Quarterly Report for Q3 2022

November 15, 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 Q3 2022 was $221.41/MWh, a 121% increase relative to Q3 last year and the highest quarterly pool price on record. The offer behaviour of some large suppliers was the principal factor in the high pool prices this quarter. In addition, increased demand, several thermal outages in late August and throughout September, low wind generation, higher natural gas prices, and a higher carbon price contributed to the high pool prices.

- The AESO declared an Energy Emergency Alert level 3 (EEA3) on September 27 and on September 28, reflecting a shortfall of supply relative to demand on those days. Thermal outages, low levels of wind generation, relatively high temperatures, and constrained imports were the main factors leading to these events. The BC intertie returned to service from a planned transmission outage during the EEA3 event on September 28 which helped to alleviate the supply shortfall on that day.

- Market factors including increased demand, thermal outages, low wind generation, and import constraints increased the market power of some large suppliers during the quarter. As discussed in this report, some large suppliers exercised market power by pricing a meaningful volume of generation capacity at high offer prices. As a result, pool prices were often significantly above marginal costs, and consequently net revenues and static inefficiencies during the quarter were unusually high.

- In the forward market, the total volume of trading in July was low but volumes were much higher in August and September. Forward prices generally increased over Q3, in part due to the higher pool prices in August and September. For example, the forward price of October increased from $136/MWh at the end of July to $192/MWh at the end of September, an increase of 41%. In annual trading, the price of power for 2023 increased by 19% over the quarter to $113/MWh. In late August, power for 2026 traded at a price of $67/MWh, far below the price of 2023.

- Retailers' expected cost of offering fixed rate electricity contracts increased significantly over Q3, and most of the largest retailers raised the price of their fixed rate contracts during the quarter. Despite this, fixed rate contract prices remain below expected regulated electricity rates. As of early October, regulated electricity rates over December through February were expected to exceed 20 ¢/kWh. Elevated pool prices drove unusually high increases in competitive variable rates in August and September.

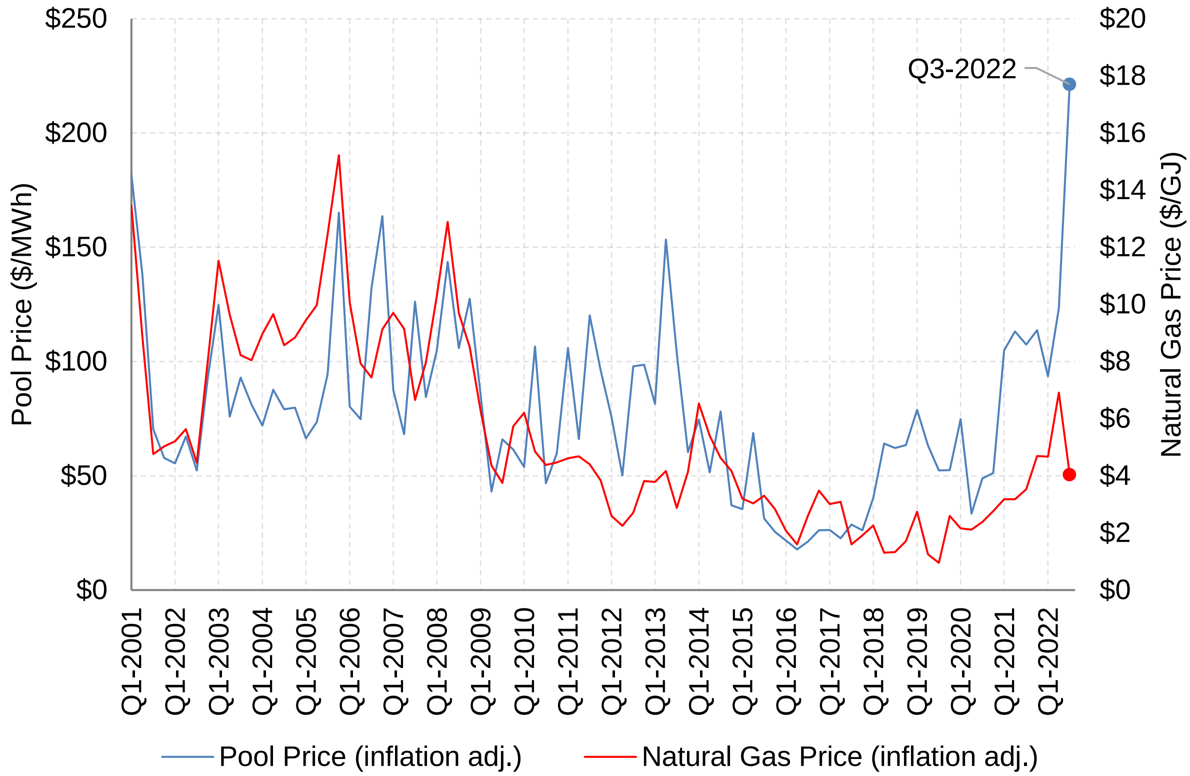
- From July 1 to September 30, 2022, the MSA closed 93 ISO rules compliance matters; 22 matters were addressed with notices of specified penalty. For the same period, the MSA closed 19 Alberta Reliability Standards Operations and Planning compliance matters; two matters were addressed with notices of specified penalty. In addition, the MSA closed 40 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; six matters were addressed with notices of specified penalty.

1 THE POWER POOL

1.1 Quarterly summary

The average pool price in Q3 was $221.41/MWh, an increase of 121% over the Q3 2021 pool price of $100.33/MWh.[1] This is the highest quarterly average pool price on record, using price data going back to Q1 2001 and after adjusting for inflation (Figure 1). Higher offer prices by some large suppliers were a principal factor in the higher pool prices in Q3. In addition, increased demand, thermal outages, higher natural gas prices, and a higher carbon price contributed to the high pool prices.

Figure 1: Quarterly average pool price and natural gas price (Q1 2001 to Q3 2022, inflation adjusted)



The monthly average pool prices in August and September were an increase of 213% and 182% compared to last year (Table 1). The August pool price of $257.75/MWh was the highest monthly average price on record at the time and was largely driven by supplier offer behaviour, high temperatures, and low wind generation. The monthly average pool price in September was higher still at $266.39/MWh, with prices largely driven by supplier offer behaviour, thermal generation outages, low wind generation, and higher demand year-over-year.

[1] Reference to Q3 means Q3 2022 unless specified otherwise. Reference to a month, or a day in a month, means a month or day in 2022 unless specified otherwise.

Table 1 shows summary market statistics for Q3 and Q3 2021. Demand was higher in August and September this year, which was driven by warmer temperatures and higher oil production.

Overall wind generation in Q3 was stable year-over-year, despite an increase in total wind capacity. The overall capacity factor of wind generation fell from 27% in Q3 2021 to 23% in Q3.

There were two EEA3 events in Q3, one on Tuesday, September 27 and one on Wednesday, September 28. These EEA3 events were declared by the AESO because there was not enough supply to reliably serve demand, and the AESO was unable to meet its minimum contingency reserve requirements. An EEA3 is the most severe alert level that can be declared by the AESO.

Table 1: Monthly market summary for Q3

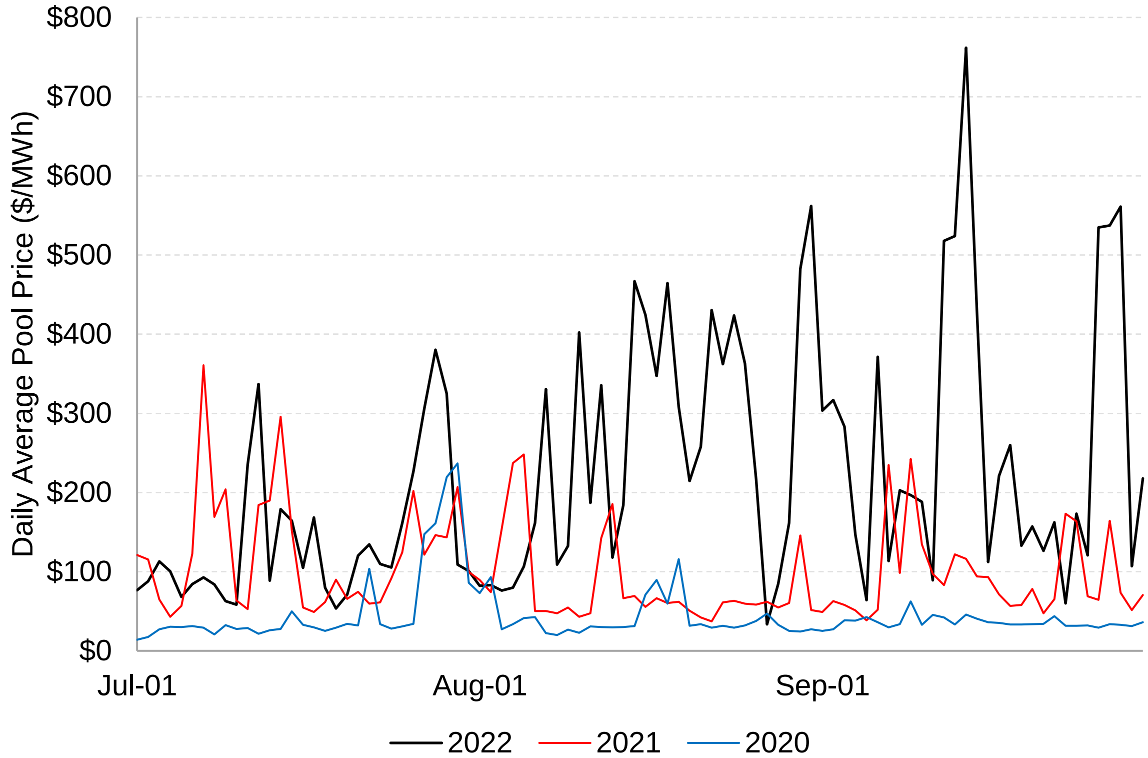
		2022	**2021**	***Change***
Pool price (Avg $/MWh)	Jul	141.55	124.10	14%
	Aug	257.75	82.26	213%
	Sep	266.39	94.45	182%
	Q3	**221.41**	**100.33**	**121%**
Demand (AIL) (Avg MW)	Jul	9,853	9,920	-1%
	Aug	9,840	9,297	6%
	Sep	9,382	9,015	4%
	Q3	**9,695**	**9,415**	**3%**
Gas price (Avg $/GJ)	Jul	5.13	3.73	38%
	Aug	2.68	2.82	-5%
	Sep	4.32	3.33	30%
	Q3	**4.04**	**3.29**	**23%**
Wind generation (Avg MW)	Jul	456	340	34%
	Aug	523	488	7%
	Sep	638	766	-17%
	Q3	**538**	**529**	**2%**
Net imports (+) Net exports (–) (Avg MW)	Jul	691	443	56%
	Aug	479	259	85%
	Sep	296	212	40%
	Q3	**491**	**306**	**61%**
Thermal outages[2] (Avg MW)	Jul	2,067	2,453	-16%
	Aug	2,173	2,700	-19%
	Sep	2,804	3,215	-13%
	Q3	**2,343**	**2,785**	**-16%**

The EEA alerts lasted for 2 hours and 55 minutes on September 27, and 1 hour and 57 minutes on September 28. During these events, the system marginal price (SMP) remained at the offer price cap of $999.99/MWh. These events are discussed in greater detail at the end of section 1.2.

A new record was set for the highest daily average pool price on Wednesday, September 14 at $761.72/MWh, although no energy alert was issued on this date. This exceeded the previous daily record of $696.24/MWh set on December 27, 2021, when the AESO declared an EEA2. Figure 2 shows the average daily pool price in Q3 of 2020, 2021, and 2022. Compared to the previous two years, pool prices in Q3 were considerably higher and more volatile in 2022. 11% of the hours in Q3 had pool prices above $700/MWh.

[2] These outage figures reflect the difference between maximum capability and total declared energy for coal, dual fuel, and natural gas assets (including cogeneration). The figures do not include the SCL1 cogeneration asset, which switched from net to gross reporting on August 5, 2022. The 2021 figures do not include the Sundance 5 mothball outage.

Figure 2: Daily average pool price (Q3 2022, 2021, and 2020)

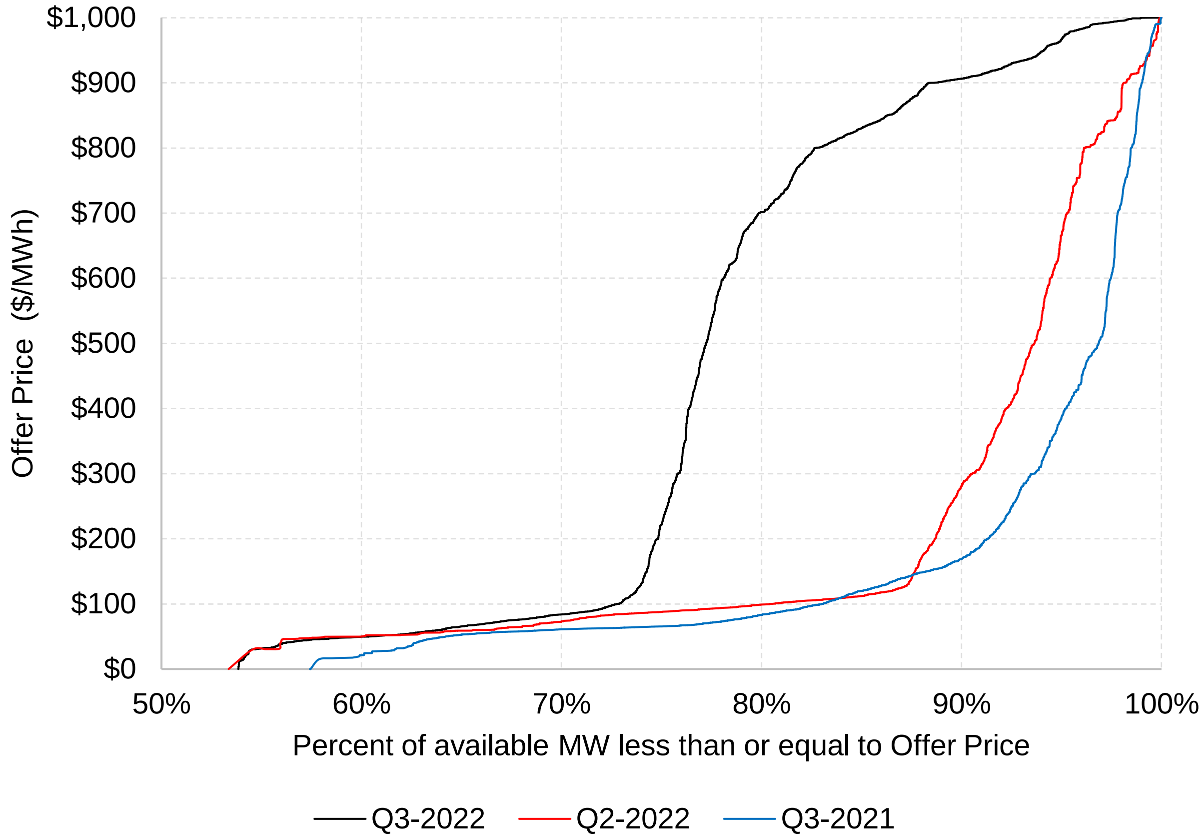


The offer behaviour of some larger suppliers was a principal driver of the high pool prices in Q3. Figure 3 shows the percent of available coal and converted coal capacity that was offered at or below different prices in Q3, Q2, and Q3 2021. As seen by the leftward shift in the distribution, there was substantially more capacity offered at higher prices in Q3 compared to Q2 2022 or Q3 2021. In Q3, around 20% of available coal and converted coal capacity was offered above $700/MWh, whereas less than 5% of capacity was offered above $700/MWh in Q2, and less than 3% was offered above $700/MWh in Q3 2021.

Unlike renewable generation, whose output is intermittent, coal and converted coal capacity can generally be dispatched up or down within the span of minutes to respond to prevailing demand and supply conditions. Coal and converted coal capacity comprises a meaningful portion of the dispatchable generation capacity in Alberta.

When a significant volume of coal or converted coal capacity is offered at higher prices, it can put considerable upward pressure on pool prices, particularly when demand is elevated and the supply of other generation is limited by outages or prevailing weather conditions. This was the case for many of the high-priced hours in August and September.

Figure 3: Distribution of offer prices on coal and converted coal capacity (Q3 2022, Q2 2022, and Q3 2021)



1.2 Market outcomes

Figure 4 illustrates trends in demand across 2020, 2021, and 2022 as a 30-day rolling average. Average demand was markedly higher in both August and September this year compared to the previous two years. The year-over-year increase in demand for these months was largely due to higher average temperatures (Table 2) and increased oil production.[3] Nonetheless, demand in August remained comparable to levels seen in July 2021 and was not exceptionally high.

The average daily temperature in August was 19.6°C which is similar to the July 2021 average of 19.7°C, and demand in August was 0.8% lower than in July 2021. Despite August being a hot month, temperatures did not reach the same highs of around 40°C seen in late June 2021. Consequently, the peak hourly demand in August of 11,202 MW was 519 MW less than the summer demand record set on June 29, 2021.

[3] AER ST3 report – Oil Supply and Disposition

Figure 4: 30-day rolling average of AIL demand (2020 to Q3-2022)

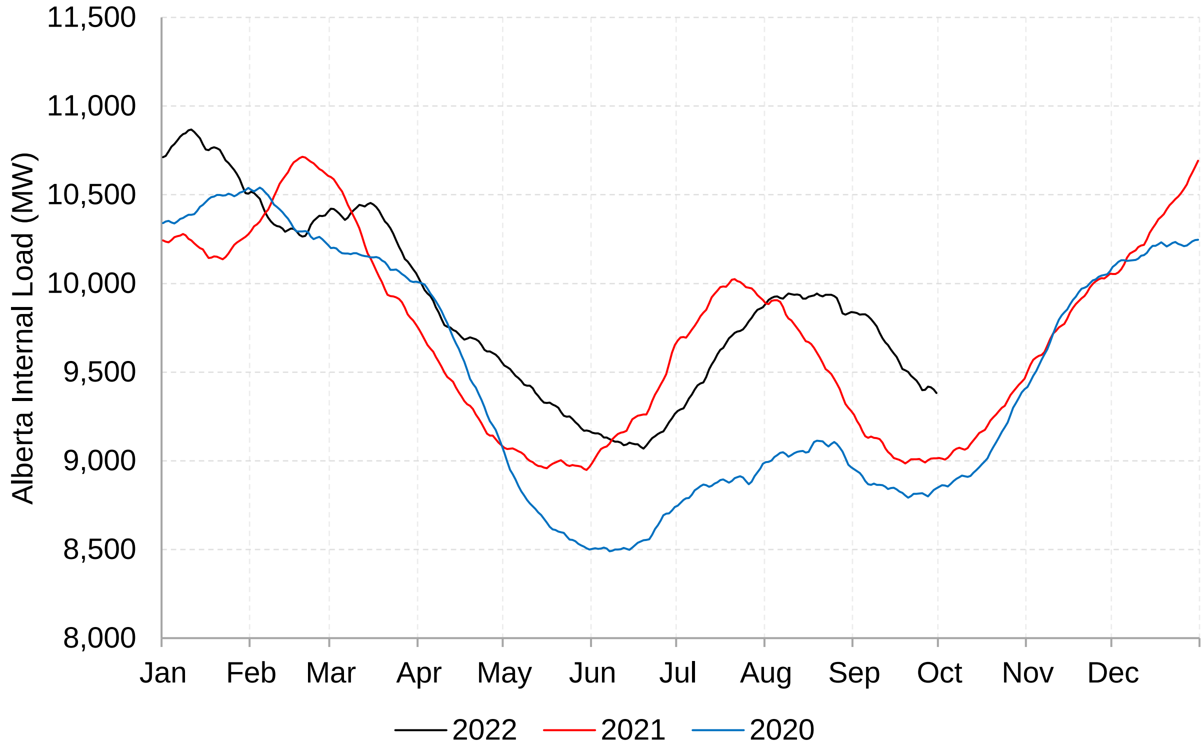


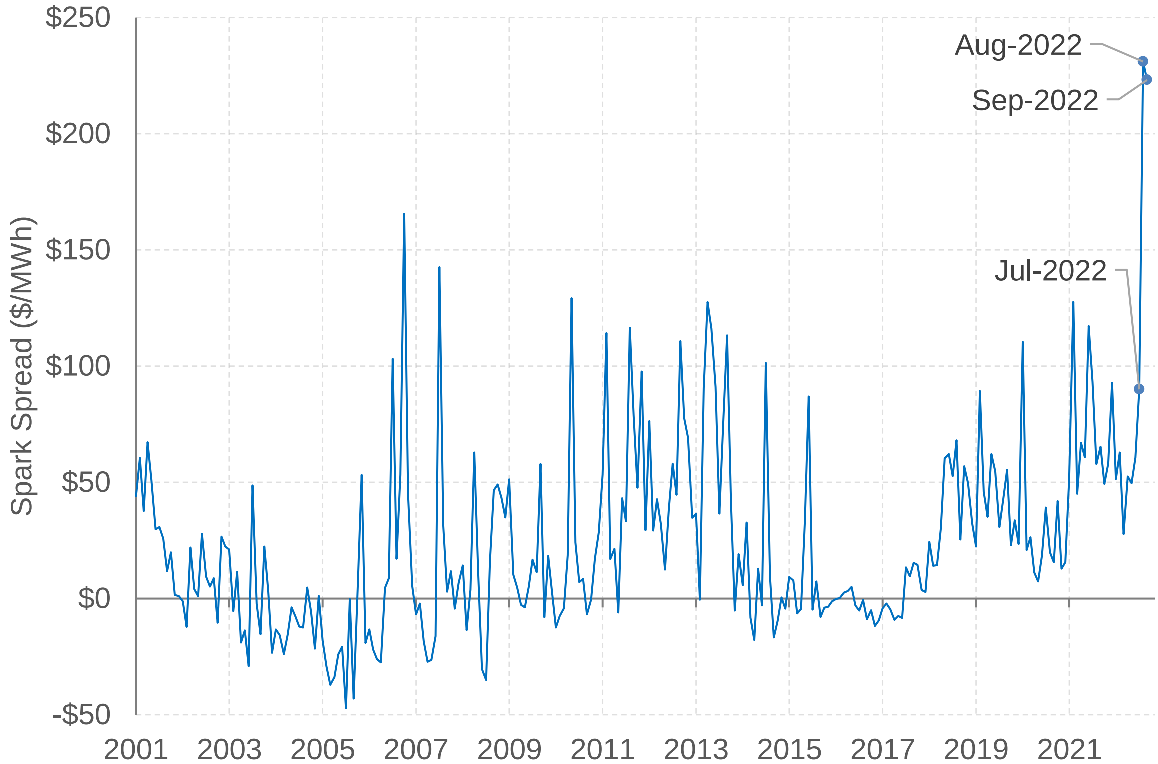
Table 2: Average monthly temperatures across Calgary, Edmonton, and Fort McMurray (°C)

	2022	2021	2020
July	18.9	19.7	17.5
August	19.6	17.0	17.2
September	14.5	12.7	11.9

Figure 5 shows the spark spread by month going back to January 2001. Spark spread is the margin between pool prices and fuel input costs for natural gas generation assets. The spark spread figures here assume a heat rate of 10 GJ/MWh.

In August, the spark spread was $231/MWh, the highest on record, with the previous high being $166/MWh in October 2006. The spark spread in August was a four-fold increase over the August 2021 spark spread of $58/MWh.

Figure 5: Monthly spark spread using a 10 GJ/MWh heat rate (January 2001 to September 2022, inflation adjusted)[4]



Low natural gas prices in Alberta were a factor in the high spark spread in August, when same-day natural gas prices fell to their lowest level since April 2021. Figure 6 plots the same-day price of natural gas in Alberta and at Henry Hub since July 1, 2021. [5] Henry Hub is a large demand centre near the Gulf Coast in Louisiana. Alberta gas typically trades at a $2 to $3 discount relative to prices at Henry Hub. This discount reflects Alberta pipeline constraints and transportation costs.

For much of August, pipeline constraints on the Eastgate (EGAT) and Upstream James River (USJR) areas of the Alberta gas pipeline network reduced export capacity and the amount of natural gas that could be put into storage. As a result, the demand for Alberta natural gas was constrained and AB-NIT prices fell significantly, even though some Alberta producers reduced production. At the same time, prices at Henry Hub were increasing on the back of high summer temperatures in the US and events in Europe. In the second half of August, the price differential between Henry Hub and Alberta was between $10 and $14/GJ (Figure 6).

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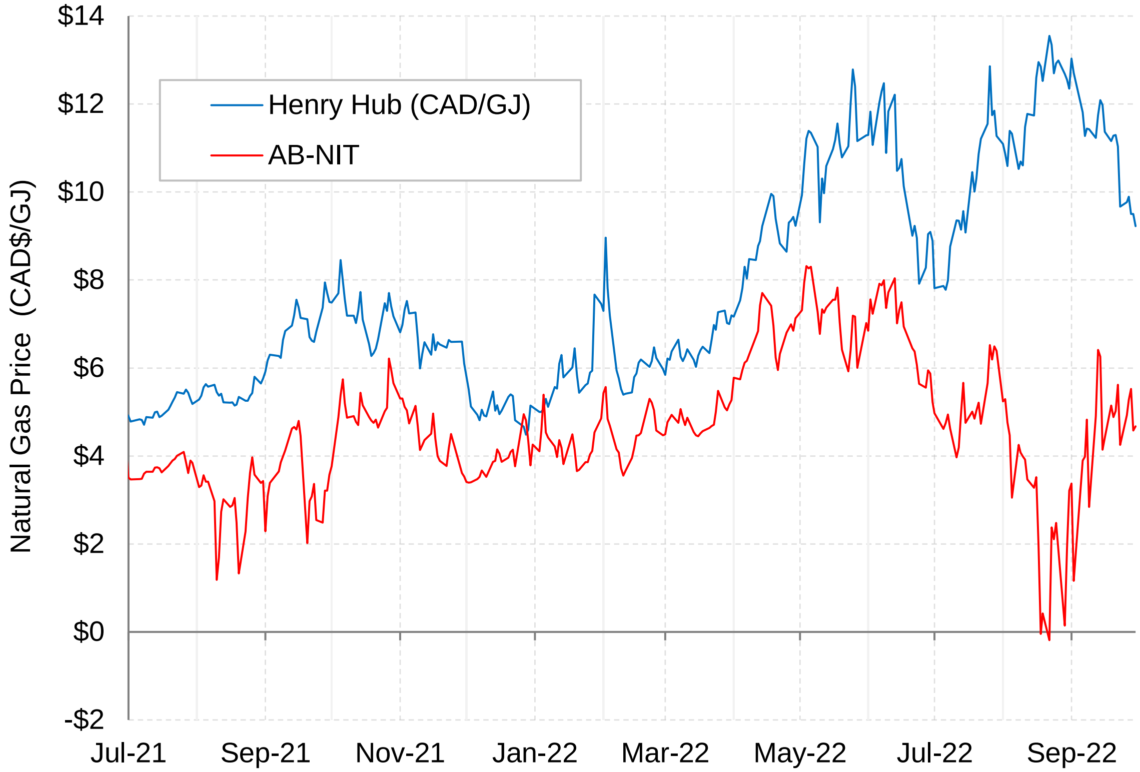
[4] Pool prices and gas prices have been adjusted for inflation and are expressed in September 2022 dollars.

[5] EIA Henry Hub spot price data is converted using the Bank of Canada's daily exchange rate to CAD$/GJ.

Figure 6: Same-day natural gas prices (July 1, 2021 to September 30, 2022)



Wind generation in Q3 was comparable to levels in Q3 of the previous two years (Figure 7). On average, wind generation was 538 MW in Q3 and 529 MW in Q3 2021. As shown by Figure 7, wind generation naturally tends to be lowest during summer months and highest during shoulder months like November, or during mild winter conditions.

Table 3 lists monthly average wind generation alongside its corresponding capacity factor. As a result of the growth in total capacity over the last two years, the same level of wind generation in Q3 now represents a lower fraction of overall capacity. In Q3, the overall capacity factor was only 23%, as compared to 27% and 30% in Q3 of the previous two years. Total wind capacity in Alberta has increased from 1,791 MW at the end of Q3 2020, to 1,988 MW at the end of Q3 2021, and to 2,469 MW at the end of Q3.[6]

[6] The capacity of new wind assets is included in full once the asset starts to generate to the grid, as opposed to being included based on its listed in-service date.

Figure 7: Monthly average wind generation (2020, 2021, and 2022)

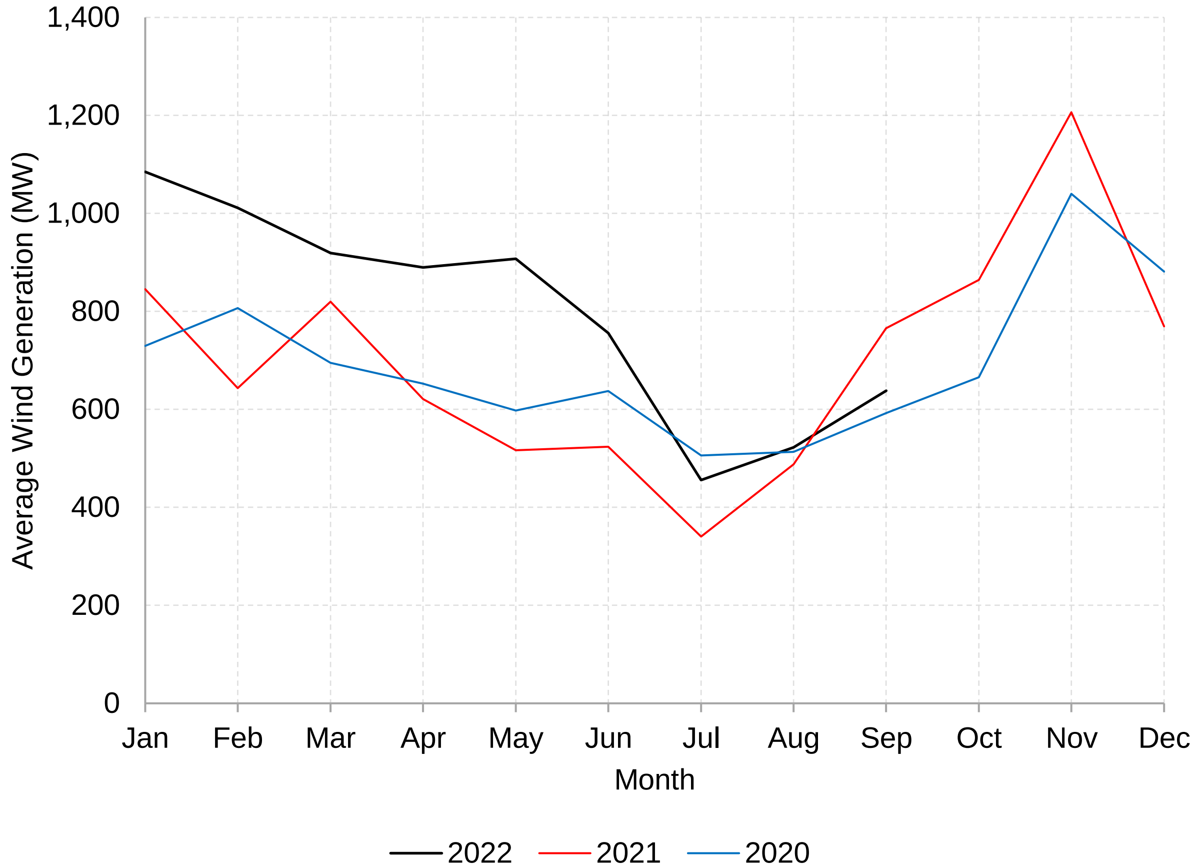


Table 3: Average wind generation and capacity factor (Q3 2022, 2021, and 2020)

	2022		2021		2020	
	Avg Wind Gen.	**Capacity Factor**	**Avg Wind Gen.**	**Capacity Factor**	**Avg Wind Gen.**	**Capacity Factor**
July	456	20%	340	18%	506	28%
August	523	23%	488	25%	513	29%
September	638	26%	766	39%	592	33%
Q3	**538**	**23%**	**529**	**27%**	**536**	**30%**

The received price of wind generation was $141.53/MWh in Q3, which is 64% of the quarterly average pool price of $221.41/MWh. Although this is a historically modest percentage relative to overall pool prices, it represents the highest quarterly received price for wind generation on record, surpassing $102.88/MWh in Q2 of 2013.

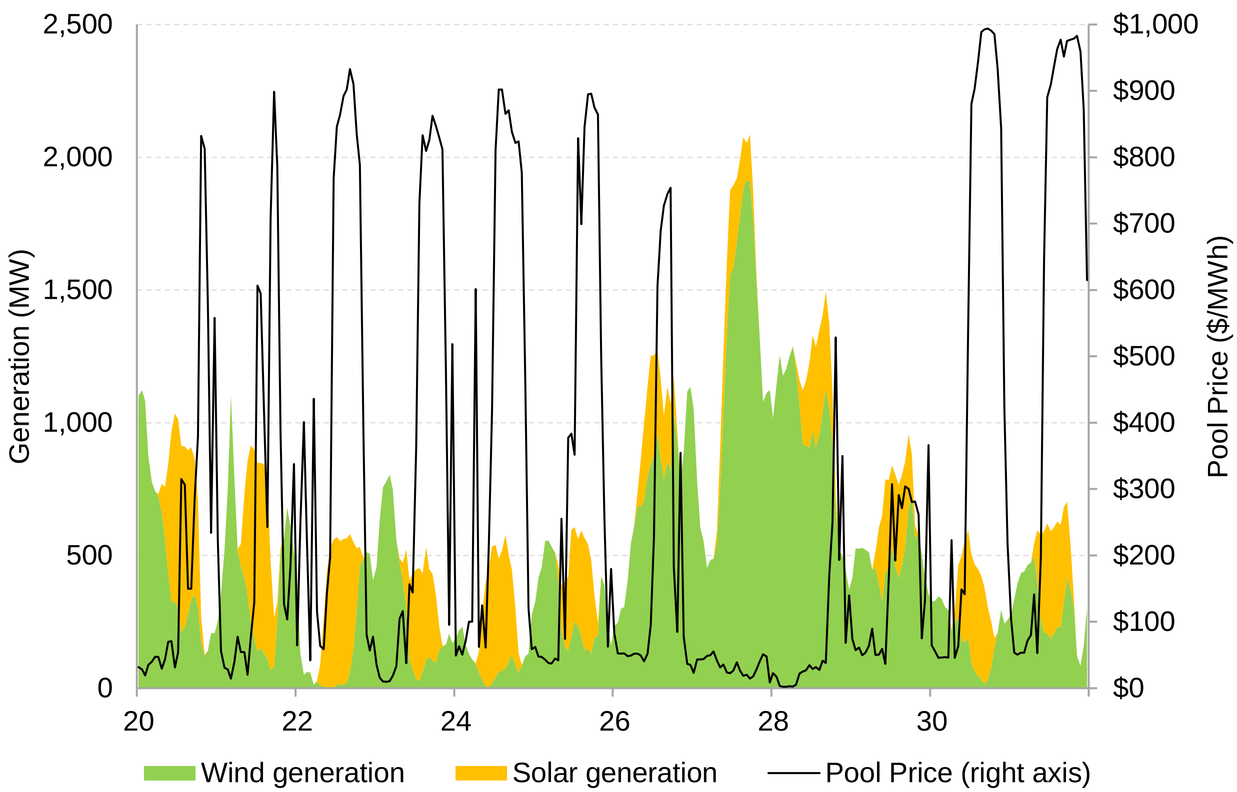
The received price of solar generation was $282.99/MWh in Q3, which is 128% of the quarterly pool price. The received price of solar tends to exceed average pool prices, especially in summer months, since solar generation is highest during peak daytime hours when demand and prices are often higher.

Figure 8 illustrates hourly pool prices along with wind and solar generation from August 20 to 31. Fluctuations in renewable generation can often be a factor that contributes to pool price volatility, particularly during tighter market conditions or when a large volume of thermal capacity is offered at higher prices.

On several high-demand days between August 20 and 31 wind generation was very low, reducing supply and putting upward pressure on pool prices. During some lower demand hours, the combined absence of wind and solar generation put upward pressure on prices, for example on August 20 and 22. Conversely, periods of higher wind generation, such as on August 27 and 28, alleviated supply pressures and pool prices were low.

Solar generation has increased year-over-year and has become increasingly important in bridging the supply gap caused by periods of low wind generation on hot summer days. In this way, the increase in solar generation helped to stabilize the intermittent output associated with wind generation in Q3.

Figure 8: Average hourly wind generation, solar generation, and pool price (August 20 to 31, 2022)



Based on the AESO's Long Term Adequacy metrics released in early November, 1,190 MW of solar capacity and 2,360 MW of wind capacity is currently under construction, with in-service dates between November 2022 and December 2023.[7]

A new record for the daily average pool price was set on Wednesday, September 14 at $762/MWh. The hourly pool price remained above $500/MWh across all 24 hours on this date. This outcome was driven primarily by supply side factors including offer behaviour, low thermal availability, and low wind generation.

On September 14, wind generation averaged only 170 MW and average thermal availability was 7,907 MW, the lowest in the quarter (Figure 9). The reduced supply created tight market conditions even as demand averaged only 9,260 MW and temperatures were moderate (Calgary temperatures peaked at 21°C, for example).

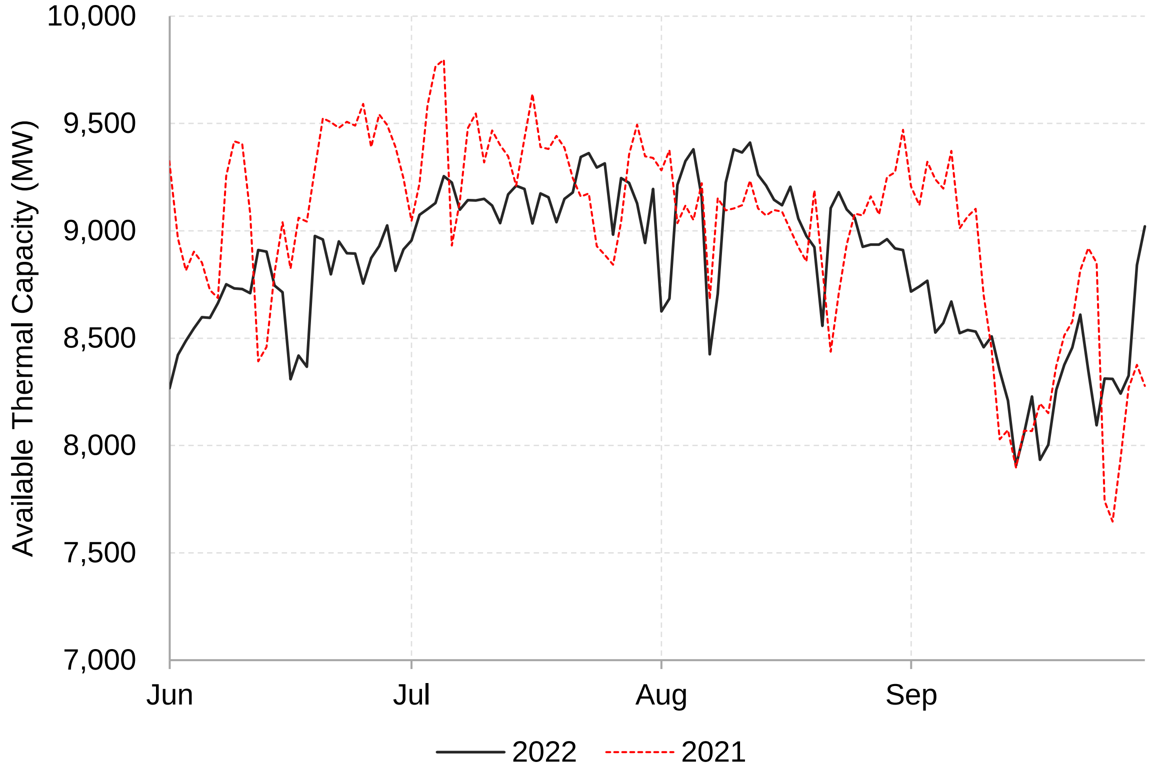
Natural gas assets including H.R. Milner (300 MW), MacKay River (207 MW), Northern Prairie Power Project (105 MW), and Valleyview 1 and 2 (100 MW) were offline. In addition, Shepard (868 MW) was materially derated for much of September 14, and there were meaningful outages at Joffre (474 MW) and other large cogeneration assets. In terms of offer behaviour, around 27% of all available coal and converted coal capacity was offered above $500/MWh, and this contributed to the high realized pool prices given the supply constraints.

Figure 9 illustrates trends in available thermal supply in Q3 and Q3 2021. Overall, there was less thermal capacity on outage in Q3 this year compared to Q3 2021. However, the Keephills 1 (395 MW) and Sundance 4 (406 MW) coal assets have retired since Q3 2021, lowering the base level of available capacity.

As shown by Figure 9, there was a decrease in available thermal capacity beginning in late August this year, which extended into the first half of September. This reduction in available thermal capacity corresponds to outages and derates at some large natural gas generation assets.

[7] AESO - Long-term adequacy metrics (November 2022)

Figure 9: Daily average of available thermal capacity
(June 1 to September 30, 2022 and 2021)[8]



Thermal outages were an important factor in the EEA3 events that occurred on September 27 and 28. On both days several large generation outages reduced available supply, including Genesee 2 (400 MW), HR Milner (300 MW), Mackay River (207 MW), Air Liquide Scotford (106 MW), and Joffre (474 MW). No coal or gas-fired steam assets were commercially offline during these EEA events.

The BC/MATL intertie came offline for a planned outage on September 26 and was unavailable for the EEA3 event on September 27. At around 14:48 on September 28, the AESO's Interconnection Available Transfer Capacity report[9] was changed to reflect that the BC intertie would return to service beginning in HE18. The BC intertie returned to service at 16:53 as the AESO had declared an Energy Emergency Alert at 15:18, indicating a shortfall in supply. The return of the BC intertie helped to alleviate the supply shortfall conditions on September 28 and an EEA0 was declared at 17:15, indicating an end to the supply shortfall.

[8] These outage figures reflect the difference between maximum capability and total declared energy for coal, dual fuel, and natural gas assets (including cogeneration). The figures do not include the SCL1 cogeneration asset, which switched from net to gross reporting on August 5, 2022.

[9] AESO Interconnection Available Transfer Capacity report

Low wind generation and relatively high temperatures were also factors that contributed to the two EEA3 events. During these events wind generation averaged only 168 MW on September 27 and 101 MW on September 28. As a result of prevailing temperatures, demand peaked at 10,296 MW on September 27 and 10,305 MW on September 28, some of the highest levels seen in September.

Table 4 compares several market metrics during certain hours of recent EEA events. In comparison to the EEA2 event in December 2021, demand during the EEA3 events in September did not reach the same peak. However, on the supply side, net imports were constrained by the outage on BC/MATL on September 27 and 28, and wind generation was slightly lower. Solar generation was an important factor in HE17 of September 28, supplying 569 MW.

Prices on all three occasions were at the offer price cap, reflecting the supply shortfall. Thermal outage levels were high and comparable across all three events, although Keephills 1 and Sundance 4 retired earlier this year, reducing thermal supply by around 700 MW in the September events relative to December 27, 2021.

Table 4: Comparison of relevant market metrics during certain hours of recent EEA events

	Dec 27, 2021 (EEA2 event)	**Sep 27, 2022 (EEA3 event)**	**Sep 28, 2022 (EEA3 event)**
Hour ending	21	19	17
Pool price ($/MWh)	$999.99	$999.99	$999.99
Demand (AIL) (MW)	11,137	9,978	10,305
Calgary Temperature (°C)	-30	26	28
Wind generation (MW)	217	145	111
Solar generation (MW)	0	93	569
Thermal outages[10] (MW)	2,875	2,982	2,911
Net Imports (MW)	511	60	0

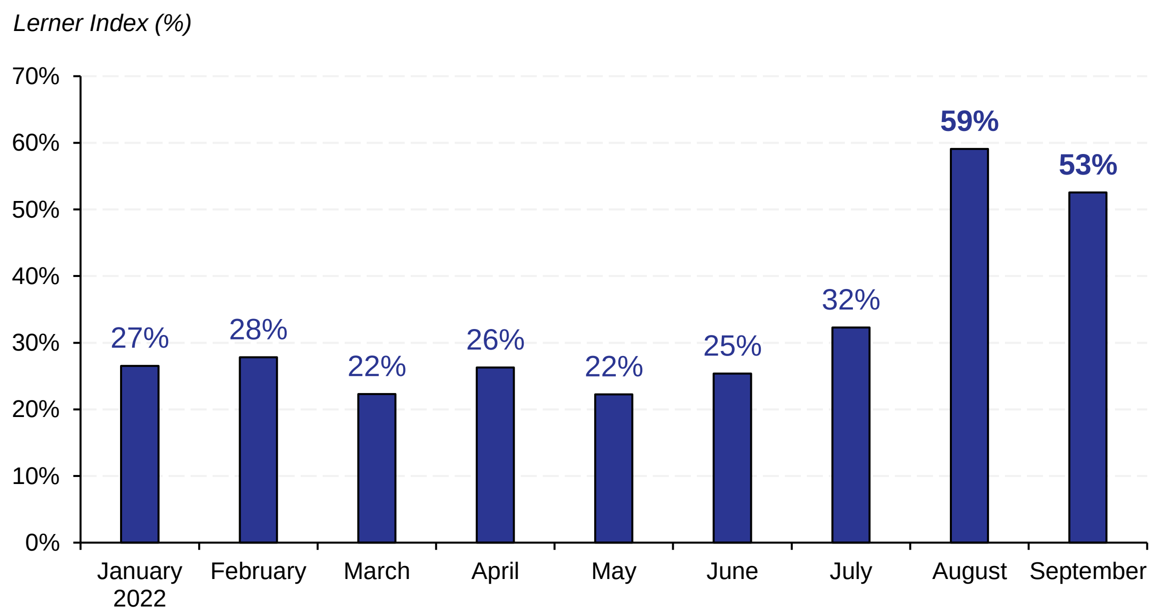
[10] These outage figures reflect the difference between maximum capability and total declared energy for coal, dual fuel, and natural gas assets (including cogeneration). The figures do not include the SCL1 cogeneration asset, which switched from net to gross reporting on August 5, 2022.

1.3 Market power

High pool prices in Q3 were primarily driven by the exercise of market power by two generation companies. The combined generation capacity of these two firms was often required for supply to meet demand in Q3, indicating market power. Prices were exacerbated by the degree to which the generation capacity of these two firms was needed to meet demand. In this section the MSA examines the degree of market power in Q3, the market outcomes resulting from the exercise of market power, the conditions that enabled the profitable exercise of market power, and how market power was exercised.

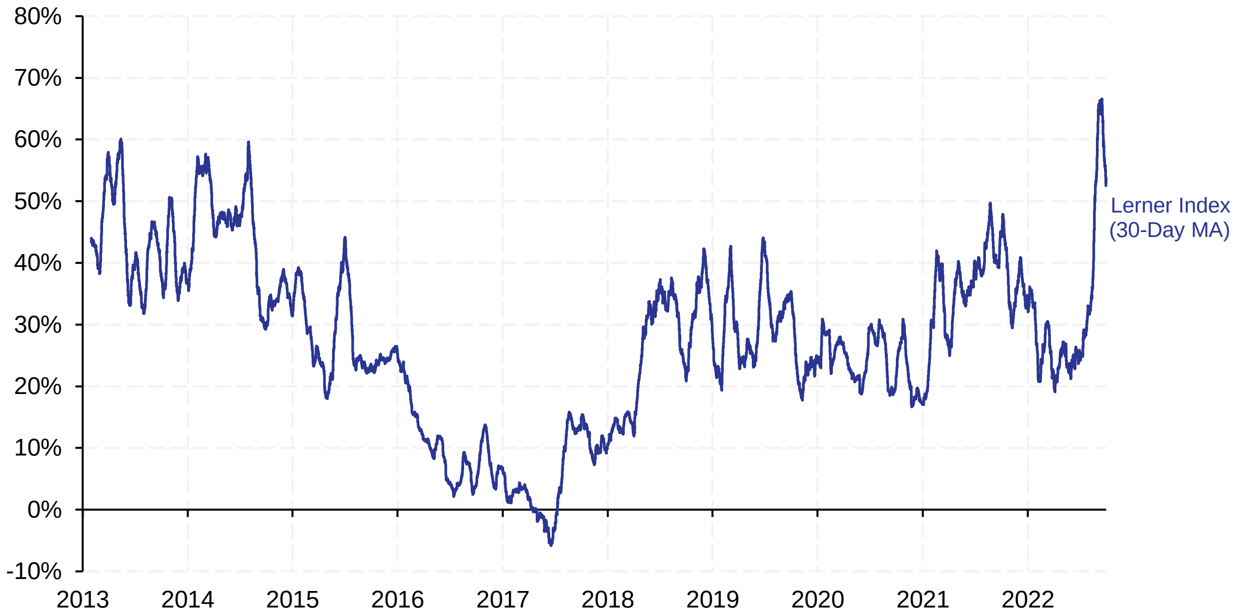
The Lerner index measures the market markup (price less marginal cost) expressed as a percentage of the price. The Lerner index is used as a proxy measure of the exercise of market power. Market markups averaged between 20% and 30% of pool price in the first six months of 2022 but increased materially in August and September (Figure 10).

Figure 10: Monthly market markups, January to September 2022



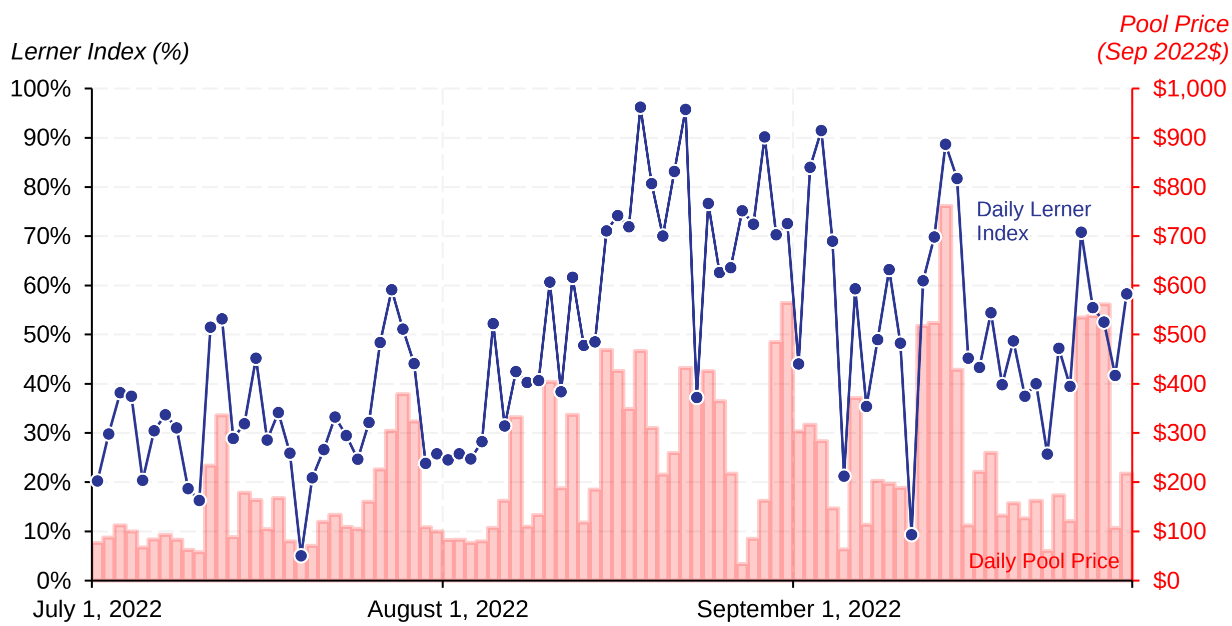
Market markups increased significantly midway through July and reached 30-day highs of over 65% in mid-September. These markups are well above recently observed levels and are similar to market markups in 2013 and 2014 (Figure 11).

Figure 11: Lerner index (30-day rolling average), 2013 to September 2022



While the monthly markups averaged between 30% and 60% in Q3, there was significant day-to-day variation in the market markup during the quarter, with four days having average markups of over 90% (Figure 12).

Figure 12: Daily average Lerner index and pool price (September 2022$), Q3 2022



Allocative efficiency refers to the state where the net benefit to consumers or producers attained using the market's resources is maximized. In the Alberta electricity market, allocative inefficiency results from reductions in demand that would have otherwise existed had pool prices been reflective of marginal cost.

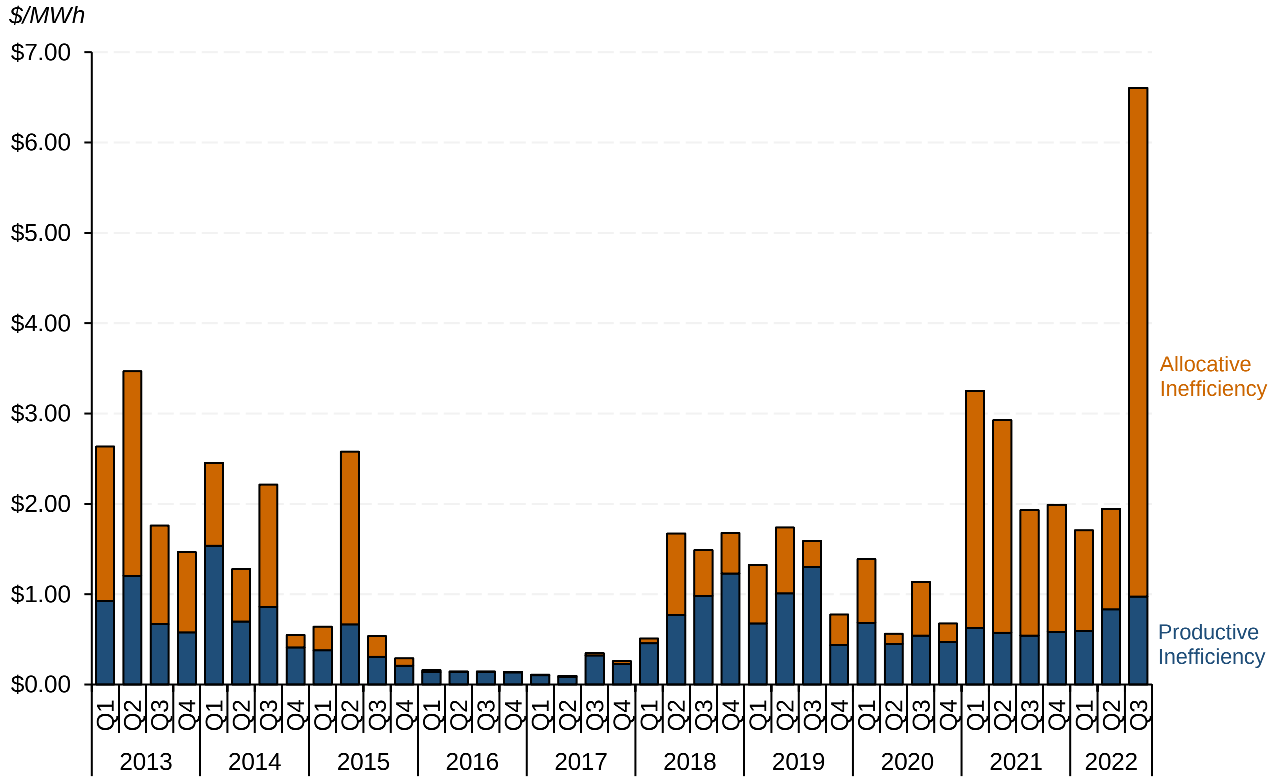
Productive efficiency refers to the state where the production costs needed to serve the observed level of demand are minimized. Productive inefficiency occurs when relatively high-cost generation is dispatched instead of lower cost generation, increasing the total production costs of the generation fleet.

Short-run allocative inefficiencies increased significantly in Q3 along with the rise in prices above marginal cost. These inefficiencies reflect losses of demand in the quarter that would have otherwise occurred (Figure 13).

Productive inefficiency also increased moderately quarter-over-quarter. This increase in productive inefficiency is notable given that productive inefficiency would be expected to decline during scarcity events, which were relatively high in number this quarter. In scarcity events most or all generators would be dispatched, leaving less room for relatively low-cost generators to go un-dispatched.

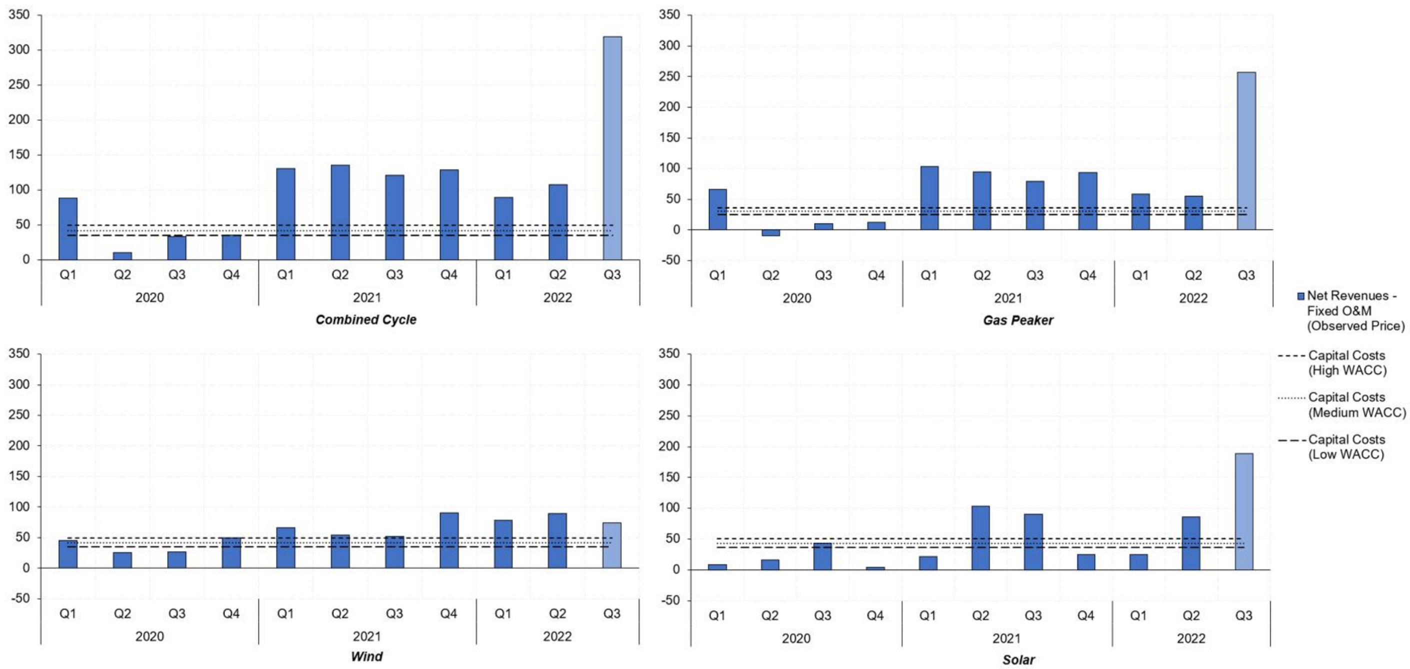
Overall, the average static inefficiency (allocative and productive) over Q3 2022 was almost double the static inefficiency in Q2 2013, the quarter with the next highest inefficiency since 2013 (Figure 13).

Figure 13: Average static inefficiency by quarter, Q1 2013 to Q3 2022 (2022$)



With the increase in pool prices and market markups, most generators earned significantly greater net revenues (net of fixed operations and maintenance costs) in Q3 2022 compared to previous quarters (Figure 14). This was particularly true for baseload combined cycle units and peaking gas-fired units, but not the case for wind generators which had lower levels of generation quarter-over-quarter.

Figure 14: Comparison of quarterly net revenues (less fixed operations & maintenance cost) and annualized capital costs by technology (2022$ thousands/MW-year), Q1 2020 to Q3 2022[11]



Energy market participants can economically withhold in the Alberta market by offering their generation capacity into the energy market at prices in excess of a generating unit's marginal cost.[12] A generating firm may raise the pool price by economically withholding its capacity but doing so may come at the cost of some of its capacity going un-dispatched. Competing firms may respond by lowering their offer prices on units that would otherwise be priced higher to undercut the firm attempting to economically withhold.

One measure of market power is analyzing the extent to which a firm's supply is pivotal in the market. Firms become pivotal when their generation capacity is needed for supply in the energy market to meet demand. The market's reliance on the pivotal firm's capacity in such hours indicates greater market power. However, in such hours, the pivotal firm may not price its capacity above all other competing firms as this would normally reduce the dispatch of the pivotal firm.

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[11] Capital costs are amortized on an annualized basis and allocated to quarterly amounts.

[12] The MSA most recently reported on the exercise of market power and the performance of the energy market in its Q2 2022 Quarterly Report.

To assess the degree to which a firm may be pivotal, the MSA uses two metrics: the Residual Supply Index (RSI) and Pivotal Supplier Index (PSI). RSI is a measure of the degree to which a firm's generation capacity is pivotal, expressed as the total supply available from other firms divided by demand. Where the total supply available from other firms is less than demand (RSI < 1), a firm is said to be pivotal. PSI is defined here as the percentage of hours in a period where a firm's generation capacity is pivotal.

PSI (and RSI) can also be used to express the joint pivotality of multiple (n) firms' combined generation capacity, expressed as n-Firm PSI. By convention, n-Firm RSI and PSI are measured using the n firms with the most generation capacity in any given hour. For example, 1-Firm PSI is a measure of the pivotality of the firm with the most generation capacity in any hour, 2-Firm PSI is a measure of the joint pivotality of the two firms with the most generation capacity in any hour, etc. The firms comprising n-Firm PSI can change between hours if the relative amount of generation capacity offered by firms changes.

In hours where 1-Firm is pivotal, it is necessarily the case that n-Firms are also jointly pivotal. However, when 2-Firms are jointly pivotal it is not necessarily the case that 1-Firm will also be pivotal alone, for example.

While 1-Firm's entire generation capacity may be pivotal in particular hours, because some or all of this capacity may be intermittent or non-dispatchable[13] a pivotal firm may not necessarily be able to economically withhold this capacity and influence pool price. To account for this, in this analysis the MSA uses adjusted RSI and PSI when assessing firms' market power in the context of economic withholding.

Where RSI is a measure of the degree to which a firm's generation capacity is pivotal, adjusted RSI measures the degree to which a firm's *dispatchable* generation capacity is pivotal. Adjusted PSI is similarly defined as the percentage of hours where a firm's *dispatchable* generation capacity is pivotal. In hours where a firm's dispatchable generation capacity is pivotal, it is not physically constrained in its ability to economically withhold, though it may still be constrained by the reduction in dispatch or by the competitive response of other firms.

The ability of some larger firms to exercise market power increased significantly in Q3 as a result of market factors including generation outages, low wind generation, import constraints, and increased demand (Figure 15). Both 1 and 2-Firm pivotality were associated with significant increases in pool prices beginning in late-July.

While monthly average pool prices were significantly higher than in previous quarters, pool prices varied significantly between days, with higher prices tending to occur on days where 1-Firm was more frequently pivotal (Figure 16). Typically pool prices were lower on days where 1-Firm was less frequently pivotal, even if 2-Firms were jointly pivotal.

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[13] Dispatchable capacity here means generation capacity priced above $0/MWh, reflective of capacity that is not intermittent or minimum stable generation.

Figure 15: 1- and 2-Firm adjusted PSI, January to September 2022 (30-day rolling average)

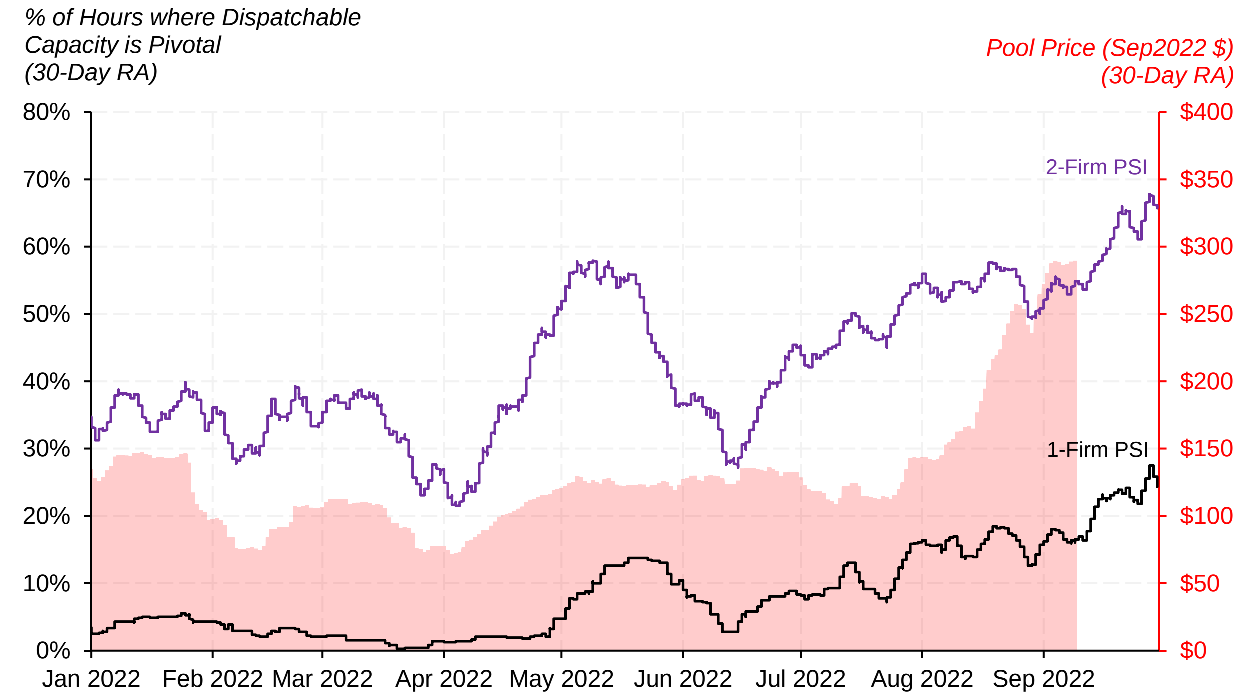
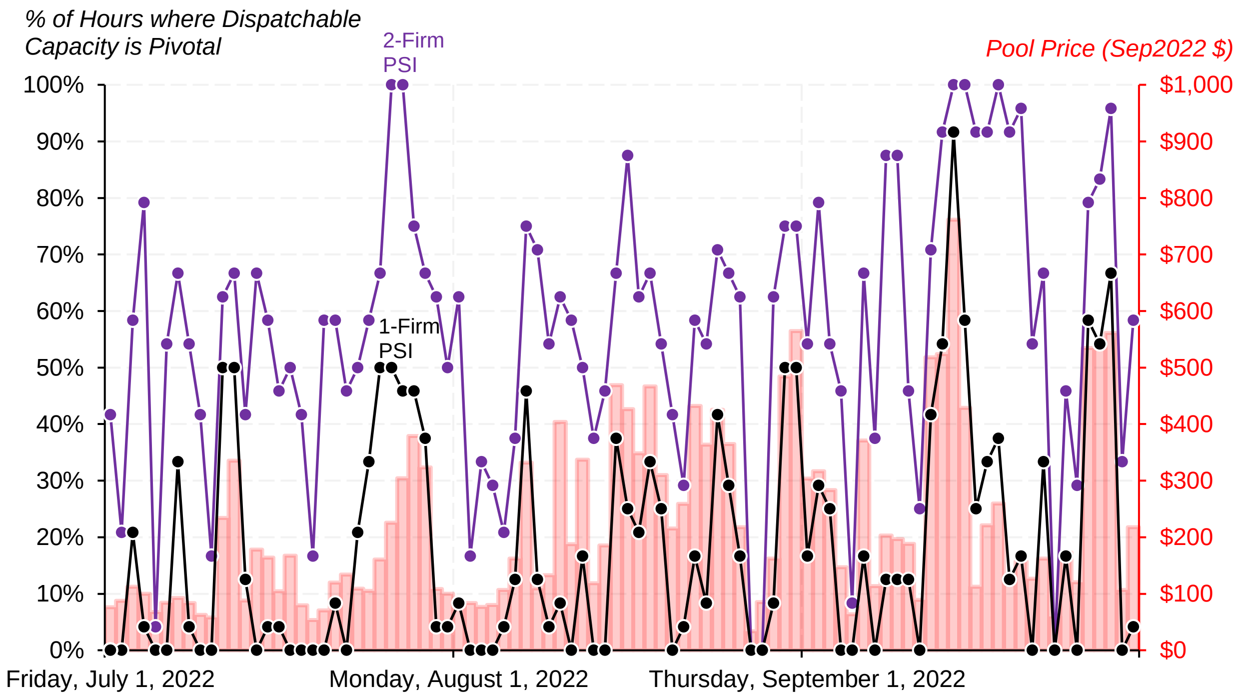


Figure 16: 1- and 2-Firm adjusted PSI, July to September 2022 (daily average)



Although the *existence* of joint pivotality (PSI) among 2-Firms was not the primary contributor to high pool prices in Q3, the extent to which the 2-Firms were pivotal[14] exacerbated pool prices and market markups. As shown by Table 5, the Lerner index is well correlated with the 2-Firm PSI, but this correlation is primarily driven by hours where 1-Firm alone is also pivotal.

Despite this, the intensity of 2-Firm joint pivotality had a greater correlation with the Lerner index than the intensity of 1-Firm pivotality. This suggests that both the first and second jointly pivotal firms economically withheld in periods where 1-Firm was pivotal, raising markups and pool prices to a greater extent than would have been possible had 1-Firm not been pivotal.

Table 5: Correlation with hourly Lerner index (July to September 2022)

Variable	**Correlation Coefficient**
2-Firms Pivotal	0.50
1-Firm Pivotal & 2-Firms Pivotal	0.47
1-Firm Not Pivotal & 2-Firms Pivotal	0.14
1-Firm Pivotality Intensity	0.32
2-Firm Pivotality Intensity	0.57

Periods with high levels of market power have been observed previously in the Alberta power market, with a number of similar events occurring since 2013 (Figure 17). Three previous events with similar levels of market power are observable over this period: in 2013, 2017 and 2021. The MSA compared the Q3 market power event with the event in 2021, as events in prior years would be less comparable due to the prior presence of the historical trading report (HTR), power purchase arrangements (PPAs), and the marginal cost offer strategy of a large market participant on a number of PPA assets.

Both 1 and 2-Firm PSI increased significantly in the summer 2021, as 1-Firm was pivotal in up to 24% of hours, while 2-Firms were pivotal in 63% of hours (Figure 18). This increase in market power over the summer of 2021 was associated with relatively moderate increases in pool prices.

[14] Intensity of pivotality is defined as the maximum of {0,1-RSI} for n-Firms, representing the percentage of demand that must be served by the n-Firms for the market to clear. Higher intensity values indicate the market is more reliant on the capacity of the n-Firms, enabling the n-Firms to more profitably economically withhold additional capacity.

Figure 17: 1- and 2-Firm adjusted PSI, January 2013 to September 2022 (30-day rolling average)

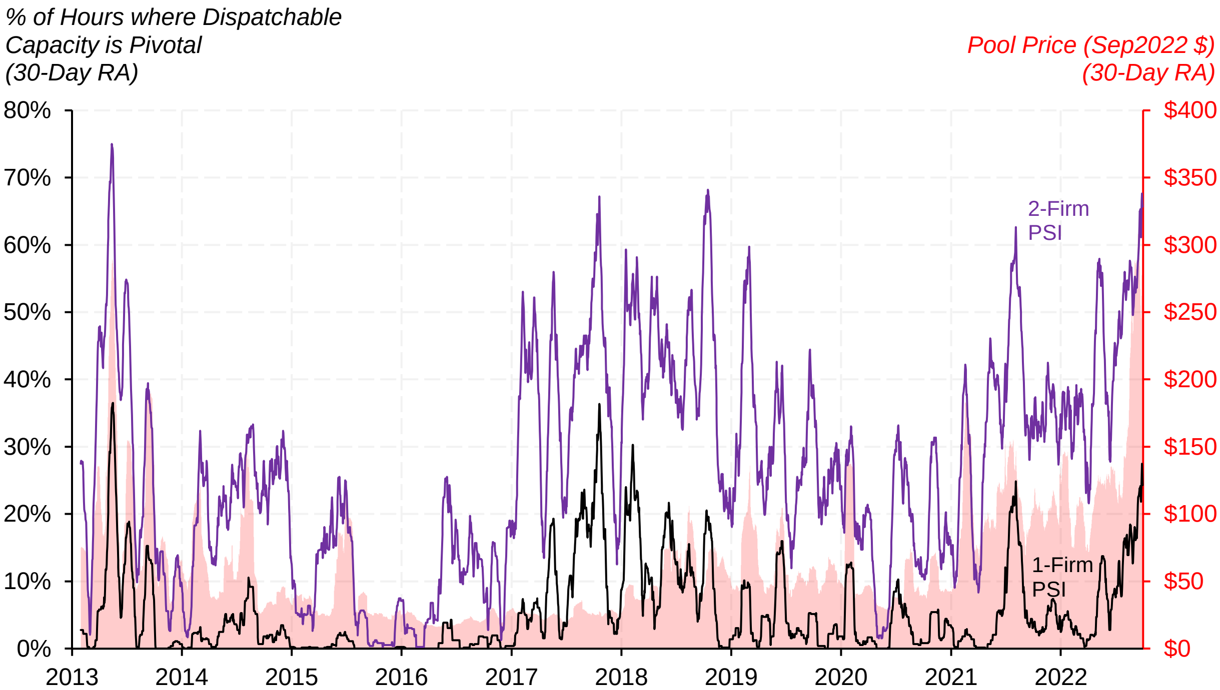
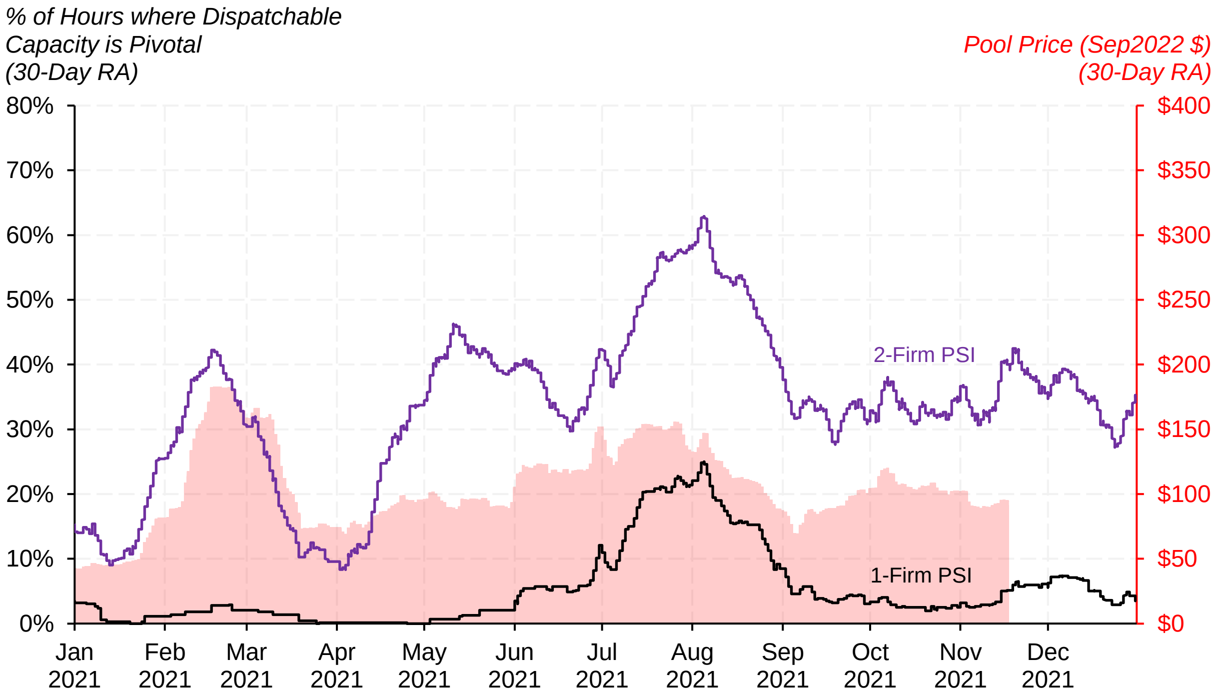
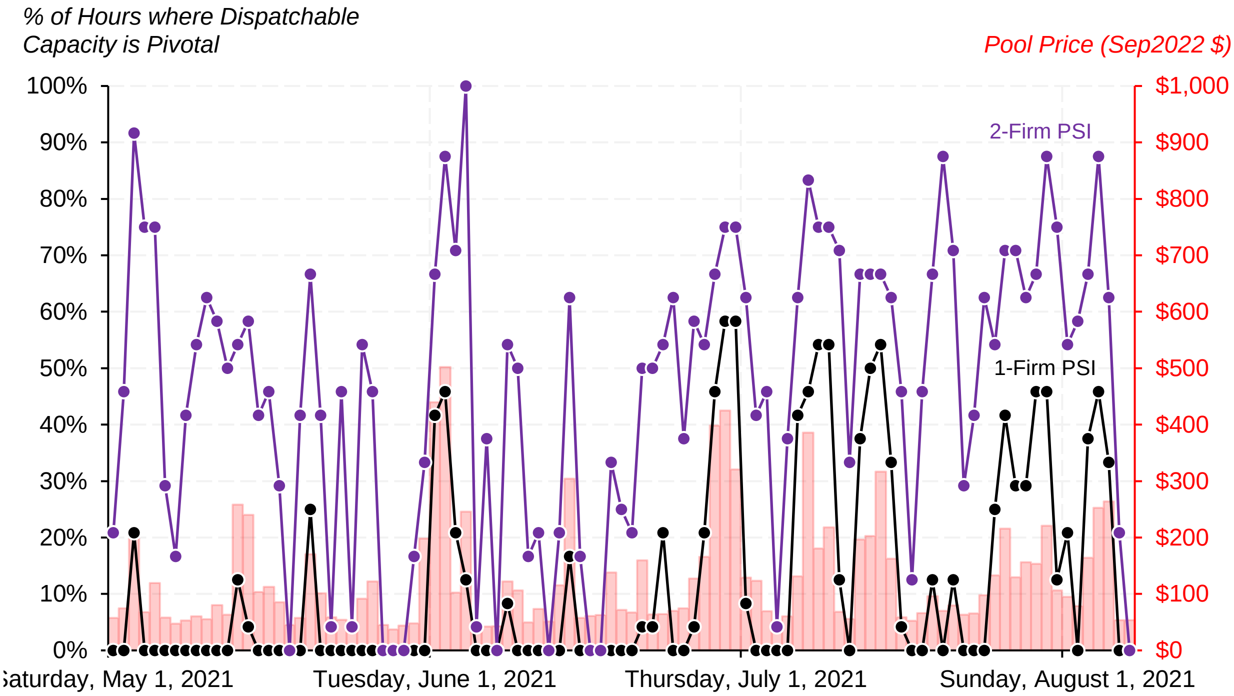


Figure 18: 1- and 2-Firm adjusted PSI, January to December 2021 (30-day rolling average)



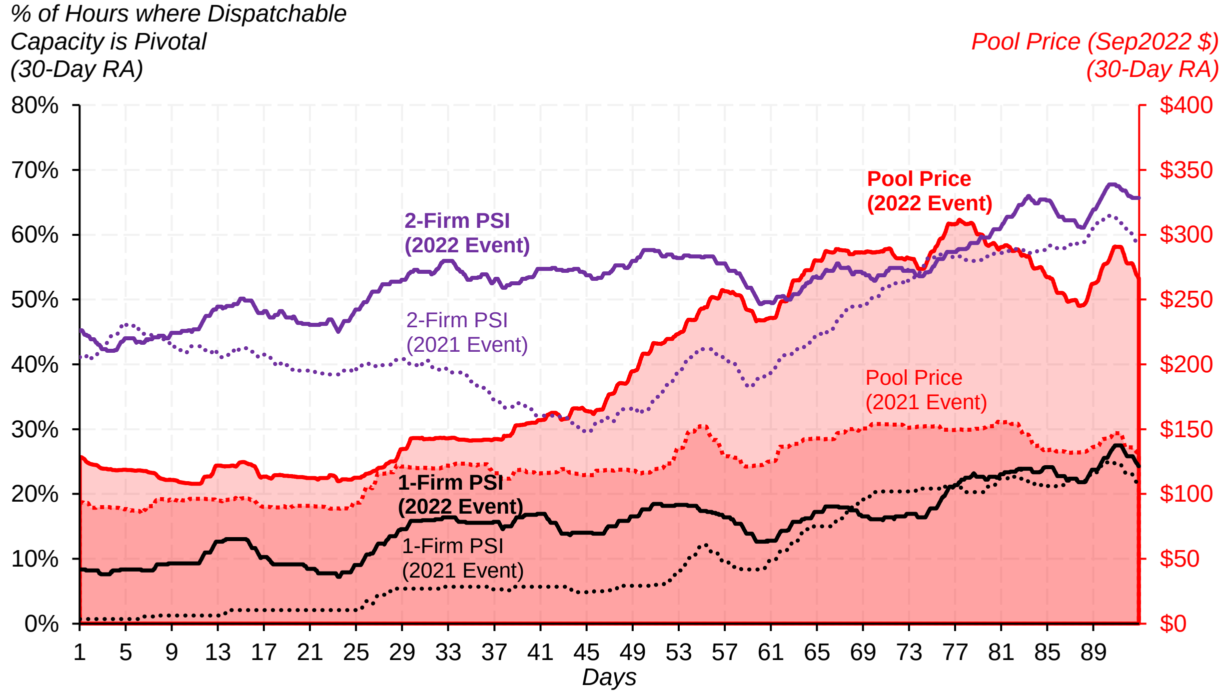
As with the market power event in 2022, the period from May 1 to August 7, 2021 exhibited similar periods of relatively high daily prices that correlated with days where 1-Firm was frequently pivotal (Figure 19).

Figure 19: 1- and 2-Firm adjusted PSI, May 1, 2021 to August 7, 2021 (daily average)



However, directly comparing the market power event in Q3 2022 to the one from May 1 to August 7, 2021, it is evident that the market power event in 2021 did not result in pool prices being as high as seen during the Q3 2022 event (Figure 20). Market power measures over the two events were similar, including the 30-day pivotality levels at the height of pool prices. Further, 30-day market markups during the height of pool prices in the Q3 2022 event were 67%, compared with 39% in the 2021 event, despite similar levels of market power.

Figure 20: Comparison of 2021 (May 8 to August 7), Q3 2022 pivotality events (30-day rolling average, 93 days)



The companies that comprise the largest and second-largest firms by dispatchable capacity can vary between hours. However, in the majority of hours where one firm was pivotal in Q3 a single company (Company A) was this pivotal firm (Figure 21).

Likewise, in most hours where two companies were jointly pivotal during the Q3 high price period, Company A was one of the jointly pivotal firms with a second company, Company B (Figure 22). Prior to Q3 2022, periods of frequent 2-Firm pivotality were more variably split between a combination of Company A & Company B, and Company A & Company C. In these prior events average pool prices did not reach the same highs as seen in Q3 2022.

During the 2021 market power event, Company A was generally the pivotal firm, and the combination of Company A & Company B were the largest two firms, as was the case during Q3 2022.

Figure 21: Companies comprising the 1-Firm pivotal firm (January to September 2022) (30-day rolling average)

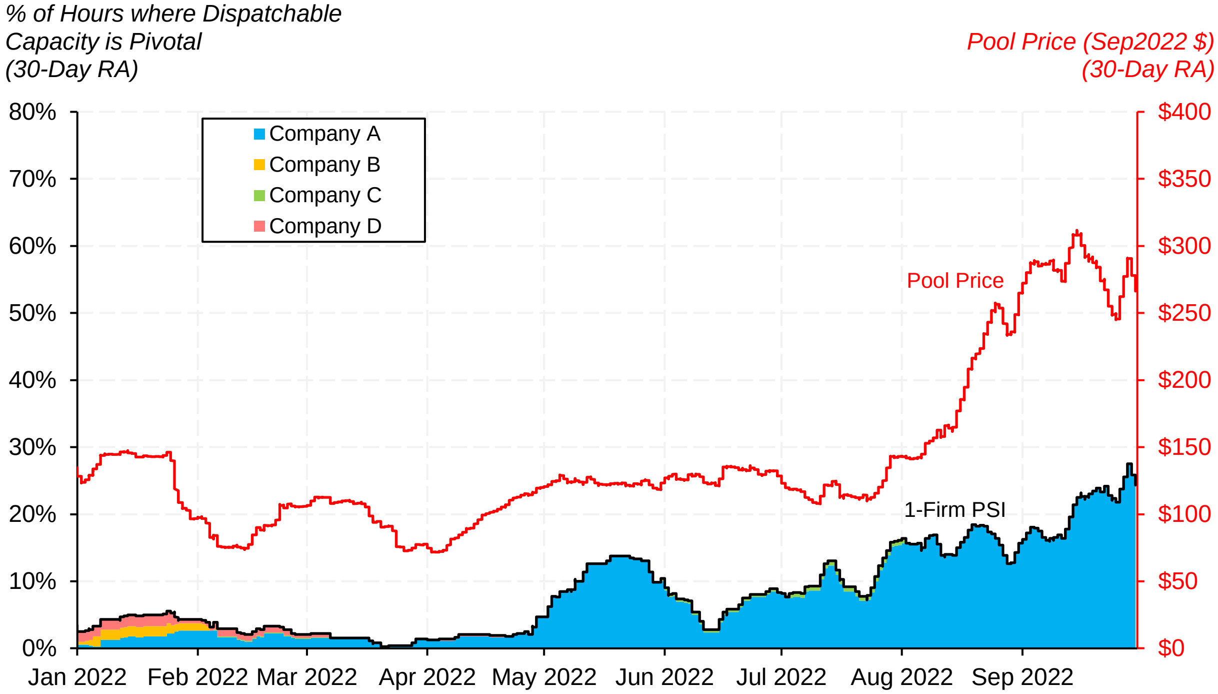
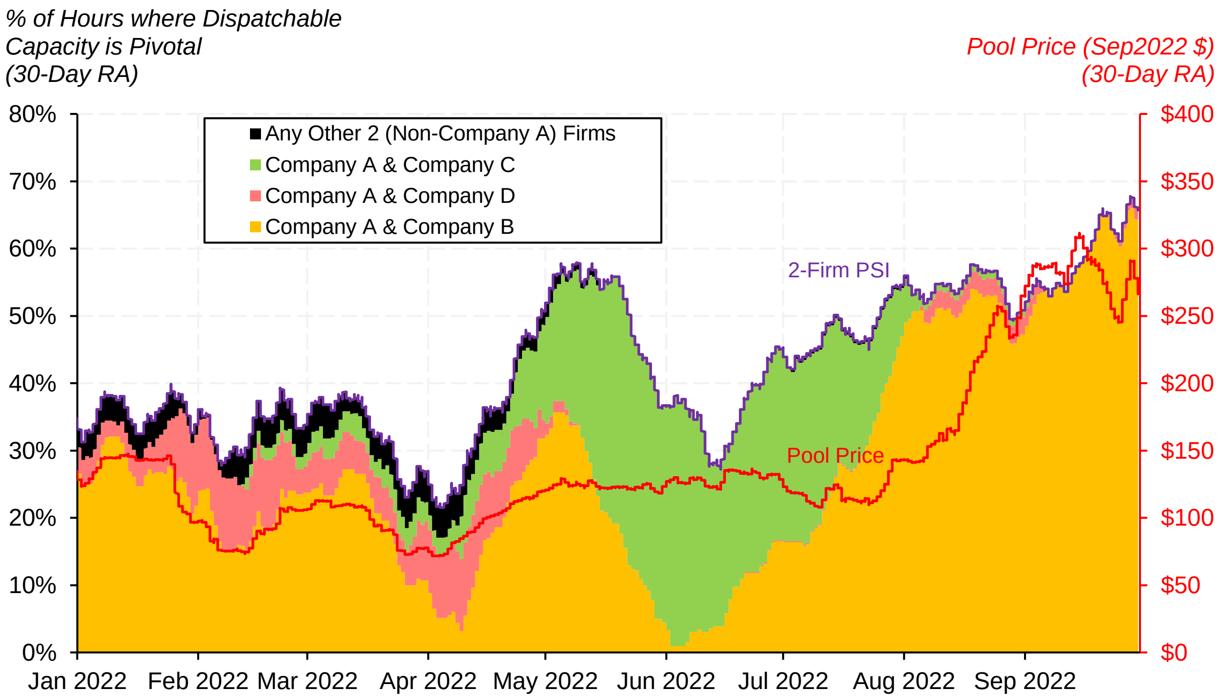


Figure 22: Two companies comprising the 2-Firm pivotal firms (January to September 2022) (30-day rolling average)



As discussed above, periods of high market power in the wholesale market occurred from June to July 2021, when pool prices averaged $132/MWh, and from August to September 2022 when pool prices averaged $262/MWh. Differences in pool price outcomes between these two periods were driven by changes in offer behaviour, with the two largest generating firms offering a greater quantity of their capacity at higher prices in Q3 2022 than in June and July of 2021.

Offers priced at or above $250/MWh can be considered strategic offers, as they are well above the marginal cost of generation in most instances. The average price and volume of these offers was significantly higher during August and September 2022, compared to June and July 2021 (Table 6). Offer behaviour in Q3 is discussed further in the following section 1.4.

Table 6: Volume weighted price and volume of offers priced between $250/MWh and $999.99/MWh

	Avg. price of offers priced [250, 999.99]		Vol. of offers priced [250, 999.99]	
	Company A	**Company B**	**Company A**	**Company B**
Jun - Jul 2021	$851.41	$638.48	667 MW	330 MW
Aug - Sep 2022	$904.43	$823.00	1,143 MW	530 MW

1.4 Offer behaviour

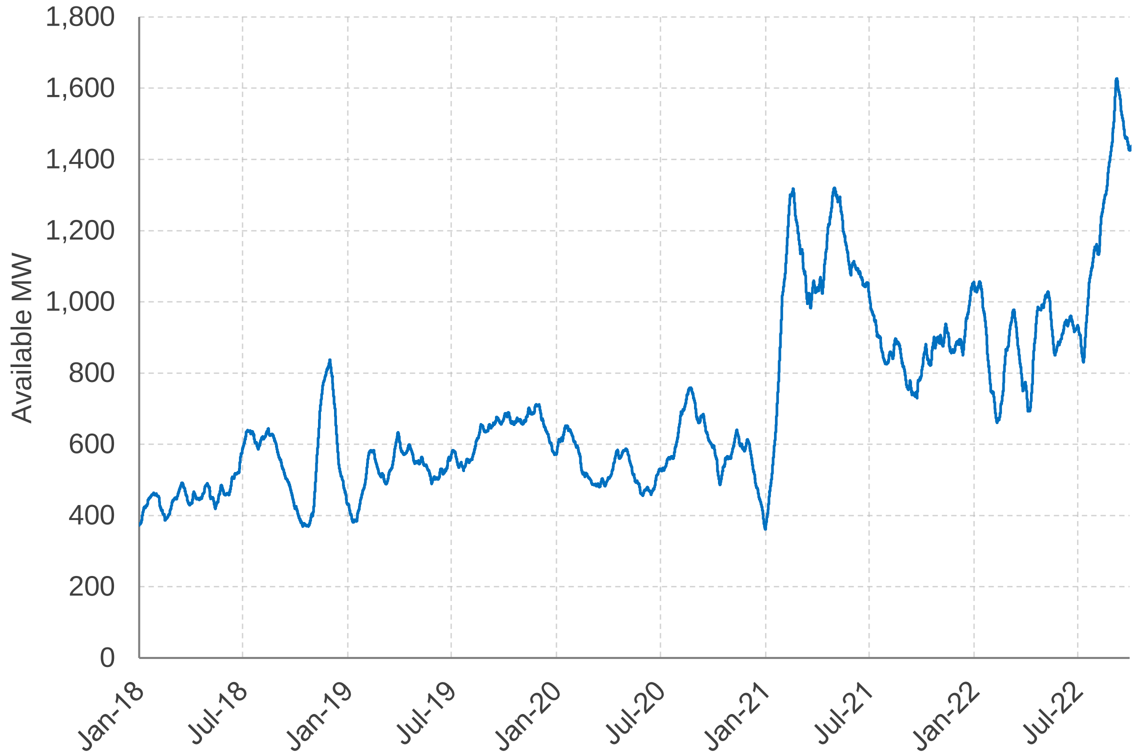
Supplier offer behaviour was a principal driver of the high pool prices experienced in Q3. Figure 3, found earlier in section 1.1, illustrates that suppliers offered more capacity at higher prices in Q3 compared to both Q2 2022 and Q3 2021. Figure 23 expands on this comparison by depicting the total amount of capacity offered above $250/MWh between January 2018 and the end of Q3 2022 as a 30-day rolling average.

In Q1 2021, there was an increase in offers priced above $250/MWh following the expiry of the remaining PPAs.[15] However, the amount of capacity offered above $250/MWh in Q3 was significantly larger than any period since 2018, including Q1 2021. Between 2018 and the start of 2021, the quantity of offers priced above $250/MWh was lower and more consistent than has been observed since.

Larger quantities of high-priced offers in Q3 had the effect of creating supply curve shapes in many hours that consisted of a wide shelf of capacity offered higher in the supply curve, up towards the offer price cap of $999.99/MWh.

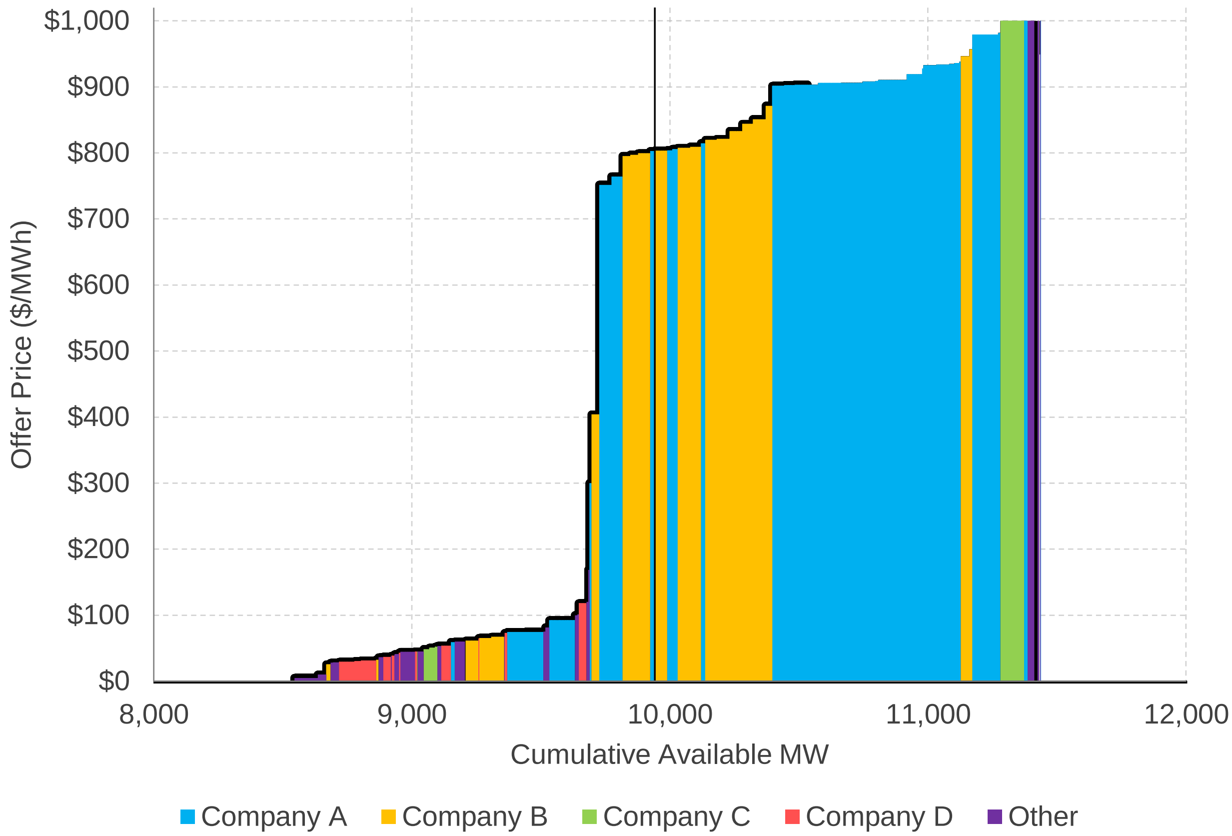
[15] The MSA noted in its Q1 2021 Quarterly Report that "high pool prices in Q1 2021 were driven by a number of factors including cold temperatures, low wind generation, and thermal outages; in addition, the offer behaviour of some larger suppliers was also a factor in the higher prices, as the last of the PPAs expired on December 31, 2020."

Figure 23: Available MW offered above $250
(30-day rolling average, January 1, 2018 to September 30, 2022)



For example, the supply curve for August 10, HE15 is shown in Figure 24. This supply curve illustrates a large high-priced shelf, a general feature that was seen in many hours of Q3. A larger high-priced shelf enabled higher pool prices to persist for longer periods of time as market conditions changed, such as changes in demand or fluctuations in wind generation. As discussed in greater detail below, this large high-priced shelf in Q3 was often primarily comprised of offers by two large market participants.

Figure 24: Illustrative Q3 2022 supply curve[16]
(August 10, 2022 HE15)



The offer price duration curves of certain large market participants for July, August, and September are provided below in Figure 25, Figure 26, and Figure 27, respectively. These figures include thermal, hydro, and storage capacity, but do not include wind generation, solar generation, imports, or exports. As shown in Figure 25, in July Company A priced a much larger proportion of its offers at high prices relative to the other three large market participants shown.

As Q3 progressed into August and September, Company A continued to offer at high price levels, and Company B increased its offer prices materially. Consequently, Company A and Company B simultaneously had offer price duration curves with significantly higher offer prices than those of other large market participants. The offer prices made by Company C and Company D remained relatively consistent throughout Q3, and at much lower levels than Company A and Company B.

[16] In this figure, wind and solar Available MW have been replaced by total wind and solar generation.

Figure 25: Offer price duration curves, July 2022

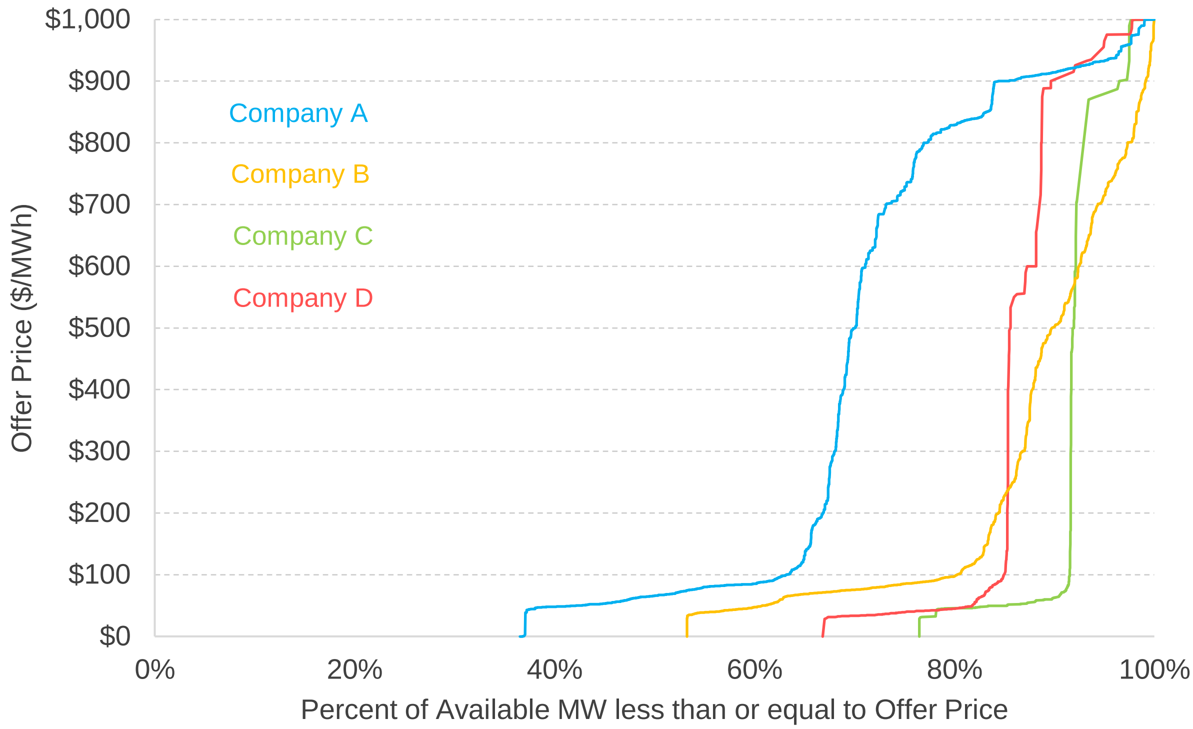


Figure 26: Offer price duration curves, August 2022

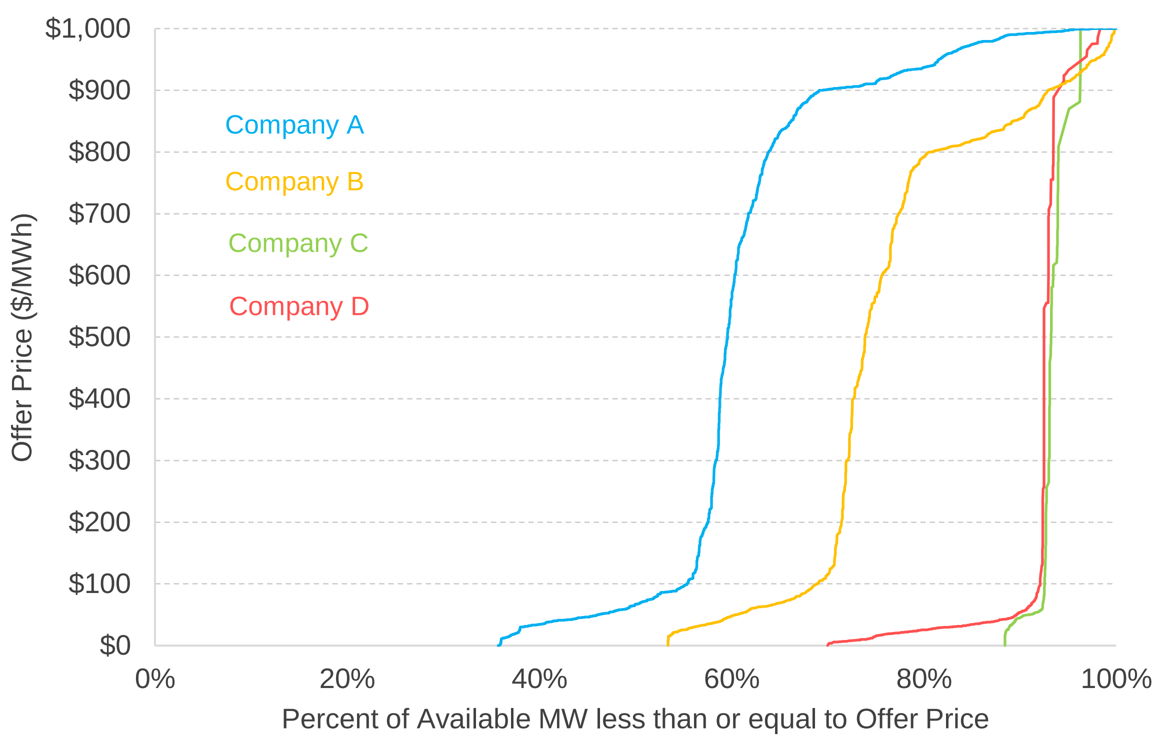


Figure 27: Offer price duration curves, September 2022

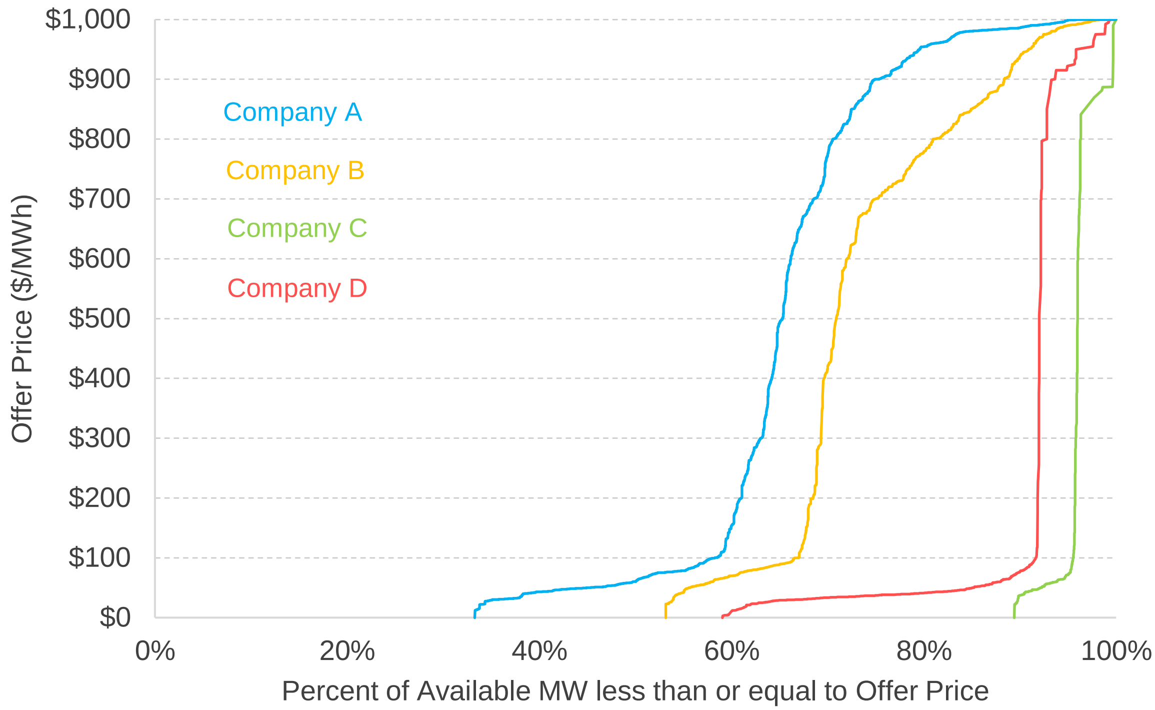


Figure 28 and Figure 29 illustrate hourly volume-weighted average offer prices for Company A and Company B on offer blocks that were priced at or above $250/MWh, for illustrative weeks in July 2021 and August 2022.

The average offer prices for Company A and Company B remained relatively constant throughout the week in August 2022, which is broadly indicative of their offer behaviour for periods of Q3. While the hour-to-hour variation in offer prices was more pronounced in July 2021, offers were more static in August 2022, in addition to being higher overall. This static offer behaviour suggests that Company A and Company B were not actively competing to increase the dispatch of their respective generation portfolios during periods of higher pool prices in August 2022. Partly because of these offers dynamics, pool price settled significantly higher in August 2022 relative to July 2021.

Figure 30 and Figure 31 on page 33 contrast the difference in intraday offer volume variation, for offers at or above $250/MWh. In July 2021 Company A typically offered a higher proportion of its capacity at higher prices during the late afternoon and evening periods compared to off-peak periods. In August 2022, Company A and Company B offered significantly greater volumes at or above $250/MWh during on and off-peak periods, and the hour-to-hour volume variation in Company A's offers was lower.

Figure 28: Volume-weighted average offer of blocks priced between [250, 999.99] (July 24, 2021 to July 31, 2021)

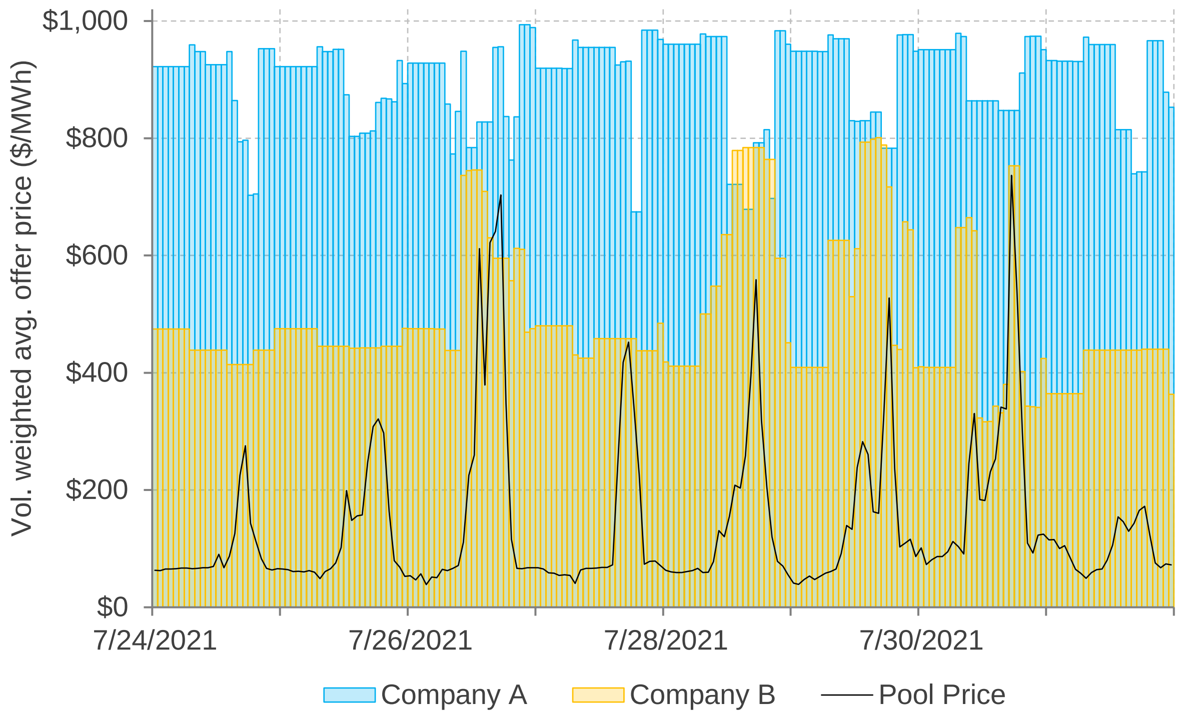


Figure 29: Volume-weighted average offer of blocks priced between [250, 999.99] (August 9, 2022 to August 16, 2022)

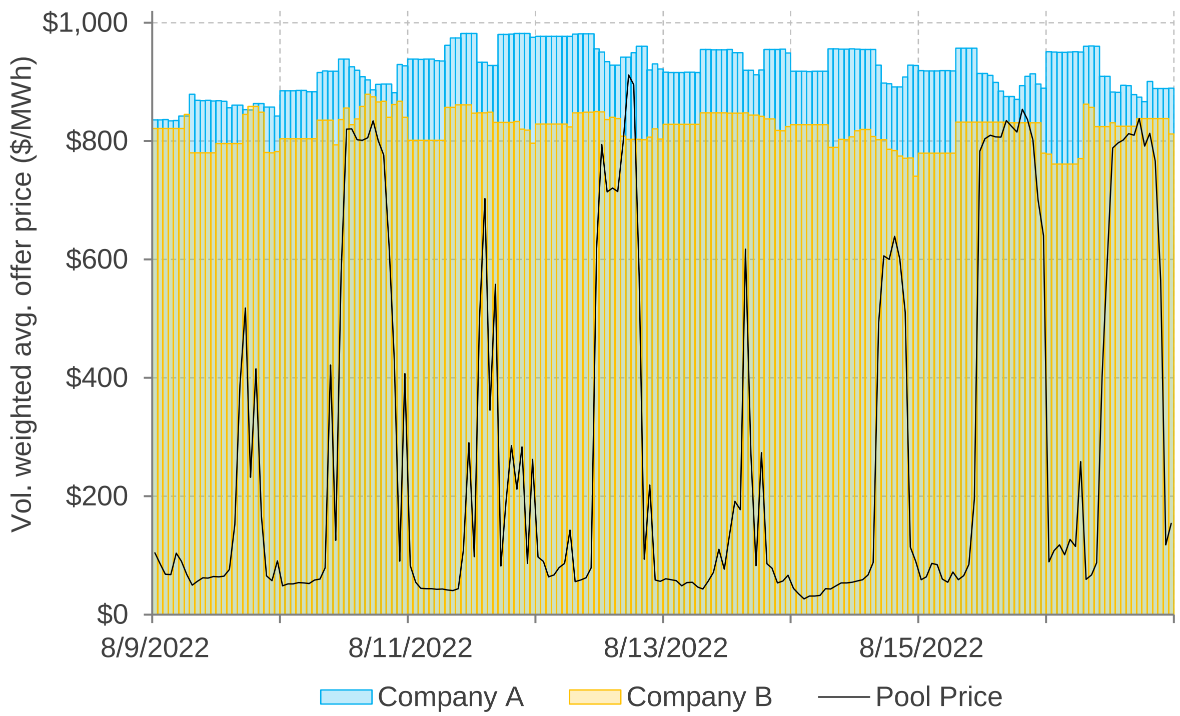


Figure 30: Volume of offers priced between $250 and $999.99 (July 24 to 31, 2021)

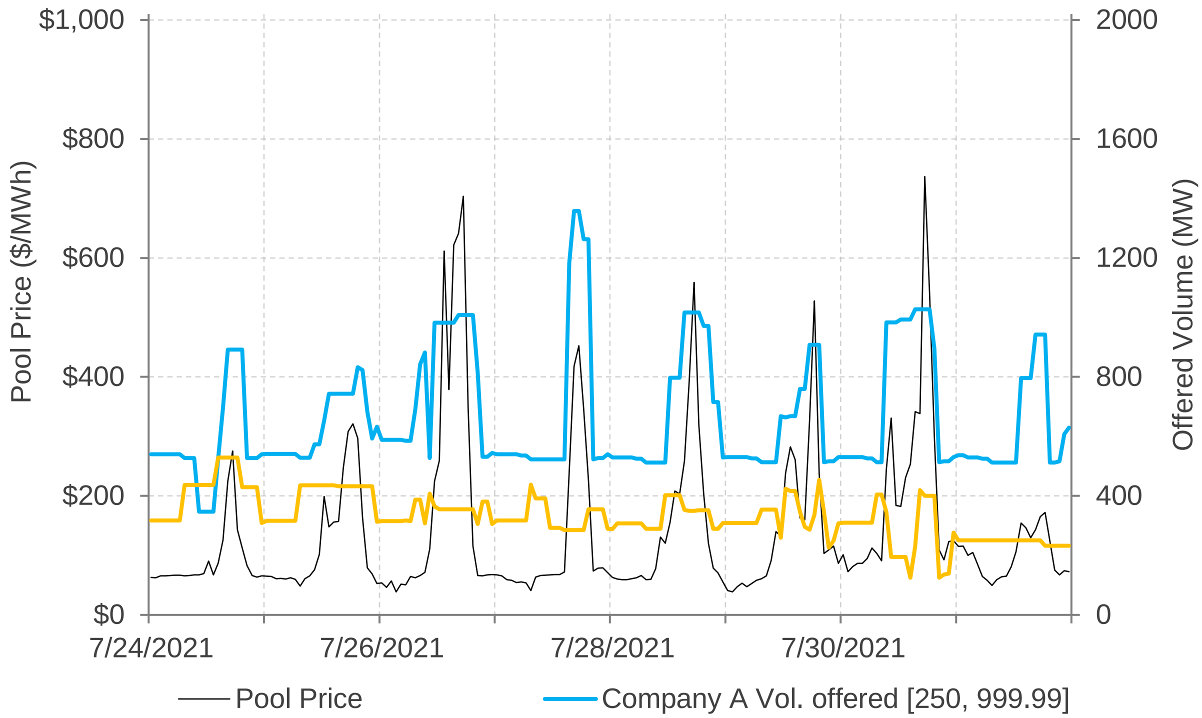


Figure 31: Volume of offers priced between $250 and $999.99 (August 9 to 16, 2022)

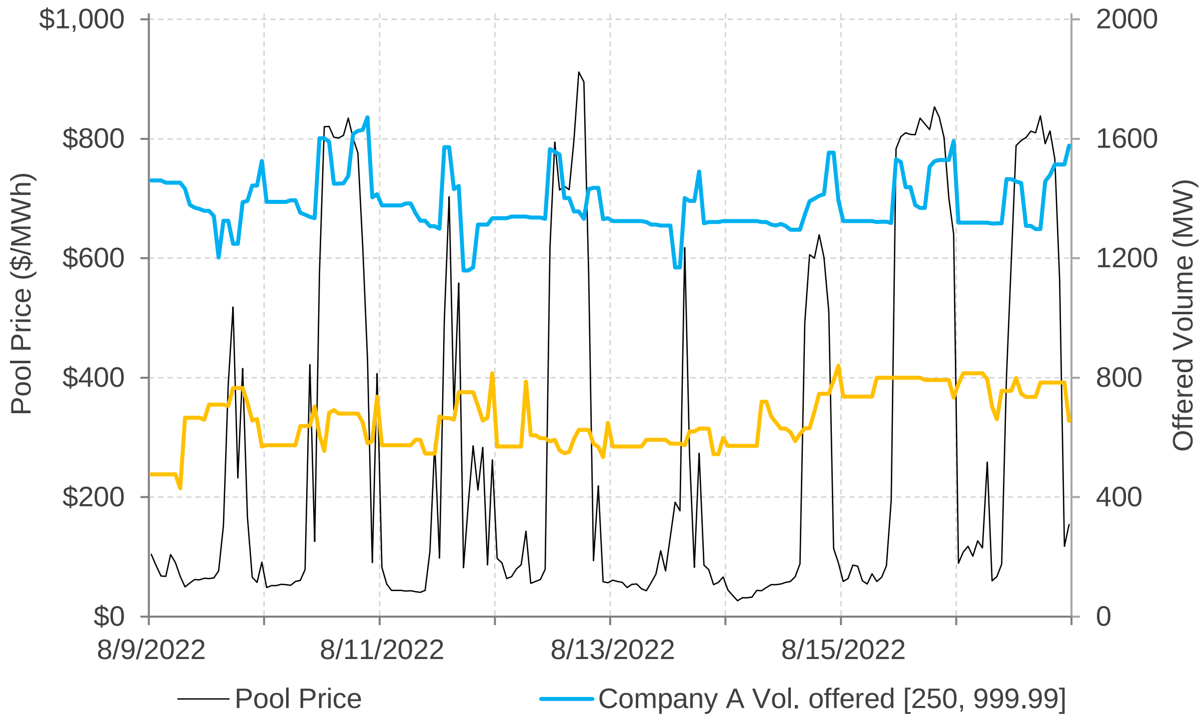


Figure 32 illustrates the relationship between pool prices and supply cushion in Q3 and Q3 2021. The lines in the figure illustrate average pool prices in 200 MW supply cushion ranges, while the markers illustrate hourly data points. When supply cushion was in the 400 to 1,800 MW range in Q3 pool prices were much higher compared to Q3 2021. This change which was largely driven more high-priced offers this year.

Figure 32: Supply cushion and pool prices (Q3 2022 and Q3 2021)

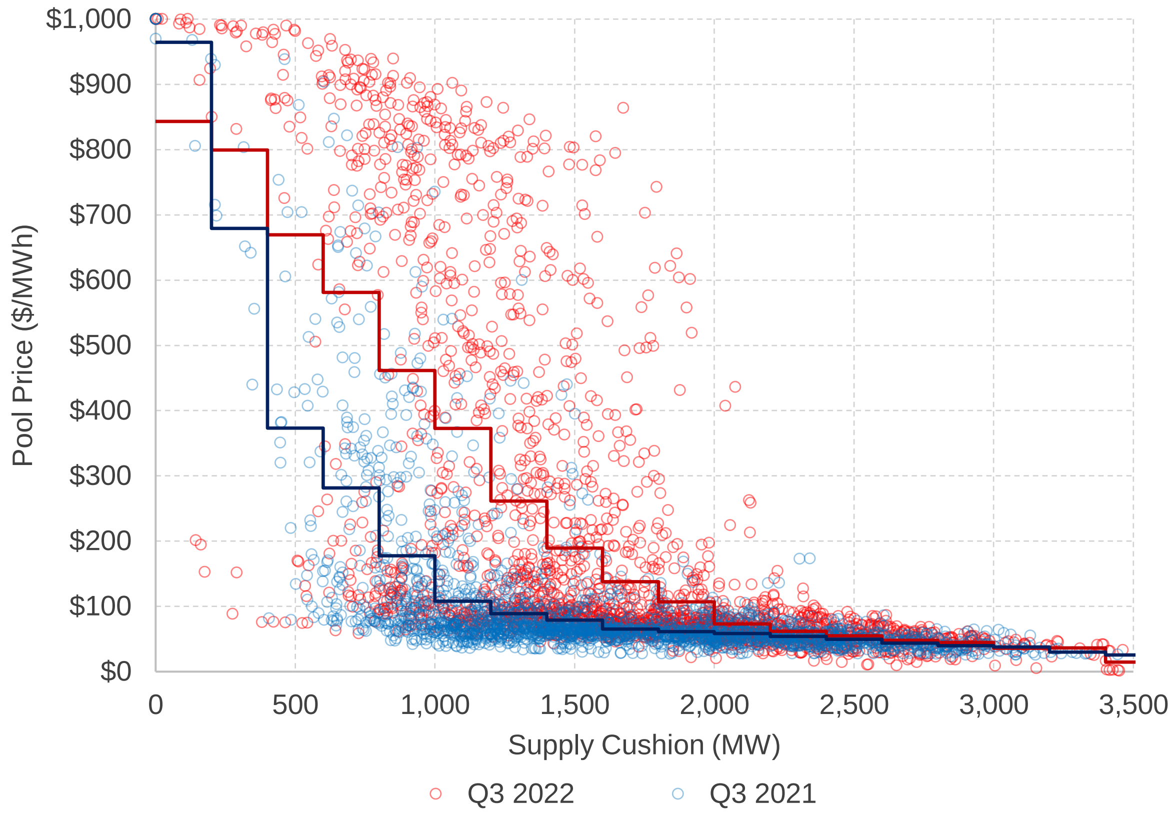
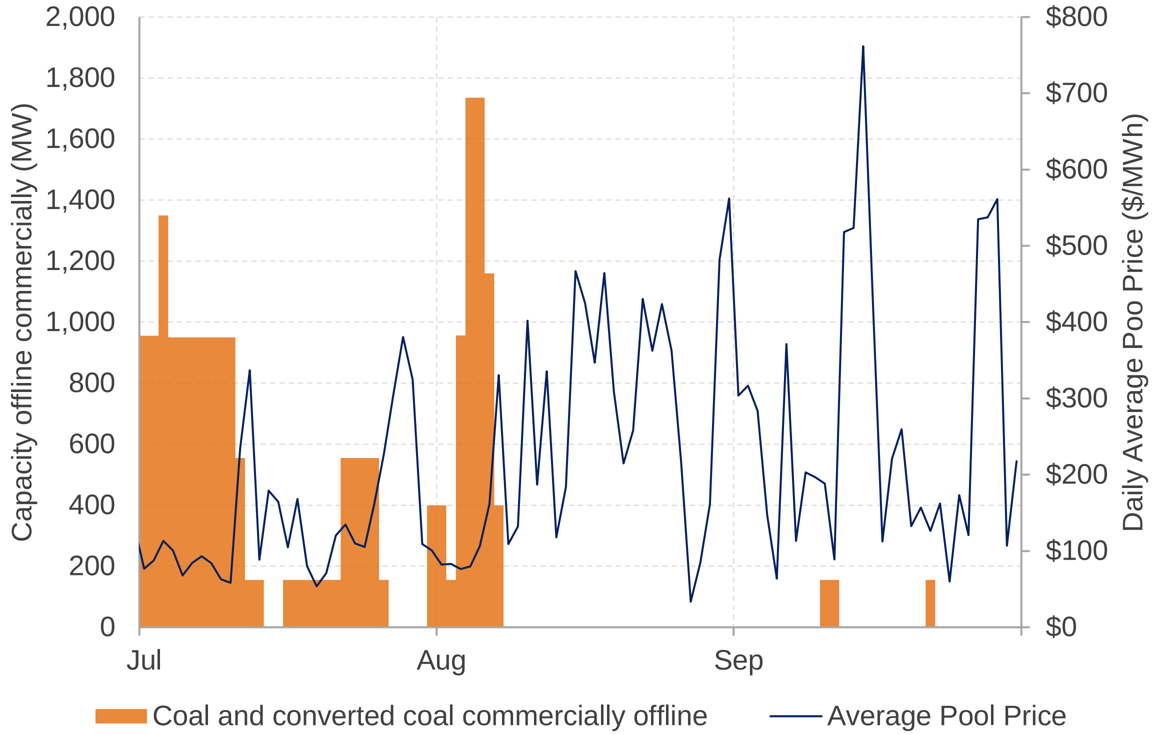


Figure 33 illustrates the amount of coal or converted coal capacity that was commercially offline in Q3. Most commercial outages in Q3 occurred during the lower pool price periods in early July and early August. There was a small gas-fired steam asset that was commercially offline for relatively brief periods of time on some weekend days in September, when pool prices were higher. However, as Figure 33 demonstrates, assets were generally not commercially offline during the volatile price periods in Q3.

Figure 33: Coal and converted coal capacity commercially offline



1.5 Imports and exports

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 markets in Mid-Columbia (Mid-C) and California.

The average volume of net imports[17] into Alberta during Q3 decreased by 13% compared to Q2, even though average pool prices were 81% higher. The reduced import flows in Q3 were largely the result of reduced available transmission capability (ATC) for imports to flow into Alberta.

Year-over-year, net imports were 61% higher in Q3 compared to Q3 2021. All the months in Q3 had a material increase in import volumes compared to Q3 last year (see Table 7).

[17] Net Imports are total imports less total exports.

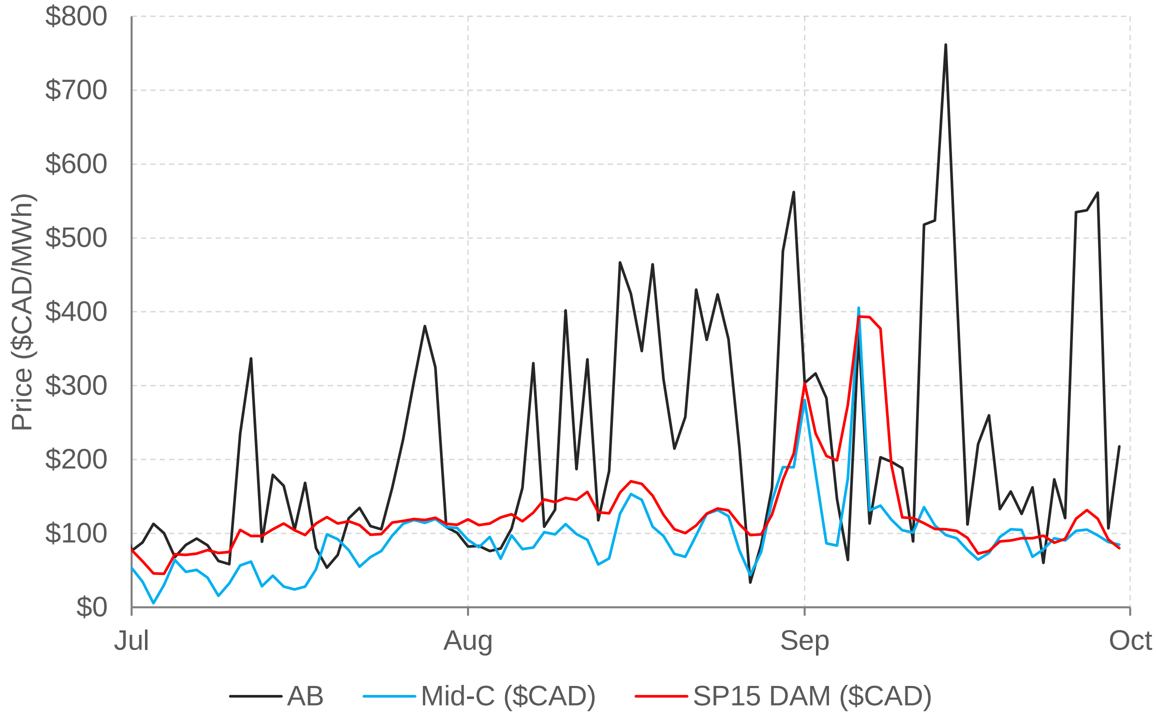
Table 7: Monthly average of net imports by month (Q3 2022 and Q3 2021)

Month	2022	2021	Percent change
July	691	443	56%
August	479	259	85%
September	296	212	40%
Q3	**491**	**306**	**61%**

The prevailing price of power in Mid-C and California are factors that can influence the direction and magnitude of intertie flows to or from Alberta. When the Alberta pool price is above prices in Mid-C and California, increased import and reduced export volumes are typically seen, and the converse is true when pool prices are relatively low.

In Q3, the average pool price in Alberta was 134% higher than the average Mid-C price and 73% higher than the average price in California. Therefore, the predominant flow of power during Q3 was imports flowing into Alberta. Figure 34 below illustrates daily average prices in Alberta, Mid-C, and California during Q3.

Figure 34: Daily average prices in Alberta, Mid-C, and California (SP15)[18] (Q3 2022)

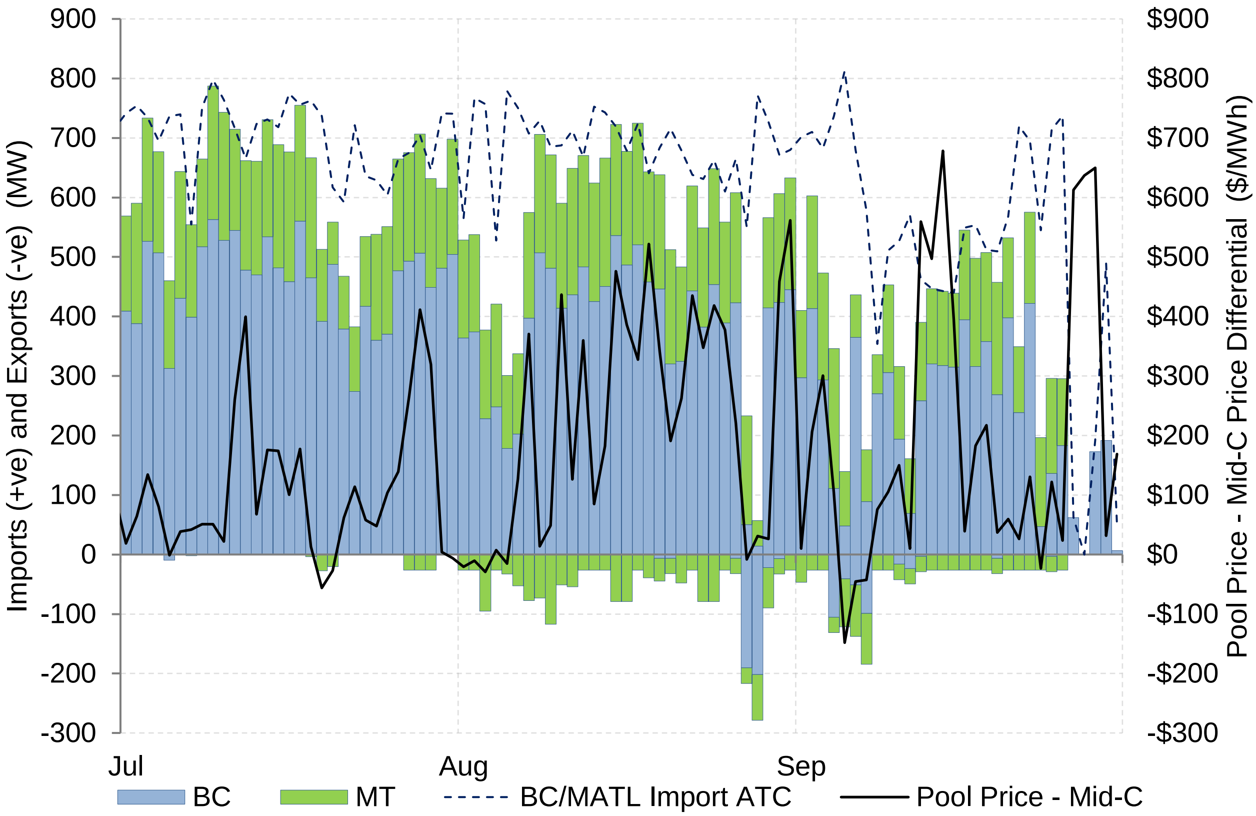


[18] South of Path 15 (SP15) is a major electricity hub in Southern California, the average prices shown here are from the Day-Ahead Market (DAM).

In Q3, the average of total import ATC was 685 MW, a decline of 9% relative to Q2. The reduced ATC in Q3 was driven by various transmission line outages, and these outages constrained import flows significantly in September. The average import ATC for BC/MATL in September was 476 MW, which is 214 MW less than in July.

Figure 35 illustrates the daily average import and export volumes on the BC/MATL intertie during peak hours from July 1 to September 30. The solid line on the figure shows the average price differential between Alberta and Mid-C during peak hours and the dashed line indicates average import ATC on the BC/MATL intertie.

Figure 35: Daily average of imports, exports, and the AB - Mid-C price differential (Q3 2022, on-peak)



In Q3 the highest average net import volumes were seen in July, when there were minimal transmission line outages that affected BC/MATL. Pool prices were higher and more volatile than in Mid-C in July, and imports utilized 88% of the total available transmission capacity.

Beginning in late July, there were some small volumes of exports scheduled to flow over the Montana line despite high pool prices. These volumes were scheduled well in advance of real-time submission deadlines, and therefore they increased the amount of imports that could be scheduled to flow into Alberta.

Despite high pool prices in August, average net imports were only 479 MW compared to 691 MW in July, a 31% fall. In early August pool prices were generally comparable to prices in Mid-C, resulting in reduced import flows. However, pool prices increased beginning on August 5 and remained volatile through to August 26. During this period of higher pool prices, import volumes increased and import capacity was generally highly utilized by market participants (Figure 35). On August 27 and 28, a period of mild weather and high wind generation pushed Alberta pool prices below prices in California and some export volumes were seen on the BC line.

A heat wave swept across California and the Mid-C region in early September, increasing power demand and prices. Prices in Mid-C and California (at SP15) were often higher than Alberta pool prices from September 4 to 9, causing a material reduction in imports to Alberta and some export volumes. On September 5 and 6, real-time prices in California peaked around US$2,000/MWh and the California system operator declared an Energy Emergency Alert level 1 (EEA1) on September 5 and an EEA3 on September 6.[19]

Alberta pool prices were high and volatile from September 12 to 22, often well above prevailing prices in Mid-C and California. Reduced import ATC was a factor in these higher pool prices, as shown in Figure 35, during this period in mid-September the availability of the BC/MATL line was reduced due to a transmission line outage on 2L294. In addition, import supply on the SK intertie was derated from 153 MW to 60 MW, a derate that lasted for much of Q3.

Beginning in HE10 of September 26, the BC/MATL intertie came offline completely for a planned outage. The BC/MATL intertie was initially scheduled to be offline until October 7, however, the BC intertie returned in HE18 of September 28 after the AESO declared an Energy Emergency Alert, indicating a shortfall in supply. The planned outage on BC/MATL resumed in HE09 of September 30 and concluded in HE22 of October 6.

1.6 Carbon emission intensity

The MSA has published analysis of the carbon emission intensity of the Alberta electricity grid in its quarterly reports since Q4 2021. In the context of power generation, carbon emission intensity is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The results are indicative only, as the MSA has not collected the precise carbon emission intensities of assets from market participants but relied on information that is publicly available. The results reported here do not include imported generation.[20]

1.6.1 Hourly average emission intensity

The hourly average emission intensity is the volume-weighted average carbon emission intensity of assets supplying the Alberta grid in an hour. Figure 36 illustrates the estimated distribution of the hourly average emission intensity of the grid in Q3 for the past four years.

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[19] CASIO news releases – September 6, 2022 and September 5, 2022

[20] For more details on the methodology, see Quarterly Report for Q4 2021.

Figure 36 shows a significant shift of the distribution to the left, indicating a decline in carbon emission intensity over time. This outcome was driven by the conversion of coal-fired generation to natural gas in addition to increased wind and solar generation. The impact of increased solar capacity is pronounced in Q3, given that solar generation peaks in summer months. Mean hourly average emission intensities are reported in Table 8, showing year-over-year and quarter-over-quarter comparisons.

Several fuel type changes occurred in late 2021. In November 2021, the Battle River 4 and 5 assets were reclassified as gas-fired steam rather than dual fuel, and in the fall of 2021 Keephills 3 was converted from coal to gas-fired steam. These changes decreased the carbon emission intensity of all three assets.[21] Additionally, the Keephills 1 coal asset retired at the end of 2021, and at the same time the capacity of Sundance 4 was lowered from 406 to 113 MW to reflect that it would no longer generate using coal but instead would run solely on existing gas-firing capabilities. The Sundance 4 asset was then retired at the end of Q1 2022.

Table 8: The mean of hourly average emission intensities (tCO2e/MWh)

	Mean
2019 Q3	0.65
2020 Q3	0.59
2021 Q3	0.55
2022 Q3	0.50

	Mean
2021 Q4	0.52
2022 Q1	0.50
2022 Q2	0.49
2022 Q3	0.50

Figure 37 on page 41 illustrates the distribution of the hourly average carbon emission intensity over the past four quarters. The mean of the distribution has declined slightly from 0.52 t/CO2e/MWh in Q4 2021 to 0.50 tCO2e/MWh in Q3 2022 (see right of Table 8). The change in these distributions reflects the coal-to-gas conversions that took place over the course of 2021 as well as increased generation from renewable assets.

However, the mean of hourly average emission intensities was higher in Q3 than the previous two quarters. Warm temperatures drove higher demand in Q3 and the decrease in wind generation from the previous quarter was met largely by gas-fired steam, combined cycle, and coal generation, which caused the distribution to become more concentrated around the mean. There were also no coal-to-gas conversions in Q1, Q2 or Q3, which have previously helped to reduce the average emission intensity of the generation mix.

The Travers Solar Project (465 MW) began generating to the grid in late March 2022, and this asset generated more than 350 MW in certain hours in Q3. The Travers asset represented a significant portion of the growth in total solar capacity over the last four quarters, which increased from 336 MW at the start of Q4 2021 to 987 MW by the end of Q3.[22]

[21] The conversion dates in this section are based upon the return of assets from the associated planned outage.

[22] The capacity of new solar and wind assets are added in full once the asset starts to generate to the grid.

Figure 36: The distribution of average carbon emission intensities in Q3 (2019 to 2022)

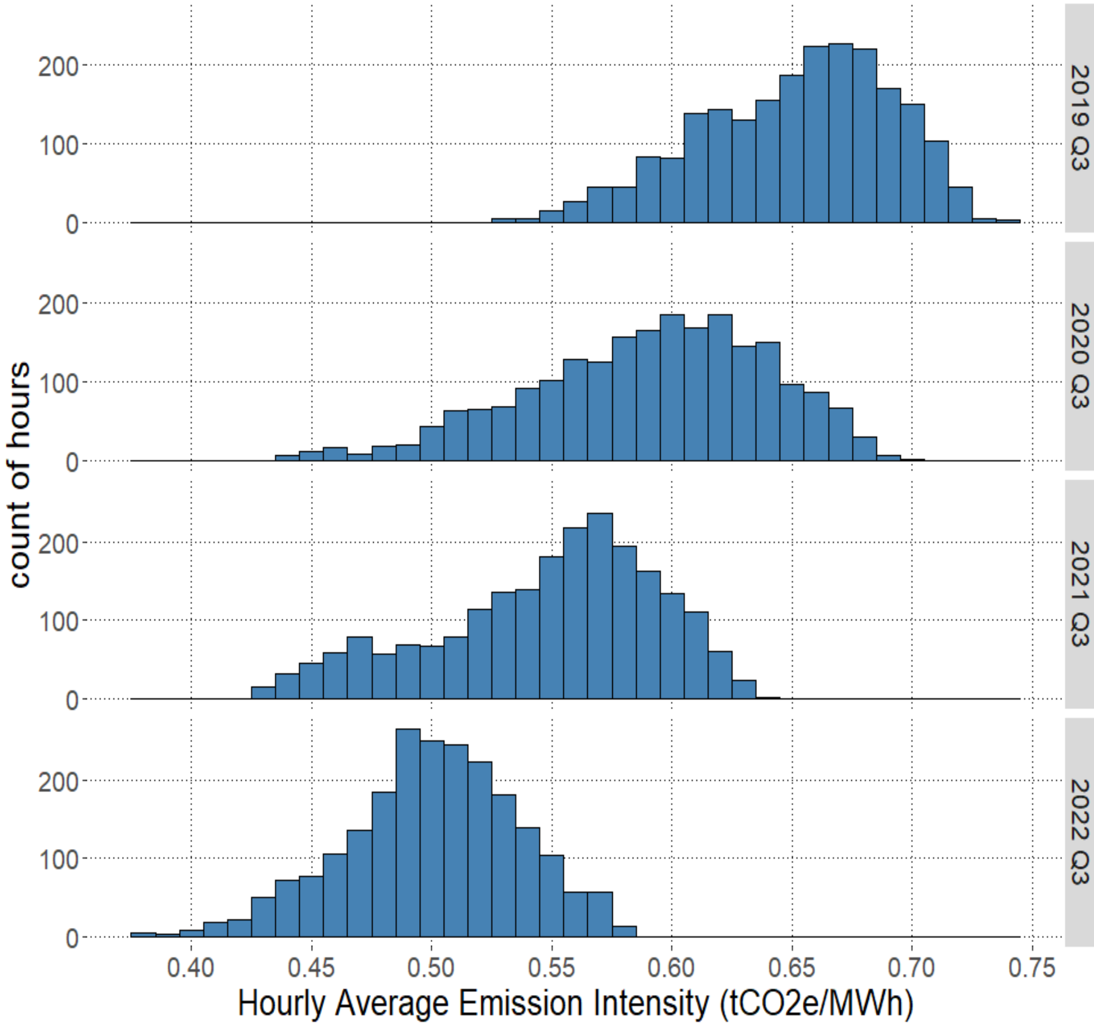
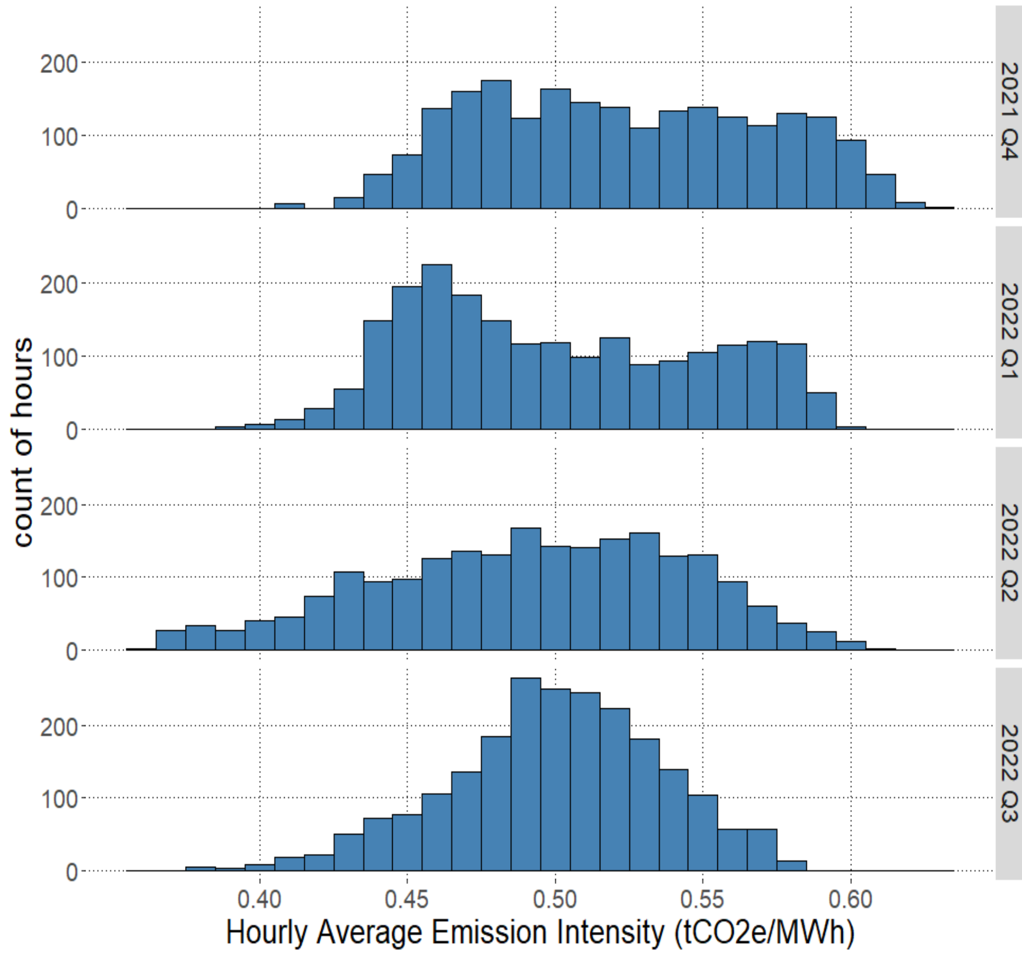
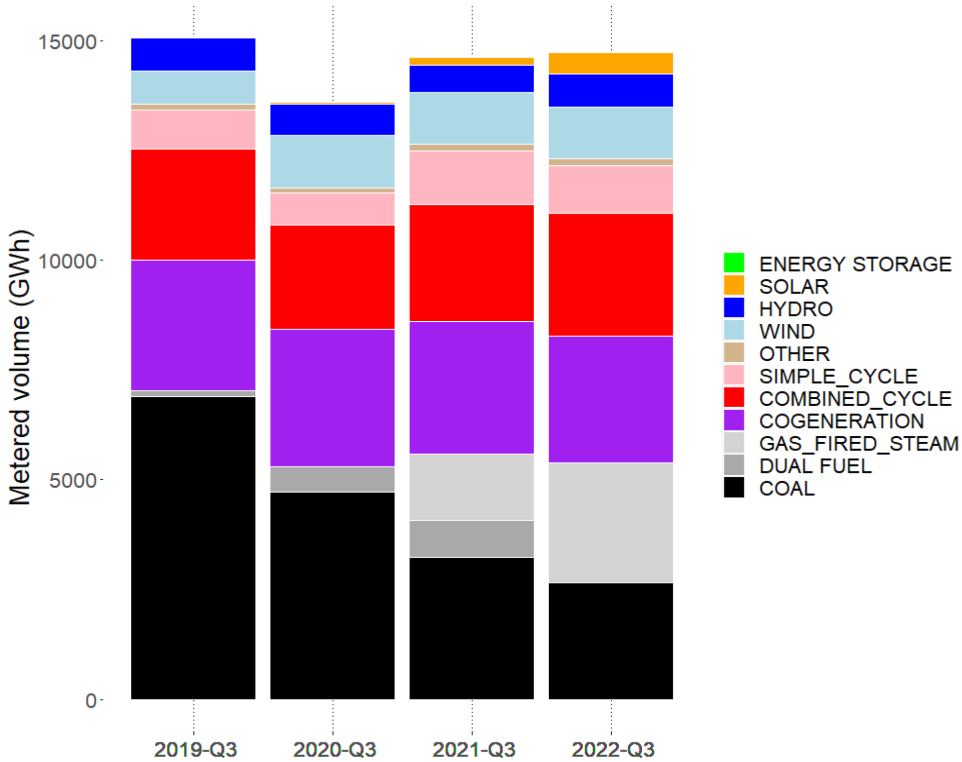


Figure 37: The distribution of average carbon emission intensities in the past four quarters (Q4 2021 to Q3 2022)



The general trends observed in the above distribution figures can be traced in Figure 38, which shows net-to-grid generation volumes by fuel type. Since 2019, there has been a decline in the volume of coal-fired generation, with generation from dual fuel and gas-fired steam assets replacing it. The increase in wind and solar generation driven by growing capacity has also contributed to the displacement of coal-fired generation since 2019.

Figure 38: Quarterly total net-to-grid generation volumes by fuel type for Q3 (2019 to 2022)

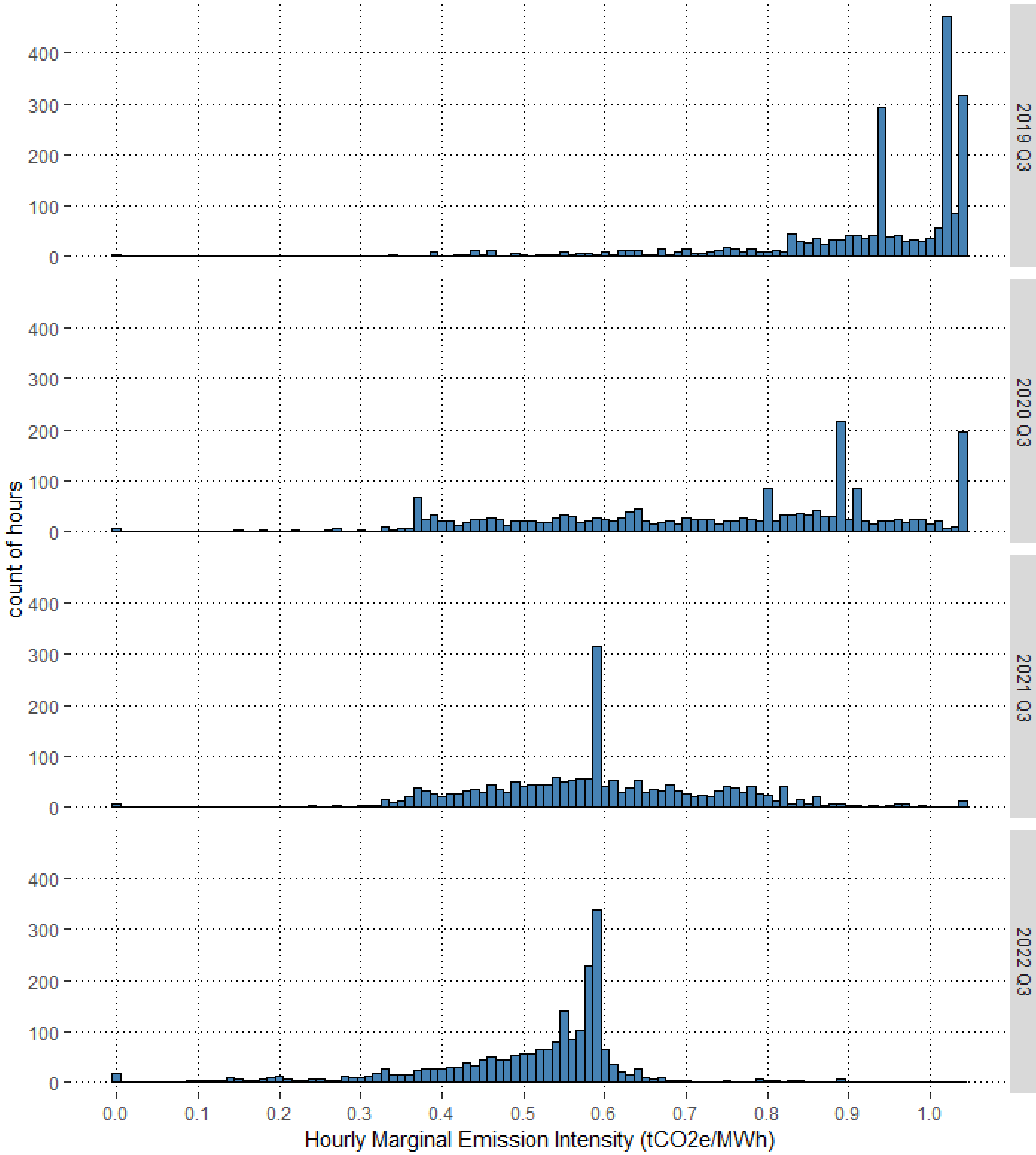


1.6.2 Hourly marginal emission intensity

The hourly marginal emission intensity of the grid reflects the carbon emission intensity of the asset setting the System Marginal Price (SMP) in an 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.

Figure 39 shows the distribution of the hourly marginal emission intensity of the grid in Q3 for the past four years. Between Q3 2020 and Q3 2021, there was a material increase in converted coal capacity, which corresponded to conversions of assets such as Keephills 2, Sundance 6, and Sheerness 1. Converted coal assets were setting the price quite often, which was a factor in the spike observed around 0.59 tCO_2/MWh in the latter two histograms.

Figure 39: The distribution of marginal carbon emission intensities in Q3 (2019 to 2022)



1.7 Long-term trends in fleet operations

As discussed in the previous section, the Alberta generation fleet has gone through significant changes in recent years, resulting in a notable reduction in carbon emissions. In this section, the MSA looks at some long-term trends in the operation of the generation fleet.

1.7.1 Capacity factors

Capacity factors illustrate the extent to which generation capacity provides generation output. Capacity factors are calculated by dividing average metered generation volume by maximum capability. For example, a generation asset with a capacity of 100 MW that provides an average of 80 MW of supply would have a capacity factor of 80%.

Capacity factors are influenced by the physical capability of assets, the availability of the applicable energy resource, and by changes in operational patterns, which may be impacted by economic considerations such as the increase in carbon prices or how the asset is offered into the market.

Figure 40 depicts changes in the monthly capacity factor for coal generation assets since January 2008. As shown, capacity factors for coal assets tend to be higher in winter months when demand is higher, and availability of coal assets is typically higher.

Between 2008 and 2011 the capacity factor of the coal fleet was generally around 80% on average. This dipped to around 70% in 2012 and 2013, in part due to extended outages at Sundance 1 and 2. The capacity factor of coal assets trended down in the period of 2018 to 2021 partly due to the carbon costs, which have made coal generation more expensive and spurred conversions to dual fuel and gas-fired steam.

In early 2018, three coal-fired assets were placed on mothball and were subsequently retired (Table 9). These three assets were excluded from the analysis in this section after being placed on mothball.[23]

Table 9: Mothball outages at coal assets not included in the analysis

Asset	Mothball started	Retired on
Sundance 2	January 1, 2018	July 31, 2018
Sundance 3	April 1, 2018	July 31, 2020
Sundance 5	April 1, 2018	September 28, 2021

So far in 2022, the remaining three coal-fired assets at Genesee have operated at relatively high capacity factors, in part because pool prices and natural gas prices have been elevated.

[23] The HR Milner mothball outage, which ran from July 2017 to May 2018, was not excluded from the analysis as the HR Milner asset subsequently returned to the market.

Figure 40: Monthly capacity factors of coal

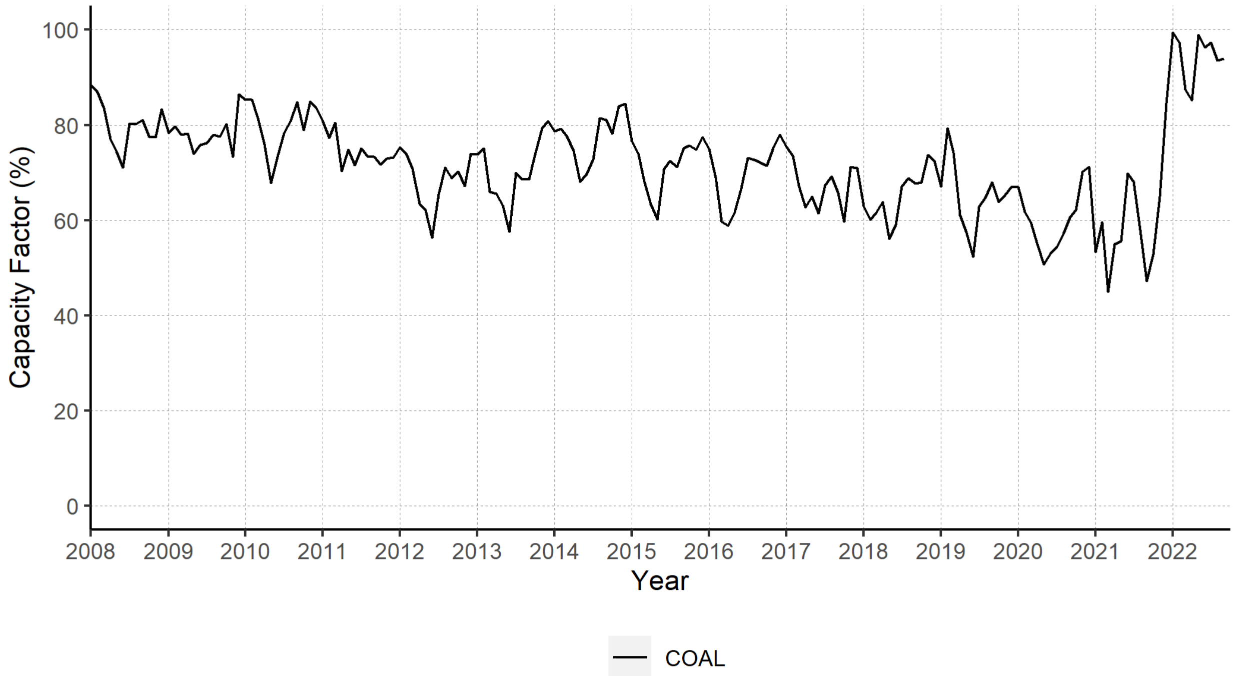
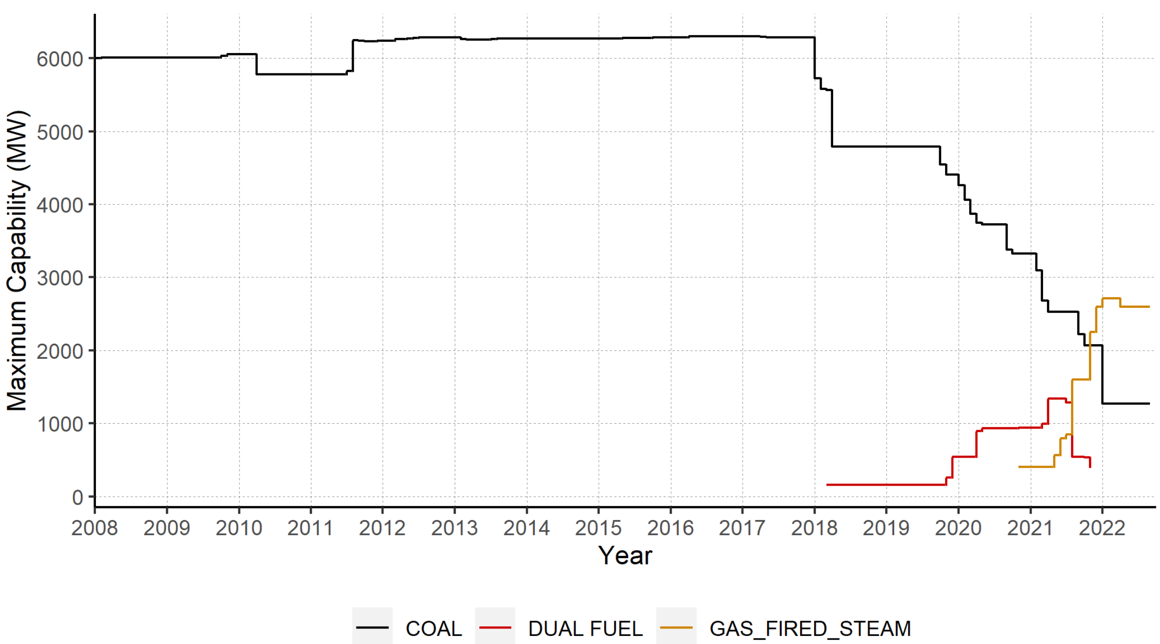


Figure 41: Monthly maximum capability of coal, dual fuel, and gas fired steam assets



In recent years, several coal assets have been converted to dual fuel and to gas-fired steam. The decline in coal capacity, and the increase in gas-fired steam capacity is illustrated in Figure 41. The conversion from coal to gas-fired steam typically reduces carbon emissions by around 50%.

Figure 42 illustrates the monthly capacity factors of coal, dual fuel, and gas-fired steam assets since January 2018.[24] The figure shows that dual fuel and gas-fired steam assets have tended to operate at lower capacity factors than those of their predecessor coal-fired assets. So far in 2022 the remaining coal assets have been generating at a capacity factor of around 95% while gas-fired steam assets have been running less, often at a capacity factor of under 50%.

The high volatility of capacity factors for dual fuel and gas-fired steam assets in earlier years is driven in part by the fact that there may be only one or two converted assets at a given point in time, making the average sensitive to the operation of those assets. In this section, the first 60 days after recording the first net-to-grid generation have been excluded from the sample of thermal assets to prevent the commissioning period from affecting the calculations. This applies to both converted and new thermal assets.

Figure 42: Monthly capacity factors of coal, dual fuel and gas fired steam assets (since 2018)

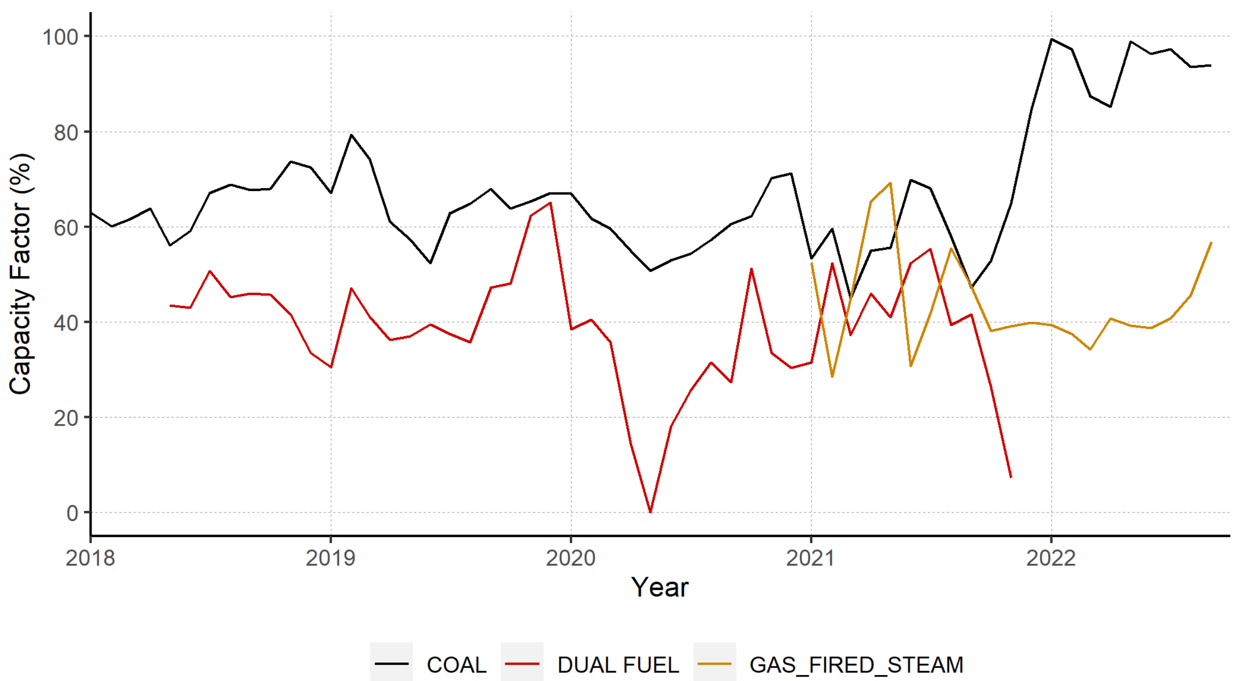


Figure 43 illustrates monthly capacity factors for combined cycle and simple cycle natural gas assets. The addition of Shepard in late 2014 more than doubled the combined cycle capacity in Alberta (Figure 44). Initially, the addition of Shepard reduced the overall capacity factor of combined cycle assets because of outages at Shepard. The availability of Shepard continues to

[24] Conversion dates here are based on the return of assets from their associated planned conversion outage.

be important; in the spring of 2021 Shepard took a planned outage and this reduced the overall capacity factor of combined cycle assets to under 40%.

Figure 43: Monthly capacity factors of simple cycle and combined cycle gas assets[25]

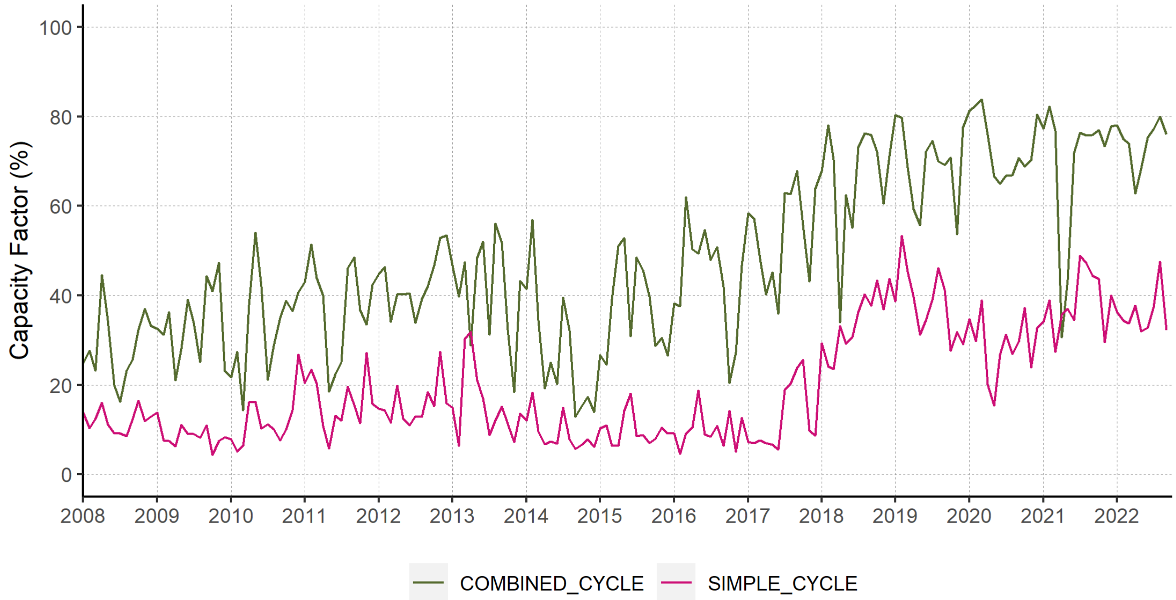
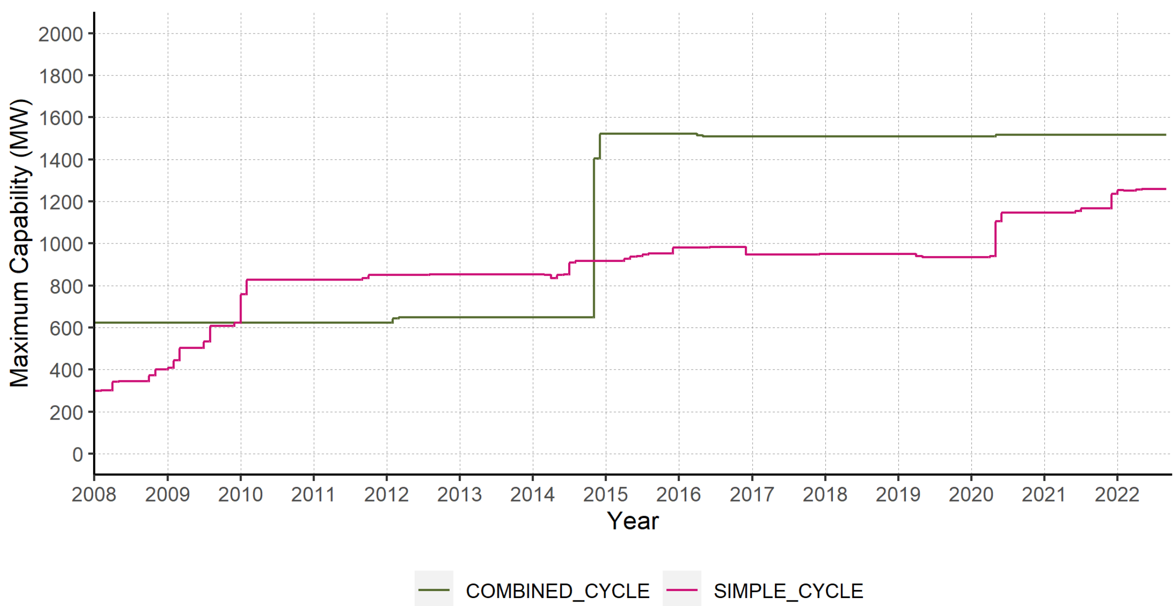


Figure 44: Monthly maximum capability of simple cycle and combined cycle gas assets



[25] The City of Medicine Hat units, operated under CMH1 were excluded from this analysis as most of its capacity is used behind the fence. During most hours, less than 20% of this capacity is used to meet Alberta Internal Load.

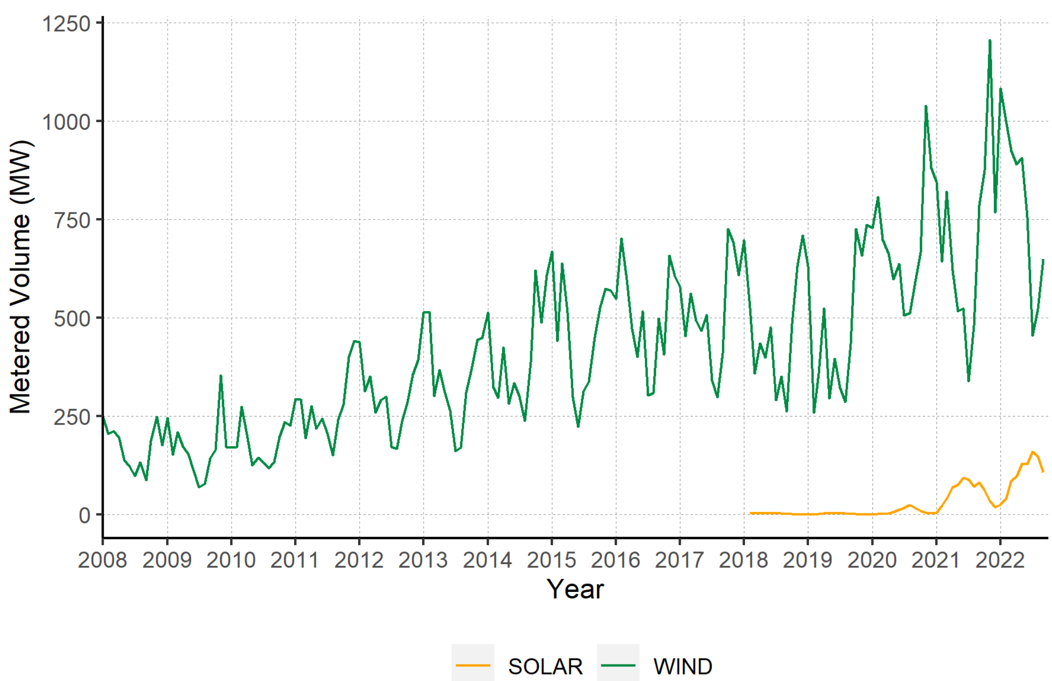
The overall capacity factor of combined cycle assets has increased steadily from 53% in 2017 to 73% in 2020 and 74% so far in 2022. An efficient combined cycle asset is used as the benchmark for carbon costs under the current TIER regime, which means some of these assets pay very little or no carbon costs, increasing their competitiveness in the market.

Since 2018, there has been a material increase in the capacity factor of simple cycle assets (Figure 43). This observation is consistent with the increasing presence of wind capacity during this time. Increased wind capacity has led to increased net demand[26] variability and therefore requires fast ramping resources such as simple cycle generators.

As illustrated in Figure 45, wind generation in Alberta has increased steadily between 2008 and 2018. In November 2021, average wind generation was 1,206 MW or 15% of total net generation for that month.

For wind and solar generating facilities, capacity factors are often driven by weather conditions, i.e., the availability of the energy resource. Therefore, the following capacity factor graphs focus on the seasonal nature of these generation types. Figure 46 depicts monthly capacity factors for total wind generation. As shown, the highest capacity factors are observed in November, December, and January while the lowest capacity factors are usually in July and August.

Figure 45: Monthly average generation of wind and solar assets



[26] Net demand refers to demand less the generation output of wind and solar assets.

Figure 46: Monthly capacity factors of wind assets by year[27]

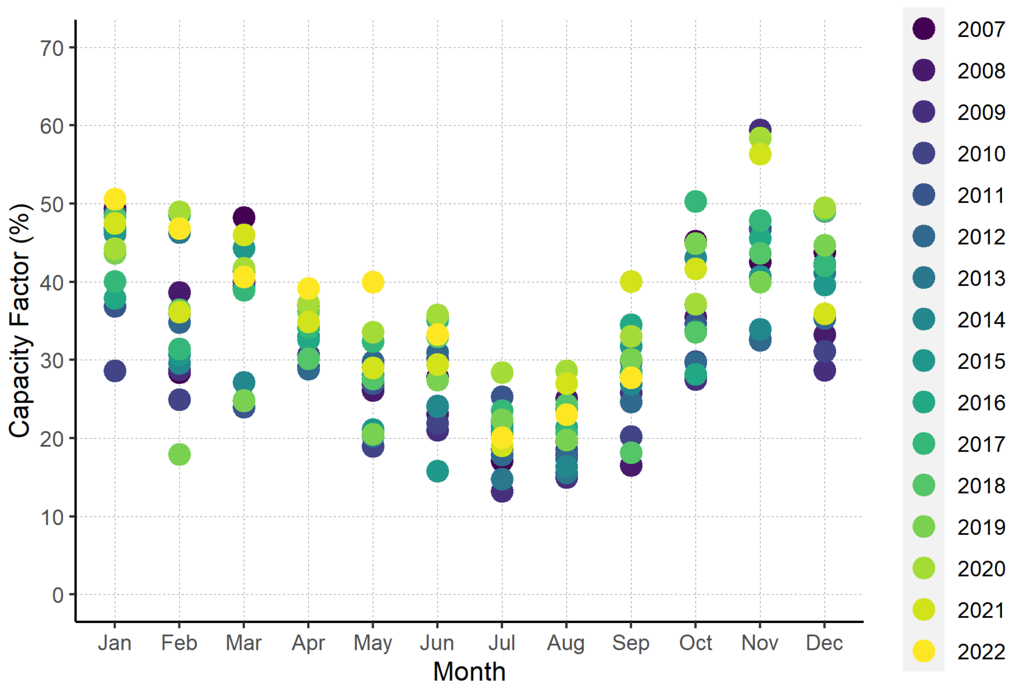
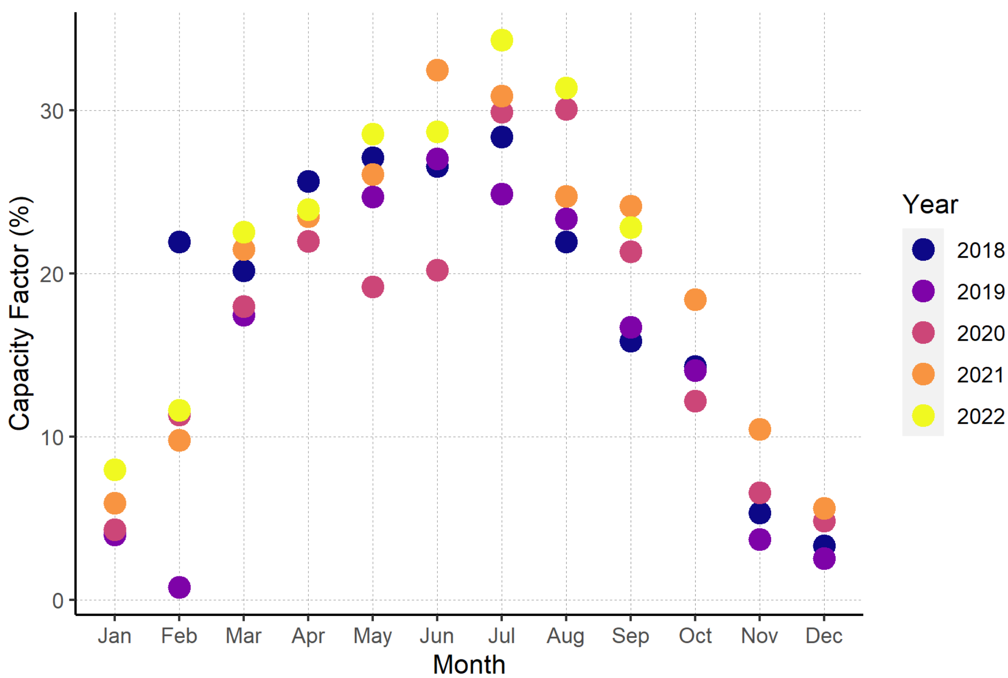


Figure 47: Monthly capacity factors of solar assets by year[28]



[27] A new wind asset is included in the analysis when its hourly generation has exceeded 30% of its Maximum Capability.

[28] A new solar asset is included in the analysis when its hourly generation has exceeded 90% of its Maximum Capability.

Figure 47 illustrates the monthly capacity factors for solar generation. As shown, the monthly pattern observed for wind generation is essentially reversed for solar. The highest capacity factors are observed during the summer months and lower capacity factors are observed in November, December, and January.

1.7.2 Availability factors

Availability factors analyze the availability of generation assets relative to their total capacity and are calculated by dividing average available capability by the maximum capability of the asset. Availability factors are largely determined by operational factors that impact the physical capability of the assets.

Figure 48 depicts changes in the monthly availability factor for coal assets since 2008. Generally speaking, the availability of coal assets has been in the 80% to 90% range. The reduced availability in the 2011 to 2013 period was affected by extended outages at Sundance 1 and 2.

In the fall of 2021, an extended forced outage at Genesee 2 and a planned conversion outage at Keephills 3 reduced the availability of coal assets, as shown. The availability of coal assets so far in 2022 has generally been higher reflecting fewer outages.

Figure 48: Monthly availability factors of coal assets

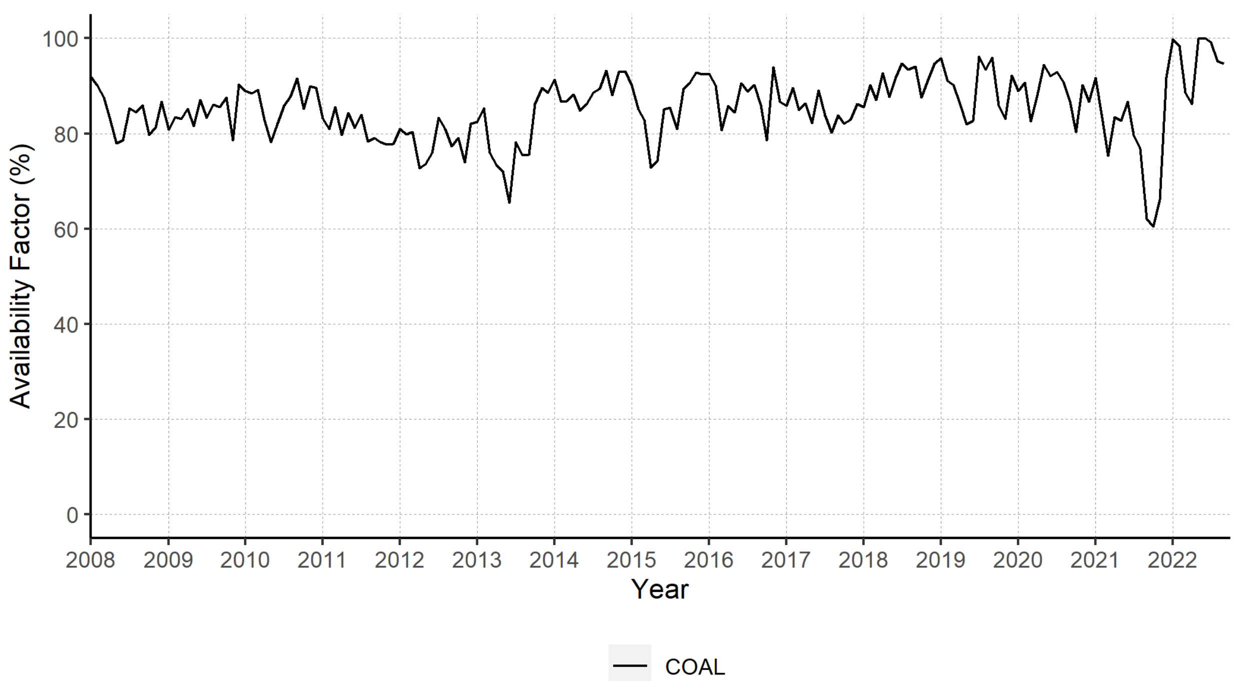


Figure 49 illustrates monthly availability factors for coal, dual fuel, and gas-fired steam assets since January 2018. The availability of dual fuel and gas-fired steam assets has generally been comparable to prior coal-fired capacity, when comparing on an individual asset basis.

Figure 49: Monthly availability factors of coal, dual fuel and gas fired steam assets (since 2018)

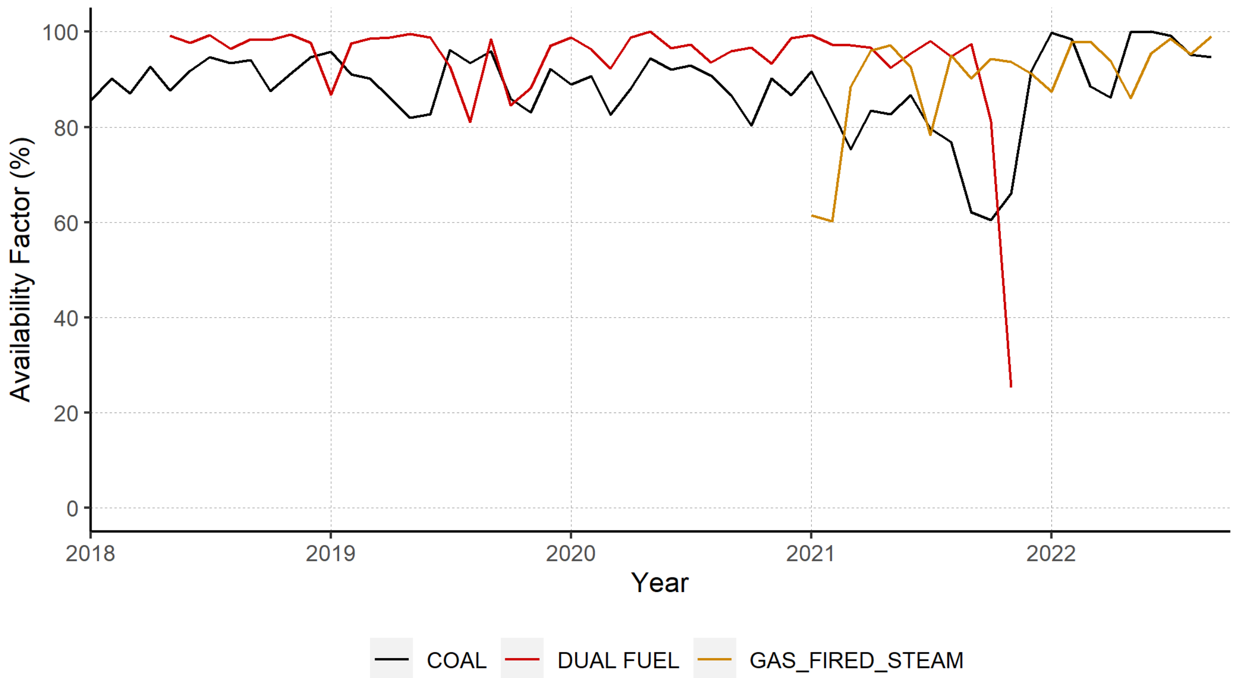


Figure 50 illustrates monthly availability factors for simple cycle and combined cycle gas assets. The lowest availability factors observed for combined cycle assets are often driven by outages at the Shepard asset, which has significantly more weight than other combined cycle assets due to its large size.

The availability factors for simple cycle capacity have generally increased and become more consistent since earlier years. In September 2022, the availability factor of simple cycle assets was reduced to under 60% because of outages, including a planned outage at HR Milner (300 MW) to expand the asset to combined cycle.

Figure 51 illustrates the average amount of capacity that has been on outage across different months of the year, for outages that were declared to the AESO more than 90 days in advance. The fuel types included in this analysis are coal, dual fuel, gas-fired steam, combined cycle, and simple cycle; this analysis does not include cogeneration assets.

The longer notice period indicates that the operators of the assets may have had sufficient discretion to choose the timing of their outage to some extent. In this figure, the capacity on outage figures is averaged over three five-year periods. In all three periods, the outages were most likely to occur during the spring or fall. The timing of outages in spring and fall is generally consistent with planned outages occurring during shoulder-season months, when electricity demand is typically lower.

Figure 50: Monthly availability factors of combined cycle and simple cycle assets

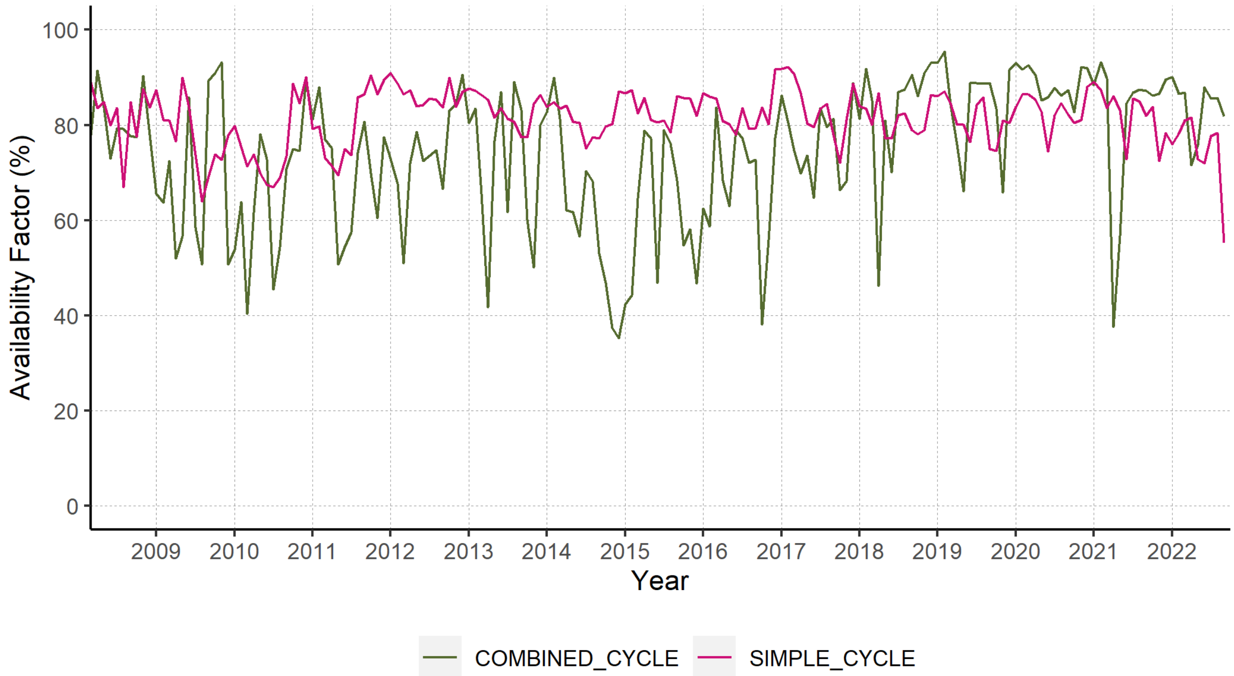
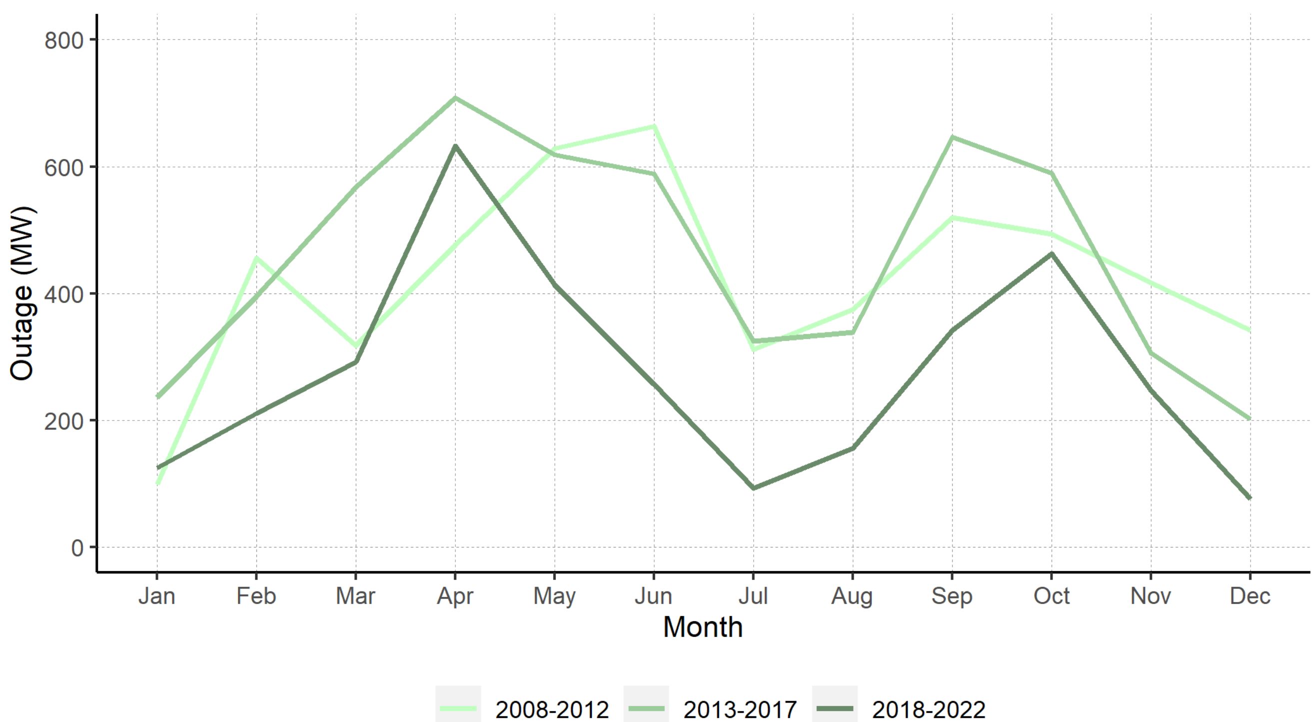


Figure 51: The average amount of thermal capacity on outage by month, for outages that were declared more than 90-days in advance



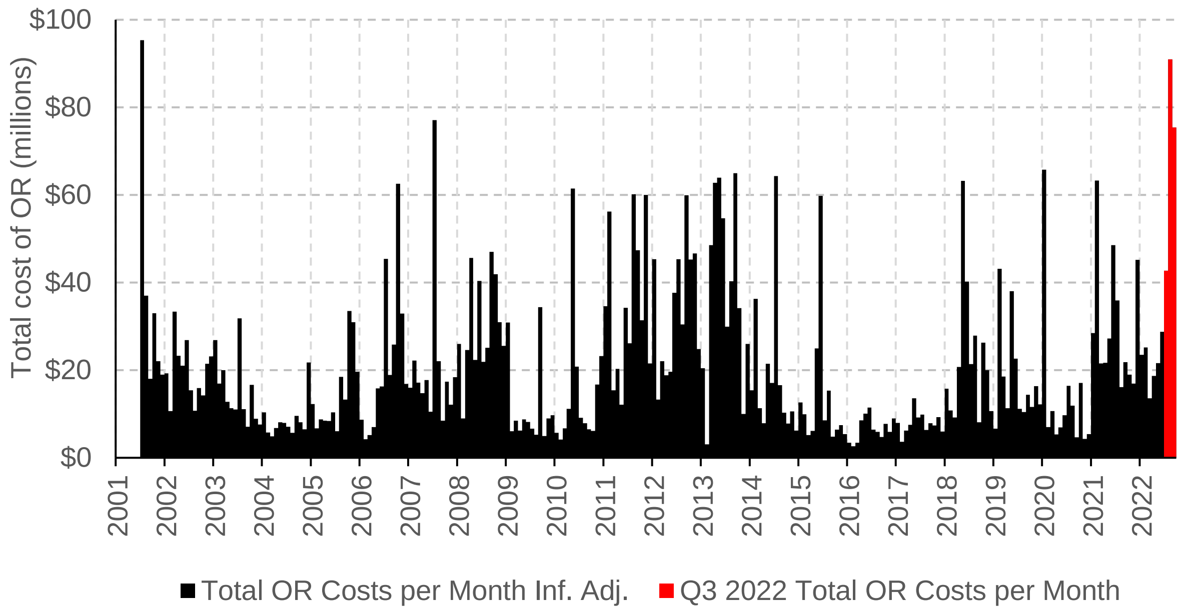
2 THE MARKETS FOR OPERATING RESERVES

There are three types of operating reserves (OR) that AESO system controllers use when there is an unexpected imbalance or lagged response between supply and demand: regulating reserve, spinning reserve, and supplemental reserve. Regulating reserve (RR) provides an instantaneous response to an imbalance of supply and demand. Spinning reserve (SR) is synchronized to the grid and provides capacity that the system controller can direct in a short amount of time when there is a sudden drop in supply, for example. Supplemental reserve (SUP) is not required to be synchronized but must be able to synchronize quickly if directed by the system controller.[29] These products are bought by the AESO through day-ahead auctions.

2.1 Costs and volumes

Total quarterly OR costs reached a record high in Q3 2022 of $209 million, driven by record-high pool prices. These costs surpassed the previous quarterly record of $181 million in Q2 2013, in inflation-adjusted September 2022 dollars (Figure 52).

Figure 52: Total cost of OR by month (July 2001 to September 2022, inflation adjusted)



Although OR costs were high, competitive offers from OR sellers, offering greater volumes at large discounts to pool price, put downward pressure on active OR equilibrium prices particularly in the last half of September. As a result, total OR costs decreased from August to September even though pool prices increased (Figure 53). In Q3 2022, standby costs remained high as a result of record high standby regulating reserve activations.

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

Figure 53: Total cost of active and standby reserves and average pool price by month

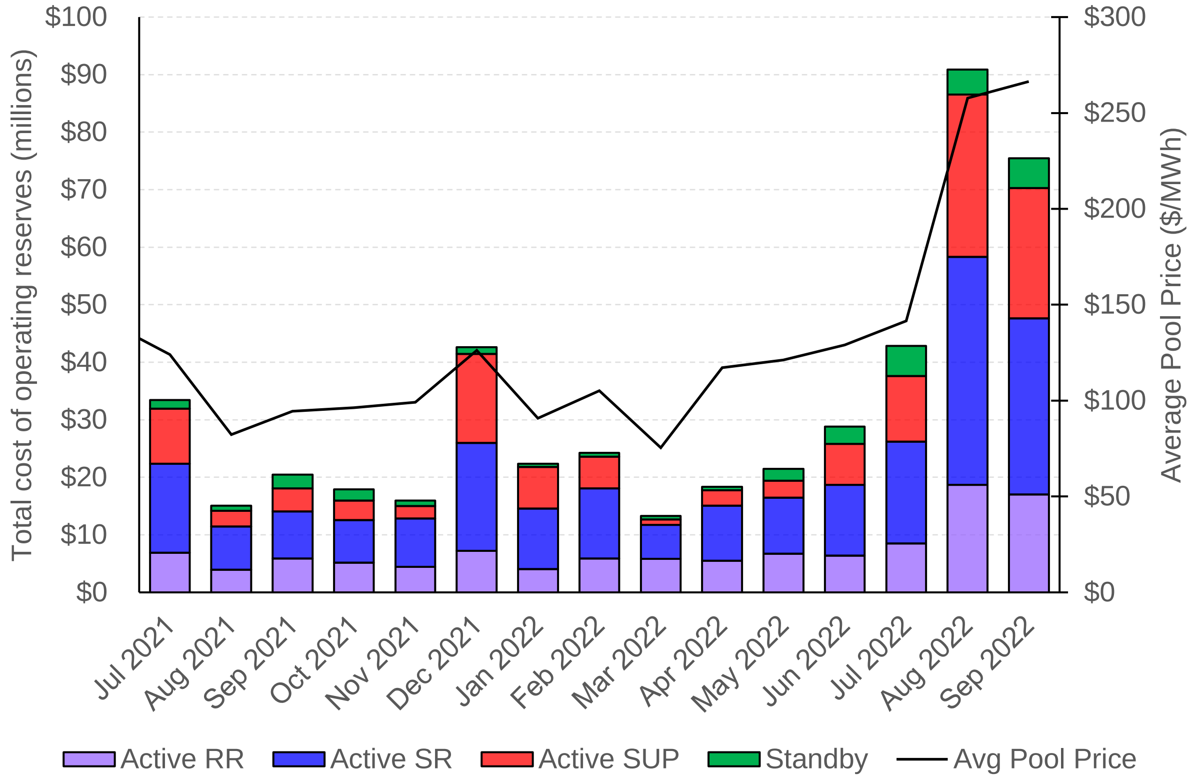


Table 10 shows year-over-year average cost changes for active OR products. Although record high pool prices contributed to record high average OR costs, average OR costs increased by less than the average pool price. Generally, active OR costs and pool price are expected to be correlated because the opportunity cost of providing active OR is often forgoing the sale of energy at pool price. Moreover, active prices are directly indexed to pool price.

Table 10: Average cost ($/MWh) of active OR products

Product	Q3 2022	Q3 2021	Q3 2022 - Q3 2021
Spinning	$151.94	$59.59	$92.35
Supplemental	$107.49	$31.23	$76.26
Regulating	$146.62	$56.22	$90.40
Avg. Pool Price	$221.41	$100.33	$121.08

Daily active on-peak volumes of spinning and supplemental reserves procured in Q3 averaged 276 MW per day, a slight increase from the 268 MW per day in Q2 2022 (Figure 54). Procured regulating reserve volumes remained around 130 MW per day, except for September 27, 28, 29, when procurement of regulating increased to 170 MW per day. This increase was likely the result of an anticipated need to manage the challenges associated with supply shortfall events towards the end of September.

Figure 54: Active on-peak OR volumes (July 2021 to September 2022)

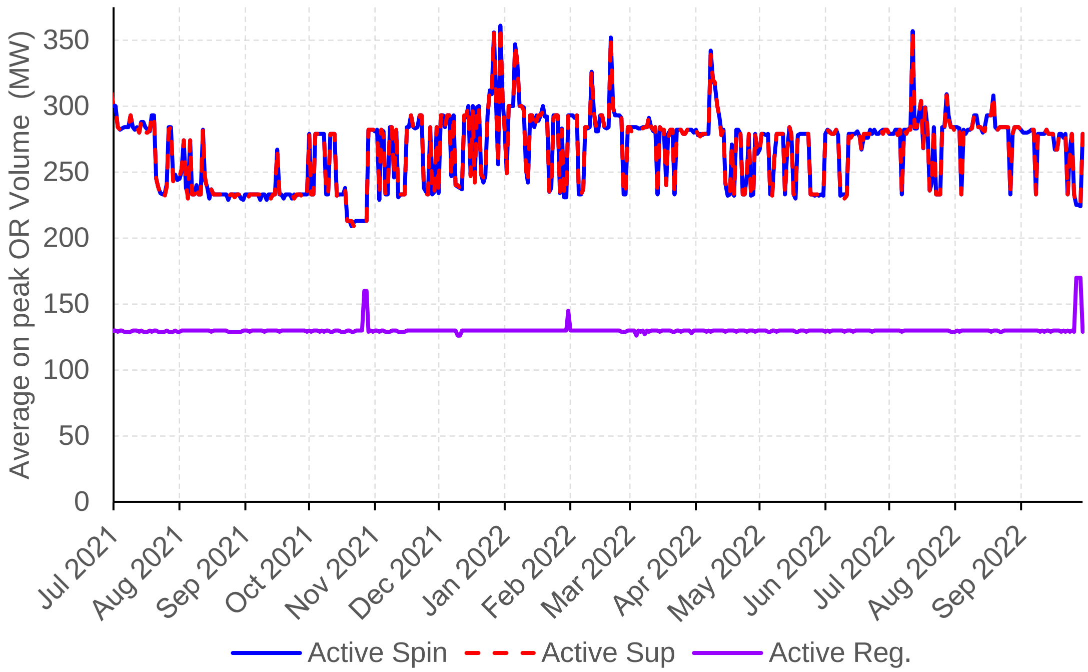
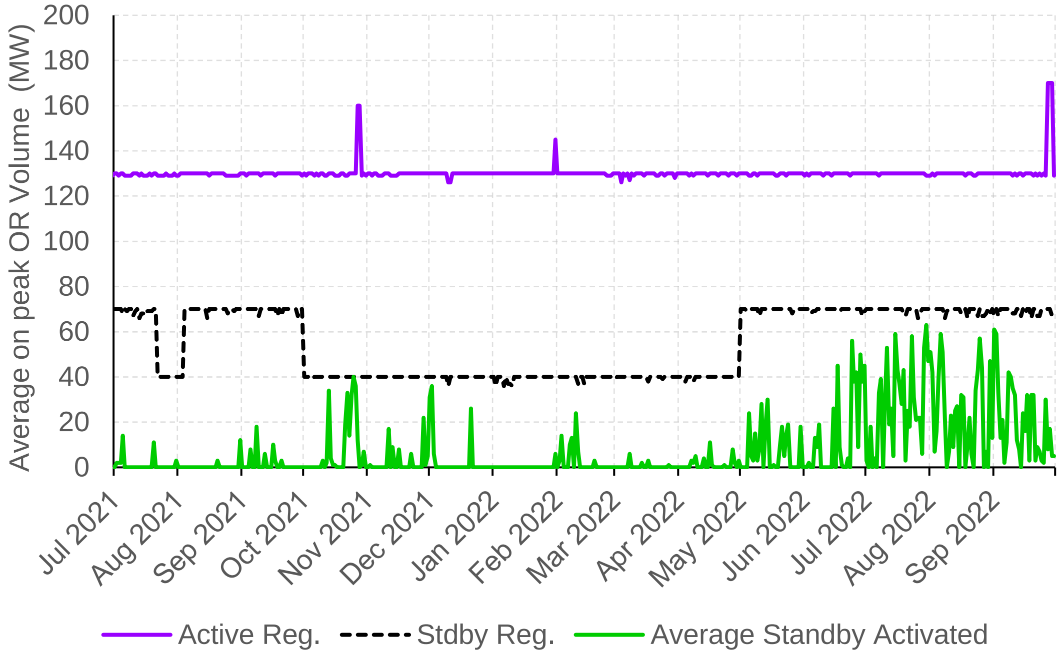


Figure 55 shows daily on-peak regulating reserve volumes from July 2021 to September 2022. Standby activations increased significantly beginning in June and were highest in August. Standby regulating activations are primarily driven by active reserve restatements but can also be driven by the volatility of renewable resources, transmission constraints, and merit order shuffles at the beginning of an hour.

Figure 55: Active and standby on-peak regulating volumes (July 2021 to September 2022)



In Q3 standby regulating activations totaled 49,151 MWh, a record. Spinning and supplemental activations were less than in Q3 2021 (Table 11). In the latter half of Q3, the number of transmission constraint directives increased, as did the number of dispatches issued for the purpose of managing block price changes between settlement intervals, resulting in merit order shuffles. These conditions, as well as active reserve restatements and renewable resource volatility, drove record high standby regulation activations. The last time standby regulating activations surpassed 40,000 MWh was almost 20 years ago, in Q1 2003.

Table 11: Quarterly standby activations (MWh)

Quarter	SR	SUP	RR
Q3 2021	12,826	5,168	2,395
Q4 2021	14,972	6,984	10,875
Q1 2022	15,522	6,281	2,004
Q2 2022	14,939	5,098	14,518
Q3 2022	11,522	3,435	49,151

2.2 Active on-peak equilibrium prices

The prices of active OR products are indexed to pool price. Specifically, OR sellers are paid the sum of the pool price and the equilibrium price,[30] which is a discount or premium. In cases where the sum of pool price and the equilibrium price is negative, the seller is not required to pay the AESO.

The equilibrium price of active on-peak OR products is typically less than zero, meaning active OR products are paid at a discount to pool price. This discount is because the provision of active OR products is normally cheaper than providing energy due to reduced fuel costs.

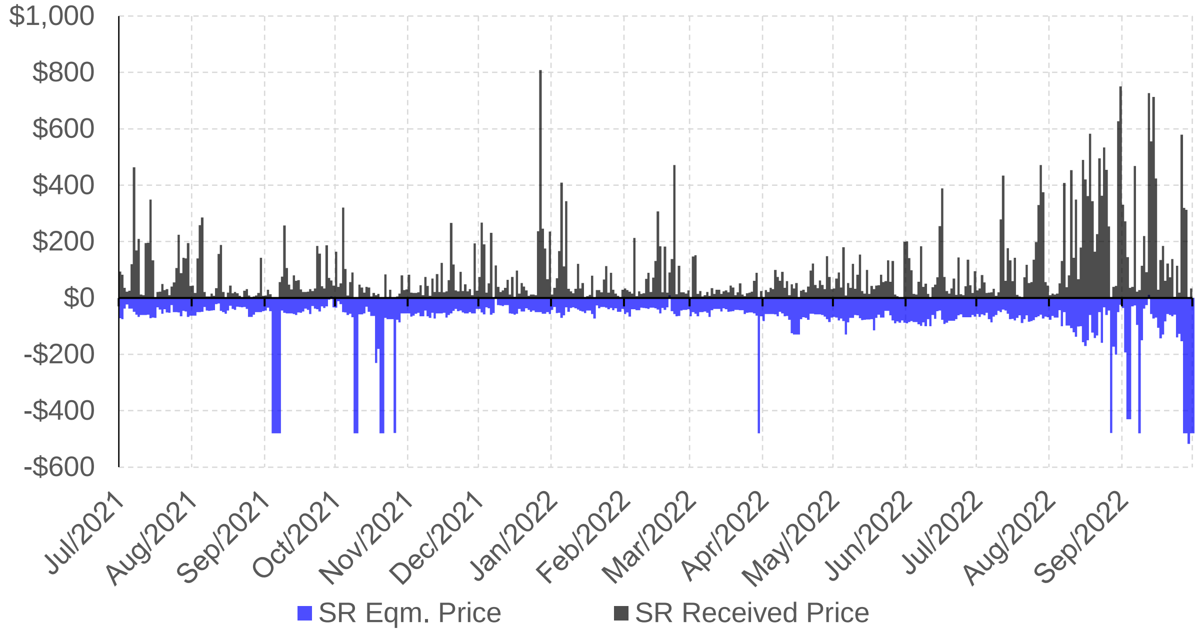
Spinning equilibrium prices decreased significantly in the second half of Q3 (Figure 56), reflecting more supply and higher expected pool prices. As expectations of pool prices increase, OR providers may be willing to offer active OR at a greater discount. In addition, new resources qualified to provide OR entered the market. Effective August 19, a 20 MW battery storage asset (ERV3) entered service, and battery assets often sell spinning reserve.

The active on-peak spinning and supplemental equilibrium prices settled at -$518/MW for September 29, 2022. This was a record low for spinning reserve, and the lowest since 2004 for supplemental reserve. Although there is no offer floor for these products, it is uncommon for active OR to be offered at less than -$999.99/MW. As equilibrium price is the average of the clearing offer price and the AESO bid price, a clearing offer of -$999.99/MW results in an equilibrium price of -$479.99/MW. Consequently, it is uncommon for OR equilibrium prices to settle below negative

[30] The AESO define the equilibrium price as the average of the AESO's bid price and the marginal offer. (ID #2013-005R, p.6)

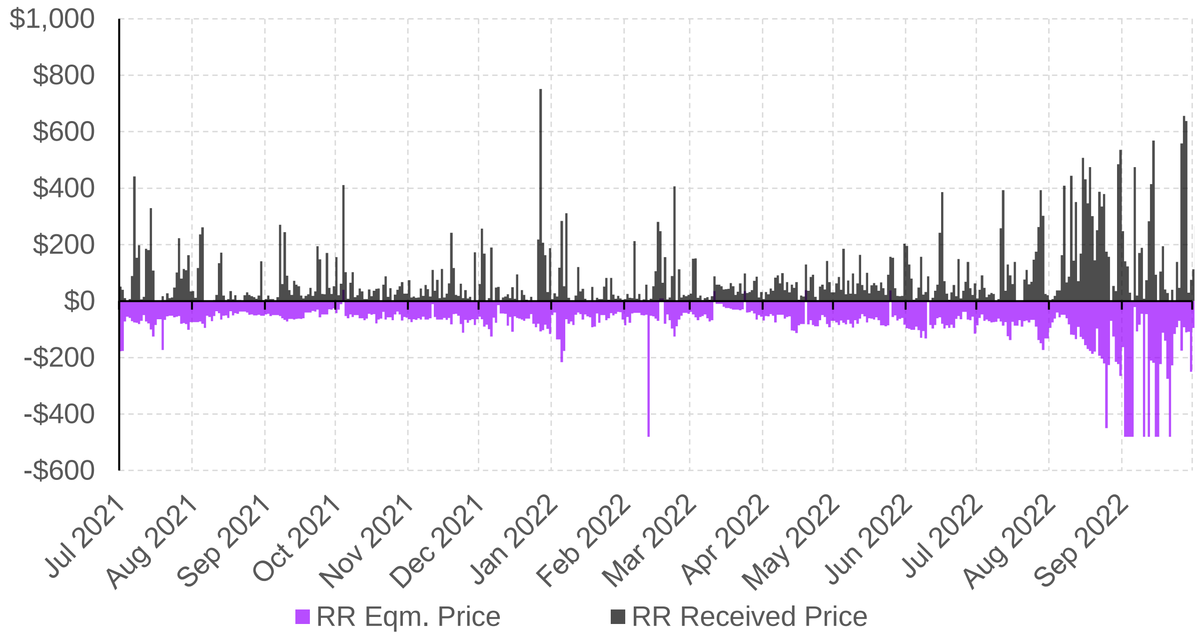
$479.99/MW. Though equilibrium prices fell, received prices (what is paid to OR providers) rose because of higher pool prices. Figure 56 illustrates that record low equilibrium prices and record high received prices occurred concurrently for active spinning reserves in Q3.

Figure 56: Daily active on-peak spinning equilibrium price and received price



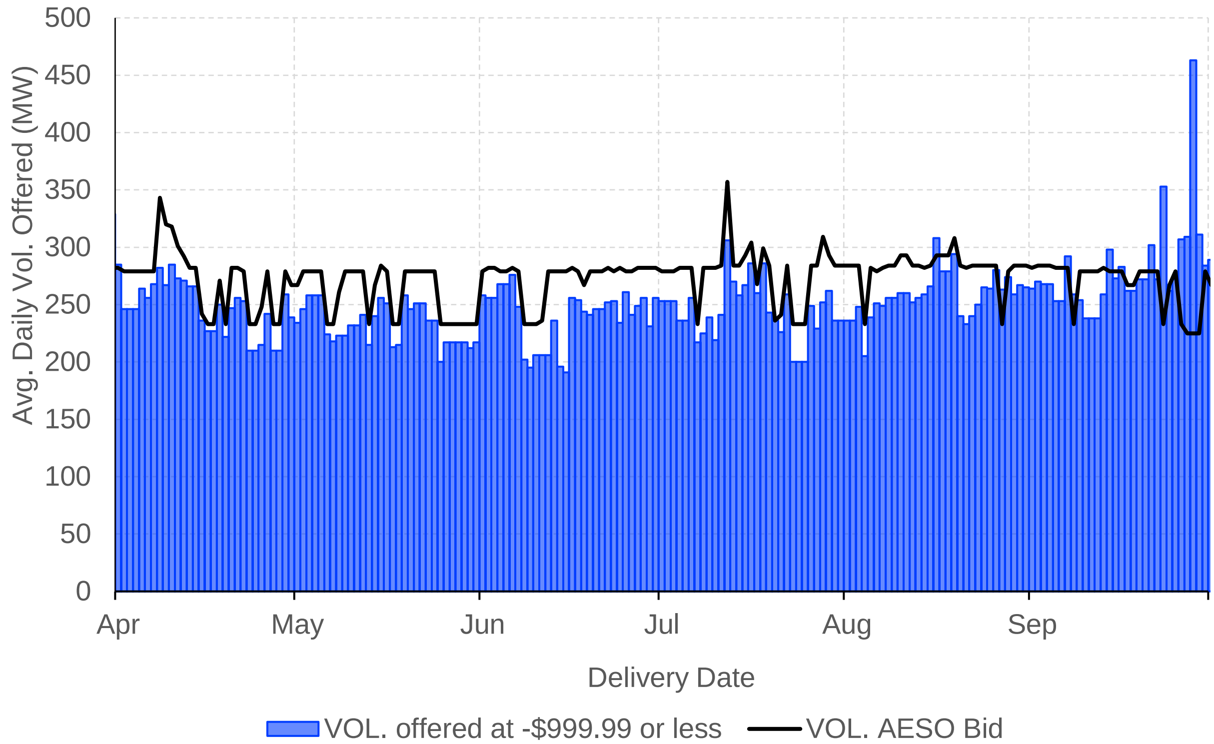
The equilibrium price for regulating reserve also declined sharply in the latter half of August, while the received price increased, following the same general trend seen in spinning reserves.

Figure 57: Active on-peak regulating equilibrium price and received price



In the latter half of Q3 2022, the volume of offers for active spinning, supplemental, and regulating that were priced at or below -$999.99/MW increased (Figure 58 illustrates spinning volumes). A majority of OR sellers that clear the market offered at or below -$999.99/MW, illustrating competition for dispatch and high pool price expectations. A lower-than-average spinning bid volume on September 29 for 225 MW of active on-peak spin resulted in a clearing offer of negative $1076/MW. The lowest offer was less than negative $1500/MW.

Figure 58: Active on-peak spinning volumes offer at -$999.99 or less, and bid volume (April 1 to September 30, 2022)



2.3 Operating reserve dispatches by fuel type

Total regulating reserve dispatches increased in Q3, reflecting high standby activations. Figure 59 shows that the greatest increase in dispatches from Q2 to Q3 was provided by hydro, followed by gas-fired steam assets. Dispatches for natural gas assets decreased slightly in Q3, partly because of transmission constraint directives issued to a gas asset, limiting this asset's ability to provide reserve, and prompting the need to activate standby resources.

Figure 60 shows spinning reserve dispatches by fuel type and illustrates the increasing role of battery assets in the spinning market throughout 2022.[31] Battery assets provided over 20% of spinning reserve dispatch volumes in September, more than gas and gas-fired steam assets

[31] The battery category includes Crossfield 3 (CRS3), a hybrid battery-gas asset, beginning in May 2021.

combined. ERV3's entry into service and rising natural gas prices in Q3 contributed to this change in dispatch share.

Figure 59: Volume of regulating reserve dispatches by fuel type (July 2021 to September 2022)[32]

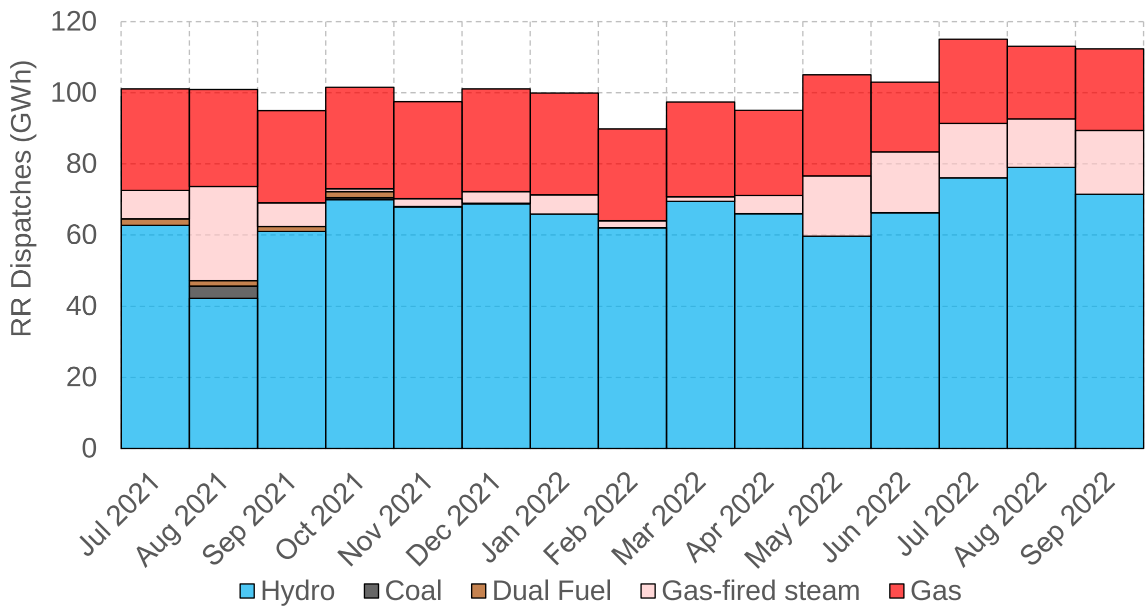
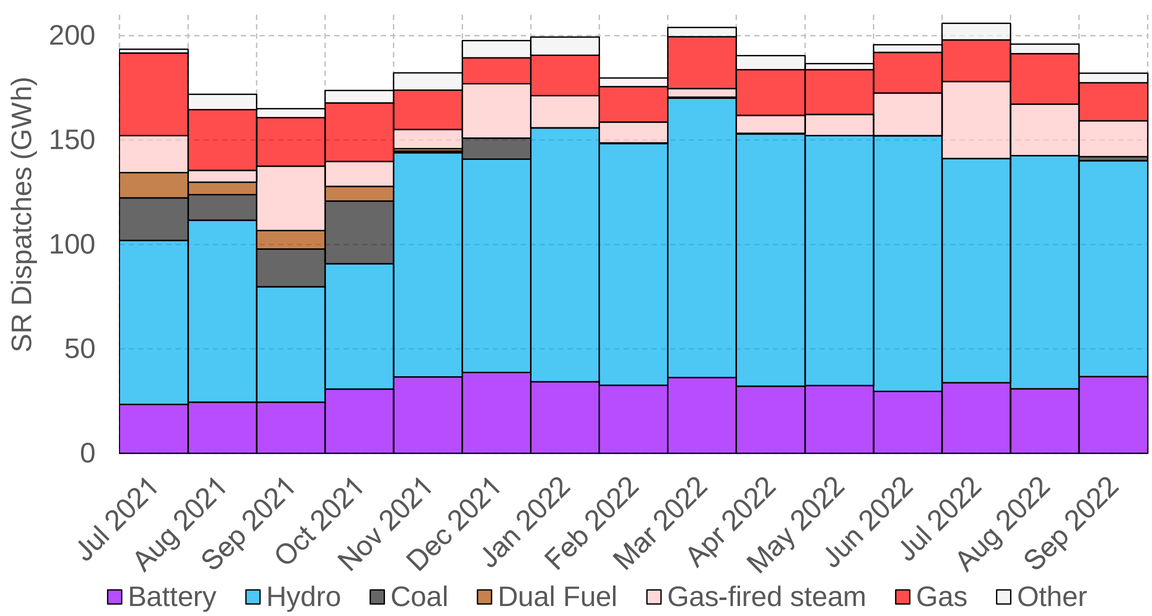


Figure 60: Volume of spinning reserve dispatches by fuel type (July 2021 to September 2022)



[32] The fuel type charts in the OR Markets section of this report group simple cycle, cogeneration, and combined cycle together as "gas", shown in red.

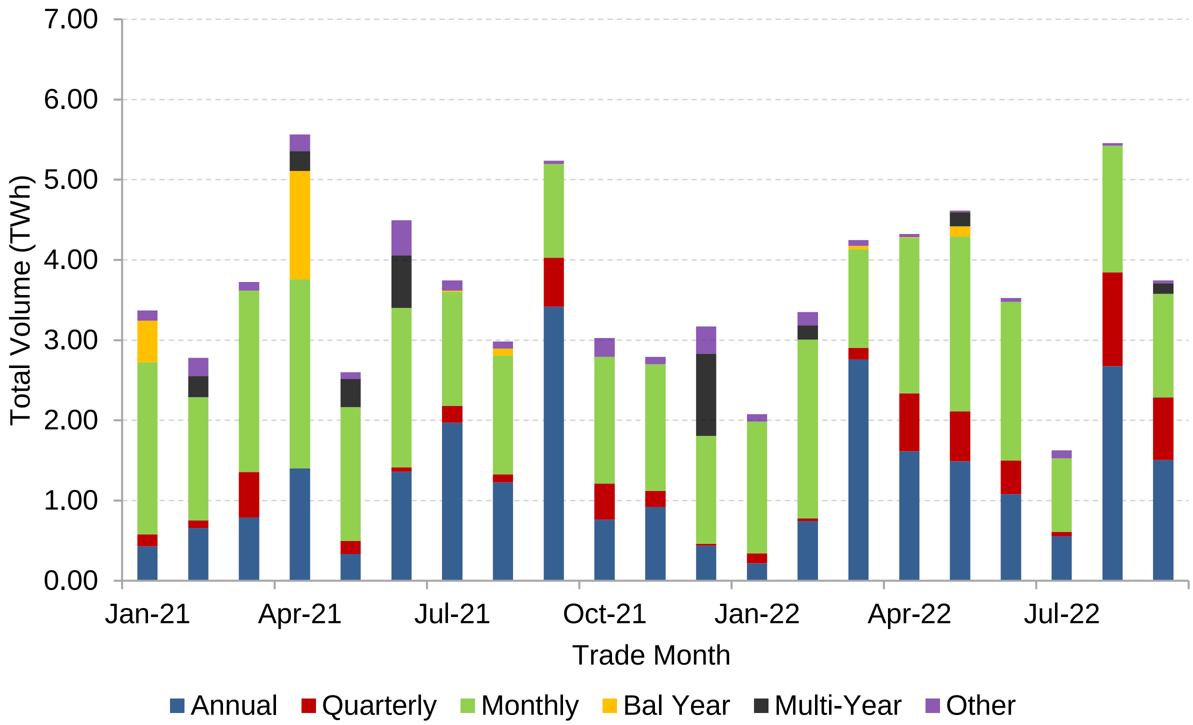
3 THE FORWARD MARKET

3.1 Forward trade 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 volatility associated with purchasing electricity to sell to retail customers. Given that electricity is sold to some customers at a fixed price, managing costs through forward market purchases will generally reduce risk, and therefore 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 is routinely collected by the MSA as part of its 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 61: Total volumes by trade month (January 2021 to September 2022)[33]



[33] The total volumes in 2021 include direct bilateral trades, which accounted for 12% of the total volumes in 2021. The MSA has not yet collected this data for 2022. The monthly volumes in 2021 and 2022 include full-load RRO trades based on the expected 4 MW traded volume.

Figure 61 shows the total volume of power that has been traded since January 2021, by the month in which the trades took place. Total volume is the total amount of power traded financially over the duration of a contract. Even though July experienced a reduction in total volumes, trading increased in August so the overall volume of trades in Q3 was only 4% less than in Q3 2021.

However, the total volume traded in Q3 was 13% lower relative to Q2. The higher volumes traded in Q2 were largely driven by higher monthly volumes, mainly for the summer months of 2022. The monthly trades in Q3 accounted for 3.79 TWh, a decline of 38% relative to Q2. The annual and quarterly volumes in Q3 were 13% and 14% higher than in Q2, respectively.

There were some periods of lower market liqudity in Q3; one which began around mid-June and ran for much of July, and another occured in mid-September. Figure 62 shows the daily maximum bid of buyers and the minimum offer of sellers for the Calendar 2023 (CAL23) contract over the trade period of May 1 to September 30. As shown, there were periods from mid-June to mid-July and in mid-September when the daily maximum bids and minimum offers diverged. During these periods, natural gas forwards for 2023 were falling while the CAL23 power price was generally flat or increasing (Figure 63).

Figure 62: Bid and offer prices for CAL23 by day (May 1 to September 30)

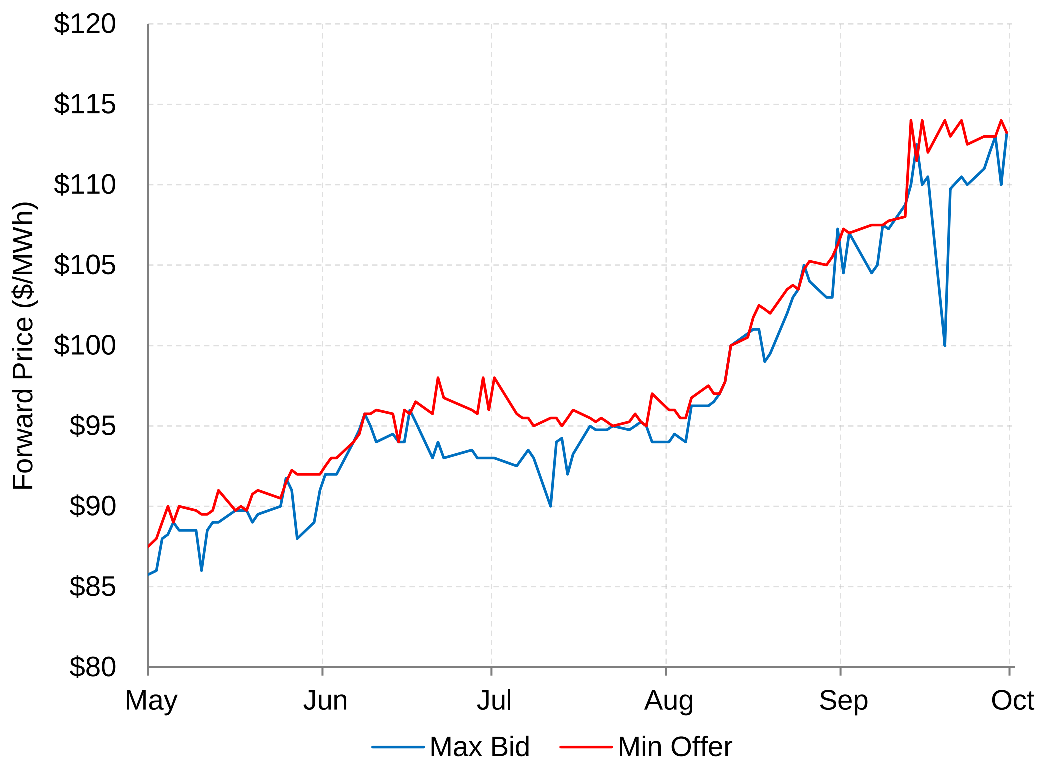
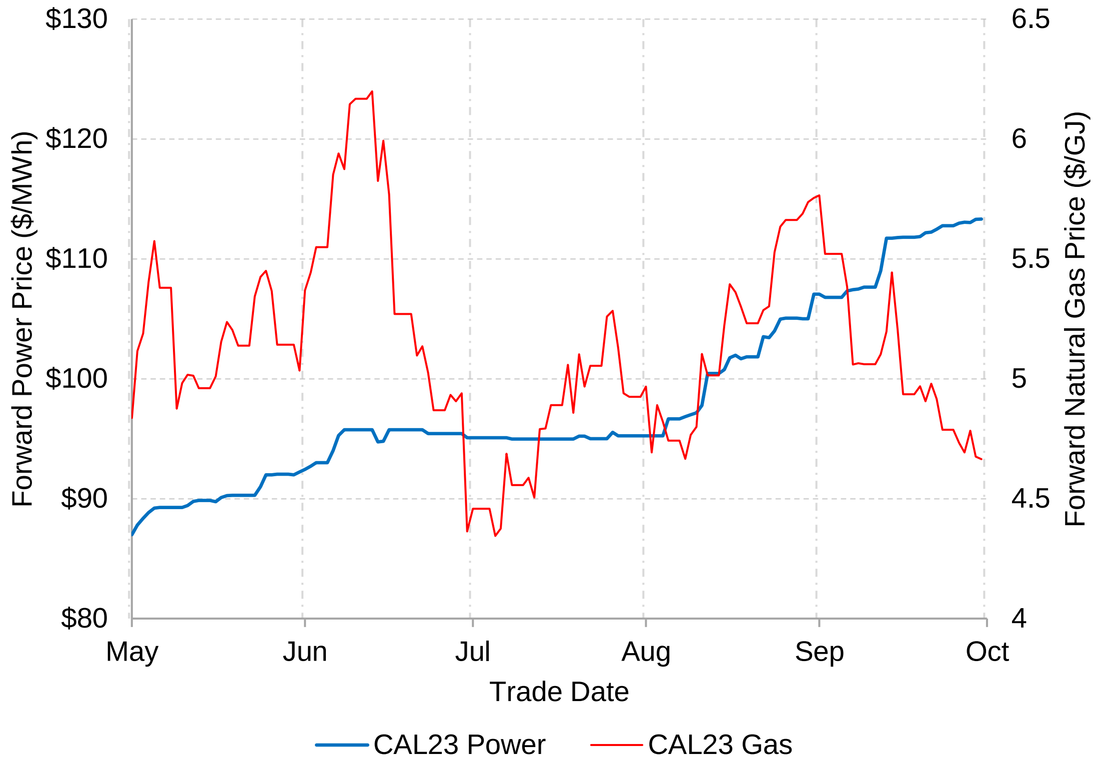


Figure 63: Power and natural gas settlement prices for CAL23 (May 1 to September 30)



3.2 Forward market prices and pool prices

Figure 64 compares monthly flat forward prices and realized pool prices for January through September. Flat monthly contracts settle against the average pool price for a given month. Monthly forward prices in August and September traded at a material discount to realized pool prices. The discount of monthly flat forward prices relative to the realized pool price increased over the quarter from 21% in July to 51% in August to 56% in September.

Increasing natural gas prices in July were a factor in July pool prices coming in above forward market expectations. The realized market heat rate[34] for July was 27.6 GJ/MWh, similar to the final forward heat rate for July of 27.1 GJ/MWh, which is based on forward power and natural gas prices on Friday, June 29.

The realized heat rates for August and September were well above forward market expectations. For August, the realized heat rate of 96 GJ/MWh was almost four times the final forward heat rate of 26 GJ/MWh. This indicates that unexpected market dynamics, such as offer behaviour, were a major factor in pool prices coming in above market expectations.

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[34] Market heat rate divides the price of power by the price of natural gas to yield an implied efficiency in GJ per MWh.

Figure 64: Forward prices and realized pool prices for monthly flat contracts (January to September 2022)

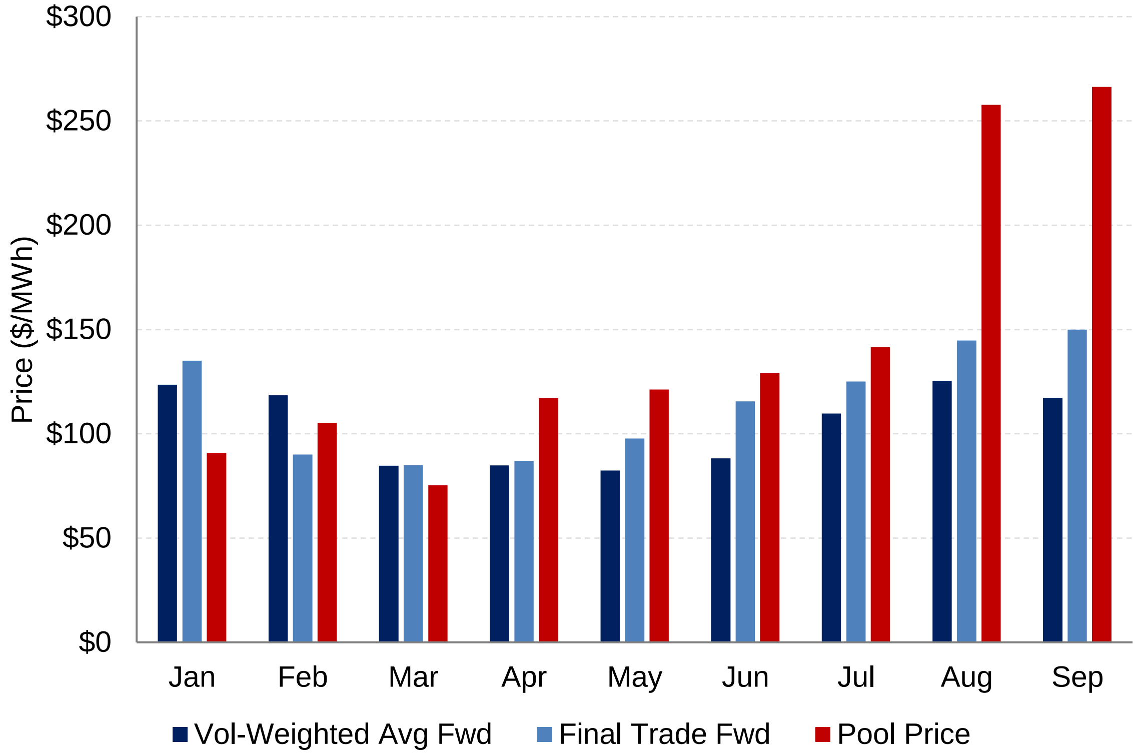


Table 12: Realised and forward market heat rates (GJ/MWh) for July, August, and September[35]

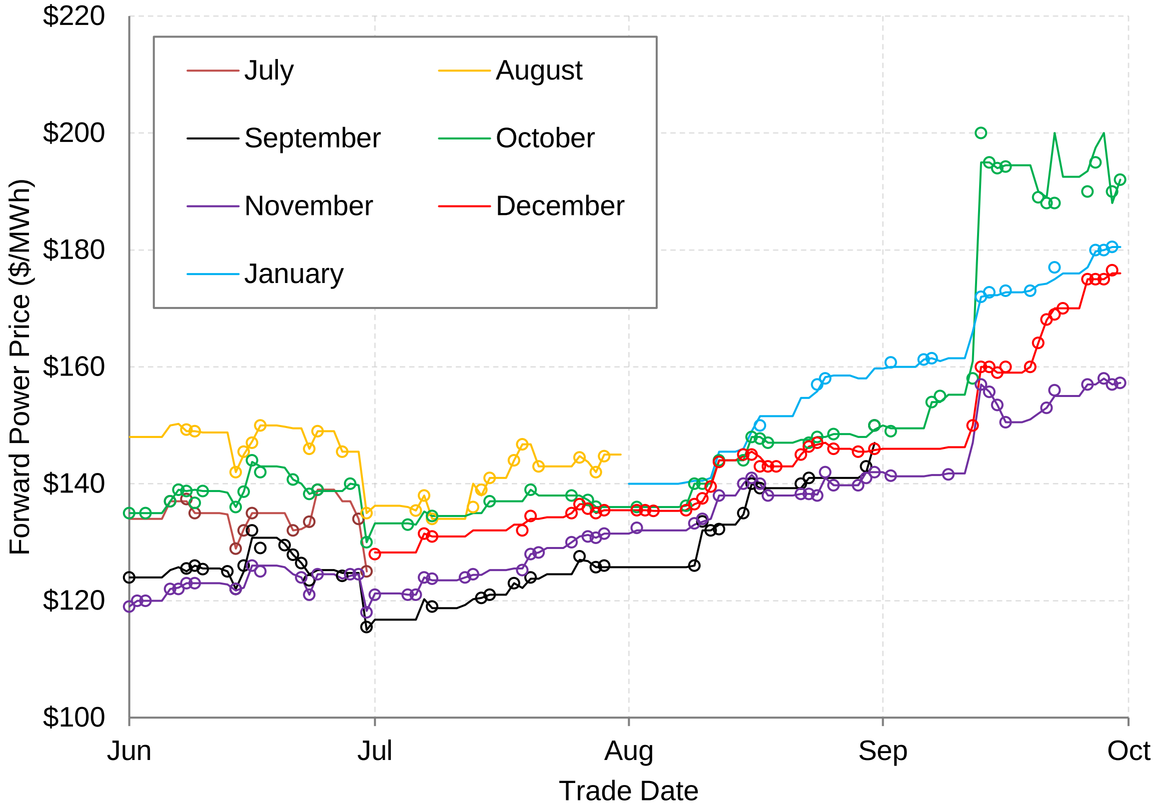
Month	Avg. forward heat rate	Final forward heat rate	Realized heat rate
July	20.0	27.1	27.6
August	23.5	26.4	96.1
September	20.7	34.9	61.6

3.3 Trading of monthly products

Figure 65 illustrates the evolution of flat forward prices for the monthly contracts of July 2022 to January 2023. As shown, forward power prices generally increased over Q3. The increases were significant in August and September, principally because of the high pool prices during these months, which were largely driven by the offer behaviour of some large suppliers.

[35] The average forward heat rate uses power and natural gas settlement prices on weekdays beginning five months prior to the start of the contract month. The final forward heat rate uses power and natural gas settlement prices on the final weekday before the start of the contract month.

Figure 65: Forward power prices for flat monthly contracts[36]



The price of the October contract increased by around $40.00/MWh on Tuesday, September 13, as a result of pool price volatility in the energy market and buying pressure from the EPCOR RRO.[37] On the morning of September 13, the market observed high pool prices in the energy market despite ample supply. For example, in HE07 the pool price was $863.56/MWh and there was 1,700 MW of supply cushion, as a number of suppliers offered generation capacity at high prices.

Beginning at 10:30 on September 13, the EPCOR RRO was procuring forward products for October on behalf of RRO customers. This was the final EPCOR RRO auction for the October delivery month. The auction was deemed to be uncompetitive by EPCOR due to the low number of offers relative to the number of products EPCOR were seeking to buy. As a result, EPCOR purchased fewer products than initially intended, and ran a subsequent auction a few days later.

Because of pool price volatility, the reduced offers to sell, and the buying pressure from the EPCOR RRO, the price of the October contract increased significantly. On September 12 the flat

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[36] The lines in this figure show settlement prices while the markers indicate the last trade price on a given day

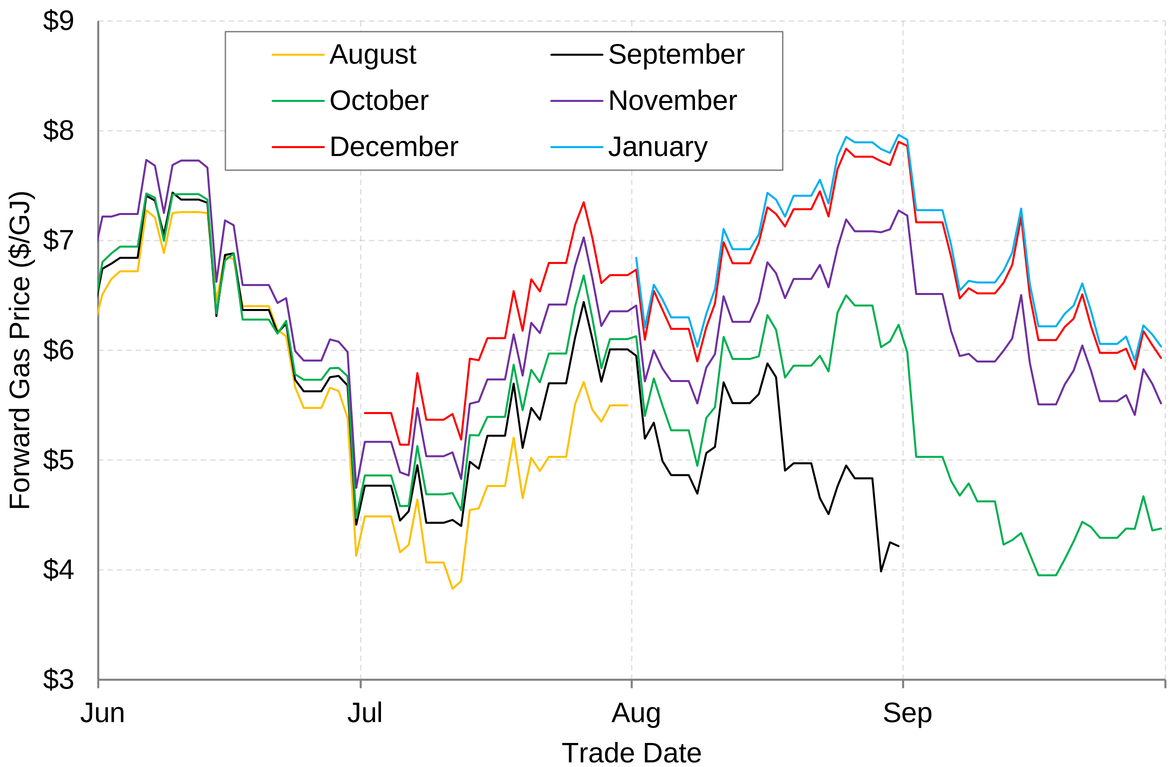
[37] The EPCOR RRO, or Regulated Rate Option, is the default retail rate for small consumers in a number of areas, including Edmonton. Outcomes from the EPCOR RRO auction are also used by other regulated providers.

contract traded for $158.00/MWh, but this increased to $199.00/MWh in the auction on September 13, an increase of 27%.

In July, power forwards increased steadily on the back of pool prices and increasing natural gas futures. After the correction to natural gas prices in late June, natural gas prices generally increased in July because of hot weather in the US and the associated cooling demand.

In mid-July, the August power price increased by 10% from $134.00/MWh on July 12 to $146.76/MWh on July 19, largely on the back of pool price volatility, increasing natural gas futures, and because of RRO buying pressure.

Figure 66: Forward natural gas prices for flat monthly contracts



Forward power prices continued to increase in August (Figure 65). The upward trend of prices in August was mainly due to the high pool prices observed during this month. On August 8, pool prices began to increase notably, and the expected average pool price for August increased from $145/MWh on August 7 to $229/MWh on August 19. This put upward pressure on forward prices for monthly contracts. For example, the forward price for September increased by 11% over this period, while October and January both increased by 8%.

The September natural gas contract did not follow the same trend as other gas forwards in mid-to-late August (Figure 66). While the price of natural gas for other months was increasing due to high temperatures and future weather expectations, the price of natural gas for September fell beginning on August 18. This reflected an expectation that pipeline constraints would continue to restrict the demand for Alberta natural gas. Pipeline constraints significantly reduced natural gas export capacity and constrained storage injections, which lowered same-day gas prices below $0/GJ for some days in August.

Despite the falling price of natural gas, the September forward power price increased over August as the high pool prices in August were largely driven by offer behaviour, rather than by natural gas prices. On August 31, the Mid-C forward price for September increased due to an expected heat wave, putting upward pressure on the Alberta power price for September, which increased by $7.00/MWh to $150.00/MWh.

The monthly forward prices for October, November, December, and January were left largely unchanged during the first week of September, despite the price of natural gas price for these months falling by over 20%. In mid-September, the monthly forward prices for the October to January contracts increased significantly on the back of the high pool prices around that time. As discussed above, the price for October increased from $158/MWh on September 12 to $199/MWh in the EPCOR RRO on September 13. Forward prices for the November and December contacts increased by 7% on September 13.

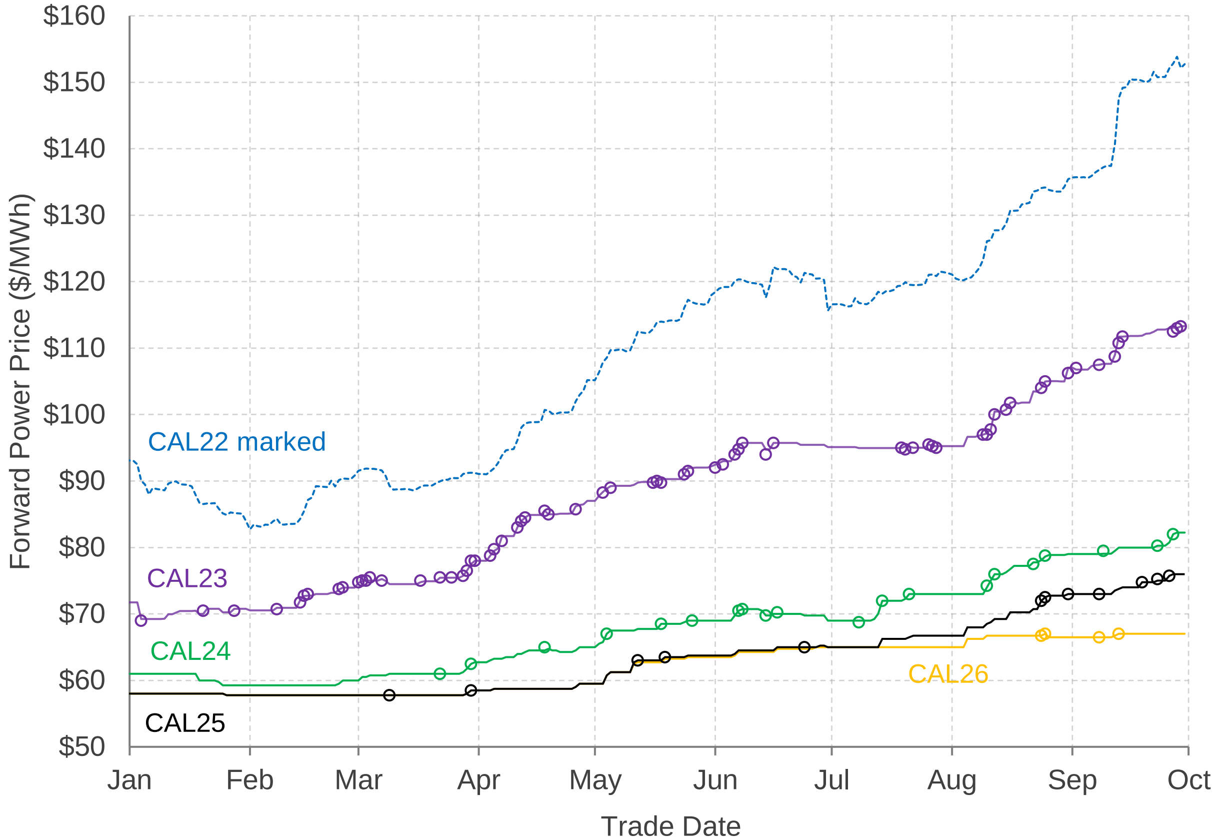
Later in September, the forward price for October fluctuated due to alterations in the schedule of the BC/MATL intertie outage. The BC/MATL intertie was initially expected to be offline from September 26 to October 7. At 16:53 on September 28, the BC intertie returned to service after the AESO had declared an Energy Emergency Alert, indicating a shortfall in supply. Around the time the BC intertie returned to service, the remainder of the BC intertie outage was removed from the AESO's ATC public report, indicating it would remain in service. Subsequently, at around 17:00 on September 29, the BC intertie outage was put back into the ATC report, and the intertie outage resumed in HE09 of September 30. This sequence of events led to some price volatility for the October contract in late September as the market tried to decipher when the BC intertie would be available.

3.4 Trading of annual products

Figure 67 shows forward prices for the annual CAL22 to CAL26 contracts over the trade date range of January 1 to September 30, 2022. The marked price of CAL22 shows the expected average pool price for 2022 based on realized pool prices and prevailing forward prices on that date.

Annual forward prices rose over Q3, largely driven by high pool prices in the quarter. As discussed above, pool prices for August and September came in well above forward market expectations and this put upward pressure on forward prices. Over the course of Q3, the marked price of CAL22 increased by 22% from $116/MWh to $153/MWh, and the forward price of CAL23 increased by 19% from $95/MWh to $113/MWh.

Figure 67: Annual forward prices for CAL22 to CAL26 (January 1 to September 30, 2022)



In July, the power price for CAL23 remained relatively flat, even though the price of natural gas for CAL23 increased steadily, by around $0.50/GJ over the month. Consequently, the spark spread[38] for CAL23 fell slightly over July. The natural gas prices for CAL24 and CAL25 increased slightly over July, resulting in a marginal increase in the power price for these years.

Pool price volatility and increasing natural gas prices put upward pressure on annual prices in August. The natural gas price for CAL23 increased by 17% to $5.76/GJ over August while the forward power price increased by 12% to $107.05/MWh. The spark spread for CAL23 increased by 8% over the month.

The power prices for CAL24 and CAL25 increased by 8% and 9% respectively over August as natural gas prices also increased. CAL26 traded for the first time on August 24, and then again on August 25, for a price of around $67.00/MWh, or a spark spread of around $20/MWh.

[38] Spark spread is the margin between the price of electricity and the input fuel cost of natural gas. These calculations assume 10 GJ of natural gas are needed to produce one MWh of electricity; a heat rate of 10 GJ/MWh. This heat rate is similar to the efficiency of simple cycle assets and is slightly lower than most gas-fired steam assets. An efficient combined cycle has a lower heat rate of around 7.5 GJ/MWh.

Forward natural gas prices for all calendar year contracts fell in September as natural gas production in the US increased. The natural gas price for CAL23 decreased by 19% to $4.67/GJ and the price for CAL24 fell by 13% over September.

However, forward power prices increased over September as pool price volatility continued. On September 14, a new record for the daily average pool price was set at $762/MWh despite mild weather conditions and no shortfall in supply. The marked price of CAL22 increased in mid-September and this put upward pressure on power prices for future years (Figure 67).

The power price for CAL23 increased by 6% over September to $113.32/MWh even as natural gas prices fell, and the spark spread for CAL23 increased by 35%. The power prices for CAL24 and CAL25 increased by 4% over September, while the natural gas prices decreased by 13% and 9%, respectively.

As shown by Table 13, over Q3 the expected spark spread for CAL22 increased by 57%, and the spark spreads for CAL23 and CAL24 increased by 30% and 40%, respectively. The expected increase in natural gas generation capacity, in addition to further renewable generation, means that the spark spreads for CAL24, CAL25, and CAL26 are trading well below CAL23 which, in turn, is priced well under the expected spark spread for CAL22 (Table 13).

Table 13: Power prices, natural gas prices, and market spark spreads for annual contracts[39]

Contract	Power Price ($/MWh)			Gas Price ($/GJ)			Spark Spread ($/MWh)		
	Jun 30	Sep 30	Chg.	Jun 30	Sep 30	Chg.	Jun 30	Sep 30	Chg.
CAL22 (marked)	$115.64	$152.72	32%	$5.12	$5.17	1%	$64.43	$101.03	57%
CAL23	$95.09	$113.32	19%	$4.36	$4.67	7%	$51.46	$66.67	30%
CAL24	$69.00	$82.25	19%	$4.10	$4.29	5%	$28.02	$39.33	40%
CAL25	$65.00	$76.00	17%	$4.08	$4.44	9%	$24.19	$31.64	31%
CAL26	$65.00	$67.00	3%	$4.14	$4.57	10%	$23.58	$21.31	-10%

[39] The spark spread figures here assume a heat rate of 10 GJ/MWh.

4 THE RETAIL MARKET

4.1 Quarterly Summary

Residential retail customers can choose from several retail energy rates. By default, retail customers are on regulated energy rates, which vary monthly and by distribution service area.

Alternatively, customers may sign with a competitive retailer. Competitive retailers typically offer both fixed and variable energy rates. Fixed energy rates are typically set for a period between one and five years, while competitive variable energy rates vary monthly.

Continuing Regulated Rate Option (RRO) trends observed for the past year, residential RRO rates increased in Q3 2022 relative to both the previous year and previous quarter. RRO rates averaged 15.92 ¢/kWh across the four major service areas in Q3 2022 (Table 14).

Average residential competitive variable electricity rates increased by 114% in Q3 2022 compared to the previous year, driven largely by uncharacteristically high pool prices in August and September.

Table 14: Monthly retail market summary for Q3 (residential customers)

		2022	**2021**	***Change***
RRO (Avg ¢/kWh)	Jul	14.79	10.22	*+45%*
	Aug	17.17	12.11	*+42%*
	Sep	15.79	10.41	*+52%*
	Q3	**15.92**	**10.92**	***+46%***
DRT (Avg $/GJ)	Jul	9.09	3.97	*+129%*
	Aug	6.68	3.89	*+72%*
	Sep	7.21	3.38	*+113%*
	Q3	**7.67**	**3.75**	***+104%***
Competitive Variable Electricity Rate (Avg ¢/kWh)	Jul	16.83	15.02	*+12%*
	Aug	30.35	9.78	*+210%*
	Sep	29.64	10.96	*+170%*
	Q3	**25.56**	**11.93**	***+114%***
Competitive Variable Natural Gas Rate (Avg $/GJ)	Jul	6.13	4.73	*+30%*
	Aug	3.68	3.82	*-4%*
	Sep	5.32	4.33	*+23%*
	Q3	**5.04**	**4.29**	***+18%***
Expected Cost, 3-Year Fixed Electricity Contract (Avg ¢/kWh)	Jul	9.16	6.84	*+34%*
	Aug	9.62	7.06	*+36%*
	Sep	10.25	7.53	*+36%*
	Q3	**9.67**	**7.14**	***+36%***
Expected Cost, 3-Year Fixed Gas Contract (Avg $/GJ)	Jul	4.86	2.99	*+63%*
	Aug	5.25	3.24	*+62%*
	Sep	5.14	3.50	*+47%*
	Q3	**5.08**	**3.24**	***+57%***

Residential Default Rate Tariff (DRT) rates remained considerably higher year-over-year in Q3 2022, partly as a result of the deferral of May DRT revenue requirements and their subsequent collection using the June to September DRT. Competitive variable natural gas rates were also higher year-over-year in Q3 2022 but well below prevailing DRT rates.

The expected cost of providing 3-year fixed rate electricity and natural gas contracts increased in Q3 2022, continuing the trend of fixed contract expected cost increases since 2021.

4.2 Retail customer movements

The MSA collects and tracks retail switching data on a one-quarter lagged basis. As such the discussion in this section focusses on retail switching in and prior to Q2 2022.

4.2.1 Regulated retailer customer losses

The number of residential RRO customers fell by around 14,000 in Q2 2022, a net loss of 2% when compared to its end-of Q1 2022 customer base. The number of residential DRT customers also fell by around 2% in Q2 2022, a net loss of around 10,000 customers.

The residential RRO customer base declined by fewer customers in Q2 compared to Q1 2022 (Figure 68). However, this smaller quarterly net loss was driven by higher quarter-over-quarter gains in new RRO customers and not by a drop in the number of customers leaving the RRO (Figure 69). Around 50,000 residential customers have continued to leave the RRO each quarter since Q2 2021.

Figure 68: RRO customer net losses, Q1 2020 to Q2 2022 (residential customers)

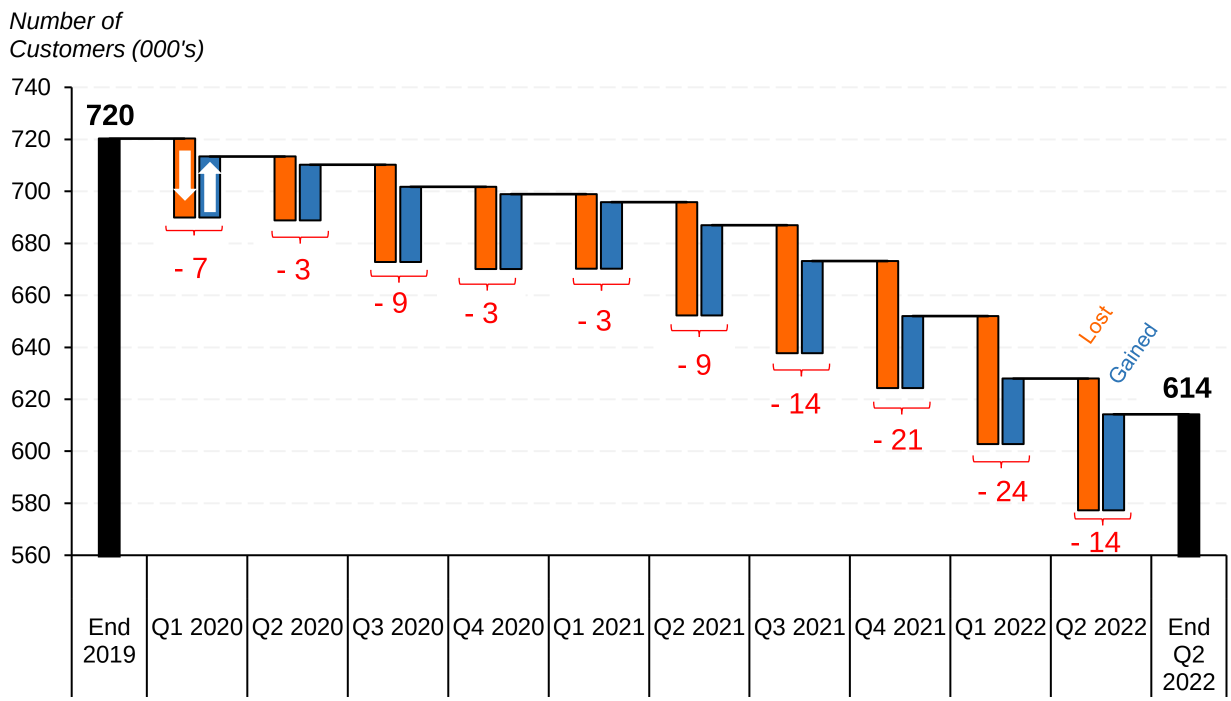
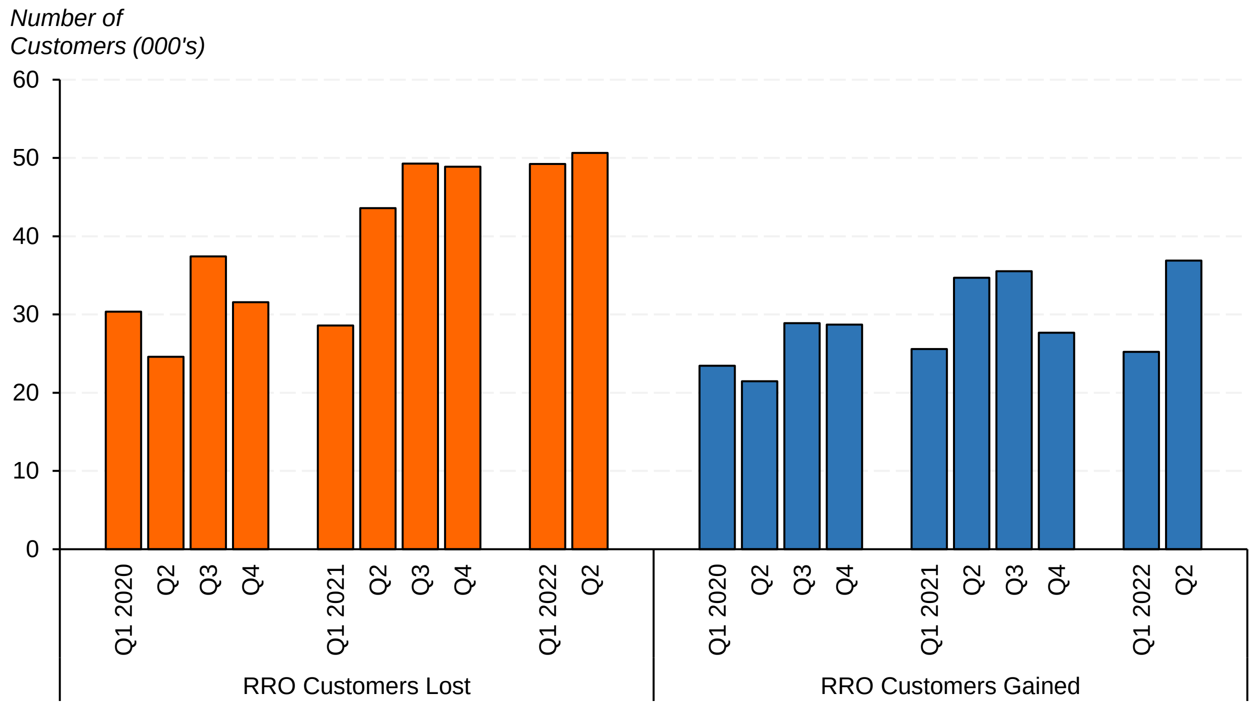


Figure 69: RRO customer losses & gains, Q1 2020 to Q2 2022 (residential customers)



The DRT also continued to lose customers in Q2 2022, losing around 10,000 residential customers (on net) (Figure 70). While quarter-over-quarter net losses were relatively similar compared to Q1, both the number of DRT customers lost and gained increased in Q2 2022 (Figure 71).

Figure 70: DRT customer net losses, Q1 2020 to Q2 2022 (residential customers)

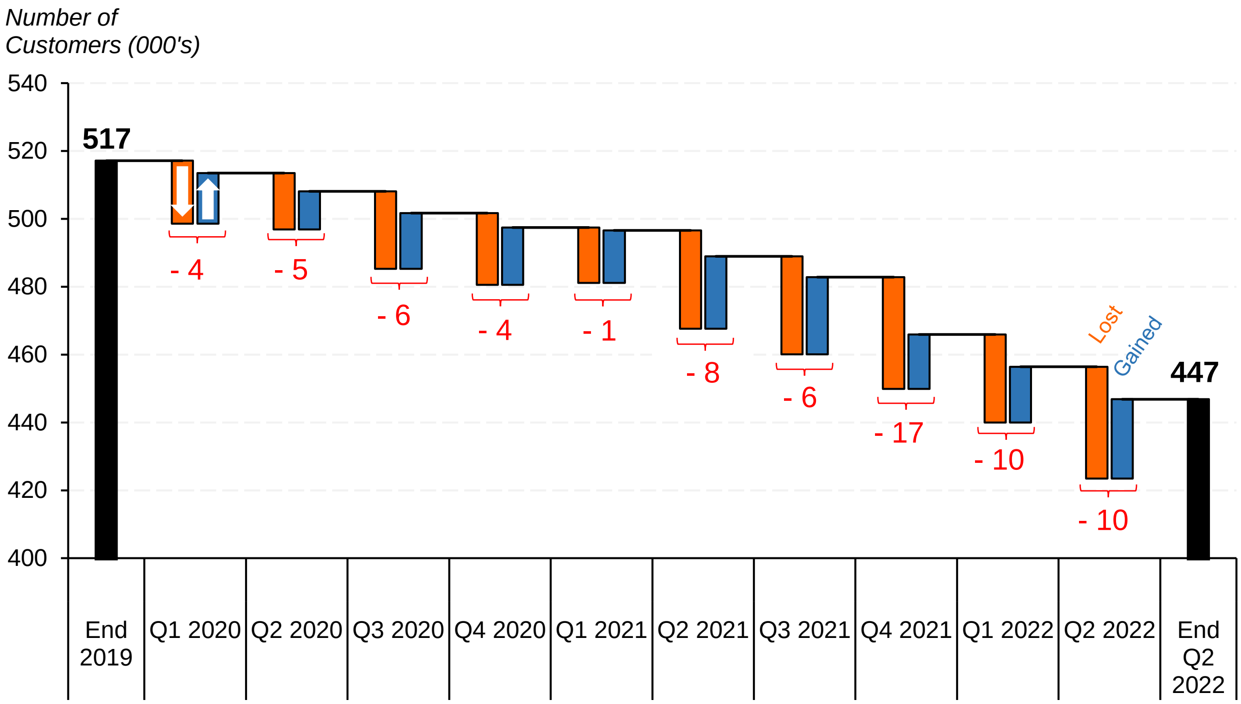
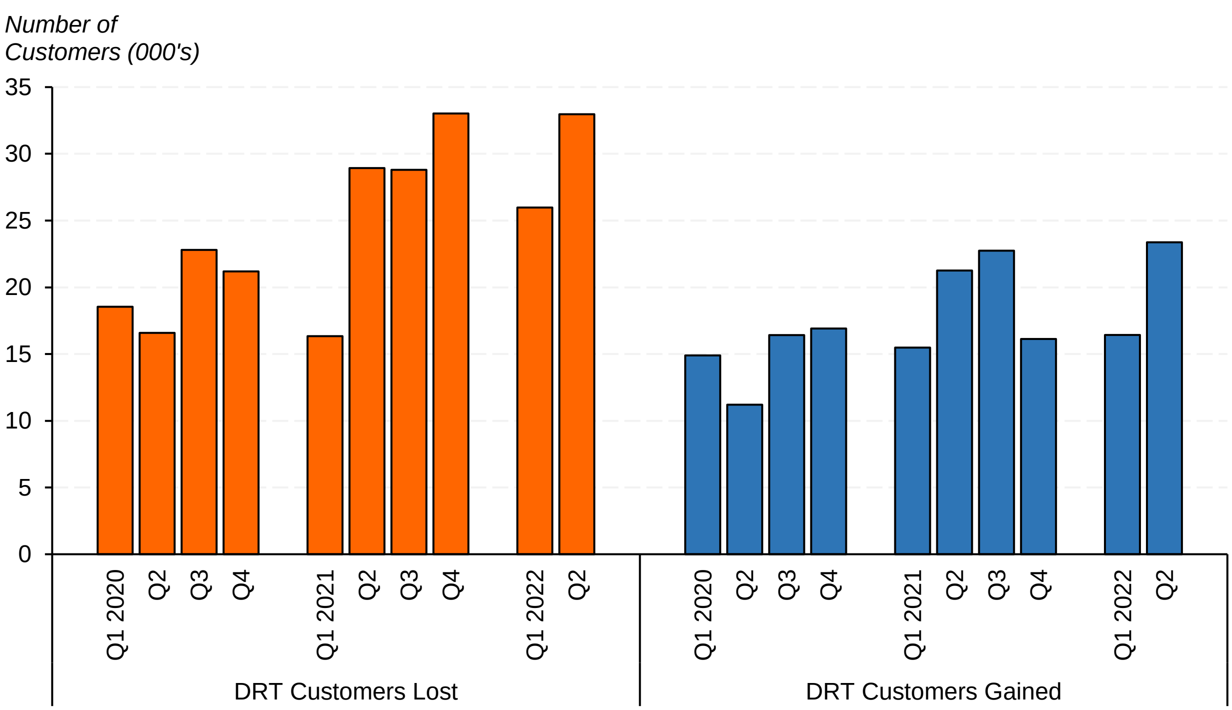


Figure 71: DRT customer losses & gains, Q1 2020 to Q2 2022 (residential customers)

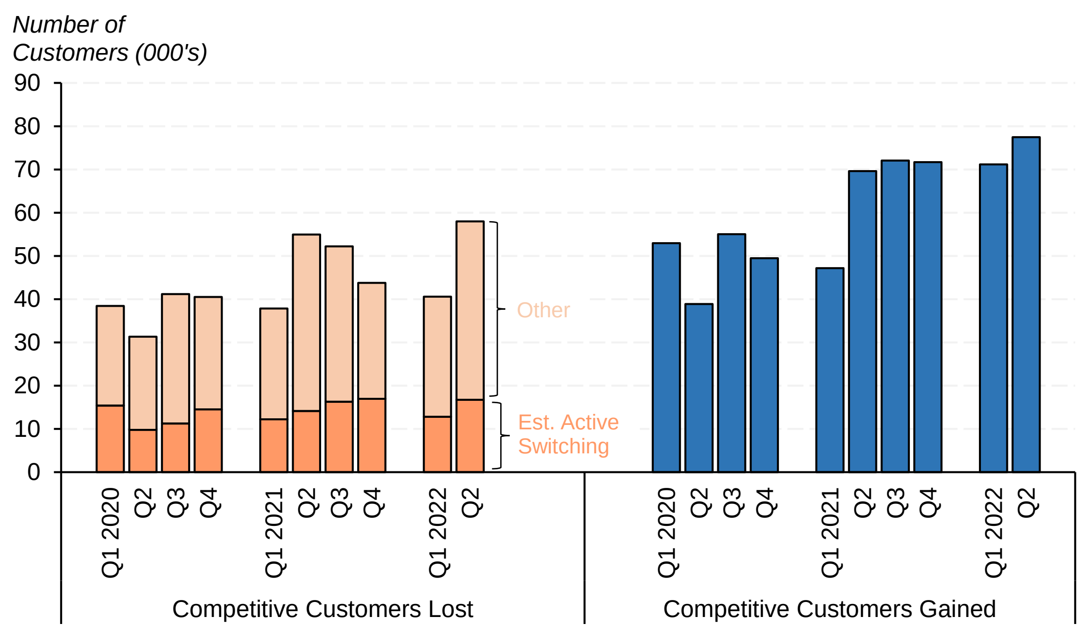


4.2.2 Competitive retailer customer gains

Competitive electricity retailers gained around 77,000 new residential customers in Q2 2022, 6,000 more than in the previous quarter (Figure 72). While competitive residential customer losses also increased to 58,000 over Q2, this change was largely driven by 13,000 more residential customers moving during the quarter compared to Q1. Such customers are counted as a loss of a customer despite the possibility they might return to their competitive retailer.

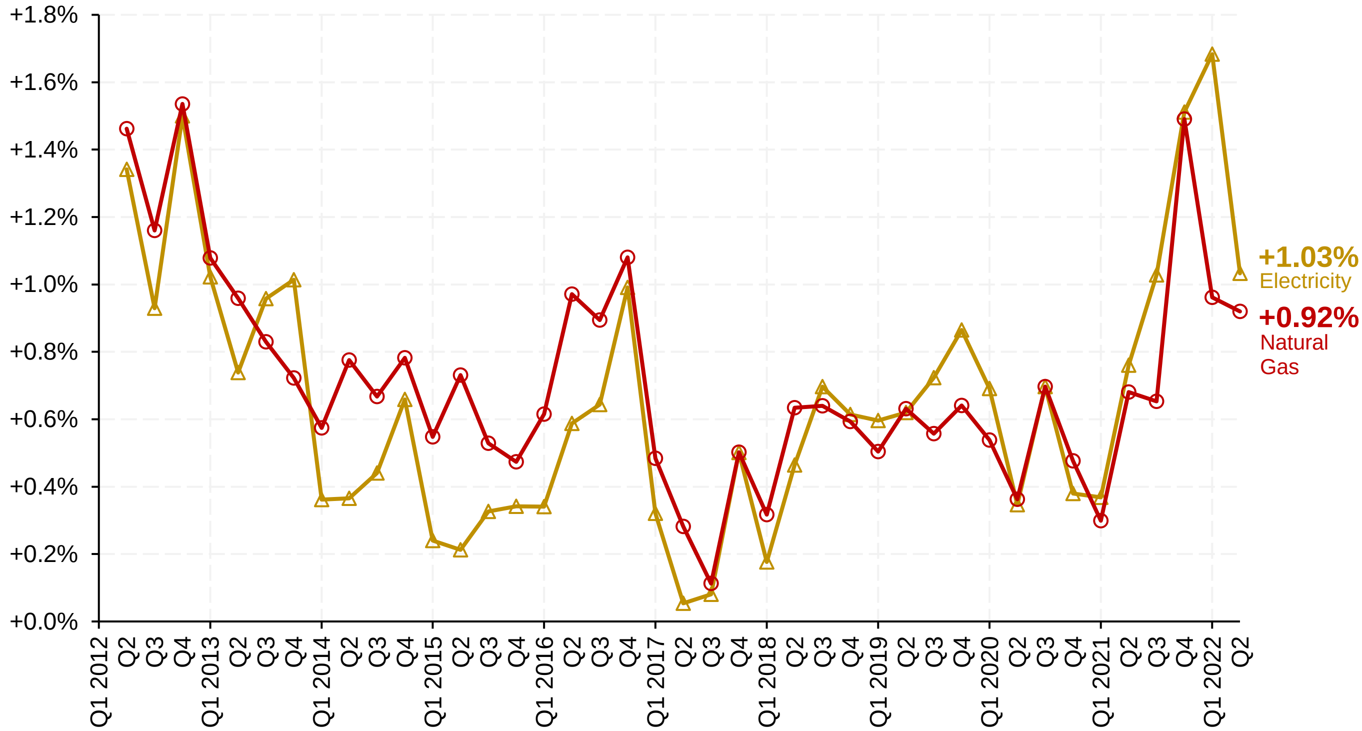
The MSA estimates around 4,000 more residential customers left their competitive retailer for reasons unrelated to a move or as a result of being dropped by their retailer in Q2 2022 compared to the previous quarter. The MSA counts such a switch as an 'Active Switch', as the decision to leave for these customers may be motivated by economic factors, such as a decision to change retailers to take advantage of a competing rate offering.

Figure 72: Competitive electricity customer losses & gains, Q1 2020 to Q2 2022 (residential customers)



Competitive retail customer shares among residential customers continued to increase in Q2 2022, although not at the rate observed in the previous two quarters (Figure 73). However, the increase in competitive share in Q2 remains above historical levels.

Figure 73: Quarterly increase in competitive retail customer share, 2012 to Q2 2022 (residential customers)



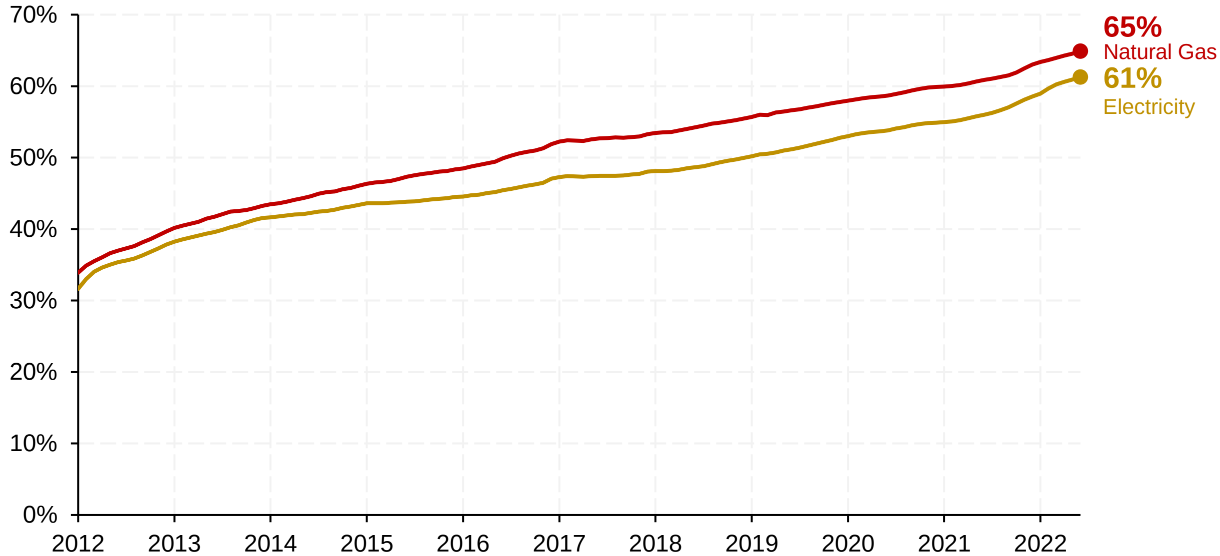
The largest increase in competitive market share among residential customers in Q2 was once again observed in service areas with relatively low competitive retail uptake (Table 15). Overall, 61% of residential electricity customers and 65% of residential natural gas customers were served by a competitive retailer in June 2022 (Figure 74).

Table 15: Competitive shares by service area (residential customers)

	ENMAX	EPCOR	FortisAlberta	ATCO
Change (Q1 2022)	+1.4%	+2.2%	+2.0%	+1.0%
Change (Q2 2022)	+0.6%	+1.3%	+1.2%	+1.6%
Competitive Share (June 2022)	*75.2%*	*48.8%*	*55.9%*	*60.3%*

	ATCO Gas North	ATCO Gas South	Apex
Change (Q1 2022)	+1.1%	+0.7%	+1.2%
Change (Q2 2022)	+1.1%	+0.7%	+1.0%
Competitive Share (June 2022)	*61.0%*	*72.5%*	*35.5%*

Figure 74: Competitive retail customer share, 2012 to Q2 2022 (residential customers)



4.2.3 Determinants of customer switching

In its Supplemental Retail Market Report for Q1 2022,[1] the MSA noted the potential impact of regulated energy bills on residential retail churn rates. As a follow-up to this analysis, the MSA has examined the impact of regulated rates and bills on regulated churn rates over the period spanning 2012 to Q1 2022. Understanding churn drivers provides insights on the behaviour of retail customers and enables a degree of prediction of future RRO churn rates.

Residential DRT and RRO rates have increased substantially since 2021. With this rise in regulated energy rates, the MSA has observed an increased number of residential customers leaving the RRO and DRT. While RRO customer losses tend to trend alongside the prevailing (current month) RRO rate (Figure 75), DRT customer losses appear to be impacted both by prevailing RRO rates and competitive natural gas rates. (Figure 75 and Figure 76). This may suggest customers on regulated rates continue to switch to dual-fuel contracts, and that such switching decisions may be motivated by prevailing RRO rates.

Figure 75: Residential RRO rates vs. RRO & DRT customer net losses

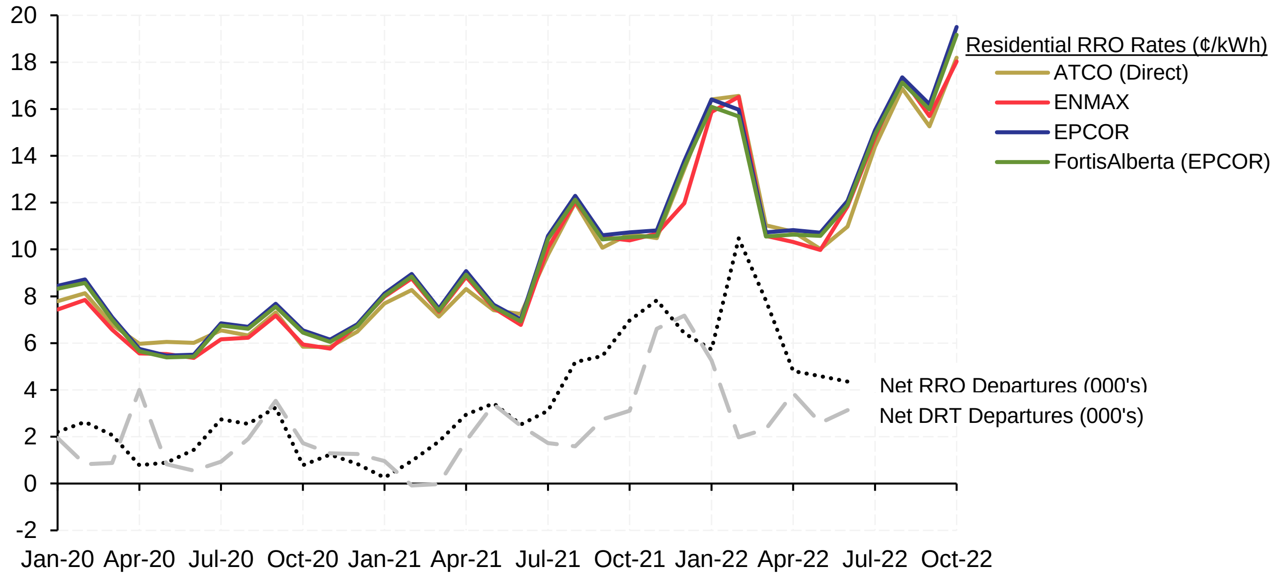
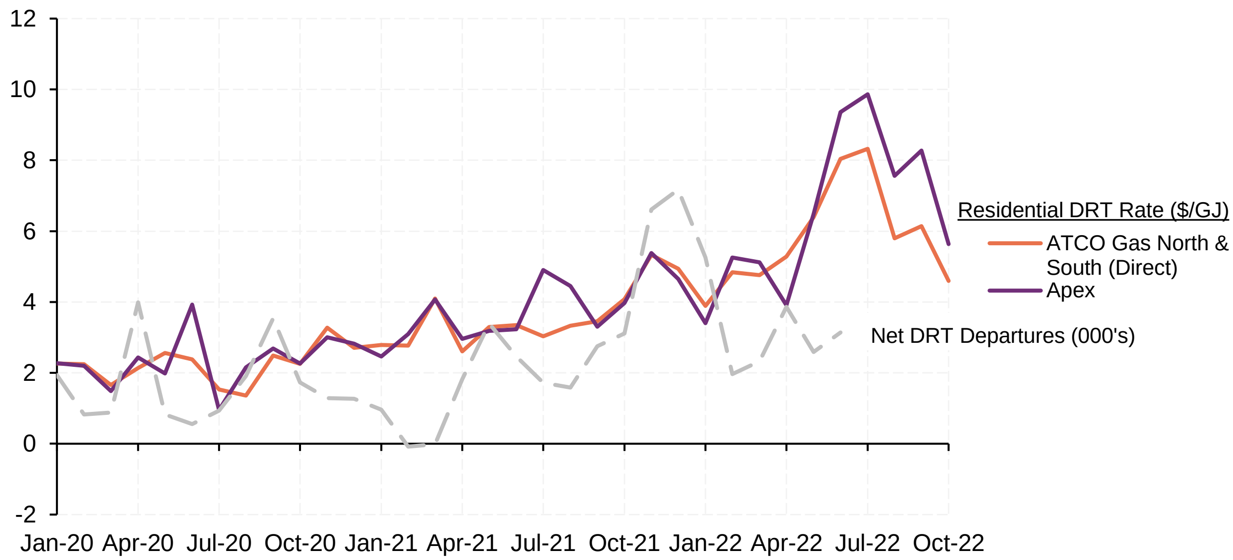


Figure 76: Residential DRT rates vs. DRT customer net losses

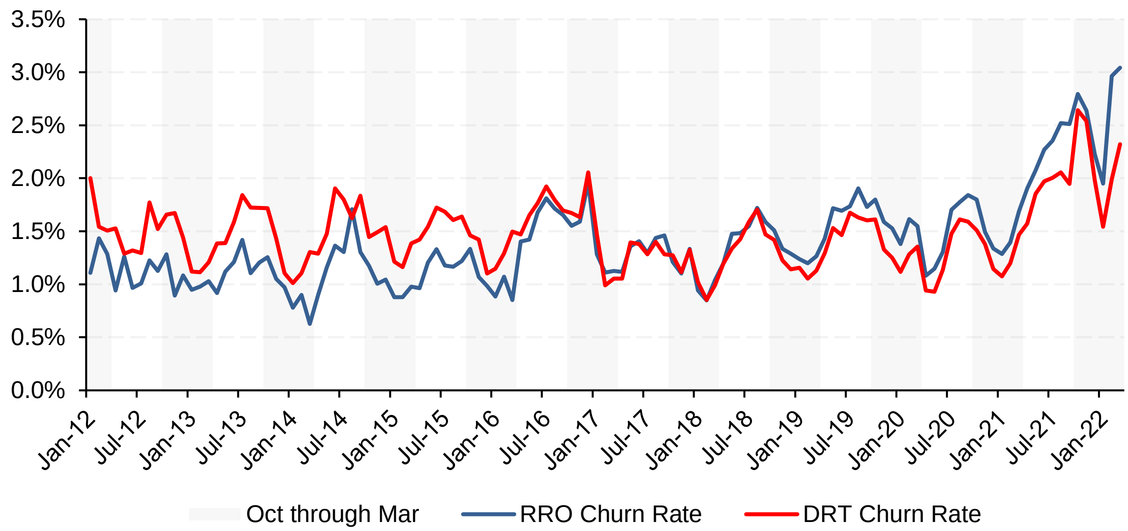


The MSA conducted a preliminary econometric analysis to assess the determinates of RRO and DRT churn. In the long run, regulated and competitive rates are found to significantly affect regulated customer losses, while the effects of bills appear to be insignificant. The significance of rates, as opposed to bills, suggests that customers are more responsive to the direct price of energy than their monthly energy bill costs. These findings are consistent across RRO and DRT customers. Discussion of the regression methodology and results can be found in Appendix A of this report.

In the short-run, a significant relationship was found between residential property moving and RRO customers losses. This finding is unsurprising, as the process of moving to a new property may spur interest in alternative retail options for regulated customers. For DRT customers in the short-run, the month-over-month change in competitive natural gas rates from two months prior was related to an increase in DRT customer losses; this suggests that a portion of DRT customers may hear about a recent competitive rate increase after its billing period and, in response, anticipate rate increases to continue.

Seasonal effects were also found to be drivers of retail switching in the short-run. Customer losses generally decrease materially during the fall and winter, before rising in the spring and peaking in the summer (Figure 77). Forces driving this seasonality are unobservable and are not explicitly controlled for in this analysis. Possible explanations for decreased customer losses in the fall and winter include scarcity of customer attention during the holidays and fear of being cut off by a competitive retailer during cold weather.

Figure 77: Seasonality of RRO and DRT churn, January 2012 to March 2022



In the long run there is a significant relationship between energy rates and regulated customer losses. For RRO customers, increases in RRO rates are correlated with increased customer losses, as expected. A significant relationship between RRO customer losses and competitive electricity was not confirmed. These results suggest that regulated customers decide to leave the RRO in response to increased RRO rates, but not in response to observed decreases in competitive alternatives. The relationship between residential property moving and RRO losses remains significant in the long-run.

For DRT customers, the RRO rate was found to be a significant driver of monthly customer losses, while the effect of DRT rates on losses could not be confirmed. The effect of the RRO rate on DRT losses may suggest that a large portion of regulated gas customers are also tied to the RRO. These customers may consider competitive alternatives in response to high electricity rates and ultimately decide to sign dual-fuel competitive contracts when leaving their regulated providers. Unexpectedly, the effect of competitive gas rates on DRT customer losses are estimated to be positive: an increase in competitive natural gas rates corresponds to more regulated customers signing onto competitive contracts.

Figure 78: RRO and DRT customer losses vs. RRO Rate

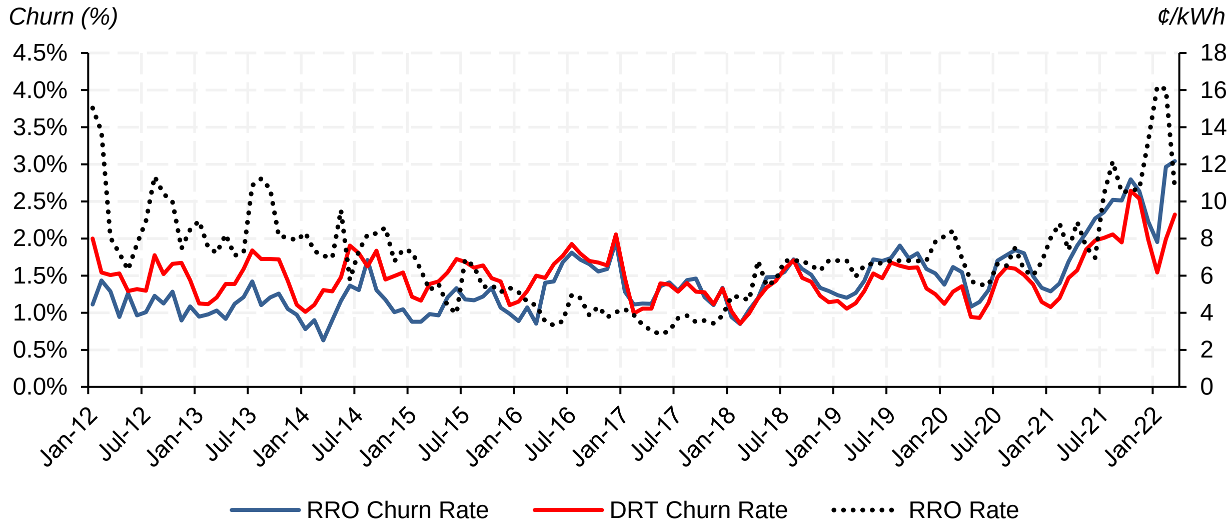
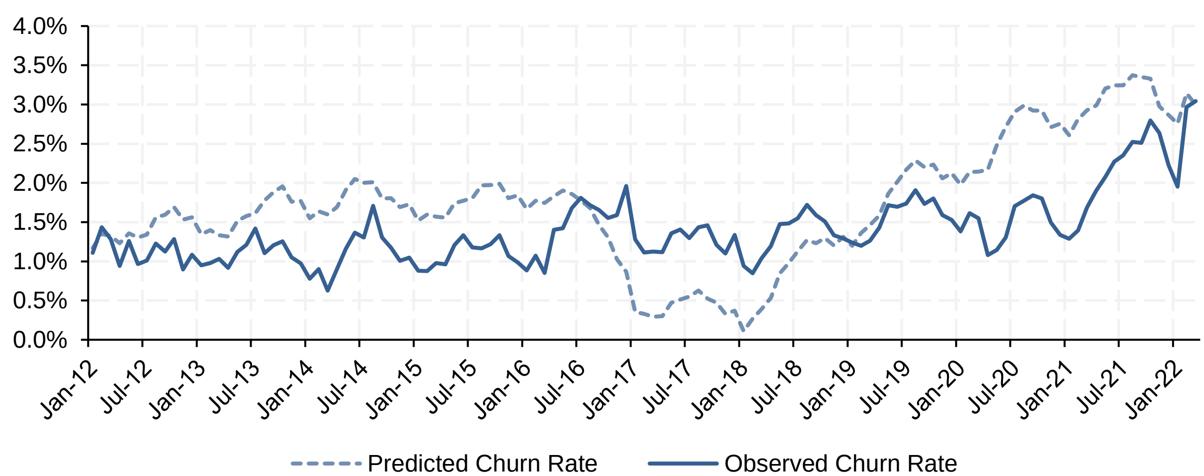


Figure 79 and Figure 80 show the observed churn rates for RRO and DRT[40] and the predicted RRO and DRT rates derived from the MSA's model. There are two periods where the trends vary significantly: from mid-2016 to early 2019, as well as from early 2019 to January 2022. The predicted and observed values in both figures begin to converge in January 2022.

Figure 79: RRO churn rate, observed and predicted, January 2012 to March 2022



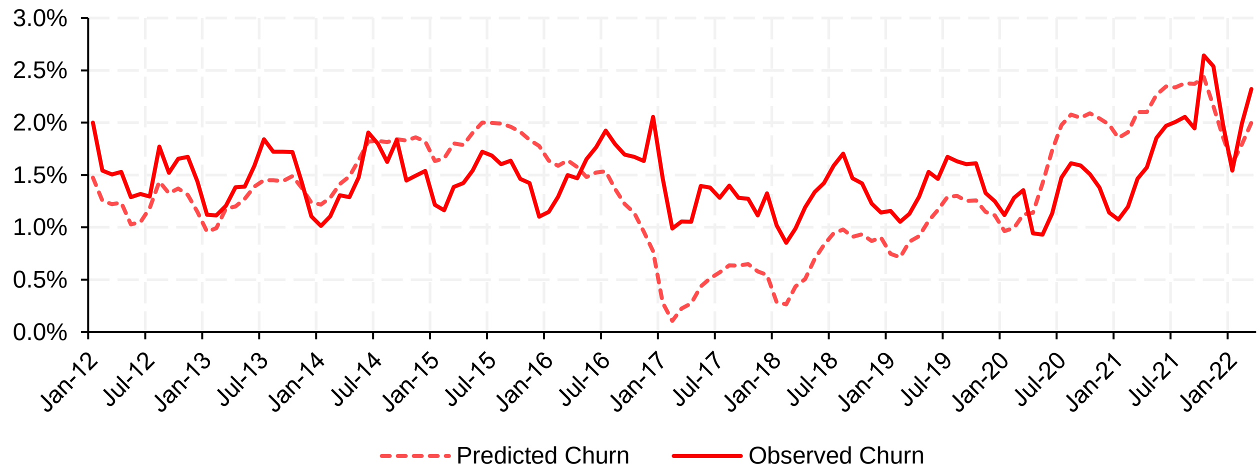
In November 2016, a province wide RRO rate cap of 6.8 ¢/kWh was announced.[41] The rate cap did not bind until April 2018 and continued to bind for most months until the rate cap expired in December 2019. Relatively low RRO rates during this period would be expected to decrease RRO

[40] Supplemental Retail Market Report for Q2 2022, August 12, 2022.

[41] Q2/17 Quarterly Report, August 11, 2017.

losses. The consistent trend of observed RRO churn during this period implies that some uncontrolled-for effects drove churn while the rate cap was in effect. The spread between observed and predicted churn from January 2020 to July 2021 is likely a product of the COVID-19 pandemic and later increases in natural gas prices. High natural gas prices during the pandemic resulted in increased regulated natural gas rates, increasing monthly churn.

Figure 80: DRT churn rate, observed and predicted, January 2012 to March 2022



The findings of the analysis show that regulated retail customers respond to regulated and competitive energy prices in the long run. This indicates a functioning retail market as regulated customers are incentivized to switch to competitive retailers when they observe a long run increase in the regulated energy costs. Regulated customers do not weigh the cost of electricity and natural gas equally, however. Both RRO and DRT customers are more responsive to regulated electricity rates than they are to natural gas rates, suggesting that regulated customers prefer to sign onto competitive dual-fuel contracts after leaving their regulated retailer in response to increased electricity prices. Long-term changes in the RRO are also expected to impact both RRO and DRT losses, while the effects of the DRT rate on regulated losses may be insignificant.

The MSA plans to revisit and refine this econometric analysis in the future. Feedback from interested parties is welcome.

4.3 Competitive retail

Competitive retail customers typically have access to fixed and variable energy rates. Fixed rates are energy rates that are fixed over a defined contract term, usually one, three or five years. Variable rates are energy rates that vary each month and can be tied to monthly pool prices or regulated rates.

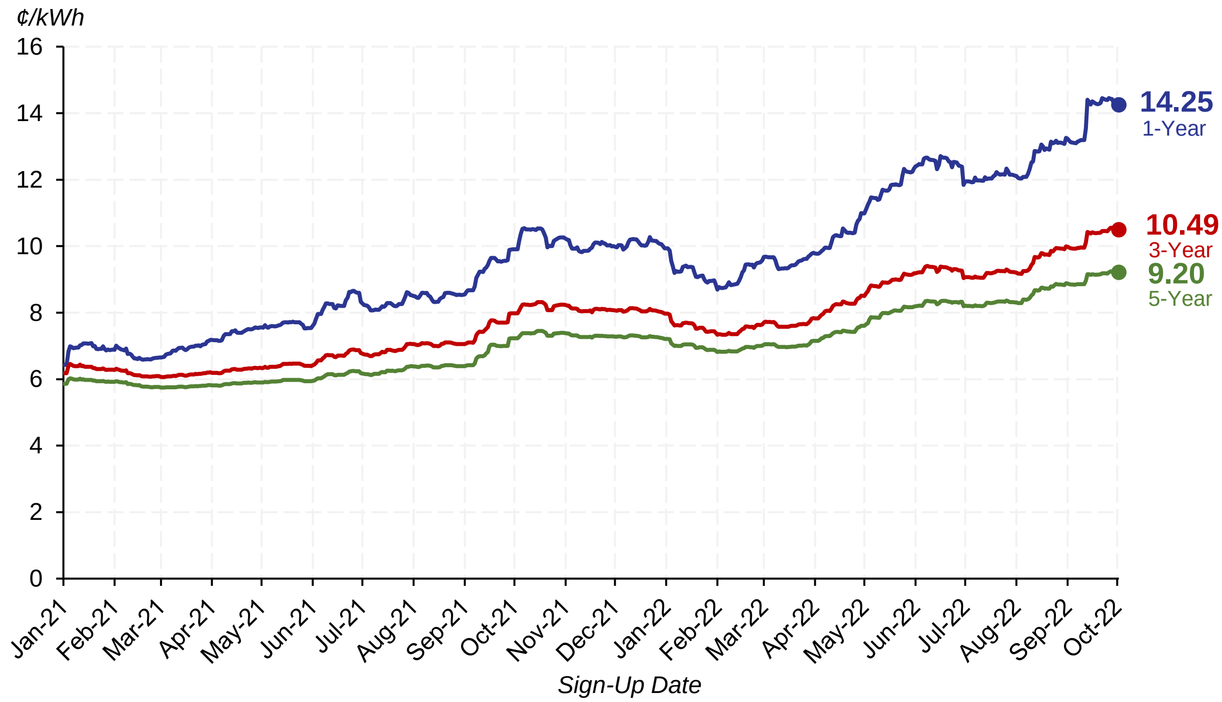
4.3.1 Fixed rate contracts

A retailer offering a fixed rate to customers would expect to face energy costs associated with that customer's consumption over the length of the contract term. In the long-run, competitive fixed rate prices would be expected to respond to changes in the expected cost of fixed rate contracts as retailers compete away any (expected) positive margins or alter their fixed rates to avoid negative margins.

Expected costs for both fixed rate electricity (Figure 81) and natural gas (Figure 82) contracts rose in Q3 2022, continuing the trend of expected cost increases since 2021.

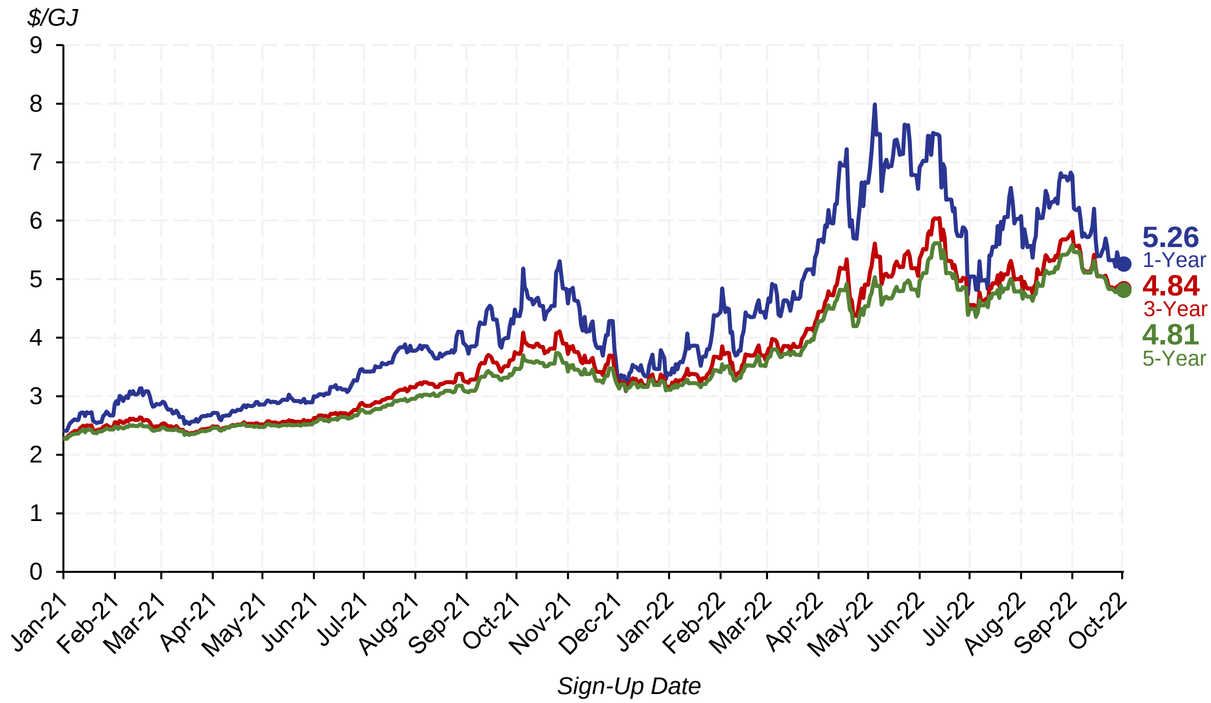
Expected costs for fixed rate electricity contracts increased more than those for natural gas contracts, with the expected cost of a 1-year contract rising to 14.25 ¢/kWh by October 2, a 2.30 ¢/kWh increase since the beginning of the quarter. The expected costs for longer-term 3 and 5-year contracts increased by more moderate amounts of 1.42 ¢/kWh and 1.00 ¢/kWh respectively. This difference in expected cost changes between different contracts is a result of the much greater appreciation of near-term forward prices when compared to longer term forward prices.

Figure 81: Expected cost, fixed rate electricity contract (residential customer), January 1, 2021 to October 2, 2022



High variability in natural gas futures prices drove significant variation in the expected cost of natural gas fixed rates over Q3 2022. Such periods of high variability were also observed in the previous quarter and in late 2021. Despite varying by $2.00/GJ over the quarter, the expected cost of a 1-year natural gas contract only increased by $0.21/GJ between July 1 and October 2, less than the increase in the expected cost of 3-year (+$0.28/GJ) and 5-year (+$0.32/GJ) contracts, which had lower variance throughout the quarter.

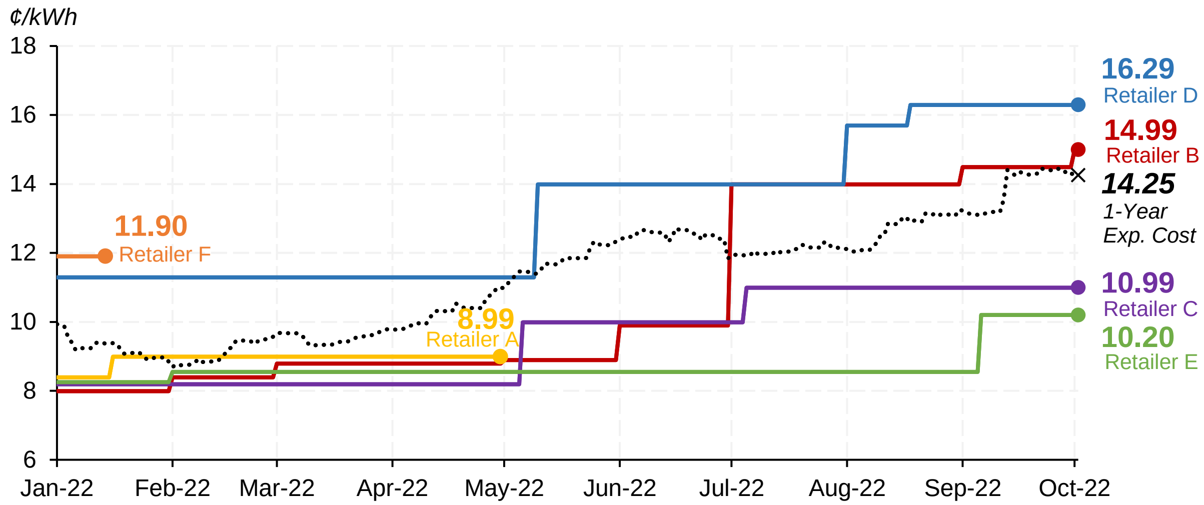
Figure 82: Expected cost, fixed rate natural gas contract (residential customer), January 1, 2021 to October 2, 2022

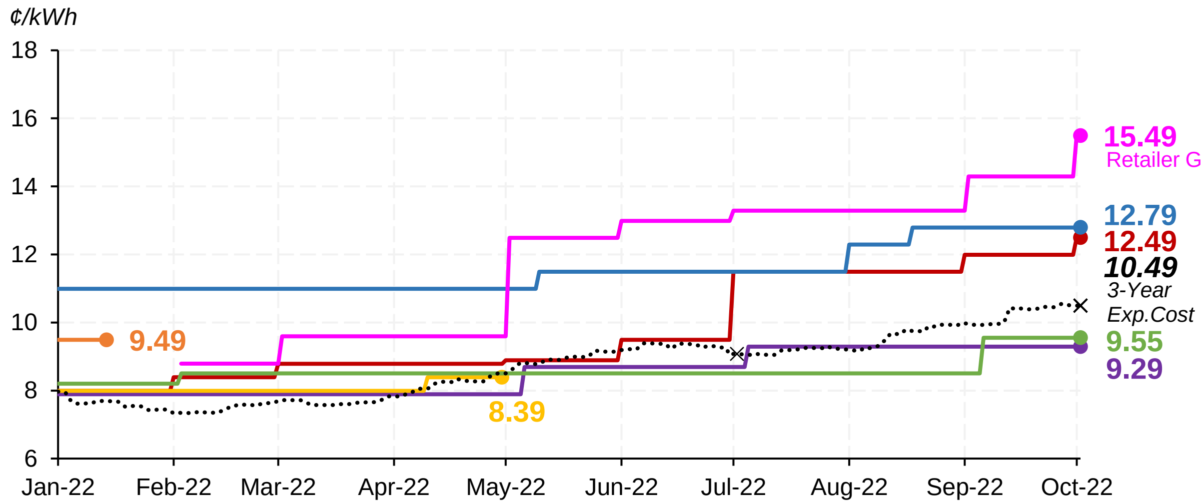


Competitive fixed rates continued to increase over Q3 2022 (Figure 83). With only a single exception (Retailer A's 5-year fixed rate offering), all major retailers increased each of their 1, 3, and 5-year fixed rate prices at least once over the quarter. Despite increases in the expected cost of electricity contracts over the quarter, many retailers increased their fixed rate prices enough to offset the increased expected cost. Those retailers that did not may be significantly hedged in either the forward or energy markets.

Some retailers also increased their fixed rate natural gas prices over Q3 2022, although such increases were typically smaller than increases in fixed rate electricity prices (Figure 84). Notably, two retailers lowered some of their natural gas fixed rates in the quarter (Retailer D and H), possibly to be more competitive as these rates had been previously in excess of expected cost.

Figure 83: 1, 3, 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (January 1, 2022 to October 2, 2022)





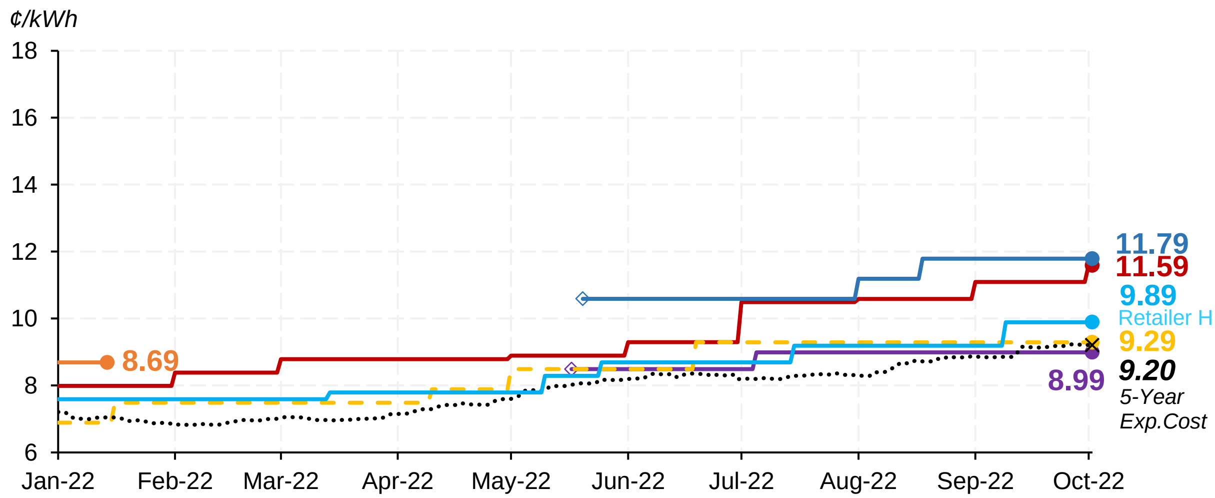
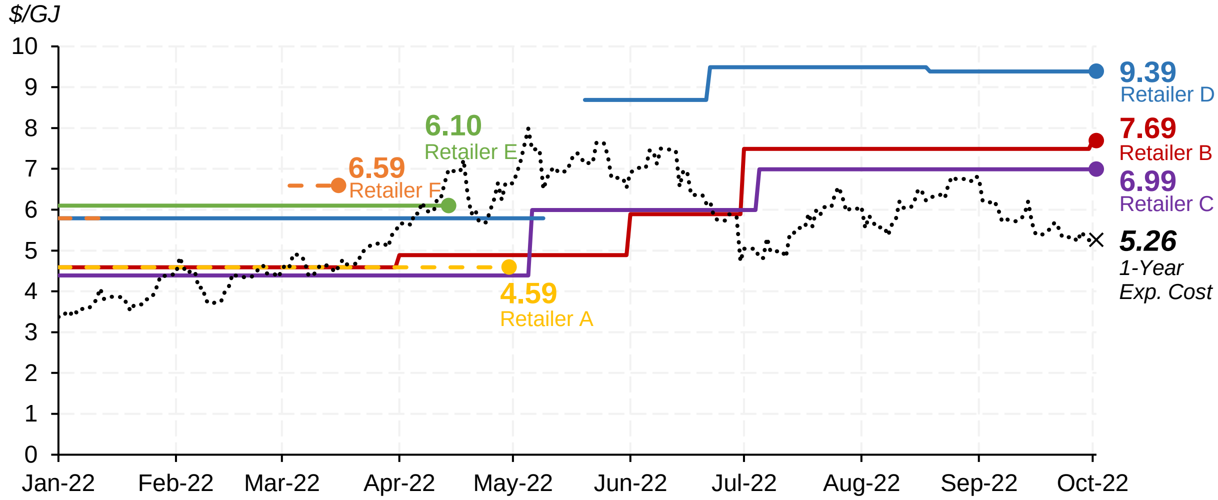
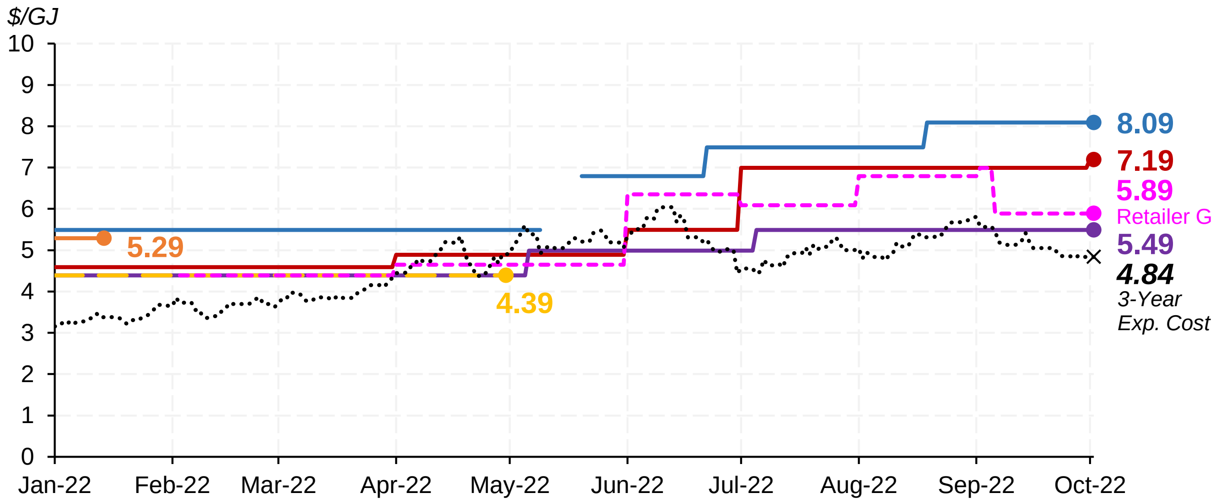
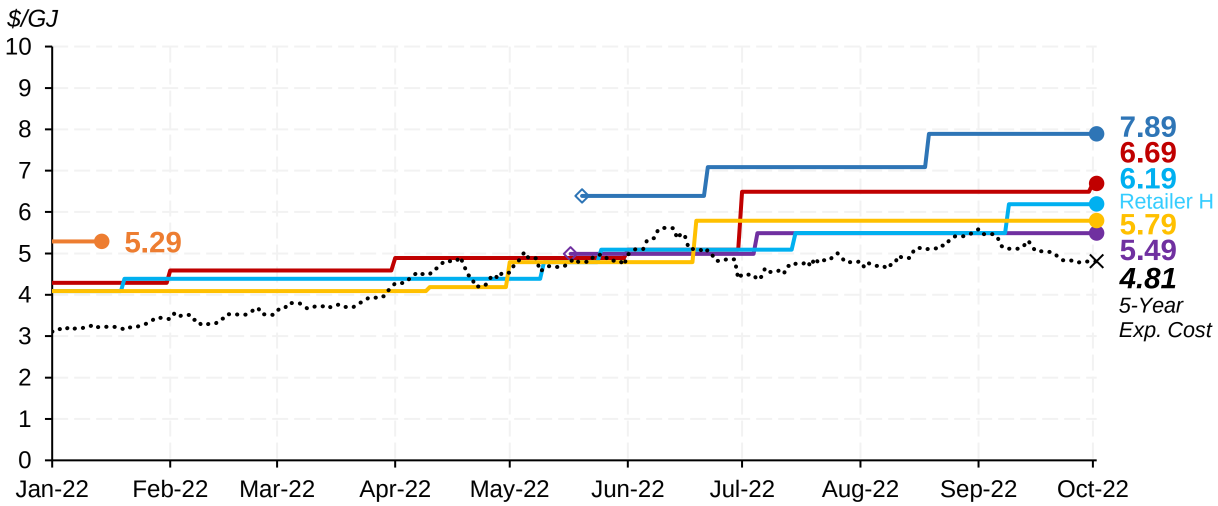


Figure 84: 1, 3, 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (January 1, 2022 to October 2, 2022)



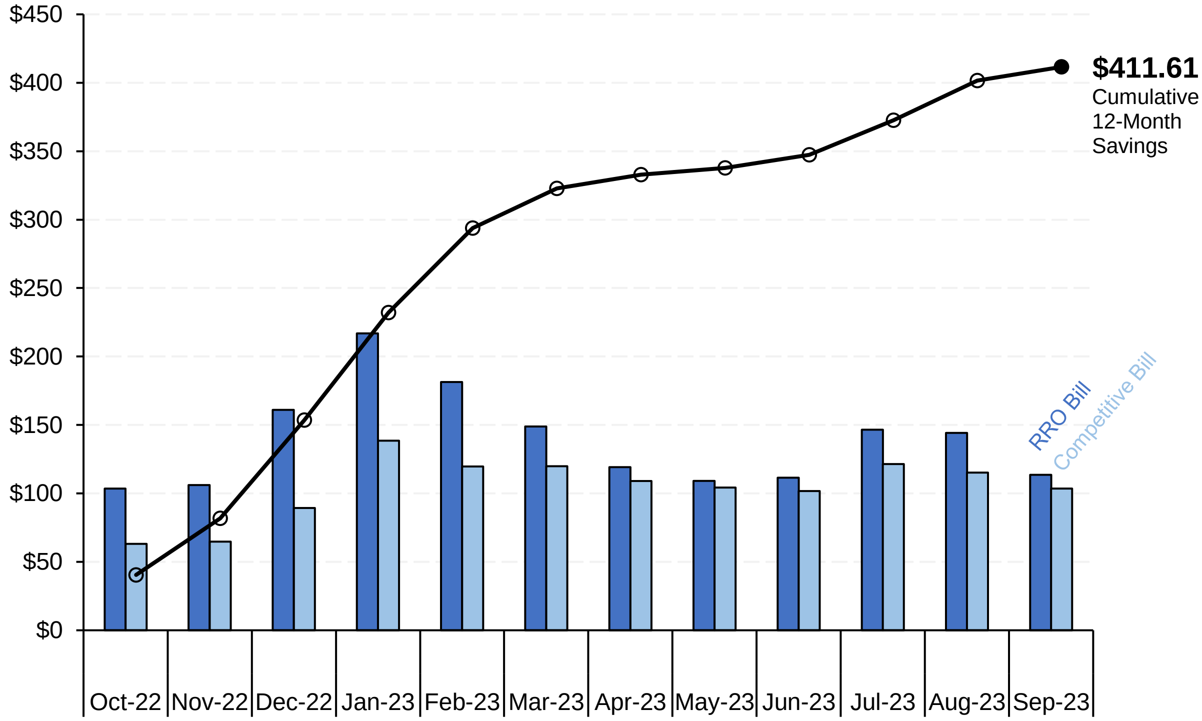




4.3.2 Fixed rate switching incentives

Residential regulated retail customers continue to face strong incentives to switch to competitive fixed electricity rates given RRO rate expectations over the next year (Figure 85). Had an average residential RRO customer switched to the lowest 3-year electricity rate in Figure 83 above on October 1, 2022, they would save more than $400 in the following 12 months.

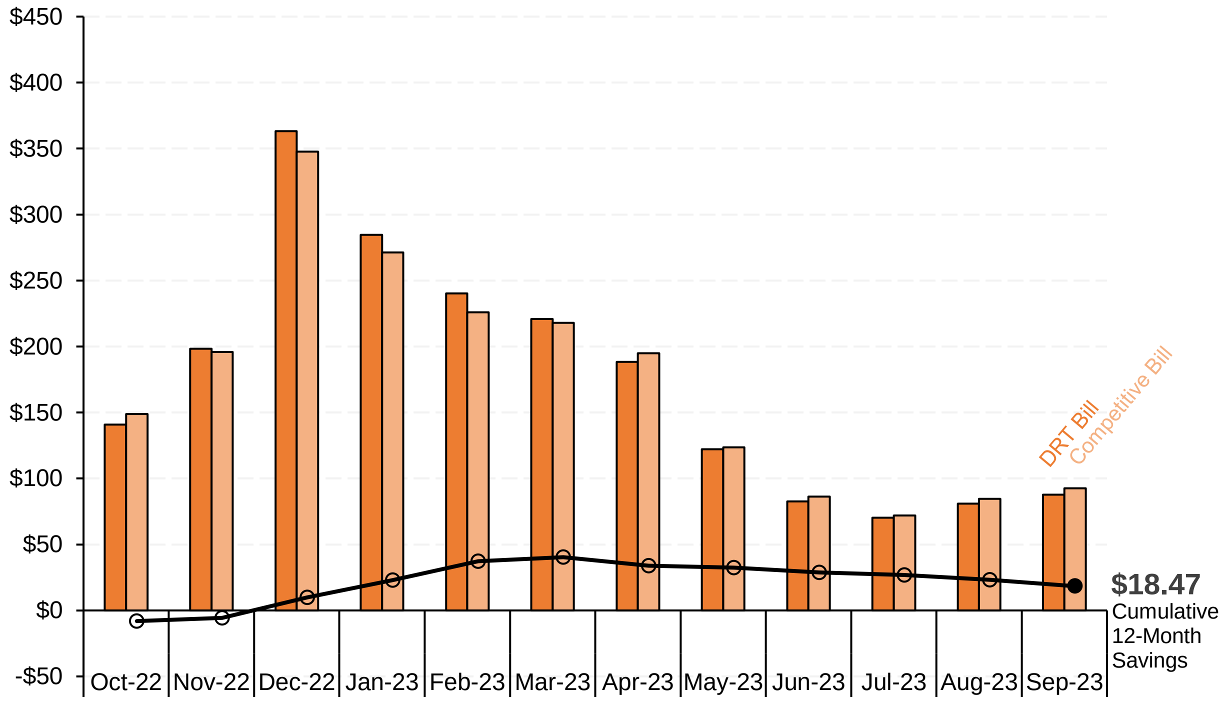
Figure 85: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at 9.29 ¢/kWh, $8.99/month)[42]



Residential regulated natural gas customers continue to have fewer incentives to switch to competitive natural gas rates relative to regulated electricity customers. If an average residential DRT customer had switched to the lowest 3-year natural gas rate in Figure 84 above on October 1, 2022, they would only be expected to save around $18 in the 12 months that follow (Figure 86).

[42] Estimated bills for a residential customer in the ENMAX service area over the October 2022 to September 2023 period.

Figure 86: Expected DRT bill vs. competitive natural gas bill (3-year fixed rate at $4.99/GJ, $6.99/month)[43]



This discrepancy in regulated switching incentives at the beginning of Q4 2022 has continued since the start of Q3 (Table 16), where both regulated electricity and natural gas customers had similar incentives to switch to competitive fixed rates (or lack thereof).

Table 16: Average 12-month expected monthly bill savings by competitive switch date (3-year fixed rates)[44]

Switch Date	Electricity	Natural Gas
April 1, 2022	$23.11	$22.64
July 1, 2022	$31.72	$4.06
October 1, 2022	$34.30	$1.54

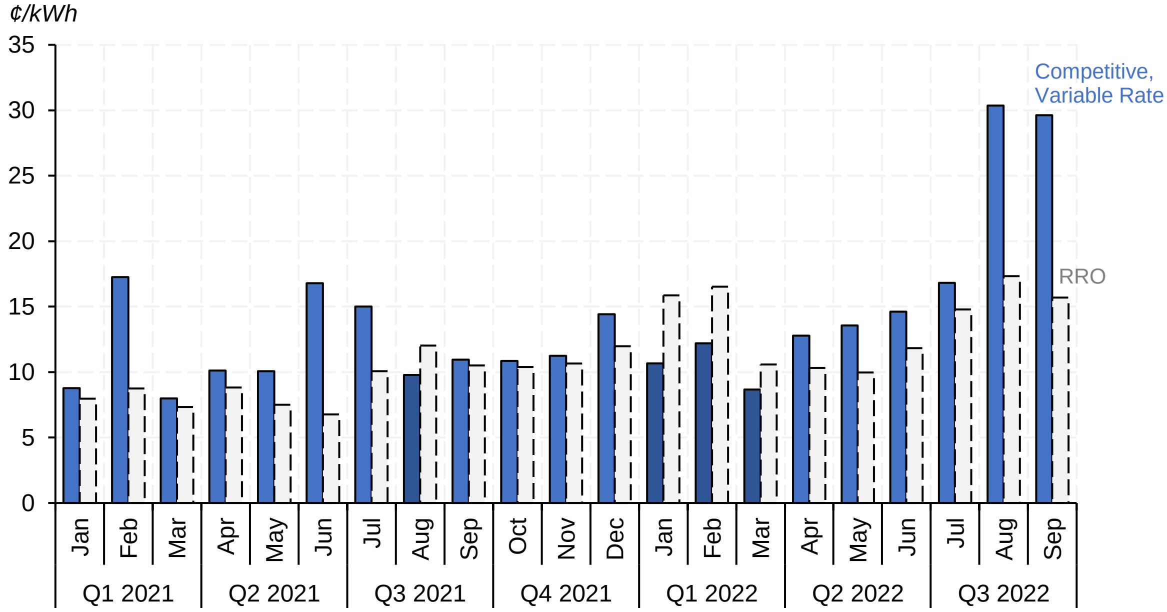
[43] Estimated bills for a residential customer in the ATCO Gas South service area over the October 2022 to September 2023 period.

[44] Assumes a residential customer switches to 3-year fixed rates on the switch date. Monthly savings from April and July switch dates assume the customer switches to the lowest available 3-year rates among rate offerings identified in Figure 83 and Figure 84.

4.3.3 Variable rates[45]

Competitive variable rates faced by residential electricity customers increased in Q3 2022. In August and September, residential customers faced variable rates in excess of 30 ¢/kWh in each of the two months (Figure 87). While competitive variable rates exceeded RRO rates in most months since 2021, the difference between the two peaked in Q3 2022.

Figure 87: Estimated competitive variable electricity rates vs. RRO, residential customers, ENMAX service area (Q1 2021 to Q3 2022)[46]



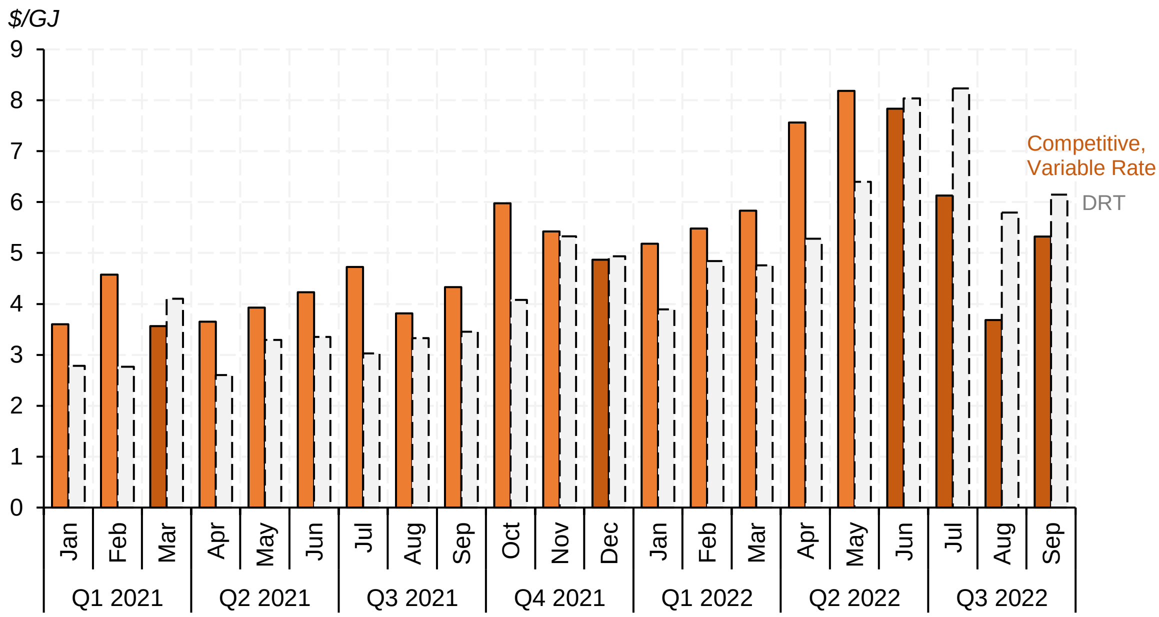
Competitive variable natural gas rates were lower than the DRT throughout Q3 2022, as they previously did in June 2022 (Figure 88). This apparent trend may be partially a result of the deferral of some of the May 2022 DRT revenue requirement, which was collected from customers from June through September and inflated DRT rates in these months.[47]

[45] For the purposes of this section, "variable rates" refers to competitive rates that vary on a monthly basis that are tied to pool prices, not regulated rates.

[46] Competitive variable electricity rates calculated as residential load-shaped pool price; includes a 1 ¢/kWh adder.

[47] See https://www.albertamsa.ca/assets/Documents/Supplemental-Retail-Market-Report-for-Q2-2022.pdf, PDF Page 34.

Figure 88: Estimated competitive variable natural gas rates vs. DRT, residential customers, ATCO Gas South service area (Q1 2021 to Q3 2022)[48]



4.4 Regulated retail rates

4.4.1 Electricity estimates

In its Supplemental Retail Market Report for Q2 2022 the MSA released RRO estimates for residential customers based on forward market data available as of July 6, 2022.[49] Increases in near-term forward prices since July resulted in increases in expected RRO rates over the winter 2022/23 period and smaller increases in RRO rates expected over the spring through fall of 2023 (Figure 89).

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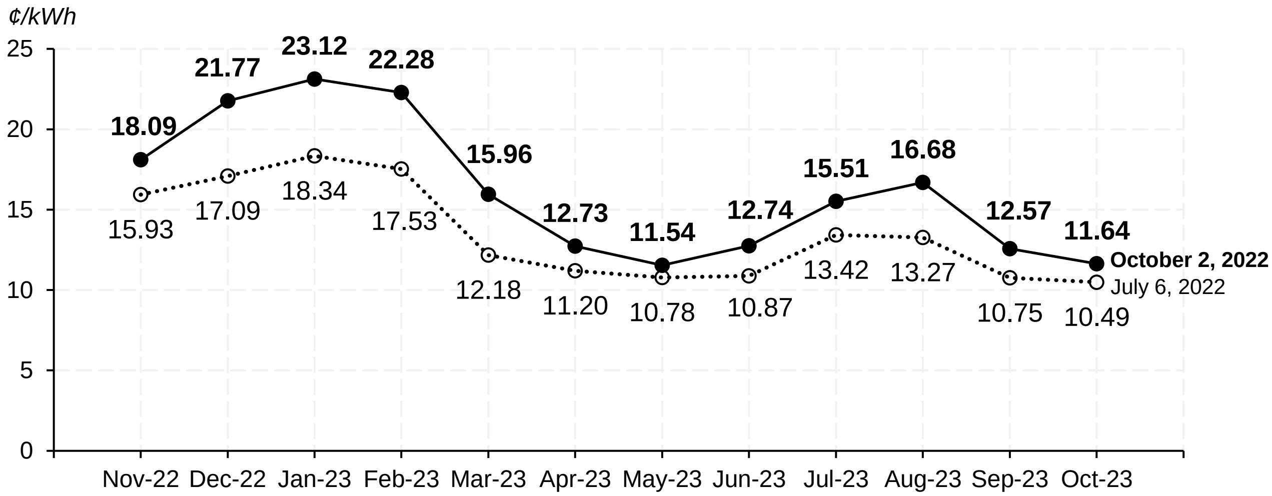
[48] Competitive variable natura gas rates calculated using the daily gas index; includes a $1/GJ adder.

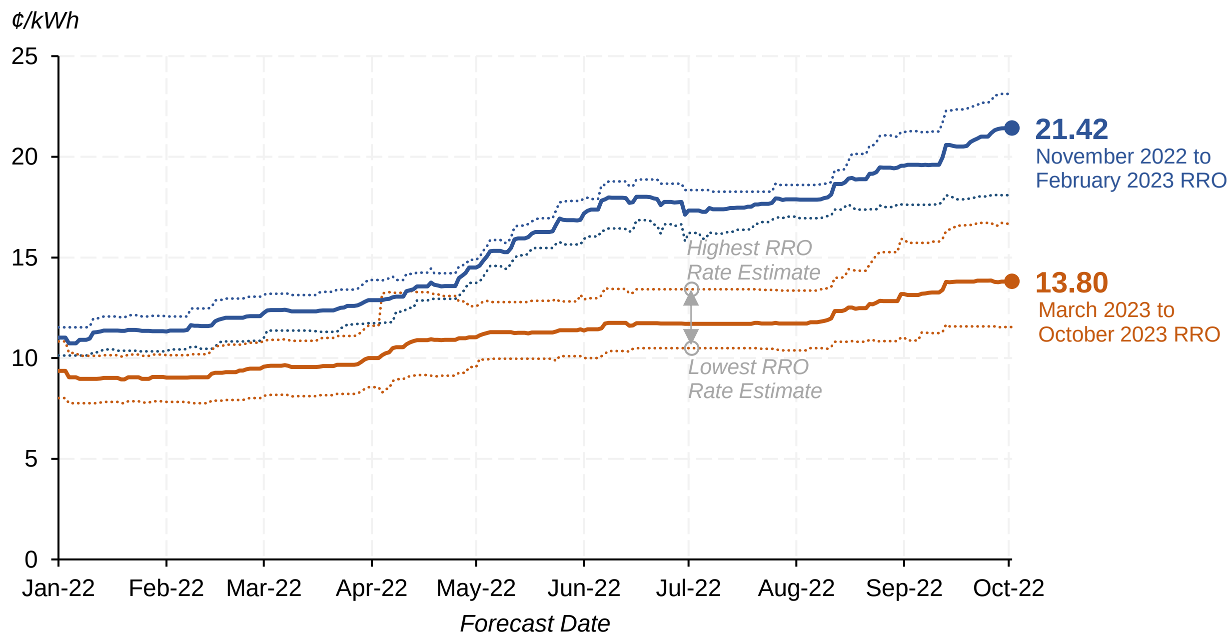
[49] https://www.albertamsa.ca/assets/Documents/Supplemental-Retail-Market-Report-for-Q2-2022.pdf

Figure 89: November 2022 to October 2023 residential RRO estimates (EPCOR service area), estimates as of July 6 vs. October 2, 2022



Residential RRO rates expected over the winter 2022/23 period have increased considerably since the beginning of the year (Figure 90). On January 1, 2022 an RRO customer could expect to pay a consumption-weighted average RRO rate of 11.03 ¢/kWh between November 2022 through February 2023 period. By October 2, the RRO customer could expect to pay 21.42 ¢/kWh over the same period. Additionally, the range of RRO rates expected over the winter period also increased significantly, from around 1.40 ¢/kWh in early January to 5.04 ¢/kWh.

Figure 90: Evolution of weighted-average expected RRO rate by range of delivery months (EPCOR service area), January 1, 2022 to October 2, 2022



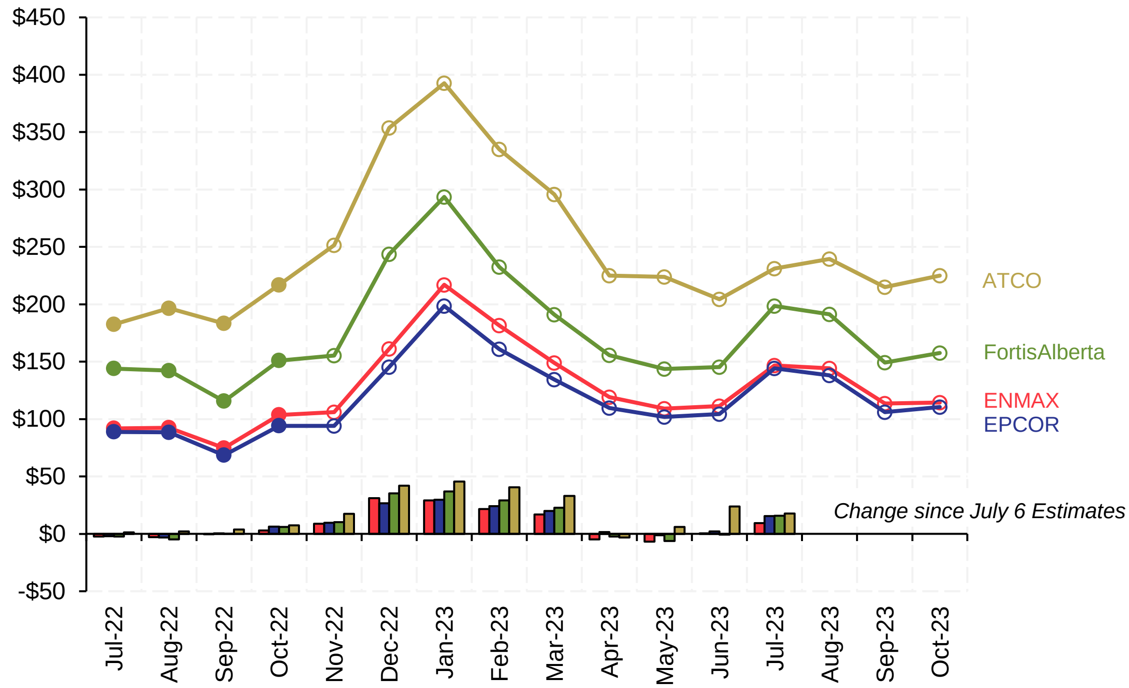
The MSA expects residential RRO estimates will be similar across service areas over the November 2022 to October 2023 period (Table 17). Differences in RRO rate estimates reflect both differences in RRO auction timing between RRO providers and differences in load shape patterns for residential customers in different service areas.

Table 17: November 2022 to October 2023 residential RRO estimates by service area (RRO provider) as of October 2, 2022

	ENMAX	**EPCOR**	**FortisAlberta (EPCOR)**	**ATCO (Direct)**
Nov-22	18.00	18.09	17.78	17.34
Dec-22	21.00	21.77	21.45	21.64
Jan-23	23.10	23.12	22.77	23.39
Feb-23	22.35	22.28	21.91	23.29
Mar-23	15.48	15.96	15.72	16.24
Apr-23	12.04	12.73	12.51	12.22
May-23	10.97	11.54	11.37	10.92
Jun-23	12.23	12.74	12.57	11.65
Jul-23	14.60	15.51	15.30	14.19
Aug-23	15.86	16.68	16.45	15.63
Sep-23	12.22	12.57	12.37	11.79
Oct-23	10.96	11.64	11.44	11.15

Higher expected RRO rates over the winter 2022/23 period may significantly increase monthly RRO bills relative to those the MSA previously estimated (Figure 91). The impact of the increase in expected RRO rates may disproportionately impact rural customers with comparatively high electricity consumption.

Figure 91: Expected residential RRO bills by service area as of October 2, 2022[50]



Between January and June 2022, residential RRO customers faced higher monthly electricity bills than in the previous year (Figure 92). RRO bills generally fell year-over-year in Q3 2022 as the $50/month electricity bill rebate blunted the billing impact of higher year-over-year RRO rates. With this rebate ending at the end of December and higher RRO rates expected on a year-over-year basis over the winter period, RRO customers may face large year-over-year electricity bill increases in the new year (Figure 93).

[50] Bill estimates include the effect of the $50 bill rebate over the July to December 2022 period.

Figure 92: Residential RRO bills by month, January 2020 to October 2022

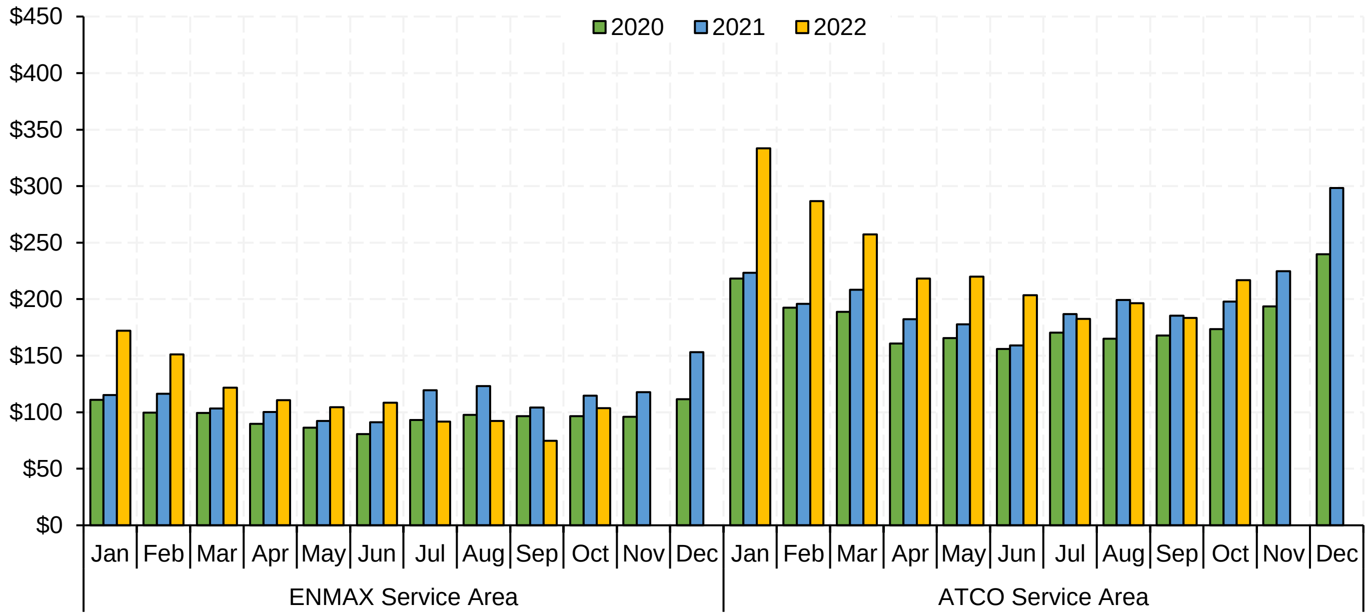
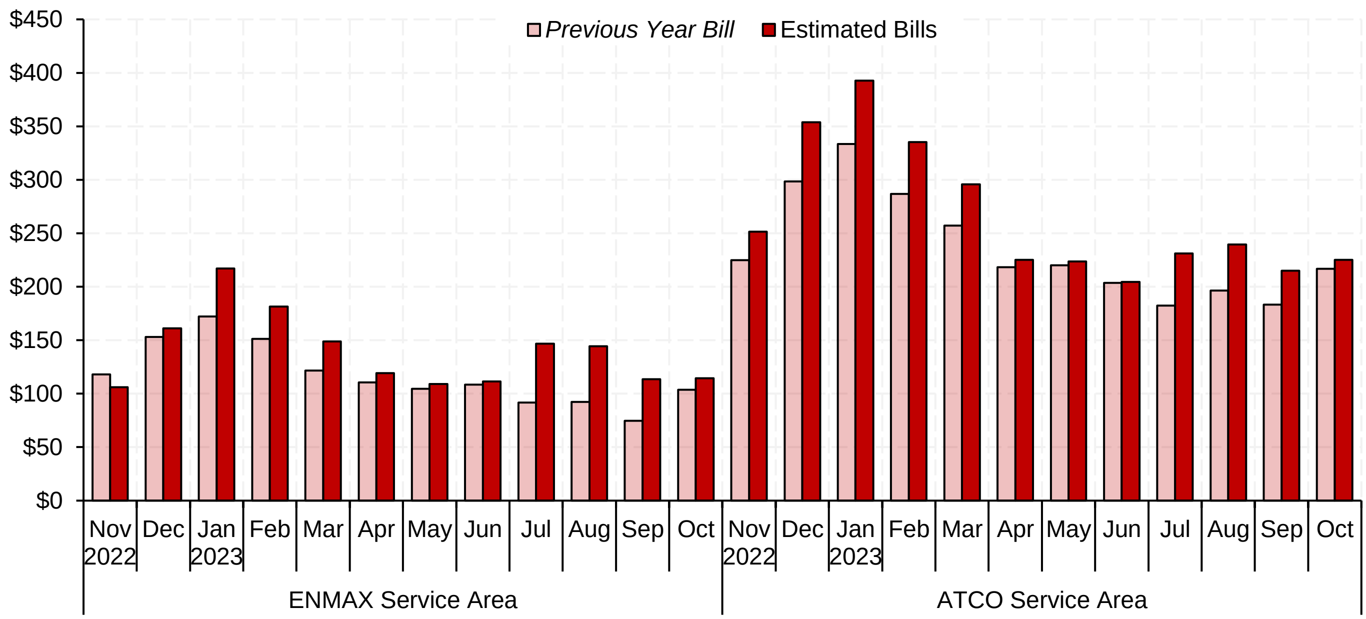


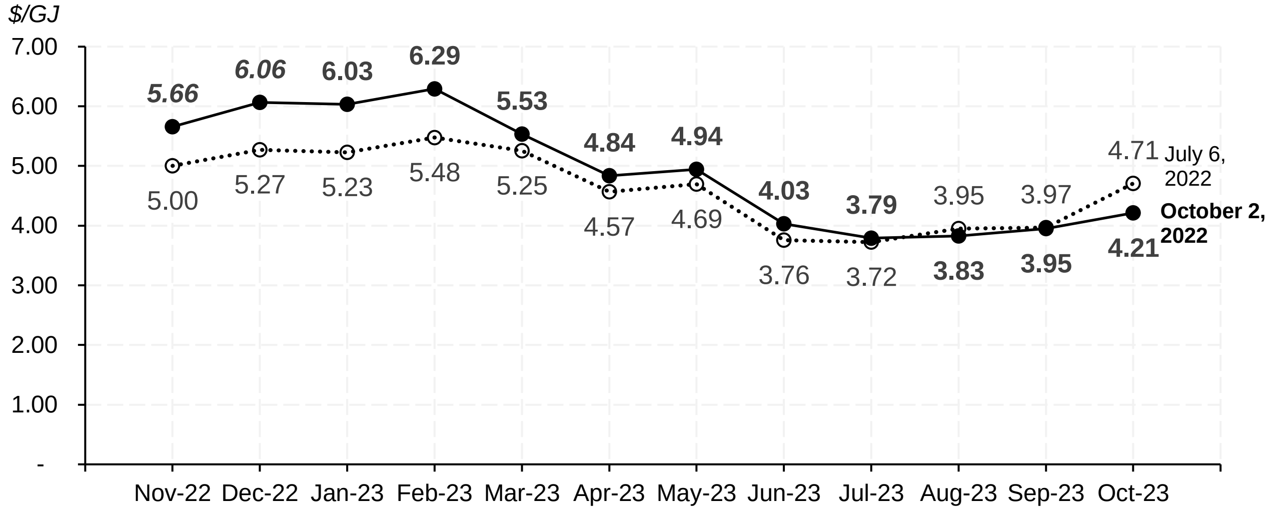
Figure 93: Expected residential RRO bills by month as of October 2, 2022



4.4.2 Natural gas estimates

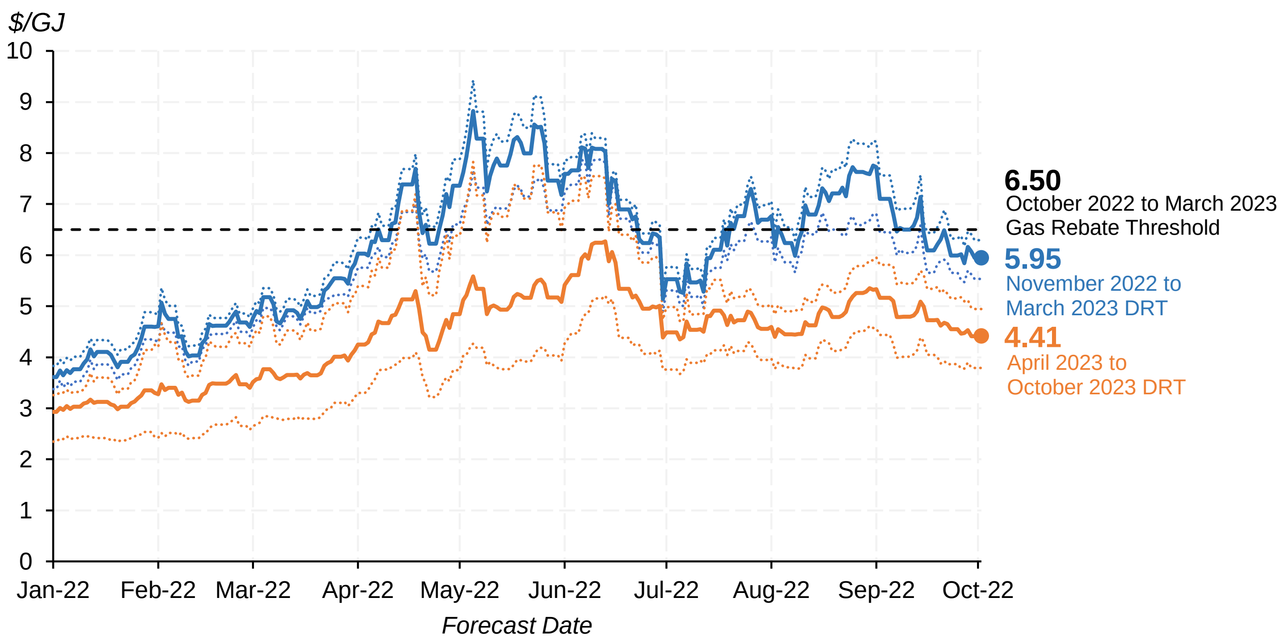
Expected DRT rates over the winter 2022/23 period (November to March) have increased moderately since the MSA's prior forecast taken on July 6, 2022 (Figure 94). DRT rates are expected to fall by between $1/GJ to $2/GJ over the spring through fall of 2023.

Figure 94: November 2022 to October 2023 residential DRT estimates (ATCO Gas service areas), estimates as of July 6 vs. October 2, 2022



Despite the small increase in the expected winter DRT rates compared to DRT estimates taken on July 6 and October 2, there was still considerable variation in winter DRT rate estimates over Q3 2022 (Figure 95). Although all DRT rates expected for winter as of October 2 are below the $6.50/GJ gas rebate threshold, the variability in DRT rate expectations over Q3 indicates the possibility of some winter DRT rates exceeding the gas rebate threshold should not be ruled out.

Figure 95: Evolution of weighted-average expected DRT rate by range of delivery months, ATCO Gas South service areas, January 1, 2022 to October 2, 2022



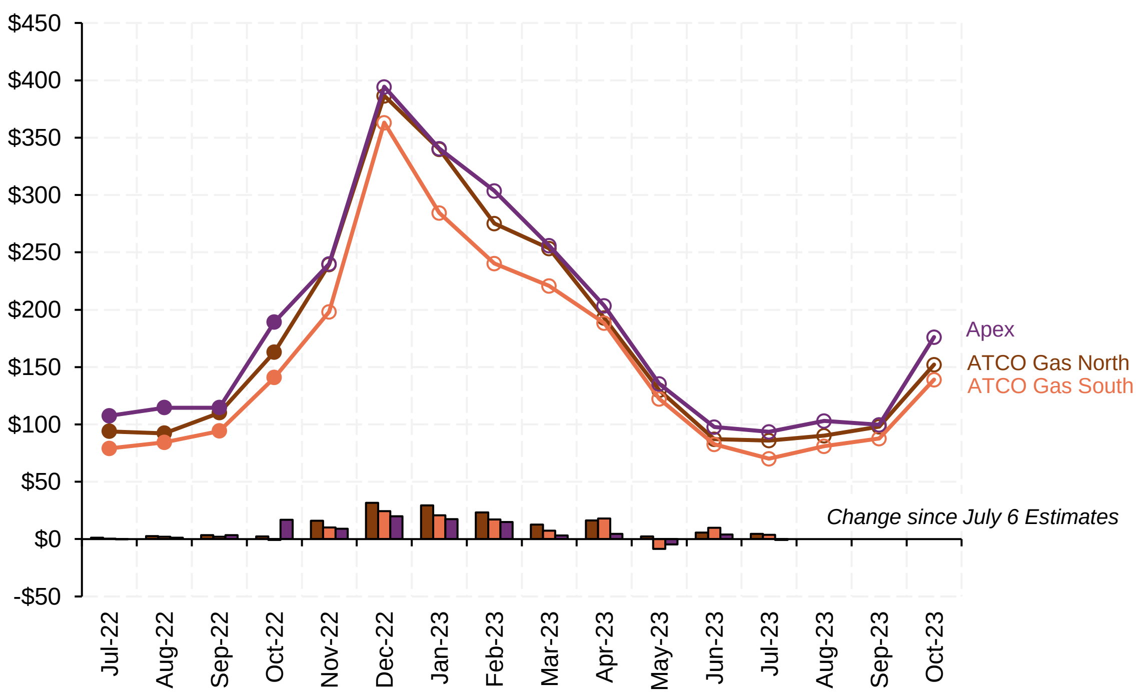
DRT rates for both major DRT providers are expected to be similar over the next twelve months (Table 18).

Table 18: November 2022 to October 2023 residential DRT estimates by service area (DRT provider) as of October 2, 2022

	ATCO Gas (Direct)	Apex
Nov-22	5.66	5.51
Dec-22	6.06	6.04
Jan-23	6.03	5.67
Feb-23	6.29	6.22
Mar-23	5.53	5.59
Apr-23	4.84	4.89
May-23	4.94	5.19
Jun-23	4.03	5.65
Jul-23	3.79	4.71
Aug-23	3.83	4.35
Sep-23	3.95	3.89
Oct-23	4.21	4.32

Small increases in DRT rates over the winter period increased the MSA's expectations of winter DRT bills (Figure 96).

Figure 96: Expected residential DRT bills by service area as of October 2, 2022



Residential DRT bills have generally increased on a year-over-year basis since 2021, with the largest bill increases occurring in high-consumption winter periods (Figure 97). This trend is expected to continue over the winter of 2022/23, after which DRT bills are expected to moderately decline (year-over-year) in the summer of 2023 (Figure 98).

Figure 97: Residential DRT bills by month, January 2020 to October 2022

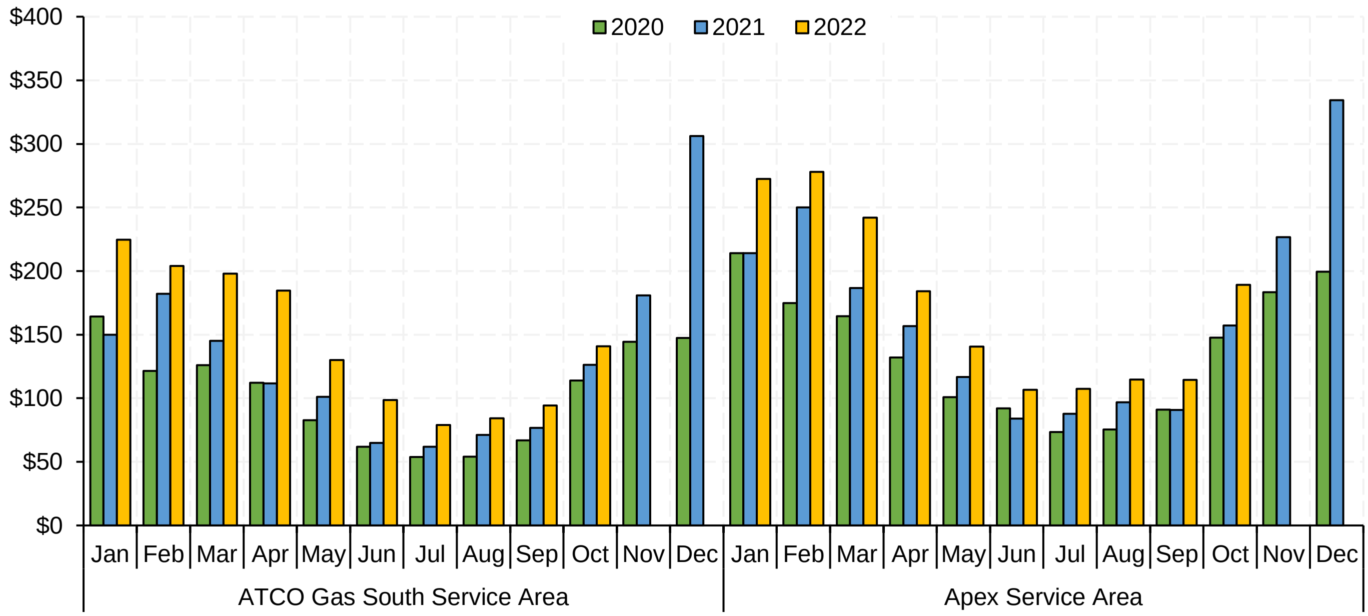
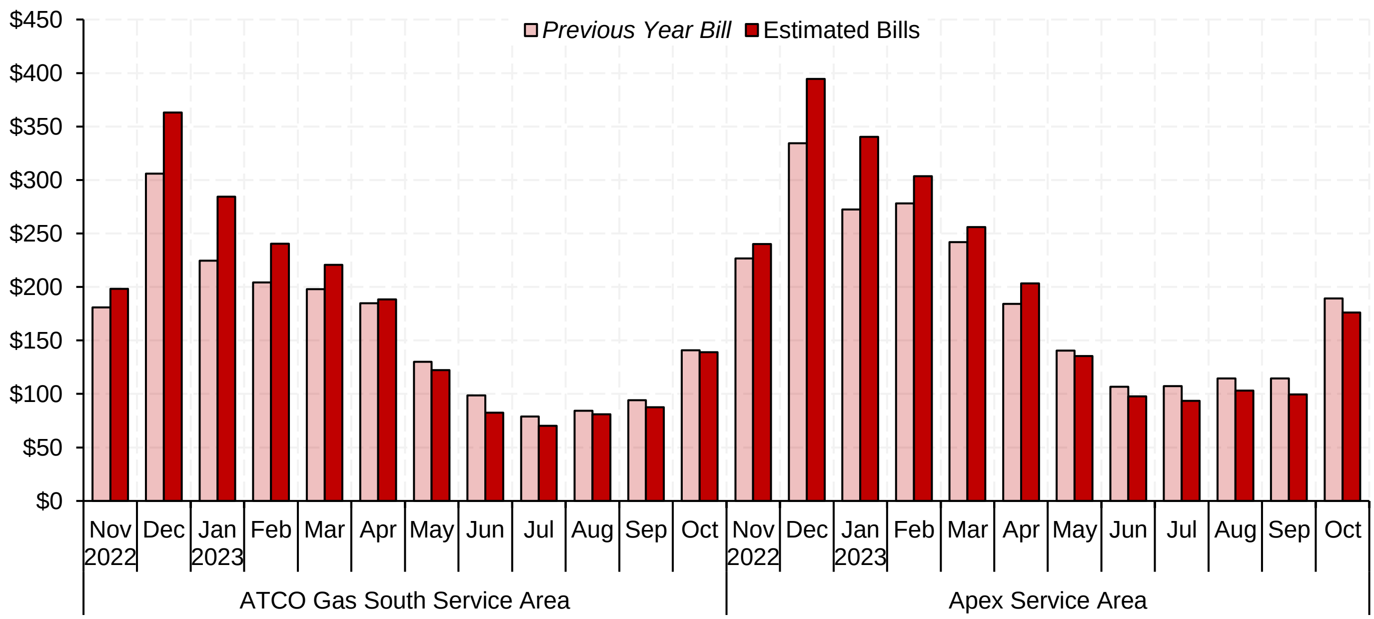


Figure 98: Expected residential DRT bills by month as of October 2, 2022



5 ENFORCEMENT AND REGULATORY MATTERS

5.1 Renewable Electricity Program (REP) Update

The AESO developed the Renewable Electricity Program (REP) in 2016 following a direction[51] from the Government of Alberta (GoA) to develop and implement a program to bring on new renewable generation capacity. Ultimately, the AESO conducted three rounds of renewable generation procurement through the REP: REP 1, REP 2, and REP 3.

The REP uses an Indexed Renewable Energy Credit (REC) or "Contract for Difference" as a financial payment mechanism. Project proponents submitted a bid price to the AESO and the amount paid to a project is calculated by subtracting the pool price from that project's bid price. If the pool price is below the project's bid price, the government would pay the generator to meet the bid price. If the pool price is higher than the bid price, the generator would pay the difference in price to the government. In essence, this mechanism allowed companies to competitively bid for the all-in price they needed to develop a project.

Table 19 provides an overview of the procurement results for REP 1, REP 2, and REP 3. All projects procured in each round were wind generation projects.

Table 19: REP procurement results[52]

	REP 1	**REP 2**	**REP 3**
Number of projects procured	4	5	3
Total MW	596	363	400
Successful bid price range ($/MWh)	$30.90 - $43.30	$36.99 - $38.97	$38.60 - $41.49
Weighted average bid price ($/MWh)	$37.35	$38.69	$40.14

Each Generator selected in a REP procurement process entered into a Renewable Electricity Support Agreement (RESA) with the AESO. Among other contractual provisions, the RESA provides that a project must commence construction and commercial operations by dates specified in the RESA. Additionally, the RESA includes consideration for the AESO to retain a Completion and Performance Security equal to $50,000 per MW of contract capacity from project proponents in circumstances where the project does not meet these specified dates.

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51 January 2016 GoA REP 1 direction to AESO

March 2018 GoA REP 2 and REP 3 direction to AESO

52 REP results » AESO

As outlined in Table 20 below, as of Q3 2022:

- four projects totaling approximately 554 MW successfully achieved commercial operation under the RESA provisions;
- four projects totaling approximately 297 MW terminated their RESA; and
- four projects totaling approximately 508 MW remain under development.

Table 20: REP project status

	Project	(MW)	Status
REP 1	Whitla Wind	201.6	Achieved Commercial Operation
	Riverview Wind Farm	115	Achieved Commercial Operation
	Phase 2 of Castle Rock Ridge Wind Power Plant	30.6	Achieved Commercial Operation
	Sharp Hills Wind Farm	248.4	RESA Terminated[53]
REP 2	Cypress Wind Power Project	201.6	Under Development
	Stirling Wind Project	113	Under Development
	Buffalo Atlee Wind Farm 1	17.25	RESA Terminated[54]
	Buffalo Atlee Wind Farm 2	13.8	RESA Terminated
	Buffalo Atlee Wind Farm 3	17.25	RESA Terminated
REP 3	Windrise Wind	207	Achieved Commercial Operation
	Jenner Wind Power Project	122.4	Under Development
	Jenner Wind Power Project 2	71.4	Under Development

Each of the projects that terminated a RESA indicated to the AESO that their project would not achieve Commencement of Construction by the Commencement of Construction Longstop date in accordance with the RESA. All projects that have terminated their RESA have paid the AESO the Completion and Performance Security set out in the RESA.

Projects that terminated a RESA may still proceed to completion. However, these projects would do so as a typical generation project and receive the hourly pool price rather than the stable REC payment stipulated in the terminated RESA.

[53] REP-Round-1-Update-Final-002.pdf (aeso.ca)

[54] REP-Round-2-and-3-Update_August-8-2022.pdf (aeso.ca)

As discussed in the MSA's Q2 2022 Quarterly Report, wind generation assets in Alberta may also receive additional sources of revenue through the sale of carbon emissions offset products.[55] However, projects subject to a RESA transfer the rights to their renewable attributes to the AESO by virtue of the agreement. Therefore, these projects do not receive any other revenue stream for renewable attributes, such as the sale of carbon emissions offsets. Therefore, a project that terminated a RESA and was later completed could produce a separate revenue stream through the sale of its renewable attributes, in addition to receiving the hourly pool price for production.

As noted in earlier in this report, average hourly pool prices in recent years have been higher than the REP procurement bid price ranges noted in Table 19.

[55] MSA Q2 2022 Quarterly Report, page 7: "Wind and solar generation typically act as price takers and offer into the energy market at the offer price floor of $0.00/MWh, receiving the prevailing pool price for their generation. In addition, wind and solar assets are eligible for carbon emission offsets, which are an additional source of revenue for these assets. A wind or solar asset brought online in 2022 may be eligible to receive $26.50/MWh in revenue from carbon emission offsets, based on the electricity grid displacement factor of 0.53 t/MWh and the carbon price of $50/MWh."

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 September 30, 2022, the MSA closed 247 ISO rules compliance matters, as reported in Table 21.[56] 100 matters were carried forward to next quarter. During this period 65 matters were addressed with NSPs, totalling $101,000 in financial penalties, with details provided in Table 22.

[56] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 247 closed matters, one matter was referred by the MSA to another body.

Table 21: ISO rules compliance outcomes from January 1, 2022 to September 30, 2022

ISO rule	Forbearance	Notice of specified penalty	No contravention
103.1	1	-	-
201.3	2	-	-
201.7	20	11	-
202.4	2	-	-
203.3	72	8	-
203.4	25	11	5
203.6	5	2	-
205.3	5	3	-
205.4	3	-	-
205.5	-	6	1
205.6	2	16	-
304.3	5	-	-
306.4	5	-	-
306.5	12	3	-
502.1	1	-	-
502.10	1	-	-
502.4	1	-	-
502.5	-	2	-
502.6	4	-	-
502.8	-	2	-
505.3	2	-	-
505.4	6	1	-
9.1.3	1	-	-
Total	**175**	**65**	**6**

Table 22: Specified penalties issued between January 1 and September 30, 2022 for contraventions of the ISO rules

Market participant	Total specified penalty amounts by ISO rule ($)											Total ($)	Matters
	201.7	203.3	203.4	203.6	205.3	205.5	205.6	306.5	502.5	502.8	505.4		
Air Liquide Canada Inc.					500	2,000	500					3,000	4
Alberta Electric System Operator				250								250	1
Alberta Pacific Forest Industries Inc.	500						2,000					2,500	3
Alberta Power (2000) Ltd.		1,000										1,000	2
AltaGas Ltd.	500											500	1
ATCO Power (2010) Ltd.		3,000	500									3,500	3
Bull Creek Wind Power Limited Partnership	500											500	1
Calgary Energy Centre No. 2 Inc.									250			250	1
Capital Power (G3) Limited Partnership								500				500	1
Capital Power (Genesee) L.P.								1,000				1,000	2
Claresholm Solar LP										1,000		1,000	2
DAPP Power L.P.			1,500									1,500	1
Enel X Canada Ltd.							27,750					27,750	7
Enfinite Generation Corporation (formerly WCSB Power Generation GP Inc.)			500									500	1
ENMAX Cavalier LP									250			250	1
ENMAX Generation Portfolio Inc.					500							500	1
Grande Prairie Generation Inc.			250									250	1
Imperial Oil Limited	500											500	1
Irrigation Canal Power Co-op Ltd.			250									250	1
Mercer Peace River Pulp Ltd.		2,000				750						2,750	3
Milner Power II Limited Partnership by its General Partner, Milner Power II Inc	500		250								250	1,000	3
Northstone Power Corp.			500									500	1
Powerex Corp.	250											250	1
Repsol Canada Energy Partnership	500											500	1

Table 23: Specified penalties issued between January 1 and September 30, 2022 for contraventions of the ISO rules (continued)

Market participant	Total specified penalty amounts by ISO rule ($)											Total ($)	Matters
	201.7	203.3	203.4	203.6	205.3	205.5	205.6	306.5	502.5	502.8	505.4		
Suffield Solar LP	500											500	1
Suncor Energy Inc.		250										250	1
TA Alberta Hydro LP			3,000		5,000	500						8,500	4
Tourmaline Oil Corp.	500		500									1,000	2
TransAlta Generation Partnership			1,500			5,500						7,000	3
TransCanada Energy Sales Ltd.				750								750	1
Voltus Energy Canada Ltd.							30,000					30,000	6
West Fraser Mills Ltd.	500	1,500										2,000	2
Whitecourt Power Ltd.	500											500	1
Total	5,250	7,750	8,750	1,000	6,000	8,750	60,250	1,500	500	1,000	250	101,000	65

7 ARS 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 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 September 30, 2022, the MSA addressed 70 O&P ARS compliance matters, as reported in Table 24.[57] An additional 16 matters were carried forward to next quarter. During this period, seven matters were addressed with NSPs, totalling $33,375 in financial penalties, with details provided in Table 25. For the same period, the MSA addressed 169 CIP ARS compliance matters, as reported in Table 26,[58] and 25 matters were addressed with NSPs, totalling $58,000 in financial penalties. An additional 90 matters were carried forward to next quarter.

[57] An ARS matter is considered closed once a disposition has been issued. Of the 70 closed matters, three matters were rejected.

[58] Of the 169 closed matters, one matter was withdrawn.

Table 24: O&P ARS compliance outcomes from January 1 to September 30, 2022

Reliability standard	Forbearance	Notice of specified penalty	No contravention
COM-001	1	-	-
COM-002	1	-	-
EOP-001	1	-	-
EOP-005	1	-	-
FAC-008	15	1	-
IRO-005	1	-	-
IRO-008	1	-	-
MOD-010&012	1	-	-
PRC-001	2	-	-
PRC-002	3	1	-
PRC-005	21	4	-
PRC-006	2	-	-
PRC-019	5	-	-
PRC-023	-	1	-
VAR-002	3	-	1
VAR-501-WECC	1	-	-
Total	59	7	1

Table 25: Specified penalties issued between January 1 and September 30, 2022 for contraventions of O&P ARS

Market participant	Total specified penalty amounts by ARS ($)				Total ($)	Matters
	FAC-008	PRC-002	PRC-005	PRC-023		
Imperial Oil Resources Limited	2,250	375	2,250		4,875	3
Pembina NGL Corporation			2,250		2,250	1
Suncor Energy Inc.			3,750	18,750	22,500	2
TransCanada Energy Ltd.			3,750		3,750	1
Total	2,250	375	12,000	18,750	33,375	7

The ARS outcomes listed in Table 24 and Table 25 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
MOD Modeling, Data, and Analysis
PRC Protection and Control
VAR Voltage and Reactive

Table 26: CIP ARS compliance outcomes from January 1 to September 30, 2022

Reliability standard	Forbearance	Notice of specified penalty	No contravention
CIP-002	13	1	1
CIP-003	11	5	-
CIP-004	26	9	1
CIP-005	5	-	-
CIP-006	16	1	-
CIP-007	33	4	1
CIP-008	3	-	-
CIP-009	3	1	1
CIP-010	18	2	-
CIP-011	7	2	-
CIP-014	3	-	1
Total	138	25	5

The ARS outcomes listed in Table 26 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

APPENDIX A: DETERMINANTS OF CUSTOMER SWITCHING

To examine the correlations between energy costs and regulated customer switching, the MSA has developed a preliminary version of an error-correction model. This error-correction model estimates the effect of energy costs on the switching behaviour of customers away from regulated retailers in both the short-run and the long-run.

The short-run in this model represents a period of time in which exogenous market events may affect the behaviour of regulated retailer customers. The long-run is defined as a period in which the retail market has fully absorbed short-run changes, so any change in switches away from regulated retailers should be driven by energy costs. If energy costs are not found to be significant drivers of switching in the long-run, it would suggest that regulated retailer customers are unresponsive to energy costs when switching from regulated options.

To validate the use of an error-correction model, a process known as bounds-testing (Perasan *et al.*, 2001) was used. In short, the process is a hypothesis test to determine if evidence of correlation between customer switching and energy costs in the long-run is present in a model. The bounds test results for both the RRO and DRT models are shown in Table 27 and Table 28 below. In both models, the computed F- and t-statistics are larger than the upper bounds in absolute terms. This provides significant evidence of a long-run relationship between customer switching and energy costs, validating the use of the model.

Table 27: Bounds test results for RRO regression model

F-Test	
Lower Bound	3.79
Upper Bound	4.85
F-statistic	9.78
P-value	0.0002**
T-Test	
Lower Bound	-2.86
Upper Bound	-3.53
T-statistic	-6.28
P-value	0.0003**

Table 28: Bounds testing results for DRT regression model

F-Test	
Lower Bound	3.79
Upper Bound	4.85
F-statistic	8.71
P-value	0.0005**
T-Test	
Lower Bound	-2.86
Upper Bound	-3.53
T-statistic	-5.81
P-value	0.0007**

In the models described below, the symbol $\gamma\hat{v}_{t-1}$ denotes what is called the error-correction term. This term represents the how quickly the market for retail switching adjusts from the short-run to the long-run. For example, if γ takes the value of 1.00 in a regression, then unexpected effects in the short-run are entirely in one period, and the short-run lasts no longer than a month.

If γ takes a value of 0.50 in a regression, this means that half of the discrepancy between the short-run and the long-run is absorbed in a month. This suggests that the market for retail switching could remain in the short-run over a number of months. If γ takes a value of 0.00, then the market never fully absorbs shocks in the short-run and may never reach long-run equilibrium.

The goal of the analysis was to use retail market data to estimate the relationship between switches away from regulated retailers and energy costs. The model used to examine RRO churn is:

$$\begin{aligned}\Delta RROSwitches = c_0 + \gamma\hat{v}_{t-1} + a_0 RRORate_{t-1} + a_1 DRTRate_{t-1} \\ + a_2 CompetitiveElectricityRate_{t-1} + a_3 \mathrm{ResidentialPropertyMoves}_{t-1} \\ + \beta_0 \Delta RRORate_t + \beta_1 \Delta DRTRate_t + \beta_2 \Delta CompetitiveElectricityRate_t \\ + \beta_2 \Delta ResidentialPropertyMoves_t + \sum_{i=1}^{11} \delta\, Month_{it} + \varepsilon_t\end{aligned}$$

$RROSwitches$ is the number of RRO customers that switch from the RRO to competitive electricity options each month. $ResidentialPropertyMoves$ is the number of competitive retailer losses in each month that are a result of customers moving to new residential properties. For this analysis, it is assumed that moving behaviour is homogenous among regulated and non-regulated retail customers.

$RRORate$ is the provincial weighted-average RRO rate (¢/kWh), across the ENMAX, EPCOR, FortisAlberta, and ATCO service areas. $Month_i$ are dummy variables representing the month of the year to control for seasonality. $\mathrm{DRTRate}$ is the provincial weighted average DRT rate ($/GJ) across the ATCO, Apex, and AECO service areas. $CompetitiveElectricityRate$ (¢/kWh) is a weighted-average index of province wide competitive fixed electricity rates.

A 'delta' symbol (Δ) denotes the first-differenced form of a variable. A first-differenced variable in this model represents the month-over-month change in the variable. For example, each observation in $\Delta RROLosses$ represents the RRO customer losses observed in each month, subtracted by observed customer losses in the month prior, and may therefore be positive or negative.

In an error-correction model, the estimated coefficient of the non-differenced first lag of a variable represents the long-run correlation between it and dependent variable. In this model, for example, the estimated value for a_1 represents the long-run correlation between competitive electricity rates and RRO customer losses. The estimated values for β_0 and β_1, on the other hand, represent the short-run relationship.

Table 29 shows the regression coefficients estimated from the model.

Table 29: RRO churn regression coefficient estimates

Error-correction term	-0.420*** (0.080)
$RRORate_{t-1}$	308.856*** (109.248)
$DRTRate_{t-1}$	141.902 (154.318)
$CompetitiveElectricityRate_{t-1}$	-451.833 (266.576)
$MonthlyPropertyMoves_{t-1}$	0.312*** (0.140)
$\Delta RRORate_t$	43.416 (121.960)
$\Delta DRTRate_t$	-145.987 (155.853)
$\Delta CompetitiveElectricityRate_t$	-529.881 (1030.053)
$\Delta MonthlyPropertyMoves_t$	0.681*** (0.169)
Constant	4106.491 (2315.314)
Number of observations	122
Degrees of freedom	101
Adjusted R-squared	0.466

*(Newey-West) Standard errors in brackets. *** indicate statistical significance at the 1% level.*

The significance of the estimated coefficient on RRO rates in the long run is expected, as RRO customers should be incentivized to switch to competitive contracts when the cost of their regulated option increases.

The estimates for residential property moves are significant in both the short-run and the long-run, suggesting that moving behaviour is a considerable driver of RRO switching in any period. Customers that are moving properties may be presented with alternative retail electricity options when deciding to move to a new property. RRO customers may also have heightened attention to utility options during the moving process.

The error correction model used to examine DRT switching:

$$\begin{aligned}\Delta DRTLosses = {} & c_0 + \gamma\hat{v}_{t-1} + a_0 RRORate_{t-1} + a_1 DRTRate_{t-1} + \ a_2 CompetitiveGasRate_{t-1} \\ & + + a_3 \mathrm{ResidentialPropertyMoves}_{\mathrm{t-1}} \ + \ \beta_0 \Delta RRORate_t \ + \ \beta_1 \Delta DRTRate_t \\ & + \ \beta_2 \Delta ResidentialPropertyMoves_t \sum_{i=1}^{5} \pi_i CompetitiveGasRate_{t-i} + \sum_{i=1}^{11} \delta \, Month_{it} \\ & + \varepsilon_t\end{aligned}$$

DRTLosses is the number of DRT customers that switch from the DRT to competitive natural gas options in each month. As in the model for RRO switching, *ResidentialPropertyMoves* is the number of competitive natural gas retailer losses that are due to customers moving to new residential properties. The moving behaviour of customers on regulated and non-regulated natural gas contracts is assumed to be identical for this analysis.

CompetitiveGasRate is an index of competitive fixed natural gas rates ($/GJ) averaged over the ENMAX, ATCO, and EPCOR service areas. Variables such as *Month*, *RRORate,* and *DRTRate* are identical to those used in the model for RRO customer switching as described above.

Table 30 shows the regression coefficients estimated from the model .

Table 30: DRT churn regression coefficient estimates

Error-correction term	-0.426*** (0.084)
$RRORate_{t-1}$	135.058*** (49.253)
$DRTRate_{t-1}$	-55.300 (150.518)
$CompetitiveNaturalGasRate_{t-1}$	746.119*** (297.966)
$MonthlyPropertyMoves_{t-1}$	0.172 (0.104)
$\Delta RRORate_t$	15.884 (102.086)
$\Delta DRTRate_t$	124.60 (130.561)
$\Delta CompetitiveNaturalGasRate_t$	-1300.143*** (572.767)
$\Delta MonthlyPropertyMoves_t$	0.230 (0.140)
Constant	4106.491 (2315.314)
Number of observations	122
Degrees of freedom	91
Adjusted R-squared	0.3618

*(Newey-West) Standard errors in brackets. *** indicate statistical significance at the 0.1% level.*

The significance of the RRO rates and the insignificant estimate of DRT rates in the long-run support the notion that a significant number of regulated DRT customers switch to competitive natural gas contracts in response to increases in regulated electricity rates. These customers likely consider competitive electricity options first, and ultimately decide to sign onto competitive dual-fuel contracts.

The sign of the coefficient of the competitive natural gas rate is in the long-run is unexpected. In the long-run it is expected that an increase in competitive natural gas rates should reduce DRT churn, as the competitive alternatives become less attractive to regulated customer. In the short-run, the estimated sign on competitive natural gas rates is negative, which is expected. The MSA may revisit this analysis in future reporting.

The absolute values of the error-correction terms in both regressions are estimated to be 0.420 and 0.426 for the RRO and DRT models, respectively. Both estimates are significant at a 5% confidence interval. This suggests that the equilibrium states for both RRO and DRT switching may remain in the short-run for several months after an unexpected shock shifts the market from the long-run equilibrium into the short-run.