APPENDIX B LOAD AND GENERATION FORECAST

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1. Introduction

This document describes the load and generation capacity forecasts used in the Central East Transfer-out (CETO) Transmission Development Planning Report (Planning Report).[1] A project-specific approach was adopted in generation dispatch assumptions development with scenarios assumed within the Study Area (as defined below). Details about the forecasts, as well as discussions about dispatch scenarios and methodology, are included within this document.

2. Study Area Background

2.1 Study Area

As defined in the Planning Report, the Study Area includes the following AESO planning areas in the South and Central Planning Regions[2]: Vegreville (Area 56), Lloydminster (Area 13), Wainwright (Area 32), Alliance/Battle River (Area 36), Provost (Area 37), Hanna (Area 42), Sheerness (Area 43), Brooks (Area 47), Empress (Area 48), Vauxhall (Area 52), and Medicine Hat (Area 4).

2.2 Historical Load

The types of load in the Study Area are very diverse. Towns and cities contribute to residential and commercial load. In addition, there is agricultural load in the southern portion of the Study Area, and industrial loads associated with oil and natural gas pipelines and oil drilling activity in the northern portion of the Study Area. Over the past two years, cryptocurrency mining load has also come online in Hanna (Area 42) and Medicine Hat (Area 4).

In this section, the statistics of historical load are reported based on a seasonal year.[3] Table 1 summarizes historical Winter Peak (WP), Summer Peak (SP), and Summer Light (SL) load levels of the Study Area. The Compound Annual Growth Rate (CAGR) of load in the Study Area from 2015 to 2019 was 1.1% for WP, 1.7% for SP, and 4.0% for SL.[4]

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[1] Filed under separate cover.

[2] The AESO Planning Regions map is available on the AESO website.

[3] The winter season starts on November 1st and ends on April 30th of the following year, and summer season starts on May 1st and ends on October 31st of the same year. The "peak" load represents the maximum load during the season; "light" load represents the minimum load during the season.

[4] $CAGR\ (\%) = \left(\left(\frac{Load_{2019}}{Load_{2015}}\right)^{\frac{1}{n}} - 1\right) \times 100, where\ n = Number\ of\ years$

Table 1 Historical Load in the Study Area

Year	Winter Peak (MW)	Summer Peak (MW)	Summer Light (MW)
2014	1,279	1,281	820
2015	1,244	1,257	813
2016	1,303	1,224	809
2017	1,348	1,299	726
2018	1,323	1,389	889
2019	1,302	1,347	951

2.3 Existing Generation Capacity

As of January 2020, the total existing generation capacity[5] in the Study Area was 2,321 MW and is comprised of coal-fired, gas-fired (i.e., combined cycle and simple cycle), wind, solar, and other generation. Table 2 summarizes the existing generation capacity in the Study Area.[6]

Table 2 Existing Generation Capacity in the Study Area

Asset (Asset ID)	Capacity (MW)	AESO Planning Area	Technology	In-service Year
Battle River 4 (BR4)	155	36	Coal-fired	1975
Battle River 5 (BR5)	385	36	Coal-fired	1981
Sheerness 1 (SH1)	400	43	Coal-fired	1986
Sheerness 2 (SH2)	390	43	Coal-fired	1990
Medicine Hat 1 (CMH1)	255	4	Combined Cycle	1970s-2017[7]
Lethbridge Taber (ME02)	8	52	Simple Cycle	2001
Lethbridge Burdett (ME03)	7	52	Simple Cycle	2001
AltaGas Bantry (ALP1)	7	47	Simple Cycle	2008
Ralston (NAT1)	20	4	Simple Cycle	2015
Bellshill (BHL1)	5	32	Simple Cycle	2018
Cancarb Medicine Hat (CCMH)	42	4	Other[8]	2000
Enmax Taber (TAB1)	81	52	Wind	2007
Ghost Pine (NEP1)	82	42	Wind	2010
Suncor Wintering Hills (SCR4)	88	43	Wind	2011
Halkirk 1 (HAL1)	150	42	Wind	2012
Bull Creek Wind 1 (BUL1)	13	37	Wind	2015
Bull Creek Wind 2 (BUL2)	16	37	Wind	2015

5 Maximum capability is used to present the capacity of the generation which is sourced from the AESO's Current Supply and Demand webpage available on the AESO website.

6 Battle River 3 (BR3) retired on December 31, 2019.

7 Medicine Hat #1 has added additional turbines after 1970s to bring their capacity to the current 255 MW.

8 CCMH is a waste heat recovery power plant.

Asset (Asset ID)	Capacity (MW)	AESO Planning Area	Technology	In-service Year
Whitla (WHT1)	202	4	Wind	2019
Brooks Solar (BSC1)	15	47	Solar	2017
TOTAL	**2,321**			

As of July 2020, two additional solar distribution-connected generation facilities near the Town of Vauxhall, Hull (HUL1) 25 MW and Vauxhall (VXH1) 22 MW, have been energized and generation projects in the Study Area have met AESO's certainty criteria[9], totaling 320 MW of incremental generation.

2.4 Proposed Generation Connection Projects

The number of requests for transmission system access service the AESO has received from market participants demonstrates high interest for generation development in the Study Area. Based on the AESO's Project List, as of January 2020[10] there were 93 generation projects seeking connection to the transmission system in the Study Area[11]. These projects represent a total requested *Supply Transmission Service* (Rate STS) contract capacity increase of 8,944 MW for the Study Area, with the vast majority of this being renewable generation, including 6,220 MW of wind and 2,530 MW of solar. There are also 138 MW of gas generation projects and 56 MW of battery energy storage projects. Table 3 shows the total amount of Rate STS contract capacity requests for projects by stage of the AESO Connection Process and type of generation.

Table 3 Total Requested Rate STS for Proposed Generation Connection Projects by AESO Connection Process Stage and Type in the Study Area

AESO Connection Process Stage	Battery Storage Projects (MW)	Gas Projects (MW)	Solar Projects (MW)	Wind Projects (MW)	Total STS Increase (MW)
Stage 1: Study Scope	16	12	36	120	183
Stage 2: Connection Proposal	40	94	1,670	3,287	5,091
Stage 3: NID & Facility Application	0	16	680	867	1,563
Stage 4: Filing & AUC Approval	0	0	0	150	150
Stage 5: Construct & Prepare to Energize	0	16	111	1,796	1,923
Stage 6: Energize, Commission & Close	0	0	34	0	34
Total STS Requested (MW)	**56**	**138**	**2,530**	**6,220**	**8,944**

[9] The AESO's certainty criteria include awarded Renewable Electricity Program (REP) projects and all generation projects that have paid their Generating Unit Owner's Contribution (GUOC).

[10] The AESO's Project List is available on the AESO website.

[11] Attachment A provides a map containing all the projects in the South West, as well as South East and Central East sub-regions.

2.5 Wind and Solar Resource Potential and Interest

In 2018, the AESO commissioned a study from AWS Truepower (AWS Report) to assess the wind and solar resource potential within the province of Alberta.[12] According to the AWS Report, the Study Area has over 2,174 GW of solar and 494 GW of wind power potential which could be hypothetically developed within 20 km from the existing transmission infrastructure of 115 kV or greater. This represents 28% of the total solar and 40% of the total wind resource development potential in Alberta. In addition, the AWS Report identified Hanna (Area 42) as having the largest solar and wind power potential among the 42 AESO planning areas.

The AWS Report included solar and wind resource maps, which show that the Study Area has high quality wind and solar resources.[13] The AWS Report conclusions regarding the locations of Alberta's solar and wind resource potential aligns with where: the existing wind and solar generation has developed; the Renewable Electricity Program (REP) projects are located; and the approved generation connection projects included in the planning studies and discussed in Section 2.4 are located.

The first utility scale solar plant in western Canada, Brooks Solar, is within the Study Area. The wind capacity of the Study Area has increased from 81 MW in 2007 to 632 MW in 2020. In addition, there are eight REP projects in the Study Area with a total generation capacity of 894 MW, as shown in Table 4. The Whitla Wind project began commercial operations in 2019, while the remaining REP projects, with a total generation capacity of 692 MW, are all anticipated to be in service by 2021.

Table 4 REP Projects in the Study Area

Project Name	Capacity (MW)	AESO Planning Area	Technology
Whitla Wind	202	4	Wind
Sharp Hills Wind Farm	248	42	Wind
Buffalo Atlee Wind Farm 1	17	47	Wind
Buffalo Atlee Wind Farm 2	14	47	Wind
Buffalo Atlee Wind Farm 3	17	47	Wind
Cypress Wind Power Project	202	4	Wind
Jenner Wind Power Project	122	47	Wind
Jenner Wind Power Project 2	71	47	Wind

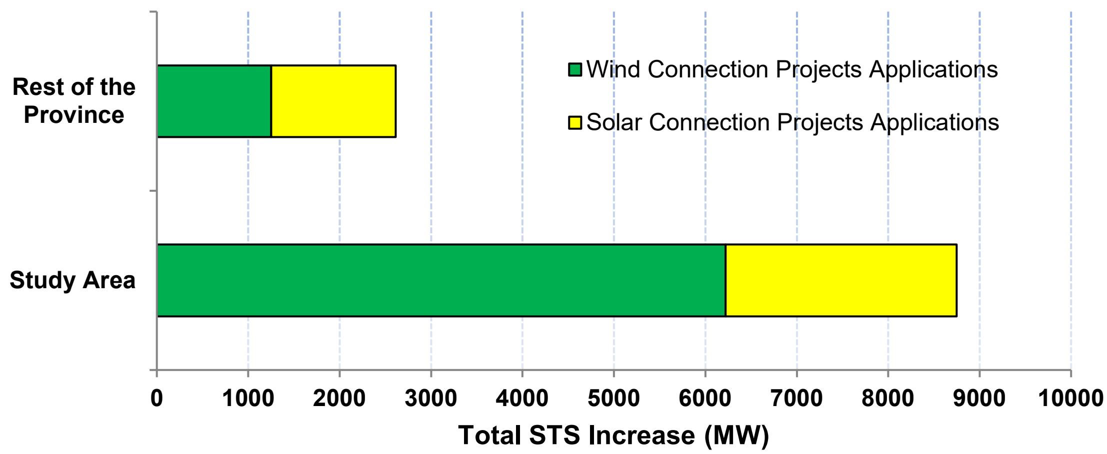
Among the proposed connection projects discussed in Section 2.4, 98% of the requested STS increase is related to renewable generation projects. Figure 1 illustrates the proposed wind and solar projects in the Study Area compared to the rest of Alberta, based on the AESO's Project List as of January 2020. The Study Area has the greatest proportion of proposed renewable development compared to the rest of Alberta. While the proposed generation connection projects currently in the AESO project list will not necessarily all proceed, the number and size of the active generation connection projects in the Study

[12] The AWS study is published as part of the AESO 2019 Long-term Outlook (2019 LTO) and is available on the AESO website.

[13] Attachments B and C provide the Alberta wind and solar resources maps, also available in the AWS study.

Area provides a strong indication of the interest in renewable development. Furthermore, interest in renewable development in the Study Area continues after REP was terminated on June 10, 2019.

Figure 1 Wind and Solar Connection Projects in the Study Area Compared to the Rest of Alberta



3. Load Forecast

The load forecast used in the Planning Report presents the latest forecast information in the Study Area and is aligned with the *AESO 2019 Long-term Outlook* (2019 LTO) Reference Case load forecast. The Reference Case load forecast represents the AESO's current expectation for long-term load growth given uncertainties facing the electricity industry. Using econometric models, the 2019 LTO provides hourly load forecasts of Alberta internal load (AIL), AESO Planning Region, AESO planning area, and Point of Delivery (POD) levels for the next 20 years.[14] The forecast accounts for variables including Alberta's gross domestic product (GDP), population, employment and oilsands production, as well as weather, policy, new technologies and industries, such as rooftop photovoltaic (PV) solar, cryptocurrency, cannabis farming and electric vehicles (EV).

The AESO used the 2019 LTO as a basis for developing the seasonal peak load forecast for the Study Area, with considerations for historical load patterns and trends, substation-level load forecasts provided by the applicable legal owners of electric distribution systems (DFOs), and recent project developments. The load growth in the near-term (2023) is due to organic load growth in the Study Area, cannabis operations expected to open over the next five years, and the one approved load connection project shown in Table 5. Organic load growth[15] is driven by population, employment, and GDP growth. The near-term load growth of cannabis, EV, PV output,[16] and organic load growth breakdown from 2018 is shown in Table 6 (all Study Area load values are at the time of the WP and SP). EV load is higher during

14 Please see the 2019 LTO section on forecast methodology for details.

15 Organic load growth refers to any load growth unrelated to projects, cannabis operations and electric vehicle (EV) load.

16 PV output has been incorporated to offset load in SP.

the WP compared to the SP due to the assumed EV charging profile.[17] Almost the entire cannabis operations load growth is in Medicine Hat (Area 4) where a new facility is expected to open by 2023. Organic load growth is distributed across the Study Area, with the majority occurring in Hanna (Area 42) and Lloydminster (Area 13) from increases in population, employment and economic activity, as well as expected increases in oil drilling activities. The Keystone XL Pipeline project was not included in the load forecast due to uncertainty facing the Keystone XL Pipeline project at the time that the load forecast was developed.

Table 5 Load Connection Project Included in the Forecast

AESO Project no. and name	AESO Planning Area	Rate DTS (MW)	Connection Process Stage	Scheduled In-service Year
P1410 ATCO Heartland Pump Station Connection	56	20	5	2020

Table 6 Near-term Load Growth Composition

Season	2018 Actual Load (MW)	Cannabis Load Growth (MW)	EV Growth (MW)	Rooftop PV Output (MW)	Organic Load Growth + AESO Project P1410 (MW)	2023 Forecast Load (MW)
WP	1,323	42	2	0	60	1,427
SP	1,389	17	0	-5	30	1,431

Table 7 provides the composition of long-term load growth from 2023 to 2039. Similar to near-term outlook, the long-term growth is driven by organic load growth in the Study Area, with more growth expected in Hanna (Area 42) and Lloydminster (Area 13). Organic load growth drivers in the long-term are the same as the near-term. There is also some EV growth expected in urban areas.

Table 7 Long-term Load Growth Composition

Season	2023 Forecast Load (MW)	Cannabis Load Growth (MW)	EV Growth(MW)	Rooftop PV Output (MW)	Organic Load Growth (MW)	2039 Forecast Load (MW)
WP	1,427	0	11	0	31	1,469
SP	1,431	0	2	-12	44	1,465

The CAGR in the Study Area from 2019 to 2039 is 0.6% for WP and 0.4% for SP. The decrease in the load growth rate relative to historic load is driven by a lower GDP outlook compared to historic GDP. Historically, GDP has grown by 3% annually from 1998 to 2019 compared to a forecast of 2% GDP growth from 2019 to 2039. The 2023, 2031, and 2039 seasonal WP, SP, and SL load forecasts for the Study Area are presented in Table 8.

[17] This assumption was taken from a study done on behalf of the Yukon Energy Corporation that found that EVs would consume more electricity in the winter months. Yukon Energy's Electric Vehicle investigation can be found on their website.

Table 8 Seasonal Load Forecasts

Year	WP (MW)	SP (MW)	SL (MW)
2023	1,427	1,431	1,019
2031	1,452	1,432	1,077
2039	1,469	1,465	1,097

4. Generation Forecast

The 2019 LTO has location assumptions of new generation in Planning Regions based on the likelihood of each technology developing in a particular region. Technology location considerations include utilizing existing infrastructure (such as brownfield sites), fuel resources (such as the location of strong wind and solar resources), future planned transmission development, and developer information. The 20 year generation forecast in the South and Central Planning Regions of the 2019 LTO Reference Case generation forecast is listed in Table 9. This information indicates potential generation development in the Study Area.

Table 9 Central Planning Region and South Planning Region Generation Forecasts

Technology	Existing (MW) [18]		2023 (MW)		2031 (MW)		2039 (MW)	
	Central	South	Central	South	Central	South	Central	South
Coal-fired	540	790	155	0	0	0	0	0
Cogeneration	1,145	95	1,196	95	1,286	95	1,331	95
Combined Cycle	0	375	0	375	479	375	958	854
Simple Cycle	5	64	52	111	331	111	331	390
Coal to Gas	0	0	385	790	0	790	0	0
Hydro	485	409	485	409	485	409	485	409
Wind	261	1,520	509	2,295	859	3,295	909	2,922
Solar	0	15	0	131	50	381	50	431
Other	50	42	50	42	50	42	50	42
Storage	0	0	0	0	0	50	0	50
Total Capacity	**2,486**	**3,312**	**2,832**	**4,248**	**3,540**	**5,548**	**4,114**	**5,193**

Overall, generation capacity in the South and Central Planning Regions is anticipated to grow, and the majority of this growth is expected to come from renewable generation development. These Planning

[18] Existing capacity in this table is as of January 2020.

Regions contain strong wind and solar resources relative to other locations within Alberta, and are thus likely to continue to see growth of wind and solar generation.

Cogeneration is anticipated to increase by approximately 186 MW by 2039 as industrial loads grow in the Central Planning Region. Both simple cycle and combined cycle generation are expected to increase as load growth occurs and existing generation retirements are replaced with new generation.

In the Study Area, the 2019 LTO Reference Case generation forecast anticipates retirement of Battle River 3 (BR3) in 2019 and Battle River 4 (BR4) in 2025 which is aligned with the federal regulation for coal-fired generation. The existing Battle River 5 (BR5) and Sheerness 1 and 2 (SH1, SH2) coal-fired capacity is expected to convert to gas. The converted Battle River 5 gas unit is then expected to retire by 2031 and is assumed to be replaced by a new combined cycle unit with 479 MW of generation capacity compared to its current generation capacity of 385 MW. The Sheerness 1 and 2 converted gas units are expected to retire by 2033 and be replaced by a new combined cycle unit with a capacity of 479 MW compared to its current generation capacity of 790 MW. The other existing thermal generation in the Study Area remains the same as listed in Table 2.

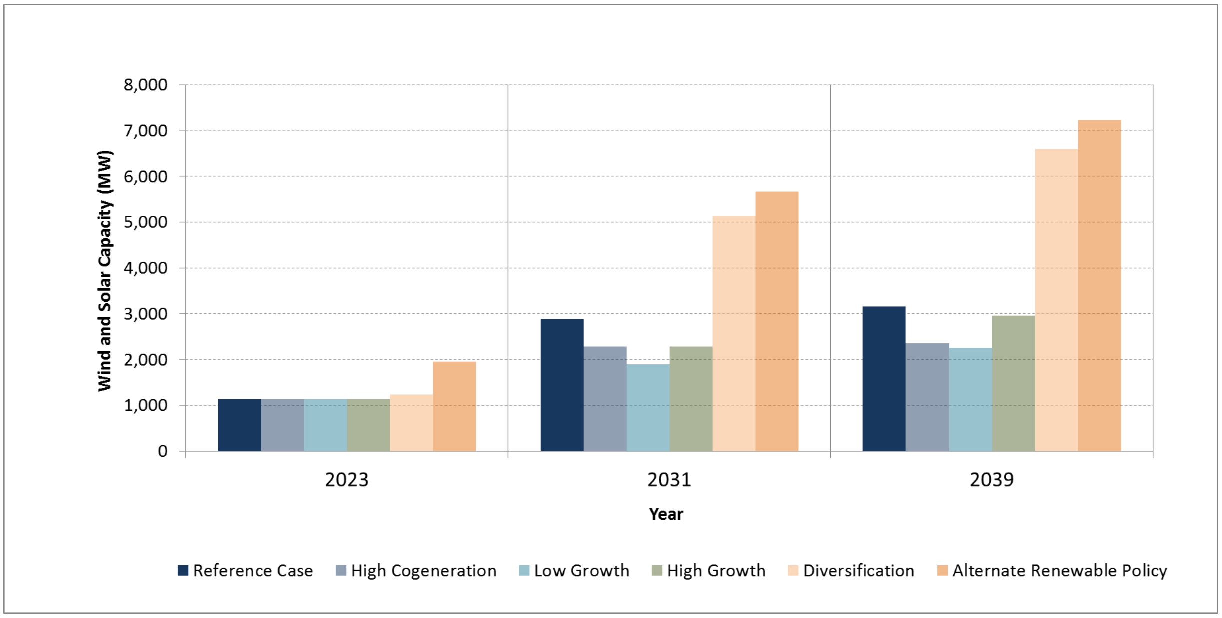
The 2019 LTO Reference Case generation forecast has assumed near-term incremental generation will develop from REP projects and Alberta Infrastructure's support for solar. Additional renewable generation is expected to develop through competitive market mechanisms and support from corporate Power Purchase Agreements (PPAs). Renewable generation developments, primarily wind generation, are split between the South and Central Planning Regions. In the 2019 LTO Reference Case, wind generation in the South and Central Planning Regions is expected to grow from an existing capacity of 1,781 MW to 3,831 MW by 2039, while solar generation is expected to grow from an existing capacity of 15 MW to 481 MW by 2039.

The 2019 LTO has assumed a 30 year life span for wind facilities, which leads to the retirement of approximately 500 MW of wind capacity in the South Planning Region over the 20 year horizon. It is assumed that these retirements extend beyond the assumed 30 year life span, or that replacement capacity is located at the same site.

Strong solar resources lead to increased solar capacity in the South and Central Planning Regions. The 2019 LTO Reference Case assumed the total solar capacity will grow to 431 MW by 2031 and 481 MW by 2039 in the South and Central Planning Regions. There is also potential for energy storage in the South Planning Region, and the 2019 LTO Reference Case assumed approximately 50 MW of energy storage additions by 2031.

The 2019 LTO also considers a variety of forecast scenarios which allow the AESO to assess uncertainties in the growth of renewable generation. Figure 2 lists all the 2019 LTO scenarios and the range of potential future wind and solar additions in Alberta, incremental to the existing 1,796 MW of wind and solar generation as noted in Table 9. Although the pace and magnitude of renewable development might be different, the 2019 LTO forecast increased future wind and solar generation capacity across Alberta in all scenarios. In addition to REP projects, the AESO forecasts that by 2023 approximately 100 MW to 900 MW incremental renewable generation above the existing renewable generation will develop in Alberta. The renewable generation is expected to continue to grow. By 2031, approximately 900 MW to 4,600 MW of incremental renewable generation is forecast to develop in addition to REP projects.

Figure 2 Incremental Wind and Solar Forecast in 2019 LTO Scenarios



The 2019 LTO provides a range of potential wind and solar generation developments and the timing of the developments. The actual magnitude, pace, and likelihood of new development is still uncertain and is dependent on a variety of drivers. These drivers include the capital costs, electricity market fundamentals including natural gas prices, carbon prices, and generation development and mix, and government policies that incent renewable generation. Changes to any of the drivers behind wind and solar development could lead to changes in the magnitude and pace of new wind and solar generation additions. Higher natural gas and carbon prices would increase production costs for gas- and coal-fired generators. This may lead to higher electricity pool prices, and, in turn, higher revenues for renewables. Likewise, lower natural gas and carbon prices may lead to lower revenues for renewables. These changes in revenues will impact the growth of renewable generation.

In addition to natural gas and carbon prices, the generation mix that develops will also impact renewable development revenues and growth. A system with large higher cost generating units, such as coal-fired generating units that have been converted to natural gas, will have electricity prices that are higher than a system with large efficient baseload units, such as cogeneration units. As a result, the generation mix that develops, and the timing of those developments, will impact revenues for renewables as well, though it is likely not as impactful as natural gas and carbon prices. Government policy that directly incents renewable development has had the largest impact on the magnitude and pace of development since the policy is designed to meet a specific goal.

5. Generation Dispatch

5.1 Thermal Dispatch Scenarios

The AESO adopted a project-specific approach to develop deterministic generation dispatch assumptions, which used assumptions of the 2019 LTO as a basis, with specific dispatch scenarios created within the Study Area. The available transmission transfer-out capability of the Study Area in future time periods depends on the replacement schedule of the existing coal-fired generation and how the generation fleet will operate. In addition, there are uncertainties associated with the timing, volume, and offer behavior of the replacement or retirement of the existing thermal generation in the CE sub-region. As a result, the AESO considered two thermal dispatch scenarios to provide additional information and facilitate the studies in the Planning Report. One scenario assumed reduced thermal capacity and dispatch in the Study Area, while the second scenario considered similar thermal capacity as the historical fleet. The reduced thermal capacity and dispatch scenario is in line with anticipated retirements and assumes that new generation does not develop to replace all the coal-fired generators in the Study Area. The second scenario considers a case with generation replacement at the coal-fired generation sites after retirements.

5.1.1 Scenario 1

Scenario 1 uses assumptions in the 2019 LTO Reference Case generation forecast, including capacity additions and retirements, location, and dispatch assumptions as listed in Section 4. It assumes retirement of Battle River 4 (BR4) in 2025 and retirement of Battle River 5 (BR5) in 2031. In addition, it assumes the Battle River 5 (BR5) and Sheerness 1 and 2 (SH1, SH2) units will be converted to natural gas-fired units before 2023. Scenario 1 assumes these coal-to-gas conversion units will be less efficient than other gas technologies including combined cycle, simple cycle, and cogeneration. These converted coal-fired units are assumed to be peaking units and would have lower output than the historical coal fleet during high renewable output or low pool price hours.

The 2019 LTO Reference Case generation forecast for 2031 assumes 479 MW of new combined cycle generation at the Battle River facility after the retirement of Battle River 5 (BR5), due to lower development costs as a result of using the existing infrastructure. Sheerness 1 and 2 (SH1, SH2) are assumed to continue to operate as coal-to-gas units until 2033, when they are assumed to be retired.

Scenario 1 represents a potential outlook where the Battle River and Sheerness facilities have lower capacity and energy dispatch than the historical coal fleet. This is due to the assumption that there would be no replacement for Battle River 3 and 4 (BR3, BR4) after their retirement, and to the peaking behavior of the assumed conversion units.

5.1.2 Scenario 2

The 2019 LTO Reference Case generation forecast assumes approximately 350 MW of new simple cycle generation would be developed at Battle River based on economics in the near-term. Scenario 2 assumes that some of these new simple cycle generation additions will occur at Battle River 3 and 4 (BR3, BR4) to maintain the overall capacity output after BR3 and BR4 retire. The new simple cycle additions at the existing BR3 and BR4 connections are considered to be peaking units in the studies in the Planning Report.

Similar to Scenario 1, Battle River 5 (BR5) and Sheerness 1 and 2 (SH1, SH2) are also assumed to be converted to gas units by 2023. However, in Scenario 2, these converted units are assumed to be baseload units which have high output during high renewable output or low pool price.

By 2031, the 2019 LTO Reference Case generation forecast assumes that 1,437 MW of new combined cycle units would be developed based on economics. Scenario 2 assumes that these new combined cycle units would be developed in the Study Area, including a 479 MW combined cycle unit at Battle River 5 (BR5), and a total of 790 MW combined cycle capacity at Sheerness 1 and 2 (SH1, SH2) in the year of 2031.

Scenario 2 represents a potential outlook where the Battle River and Sheerness facilities have similar capacity as the historical thermal fleet.

Table 10 summarizes the assumptions for the Battle River and Sheerness facilities under each dispatch scenario for the study years in the Planning Report.

Table 10 Thermal Generation Dispatch Scenarios by Study Year[19]

		Scenario 1		Scenario 2	
Generating Unit Asset ID	Existing Capacity (MW)	2023	2031	2023	2031
BR3	149	Retired	Retired	New Simple Cycle	New Simple Cycle
BR4	155	Co-firing[20]	Retired		
BR5	385	Conversion	New Combined Cycle (479 MW)	Conversion	New Combined Cycle (479 MW)
SH1	400	Conversion	Conversion	Conversion	New Combined Cycle (790 MW)
SH2	390	Conversion	Conversion	Conversion	
Total Capacity (MW)	1,479	1,330	1,269	1,479	1,573

5.2 Dispatch Methodology

The deterministic generation dispatches were developed using both a statistical method and a simulation method to have a reasonable range of stressed study cases. A statistical method was used to create generation dispatches during pre-defined planning conditions at SP, WP and SL. A simulation method was also used to create hourly dispatches which were then evaluated to select study cases for the Planning Report based on stressed power flow conditions.

5.2.1 Statistical Dispatch Method

The statistical dispatch method focuses on the critical conventional generating units (such as Battle River and Sheerness) and creates in-merit dispatches guided by historical statistics during the specific transmission system load conditions. In this method, various transmission system conditions are considered, including the study year, season hour (WP, SP or SL), regional generation level (low, typical or high), intertie status, and assumptions for variable generation (wind and solar). Based on these planning conditions, this method determines anticipated in-merit energy using historical statistics and relative economic merit.

Specifically, existing conventional units and regional output during the bottom 2.5% summer load hours (approximately 110 hours per year) and the top 2.5% of summer and winter load hours (approximately 110 hours each season per year) in the past 3 years were selected as sample points to produce conventional generation dispatch statistics at WP, SP and SL. New units that do not have historical data to determine the outputs are anticipated to operate in a similar manner to existing units in the same technology group or according to relevant available project information. Generation sources such as wind

[19] The future facility capacity is the same as the existing facility capacity if a capacity size is not specified in the table.

[20] Alterations to the Battle River Power Plant to allow additional natural gas as a supplemental fuel at Battle River 4 (BR4).

and solar are more variable. Therefore, in the planning studies found in the Planning Report, the AESO assumed wind and solar at their highest expected coincident output based on historical observations.

The critical conventional generating units are first set as the 95th percentile of their historical output, which would represent a high output scenario. Not all of the units would be high at the same time, however, due to differences in plant physics, availability, and offer dynamics. When the overall output of the existing units in the Study Area exceeds the historical levels at the predefined load condition, the existing conventional unit output is adjusted based on a generic merit order such that the total existing output is within the historical boundary.

The conventional units outside of the Study Area start at the 50th percentile of historical output at the specified load condition. After meeting the predefined intertie, wind and solar level, and the Study Area dispatch level, the generation dispatch values outside of the Study Area are scaled using a generic merit order to balance load and generation.

5.2.2 Market Simulation Dispatch Method

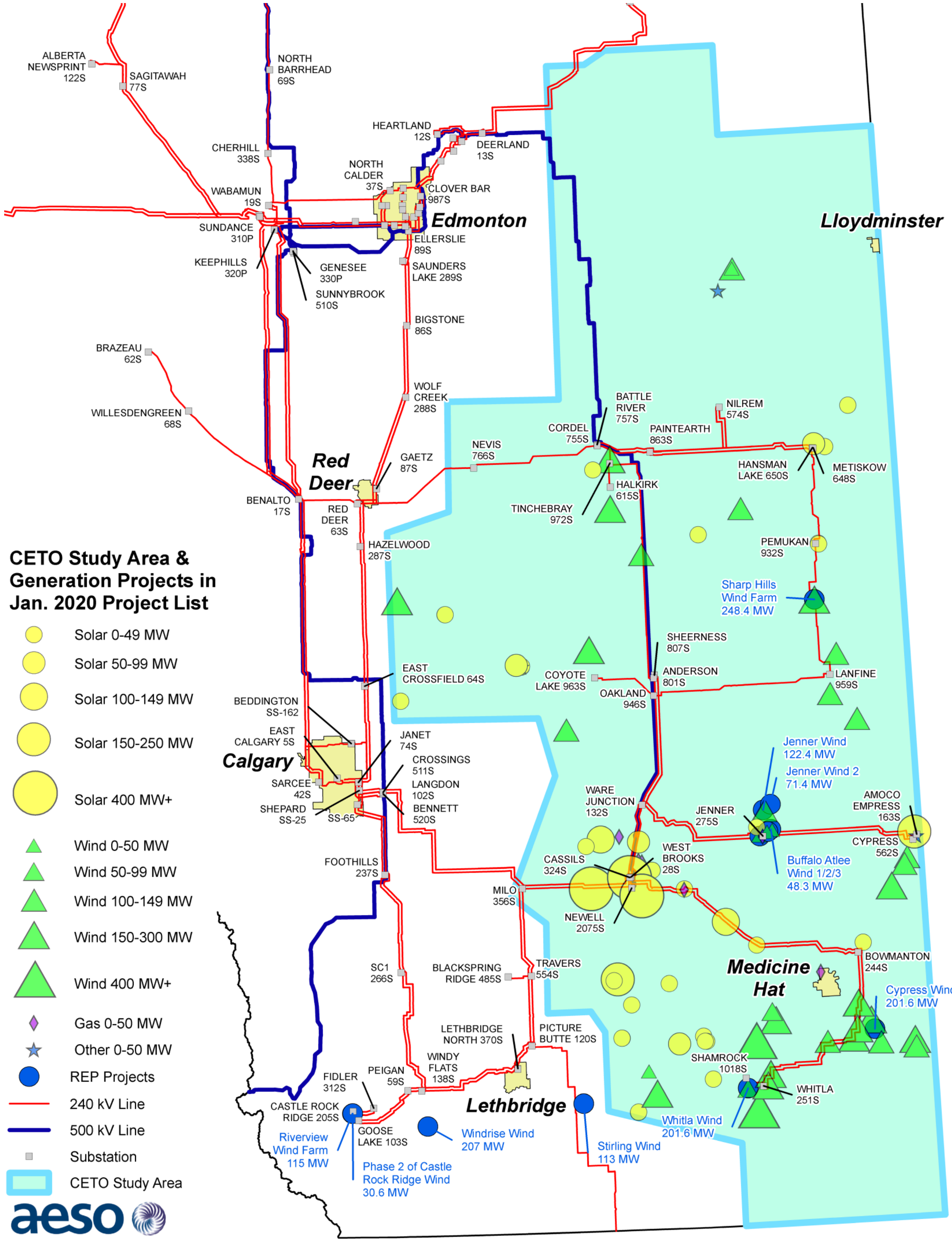
The AESO created additional generation dispatches using the Aurora[21] software platform for the market simulation dispatch method. This method applies the latest market simulation model adopted in the 2019 LTO generation outlook development.[22]

The market simulation model incorporates bidding strategies and generating unit characteristics to build an economic dispatch. Different from the statistical method, the market simulation method does not use the static historical statistics and generic merit order to represent generation dispatches. This method uses market simulation to forecast hourly merit orders. This method considers uncertainties in load and generation facility development and availability, dynamics in market conditions, intermittent generation output, and intertie flows. The market simulation models hourly bus-level load variabilities and uses a probabilistic approach to incorporate uncertainty of variable generation and firm generation availability. In addition, the same transmission development assumptions and network model used in the Planning Report were also incorporated in the market simulation to create generation dispatches. This allows the AESO to consider the dynamic relationship between the supply, demand, and transmission system in an integrated manner to create generation dispatches.

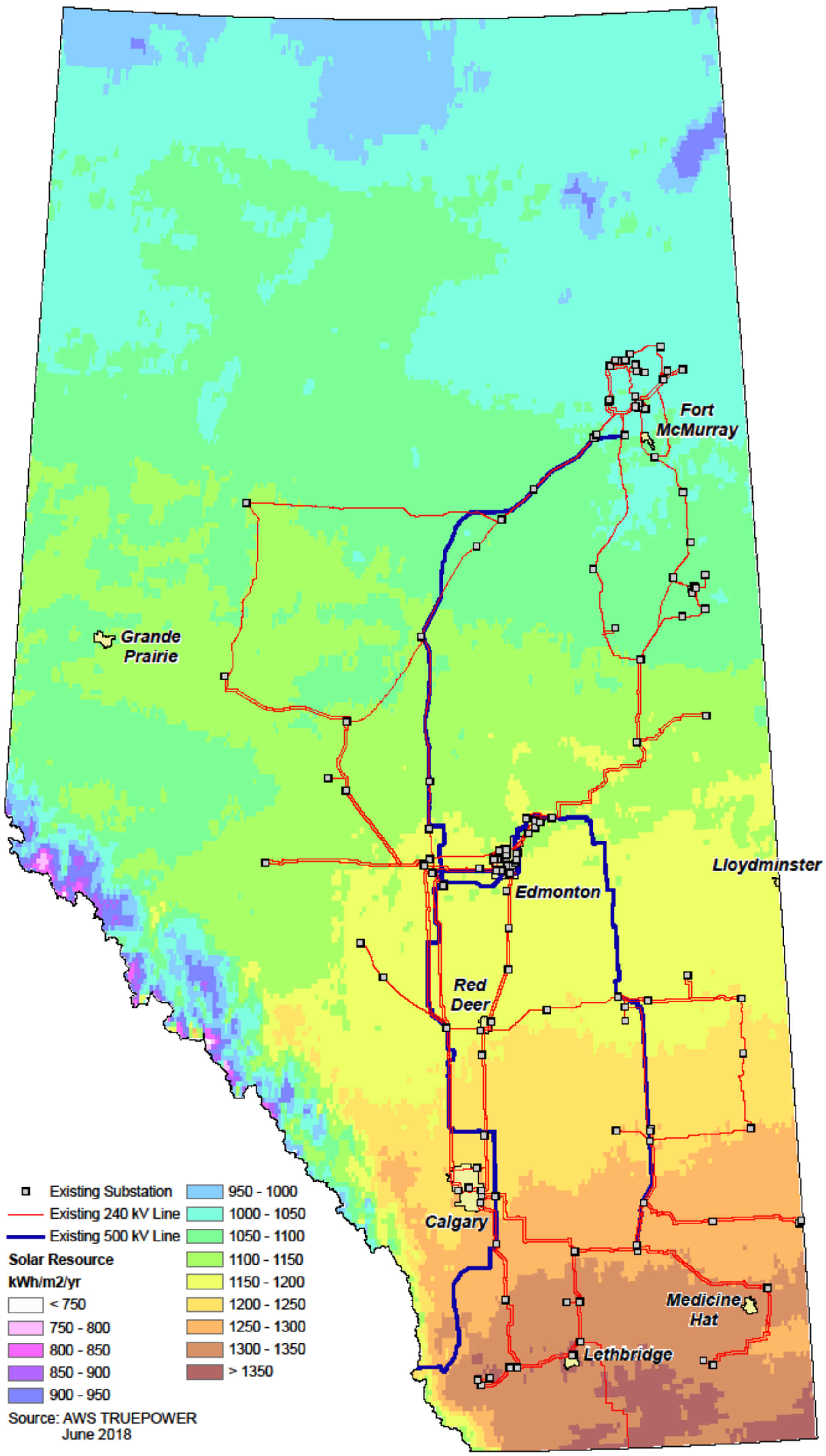
[21] For more information regarding the software Aurora, please refer to the Energy Exemplar website.

[22] Please refer the AESO's 2019 LTO for the market simulation assumptions.

Attachment A - Renewable Generation Projects



Attachment B - Alberta Solar Resources



Attachment C - Alberta Wind Resources