Ontario Wholesale Electricity Market Price Forecast

For the Period November 1, 2024 through April 30, 2026

Prepared for: Ontario Energy Board

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Submitted by:
Power Advisory
55 University Ave, Suite 700, PO Box 32
Toronto, ON M5J 2H7
www.poweradvisoryllc.com

POWER ADVISORY

EXECUTIVE SUMMARY

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the November 1, 2024 to April 30, 2026 period. This wholesale electricity price forecast will be used by the OEB, as one of a number of inputs, to set the Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*.

Power Advisory used a complex model of Ontario's electricity market to forecast the Hourly Ontario Electricity Price (HOEP). The model combines regression analysis and dispatch modelling to generate hourly price curves that are consistent with historical market behaviour and reflective of forward-looking analysis that predicts market changes. Amongst other data, the model reflects Ontario's electricity demand and hourly load shape, all committed new entrant generation, all planned generation retirements, the operating profiles of Ontario's hydroelectric generation (including both baseload and peaking resources), the operating characteristics of Ontario's thermal generation, and expected fuel and carbon prices. The assumptions used by Power Advisory and their sources are discussed in detail in Chapter 3 of this report.

Table ES-1 presents the results of the base case market price forecast resulting from Power Advisory's modelling. The prices presented are simple averages (i.e., not load-weighted).

Table ES-1: HOEP Forecast ($ CAD per MWh)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2024 - Jan 2025	$39.43	$28.18	$33.30
Feb 2025 - Apr 2025	$39.59	$30.64	$34.75
May 2025 - Jul 2025	$38.81	$24.21	$30.95
Aug 2025 - Oct 2025	$40.34	$27.78	$33.50
Nov 2025 - Jan 2026	$58.51	$43.02	$50.08
Feb 2026 - Apr 2026	$56.68	$44.80	$50.26
Nov 2024 - Apr 2026	$45.56	$33.11	$38.81

Source: Power Advisory

Notes:

1) Assumes natural gas prices that reflect an average of the exchange rate forecasts of five major Canadian banks (Bank of Montreal, Canadian Imperial Bank of Commerce, Royal Bank, Scotiabank, and Toronto-Dominion) as reported in their public economic forecasts as of September 17 2024. For the November 2024 to April 2026 HOEP forecast period, the average exchange rate is US$1 = C$1.35.

2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

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1. INTRODUCTION

Power Advisory LLC (Power Advisory) was engaged by the Ontario Energy Board (OEB) to produce a forecast of wholesale electricity market prices in Ontario for the November 1, 2024 to April 30, 2026 period (forecast period). This wholesale electricity price forecast will be used by the OEB, as one of a number of inputs, to set November 1, 2024 Regulated Price Plan (RPP) prices for eligible consumers under the *Ontario Energy Board Act, 1998*. Wholesale electricity prices affect the RPP supply cost and the resulting RPP prices by determining RPP-weighted wholesale electricity costs, and by affecting payments to regulated and contracted generators that are funded through the Global Adjustment.

This report presents the results of Power Advisory's forecast, the key assumptions driving this forecast, and the information sources on which these assumptions were based.

1.1 Contents of This Report

This report is organized into four chapters, starting with this introduction. Chapter 2 outlines the price forecasting methodology and identifies the key forecast drivers. Chapter 3 reviews the forecast assumptions and identifies the information sources on which these assumptions are based. Chapter 4 presents the Ontario wholesale electricity market price forecast results.

2. PRICE FORECASTING METHODOLOGY

2.1 Overview of Ontario's Wholesale Electricity Market

Wholesale prices in Ontario are determined by the Independent Electricity System Operator (IESO) based on provincial electricity demand and the monies paid to generators to supply it. Generators supplying electricity to the Ontario wholesale market must offer their output to the IESO as a series of hourly price and quantity pairs. Based on these offers, the IESO uses a dispatch algorithm to choose the least-cost combination of generation resources which can meet forecast demand in each five-minute interval of each hour. The selection of resources based on cost is subject to technical factors such as ramp rates for gas-fired generation, transmission constraints, and other physical limitations.

For each five-minute interval, the offer price of the most expensive generation selected becomes the Market Clearing Price (MCP) for that period. Each generator in Ontario receives the MCP for its energy output, regardless of what price it offered to the IESO. For each hour, the twelve five-minute MCPs are averaged to determine the Hourly Ontario Electricity Price (HOEP). Thus, the interaction of hourly supply and demand determines Ontario's wholesale electricity market price.

2.2 Overview of the Forecasting Model

The major factors known to drive the equilibrium between electricity supply and demand in Ontario are reflected in Power Advisory's HOEP Forecast Model. Accordingly, the model reflects the history of the Ontario electricity market and specifically the relationship between the drivers of market prices and the resulting market prices. This relationship is then extrapolated forward to produce a forecast of expected wholesale electricity prices.

However, no model can accurately simulate all of the factors and interactions that affect prices in an electricity market the size of Ontario's. In order to retain as much historical information as possible regarding the nuances of market operation, the starting point for Power Advisory's model is hourly prices over the past five years (2019-2023). For each forecast year, the model takes the hourly prices for the first historical base year (2019), reflecting supply, demand, fuel prices, weather, etc. in that year, and adjusts each of these 8,760 hourly prices[1] based on expected changes in supply, demand, and fuel prices in each forecast year. For example, if the amount of nuclear capacity in-service in the forecast year is expected to be less than what was available in the base year, supply will be reduced, and prices correspondingly increased to reflect the revised supply mix, in all hours of the forecast year. If more wind capacity is expected to be in service, supply in the forecast year is increased, but with a greater impact on prices in hours which experienced greater wind in the base year. The relationship between supply, demand, and price is established through regression analysis as part of the modelling process. Prices are further adjusted to reflect market rules on curtailment of wind, solar, and nuclear generation,

[1] In leap years, February 29 is excluded. As a result, every year is modeled as having 8,760 hours.

as appropriate. The process is repeated for the same forecast year using each of the remaining four historical base years (2020, 2021, 2022 and 2023), and the results using all five base years are averaged to produce the forecasts shown in this report.

2.3 Key Forecast Drivers

Although other influences exist, forecast price changes are driven by three primary factors:

- Hourly demand for electricity, including both changes in total monthly or annual demand, and changes in the time of day when consumers use electricity.
- Generation in service, taking into account capacity additions (such as wind, solar, hydro, gas and other facilities coming into service), retirement of older capacity, the expiration of generation contracts and temporary shut-downs, especially for the refurbishment of the Bruce and Darlington nuclear plants.
- Cost of burning natural gas, including both the market price of natural gas and the costs due to greenhouse gas (GHG) emissions. The marginal cost of generating electricity from natural gas is an important determinant of electricity prices in Ontario in many hours during the forecast period. When Ontario demand is high relative to supply, the marginal source of supply (which either sets or strongly affects the MCP) is usually either domestic gas generation, or imports from other markets where the price is often set by natural gas generation. When supply is high relative to Ontario demand, the province exports electricity to neighbouring markets, and the price received is often set by the cost of natural gas generation in those markets.

3. KEY FORECAST ASSUMPTIONS

The major assumptions used in the HOEP forecast model, as well as their sources, are presented below.

3.1 Demand Forecast

The basis for Power Advisory's energy demand forecast is the IESO's *Reliability Outlook: An adequacy assessment of Ontario's electricity system October 2024 to March 2026* (released September 23, 2024) (*Reliability Outlook).*[2] The IESO's forecast contained in this report takes conservation and demand management programs into account. It assumes "normal weather" – i.e., the energy forecast is based on daily weather conditions that are representative of typical weather conditions for that time of year. For the October 2024 through March 2025 period, the demand forecast in the current *Reliability Outlook* (dated September 23, 2024) overlaps with that in the Reliability Outlook published in September 2023 that informed November 1, 2023 RPP prices. For the five months of overlap (November 2024 – March 2025), the new (September 2024) forecast is on average 1.6% higher than the older (September 2023) forecast.

The IESO forecasts demand at the transmission grid level. However, Ontario has a significant and growing supply of generation "embedded" in the distribution network, which supplies a corresponding volume of consumer demand that does not pass through the transmission system. Therefore, the IESO adjusts its forecast of grid-level demand to exclude embedded generation (technically, to exclude the demand that it supplies). Power Advisory's HOEP forecast model takes into account both grid-level demand, and the demand supplied by embedded generation.

The forecast period for this report (November 1, 2024 - April 30, 2026) extends slightly beyond the energy forecast period covered by the IESO's *Reliability Outlook* and therefore Power Advisory has extrapolated the IESO's forecast to cover the entire forecast period. Table 1 shows the forecast of monthly energy consumption used in the model.

[2] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlook2024Sep.pdf

Table 1: Forecast Monthly Energy Consumption and Peak Demand

Month	Grid-Level Demand (TWh)	Embedded Demand (TWh)	Total Demand (TWh)	Peak Grid Demand (MW)
Nov 2024	11.50	0.46	11.96	20,218
Dec 2024	12.63	0.43	13.06	21,037
Jan 2025	13.22	0.45	13.67	21,898
Feb 2025	11.72	0.46	12.18	21,340
Mar 2025	12.19	0.50	12.69	20,078
Apr 2025	10.80	0.61	11.41	18,165
May 2025	10.94	0.60	11.54	19,640
Jun 2025	11.34	0.62	11.96	22,819
Jul 2025	12.78	0.59	13.36	23,243
Aug 2025	12.79	0.57	13.36	22,909
Sep 2025	11.41	0.50	11.91	22,288
Oct 2025	11.39	0.49	11.88	18,470
Nov 2025	11.90	0.46	12.36	20,715
Dec 2025	13.13	0.43	13.56	21,573
Jan 2026	13.92	0.45	14.37	22,294
Feb 2026	12.30	0.46	12.76	21,551
Mar 2026	12.80	0.50	13.30	21,039
Apr 2026	11.26	0.61	11.87	18,942
Total/Maximum	218.01	9.20	227.21	23,243

Source: IESO, Reliability Outlook (September 23, 2024), Tables 3.1.1 and 3.3; Power Advisory

3.2 Supply Resources

Power Advisory's generation capacity assumptions are consistent with the IESO's *Reliability Outlook*. Assumptions regarding expected generation capacity additions, available nuclear capacity and hydro generation, and Ontario's interconnection limits are detailed below.

3.2.1 Generation Capacity Additions

In addition to the existing supply resources, one major supply project (Oneida Storage) is expected to come into service during the forecast horizon, as shown in Table 2. This has been included in the model specification.

Table 2: Major Generation Capacity Changes

Project Name	Resource Type	Capacity (MW)	Estimated Effective Date
Pickering G1	Nuclear	-515	2024-Q4
Pickering G4	Nuclear	-515	2024-Q4
Oneida Storage	Storage	235	2025-Q2

Source: IESO, Reliability Outlook (September 23, 2024), Table 4.2.

The IESO is not forecasting any changes in distribution-connected generation capacity during the forecast period.[3] However, Power Advisory is forecasting small increases in behind-the-meter solar generation, not under contract with the IESO. Including distribution-connected generation, the model assumes that 2,800 MW of solar capacity and 5,400 MW of wind capacity will be in service by April 2026, capable of generating enough electricity to meet approximately 13% of Ontario's demand. Solar and wind generation put downward pressure on Ontario's wholesale electricity prices.

3.2.2 Nuclear Capacity

There are currently three nuclear units out of service for refurbishment: Bruce A Unit 3, Darlington 1, and Darlington 4. Looking forward, Bruce Unit A4 is scheduled to begin refurbishment in January 2025, and Darlington Unit 1 is scheduled to return to service after refurbishment in May 2025. Pickering Units 1 and 4 are expected to be retired in late 2024, as shown in Table 2 above. As well, based on the IESO's 2024 Annual Planning Outlook[4], the four Pickering B nuclear units are expected to retire at the end of 2025.[5]

Based on this, and historical generation patterns, the HOEP forecast model assumes total nuclear generation of 101 TWh over the forecast period, as shown in Table 3 below. This implies a capacity factor of 86.8%, which is calculated as the average power generated over the rated peak power available through the nuclear fleet, excluding the units which are out of service. It takes into account expected curtailment of some of the Bruce units during times when domestic supply exceeds demand. All plants show higher capacity factors during summer and winter and lower capacity factors during the shoulder seasons (spring and fall), indicative of the

[3] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/reliability-outlook/ReliabilityOutlookTables_2024Sep.ashx, Table 3.3.6.

[4] https://www.ieso.ca/-/media/Files/IESO/Document-Library/planning-forecasts/apo/Mar2024/2024-Annual-Planning-Outlook.pdf, Figure 16.

[5] On October 11, 2024, the Canadian Nuclear Safety Commission (CNSC) amended OPG's licence to authorize OPG to operate the Pickering B units until December 31, 2026. This recent development has not been reflected in the wholesale electricity price forecast and would impact the last four months of the forecast period (January – April 2026).

planned maintenance that tends to be scheduled for the shoulder seasons when demand is lower.

Table 3: Forecast Nuclear Generation

Month	Nuclear Generation (TWh)
Nov 2024	5.77
Dec 2024	6.26
Jan 2025	5.86
Feb 2025	4.94
Mar 2025	5.24
Apr 2025	5.35
May 2025	5.90
Jun 2025	6.28
Jul 2025	6.61
Aug 2025	6.78
Sep 2025	6.06
Oct 2025	5.75
Nov 2025	5.57
Dec 2025	6.03
Jan 2026	5.18
Feb 2026	4.37
Mar 2026	4.64
Apr 2026	4.81
Total	101.41

Source: Power Advisory

3.2.3 Hydro Generation

Hydroelectric generation can vary significantly from year to year depending on the level of precipitation in the province. The starting point for Power Advisory's HOEP forecast model is historical supply and demand for the five base years (2019-2023). During these years, annual output of transmission-connected hydro ranged from a low of 33.7 TWh in 2021 to a high of 37.5 TWh in 2022. This range is reflected in the forecast, which is based on an average of the forecast developed using each of the five base years. The forecasts of hydro output are adjusted for changes in installed hydro capacity between the forecast year and the base year (such as the addition of 63 MW of distribution-connected hydro capacity between 2019 and 2023).

3.2.4 Transmission Capabilities and Constraints

Unlike many electricity systems which have different electricity prices in different areas, Ontario has a uniform electricity price that applies across the entire province. HOEP therefore does not directly reflect transmission constraints within Ontario. The forecast model reflects this, and does not model internal transmission constraints. To the extent that transmission constraints have indirect impacts on wholesale market prices, these are implicitly factored into the model through the use of historic price curves.

External transfer limits can also affect Ontario prices. Limited transfer capability can mean higher prices when demand exceeds supply, because less expensive imports cannot be brought in. Similarly, when supply exceeds demand, suppliers may be unable to sell their surplus in other markets due to transfer limits. The transfer capabilities of transmission interconnections with adjacent markets are shown in the IESO's *Reliability Outlook*, differentiated by season and direction of flow. Table 4 shows the ratings of Ontario's interconnections with adjacent markets based on the information presented in the IESO's *Reliability Outlook*.

Table 4: Ontario Interconnection Limits

(MW)	Flows Out of ON		Flows Into ON	
	Summer	Winter	Summer	Winter
Manitoba	246	300	260	368
Minnesota	150	150	100	100
Michigan	1,650	1,650	1,550	1,700
New York	1,800	2,100	1,500	1,900
Québec	2,145	2,165	2,330	2,350

Source: IESO, Reliability Outlook (September 23, 2024), Table B3

3.3 Natural Gas Prices

Given the uncertainty associated with fuel price forecasts, Power Advisory typically relies on liquid financial and physical markets to specify natural gas market price forecasts. For Ontario electricity prices, the most relevant pricing hub is the Dawn/Union hub in Southwestern Ontario. While trade volumes at this hub are lower, and therefore less widely reported than at other gas hubs, S&P Global Intelligence reports forward prices for up to thirteen years into the future. Power Advisory uses these prices in its forecasts.

Future prices based on trading over a single day may be pushed up or down by very short-term factors that do not reflect long-term trends. To reduce the impact of such volatility on forecast prices, an average of settlement prices over 21 days (August 27 – September 16, 2024) is used. The resulting prices were then adjusted to reflect systematic differences between futures prices and actual day-ahead prices.

These forward prices are reported in US dollars and therefore must be converted into Canadian dollars. The price forecast reflects an average exchange rate of $1.35 CAD per USD between

November 2024 and April 2026. The monthly exchange rate forecast is based on an average of the exchange rate forecasts of five major Canadian Banks (Bank of Montreal, Canadian Imperial Bank of Commerce, Royal Bank, Scotiabank, and Toronto-Dominion) as reported in their public economic forecasts as of September 17, 2024. As well as affecting the forecast of the natural gas price in Ontario, the forecast exchange rate affects the price of electricity imports from, and exports to, neighbouring markets.

3.3.1 GHG Emission Allowance Price Forecast

The HOEP forecast takes into account the cost of GHG emission allowances incurred when burning natural gas to generate electricity.

Effective January 1, 2019, gas-fired generation in Ontario (as well as in some other provinces) has been subject to Part II of the federal government's *Greenhouse Gas Pollution Pricing Act*, and the associated Output-Based Pricing System Regulations.[6] That legislative regime introduced an output-based pricing system (OBPS), including compliance benchmarks, and prices on emissions above those benchmarks.

On March 29, 2021, the government of Canada announced that it had accepted the province's Emissions Performance Standards (EPS) program as an alternative to the OBPS system. As of January 1, 2022, the province has fully transitioned from the OBPS to the EPS.[7] The EPS system is quite similar to the OBPS system, including identical charges for excess emissions: $80 per tonne of carbon dioxide equivalents (CO_2e) emitted in 2024, $95 per tonne in 2025, and $110 per tonne in 2026. One difference is in the benchmark above which excess emission charges would need to be paid: 247 tonnes/GWh in the federal OBPS in 2024, falling to 164 tonnes/GWh in 2026,[8] compared to 310 tonnes/GWh in Ontario's EPS.[9] Generators in Ontario are assumed to be subject to the 310 tonnes/GWh benchmark throughout the forecast period (November 2024 through April 2026).

Participants in the EPS are required to report and manage their own carbon-related compliance obligations. If their annual emissions exceed their sector-based emission intensity benchmark, they must either pay for compliance units at the above carbon prices, or purchase compliance units from another facility.

The following example illustrates how the excess emissions charge payable by Ontario's gas-fired generators is calculated: a combined-cycle plant that emitted 430 tonnes of CO_2e in the

[6] https://laws-lois.justice.gc.ca/eng/regulations/SOR-2019-266/index.html

[7] https://www.ontario.ca/page/emissions-performance-standards-program

[8] https://gazette.gc.ca/rp-pr/p2/2019/2019-07-10/html/sor-dors266-eng.html

[9] Ontario Ministry of the Environment, Conservation and Parks, GHG Emissions Performance Standards and Methodology for the Determination of the Total Annual Emissions Limit, December 2022 (https://prod-environmental-registry.s3.amazonaws.com/2022-12/GHG%20EPS%20and%20Methodology%20for%20determination%20of%20TAEL_December%202022%20(EN).pdf)

process of generating 1 GWh of electricity would pay $9,600 in excess emissions charges in 2024. The $9.600 charge is determined based on CO_2e emissions of 120 tonnes (being the difference between the 430 tonnes emitted and the 310 tonnes/GWh EPX benchmark) x $80/tonne, the excess emissions charge in 2024. That same plant would pay excess emission charges of $11,400 per MWh in 2025 and $13,200 in 2026, based on the same volume of excess emissions (120 tonnes), but with charges increasing to $95/tonne and $110/tonne in 2025 and 2026 respectively. Less efficient gas-fired plants will pay more.

3.3.2 Natural Gas Price Forecast

Natural gas price assumptions are presented in Table 5 below. The forecast average Dawn/Union hub natural gas market price for the forecast period is C$3.39/MMBtu, and the forecast effective price, including the impact of excess emissions charges, is C$4.67/MMBtu.[10]

[10] The effective price assumes a heat rate of 8 MMBtu/MWh (typical for a combined cycle plant including starts) and an emissions factor of 52 kg of CO_2e per MMBtu of natural gas. This heat rate corresponds to an emissions average of 416 tonnes/GWh.

Table 5: Natural Gas and GHG Allowance Price Forecasts

Month	Forward Price @ Dawn Hub		OBPS/EPS Performance Standard	Excess Emission Charges	Effective Gas Price
	US$/MMBtu	C$/MMBtu	tonnes/GWh	C$/tonne	C$/MMBtu
Nov 2024	$2.00	$2.73	310	$80.00	$3.79
Dec 2024	$2.43	$3.33	310	$80.00	$4.39
Jan 2025	$2.36	$3.23	310	$95.00	$4.49
Feb 2025	$2.48	$3.39	310	$95.00	$4.65
Mar 2025	$2.31	$3.14	310	$95.00	$4.40
Apr 2025	$2.35	$3.19	310	$95.00	$4.45
May 2025	$2.15	$2.91	310	$95.00	$4.17
Jun 2025	$2.25	$3.03	310	$95.00	$4.29
Jul 2025	$2.44	$3.28	310	$95.00	$4.54
Aug 2025	$2.41	$3.25	310	$95.00	$4.51
Sep 2025	$2.36	$3.17	310	$95.00	$4.43
Oct 2025	$2.39	$3.20	310	$95.00	$4.46
Nov 2025	$2.74	$3.67	310	$95.00	$4.93
Dec 2025	$3.05	$4.08	310	$95.00	$5.33
Jan 2026	$2.90	$3.86	310	$110.00	$5.32
Feb 2026	$3.05	$4.06	310	$110.00	$5.52
Mar 2026	$2.85	$3.79	310	$110.00	$5.25
Apr 2026	$2.85	$3.78	310	$110.00	$5.23
Average	$2.52	$3.39	310	$96.62	$4.67

Source: S&P Global Intelligence, Power Advisory

4. REVIEW OF FORECAST RESULTS

The results of Power Advisory's base case market price forecast are shown in Table 6. Consistent with previous editions of this report to the OEB, these prices are presented as simple averages, with high-demand and low-demand hours having equal weight.

Ontario electricity prices typically show a distinct seasonal pattern (higher in summer and winter, lower in spring and fall) which reflects natural gas prices, Ontario's load shape, typical hydroelectric generation output profiles, and the timing of maintenance outages. Natural gas prices tend to be higher in winter because of heating demand. Electricity demand in Ontario tends to be higher in summer (due to air conditioning) and in winter (due to heating) than in spring and fall. Hydroelectric generation tends to be highest in May and June due to the downstream effects of snowmelt (called the spring freshet). Maintenance outages, particularly at nuclear and gas generation facilities, are most often scheduled in the shoulder seasons. The effect of these planned outages is to mitigate the downward price impact of reduced load in the shoulder seasons and increased hydroelectric generation in the spring.

The forecast prices depart from this pattern, in that the highest quarterly average prices occur from February to April of 2026. This is due partly to carbon emission charges, which are scheduled to increase to $100/tonne on January 1, 2026, and partly to the scheduled retirement of the four Pickering B nuclear units at the end of 2025.[11] Combined with the retirement of Pickering Units 1 and 4 and the refurbishment of Bruce Units 3 and 4 and Darlington Unit 4, this will mean nine nuclear units will be out of service for all of that quarter (February to April 2026).

The IESO is planning to launch its Market Renewal Program (MRP) in May 2025, but due to the lack of sufficient data to assess its impact on the wholesale electricity price forecast, its potential effects have not been included.

Table 6: HOEP Forecast (C$/MWh)

Calendar Period	On-Peak	Off-Peak	Average
Nov 2024 - Jan 2025	$39.43	$28.18	$33.30
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2) On-peak hours are between 7 a.m. and 11 p.m. Eastern Standard Time (EST) on non-holiday weekdays. Off-peak hours are all other hours (weekends, holidays, and overnight). The times for the calculation of on-peak and off-peak hours are not adjusted for Daylight Savings Time (DST).

Power Advisory's forecast is based on a set of assumptions related to supply and demand that have been derived from best available information. Although Power Advisory has taken great care to ensure the forecast methodology is sound, by their nature forecasts are uncertain and cannot be guaranteed.