Supplementary 2022 Forecast Information

1. Disclaimer

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2. Pool Price

a) 2021 Pool Price

The 2021 projected average pool price is $98 per MWh compared to the 2021 forecast pool price of $54 per MWh (as provided in the 2021 Budget Review Process (BRP)). The 2021 projection incorporates actual pool prices (from January 2021-July 2021) and forecast information from the EDC Associates' "Quarterly Forecast Update – Third Quarter 2021" (released August 16th 2021).

The 2021 projected average pool price is higher than the 2021 BRP forecast due to a multitude of drivers. Such drivers included periods of high domestic demand driven by both extreme cold and heat combined with modest wind generation, strong pricing in interconnected markets, higher than forecast natural gas prices, and the return of the PPA assets to the owners from the Balancing Pool at the end of 2020.

b) 2022 Pool Price Forecast

Consistent with previous BRPs, the AESO used EDC Associates' hourly pool price forecast for 2022. The hourly pool prices were taken from the seed that had an average annual price closest to the EDC summary annual price. The hourly pool price forecast is used as an input to calculate the ancillary services and transmission line losses costs.

There are numerous variables and assumptions used in the hourly pool price forecast and it is understood that recent market fundamentals, such as those below, have been considered by EDC:

- the impacts of carbon pricing
- pricing impacts associated with mothballs, retirements, and conversions of coal assets
- outages of generation units or transmission assets
- natural gas prices, and
- renewables additions

The 2022 average pool price is forecast to be $74 per MWh compared to the 2021 projected average pool price of $98 per MWh, a decrease of 25 per cent. The lower pool prices anticipated for 2022 can be mainly attributed to increased renewable generation entering commercial operations through 2022 combined with an assumption of normal weather.

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3. Load Forecast

a) Load Measurement Definitions

Alberta Internal Load (AIL): System Load plus load served by on-site generating units, including those within an industrial system designation and the City of Medicine Hat. AIL is an input into the operating reserve volumes forecast and specifically impacts the amount of contingency reserves procured during higher import hours.

Net-to-grid (NTG) Load: System Load plus load served by distributed generation (greater than 5 MW) and Duplication Avoidance Tariff Volumes ("DAT", see Riders A1, A2, A3, and A4 of the ISO tariff: https://www.aeso.ca/rules-standards-and-tariff/tariff/). NTG Load is one of the primary inputs in the operating reserve volumes forecast and specifically impacts the base amount of contingency reserves procured.

System Load: The total, in an hour, of all metered demands under Rate DTS, Rate FTS and Rate DOS of the ISO tariff plus transmission system line losses. System Load volumes are a key input for establishing the annual MWh base (denominator) for the energy market trading charge.

b) 2021 AIL

2021 Alberta Internal Load (AIL) is projected to be higher than 2020 actuals and the 2021 BRP forecast due to:

- the effects of the extreme weather events driving higher load
- earlier than expected recovery from the pandemic
- rising oil prices
- expected growth in Alberta's economy as well as oilsands production outlook

c) 2022 AIL Forecast

The 2022 BRP AIL forecast utilizes economic inputs from the Conference Board of Canada's August 2021 Alberta's Two-Year Outlook, including real gross domestic product (GDP), employment, and population variables for Alberta. The 2022 BRP AIL forecast also includes considerations for the impact of the pandemic, oil production expectations, P50 weather (over the last 30 years), seasonality, days of the week, hour of the day, and holidays.

Forecasted load growth in 2022 compared to 2021 projected is expected to increase by 2 per cent due to an expected recovery from the pandemic, forecasted economic and population growth, and forecasted oilsands production growth.

d) 2021 Net-to-grid Load and System Load

2021 Net-to-grid Load and System Load are projected to be higher than 2020 actuals due to:

- the effects of the extreme weather events driving higher load
- earlier than expected recovery from the pandemic
- expected growth in Alberta's economy

e) 2022 Net-to-grid Load and System Load Forecast

The 2022 BRP NTG Load and System Load forecasts consider economic inputs from the Conference Board of Canada's August 2021 Provincial Outlook, including real gross domestic product (GDP), employment, and population variables for Alberta. The 2022 BRP NTG Load and System Load forecasts also include considerations for the impact of the pandemic, P50 weather (over the last 30 years), time-series trend variables to capture load not served by the transmission system, seasonality, days of the week, hour of the day, and holidays.

Forecasted NTG load growth in 2022 compared to 2021 projected is expected to increase by 1.7 per cent due to an expected recovery from the pandemic, forecasted growth in distributed generation, and forecasted economic and population growth.

Forecasted System Load growth in 2022 compared to 2021 projected is expected to increase by 0.7 per cent due to an expected recovery from the pandemic and forecasted economic and population growth. The difference in growth between the NTG Load forecast and the System Load forecast is due to the expected growth in greater than 5 MW distributed generation.

4. Wires

a) Description of Service

Wires costs represent the amounts paid primarily to transmission facility owners (TFOs) in accordance with their Alberta Utilities Commission (AUC)-approved tariffs and are not controllable costs of the AESO nor are these approved by the AESO Board. Wires costs also include long-term contracts related to Invitation to Bid on Credit (IBOC) and Location Based Credit Standing Offer (LBC SO) programs, since these programs were initiated as incentives for generation to locate closer to major load centers and provide a non-wires solution to transmission wires issues in Alberta. These forecasts are approved by the AESO Board.

b) Update of 2021 Wires

Wires costs in the 2021 projection are $1,674.6 million, which is $259.2 million or 13 per cent lower than the 2021 BRP forecast of $1,933.8 million based on the amounts paid primarily to the TFOs in accordance with their AUC-approved tariffs. The variance between the 2021 projection and the 2021 forecast is mainly attributable to the tariff refund from Altalink Management Ltd. of approximately $223.5 million (proceeding 26248).

The 2021 projection is based on TFO tariffs approved or applied-for as of September 2021 with a majority of the projection reflecting: i) filed 2021 tariffs; ii) filed 2021 negotiated settlements; or iii) AUC approvals for 2020 and 2021 tariffs.

c) 2022 Forecast

The 2022 forecast for wires costs is $1,896.7 million, which is $222.1 million or 13 per cent lower than the 2021 projection of $1,674.6 million. The 2022 forecast is based on TFO tariffs ($1,895.0 million) and the AESO's forecast for LBC SO costs ($1.7 million).

The 2022 forecast is based on TFO tariffs approved or applied-for as of September with a majority of the forecast reflecting: i) filed 2022 tariffs; ii) filed 2022 negotiated settlements; or ii) AUC approvals for 2021 and 2022 tariffs.

5. Ancillary Services

Ancillary services are procured by the AESO to ensure reliability of the system and include operating reserves and services with generation capacity and load reduction capabilities. Ancillary services are procured through various methods including a daily competitive exchange for operating reserves and competitive processes that result in contracts for other types of ancillary services.

5.1. OPERATING RESERVES

a) Description of Service

Operating reserves are generating capacity or load that is held in reserve and made available to the System Controller to manage the transmission system supply-demand balance in real time. The procurement of operating reserve volumes is directly correlated to load and generation. Operating reserves are procured through an online, day-ahead exchange. In exchange for this payment, the AESO obtains the right to utilize the provider's energy and/or capacity as reserves.

Categories of Operating Reserves

1) **Active operating reserves:**
   - required to automatically balance small changes in supply and demand
   - required to maintain system reliability during unplanned events such as the loss of a generator, loss of a transmission line, or a sudden increase in demand
   - Alberta Reliability Standards (ARS) define the minimum levels that must be procured
   - costs are the product of volumes procured multiplied by operating reserve price, which is indexed to the hourly pool price
   - represents approximately 95 per cent of total operating reserves costs
   - costs are impacted by pool price fluctuations, supply of offered reserves and market participant offer behavior

2) **Standby operating reserves:**
   - provide additional reserves when the active operating reserves are insufficient to ensure system reliability
   - pricing includes two components: i) an option premium, paid for the capability to activate the standby reserves; and ii) an activation price, paid only if the standby reserves are activated to provide energy
   - represents approximately 5 per cent of total operating reserves costs

Operating Reserve Products (in both the active and standby markets)

1) **Regulating reserves** – The generation capacity, energy and maneuverability responsive to the AESO's automatic generation control (AGC) system that is required to automatically balance supply and demand on a minute-to-minute basis in real time.

2) **Spinning reserves** – Unloaded generation that is synchronized to the transmission system, automatically responsive to frequency deviation and ready to provide additional energy in response to an AESO System Controller directive. Spinning reserve suppliers must be able to ramp up their generator within 10 minutes of receiving a System Controller directive.

3) **Supplemental reserves** – While similar to spinning reserves, supplemental reserves are not required to respond to frequency deviations. They include unloaded generation, off-line generation

or system load that is ready to serve additional energy (generator) or reduce energy (load) within 10 minutes of receiving a System Controller directive.

b) Update of 2021 BRP

The operating reserves projection for 2021 is based on:

- **actual hourly volumes of operating reserves and hourly pool prices/operating reserve prices**: January-July 2021;
- **forecast hourly volume of operating reserves**: based on Alberta Reliability Standards requirements using forecast generation, load, and import data;
- **forecast hourly pool prices**: obtained from the EDC Associates' Quarterly Forecast Update – Third Quarter 2021 for the period from August 2021 to December 2021; and
- **estimated operating reserve prices**: average prices over the previous 24 months of historical data`

Operating reserve costs in the 2021 projection are $319 million, which is $159.1 million or 99 per cent higher than the 2021 BRP forecast of $159.9 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices, and operating reserve prices.

The 2021 projected operating reserves volumes is 7.0 terawatt hours, which is 0.2 terawatt hours or 3 per cent lower than the 2021 BRP forecast of 7.2 terawatt hours.

The cost variance in 2021 is attributed to:

- a higher 2021 projected average pool price of $98 per MWh compared to $54 per MWh used in the 2021 BRP forecast
- higher actual pool prices due to higher than expected demand driven by extreme cold and heat events in 2021, strong pricing in interconnected markets, higher than forecast natural gas prices, and the return of the PPA assets to the owners from the Balancing Pool at the end of 2020
- high import volumes in 2021, and
- higher than expected load levels

c) 2022 Forecast

The 2022 forecast for operating reserves costs is $169.3 million, which is $149.7 million or 47 per cent lower than 2021 projected costs of $319 million.

The 2022 operating reserves volumes forecast is 6.8 terawatt hours, which is 0.2 terawatt hours or 2.9 per cent lower than the 2021 projection of 7.0 terawatt hours. The 2022 forecast operating reserves volumes are lower than the 2021 projection due to reductions in standby operating reserve volumes procured and standby activation volumes.

Operating reserve costs in the 2022 forecast are lower than the 2021 projection. The cost variance is primarily attributed to a lower 2022 forecasted average pool price of $74 per MWh, which is 25 per cent lower than the 2021 projection of $98 per MWh. The cost variance is also partly attributed to reduction in standby reserve requirements with lower standby procured volumes as well as lower standby activations.

5.2. OTHER ANCILLARY SERVICES

d) Description of Service

The AESO procures other ancillary services for the secure and reliable operation of the Alberta Interconnected Electric System (AIES). These services are procured through a competitive procurement process where possible, or in such instances where such procurements may not be feasible, through bilateral negotiations.

Load shed service for imports (LSSi) is interruptible load that can be armed to trip, either automatically or manually, on the loss of the Alberta-British Columbia intertie to allow for increased import available transfer capability (ATC).

Black start services are provided by generators that are able to restart their generation facility with no outside source of power. In the event of a system-wide black-out, black start services are used to re-energize the transmission system and provide start-up power to generators who cannot self-start. Black start providers are required in specific areas of the AIES to ensure the entire system has adequate start-up power.

Transmission must-run (TMR) occurs when generation is required to mitigate the overloading of transmission lines associated with line outages, system conditions in real time or the loss of generation in an area. In circumstances when this service is required for an unforeseeable event and there is no contracted TMR, non-contracted generators may be dispatched to provide this service (referred to as conscripted TMR). In the event of foreseeable TMR, the AESO may enter into a contract with a generator to provide TMR services.

The TMR agreement with Poplar Hill was terminated on July 29, 2019. During the term of the agreement, the generator provided voltage support (VArs) in addition to power (MW), to support transmission system reliability in the province.

Reliability services are provided through an agreement with Powerex Corp. for grid restoration balancing support in the event of an Alberta blackout and emergency energy in the event of supply shortfall. The agreement came into effect on April 1, 2015.

Transmission constraint rebalancing costs are incurred when the transmission system is unable to deliver electricity from a generator to a given electricity consuming area without contravening reliability requirements. When this occurs, a market participant downstream of a constraint may be dispatched for purposes of transmission constraint rebalancing under the ISO Rules and would receive a transmission constraint rebalancing payment for energy provided for that purpose. Transmission constraint rebalancing came into effect on November 26, 2015.

e) 2022 Forecast

The 2022 forecast for other ancillary services costs is $40.8 million, which is $1.4 million or three per cent lower than the 2021 projection of $42.2 million.

Other Ancillary Services Costs ($ million)

	2022 Forecast	2021 Projected	2021 BRP	2020 Actual	2019 Actual
Load Shed Service for Imports	29.4	29.8	32.6	28.3	16.1
Contracted Transmission Must-run	-	-	-	3.0	3.0
Conscripted Transmission Must-run	5.0	5.0	0.4	0.7	0.3
Reliability Services	2.9	2.9	2.9	2.9	2.9
Poplar Hill	-	-	-	-	0.9
Black Start	2.5	2.5	2.4	2.3	2.3
Transmission Constraint Rebalancing	1.0	2.0	0.1	0.5	0.3
Other Ancillary Service Costs	40.8	42.2	38.4	37.7	25.8

Differences are due to rounding

Updates to 2021 costs from the 2021 BRP due to:

- **Load Shed Service for Imports (LSSi)** – 2021 projections are lower than BRP forecast due to lower-than-expected availability volumes. Arming payments are also slightly lower than BRP forecast. This is offset by payments for two trip events that were not included in the original forecast.

- **Conscripted Transmission Must-run** – Unanticipated system conditions in the North West combined with transmission equipment constraints and an increase in planned outages led to conscripting TMR services which led to an increase in costs for conscripted TMR, as compared to the forecast for the 2021 BRP.

- **Transmission Constraint Rebalancing** – Constrained down generation during islanded operations as well as constraints on generation due to transmission line upgrades and limits led to increased TCR costs as compared to the forecast for the 2021 BRP.

The 2022 forecast methodology:

- **Load Shed Service for Imports** (LSSi) – The 2022 LSSi forecast considers historical availability levels and forecast import and arming volumes.

- **Contracted Transmission Must-run** – As of September 30, 2020 the TMR agreement has expired. The AESO does not currently have any contracts in place for Transmission Must-run.

- **Conscripted Transmission Must-run** – based on the 2021 projected cost as operational conditions in 2022 are anticipated to be similar to those in 2021.

- **Reliability Services** – based on an existing contract; no new contracts for services in 2022.

- **Poplar Hill** – As of July 29, 2019, the AESO has terminated the Poplar Hill Agreement.

- **Black Start** – no additional black start services are planned for 2022. The 2022 Forecast includes the payments for the agreements with existing units under contract.

- **Transmission Constraint Rebalancing** – based on the 2021 projected cost as operational conditions in 2022 are anticipated to be similar to those in 2021.

6. *Line Losses*

a) Description of Service

Transmission line losses represent the volume of energy that is lost as a result of electrical resistance on the transmission lines. Volumes associated with line losses are determined through the energy market settlement process as the difference between generation and import volumes, less consumption and export volumes. The hourly volumes of line losses vary based on load and export levels, generation (baseload, peaking units and import) able to serve load, weather conditions, and changes in the transmission topology. System maintenance schedules, unexpected failures, dispatch decisions on the AIES, and short-term system measures (such as demand response) may also affect the volume of losses.

The annual volume forecast for transmission line losses is based on statistical models that use variables such as economic inputs, weather, and seasonal effects to forecast hourly losses volumes.

The annual forecast for transmission line losses costs is the aggregate of the hourly forecast losses volumes multiplied by the hourly forecast pool prices. As such, the transmission line losses costs are highly correlated with the pool price forecast.

b) Update of 2021 BRP

Transmission line losses costs in the 2021 projection are $190.8 million, which is $86.4 million or 83 per cent higher than the 2021 BRP of $104.4 million.

The 2021 projected transmission line losses volumes are 1,901 gigawatt hours, which is 21 gigawatt hours or one per cent higher than the 2021 BRP of 1,880 gigawatt hours. The slight increase in volumes of losses can be partly attributed to the fact that generation in high loss factor regions has run at higher capacity factors.

The cost variance is mainly impacted by a higher 2021 projected average pool price of $98 per MWh compared to $54 per MWh used in the 2021 BRP forecast.

c) 2022 Forecast

The 2022 forecast for transmission line losses is $143.3 million, which is $47.5 million or 25 per cent lower than the 2021 projected cost of $190.8 million. This is mostly attributable to a decrease in the 2022 forecasted average pool price to $74 per MWh compared to $98 per MWh for the 2021 projected pool price.

The 2022 transmission line losses volumes forecast is 1,900 gigawatt hours, which is 1 gigawatt hours or less than 1 per cent lower than the 2021 projection of 1,901 gigawatt hours. Losses volumes in 2022 are expected to be at similar level to the 2021 projected volumes.