1. Disclaimer

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2. Pool Price

Slides 20-24

a) 2020 Pool Price

The 2020 projected average pool price is $49 per MWh compared to the 2020 forecast pool price of $58 per MWh (as provided in the 2020 Budget Review Process (BRP)). The 2020 projection incorporates actual pool prices (from January 2020-July 2020) and forecast information from the EDC Associates' "Quarterly Forecast Update – Third Quarter 2020" (released August 17th, 2020).

The 2020 projected average pool price is lower than the 2020 BRP forecast mainly due to lower than expected demand related to the effects of the pandemic and low oil prices.

b) 2021 Pool Price Forecast

Consistent with previous BRPs, the AESO has chosen to use the EDC Associates' hourly pool price forecast for 2021. 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 effects of the pandemic and low oil prices on demand
- the impacts of carbon pricing
- pricing impacts associated with mothballs, retirements, and conversions of coal assets, and
- renewables additions

The 2021 average pool price is forecast to be $54 per MWh compared to the 2020 projected average pool price of $49 per MWh, an increase of 10 per cent. The higher pool prices anticipated for 2021 can be mainly attributed to an expected partial recovery of demand.

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3. Load Forecast

Slides 25-32

a) Load Measurement Definitions

Alberta Internal Load (AIL): System Load plus load served by on-site generating units, including those within an industrial system and the City of Medicine Hat. AIL is an input into the operating reserve volumes forecast and specifically impacts the amount 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) 2020 AIL

2020 Alberta Internal Load (AIL) is projected to be lower than 2019 actuals and the 2020 BRP forecast due to:

- the effects of the pandemic
- the continuation of government mandated oil production limits
- the impact of low oil prices on demand
- a slowdown in economic growth

c) 2021 AIL Forecast

The 2021 BRP AIL forecast utilizes economic inputs from the RBC June 2020 Outlook, including real gross domestic product (GDP), employment, and population variables for Alberta. The 2020 BRP AIL forecast also includes considerations for: the impact of the pandemic, oil production, P50 weather (over the last 30 years), seasonality, days of the week, hour of the day, and holidays.

Forecasted load growth in 2021 compared to 2020 projected is expected to increase by 1 per cent due to an expected partial recovery from the pandemic, forecasted economic and population growth, and forecasted oilsands production growth.

d) 2020 Net-to-grid Load and System Load

2020 Net-to-grid Load and System Load are projected to be lower than 2019 actuals due to:

- the effects of the pandemic
- a slowdown in economic growth

e) 2021 Net-to-grid Load and System Load Forecast

The 2021 BRP NTG Load and System Load forecasts consider economic inputs from the RBC June 2020 Outlook, including real gross domestic product (GDP), employment, and population variables for Alberta. The 2020 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 2021 compared to 2020 projected is expected to increase by 2 per cent due to an expected partial recovery from the pandemic, forecasted growth in distributed generation, and forecasted economic and population growth.

Forecasted System Load growth in 2021 compared to 2020 projected is expected to increase by 1 per cent due to an expected partial 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 distributed generation.

4. Wires

Slides 18-19

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 2020 Wires

Wires costs in the 2020 projection are $1,924.0 million, which is $8.0 million or half of one per cent higher than the 2020 BRP forecast of $1,916.0 million based on the amounts paid primarily to the TFOs in accordance with their AUC-approved tariffs.

The 2020 projection is based on TFO tariffs approved or applied-for as of September 2020 with the majority of the projection reflecting: i) filed 2020 tariffs; ii) filed 2020 negotiated settlements; or iii) AUC approvals for 2019 and 2020 tariffs.

c) 2021 Forecast

The 2021 forecast for wires costs is $1,933.8 million, which is $9.8 million or half of one per cent higher than the 2020 projection of $1,924.0 million. The 2021 forecast is based on TFO tariffs ($1,929.8 million) and the AESO’s forecast for IBOC and LBC SO costs ($4.0 million).

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

5. Ancillary Services

Slides 33-35

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 90 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
   - represents approximately 10 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 2020 BRP

The Operating reserves projection for 2020 is based on:

- **actual hourly volumes of operating reserves and hourly pool prices/operating reserve prices**: January-July 2020;
- **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 2020 for the period from August 2020 to December 2020; and
- **estimated operating reserve prices**: average prices over the previous 48 months of historical data.

Operating reserve costs in the 2020 projection are $166.2 million, which is $62.9 million or 27 per cent lower than the 2020 BRP forecast of $229.1 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices, and operating reserve prices.

The 2020 projected operating reserves volumes is 7.7 terawatt hours, which is 0.1 terawatt hours or 1 per cent lower than the 2020 BRP forecast of 7.8 terawatt hours.

The cost variance in 2020 is attributed to:

- a lower 2020 projected average pool price of $49 per MWh compared to $58 per MWh used in the 2020 BRP forecast
- Reductions in active operating reserve volumes procured, which offset the effects of high import volumes in 2020; and
- lower than expected load levels

c) 2021 Forecast

The 2021 forecast for operating reserves costs is $164.3 million, which is $1.9 million or 1 per cent lower than 2020 projected costs of $166.2 million.

The 2021 operating reserves volumes forecast is 7.2 terawatt hours, which is 0.5 terawatt hours or 6 per cent lower than the 2020 projection of 7.7 terawatt hours. The 2021 forecast operating reserves volumes are lower than the 2020 projection, partly due to lower forecast import levels in 2021.

Operating reserve costs in the 2021 forecast are similar to the 2020 projection. Despite an increase of $5 per MWh or 10 per cent for the 2021 forecast average pool price, a decrease of 0.5 terawatt hours or 6 per cent for 2021 operating reserve volumes has an offsetting effect which results in 2021 forecast operating reserve costs being similar to the 2020 projection.

5.2. OTHER ANCILLARY SERVICES

a) 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.

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.

b) 2021 Forecast

The 2021 forecast for other ancillary services costs is $38.4 million, which is $1.8 million or four per cent lower than the 2020 projection of $40.2 million.

Other Ancillary Services Costs ($ million) ~ by production year

	2021 Forecast	2020 Projected	2020 BRP	2019 Actual	2018 Actual
Load Shed Service for Imports	32.6	31.7	20.6	16.2	31.0
Contracted Transmission Must-run	-	2.8	2.4	3.0	3.1
Conscripted Transmission Must-run	0.4	0.4	0.2	0.4	0.4
Reliability Services	2.9	2.9	2.9	2.9	2.9
Black Start	2.4	2.3	2.3	2.3	2.2
Transmission Constraint Rebalancing	0.1	0.1	0.1	0.3	0.0
Poplar Hill	-	-	-	0.9	2.3
Other Ancillary Service Costs	38.4	40.2	28.7	26.0	41.9

Differences are due to rounding

Updates to 2020 costs from the 2020 BRP due to:

- **Load Shed Service for Imports (LSSi)** – increased utilization of LSSi due to higher import demand and changes made to the LSSi arming table in June 2020. Volume of arming is expected to end 2020 significantly higher than the 2020 BRP forecast. Availability of LSSi has been similar to 2020 BRP expectations, and Trip payments were issued in June as a result of the June 7, 2020 Trip event.

- **Contracted Transmission Must-run** – higher dispatch volumes for contracted unit than 2020 BRP forecast. The agreement expires as of September 30, 2020.

- **Conscripted Transmission Must-run** – projected 2020 costs for conscripted TMR are consistent to the forecast for the 2020 BRP.

The 2021 forecast methodology:

- **Load Shed Service for Imports** (LSSi) – The 2021 LSSi forecast considers historical availability levels and arming volumes from the 2017 to 2020 period.

- **Contracted Transmission Must-run** – No services under contract in 2021.

- **Conscripted Transmission Must-run** – based on the 2020 projected cost as operational conditions in 2021 are anticipated to be similar to those in 2020.

- **Reliability Services** – based on an existing contract; no new contracts for services in 2021.

- **Black Start** – no additional black start services are planned for 2021. New agreements for services with the same facilities are being procured effective January 1, 2021 and the 2021 Forecast is based on the expected fixed and variable payments and training expenses under the new agreements.

- **Transmission Constraint Rebalancing** – based on the 2020 projected costs as operational conditions in 2021 are anticipated to be similar to those in 2020.

Line Losses

a) Description of Service

Slides 36-38

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 2020 BRP

Transmission line losses costs in the 2020 projection are $95.8 million, which is $17.7 million or 16 per cent lower than the 2020 BRP of $113.5 million.

The 2020 projected transmission line losses volumes are 1,916 gigawatt hours, which is 46 gigawatt hours or 2 per cent higher than the 2020 BRP of 1,870 gigawatt hours. The increase in volumes of losses is attributed to less NW gas-fired generation, which may be due to the higher than expected natural gas prices projected in 2020.

The cost variance is mainly impacted by a lower 2020 projected average pool price of $49 per MWh compared to $58 per MWh used in the 2020 BRP forecast.

c) 2021 Forecast

The 2021 forecast for transmission line losses is $104.4 million, which is $8.6 million or nine per cent higher than the 2020 projected cost of $95.8 million. This is mostly attributable to an increase in the 2021 forecasted average pool price to $54 per MWh compared to $49 per MWh for the 2020 projected pool price.

The 2021 transmission line losses volumes forecast is 1,880 gigawatt hours, which is 36 gigawatt hours or less than 2 per cent lower than the 2020 projection of 1,916 gigawatt hours. Losses volumes in 2021 are expected to be at similar levels to historic values.