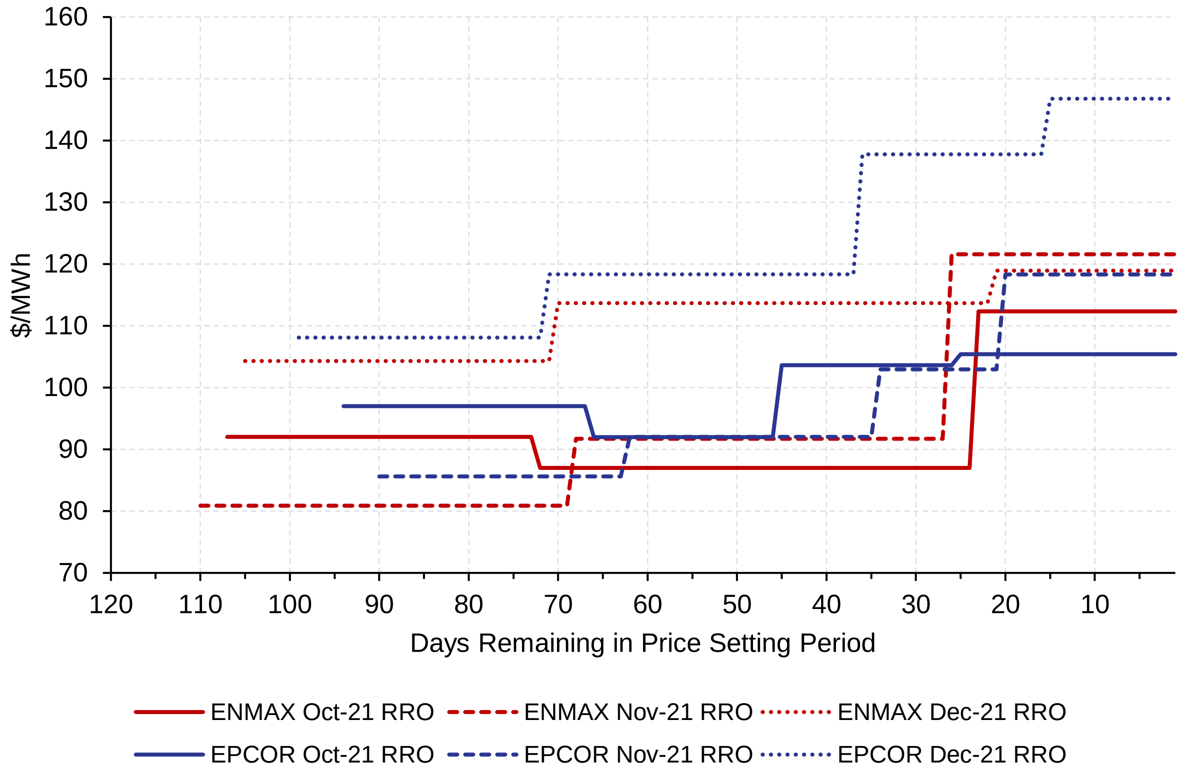


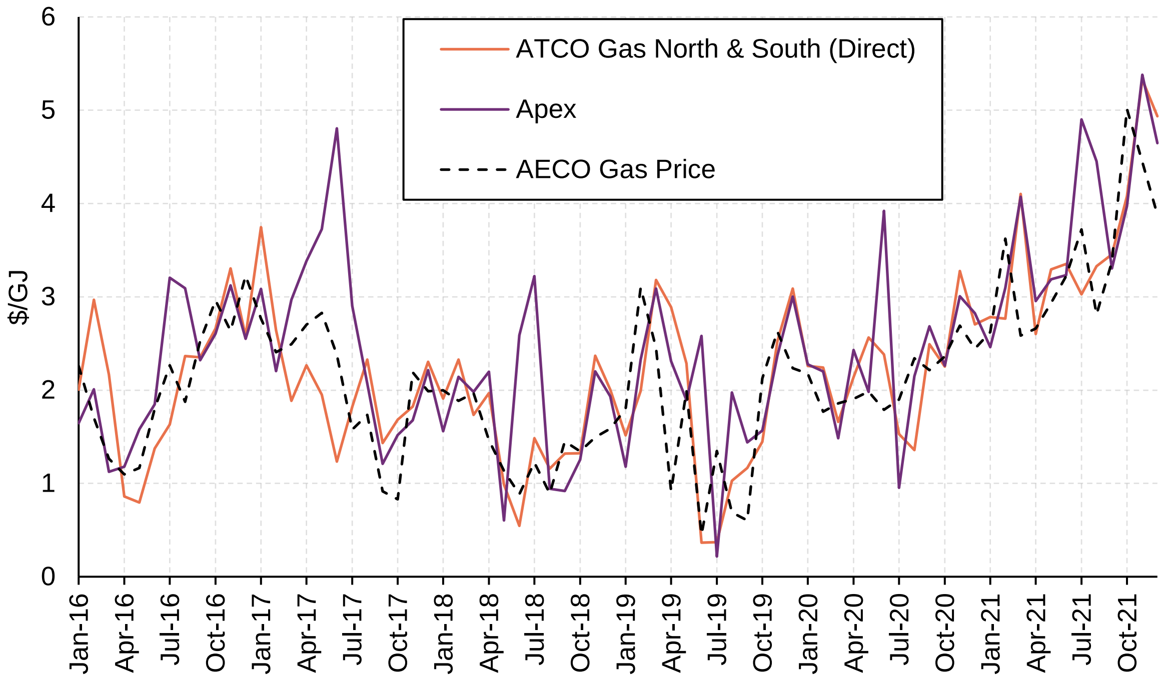
Table 12: March and April 2022 residential RRO estimates by service area (¢/kWh)

		March 2022	April 2022
1 – Base Case	ENMAX	11.12	11.08
	EPCOR	10.91	10.76
	FortisAlberta	10.77	10.59
	ATCO	10.94	10.63
2 – Increasing Price Case	ENMAX	11.55	12.27
	EPCOR	11.45	13.83
	FortisAlberta	11.30	13.62
	ATCO	11.48	13.67
3 – Decreasing Price Case	ENMAX	10.74	9.94
	EPCOR	10.36	9.02
	FortisAlberta	10.22	8.88
	ATCO	10.38	8.92

4.3.2 Default Rate Tariff

Residential DRT rates increased significantly in Q4 in response to increasing forward prices and same day prices for natural gas. DRT rates averaged 4.74 $/GJ over the three service areas in Q4 compared to 3.59 $/GJ in the previous quarter (Figure 53). Monthly DRT rates peaked in November at over 5.30 $/GJ in each service area. Alberta has not experienced such DRT rates in both service areas since 2014.

Figure 53: Residential Default Rate Tariff by service area (DRT Provider), 2016 to 2021



In January and February 2022 residential DRT rates averaged 3.73 $/GJ and 4.98 $/GJ, respectively. As of January 12, the MSA has forecasted residential DRT rates to decline moderately by March, with rates of around 4 $/GJ expected in both March and April 2022 based on prevailing and historical forward market data (Table 13).

Table 13: March and April 2022 residential DRT estimates by service area ($/GJ)

		March 2022	**April 2022**
1 – Base Case	ATCO Gas North	4.08	3.76
	ATCO Gas South	4.08	3.76
	Apex	4.14	4.42
2 – Increasing Price Case	ATCO Gas North	8.59	6.05
	ATCO Gas South	8.59	6.05
	Apex	8.73	7.10
3 – Decreasing Price Case	ATCO Gas North	1.52	2.27
	ATCO Gas South	1.52	2.27
	Apex	1.54	2.67

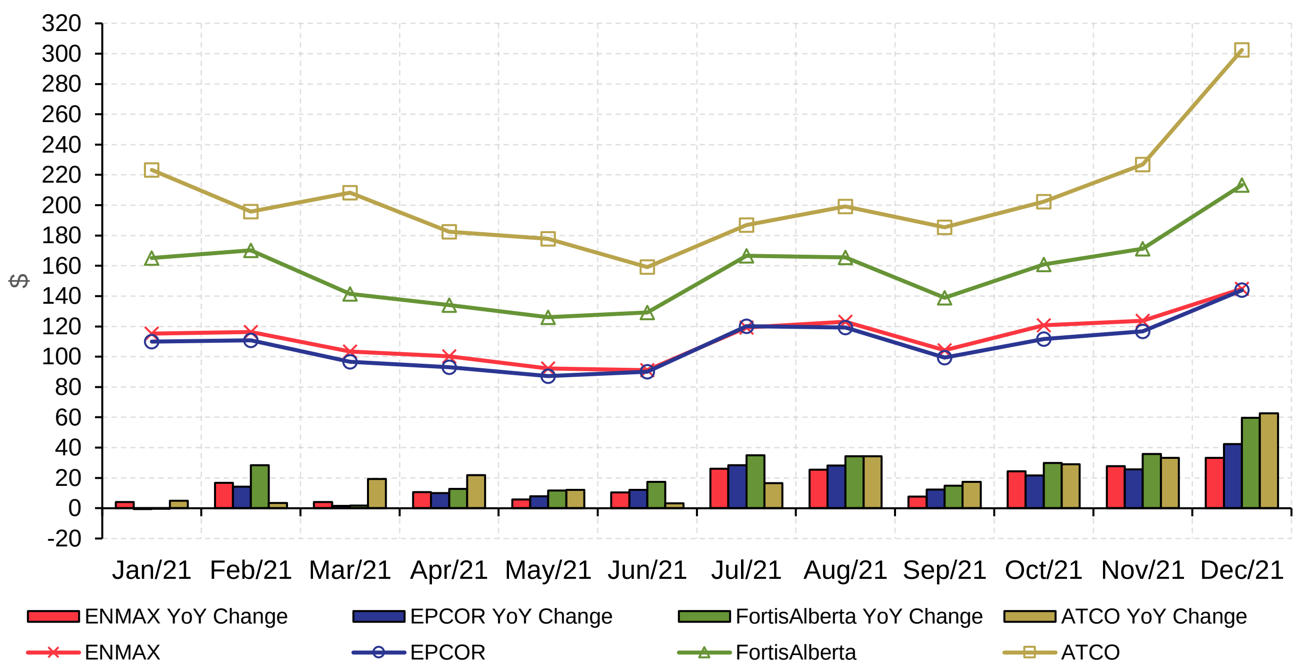
4.3.3 *Regulated energy bills*[42]

An average residential RRO customer saw their annual electricity bill increase by between $200 to $280 in 2021 (Table 14). These increases were particularly driven by higher bills in the second half of 2021, when residential RRO customers typically received monthly electricity bills that were over $20 more than last year (Figure 54). Bill increases were particularly high in rural service areas where household electricity consumption is generally higher.

Table 14: Annual RRO bills by service area, 2020 vs. 2021 ($)

	ENMAX	EPCOR	FortisAlberta	ATCO
2020	1,158.33	1,094.93	1,601.94	2,192.14
2021	1,354.59	1,298.66	1,882.86	2,450.11
Difference	+ 196.26	+ 203.73	+ 280.92	+ 257.97

Figure 54: Monthly residential RRO bills by service area, 2021



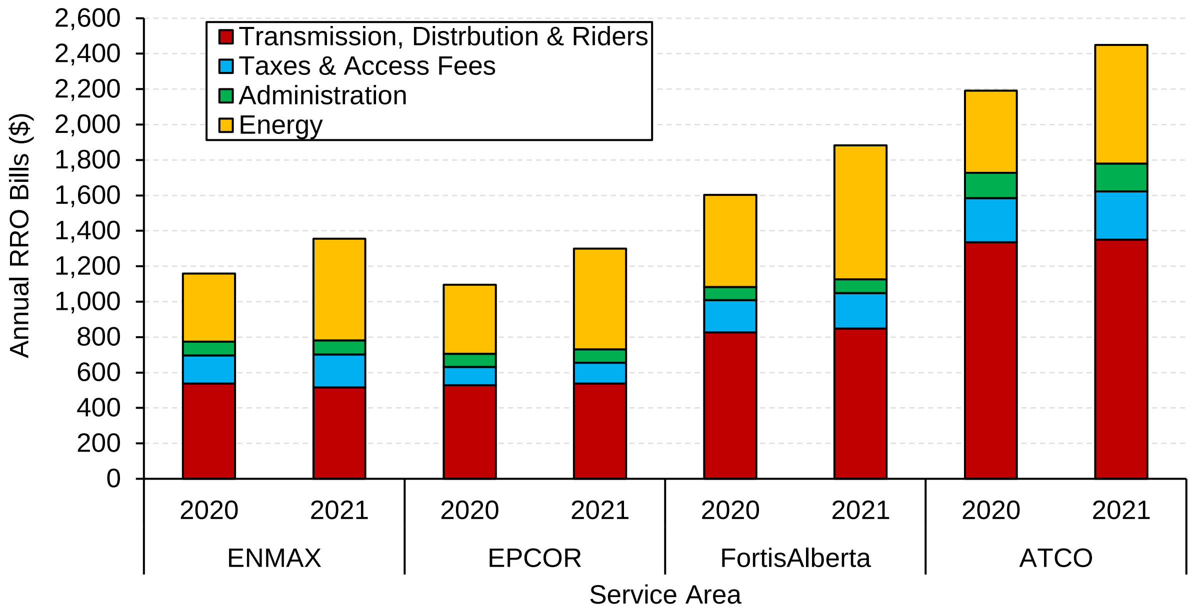
Residential RRO bill increases were caused by increases in RRO rates throughout the year (Figure 55). Increased energy charges comprised at least 80% of the annual increase in RRO bills in each service area.

The Utility Payment Deferral Program (UPDP) rider, implemented beginning in November 2021, had a minimal billing impact on residential RRO bills, increasing RRO bills by between $0.50 and $0.65 over the last two months (combined) and accounting for approximately 0.3% of the annual

[42] Consumption forecasts for Q4 2021 have been used to construct billing estimates in this section.

increase in RRO bills. The UPDP rider is scheduled to be applied to bills between November 2021 and February 2022.

Figure 55: RRO bill components by service area, 2020 vs. 2021

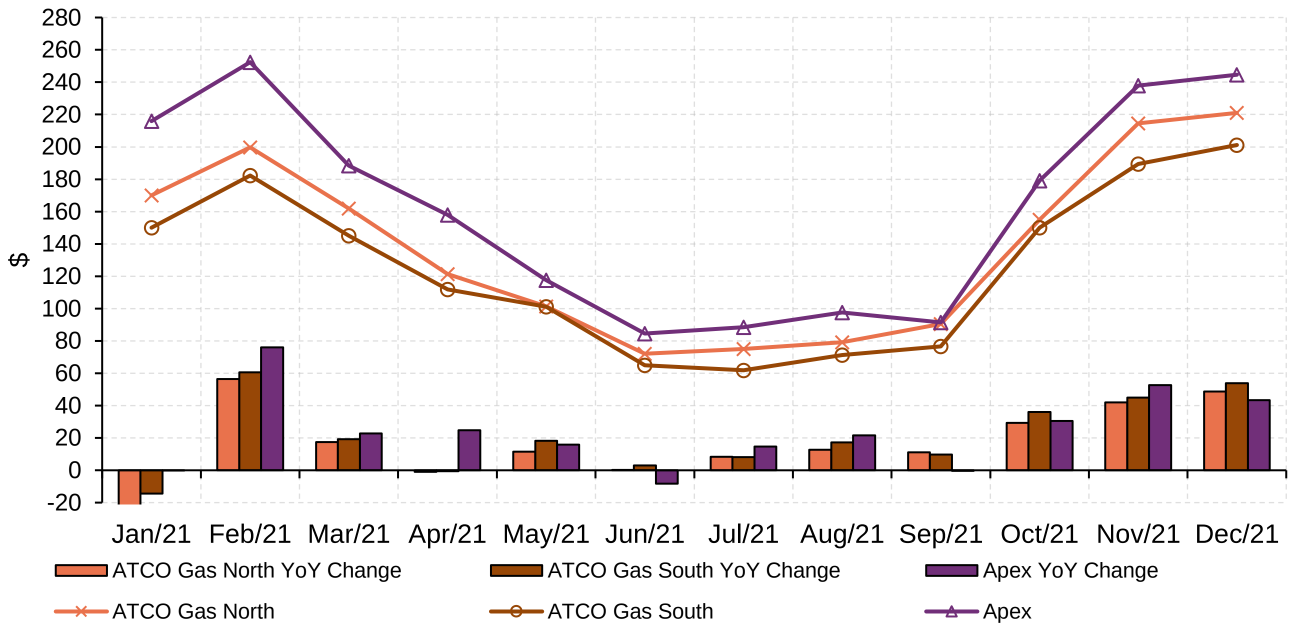


An average residential DRT customer also saw their annual natural gas bill increase in 2021 by around $215 to $295 (Table 15). These increases were driven by higher bills in February 2021 and Q4 2021, when residential DRT customers often received monthly natural gas bills over $40 more than similar bills in 2020 (Figure 56).

Table 15: Annual DRT bills by service area, 2020 vs. 2021 ($)

	ATCO Gas North	ATCO Gas South	Apex
2020	1,448.64	1,249.36	1,662.49
2021	1,661.80	1,505.57	1,956.10
Difference	+ 213.17	+ 256.21	+ 293.61

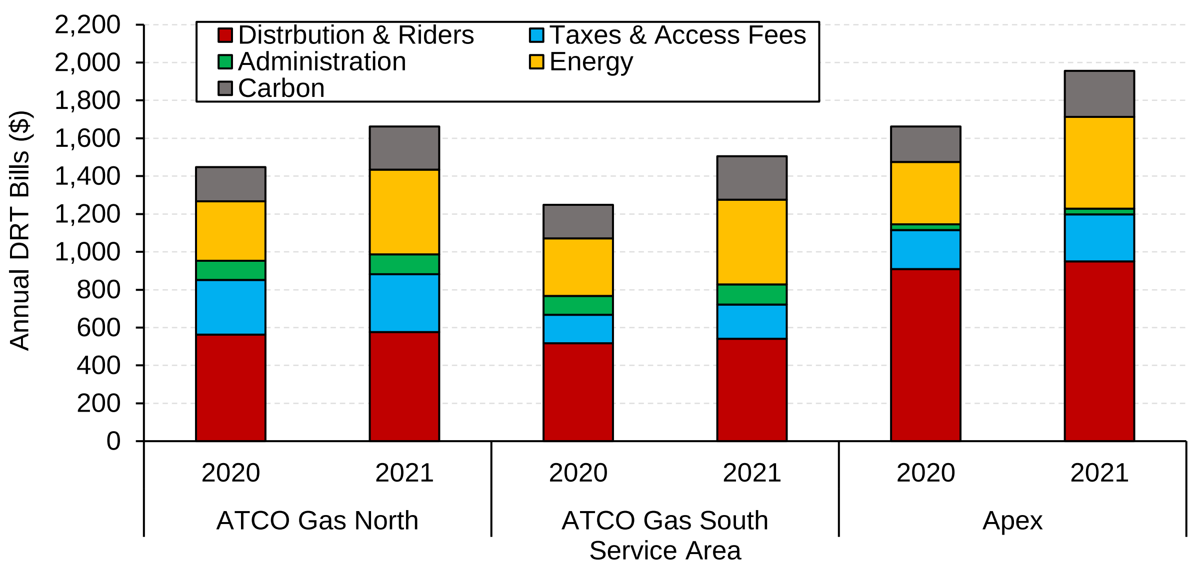
Figure 56: 2021 monthly residential DRT bills by service area



Residential DRT bill increases were also impacted by other billing components (Figure 57). While increased energy charges comprised 50 to 60% of the annual increase in DRT bills in each service area, the April 2021 increase in the carbon levy on natural gas also contributed to DRT bill increases, comprising around 20% of the increase. Changes in distribution rates and taxes each made up around 10% of the increase.

The UPDP rider increased residential DRT bills by approximately $1 over the last two months of the year (combined), accounting for around 0.5% of the DRT bill increase year-over-year.

Figure 57: DRT bill components by service area, 2020 vs. 2021



4.4 Retail regulatory updates

4.4.1 Energy Price Setting Plan developments

On October 27, 2021, the Alberta Utilities Commission (AUC) approved the 2021-2024 Energy Price Setting Plan (EPSP) for EPCOR Energy Alberta GP Inc. (EPCOR).[43] Conditional on the timing of an executed backstop agreement filing, the new EPSP is expected to first apply to the May 2022 RRO. Compared to its prior EPSP, the 2021-2024 EPSP contains improvements to the clarity of language and calculations and adjustments to the backstop mechanism, among others, but is otherwise substantively similar to its prior EPSP.

[43] Decision 26316-D02-2021 - EPCOR Energy Alberta GP Inc. 2021-2024 Energy Price Setting Plan, October 27, 2021.

5 ENFORCEMENT MATTERS

5.1 The MSA discontinued an investigation related to offer strategies undertaken at PPA units by the Balancing Pool

On September 2, 2020, the MSA issued the following public statement:

> The Market Surveillance Administrator (MSA) has initiated an investigation under section 42(1)(b) of the *Alberta Utilities Commission Act*. The investigation focuses on the Balancing Pool's conduct in relation to potential breaches of the *Electric Utilities Act*, including sections 6 and 85, the *Fair, Efficient and Open Competition Regulation*, and the Settlement Agreement between the MSA and Balancing Pool that was approved by the Alberta Utilities Commission on January 14, 2020.[44]

The purpose of this notice is to inform market participants and stakeholders that the MSA discontinued the investigation described above. The MSA found that it is not in the public interest to continue further investigation or proceed with enforcement action because:

- the Balancing Pool has no current or future physical or financial interest in the Alberta electricity market;
- the Balancing Pool has no access to funds other than charges levied on electricity consumers through the Balancing Pool Allocation; and
- there is limited specific or general deterrence that would result from proceeding with this matter, since the Balancing Pool was a unique market participant that is no longer in the market.

5.2 Municipal Own-Use Regulation

Participation by municipalities in the Alberta electricity market is limited by section 95 of the *Electric Utilities Act* SA 2003 c E-5.1 (EUA) and the *Municipal Own-Use Generation Regulation* AR 80/2009 (MOUGR). Section 95 of the *EUA* allows municipalities or their subsidiaries to hold an interest in a generating unit if, among other requirements:

- the generating unit is part of a process carried out on the property of the municipality or its subsidiary and the electric energy produced by that generating unit is incidental to the main purpose of the process,[45]

[44] MSA Notice re Balancing Pool Investigation, September 2, 2020.

[45] EUA, s. 95(8)

- the majority of electric energy produced annually by a generating unit located on the property of the municipality or its subsidiary is used by the municipality or its subsidiary on that property,[46] or

- the Minister of Energy authorizes the municipality or its subsidiary to hold an interest in a generating unit after an independent assessment concludes that the arrangement by which the municipality or its subsidiary holds the interest in the generating unit is structured in a way that prevents any advantage as a result of association with the municipality.[47]

The MOUGR adds an additional exemption to the prohibition of municipal ownership of generation if:

- an arrangement is in place to ensure all of the electric energy produced by the unit in each settlement interval is purchased by the municipality for one or more sites within the boundaries of the municipality,[48] and

- The municipality owns or leases the property where the electricity is consumed and is responsible for paying the electricity bill for those sites.[49]

Section 3(1) of the MOUGR requires that a municipality looking to hold an interest in a generating unit file a compliance plan with the MSA outlining how they will comply with the requirements of the MOUGR, prior to exchanging electric energy with the interconnected electric system.

The MSA received four inquiries regarding proposed generating units and the MOUGR from municipalities in 2020 and 2021. Three of the proposed generating units would produce enough electricity, on average over the year, to approximately meet the municipality's demand. However, the MOUGR requires a municipality holding an interest in a generating unit under the MOUGR to purchase all of the electricity produced by that generating unit for each settlement interval. "Settlement interval" is defined in the ISO rules as the clock hour; that is, the period beginning on the hour and ending 60 minutes later.[50] As such, the MSA has provided guidance to these municipalities that project configurations based on average annual electricity consumption would not meet the requirements of the MOUGR.

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[46] EUA s. 95(9)

[47] EUA s. 95(10-12)

[48] MOUGR s. 2(a)

[49] MOUGR s. 2(b), 2(c). EUA ss. 95(4) – (7) outline the requirements for the City of Medicine Hat to hold an interest in a generating unit.

[50] See AESO Consolidated Authoritative Document Glossary, Term: "settlement interval", page 35, and EUA s.1(xx.1)

6 ISO RULES COMPLIANCE

The purpose of the ISO rules is to promote orderly and predictable actions by market participants and to facilitate the operation of the Alberta Interconnected Electric System (AIES). The MSA is responsible for the enforcement of the ISO rules and endeavours to promote a culture of compliance and accountability among market participants, thereby contributing to the reliability and competitiveness of the Alberta electric system. If the MSA is satisfied that a contravention has occurred and has determined that a notice of specified penalty (NSP) is appropriate, then AUC Rule 019 guides the MSA on how to issue an NSP.

From January 1 to December 31, 2021 the MSA closed 462 ISO rules compliance matters, as reported in Table 16.[51] An additional 56 matters were carried forward to next year. During this period 75 matters were addressed with NSPs, totalling $129,250 in financial penalties, with details provided in Table 17.

[51] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 462 closed matters, one matter was rejected and one matter was withdrawn.

Table 16: ISO rules compliance outcomes from January 1 to December 31, 2021

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.12	2	1	-
201.1	1	-	-
201.3	-	3	-
201.4	2	-	-
201.7	51	2	14
203.1	3	3	-
203.3	104	10	-
203.4	64	4	15
203.6	18	6	1
205.3	11	5	-
205.4	7	-	-
205.5	10	12	4
205.6	13	23	7
205.8	2	-	-
301.2	1	-	-
303.1	-	-	2
304.3	1	-	-
304.4	2	1	-
306.4	18	2	-
306.5	4	1	-
502.1	1	-	-
502.4	-	1	1
502.5	5	-	-
502.6	3	-	-
502.8	1	1	-
502.9	1	-	-
502.10	1	-	-
505.3	3	-	-
505.4	10	-	-
9.1.3	1	-	-
9.1.4	1	-	-
Total	341	75	44

Table 17: Specified penalties issued between January 1 and December 31, 2021 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)															Total ($)	Matters
	103.12	201.3	201.7	203.1	203.3	203.4	203.6	205.3	205.5	205.6	304.4	306.4	306.5	502.4	502.8		
Alberta Electric System Operator														500		500	1
ATCO Electric Ltd.												500				500	1
Balancing Pool									500							500	2
Campus Energy Partners LP								500								500	1
Canadian Hydro Developers, Inc.		250						500	2,000							2,750	4
Capital Power (Genesee) L.P.									250							250	1
Capital Power (Whitla) L.P.						750										750	1
City of Medicine Hat					250											250	1
CNOOC Marketing Canada / ENMAX Balzac LP					750											750	1
DAPP Power L.P.						1,500										1,500	1
Enel X Canada Ltd.										26,000						26,000	7
ENMAX Cavalier LP					750											750	1
ENMAX Generation Portfolio Inc.				1,000												1,000	2
Grande Prairie Generation Inc.					1,500											1,500	1
Hut 8 Holdings Inc.								750								750	1
Macquarie Energy Canada Ltd.							250									250	1
Mercer Peace River Pulp Ltd.									500							500	1
Millar Western Forest Products Ltd.										250						250	1
Milner Power Limited Partnership by its General Partner Milner Power Inc.				500									1,500			2000	2
Morgan Stanley Capital Group Inc.							1,500									1500	1
Northstone Power Corp.			1,000		2,250					750						4000	5
NRGreen Power Limited Partnership					1,500											1500	1
Powerex Corp.							750									750	1

Table 17: Specified penalties issued between January 1 and December 31, 2021 for contraventions of the ISO rules (continued)

Market participant	Total specified penalty amounts by ISO rule ($)															Total ($)	Matters
	103.12	201.3	201.7	203.1	203.3	203.4	203.6	205.3	205.5	205.6	304.4	306.4	306.5	502.4	502.8		
Repsol Canada Energy Partnership						1,500										1,500	1
Shell Energy North America (Canada) Inc.							250									250	1
Suncor Energy Inc.												250				250	1
TA Alberta Hydro LP					5,000			2,000	500	500						8,000	5
TransAlta Corporation															500	500	1
TransAlta Generation Partnership	500	500			1,250	250			16,500		500					19,500	8
TransCanada Energy Sales Ltd.							1,500									1,500	2
Voltus Energy Canada Ltd.										46,500						46,500	13
WCSB Power Holdings GP Ltd.									1,000							1000	2
West Fraser Mills Ltd.					750											750	1
Whitecourt Power Ltd.		500														500	1
Total	500	1,250	1,000	1,500	14,000	4,000	4,250	3,750	21,250	74,000	500	750	1,500	500	500	129,250	75

The sections of ISO rules listed in Table 16 and Table 17 are contained within the following categories:

103 Administration
201 General (Markets)
203 Energy Market
205 Ancillary Services Market
301 General (System Reliability and Operations)
303 Interties
304 Routine Operations
306 Outages and Disturbances
502 Technical Requirements
505 Legal Owners of Generating Facilities
9 Transmission

7 ALBERTA RELIABILITY STANDARDS COMPLIANCE

The MSA has the jurisdiction to assess whether or not a market participant has complied with Alberta Reliability Standards (ARS) and apply a specified penalty where appropriate.

The purpose of ARS is to ensure the various entities involved in grid operation (legal owners and operators of generators, transmission facilities, distribution systems, as well as the independent system operator) are doing their part by way of procedures, communications, coordination, training and maintenance, among other practices, to support the reliability of the AIES. ARS apply to both market participants and the AESO. ARS are divided into two categories: Operations and Planning (O&P) and Critical Infrastructure Protection (CIP). The MSA's approach with respect to compliance with ARS is focused on promoting awareness of obligations and a proactive compliance stance. The MSA has established a process that, in conjunction with AUC rules, provides incentives for robust internal compliance programs, and self-reporting.

In accordance with AUC Rule 027, NSPs for CIP ARS contraventions are not made public, as well as any information related to the nonpayment or dispute of a CIP ARS NSP. CIP matters often deal with cyber security issues and there is concern that granular public reporting may itself create a security risk. As such, the MSA will only report aggregated statistics regarding CIP ARS outcomes.

From January 1 to December 31, 2021, the MSA addressed 80 O&P ARS compliance matters, as reported in Table 18.[52] An additional 25 matters were carried forward to next year. During this period, 12 matters were addressed with NSPs, totalling $22,000 in financial penalties, with details provided in Table 19. For the same period, the MSA addressed 294 CIP ARS compliance matters, as reported in Table 20,[53] and 87 matters were addressed with NSPs, totalling $216,350 in financial penalties. An additional 76 matters were carried forward to next year.

[52] An ARS matter is considered closed once a disposition has been issued.

[53] Of the 294 closed matters, one matter was rejected.

Table 18: O&P ARS compliance outcomes from January 1 to December 30, 2021

Reliability standard	Forbearance	Notice of specified penalty
COM-001	2	-
EOP-001	1	-
EOP-005	4	-
EOP-008	3	-
FAC-003	1	-
FAC-008	10	7
FAC-501-WECC	1	-
IRO-008	2	-
PER-003	1	-
PER-005	5	1
PRC-001	3	-
PRC-002	5	-
PRC-004	1	1
PRC-005	12	3
PRC-018	1	-
PRC-023	2	-
VAR-002	11	-
VAR-002-WECC	3	-
Total	68	12

Table 19: Specified penalties issued between January 1 and December 31, 2021 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)				Total ($)	Matters
	FAC-008	PER-005	PRC-004	PRC-005		
AltaLink L.P., by its general partner, AltaLink Management Ltd.	2,250				2,250	1
ATCO Electric Ltd.		2,250	3,750		6,000	2
ENMAX Energy Corporation	2,250				2,250	2
EPCOR Distribution & Transmission Inc.				4,750	4,750	2
MATL Canada L.P.	2,250				2,250	2
TransAlta Generation Partnership				2,250	2,250	1
Western Sustainable Power Inc.	2,250				2,250	2
Total	9,000	2,250	3,750	7,000	22,000	12

The ARS outcomes listed in Table 18 and Table 19 are contained within the following categories:

COM	Communications
EOP	Emergency Preparedness and Operations
FAC	Facilities Design, Connections, and Maintenance
IRO	Interconnection Reliability Operations and Coordination
PER	Personnel Performance, Training, and Qualifications
PRC	Protection and Control
VAR	Voltage and Reactive

Table 20: CIP ARS compliance outcomes from January 1 to December 31, 2021

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	14	2	5
CIP-003	6	8	-
CIP-004	48	14	2
CIP-005	8	8	-
CIP-006	15	4	2
CIP-007	58	20	-
CIP-008	1	-	-
CIP-009	6	7	-
CIP-010	30	16	-
CIP-011	9	8	-
CIP-014	2	-	-
Total	197	87	9

The ARS outcomes listed in Table 20 are contained within the following categories:

CIP-002	BES Cyber System Categorization
CIP-003	Security Measurement Controls
CIP-004	Personnel & Training
CIP-005	Electronic Security Perimeter(s)
CIP-006	Physical Security of BES Cyber Systems
CIP-007	System Security Management
CIP-008	Incident Reporting and Response
CIP-009	Recovery Plans for BES Cyber Systems
CIP-010	Configuration Change Management and Vulnerability Assessments
CIP-011	Information Protection
CIP-014	Physical Security