Net Demand Variability

System Impact and Mitigation Assessment within the AESO's current Market and Operations Framework

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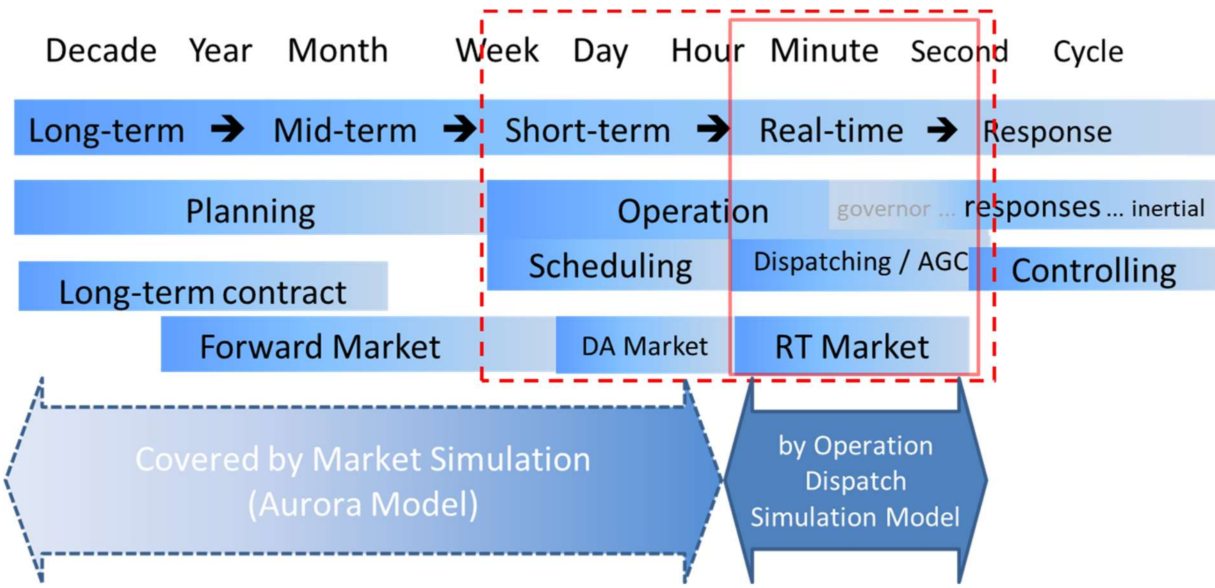
[1] Draft-0 available @ Nov/01: first version; Draft-1 @ Nov/08: with the inputs from JHK, Dilhan & Dianne(some) addressed; Draft-2 @ Nov/20: with Amir's inputs addressed; Draft-3 @ Nov/27: with JHK's further input addressed; V1 D4: Final round of technical editing and review (Imran, Dianne, Amir, Dennis); V1 Final: changes reviewed and accepted by Ming; V2 Draft @ 2018/Aug/07: to address the identified MSG data issue notes as red above, also to include the simulation result of two updated generation scenarios in supporting DR&S work, and additional analysis of potential benefit of using interchange to manage NDV.

Executive Summary

Purpose and Concepts

This report documents the findings of technical studies completed in support of the Energy and Ancillary Service (EAS) Changes work stream in the AESO's Capacity Market Transition initiative. The results of this work outline impacts of Net Demand Variability (NDV) as well as mitigation required under the current market and operation practice framework. The EAS covers timeframes from pre-real-time resource scheduling through real-time operational practices (as shown in the figure below). The NDV studies focus on impacts and mitigation in the real-time practice timeframe. The pre-real-time (resource scheduling) timeframe is the focus of parallel and coordinated market analyses.

The key task of electric power system is to ensure the electric power balancing between supply and demand at all different timeframes. The task involves related practices from building adequate and suitable resources mix at long-term timeframe, to scheduling adequate resources at pre-real-time operation timeframe, and to the resources dispatch and deployment at the real-time operation timeframe.



Traditionally, in a system where generation is predictable and dispatchable, the primary focus of system control practices is to balance supply with load demand variability. With more and more non-dispatchable variable generation integrated into the power system, control practices must consider an additional balancing requirement to match/offset variable generation output variability, which is mainly arises from renewable sources. The overall variability of combined load demand and variable generation is defined as Net-Demand-Variability (NDV), with the *net-demand* defined as *load demand* minus *variable generation output*. An increase in NDV will have impacts on the related practices for keeping the power system balanced.

Methodology

Two different approaches were used to assess impacts of NDV and effectiveness of mitigations under the AESO's current practice framework:

- **Data Analysis** enabled us to quantify the change in NDV from 2015 to 2030 and identify potential impacts on our current operational practices.
- **Dispatch Simulation Analysis** enabled us to assess how current practices will meet reliability and market performance requirements under the forecasted NDV to 2030. Practices used in the simulation include existing dispatch rules and behavior. These rules and practices may change in the future.

The dispatch simulation analysis for real-time utilized the hourly energy market merit order (EMMO) result from the market simulation model (Aurora) and analysis performed by the Market team. Input of that model is based on the long term load and generation forecast scenarios presented in 2017 LTO. The dispatch simulation also takes the generator asset ramping characteristics to simulates real-time system and market operation practices and related performances impacts.

Findings

For the pre-real-time operation timeframe, the Market simulation results indicate that around the mid-2020s we will observe an increase in annual supply surplus hours and more generation unit cycling. Based on the reference case scenario, the surplus hours could be up to approximately 1,000 hours annually, and the size-normalized generation unit cycling for long-lead start assets could increase more than 3 times by 2030. The EAS work stream is further assessing mitigation solutions, such as changes to resource scheduling and resource commitment practices.

For the real-time operation timeframe, assuming that historically observed asset offer behaviors continue in a consistent manner[2], the dispatch simulation analysis concludes that real-time NDV reliability impacts can be mitigated. In order to achieve this, the current proactive dispatch practice will require more additional-dispatch-for-ramp (ADfR) and more aggressive[3] real-time wind power forecasting. Both of these solutions are achievable within our current market and operation practice framework. The more proactive dispatch practice will also require generator dispatch performance to be more predictable. This issue is planned to be addressed in the change and enhancement of dispatch tolerance rule[4] (Rule 203.4) that is being assessed and investigated in the EAS work stream to ensure that current practice of generator ramp rates becomes more of a requirement.

[2] The future asset offer behaviors may be different than those observed in the past.

[3] Wind power persistent ramping forecast, by assuming the wind power output in next interval continue to change as observed in previous interval.

[4] Presentation to the AESO Executives in August 2016. System Operations Impact_Exec_Aug_2016_7.pptx "Current Dispatch Delivery Rule is a Concern. Performance at current wind generation levels could NOT be achieved if generation behavior just satisfied the requirements of the dispatch delivery rule."

The more proactive dispatch practice handles the increasing NDV by more energy market dispatch up and down. This more proactive dispatch approach, particularly with the increased NDV variability, could lead to the market concerns of:

- increased energy market price volatility
- lack of aligned market incentive to those assets providing the ramping to handle the increased NDV

Market impacts and mitigation to address these concerns are being investigated in the EAS work stream.

Note that proactive dispatch is one potential solution amongst others to mitigate the increased NDV. Other potential mitigation beyond the current market and operation practice framework are also being investigated in the EAS work stream.

Studies conducted during 2016 indicated that reliability issues would develop as the system approaches 3,000 MW of variable renewable generation. As the previous study did not have coordinated market simulation work, the inputs and results were simplified based on assumptions without enough detail to enable modelling of future generation mix, outages, and commitments in the form of hourly EMMO. The lack of detail prevented further simulations that would have enabled us to quantify the impacts on each practice performance such as addition dispatch for ramp, supply surplus situations, unit cycling, etc.

Recommendations

The 2017 NDV studies confirm five of six recommendations for real-time operation that were provided in the 2016 study. The recommendations are related to implementing more proactive dispatch practice:

1. Modify and enhance AESO Rule 203.4 – *Delivery Requirements for Energy* regarding dispatch tolerance to ensure efficient, predictable and achievable generator dispatch responses and ensure current ramp rate behavior is sustained.
2. The System Controller is to assume persistent ramping in addition to persistent MW in the wind power forecasting to ensure more proactive dispatch decisions and accommodate increased variable generation.
3. Modify the dispatch response practice to increase pre-dispatch generation from the more efficient generators to minimize the potential for response delay.
4. Investigate the potential for using day-ahead variable generation forecast data and interchange forecast data for regulating reserve procurement such as moving to an hourly volume profile versus on/off peak. (Note that time-based "on/off peak" might not be relevant in the future.)
5. Evaluate a potential change to AESO Rule 304.3 – *Wind Power Ramp Up Management* to ensure effective and efficient use of the available ramping capability in energy market.

The recommendation proposed in 2016 to automatically dispatch in 5-minute intervals, is not recommended at this time. To pursue this solution is still premature given all related ongoing work in the EAS work stream.

Analyses presented in this report focus on real-time timeframe. However, it also introduces and discusses the performance metrics that lay out the technical framework for assessing additional NDV impacts at pre-real-time timeframe. The pre-real-time results and suggestions presented in this report are for purposes of context and discussion only. Please refer to the market simulation study for pre-real-time detailed results and findings.

Based on the findings presented in this report, we suggest that the Market team:

- consider whether rule changes are required for current unit commitment (self-commitment) practices, or whether the system controller can achieve the desired outcome through scheduling (central-commitment) practices
- develop supply surplus and unit cycling metrics to assess the impact of NDV on generation assets and future pre-real-time offer/commitment behavior

New or revised AESO rules may be required to ensure that assumptions used in the market studies can be reflected in actual market operation in the future.

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Abbreviations

ADfR	Addition Dispatch for Ramp
AESO	Alberta Electricity System Operator
AIES	Alberta Interconnected Electric System
AIL	Alberta Internal Load
AS	Ancillary Services
AGC	Automatic Generation Control
ATC	Available Transfer Capability
CC	Combined cycle
CDG	Constrain Down Generation
CTG / CtG	Coal To Gas conversion
CPS2	NERC Control Performance Standard 2
DDS	Dispatch Down Service
DER	Distributed Energy Resource
DR&S	Dispatchable Renewable & Storage
EAS	Energy and Ancillary Services market changes
EMMO	Energy Market Merit Order
GHG	Greenhouse Gas
HCTG	High Coal-To-Gas
MATL	Montana-Alberta Tie Line (see Path 83)
MCTG	Mid Coal-To-GAS
Mid-C Price	Mid-Columbia gas station Price
MSG	Minimum Stable Generation
MW	Megawatt
NDV	Net Demand Variability
NWP	Numerical Weather Prediction
NERC	North American Electric Reliability Corporation
RPS	Renewable energy Portfolio Standard
RR	Regulating Reserve
SC	Simple cycle
SPC	SaskPower
TMR	Transmission Must Run
TRM	Transmission Reliability Margin
TTC	Total Transfer Capability
WPM	Wind Power Management for Ramp up

1 Introduction

1.1 Background

This report documents the findings of technical studies completed in support of the Energy and Ancillary Service (EAS) Changes work stream in the AESO's Capacity Market Transition initiative[5]. The results of this work outline impacts of Net Demand Variability (NDV) as well as mitigation required under the current market and operation practice framework. The EAS covers timeframes from pre-real-time resource scheduling through real-time operational practices. The NDV studies focus on impacts and mitigation in the real-time practice timeframe. The pre-real-time (resource scheduling) timeframe is the focus of parallel and coordinated market analyses.

1.2 Net Demand Variability and Related Timeframes and Practices

The key task of electric power system is to ensure the electric power balancing between supply (generation) and demand (load) at all different timeframes from real-time operation to pre-real-time resource scheduling and longer term resource adequacy. In systems without a significant amount of variable generation, imbalances are mainly due to variability in load demand. Consequently, balancing practices focus on controlling generation output to match the load demand variability. As more and more variable generation is integrated into the system, there is an additional balancing requirement to match or offset the variable generation output variability.

The overall variability of combined load demand and variable generation is defined as NDV, where net demand is defined as load demand minus variable generation output. Practices that address the issues caused by NDV cover the timeframe from pre-real-time resource scheduling/commitment (activities that happen one hour to days ahead of issues) to real-time dispatch and deployment (which happens within minutes to about an hour of an observed issue).

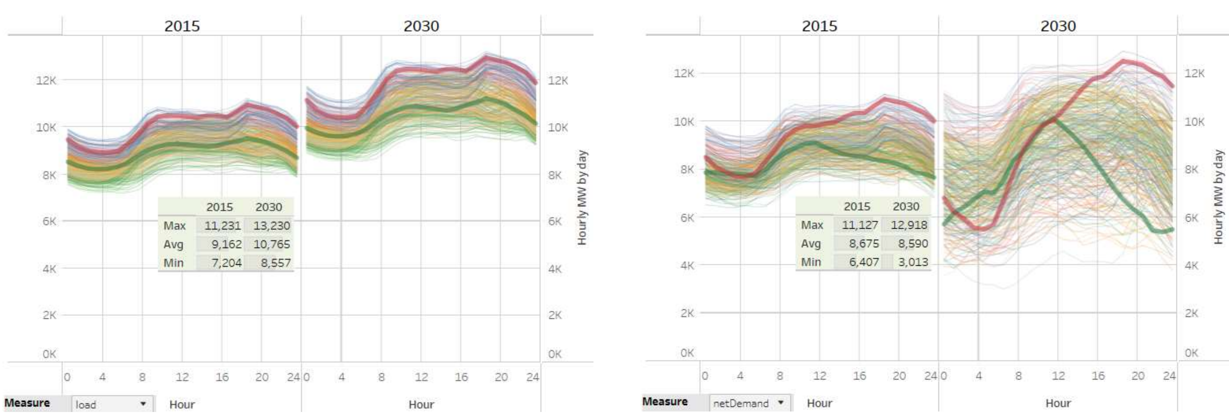


Figure 1. Daily Curves of Load Demand and Net Demand – 2015 and 2030

To illustrate the NDV concept and related impact, Figure 1 shows how the daily curves of load demand variance and the net demand variability evolve with increased variable generation. The load demand (left)

[5] In 2018, in support the Dispatchable Renewable and Storage (DR&S) initiative, this study was updated to include two additional adjusted generation scenarios with extended study period to 2040

will continue growth in the clear patterns observed in the history; while the net demand (right) will change significantly and with much less predictability. It also shows the maximum annual hourly NDV will increase from 4,720 MW (6,407 MW ≤11,127 MW) in 2015 to 9,905 MW (3,013 MW ≤ 12,918 MW) in 2030. The two thicker lines represent two days where impacts can be observed. The same two days are shown on all four charts. On the load charts on the left, the patterns are very clear; on the net-demand charts on the right, the patterns vary significantly and with the variability increases with more wind power generation.

1.3 Timeframes and Practices

This increased NDV together with its significantly changed pattern have direct and significant impacts on system and market operation practices in the timeframes from real-time operation (resource dispatch) to pre-real-time for resource scheduling/commitment, and have indirect impacts on longer term for resource adequacy (what resource to build). Figure 2 illustrates the different timeframes and related system and market practices.

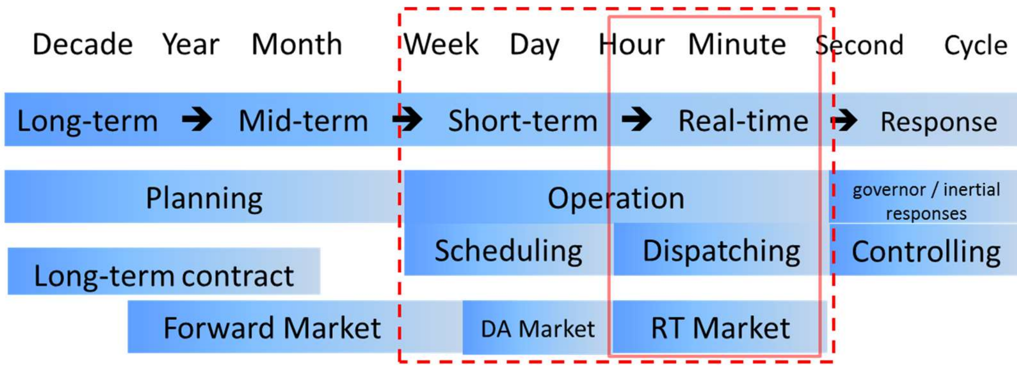


Figure 2. Relationships Among Practices and Timeframes

NOTE: This report focuses on the real-time actions and processes within the solid red line.

In other words, to handle the NDV increase and the related unpredictability, we need to increase system ramping capability and flexibility. Accomplishing this objective involves coordinating a number of different actions and practices across a number of different timeframes, including:

- building an adequate, suitable and reliable resource mix over the long-term
- scheduling adequate resources pre-real-time operation (i.e., in anticipation of what operational challenges will be encountered)
- dispatching and deploying resources during real-time operation

1.4 Purpose of this Report

The NDV concept and related impacts on system and market operation are relatively new and have been relatively less well accepted in the industry than more traditional concepts. This report explains how the AESO is investigating NDV in the context of our existing market and operational framework, and focuses on studies conducted to improve operational practices.

Specifically, the report outlines:

- the technical analysis framework and methodology we used to assess and quantify NDV and its impacts
- assumptions used in the analysis and related limitations
- key findings, recommendations and conclusions regarding NDV impacts for system and market operation (with a focus on dispatch simulation analysis; no results are presented from the market studies)
- any changes to our recommendations compared with previous analysis
- potential mitigation measures with the objective of supporting the EAS work stream

2 Methodology and Analysis Framework

The key concern related to balancing power in a system with increasing variable generation is that the generation supply system and related practice might not have enough capability (ramping and flexibility) to handle the increased NDV. To address this concern, we need to achieve a better understanding of the system ramping and flexibility requirements, then we can evaluate system and market operation practices used to commit, dispatch and deploy generation to match the required system ramping and flexible capability.

Two different approaches were used to assess impacts of NDV and effectiveness of mitigation under the AESO's current practice framework:

- **Data Analysis** enabled us to quantify the change in NDV from 2015 to 2030 and identify potential impacts on our current operational practices.
- **Dispatch Simulation Analysis** enabled us to assess how current practices will meet reliability and market performance requirements under the forecasted NDV to 2030. Practices used in the simulation include existing dispatch rules and behavior. These rules and practices may change in the future.

2.1 Data Analysis to Understand the Potential Impacts of NDV

As discussed in the previous section, NDV is the aggregated variability of load demand and variable generation output, and its impacts are at different timeframes from real-time operation to pre-real-time resource scheduling. To understand NDV from a different prospective, in Table 1, we define and propose different data analysis metrics to use data analysis techniques to illustrate the NDV in quantitative manner.

Table 1. General Data Analysis Metrics to Quantify NDV

Data metric	Measures	Timeframes	Definition / Notes
Daily Range	Load, net demand	Daily	Daily variance between min. and max. hourly values.
Day-to-Day Change	Range of load and net demand	Day to day	Day to day variance of daily ranges. This metric is used to understand the difference between 2 adjacent days.
Weekly Range	Load, net demand	Weekly	Weekly variance between min. and max. hourly values.
10-minute variance	Wind[7], net demand	10 minutes	Change over 10 minutes
20-minute variance	Wind, net demand	20 minutes	Change over 20 minutes
60-minute variance	Wind, net demand	1 hour	Change over 60 minutes

[7] The analysis focuses on wind power only as the solar power capacity is much less (500 MW in 2030), the impact's by solar is small as indicated in the sensitivity analysis of additional 500 MW of solar power in Section 3.1.4.

Data metric	Measures	Timeframes	Definition / Notes
Ramp Event	Wind, load, net demand	Various	A change period to meet all of following conditions: • 1 MW per minute • 0.5 MW per minute for pause period (10 minutes), otherwise event stop • event MW change > 50 MW • event ramp rate > 100 MW/hour

The top three metrics are for the pre-real-time timeframe, and the next three are for the real-time timeframe. After calculating the above metrics, we examined the results of each metric in conjunction with the practices that govern each one to determine their respective impacts on system and market operation.

2.2 Dispatch Simulation Analysis to Assess Existing Practices

As shown above, increases in NDV would be managed in different timeframes by system and market operation practices, and its impacts would be reflected in the identified metrics. The next step is to use those metrics in studies that simulate human decisions and judgements based on rules, practices and related processes so we can determine practice effectiveness.

Power System and Market Operation Practices

Both the power system operation and market operation impacts and practices need to be modelled in the simulation analysis. The green shaded practices in Table 2 relate to the market operation practices which coincide with the long term to pre-real-time periods. The blue shaded practices in Table 2 relate to power system dispatch practices that coincide with the real-time period. The market simulation was performed by the Market Team while the dispatch simulation was performed by the Operations Team. These analyses were performed in a coordinated manner between the teams.

Table 2. Practices related to NDV Management –Modelled in the Simulation Analysis

Practice	Timeframe	Note
Long-term load forecast	LT: multiple years ahead	Inputs include, annual min./avg./max. load from the 2017 LTO, applied on a detailed historical profile.
Generation development	LT: multiple years ahead	As input from LTO to meet supply adequacy / RPS
Maintenance and outage	MT: weeks to months ahead	Based on historical analysis
Pre-real-time forecast	ST: hours to day ahead	Based on forecast simulation
AGC/Regulation Reserve Procurement	ST: day ahead	Based on historical volume
Resource Schedule/Commitment	ST (pre-RT): hours to days	Market economic algorithm
Energy Market Offer	ST (pre-RT): hours to day	Based on historical analysis
Interchange scheduling	ST (pre-RT): hours ahead	Mid-C pricing arbitrage algorithm
Short-term load forecast	RT: minutes to sub-hour	Similar-day forecast algorithm

Practice	Timeframe	Note
Short-term variable generation forecast	RT: minutes to sub-hour	Persistent level / ramp for wind generation; similar day for solar
Energy Market Dispatch, including dispatch-for-ramp	RT: minutes to sub-hour	Block-by-block EMMO modelling
Response to dispatch	RT: minutes to sub-hour	Response delay and ramp rate based on historical analysis
Wind Power Ramp-Up Management (WPM)	RT: minutes to sub-hour	Based on rule 304.3 of Wind Power Ramp Up Management
AGC/Regulation Reserve Dispatch and Response	RT: up to 10 minutes	Based on technical requirement of 10% per minute

NOTES:

LT = long term (years); MT = medium term (weeks to months); ST = short term (hours to days); RT = real time (minutes to 1 hour)

AGC = automatic generation control; LTO = AESO's Long-term Outlook

Based on the different timeframes of these practices, we can separate them into two groups: real-time and non-real-time (from pre-real-time to beyond). Two different types of simulation analysis were used to simulate and evaluate these practices in a coordinated manner, just as they are coordinated in real world situations.

Simulation Models – Market and Dispatch Simulations

The *market simulation* captures what happens during the timeframes of pre-real-time and beyond. It covers all the practices that are shaded green in the table, including long-term load forecast, generation scenarios, unit outage, unit commitment, market offer and interchange scheduling. This simulation is based on AESO's market simulation tool (Aurora model), and uses hourly resolution.

The *dispatch simulation* captures what happens during the real-time timeframe. It covers all the practices that are shaded blue in the table, including short-term forecast of load and variable-generation, energy market dispatch (including dispatch-for-ramp), response to dispatch, wind power management and AGC dispatch and response. This simulation is based on the AESO's operation dispatch simulation tool (built in house), and models the above practices using 1-minute resolution.

The two simulations were coordinated through data exchange and consistency in modelling inputs and assumptions:

- They use the same load profile, but with different resolution.
- They use the same variable generation profile, but with different resolution.
- They use the same generation development profile for each generation scenario.
- The dispatch simulation model takes the following output from the market simulation as its input:
    - Hourly energy market merit order (EMMO) data: The EMMO result is for every hour of all future years up to 2030 and has block-by-block details for each hour. The EMMO data reflects the market simulation results of generation development, forced and planned outages, generation commitment and energy market offer.
    - Hourly interchange scheduling results: These results include DC interconnection with SaskPower (AB-SK Intertie) and a combined AC interconnection (AB-BC Intertie and MATL).

Simulation Performance Metrics

In order to evaluate how effective the simulated practices are at managing the simulated NDV into the future, performance metrics were defined to quantify the overall practice performance effectiveness. In Table 3 below, the first 3 simulation metrics (green-shaded) are market simulation metrics which focus on the practice performance in timeframes from 1 hour and beyond. They can be calculated from the result of hourly market simulation analysis. The remaining 5 simulation metrics (blue-shaded) are dispatch simulation metrics which focus on the practice performance in real-time from 1 minute to sub-hour.

Table 3. Simulation Metrics to Quantify Practice Performance

Simulation Metric	Related Practice	Description
Supply flexibility characteristics	• Generation mix	The average overall $0-offer ratio, MSG ratio, Total flexible ramp-rate for up and down for non-$0-offer blocks
Supply surplus/shortfall situations	• Generation mix • Pre-real-time forecast • Unit commitment • Interchange scheduling	To Identify impact of unit commitment on supply surplus and shortfall situations
Generation cycling		Quantify cycling of different types of thermal generation units (CC, SC, CTG and coal for some years)
Control Performance Standard 2 [8](CPS2) as defined in ARS BAL-001-AB-0a	• AGC procurement • Market offer • Real-time forecast • Energy market dispatch • Dispatch response • AGC dispatch • WPM	To measure the 10-minute ACE (Area Control Error – Balancing authority MW imbalance) performance
System Operating Limit (SOL) violation, as defined in ARS TOP-007-AB-0		To measure the 30 minute period ACE performance when interchange schedule set close to ATC (with the risk of SOL violation as defined in TOP-007-AB-0) Both event count and magnitude
Big ACE event This is the defined metric for analysis purposes.		To measure the 30 minute period ACE performance for the period without SOL violation risk, for the impact on interties and neighboring systems
Dispatch mileage This is to measure the additional dispatch for ramp (ADfR) in both relative ratio and MW up and down volumes		Amount of additional energy market dispatch needed to achieve required ramp rate
Variable energy spill due to power management tool activations, as described in AESO Rule 304.3		Potential spill of variable energy due to using the AESO's power management tool,

[8] The NERC-001-2 requires replacing CPS2 with RBC/BAAL. AESO is in the process to implement BAAL. For analysis and benchmarking purpose, CPS2 is a good metric to use

Simulation Metric	Related Practice	Description

NOTES:

AGC = automatic generation control; ATC = available transfer capability

CC = combined cycle; CTG = coal-to-gas conversion; SC = simple cycle

ADfR = additional dispatch for ramp; ARS = Alberta Reliability Standards; CPS2 = Control Performance Standard 2

ACE = area control error; MSG = minimum stable generation; SOL = system operating limit

Interchange SOL Event and Big-ACE Event

The SOL event and Big-ACE event are both interchange imbalance event with ACE bigger that TRM (65MW) for longer than 30-minute period. In the case of SOL event, the interchange is scheduled at or close to ATC limit, the event MW imbalance could result into over ATC more than TRM for longer than 30-minute period, as the right event shown in Figure xx. In the case of big-ACE event, there is enough room between interchange schedule and ATC, the event MW imbalance cannot result into over ATC more than TRM for longer than 30-minute period, as the left event shown in Figure 3.

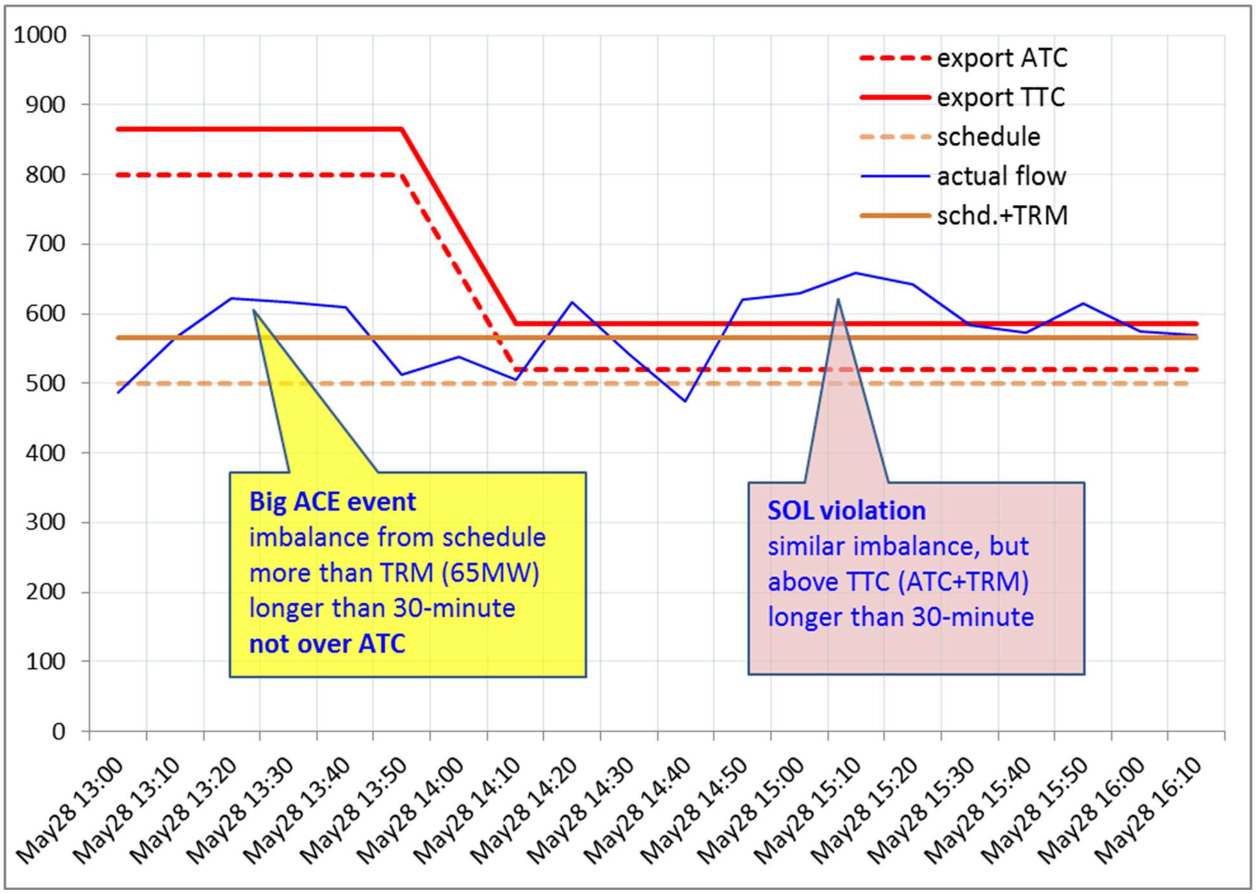


Figure 3. Illustration of SOL event and Big-ACE event

The Concept of Additional Dispatch for Ramp

Most simulation metrics in Table 3 are either straightforward or described clearly in related AESO rule or standard. However, additional dispatch for ramp (ADfR) is a relatively new concept. Figure 4, shows an example representing one hour of the Energy Market Merit Order (EMMO). Each slice in the EMMO represents one offer block in the energy market for that hour. The slices are stacked in the order of offer price starting at $0. All the red shaded blocks are $0-offers; the blue shaded blocks are non-$0-offers. The $0-offers tend to be less flexible options such as cogeneration or minimal stable generation (MSG) for thermal units, whereas the non-$0 offers represent the EMMO flexibility[9] for that hour, as these blocks are more dispatchable up and down.

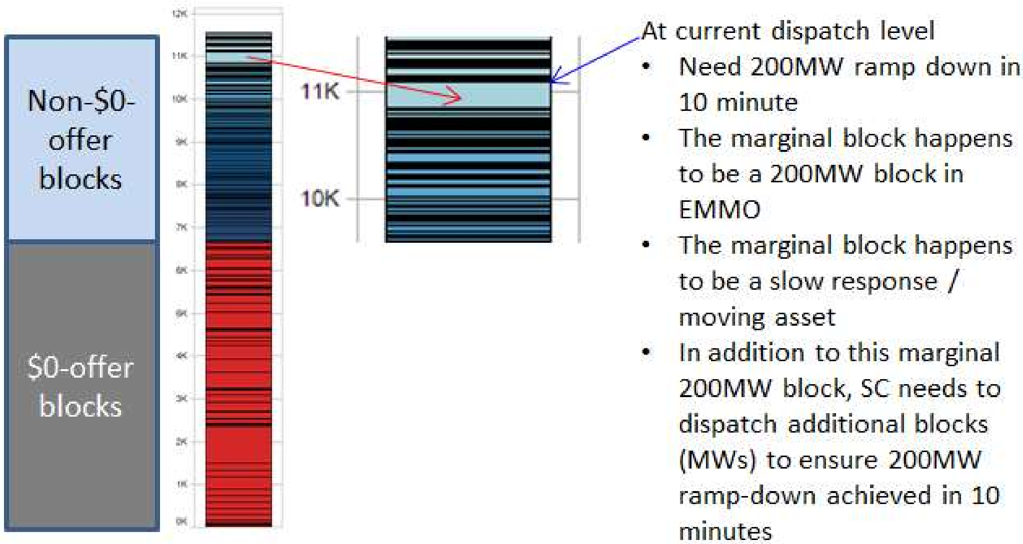


Figure 4. Illustration of ADfR

The text in figure 4 illustrates why the additional-dispatch-for-ramp is required. In this example, there is a need for 200 MW ramp down within 10 minutes. The marginal offer block asset has a slow response ramp down capability and therefore the System Controller has to dispatch an additional offer blocks in order to achieve the 200 MW ramp down within 10 minutes. These additional offer block MW are what is referred to as ADfR.

The additional dispatch for ramp may be required to address both ramping up or ramping down situations. The additional MW volume and ramping due to the additional-dispatch-for-ramp will have an impact on the next real-time dispatch decision. Assuming both the net demand and the dispatched assets' responses are as expected for the dispatch target period, after the expected target time, the dispatched assets will continue to ramp until they reach their dispatched level. The System Controller needs to take this continued ramping into account in the coming dispatch decision(s). In the case where there is no increase in net demand forecasted in coming target period, the System Controller will need to make an opposite dispatch to offset the additional MW volume.

[9] In addition, there is some flexibility inside $0 blocks if an asset $0 block is bigger than its minimum stable generation (MSG). These additional MWs can be dispatched down, on a pro-rata basis, during supply surplus situation, as described in AESO Rule 202.5.

To quantify this additional dispatch for ramp, let us start with the analysis of dispatch behaviors and how those behaviours relate to NDV in the past. Figure 5 shows the actual 2015 10-minute NDV and the correspondent 10-minute overall dispatch level change (named as Overall Dispatch Variance, or ODV). In the situation of a perfect forecast and perfect ramping, the system controller can make the perfect dispatch exactly to meet the NDV, and if the dispatched assets can ramp perfectly, than the ODV can be identical to the NDV. The differences between the NDV and ODV reflect the additional amount of MW dispatch to compensate the lack of ramp or the under forecast of ramp in the previous dispatch action, or the total ADfR.

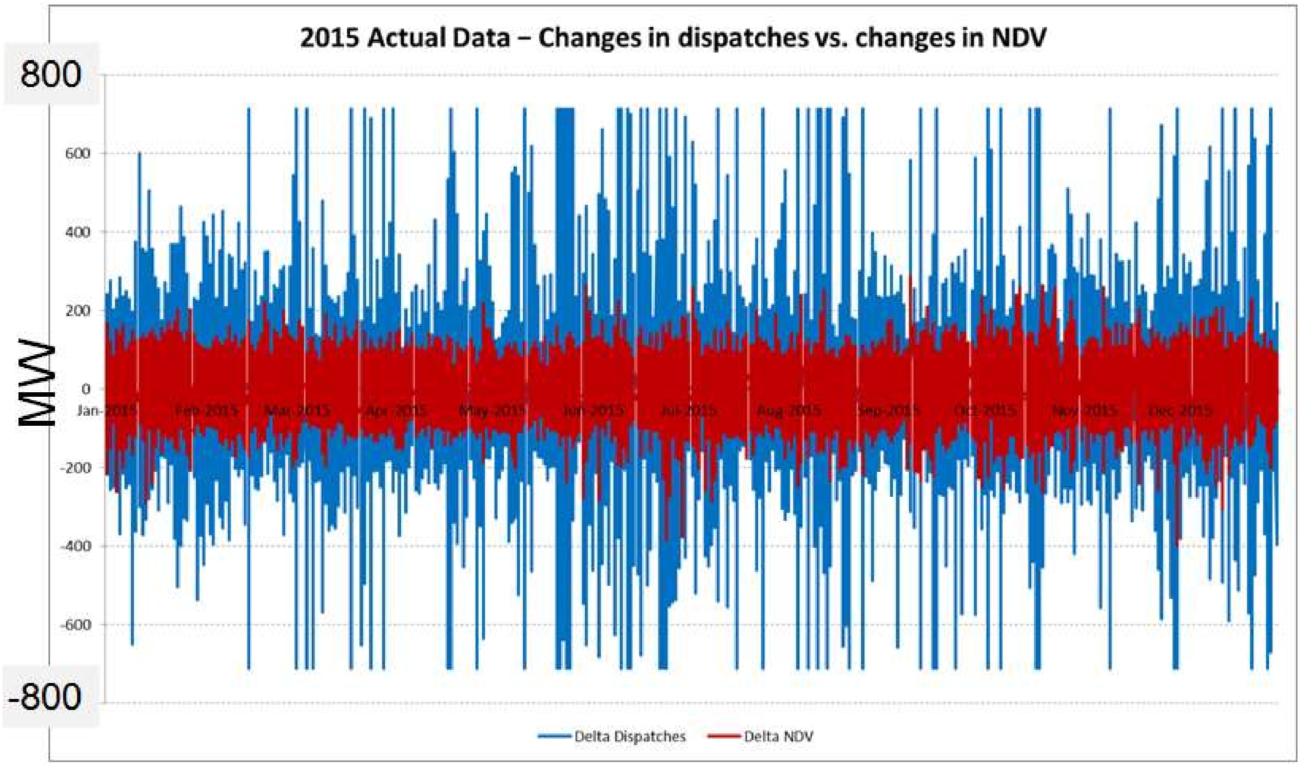


Figure 5. 10-minute NDV and 10-minute ODV – 2015

So, the 10-minute ODV reflects the overall dispatch requirement to meet both the change in net demand (NDV) and additional dispatch required to balance insufficient ramping and related forecast error. As such, it can be used to quantify the ADfR. Following the logic of this discussion, we can calculate the standard deviation of this ODV for the whole year. The result represents a certain average of the annual 10-minute ODV. We can use this calculation as a simulation metric to quantify ADfR. In addition, we can calculate the standard deviation for the 10-minute NDV, and calculate the ratio of the two standard deviations. A large ratio indicates a greater requirement for ADfR.

The concept of Dispatch Mileage or Ramping Mileage

Total dispatch mileage (sum of the magnitude of all dispatch level changes) is another metric we can use to measure ADfR without using the standard deviation of 10-minute NDV and ODV.

A simple way to think of dispatch mileage is to compare it with planning a hiking trip. You want to know the trail distance, as well as the elevation gain and loss that will significantly impact your effort estimation (see Figure 6).

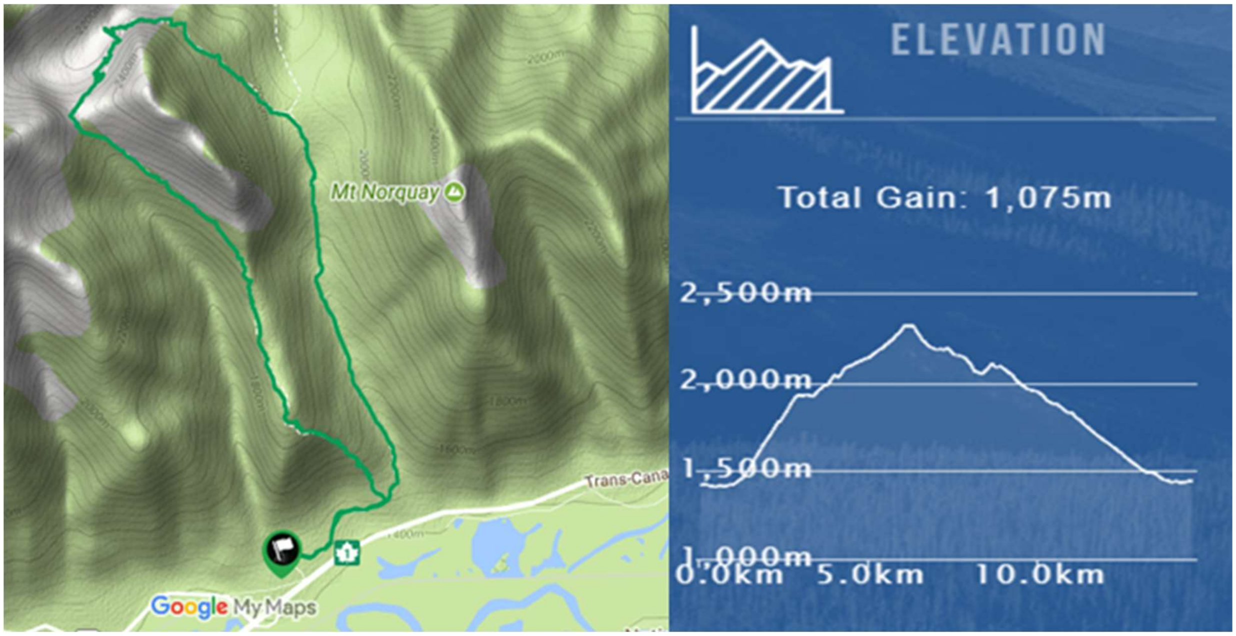


Figure 6. Analogy for Dispatch Mileage

Trail information of "Edith and Cory Pass Circuit"; Source: https://10hikes.com/

In this analogy:

- the generator is like the hiker
- carrying a stable load is like hiking on a flat trail
- ramping up and down is like hiking up and down
- dispatch up and down is like elevation gain and loss that can be measured in terms of elevation (mileage)

From a system perspective, the System Controller needs to dispatch the system up and down to balance NDV. The effort required to dispatch up and down can be measured as dispatch mileage.

From a generator perspective, effort is expended each time it is dispatched up and down, and that effort can be measured as dispatched mileage, or ramping mileage.

Using dispatch mileage metric to quantify the required ramping effort (such as ADfR) is more straightforward than using the statistics term of standard deviation. The "additional dispatch" is representing by the difference of dispatch mileage (MW up and down).

The dispatch mileage metric can be calculated as different aggregate levels from any individual asset, to aggregation of any type of generation, and to the aggregation of system overall. These different aggregations can be used to quantify the required ramping for each asset, each type of asset and system aggregation. The difference between the system overall dispatch mileage aggregation and the sum of all individual asset dispatch mileage indicates the system overall ramp cancelling effect among different assets (dispatch an asset to ramp up to offset another asset's ramp down).

The dispatch mileage metric can also be used to quantify the ramp performance details of individual asset or assets' aggregation (e.g. by technology type). Figure 7 shows the annul 10-minute dispatch level of an asset. The asset's dispatch level change reflects its dispatch mileage that can be further separated into 2 parts: the part above MSG and the part below MSG. the part below MSG is due to the asset on-off cycling and can be quantified in the on-off cycling metric. In the dispatch mileage metric calculation, we could include or exclude the part of dispatch mileage below MSG.

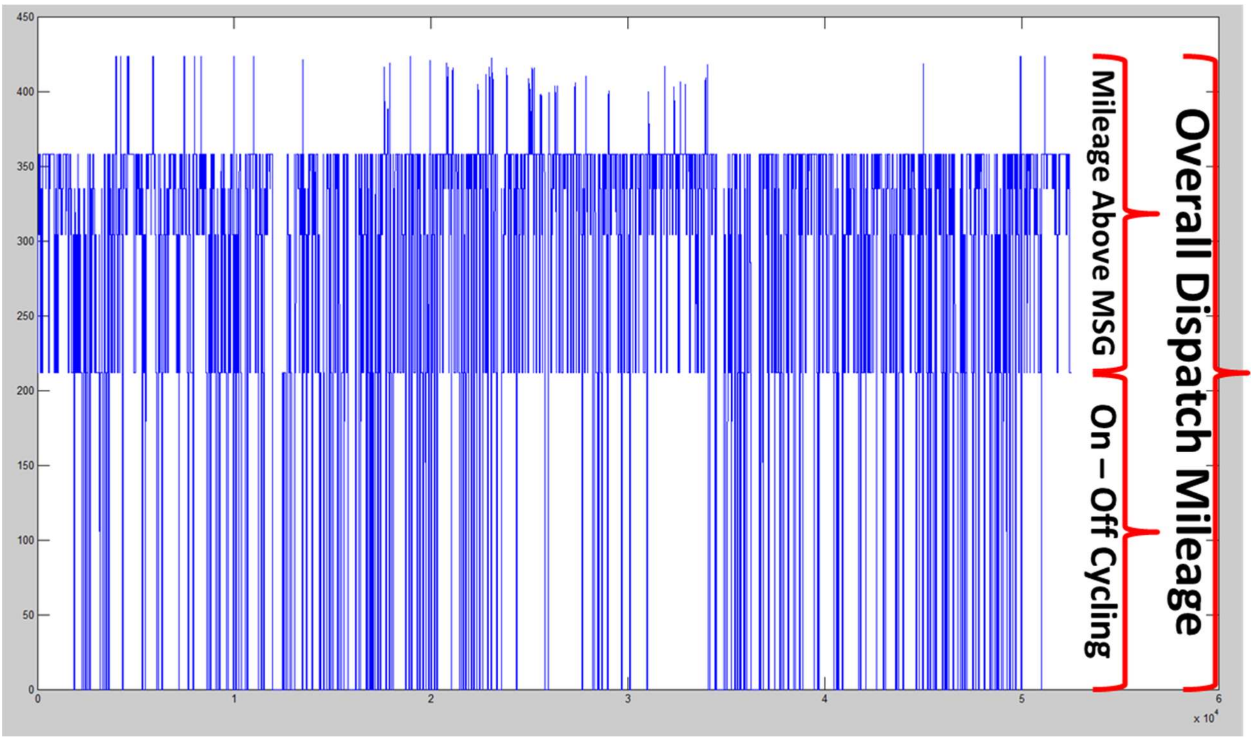


Figure 7. An Asset Annual 10-minute Dispatch Level Simulation Result Example

Another dispatch mileage performance metric is the "ramp mileage". In the situation of dispatch-for-ramp, some slow response asset might not able to finish the required dispatch level change before next dispatch level change instruction. This "ramp mileage" is the metric to how much the required dispatch mileage is achieved (ramped or performed).

Sensitivity Pattern Analysis Approach for Dispatch Simulations

Sensitivity pattern analysis makes it possible to identify and understand any pattern or trend by doing a series of different degrees of sensitivities. For example, a sensitivity analysis on different time could be done on two years, 2018 and 2030, while sensitivity pattern analysis might cover every year between 2018 and 2030. The latter case will enable us to achieve a better understanding of the trends and would not miss the potential impact due to non-linear impact pattern by certain factor and avoid the randomness impacts arising from a smaller dataset. The sensitivity pattern analysis approach can be used to extend the sensitivity analysis for any individual factor to get better understanding based on greater detail/more granularity.

As sensitivity pattern analysis will involve significant more simulations and results due to the significant more assumption sensitivity combinations. There are needs for more efficient and effective approach for simulation, analysis and result communication to handle the increase amount of simulation and post analysis work. For the simulation work, we implemented several process automation techniques for data input, scenario configuration, simulation running and result data output. For post analysis work, we adopt database and standardized & interactive dashboard techniques to enable more efficient semi-automatic post analysis; Figure 8 shows an example of such interactive standard analysis dashboard.

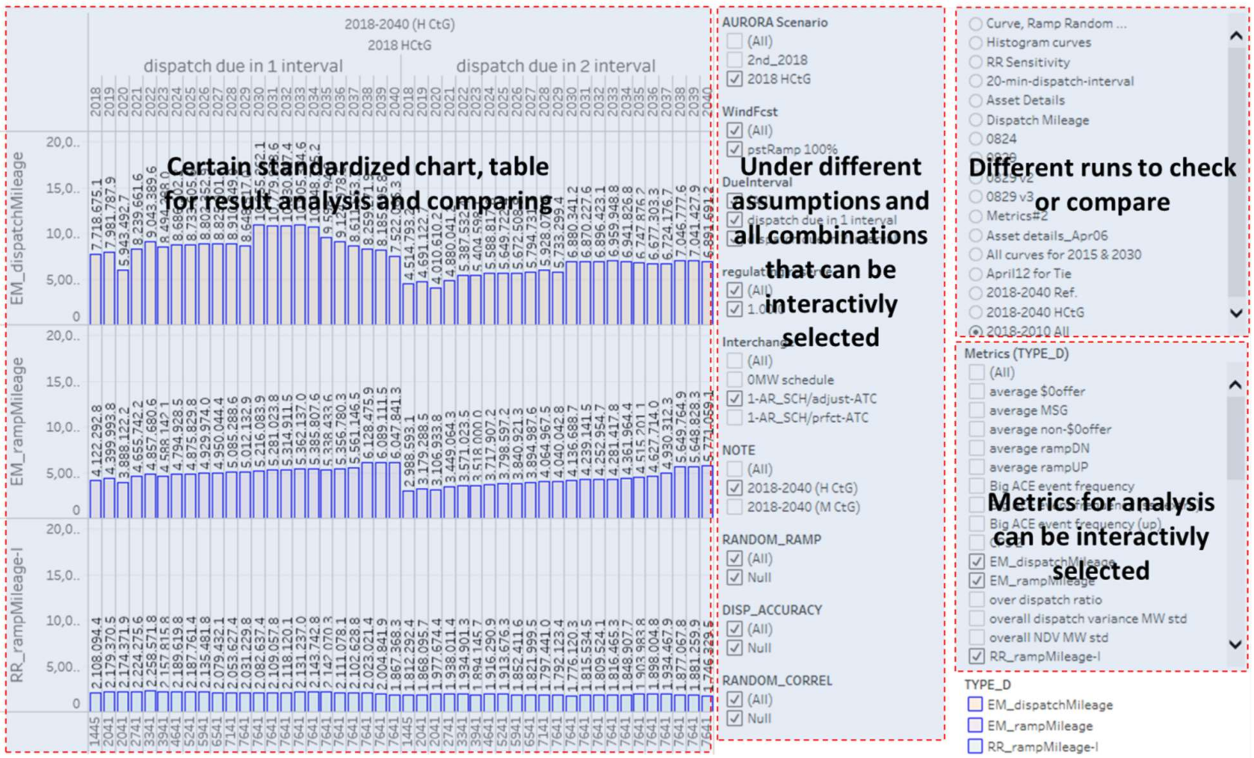


Figure 8. Interactive Analysis Dashboard Example

For result communication, we use the "parallel coordinates" (a data visualization technique) and D3.js (a JavaScript library for manipulating documents based on data) to present and visualize the results that involve complex interrelations and independence of different impacts and different assumptions, in transparent and interactive manner. The Figure 9 shows how the "parallel coordinates" can coordinate the discussion of many metrics, assumptions and interrelations on one dashboard. The interactive feature makes it a powerful way to be able to focus on specific aspect without losing the whole picture and other details.

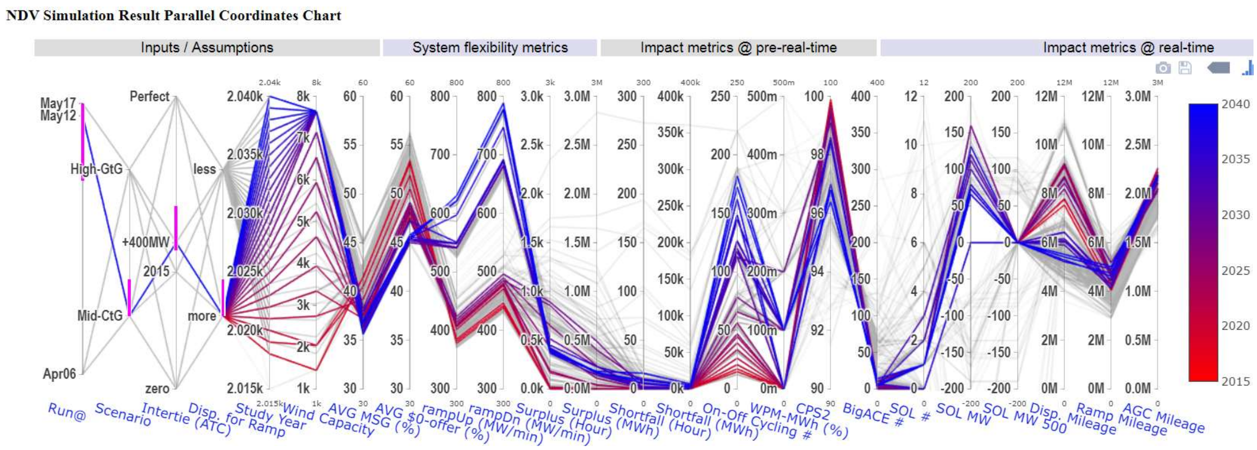


Figure 9. Interactive "Parallel Coodinates" Analysis Dashboard

Key Sensitivity Analysis Was Performed: Dispatch Aggressiveness

In Alberta, the real-time energy market dispatch is performed by a System Controller through dispatch orders (a manual operation). Continuous real-time System Controller dispatch decisions maintain the balance between changing supply and changing demand. Every minute, the System Controller faces uncertainty as to what the next minute, 10 minutes, 20 minutes of net demand will be and how to match the demand with dispatchable resources. The accuracy of real-time forecasts is not perfect; therefore, issues can arise because of uncertainty or forecast error.

The System Controller can handle uncertainty through a range of less proactive to more proactive dispatch behavior. In the more proactive approach, the dispatch decision is based on an expectation that a severe result will occur if no action is taken. Therefore, proactive dispatch action is taken to avoid the expected severe result. Due to the uncertainty, the actual situation can be less severe than expected. In that case, proactive behaviour will result in unnecessary dispatch or over-dispatch.

System Controllers may have different styles and experience, and may have different assessment and risk tolerance when facing uncertainty in different real-time situations. Dispatch practice behavior can vary among System Controllers and across different situations. As future situations will become more challenging with increasing variability and uncertainty, determining the appropriate degree of behavior for different situations will become more critical.

We studied various degrees of proactive dispatch practice by assuming that two related considerations affect real-time dispatch decisions:

- **How persistent will the forecast ramp be in the next period?** Forecast expectations regarding wind power generation (the main uncertainty of NDV):
  - Persistent level forecast: less proactive (blue line in left chart in Figure 10.)
  - Persistent ramping forecast: more proactive (red line in left chart in Figure 10.)
  - Equally weighted persistent level and persistent ramping forecasts: mid-ground
- **How quickly does the System Controller want to achieve the forecasted dispatch level?** The target due-period for the system dispatch response (i.e., the time within which system

dispatch response) should match the forecasted change. The shorter the target due-period the more proactive the System Controller will be in their behaviour, as illustrated in the right chart in Figure 10.

- Target is at the end of the current dispatch interval: more proactive
- Target is at the end of the next dispatch interval: less proactive
- Equally weighted between the above two targets: mid-ground

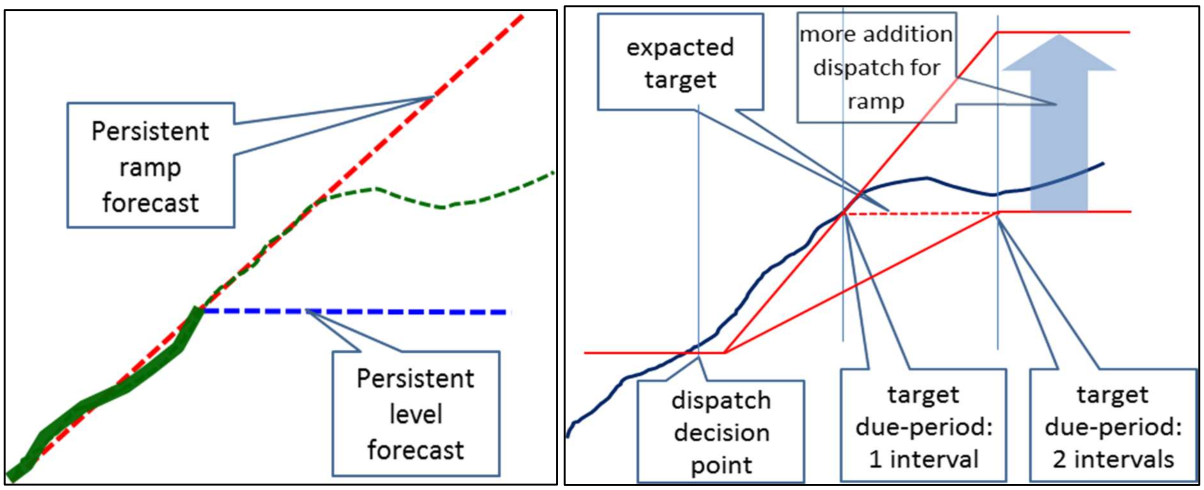


Figure 10. Concepts of Wind Power Persistent Ramp/Level Forecast and Dispatch Target Due-Period

Together, there are nine (3 x 3) possible combinations to represent different degrees of proactive dispatch action under the generation forecast and target due-period assumptions presented above. Among these, the most proactive action is "persistent ramping forecast + target at current interval end" and the least proactive action is "persistent level forecast + target at next interval end".

The dispatch interval is another factor that affects dispatch behavior. In current AESO dispatch practice there is no standard frequency for a System Controller to dispatch the market. That decision is left to individual System Controller's judgement and risk tolerance. There are two general considerations:

1. Meet the required performance criteria.
2. Avoid unnecessary dispatch if there is no performance concern.

Experience and judgement based dispatch behavior is difficult to model and simulate. As such, a configurable fixed time dispatch decision interval (10, 15 or 20 minutes) was implemented in the simulation model. Based on the analysis of historical dispatch data analysis, a 10-minute decision interval was used in this study.

2.3 Analysis Inputs and Related Assumptions

2.3.1 Reference Case from the 2017 LTO

The annual forecasts of load and generation (including renewable) scenarios are based on the results of the 2017 LTO.

Annual Load Forecast

Table 4 lists the long-term load forecast numbers from the 2017 LTO.

Table 4. Long-term Load Forecast – 2017 LTO

Calendar Year	Sum of AIL (MWh)	Max of AIL (MW)	Min of AIL (MW)	Average of AIL (MW)
2017	82,606,760	11,539	7,444	9,430
2018	83,884,418	11,737	7,580	9,576
2019	85,466,975	11,939	7,734	9,757
2020	86,535,549	12,018	7,824	9,851
2021	87,295,111	12,144	7,922	9,965
2022	87,872,228	12,260	8,008	10,031
2023	88,252,729	12,321	8,041	10,075
2024	89,223,343	12,428	8,099	10,157
2025	89,938,560	12,557	8,175	10,267
2026	90,677,147	12,678	8,247	10,351
2027	91,682,049	12,814	8,324	10,466
2028	92,707,672	12,945	8,398	10,554
2029	93,388,692	13,089	8,478	10,661
2030	94,304,478	13,231	8,557	10,765

Source: Load Forecast Team

Annual Generation Scenarios – Reference Scenario

Figure summarizes the generation capacity forecast for the Reference Case scenario from 2017 LTO, and

Table 5 shows the annual generation capacity forecast for variable renewable generation including both wind power and solar power.

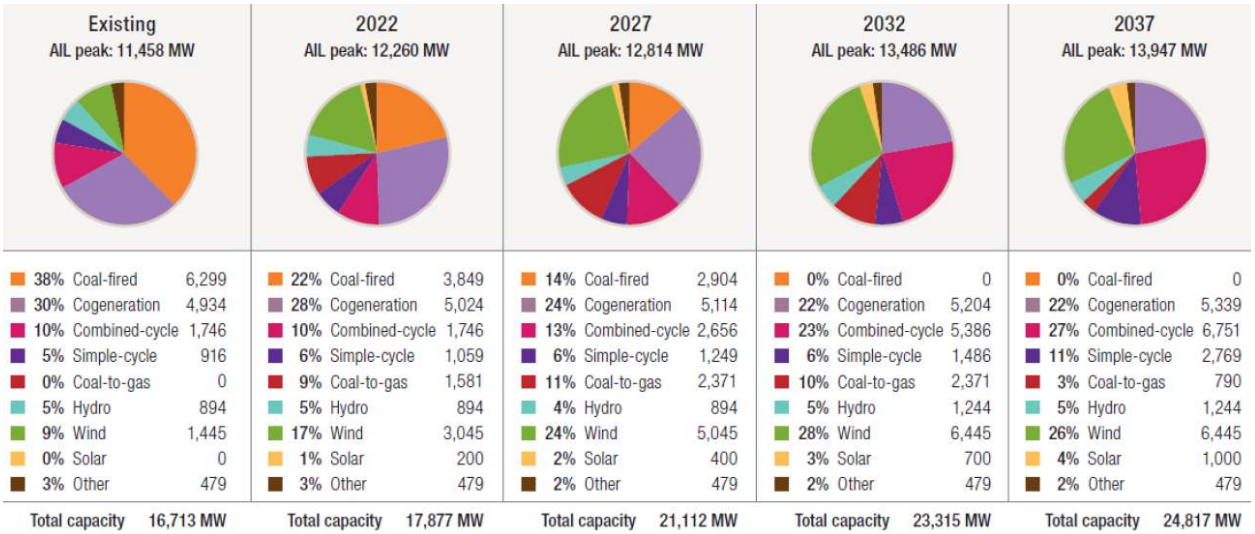


Figure 11. Long-term Load Forecast – 2017 LTO

Source: slides of 2017 LTO Information Session

Table 5. Long-term Annual Generation Capacity Forecast with variable Generation Capacity (MW)

Year	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Wind	1,445	1,445	1,845	2,245	2,645	3,045	3,445	3,845	4,245	4,645	5,045	5,445	5,945	6,445
Solar	0	0	100	100	100	200	200	200	300	300	400	400	500	500

Source: Generation Forecast Team

Generation Scenarios for Potential Sensitivity and Mitigation Analysis

Depending on the results from the Reference Case scenario studies, other 2017 LTO scenarios could be analyzed to further evaluate the impacts' sensitivity and potential mitigation solutions.

Table 6 lists other 2017 LTO scenarios, which may lead to further sensitivity and mitigation analysis.

Table 6. List of Generation Scenarios for Potential Sensitivity and Impact Analysis

Name	Type	Details
Reference case *	Primary / base case	This will be our primary (base) scenario, Based on this scenario
High Coal to Gas Conversion *	Sensitivity case	Show impact on ramping capability
Low Coal to Gas Conversion *	Sensitivity case	Show impact on ramping capability
High CoGen *	Sensitivity case	This scenario may show decreases to flexibility on the system
DER	Sensitivity case	We can assess the impact of distribution vs. transmission renewables on the basis of: location, visibility and controllability
Coal to Wind Optimization	Mitigation case	This scenario can be used to assess how the timing of any issues that occur in Scenario 1 could be mitigated with different timings of the addition of renewables
Hydro Rich *	Mitigation case	Show impact on ramping capability
Western Alliance (Intertie) *	Mitigation case	Intertie restoration will be considered in the base analysis. This scenario would consider an additional intertie
High Storage	Mitigation case	Storage impacts
DR/EE	Mitigation case	Demand response and energy efficiency impacts

In 2018, in supporting the DR&S work, we included two additional adjust scenarios with study period extended to 2040. One scenario is the adjusted reference scenario based on the original reference scenario, adjusted with more (~1200MW) wind power generation; the other is the adjusted high coal-to-gas scenario. The generation installed capacities of these two scenarios are summarized in table 7.

Table 7. List of Generation Scenarios for Potential Sensitivity and Impact Analysis

Scenarios	Reference (MCtG)		High CtG (HCtG)	
Year	2030	2040	2030	2040
COAL	0	0	0	0
Cogeneration	5,108	5,243	5,108	5,243
Combined-cycle	5,004	6,455	3190	8994
Simple-cycle	2,072	3,493	915	915
Coal-to-gas	2,371		5,267	
Hydro	734	734	734	734
Wind	7,641	7,641	7,641	7,641
Solar	500	500	500	500
Other	388	388	388	388

Figure 12 shows the key difference of generaion capacity betwee new MCtG (left) and new HGtG (right), also with the yellow shades to highlight the key difference from previous MCtG (2018-2030 only).The new HCtG scenario has more CtG and less SC and CC installed capacity from 2028 to 2030. All CtG dicommision are from 2035 to 2040 and is replaced by more CC generation.

The assumptions of generation characteristics such as ramp rate, MSG, cycling cost and related parameters for unit commission algorism are also updated based on most updated information and research by market simulation team.

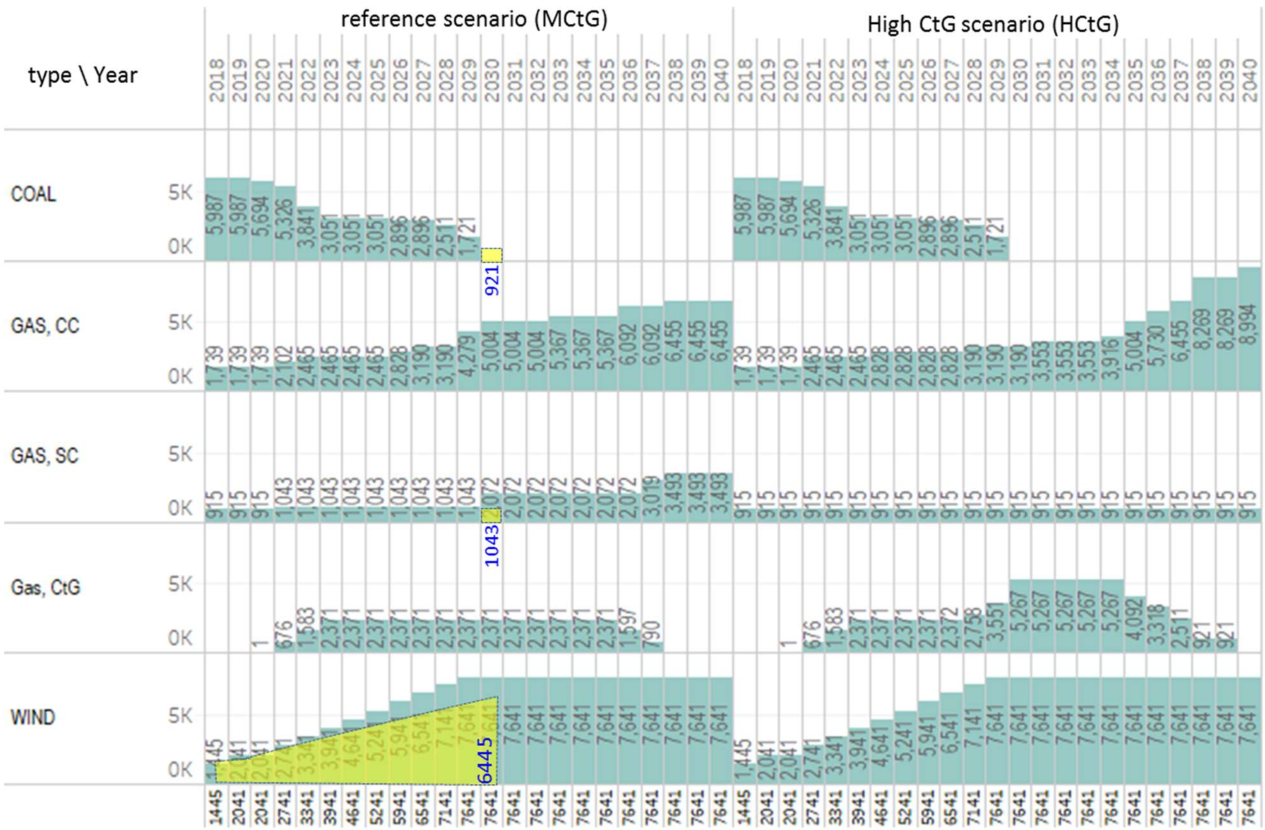


Figure 12. Difference of Generation Installation Capacity by year amond MCtG and HCtG

2.3.2 Annual Load Profile – Scaled to Provide Hourly/Minute Profile

In addition to the annual profile from the 2017 LTO, hourly and minute-based load profiles were required to perform more detailed market simulation and minute-by-minute system dispatch simulation. In order to ensure the load profiles were consistent between the two simulations (market and dispatch), the annual load profile was scaled to reasonably reflect the load variances between seasons, months, weeks, days, hours and minutes. The method used to scale the annual load profile was as follows:

- Create a historical based hourly/minute load profile using 3 years (2014 to 2016) of actual hourly/minute profile data, to better reflect actual load variances and patterns.
- Scale the historical based load profile to meet forecasted annual load profile levels, each year, based on the method illustrated below in Figure .

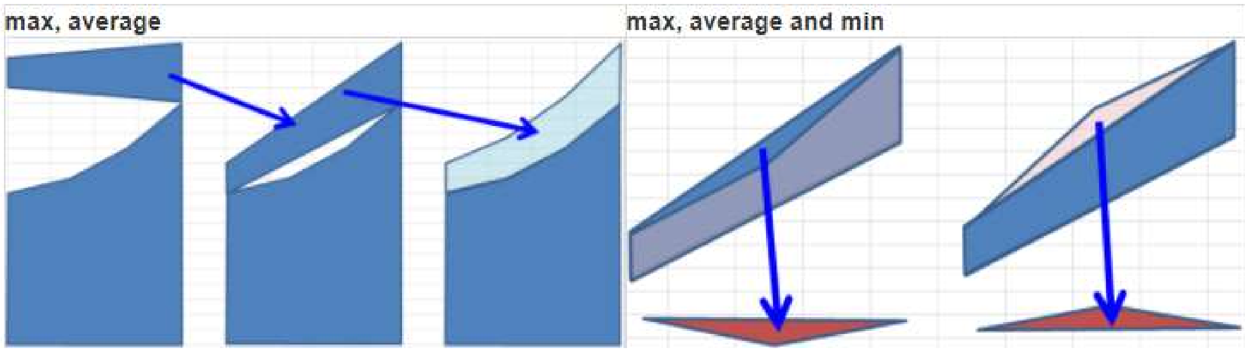


Figure 13. Load Profile Adjustment based on a Load Duration Curve

Figure illustrates the steps used to adjust a percentile-based load curve (load duration curve):

1. Start with the historical load-based profile. Add a keystone shape with the one side for the maximum load equal to the forecasted increase in maximum load, and the other side for the forecasted increase in minimum load in the next year.
2. The combined new load curve, represented by the third shape in Figure 13, is adjusted to meet the forecasted annual minimum and maximum load in the next year. The resulting average load could be mathematically higher or lower than the forecasted average load in the next year.
3. Apply a triangle shape on top of the third shape in Figure 13 to adjust the load curve so that the forecasted average load is now also met. The free vertex is set on the triangle median line.
4. The new combined shape (the keystone plus the triangle) represents the required scaled load profile to meet the forecasted maximum/minimum/average load levels.

2.3.3 Wind Generation Profile – Scaled to Hourly/Minute Profile

In addition to a scaled load profile, we need a corresponding scaled wind power generation output profile for future years in hourly and minute-by-minute resolution. Two key considerations go into preparing this profile for market simulation and system dispatch simulation analysis.

One important consideration for scaling the wind power generation output profile is that the load and wind power are both correlated with weather and climate variables. In short, we need to create a weather-synchronized wind generation profile that is correlated with the load profile.

Another consideration is that the future profiles are impacted by assumptions regarding where, when, and what wind power generation will be developed in future years to meet the target of 30% renewables by 2030. Geographic distribution affects the aggregated generation output and ramping profile of wind power generators due to site diversification effects. Figure 9 provides a period of actual historical wind power generation output profile to demonstrate the site diversification concept.

Example of Wind Power Generation Diversification

Figure shows an aggregate wind power output profile from 8 PM to 2 AM. During this 6-hour period, there are two relatively large ramp-up periods. One is about 400 MW from 8 PM to 9:30 PM, and the other is about 350 MW from 12:30 AM to 2 AM. A closer look reveals that the first one is mainly from the wind farms in Central and Southeast Alberta, and the second one is mainly from the wind farms in

Southwest and Southcentral Alberta. This example illustrates the impact on aggregate wind generation output profile due to diversification of different geographic location and technology.

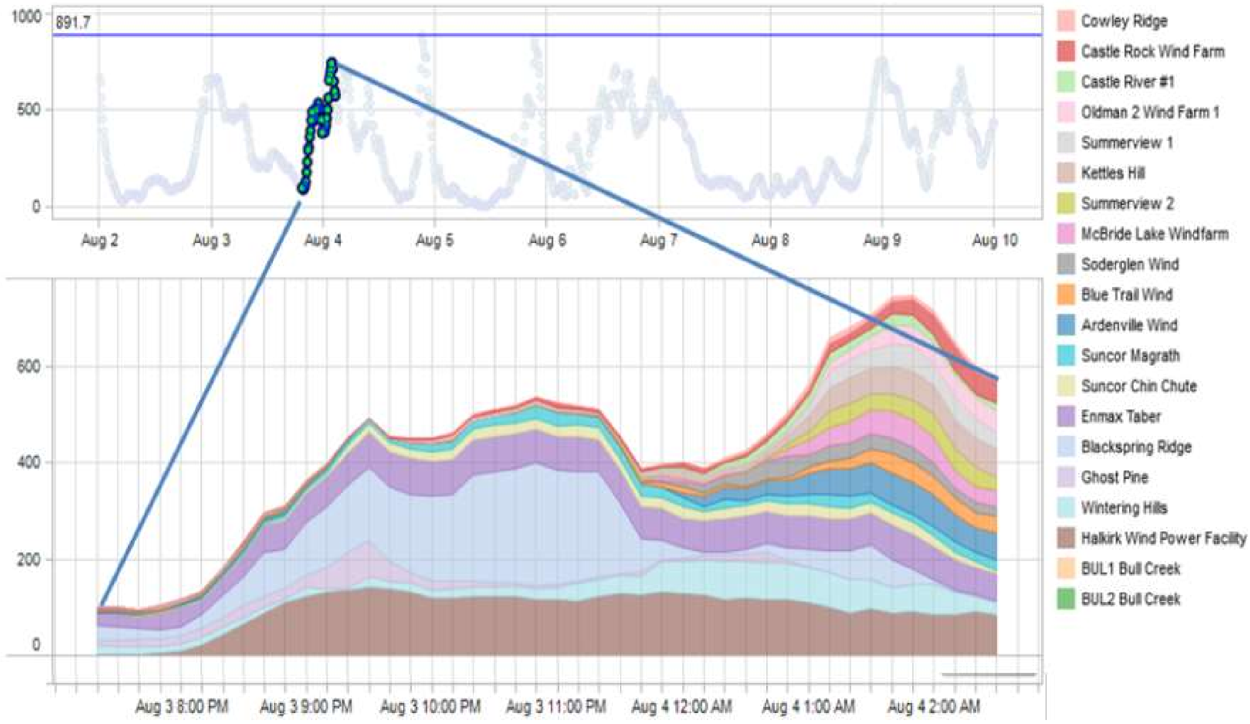


Figure 14. Historical Wind Power Generation Output Profile and MW Breakdown by Wind Farm

Wind Generation Output Simulation using Historical Weather Data and Actual Wind Farm Sites

To simulate the diversification effects of geographic location and technology, we identified potential (120+) wind farm sites across Alberta based on information AESO received from wind generation developers prior to June 2016 (left chart in Figure 15). The wind power forecast service provider (WEPROG) provided 10-minute resolution wind power generation output simulation for three years (2014, through 2016) at each potential future wind farm site. Inputs of the simulation for each site were:

- WEPROG's Numerical Weather Prediction (NWP) model calculation based on historical weather data across Alberta
- local weather historical data and power generation data for existing wind farms nearby
- the windfarm generation model from nearby existing sites with adjustments to current technology

In short, this approach provided the simulated generation output for each potential future wind farm as if was in operation over those three years. Using this information, the simulated aggregate generation output of any combination of these wind farms can be created for those three years.

As the NWP-based simulation method and corresponding load profiles were based on the same historical weather conditions, we ensured that load and wind power profiles were synchronized with weather, as discussed above.

Selection of Wind Generation Sites for Future Scenario

The 2017 LTO provides the forecasted annual wind power installation capacity without the further details of the geographic distribution for the new sites needed to deliver the increased wind generation. The geographical information has impacts on the aggregate wind generation profile due to the diversification discussed. As a starting point for addressing this issue, we assumed a base geographic distribution scenario by considering information about transmission utilization, such as:

- project stage
- distance from the project to existing and planned transmission facilities with additional generation interconnection capability

This transmission utilization scenario is illustrated in the right chart in Figure .

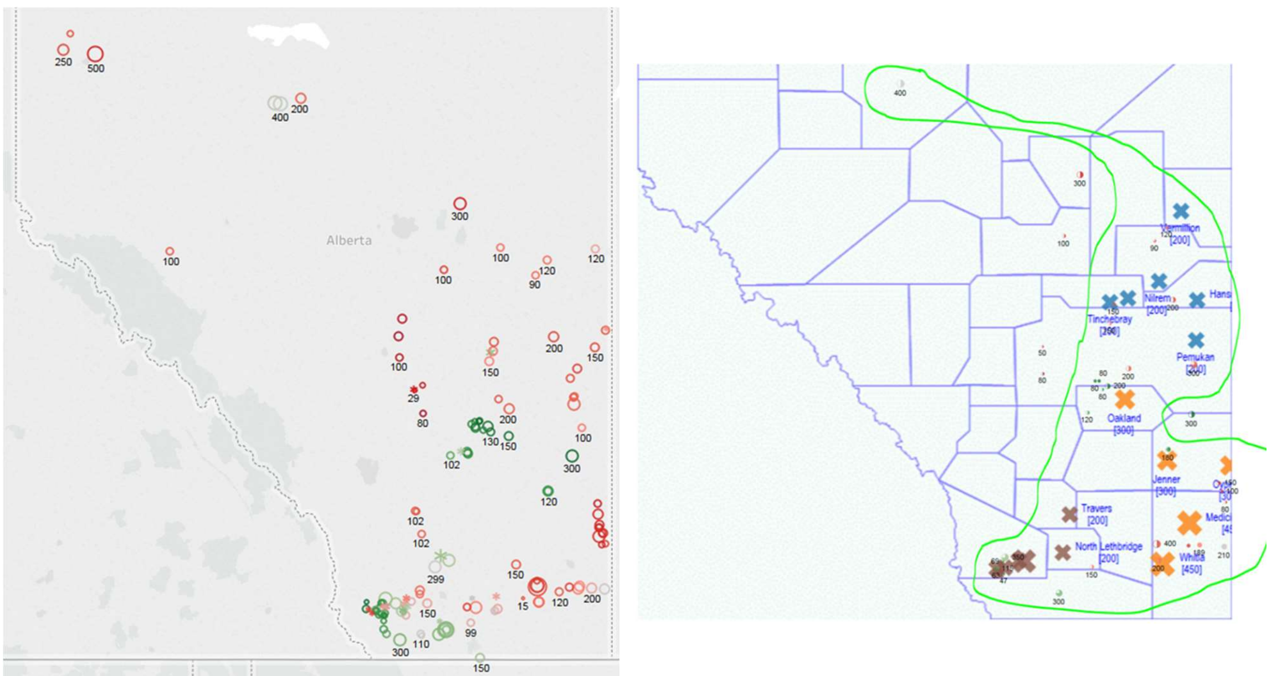


Figure 3. Identified Wind Generation Sites – All Sites (left) and Future Scenario (right)

One existing and two future aggregate wind power scenario profiles are used to create the aggregate wind generation output profiles for every future year until 2030:

- Existing wind
- Existing wind + approximately 2,000 MW (based on the AESO wind projects at Stage 3 and above as of June 2016)
- Existing wind + approximately 5,000 MW (AESO wind projects at Stage 2 and above as of June 2016)

The capacity breakdowns by region of these scenarios are provided in Table .

Table 8. Wind Power Capacity Breakdown by Region for Existing and Future Scenario

Region	Existing Wind	Existing + 2,000 MW	Existing + 5,000 MW
Central East	261	931	1,831
South East	169	594	2,264
South West	1,033	1,977	1,977
North West	0	0	400
Total	**1,463**	**3,502**	**6,472**

For the years with total installed wind capacities between the values in these scenarios, the aggregate wind power generation output profile was created based on the interpolation of the two adjacent scenario profiles.

Pre-real-time Wind Power Generation Output Forecast Profiles

In addition to the wind power generation output profile used in real-time market and system dispatch simulation, we also asked WEPROG to provide the correspondent pre-real-time wind power generation output forecast profiles for the market simulation model to simulate the unit commitment practice:

- Day-ahead wind power generation forecast delivered daily around noon (GMT 1800)
- Intra-day wind power generation forecast delivered around every 6 hours (GMT 0, 600, 1200 1800)

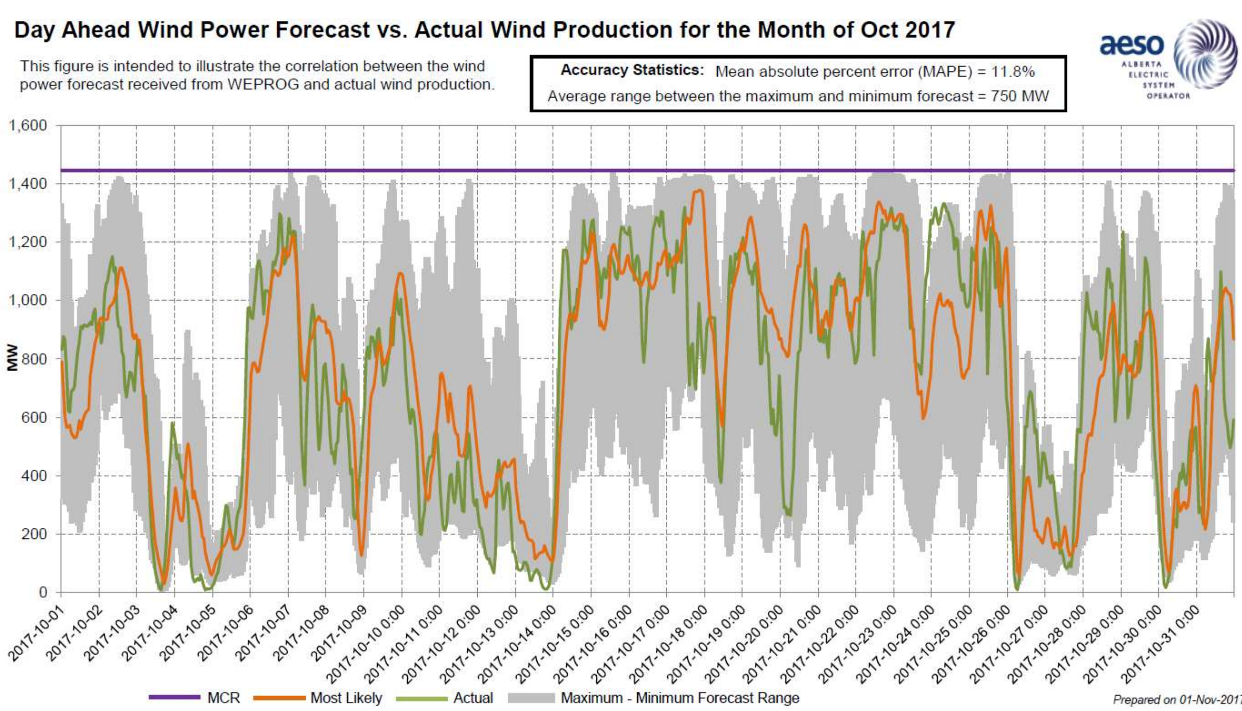


Figure 4. Example of Day-ahead Forecast provided by WEPROG for October 2017

2.3.4 Solar Power Generation Output Profile

The solar generation output profile is based on the annual hourly profiles generated by the National Renewable Energy Laboratory's PVWatts calculator for several different locations in Alberta. The aggregate generation profiles are based on weighted combination of four locations:

- Calgary, 20% weight
- Lethbridge, 20% weight
- Edmonton, 20% weight
- Medicine Hat, 40% weight

2.3.5 Interchange Capability and Schedule

Available Transfer Capability

Interchange capability is represented by its annual hourly available transfer capability (ATC) for each path. For simplification, we modeled one AC intertie (that combines both the AB-BC Intertie and MATL) and one DC intertie (AB-SK Intertie). The intertie restoration initiative was reflected from 2021 with over 300 MW increase in ATC for the AB-BC/MATL intertie.

In the market simulation analysis, there are two book end scenarios used to analyze the impact of the interchange:

- No interchange (0 MW interchange for every hour)
- Interchange capability of each path is always at its path rating (every hour)

Table 9. Annual Interchange ATC – 2018 to 2030

ATC	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
AB-BC/MATL import	840	862	882	1,199	1,217	1,232	1,243	1,256	1,270	1,281	1,294	1,311	1,326
AB-BC/MATL export	935	935	935	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250	1,250
AB-SK import	153	153	153	153	153	153	153	153	153	153	153	153	153
AB-SK export	153	153	153	153	153	153	153	153	153	153	153	153	153

In the dispatch simulation analysis, two additional AC interchange scenarios were modelled:

- Historical AB-BC/MATL ATC that reflects existing interchange capability with day-to-day operation constraints such as planned and forced outage of related transmission system
- Historical AB-BC/MATL ATC plus 400 MW for both import and export ATC during the periods that BC 500 kV is in service. This is to reflect the potential capability increase due to the intertie restoration plan for future.

The difference between these two additional scenarios helped us to understand the potential benefits of intertie restoration on NDV impact mitigation.

Interchange Schedule

For the 2015 simulation analysis, the 2015 historical actual hourly interchange schedules are used to validate and tune the simulation model. For future years, the interchange schedule used in the dispatch simulation is based on the output from the market simulation model using a Mid-C pricing arbitrage algorithm.

2.3.6 Energy Market Offer Behavior

Energy market offer behavior was analyzed through the market simulation model. The results (in hourly EMMO format) were used as input to the system dispatch simulation model.

As in practice, the EMMO was ordered (by offer price) energy market offer blocks/stack. According to market Rule 203.1, each participating asset must offer all their available capacity into the energy market in 1 to 7 blocks, each block has an offer price in $/MWh and an offer size in MW (price/quantity pair). Existing units have the price quantity pairs created through a historical analysis of past unit bidding behaviour, with past bidding behaviour applied over the unit's heat rate. For future units, we used a representative existing unit of the same technology for the assumed price quantity pairs. New technologies, such as coal to gas conversions, have price quantity pairs developed based on operational considerations such as unit minimal stable, unit heat rates, and relative bidding behavior of other technologies (if simple cycle (SC) has traditionally bid higher than marginal cost, coal to gas will bid relatively higher to maintain the marginal technology order).[10]

The merit order was validated in two ways. Near term runs confirmed that the price from the model is aligned with actual prices. We also confirmed that generation output is reasonably similar to historical output. Appendix A has the first week EMMO snapshots for 2015 actual and 2030 forecast.

2.3.7 Generation Asset Dispatch Response Characteristics

The dispatch response of each asset was modelled using historical data and based on the following characteristics:

- average time for the asset's first block to respond from non-generating status (i.e., response delay)
- average ramp-up rate from non-generating status
- average response delay for the asset's other block to respond from generating status
- average ramp-up rate from a lower generating level
- average ramp-down rate from a higher generating level

Future assets/units were assigned dispatch response characteristics from a representative existing asset/unit of the same technology. For new technologies, we used values based on similar technologies with adjustments based on research and internal discussion. Table lists average historical (2015) dispatch response characteristics for each coal asset and averages for other technology types: combined-cycle, simple-cycle and co-generation units.

[10] Statement from market simulation team

Table 10. Average Dispatch Response Characteristics of Coal and other types of Generation – 2015

Generator	Average from Non-Generating Status		Average from Generating Status		
	Delay (min.)	Ramp Rate	Delay (min.)	Ramp Down (MW/min.)	Ramp Up (MW/min.)
Battle River 3	2.4	2.3	2.2	3	2.4
Battle River 4	3	0.6	2.8	2.5	2.5
Battle River 5	4.3	1.3	2.3	5.9	5.7
Genesee 1	2.3	2.3	2.4	3.9	4.1
Genesee 2	4.3	2.9	2.6	4.2	4.7
Genesee 3	2.7	2.3	2.5	1.8	1.8
HR Milner	5.7	2.1	2.8	2.7	2.6
Keephills 1	2.1	3.7	1.9	5.9	6.2
Keephills 2	3.4	2.8	1.9	6.1	6.5
Keephills 3	2.5	2.3	2.4	5.2	5.1
Sheerness 1	2.9	2.3	2.9	4.7	4.6
Sheerness 2	2.9	2.3	2.9	4.9	4.8
Sundance 1	2.7	2.3	2.7	3.4	3
Sundance 2	2.8	2.3	2.8	3.4	2.9
Sundance 3	2.1	2.3	2.1	6.7	6.3
Sundance 4	2.3	2.3	2.3	6.1	6.3
Sundance 5	2.1	2.3	2.2	6.8	6.1
Sundance 6	3	0.6	2.1	6.5	6
Coal average	**3**	**2.2**	**2.4**	**4.6**	**4.5**
CC average	**4.1**	**2.3**	**2.2**	**2.3**	**1.9**
SC average	**6.8**	**13.6**	**2.5**	**10.6**	**10**
COGEN average	**3.1**	**2.6**	**2.4**	**3.8**	**2.8**

NOTES:

CC = combined cycle; SC = simple cycle; COGEN = cogeneration

Please refer to Appendix B (Table B-1 through Table B-7) for individual asset dispatch response characteristics of other types.

2.3.8 Ancillary Services

As discussed in Section 2.2 (Table 2), the regulation reserve (AGC) forecast and procurement was based on the historical actual hourly profile. More Increases in regulating reserve volume (such as double or triple) procurement can be modeled as a sensitivity to determine the impact this may have on the performance metrics.

2.3.9 Assumptions regarding Unit Commitment

The unit commitment practice is in the timeframe of hours to days; the market simulations were based on the current self-commitment practice. Output from the market simulations (in the format of hourly EMMO) was used as input into the dispatch simulation model for further analysis in the real-time timeframe, with two key considerations regarding unit commitment, as explained below.

One consideration is about commitment with uncertainty. Depending on technology and other operational/market situations, assets can have operational constrains such as: start lead time, minimum stable generation level, minimum up time and minimum down time, etc. Decisions about unit commitment (cycling up and down) need to be made hours to days in advance with significant uncertainty of future net-demand forecast, especially associated with the wind power generation forecast. To better understand the impact of the wind power forecast uncertainty, the unit commitment practice was modeled using both the future wind power generation output simulation profile and the future wind power generation output forecast simulation profile (with uncertainty) as discussed in Section 2.3.3.

The other is about commitment by generator owner (self-commitment) or by system operator (centralized commitment or centralized scheduling); Alberta's current practice is mainly based on self-commitment. The key differences are the degree of coordination and the decision responsibility. Self-commitment and centralized commitment should be modelled and analyzed in the market simulation so that their impacts can be compared. Those results could then be passed into the dispatch simulation model for further analysis in the real-time timeframe.

2.3.10 Limitations of these Assumptions

The contingency reserve related practices (forecast, procurement, dispatch, directive) are not modeled in the dispatch simulation analysis, as the dispatching simulation analysis is focused on the impact of normal system operation, and the generation contingency (forced outage) is assumed to be handled by the contingency reserve related practice in the business as usual manner.

The practices around TMR, DDS, CDG, $0 pro-rata dispatch are not considered in the dispatch simulation analysis.

The Wind Power Management (WPM) practice has two separate and related functions; one is to determine the system aggregate wind power limit every 10 minutes, the other is to allocate the aggregate limit to each individual wind power facilities. In the dispatch simulation model, the wind power generation is modeled in aggregate, so the WPM allocation by site cannot be modeled, and optimal allocation is, therefore, assumed.

3 Analysis Results

As discussed in the methodology section, data analysis was performed to understand the level of NDV and the impact the changing NDV would have on performance metrics.

3.1 Data Analysis to Understand the NDV and Potential Impacts

In the data analysis, we calculate the related data metrics defined in Table 1.

3.1.1 Data Analysis Metrics – Pre-Real-Time

Daily Load and Net Demand Variability

In Figure below, the blue curves are the daily load demands for 2015 (left charts) and 2030 (right charts), and the orange curves are the daily net demands.

From Figure 17, in 2015 the daily load demand ranges from 618 MW to 2,285 MW (a 1,667 MW range) and in 2030 it ranges from 668 MW to 2,839 MW (a 2,171 MW range), equating to a 30% (500 MW) increase in variability between 2015 and 2030. However, the NDV increases by 230% (3,460 MW) between 2015 and 2030. The 2015 daily net demand ranges from 589 MW to 3,233 MW (a 2,644 MW range) and in 2030 it ranges from 901 MW to 7,005 MW (a 6,104 MW range) in 2030.

The largest daily net demand range of about 7,000 MW (3,700 MW increase over 2015) will create significant challenges to pre-real-time resource scheduling/commitment decisions and related practices.

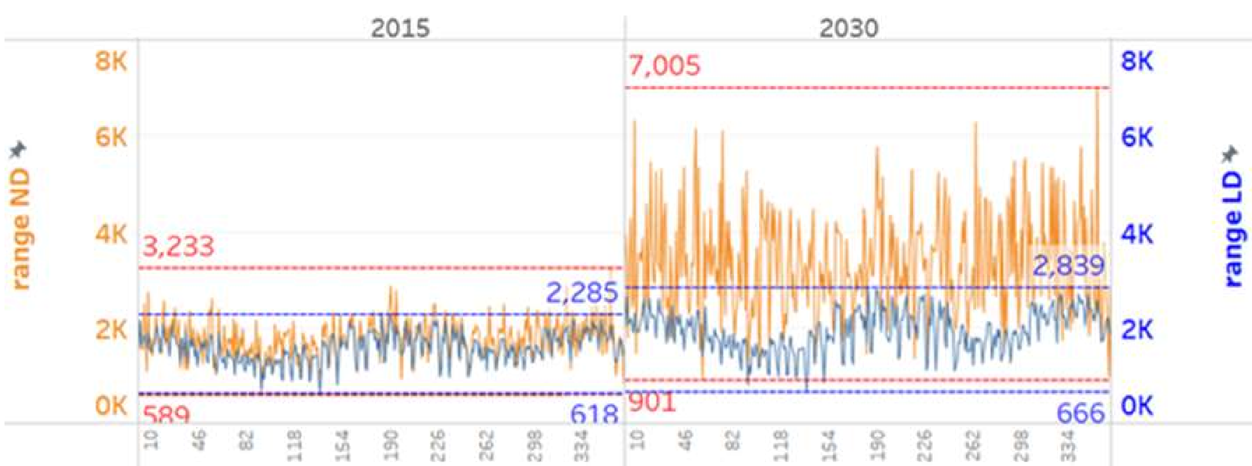


Figure 5. Daily Range' Metrics Calculation Results

Day-to-day change metric results are shown in Figure .

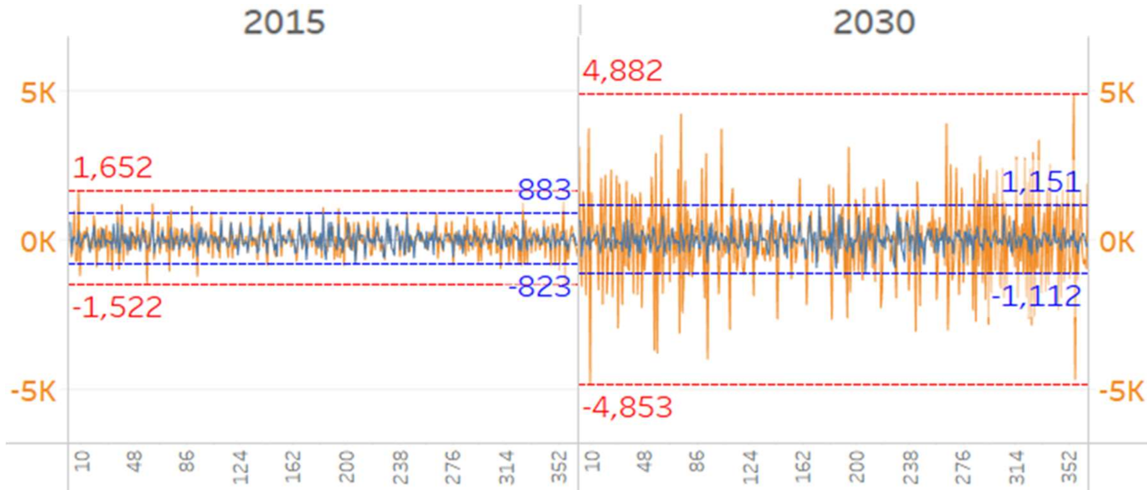


Figure 6. Day-to-day Change in Daily Range

Figure 18 shows that the daily range difference between two adjacent days could be as big as 4,800 MW in 2030 with approximately 6,500 MW of wind power generation in operation. A daily range of up to 4,800 MW will have significant impacts on day-ahead resource scheduling/commitment decisions and related practices.

Weekly Load and Net Demand

Weekly range metric results are shown in Figure .

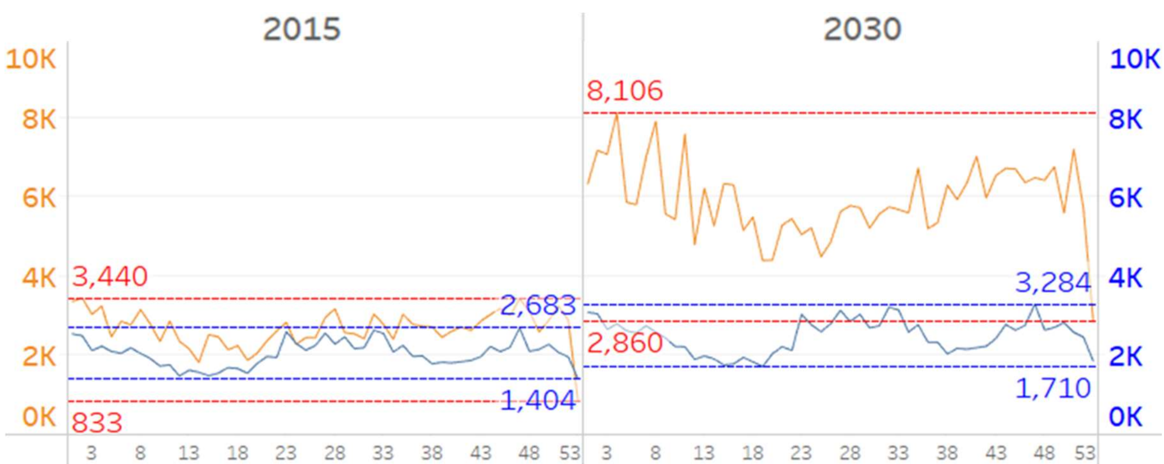


Figure 7. Weekly Range Merics

The numbers on the charts shows that the NDV weekly range varies from 833 to 3,440 MW in 2015 and from 2,860 MW to 8,106 MW in 2030. This more than doubling of NDV weekly range will have significant impacts on day-ahead and multiple-day-ahead resource scheduling/commitment decisions and related practices.

Figure 17, Figure 18 and Figure 19 show significantly greater deviation between load (blue) and net demand (orange) between 2015 and 2030. These results indicate that in 2030 load comprises a relatively small proportion of NDV; the most significant contributor is variability in wind power generation output.

3.1.2 Data Analysis Metrics – Real-Time

Figure shows the results of 10-minute, 20-minute and 60-minute change for both wind power output and net-demand for both 2015 (blue) and 2030 (green). The results are shown in the form of a distribution curve in log-scale. The use of log-scale provides better display resolution for the distribution curve tails. The top-left chart shows that the 10-minute wind power variances are:

- (-244) MW – (+277) MW for 2015
- (-392) MW – (+420) MW for 2030

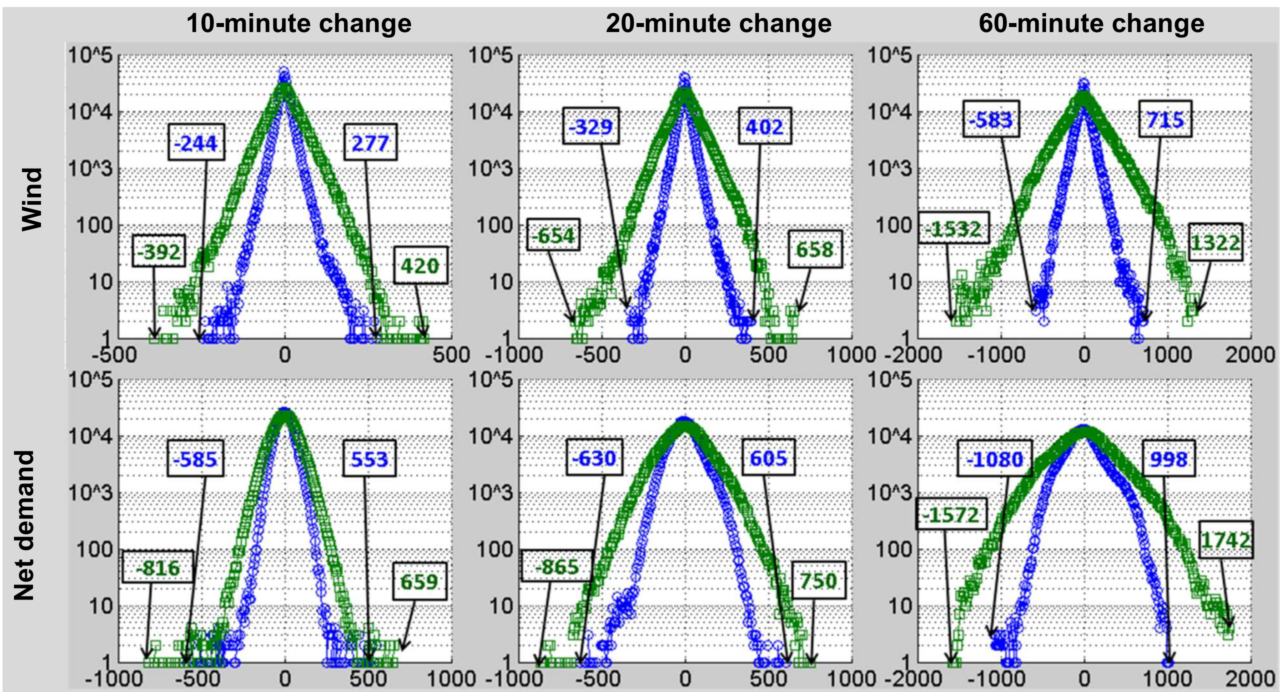


Figure 20. Real-time Data Analysis Metrics

The net demand variability increases at a significantly less rate (1.9 times) versus the wind generation variability (4.5 times) due to the wind site location driven diversification effect explained in Section 2.3.3. The wind power generation capacity increased from about 1,450 MW in 2015 to about 6,500 MW in 2030, about 4.5 times. The most extreme 10-minute, 20-minute and 60-minute wind power output variances increase between 1.5 to 2.6 times (based on the numbers on the three wind charts) with an average of 1.9 times.

The 10-minute to 60-minute NDV increases will still bring challenges to the real-time dispatch practices for balancing the NDV.

Table 11. summarize the above NDV general data analysis result of different timeframe for cross comparison purpose

Table 11. NDV Results Comparing Across different Timeframes

Time frame	1500MW in 2015	6500MW in 2030	increase	times
10-minute	-400MW / +300MW	-500MW / +400MW	+ 20-30%	1.2 - 1.3
20-minute	-500MW / +400MW	-600MW / +700MW	+ 20-60%	1.2 - 1.6
60-minute	-1,000MW / +1,000MW	-1,500MW / +1,700MW	+ 50-70%	1.5 - 1.7
daily range	600 - 3,200MW	900 - 7,000MW	+ 50-120%	1.5 - 2.2
day to day	-1,500MW / +1,650MW	-4,850MW / +4,880MW	+ ~200%	~3
weekly range	800 - 3,440MW	2,860 - 8,106MW	+ ~140%	~2.4

Table 11 shows that the increases of NDV from 2015 to 2030 (with 5000MW additional wind power) range from 20% for short timeframe to ~200% for long time frame. The longer the timeframe has bigger increase, this indicate that the NDV's will likely have bigger impact on those pre-real-time practice (with longer timeframe) than real-time practice (with short timeframe)

3.1.3 Event-based Analysis of Ramp

Figure is the wind power ramp event analysis for 2015 installed capacity (left) and 2030 expected installed capacity (right), both are based on the 2015 weather year.

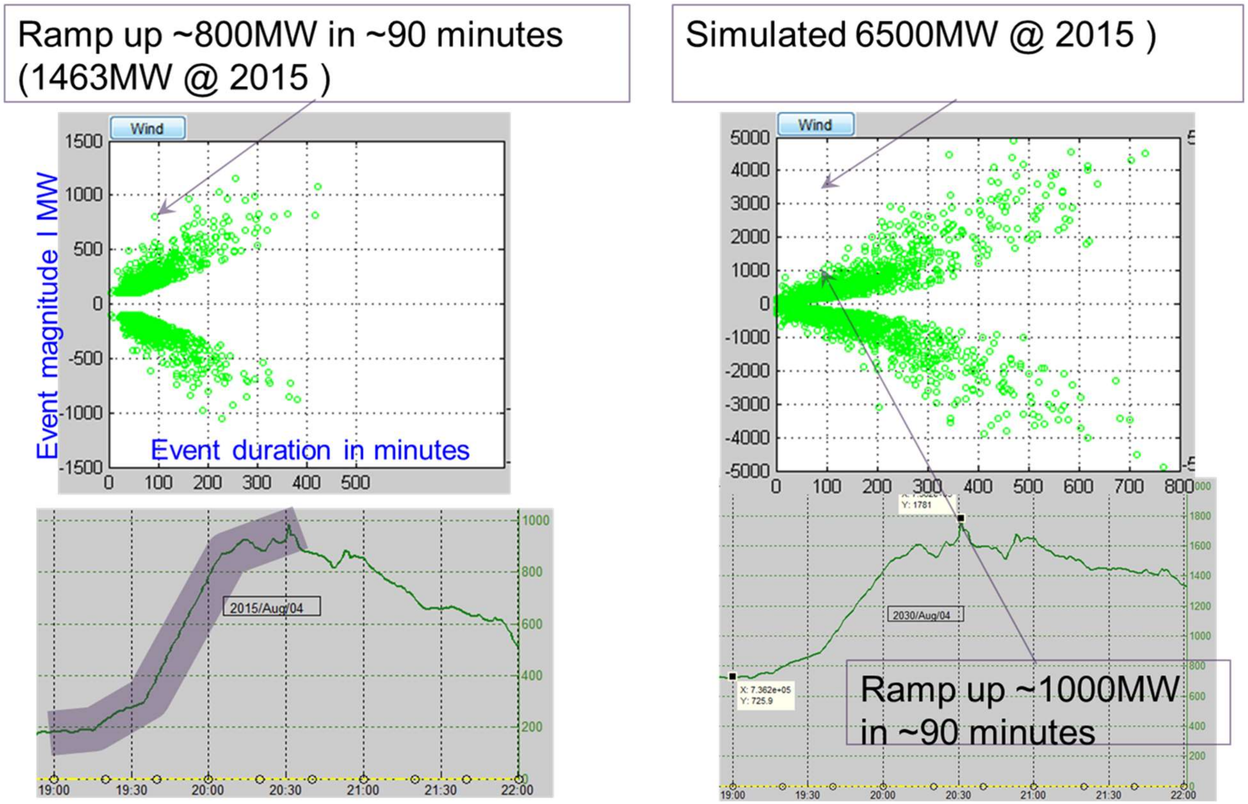


Figure 21. Wind Power Ramp Event Analysis

The highlighted point on the top-left chart represents a single wind ramp-up event of about 800 MW during 90 minutes on August 4, 2015 (bottom-left chart), corresponding to about 1,450 MW of wind installed capacity. In the case of 6,500 MW of installed capacity (bottom-right chart), the same event increases to 1,000 MW during 90 minutes. By comparing the two wind power ramp evets, we observe that as wind capacity is added to the system ramp events will generally grow larger in magnitude and also span a longer period. The overall ramp rate is larger in magnitude, but is also smaller relative to the increase in installed capacity, again due to location diversification effects.

Figure 22 shows the ramp event analysis for load (grey) and net demand (green) for both 2015 (left) and 2030 (right). As illustrated in the charts, the results for load follow a similar pattern; but for net demand, with more variable generation (mainly wind power) installed, there are more events with larger magnitudes and longer durations.

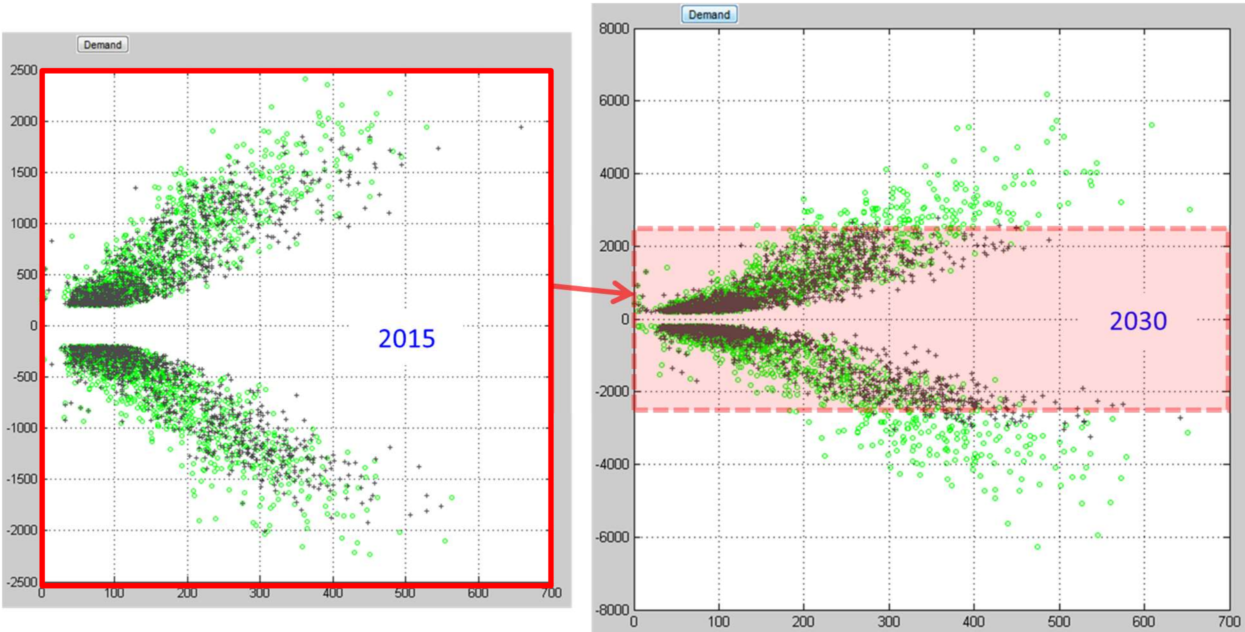


Figure 22. Ramp Event Analysis – Load and Net Demand

3.1.4 Sensitivity Data Analysis – Other Weather-years

The data analyses presented above were based on the weather-year 2015. Sensitivity analysis for other weather years (2014 and 2016) was conducted to determine what the potential differences may be between weather-years. Figures 18 to 20 confirm that the weather-year has little effect on the NDV results as the various outputs (load, wind, NDV) do not change materially between weather years. Therefore, only 2015 weather-year was used in the analysis because:

- It avoids unnecessary analysis for no material benefit.
- The preliminary simulation analysis performed in 2016 also only utilizes 2015 data.
- In 2016, 1000s of MW of PPAs returned to the Balancing Pool, triggering atypical energy market offer practices and corresponding system and market operation practices. Therefore, 2015 is considered more indicative of expected future behaviour.

As explained in Section 2 (Methodology) the load and wind power output profiles were constructed based on actual historical data (load, wind power output, weather data) in a time-synchronized manner to ensure weather-synchronized profiles between load and wind power output were retained for each weather-year.

Figure shows the 20-minute, 60-minute and 240-minute variances distribution pattern for weather-years 2014, 2015 and 2016.

Figure shows the 20 minute variance for both wind power output and net-demand (without solar) for weather-years 2014, 2015 and 2016, and 20 minute variance for both wind & solar power output and net-demand (with solar) for weather-years 2015 (we only have one year of solar generation profile to use for now).

Figure shows the ramp event analysis comparison for load (blue) and wind (and solar) power output (green on the bottom charts) and net-demand (green on top charts) for weather-years 2014, 2015 and 2016.

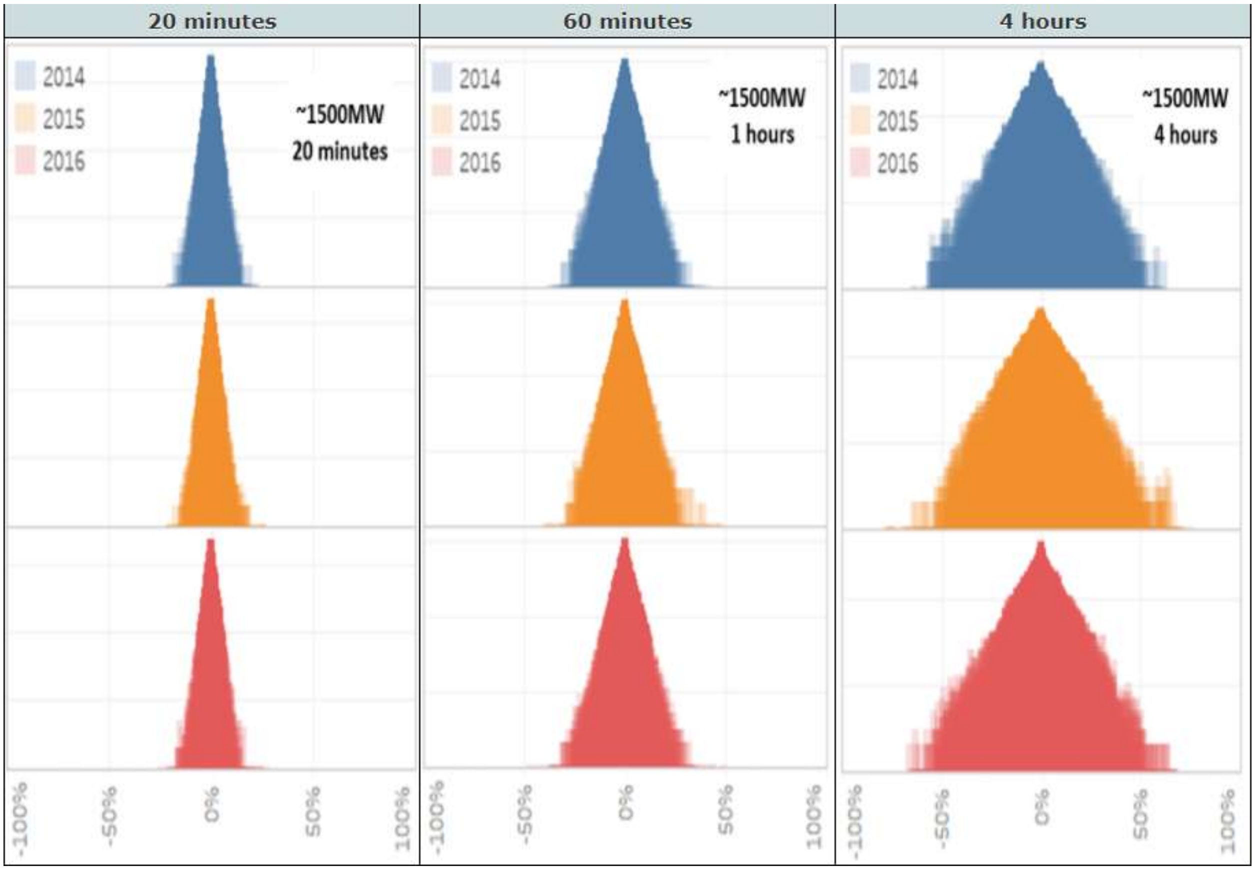


Figure 24. Wind Power Output Variances for Different Weather-years

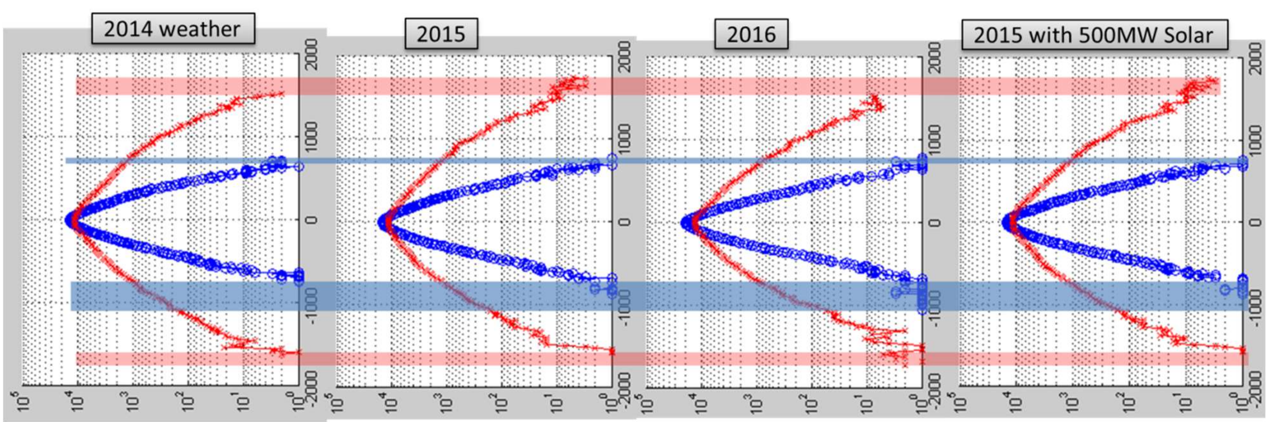


Figure 25. 20-minute Variance for Different Weather-years

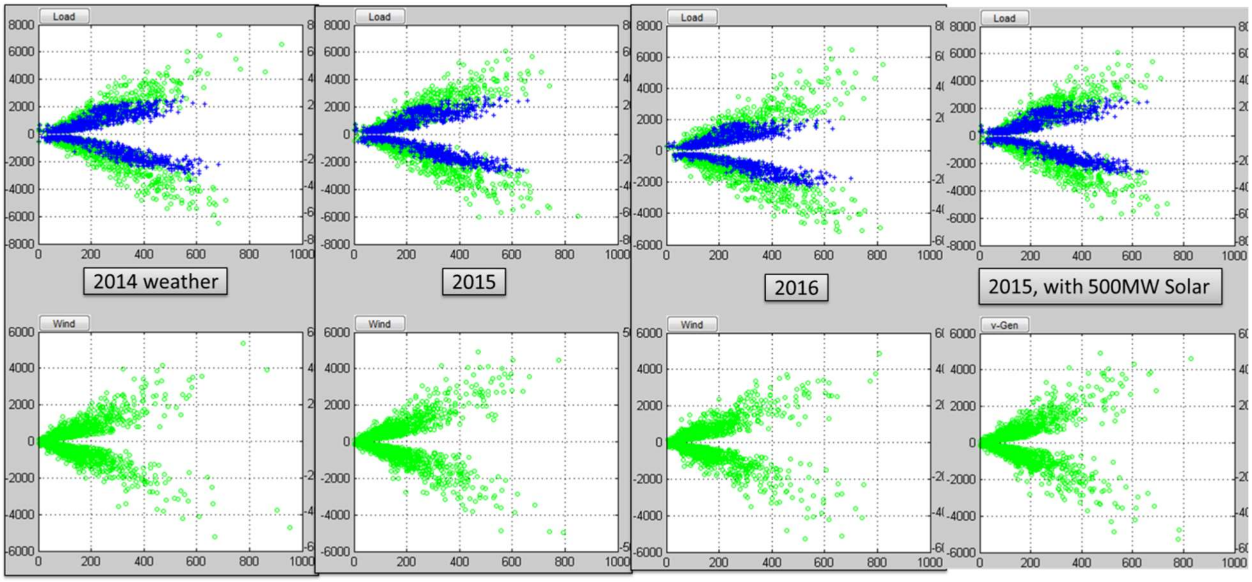


Figure 26. Ramp Event Analsysis for Different Weather-years

3.2 Summary of the 2016 Preliminary Simulation Study

In 2016 a preliminary dispatch simulation study concluded that current operation practices and market behavior may create performance issues above 3,000 MW of variable generation, which is expected on the grid by 2022 or 2023.

Recommendations from this study included:

- Implement quicker and more proactive dispatch practices, including pre-dispatch, dispatch automation and enhancement of the dispatch tolerance rule (Rule 203.4)
- To improve other related operation practice and rule, including: real-time wind power forecast, wind power management and regulating reserve procurement profile.
- further collaborate with Markets team to investigate improvements related to operation / market practice beyond real-time timeframes related with unit commitment/cycling, STA, supply surplus

The key differences between the studies conducted in 2017 and the previous study in 2016 are that the previous study did not have the coordinated market simulation work, and the key market inputs were based on simple assumptions without sufficient details to model future generation mix, outages, and commitments in the form of hourly EMMO. The lack of details in both input data and simulation modelling prevented further simulation and quantification of the impacts on each practice performance such as addition dispatch for ramp, supply surplus situations, unit cycling etc. The conclusions as such were at a more general level based on limited analysis. This was why the 2016 study recommended this more detailed study (including both markets and operations contributions) be performed at the end of the 2016 study.

With the more detailed analysis in this new study the previously conclusion of "may create performance issues" is translated into more details (discuss in Section 3.3) as:

- performance issue are observed; but can be mitigated by more proactive operation practice and more consistent dispatch response
- more supply surplus situation and more unit cycling

And almost all the recommendations made in the 2016 study are still valid.

3.3 Supply Flexibility Characteristics – Market Simulation Results

The supply flexibility metric results are provided in Table for different generation scenarios based on the hourly EMMO results from market simulation analysis. The following key observations should be noted:

- For the reference scenario: From 2015 to 2020, about 840MW of coal generations are retired, and about 510MW Cogen, 200MW CC, 30MW of SC, 780MW wind and 100MW solar are installed. As both installed Cogen and CC generation have higher $0-offer that the retired coal generation, it results into higher system average $0-offer ratio during 2018 to 2020; Start from 2021, CTG starts to be installed into the system to replace the retired coal generation, as CTG has lower $0-offer and MSG than coal, both $0-offer ratio and MSG ratio is trending down (more flexible EMMO). Both system total ramp-up rate and ramp-down rate increase as more coal generation (with relatively slow ramp rate) being replaced by gas generation (faster EMMO).
- Comparing with reference scenario, the High Cogeneration (high-cogen) scenario (with more cogen, less combined cycle [CC] and less simple cycle [SC]) has higher $0-offer ratio and MSG ratio, and has slower total ramp-up rate and ramp-down rate.
- The Lower-$0 scenario (similar to the Reference Case, but assuming reduced $0-offer for coal and new-CC to their MSG level) has a lower $0-offer ratio.
- The High Coal-to-Gas (high-CTG) scenario (with more CTG with MSG at 20% and less CC and SC) has lower $0-offer ratio and MSG ratio, but slower total ramp rates.
- The no-CTG scenario (with no CTG and more CC and SC) has higher $0-offer ratio and MSG ratio, but the fastest total ramp rates.
- The High Hydroelectric (high-hydro) scenario (with more run-of-river hydro and less CC and SC) has the highest $0-offer ratio and MSG ratio, but the slowest total ramp rates.

Table 12. Supply (EMMO) Flexibility Characteristics Metrics – Future Generation Scenarios

	YEAR	Reference	High CoGen	Lower $0-offer	High CTG	No CTG	High Hydro
average $0offer	2018	54.1	53.9				
	2019	55.3	53.5				
	2020	56.2	53.2				
	2021	52.9	53.6				
	2022	52.0	53.9				
	2023	50.5	53.4				
	2024	50.2	53.1				
	2025	51.0	53.8	47.9	50.7	50.0	52.6
	2026	51.3	54.1	48.0	50.8	51.0	52.9
	2027	50.9	54.6	47.5	50.7	49.9	53.2
	2028	51.2	55.1	47.5	50.7	49.2	53.4
	2029	52.0	56.3	47.4	50.1	49.4	54.3
	2030	52.7	57.1	47.7	47.5	49.8	55.2
average MSG	2018	41.5	54.6				
	2019	41.4	54.3				
	2020	41.3	53.8				
	2021	41.3	42.2				
	2022	40.3	43.0				
	2023	39.0	42.4				
	2024	38.8	42.3				
	2025	39.3	42.9	39.5	39.5	39.2	49.6
	2026	39.4	43.3	39.6	39.5	38.5	48.9
	2027	39.0	43.8	39.2	39.5	38.7	49.5
	2028	39.2	44.1	39.5	39.3	37.7	49.2
	2029	39.5	44.7	39.7	38.8	37.6	48.8
	2030	40.0	45.3	40.3	38.1	37.8	48.1
average rampDN	2018	457.2	326.5				
	2019	455.1	327.0				
	2020	451.6	327.0				
	2021	440.1	439.2				
	2022	477.0	441.9				
	2023	483.4	442.6				
	2024	483.7	441.9				
	2025	486.9	440.2	485.3	451.2	647.6	375.3
	2026	487.7	439.8	485.8	451.5	710.2	379.0
	2027	526.3	437.1	524.7	450.7	713.5	388.4
	2028	536.2	439.3	533.6	456.0	764.3	372.2
	2029	563.0	446.6	561.8	457.0	806.0	377.7
	2030	591.1	458.6	591.2	468.2	858.8	389.7
average rampUP	2018	395.0	285.5				
	2019	392.8	285.7				
	2020	389.5	286.5				
	2021	378.8	377.4				
	2022	410.0	379.5				
	2023	415.0	379.6				
	2024	415.4	379.0				
	2025	418.1	377.4	416.3	388.2	551.4	342.0
	2026	418.5	376.7	416.5	388.3	602.4	345.9
	2027	450.3	374.2	448.6	387.6	605.5	353.6
	2028	458.7	375.8	456.1	392.1	646.9	342.7
	2029	480.8	381.9	479.4	393.2	680.8	348.8
	2030	506.0	393.6	505.9	405.4	726.3	360.8

The EMMO total ramp-rate (MW/min) is above +/- 300 MW/min, even in the slowest ramp rate generation scenario. This ramping capability appears to be more than adequate when compared to the highest 10-minute NDV ramp of [-816, +660] observed in Figure .

However, there are two key assumptions that enable this total EMMO ramp rate to be available for dispatch in real-time operation:

1. Addition-dispatch-for-ramp practice: As the total ramp rate is from all the EMMO blocks across the entire EMMO, more EMMO blocks need to be dispatched in order to get more ramp rate, if no EMMO skipping is allowed (based on current practice). This may result in price fidelity/market efficiency impacts.
2. Depending on the marginal position in the EMMO during real-time operation, the entire total ramp rate is not all available to be dispatched for ramp. The EMMO blocks below the marginal block can only be dispatched down, and the blocks above the marginal block can only be dispatched up. As such, the amount of achievable ramp rates (up or down) at any particular time is only part of the total ramp rate. It also depends on the marginal position that is determined by the real-time NDV and EMMO (all on-line generation offers), and the EMMO is directly impacted by the pre-real-time resource scheduling/commitment practice.

The market simulation work was based on assumptions that resulted in the hourly EMMO that reflected unit commitment. The market simulation team will deal with recommendations that may require AESO rules to ensure related assumptions used in their study will lead to actual market operation in the future. For example, the Market Team will need to consider if rule changes are required for unit commitment, or whether the System Controller should schedule to achieve the desired outcome of their assumptions.

It should also be noted that the current market rules do not restrict over dispatching the energy market to obtain ramp rate. So it is assumed that 'all' online generation capacity can be ramped up to full capacity or down to minimum stable capacity to acquire the necessary ramp rate. This over dispatch action is result in spikes or dips in the system marginal price which may not be reflected in the market simulations at hourly resolution.

3.4 Dispatch Simulation Analysis – Practice Performance Impacts under the Reference Case Scenario

The system operation (dispatch) simulation analysis uses the hourly EMMO and interchange schedule output from the market simulation analysis for the different generation scenarios conducted by market simulation team which used the Aurora simulation tool. In the operation dispatch simulation analysis, only the Reference Case scenario was studied and depending on the results, other generation scenarios may require study.

3.4.1 Impact of Various Degrees of Proactive Dispatch

As discussed in Section 2.2, nine different combinations of proactive dispatch behaviour were identified. All nine dispatch practice behaviors were analyzed and performance metrics were calculated (as shown in Table 3). Table 13 summarizes the results for four different performance metrics (CPS2, ADfR, big ACE, SOL) and four different years in the Reference Case scenario, which would have four different levels of variable generation.

The resulting performance metrics for 2015 were:

- CPS2: 97.31%
- Interchange SOL violation: 0
- Big ACE events: 3
- ADfR:
  - 10-minute NDV: about 50 MW measured in standard deviation
  - 10-minute overall dispatch variance: 83 MW measured in standard deviation

The performance metrics results in Table show that as the dispatch practice moves from less to more proactive, there will be:

- a larger overall dispatch variance (127 MW to 255 MW measured in standard deviation for 2015 due to more dispatch for ramp)
- better CPS2 (97.3% to 99.7% for 2015),
- fewer big-ACE events (43 to 0 instances for 2015)

- less interchange SOL violation (1 to 0 instances for 2015)

Further, when we compared the 2015 actual performance metrics with the simulation results in Table , we found that the least proactive dispatch behavior was very close for CPS2 (around 97.3%), but with higher overall dispatch variance (127 MW vs. 83 MW). We also noted more SOL violation (1 instance vs. 0 instances) and significantly more big-ACE events (43 instances vs. 3 instances).

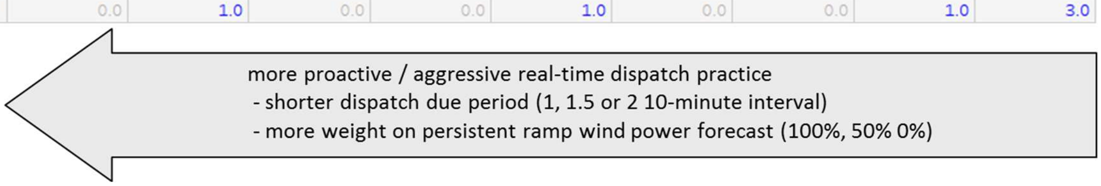
The explanations of these differences between recorded actual results and model simulated results are:

- The model can only simulate one dispatch practice pattern (degree of proactive) at a time; it does not simulate the actual human intelligence of adapting the dispatch approach through time. The simulation results also suggest that in actual operation, during the situations of the one SOL violation and 43 big-ACE events, the System Controllers can switch to a more proactive dispatch practice in order to manage the impacts. In most situations (outside big-ACE events) the System Controllers can manage the supply demand balance by adopting the least proactive dispatch practice to avoid unnecessary ADfR and avoid unintended market impact.
- The dispatch simulation result is based on dispatch decisions at fixed 10-minute intervals, which again does not simulate the actual human intelligence of adapting the dispatch approach though time. So the simulation results are expected to have more dispatch variance than actual performance by System Controllers.

Another observation is that the improvement of CPS2 and the reduction of big-ACE events by adopting the persistent-ramping forecast approach is more pronounced for later years than during early years. This suggests that with more variable (mainly wind power) generation in later years, the overall aggregate variable generation output will have more persistent changing behaviors than earlier years due to the diversification effect.

Table 13. Real-time Simulation Metrics for Proactive Dispatch Practices

		dispatch due in 1 interval			dispatch due in 1.5 interval			dispatch due in 2 interval		
	YEAR	pstRamp 100%	pstRamp 50%	pstMW	pstRamp 100%	pstRamp 50%	pstMW	pstRamp 100%	pstRamp 50%	pstMW
CPS 2	2015	99.7	99.7	99.5	99.3	99.2	98.9	98.1	97.8	97.3
	2020	99.4	99.5	99.1	99.2	99.0	98.3	98.1	97.6	96.7
	2025	99.3	99.3	98.1	99.2	98.7	96.8	98.1	97.0	94.6
	2030	99.0	98.8	96.8	98.8	98.2	95.7	97.8	96.8	93.9
overall dispatch variance MW std	2015	256.9	238.2	225.9	170.6	160.8	154.4	138.1	131.8	127.9
	2020	243.7	227.5	215.7	172.3	162.2	155.7	142.3	134.6	129.4
	2025	244.3	233.9	228.6	189.6	181.7	176.2	162.0	155.4	151.2
	2030	175.8	169.5	167.1	153.3	148.5	145.3	140.8	136.2	133.3
Big ACE event frequency	2015	0.0	0.0	0.0	0.0	0.0	2.0	20.0	21.0	43.0
	2020	3.0	3.0	4.0	3.0	4.0	14.0	15.0	27.0	56.0
	2025	0.0	0.0	11.0	0.0	1.0	42.0	11.0	32.0	131.0
	2030	3.0	3.0	22.0	3.0	6.0	45.0	9.0	23.0	107.0
SOL violation frequency	2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
	2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2025	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	4.0
	2030	0.0	1.0	0.0	0.0	1.0	0.0	0.0	1.0	3.0



For simplicity, only the least and most proactive dispatch practice results will be shown in the rest of this report.

3.4.2 Metrics for Future Performance

In this section, the yearly performance metric results for the Reference Scenario are provided.

Performance Metrics of CPS2, ADfR and Big-ACE

Table has the CPS2 and related performance metrics for years 2015 and 2018 to 2030, and for different degrees of aggressiveness for dispatch practice. It helps us to better understand the relationship between NDV and performance metrics of CPS2, ADfR, big-ACE.

From the results in Table we can make following key observations:

- The 10-minute NDV standard deviation increases from 53 MW (2015) to 82 MW (2030), which is a 55% increase in 10-minute NDV.
- The CPS2 metric reduces over the same period, but it is better than the minimum 90% requirement for every year even under the least aggressive dispatch practice.
- For each degree of proactive dispatch practice (vertically comparing among rows in Table , the overall dispatch variance (ODV, measured in standard deviation) increases over years, but not as fast as the NDV increases. For example, with the least proactive practice the ODV increased from 128 MW to 133 MW while the NDV increase was from 53 MW to 82 MW. This slower increase can be explained by the faster overall ramping capability of the future generation fleet (replacing slower-ramping coal generation with relatively faster gas generation).
- For different degrees of proactive dispatch practice (horizontally comparing among columns), the ODV increases from least to most proactive dispatch practice as expected, resulting in better CPS2 performance, and fewer big-ACE events.
- The least proactive dispatch practice will have acceptable CPS2 performance and least ODV (or ADfR), but will have a large number (up to 162) of big-ACE events. This many big-ACE events can be mitigated to single-digit number if the System Controller adopts the most proactive dispatch practice during those events, as is typically done under the current operational dispatch practice.

In summary, the increased NDV due to increasing variable generation will have some impacts on CPS2 and number of big-ACE events. With the future generation fleet, the CPS2 is still above the required 90% threshold, and the number of big-ACE events can be managed at acceptable levels when System Controllers use most-proactive dispatch more frequently.

Table 14. Simulation Metrics – CPS2, ADfR, and Big-ACE

		dispatch due in 1 interval			dispatch due in 1.5 interval			dispatch due in 2 interval		
	YEAR	pstRamp 100..	pstRamp 50%	pstMW	pstRamp 100..	pstRamp 50%	pstMW	pstRamp 100..	pstRamp 50%	pstMW
CPS 2	2015	99.7	99.7	99.5	99.3	99.2	98.9	98.1	97.8	97.3
	2018	99.6	99.7	99.6	99.5	99.4	99.1	98.6	98.3	97.8
	2019	99.5	99.5	99.3	99.3	99.1	98.6	98.5	98.0	97.2
	2020	99.4	99.5	99.1	99.2	99.0	98.3	98.1	97.6	96.7
	2021	99.1	99.3	98.8	99.2	98.9	97.9	98.1	97.5	96.2
	2022	99.1	99.2	98.6	99.1	98.7	97.5	97.9	97.1	95.6
	2023	99.2	99.3	98.4	99.1	98.8	97.4	98.0	97.2	95.3
	2024	99.4	99.3	98.3	99.2	98.8	97.1	98.1	97.0	94.9
	2025	99.3	99.3	98.1	99.2	98.7	96.8	98.1	97.0	94.6
	2026	99.2	99.1	97.7	99.1	98.5	96.4	97.8	96.6	93.9
	2027	99.1	99.0	97.6	99.0	98.4	96.2	97.9	96.5	93.7
	2028	99.1	99.0	97.4	99.0	98.4	96.0	97.9	96.5	93.6
	2029	99.1	98.9	97.2	98.9	98.4	96.0	98.0	96.8	94.0
	2030	99.0	98.8	96.8	98.8	98.2	95.7	97.8	96.8	93.9
overall NDV MW std	2015	53.1	53.1	53.1	53.1	53.1	53.1	53.1	53.1	53.1
	2018	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0	54.0
	2019	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5	56.5
	2020	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6	58.6
	2021	59.3	59.3	59.3	59.3	59.3	59.3	59.3	59.3	59.3
	2022	63.2	63.2	63.2	63.2	63.2	63.2	63.2	63.2	63.2
	2023	63.7	63.7	63.7	63.7	63.7	63.7	63.7	63.7	63.7
	2024	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0	65.0
	2025	67.8	67.8	67.8	67.8	67.8	67.8	67.8	67.8	67.8
	2026	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4	70.4
	2027	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8	71.8
	2028	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8	74.8
	2029	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1	79.1
	2030	81.7	81.7	81.7	81.7	81.7	81.7	81.7	81.7	81.7
overall dispatch variance MW std	2015	256.9	238.2	225.9	170.6	160.8	154.4	138.1	131.8	127.9
	2018	248.1	235.2	225.9	172.4	164.3	158.5	140.5	134.5	131.5
	2019	237.8	224.5	216.6	169.5	160.5	154.9	140.0	132.9	128.5
	2020	243.7	227.5	215.7	172.3	162.2	155.7	142.3	134.6	129.4
	2021	242.4	225.7	214.1	179.0	166.5	159.8	149.9	141.4	136.8
	2022	261.2	243.5	231.4	190.9	178.3	169.8	158.7	149.2	143.7
	2023	266.2	248.0	235.4	198.7	186.6	178.0	167.3	158.3	152.6
	2024	252.8	241.7	236.5	191.3	183.3	179.0	163.8	158.2	154.0
	2025	244.3	233.9	228.6	189.6	181.7	176.2	162.0	155.4	151.2
	2026	244.0	234.5	230.7	191.7	183.7	179.1	165.9	159.7	155.8
	2027	242.4	231.6	225.8	188.9	180.3	175.4	163.2	156.7	152.3
	2028	223.4	211.7	208.4	178.8	171.6	166.1	155.4	149.1	145.4
	2029	185.0	178.1	175.3	155.7	149.5	145.9	139.4	133.9	131.3
	2030	175.8	169.5	167.1	153.3	148.5	145.3	140.8	136.2	133.3
Big ACE event frequency	2015	0.0	0.0	0.0	0.0	0.0	2.0	20.0	21.0	43.0
	2018	1.0	0.0	1.0	1.0	0.0	3.0	5.0	4.0	19.0
	2019	1.0	1.0	3.0	1.0	2.0	6.0	7.0	12.0	36.0
	2020	3.0	3.0	4.0	3.0	4.0	14.0	15.0	27.0	56.0
	2021	0.0	0.0	1.0	0.0	3.0	15.0	13.0	32.0	79.0
	2022	1.0	1.0	1.0	1.0	3.0	26.0	11.0	35.0	89.0
	2023	1.0	1.0	6.0	1.0	3.0	24.0	6.0	29.0	97.0
	2024	0.0	0.0	5.0	2.0	3.0	42.0	7.0	28.0	127.0
	2025	0.0	0.0	11.0	0.0	1.0	42.0	11.0	32.0	131.0
	2026	5.0	3.0	17.0	3.0	5.0	48.0	10.0	33.0	142.0
	2027	8.0	7.0	17.0	8.0	12.0	62.0	16.0	36.0	145.0
	2028	5.0	5.0	23.0	5.0	8.0	69.0	15.0	40.0	162.0
	2029	5.0	5.0	27.0	5.0	6.0	51.0	12.0	29.0	111.0
	2030	3.0	3.0	22.0	3.0	6.0	45.0	9.0	23.0	107.0

Interchange SOL Violations

Three different time periods were assessed for interchange SOL violations against different degrees of proactive dispatch. The resulting performance metrics are provided in Table . The first situation (at the top) is for the period without supply surplus, the second situation (in the middle) is for the period without supply surplus and BC ATC within +/-100 MW (BC 500 kV out of service), and the third situation is for the period with supply surplus.

The three different situations assessed are:

1. periods with no supply surplus hours (results in the top section of Table)

2. periods with no supply surplus hours and the BC ATC within +/-100 MW due to the 500 kV tie being out of service (results in the middle of Table ; these are a sub-set of previous periods)
3. periods with supply surplus hours (results in the bottom section of Table)

Different degrees of proactive dispatch included:

- achieving the dispatch level in 1, 1.5 or 2 time intervals
- different levels of persistent wind forecast

Table 15. Interchange SOL Violations

		dispatch due in 1 interval			dispatch due in 1.5 interval			dispatch due in 2 interval		
	YEAR	pstRamp 10..	pstRamp 50%	pstMW	pstRamp 10..	pstRamp 50%	pstMW	pstRamp 100..	pstRamp 50%	pstMW
SOL violation frequency	2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
	2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	3.0
	2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	5.0
	2025	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	4.0
	2026	1.0	1.0	1.0	1.0	1.0	2.0	1.0	2.0	9.0
	2027	0.0	0.0	0.0	0.0	0.0	2.0	0.0	1.0	8.0
	2028	0.0	0.0	0.0	0.0	0.0	1.0	0.0	2.0	4.0
	2029	0.0	0.0	0.0	0.0	0.0	2.0	0.0	1.0	5.0
	2030	0.0	1.0	0.0	0.0	1.0	0.0	0.0	1.0	3.0
SOL violation frequency when ATC within +/- 100MW	2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
	2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	2.0
	2023	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	1.0
	2025	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	3.0
	2026	0.0	0.0	0.0	0.0	0.0	1.0	0.0	1.0	7.0
	2027	0.0	0.0	0.0	0.0	0.0	1.0	0.0	0.0	6.0
	2028	0.0	0.0	0.0	0.0	0.0	1.0	0.0	2.0	4.0
	2029	0.0	0.0	0.0	0.0	0.0	2.0	0.0	1.0	5.0
	2030	0.0	1.0	0.0	0.0	1.0	0.0	0.0	1.0	3.0
SOL violation frequency during, SSS extra	2015	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2018	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2019	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2020	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2021	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2022	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2023	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	2024	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	2025	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	2026	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0	1.0
	2027	1.0	1.0	1.0	2.0	1.0	1.0	2.0	2.0	2.0
	2028	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0	4.0
	2029	8.0	8.0	8.0	8.0	8.0	8.0	8.0	8.0	9.0
	2030	12.0	12.0	13.0	13.0	12.0	13.0	15.0	15.0	17.0

The observed double-digit instances of interchange SOL violations occurred when dispatching in the least-proactive mode. These violations can be reduced to two events per year, or fewer, by using a more proactive dispatch practice, and the two events are only in the periods with interchange ATC less than 100 MW (the BC 500 kV line out of service). With the 500 kV tie out, the System Controller will need to adopt a more proactive dispatch practice to manage the NDV balance as this is no and less chance to get help from intertie, or alternatively procure and activate additional regulation reserves.

The SOL violations reported during supply surplus situation can be resolved by addressing the supply surplus issue. To do that would likely require pro-rata dispatch down in the real-time of the $0-offered energy to eliminate the supply surplus and/or reduce the volume of $0-offered energy in advance during pre-real-time resource commitment.

Wind Power Energy Limited Due to WPM

Simulations were also performed to determine the amount of wind power that could be expected to be curtailed due to wind power management practices. The results in Table indicate that for different years and for different dispatch practice, the total wind power energy curtailed due to the current WPM practice/rule is always less than 0.1% of the total wind power generation.

Table 16. Wind Power Energy Limited due to WPM

		dispatch due in 1 interval		dispatch due in 2 interval	
	YEAR	pstRamp 100%	pstMW	pstRamp 100%	pstMW
WPM energy%	2015	0.01	0.01	0.01	0.01
	2018	0.00	0.00	0.00	0.01
	2019	0.01	0.00	0.00	0.00
	2020	0.01	0.01	0.01	0.01
	2021	0.01	0.01	0.01	0.01
	2022	0.01	0.01	0.01	0.02
	2023	0.02	0.03	0.03	0.03
	2024	0.02	0.02	0.03	0.03
	2025	0.03	0.03	0.03	0.03
	2026	0.03	0.02	0.03	0.03
	2027	0.04	0.03	0.04	0.04
	2028	0.04	0.04	0.04	0.04
	2029	0.09	0.08	0.09	0.08
	2030	0.10	0.09	0.10	0.08

Supply Surplus or Shortfall and Unit Cycling

Supply surplus and unit cycling metrics can be found in the market simulation results. The dispatch simulation model only provides some estimated results in this document for reference and discussion purposes. The results are based on commitment to day-ahead wind forecast.

The simulation metrics results in Table include annual supply surplus hours, correspondent surplus energy in MWh, supply shortfall hours and high level size-normalized generation cycling events for generation technologies with non-zero MSG and long lead start time (Coal, CC and CtG, Cogen is not included here as its cycling is mainly due to its own production process requirement).

A size-normalized generation cycling metric is defined below, which averages the number of cycling events for any particular type of generation over the capacity of those generators.

$$\frac{\sum(individul\ unit\ capacity * individualunit\ cycling\ number)}{\sum individul\ unit\ capacity}$$

Table 17. Estimated Market Simulation Performance Metrics

	YEAR	No interchange	Historical ATC	Historical ATC +400MW (restoration)	always @ path rating with restoration
supply surplus hours (i)	2015	0.0	0.0	0.0	0.0
	2018	8.9	25.8	36.4	45.0
	2019	23.8	125.1	156.4	174.9
	2020	63.1	260.5	269.3	321.5
	2021	5.4	20.6	15.5	19.8
	2022	36.9	141.4	78.4	123.6
	2023	7.5	295.1	20.3	59.8
	2024	92.8	253.5	120.8	162.0
	2025	137.8	232.3	110.6	156.8
	2026	259.4	340.0	304.2	361.7
	2027	347.3	438.5	437.5	508.3
	2028	623.4	627.9	500.9	542.1
	2029	955.4	923.6	747.0	768.1
	2030	1,381.0	1,180.4	999.1	976.1
supply surplus MWh (i)	2015	0.0	0.0	0.0	0.0
	2018	411.1	1,858.0	3,062.7	3,972.3
	2019	3,682.7	25,904.2	33,466.0	37,415.3
	2020	11,642.1	80,217.5	78,661.4	94,294.2
	2021	1,228.6	3,829.5	3,004.8	4,156.9
	2022	13,134.5	48,153.6	20,869.1	35,152.3
	2023	3,513.6	162,537.7	1,903.1	11,097.0
	2024	49,972.2	144,304.0	64,502.0	75,660.0
	2025	39,069.3	99,662.0	19,521.0	36,818.5
	2026	118,362.6	131,918.8	110,406.9	124,539.3
	2027	164,472.8	228,566.8	219,734.7	255,063.2
	2028	340,828.0	288,879.1	196,505.8	206,338.7
	2029	587,495.5	494,895.4	314,203.3	310,867.5
	2030	1,066,585.2	633,456.1	473,942.9	422,462.9
supply shortfall hours (i)	2015	0.0	0.0	0.0	0.0
	2018	0.0	0.0	0.0	0.0
	2019	0.0	0.0	0.0	0.0
	2020	0.0	0.0	0.0	0.0
	2021	0.0	0.0	0.0	0.0
	2022	0.0	0.0	0.0	0.0
	2023	0.0	0.0	0.0	0.0
	2024	0.0	0.0	0.0	0.0
	2025	0.0	0.0	0.0	0.0
	2026	0.0	0.0	0.0	0.0
	2027	0.0	0.0	0.0	0.0
	2028	0.0	0.0	0.0	0.0
	2029	0.0	0.0	0.0	0.0
	2030	0.0	0.0	0.0	0.0
System cycling (Coal CC CtG)	2015	21.2	21.2	21.2	21.2
	2018	12.0	12.0	12.0	12.0
	2019	12.5	12.6	12.5	12.5
	2020	12.4	12.4	12.4	12.4
	2021	31.8	32.0	31.8	31.8
	2022	39.8	39.9	39.8	39.8
	2023	46.3	46.3	46.3	46.3
	2024	51.2	51.2	51.2	51.2
	2025	53.8	53.8	53.8	53.8
	2026	53.4	53.4	53.4	53.4
	2027	54.2	54.2	54.2	54.2
	2028	55.8	55.8	55.8	55.8
	2029	61.2	61.3	61.2	61.2
	2030	74.4	74.3	74.4	74.4

There are no supply shortfall hours in the market simulation results for all future years under all 4 different interchange assumptions.

Depending on the interchange assumption, the supply surplus starts to surpass historic levels (about 40 hours) around the mid-2020s and reach to about 950 to 1,400 hours range by 2030, or above 10% of the hours annually. As expected, the higher the ATC, the lower the number of surplus hours.

For generation cycling, we observe a gradual increase in generation cycling, based on only commitment units (coal, CTG and CC), the normalized generation cycling numbers increase more than 3 times from 2015 to 2030.

For more details information about supply surplus/shortfall and generation cycling, please refer to the market simulation analysis results.

3.5 Dispatch Simulation Analysis Results for Additional Scenarios

3.5.1 Sensitivity Analysis to Quantify ADfR Impacts

The current practice of dispatching up and down the EMMO to meet the changing net demand requires the System Controller to dispatch additional resources to achieve the size and speed of the ramps. These additional resources (up or down) are referred to as the ADfR.

A sensitivity analysis was performed to determine how incremental regulating reserves (AGC) may reduce the level of additional dispatch for ramp. Three different levels of AGC were modeled:

1) Increase AGC volumes by the same percentage that load increases
2) Double the AGC volumes from today
3) Triple the AGC volumes from today

A second sensitivity analysis was performed on the ramp rates. The NDV base analysis assumed the ramp rates for each asset was based on historical ramping behavior. Future ramping behavior may differ, especially as assets are asked to dispatch more frequently up and down to match a more volatile NDV. This second sensitivity assumed a slower ramp rate response as compared to historical ramping behaviour. The slower ramp rate response tested was a 25% longer response delay and 25% slower in ramp rate.

The performance metrics for these sensitivities can be found in Table . Each of the columns in Table 16 represents a different sensitivity. All sensitivities used a persistent ramp wind forecast.

- The first two columns use the reference case scenario and achieves the dispatch level in either one dispatch interval (proactive) or two dispatch intervals;
- The next three columns (3, 4, 5) use the Reference Case scenario with achieving the dispatch level in two dispatch intervals and then increases the AGC volume at load growth, double and triple.
- The final two columns (6, 7) use the same two reference case scenarios as the first two columns, but with a 25% slower ramp rate response.

By comparing Column 1 (Reference Case with one-interval dispatch response – the most proactive behavior) with Column 2 (the Reference Case with two-interval dispatch response – a less proactive behavious), we can observe that reliability performance metrics (higher CP2, fewer big-ACE events) are better for the more proactive dispatch, but about 36% additional dispatch mileage is required.

Comparing increased AGC volumes (Columns 3, 4 and 5) with proactive dispatch (Columns 1 and 2), we see that increasing AGC volumes improves the reliability performance metrics and decreases the amount of ADfR in all cases. Doubling AGC volumes (Column 4) provides better reliability performance metrics than using proactive dispatch (Column 1) and requires about 36% less dispatch mileage.

Table 18. Sensitivity Analysis – Impact of Dispatch for Ramp and Dispatch Mileage

metric	year	Reference Generation scenario					25% slower dispatch response	
		dipstach due in 1 interval	dipstach due in 2 interval	dipstach due in 2 interval			dipstach due in 1 interval	dipstach due in 2 interval
		RR 100%	RR 100%	RR Load%	RR 200%	RR 300%	RR 100%	RR 100%
CPS 2	2015	99.7	98.1					
	2018	99.6	98.6	98.7	99.7	99.9	99.1	98.5
	2019	99.5	98.5	98.6	99.6	99.9	98.7	98.2
	2020	99.4	98.1	98.3	99.5	99.8	98.5	98.0
	2021	99.1	98.1	98.4	99.6	99.8	96.5	97.8
	2022	99.1	97.9	98.2	99.5	99.8	96.5	97.6
	2023	99.2	97.9	98.4	99.6	99.9	96.6	97.7
	2024	99.3	98.1	98.5	99.7	99.9	97.1	97.9
	2025	99.2	98.1	98.5	99.6	99.8	97.1	97.7
	2026	99.2	97.8	98.3	99.5	99.8	97.0	97.4
	2027	99.0	97.8	98.3	99.5	99.8	95.7	97.4
	2028	99.1	97.9	98.4	99.5	99.8	95.9	97.4
	2029	99.1	98.0	98.5	99.5	99.7	95.4	97.3
	2030	99.0	97.9	98.3	99.3	99.7	94.9	97.0
overall dispatch variance MW std	2015	256.9	138.1					
	2018	247.6	140.5	140.4	140.3	140.1	309.8	163.1
	2019	237.7	139.9	139.9	139.0	139.5	299.1	160.8
	2020	243.3	142.1	142.1	141.1	141.4	302.4	161.8
	2021	242.0	149.4	149.7	151.5	152.6	324.8	169.7
	2022	262.1	158.9	158.3	158.6	159.9	359.2	181.8
	2023	269.4	169.4	167.2	167.0	167.2	352.1	186.2
	2024	253.9	164.0	163.3	163.0	163.0	334.4	182.5
	2025	246.8	163.5	162.1	159.2	158.8	318.3	181.1
	2026	244.8	166.4	166.2	164.4	163.2	321.3	182.2
	2027	243.0	164.1	163.0	162.6	160.7	321.6	179.9
	2028	224.0	156.1	155.3	153.3	151.5	289.4	170.1
	2029	186.3	140.4	138.5	137.0	135.4	253.4	150.8
	2030	175.8	140.6	139.7	137.9	135.1	242.0	150.2
Big ACE event frequency	2015	0	20					
	2018	1	5	5	0	0	2	8
	2019	1	6	6	1	0	5	8
	2020	3	15	14	3	3	5	18
	2021	0	13	10	2	1	2	21
	2022	0	11	12	4	2	2	19
	2023	1	8	5	1	1	2	9
	2024	2	7	7	0	0	3	12
	2025	3	12	9	2	0	5	21
	2026	5	12	9	4	3	7	19
	2027	9	18	13	6	6	10	18
	2028	5	14	13	5	5	6	20
	2029	4	11	9	7	5	3	16
	2030	3	9	8	3	3	7	22
SOL violation frequency	2015	0	0					
	2018	0	0	0	0	0	0	0
	2019	0	0	0	0	0	0	0
	2020	0	0	0	0	0	0	0
	2021	0	0	0	0	0	0	0
	2022	0	0	0	0	0	0	0
	2023	0	0	0	0	0	0	0
	2024	1	0	0	0	0	0	0
	2025	1	0	1	1	1	0	0
	2026	1	3	1	1	1	1	1
	2027	0	1	0	0	0	0	0
	2028	0	0	0	0	0	1	0
	2029	0	0	0	0	0	0	0
	2030	0	0	0	0	0	3	3
system perfect dispatch volume / mileage	2015	1,987,872	1,987,872					
	2018	2,036,449	2,036,449	2,036,636	2,046,032	2,064,436	2,036,448	2,036,448
	2019	2,126,114	2,126,114	2,126,344	2,134,598	2,152,340	2,126,120	2,126,120
	2020	2,209,760	2,209,760	2,209,974	2,217,552	2,233,259	2,209,760	2,209,760
	2021	2,241,708	2,241,708	2,242,111	2,250,840	2,268,601	2,241,710	2,241,710
	2022	2,377,448	2,377,448	2,377,849	2,386,384	2,403,263	2,377,441	2,377,441
	2023	2,424,564	2,424,564	2,425,020	2,433,780	2,451,191	2,424,546	2,424,546
	2024	2,491,147	2,491,147	2,491,546	2,499,697	2,516,841	2,491,129	2,491,129
	2025	2,594,667	2,594,667	2,595,160	2,603,317	2,620,010	2,594,648	2,594,648
	2026	2,687,851	2,687,851	2,688,414	2,696,008	2,712,256	2,687,832	2,687,832
	2027	2,763,693	2,763,693	2,764,317	2,771,937	2,787,690	2,763,673	2,763,673
	2028	2,862,846	2,862,846	2,863,435	2,870,502	2,885,791	2,862,833	2,862,833
	2029	2,997,164	2,997,164	2,997,950	3,005,417	3,021,351	2,997,154	2,997,154
	2030	3,101,364	3,101,364	3,102,388	3,110,672	3,126,706	3,101,339	3,101,339
Dispatch mileage	2015	9,237,968	4,968,764					
	2018	9,208,203	5,163,102	5,167,417	5,139,611	5,154,594	11,296,360	5,979,562
	2019	8,681,650	5,086,727	5,078,410	5,046,941	5,032,929	10,696,994	5,817,805
	2020	8,738,020	5,089,145	5,087,360	5,057,522	5,078,441	10,637,050	5,771,118
	2021	8,644,398	5,293,322	5,338,794	5,433,480	5,500,539	11,381,914	6,009,076
	2022	9,377,280	5,718,864	5,684,012	5,687,893	5,756,243	12,441,639	6,430,728
	2023	9,801,263	6,165,390	6,023,380	6,019,904	6,021,469	12,036,861	6,562,339
	2024	9,167,009	5,904,567	5,825,305	5,814,429	5,807,291	11,660,646	6,429,567
	2025	8,861,588	5,884,160	5,833,844	5,740,213	5,703,600	10,866,255	6,283,986
	2026	8,554,619	5,852,205	5,799,892	5,720,869	5,664,185	10,758,853	6,261,457
	2027	8,396,354	5,718,129	5,697,331	5,683,421	5,583,355	10,799,076	6,190,459
	2028	7,621,163	5,509,011	5,468,567	5,390,092	5,305,448	9,508,940	5,740,205
	2029	6,082,063	4,799,989	4,705,380	4,634,361	4,559,683	7,925,593	4,880,935
	2030	5,425,429	4,559,511	4,507,360	4,429,465	4,336,763	7,314,521	4,610,845

3.5.2 Impact of Generation Mix Scenarios on Supply Surplus and Generation Cycling

As mentioned previously, supply surplus and unit cycling metrics can be found in the Market Team's market simulation results. The dispatch simulation model only can also provide supply surplus and unit cycling metrics. The results are based on commitment to day-ahead wind forecast.

Table provides the results for annual supply surplus hour, correspondent surplus energy, and high level normalized generation cycling instance for all thermal generations technologies with non-zero MSG (simple cycle usually has zero MSG) for five different generation scenarios and the Reference Case scenario.

Table 19. Sensitivity Analysis – Supply Surplus and Generation Cycling

	YEAR	Reference	High-CoGen	Lower $0-offer	High CtG	No CtG	High Hydro
supply surplus hours (i)	2015	0.0					
	2018	36.4	496.0				
	2019	156.4	653.7				
	2020	269.3	840.3				
	2021	15.5	42.4				
	2022	78.4	351.6				
	2023	20.3	224.4				
	2024	120.8	294.8				
	2025	110.6	412.5	147.2	96.1	631.4	2,917.9
	2026	304.2	583.2	287.6	337.2	727.2	3,284.1
	2027	437.5	880.8	306.9	331.4	689.3	3,554.5
	2028	500.9	1,233.2	360.7	618.9	660.3	3,642.8
	2029	747.0	1,463.4	409.1	523.8	798.6	3,915.9
	2030	999.1	1,779.4	575.3	507.6	973.8	4,556.5
supply shortfall hours (i)	2015	0.0					
	2018	0.0	0.0				
	2019	0.0	0.0				
	2020	0.0	0.0				
	2021	0.0	0.0				
	2022	0.0	0.0				
	2023	0.0	0.0				
	2024	0.0	0.0				
	2025	0.0	0.0	0.0	0.0	0.0	0.0
	2026	0.0	0.0	0.0	0.0	0.0	0.0
	2027	0.0	0.0	0.0	0.0	0.0	0.0
	2028	0.0	0.0	0.0	0.0	0.0	0.0
	2029	0.0	0.0	0.0	0.0	0.0	0.0
	2030	0.0	0.0	0.0	0.0	0.0	0.0
System cycling (Coal CC CtG)	2015	21.2					
	2018	12.0	88.0				
	2019	12.5	88.2				
	2020	12.4	87.8				
	2021	31.8	32.1				
	2022	39.8	41.1				
	2023	46.3	48.9				
	2024	51.2	54.0				
	2025	53.8	56.1	48.4	53.1	28.6	92.1
	2026	53.4	56.2	49.0	53.7	32.0	91.6
	2027	54.2	58.6	48.1	53.1	27.9	89.5
	2028	55.8	64.6	48.4	60.9	33.3	88.2
	2029	61.2	77.5	47.6	71.1	45.2	85.3
	2030	74.4	92.7	50.7	77.3	57.2	86.4

3.6 Dispatch Simulation Analysis Results at Further Detailed Levels

The analysis metrics results presented so far are all at the system aggregate level, which can help to understand the general trending at the system aggregation level. For some metrics such as on/off cycling and dispatch mileage, model details at technology (generation type) and individual asset level can further facilitate the better understanding of the future situations. The further details can also help us to validate the assumption and input data and identify / reveal any potential defect / flaw in them.

Table 20 provides the results for annual supply surplus hour, correspondent surplus energy, and high level normalized generation cycling instance for all thermal generations technologies with non-zero MSG (simple cycle usually has zero MSG) for five different generation scenarios and the Reference Case scenario.

Table 20. The simulation result details at each technology level

		Capacity		# of Asset		MSG		$0-Offer		On-Off_Cycling		Mileage_Dispatch		Mileage_Ramped	
	ID	2015	2030	2015	2030	2015	2030	2015	2030	2015	2030	2015	2030	2015	2030
generation	COAL	6,259	921	18	2	2,608	352	2,694	541	126	57	7,916,983	466,451	3,223,552	304,172
generation	GAS, COGEN	4,349	5,131	58	69	1,760	1,788	2,681	3,349	2,868	4,184	727,714	592,507	685,232	569,003
generation	GAS, CC	1,470	1,666	12	13	715	734	470	635	1,093	602	285,490	821,111	252,071	764,076
generation	GAS, SC	889	916	26	26	279	279	12	19	928	965	78,339	281,458	77,323	283,505
generation	GAS, CtG		2,371		6		474		208		712		850,727		290,241
generation	GAS, NewCC		3,385		8		1,312		1,517		573		1,627,278		1,497,495
generation	GAS, NewSC		425		10		0		0		294		448,883		428,404
generation	HYDRO	734	1,083	8	9	26	26	218	446	273	284	197,720	215,116	194,872	210,381
generation	OTHER	332	337	10	11	60	69	239	236	759	723	31,806	48,304	29,835	45,481
generation	WIND	1,465	6,445											709,160	1,809,342
generation	SOLAR	0	500											0	222,559
system	Dispatchable											9,238,052	5,351,836	4,462,884	4,392,760
system	VGEN													709,154	1,806,100
system	LOAD													1,539,465	1,893,913
system	NDV													1,761,812	2,774,895
system	NDV+Tie													1,987,897	3,022,911
system	ODV_system											8,971,404	5,254,564	3,615,411	4,057,160

These result details at technology level can help us to have better understanding and communication of the impact of overall system flexibility by technology, and the NDV's impact on generation operation by different type, in term of potential increasing on-off cycling and ramping up and down (mileage). For example of the 6 CtG assets (2370MW in total), it shows 712 times of on-off cycling in 2030 (about twice a week per asset), it also shows that CtG assets achieved 290,241MW out of 850,727 MW dispatched mileage. The achieved ratio is about 30% only, indicates CtG asset has slower ramp rate. The 290,241MW achieved dispatched mileage is equivalent to about 60 full MW cycles per asset. These are important information to understand the NDV's impact of generation operation and related cost at technology and asset level. The further detail at individual asset level is also available for asset level.

3.7 Interchange Restoration's Effect on SOL Violation Due to NDV

Additional Interchange capacity cannot directly mitigate Interchange imbalance at operation timeframe, it is not a direct NDV mitigation measure. However it could reduce the chance and magnitude of an interchange SOL violation event as the additional interchange capacity can result into more room between interchange ATC and interchange schedule during period when the additional Interchange capacity is not used for energy schedule. The interchange restoration only increases the ATC capability when 500kV tie-line is in service, it could have this reducing effect on potential SOL violation. This reducing effect is also limited due to the nature compensating / mitigating effect between wind generation and interchange ATC violation risk. In the sense of more room between interchange schedule and ATC, there is no difference between increased ATC and reduced schedule.

Regarding potential SOL violation due to NDV, there is the concern of significant wind power ramp down during high wind power output time. If the internal generation cannot response fast enough, this could lead to reduced export flow or increased import flow that can trigger an import SOL violation event. However, when wind power output is high, there is relatively more internal generation and the pool price is usually lower, as well as the lower chance of high import, which results into less chance of import SOL violation. So, the concern / risk of import SOL violation due to potential significant wind power ramp-down during high wind power period is naturally "mitigated" by the corresponding less import schedule level. Vice versa, the concern / risk of export SOL violation due to potential significant wind power ramp-up during low wind power period is naturally "mitigated" by the corresponding less export schedule level. This nature compensating / mitigating effect between wind generation and interchange ATC violation risk can be observed in Figure 27.

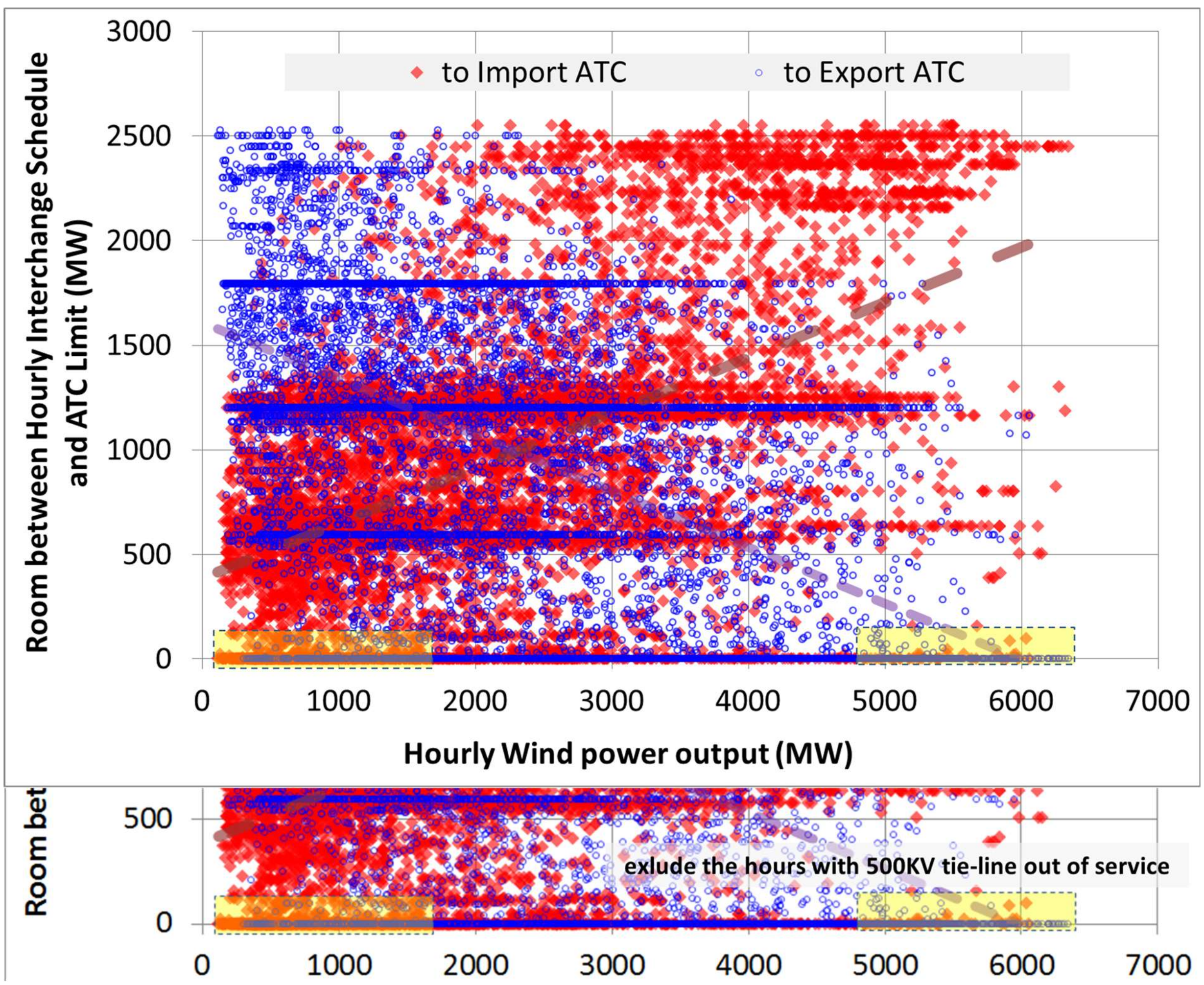


Figure 27. 2030 hourly wind power output and room between interchange schedule and ATC

In spite of the nature mitigating effect, there are still some exceptional hours with low export ATC room during low wind power period (blue points inside the left yellow shade), and low import ATC room during high wind power period (red inside the right yellow shade). When excluding those hours with 500kV tie-line out-of-service, these exceptional hours are reduced, as shown in the lower half chart (less blue points in left yellow shade, and less red in right shade). It indicates that there are still some low export ATC room hours during low-medium wind power period (risk of export SOL violation due to NDV), and low impact ATC room hours during medium-high wind power period (risk of import SOL violation due to NDV).

To assess the interchange restoration reduction effect on SOL violation due to NDV's, we included two additional AC interchange scenarios as described in section 2.3.5. One scenario's AC interchange ATC is based on 2015 historical performance; the other scenario is also the same basis with additional 400MW on both import and export ATC (for the periods with 500kV in service) to reflecting the interchange restoration. Both scenarios are assumed to have the same hourly interchange schedule.

Table 21. Interchange SOLViolation results for scenarios with and without Intertie restoration

		reference scenario with historical ATC		reference scenario with historical ATC + 400MW	
	YEAR	PersistentRamp Forecast more proactive	PersistentRamp Forecast less proactive	PersistentRamp Forecast more proactive	PersistentRamp Forecast less proactive
SOL violation frequency	2021	0.0	0.0	0.0	0.0
	2022	0.0	0.0	0.0	0.0
	2023	1.0	0.0	0.0	0.0
	2024	0.0	1.0	0.0	0.0
	2025	1.0	1.0	1.0	1.0
	2026	1.0	1.0	1.0	1.0
	2027	2.0	2.0	0.0	0.0
	2028	1.0	1.0	1.0	1.0
	2029	1.0	2.0	0.0	0.0
	2030	1.0	2.0	0.0	0.0
SOL violation MW	2021	0.0	0.0	0.0	0.0
	2022	0.0	0.0	0.0	0.0
	2023	-84.3	0.0	0.0	0.0
	2024	0.0	-70.6	0.0	0.0
	2025	86.9	92.9	86.9	92.9
	2026	94.2	94.2	94.2	94.1
	2027	74.0	70.6	0.0	0.0
	2028	88.4	88.5	88.5	88.5
	2029	66.2	96.4	0.0	0.0
	2030	68.6	100.9	0.0	0.0

For the less-proactive operation approach, without intertie restoration, there are 10 simulated SOL events with the most extreme event at ACE magnitude of 101MW over 30 minutes, 36MW violation. They are reduced to 3 simulated SOL events with the most extreme at ACE magnitude of 94MW over 30 minutes. The other 7 "mitigated" events are still big-ACE events.

3.8 Additional two scenarios to support DR&S work

In order to get directional / book-end understanding of the impact for the even more variable renewable target situation (40% energy from renewables) in supporting DR&S work, we performed simulation analysis for the two additional generation scenarios. (as described in section 2.3.1 and table 7). The two parallel chars in Figure 28 summarize the analysis results of both these two scenarios. The top chart is for Mid-CtG scenario, the bottom chart is for High-CTG. There are 22 parallel "coordinates" (dimensions) in each chart, different coordinate represents a different input condition or different result metric. The yellow shades on the two charts highlight the diffident result metric (defined in section 2.1 and Table 3) along each coordinate. The green shades highlight the significant outliers.

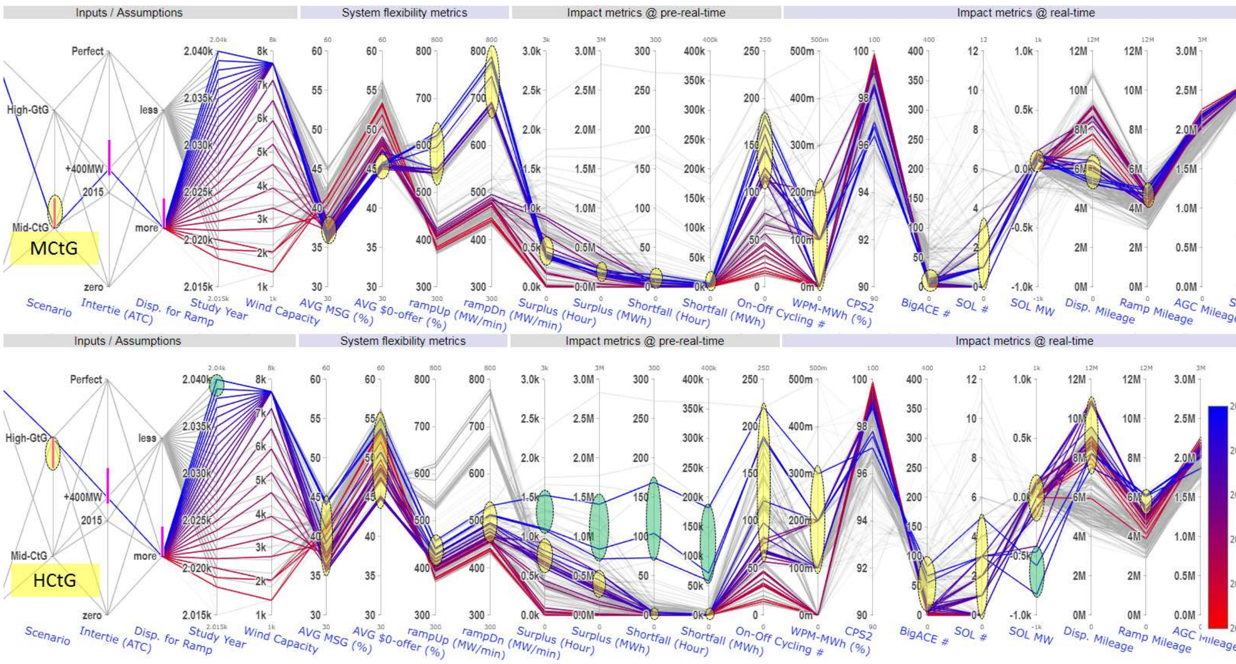


Figure 28. The Input and Results Metrics Comparing between MCtG and HGtG

For the new reference scenario (MCtG), with up to 1200MW more wind generation at later 2020s, its simulation is not significet difference from previous MCtG. The supply surplus situation of 2029-2030 appears to be improved due to less run-of-river hydro, less coal and more SC in 2030, and possiblelly improved cycling / commitment algorism.

By comparising the two charts especially for those later years (more blueish) with more wind power and more difference in generation mix between these two scenarios, we can see:

- The HCtG has less overall system flexibility in term of higher MSG, $0-offer level and slower EMMO ramp rate. It can be explained by the less SC, more CtG and CC in those later years.
- The HCtG has more supply surplus hours (up to 1500 hours a year) due to its less overall system flexibility situation. The last 3 years (2038 - 2040) have significant different results (green shaded) in both supply surplus and shortfall. They can be explained by the significant more (~1800-3600MW) CC generation and significant less (~2600MW) SC generation.
- For the same reasons, the HCtG aslo has more on-off cycling for those commitment assets (with long-lead start time, such as Coal, CtG, CC, COGEN) at per asset basis.
- The limited energy due to WPM of HCtG is within 0.3% of total wind power generation, about 0.1% more than MCtG. It is due to its lower ramp rate.
- For 10-minute NDV impact (CPS2) in both HGtC and NCtG have no concerns.
- For 30-minute NDV impact, the HCtG has more big-ACE and SOL violation instances, especially in the last 3 years with significant more CC and less SC than MCtG. Further details look of the input hourly EMMO reveal that several significant larger SOL violation magnitude caused by some significant EMMO offer swings of 6-8GW. This observation of significant EMMO offer swing has been reported to market simulation team for further investigation in future.
- The HGtG also has higher dispatched-mileage results that can be caused by more dispatch-for-ramp due to lower ramp rate and/or by more EMMO offer swings, as the result of more CC and less SC.

4 Findings and Recommendations

4.1 Findings

Between 2015 and 2030, NDV is expected to grow considerably as more variable generation is brought onto the system. The frequency of NDV ramps, the magnitude or MW size of NDV ramps and the overall volume of ramping will increase materially. This increased NDV will bring growing challenges to the System Controllers to match supply resources to this growing NDV.

The dispatch simulation analysis performed was based upon on two key dispatch assumptions:

1. The historical ramping behavior by asset owners will continue into the future.
2. The entire merit order above zero-dollar offers, as provided from the market simulation, is available for ramping.

Within the constraints of these assumptions, the real time NDV can be matched by proactively dispatching the energy market merit order. Should the future asset owner ramping behavior change materially, the reliability performance metrics could be materially different.

The more aggressively the System Controller dispatches the merit order, the better the reliability performance metrics will be, however, the trade-off is that more additional-dispatch-for-ramp is required. Doubling AGC volumes can achieve similar reliability performance metrics with 35% lower additional dispatch for ramp. During periods of low ATC due to tie line outages, the System Controller will need to be more aggressive in using the merit order to match the NDV or will need to have more regulating reserves available in those situations.

It should be noted that as more proactive dispatching is required, particularly with the increased NDV variability, this could lead to the following market concerns (being assessed in EAS work):

- increasing energy market price volatility
- increasing asset ramping with corresponding offer and ramping behavior changes
- increasing need to align compensation for providing ramping to those assets delivering the ramping capabilities. The current approach through the merit order provides increased compensation to whichever assets are generating at the time of an up-ramp, regardless of whether they provide any ramping. Equally misaligned is that the current approach through the merit order penalizes or takes compensation from whichever assets are generating at the time of a down-ramp.
- increased reliance on predictable generator dispatch and ramp performance through tighter dispatch tolerance rules (Rule 203.4)

For the pre-real-time operation timeframe, the market simulation analysis concludes that for reference case generation scenario, the NDV results in more annual supply surplus hours and more generation unit cycling, exceeding historical volumes around the mid-2020s. The surplus hours could be up to about 1000 hours and the assets cycling of commitment assets could be more than triple in 2030 when compared to 2015. These will require additional assessment and potentially the development of mitigation solutions in the pre-real-time time frame such as changes in practice to resource scheduling and commitment. The EAS work stream is assessing potential mitigation solutions, for the future.

4.2 Recommendations

The 2017 NDV studies confirm five of six recommendations for real-time operation that were provided in the 2016 study. The recommendations are related to implementing more proactive dispatch practice:

1. Modify and enhance AESO Rule 203.4 – *Delivery Requirements for Energy* regarding dispatch tolerance to ensure efficient, predictable and achievable generator dispatch responses and ensure current dispatch response behavior is sustained.
2. The System Controller is to assume persistent ramping in addition to persistent MW in the wind power forecasting to ensure more proactive dispatch decisions and accommodate increased variable generation.
3. Modify the dispatch practice to increase pre-dispatch generation to minimize the potential for response delay.
4. Investigate the potential for using day-ahead variable generation forecast data and interchange forecast data for regulating reserve procurement such as moving to an hourly volume profile versus on/off peak. (Note that time-based "on/off peak" might not be relevant in the future.)
5. Evaluate a potential change to AESO Rule 304.3 – *Wind Power Ramp Up Management* to ensure effective and efficient use of the available ramping capability in energy market.

The recommendation proposed in 2016 to automatically dispatch in 5-minute intervals, is not recommended at this time. To pursue this solution is still premature given all related ongoing work in the EAS work stream.

Analyses presented in this report focus on real-time timeframe. However, it also introduces and discusses the performance metrics that lay out the technical framework for assessing additional NDV impacts at pre-real-time timeframe. The pre-real-time results and suggestions presented in this report are for purposes of context and discussion only. Please refer to the market simulation study for pre-real-time detailed results and findings.

Based on the findings presented in this report, we suggest that the Market team:

- consider whether rule changes are required for current unit commitment (self-commitment) practices, or whether the system controller can achieve the desired outcome through scheduling (central-commitment) practices
- develop more detailed supply surplus and unit cycling metrics to assess the impact of NDV on generation assets and future pre-real-time offer / commitment behavior

New or revised AESO rules may be required to ensure that assumptions used in the market studies can be reflected in actual market operation in the future.

Appendix A: EMMO Snapshot

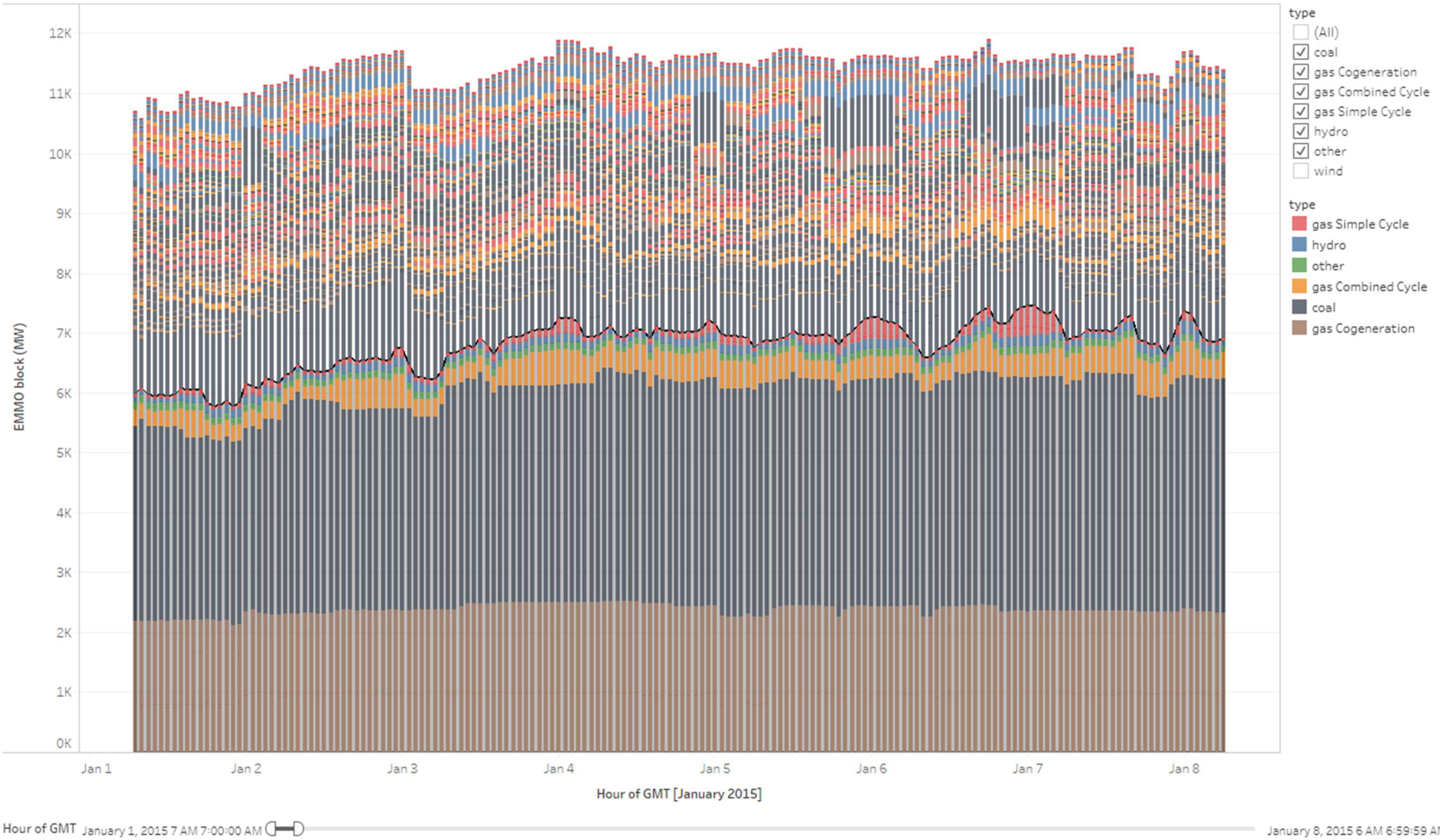
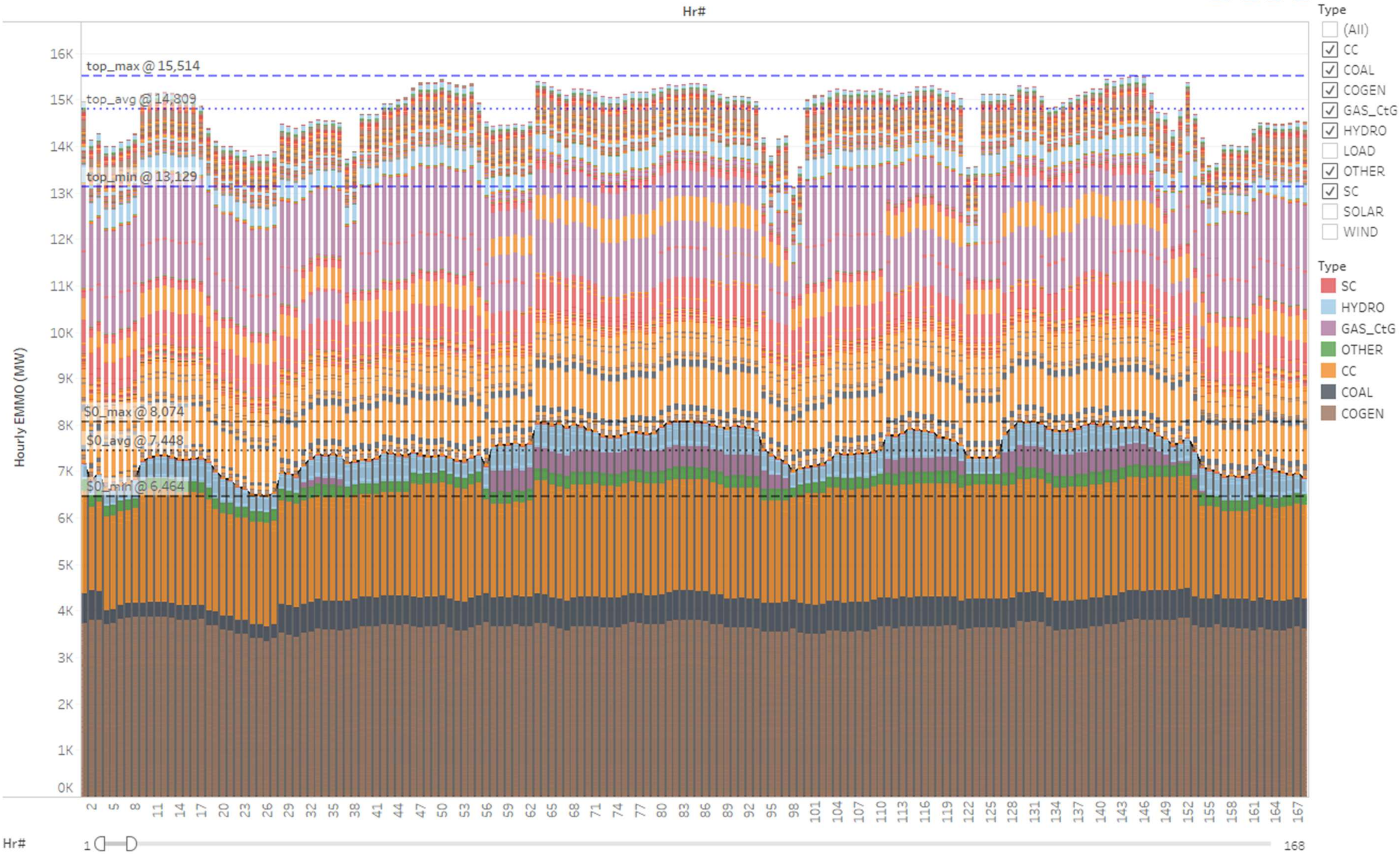


Figure A-1. 2015 First Week EMMO Snapshot


Hr#
top_max @ 15,514
top_avg @ 14,809
top_min @ 13,129
S0_max @ 8,074
S0_avg @ 7,448
S0_min @ 6,464
Hourly EMMO (MW)
16K
15K
14K
13K
12K
11K
10K
9K
8K
7K
6K
5K
4K
3K
2K
1K
0K
Type
(All)
CC
COAL
COGEN
GAS_CtG
HYDRO
LOAD
OTHER
SC
SOLAR
WIND
Type
SC
HYDRO
GAS_CtG
OTHER
CC
COAL
COGEN
Hr#
1
168

Appendix B: Generation Asset Dispatch Response Characteristics

(Provided by the Market Team)

Table B-1. Coal Asset Dispatch Response Analysis Result

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
Battle River 3	2.4	2.3	2.2	3	2.4
Battle River 4	3	0.6	2.8	2.5	2.5
Battle River 5	4.3	1.3	2.3	5.9	5.7
Genesee 1	2.3	2.3	2.4	3.9	4.1
Genesee 2	4.3	2.9	2.6	4.2	4.7
Genesee 3	2.7	2.3	2.5	1.8	1.8
HR Milner	5.7	2.1	2.8	2.7	2.6
Keephills 1	2.1	3.7	1.9	5.9	6.2
Keephills 2	3.4	2.8	1.9	6.1	6.5
Keephills 3	2.5	2.3	2.4	5.2	5.1
Sheerness 1	2.9	2.3	2.9	4.7	4.6
Sheerness 2	2.9	2.3	2.9	4.9	4.8
Sundance 1	2.7	2.3	2.7	3.4	3
Sundance 2	2.8	2.3	2.8	3.4	2.9
Sundance 3	2.1	2.3	2.1	6.7	6.3
Sundance 4	2.3	2.3	2.3	6.1	6.3
Sundance 5	2.1	2.3	2.2	6.8	6.1
Sundance 6	3	0.6	2.1	6.5	6
Coal average	3	2.2	2.4	4.6	4.5

Table B-2. Combined-Cycle Asset Dispatch Response Analysis Result

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
EnCana #1 CC1	4.5	1.5	1.8	2.3	2.6
EnCana #1 CC2	4.5	1.5	1.8	2.3	2.6
Calgary Energy Centre	5	0.6	1.7	6.8	6.2
ENMAX Shepard CC1	5.2	2.5	2.1	3.9	2.1
ENMAX Shepard CC2	5.2	2.5	2.1	3.9	2.1
FNG1 Fort Nelson	3.5	2.5	2.9	2.2	2.1
Medicine Hat #1 CC10	2.7	2.5	2.6	0.7	0.7
Medicine Hat #1 CC11	2.7	2.5	2.6	0.7	0.7
Medicine Hat #1 CC14	2.7	2.5	2.6	1	1
Medicine Hat #1 CC15	2.7	2.5	2.6	1	1
Medicine Hat #1 CC16	2.7	2.5	2.6	0.7	0.7
Nexen Inc #1 CC1	6.2	3.1	1.9	2	1.7
Nexen Inc #1 CC2	6.2	3.1	1.9	2	1.7
CC average	4.1	2.3	2.2	2.3	1.9

Table B-3. Simple-cycle Asset Dispatch Response Analysis Result

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
AB Newsprint	8.3	9.7	3	8.2	3.8
AltaGas Bantry	6.8	13.8	2.5	10.1	10
AltaGas Burdett	6.8	13.8	2.5	10.1	10
AltaGas Coaldale	6.8	13.8	2.5	10.1	10
AltaGas Parkland	6.8	13.8	2.5	10.1	10
AltaGas Taber	6.8	13.8	2.5	10.1	10
Bellshill	6.8	13.8	2.5	10.1	10
Carson Creek	6.8	13.8	2.5	10.1	10
Cloverbar #1	7.1	8.3	3	9.4	7.5
Cloverbar #2	7.4	17.8	1.8	22.7	18.3
Cloverbar #3	7.4	17.9	1.8	21.6	16.2
Crossfield Energy Centre #1	6.9	7.7	2.1	7.4	4.7
Crossfield Energy Centre #2	6.9	7.5	1.9	7.6	3.6
Crossfield Energy Centre #3	6.8	13.8	2.5	10.1	10
Drywood G1	6.8	13.8	2.5	10.1	10
Elmworth (G5-G9)	6.8	13.8	2.5	10.1	10
House Mountain	6.8	13.8	2.5	10.1	10
Jenner	6.8	13.8	2.5	10.1	10
Judy Creek	6.8	13.8	2.5	10.1	10
Landry	6.8	13.8	2.5	10.1	10
Mazepa	6.8	13.8	2.5	10.1	10
Muskwa	6.8	13.8	2.5	10.1	10
Northern Prairie Power	5	6.8	2.7	6.5	5.5
Northstone 3	6.8	13.8	2.5	10.1	10
NW Onsite 1	6.8	13.8	2.5	10.1	10
NW Onsite 2	6.8	13.8	2.5	10.1	10
NW Onsite 3	6.8	13.8	2.5	10.1	10
NW Onsite 4	6.8	13.8	2.5	10.1	10
NW Onsite 5	6.8	13.8	2.5	10.1	10
NW Onsite 6	6.8	41.4	2.5	30.2	30.1
NW Onsite 7	6.8	27.6	2.5	20.1	20.1
Peace Butte	6.8	13.8	2.5	10.1	10
Poplar Hill #1	6.5	8.1	2.2	4.4	6.5
Rainbow #5	7.1	8.6	2.5	5.1	6.8
Ralston	6.1	2.1	4.9	1	1.3
Valley View 1	6.9	8.4	2.2	8	6.2
Valley View 2	6.8	13.8	2.5	10.1	10
Vauxhall #1	6.8	13.8	2.5	10.1	10
Vauxhall #2	6.8	13.8	2.5	10.1	10
West Cadotte	6.8	13.8	2.5	10.1	10
Average	6.8	13.6	2.5	10.6	10

Table B-4. CoGen Asset Dispatch Response Analysis Result (1)

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
Air Liquide Scotford #1	3.3	4.4	1.5	3.4	3.5
AltaGas Harmattan GT1	2.9	2.8	2.7	1.1	1
AltaGas Harmattan GT2	2.9	2.8	2.7	1.1	1
AltaGas Harmattan GT3	2.9	2.8	2.7	1.1	1
Aspen GT1	3.4	2.8	2.4	3.7	2.5
ATCO Scotford Upgrader	1.4	2.8	1.5	4.7	5
Bear Creek (CC)	2.6	1.9	3.8	8.8	1.9
Bear Creek (MR ST)	6	0.5	3.9	0.9	1.2
Blackrod GT1	3.4	2.8	2.4	3.7	2.5
Blue Earth JBS	3.4	2.8	2.4	3.7	2.5
Brion MacKay River	3.4	2.8	2.4	3.7	2.5
BuckLake	3.4	2.8	2.4	3.7	2.5
Cargill Camrose	3.4	2.8	2.4	3.7	2.5
Carseland Cogen GT1	3	1.3	3.1	1.2	1.3
Carseland Cogen GT2	3	1.3	3.1	1.2	1.3
CEN Christina Lake GT1	3.4	2.8	2.4	3.7	2.5
CEN Christina Lake GT2	3.4	2.8	2.4	3.7	2.5
CEN Narrows Lake GT1	3.4	2.8	2.4	3.7	2.5
CNRL Horizon 2	3.4	2.8	2.4	3.7	2.5
CNRL Horizon	3.4	2.8	2.4	3.7	2.5
Dover North	3.4	2.8	2.4	3.7	2.5
Dover West GT1	3.4	2.8	2.4	3.7	2.5
Dow Hydrocarbon G101	1.6	2.8	1.6	2.1	2
Dow Hydrocarbon G201	1.6	2.8	1.6	2.1	2
Dow GT1 + ST1	1.6	2.8	1.6	2.9	2.8
Foster Creek GT1	2.7	1.9	4.2	6.9	2.3
Foster Creek GT2	2.7	1.9	4.2	6.9	2.3
Frontier GT1	3.4	2.8	2.4	3.7	2.5
GCogen_A1	3.4	2.8	2.4	3.7	2.5
GCogen_A2	3.4	2.8	2.4	3.7	2.5
GCogen_B1	3.4	2.8	2.4	3.7	2.5
GCogen_B2	3.4	2.8	2.4	3.7	2.5
GCogen_C1	3.4	2.8	2.4	3.7	2.5
GCogen_C2	3.4	2.8	2.4	3.7	2.5
GCogen_D	3.4	2.8	2.4	3.7	2.5
GCogen_E	3.4	2.8	2.4	3.7	2.5
GCogen_F	3.4	2.8	2.4	3.7	2.5
Generic 2nd 10 yr	3.4	2.8	2.4	3.7	2.5
Grand Rapids	3.4	2.8	2.4	3.7	2.5
IOR Strahcona Cogen	3.4	2.8	2.4	3.7	2.5
Joffre #1 COG1	2.6	2.9	1.4	3.7	3.8
Joffre #1 COG2	2.6	2.9	1.4	3.7	3.8

Table B-5. CoGen Asset Dispatch Response Analysis Result (2)

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
Joslyn	3.4	2.8	2.4	3.7	2.5
Kearl ST	3.4	2.8	2.4	3.7	2.5
Lindbergh	3.4	2.8	2.4	3.7	2.5
MacKay River	2.4	2.8	2.1	5.1	4.9
Mahkeses GT1	2	2.1	1	0	2.5
Mahkeses GT2	2	2.1	1	0	2.5
MEG Christina Lake GT1	3.4	2.8	2.4	3.7	2.5
MEG Christina Lake GT2	3.4	2.8	2.4	3.7	2.5
MEG Christina Lake GT2B4X	3.4	2.8	2.4	3.7	2.5
MEG Christina Lake GT3A	3.4	2.8	2.4	3.7	2.5
MEG Christina Lake GT4	3.4	2.8	2.4	3.7	2.5
Muskeg River GT1	1.5	2.8	1.5	3.1	3
Muskeg River GT2	1.5	2.8	1.5	3.1	3
Nabiye GT1	1.8	2.8	1.9	1.6	2.1
Nabiye GT2	1.8	2.8	1.9	1.6	2.1
Nexen Inc #2 GT1	1	1.8	1.9	2	1.6
Nexen Inc #2 GT2	1	1.8	1.9	2	1.6
Primrose #1	3.5	2.6	2.6	4.3	4.6
Rainbow Lake #1	5	3.7	0.9	3.5	1.3
Redwater Cogen	3.3	5.9	3	5.7	0.8
Shell Caroline	3.4	2.8	2.4	3.7	2.5
Suncor 1	3.5	0.2	3.1	0.9	0.8
Suncor 2	3.5	0.5	3.1	2.2	2
Suncor Firebag 1	3.5	1.8	3.1	7.4	6.7
Suncor Firebag 2	3.5	1.8	3.1	7.4	6.7
Suncor Firebag 3	3.5	1.8	3.1	7.4	6.7
Suncor Firebag 4	3.5	1.8	3.1	7.4	6.7
Suncor Fort Hills GT1	3.4	2.8	2.4	3.7	2.5
Suncor Fort Hills GT2	3.4	2.8	2.4	3.7	2.5
Suncor Millennium 3	3.5	1.2	3.1	4.9	4.4
Suncor Millennium 4	3.5	1.4	3.1	5.6	5
Suncor Millennium 5	3.5	2.4	3.1	9.7	8.8
Suncor Millennium 6	3.5	2.4	3.1	9.7	8.8
Suncor Millennium 7	3.5	1.8	3.1	7.4	6.7
Syncrude G1	3.4	2.8	2.4	3.7	2.5
Syncrude G2	3.4	2.8	2.4	3.7	2.5
Syncrude G3	3.4	2.8	2.4	3.7	2.5
Syncrude G4	3.4	2.8	2.4	3.7	2.5
Syncrude G5	3.4	2.8	2.4	3.7	2.5
Syncrude G6	3.4	2.8	2.4	3.7	2.5
Syncrude G20	3.4	2.8	2.4	3.7	2.5
Syncrude G21	3.4	2.8	2.4	3.7	2.5
Syncrude Mildred Lake	3.4	2.8	2.4	3.7	2.5
Syncrude-UE-1-G11	3.4	2.8	2.4	3.7	2.5
Syncrude-UE-1-G12	3.4	2.8	2.4	3.7	2.5
Talisman Edson GT1	3.4	2.8	2.4	3.7	2.5
Talisman Edson GT2	3.4	2.8	2.4	3.7	2.5
Telephone Lake	3.4	2.8	2.4	3.7	2.5
U of C Generator	3.4	2.8	2.4	3.7	2.5
University of Alberta ST1	3.4	2.8	2.4	3.7	2.5
University of Alberta ST2	3.4	2.8	2.4	3.7	2.5
Williams Strathcona Cogen	3.4	2.8	2.4	3.7	2.5
COGEN average	3.1	2.6	2.4	3.8	2.8

Table B-6. Coal-to-Gas Asset Dispatch Response Analysis Result

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
Battle River 4 CTG	3	0.6	2.8	2.5	2.5
Battle River 5 CTG	4.3	1.3	2.3	5.9	5.7
Genesee 1 CTG	2.3	2.3	2.4	3.9	4.1
Genesee 2 CTG	4.3	2.9	2.6	4.2	4.7
Genesee 3 CTG	2.7	2.3	2.5	1.8	1.8
Keephills 1 CTG	2.1	3.7	1.9	5.9	6.2
Keephills 2 CTG	3.4	2.8	1.9	6.1	6.5
Keephills 3 CTG	2.5	2.3	2.4	5.2	5.1
Sheerness 1 CTG	2.9	2.3	2.9	4.7	4.6
Sheerness 2 CTG	2.9	2.3	2.9	4.9	4.8
Sundance 3 CTG	2.1	2.3	2.1	6.7	6.3
Sundance 4 CTG	2.3	2.3	2.3	6.1	6.3
Sundance 5 CTG	2.1	2.3	2.2	6.8	6.1
Sundance 6 CTG	3	0.6	2.1	6.5	6
CTG average	2.9	2.2	2.4	5.1	5.1

Table B-7. Hydro Generation Asset Dispatch Response Analysis Result

	average from non-generating status		average from generating status		
	delay (minute)	ramp rate	delay (minute)	ramp dn MW/min	ramp up MW/min
Barrier	2.6	1.5	2.2	0.3	0.2
Bearspaw	2.6	1.5	2.2	0.4	0.3
Bighorn 1 & 2	2.8	1.5	1.5	12.8	14
Brazeau 1 - 2	3.1	5.8	1.6	16.6	18.6
Cascade 1 - 2	2.6	1.5	2.2	0.7	0.6
Chin Chute	4.3	1.5	1.7	15.9	17.6
Dickson Dam	4.3	1.5	1.7	15.9	17.6
Generic Hydro	4.3	1.5	1.7	15.9	17.6
Ghost 2 - 4	2.6	1.5	2.2	1.4	1.1
Horseshoe 1 - 4	2.6	1.5	2.2	0.4	0.3
Interlakes	2.6	1.5	2.2	0.1	0.1
Irrican Hydro	4.3	1.5	1.7	15.9	17.6
Kananaskis 1 - 3	2.6	1.5	2.2	0.5	0.4
Oldman River	4.3	1.5	1.7	15.9	17.6
Pocaterra	2.6	1.5	2.2	0.3	0.3
Raymond Reservoir	4.3	1.5	1.7	15.9	17.6
Rundle 1 - 2	2.6	1.5	2.2	1.2	1
Spray 1 - 2	2.6	1.5	2.2	2.4	1.9
Taylor Hydro	4.3	1.5	1.7	15.9	17.6
Three Sisters	2.6	1.5	2.2	0	0
Total	3.2	1.9	1.9	8.1	8.8