# Quarterly Report for Q4 2022

February 10, 2023

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

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## THE QUARTER AT A GLANCE

- The average pool price in Q4 2022 was $213.92/MWh, a 99% increase relative to Q4 2021. The average pool price for the quarter increased because of prices in December which averaged $311.73/MWh. The higher prices in December were largely driven by record-high demand, large export volumes, offer behaviour, and variable wind generation. On an annual basis, 2022 was the highest priced year on record due in part to the higher prices in August, September, and December.

- In 2022, System Marginal Prices in the energy market cleared at the offer price cap of $999.99/MWh for a total of 26 hours and 28 minutes, the highest since 2013 when prices were at the offer cap for a total of 45 hours. The AESO declared an Energy Emergency Alert Level 3 (EEA3) seven times in 2022, though firm load was not shed. In Q4, Energy Emergency Alert (EEA) events occurred on November 29 and December 1, 20, and 21. In these EEA events, low renewable generation, increased demand driven by weather, and natural gas generation outages contributed to the scarcity conditions.

- The market power of larger suppliers was increased in Q4 by factors such as high demand, reduced wind generation, and exports. Market power levels in Q4 were comparable with those seen in Q3. The offer behaviour of a few large suppliers raised pool prices above marginal costs in some hours. However, less capacity was offered at high prices in Q4 relative to Q3, as high prices were more related to tighter market conditions.

- The total volume of forward trading in 2022 was 25% higher than in 2021, although total volumes remain below those observed historically from 2013 to 2017. Realized pool prices in 2022 generally came in above forward market expectations, particularly in August, September, and December. Prices in the forward market largely increased over Q4 because of higher forward prices in California and Mid-Columbia, buying pressure from the RRO auctions, extensions to a planned outage at HR Milner, and the delay of the 900 MW Cascade power project. The price of CAL23 increased by 60% from $113/MWh to $181/MWh over the quarter, despite forward natural gas prices for 2023 declining by 23%.

- Expected residential RRO monthly rates over 2023 have increased since October. Residential regulated retail customers continue to face strong incentives to switch to competitive fixed electricity rates given RRO rate expectations over the next year. Residential variable rates were more than 33 ¢/kWh in December, the highest since 2021. However, regulated rates in December were also high, keeping the difference between the two rates small.

- From October 1 to December 31, 2022, the MSA closed 125 ISO rules compliance matters; 26 matters were addressed with notices of specified penalty. For the same period, the MSA closed 10 Alberta Reliability Standards Operations and Planning compliance matters; no matters were addressed with notices of specified penalty. In addition, the MSA closed 74 Alberta Reliability Standards Critical Infrastructure Protection compliance matters; 10 matters were addressed with notices of specified penalty.

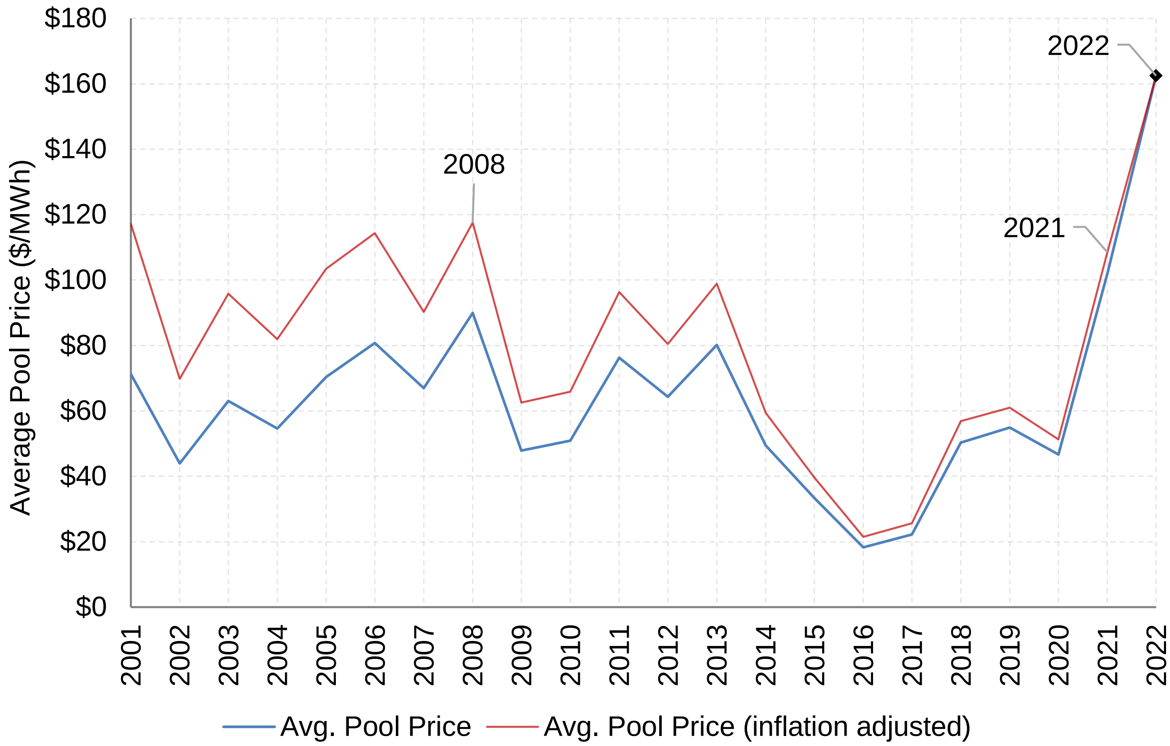
# 1 POWER POOL

## 1.1 Annual summary

The average pool price in 2022 was the highest on record at $162.46/MWh, breaking the previous record of $110/MWh set in 2008, adjusting for inflation (Figure 1). Compared with 2021, the average pool price was 59% higher in 2022.

Increased offer prices on some generation assets, increased demand, higher natural gas prices, and a higher carbon price all contributed to the high pool prices in 2022. In Q4, increased export volumes also put upward pressure on pool prices.

*Figure 1: Average annual pool prices (2001 to 2022)*[1]




Average demand in 2022 was 9,883 MW, which is 1.6% higher than in 2021 (Table 1). The record peak for hourly demand, last set in February 2021, was surpassed on three days in 2022: January 3, December 19, and December 21. Demand was higher in 2022 largely because of increased economic activity, higher oil and natural gas production, and prevailing temperatures.

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

*Table 1: Annual summary market statistics*

| | 2019 | 2020 | 2021 | **2022** |
|---|---|---|---|---|
| Pool Price (Avg $/MWh) | $54.88 | $46.72 | $101.93 | **$162.46** |
| Demand (AIL) (Avg MW) | 9,695 | 9,462 | 9,728 | **9,883** |
| Gas Price (2A) (Avg $/GJ) | $1.68 | $2.11 | $3.39 | **$5.08** |
| Wind (Avg MW) | 470 | 690 | 700 | **835** |
| Net Imports (Avg MW) | 174 | 440 | 459 | **412** |
| Supply Cushion (Avg MW) | 1,604 | 1,933 | 1,742 | **1,540** |

Although demand increased relative to 2021, market demand was not the main driver of higher pool prices in 2022 (Figure 2). For example, in September demand peaked at 10,754 MW while the average price for that month was $266.39/MWh. In contrast, January demand was higher, peaking at 11,939 MW, but the average pool price was much lower at $90.81/MWh.

*Figure 2: Peak hourly demand and average pool prices by month in 2022*

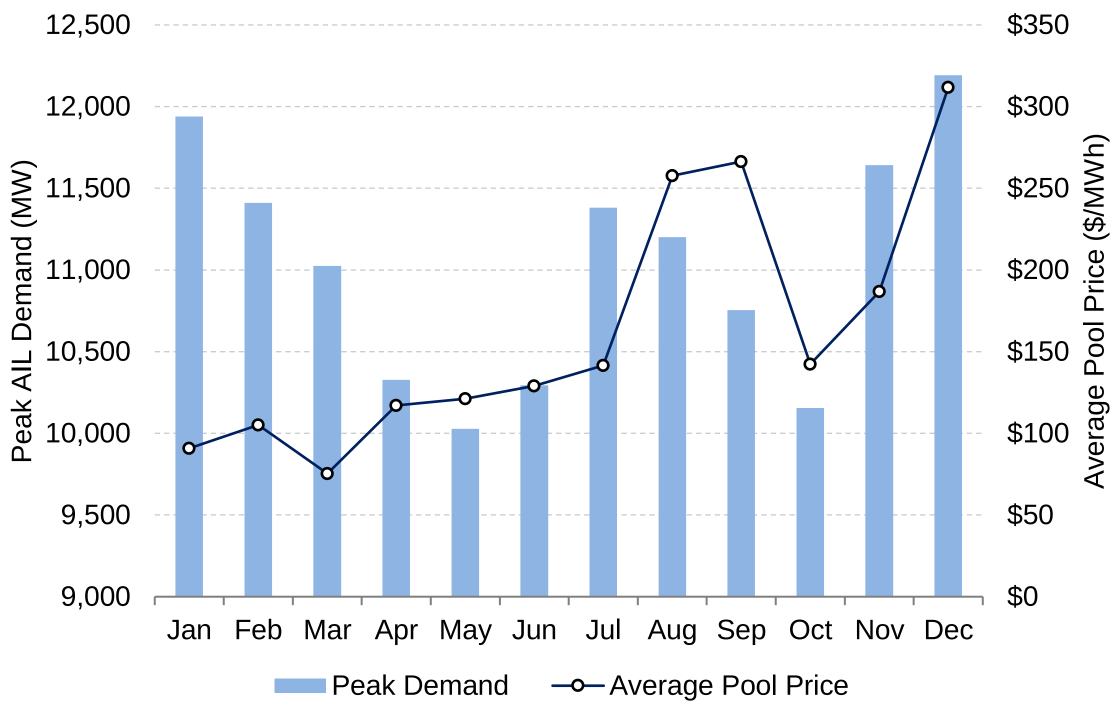
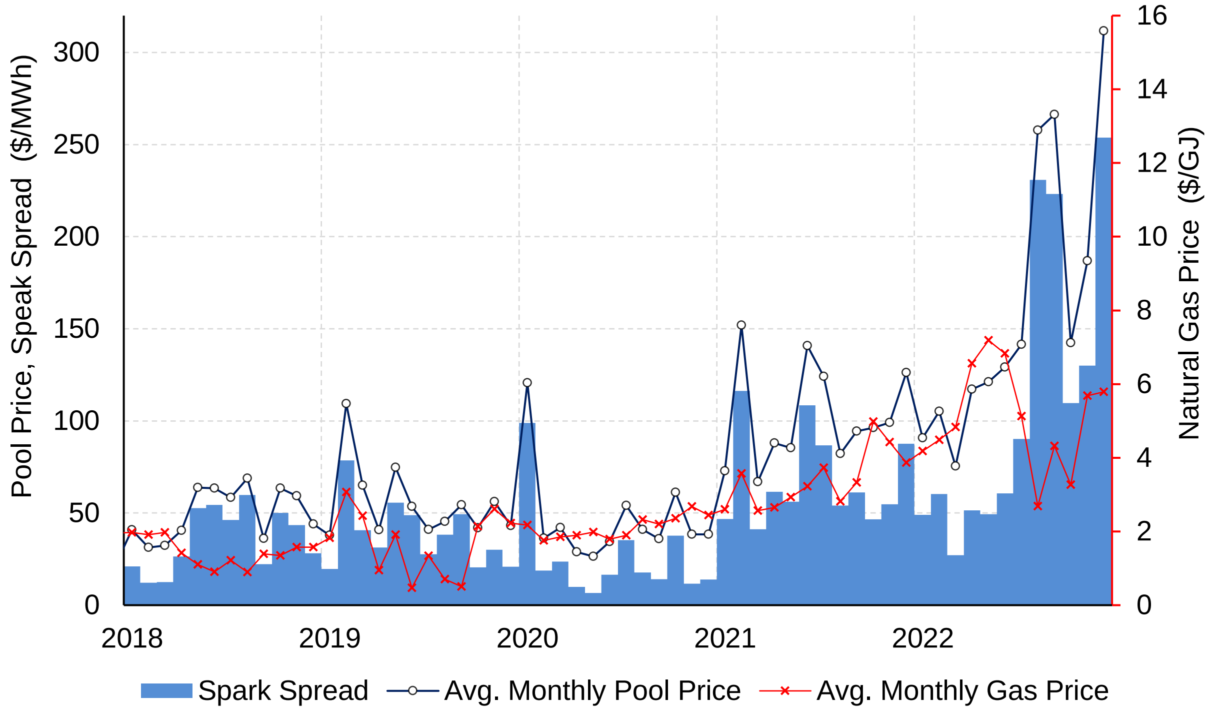


Figure 3 shows monthly average pool prices, natural gas prices, and spark spreads in 2022. Spark spread is an indicator of the margin between pool prices and natural gas fuel costs. This analysis assumes a heat rate of 10 GJ/MWh, which is approximately the efficiency of a peaking gas asset.

The monthly spark spreads were highest during August, September, and December driven by higher pool prices in these months. The annual average spark spread in 2022 reached a record of $112/MWh, up from $68/MWh in 2021. The increase in spark spread and weakening correlation between average pool prices and natural gas prices in the latter half of the year indicates that natural gas prices were not a major driver of average pool prices.

*Figure 3: Average pool price, natural gas price, and spark spread by month (January 2018 to December 2022)*




Starting in late July and early August, a greater volume of available capacity in the energy market was offered at prices above $250/MWh (Figure 4). The higher offer prices coincided with hot weather and low wind generation in August to drive a record high for average pool prices over the month, despite the lowest monthly average gas price of 2022.

Available thermal capacity decreased in September because of outages at several large thermal assets (Figure 5).[2] Year-over-year, average available thermal capacity was 8,400 MW in September compared to 8,550 MW in September 2021. In addition, higher offer prices continued

[2] The outage figures reflect the difference between Maximum Capability and Available Capability. The SCL1 asset was not included because it has changed from net to gross reporting. The SD3 and SD5 assets, which are retired and were previously mothballed, were also excluded.

into September and, combined with low wind generation and reduced import capacity, resulted in another record-setting monthly average pool price.

*Figure 4: Average amount of available capacity offered above $250/MWh by month (January 2018 to December 2022)*

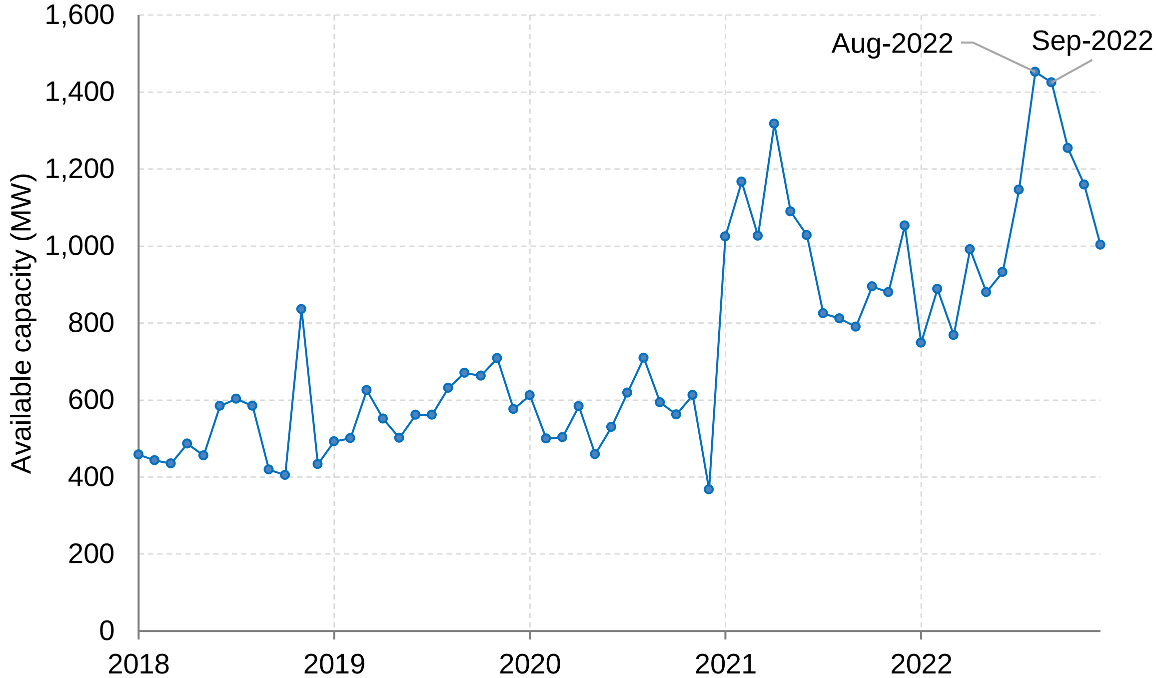
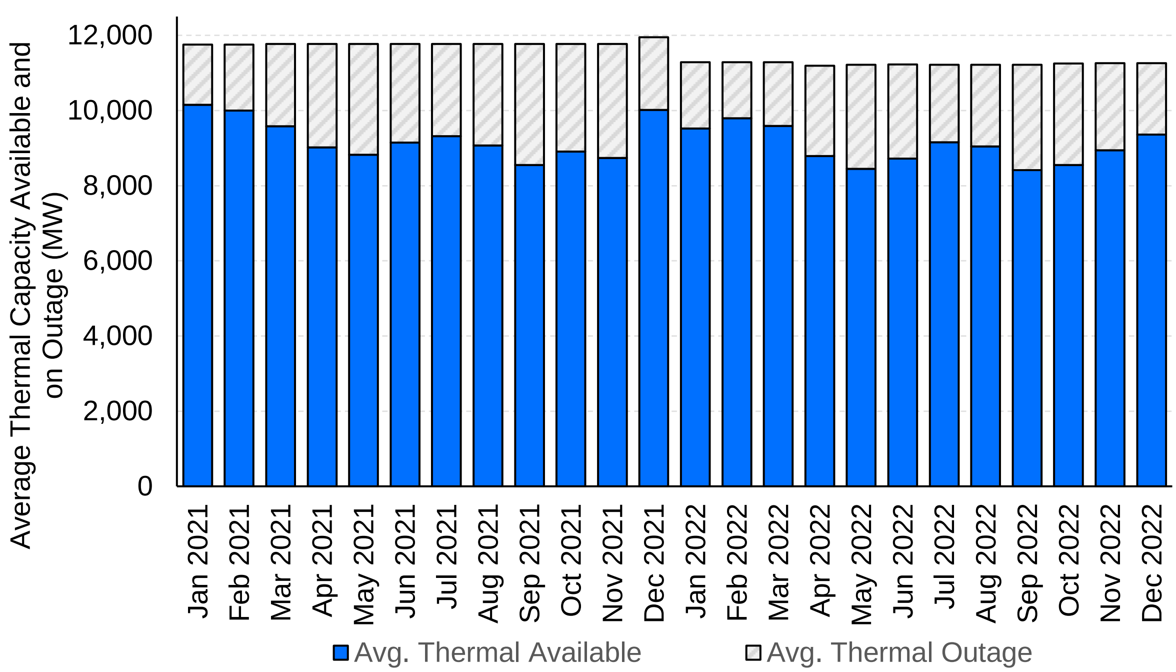



*Figure 5: Average thermal capacity available and on outage by month (January 2021 to December 2022)*



Thermal availability was 650 MW lower on average in December 2022 compared to December 2021 (Figure 5). This was largely the result of coal retirements at the Keephills 1 and Sundance 4 assets early in 2022.

Power prices in Mid-Columbia (Mid-C) and California were elevated in December, leading to significant export volumes from Alberta. December's record-high demand levels further contributed to tight market conditions and drove the December average price to $311.73/MWh, setting a new record for monthly average pool price for the third time in 2022.

Natural gas generation assets set the System Marginal Price (SMP) more often in 2022. Figure 6 shows that in 2022, gas assets set price 90% of the time, a marked increase from previous years. As a result, natural gas prices are now the main fundamental cost driver for the Alberta power market, although average pool prices in 2022 were not primarily driven by input costs.

*Figure 6: Marginal price-setting fuel type by year (2018 to 2022)*

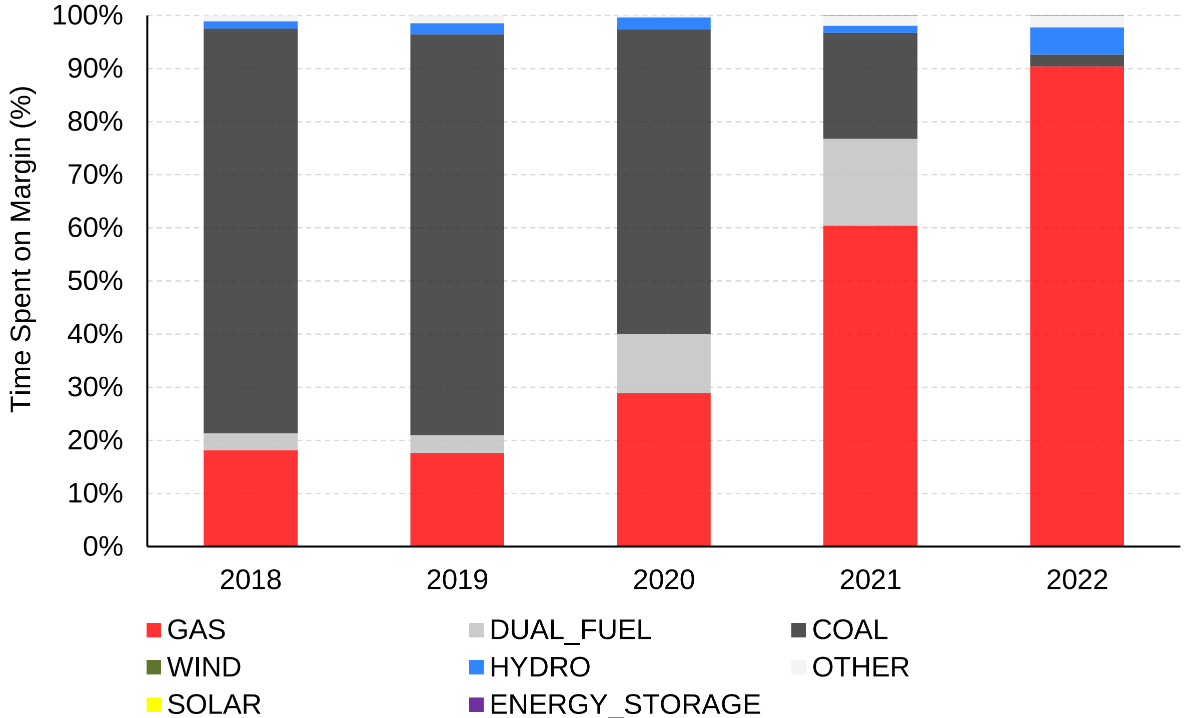
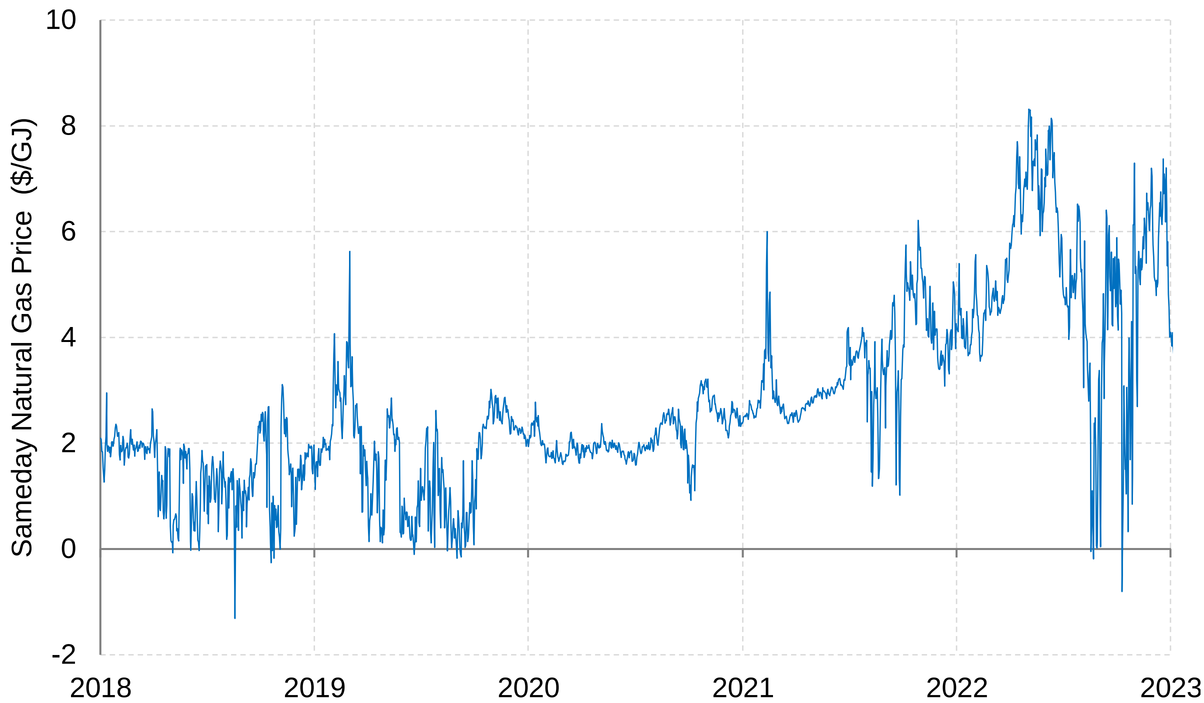



Figure 7 shows same-day natural gas prices from January 1, 2018 to December 31, 2022. Natural gas prices were higher and more volatile in 2022 compared to the prior years shown. Higher natural gas prices were a principal driver of pool prices in early 2022, particularly in Q2, when natural gas prices were elevated and spark spreads were lower (see Figure 3).

*Figure 7: Same-day natural gas prices (AB-NIT) (January 1, 2018 to December 31, 2022)*




## 1.2 Quarterly summary

The average pool price in Q4 was $213.92/MWh, which was approximately double that of Q4 2021.[3] The higher pool prices in Q4 relative to Q4 2021 were driven by offer behaviour, reduced imports and higher export flows, increased demand, higher natural gas prices in November and December, and a higher carbon price.

Table 2 provides summary market statistics for Q4 compared to Q4 2021. Average demand in November and December was higher in 2022, driven by cold weather and high oil production. Oil production in Alberta set a new monthly record during October and remained high in November and December.[4]

December set a record high for the monthly average pool price at $312/MWh, surpassing $267/MWh in September. High prices in other power markets, including Mid-C and California, drove export volumes from Alberta in December, increasing prices in Alberta. Year-over-year, average December flows on the interties went from 393 MW of imports in 2021 to 168 MW of exports in 2022, an average supply reduction of 561 MW (imports and exports are discussed further in Section 1.6).

[3] Reference to Q4 means Q4 2022 unless specified otherwise. References to a month or a day in a month mean a month or day in 2022 unless specified otherwise.

[4] Alberta Energy Regulator - ST3 report, and Alberta Government Dashboard - Oil Production

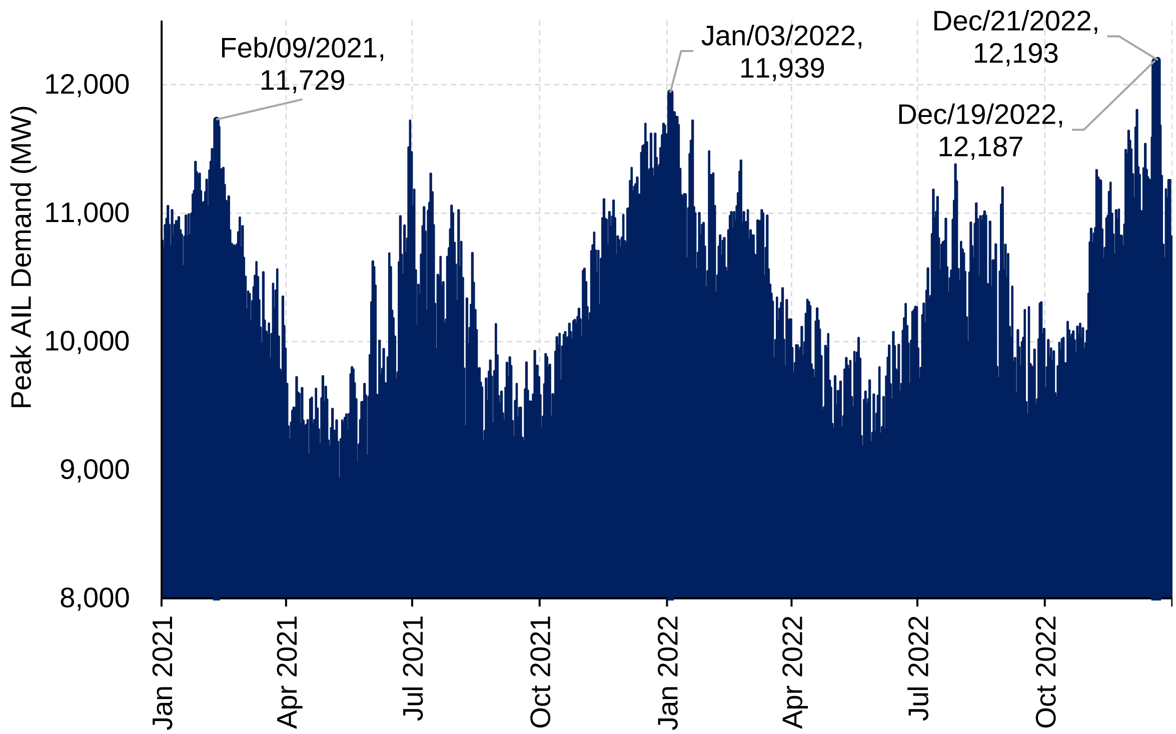
*Table 2: Energy market summary statistics for Q4*

| | | 2022 | 2021 | Change |
|---|---|---|---|---|
| Pool Price (Avg $/MWh) | Oct | $142.34 | $96.35 | 48% |
| | Nov | $186.84 | $99.07 | 89% |
| | Dec | $311.73 | $126.27 | 147% |
| | **Q4** | **$213.92** | **$107.31** | **99%** |
| Demand (AIL) (Avg MW) | Oct | 9,468 | 9,453 | 0% |
| | Nov | 10,336 | 10,056 | 3% |
| | Dec | 10,750 | 10,670 | 1% |
| | **Q4** | **10,183** | **10,060** | **1%** |
| Gas Price AB-NIT (2A) (Avg $/GJ) | Oct | $3.27 | $4.98 | -34% |
| | Nov | $5.69 | $4.42 | 29% |
| | Dec | $5.79 | $3.87 | 50% |
| | **Q4** | **$4.91** | **$4.42** | **11%** |
| Wind (Avg MW) | Oct | 819 | 864 | -5% |
| | Nov | 1,128 | 1,206 | -7% |
| | Dec | 908 | 770 | 18% |
| | **Q4** | **950** | **944** | **-2%** |
| Net Imports (+) Net Exports (-) (Avg MW) | Oct | 87 | 289 | -70% |
| | Nov | 257 | 523 | -51% |
| | Dec | -168 | 393 | -143% |
| | **Q4** | **57** | **400** | **-86%** |
| Thermal Outages (Avg MW) | Oct | 2,698 | 2,862 | -6% |
| | Nov | 2,314 | 3,037 | -24% |
| | Dec | 1,898 | 1,939 | -2% |
| | **Q4** | **2,303** | **2,608** | **-12%** |

In addition, Alberta demand was notably high, peaking at 12,193 MW during a period of cold weather in late December. Figure 8 shows that the peak record for hourly demand was broken twice in December, both during periods when prices were at or close to the offer cap of $999.99/MWh. When prices are at these high levels, price-responsive loads can generally be expected to have reduced their electricity consumption by around 400 MW in total.

Offer behaviour also drove price increases from Q4 2021 to Q4 2022. For example, in Q4 2021 5% of coal and converted coal capacity was offered above $700/MWh, but this increased to 12% in Q4 2022. Coal and converted coal capacity is a meaningful portion of the dispatchable generation capacity in Alberta and offer prices on these assets can have an impact on pool prices, especially when market conditions are tighter (market power and offer behaviour are discussed further in Sections 1.4 and 1.5).

*Figure 8: Peak daily demand (January 1, 2021 to December 31, 2022)*

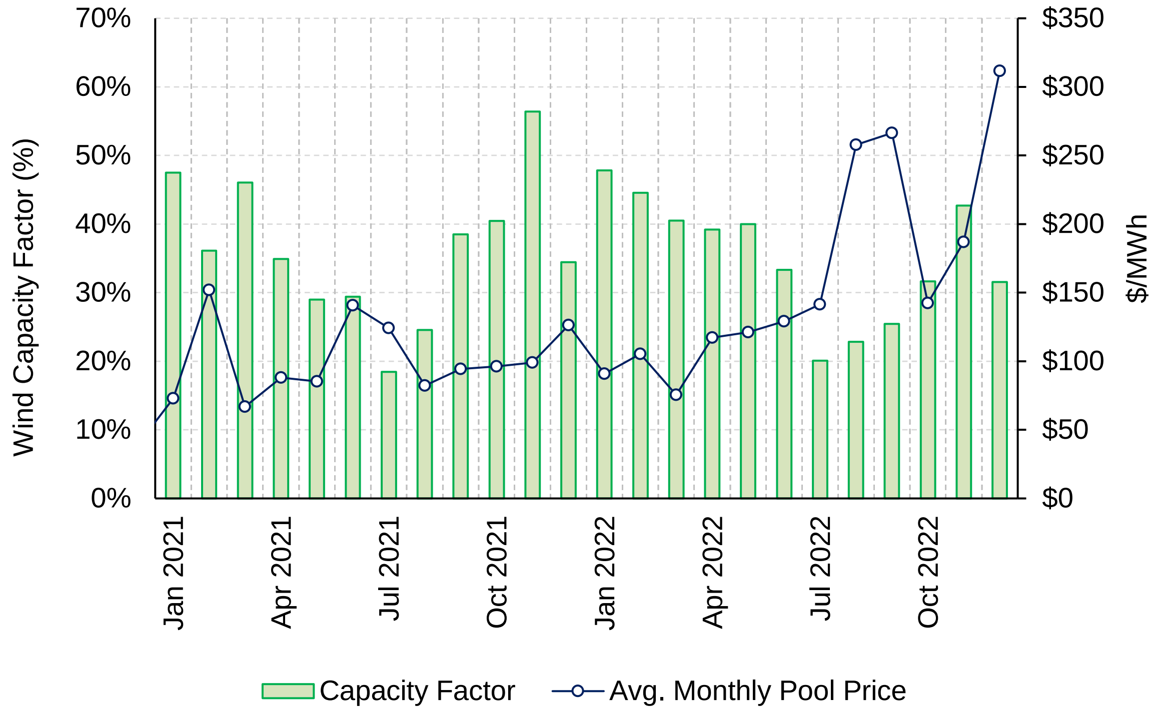



Natural gas prices have a direct impact on the marginal cost of price-setting assets in Alberta since gas-fired generators are the primary marginal price setters. In November and December, natural gas prices were 29% and 50% higher year-over-year (Table 2). The higher natural gas prices in November and December increased prices in hours where price was set by natural gas generators that submitted offer prices reflecting their marginal cost.

Average wind generation in Q4 was 950 MW, up 1% from 944 MW in Q4 2021. As wind capacity increased by approximately 400 MW over this time, this represents a decrease in wind's capacity factor from 44% to 35% year-over-year (Figure 9). The capacity factor of wind generation is often lowest during periods of extremely high or low temperatures, when demand is generally highest. In 2022, the capacity factor of wind decreased during the hot summer months and during the cold weather in December.

In early October, the Genesee 3 asset was taken offline for a planned outage to convert the asset from coal to run exclusively on natural gas. The asset returned to the market in mid-November and was a factor in reducing average carbon emissions later in Q4. The coal-to-gas conversion process generally reduces the carbon emission intensity of an asset from 1.0 tCO2e/MWh to 0.5 tCO2e/MWh (Section 1.8 analyzes carbon emissions in the Alberta power market).

*Figure 9: Wind capacity factor and average pool prices by month (January 2021 to December 2022)*




### *1.2.1 Energy Emergency Alert events*

The AESO declared an EEA3 seven times in 2022.[5] An EEA3 is declared when firm load interruption is imminent or in progress, and the AESO is unable to meet minimum contingency reserve requirements.

Figure 10 illustrates average generation by fuel type in 2022 alongside average generation levels during the EEA3 events in 2022. Although wind generation averaged 835 MW over the year, median wind generation during the seven EEA3 events in 2022 was only 86 MW.

There were five EEA3 events in Q4. On November 29 a decrease in wind and solar generation to almost zero in the evening combined with low temperatures and several gas-fired outages, including a forced outage at Sundance 6, which resulted in an EEA3 being declared.

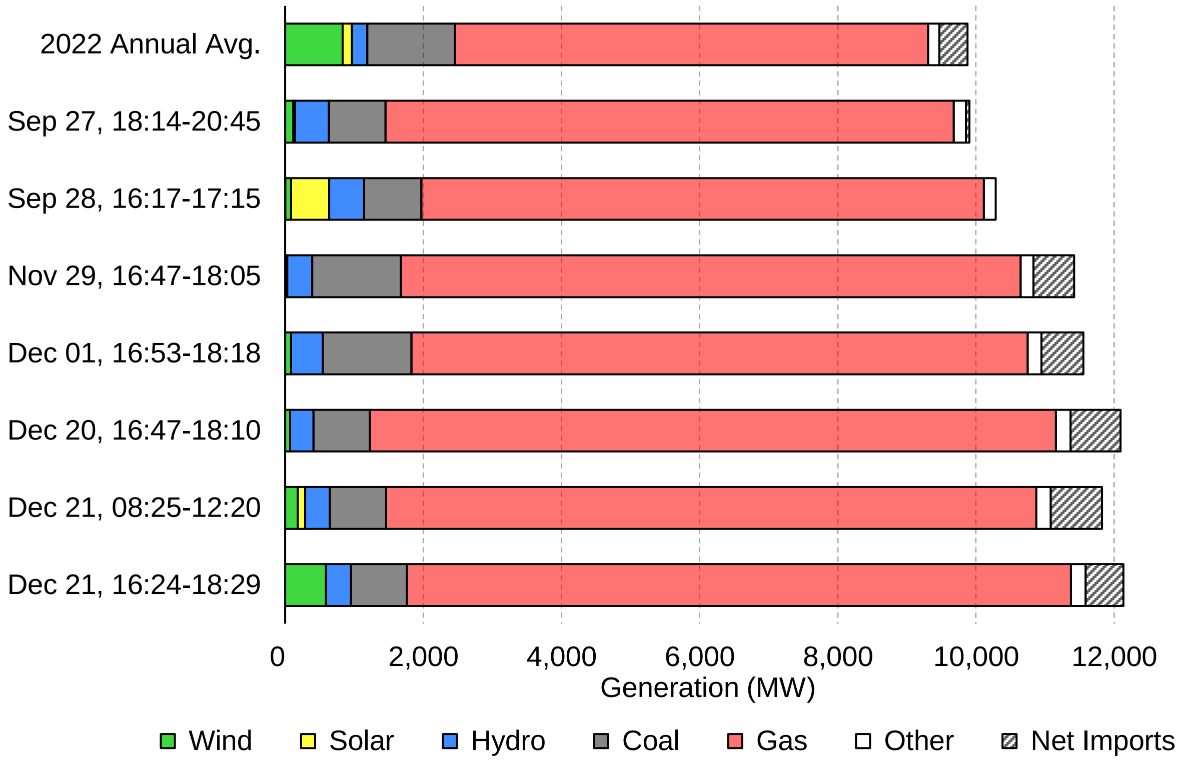
The EEA3 events declared on December 1 and 20 were largely the result of cold weather driving higher demand combined with low output from wind and solar generation. Overall thermal availability was relatively high on these dates.

The AESO declared an EEA3 twice on December 21. In the morning, Keephills 3 tripped offline during tight market conditions, causing the declaration of an EEA3 at 08:25 that lasted until 12:20. Later, during the evening peak of December 21, market conditions grew tighter as demand

[5] AESO: EOP-011 Emergency Operations

increased. An increase in wind generation during the demand peak period was a factor which contributed to the avoidance of firm load shed.

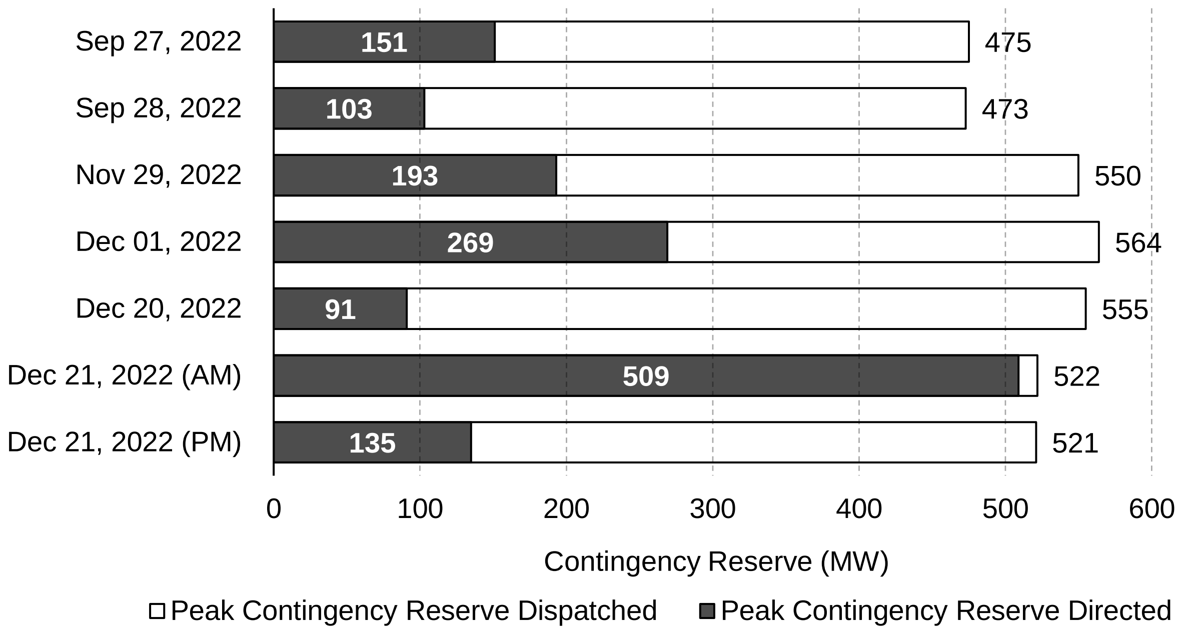
*Figure 10: Average generation by fuel type during EEA3 events in 2022*




The AESO procures contingency reserve to be used (directed-on) during contingency events such as a generator trip or the loss of an intertie carrying imports. Typical contingency events occur when there are still resources available in the energy market, but the system requires fast-responding contingency reserve resources. During an EEA, the AESO may direct on contingency reserve resources to maintain supply-demand balance when the energy market has been exhausted. Over the course of an EEA event, contingency reserve use changes as assets providing reserve are directed on or off.

Figure 11 shows the quantity of contingency reserve dispatched by the AESO during the EEA events in 2022. The figure also shows the highest quantity of reserves directed-on to provide real power because of scarcity during the EEA3 events in 2022. The AESO used 98% of contingency reserve from 08:03 to 08:21 on December 21, just prior to declaring an EEA3 at 08:25. The directives in this instance were a response to the trip at Keephills 3, which was a supply loss of 463 MW.

*Figure 11: Peak contingency reserve use during EEA3 events in 2022*




## 1.3 Market outcomes

Figure 12 shows the daily average pool price from October 1 to December 31 of 2022 and 2021. The highest daily average pool price in Q4 2022 was $738.07/MWh on December 20, which was driven by cold weather, high demand, low renewable generation, and offer behaviour. The daily average price on December 20 was the second highest on record, with the highest set on September 14, 2022 at $761.72/MWh.

The lowest daily average price in the quarter occurred on October 24 when prices averaged $36.73/MWh, a heat rate of 22 GJ/MWh relative to the same-day gas price. The lower pool prices on this day were driven by high renewable generation, low natural gas prices, and low demand.

The higher prices in December were the result of high demand, large export volumes, and the offer behaviour of some larger suppliers. Figure 13 illustrates daily average temperatures in Q4 of 2022 and 2021. At the end of November, the beginning of December, and from December 20 to 22, periods of low temperatures contributed to tight market conditions (Figure 13). These weather patterns pushed up heating demand and reduced supply from wind generation.

Supply in Q4 was also lowered by an extended outage at the 300 MW HR Milner natural gas asset. That asset went offline in early September for a planned outage to transition the asset from simple cycle to combined cycle. The asset was originally scheduled to be back online in early November 2022, but the outage has been extended on a few occasions.[6] At the time of writing, the asset is expected to return in July 2023.

[6] Maxim Power – News Releases

*Figure 12: Daily average pool prices in Q4 (2022 and 2021)*

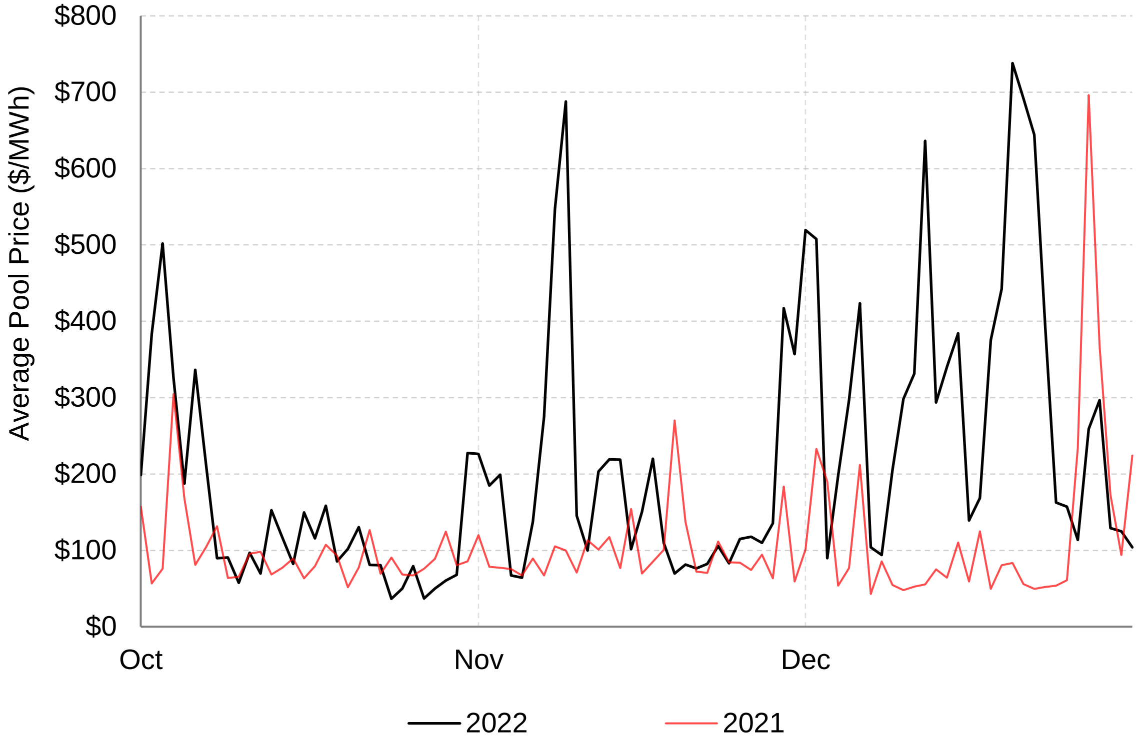
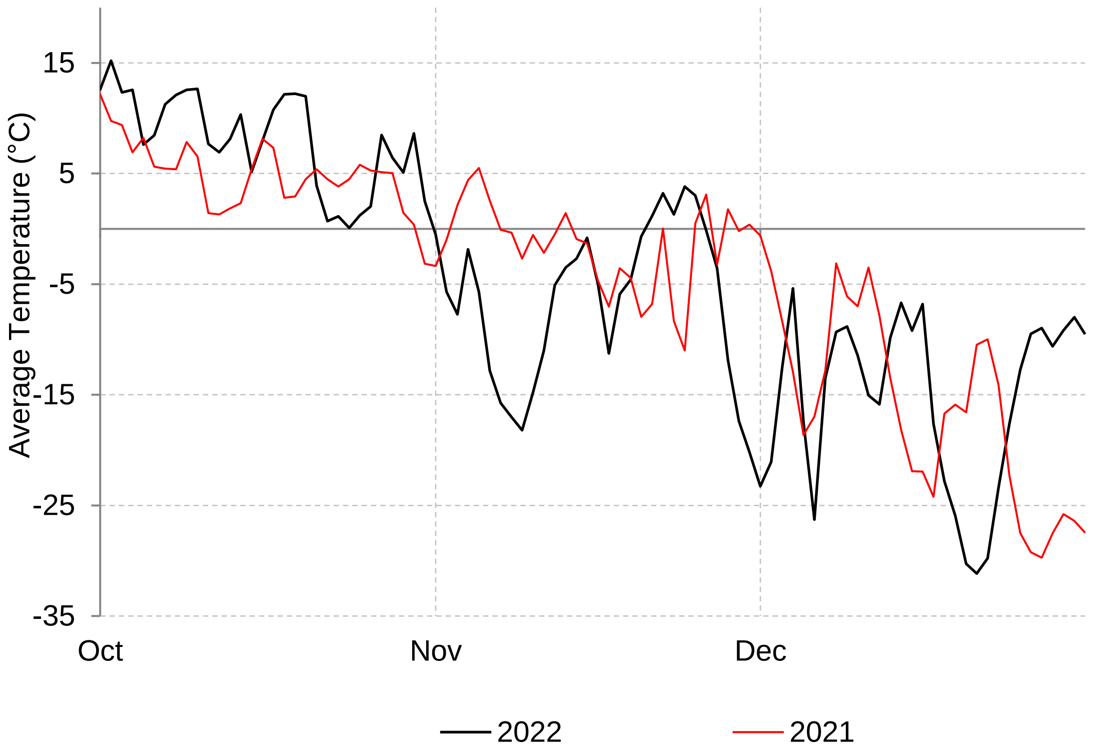



*Figure 13: Daily average temperatures in Q4 (2022 and 2021)*



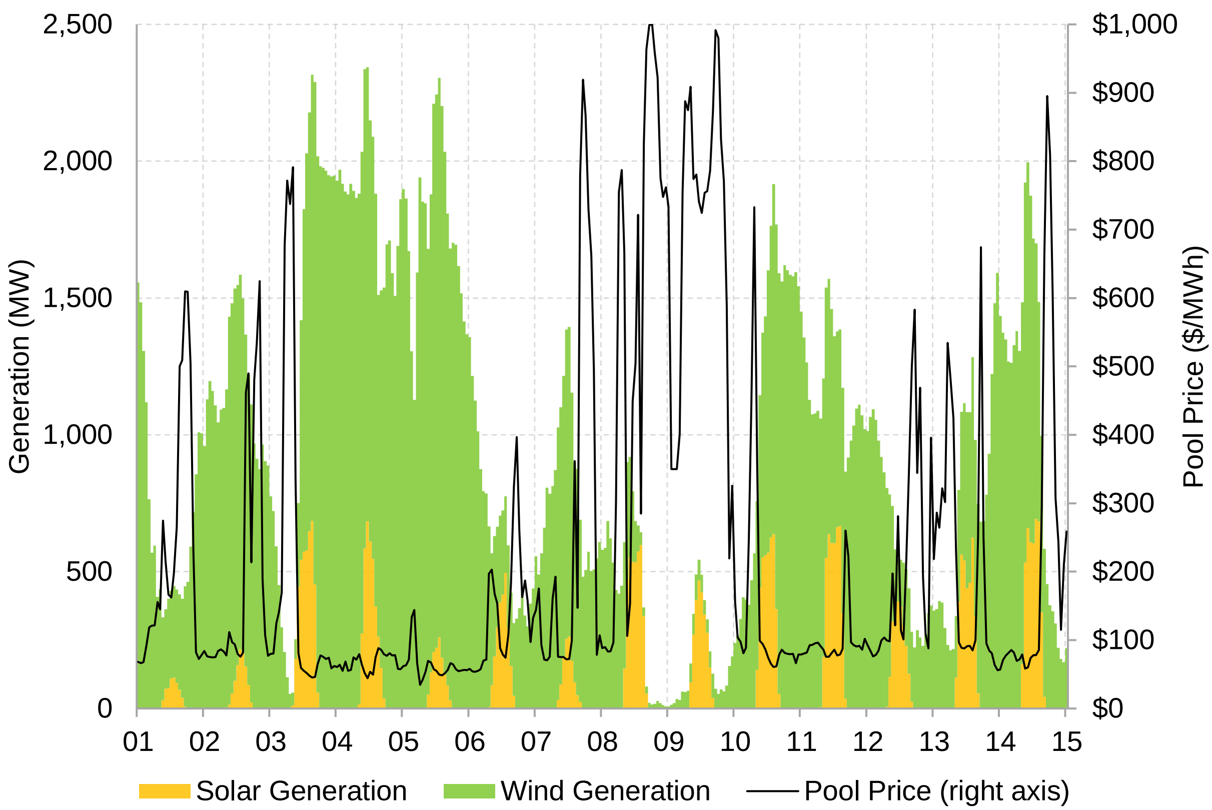
The volatility of renewable output was a major driver of market outcomes in November, when the total hourly output from wind and solar assets ranged from 8 MW to 2,509 MW. Figure 14 illustrates hourly wind and solar generation from November 1 to 14, 2022.

As shown in Figure 14, pool prices were highly dependent upon the output of renewable generation during this period. When wind generation was high, pool prices were low, and when wind generation was low prices were often high. As a result, the average received price of wind generation was 40% less than the average pool price in November (Table 3).

The average received price for solar generation was also less than the average pool price in November and December due to the reduction in daylight hours; in winter months, the peak in market demand occurs in the evening following sunset (Table 4).

The capacity of renewable generation in Alberta is set to increase further in the coming months. The AESO recently estimated that 1,250 MW of wind and 1,030 MW of solar capacity will be added before the end of 2023.[7]

*Figure 14: Wind generation, solar generation, and pool prices (November 1 to 14, 2022)*

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[7] AESO Long Term Adequacy metrics, Generation Projects under Construction – February 2023

*Table 3: Average received prices for wind generation and pool prices by month in Q4 2022*

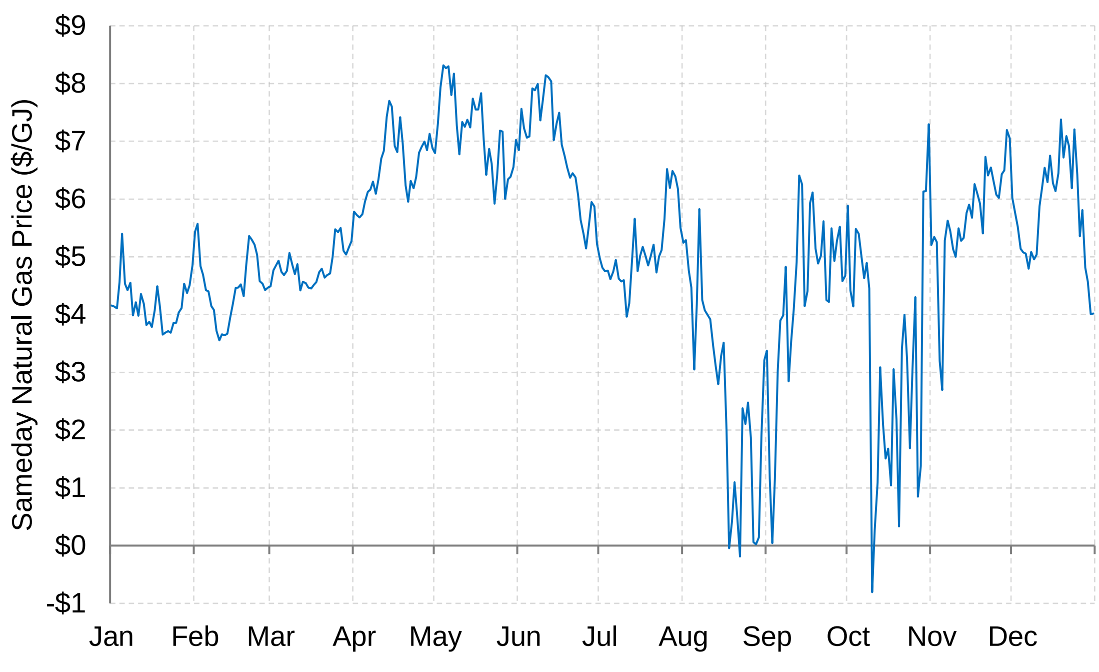
| | **Received price ($/MWh)** | **Pool price ($/MWh)** | **Premium to pool price (%)** |
|---|---|---|---|
| October | $77.84 | $142.34 | -45% |
| November | $111.86 | $186.84 | -40% |
| December | $205.42 | $311.73 | -34% |

*Table 4: Average received prices for solar generation and pool prices by month in Q4 2022*

| | **Received price ($/MWh)** | **Pool price ($/MWh)** | **Premium to pool price (%)** |
|---|---|---|---|
| October | $151.36 | $142.34 | 6% |
| November | $145.99 | $186.84 | -22% |
| December | $256.06 | $311.73 | -18% |

Pool prices in the first week of October were elevated because of offer behaviour, reduced wind generation, a planned outage on the BC/MATL intertie, and a planned generation outage at Genesee 3. On the evening of October 6, the BC intertie returned to service, increasing import supply. This return to service was a factor in lowering pool prices for the remainder of the month. In addition, wind generation was generally higher after the first week in October, weather conditions were mild, and natural gas prices were low. Same-day natural gas prices in Alberta fell from $4.45/GJ on October 9 to a low of -$0.80/GJ on October 10 and remained relatively low for much of the month (Figure 15). The low natural gas prices during this period were because of pipeline constraints, which meant Alberta export and storage volumes were limited.

*Figure 15: Same-day natural gas prices at AB-NIT in 2022*



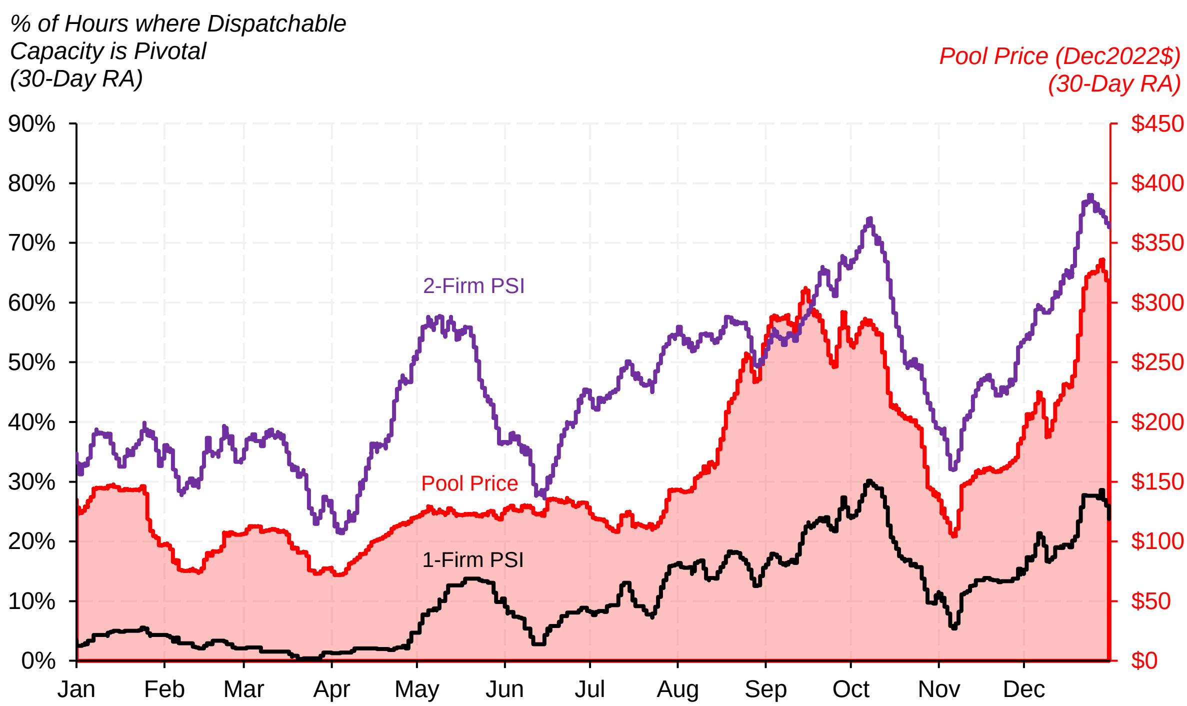
## 1.4 Market power: Pivotality of large generators, markups, and net revenues[8]

Market power was a significant contributor to high pool prices in Q4 2022. This section explores the extent of the market power that was exercised and its impact on pool prices.

### *1.4.1 Prevalence of pivotality*

Generators had market power in a similar number of hours in Q3 and Q4, but many of the Q4 hours where generators had market power were concentrated in December, resulting in historically high prices in that month (Figure 16).

*Figure 16: 1- and 2-Firm adjusted PSI, January to December 2022 (30-day rolling average)*




Market power in this section is proxied using the Pivotal Supplier Index (PSI), which indicates whether a generator is pivotal in a particular hour. A generator is pivotal if the energy market cannot clear without some of their supply. This measure is constructed using only a generator's dispatchable capacity.[9]

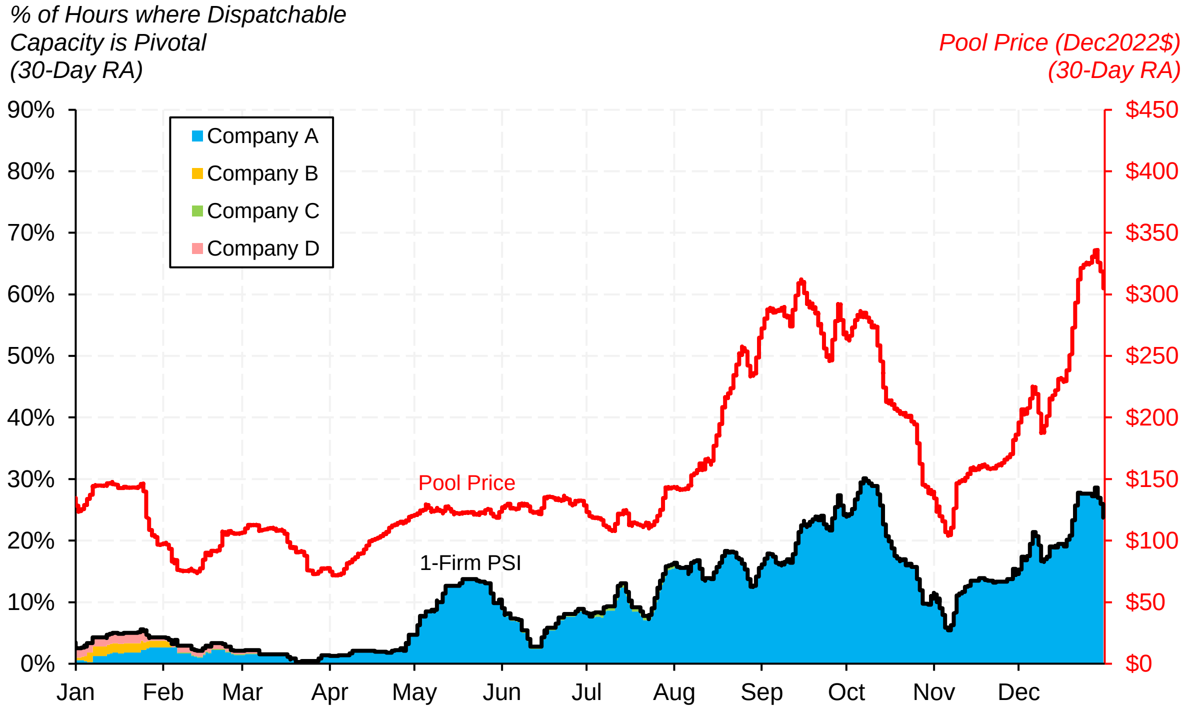
The PSI measure can analyze generators individually or collectively with other generators. 1-Firm PSI measures the frequency of hours where the largest company was pivotal. In 2022 four companies were pivotal in at least one hour while also having the most dispatchable capacity that

[8] Estimated historical data in this section has been revised to reflect updated data and demand estimates. As a result, some figures may appear moderately different from previous quarterly reports.

[9] Dispatchable capacity refers to a company's capacity priced above $0/MWh.

hour (denoted companies A through D). Company A was pivotal in 18% of hours in Q3 and 17% of hours in Q4 (Figure 17).

*Figure 17: Companies comprising the 1-Firm pivotal firm, January to December 2022 (30-day rolling average)*




Two companies are collectively pivotal in hours where their combined dispatchable capacity is needed for the market to clear. The 2-Firm PSI measures the frequency of hours where this is the case with respect to the two largest companies.

The two largest firms were collectively pivotal in 57% of hours in Q3 and 56% of hours in Q4. Company A and B were often the two largest companies that were pivotal in the second half of 2022 (Figure 18). In hours where the two largest firms were collectively pivotal, Company A was one of these companies in 99.8% of such hours in Q3 and 100% of such hours in Q4, whereas Company B was one of these companies in 92% of hours in Q3 and 81% of such hours in Q4.

The frequency with which generators were pivotal generally increased as 2022 progressed (Figure 19). The monthly share of hours in which the two largest companies were both individually pivotal increased throughout the year, reaching 11% in December due to the scarcity conditions present in that month.

*Figure 18: Companies comprising the 2-Firm pivotal firms, January to December 2022 (30-day rolling average)*

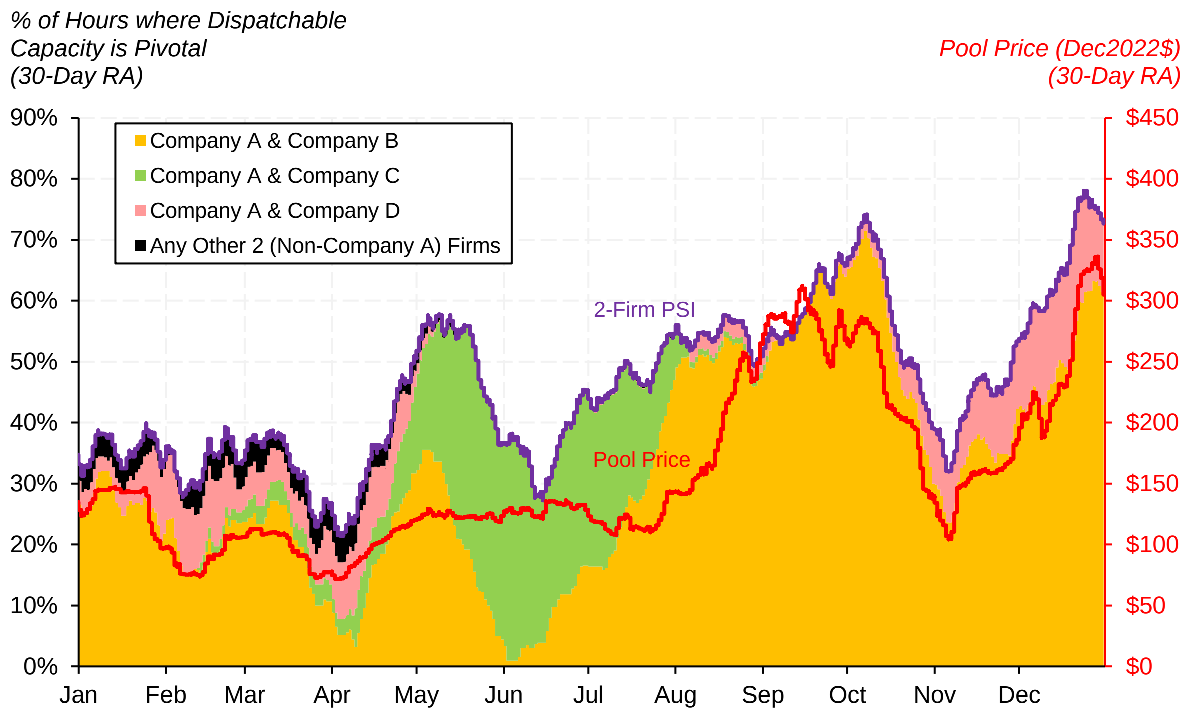
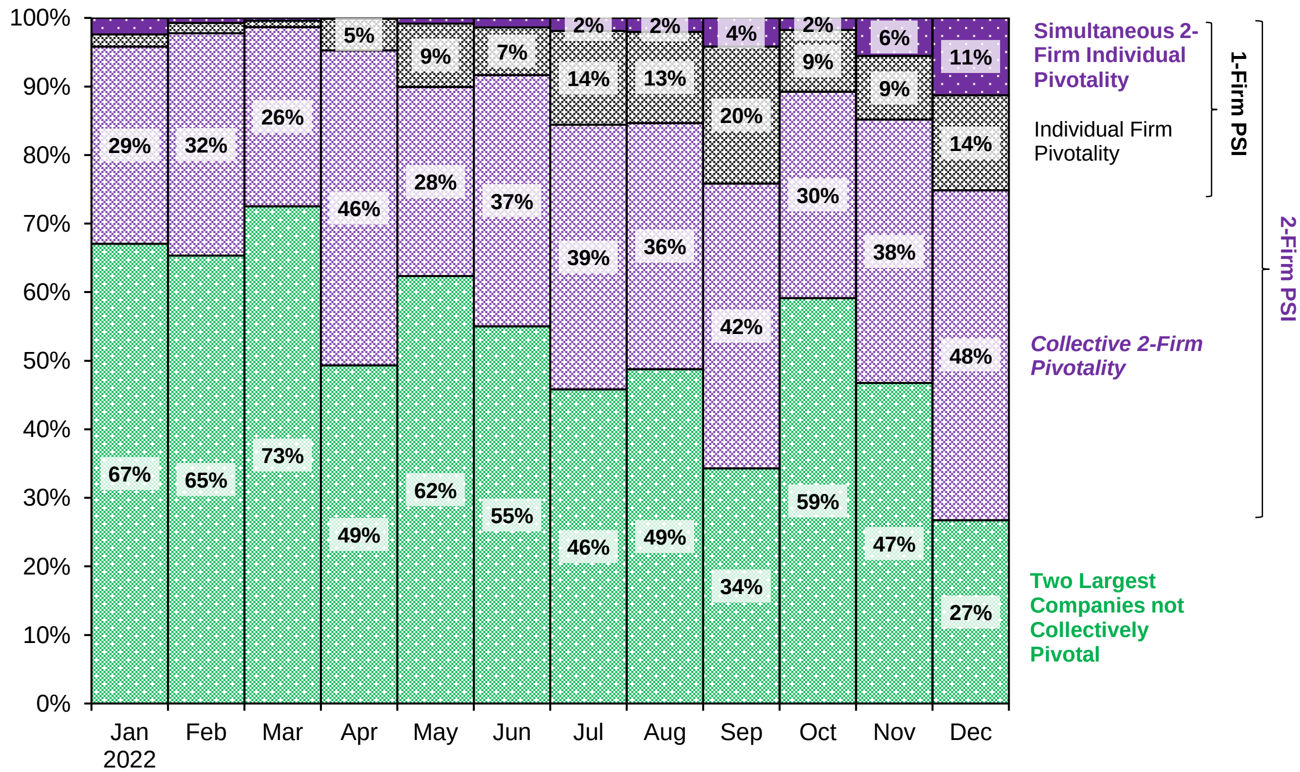


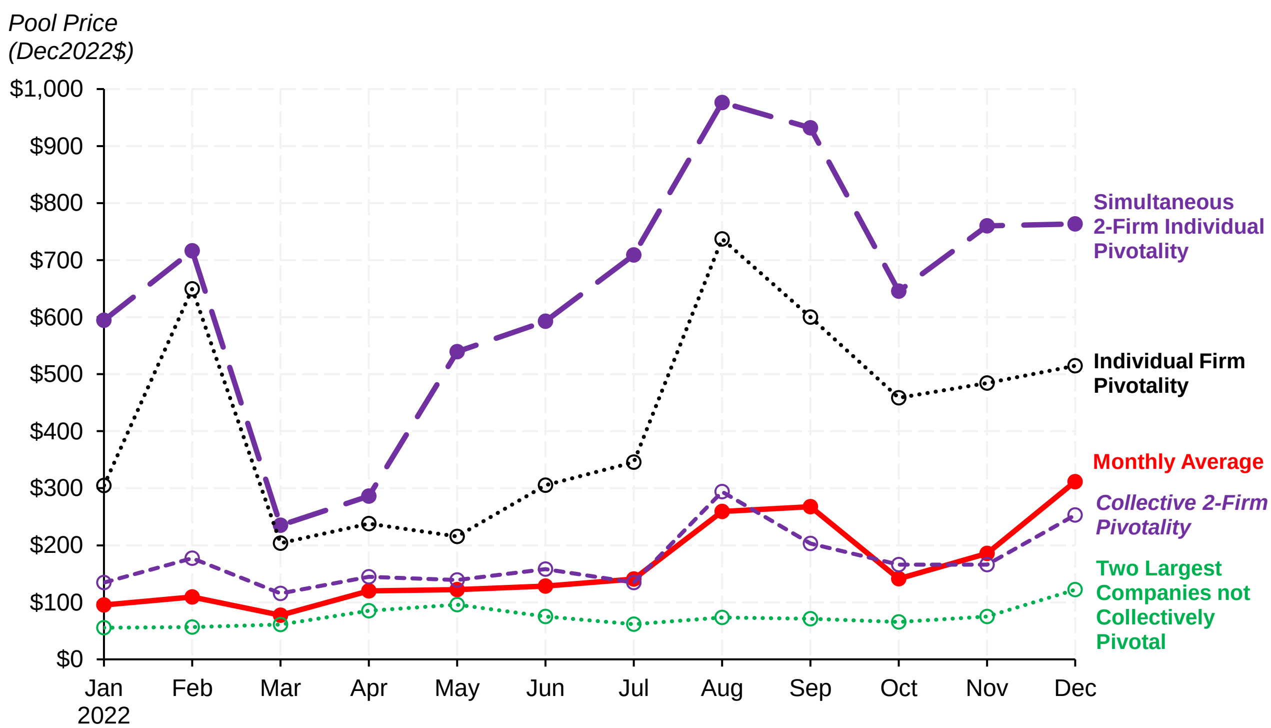

*Figure 19: Monthly frequency of pivotality conditions, January to December 2022*



Hourly pool prices differed depending on market conditions in each hour of 2022. In hours where the top two generators were not pivotal, pool prices were relatively low and stable throughout January to November (Figure 20). This changed in December, where pool prices increased in such hours due to higher demand, necessitating the dispatch of higher cost assets.

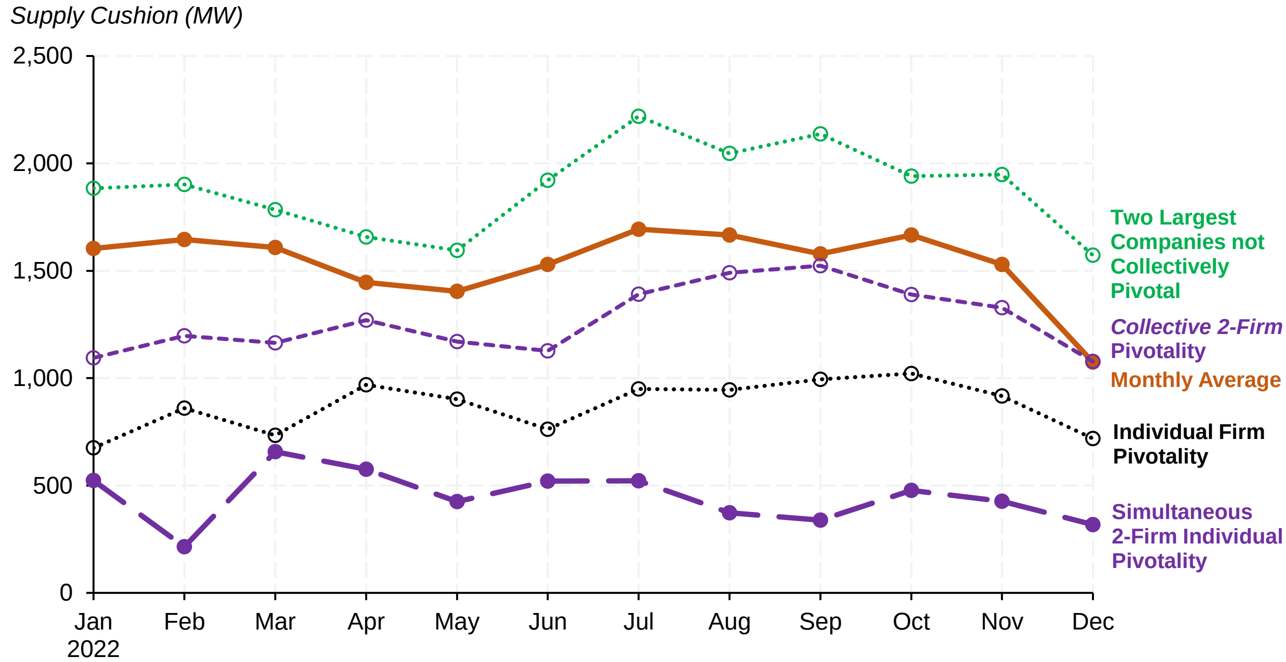
Pool prices were higher in hours where the first or second largest generators were pivotal, particularly in Q3 and Q4. Hours where two companies were collectively pivotal drove most of the increases in pool prices observed in August, September, and December, with prices higher in hours where only one firm was pivotal, and even more so in hours where each of the two largest firms were individually pivotal.

*Figure 20: Average pool prices during different market conditions, January to December 2022*




All else equal, where supply cushion is lower, a pivotal company faces greater residual demand that only it can serve, incentivizing it to offer its dispatchable capacity at higher prices. For given levels of pivotality, the average supply cushion was relatively stable across the summer of 2022, and declined in November and December (Figure 21). This suggests firms that were pivotal had an increased incentive to exercise market power by offering their dispatchable capacity at higher prices in November and December than in the summer months, all else equal.

*Figure 21: Average supply cushion during different market conditions, January to December 2022*




### *1.4.2 Impact of market power*

The impact of the exercise of market power can be seen in the differences between observed pool prices and counterfactual pool prices. Counterfactual pool prices are constructed by the MSA based on an energy market model where units are assumed to offer their capacity at short-run marginal cost (SRMC). The resulting average counterfactual pool prices are lower than observed pool prices (Figure 22). In 2022, the average pool price was $81/MWh higher than the counterfactual average pool price, which was largely driven by higher observed prices in August, September, and December (Figure 23).

Year-over-year, the average counterfactual pool price increased by $29/MWh, from $54/MWh in 2021 to $83/MWh in 2022, driven by asset retirements, increased demand, higher natural gas prices, and, to a lesser extent, higher carbon compliance costs. The counterfactual annual average price was also increased by scarcity conditions in December, which led to higher cost generators being dispatched in that month.

A common way to quantify the exercise of market power is to measure the extent to which price exceeds marginal cost. The Lerner index is used by the MSA for this purpose, and is defined as the price markup over marginal cost, expressed as a percentage of price. Market markups were similar in 2021 and 2022 (Figure 24).

*Figure 22: Annual average observed and counterfactual (SRMC offers) pool prices, 2013 to 2022*

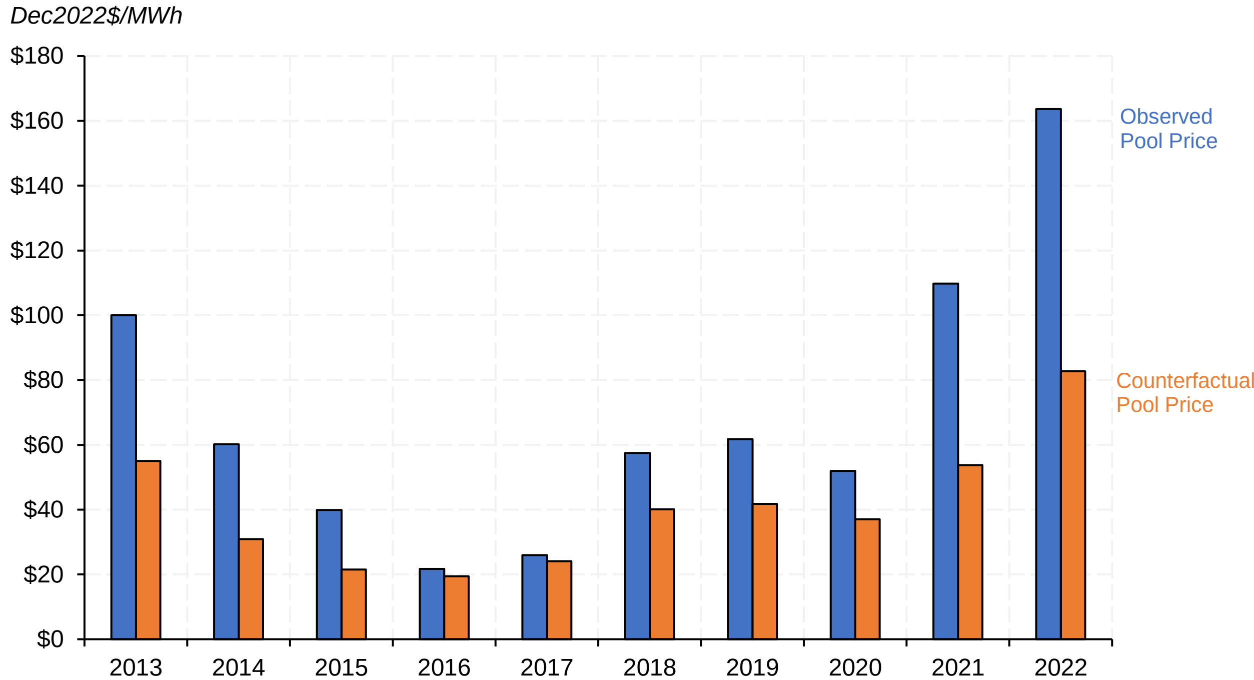



*Figure 23: Monthly average observed and counterfactual (SRMC offers) pool prices, January to December 2022*

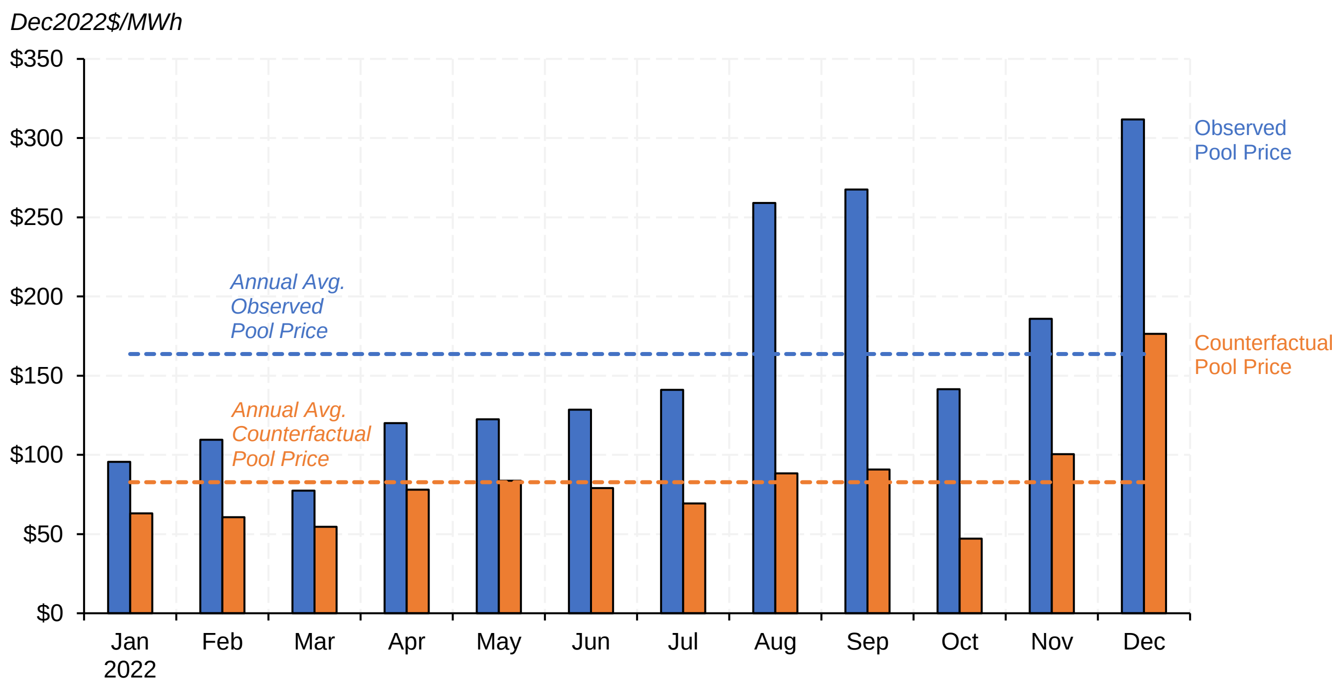
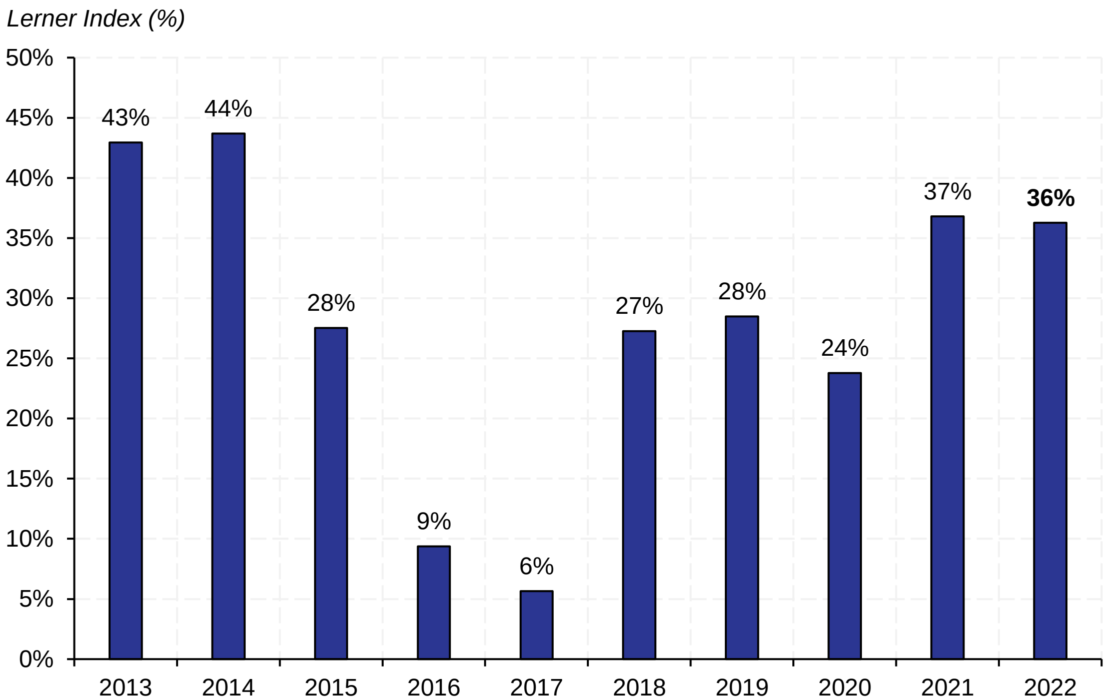


*Figure 24: Average of hourly market markups by year, 2013 to 2022*[10]




Market markups averaged below 30% for the first six months of 2022 and increased over the second half of the year when market power was more frequent and was exercised to a greater extent (Figure 25).

The market markup in hours where companies were not pivotal also increased. This is consistent with declines in same day natural gas costs, such as in August and October, not being reflected in the offers of natural gas-fired generators (Figure 26). This generally increased the market markup in hours where no companies were pivotal in these periods despite little change in pool prices in such hours (Figure 20).

---

[10] In a given hour, the Lerner index is calculated as the observed price less the marginal cost of the asset setting price if assets had been dispatched according to marginal cost, expressed as a percentage of the price. Demand is not changed in the Lerner index calculation.

To calculate the counterfactual prices reported in Figures 22 and 23, the offers of all assets are set to SRMC, and demand may change because of the different price level.

*Figure 25: Average market markups & market markups in hours without pivotality, January to December 2022*

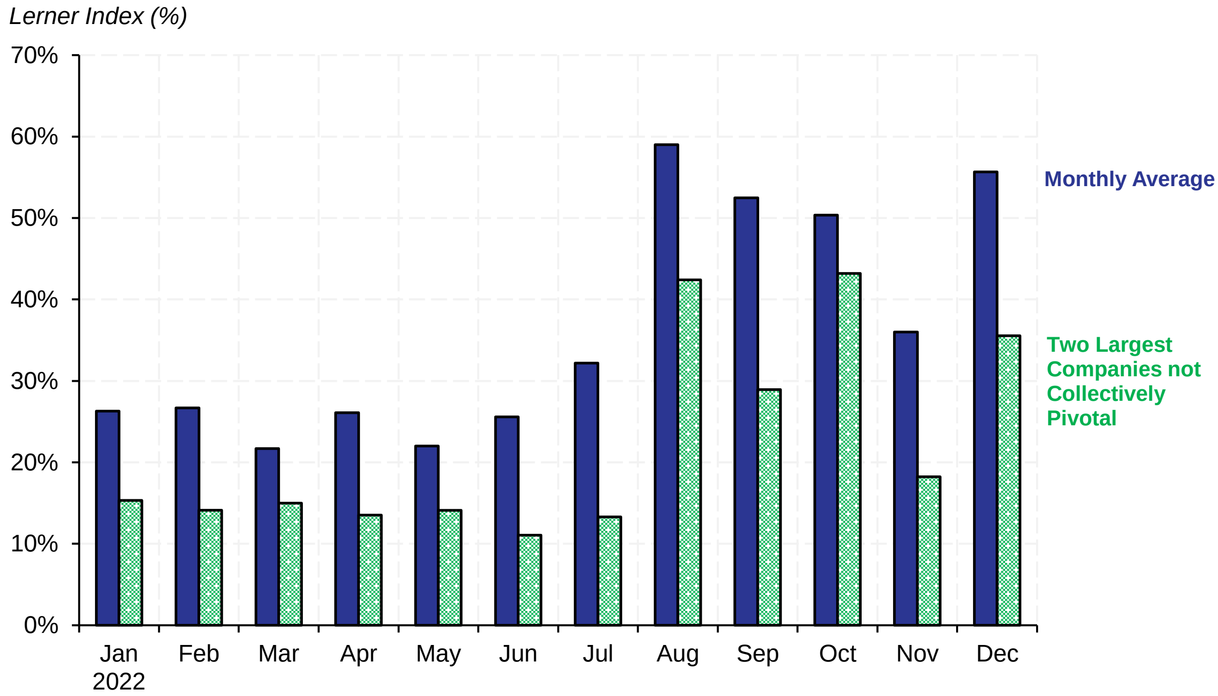
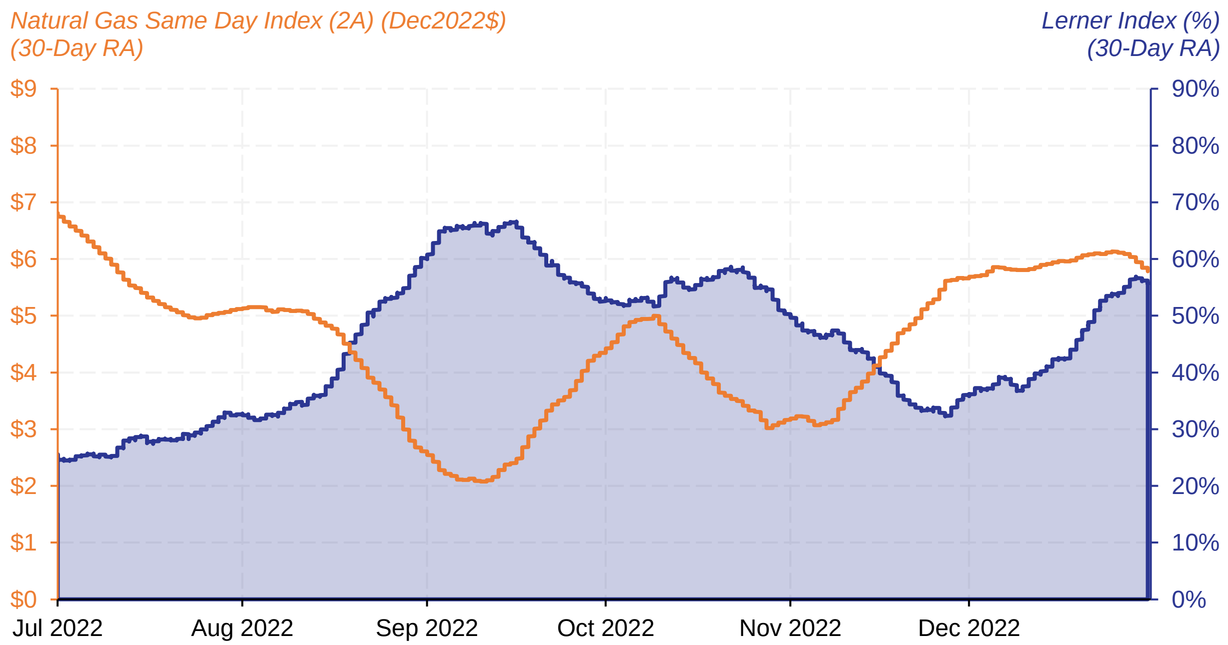


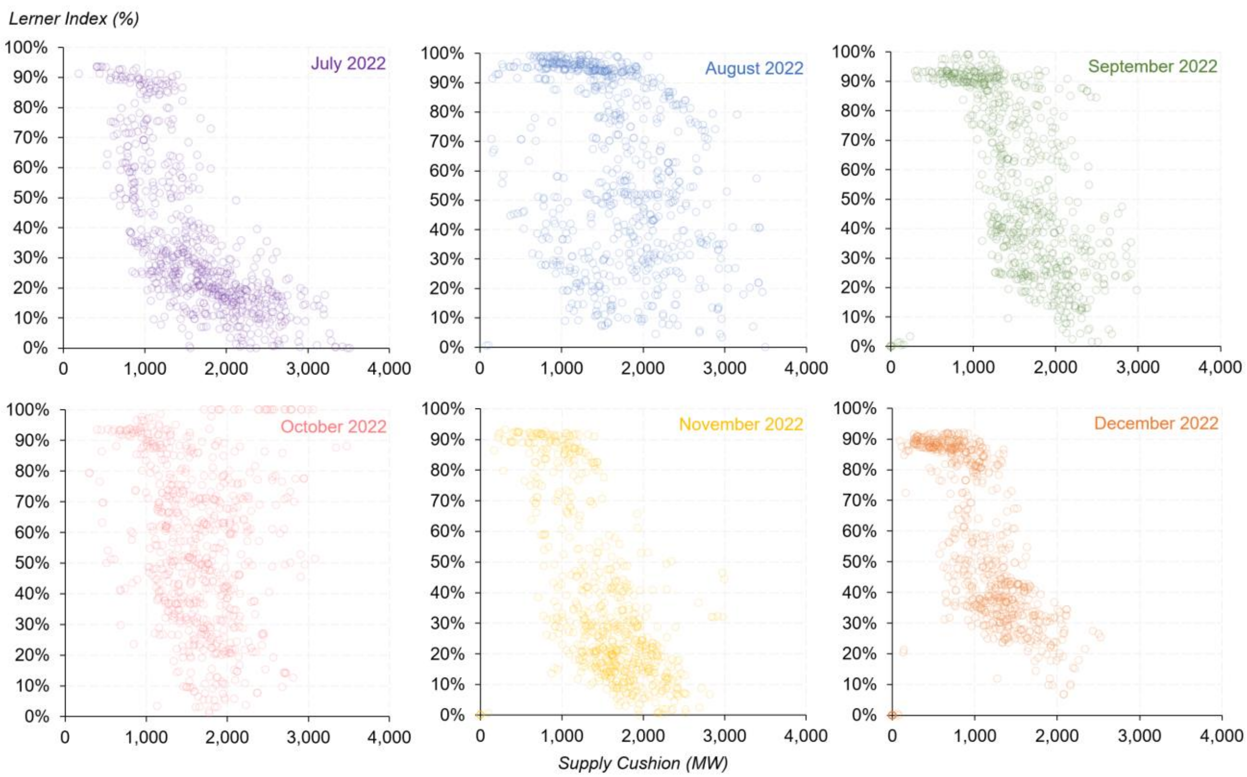

*Figure 26: Natural gas 2A price index and market markups, July to December 2022 (30-day rolling average)*



Market power was exercised to a lesser extent in December than in August and September, and that exercise of market power in December more often occurred in relatively scarce periods (Figure 27). All else equal, as the energy market becomes tighter, companies have a greater ability to exercise market power by increasing their offer prices.

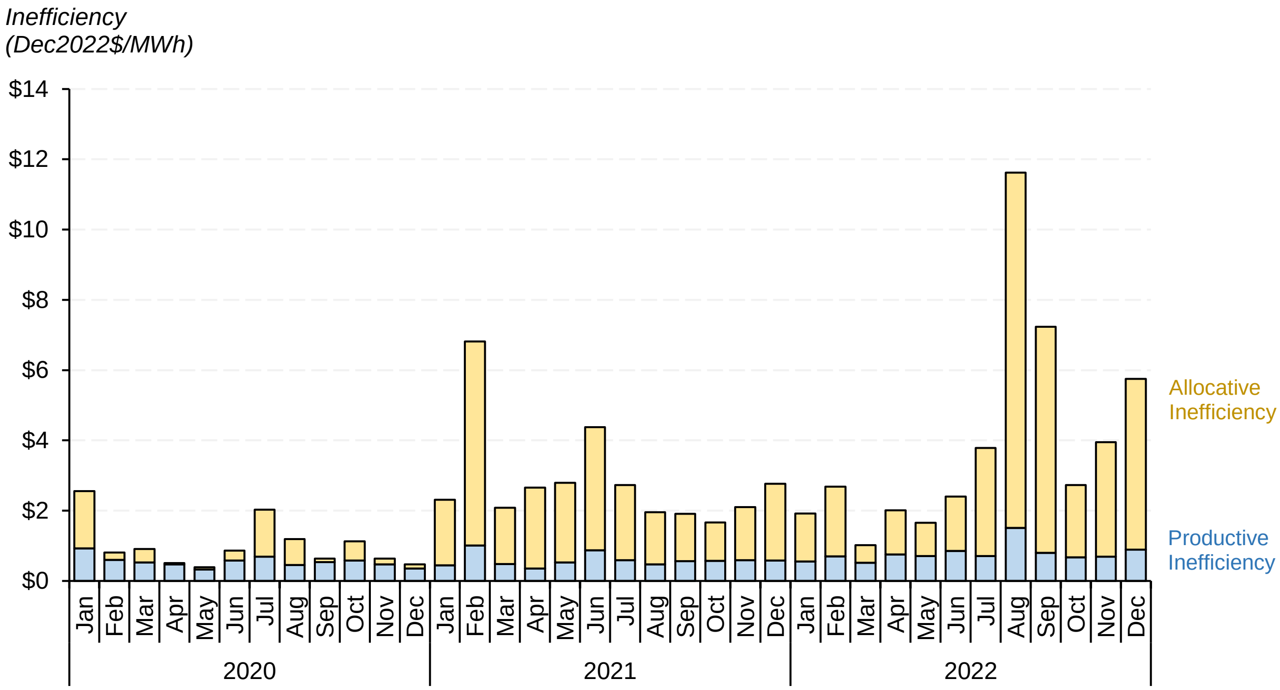
In August and September high markups were often associated with moderate supply cushion levels, around 1,000 to 2,000 MW, whereas high markups in December typically occurred in hours where the supply cushion was lower, indicative of the relative scarcity observed in that month. It is also notable that in December there were hours of extreme scarcity when the supply cushion was 0 MW, which was less often the case in prior months. In these hours, the market markup was 0%, reflective of the high opportunity costs of hydro generation and the exhaustion of available supply.

*Figure 27: Supply cushion vs. Lerner index, July to December 2022*



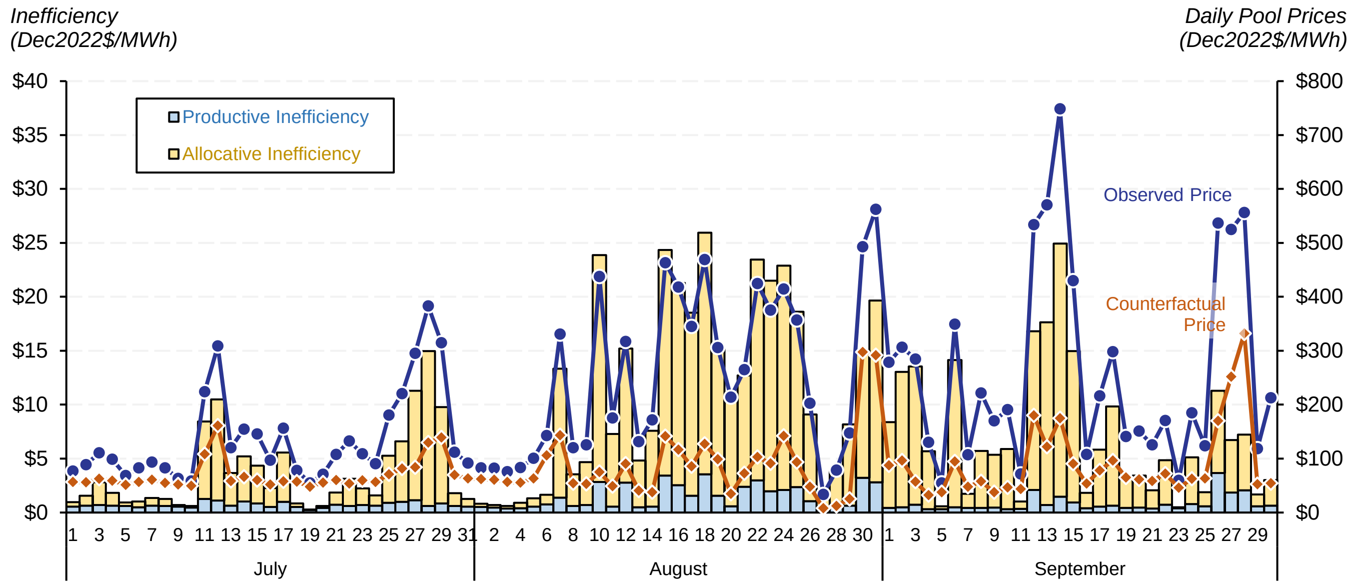

Static inefficiencies in 2022 were higher than in 2020 and 2021 and were primarily driven by high market prices in August, September, and December, to a lesser degree (Figure 28). Despite December having the highest prices of any month in 2022, static inefficiencies were comparatively low due to the relative scarcity conditions seen in that month.

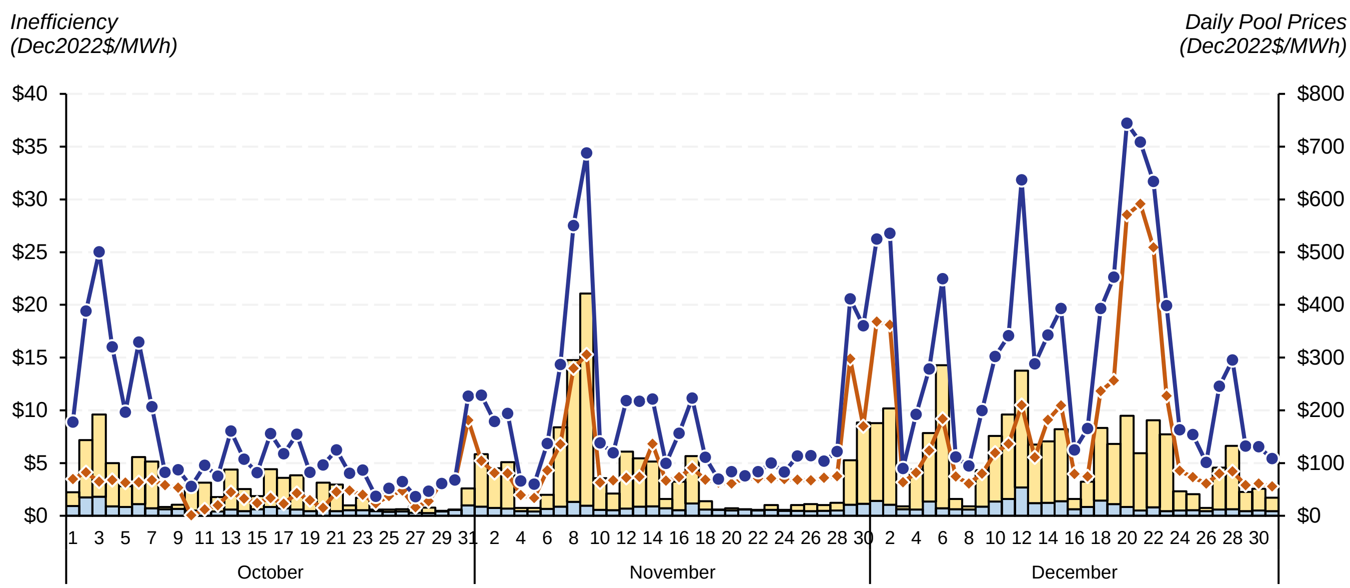
*Figure 28: Monthly average static inefficiency, 2020 to 2022*




Daily average static inefficiencies over Q3 and Q4 were positively correlated with daily pool prices (Figure 29). This was particularly true in months with limited scarcity like August, where counterfactual SRMC-based offer prices were well below observed pool prices, reflective of economic withholding. While static inefficiencies did occur in December, they were typically higher in August and September when observed pool prices exceeded SRMC-based prices and the market was not in periods of scarcity. Periods of extreme scarcity, such as occurred between December 20 and 22, exhibit lower static inefficiencies despite having very high daily prices.

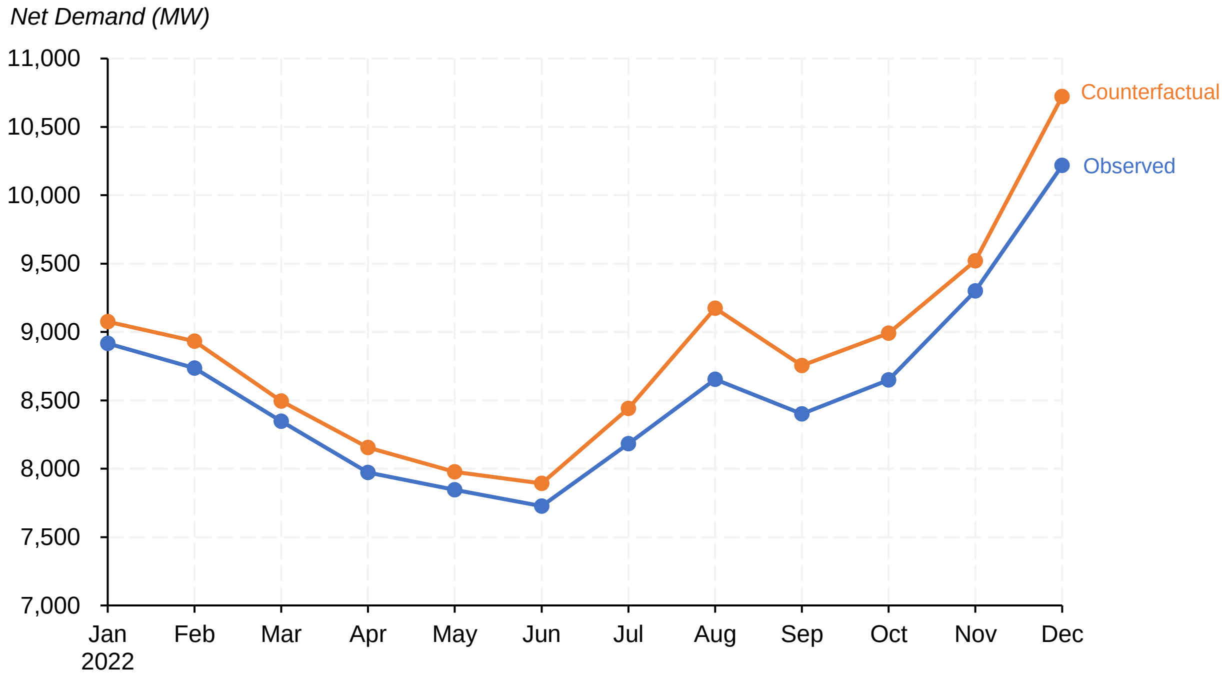
*Figure 29: Daily average static inefficiency, observed pool prices, counterfactual (SRMC offers) pool prices, July to December 2022*




Static inefficiency is driven by consumption foregone as a result of observed prices exceeding SRMC. The amount of consumption foregone increased in both August and December (Figure 30). Periods where significant consumption was foregone in August were associated with lower counterfactual SRMC-based prices, while periods with significant consumption foregone in December were generally associated with higher SRMC-based prices as a result of scarcity conditions in that month. The result was that static inefficiencies were higher in August than in December, despite similar quantities of consumption foregone in both months.

*Figure 30: Monthly observed and counterfactual (SRMC offers) net demand, January to December 2022*




### *1.4.3 Net revenues*

Hypothetical generators earned higher net revenues in 2022 compared to any previous year since 2013 (Figure 31). In a counterfactual market with SRMC offers, net revenues would have been sufficient to cover annualized capital costs for the hypothetical wind and combined cycle generator regardless of their weighted-average cost of capital (WACC), but only sufficient to recover annualized capital costs financed at the lowest WACC for gas peaker and solar units. This is an atypical result; on average over the past ten years SRMC-based offers would not enable generators to recover their capital costs.

Most of the 2022 net revenues earned by the hypothetical gas thermal units were earned in Q3 and Q4 (Figure 32). Net revenues earned by the hypothetical wind unit were relatively consistent through the year, but moderately higher in Q4 largely due to the impacts of higher wind generation and pool prices in off-peak periods that quarter. Net revenues for a hypothetical solar unit in 2022 were largely earned in Q3 when both pool prices and solar generating potential were high.

*Figure 31: Annual observed, counterfactual (SRMC offers) net revenues by hypothetical generator (Dec2022$ thousands/MW-year), 2013 to 2022*

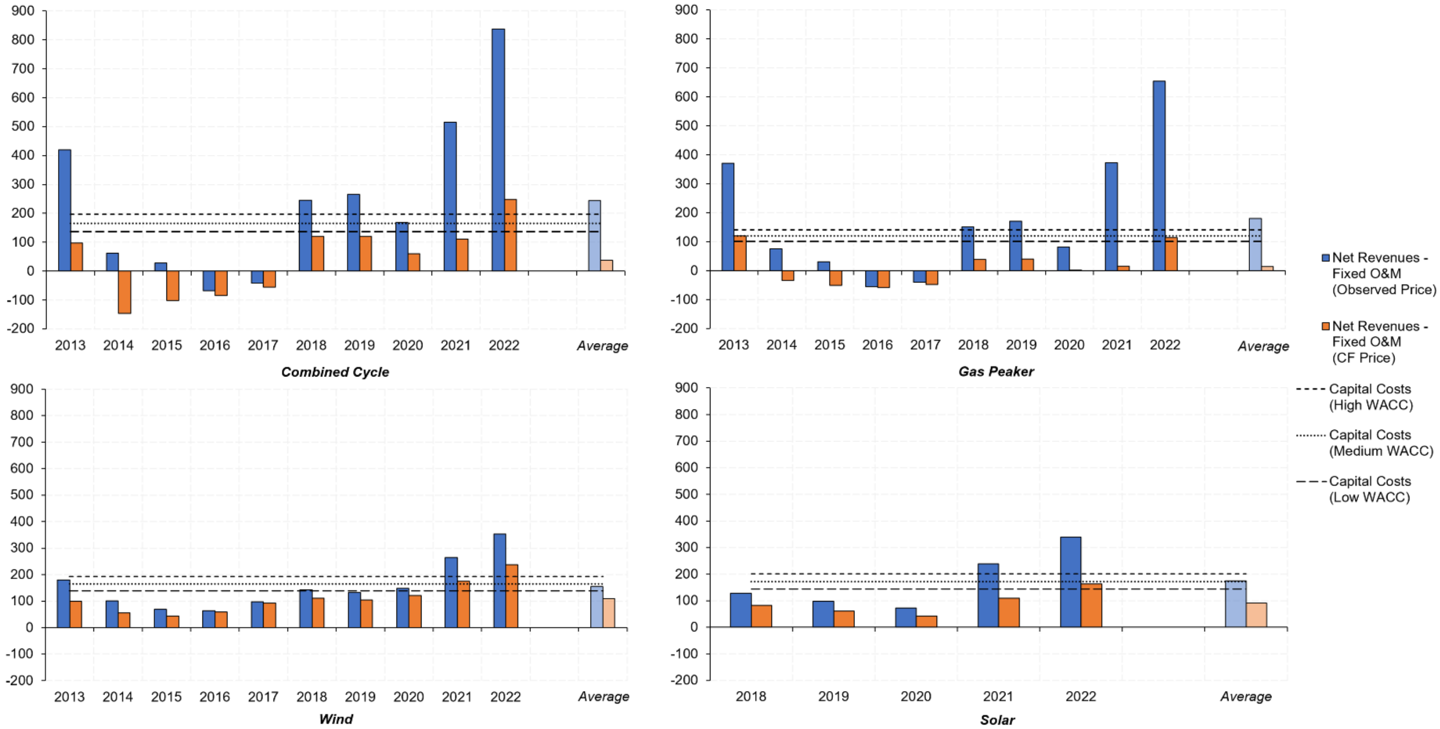
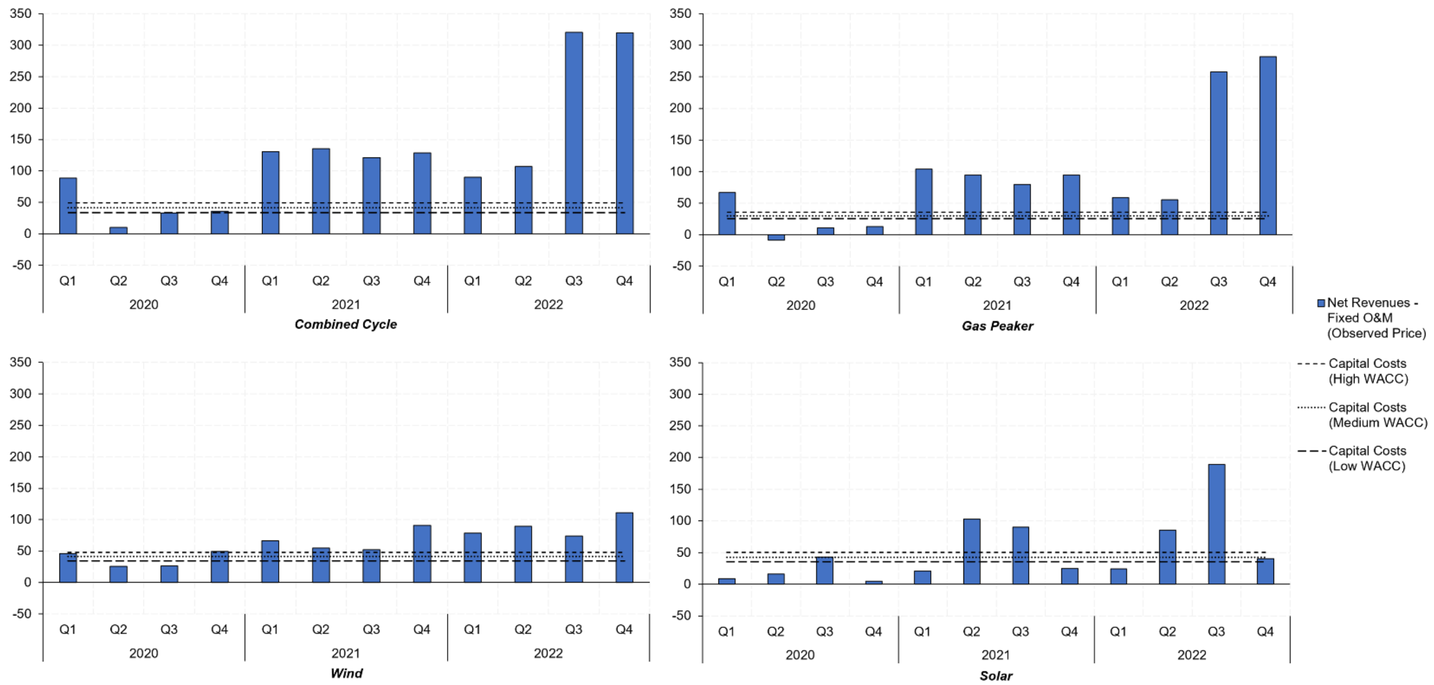
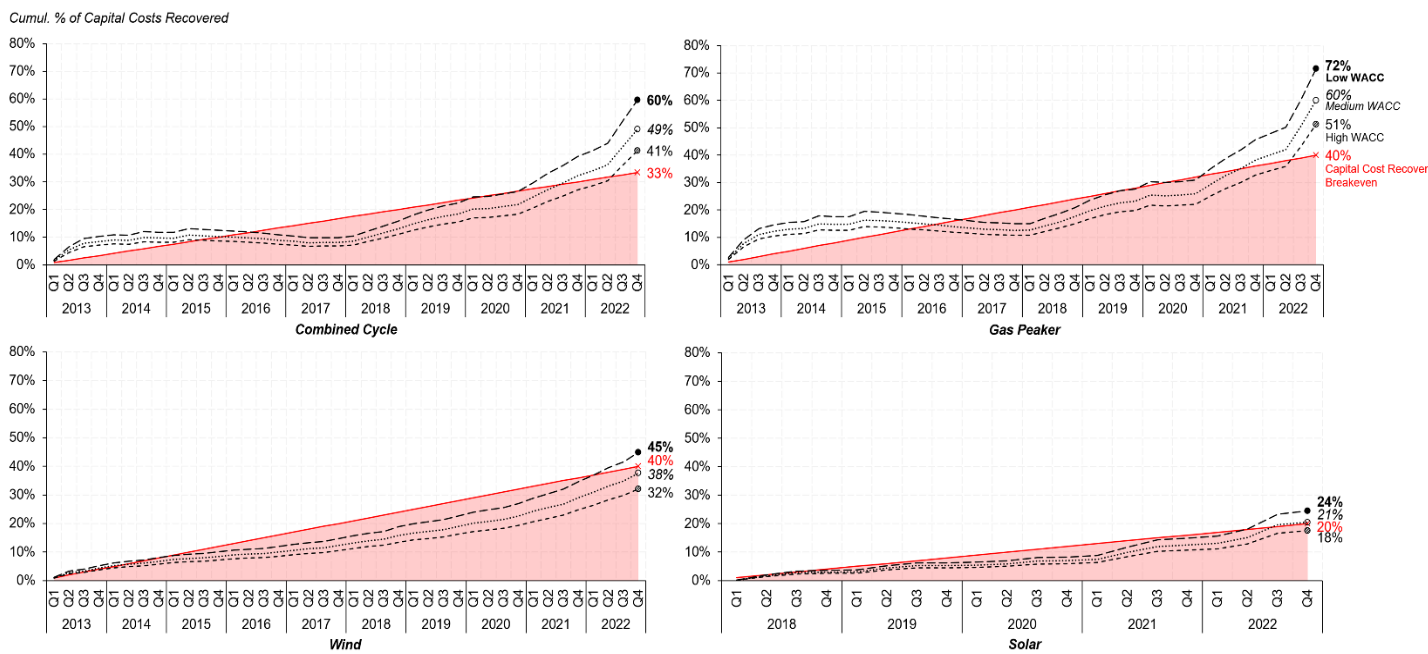



*Figure 32: Quarterly observed net revenues by hypothetical generator (Dec2022$ thousands/MW-year), 2020 to 2022*



Generators financed under different WACCs face different capital costs over their lifetime. All else equal, generators with a lower WACC will be able to recover their capital costs sooner than a generator with a higher WACC. Assuming the above hypothetical generators began operations in 2013 (2018 for solar), net revenues less fixed operations and maintenance costs in the Alberta energy market would have outpaced annualized capital costs financed at the lowest WACC by the end of 2022, with particularly high gains over capital costs in the past year (Figure 33). Notably, hypothetical combined cycle or gas peaking units would have earned more net revenues than its annualized capital costs financed at any of the three WACC levels over the last ten years, with much of this result stemming from prices in Q3 and Q4 2022.

*Figure 33: Quarterly cumulative capital cost recovery by hypothetical generator, 2013 to 2022*




Over 2021 to 2022 each of the four hypothetical units recovered sufficient net revenues to cover their annualized capital costs over those two years regardless of their WACC (Table 5). This was particularly true for combined cycle and gas peaker units, who recovered considerably more in net revenues than necessary to pay off two years' worth of annualized capital costs.

*Table 5: Capital costs recovered over 2021 to 2022 by hypothetical generator*

| | **Low WACC** | **Medium WACC** | **High WACC** | ***Two-year capital cost recovery breakeven*** |
|---|---|---|---|---|
| **Wind** | 17.8% | 15.0% | 12.8% | *8.0%* |
| **Solar** | 16.1% | 13.5% | 11.6% | *8.0%* |
| **Combined cycle** | 33.2% | 27.3% | 23.0% | *6.7%* |
| **Gas peaker** | 40.6% | 34.0% | 29.1% | *8.0%* |

### 1.5 Offer behaviour

This section analyzes the extent to which generator market power was exercised through increased offer prices. The analysis looks at how offer prices have changed over time in response to changes in the market, such as the supply and demand fundamentals. The section also analyzes the long-lead capacity that was taken offline for commercial reasons.

Figure 34 below illustrates trends in economic withholding since January 2020. The figure illustrates a 30-day rolling average of the amount of capacity that was offered into the energy market above $250/MWh, or well above marginal production costs.

In Q3 there was a marked increase in the amount of capacity offered at higher prices. The 30-day rolling average peaked at around 1,600 MW in late September, which surpassed the levels seen in early 2021 following the expiry of the remaining PPAs.

In Q4 the amount of capacity offered higher in the supply curve declined, and the 30-day rolling average ended the quarter at around 1,000 MW. As shown by Figure 34, 1,000 MW is similar to the amount of capacity offered at higher prices during Q2 but is higher than the levels observed in 2020.

*Figure 34: Available capacity offered above $250/MWh, 30-day rolling average (January 1, 2020 to December 31, 2022)*

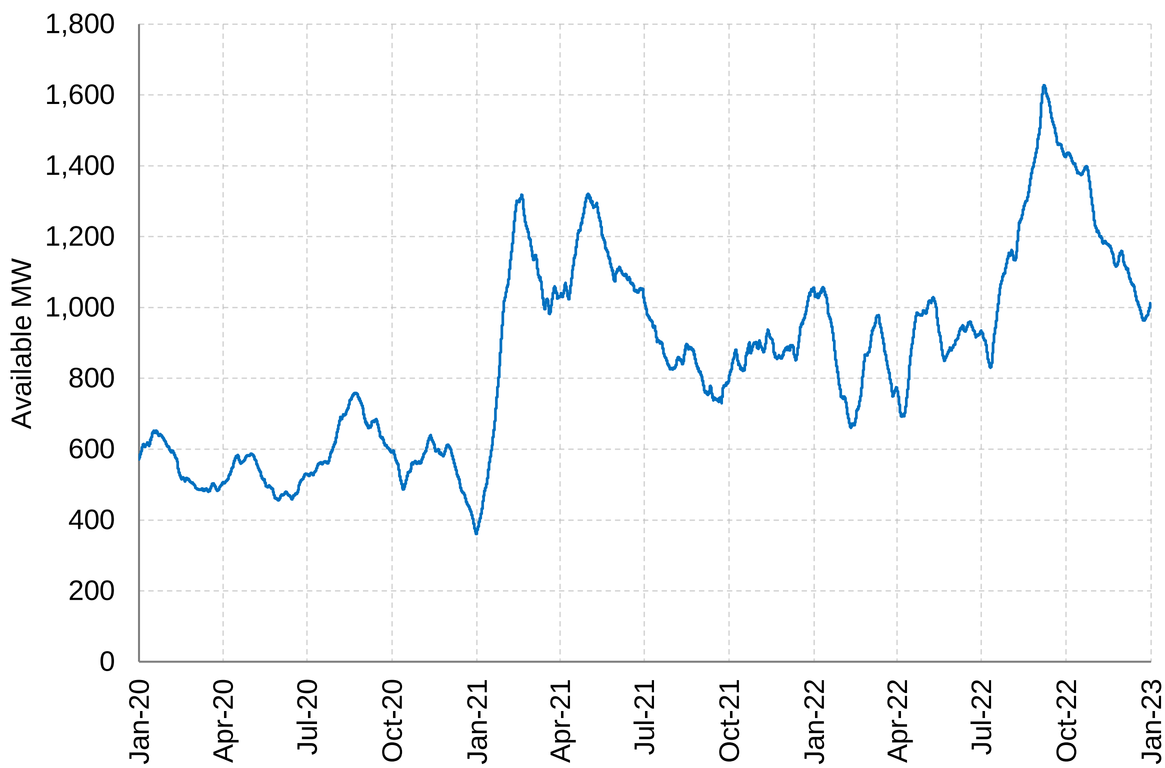
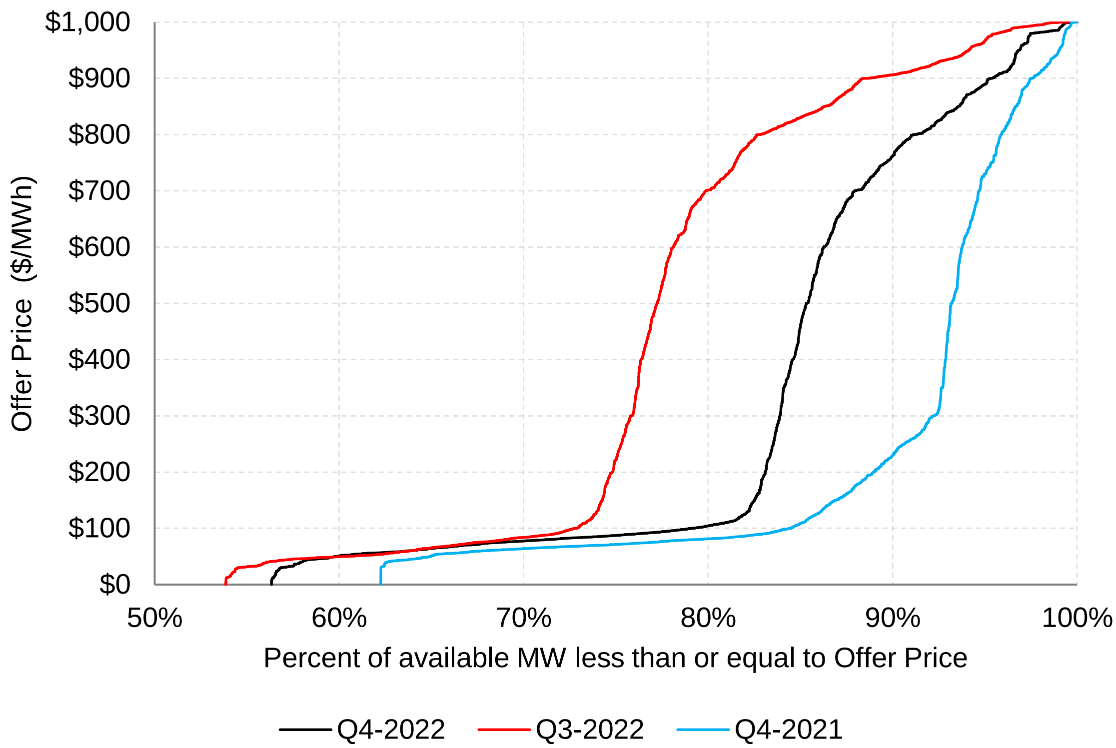


Figure 35 illustrates duration curves of offer prices on coal and converted coal assets. These assets include the thermal generating units at Battle River, Genesee, Keephills, Sheerness, and Sundance. In total, these assets represent around 3,900 MW of generation capacity and are a meaningful portion of the dispatchable capacity in Alberta.

The figure illustrates a rightward shift from Q3 to Q4, indicating that offer prices on these assets were generally lower in Q4. For example, in Q3 80% of coal and converted coal capacity was offered below $700/MWh and 20% was offered above $700/MWh. In Q4, 12% of available coal and converted coal capacity was offered above $700/MWh, or 8% less than in Q3.

Figure 35 illustrates a leftward shift year-over-year from Q4 2021 to Q4 2022, showing that offer prices on these assets were generally higher in Q4 2022 relative to Q4 2021. For example, in Q4 2021 5% of available coal and converted coal capacity was offered above $700/MWh, compared to 12% in Q4 2022.

*Figure 35: Offer duration curves for available coal and converted coal capacity (Q4-2022, Q3-2022, and Q4-2021)*




Changes in offer prices can have an impact on price outcomes in the energy market. Figure 36 illustrates the relationship between pool prices and supply cushion in Q4 2022 and Q4 2021. Supply cushion is the amount of available generation capacity in the energy market that is not being used to serve prevailing demand. A lower supply cushion indicates a tighter supply-demand balance in the energy market, whereas a higher supply cushion indicates more available supply relative to demand.

As shown in Figure 36, when the supply cushion was under 1,300 MW pool prices were generally higher in Q4 2022 compared to Q4 2021 for the same level of supply cushion. The higher pool prices in Q4 2022 during these hours was largely the result of higher offer prices submitted by larger suppliers in the market.

*Figure 36: The relationship between hourly pool prices and supply cushion (Q4-2022 and Q4-2021)*[11]

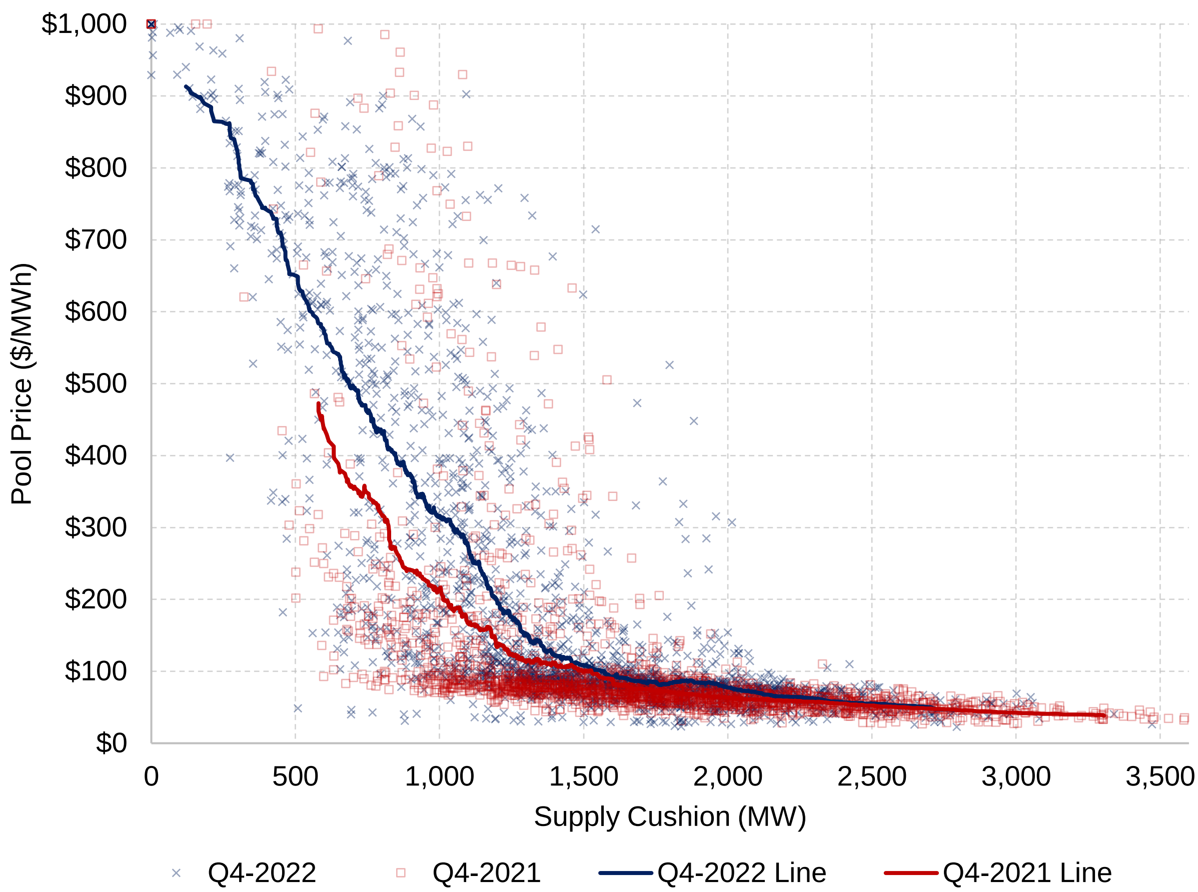



Figure 37 illustrates monthly average pool prices since January 2018 alongside the number of hours in each month where the supply cushion was under 800 MW. For context, 800 MW is equivalent to the full capacity of two large gas-fired steam generation assets. The number of hours with a supply cushion of under 800 MW provides a general measure of market tightness for each month.

The figure illustrates a marked change at the beginning of 2021 when the remaining PPAs expired. Following the expiration of the PPAs, average pool prices increased for a similar level of

[11] The lines in the figure illustrate the average pool price amongst 200 observations with supply cushion values around that particular supply cushion point; 100 observations above and 100 below. No averages were taken once there were under 50 observations.

market tightness. In August and September of 2022 pool prices were notably high despite the fact there were relatively few hours with a supply cushion of under 800 MW.

In December market conditions were tighter. The number of hours with a supply cushion of under 800 MW was 215 in December compared to 60 in August and 63 in September. The average pool price in December was $311.73/MWh, a new record and an increase of 17% over the previous record set in September.

In February 2019 the supply cushion was under 800 MW in 242 hours, which was 27 more than in December. The average pool price in February 2019 was much lower at $109.21/MWh, approximately a third of the average pool price in December.

*Figure 37: Monthly average pool price and the number of hours in which supply cushion was below 800 MW (January 2018 to December 2022)*

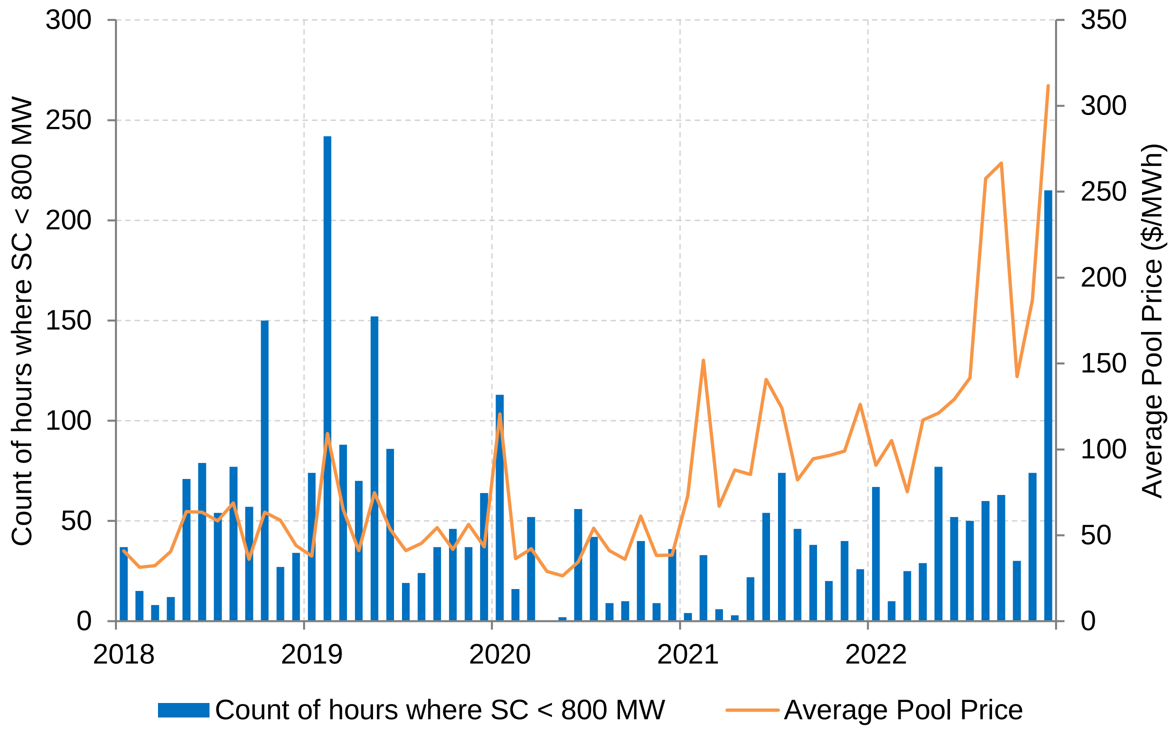



Figure 38 illustrates how often different companies set the SMP in each year from 2018 to 2022. In 2018, 2019, and 2020 the Balancing Pool often set price in the energy market. For example, in 2020 the Balancing Pool set the SMP 55% of the time. Following the expiration of the remaining PPAs, the Balancing Pool did not have offer control over any generation assets in 2021 and 2022.

As discussed in prior MSA reports, the remaining PPA capacity was returned to three large suppliers with other generation capacity in the market. As a result, the percentage of time these companies set price increased from 2020 to 2021. In 2022, the largest supplier set price 37% of the time and another company set price 27% of the time.

*Figure 38: The percent of minutes companies were setting price in the energy market by year (2018 to 2022, anonymized)*

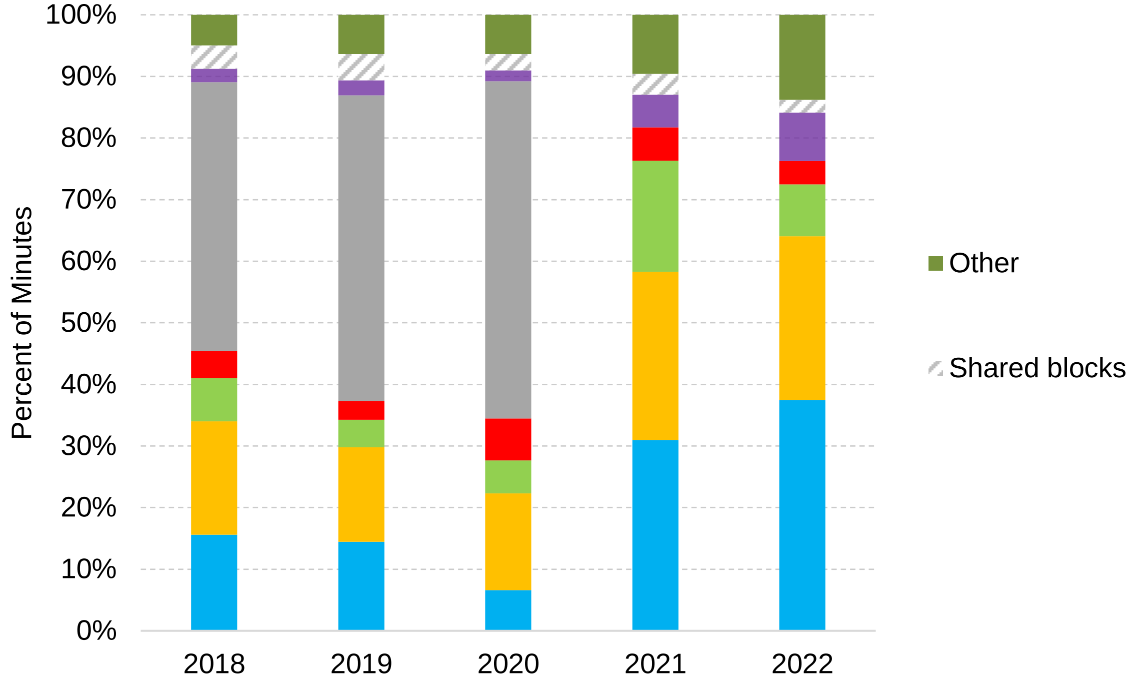



*Figure 39: The percentage of minutes that SMP was below $250/MWh, and by company for minutes in which the SMP was above $250/MWh, by year (2018 to 2022, anonymized)*

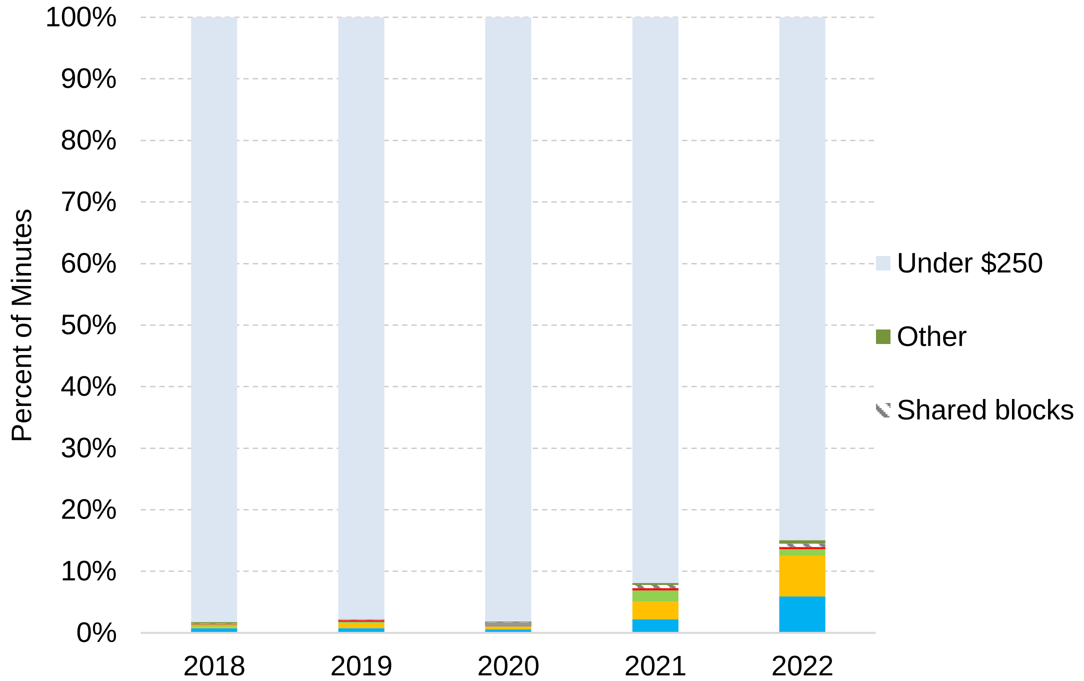
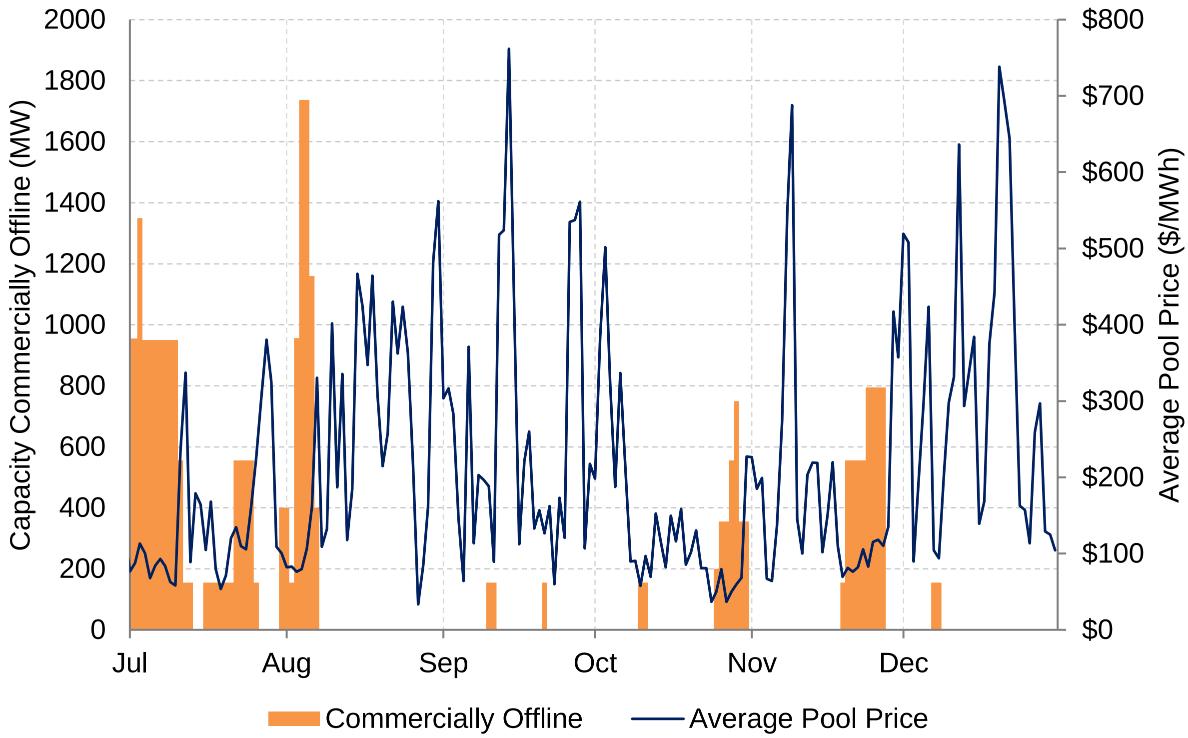


Figure 39 shows the percentage of time SMP was at or below $250/MWh in each year since 2018. For SMPs that were above $250/MWh, the figure shows the percentage of time that different companies were setting the price. In 2022 the SMP was above $250/MWh 15% of the time, which is up from 8% in 2021. When prices were above $250/MWh in 2022 the price was largely set by one of two companies, with one company setting the price 39% of the time price was above $250/MWh, and another setting the price 44% of the time price was above $250/MWh.

Figure 40 illustrates the amount of coal and converted coal capacity that was taken commercially offline over Q3 and Q4 alongside the daily average pool price. Because of the high and volatile pool prices over much of this period, there were often no assets offline commercially. In some lower-priced periods there was an increase in capacity taken offline commercially, as seen in early July, early August, late October, and late November.

On a few occasions converted coal assets were commercially offline when pool prices were relatively high. For example, on October 31 two gas-fired steam assets were commercially offline as pool prices averaged $227/MWh, or a heat rate of 31 GJ/MWh relative to the same-day gas price.

*Figure 40: The amount of coal and converted coal capacity that was commercially offline during the daily peak in pool price, and daily average pool prices (July 1 to December 31, 2022)*



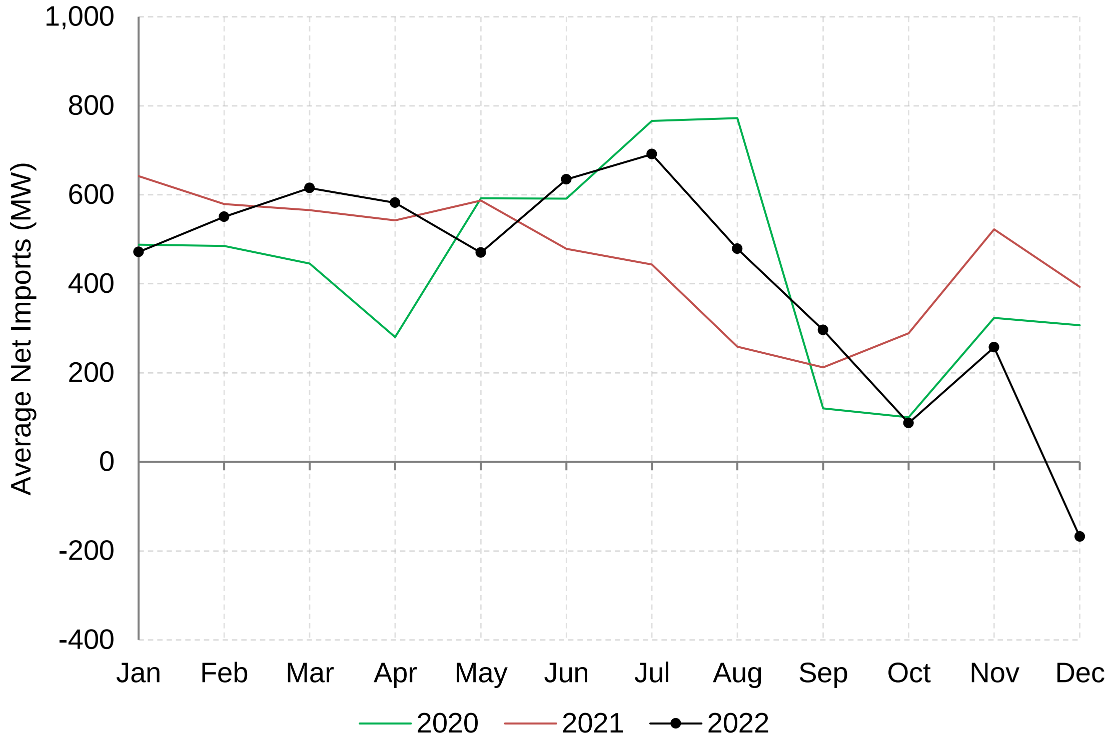

## 1.6 Imports and exports

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 treats BC and MATL as one intertie (BC/MATL) because any trip on the BC intertie will also cause MATL to trip offline. These interties indirectly link Alberta's electricity market to markets in Mid-C and California.

Average net imports were low in Q4 at 57 MW, 89% lower than Q3, and a fall of 86% compared to Q4 2021. The reduced net import volumes were largely the result of high prices in neighbouring markets in December, which led to increased export volumes.

*Figure 41: Average net imports by month (2020, 2021, and 2022)*

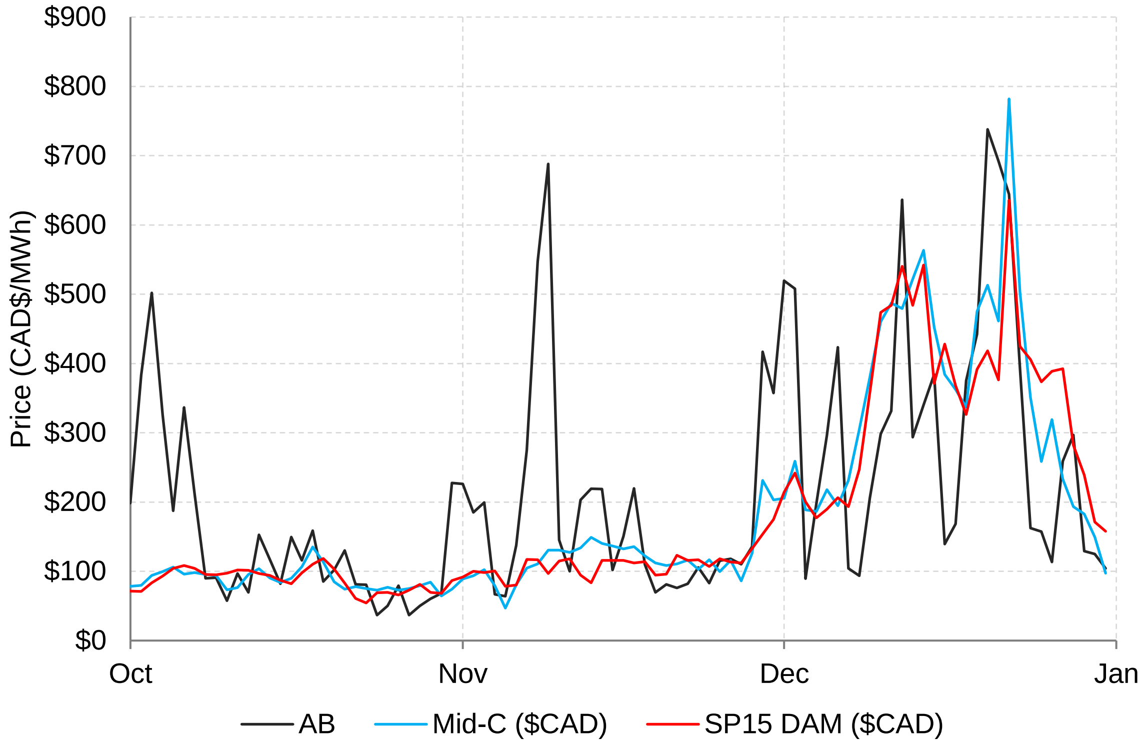



In December average net exports were 168 MW, a supply decrease of 561 MW compared to net imports of 393 MW in December 2021. The average net export volumes seen in December 2022 were the highest since December 2018. Figure 42 provides daily average prices in Alberta, Mid-C, and California in Q4.

In early October the BC/MATL intertie was offline and unavailable, and this reduced supply was a factor in the higher pool prices during this period. The intertie returned on October 6 and pool prices for the remainder of the month were generally comparable with Mid-C and California (Figure 42). This resulted in relatively low import volumes during much of October and some export volumes later in the month (Figure 43).

Pool prices increased above Mid-C prices on some days in early and late November, causing import volumes to increase (Figure 43).

*Figure 42: Daily average power prices in Alberta, Mid-C, and SP15 in California (Q4 2022)*




In December power prices were volatile in Alberta, Mid-C, and California (Figure 42). On certain days in December, pool prices were above prices in Mid-C and California resulting in import volumes, while on other days prices were higher in Mid-C and California resulting in exports (Figure 43).

Beginning in late November, power prices in Mid-C and California increased due to higher natural gas prices.[12] In early December, natural gas prices in the Western US increased further because of weather forecasts and pipeline constraints.[13] On December 8, power prices in Mid-C averaged CAD$305/MWh, or CAD$211/MWh higher than Alberta prices, and net export volumes averaged 732 MW.

Net export volumes averaged 860 MW on December 26, the highest on record, as pool prices averaged $113/MWh while average prices in Mid-C were CAD$319/MWh, and average prices at SP15 in California were CAD$389/MWh.

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[12] See EIA Natural Gas Weekly Updates released on December 1, 2022 and December 8, 2022, for example

[13] Natural Gas Intelligence article – December 8, 2022

*Figure 43: Daily average import and export volumes on BC/MATL, and the average price differential between Alberta and Mid-C (Q4 2022)*

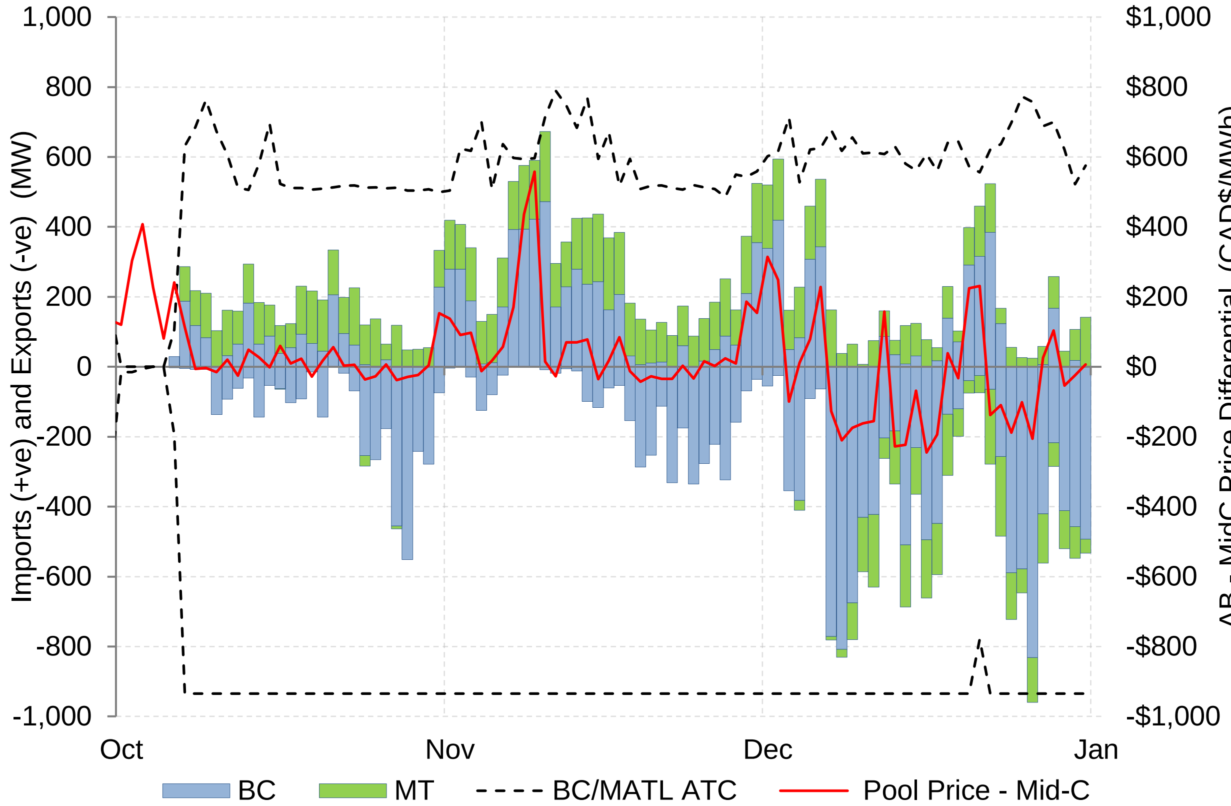


Figure 44 illustrates hourly pool prices in Alberta and prevailing hourly prices in Mid-C over December. As shown, prices in both markets were volatile during December. In Alberta, SMPs cleared at the offer price cap of $999.99/MWh for some periods of December 1, 2, 20, 21, and 22 reflecting scarcity in supply.

The AESO declared an EEA3 on December 1, 20, and in the morning and evening of December 21. Import supply on BC/MATL generally used all available transmission capacity (ATC) to supply power into Alberta during these reliability events.

However, for HE09 of December 21 there was 100 MW of exports, which were initially scheduled on MATL the day before. Imports on BC/MATL during this hour were scheduled for 556 MW and, with 100 MW of exports, net imports were scheduled for 446 MW while ATC was 556 MW. At 08:46 the AESO curtailed export volumes to 0 MW due to the EEA3 event in Alberta (Figure 10). The 100 MW export volumes were also curtailed for HE10 and 11 of December 21. Prices in Mid-C averaged around CAD$425/MWh and real-time prices at SP15 averaged CAD$318/MWh during these hours, well below prevailing pool prices in Alberta.

On December 22, prices in Mid-C exceeded the Alberta price cap for four hours, peaking at CAD$1,231/MWh in HE19 (Table 6 and Figure 44). Despite the higher prices in Mid-C, net import supply from BC/MATL was relatively strong during the peak hours.

*Figure 44: Hourly power prices in Alberta and Mid-C (December 1 to 31, 2022)*

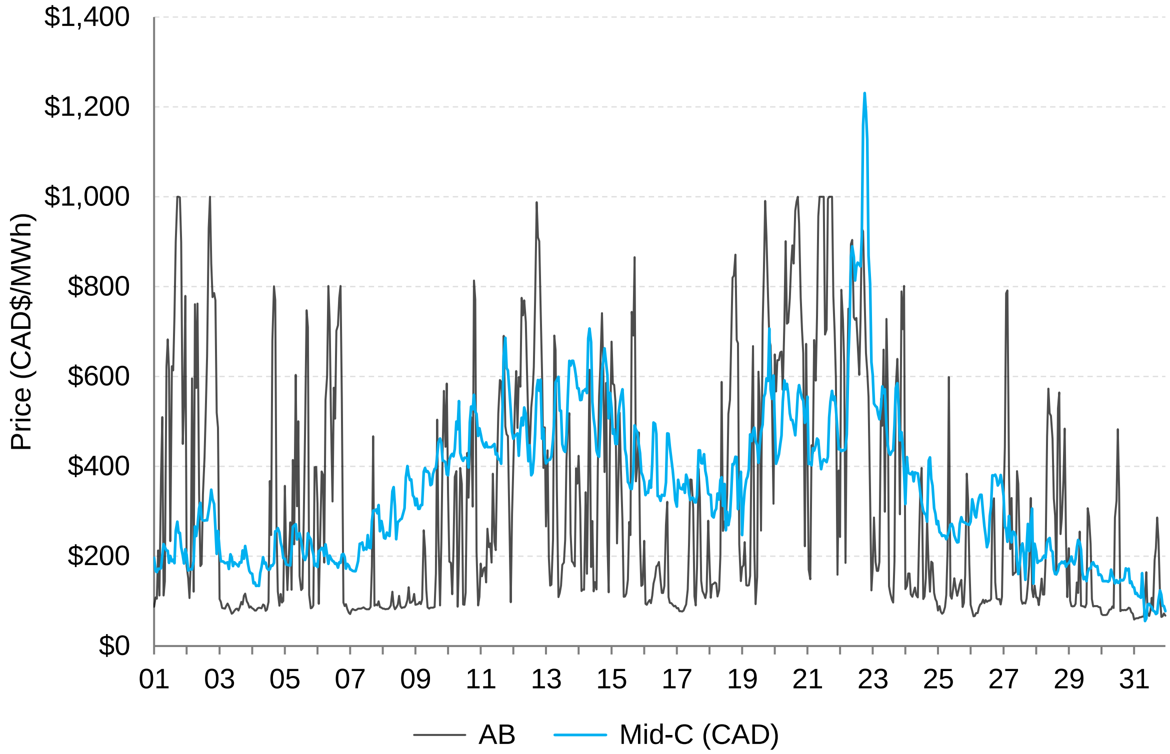


*Table 6: Pool prices, Mid-C prices, and BC/MATL net imports on December 22, 2022*

| Hour Ending (MST) | AB Pool Price (CAD$) | Mid-C Price (CAD$) | BC/MATL Net Imports (MW) |
|---|---|---|---|
| 15 | $603 | $850 | 472 |
| 16 | $727 | $845 | 472 |
| 17 | $929 | $913 | 507 |
| 18 | $923 | $1,159 | 571 |
| 19 | $767 | $1,231 | 472 |
| 20 | $652 | $1,189 | 450 |
| 21 | $611 | $1,127 | 350 |
| 22 | $555 | $869 | 250 |
| 23 | $327 | $806 | -11 |
| 24 | $124 | $632 | -3 |

## 1.7 An analysis of electricity load in Alberta

The purpose of this section is to summarize certain characteristics of electricity load in Alberta for January 1, 2013 through December 31, 2022. This analysis is intended to improve understanding of electricity load in Alberta, including its hourly and spatial variation.

Two key measures for electricity load in Alberta are Alberta Internal Load and System Load:

> **Alberta Internal Load (AIL)** means a number in MW: (i) that represents, in an hour, system load plus load served by an on-site generating unit or aggregated generating facility, including those within an industrial system and the City of Medicine Hat; and (ii) which the ISO, using SCADA data, calculates as the sum of the output of each generating unit and aggregated generating facility in Alberta and the Fort Nelson area in British Columbia, plus import volumes and minus export volumes.[14]
>
> **System Load** means the total, in an hour, of all metered demands under Rate DTS, Rate FTS and Rate DOS of the ISO tariff plus transmission system losses.[15]

Functionally, the difference between the two load definitions is the inclusion of load served by on-site generation in AIL. Transmission losses are included in both, and exports are excluded from both. Computationally, however, the two measures are calculated through different processes. AIL is calculated as part of real time operations and is based on generation output (net domestic generation and net interchange). In contrast, system load is calculated based on data submissions provided to the AESO by meter data managers pursuant to AUC Rule 021.[16]

### *1.7.1 Variation over time in AIL, system load, and implied behind-the-fence load*

As discussed above, the amount of load served by on-site generation can be deduced from the difference between the two load measures. Figure 45 shows the average hourly load for AIL, system load and implied behind-the-fence load, by month, for January 2013 to December 2022.

The most significant change over this time period was the increase in behind-the-fence load, which grew at a compound annual rate of 3.1% (from 2,063 MW in 2013 to 2,797 MW in 2022). In contrast, system load remained relatively stable, growing at a compound annual rate of 1% over the six years from 2013 to the end of 2018 (from 6,778 MW in 2013 to 7,182 MW in 2018) and then slightly declining from 2018 to 2022 (to 7,085 MW in 2022).

For AIL and system load, a distinct seasonal pattern can be observed where annual monthly peaks occur around January. This seasonal variation is also observed for behind-the-fence load though it is not as pronounced.

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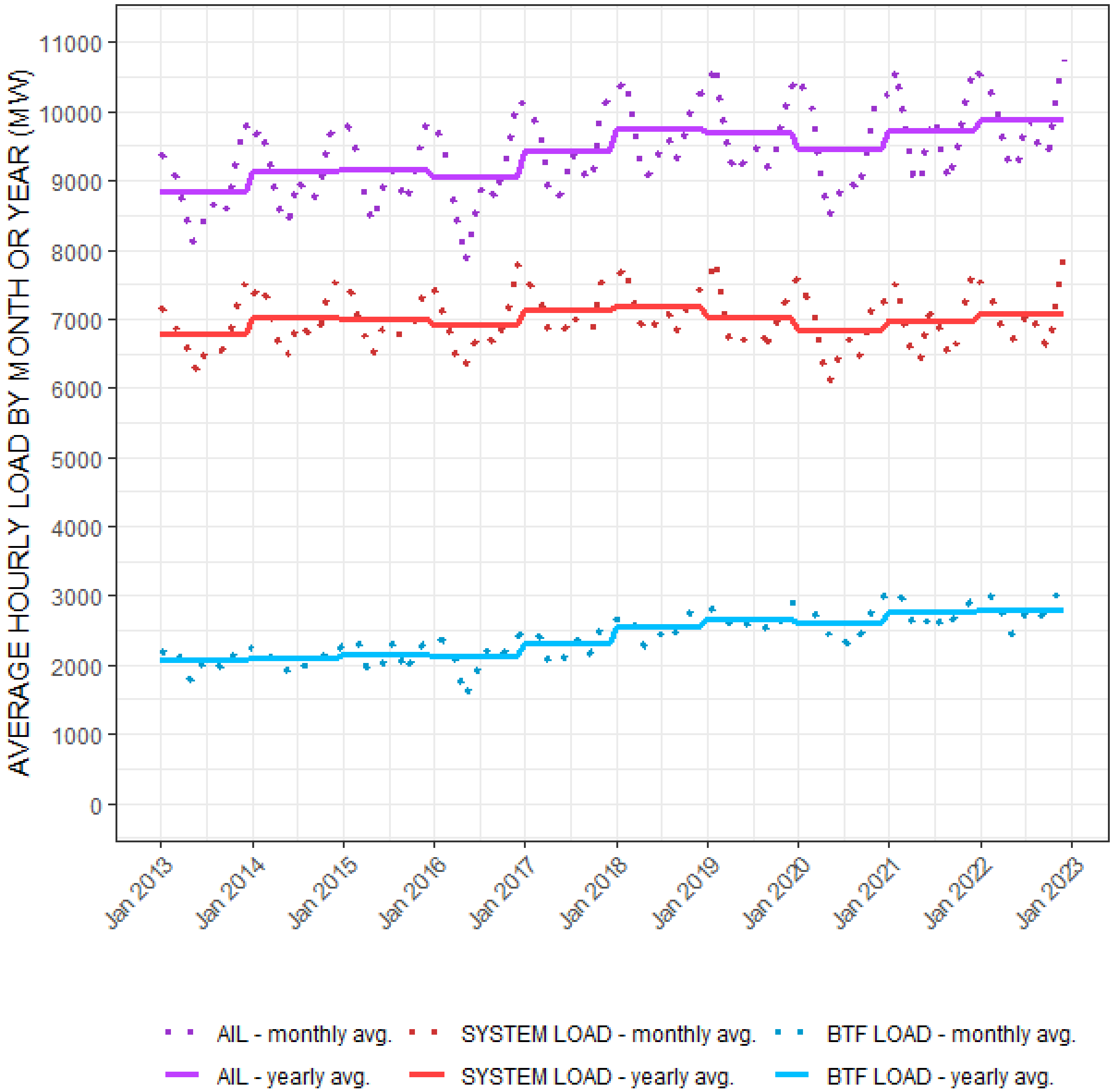
[14] Consolidated Authoritative Document Glossary, posted: July 1, 2021.

[15] Consolidated Authoritative Document Glossary, posted: July 1, 2021.

[16] It may take up to four months for this data to be finalized.

*Figure 45: Average hourly load for AIL, system load, and implied behind-the-fence load*

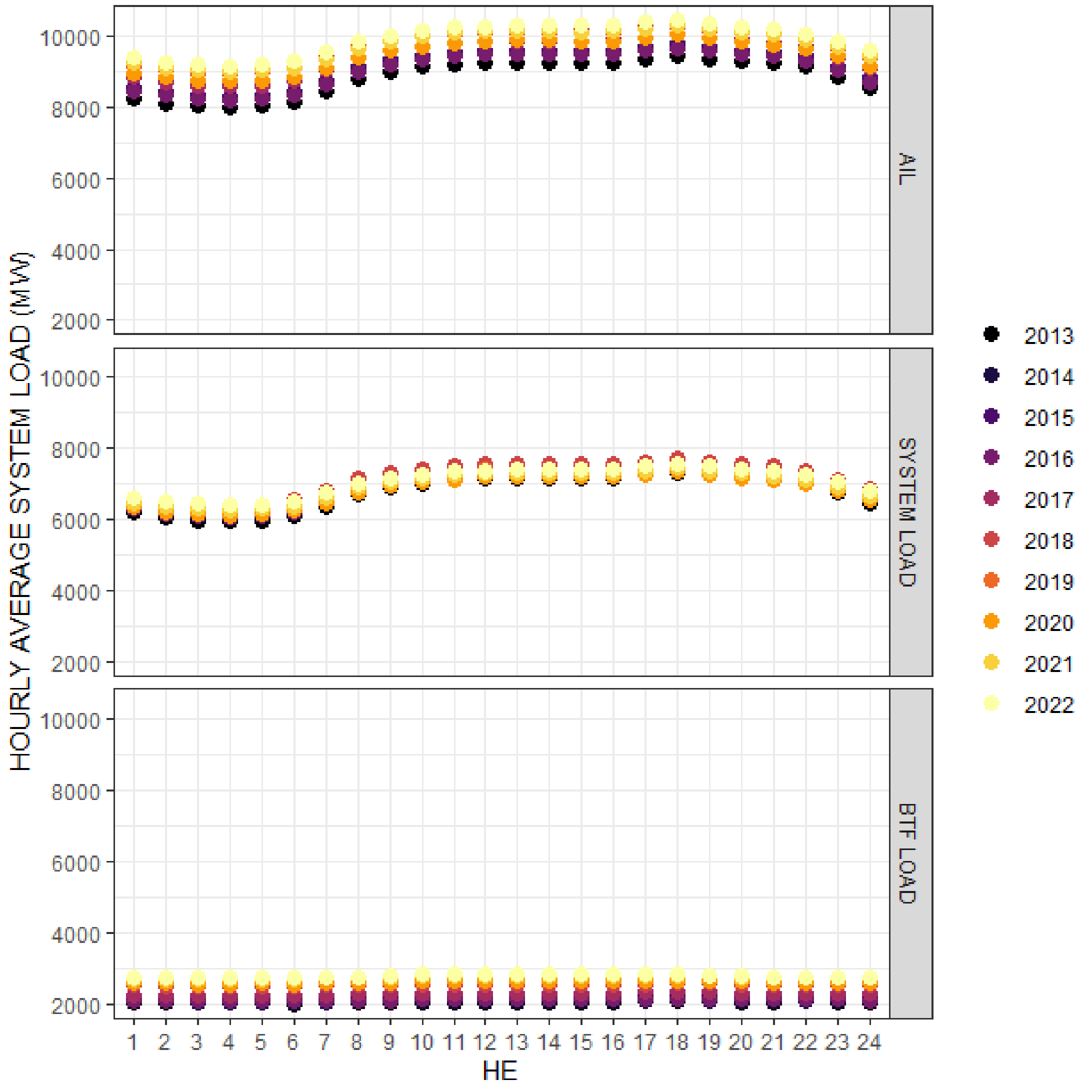



### *1.7.2 Hourly variation in AIL, system load, and implied behind-the-fence load*

While the previous section focused on the seasonal and yearly variation, this section focuses on the variation of load within the day. Figure 46 shows the average load by hour of the day for each of the load measures.

For both AIL and system load, and for each year between 2013 and 2022, the highest average load is observed in HE18 and the lowest average load is observed in HE 4. The difference between the maximum average system load observed in HE18 and the minimum average observed in HE 4 was 1,165 MW in 2022, which is somewhat lower than the levels observed in previous years. Implied behind-the-fence load has been relatively stable across the hours.

*Figure 46: Average system load by hour*




### *1.7.3 Load met by the energy market merit order*

To examine the extent of load met by the energy market merit order, we compare AIL and energy dispatched in the merit order. In doing so, there are a few points that need to be addressed. First, imports and exports need to be considered. AIL is met by internal generation as well as imports, while dispatched generation in the merit order not only serves internal load but can also be exported to other jurisdictions. Second, exports and imports in the merit order reflect scheduled volumes rather than metered volumes. Third, wind and solar generation blocks represented in the merit order reflect their available capability, which is regarded as the maximum MW that the asset is physically capable of providing, regardless of the prevailing wind or solar conditions at any given time.[17]

To make a balanced comparison addressing these points, in Figure 47, we compared *AIL plus metered exports* versus *dispatched internal generation from the merit order plus metered imports*. Furthermore, where a wind or solar energy block appears in the merit order, we replaced those volumes with actual metered volumes. It should be noted that wind generation was not offered into the merit order prior to April 1, 2015.[18]

After these adjustments, the difference in Figure 48 represents the generation that is not offered in the energy merit order. As noted above, the step decline in April 2015 is reflective of the regulatory changes regarding wind offers. But more generally, generation that is not offered in the energy merit order includes source assets with a maximum capability of less than five MW and electric energy that is not required to be exchanged through the power pool. Section 2 of *Electric Utilities Act* sets out exemptions of its application in a number of circumstances including "electric energy produced on property of which a person is the owner or a tenant, and consumed solely by that person and solely on that property," and electric energy produced and consumed in the City of Medicine Hat. To the extent that there is on-site generation that serves on-site load, and this generation is dispatched on a net basis (i.e., on site generation minus on-site load), such generation would be captured in the amount of generation that is not offered in the energy merit order, as represented by the blue dashed line in Figure 47. The difference also includes energy from regulating reserves and directed operating reserves.

Figure 48 shows that the percentage of load that is not met by energy merit order dispatches fluctuates monthly but has been on the decline over the course of 2022, reflecting a greater increase in generation that is offered through the merit order versus generation that is not.

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[17] Consolidated Authoritative Document Glossary, posted: July 1, 2021. The real power capability of these assets is addressed as part of the definition of "allowable dispatch variance."

[18] The AESO amended certain rules to (1) allow wind assets to be dispatchable according to price and (2) require wind assets submit energy market offers in the same manner as all other generators. These "Dispatchable Wind Rule Changes" came into effect as of April 1, 2015.

*Figure 47: AIL v. dispatched generation from the merit order*

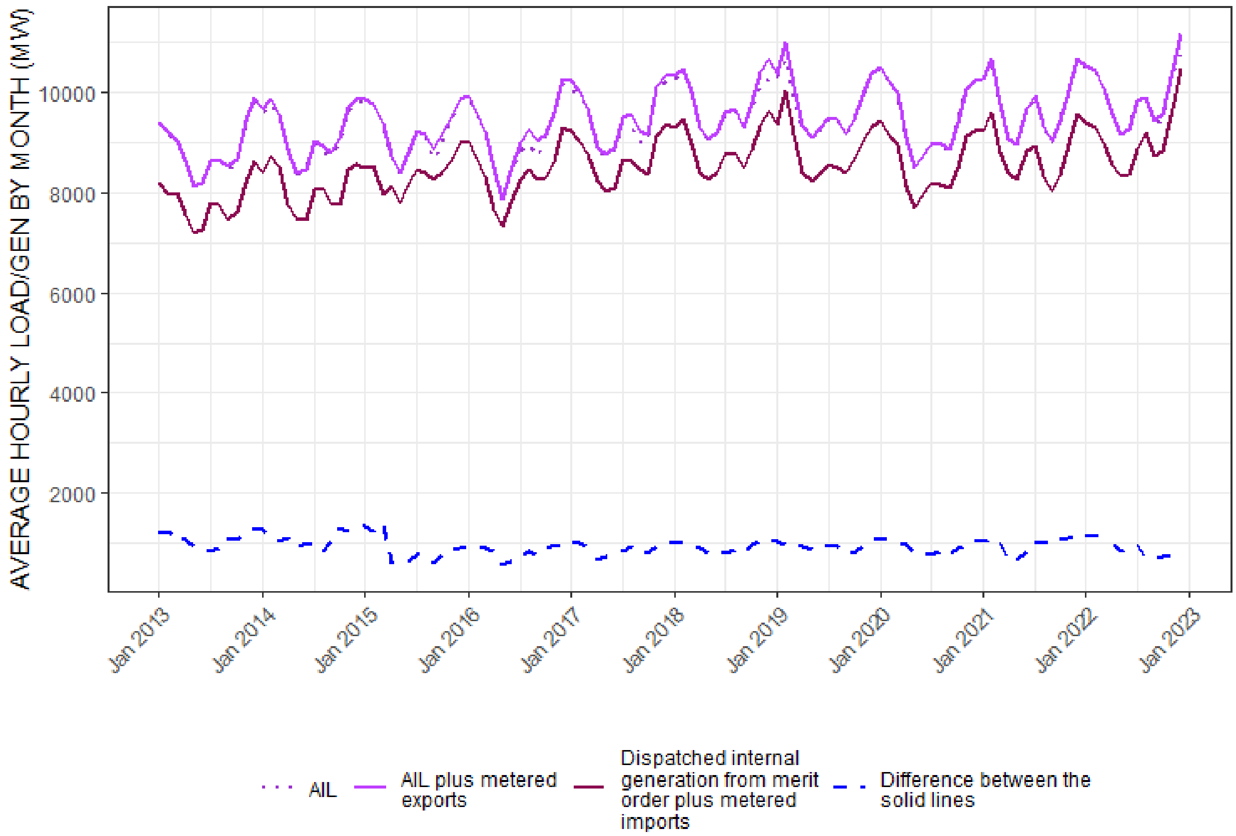
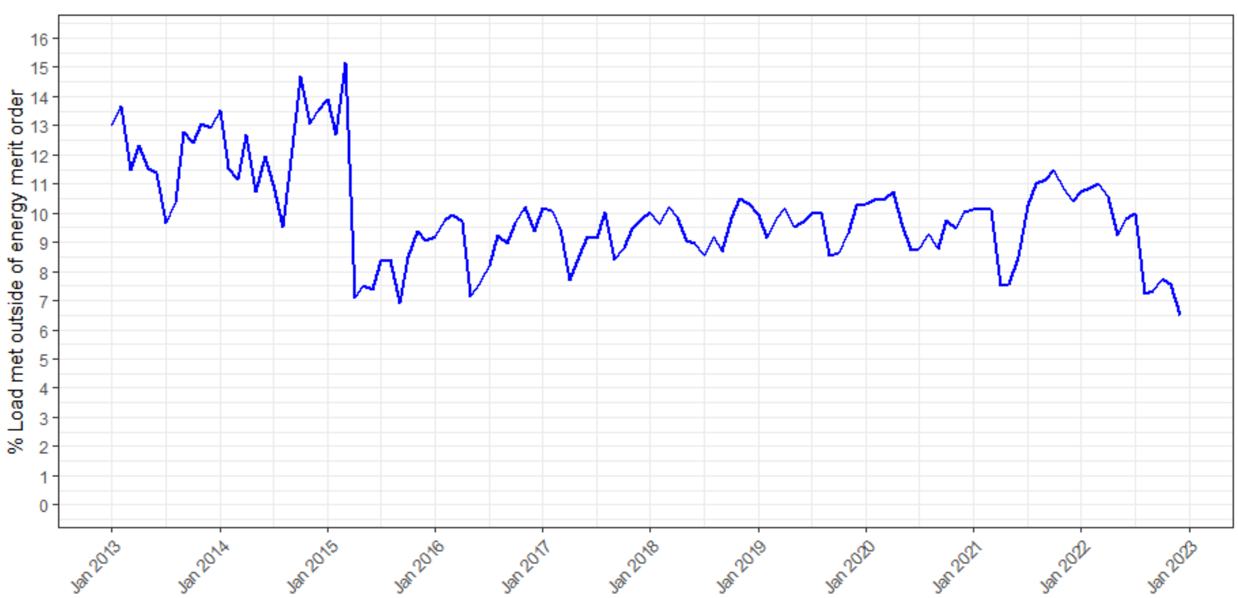


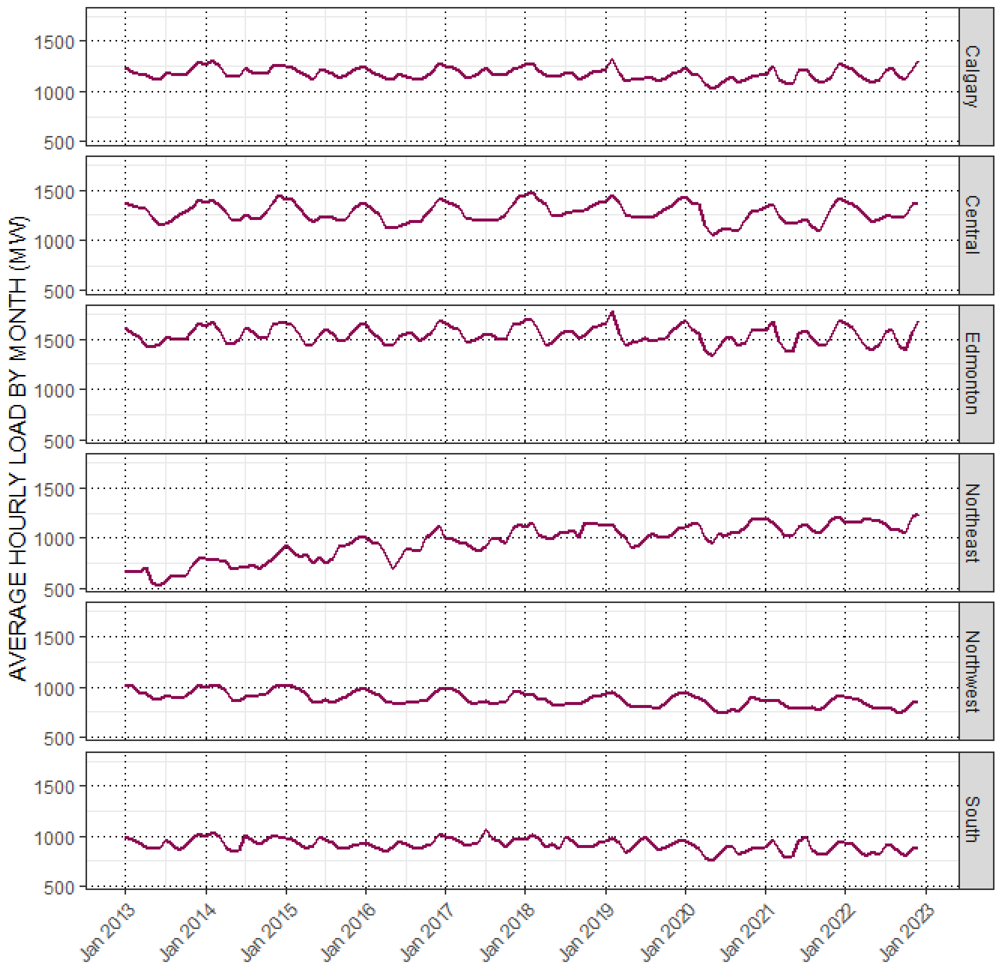

*Figure 48: Percentage of load met by resources outside the energy merit order*



### *1.7.4 Spatial variation in regional system load (without transmission losses)*

The AESO considers the Alberta transmission system as consisting of six planning regions: Calgary, Edmonton, Central, Northeast, Northwest, and South.[19] In this section, we analyze system load without transmission losses for each of the AESO's six planning regions and some of the transmission planning areas within these regions.

*Figure 49: Average monthly load by planning region*



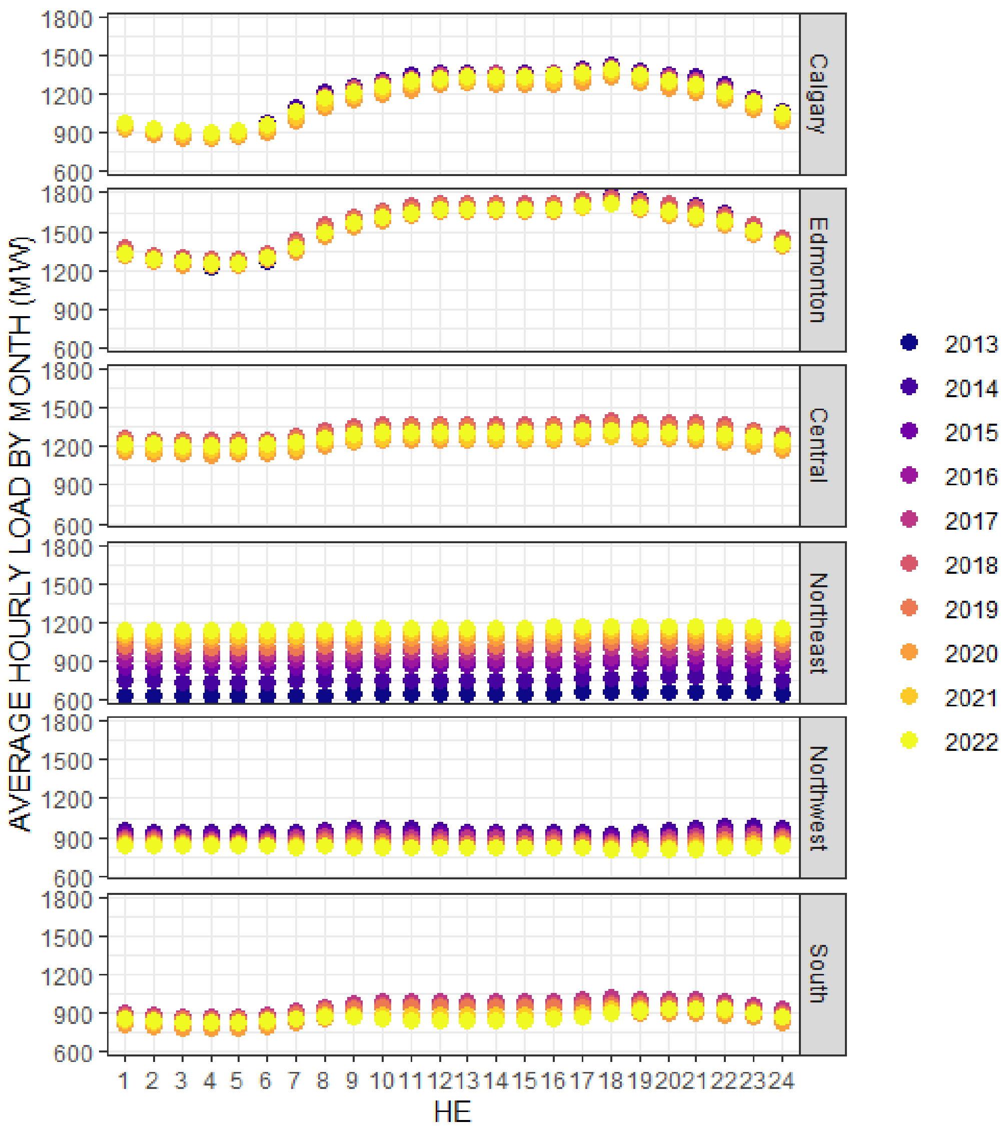

The Edmonton region has the highest average hourly load, followed by the Central and Calgary regions. In 2022, the Calgary region experienced a 2% decrease compared to its highest average load, observed in 2014. The Edmonton and Central regions saw decreases of 4% and 3%, respectively, compared to their highest levels observed in 2018. The Northwest and South regions experienced decreases of 13% and 10%, respectively, from the highest average loads observed in these regions, which occurred in 2014.

[19] Planning-Regions.pdf (aeso.ca)

The Northeast region experienced a steady increase, and its highest load was observed in 2022, at a level 78% higher than its lowest average load observed in 2013. The Northwest region, in contrast, experienced a decrease and its lowest average load was observed in 2022. For all regions except for Northwest and Northeast, the lowest level of demand was observed in 2020.

Figure 50 shows the load profile across hours of the day for each of the regions. Load in the Calgary and Edmonton regions exhibits a clear pattern of a morning ramp, and close to a 500 MW of difference between the average highest load and average lowest load hours. To a lesser degree, a similar pattern exists for the Central and South regions. In 2022, the lowest load was observed in HE 4 in these four regions. The highest load was observed in HE 18 in the Calgary, Edmonton, and Central regions, and HE 21 in the South region. The load profile in the industrial Northeast and Northwest regions are relatively flat.

*Figure 50: Average regional load by hour of day*



The AESO divides the six planning regions into 42 transmission planning areas. The transmission planning areas differ in terms of their load profile. Most areas have relatively flat hourly load profiles. The following three figures present hourly load profiles from areas that differ from this pattern. Figure 51 presents hourly load profiles for the large urban planning areas in Alberta.

The Calgary transmission planning area has the highest dispersion across hours in terms of the difference between its maximum and minimum average hourly load in the entire province. Similar to Calgary, the Edmonton area experiences a significant morning ramp.

*Figure 51: Average load by hour in large urban planning areas*

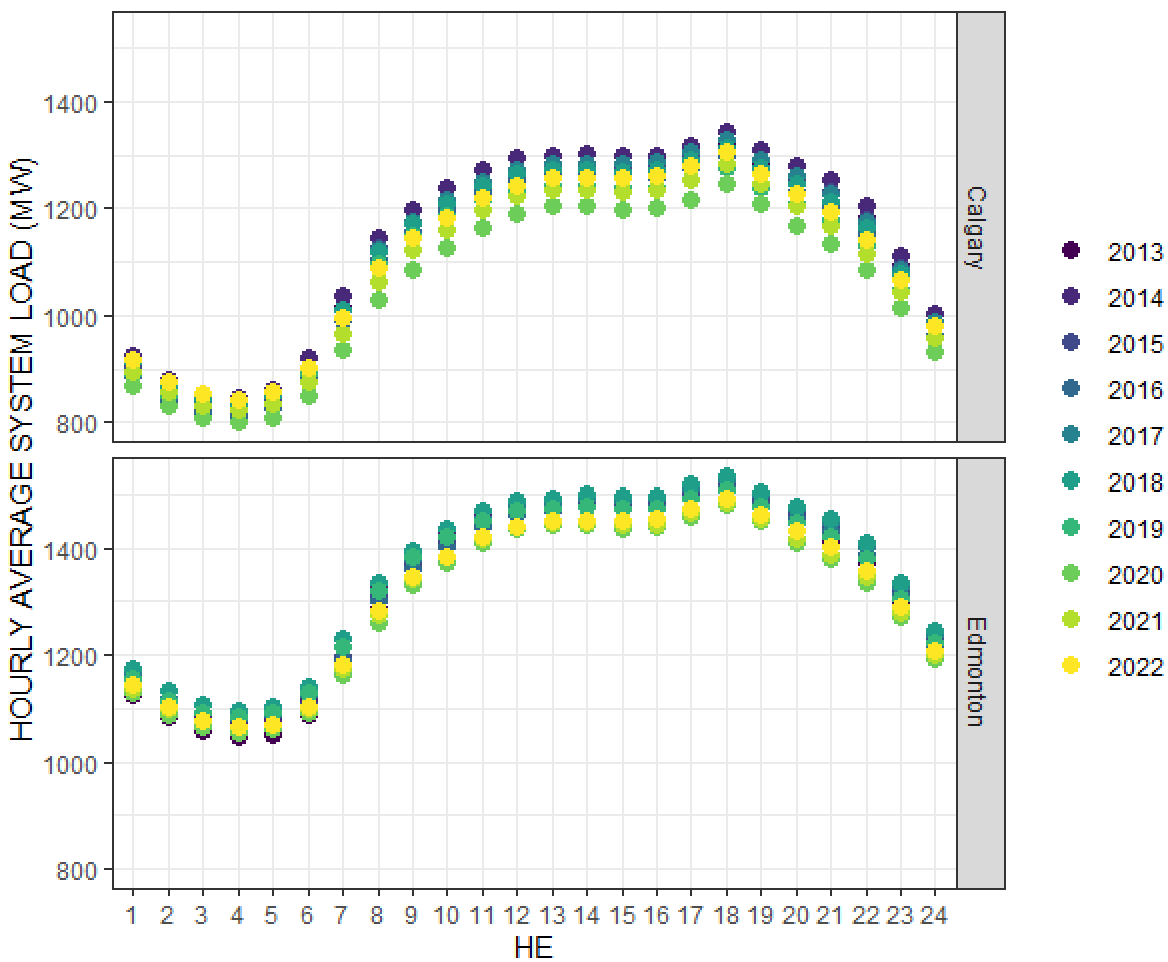



Figure 52 shows hourly load profiles for smaller urban areas, Red Deer and Lethbridge. The shapes are similar to those of large urban areas but, due to their size, the difference between the highest and lowest average load is smaller. In all four urban areas, the highest average load is observed in HE 18 and the lowest in HE 4.

*Figure 52: Average load by hour in smaller urban planning areas*

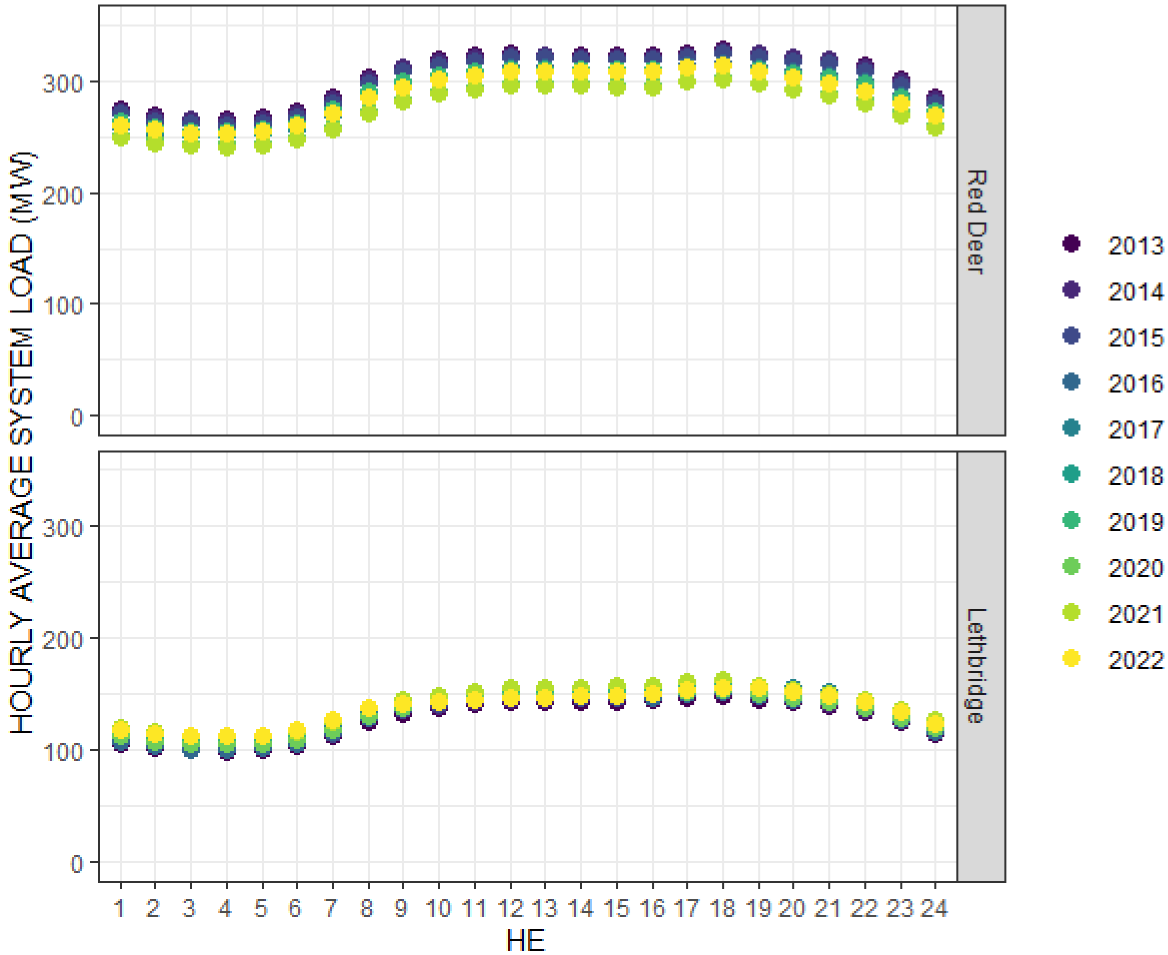
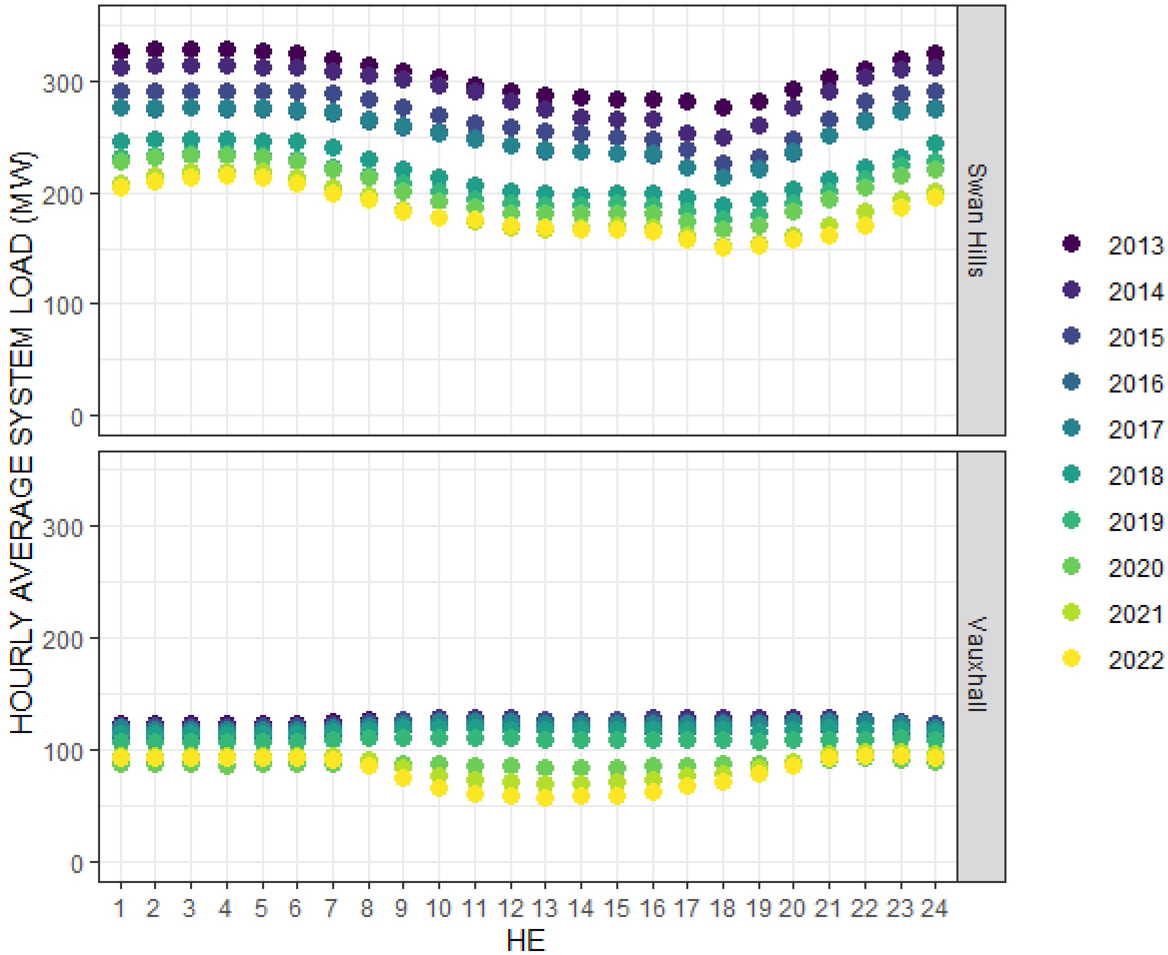



Figure 53 shows the load profile in two transmission planning areas, Swan Hills and Vauxhall, where the hourly load profile exhibits unusual patterns.

The hourly load profiles for transmission planning areas in the Northwest region are typically flat except for the Swan Hills area. While there is significant hourly variation in this area, the shape of the load is virtually the inverse (Figure 53) of the shape observed in the urban centres discussed above. This planning area is host to some price and transmission tariff responsive loads, and the hourly average load reflects this behaviour.

The Vauxhall transmission planning area is in the South planning region and exhibits a unique pattern (Figure 53). Since 2020, the previously flat load profile has changed to reflect lower average loads in all hours, but specifically between HE 8 and HE 20. This situation appears to be due to the successive additions of distribution connected solar generation facilities in this transmission planning area.

*Figure 53: Inverted patterns*



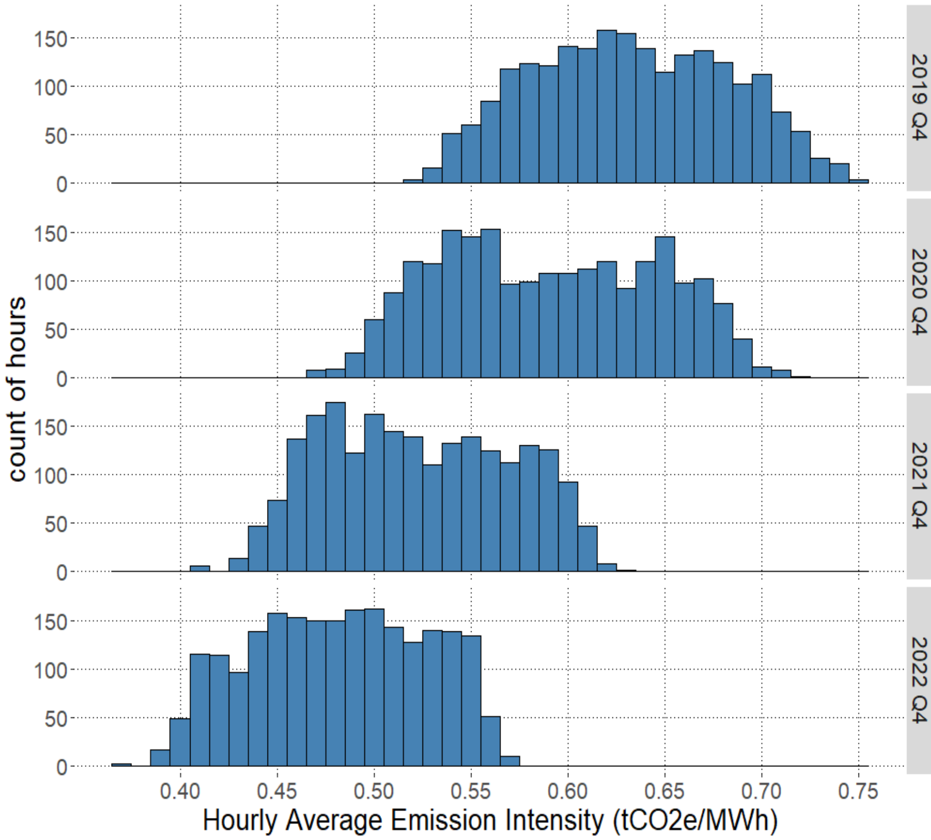

### 1.8 Carbon emissions intensity

The carbon emission intensity of power generation is the amount of carbon dioxide equivalent emitted for each unit of electricity produced. The results are indicative only, as the MSA relies on publicly available information rather than collecting the precise carbon emission intensities of assets from market participants. The results reported here do not include imports or behind-the-fence generation.

#### *1.8.1 Hourly Average Emission Intensity*

The hourly average emission intensity of the grid is the volume-weighted carbon emission intensity of assets supplying the Alberta grid in an hour. Assets that generate more to the grid in an hour are more heavily weighted in this analysis. Figure 54 shows the distribution of the hourly average emission intensity of the grid in Q4 of the four years prior. The leftward shift indicates a decline in the carbon emission intensity of the grid over time, which was the result of coal-to-gas conversions and increased wind and solar generation.

*Figure 54: Distribution of average carbon emission intensities in Q4 (2019 to 2022)*




In Q4 2021, 10% of hours had an average emission intensity above 0.59 tCO2e/MWh. In Q4 2022, all hours had an average emissions intensity below this level. This outcome was largely driven by coal-to-gas conversions.

In late 2021, the Keephills 3 asset was converted from coal to gas-fired steam and Battle River 4 was converted from dual fuel to gas-fired steam. In early November 2021, Battle River 5 was re-categorized as gas-fired steam rather than dual fuel because the operating company committed to solely running the asset on natural gas.[20] In addition, the Keephills 1 coal asset was retired at the end of 2021 and, beginning in 2022, the Sundance 4 asset ran solely on natural gas before its retirement in March 2022. In late 2022, the Genesee 3 asset was converted from coal to gas-fired steam.[21]

Figure 55 shows how average emission intensities in November and December evolved over the last four years and contributed to the shift in the quarterly distribution. Several large thermal assets were reclassified as gas-fired steam in November 2021, reducing hours with emissions intensities

[20] Heartland Announcement – November 9, 2021

[21] The MSA has classified Genesee 3 as a gas-fired steam asset post-conversion, as the operating company has committed to using only natural gas (see Capital Power Q3 2022 transcripts at page 8).

above 0.6 tCO2e/MWh thereafter, even during winter months where demand was elevated and thermal outages are reduced.

November was also a month with high wind generation, which is reflected in a higher number of hours at the lower end of the distribution. The same was true in December, which tends to have moderately high wind generation. The growth in wind capacity and generation since 2020 can be seen in the bimodal distribution of emissions intensities in 2020, as well as December 2021, when thermal output and wind were both relatively high.

In 2022, there were three coal-fired assets supplying electricity to the Alberta grid. In Q4, only two of these coal assets were generating, while Genesee 3 was on a conversion outage from early October until mid-November. This resulted in a reduction in the average emission intensity of the grid from December 2021 to December 2022 (Figure 55).

*Figure 55: Distribution of average carbon emission intensities in November and December (2019 to 2022)*

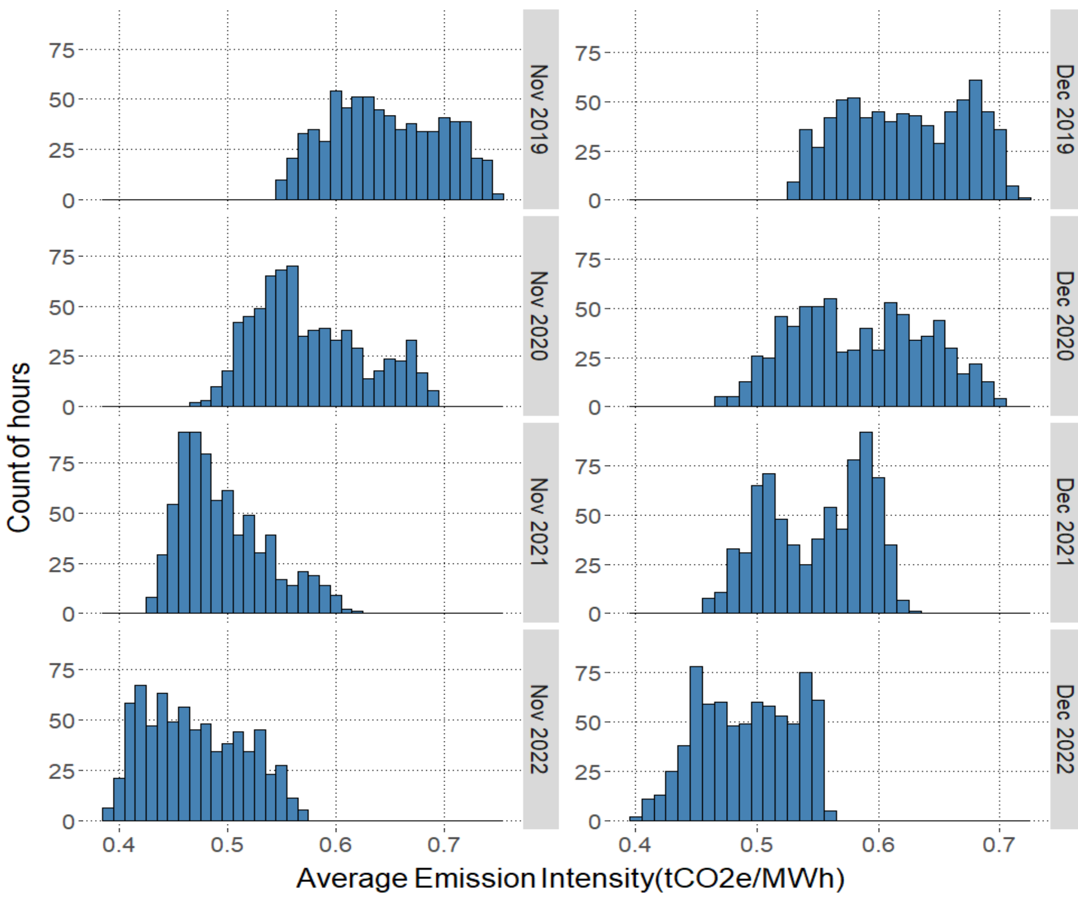


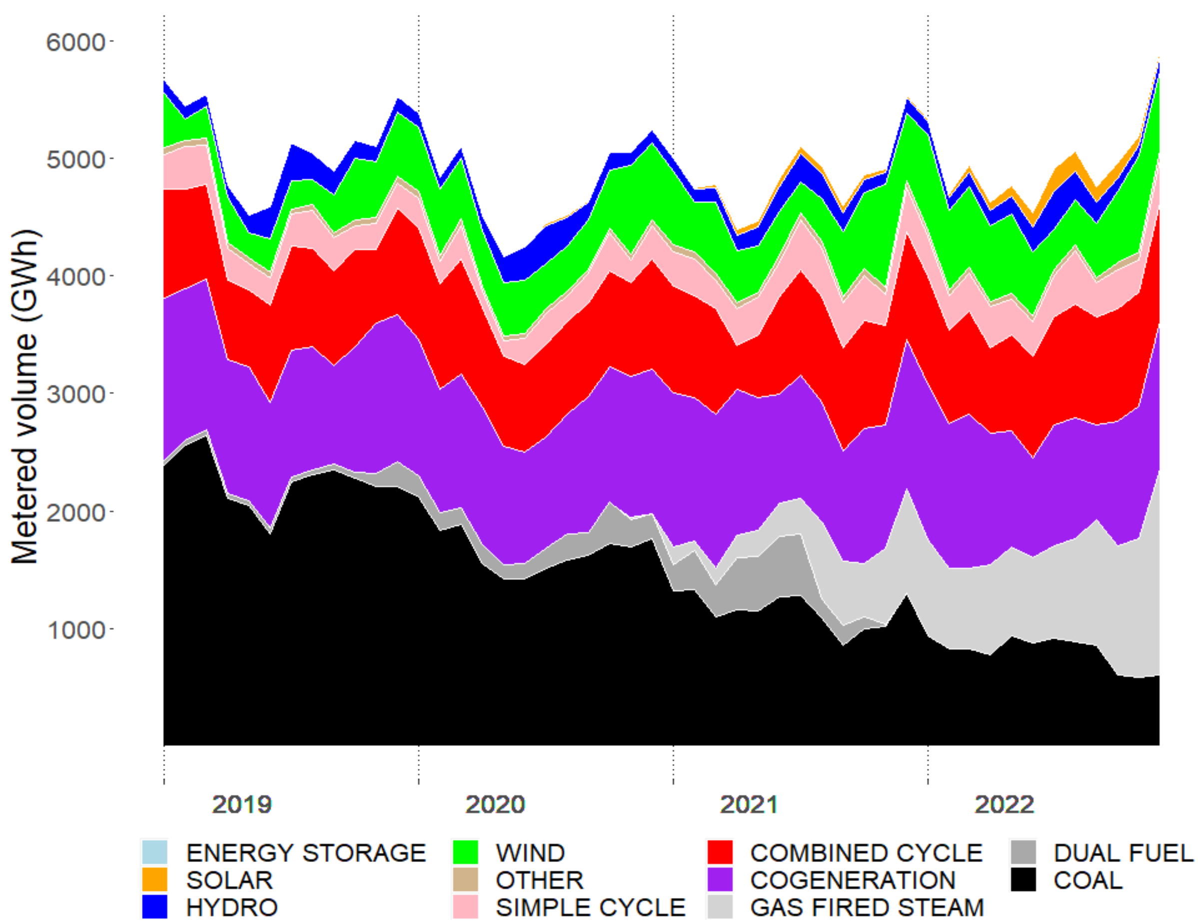
*Table 7: The mean of hourly average emission intensities (tCO2e/MWh)*

| | Mean |
|---|---|
| **Nov 2019** | 0.65 |
| **Nov 2020** | 0.58 |
| **Nov 2021** | 0.50 |
| **Nov 2022** | 0.47 |

| | Mean |
|---|---|
| **Dec 2019** | 0.62 |
| **Dec 2020** | 0.58 |
| **Dec 2021** | 0.55 |
| **Dec 2022** | 0.49 |

The trends discussed above are illustrated in Figure 56, which shows net-to-grid generation volumes by fuel type. Coal-fired generation accounts for an increasingly small portion of the total generation mix, offset primarily by gas-fired steam assets. The increase in wind and solar generation also contributed to the displacement of coal-fired generation since 2019. In the latter half of 2022, coal generation dropped because of the Genesee 3 conversion outage, followed by the re-introduction of gas-fired steam into the generation mix upon its return. Coal-fired generation is expected to decline to zero in 2024.

*Figure 56: Monthly total net-to-grid generation volumes by fuel type (2019 to 2022)*



## 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. Supplemental reserve (SUP) is not required to be synchronized but must be able to respond quickly if directed by the system controller.[22] These products are bought by the AESO through day-ahead auctions.

### 2.1 Annual summary

In 2022, total OR costs were $499 million, compared to $339 million in 2021 and $148 million in 2020. This is the highest annual total cost for OR since the beginning of the market. The higher OR costs in 2022 reflect higher pool prices during the year.

OR costs and pool prices are positively correlated because the opportunity cost of providing OR is usually foregoing the sale of energy. This is particularly true for active OR products since active prices are indexed directly to pool price. Table 8 shows the year-over-year change in average cost for active OR products.

*Table 8: Average cost ($/MWh) of active OR products*

| Product | 2022 | 2021 | Difference (2022 - 2021) |
|---|---|---|---|
| Spinning | $98.16 | $64.41 | +$33.75 |
| Supplemental | $56.29 | $42.96 | +$13.33 |
| Regulating | $97.36 | $64.33 | +$33.03 |
| **Avg. Pool Price** | **$162.46** | **$101.93** | **+$60.53** |

The increase in the average cost of active OR products was less than the increase in pool price year-over-year. As shown in Table 8, pool price increased by $60.53/MWh while the costs of spinning, supplemental, and regulating reserves increased by less, which suggests OR markets were more competitive in 2022. The OR markets became increasingly competitive in the second half of the year, with on-peak spinning and supplemental products setting record lows for equilibrium prices in Q3 and Q4.

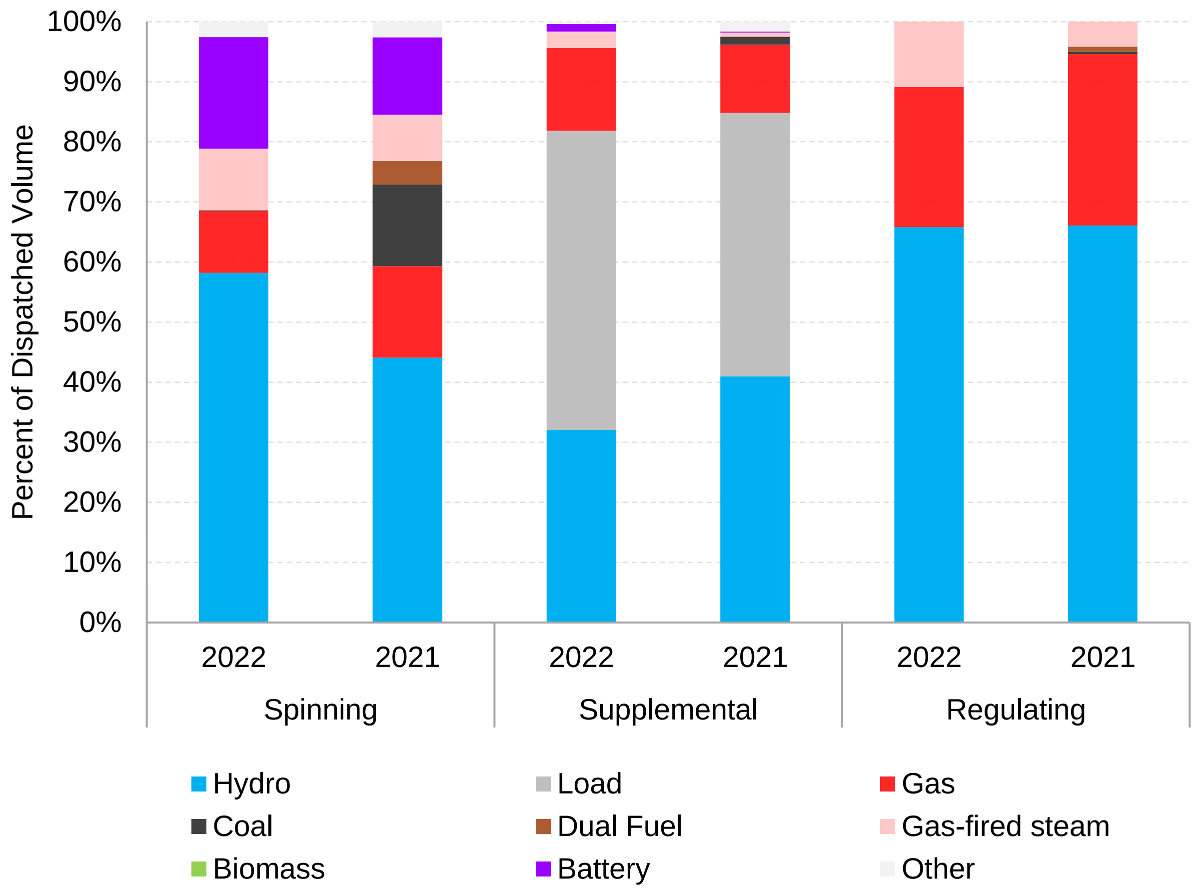
Figure 57 shows the dispatched volume of spinning, supplemental, and regulating reserves by fuel type for 2021 and 2022. As shown, coal accounted for 14% of spinning reserve dispatches in 2021 but only for 0.13% in 2022 due to several coal-to-gas conversions that occurred since 2021. The reduction in coal volume was offset by an increase in hydro and battery dispatches.

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

Battery assets made up 19% of spinning dispatches in 2022, reflecting the increased presence and participation of new battery assets in the market.

Load provision of supplemental reserves increased from 44% in 2021 to 50% in 2022. Of all OR products, loads are only capable of providing supplemental reserve since it does not require providers to be continuously synchronized to the grid and providing frequency response.

*Figure 57: Operating reserves dispatched by product and fuel type (2021 and 2022)*




## 2.2 Costs and volumes

Total monthly OR costs reached record highs in 2022, with August costs totalling $90.1 million and December $90 million. Adjusted for inflation, these are the two highest monthly costs since 2005. Given that the prices of active OR products are indexed to pool price, these high costs reflect high and volatile pool prices. As shown in Figure 58, August and December total costs were comparable, however spinning costs accounted for a greater share of costs in December while supplemental costs were lower in December due to increasingly competitive offers in the supplemental market by hydro and load providers.

*Figure 58: Total cost of active and standby reserves and average pool price by month (January 2021 to December 2022)*

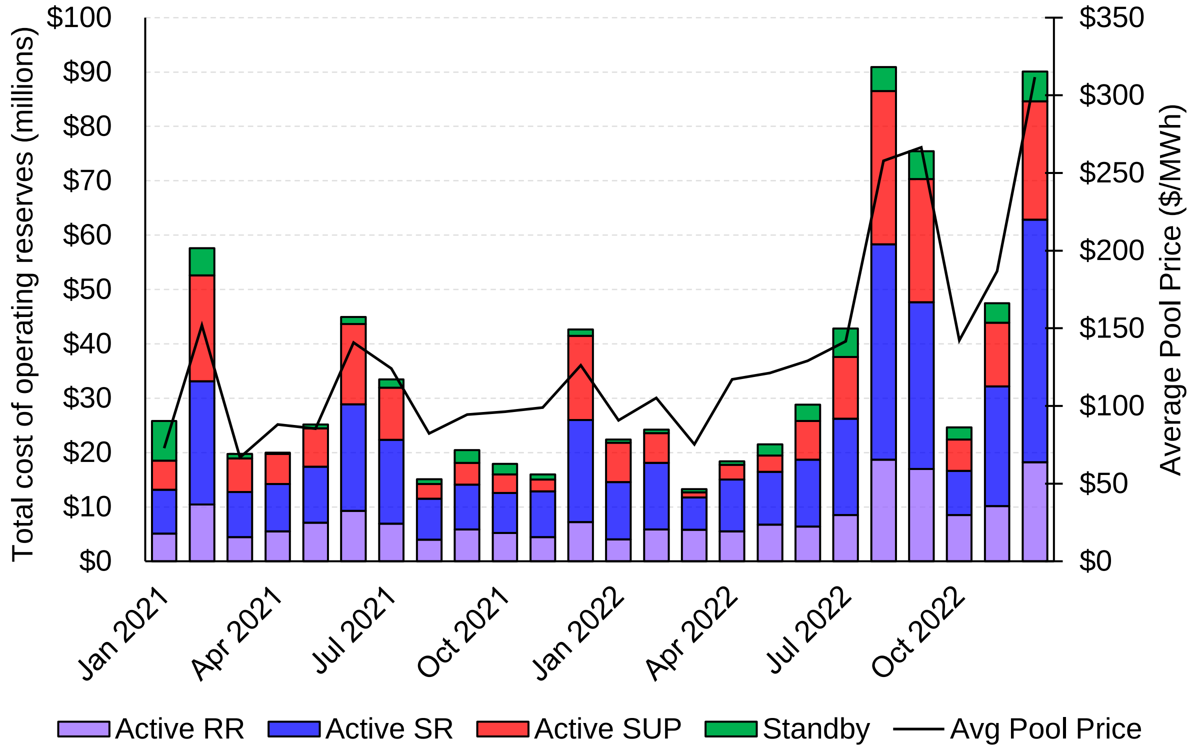


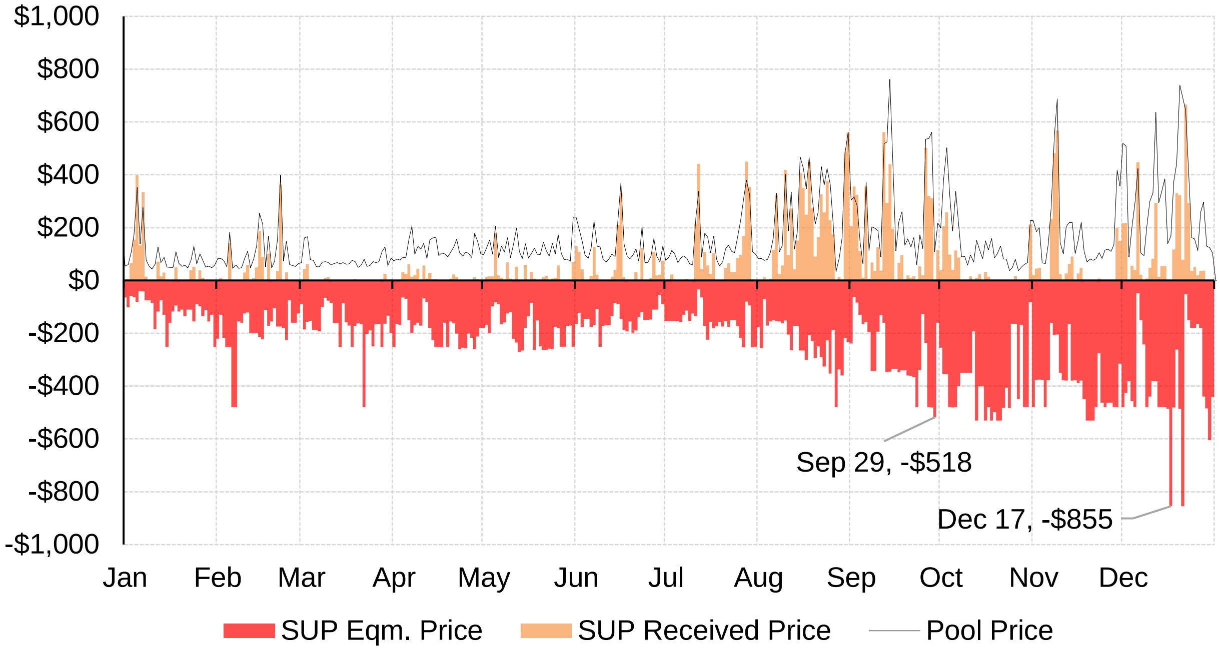

Table 9 shows the quarterly average cost of active OR products. Pool price increased by $106.60/MWh year-over-year but OR costs increased by less than that, which indicates a higher level of competitiveness in OR markets across all three active products in Q4. Offers in the supplemental market were particularly competitive in Q4.

*Table 9: Average cost ($/MWh) of active OR products (Q4 2021 and 2022)*

| Product | Q4 2022 | Q4 2021 | Q4 2022 - Q4 2021 |
|---|---|---|---|
| Spinning | $134.81 | $63.32 | $71.49 |
| Supplemental | $70.75 | $38.54 | $32.21 |
| Regulating | $122.20 | $56.77 | $65.43 |
| **Avg. Pool Price** | **$213.92** | **$107.31** | **$106.60** |

On-peak supplemental equilibrium prices cleared at -$855/MWh on December 17 and again on December 21. The previous record in 2022 was set at -$531/MWh on October 21. These record-low prices are significant because they fall below -$479.99/MWh, which has typically been among the lowest observed equilibrium prices in OR markets. -$479.99/MWh corresponds to a clearing unadjusted offer price of -$999.99/MWh.[23] However, offers below this level have been observed more frequently in recent months.

*Figure 59: Daily active on-peak supplemental equilibrium price, received price, and pool price (January 1 to December 31, 2022)*




Across December, the AESO procured an average of 277 MW of on-peak supplemental reserve each day, but only procured 250 MW on December 17. This contributed to an equilibrium price of -$855/MWh, shown by the intersection of supply and demand in Figure 60. The figure also shows that over 100 MW of on-peak supplemental reserve was offered at an adjusted offer price of -$1000/MWh, which is derived from an unadjusted offer price of -$2040/MWh. This is much lower than -$999.99/MWh, which was often the lowest offer price observed.

Figure 61 shows the on-peak supplemental supply curve from September 24, 2022, which was a comparable day to December 17 in terms of pool price, day of week, and total procurement volume. The lowest offers on September 24 were only -$479.99/MWh, corresponding to an unadjusted offer of -$999.99/MWh.

[23] The average between (i) an offer price of -$999.99/MWh and (ii) the AESO's bid price of $40/MWh equals -$479.99/MWh. See ID #2013-005R, p.6 for more information on how the equilibrium price is defined.

*Figure 60: Adjusted on-peak supplemental reserve offers, December 17, 2022*

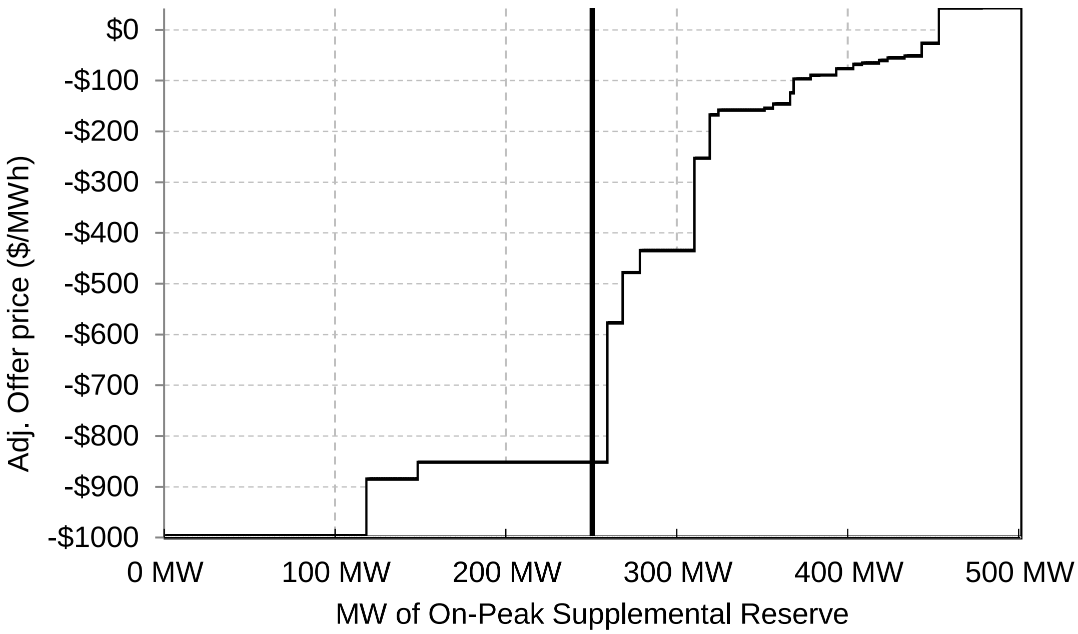
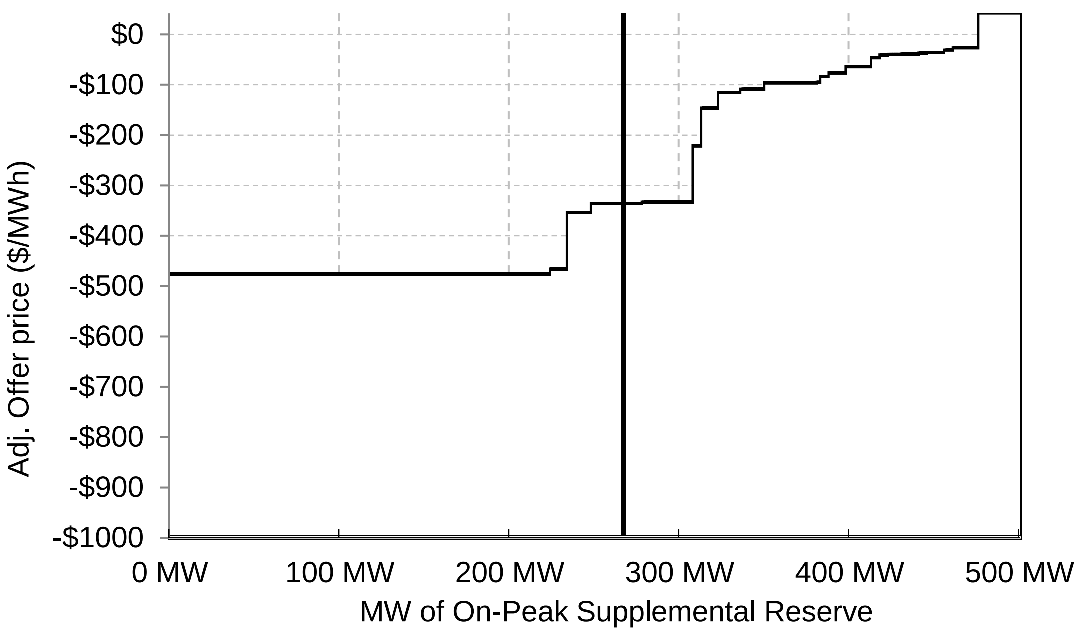



*Figure 61: Adjusted on-peak supplemental reserve offers, September 24, 2022*




Starting in late September, supplemental providers began offering volumes below -$999.99/MWh (see Figure 62). There was 188 MW offered below -$999.99/MWh on September 27 and the equilibrium price subsequently cleared at new lows of -$481/MWh on September 28 and -$518/MWh on September 29. Figure 63 shows the same trend happening with on-peak spinning reserve offers. This also started on September 27 and similarly resulted in a record low equilibrium price of -$518/MWh on September 29.

*Figure 62: Active on-peak supplemental volumes offered below -$999.99, and bid volume (June 1 to December 31, 2022)*

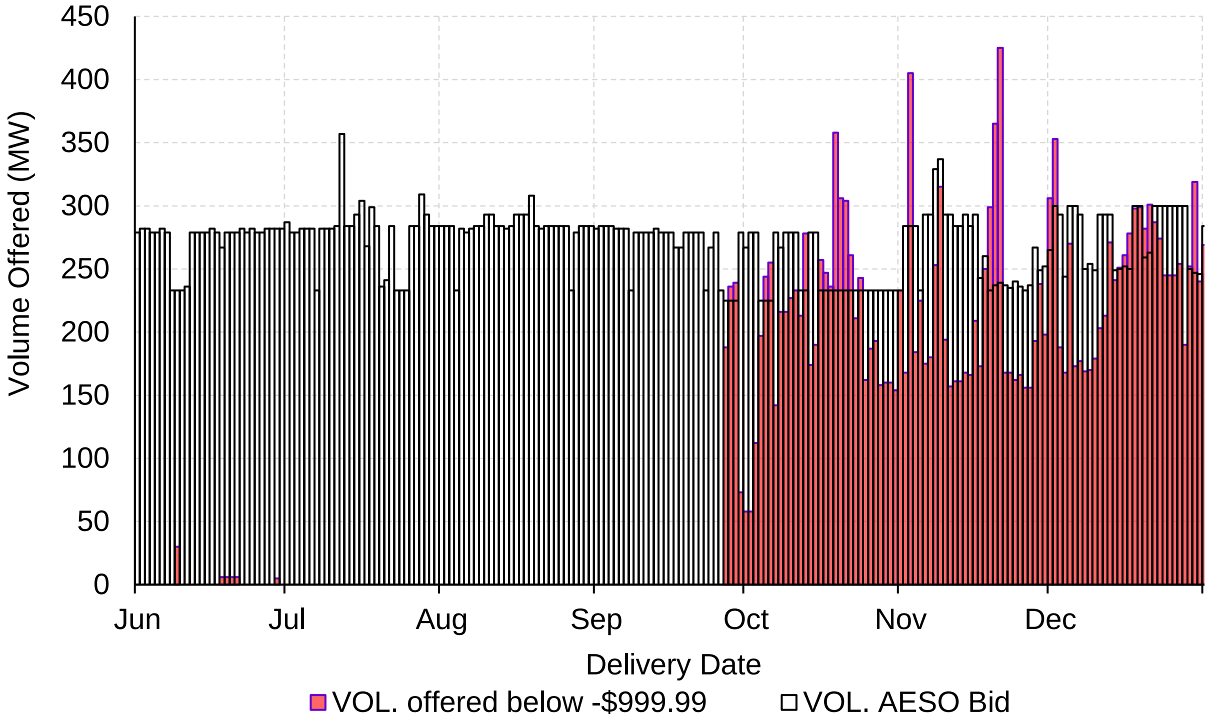
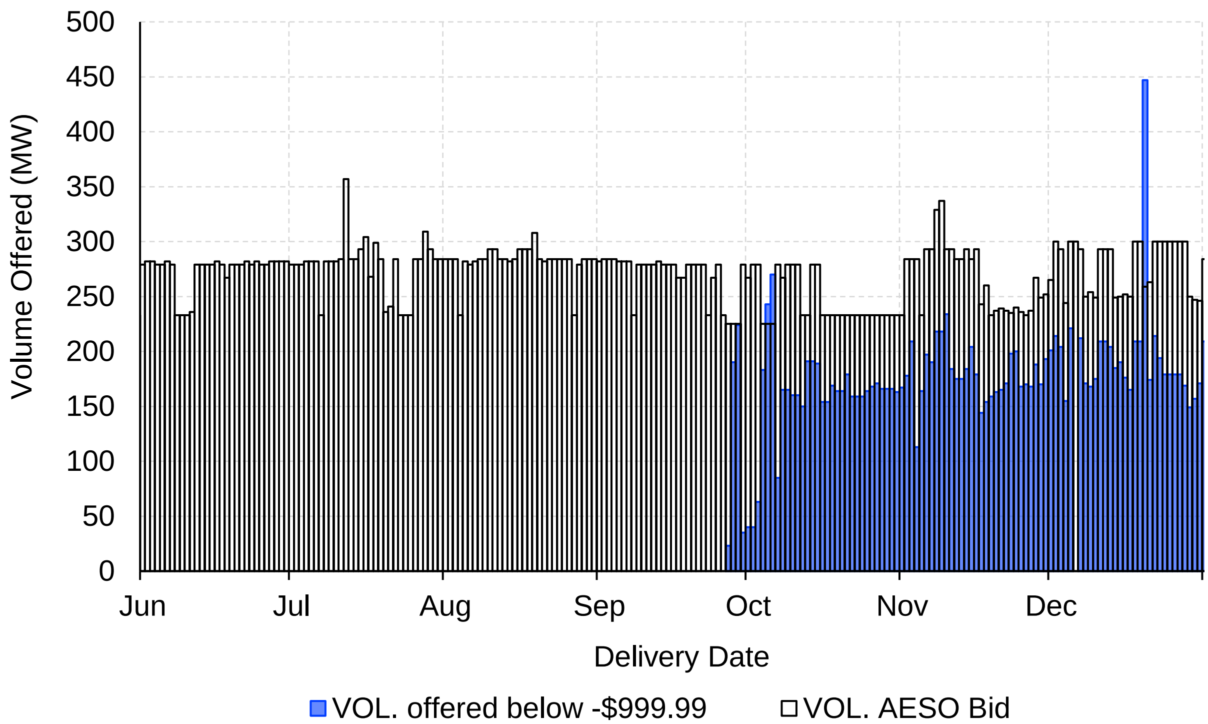



*Figure 63: Active on-peak spinning volumes offered below -$999.99, and bid volume (June 1 to December 31, 2022)*

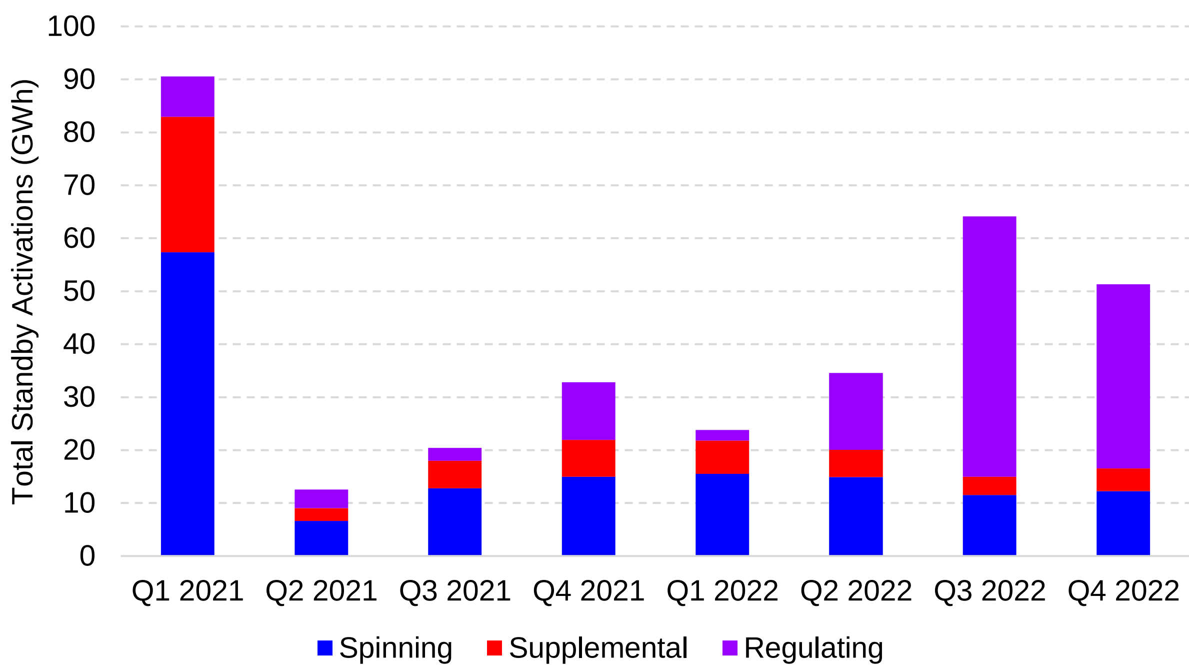


### 2.3 Standby activations

Figure 64 shows the total volume of standby activations for spinning, supplemental, and regulating reserves. After the AESO began procuring more active reserves day-ahead in February 2021, the volume of standby spinning and supplemental reserves have remained lower. Spinning and supplemental standby activations are impacted by the available amount of active reserves relative to imports, and stable throughout 2022. However, regulating reserve activations increased substantially in Q3 and Q4, and were highest in August.

Activations of standby regulating reserves can be driven by an asset's inability to provide active regulating reserves,volatility in wind generation, or merit order changes at the top of an hour. The number of transmission constraint directives increased in the second half of Q3 and remained high into the first half of Q4. In these cases, an asset providing regulating reserves was no longer able to do so, since the provider's operating reserves are curtailed before their offered energy supply. There were also more standby regulating activations issued to manage renewable volatility and hourly changes in the energy market merit order in Q3 and Q4.

*Figure 64: Total quarterly standby reserve activations (Q1 2021 to Q4 2022)*

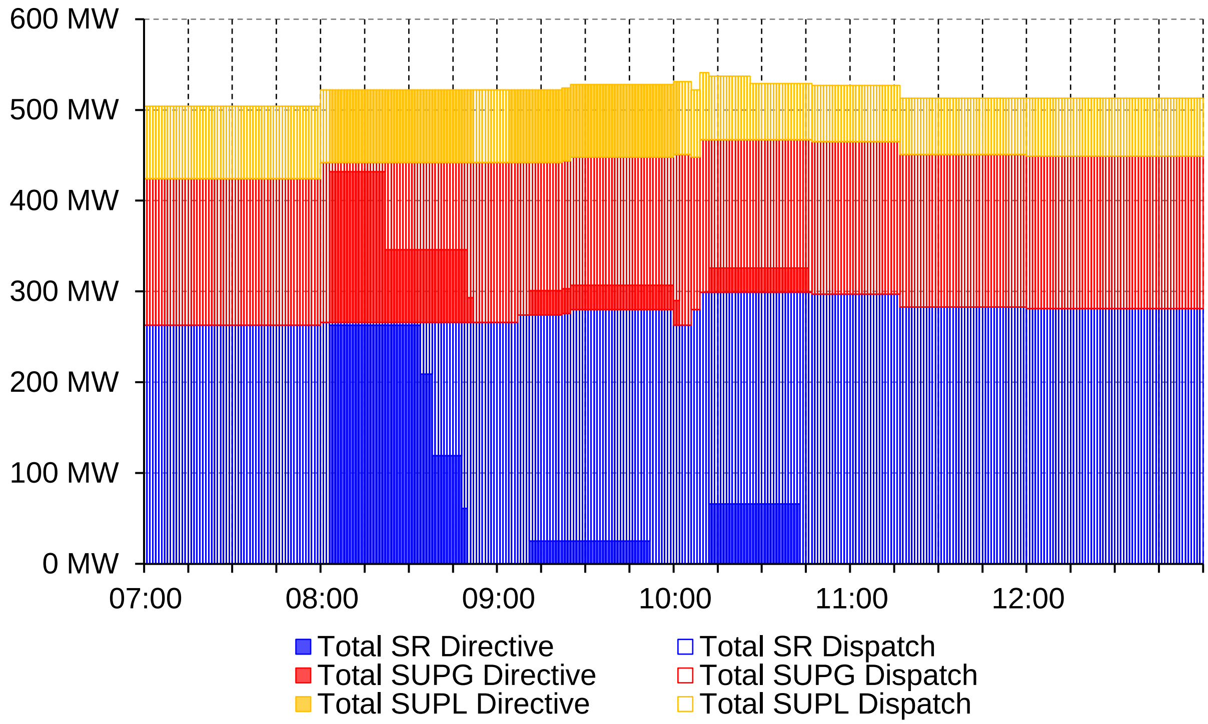



### 2.4 Contingency reserves and EEA events

As summarized in Figure 10, the AESO declared seven EEA3 events in 2022. The specific contributing factors are unique to each event, which impacts the way contingency reserves are used in response by system controllers.

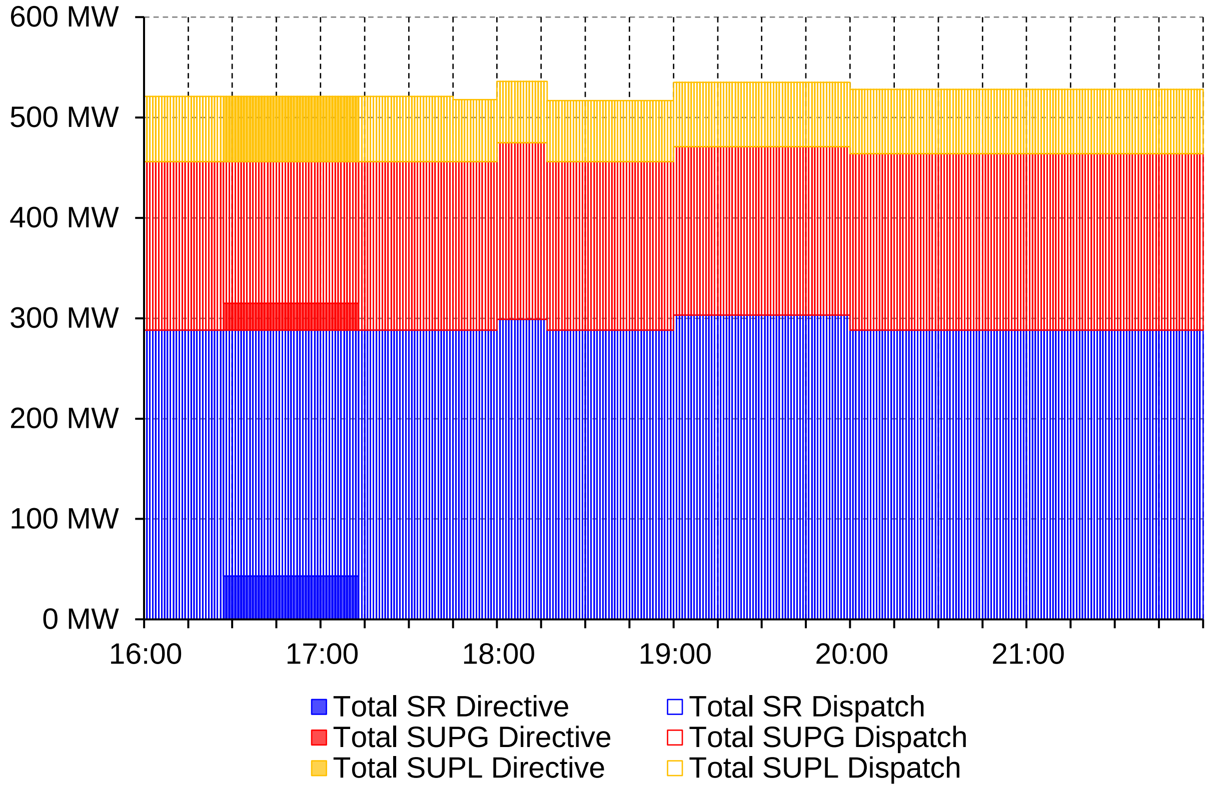
On December 21, Keephills 3 (463 MW) unexpectedly tripped offline at 08:02 which led to the AESO declaring an EEA3 event at 08:25. Since this happened during cold weather and tight market conditions, the sudden supply loss required almost all available contingency reserve resources immediately following the trip (see Figure 65). During the peak minutes of directed volume, 509 MW of contingency reserves were directed, or 98% of the available reserves. This was the highest utilization level across all seven EEA3 events in 2022. The EEA3 lasted over four hours, ending at 12:20. Contingency reserves were primarily directed during the first half of the event to restore balance during the morning peak.

*Figure 65: Minute-level dispatch and directive of contingency reserves (Morning EEA3 event on December 21, 2022)*




In contrast, the EEA3 event the evening of December 21 was not caused by a sudden contingency event. Prevailing conditions indicated in advance that a supply shortfall was likely during the evening peak, and the AESO declared an EEA3 that lasted from 16:24 until 18:29. Compared to the morning event, considerably lower levels of spinning and supplemental reserves were directed (135 MW at the peak) though supplemental load resources were fully directed, as shown in Figure 66. Whenever supplemental load resources were directed during EEA events in 2022, it was almost always a full directive for all available resources. In comparison, directives for supplemental generation and spinning resources were often only partial, leaving a portion of these resources available for further use.

*Figure 66: Minute-level dispatch and directive of contingency reserves (Evening EEA3 event on December 21, 2022)*



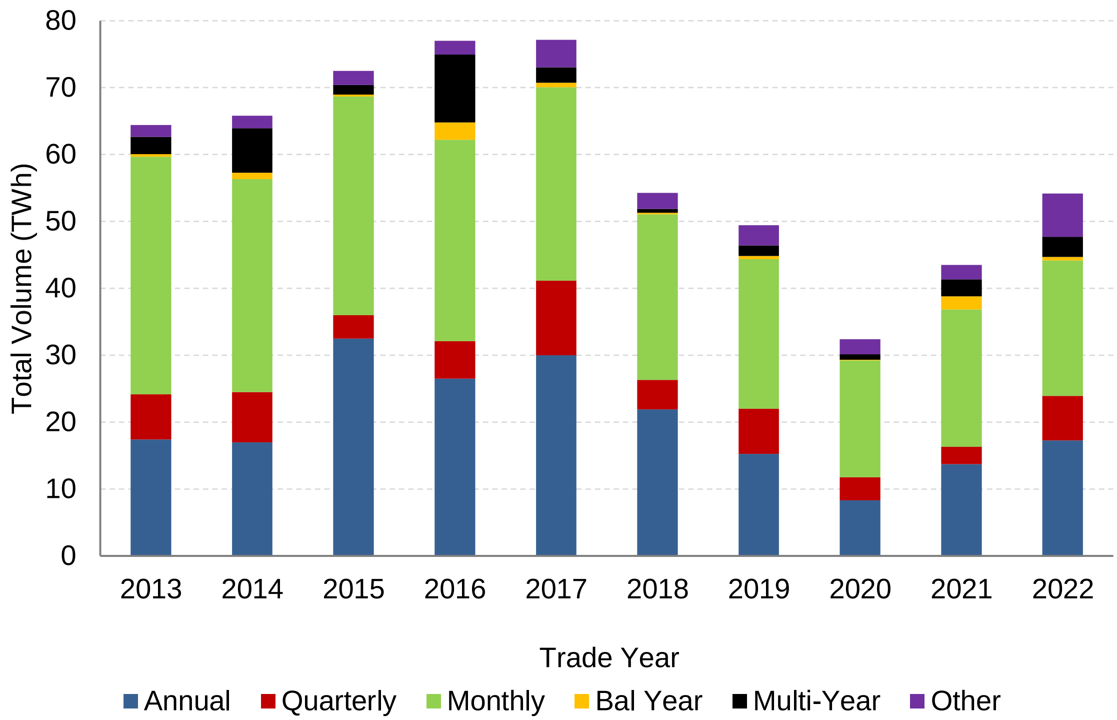
## 3 FORWARD MARKET

### 3.1 Forward market volumes

The financial forward market is an important component of Alberta's energy-only market design, as it allows generators and larger loads to hedge against pool price volatility. Similarly, the forward market enables retailers to reduce price risk by hedging sales to retail customers.

Total volume is the total amount of power traded financially over the duration of a contract, in MWh. The total volume of power traded in 2022 was 54.2 TWh, which is 25% higher than the total volume in 2021 (Figure 67).[24] In 2021 and 2022, total volumes were above the volume that traded in 2020, when trading activity was affected by a reduction in economic activity. As shown, total volumes have been lower since 2018 compared with prior years, such as 2016 and 2017 when total volumes were above 75 TWh.

*Figure 67: Total volume by trade year (2013 to 2022)*

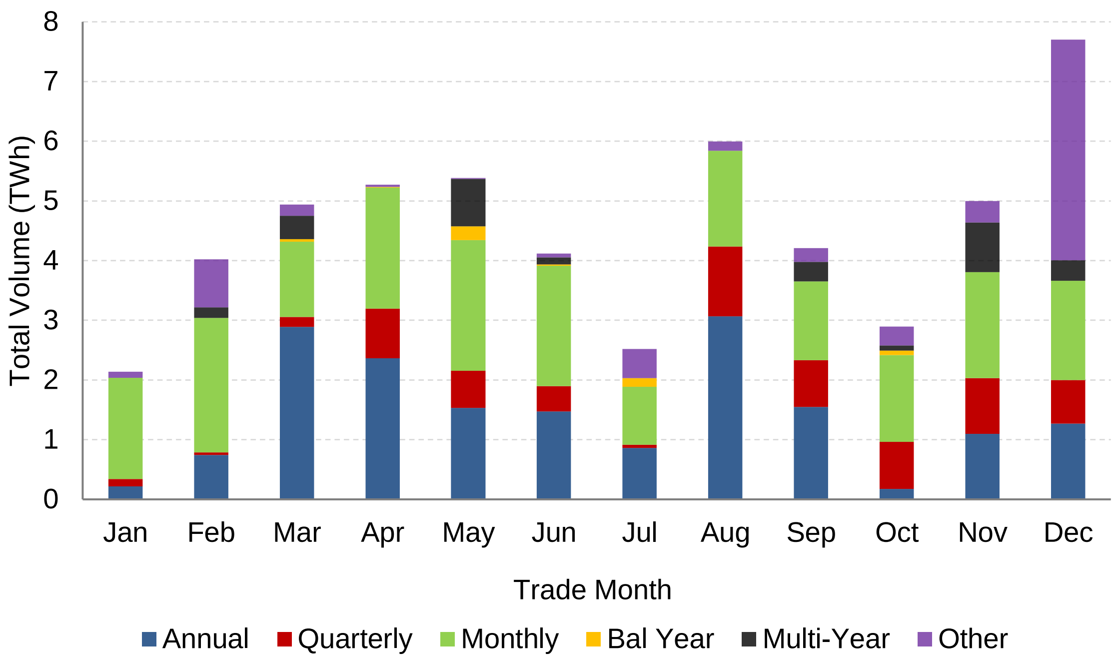



[24] The MSA's analysis in this section incorporates trade data from ICE NGX and two over-the-counter (OTC) brokers: Canax and Velocity Capital. Data from these trade platforms is routinely collected by the MSA as part of its surveillance and monitoring functions. Data on direct bilateral trades up to a trade date of December 31, 2022 is also included. Direct 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.

Direct bilateral trades accounted for 21% of total volumes in 2022, which is an increase from 2021 when direct bilateral trades accounted for 12% of total volumes.

Figure 68 illustrates total volumes by trade month in 2022. As shown, total volumes were highest in December when volumes were increased by a large direct bilateral deal. Trading of the Calendar 2023 (CAL23) contract was limited in Q4, as volumes for CAL23 fell by 84% compared to Q3.

*Figure 68: Total volume by trade month in 2022*



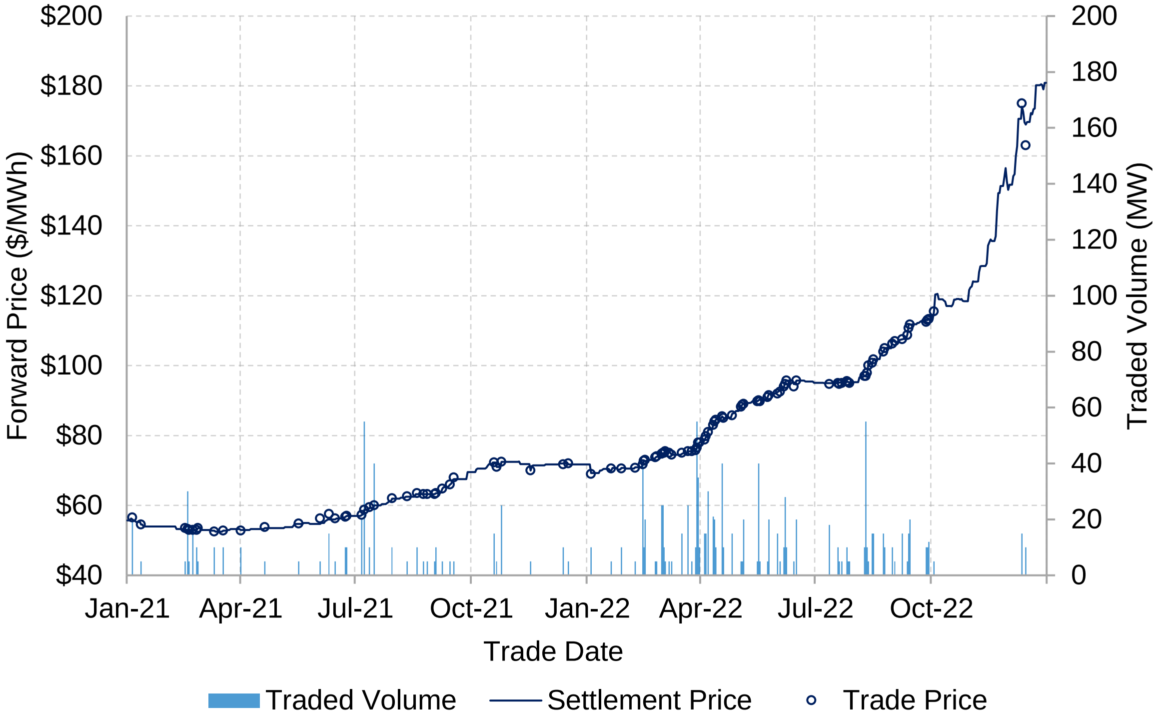

The price of CAL23 increased in Q4 (Figure 69). The higher price of CAL23 was partly the result of increasing forward prices in Mid-C and California, as increasing natural gas prices in these regions put upward pressure on the price of power. Higher power prices in these markets led to forward market expectations that exports of Alberta power would increase.

In addition, on November 4 the estimated completion date of the Cascade combined cycle project was delayed from September 2023 to December 2023. The Cascade project is a 900 MW generation asset being developed near Edson, Alberta.[25] The delay of this project reduced expected supply in Q4 2023, putting upward pressure on prices.

The reduction in traded volume for CAL23 during Q4 can be seen in Figure 69. Traded volume is the amount of power traded per hour in a contract, in MW. In total trading for CAL23, 1,660 MW was traded, compared to around 1,500 MW of CAL22 and CAL21. Traded volumes were higher for CAL19 and CAL20 at around 3,000 MW.

[25] Cascade Power Project website

*Figure 69: The price and traded volume for CAL23 flat (January 1, 2021 to December 31, 2022)*[26]




### 3.2 Trading of monthly products

Figure 70 illustrates forward prices for flat monthly contracts going back to January 2013. The price for each month is the volume-weighted average forward price, which provides an overall picture of where forward prices for that month traded. These flat contracts settle against the average pool price for a given month (Figure 70).

In 2022, pool prices for some months settled well above monthly forward prices. In December, pool prices averaged $312/MWh, a premium of 108% over the volume-weighted monthly average forward price of $150/MWh. Pool prices in December were increased by cold weather, offer behaviour, reduced wind supply, and increased export volumes. In August and September, pool prices were a premium of 105% and 127% over monthly forward prices, and these premiums were largely the result of a change in offer behaviour.

Over the full year of 2022, pool prices averaged $162/MWh compared to a price of $112/MWh based on monthly forward prices. This yields a pool price premium of $51/MWh or 45% over monthly forwards in 2022. In 2021 the pool price premium was $29/MWh, or 40% above monthly forwards.

[26] The markers illustrate the trade price of the last trade on that day.

*Figure 70: Monthly forward prices and realized pool prices (January 2013 to December 2022)*

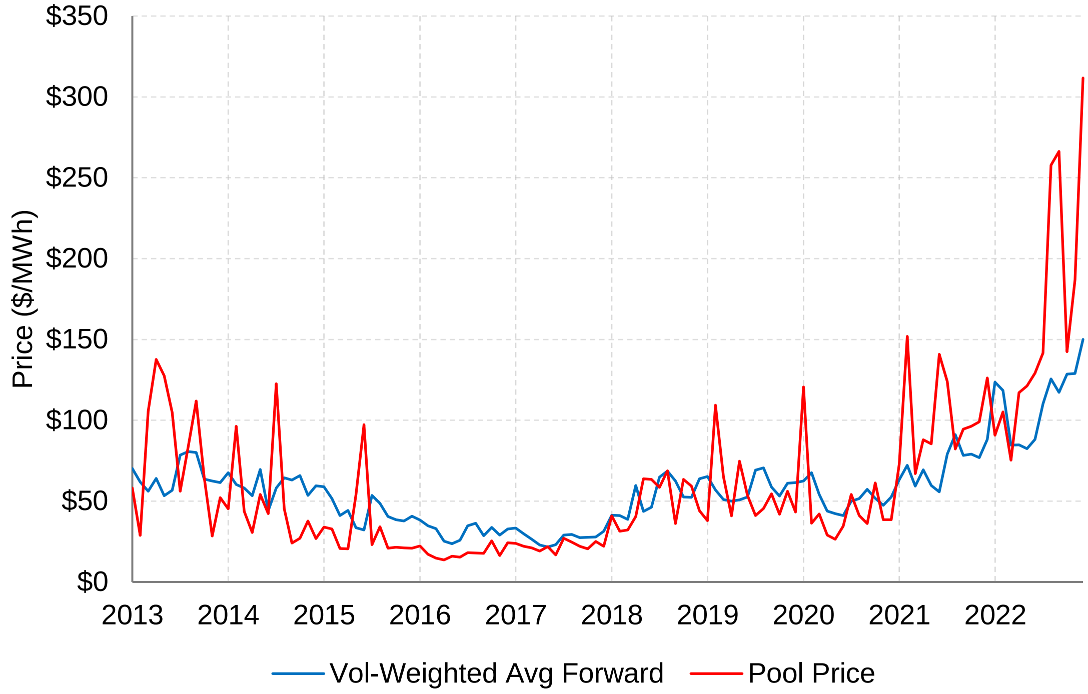
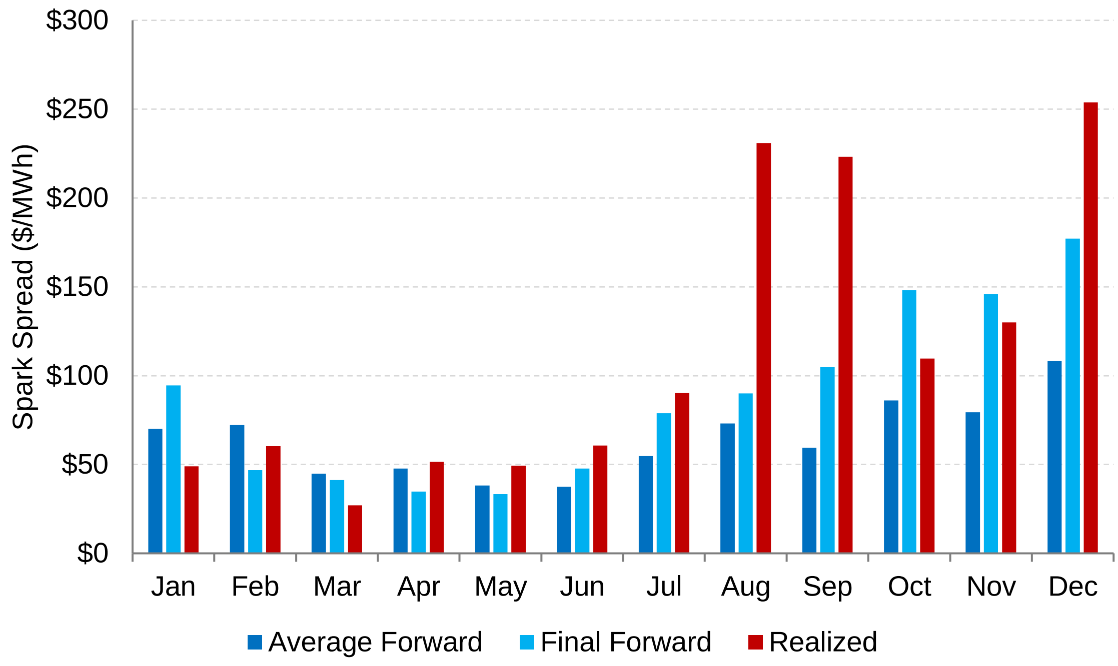



*Figure 71: Forward versus realized spark spread by month in 2022*[27]




[27] The spark spreads assume a heat rate of 10 GJ/MWh. The average forward spark spread is based on the average spark spread of daily settlement prices beginning five months prior to the contract start. The final forward spark spread is based on closing prices on the last trading day before the contract start.

Figure 71 illustrates forward versus realized spark spreads for each month in 2022. Spark spread provides an indication of margin for natural gas generation assets, based on the difference between pool prices and sameday natural gas prices.

For the first half of 2022 spark spreads in the energy market were relatively comparable with forward market expectations. However, realized spark spreads in August and September were well above forward expectations. For December, forward market expectations increased as the month approached, but the final forward spark spread of $177/MWh was still well short of $254/MWh, the realized spark spread for the month.

Figure 72 shows the evolution of monthly forward prices from September 1 to December 31. The figure provides forward prices for monthly contracts in Q4 2022 and Q1 2023 beginning five months out.

As shown, forward prices increased in October and November despite pool prices coming in below market expectations. Part of this increase was a response to rising forward prices in Mid-C and California. The Mid-C peak price for December increased from US$104/MWh on October 4 to US$224/MWh on November 30, an increase of 116%.

The extension of the outage at HR Milner (300 MW) also added upward pressure to some forward prices over the course of Q4. The gas asset went offline in early September for a planned outage to transition from simple cycle to combined cycle and was expected to return in early November.[28]

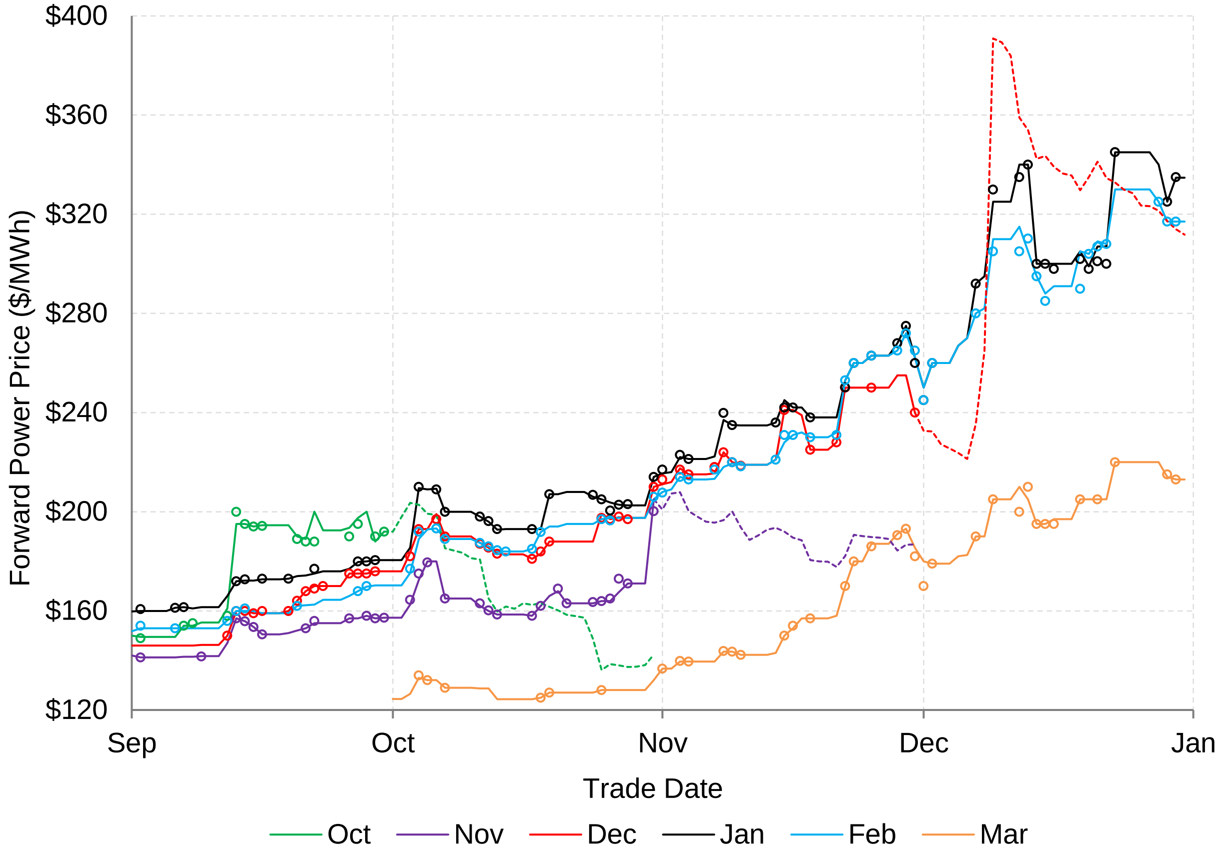
- On Sunday, October 2, the end date of the outage was extended from early November to early January, putting upward pressure on winter prices for 2022/2023. For example, the price of December increased by $7.50/MWh on October 3.

- On November 29, the end date of the outage was extended from early January to early April, putting upward pressure on forward prices for Q1 2023. The prices for January and February increased by $7.00/MWh on the day.

- After trading hours on December 13, the end date of the outage was extended into July 2023, putting upward pressure on summer prices in 2023. The price for July increased by $13.50/MWh on December 14.

[28] Maxim Power – news releases

*Figure 72: Monthly flat forward prices (trade dates September 1 to December 31)*[29]




Beginning on December 7, power prices in Mid-C and California increased on the back of cold weather forecasts and pipeline constraints, which caused natural gas prices there to soar.

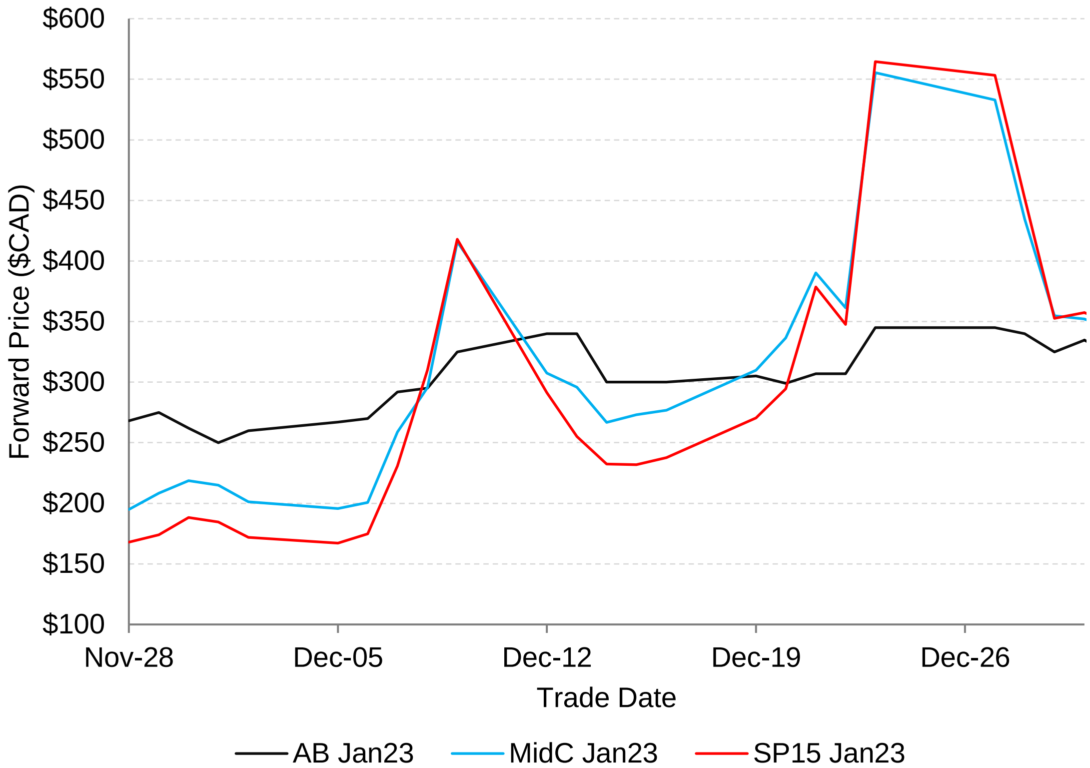
The increasing power prices in Mid-C and California resulted in large volumes of exports from Alberta, and effectively increased the demand for Alberta power (see Section 1.6). As a result, the expected average pool price for December increased from $221/MWh on December 6 to $391/MWh on December 9, an increase of 77% (see the dashed red line in Figure 72).

Forward power prices in December for the January contracts in Mid-C and California indicated that this dynamic would continue. Figure 73 illustrates forward power prices for January 2023 in Alberta, Mid-C, and California (SP15). In early December, forward prices for January in Mid-C and SP15 increased above the Alberta forward price before declining.

[29] The markers illustrate the last trade price on a trade date. The dashed lines indicate marked prices over time, which are based on realized pool prices and balance-of-month forward prices.

In late December, during a major storm event, forward prices in Mid-C and SP15 increased and put upward pressure on Alberta forward prices for a few days. However, in late December, forward power prices in these markets declined back down to prior levels (Figure 73).

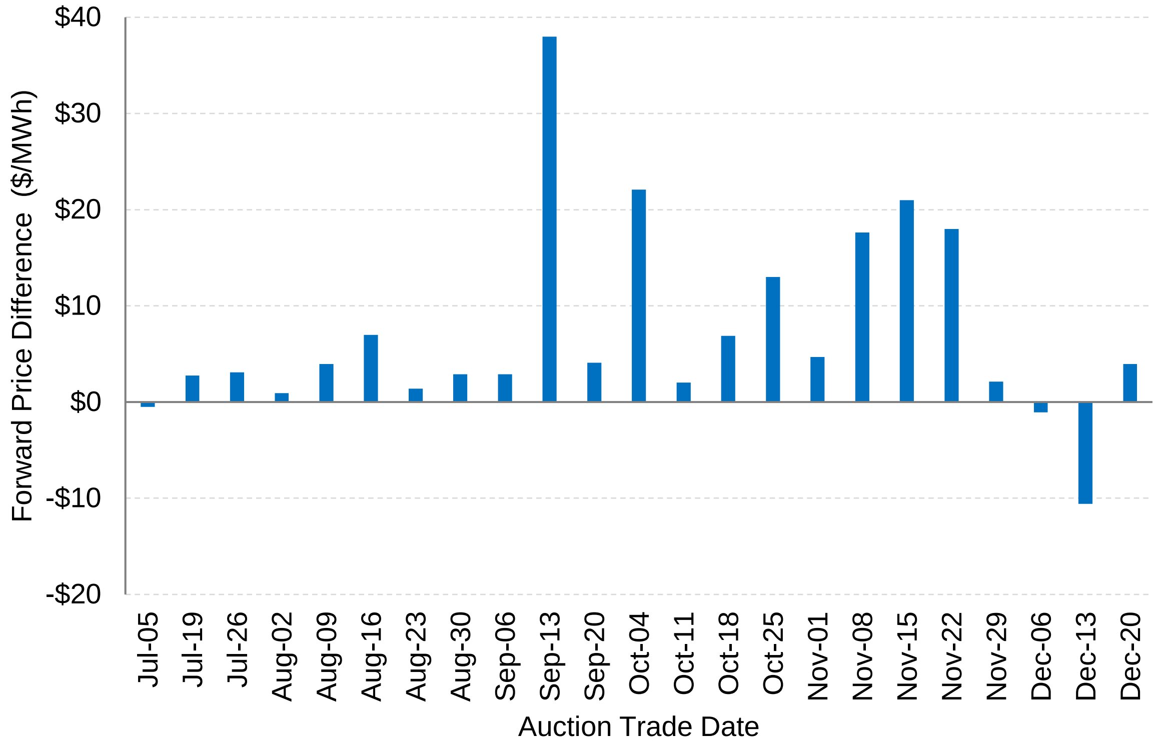
*Figure 73: January 2023 flat forward prices in Alberta, Mid-C, and SP15 (trade dates between November 28 to December 30, 2022)*




In addition, buying pressure from the EPCOR RRO and ENMAX RRO auctions increased forward prices in Q4. The EPCOR RRO auctions occur on Tuesdays and typically buy between 70 and 170 MW of traded volumes across the flat, extended peak, and full load products. The ENMAX RRO auctions typically buy between 40 MW and 60 MW and occur on Wednesdays.

Figure 74 illustrates the difference in price between Monday's closing flat forward price and the flat forward price in the EPCOR RRO auction on Tuesday morning. The figure spans auctions from July through December and illustrates a consistent premium in the EPCOR RRO auction relative to the closing price from the day before for much of the period. In late October and throughout November, the auction premium was generally more than $10/MWh.

*Figure 74: The difference between flat forward prices in EPCOR RRO auctions and the flat forward closing price from the day before*




### 3.3 Trading of annual products

The average pool price of $162/MWh in 2022 was well above forward market expectations for the year. The final trade for CAL22 was priced at $93.00/MWh on December 16, 2021 and the volume-weighted average of all CAL22 trades was $65.80/MWh. As indicated above, the higher pool prices in August, September, and December were a major factor in the average for 2022.

The price of CAL23 increased in Q4, partly because of market conditions in Mid-C and California, the postponement of the Cascade project, and the outage extension at HR Milner. On December 30, 2022 the CAL23 contract was valued at $181/MWh, which compares to the volume-weighted average price of $77.55/MWh for all CAL23 trades.

*Figure 75: Forward prices compared to realized pool prices, annual contracts (2013 to 2022)*

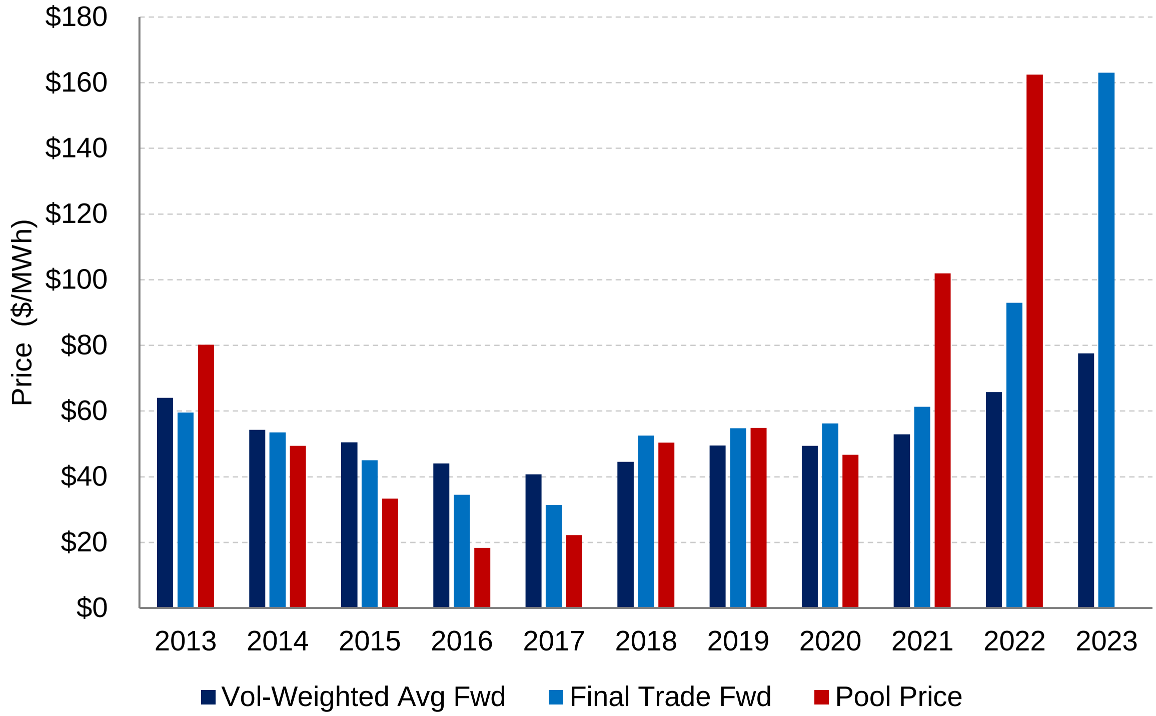
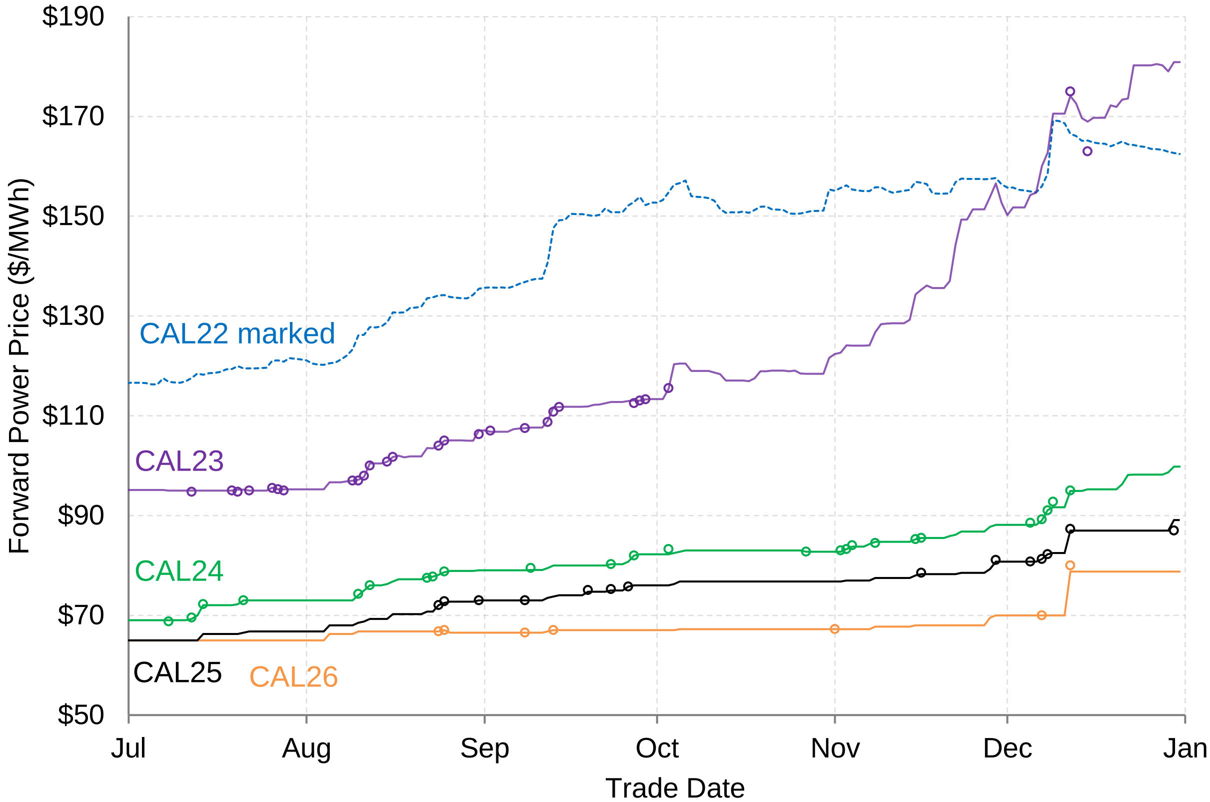



Figure 76 illustrates the evolution of prices for CAL22 to CAL26 from July 1 to December 31. Over Q4, the price of CAL23 increased by 60% from $113/MWh to $181/MWh, despite the price of natural gas for CAL23 declining by 23% over the same period.

Although relatively low volumes of the CAL23 contract traded in Q4, monthly and quarterly contracts within 2023 were actively trading. Since the prices of these monthly and quarterly contracts underpin the price valuation of CAL23, a higher price for CAL23 reflects higher monthly and quarterly prices within 2023.

The dashed blue line in Figure 76 shows the marked price of CAL22, which illustrates the expected average pool price for CAL22 based on realized pool prices and prevailing forward prices. In early December, the price of CAL23 increased above the expected price of CAL22. The price of the CAL24, CAL25, and CAL26 annual contracts increased as well, although not to the same extent as CAL23.

*Figure 76: Annual power prices for CAL22 to CAL26*
*(trade dates July 1 to December 31, 2022)*




The increasing power price and declining natural gas price for CAL23 meant the expected spark spread increased by 118% from $67/MWh to $145/MWh over Q4 (Figure 77). For context, the realized spark spread for 2022 was $112/MWh, a record high, while the spark spread for 2021 was $68/MWh.

The spark spreads for CAL24, CAL25, and CAL26 also increased over Q4 as shown in Figure 77 and Table 10. The power and natural gas prices for CAL27 are also listed in Table 10 as some multi-year power trades in 2022 incorporated 2027.

*Figure 77: Annual spark spreads for CAL21 to CAL26 [30] (November 1, 2021 to December 31, 2022)*

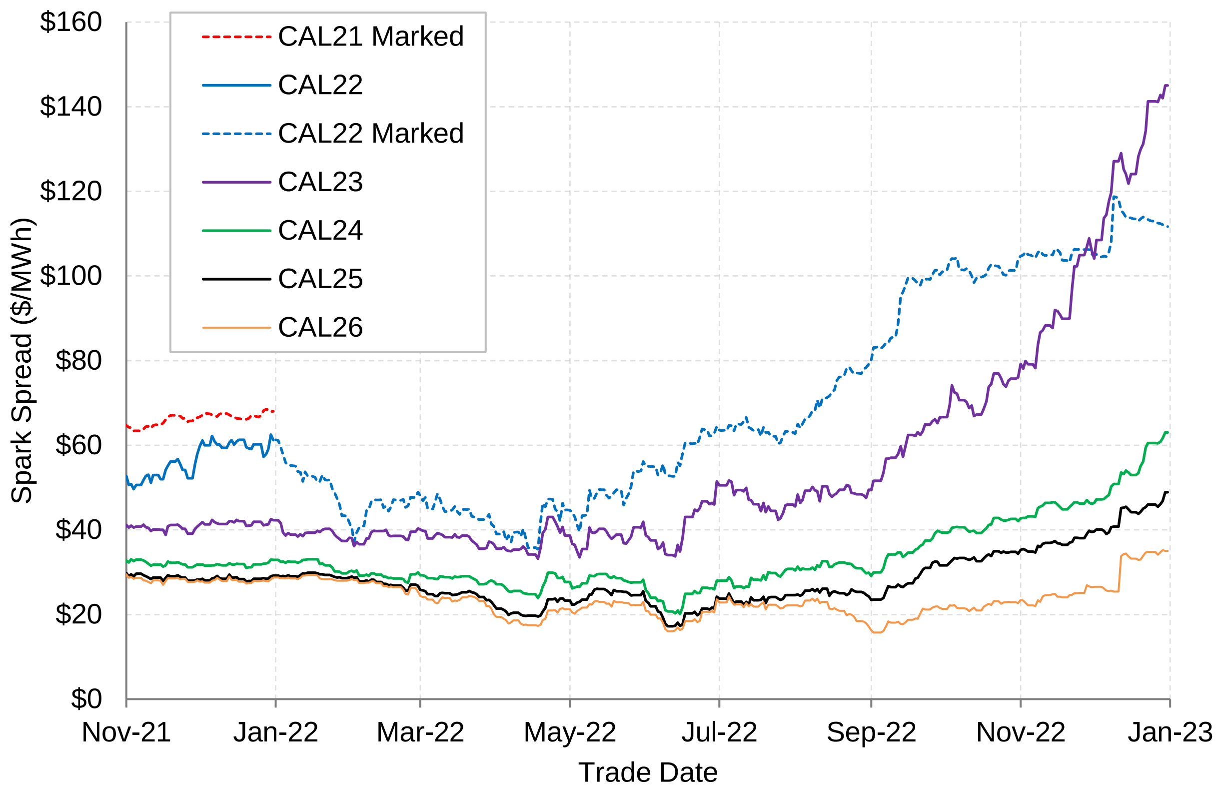



*Table 10: Power prices, natural gas prices, and spark spreads for annual contracts (changes over Q4)*

| Contract | Power Price ($/MWh) | | | Gas Price ($/GJ) | | | Spark Spread ($/MWh) | | |
|---|---|---|---|---|---|---|---|---|---|
| | Dec 31 | Sep 30 | % Change | Dec 31 | Sep 30 | % Change | Dec 31 | Sep 30 | % Change |
| CAL22 (marked) | $162 | $153 | 6% | $5.08 | $5.17 | -2% | $112 | $101 | 11% |
| CAL23 | $181 | $113 | 60% | $3.59 | $4.67 | -23% | $145 | $67 | 118% |
| CAL24 | $100 | $82 | 21% | $3.68 | $4.29 | -14% | $63 | $39 | 60% |
| CAL25 | $89 | $76 | 17% | $4.02 | $4.44 | -9% | $49 | $32 | 55% |
| CAL26 | $79 | $67 | 18% | $4.37 | $4.57 | -4% | $35 | $21 | 64% |
| CAL27 | $80 | $69 | 16% | $4.54 | $4.55 | 0% | $34 | $23 | 47% |

[30] Assumes a heat rate of 10 GJ/MWh

# 4 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 Q4 2022 relative to the previous year. RRO rates in Q4 were 25% and 73% higher than Q3 2022 and Q4 2021 respectively. RRO rates averaged 19.84 ¢/kWh across the four major service areas in Q4 2022 (Table 11).

Average residential competitive variable electricity rates increased by 92% in Q4 compared to the previous year, driven largely by high pool prices but fell 8% compared Q3 2022.

*Table 11: Monthly retail market summary for Q4 (Residential customers)*

| | | 2022 | 2021 | Change |
|---|---|---|---|---|
| RRO (Avg ¢/kWh) | Oct | 18.72 | 10.57 | *+77%* |
| | Nov | 17.73 | 10.64 | *+67%* |
| | Dec | 22.99 | 13.18 | *+74%* |
| | **Q4** | **19.84** | **11.47** | ***+73%*** |
| DRT (Avg $/GJ) | Oct | 5.11 | 4.03 | *+27%* |
| | Nov | 5.51 | 5.35 | *+3%* |
| | Dec | 6.15 | 4.79 | *+28%* |
| | **Q4** | **5.59** | **4.72** | ***+19%*** |
| Competitive Variable Electricity Rate (Avg. ¢/kWh) | Oct | 15.88 | 10.86 | *+46%* |
| | Nov | 20.70 | 11.24 | *+84%* |
| | Dec | 33.54 | 14.43 | *+132%* |
| | **Q4** | **23.40** | **12.19** | ***+92%*** |
| Competitive Variable Natural Gas Rate (Avg. $/GJ) | Oct | 4.27 | 5.98 | *-29%* |
| | Nov | 6.69 | 5.42 | *+23%* |
| | Dec | 6.79 | 4.87 | *+39%* |
| | **Q4** | **5.91** | **5.42** | ***+9%*** |
| Expected Cost, 3-Year Electricity Contract (Avg. ¢/kWh) | Oct | 10.60 | 8.19 | *+29%* |
| | Nov | 11.33 | 8.10 | *+40%* |
| | Dec | 12.82 | 8.07 | *+59%* |
| | **Q4** | **11.58** | **8.12** | ***+43%*** |
| Expected Cost, 3-Year Natural Gas Contract (Avg. $/GJ) | Oct | 4.74 | 3.87 | *+23%* |
| | Nov | 4.58 | 3.60 | *+27%* |
| | Dec | 4.47 | 3.24 | *+38%* |
| | **Q4** | **4.60** | **3.57** | ***+29%*** |

By comparison, residential Default Rate Tariff (DRT) rates increased moderately year-over-year in Q4 2022. Competitive variable natural gas rates were also moderately higher year-over-year in Q4 2022 but were above prevailing DRT rates.

The expected cost of providing 3-year fixed rate electricity and natural gas contracts increased in Q4 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 Q3 2022.

### *4.2.1 Regulated retailer customer losses*

The number of residential RRO customers fell by around 19,000 in Q3 2022, a net loss of 3% compared to the number at the end of Q2 2022. The number of residential DRT customers fell by around 11,000 customers in Q3 2022, a net loss of around 2.5%.

The residential RRO customer base declined by more customers in Q3 compared to Q2 2022 (Figure 78). RRO customer losses were greater in Q3 compared to Q2 2022, while RRO customer gains were lower (Figure 79). Around 50,000 residential customers have continued to leave the RRO each quarter since Q2 2021.

*Figure 78: RRO customer net losses, Q1 2020 to Q3 2022 (residential customers)*

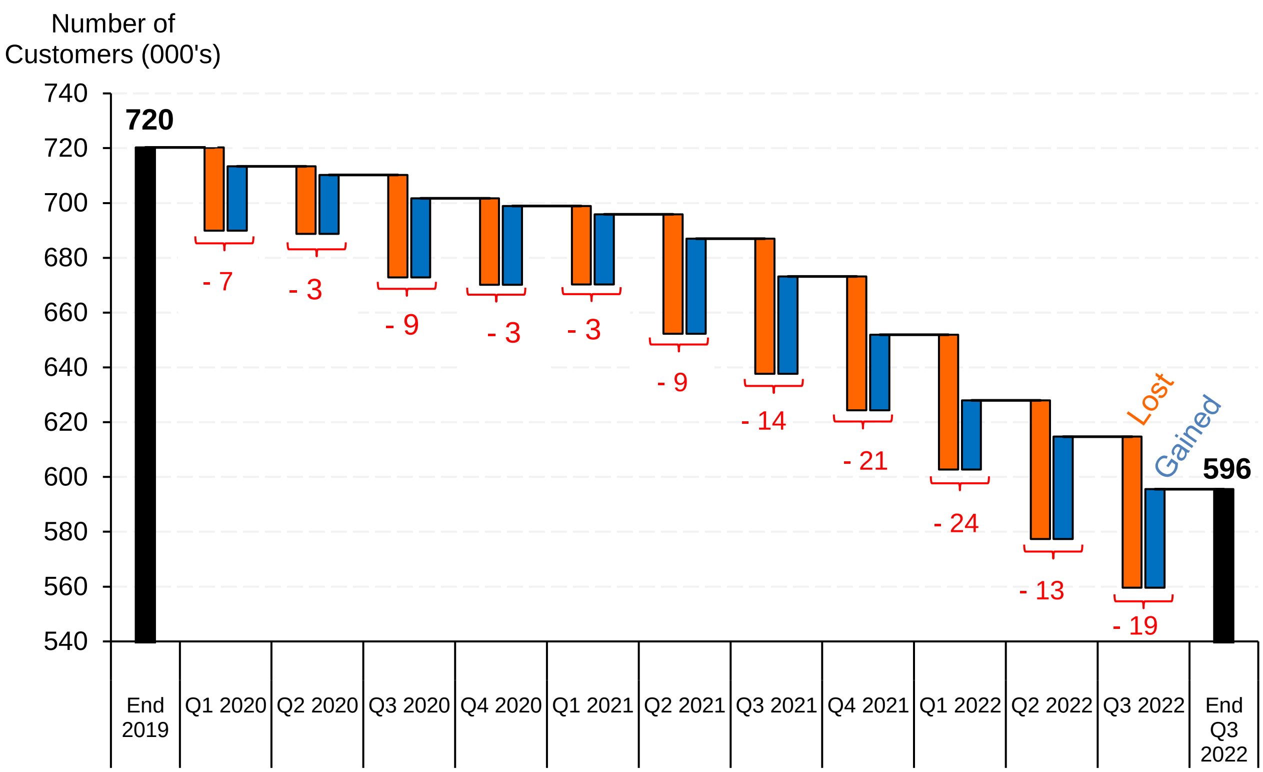
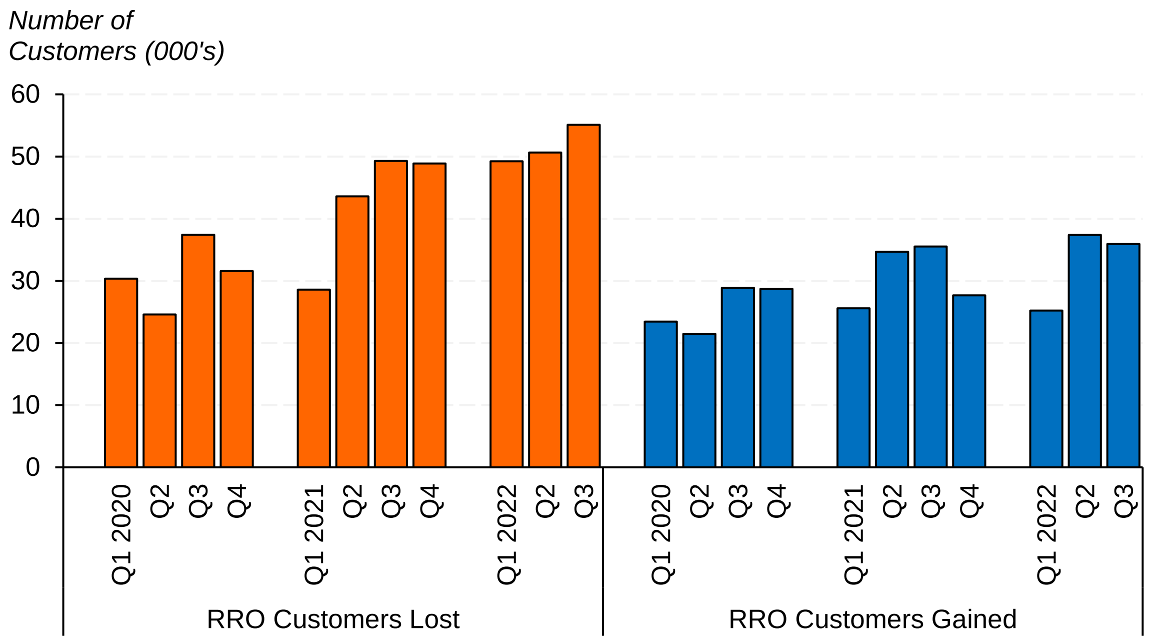


*Figure 79: RRO customer losses & gains, Q1 2020 to Q3 2022 (residential customers)*




The DRT also continued to lose customers in Q3 2022, losing around 11,000 residential customers (on net) (Figure 80). While quarter-over-quarter net losses were relatively similar compared to Q2, both the number of DRT customers lost and gained increased in Q3 2022 (Figure 81).

*Figure 80: DRT customer net losses, Q1 2020 to Q3 2022 (residential customers)*

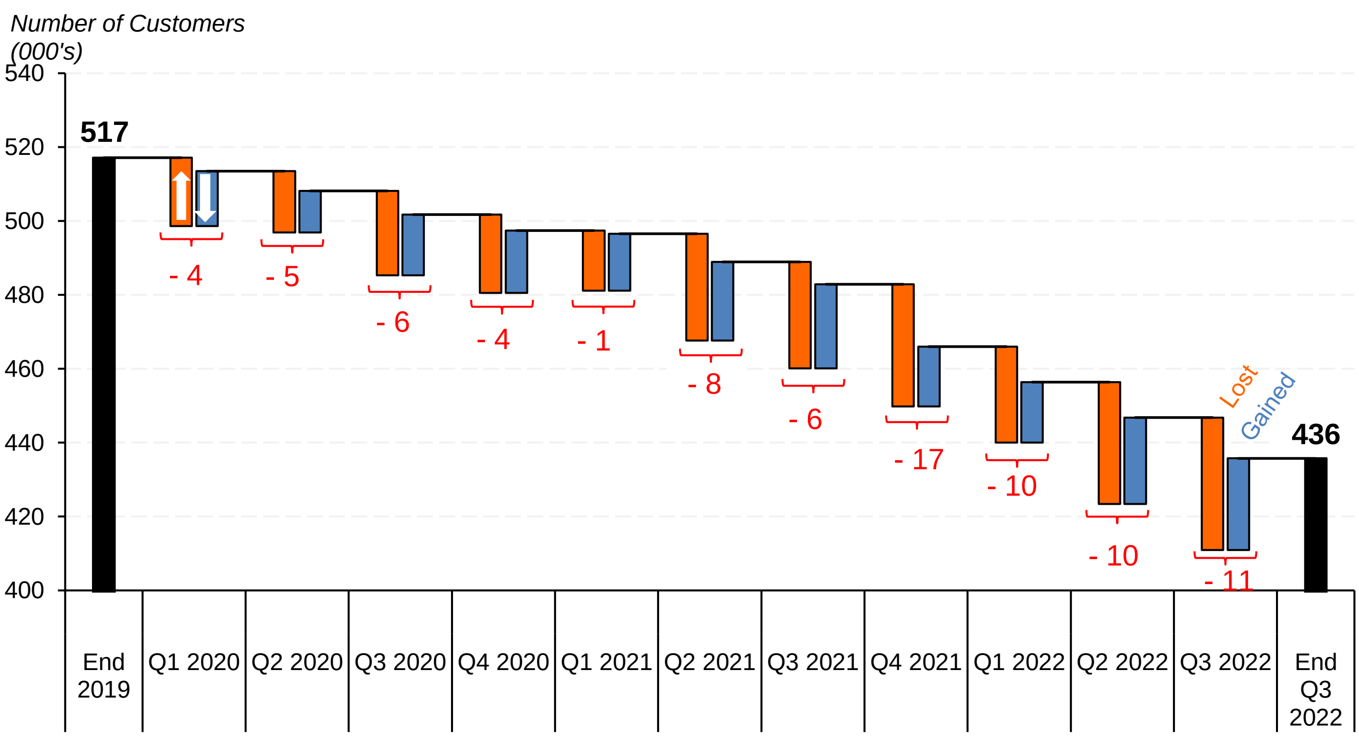
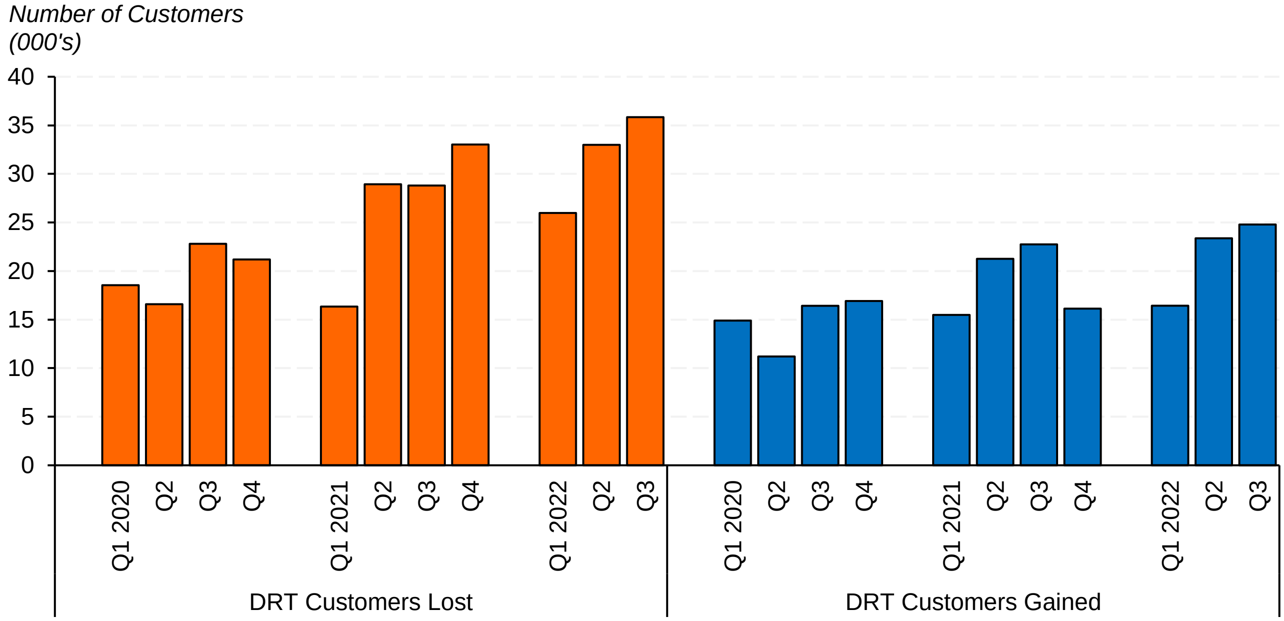


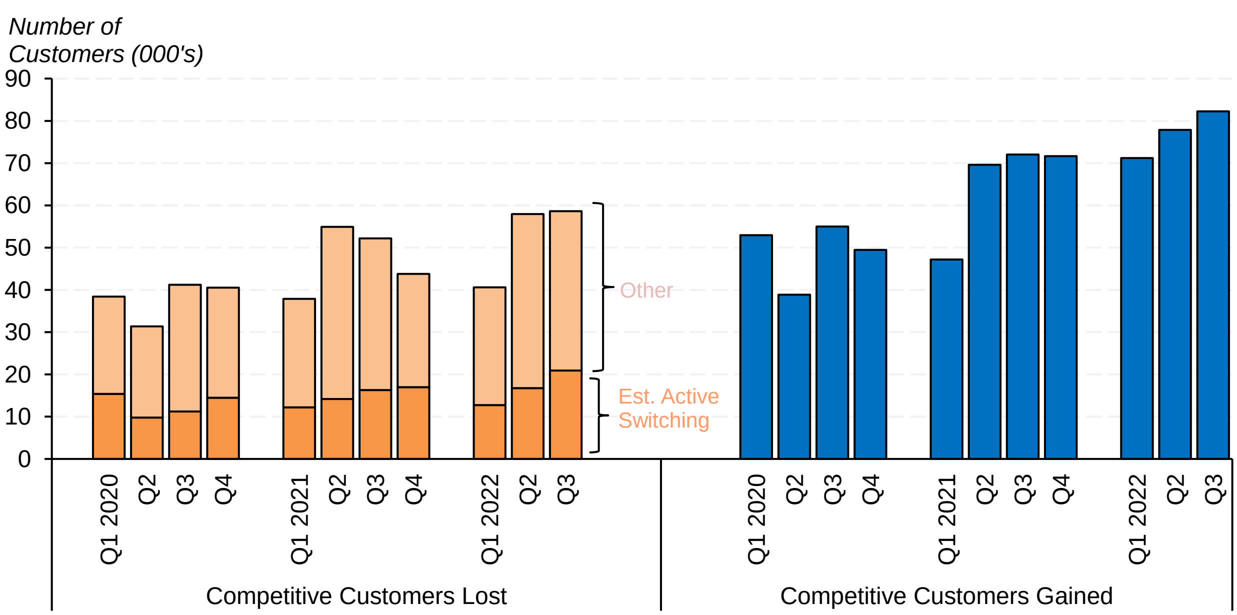
*Figure 81: DRT customer losses & gains, Q1 2020 to Q3 2022 (residential customers)*




#### 4.2.2 Competitive retailer customer gains

Competitive electricity retailers gained around 82,000 new residential customers in Q3 2022, 4,000 more than in the previous quarter (Figure 82). While competitive residential customer losses also increased to around 59,000 over Q3, roughly 38,000 of these losses were driven by residential customers moving during the quarter. Such customers are counted as a loss of a customer despite the possibility they might return to their competitive retailer.

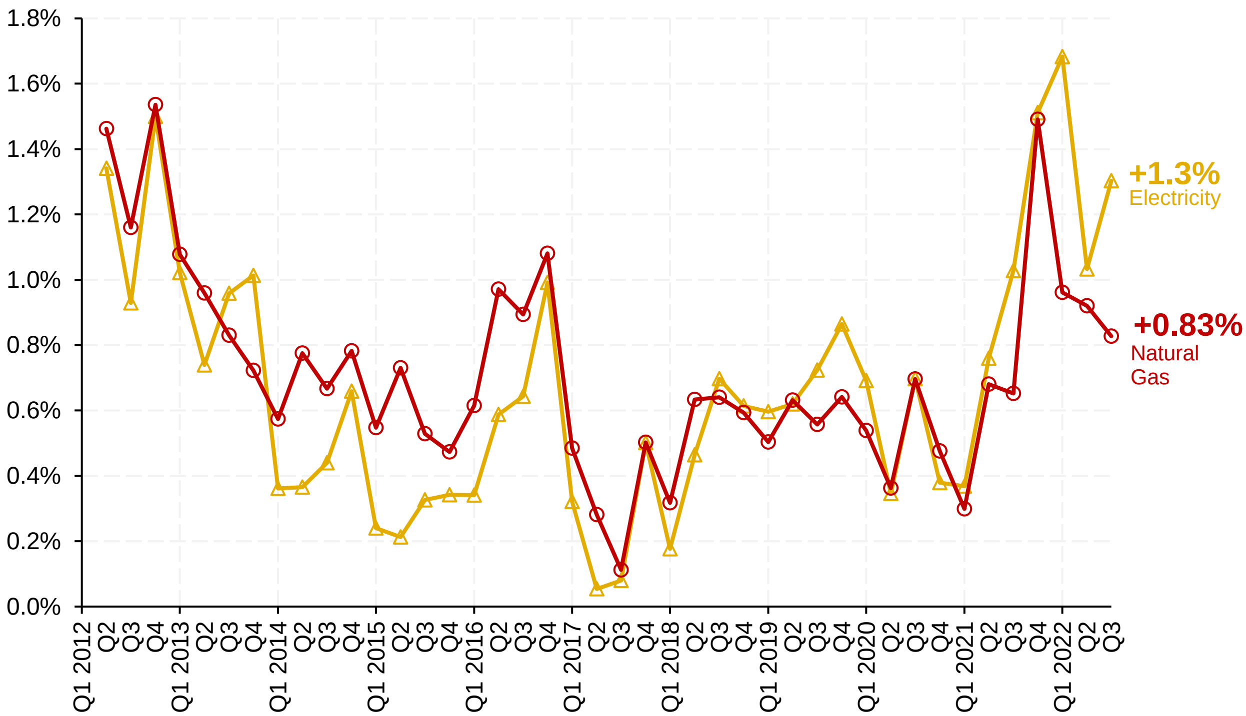
*Figure 82: Competitive electricity customer losses & gains, Q1 2020 to Q3 2022 (residential customers)*



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 Q3 2022 compared to the previous quarter. The MSA counts such a switch as an 'Active Switch', because 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.

Competitive retail customer shares among residential customers for electricity continued to increase in Q3 2022, at a rate slightly higher than what was observed in the previous quarter (Figure 83). The increase in competitive share in Q3 remains above historical levels.

*Figure 83: Quarterly increase in competitive retail customer share, 2012 to Q3 2022 (residential customers)*



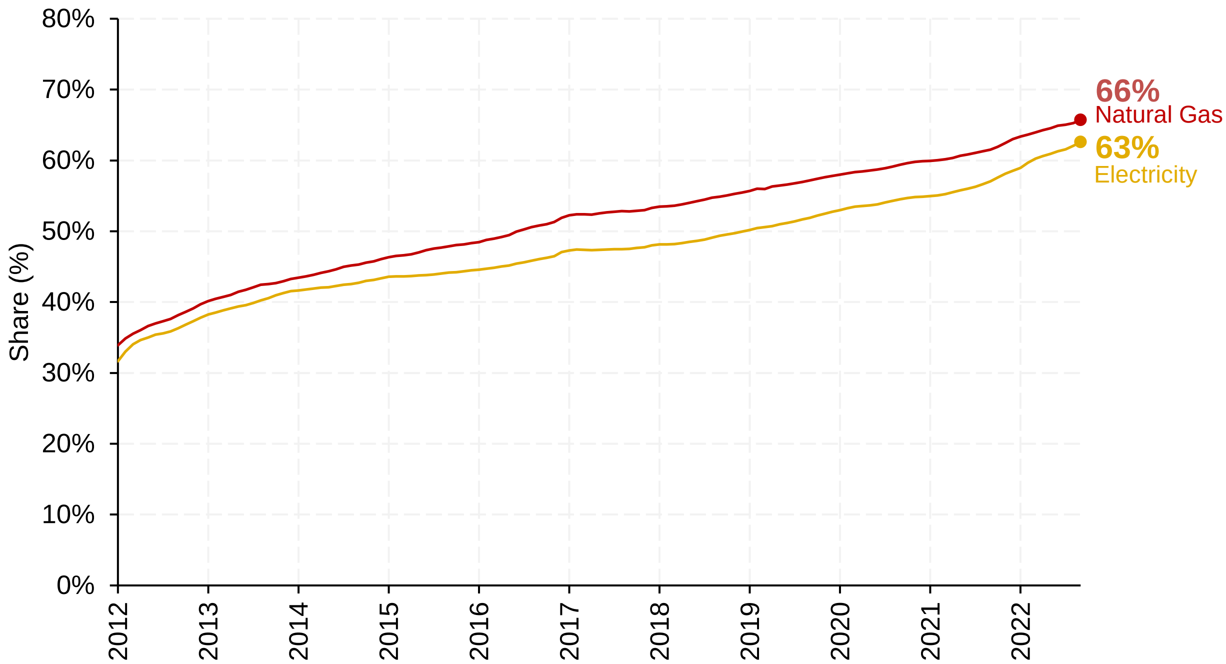

The largest increase in competitive market share among residential electricity customers in Q3 was observed in EPCOR and FortisAlberta service areas. Among residential natural gas customers, the increase in market share was highest in the Apex service area (Table 12). Overall, 63% of residential electricity customers and 66% of residential natural gas customers were served by a competitive retailer in September 2022 (Figure 84).

*Table 12: Competitive shares by service area (residential customers)*

| | ENMAX | EPCOR | FortisAlberta | ATCO |
|---|---|---|---|---|
| Change (Q2) | +0.6% | +1.3% | +1.2% | +1.6% |
| Change (Q3) | +1.2% | +1.6% | +1.5% | +0.1% |
| Competitive Share (Sept 2022) | 76.4% | 50.5% | 57.5% | 60.4% |

| | ATCO Gas North | ATCO Gas South | Apex |
|---|---|---|---|
| Change (Q1) | +1.1% | +0.7% | +1.0% |
| Change (Q2) | +0.8% | +0.7% | +1.8% |
| Competitive Share (Sept 2022) | 61.8% | 73.2% | 37.2% |

*Figure 84: Competitive retail customer share, 2012 to Q3 2022 (residential customers)*




### 4.3 Competitive retail rates

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.

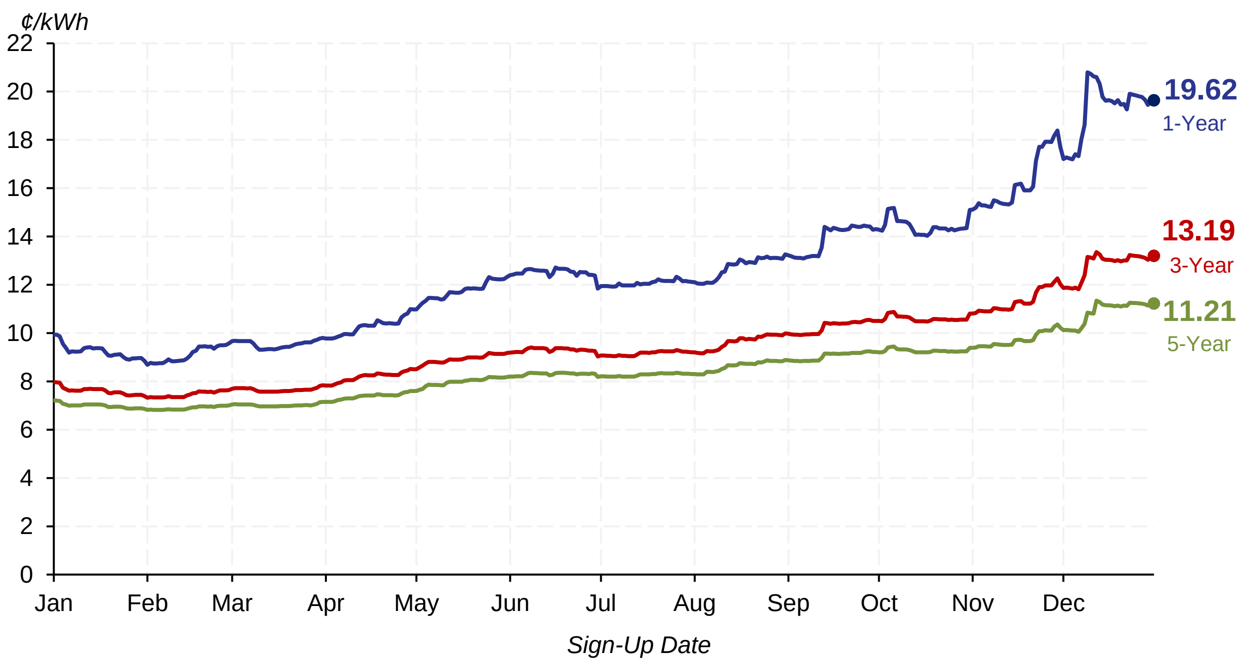
### *4.3.1 Fixed rate contracts*

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 fixed rate electricity contracts rose in Q4 2022 (Figure 85), continuing the trend seen in the previous two quarters of 2022. However, the expected cost for fixed rate natural gas contracts declined in Q4 2022 (Figure 86).

The expected cost of 1-year fixed rate electricity contract increased from 14.40 ¢/kWh on September 30 to 19.62 ¢/kWh on December 31, a 37% increase over the quarter. Similarly, expected cost of 3-year and 5-year fixed rate electricity contracts increased by 26% and 22% respectively in Q4 2022. An increase in expected cost for all electricity contracts was observed in the first week of December, driven by an increase in near-term and longer-term forward electricity contract prices. The difference in expected cost changes between different length contracts is a result of the much greater appreciation of near-term forward prices compared to longer term forward prices.

*Figure 85: Expected cost, fixed rate electricity contract (residential customer), January 1 to December 31, 2022*




High variability in natural gas futures prices drove significant variation in the expected cost of natural gas fixed rates over Q4 2022, a trend that has been ongoing since late 2021 (Figure 86). The expected cost of a 1-year natural gas contract dropped by $1.30/GJ over the quarter, while expected cost of a 3-year and 5-year natural gas contracts dropped by $0.76/GJ and $0.48/GJ in

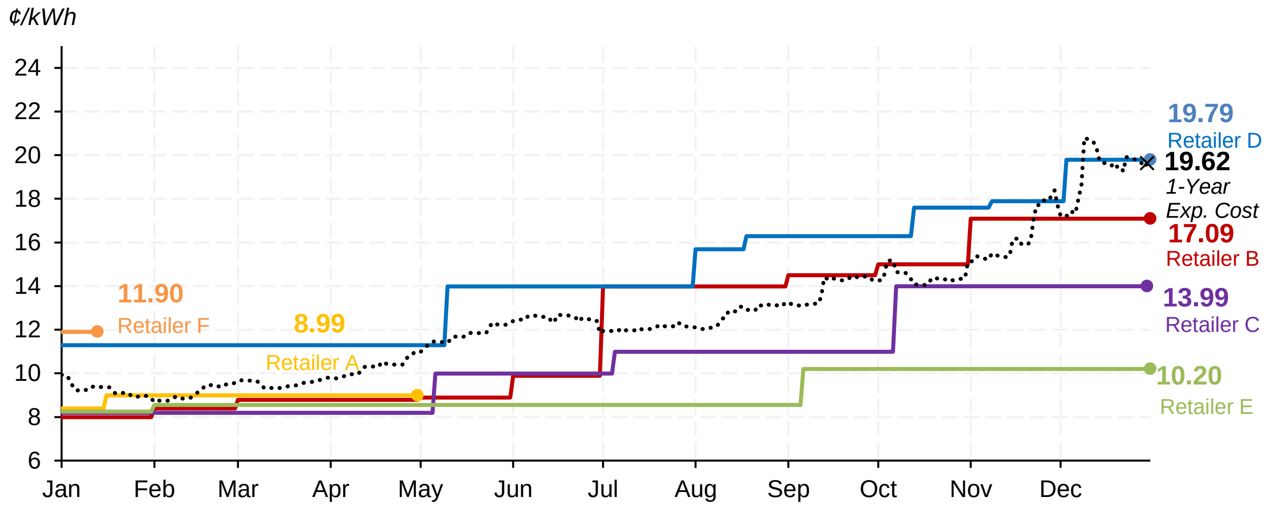
Q4 2022. Similar to the previous quarters in 2022, the 3-year and 5-year contracts exhibited lower variance in expected cost than the 1-year contact in Q4 2022.

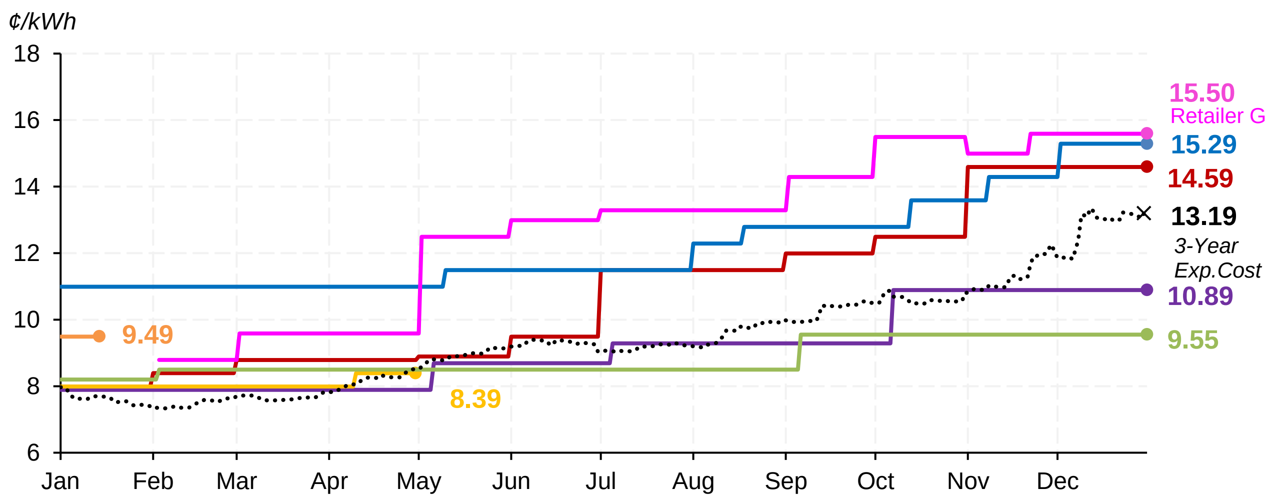
*Figure 86: Expected cost, fixed rate natural gas contract (residential customer), January 1 to December 31, 2022*


Competitive fixed rates (electricity and natural gas) continued to increase over Q4 2022 (Figure 87 and Figure 88). All major retailers (except Retailer E) increased each of their 1, 3, and 5-year fixed rate electricity prices at least once over the quarter. Retailer E did not change their 1- and 3-year fixed rate prices in Q4. Many retailers increased their fixed rate prices enough to offset the increased expected cost. Those retailers that did not may be hedged in the forward market.

The increase in fixed rate natural gas prices over Q4 2022 was not significant as the expected cost for natural gas fixed rates dropped over the quarter. Moreover, two major retailers (Retailer D and Retailer G) substantially reduced their fixed rates in Q4 2022, possibly to be more competitive as these rates were previously above expected cost (Figure 88).

*Figure 87: 1, 3, 5-year fixed rate electricity contract prices, residential customers, ENMAX service area (January 1 to Dec 31, 2022)*



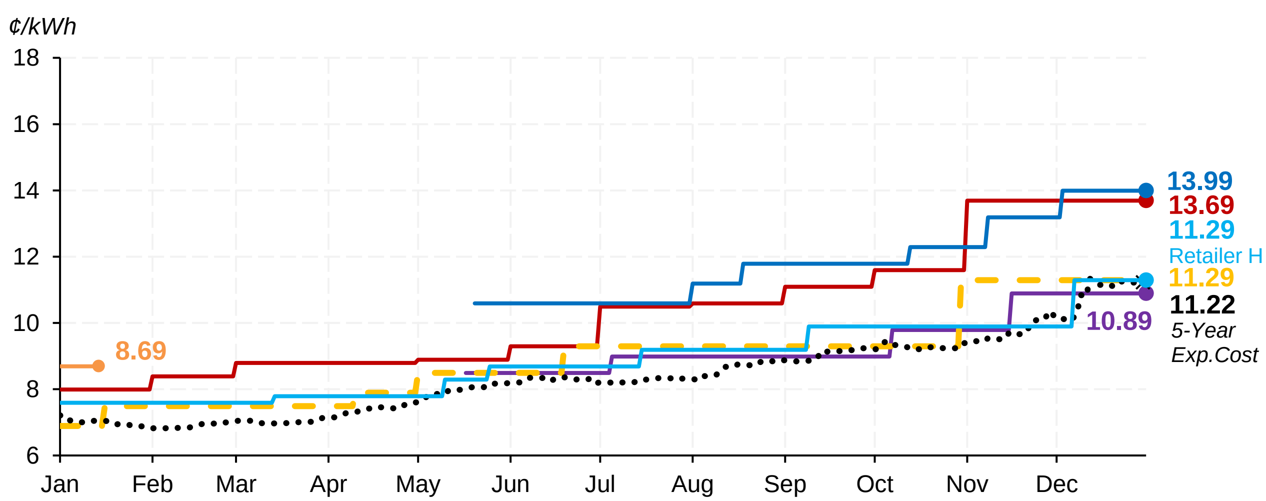
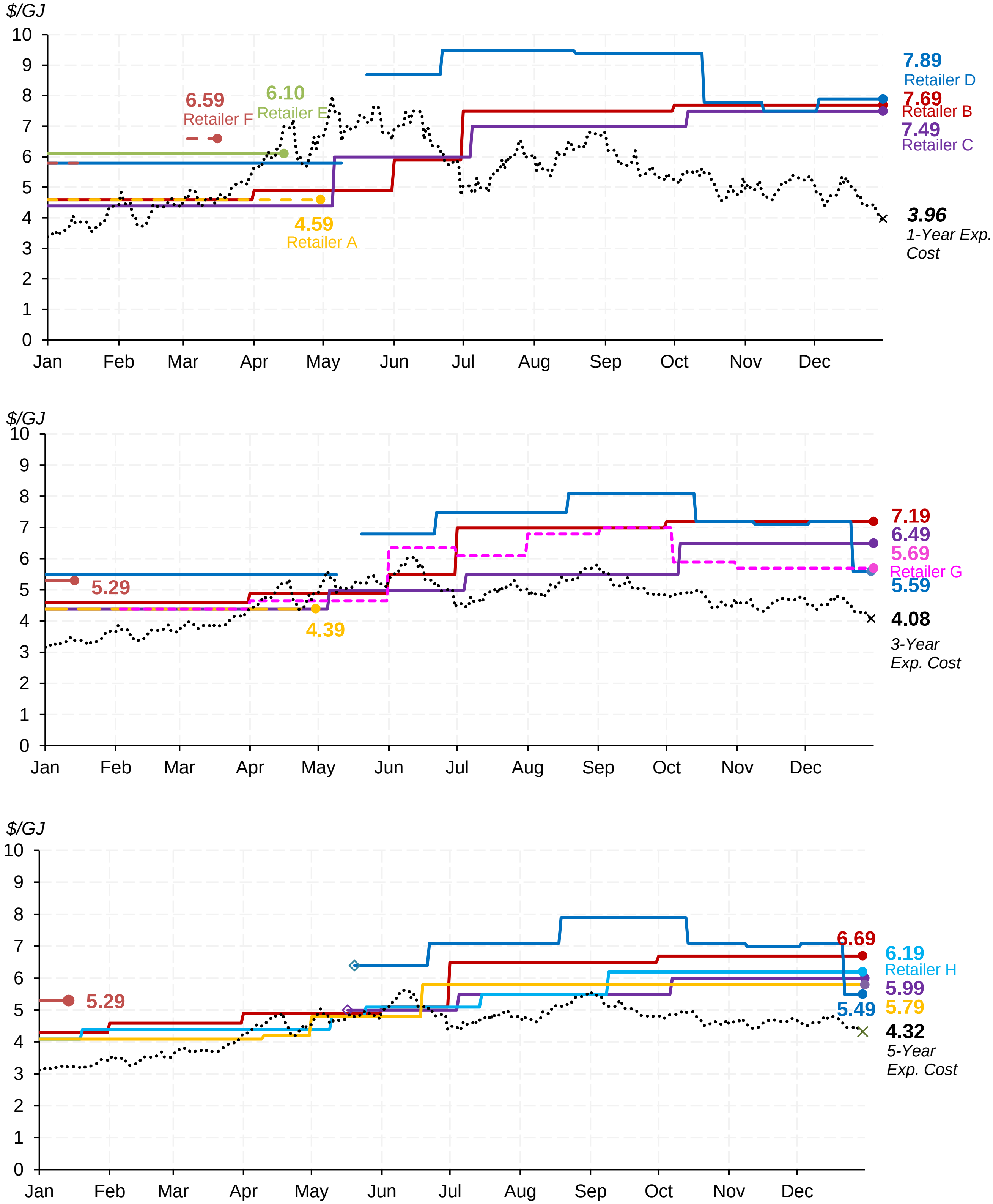



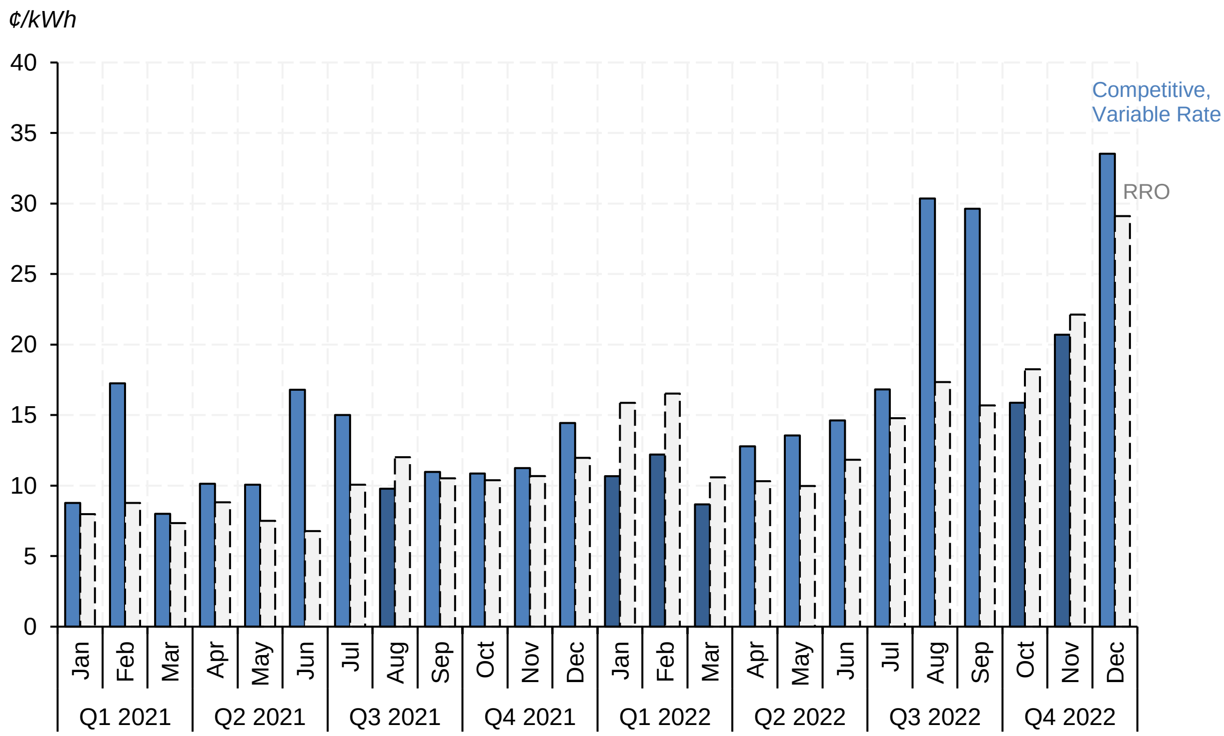
*Figure 88: 1, 3, 5-year fixed rate natural gas contract prices, residential customers, ATCO Gas South service area (January 1 to Dec 31, 2022)*



### *4.3.2 Variable rates*[31]

Competitive variable rates faced by residential electricity customers dropped considerably in October and November after the unusually high pool prices observed in August and September. Variable rates increased by approximately 18 ¢/kWh over Q4 2022. In October and November, residential customers obtained a marginal discount on competitive variable rates over the RRO, but in December variable rates were at a premium over the RRO. Residential customers faced a variable rate of more than 33 ¢/kWh in December (Figure 89), the highest since 2021. However, RRO rates in December were also high, minimizing the difference between the two rates in December 2022.

*Figure 89: Estimated competitive variable electricity rates vs. RRO, residential customers, ENMAX service area (Q1 2021 to Q4 2022)*[32]

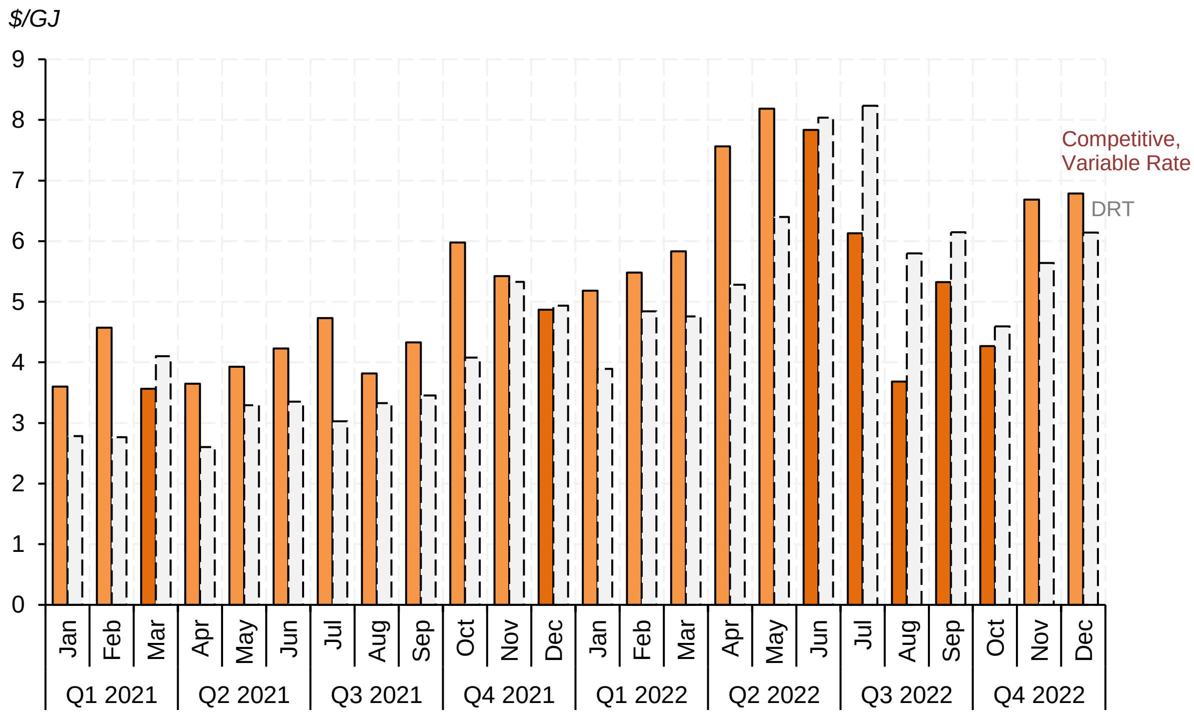



Competitive variable natural gas rates were lower than the DRT in October, as they previously were in Q3 2022 (Figure 90). Competitive variable natural gas rates surpassed DRT later in the quarter in November and December. The variable gas rates were $1.00/GJ and $0.65/GJ in excess of the DRT in November and December respectively.

[31] For the purposes of this section, “variable rates” refers to competitive rates that vary monthly that are tied to pool prices, not regulated rates.

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

*Figure 90: Estimated competitive variable natural gas rates vs. DRT, residential customers, ATCO Gas South service area (Q1 2021 to Q4 2022)[33]*




## 4.4 Regulated retail rate estimates

### *4.4.1 Electricity regulated rate estimates*

Expected residential RRO monthly rates (that is, the RRO rate not accounting for any effect of the RRO ceiling in place in January, February and March 2023 or for recovery of deferred revenue thereafter) over the next year have increased since October along with increases in forward prices (Figure 91). The estimate for each of the major RRO providers is set out in Table 13.

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

*Figure 91: February 2023 to January 2024 residential RRO monthly rate estimates (EPCOR service area), estimates as of October 2, 2022 vs. January 1, 2023*

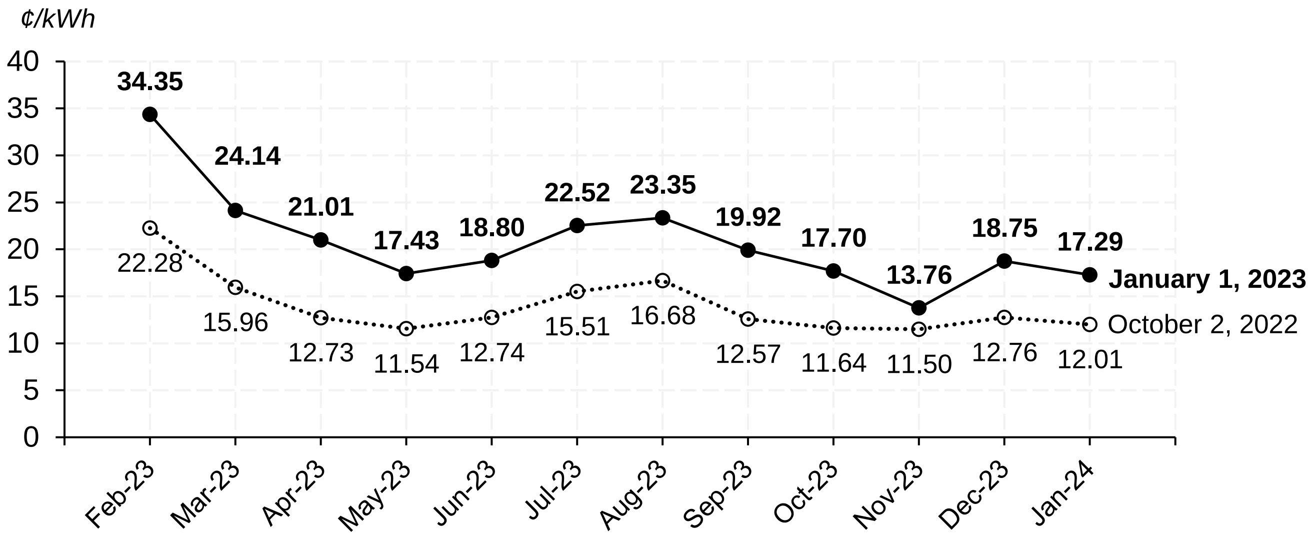


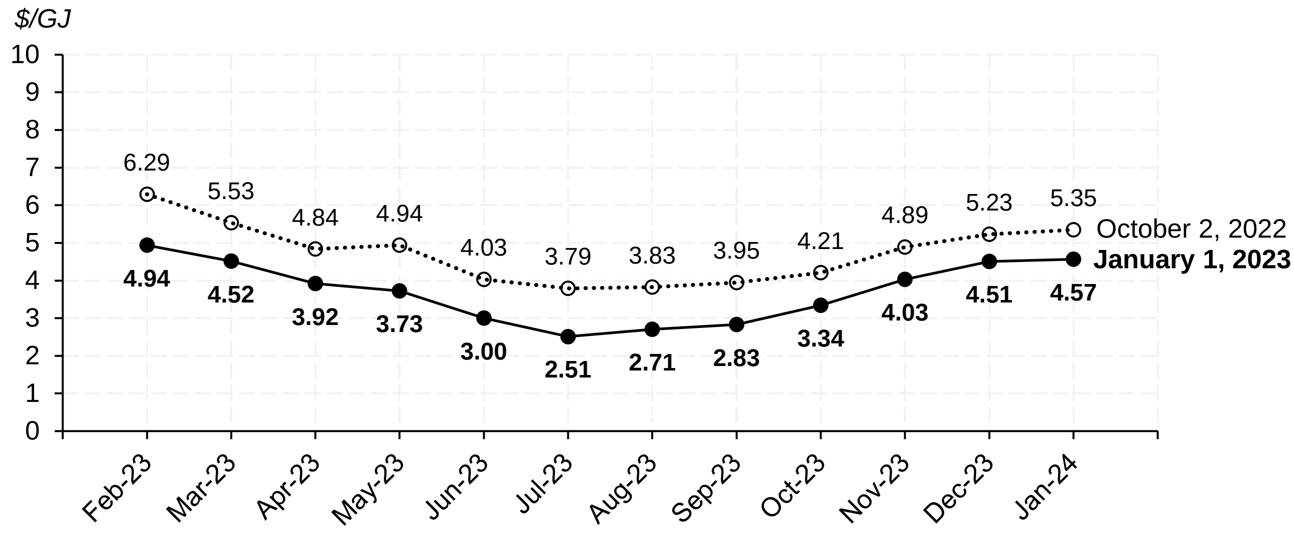

*Table 13: February 2023 to December 2024 residential RRO monthly rate estimates by service area (RRO provider) as of January 1, 2023*

| | ENMAX | EPCOR | FortisAlberta (EPCOR) | ATCO (Direct) |
|---|---|---|---|---|
| Feb-23 | 32.60 | 34.35 | 33.79 | 35.24 |
| Mar-23 | 23.18 | 24.14 | 23.77 | 24.52 |
| Apr-23 | 20.48 | 21.01 | 20.66 | 20.27 |
| May-23 | 16.56 | 17.43 | 17.17 | 16.49 |
| Jun-23 | 18.05 | 18.80 | 18.55 | 17.19 |
| Jul-23 | 21.20 | 22.52 | 22.22 | 20.61 |
| Aug-23 | 22.19 | 23.35 | 23.03 | 21.87 |
| Sep-23 | 19.36 | 19.92 | 19.59 | 18.68 |
| Oct-23 | 16.67 | 17.70 | 17.40 | 16.96 |
| Nov-23 | 13.57 | 13.76 | 13.52 | 13.21 |
| Dec-23 | 17.52 | 18.75 | 18.47 | 18.09 |
| Jan-24 | 16.83 | 17.29 | 17.01 | 16.63 |

### *4.4.2 Natural gas regulated rate estimates*

Expected DRT rates over 2023 have decreased since the MSA's prior October 2, 2022 forecast (Figure 92). DRT rates are expected to fall by between roughly $1/GJ to $2/GJ over spring through fall of 2023.

*Figure 92: February 2023 to January 2024 residential DRT estimates (ATCO Gas service areas), estimates as of October 2, 2022 vs. January 1, 2023*




Although DRT rates expected for winter as of January 1, 2023 are below the $6.50/GJ gas rebate threshold, the variability in DRT rate expectations over Q3 and Q4 indicates that the possibility of some winter DRT rates exceeding the gas rebate threshold cannot not be ruled out.

#### *4.4.3 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 93). Despite the 1-year bill savings impact of the RRO rate ceiling policy, a residential RRO customer can still expect to save by switching to a competitive fixed rate contract. An average residential RRO customer in the ENMAX service area could expect to save over $560 in 2023 by switching to the lowest priced 3-year contract available on January 1, 2023.

However, risk-neutral DRT customers are disincentivized from switching to 3-year natural gas fixed rate contracts as of January 1, 2023. If an average residential DRT customer had switched to the lowest 3-year natural gas rate on January 1, 2023, they would be expected to pay around $144 more in the 12 months that follow (Figure 94).

These trends of increasing incentives for RRO customers to switch to competitive electricity fixed rates and decreasing incentives for residential DRT customers to do the same is a continuation of a trend observed since 2022.

*Figure 93: Expected RRO bill vs. competitive electricity bill (3-year fixed rate at 9.55 ¢/kWh, $6.85/month)*[34]

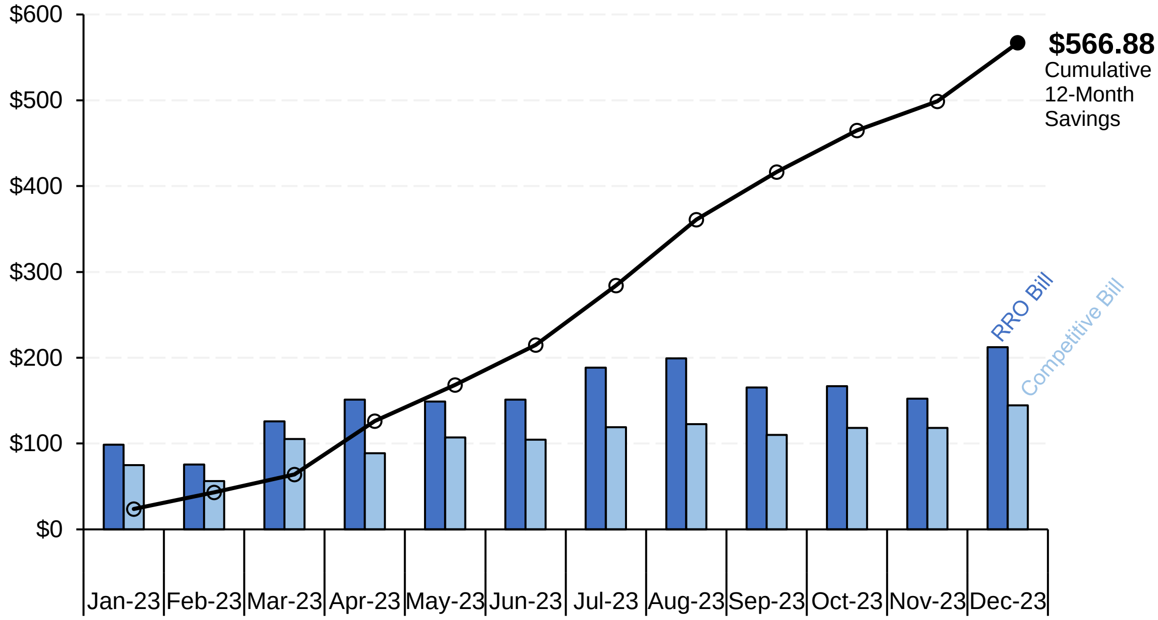
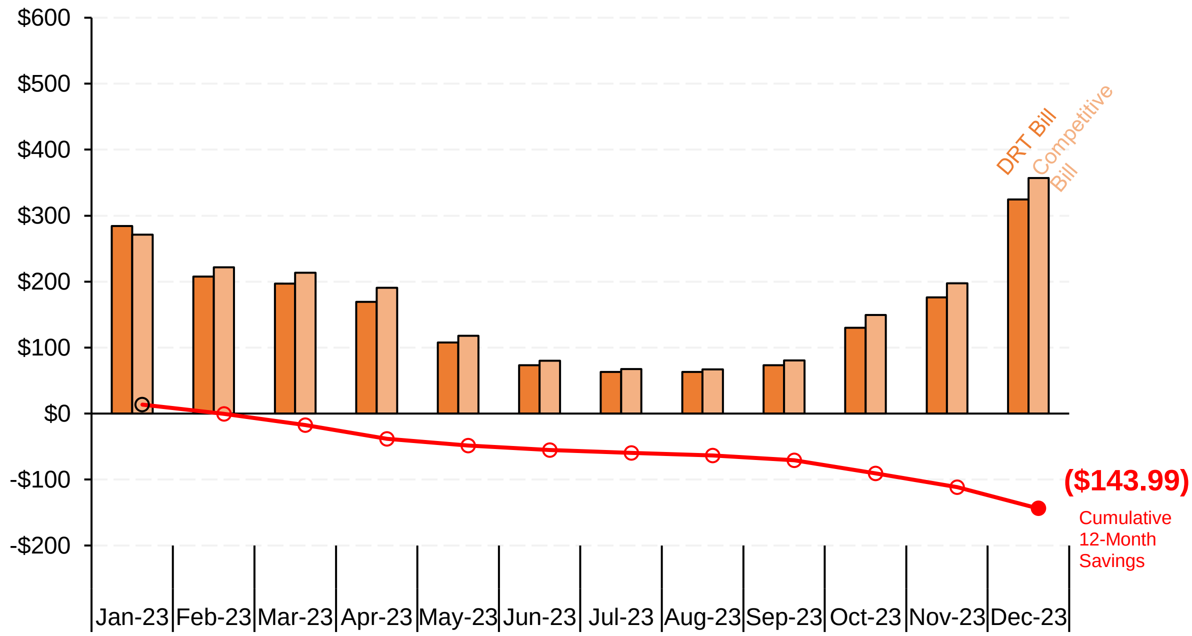



*Figure 94: Expected DRT bill vs. competitive natural gas bill (3-year fixed rate at $5.89/GJ, $6.85/month)*[35]




[34] Estimated bills for a residential customer in the ENMAX service area over the January 2023 to December 2023 period.

[35] Estimated bills for a residential customer in the ATCO Gas South service area over the January 2023 to December 2023 period.

# 5 REGULATORY AND ENFORCEMENT MATTERS

## 5.1 Regulated Rate Option Stability Act

In December 2022, the Alberta legislature enacted the *Regulated Rate Option Stability Act* (RROSA). The RROSA places a ceiling on regulated electricity rates at a maximum of 13.5 cents/kWh for the months of January, February, and March 2023. Deferred revenue that results from this rate ceiling will be recovered through regulated rate customer bills over the period of April 2023 to December 2024.

Each Owner[36] must establish a deferral account with the approval of their Reviewing Agency on or before December 23, 2022, for the purpose of administering the recovery of the monthly amounts. For Owners whose regulated rate tariff is approved by the Alberta Utilities Commission (AUC), the Reviewing Agency is the AUC. For Owners whose regulated rate tariff is approved by the council of a municipality or the board of directors of a rural electrification association and for the City of Medicine Hat's Electric Utility, the Reviewing Agency is the MSA.

On December 14, 2022, the MSA provided correspondence to Owners informing them of their obligations under the RROSA.[37]

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[36] "Owner" means (i) the owner of an electric distribution system, or (ii) if the owner makes arrangements under which one or more other persons perform any or all of the duties or functions of the owner, the owner and those one or more other persons. When referred to in this document, Owner also includes the City of Medicine Hat's Electric Utility.

[37] MSA Letter, December 14, 2022

## 6 ISO RULES COMPLIANCE

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

From January 1 to December 31, 2022, the MSA closed 372 ISO rules compliance matters, as reported in Table 14.[38] Sixty-three matters were carried forward to next year. During this period 91 matters were addressed with NSPs, totalling $143,500 in financial penalties, with details provided in Table 15.

[38] An ISO rules compliance matter is considered to be closed once a disposition has been issued. Of the 372 closed matters, one matter was referred by the MSA to another body.

*Table 14: ISO rules compliance outcomes from January 1, 2022 to December 31, 2022*[39]

| ISO rule | Forbearance | Notice of specified penalty | No contravention |
|---|---|---|---|
| 103.1 | 1 | - | - |
| 201.3 | 2 | - | - |
| 201.7 | 35 | 11 | - |
| 202.4 | 2 | 1 | - |
| 203.3 | 90 | 13 | - |
| 203.4 | 48 | 13 | 7 |
| 203.6 | 13 | 7 | - |
| 205.3 | 6 | 3 | - |
| 205.4 | 5 | - | - |
| 205.5 | 2 | 9 | 2 |
| 205.6 | 5 | 23 | - |
| 301.2 | - | 2 | - |
| 304.3 | 7 | - | - |
| 304.7 | 2 | - | - |
| 306.4 | 8 | - | - |
| 306.5 | 17 | 3 | - |
| 502.1 | 1 | - | - |
| 502.4 | 2 | - | - |
| 502.5 | - | 2 | - |
| 502.6 | 11 | - | - |
| 502.8 | 3 | 2 | - |
| 502.10 | 1 | - | - |
| 505.3 | 3 | - | - |
| 505.4 | 6 | 2 | - |
| 9.1.3 | 1 | - | - |
| 9.1.5 | - | - | - |
| **Total** | **271** | **91** | **9** |

[39] One matter was referred.

*Table 15: Specified penalties issued between January 1 and December 31, 2022 for contraventions of the ISO rules*

| Market participant | Total specified penalty amounts by ISO rule ($) | | | | | | | | | | | | | Total ($) | Matters |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 201.7 | 202.4 | 203.3 | 203.4 | 203.6 | 205.3 | 205.5 | 205.6 | 301.2 | 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 | | | | | | | | | | 1,000 | 2 |
| ATCO Power (2010) Ltd. | | | 3,000 | 500 | | | | | | | | | | 3,500 | 3 |
| British Columbia Hydro and Power Authority | | | | | | | | | | | | | 500 | 500 | 1 |
| 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 |
| Concord Coaldale Partnership | | | 250 | | | | | | | | | | | 250 | 1 |
| CP Energy Marketing L.P. | | | | | 250 | | | | | | | | | 250 | 1 |
| DAPP Power L.P. | | | 500 | 1,500 | | | | | | | | | | 2,000 | 2 |
| Enel X Canada Ltd. | | | | | | | | 40,250 | | | | | | 40,250 | 10 |
| Enfinite Corporation | | | | | | | 500 | | | | | | | 500 | 2 |
| Enfinite Generation Corporation | | | | 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 | | 250 | | | | | | | | | | | 750 | 2 |
| Irrigation Canal Power Co-op Ltd. | | | | 250 | | | | | | | | | | 250 | 1 |

*Table 15: Specified penalties issued between January 1 and December 31, 2022 for contraventions of the ISO rules (continued)*

| Market participant | Total specified penalty amounts by ISO rule ($) | | | | | | | | | | | | | Total ($) | Matters |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | 201.7 | 202.4 | 203.3 | 203.4 | 203.6 | 205.3 | 205.5 | 205.6 | 301.2 | 306.5 | 502.5 | 502.8 | 505.4 | | |
| 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 | | | | | | | | | 500 | 2 |
| Repsol Canada Energy Partnership | 500 | | | | | | | | | | | | | 500 | 1 |
| Suffield Solar LP | 500 | | | 250 | | | | | | | | | | 750 | 2 |
| Suncor Energy Inc. | | | 250 | | | | 250 | | | | | | | 500 | 2 |
| Syncrude Canada Ltd. | | | 250 | | | | | | | | | | | 250 | 1 |
| TA Alberta Hydro LP | | | | 3,000 | | 5,000 | 500 | | | | | | | 8,500 | 4 |
| Tourmaline Oil Corp. | 500 | | | 500 | | | | | | | | | | 1,000 | 2 |
| TransAlta Energy Marketing Corp. | | | | | 250 | | | | | | | | | 250 | 1 |
| TransAlta Generation Partnership | | 250 | | 1,500 | | | 5,500 | | | | | | | 7,250 | 4 |
| TransCanada Energy Sales Ltd. | | | | | 5,750 | | | | | | | | | 5,750 | 3 |
| Voltus Energy Canada Ltd. | | | | | | | | 50,000 | | | | | | 50,000 | 10 |
| West Fraser Mills Ltd. | 500 | | 1,500 | | | | | | | | | | | 2,000 | 2 |
| Whitecourt Power Ltd. | 500 | | 250 | | | | | | | | | | | 750 | 2 |
| Yellow Lake & Burdett Solar LP | | | | | | | | | 500 | | | | | 500 | 2 |
| **Total** | 5,250 | 250 | 9,250 | 9,500 | 6,750 | 6,000 | 9,500 | 92,750 | 500 | 1,500 | 500 | 1,000 | 750 | 143,500 | 91 |

# 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 December 31, 2022, the MSA addressed 80 O&P ARS compliance matters, as reported in Table 16.[40] An additional 25 matters were carried forward to next year. During this period, seven matters were addressed with NSPs, totalling $33,375 in financial penalties, with details provided in Table 17. For the same period, the MSA addressed 243 CIP ARS compliance matters, as reported in Table 18,[41] and 35 matters were addressed with NSPs, totalling $91,625 in financial penalties. An additional 76 matters were carried forward to next year.

[40] An ARS matter is considered closed once a disposition has been issued. Of the 80 closed matters, three matters were rejected.

[41] Of the 243 closed matters, two matters were withdrawn.

*Table 16: O&P ARS compliance outcomes from January 1 to December 31, 2022*

| Reliability standard | Forbearance | Notice of specified penalty | No contravention |
|---|---|---|---|
| COM-001 | 1 | - | - |
| COM-002 | 1 | - | - |
| EOP-001 | 1 | - | - |
| EOP-005 | 1 | - | - |
| FAC-008 | 18 | 1 | - |
| IRO-005 | 1 | - | - |
| IRO-008 | 1 | - | - |
| MOD-010&012 | 1 | - | - |
| PRC-001 | 6 | - | - |
| PRC-002 | 3 | 1 | - |
| PRC-005 | 23 | 4 | - |
| PRC-006 | 2 | - | - |
| PRC-019 | 6 | - | - |
| PRC-023 | - | 1 | - |
| VAR-002 | 3 | - | 1 |
| VAR-501-WECC | 1 | - | - |
| **Total** | 69 | 7 | 1 |

*Table 17: Specified penalties issued between January 1 and December 31, 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 16 and Table 17 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 18: CIP ARS compliance outcomes from January 1 to December 31, 2022*

| Reliability standard | Forbearance | Notice of specified penalty | No contravention |
|---|---|---|---|
| CIP-002 | 15 | 1 | 2 |
| CIP-003 | 13 | 5 | - |
| CIP-004 | 46 | 10 | 1 |
| CIP-005 | 6 | 1 | - |
| CIP-006 | 22 | 1 | - |
| CIP-007 | 46 | 6 | 1 |
| CIP-008 | 3 | - | - |
| CIP-009 | 5 | 1 | 1 |
| CIP-010 | 29 | 5 | - |
| CIP-011 | 12 | 5 | - |
| CIP-014 | 3 | - | 1 |
| **Total** | 200 | 35 | 6 |

The ARS outcomes listed in Table 18 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