Supplementary 2020 Forecast Information

1. Disclaimer

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2. Pool Price

Slides 8-11

a) 2019 Pool Price

The 2019 projected average pool price is $56 per MWh compared to the 2019 forecast pool price of $58 per MWh (as provided in the 2019 Budget Review Process (BRP)). The 2019 projection incorporates actual pool prices (from January 2019-August 2019) and forecast information from the EDC Associates' "Quarterly Forecast Update – Third Quarter 2019".

The 2019 projected average pool price is lower than the previous 2019 BRP forecast mainly due to lower than expected demand.

b) 2020 Pool Price Forecast

Consistent with the 2018 and 2019 BRP, the AESO has chosen to use the EDC Associates' hourly pool price forecast for 2020. While the AESO has prepared an internal hourly pool price forecast in previous years, competing priorities for staff resources contributed to the decision to continue to use the EDC forecast for the 2020 BRP. 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 the following assumptions have been considered by EDC:

- recent market fundamentals
- the impact of the carbon pricing regimes
- pricing impacts associated with mothballs/retirements, and
- Renewable Electricity Program (REP) round one additions

The 2020 average pool price is forecast to be $58 per MWh compared to the 2019 projected average pool price of $56, an increase of four per cent. The higher pool prices anticipated for 2020 can be mainly attributed to higher demand in 2020

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3. Load Forecast

Slides 13-15

a) 2019 Load

2019 Alberta Internal Load (AIL) is projected to be similar to 2018 actuals due to:

- Government mandated oil production cuts beginning in 2019
- A slowdown in economic growth

2019 AIL is projected to be lower than 2019 BRP forecast due to:

- Lower than expected oilsands production growth
- Lower than expected economic growth

2020 Load Forecast

The 2020 BRP load forecast utilizes economic inputs from the Conference Board of Canada's Summer 2018 Outlook, including real gross domestic product (GDP), employment, and population variables for Alberta. The 2020 BRP load forecast also includes considerations for oil production, seasonality, days of the week, hour of the day, holidays, and normal weather (median temperatures over the last 10 years).

Forecasted load growth in 2020 compared to 2019 projected is expected to increase by three per cent due to forecasted economic and population growth, forecasted oilsands production growth, and additional load drivers (including cannabis and cryptocurrency).

4. Wires

Slide 6

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 2019 Wires

Wires costs in the 2019 projection are $1,851.8 million, which is $17.2 million or one per cent higher than the 2019 BRP forecast of $1,834.6 million based on the amounts paid primarily to the TFOs in accordance with their AUC-approved tariffs.

The 2019 projection is based on TFO tariffs approved or applied-for as of November 2019 with a majority of the projection reflecting: i) filed 2019 tariffs; ii) filed 2019 negotiated settlements; or iii) AUC approvals for 2018 and 2019 tariffs.

c) 2020 Forecast

The 2020 forecast for wires costs is $1,916.0 million, which is $64.2 million or three per cent higher than the 2019 projection of $1,851.8 million. The 2020 forecast is based on TFO tariffs ($1,911.2 million) and the AESO's forecast for IBOC and LBC SO costs ($4.8 million).

The 2020 forecast is based on TFO tariffs approved or applied-for as of November 2019 with a majority of the forecast reflecting: i) filed 2020 tariffs; ii) filed 2020 negotiated settlements; or ii) AUC approvals for 2018 and 2020 tariffs.

5. Ancillary Services

Slides 17-18

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. Over-the-counter contracts are used only as a back up to procure operating reserves in the absence of the availability of the online exchange. All providers who sell volumes over-the-counter are paid their offer price.

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 2019 BRP

The Operating reserves projection for 2019 is based on:

- **actual hourly volumes of operating reserves and hourly pool prices/OR prices**: January-August 2019;
- **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 2019 for the period from September 2019 to December 2019; and
- **estimated operating reserve prices**: average prices over the previous 48 months of historical data
    - The historical range has been increased from 24 months (in the 2019 BRP) to 48 months to incorporate a wider range of market conditions in Alberta, including imports

Operating reserve costs in the 2019 projection are $200.5 million, which is $70.1 million or 26 per cent lower than the 2019 BRP forecast of $270.6 million. The cost of operating reserves is impacted by actual volumes, hourly pool prices, and operating reserve prices.

The 2019 projected operating reserves volumes is 7.9 terawatt hours, which is similar to the 2019 BRP forecast.

The cost variance is partly attributed to lower active operating reserve premiums (or discounts) over the first eight months of 2019 than expected in the 2019 BRP. The cost variance is also partly attributed to a lower 2019 projected average pool price of $56 per MWh compared to $58 per MWh used in the 2019 BRP forecast.

2020 Forecast

The 2020 forecast for operating reserves costs is $229.1 million, which is $28.6 million or 14 per cent higher than 2019 projected costs of $200.5 million.

The 2020 operating reserves volumes forecast is 7.8 terawatt hours, which is 0.1 terawatt hours or one per cent lower than the 2019 projection of 7.9 terawatt hours. The 2020 forecast yields similar operating reserves volumes to the 2019 projection associated with similar forecasted import conditions.

The cost variance is partly attributed to higher expected 2020 active operating reserve premiums (or discounts) in line with historic levels over the last four years. The cost variance is also partly attributed to a higher 2020 forecasted average pool price of $58 per MWh, which is four per cent higher than the 2019 projection of $56 per MWh.

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.

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

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) 2020 Forecast

The 2020 forecast for other ancillary services costs is $28.7 million, which is $1.0 million or four per cent higher than the 2019 projection of $27.7 million.

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

	2020 Forecast	2019 Projected	2019 BRP	2018 Actual	2017 Actual
Load Shed Service for Imports	20.6	18.0	32.8	30.9	22.9
Contracted Transmission Must-run	2.4	3.1	3.2	3.1	3.0
Conscripted Transmission Must-run	0.4	0.4	0.2	0.4	0.5
Reliability Services	2.9	2.9	2.9	2.9	2.9
Poplar Hill	-	0.9	1.7	2.4	2.8
Black Start	2.3	2.3	2.3	2.2	2.1
Transmission Constraint Rebalancing	0.1	0.1	0.1	0.0	0.0
Other Ancillary Service Costs	28.7	27.7	43.2	41.9	34.3

Differences are due to rounding

Updates to 2019 costs from the 2019 BRP due to:

- **Load Shed Service for Imports (LSSi)** – lower utilization of LSSi due to lower import demand. Volume of arming is expected to end 2019 significantly lower than the 2019 BRP forecast. Availability of LSSi has been similar to 2019 BRP expectations and there have been no trip events to date.

- **Conscripted Transmission Must-run** unanticipated system conditions in the North West in the first week of June due to a transmission line outage and planning for transmission contingency due to the line outage led to an increase in costs for conscripted TMR, as compared to the forecast for the 2019 BRP.

The 2020 forecast methodology:

- **Load Shed Service for Imports** (LSSi) – The 2020 LSSi forecast considers historical availability levels and arming volumes from the preceding 36 months.

- **Contracted Transmission Must-run** – includes one unit currently under contract. The TMR agreement is forecast at 100% availability for the purpose of the 2020 Forecast, until the termination of the contract at the end of September.

- **Conscripted Transmission Must-run** – based on the 2019 projected cost as operational conditions in 2020 are anticipated to be similar to those in 2019

- **Reliability Services** – based on an existing contract; no new contracts for services in 2020.

- **Poplar Hill** – As of July 29, 2019, the AESO has terminated the Poplar Hill Agreement. No services will be required from this facility in 2020.

- **Black Start** – no additional black start services are planned for 2020. The 2020 Forecast includes the fixed payments for the agreements with existing units under contract.

- **Transmission Constraint Rebalancing** – based on the 2019 projected costs as operational conditions in 2020 are anticipated to be similar to those in 2019.

Line Losses

a) Description of Service

Slides 20-21

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) available 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 including economic drivers, 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 2019 BRP

Transmission line losses costs in the 2019 projection are $108.9 million, which is $17.2 million or 14 per cent lower than the 2019 BRP of $126.1 million.

The 2019 projected transmission line losses volumes is 1,874 gigawatt hours, which is 236 gigawatt hours or 11 per cent lower than the 2019 BRP of 2,110 gigawatt hours. The decrease in volumes of losses is likely attributed to changes in generation dispatches resulting from more gas-fired generation in conjunction with less coal-fired generation. Less coal-fired generation is being dispatched as a result of mothballs/retirements and market fundamentals.

In addition, the cost variance is impacted by a lower 2019 projected average pool price of $56 per MWh compared to $58 per MWh used in the 2019 BRP forecast.

c) 2020 Forecast

The 2020 forecast for transmission line losses is $113.5 million, which is $4.6 million or four per cent higher than the 2019 projected cost of $108.9 million. This is mostly attributable to an increase in the 2020 forecasted pool price to $58 per MWh compared to $56 per MWh for the 2019 projected pool price.

The 2020 transmission line losses volumes forecast is 1,870 gigawatt hours, which is 4 gigawatt hours or less than 1 per cent lower than the 2019 projection of 1,874 gigawatt hours. Despite significant load growth, losses volumes are expected to stay flat in 2020 assuming similar conditions to 2019.