Alaska Railbelt Wind Integration Study

September 2024

Energy+Environmental Economics

Authors & Acknowledgements

Energy and Environmental Economics, Inc. (E3) is a leading economic consultancy focused on the clean energy transition. E3's analysis is utilized by the utilities, regulators, developers, and advocates that are writing the script for the emerging clean energy transition in leading-edge jurisdictions such as California, New York, Hawaii and elsewhere. E3 has offices in San Francisco, Boston, New York, Denver, and Calgary.

Project Team

E3 Study Team:

- Jimmy Nelson
- Chen Zhang
- Saamrat Kasina
- Sam Kramer
- Alexandra Gonzalez
- Zach Tzavelis
- Chris Herman
- Arne Olson

Railbelt Staff:

- Golden Valley Electric Association (GVEA): Dan Bishop, Keith Palchikoff
- Chugach Electric Association (CEA): Hans Thompson, Mark Henspeter
- Matanuska Electric Association (MEA): Edward Jenkin, Josh Craft
- Homer Electric Association (HEA): Larry Jorgensen, Andrew Patrick

Acknowledgements

The E3 study team would like to acknowledge:

- Funding from the Alaska Energy Authority Renewable Energy Fund round 14 (grant number 7014029) and matching funds from the Railbelt utilities.
- Marty Schwarz and Paul Denholm from the National Renewable Energy Laboratory (NREL) for providing fuel price projections and a representation of the Railbelt electricity system in PLEXOS.
- Railbelt utility staff for their time and input throughout the study process.
- James Cote and Rich Meier from Electric Power Systems, Inc. (EPS) for providing results of their reliability analysis of the Railbelt to E3, and for input throughout the study process.
- Matthew Perkins and Andrew McDonnell from Alaska Renewables for providing 5-minute simulated wind production profiles and estimates of wind forecast accuracy.

Disclaimer

The Railbelt utilities retained E3 to provide an independent assessment of wind integration in the Railbelt. The Railbelt utilities provided technical information and informed the development of study assumptions and sensitivities. E3 utilized data from the Railbelt utilities, NREL, and other sources to develop a PLEXOS production cost model of the Railbelt. E3 retained full editorial control over the report and is solely responsible for all contents.

© 2024 Energy & Environmental Economics, Inc.

Table of Contents

Executive Summary

Study Context

Many factors are causing an increased interest in renewable energy in Alaska, including federal tax credits for renewable energy generation and storage, changing fuel costs and availability, and the possibility that legislative action may at some point require more renewables to be added to electrical grids in Alaska. The Alaska Railbelt power system, which serves over three quarters of electric demand in Alaska, is an electrical "island" as it is not connected to the larger North American grids. Smaller, isolated electrical systems like the Railbelt experience more acute challenges with integrating variable renewable energy sources than larger electrical interconnections with more resource diversity.

The largest Railbelt utilities – Golden Valley Electric Association (GVEA), Chugach Electric Association (CEA), Matanuska Electric Association (MEA), and Homer Electric Association (HEA) – retained Energy and Environmental Economics, Inc. (E3) to perform a detailed production simulation analysis of the Railbelt system with much more wind generation than is currently online.

Study Questions

With 300 MW of new wind capacity in the Alaska Railbelt:

- Can reliability be maintained?
- What are the production cost (fuel, variable cost, and start cost) savings?
- By how much would greenhouse gas (GHG) emissions be reduced?
- What level of wind curtailment would be expected?
- How can the Railbelt's transmission, generation, and storage resources be used to balance wind variability and uncertainty?
- How should Railbelt operations evolve to accommodate more wind?

Production Cost Modeling

Our analysis evaluates the potential operational cost savings and emission reductions associated with additional wind generation in the Alaska Railbelt in the context of the operating constraints and unique inflexibilities associated with operation of the Railbelt grid. E3 uses the industry standard production cost modeling platform PLEXOS to perform unit commitment and dispatch of the Railbelt system for a simulated year using 5-minute chronological load and wind data.

The Railbelt system is represented with the current fleet of generation and storage resources, except for the Healy 2 coal unit which is assumed to be retired. The Chugach/Matanuska battery storage resource is modeled as in-service. Transmission capacity between the Railbelt load zones is represented at current levels. Two levels of wind generation are studied: the current 43 MW of wind capacity and an additional 300 MW of wind capacity above the current wind capacity (Figure ES-1). The 300 MW of new wind capacity represents a sevenfold increase in wind capacity and therefore represents a potentially transformational change to how the Railbelt is operated.

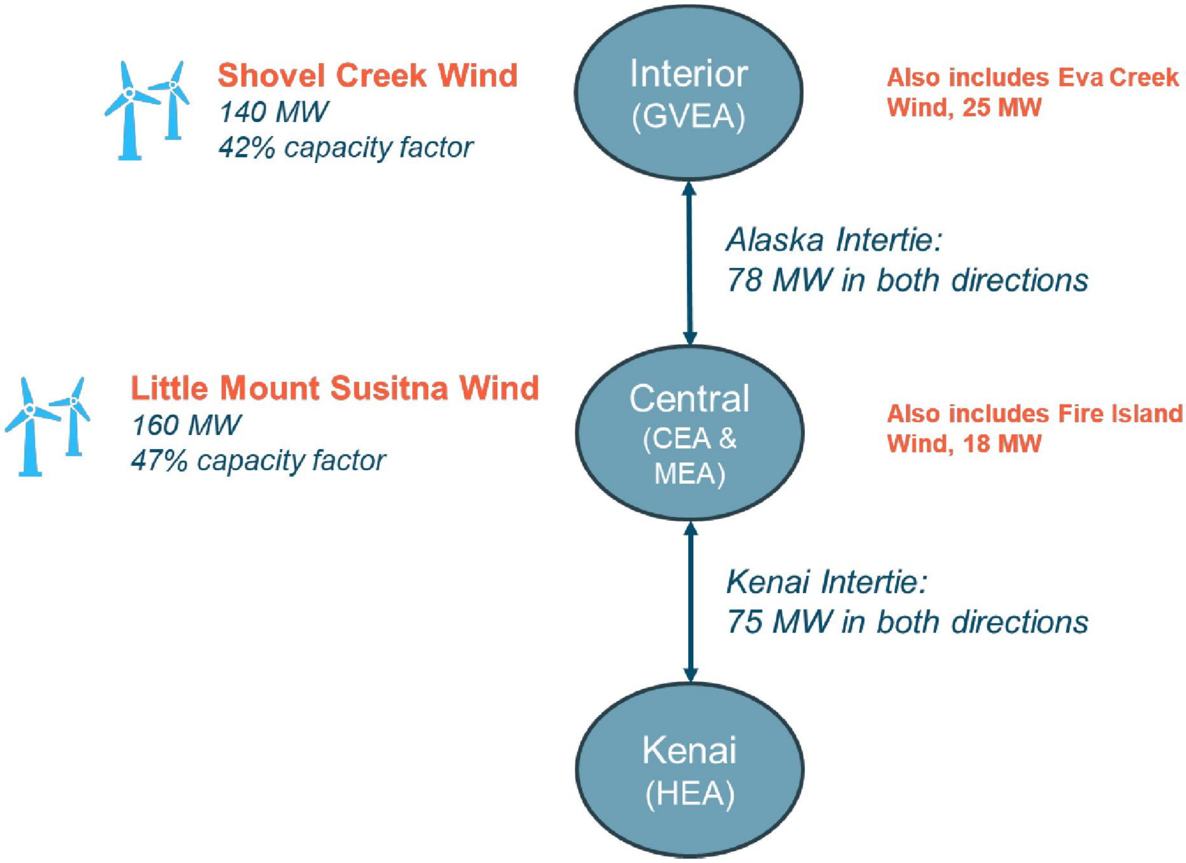


Figure ES-1: Modeled topology and wind capacity

The Railbelt utilities provided guidance that the Railbelt should be modeled as a single Local Balancing Authority (LBA) for the purposes of this study and therefore no transmission "wheeling" charges are included for transfers between the three load balancing zones (Interior, Central, and Kenai). Additionally, the PLEXOS optimization minimizes operating costs across the entire Railbelt grid as if all resources were dispatched by a single system operator. The Railbelt is not currently operated as a single LBA and thus the choice to model it as such represents an evolution from current practice.

Railbelt system reliability is included in the modeling in the following ways:

- 5-minute real-time modeling ensures that over 100,000 individual 5-minute intervals can balance load and resources, and that impact of wind variability on power system operations is considered.
- Day-ahead scheduling with load and wind forecast errors between day-ahead scheduling and real-time dispatch ensures that the impact of forecast errors is represented.

- Contingency and regulation reserves are held at all times to ensure that adequate capacity is available to address contingency events and to balance the system via automatic generation control.
- Voltage and inertial stability are ensured through commitment of certain thermal and hydroelectric units.

An important operating constraint specific to the Railbelt is that real-time gas consumption must generally follow the schedule nominated before the operating window. E3 requires gas consumption in real-time dispatch to fall within +/- 10% of the day-ahead gas nomination, which limits the ability of gas-fired resources to respond to wind forecast errors as they commonly do in other systems.

Key Findings

- **Reliability:** At the resolution of 5-minute dispatch, the Railbelt system can be reliably operated with 300 MW of new wind. This study assumes operational practices similar to those that have been implemented by Independent System Operators (ISOs); E3 did not study system reliability with additional wind capacity and current Railbelt operational practices.
  - No loss of load events and minimal levels of regulation shortages are observed over an entire year of 5-minute operations.
  - Dynamic stability (voltage and inertia) is ensured by commitment of thermal and hydro units.
  - The study approximates the need for balancing within each 5-minute dispatch interval using simulated 5-minute wind production data; additional study and operational experience are required to determine the correct level of regulation reserves to balance wind fluctuations within each 5-minute interval. Higher levels of reserves to regulate wind fluctuations, if necessary, would be expected to decrease production cost savings from additional wind and/or increase the need for fast-ramping resources (especially batteries).
- **Fuel and Variable Operations and Maintenance (VO&M) Cost Savings:** Adding 300 MW of wind reduces fuel consumption and VO&M costs, decreasing production costs by $97 - $126 M/yr in 2030. While we observe material production cost savings from the addition of new wind, this study does not determine whether new wind is cost effective because we do not compare production cost savings from new wind to the cost to build, interconnect, and operate the new wind resources. To avoid increasing costs to Railbelt customers, the annual Power Purchase Agreement (PPA), infrastructure, and operational costs related to adding more wind would need to be less than $97 - $126 M/yr in 2030.
  - On average, each MWh of wind production decreases production costs by $82 - $106 per MWh in 2030, which is calculated by dividing the annual savings ($97 - $126 M/yr) by the annual production from 300 MW of wind (1,180 GWh/yr).
  - The production cost savings from wind are expected to scale with fuel prices and are lower with near present-day (2025) fuel prices. Savings are likely to increase over the lifetime of the wind power plants because Railbelt fuel costs are projected to increase over time.

- Figure ES-2 shows how the addition of more wind primarily reduces natural gas generation; it is this reduction in natural gas that is the main source of the cost reduction. Without new wind, the Interior zone frequently relies on natural gas imports from the Central and Kenai regions. With the addition of more wind, Interior imports decrease on an annual basis but become more variable.

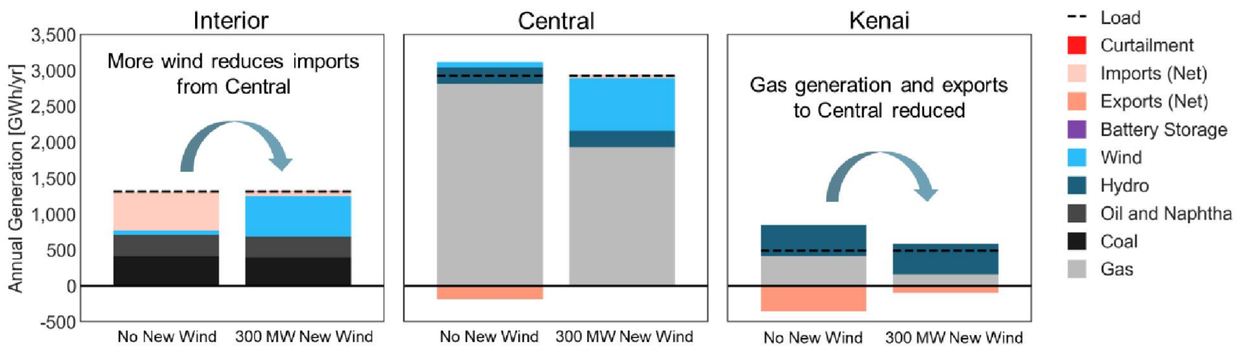


Figure ES-2: Annual generation comparison between the No New Wind and 300 MW New Wind Scenarios, broken out by zone. Generation is depicted based on the physical location of the resource, not by ownership. For example, generation from the Bradley hydro resource is depicted in the Kenai zone even though much of the generation is exported to utilities outside of the Kenai zone.

- **CO_2 emissions:** Wind reduces CO_2 emissions by reducing predominantly gas generation. 300 MW of wind would reduce Railbelt-wide CO_2 emissions by roughly one quarter, from 1.99 to 1.50 $MMTCO_2$/yr. Adding 300 MW of wind reduces Railbelt-wide emissions intensity (CO_2 per MWh of demand) from 0.42 to 0.32 tCO_2/MWh.
- **Curtailment:** Wind curtailment occurs when the system is unable to absorb wind generation by ramping down other generators. Curtailment is observed but does not represent a large fraction of the wind production potential. Our results indicate that as little as 1% of the wind production potential may need to be curtailed.
- **Resource operations:** Optimal dispatch of batteries, hydro, thermal, and transmission allows for almost all of the 300 MW of new wind to be absorbed. As shown in Figure ES-3, each resource plays a different role in wind integration.
  - *Batteries* can help to balance short-duration fluctuations in wind output but are limited in their ability to balance multi-hour forecast error events due to their limited energy capacity. 127 MW of batteries are assumed to be operating on the Railbelt system, though the 40 MW GVEA battery is only available to provide spinning reserve due to its age and limited energy capacity.
  - *Hydroelectric* resources play a large role in balancing wind because energy stored in reservoirs enables dispatch flexibility. Using hydro resources to balance wind forecast errors is an important operational strategy to cost-effectively integrate wind generation in the Railbelt. The largest hydroelectric resource that is used for balancing is the 120 MW Bradley Lake project on the southern part of the Kenai Peninsula.

- *Natural gas* resources have limited ability to respond to fluctuations in wind generation because gas fuel must be scheduled many hours in advance; much of the wind variability and forecast error occurs after gas fuel schedules have been determined and therefore must be managed with other resources.
- *Naphtha and oil* resources in the Interior zone increase generation during wind over-forecast events (when less wind power is available in real-time relative to the day-ahead forecast). The oil and naphtha resources are expensive to operate relative to other Railbelt resources, so this strategy is used only when other forms of flexibility have been exhausted.
- *Wind* under-scheduling (pre-curtailment) is used as a strategy at times to reduce the cost of integrating wind.

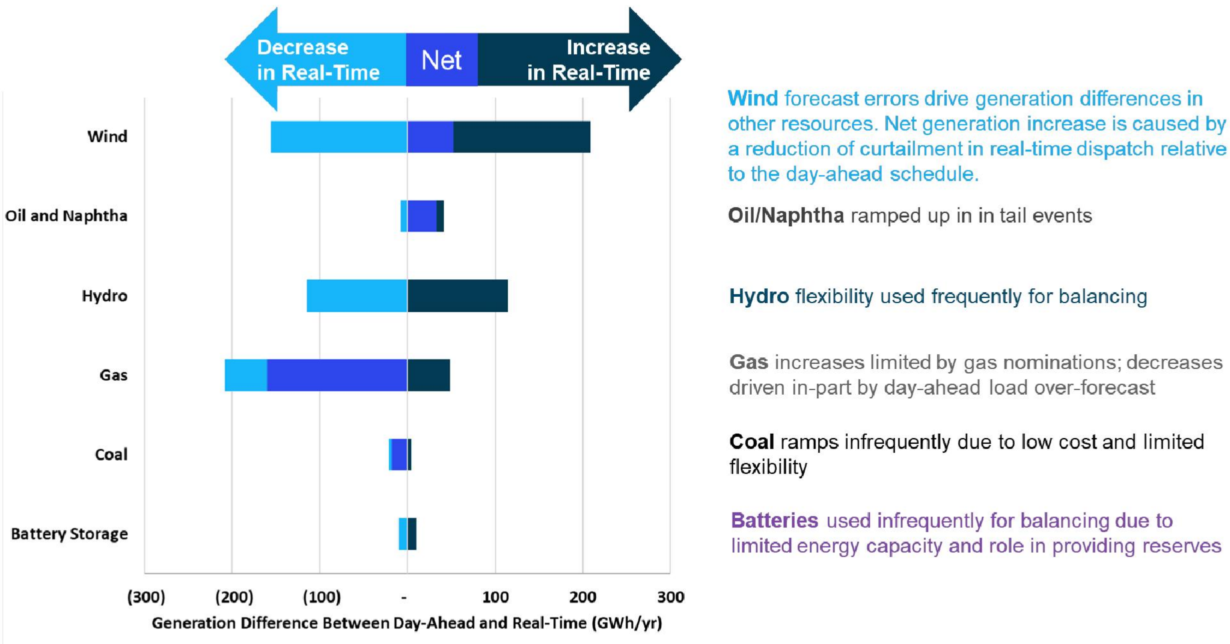
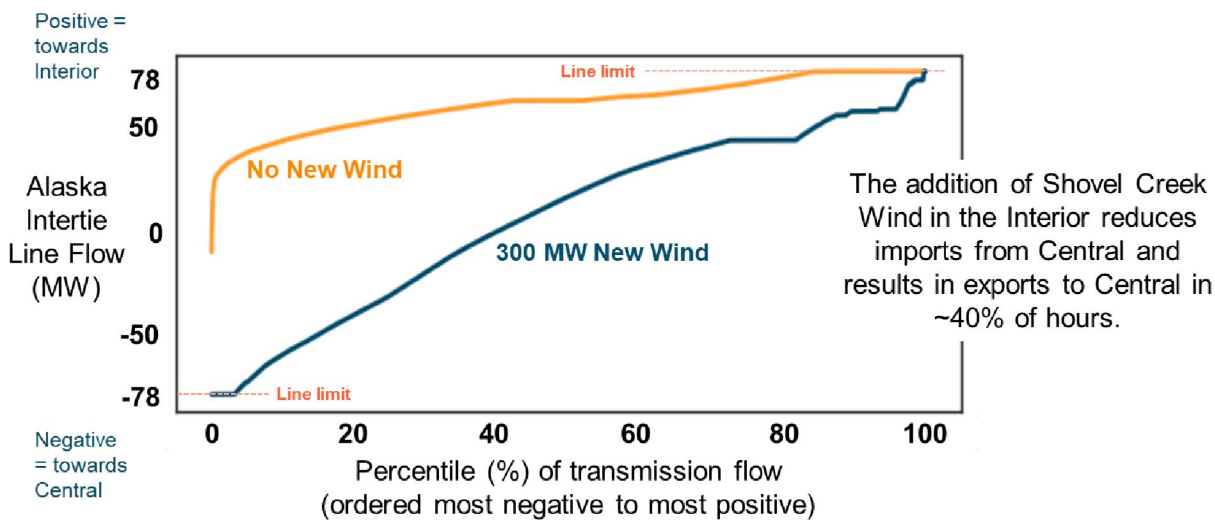


Figure ES-3: Difference between day-ahead schedule and real-time generation, grouped by fuel type. Positive values indicate that generation increases in real-time dispatch relative to the day-ahead schedule. As indicated by the legend at the top of the figure, the dark and light blue bars indicate the gross amount of generation increase and decrease (respectively) across the year, while the bright blue bars indicate the net increase (gross increase – gross decrease).

- **Transmission** between Railbelt zones is a crucial tool for managing wind variability and forecast errors. With Bradley hydro and the HEA battery in the Kenai zone, dispatchable naphtha and oil in the Interior, and fuel-constrained gas in the Kenai and Central zones, dynamic utilization of transmission between zones is important to access the diversity of Railbelt resources. Figure ES-4 shows how transmission flows change drastically with the addition of 300 MW of wind.



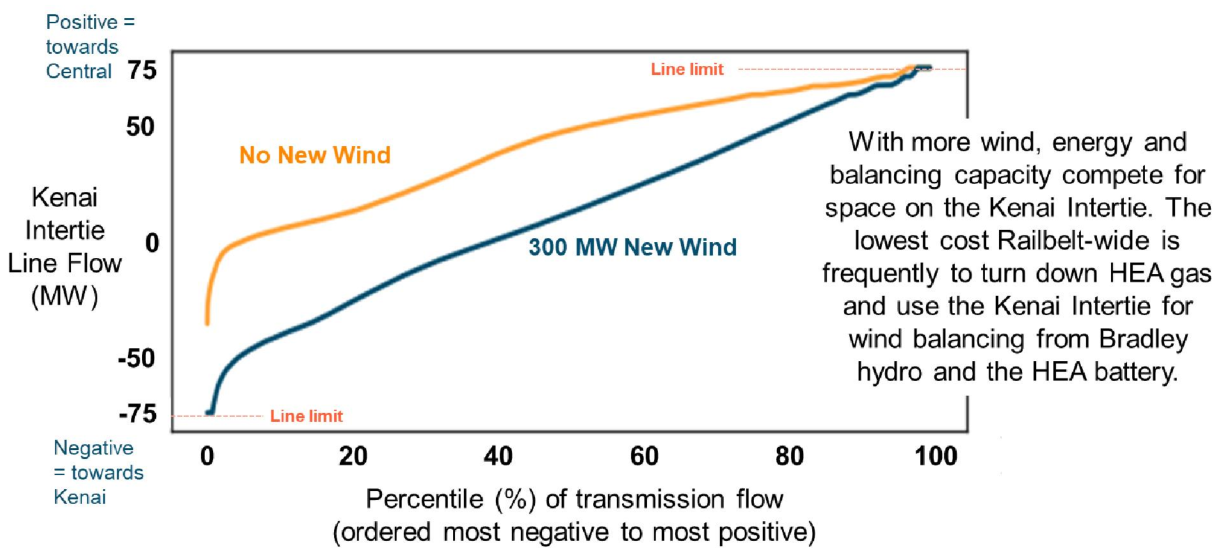


Figure ES-4: Transmission flow duration curve for the Alaska Intertie (top) and the Kenai Intertie (bottom) for the No New Wind and 300 MW New Wind Scenarios. The curves are created by ranking the modeled transmission flows in each 5-minute real-time interval across the year from most negative to most positive.

- **System Operations:** Railbelt system operations are represented in this study as more flexible than current practice. While no single aspect of system flexibility is central to the ability to absorb more wind energy on the Railbelt system, our results are based on operational practices that are an evolution from current practice. Increasing system flexibility could reduce Railbelt production costs even without the addition of more wind generation, but the benefits of additional operational flexibility are likely to increase with more wind generation. The following enhancements to Railbelt operations should be considered:
  - Coordinated, Railbelt-wide unit commitment and dispatch
  - Transmission scheduling without wheeling charges

- Co-optimization of energy and reserves on transmission lines
- Use day-ahead wind forecasts in unit commitment
- Scheduling upward and downward regulation reserve capacity separately, potentially on different resources
- Differentiating wind balancing needs by the length of the balancing service required (day-ahead forecast error, within-hour variability, 5-minute regulation)
- Exploring opportunities to increase the flexibility of gas fuel nominations
- Exploring opportunities to ensure system stability with lower levels of thermal generation

1. Introduction

1.1 Motivation

Many factors are causing an increased interest in renewable energy in Alaska, including federal tax credits for renewable energy generation and storage, changing fuel costs and availability, and the possibility that legislative action may at some point require more renewables to be added to electrical grids in Alaska. The feasibility and implications of increasing the level of renewable energy in Alaska is being explored by many groups. Recent work has explored the long-term impacts of additional renewables in Alaska.[1,2,3] E3's study focuses on near-term (2025-2030) impacts of wind capacity additions to Alaska Railbelt power system that could reasonably be online by the end of the decade or sooner.

The Alaska Railbelt power system, which serves over three quarters of electric demand in Alaska, is not connected to the larger North American grids. Smaller, isolated electrical systems like the Railbelt tend to experience more acute challenges with integrating variable renewable energy sources relative to larger electrical interconnections. Smaller grids can experience challenges related to lower levels of geographic diversity of renewable resource production, a smaller set of generation and storage resources with which to balance renewable variability and uncertainty, more frequent fuel supply constraints, and amplified concerns about system stability and reliability.

The largest Railbelt utilities – Golden Valley Electric Association (GVEA), Chugach Electric Association (CEA), Matanuska Electric Association (MEA), and Homer Electric Association (HEA) – retained Energy and Environmental Economics, Inc. (E3) to perform a detailed production simulation analysis of the Railbelt system with much more wind generation than is currently online. This analysis, which uses the PLEXOS model, evaluates the potential production cost savings and emission reductions associated with additional wind generation in the Alaska Railbelt in the context of the operating constraints and unique inflexibilities associated with operation of the Railbelt grid.

1.2 Study Questions

The primary aim of this study is to answer key operational questions about higher levels (+300 MW) of wind generation in the Railbelt, including:

- Can reliability be maintained?

---

[1] Denholm, Paul, Marty Schwarz, Elise DeGeorge, Sherry Stout, and Nathan Wiltse. 2022. Renewable Portfolio Standard Assessment for Alaska's Railbelt. Golden, CO: National Renewable Energy Laboratory. NREL/TP-5700-81698. https://www.nrel.gov/docs/fy22osti/81698.pdf.

[2] P. Cicilio et al., "Alaska's Railbelt Electric System: Decarbonization Scenarios for 2050," Alaska Center for Energy and Power, University of Alaska, Fairbanks, 2023. UAF/ACEP/TP-01-0003. DOI:10.5281/zenodo.10520543 https://www.uaf.edu/acep/files/media/ACEP_Railbelt_Decarbonization_Study_Final_Report.pdf

[3] Denholm, Paul, Marty Schwarz, and Lauren Streitmatter. 2024. Achieving an 80% Renewable Portfolio in Alaska's Railbelt: Cost Analysis. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85879. https://www.nrel.gov/docs/fy24osti/85879.pdf.

- What are the production cost savings?
  - Production cost savings include fuel, variable operations and maintenance, and generator start costs but exclude capital and fixed operations and maintenance costs.
- By how much would GHG emissions be reduced?
- What level of wind curtailment would be expected?
- How can the Railbelt's transmission, generation, and storage resources be used to balance wind variability and uncertainty?
- How should Railbelt operations evolve to accommodate more wind?

The study is designed to inform Railbelt decisions on wind procurement and operations in the next few years and as such includes minimal changes to the current resource portfolio.

Sensitivity analysis explores the impact of the following factors in the context of 300 MW of new wind capacity:

- A replacement battery in the Interior zone
- Additional transmission capacity between zones
- Gas supply flexibility
- Resource commitment timeframes
- Kenai Intertie outages
- Sourcing short-duration regulation from wind resources
- Stability commitment constraints
- Near-term fuel prices

2. Modeling Approach

To conduct this study, E3 created a two-stage simulation of the Alaska Railbelt system using the PLEXOS production cost model licensed by Energy Exemplar. The two-stage simulation includes various challenges associated with integrating wind energy in the Railbelt, such as forecast errors and gas scheduling inflexibilities. Below we provide a summary of the study data and key assumptions.

2.1 Production simulation model

To assess the system operability, E3 uses Energy Exemplar's PLEXOS ST (Short Term) model, which provides chronological production simulation that reflects operational constraints such as integer unit commitment, ramp rates, minimum uptime and downtime, storage state of charge, hydro energy limits, and more. The detailed operability modeling also incorporates the need for operational reserves, which increase as more wind is added to the Railbelt system. More information about the PLEXOS ST model is available on the Energy Exemplar website (https://www.energyexemplar.com/plexos).

2.2 Topology and resources

As shown in Figure 1, the Railbelt system is modeled with three zones in which load and resources are balanced: Interior (GVEA), Central (CEA and MEA), and Kenai (HEA). The three zones are connected by two transmission lines: a line with 78 MW rated capacity in both directions between the Interior and Central zones and a line with 75 MW rated capacity between the Central and Kenai zones.[4] This study did not model losses on the transmission lines.

The Railbelt utilities provided guidance that the Railbelt should be modeled as a single Local Balancing Authority (LBA) for the purposes of this study and therefore no wheeling charges are included for transfers between the three load balancing zones (Interior, Central, and Kenai). The implementation of the single LBA assumption in PLEXOS also includes coordinated scheduling and dispatch of energy and reserves across transmission lines. While CEA and MEA currently have a coordinated power pool, the Railbelt as a whole is not currently operated as a single LBA and thus the choice to model it as such is an evolution from current practice.

[4] While Railbelt staff provided guidance that the Alaska and Kenai interties should be modeled with the same rated capacity in both directions, further study may be required to determine the rated capacity from North to South for both lines.

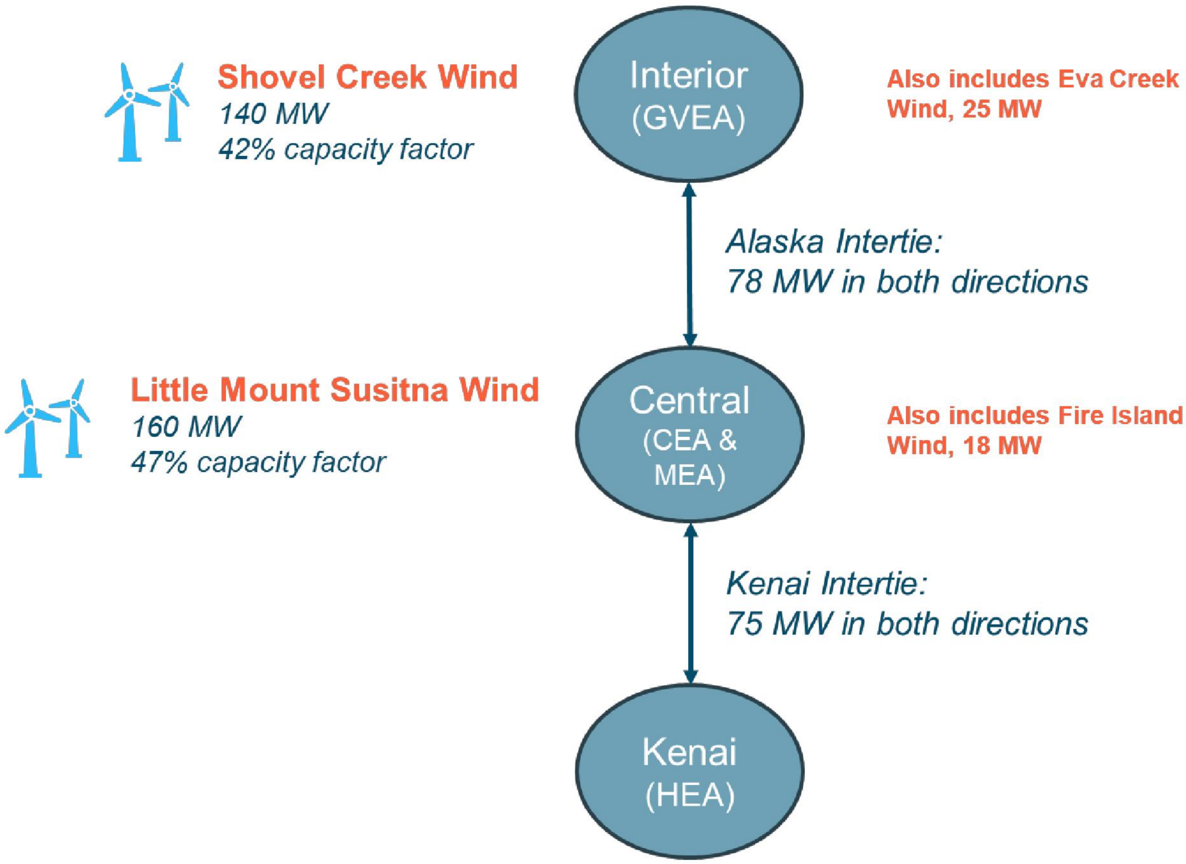


Figure 1: Modeled topology and wind capacity

This study models the expected capacity and capability of Railbelt generation and storage resources in the year 2025.[5] Two important resource changes in the Railbelt are modeled between present day and 2025:

- Addition of a 40 MW, 2-hour battery in Central.[6] This battery currently is under construction and is expected to be online before the new wind projects studied herein would come online.
- The GVEA coal unit Healy 2 is retired.[7]

While the study examines both 2025 and 2030, E3 was advised by Railbelt staff to keep generation and storage resources the same for both years.

Two small existing wind projects are included in all simulations: the 25 MW Eva Creek wind project in GVEA and the 18 MW Fire Island wind project in Central. In all simulations except the No New Wind Scenarios, two large new wind projects are added to the Railbelt system: the 140 MW Shovel Creek wind

---

[5] We do not include solar resources in this study due to their small capacity relative to the size of the Railbelt system.

[6] The CEA/MEA battery is expected to primarily provide spinning reserve. E3 has modeled this resource as also being able to provide regulation reserves and perform energy arbitrage. While the battery can perform these functions from a technical perspective, operational and/or contractual changes may be necessary to enable energy arbitrage or regulation from the CEA/MEA battery.

[7] The retirement of Healy 2 is assumed in this study but the unit has not yet retired. The retirement timeline is not well defined due to shortages of natural gas in the Cook Inlet region.

project in the Interior zone and the 160 MW Little Mount Susitna wind project in the Central zone, totaling 300 MW of additional wind capacity.

This study represents each resource at its physical location and does not enforce any contractual arrangements that would result in generation being sent between zones. Bradley hydro is modeled in the Kenai zone without an explicit allocation of the energy production to different Railbelt utilities. The production simulation is free to choose the cost-minimizing dispatch of generation and storage resources, as well as the associated transmission flows; attributing generation, storage dispatch, transmission flows, production costs, and emissions to specific utilities is out of scope of the study. The resource capacity modeled in each zone is shown in Figure 2.

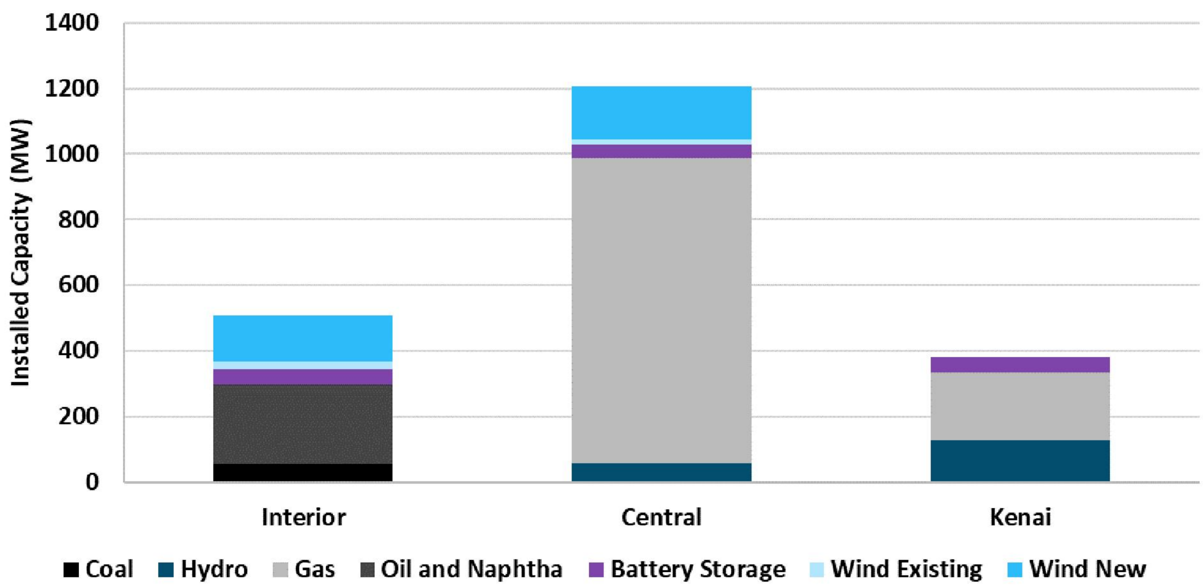


Figure 2: Resource capacity in each load-resource balance zone.

Generator and battery resource parameters are based on a PLEXOS model of the Railbelt system provided by the National Renewable Energy Laboratory (NREL). Railbelt staff provided updates to resource parameters and capabilities where necessary.

2.3 Multi-stage modeling

As shown in Figure 3, two model stages (individual production cost optimization runs) are executed for each of the simulations performed in this study. First, a day-ahead stage commits long-start generation and nominates gas fuel at an hourly resolution. Second, a real-time stage performs dispatch at a 5-minute resolution, using long-start unit commitments and gas nomination inputs from the day-ahead stage. The 5-minute resolution of the real-time stage tests system operations on the sub-hourly time scale; the day-ahead stage has an hourly resolution because there is not adequate foresight in the day-ahead timeframe to make commitment and dispatch decisions at sub-hourly resolution. Both the day-ahead and real-time stages are performed one day at a time, resulting in 2 x 365 = 730 model runs over the year.

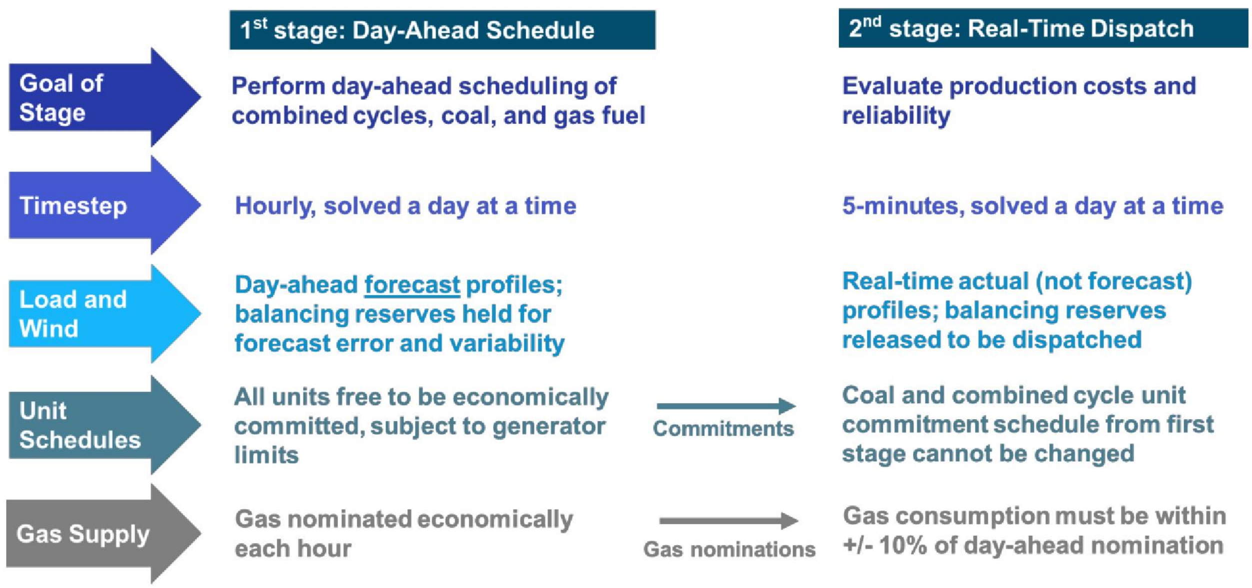


Figure 3: Description of day-ahead and real-time model stages.

The day-ahead stage includes load and wind forecast error relative to the actual load and wind values that occur in the real-time stage. To manage this forecast error, the day-ahead stage holds flexibility on generators and batteries in the form of day-ahead forecast error and within-hour regulation reserves (Sections 2.5 and Appendix) to respond to changes in load or variable energy resources between the day-ahead and real-time stages. Resource capacity held for forecast error and within-hour regulation reserves is released in the real-time stage such that it can be dispatched.

In the day-ahead stage, natural gas fuel consumption is scheduled ("nominated") on an hourly basis. PLEXOS is free to determine the economical amount of gas to schedule in each hour of the day-ahead stage. Gas nominations from the day-ahead stage must be upheld in the real-time within a +/- 10% flexibility band that reflects current contractual flexibility, allowing real-time gas consumption to be as low as 90% or as high as 110% of the day-ahead consumption. Gas nomination limits are further described in Section 2.8.

Resource dispatch, production costs, CO_2 emissions, and reliability metrics (unserved energy and reserve shortages) are reported from the real-time stage.

2.4 Load and wind profiles

2.4.1 Data requirements

This study models long-start unit commitment and gas nomination in the day-ahead timeframe, followed by real-time dispatch. Time-coincident load and wind forecasts and real-time data is necessary to study how the Railbelt system would navigate load and wind forecast errors. The model studies future years (2025 and 2030) by updating model inputs to be consistent with the future, but relies on load and wind real-time profiles based on 2022 conditions to ensure that correlations between load and wind generation are included. Load forecasts originate from 2022 historical data and synthetic wind forecasts are generated in a way that retains temporal correlations to real-time wind conditions.

2.4.2 Load data

The Railbelt utilities provided 5-minute real-time load data from Homer, CEA, MEA, and GVEA for 2022. The data was cleaned and is used as the load input to the real-time stage of PLEXOS. HEA, CEA, and MEA also provided hourly day-ahead load forecasts for 2022. A synthetic day-ahead load forecast for GVEA is created by calculating the CEA percent load forecast error on an hourly basis and applying that forecast error percentage to GVEA real-time loads in blocks of one day at a time, randomized between days within the same month and weekday type. The purpose of the randomization is to avoid unrealistic coincident load forecast errors. The resultant percentage forecast error timeseries is applied to GVEA real-time loads to create a day-ahead load forecast timeseries for GVEA.

2.4.3 Real-time wind data

Alaska Renewables provided 5-minute real-time production profiles for the Shovel Creek and Little Mount Susitna wind sites for 2022 weather conditions. E3 scaled the Shovel Creek production profile to the MW capacity in this study (140 MW) and used this profile directly in PLEXOS for the real-time Shovel Creek production profile. Due to issues with the plant-level power output profile for Little Mount Susitna, E3 used windspeeds from Little Mount Susitna profile from Alaska Renewables and created a power output timeseries using a Vestas V150 wind turbine power curve, derated for plant-level impacts.

For the existing Railbelt wind plants, E3 used the 2022 power production from Eva Creek wind directly. A 5-minute real-time profile for Fire Island wind was not readily available and therefore the Little Mount Susitna profile was scaled to the Fire Island resource capacity.

2.4.4 Wind day-ahead forecast creation

Day-ahead forecasts of wind production potential consistent with the 2022 real-time wind data described in the previous section were not available. E3 created synthetic day-ahead forecasts for each wind plant that match forecast error statistics that are expected for Alaska wind projects.

Alaska Renewables provided wind forecast error statistics for the Eva Creek windfarm that had been produced by the consultant DNV. E3 used the DNV 24-hour ahead values of nRMSE (normalized root mean square error) of 15% and nMAE (normalized mean absolute error) of 21% when creating synthetic forecasts. DNV expects similar forecast error values for wind resources with the challenging terrain that is present for the Railbelt wind sites, which confirms that the forecast error values are appropriate for this study. The nMAE statistic reflects the average level of error in the wind forecasts; the nRMSE statistic emphasizes extreme error events. By tuning to both metrics simultaneously, E3's synthetic forecasts include information about the average and extreme errors that Alaska wind sites will experience.

To create synthetic wind forecasts for each of the four wind sites, E3 first created a "persistence" forecast that assumes that the production in hour t+24 is equal to the production in hour t. E3 then took a weighted average of the 24-hour persistence forecast and the actual 5-minute real-time production data, adding stochasticity and mean reversion to the forecast to reproduce nMAE and nRMSE and to ensure that extreme forecast errors were modeled. An example of the resultant distribution of forecast errors for Little Mount Susitna is plotted in Figure 4. The other three wind sites (Shovel Creek, Eva Creek, and Fire Island) exhibit similar forecast error distributions. E3 developed the forecast profiles for each of the four wind sites independently but the forecasts are tied to the underlying time-correlated 5-minute production through mean reversion.

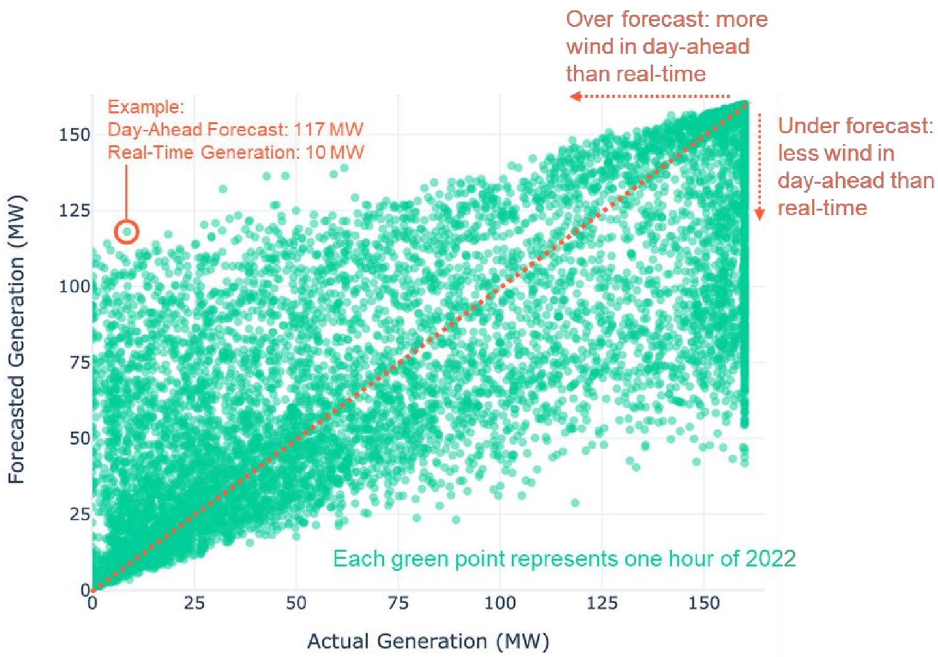


Figure 4: Simulated forecast error distribution for the 160 MW Little Mount Susitna wind resource.

2.5 Operational reserves

Operational reserves are held by system operators to ensure reliable operation. Operational reserves are distinct from capacity/resource adequacy reserves in the planning context; the former ensures reliable operation on a day-to-day basis whereas the latter ensures that the system has adequate installed capacity to meet load during peak periods.

As is common in many renewable integration studies, the need for operational reserves is divided into two categories: balancing (Section 7.1) and contingency (Section 7.5). Balancing reserves hold capacity on resources to manage net load (load minus variable renewable production) forecast error and variability. Contingency reserves are held to prepare for the loss of a large resource or transmission line. A summary of operational reserve modeling can be found in the Appendix (Section 7).

Due to the possibility of severe forecast errors, we assume that all wind generation must be backed up by other resources in the day-ahead timeframe. However, only the scheduled wind production is covered by upward (headroom) reserves as there is not a need to hold reserves for generation above the level that is scheduled. Wind is modeled as curtailable in this study, and we assume that wind can be curtailed in 5-minute intervals in real-time when oversupply is a concern. Wind balancing reserves are divided into three timeframes (day-ahead forecast error, within-hour variability, and 5-minute regulation) in day-ahead unit commitment to ensure efficient and reliable real-time operation. In the real-time stage, the capacity held for forecast error and within-hour variability is released for dispatch, but the 5-minute regulation capacity is held such that Railbelt operators have capacity on automatic generation control to manage net load variations within each 5-minute dispatch interval.

While both balancing and contingency reserves are important for reliable system operation, balancing reserves in the Railbelt change more with additional wind generation due to the need to balance additional wind variability and uncertainty. Contingency reserves remain unchanged with more wind because of the Railbelt's design decision to interconnect wind projects in a way that does not increase the single largest contingency.

2.6 Hydro modeling

Hydro units are modeled as having the same amount of energy available on each day of the month based on United States Energy Information Agency data for the historical year 2018 (Figure 5). Hydro resources are modeled with flexibility to dispatch the available energy within each day, provided that the daily budget is met. All units are able to re-dispatch their energy in the real-time stage, thereby allowing them to adapt to grid conditions that evolve between day-ahead and real-time. We do not model the movement of hydro energy between days, even though there are opportunities to do so in actual operations, especially at the Bradley hydro facility.

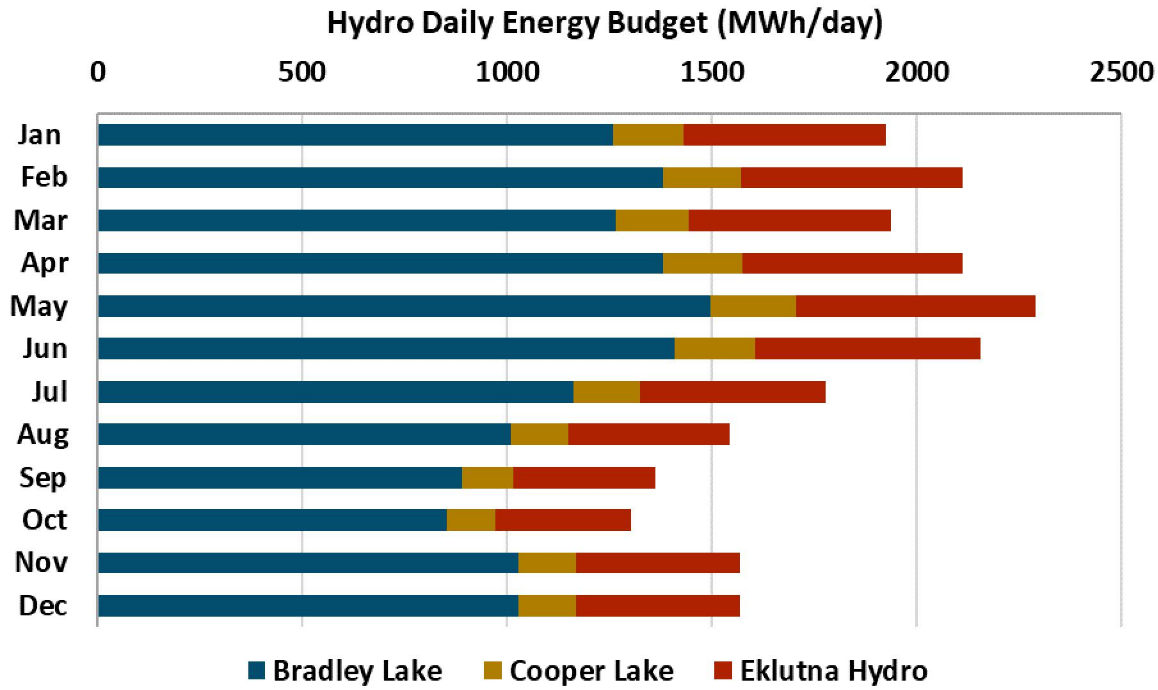


Figure 5: Hydro daily energy budgets, broken out by month and hydro plant

2.7 Stability commitment constraints

The production cost model used in this study focuses on a broad set of conditions over which to evaluate the economics and reliability of the Railbelt system. Because production cost models cannot easily include a number of factors that influence system reliability, it is common to use data from models that focus on power flow, contingencies, voltage, and stability to ensure reliable operation. In the PLEXOS model of the Railbelt system, E3 includes stability constraints that require commitment of specific units or specific combinations of units to maintain system stability. These constraints originate from a contingency and stability analysis of the Railbelt system performed by Electric Power Systems, Inc. (EPS).[8] The EPS study determines the number of thermal and hydro units required to be online in different parts of the Railbelt with the same wind project additions as are studied in the E3 study: Little Mount Susitna and Shovel Creek (total of 300 MW of incremental wind capacity). The EPS study focuses on maximum wind output and minimum load conditions to determine the minimum number of units that must be committed in each zone of the Railbelt.

The constraints implemented in the PLEXOS model are:

- In the Interior zone, at least one North Pole unit must always be committed. Additional stability constraints would be required to model periods in which the Alaska Intertie is out of service but

[8] Electric Power Systems, Inc. Railbelt Wind Integration Study. Dec. 22, 2023 (Revision 0)

the Alaska Intertie is always in service in this study so no additional constraints are necessary. The unit commitment constraint implemented in PLEXOS is:

  - North Pole U1 + North Pole U2 + North Pole CC >= 1

- In the Kenai zone, either the Nikiski combined cycle or Soldotna combustion turbine must always be committed. In addition, a minimum of two units must be committed, one of which could be a Bradley hydro unit. While the modeling performed in the EPS study suggests that it may be possible to maintain system stability under some conditions with only Bradley hydro units committed (i.e. no thermal generation), staff from HEA indicated that operating their system without any thermal generation committed would not deliver acceptable reliability. As a result, E3 includes a thermal commitment constraint that requires at least one thermal unit to be online in the Kenai zone. The unit commitment constraints implemented in PLEXOS are:
  - Nikiski CC + Soldotna CT >= 1
  - Bradley U1 + Bradley U2 + Nikiski CC + Soldotna CT >= 2
- In the Central zone, at least one of the large combined cycle plants - Southcentral Power Plant or Sullivan Plant 2A - must be committed. These combined cycles are represented as a single unit in PLEXOS, so the commitment of a single combined cycle represents the commitment of at least two individual generating units – a steam turbine and at least one combustion turbine. The unit commitment constraint implemented in PLEXOS is:
  - Southcentral Power Plant + Sullivan Plant 2A >= 1
- Also in the Central zone, a minimum number of units from the Eklutna Generating Station (EGS) and Eklutna hydro resource are required to be online. As shown in Table 1, the number of units increases with more load in the MEA region. While E3 models CEA and MEA load together in the Central zone in the production simulation, E3's implementation of the MEA stability constraint uses only the MEA load to determine the number of EGS and Eklutna hydro units that must be committed.

Table 1: MEA minimum commitment requirements

MEA Load (MW)	<60	60-70	70-80	80-100	100-120	>120
EGS + Eklutna Hydro Minimum Units Online	0	1	2	3	4	5

The minimum commitment limits from EPS (referred to as minimum generation limits in EPS report) require that units are online/committed, but do not specify the MW output level at which each plant must operate. This is because the stability issues found in EPS' study stem from inertia or voltage control requirements and the provision of these grid services from thermal units is more tied to the online status of the unit than the MW output from the unit. Even though a specific output level is not specified for the stability constraints, each of the units included in the stability constraints have a minimum stable level (also called the "PMin" or minimum power level), which specifies the minimum amount of power produced by the unit when it is online. As a result, the stability constraints require power production from thermal power plants that is greater than or equal to the PMin of the units that the production simulation optimization chooses to meet the stability constraints. Future study should explore the ability of other resources (wind, batteries, synchronous condensers, power electronics, etc.) to supply the reliability services currently provided via the minimum commitment requirements.

2.8 Gas nomination constraints

One of the important operating constraints of the Railbelt utilities, specifically Central (MEA & CEA) and HEA, is that the real-time gas consumption must generally follow the schedule nominated before the operating window. While it may be possible to increase gas consumption outside of what was nominated in the case of an emergency, the Railbelt utilities advised E3 that current contractual and physical limitations of the gas system would not allow frequent large deviations from the level of gas nominated. The requirement to follow the gas nomination schedule restricts the ability of gas resources to respond to wind and load variability and forecast errors.

Railbelt gas supply flexibility is modeled in PLEXOS as follows:

- 1st Stage – Day-Ahead Commitments:
  - The model is allowed to choose how much gas to schedule in each hour of the day
  - This scheduling process is performed using the day-ahead wind and load forecasts, which are likely to differ from the amount of load and wind that will occur in the real-time stage.
  - The model chooses how much gas to schedule in the Central and Kenai zones independently.
  - We include two restrictions on the ability of natural gas plants to provide reserves to ensure that the model does not plan to dispatch gas plants up in the event of a forecast error between the day-ahead and real-time stages, only to be limited by real-time gas consumption limits. The first restriction is that the capacity of forecast error and within-hour regulation reserves that can be sourced from online gas plants in the day-ahead model stage is less than or equal to 10% above the MW level of gas generation. The second restriction is that gas plants are not modeled as contributing offline capacity to forecast error reserve.
- 2nd Stage – Real-Time Dispatch:
  - Gas consumption is constrained to be within +/- 10% of day-ahead gas consumption separately for the Central and Kenai zones in each hour. Gas consumption in each 5-minute interval can be outside of the +/- 10% limit but the sum of gas consumption across the hour must fall within +/- 10% of the day-ahead gas consumption.
    - While the +/- 10% flexibility band is applied across the day in utility gas operations, it is applied to each hour in this study to avoid significant under and over-consumption within the day that could lead to gas supply issues.
  - The model is allowed to violate the gas consumption constraints and consume more than 110% or less than 90% of the day-ahead gas nomination, but this option is available at an arbitrarily high penalty cost and thus the production simulation will stay within the +/- 10% band of gas consumption except for periods where reliability is in jeopardy.
  - Due to technical considerations in the PLEXOS model, fuel consumed during start-up is not included in the gas consumption constraints. Combined cycle units are required to adhere to their unit commitment schedule from the day-ahead stage in real-time and thereby will not change their scheduled startup fuel consumption between day-ahead and real-time stages.

Gas consumption constraints are not considered when committing natural gas-fueled units to provide spinning, non-spinning, and 5-minute regulation reserves. It is assumed that gas will be available if the reserve is dispatched because deployment of these reserves would require additional gas for short periods of time.

2.9 Fuel prices

Fuel prices are important because the cost of fuel is a large portion of the production cost of thermal resources. Railbelt staff directed E3 to use the fuel prices in a 2024 NREL report on renewable energy in the Railbelt.[9] While the NREL fuel prices are not identical to fuel cost projections used by the utilities, the fuel prices in Table 2 are close enough to utility values to accurately study the economics of wind in the Railbelt. The prices in Table 2 are in nominal dollars, whereas values depicted in the NREL report are in real $2023. E3 assumed a 2% inflation rate to convert from real to nominal dollars.

[9] Denholm, Paul, Marty Schwarz, and Lauren Streitmatter. 2024. Achieving an 80% Renewable Portfolio in Alaska's Railbelt: Cost Analysis. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-85879. Figure 5. https://www.nrel.gov/docs/fy24osti/85879.pdf.

Table 2: Fuel prices. The 2030 fuel prices, highlighted in bold, are used in all model runs except for the 2025 fuel price sensitivity runs.

Fuel type	Fuel price ($/MMBtu, nominal)	Zone in which fuel is available	Notes
Natural Gas	2025: 10.1 **2030: 14.0**	Central, Kenai	The same natural gas fuel price is used for all natural gas generators. NREL prices assume a switch to liquified natural gas (LNG) between 2025 and 2030.
Naphtha and Oil	2025: 19.4 **2030: 23.9**	Interior	Naphtha and oil prices are assumed to be the same.
Ultra Low Sulfur Diesel	2025: 29.8 **2030: 35.3**	Interior	Ultra-low sulfur diesel is required for North Pole Units 1 and 2 between October 1 and March 31. Reflecting current market conditions, a $10/MMBTU ($2023) price premium on the oil fuel cost is assumed for ultra-low sulfur diesel.
Coal	2025: 5.1 **2030: 5.7**	Interior	The coal fuel price is constant in real $.
Landfill Gas	2025: 2.2 **2030: 2.4**	Central	Landfill gas generators have limited dispatchability and thus the landfill gas fuel price will have minimal impact on model results. The landfill gas price used in this study is the same as NREL's Railbelt PLEXOS model.

Fuel for thermal resources is assumed to be available when needed; fuel storage limitations are not considered, nor are costs to expand fuel storage if necessary. E3 models each resource with a single fuel and does not model dual fuel resources such as natural gas plants that can run on fuel oil if necessary.

2.10 Modeled vs. present day representation of Railbelt grid

While simulation models strive to represent the system of interest (in this case the Railbelt grid) as accurately as possible, a number of aspects of current operations were not modeled exactly as they occur in the present day Railbelt system. Railbelt staff requested that differences be noted in this report.

- Reflecting possible future dispatch coordination, the Railbelt utilities recommended that E3 model the Railbelt as a single load balancing area. In current operations, CEA and MEA have a joint balancing agreement but HEA and GVEA resources are balanced separately. In PLEXOS, all zones are balanced simultaneously, wheeling charges are not included on transfers between zones, and there is coordinated scheduling of energy and reserves.
    - *Impact:* The single load balancing area assumption is an evolution of Railbelt operations that results in more flexibility in the model than is available currently. The additional flexibility from coordinated operations in PLEXOS makes it easier to integrate wind than it would be with current levels of coordination.

- Upward and downward regulation capacity is modeled separately in PLEXOS (different resources can meet upward and downward regulation needs in the same interval). Current operational practice frequently commits resources to provide both upward and downward regulation capacity simultaneously.
    - *Impact:* Splitting regulation into upward and downward components in PLEXOS make it easier to integrate wind relative to current practice because resources can have different costs of providing upward and downward regulation services.
- Gas fuel supply is modeled in PLEXOS with the current amount of flexibility available to Railbelt resources, which restricts the ability of gas generators to respond to wind forecast errors and variability.
    - *Impact:* Future gas contracts may have additional flexibility, which would make it easier to integrate wind relative to what is modeled in PLEXOS. The degree to which gas fuel flexibility could be increased is unknown.
- Hydro resources are modeled without the ability to shift energy between days. Current operations allow for shifting hydro energy between days, enabling Railbelt operators to increase or decrease hydro production in response to wind generation.
    - *Impact:* The modeled results do not include any benefits of between-day energy shifting that occur in present day operations, especially for the Bradley hydro resource. Shifting energy between days could lower the cost of balancing wind forecast errors and reduce reliance on expensive peaking units to provide power when wind generation is lower than expected.
- The Kenai and Alaska Interties are modeled as always in-service, except for the Kenai Intertie Outage sensitivity.
    - *Impact:* The interties are an important source of operational flexibility to balance wind. Relative to what is modeled in PLEXOS, including intertie outages would make it more challenging to integrate wind during the outage periods.
- No resource outages modeled, but contingency reserves (spinning and non-spinning) are held in all intervals to ensure that adequate capacity is available to ramp up if an outage occurs.
    - *Impact:* The impact of resources outages on wind integration is unknown.
- Combustion turbines within combined cycle plans are not modeled as able to function without the steam turbine, even though this ability exists in actual operations.
    - *Impact:* The exclusion of independent combustion turbine operation for combined cycles represents less operational flexibility in the model than is currently available to operators.
- Transmission losses are not modeled in PLEXOS.
    - *Impact:* Including transmission losses would discourage sending power along transmission lines relative to that which is modeled in PLEXOS. This impact would be present both with and without new wind, and therefore the resulting impact on the cost savings from wind is uncertain.

2.11 Wind flexibility modeling

Curtailing wind resources can be a valuable operational strategy to avoid periods of oversupply and to reduce balancing costs from expensive resources. The way in which wind curtailment is represented in operational studies impacts the cost of integration and the value of the resource. On one end of the spectrum, must-take wind requires the system operator to cover all possible variations of the wind resource, resulting in the highest costs and lowest value for wind. On the other end of the spectrum, the wind resource actively participates in balancing the system, ramping up and down as necessary depending on system conditions. As described below, this study models wind in between the two extremes, with wind performing some, but not all, of the possible balancing functions.

Ways in which wind is modeled as flexible:

+ Wind can be curtailed in every hourly interval in the day-ahead stage, and each 5-minute interval in the real-time stage.
+ In day-ahead stage, the forecast error and within-hour variability reserves that are being held to balance wind resources are reduced when wind is scheduled to be curtailed.
+ In day-ahead stage, downward forecast error and downward within-hour variability reserves are not held for wind because wind can be curtailed in the real-time stage if necessary.

Ways in which wind is not flexible in the current modeling:

+ Wind is not modeled as supplying regulation for within 5-minute balancing needs, except in the Wind 5-Minute Regulation Sensitivity.
+ Curtailed wind cannot contribute to reserve needs that result from the uncertainty and variability of load.
+ Curtailed wind cannot contribute to contingency reserves.

3. 300 MW New Wind Modeling Results

We quantify the changes that result from the addition of 300 MW of wind to the Railbelt system by comparing two PLEXOS simulations. The No New Wind Scenario includes the existing Railbelt wind plants (Fire Island, 18 MW and Eva Creek, 25 MW). In addition to the existing wind plants, the 300 MW New Wind Scenario adds 300 MW of wind two sites: 140 MW of wind at Shovel Creek to the Interior zone and 160 MW of wind at Little Mount Susitna to the Central zone. To ensure that the Railbelt can be operated reliably with the addition of 300 MW of wind, balancing capacity is added in the form of reserves, described in more detail in Section 2.5 and the Appendix (Section 7).

3.1 Annual generation

As shown in Figure 6, adding 300 MW of wind to the Railbelt offsets 1,165 GWh/year of thermal generation, most of which is gas in the Central and Kenai zones. The production potential of the two new wind projects is 1,180 GWh/year, indicating that almost all of the wind production potential results in decreased thermal generation. Wind curtailment is low even with 300 MW of new wind: 13 GWh/year of wind curtailment is observed in the 300 MW New Wind Scenario, which represents 1% of the total wind production potential.

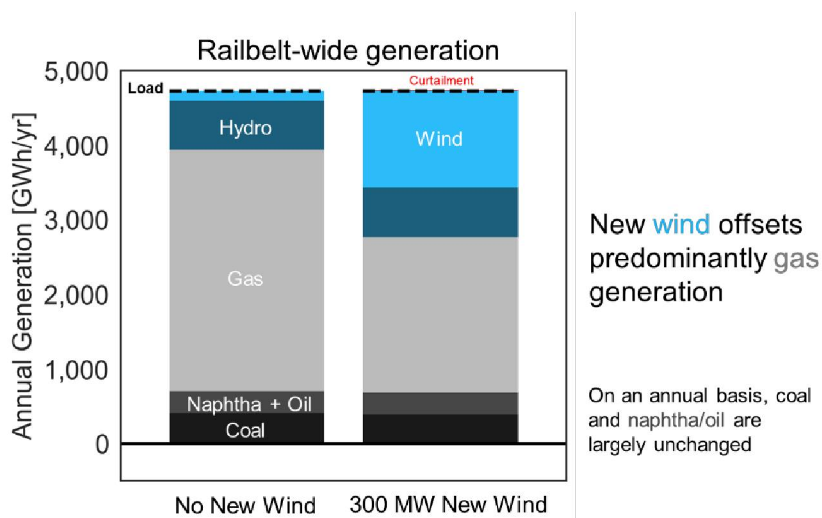


Figure 6: Railbelt-wide annual generation comparison between the No New Wind and 300 MW New Wind Scenarios. The same information broken out by zone is found in Figure 7.

In the No New Wind Scenario, gas resources in the Central and Kenai zones, which have lower fuel costs than Interior oil and naphtha resources, are frequently dispatched to meet load in the Interior zone (Figure 7). When 300 MW of wind is added in the 300 MW New Wind Scenario, the Interior zone frequently reduces imports from Central, resulting in much lower levels of imports on an annual average basis. Central gas turns down due to the addition of Little Mount Susitna wind, as well as decreased exports to the Interior zone.

Similar levels of naphtha and oil generation are observed in the Interior zone with and without the addition of 300 MW of wind. The stability constraints requiring commitment of at least one North Pole unit and the limited transmission capacity on the Alaska Intertie are likely causes of the relatively constant level of Interior naphtha and oil generation between the two simulations. The Interior Healy 1 coal unit has a low fuel cost relative to other resources and therefore has similar production between the two model runs.

As discussed in section 3.2, Kenai zone gas generation turns down to accommodate additional reserves from Bradley hydro and the HEA battery. Kenai resources also turn down to import wind power during times when wind production is abundant in the Central and Interior zones.

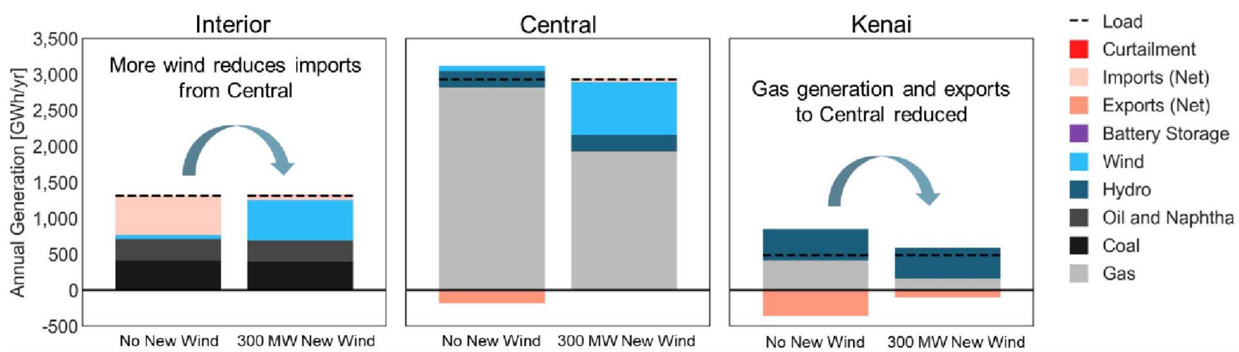


Figure 7: Annual generation comparison between the No New Wind and 300 MW New Wind Scenarios, broken out by zone. Generation is depicted based on the physical location of the resource, not by ownership. For example, generation from the Bradley hydro resource is depicted in the Kenai zone even though much of the generation is exported to utilities outside of the Kenai zone.

3.2 Transmission flows

Transmission flows on the Alaska Intertie (between the Central and Interior zones) become more variable with more wind capacity. In the No New Wind Scenario, transmission flows between the Central and Interior zones almost always flow towards the Interior zone due to the higher fuel costs of Interior oil and naphtha resources (Figure 8). In the 300 MW New Wind Scenario, the addition of the Shovel Creek wind resource in the Interior reduces imports from Central and results in exports to Central in about 40% of hours. The addition of a large wind plant to the Interior zone results in exports during many hours because the wind generation, naphtha generation from the North Pole power plant to satisfy stability and reserve requirements, and low cost but relatively inflexible coal generation can result an abundance of energy that can be larger than demand. Over the year, the Interior zone exports and imports roughly the same amount of energy, though in individual dispatch intervals the Interior zone may be either importing from or exporting to Central.

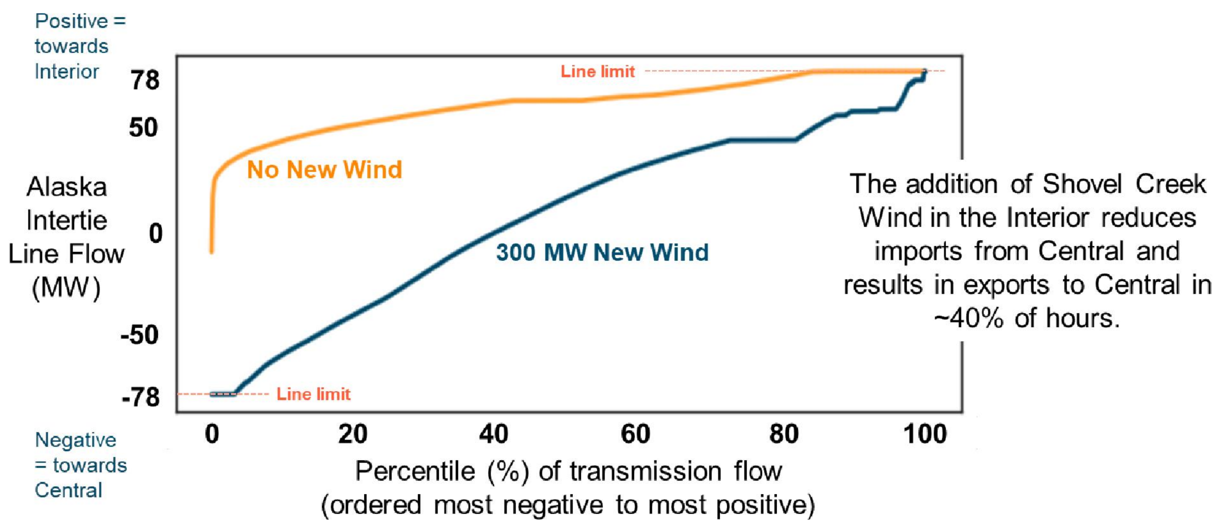


Figure 8: Transmission flow duration curve for the Alaska Intertie for the No New Wind and 300 MW New Wind Scenarios. The curves are created by ranking the modeled transmission flows in each 5-minute real-time interval across the year on the Alaska Intertie from most negative (towards Central) to most positive (towards Interior).

Transmission capacity on the Kenai Intertie (between the Kenai and Central zones) is frequently used to balance wind new wind generation. In the No New Wind Scenario, the Kenai zone, which includes the Bradley hydro power plant, typically has excess power to send to the Central zone due to the energy from Bradley and gas generation from HEA's Nikiski combined cycle plant. The overall amount of power sent on the Kenai Intertie is much lower in the 300 MW New Wind Scenario relative to the No New Wind Scenario (Figure 9), and the 300 MW New Wind Scenario includes flows in both directions, not just the Kenai to Central direction observed in the No New Wind Scenario.

In the 300 MW New Wind Scenario, the Nikiski combined cycle plant is committed infrequently and instead the Soldotna gas plant fulfills the requirement that at least one gas generator must always be committed (Section 2.7) in the Kenai zone. The Soldotna gas plant has a much lower minimum operating level (PMin) of 5 MW[10] relative to Nikiski (40 MW); committing Soldotna frees up transmission capacity for reserves to balance wind generation, especially in the day-ahead timeframe (Section 3.9). The Kenai Intertie plays an important role in balancing the new wind projects predominantly through flexible dispatch and reserves from Bradley hydro and the HEA battery.

[10] HEA staff provided input that Soldotna can technically be dispatched down to 3 MW but can be unstable below 5 MW, so it is modeled with a PMin of 5MW.

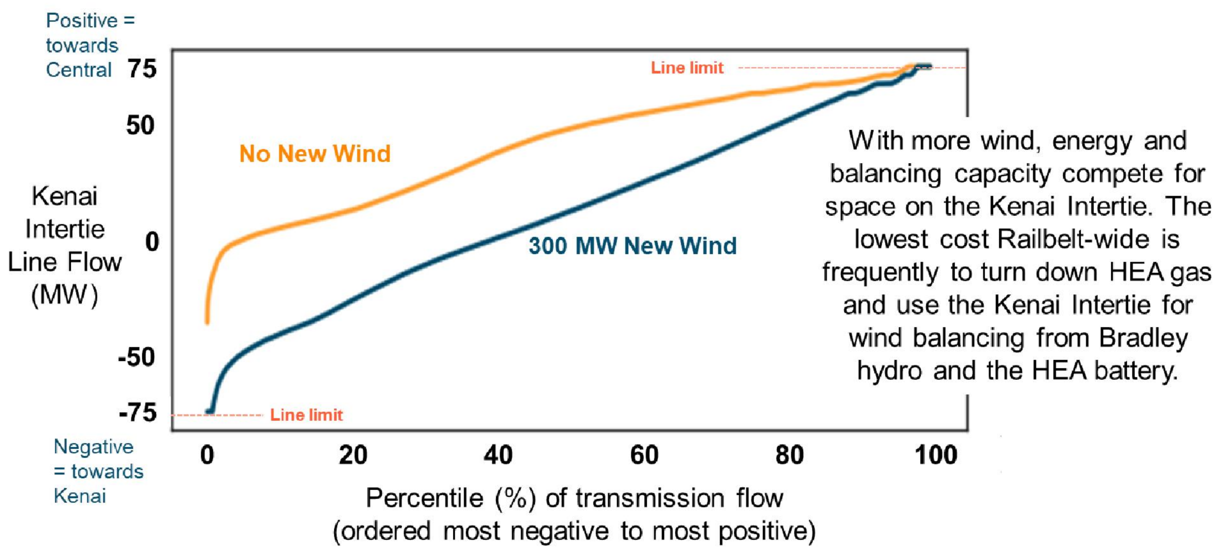


Figure 9: Transmission flow duration curve for the Kenai Intertie for the No New Wind and 300 MW New Wind Scenarios. The curves are created by ranking the modeled transmission flows in each 5-minute real-time interval across the year on the Kenai Intertie from most negative (towards Kenai) to most positive (Towards Central).

3.3 Dispatch plots

To demonstrate how Railbelt system dispatch changes between the No New Wind and 300 MW New Wind Scenarios, we include a comparison of dispatch on two sample days below – one with abundant wind (Figure 10) and one with intermediate wind (Figure 11). While the plots depict only two of the 365 days modeled in this study, they show examples of how load and resources could be balanced in the Railbelt on a 5-minute basis with more wind generation than is currently on the system. In Figure 12 we show how the dispatch of naphtha and oil resources changes from the addition of 300 MW of wind over 15 example days in April.

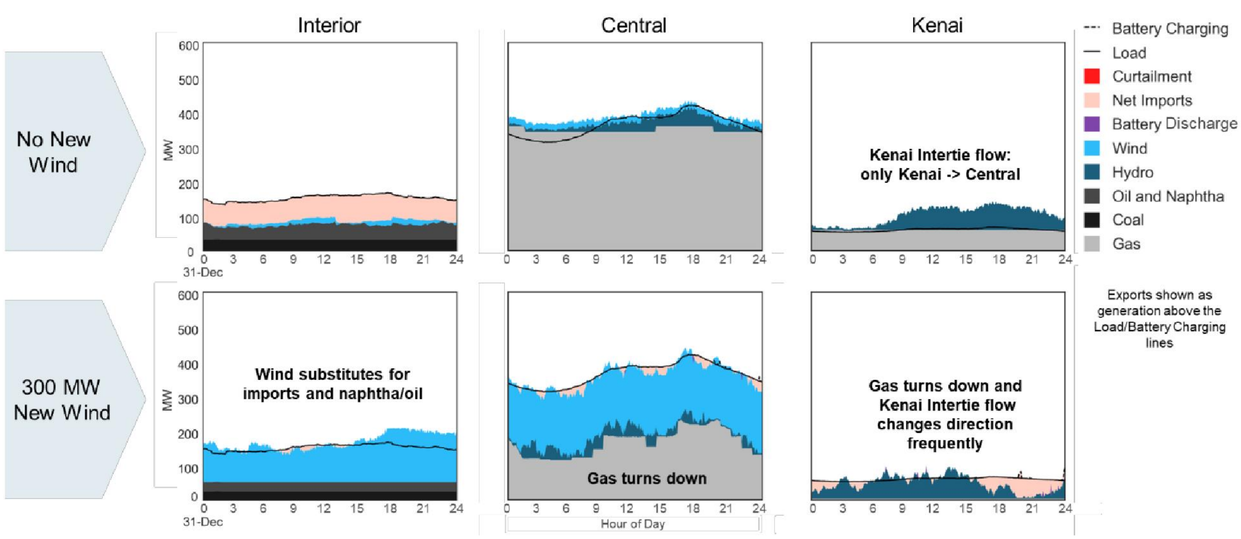


Figure 10: Dispatch plot comparison between the No New Wind Scenario (top) and the 300 MW New Wind Scenario (bottom) on a day with abundant wind generation. Generation is depicted based on the physical location of the resource.

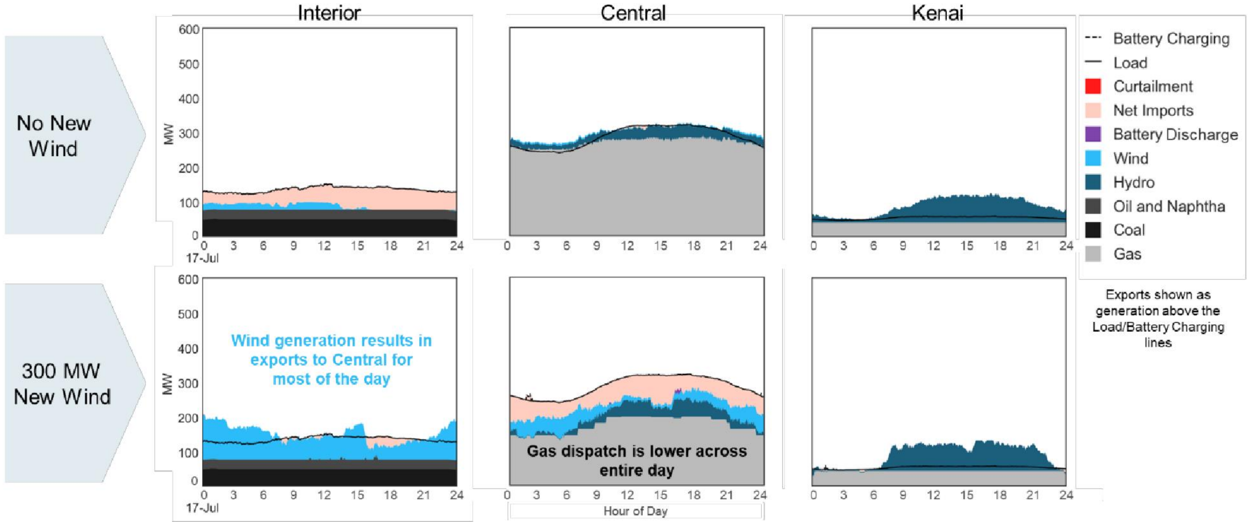


Figure 11: Dispatch plot comparison between the No New Wind Scenario (top) and the 300 MW New Wind Scenario (bottom) on a day with intermediate wind generation. Generation is depicted based on the physical location of the resource.

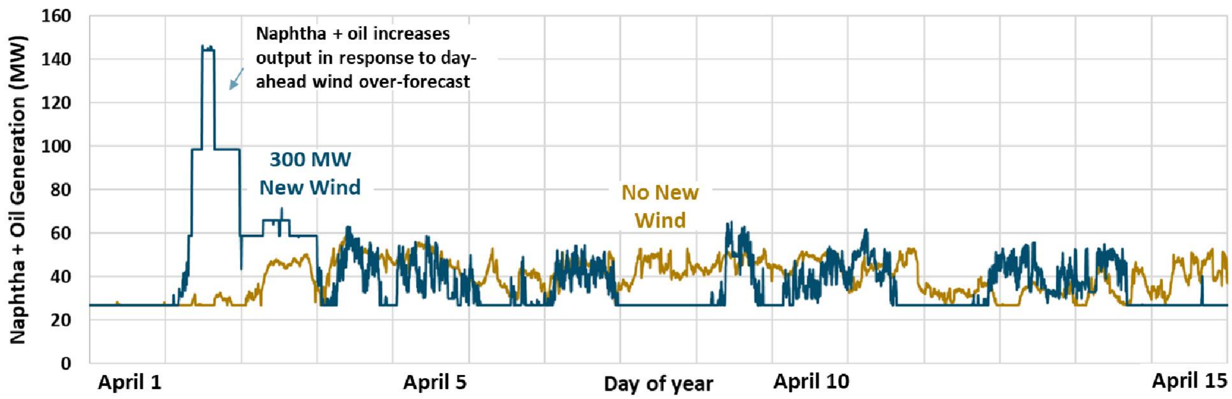


Figure 12: Naphtha and oil dispatch over 15 days of chronological 5-minute real-time dispatch in April. While the total generation from naphtha and oil resources is similar in this time window, the addition of 300 MW of wind results in lower generation during many periods but also higher generation in a few key intervals.

3.4 Production cost savings

Comparing the costs of the No New Wind Scenario and 300 MW New Wind Scenario shows that adding 300 MW of wind results in Railbelt-wide production cost savings of $112 M/yr in 2030 ($97 M/yr in $2023).[11] On average, each MWh of wind production added in the 300 MW New Wind Scenario decreases production costs by $95 per MWh in 2030, which is calculated by dividing the annual savings ($112 M/yr) by the annual production from 300 MW of wind (1,180 GWh/yr). This savings figure includes fuel, start, and variable operations and maintenance costs and excludes other potential savings such as resource adequacy value. No value is assigned to greenhouse gas (GHG) emission reductions or the renewable attribute of wind power (such as a renewable energy certificate). The addition of more wind primarily reduces natural gas generation; it is this reduction in natural gas that is the main source of the cost reduction.

The capital and fixed costs of the additional wind are not included in the production cost savings. The Railbelt utilities would need to pay the wind power purchase agreement (PPA) price plus the cost of any infrastructure upgrades (e.g. substations and transmission lines) and operational changes that are required to connect the wind projects. A comparison of future production cost savings, wind PPA costs, infrastructure upgrade costs, and other costs and benefits over the wind project lifetime would determine whether adding more wind to the Railbelt is cost-effective. This report does not determine wind cost effectiveness as it focuses on only production cost savings and does not estimate wind PPA costs, infrastructure upgrade costs, or other costs and benefits from adding wind.

Fuel savings, the largest component of production cost savings, occur primarily in the Central and Kenai zones (Figure 13) where gas plants are frequently scheduled and dispatched at lower output levels as a result of more wind generation. The Central zone saves $86M/yr ($75M/yr in $2023), which represents

[11] E3 uses a 2% inflation rate to convert between real $2023 costs and future year (nominal) costs.

roughly three quarters of the Railbelt-wide savings value. The Kenai zone saves $26M/yr ($23M/yr in $2023), which represents roughly one quarter of the Railbelt-wide savings value. The Interior zone sees a small increase in production costs of $1M/yr. We do not allocate costs to utilities so the production cost savings (or increase) in each zone does not directly translate into a rate impact for load served by utilities in each zone; generation ownership and the allocation of import and export costs is out of scope for this study.

The small magnitude of the Interior zone cost difference can be attributed to a number of factors including stability constraints that limit the reduction in naphtha generation and the role of Interior oil and naphtha plants in balancing wind power over-forecasts (see section 3.8). The relatively limited amount of oil and naphtha generation in the No New Wind Scenario highlights the impact of the single load balancing area assumption and other ways in which the PLEXOS dispatch results are optimized relative to current operational practice. More naphtha and oil generation is observed in historical operations than is present in the No New Wind 2025 Fuel Price Scenarios (Section 5.3).[12] As a result of the relatively low levels of naphtha/oil generation in the No New Wind Scenario, we do not observe large production cost savings in the Interior zone when wind is added in the 300 MW New Wind Scenario.

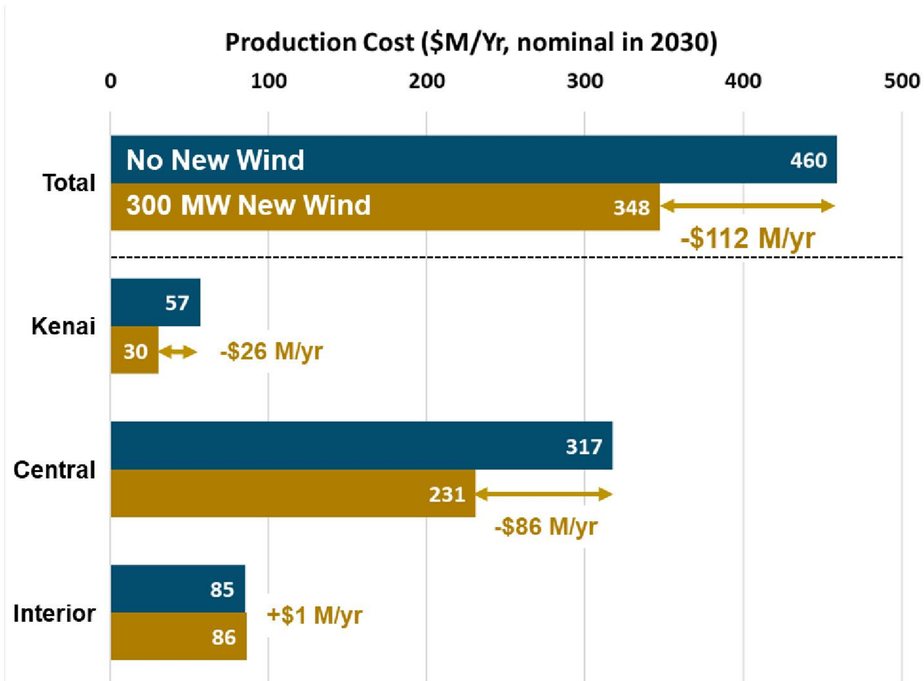


Figure 13: Production cost savings from adding 300 MW of wind, by zone and total.[13] The production cost savings by zone are not a reflection of utility rate impacts because the

[12] E3 did not model upper limits on fuel consumption in Central and Kenai gas resources but in practice there may be factors that would limit the amount of gas generation available to export from the Central and Kenai zones to the Interior.

[13] Independent rounding causes a slight Kenai zone cost difference inconsistency (26 vs. 57-30=27 $M/yr).

ownership share of each resource is not represented and the costs of imports and exports are not allocated to each utility.

The fuel cost savings from wind are expected to scale with fuel prices. We perform a sensitivity (Section 4.9) using with near present-day (2025) fuel prices to explore how the production cost savings from wind change with fuel prices. A key difference between the 2025 and 2030 fuel price projections is Liquified Natural Gas (LNG) pricing by 2030, which increases the cost natural gas relative to present-day (Figure 14). Production cost savings from wind are lower in 2025 relative to 2030 ($70/MWh vs. $95/MWh respectively). Fuel savings are likely to increase over the 20+ year lifetime of the wind power plants because Railbelt fuel costs are projected to increase over time. The value of wind resources would also be expected to change over time from other factors such as load growth, a changing generation mix, and potentially the addition of more transmission or storage capacity.

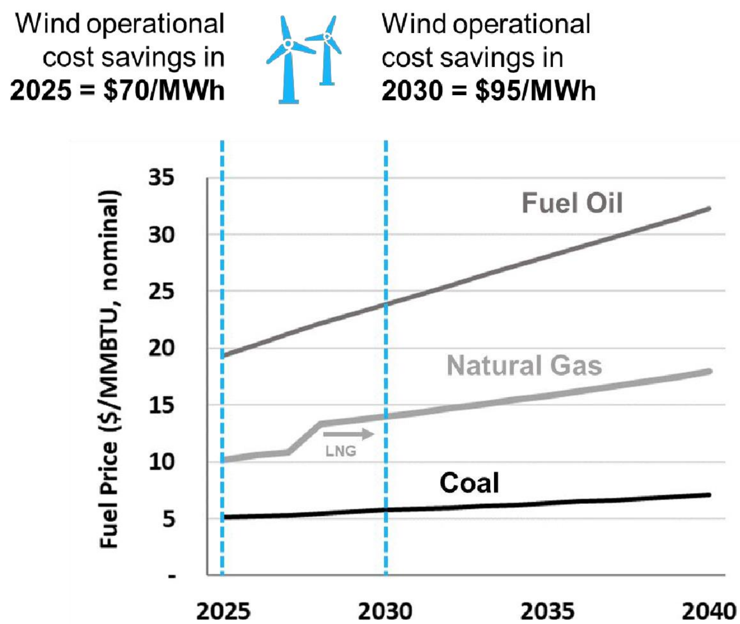


Figure 14: Fuel cost projections between 2025 and 2040, and production cost savings from wind using 2025 and 2030 fuel costs. As described in section 2.9, fuel cost projections are from the National Renewable Energy Laboratory, converted to nominal dollars using a 2% inflation rate.

3.5 CO_2 emissions results

300 MW of wind would reduce Railbelt-wide CO_2 emissions by roughly one quarter, from 1.99 $MMTCO_2$/yr to 1.50 $MMTCO_2$/yr (Figure 15). Adding 300 MW of wind reduces Railbelt-wide emissions intensity (CO_2 per MWh of demand) from 0.42 to 0.32 tCO_2/MWh.

Most of the emission reductions in the Railbelt occur in the Central and Kenai zones because gas resources in these zones decrease generation as a result of more wind. At 0.41 tCO_2/MWh, the CO_2 emissions reduced per MWh of wind generation is in the range of a typical natural gas emissions factor. Interior resources do not see a material reduction in emissions because annual generation from Interior thermal units is very similar in the No New Wind and 300 MW New Wind Scenarios.

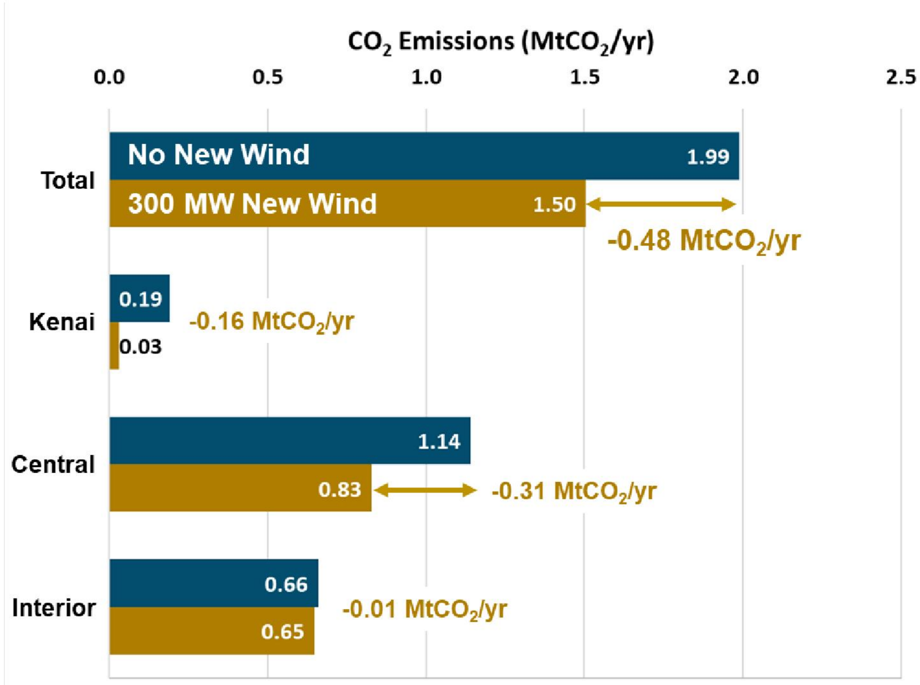


Figure 15: CO_2 emissions savings from adding 300 MW of wind, by zone and total.[14] Emissions are depicted based on the physical location of the resource and do not directly show the CO_2 emissions impact of each utility because the ownership share of each resource is not represented and the CO_2 emissions associated with imports and exports are not allocated to each utility.

3.6 Reserve and reliability results

As discussed in Section 2.5 and the Appendix (Section 7), many different types of contingency and balancing reserves are included in the production simulation modeling to ensure operability and reliability of the Railbelt system with higher levels of wind. The day-ahead and real-time model stages have the same reserve products, except for two reserves that are held in day-ahead to ensure real-time operability: within-hour regulation and forecast error reserves. Consistent with the single load balancing assumption adopted throughout this study, resources anywhere in the Railbelt can contribute to either of these day-ahead reserve products, subject to transmission availability.

As shown in Figure 16, within-hour regulation reserve is provided by a mix of flexible resources, including gas, oil/naphtha, hydro, and batteries. Forecast error reserves are provided predominantly by naphtha/oil and hydro resources. The naphtha and oil resources provide more forecast error reserve capacity than gas resources because of the limited ability to adjust gas consumption between day-ahead and real-time. Wind resources are occasionally under-scheduled (i.e. scheduled at less than their day-ahead production potential forecast), which reduces the need for balancing services to be held on other resources – this is

---

[14] Independent rounding causes a slight discrepancy in the reported difference (0.48 vs. 1.99-1.50=0.49 $MMTCO_2$/yr).

shown in Figure 16 as wind "providing" within-hour regulation reserve and forecast error reserve. Though we do not quantify the cost savings attributable to wind under-scheduling, our results suggest that under-scheduling wind can reduce the cost of wind integration by avoiding energy production from more expensive resources.

In real-time, the capacity held in day-ahead for within-hour regulation and forecast error reserve is released to be dispatched; the flexibility resulting from these reserves can be observed by comparing day-ahead and real-time dispatch (Section 3.8 below).

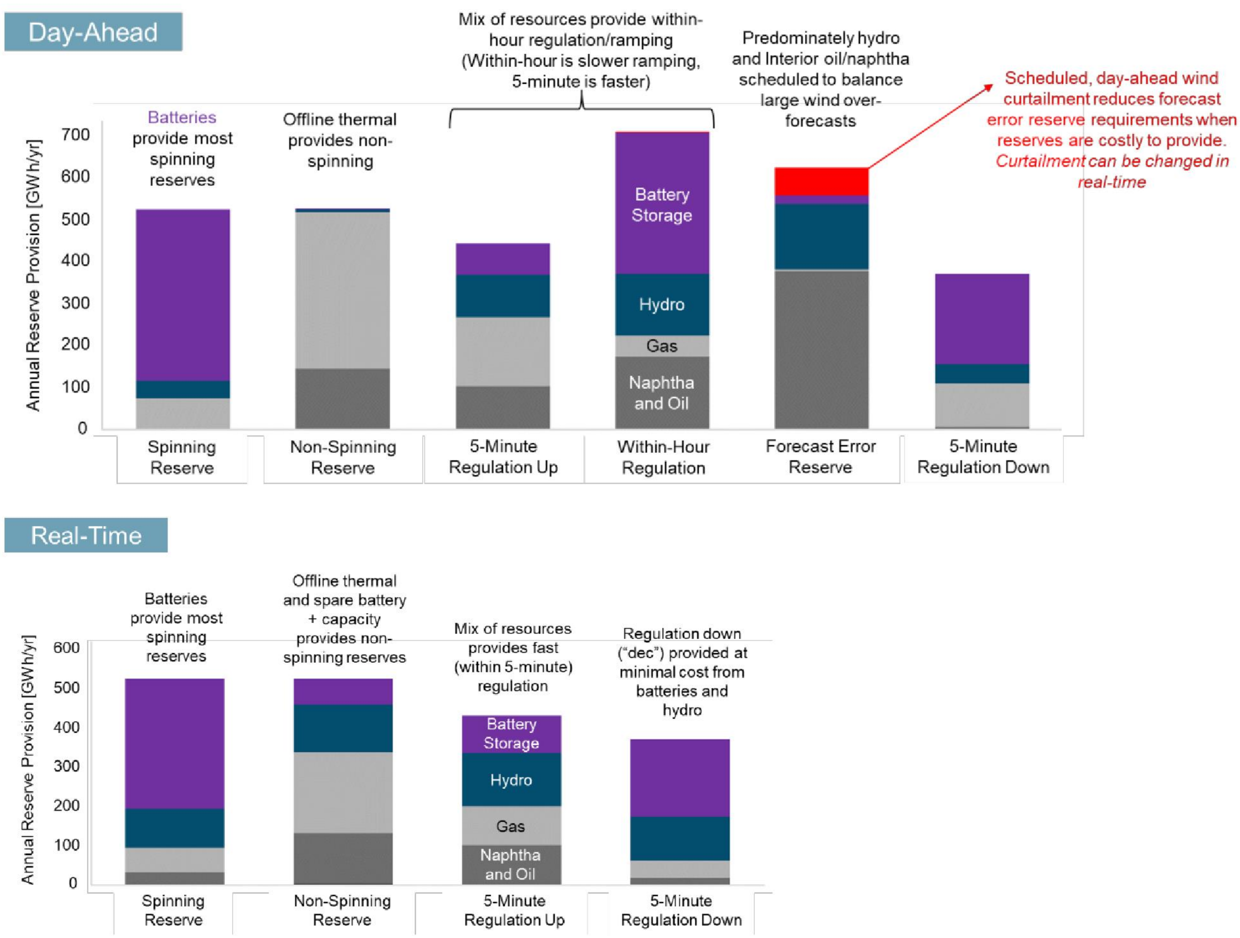


Figure 16: Day-ahead (top) and real-time (bottom) reserve commitments by resource type and reserve. This plot shows which resources are scheduled to provide each reserve over the entire year.

Four categories of reserves – spinning, non-spinning, 5-minute regulation up, and 5-minute regulation down – are held in both the day-ahead and real-time model stages. In E3's modeling, "5-minute" regulation refers to capacity held to cover ramping events *within* each 5-minute interval. The following reserve behavior is observed:

- Contingency reserves
    - Spinning reserve, 75% of which must be available on the primary frequency response timeframe, is held predominantly on batteries. Gas and hydro units have a somewhat

limited contribution to spinning reserves, and oil/naphtha units provide a small amount of spinning reserves due to their high fuel costs.
    - Non-spinning reserves, which are frequently inexpensive for offline resources to provide, are held on naphtha and oil in GVEA and predominantly gas in Central and Homer (with smaller contributions from hydro and batteries).
- Regulation reserves
    - 5-minute regulation up reserve is provided by a mix of resources, including hydro, gas, naphtha and oil, and batteries. In PLEXOS modeling 5-minute regulation up reserve for wind variability can be shared between the Central and Interior zones if adequate transmission capacity is available. We observe the Central and Interior zones frequently providing regulation across the Alaska intertie.
    - 5-minute regulation down reserve is held primarily on batteries, hydro, and gas. Batteries are well-equipped to provide regulation down as they are usually able to absorb excess energy quickly when needed.

Reserve shortages or periods of unserved energy (load shedding) indicate reliability challenges. We do not observe unserved energy in any 5-minute dispatch interval in any zone in the 300 MW New Wind Scenario, indicating that the Railbelt can match resources to load on a 5-minute basis over the course of an entire year, even with an additional 300 MW of wind. We observe minimal reserve shortages of 5-minute regulation up reserve in real-time: 3.4 MWh/yr (Interior) and 0.1 MWh/yr GWh (Central); no shortages of any other reserve are observed in real-time. This level of reserve shortage is common in 5-minute modeling and is very small relative to the need for reserves - for example the 5-minute regulation up requirement in Interior and Central is 402 GWh/yr, so only 0.001% of the reserve requirement is not met.

Minimal reserve shortages of 0.2 MWh of Interior 5-minute regulation up reserve and 0.6 MWh of within-hour regulation reserve are observed in day-ahead stage, which are also very small relative to the need for reserves in the day-ahead stage.

It is important to note that the need for balancing within each 5-minute dispatch interval is approximated using simulated 5-minute wind production data; additional study and operational experience are required to determine the correct level of regulation reserves to balance wind fluctuations within each 5-minute interval. Higher levels of reserves to regulate wind fluctuations, if necessary, would be expected to decrease production cost savings from additional wind and/or increase the need for fast-ramping resources (especially batteries).

3.7 Thermal resource starts

Thermal generators help to integrate variable wind generation by starting more frequently in the 300 MW New Wind Scenario relative to the No New Wind Scenario. Start costs are included in the PLEXOS modeling and the increase in start cost associated with more frequent starts is captured in the total production cost difference between the cases.[15]

Table 3: Thermal unit starts

Generator Category	Number of units starts per year	
	No New Wind	300 MW New Wind
Interior naphtha and oil	166	320
Central combined cycle	0	8
Central steam, reciprocating engine, and combustion turbine	636	2,221
Kenai gas	204	776

3.8 Real-time changes relative to day-ahead schedule

To simulate the impact of forecast errors and within-hour variability, the load and wind profiles are updated from the forecasts used in the day-ahead scheduling model stage to actual (i.e. non-forecast) profiles in the real-time dispatch stage. Resource dispatch must respond to the updated profiles by increasing or decreasing generation, storage charging/discharging, and transmission flows, while also adhering to day-ahead schedules for gas fuel nomination, combined cycle unit commitment, and coal unit commitment. Figure 17 shows the extent to which resource types turn up and down between day-ahead and real-time.

[15] While E3 includes start costs for thermal units, we do not explore whether additional starts would lead to increased maintenance costs above that quantified in the start cost values.

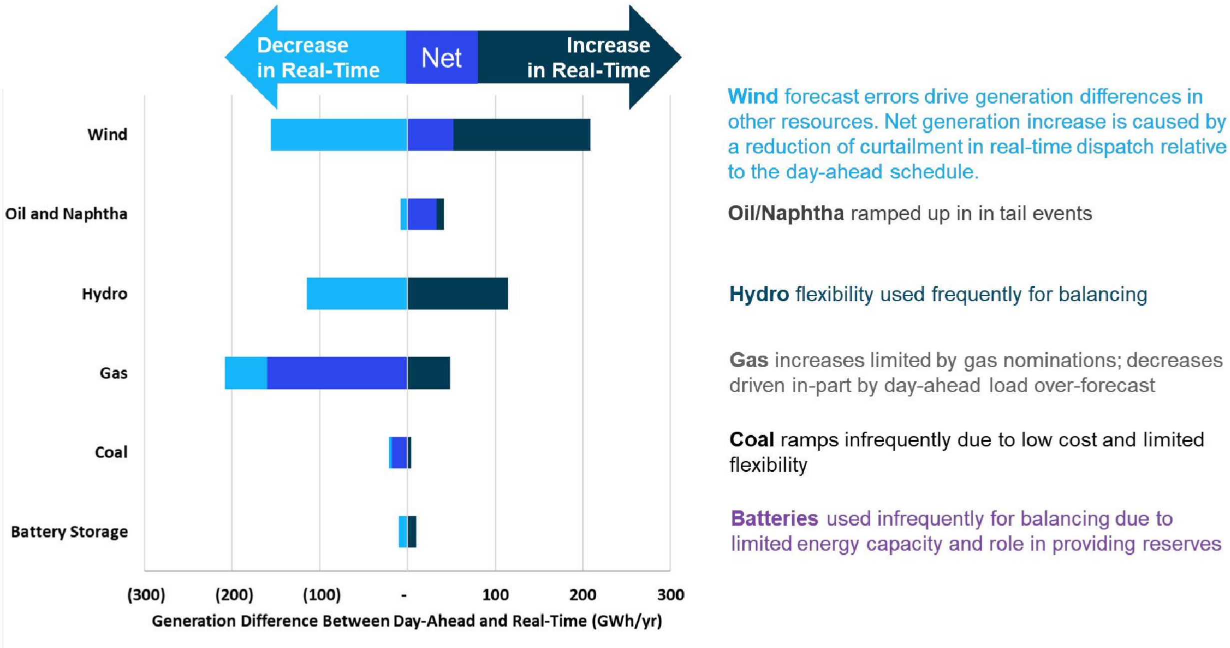


Figure 17: Difference between day-ahead schedule and real-time generation, grouped by fuel type. Positive values indicate that generation increases in real-time dispatch relative to the day-ahead schedule. As indicated by the legend at the top of the figure, the dark and light blue bars indicate the gross amount of generation increase and decrease (respectively) across the year, while the bright blue bars indicate the net increase (gross increase – gross decrease).

Railbelt hydro resources, especially Bradley, dispatch up and down frequently to balance forecast errors. Coal is ramped infrequently due to the dispatch limitations of coal resources, as well as the low cost of Healy 1 (the only coal plant modeled as dispatchable in this study), which makes Healy 1 less likely to be ramped up or down in real-time than other units. Batteries play a relatively small role in addressing forecast errors because the Railbelt batteries have a short duration (2 hours or less) relative to wind forecast errors. Batteries play a key role in providing spinning reserves in the Railbelt system, which reduces their ability to perform energy arbitrage. Batteries are occasionally observed charging or discharging to smooth out short (within-hour) energy shortages or surpluses.

In the larger electrical interconnections found in the lower 48 states of the United States, it is common for natural gas units to dispatch up or down in response to forecast errors. In the Railbelt, the ability of the gas fleet to respond to wind forecast errors is limited by day-ahead gas nomination restrictions. As a result, PLEXOS utilizes the Interior zone oil and naphtha units to increase generation during wind over-forecast events (when less wind power is available in real-time relative to the day-ahead forecast). Naphtha and oil resources are expensive to operate relative to other Railbelt resources, so this strategy is used only when other forms of flexibility have been exhausted.

As shown in Figure 18, the overall impact of re-dispatch between day-ahead and real-time on an annual basis is relatively small. This is consistent with Figure 17, which shows that generation increases and decreases between day-ahead and real-time mostly cancel out on an annual basis. The Interior and Central zones show differences between day-ahead and real-time resulting from Interior naphtha and oil resources increasing output to balance forecast errors in both Interior and Central. As a result, there is more naphtha/oil generation in the Interior zone in real-time than there was in day-ahead, and less gas generation in Central. A load over-forecast present in the Central day-ahead and real-time load forecasts also accounts for some of the decrease in Central gas generation between day-ahead and real-time.

Wind is sometimes under-scheduled in day-ahead (for example the curtailment in the day-ahead Interior column of Figure 18), but most of this wind can be absorbed in real-time. Under-scheduling wind is an option that should be explored by Railbelt operators as it can reduce the need to commit units to address wind variability and forecast errors, thereby reducing the cost of wind integration in certain circumstances.

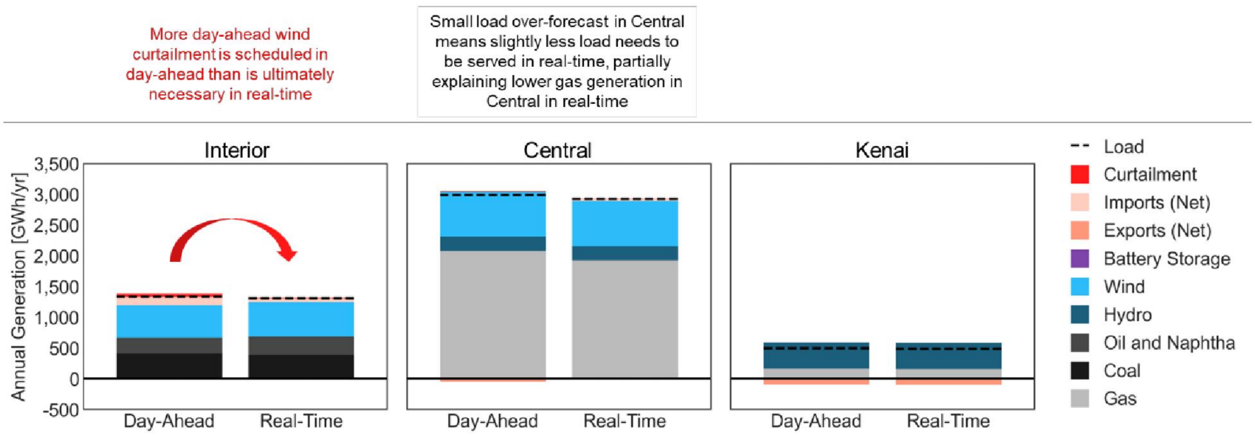


Figure 18: Annual generation in the 300 MW New Wind Scenario comparing day-ahead scheduled generation to real-time generation.

Figure 19 shows an example of how the Railbelt system responds to a large wind over-forecast. On the specific day depicted in the figure, Little Mount Susitna wind in the Central zone was over-forecasted for almost the entire day. In response, Interior naphtha and oil units increase output and Central decreases exports to the Interior zone.

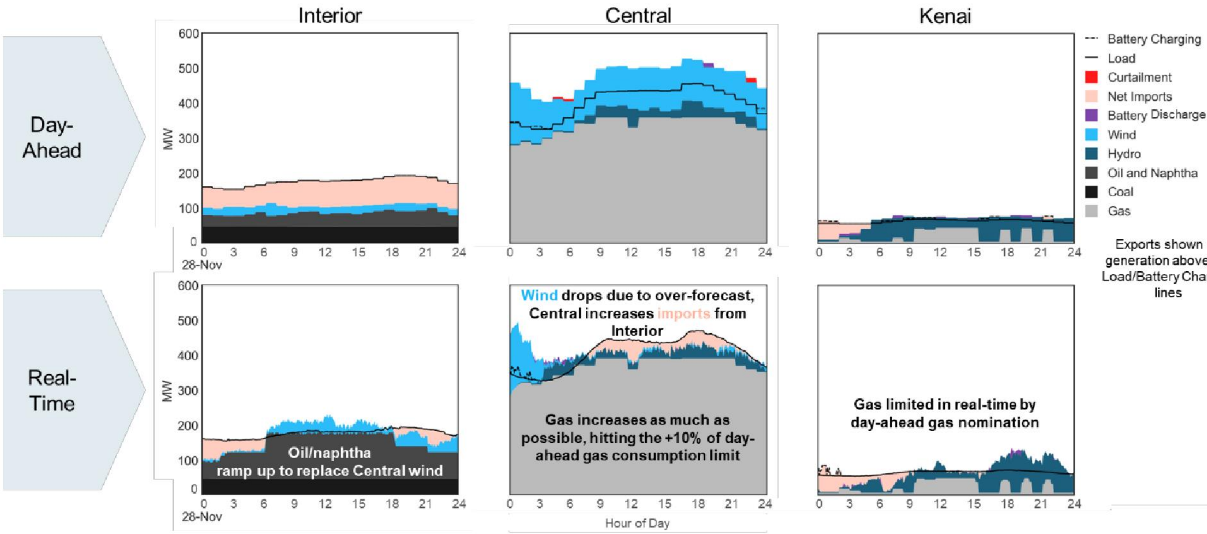


Figure 19: Dispatch plots from the 300 MW New Wind Scenario depicting the day-ahead schedule (top) and real-time dispatch (bottom) on a day where wind was over-forecasted in Central. Generation is depicted based on the physical location of the resource.

Figure 20 shows an example of how the Railbelt system responds to a large wind under-forecast. On the specific day depicted in the figure, more wind is available in real-time in both the Interior and Central zones than was forecasted. As a result, more gas generation is scheduled in day-ahead than was ultimately required. To stay within 90% of the day-ahead gas nomination but also create as much space for wind as possible, the production simulation chooses to increase the average heat rate of gas generation in Central. Some of the additional wind generation on this day could not be absorbed by the system, resulting in curtailment. As mentioned in Section 3.1, wind curtailment in the 300 MW New Wind Scenario is relatively infrequent and only 1% of the new wind production potential is curtailed.

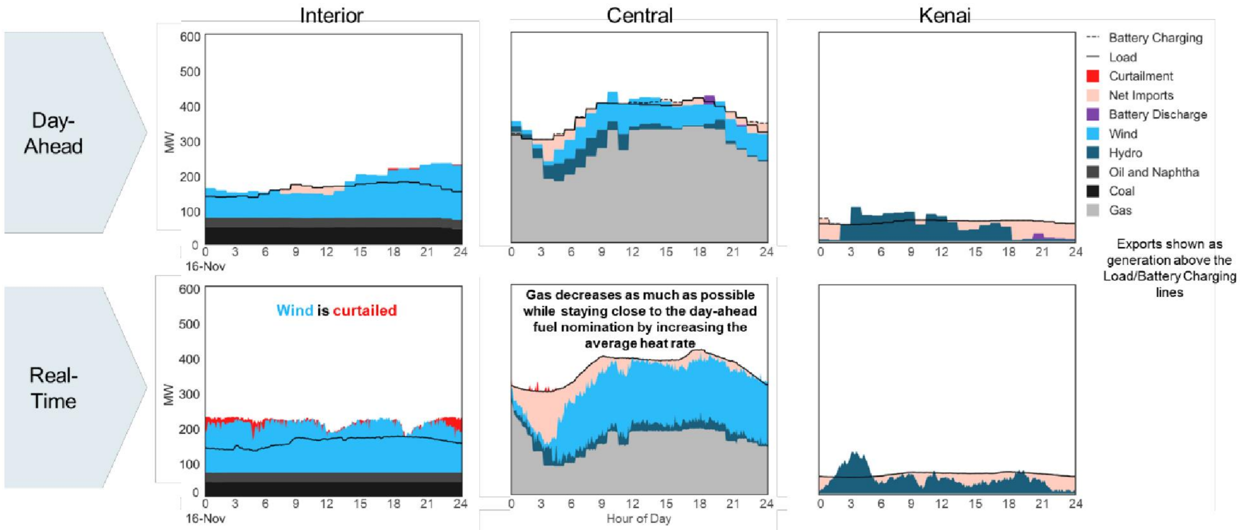


Figure 20: Dispatch plots from the 300 MW New Wind Scenario depicting the day-ahead schedule (top) and real-time dispatch (bottom) on a day where wind was under-forecasted. Generation is depicted based on the physical location of the resource.

3.9 Transmission schedules: day-ahead vs. real-time

Transmission between Railbelt zones is important to balance wind forecast errors. With Bradley hydro and the Homer battery in the south, dispatchable naphtha and oil in the north (GVEA), and flexible but fuel-constrained gas in Homer and Central, dynamic utilization of transmission between zones is important to access the diversity of Railbelt resources.

With more wind, transmission flows deviate more frequently in real-time from their day-ahead schedules on both the Alaska Intertie and the Kenai Intertie (Figure 21). The increased re-scheduling of transmission between day-ahead and real-time with more wind is especially apparent on the Alaska Intertie. Two large wind resources are located on either side of the Alaska Intertie, and a forecast error in one or both wind resources can cause the flow along the Alaska Intertie to change. In addition, Interior naphtha and oil resources are used to balance forecast errors across the Railbelt, resulting in changes to transmission flows when the origin of the forecast error is outside of the Interior zone.

As shown in Figure 21, the Kenai Intertie also experiences larger changes in flows between day-ahead schedules and real-time dispatch in the 300 MW New Wind Scenario relative to the No New Wind Scenario. The flexibility of Bradley hydro, located at the Kenai side of the Kenai Intertie, is used to balance wind resources at the other end of the intertie in the Central and Interior zones.

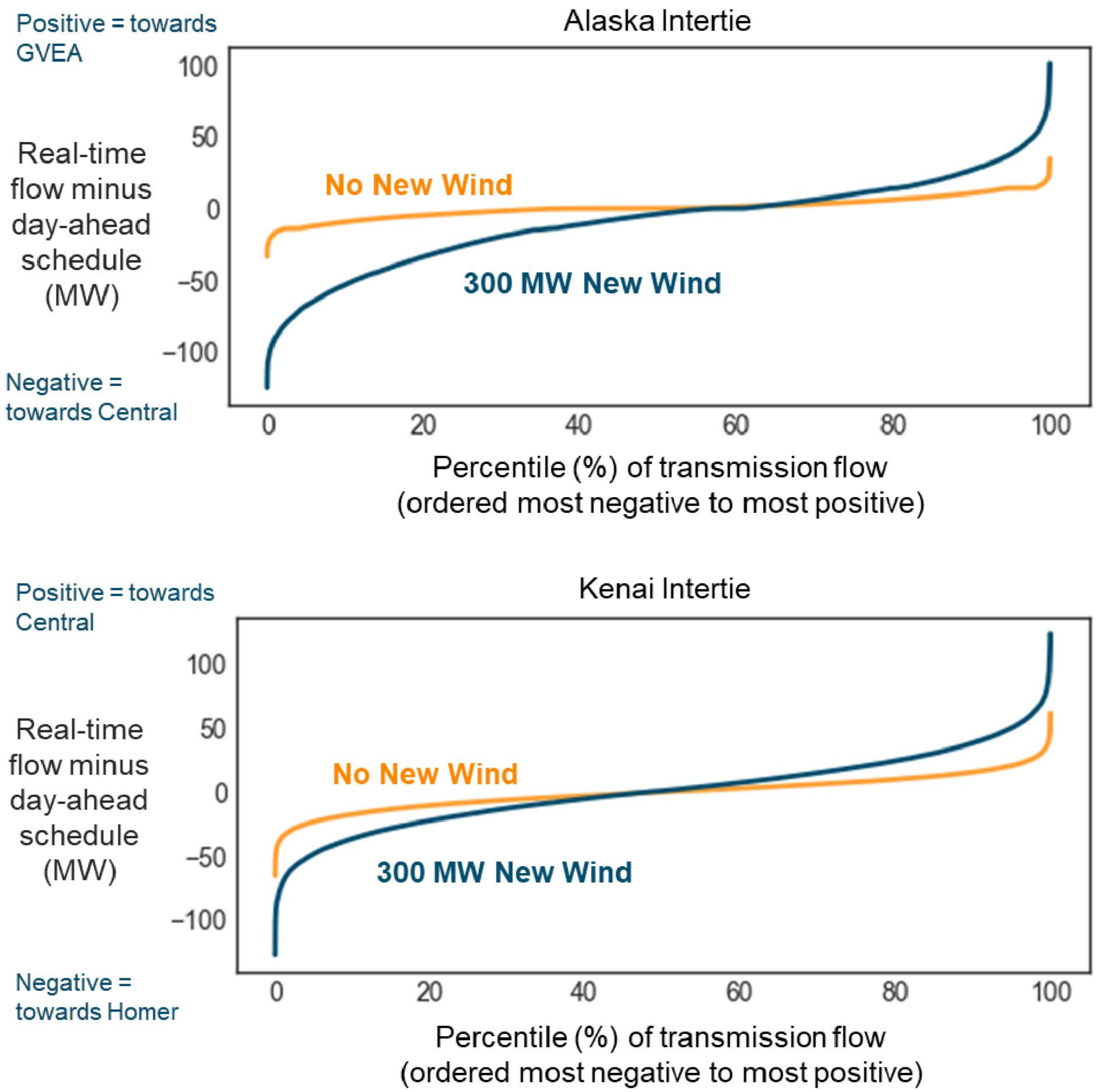


Figure 21: Difference between transmission schedules and real-time transmission flows on the Alaska Intertie (top) and Kenai Intertie (bottom). Values can exceed the rated capacities of the interties in the infrequent event that flows are reversed between day-ahead and real-time – this does not violate the flow limit of the line.

The need to balance wind forecast errors and variability results in variable flows between regions in the 300 MW New Wind Scenario (Figure 8 and Figure 9) in real-time dispatch. These variable real-time flows are in part a product of how the interties are scheduled in the day-ahead timeframe. We have modeled reserve sharing across the interties in the day-ahead timeframe, which allows resources on one side of the intertie to provide forecast error, within-hour variability, and 5-minute regulation up reserve capacity to wind deviations that occur on the other side of the intertie.

The Alaska Intertie is used for a combination of energy schedules and reserves in the day-ahead timeframe in both directions, reaching up to the line's maximum capacity of 78 MW in most intervals (Figure 22). In the No New Wind scenario, the Interior to Central direction of the Alaska intertie is not used frequently because the line is almost always flowing towards the Interior zone, and the forecast error and variability in the No New Wind Scenario is relatively low. As wind is added to the system, the scheduled flows become more variable and the need for reserves increases on both sides of the Alaska Intertie. Both factors contribute to the high utilization (energy + reserve schedules) in both directions of the Alaska Intertie in the 300 MW New Wind Scenario.

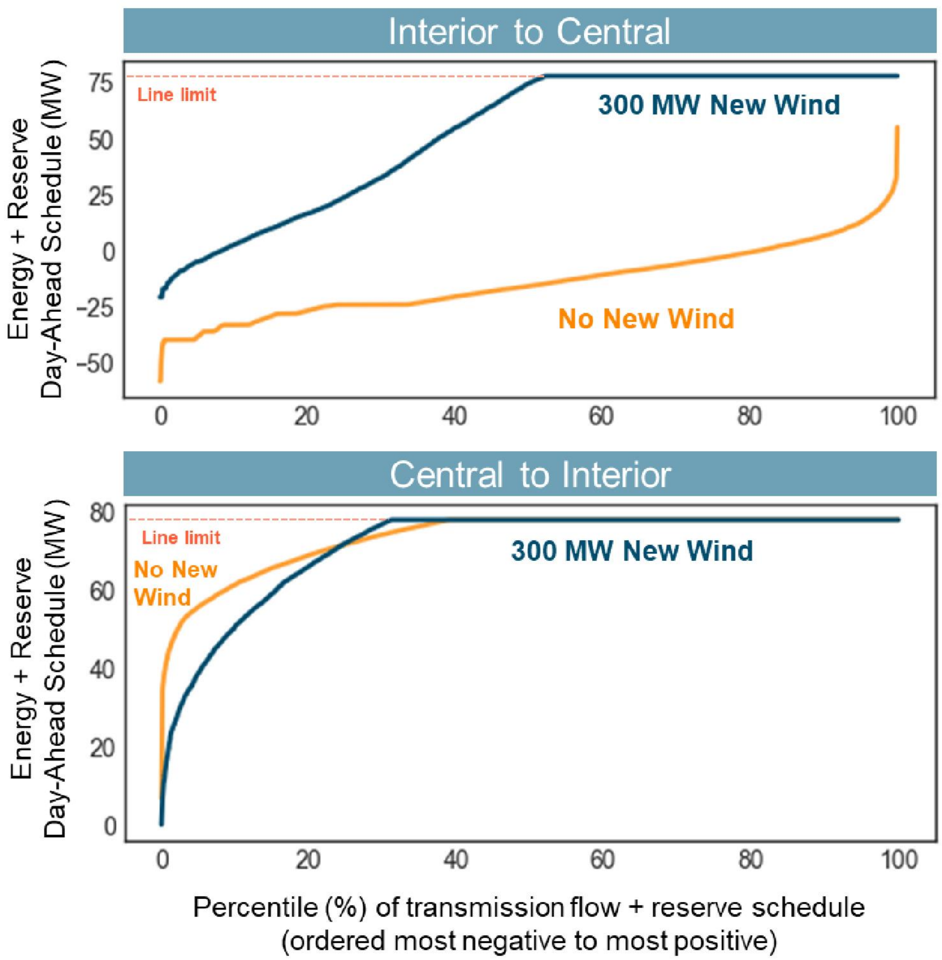


Figure 22: Day-ahead utilization (energy + reserve schedule) of the Alaska Intertie in each direction for both the No New Wind Scenario and the 300 MW New Wind Scenario.

Similar behavior is seen in the Kenai to Central direction of the Kenai Intertie (Figure 23), indicating that the line is frequently scheduled at its maximum capacity of 75 MW for a combination of energy and reserves in the Kenai to Central direction. Figure 9 shows that the amount of energy sent on the Kenai Intertie in the Kenai to Central decreases as wind is added to the system, and yet Figure 23 shows increased utilization of the Kenai to Central direction in the 300 MW New Wind Scenario. In the 300 MW New Wind Scenario, the Kenai Intertie is being scheduled predominantly for reserves (as opposed to energy) in the day-ahead timeframe.

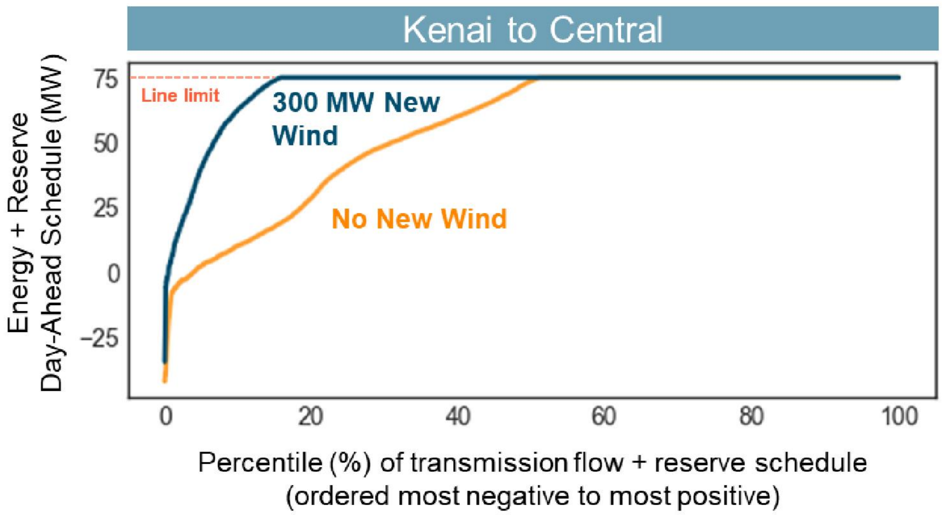


Figure 23: Day-ahead utilization (energy + reserve schedule) of the Kenai Intertie in the Homer to Central direction for both the No New Wind Scenario and the 300 MW New Wind Scenario. E3 did not model reserve-transmission limits in the Central to Homer direction due to the low reserve needs in the Homer zone.

3.10 Gas fuel flexibility limits

As described in Section 2.8, to model the limited flexibility of Railbelt natural gas supply in PLEXOS, real-time gas consumption in Central and Homer is limited to be +/- 10% from the day-ahead gas nomination in every hour. If necessary, Railbelt operators can request changes to the volume of gas fuel provided outside of the +/- 10% band, but operators attempt to minimize gas deviations in real-time operations to avoid cost penalties as well as the potential that it may not be possible for the gas supply to be adjusted quickly. To mimic operational practice, in PLEXOS we allow the +/- 10% gas nomination constraints to be violated with a very high penalty price.

We observe that in the 300 MW New Wind Scenario, 99% of hours in the Central and Kenai zones stay within +10% of the day-ahead gas nomination, and the maximum hourly violation is 8% above the +10% limit (118% of the day-ahead nomination for the hour) in the Kenai zone. On all of the 365 days modeled, the daily gas consumption is within +10% of the amount nominated across the day in the day-ahead model stage. Discussions with Railbelt staff indicate that the low level of gas nomination violations observed here would be acceptable in practice. The gas nomination results indicate that the flexibility held in the day-ahead stage (including forecast error and within-hour regulation reserves) is adequate to avoid nearly all potential issues with over-consumption of gas in real-time driven by wind forecast errors. Reliance on Interior naphtha and oil units to dispatch up to compensate for wind over-forecasts is an important source of flexibility to avoid consuming too much gas in real-time relative to the day-ahead nomination.[16] Dispatch flexibility on hydro and battery resources is also important to minimize gas nomination issues.

In the downward direction (where gas consumption in real-time is less than the day-ahead nomination), we observe minor deviations outside of the 90% limit, with a minimum hourly gas consumption of 83% of the day-ahead nomination across the entire year. During periods of abundant wind, wind curtailment is utilized to avoid downward gas violations. To maintain the day-ahead gas consumption while backing down the MW output from gas units, PLEXOS sometimes chooses to run the gas fleet less efficiently and/or turn on less efficient peaking units. This strategy represents a way to comply with day-ahead gas nomination limits but is less than ideal because the gas fleet is being operated less efficiently than it would be without the 90% gas nomination constraint. Any flexibility that could allow the Railbelt system operators to reduce gas generation *and* reduce gas fuel consumption below the 90% level would be preferred and would reduce the cost of wind integration.

Across the year, we observe that gas consumption in Central is 4% lower in real-time relative to the amount nominated in the day-ahead stage (Figure 24 and Table 4). This result is in part due to a small forecasting bias in the Central load forecasts that results in lower load in real-time relative to day-ahead. Other dispatch dynamics, including the utilization of Interior oil and naphtha units to counter wind under-forecasts, also have an impact on the amount of gas consumed in real-time relative to day-ahead. Kenai gas consumption values are similar between day-ahead and real-time throughout the year.

Table 4: Annual scheduled gas nominations vs. real-time consumption

	Central	Kenai
Day-ahead annual gas consumption (BBTU)	15,499	1,994
Real-time annual gas consumption (BBTU)	14,955	2,010
Annual difference (BBTU)	-544	+16
Difference (%)	-4%	+1%

[16] Further investigation is required to determine if additional fuel storage for naphtha and oil units would be required to operate as depicted in this study.

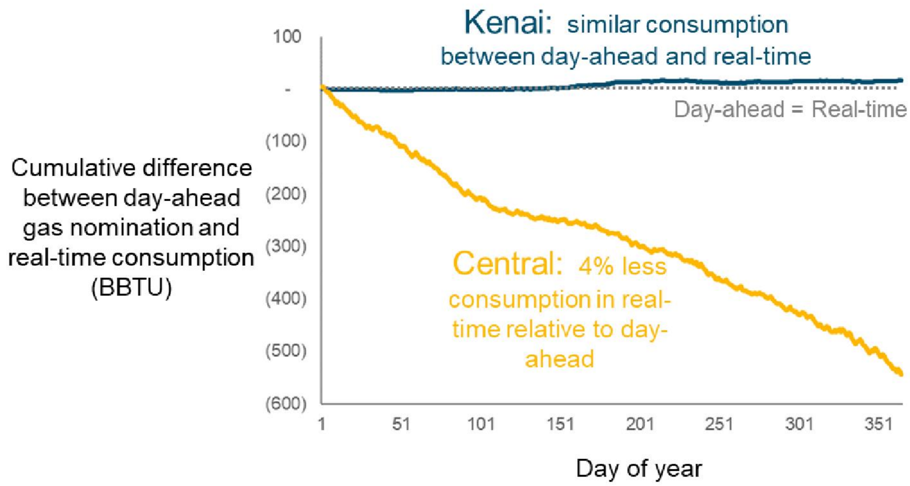


Figure 24: Cumulative difference between gas day-ahead nomination and real-time consumption.

4. Sensitivity analysis

4.1 Introduction

The value and operational impact of additional wind under different assumptions is explored by performing sensitivity model runs on the 300 MW New Wind Scenario.

- The **GVEA Battery Replacement Sensitivity** replaces the existing short-duration GVEA battery with a 2-hour battery.
- The **Transmission Reinforcement Sensitivity** increases transfer capacity between the Interior and Central zones, and also between the Central and Kenai zones. It also removes the Interior stability constraint on the assumption that it would not be required with higher voltages on the Alaska intertie.
- The **Kenai Intertie Outage Sensitivity** takes the Kenai Intertie out of service for two weeks in Feb and two weeks in July. During the outage periods, the Kenai zone must be operated as an island and Kenai resources (especially Bradley hydro and the Homer battery) are not available to the rest of the Railbelt to balance wind generation.
- The **Gas Scheduling Flexibility Sensitivity** removes gas nomination limits to explore the value of more flexible gas fuel utilization.
- The **Commit All Day-Ahead Sensitivity** restricts real-time commitment flexibility to explore the value of real-time, sub-hourly dispatch modeled in PLEXOS.
- The **Wind 5-Minute Regulation Sensitivity** includes new wind as an option for providing regulation within each 5-minute dispatch interval.
- The **Relax Stability Commitment Constraints Sensitivity** removes all stability-related thermal and hydro commitment constraints to explore the value of providing grid stability services without specific thermal and hydro commitments.
- The **2025 Fuel Price Sensitivity** explores savings from additional wind with near-term (2025) fuel prices.

Each sensitivity is discussed individually below, followed by a summary of sensitivity results.

4.2 GVEA battery replacement sensitivity

GVEA is considering a replacement for their current battery system, both because the current battery has a limited lifetime, and because a new battery may aid in system balancing and wind integration. The **GVEA Battery Replacement Sensitivity** replaces existing short-duration GVEA battery with a 2-hour battery. The sensitivity has the same wind portfolio as the 300 MW New Wind Scenario and therefore explores the production cost savings of a replacement battery in the context of more much wind than is currently present in the Railbelt. The sensitivity quantifies only production cost savings and does not explore reliability or resource adequacy-related value for a replacement battery.

4.2.1 Changes from 300 MW New Wind

- The existing 46MW/6MWh Fairbanks battery is replaced with a 46MW/92MWh (2-hour) battery.
- Due to the age and limited capabilities of the existing battery, it is limited to only providing spinning reserves; the replacement battery can provide all types of reserves.
- The replacement battery can perform energy arbitrage, whereas the existing battery is limited to exclusively provide reserves.

4.2.2 Results

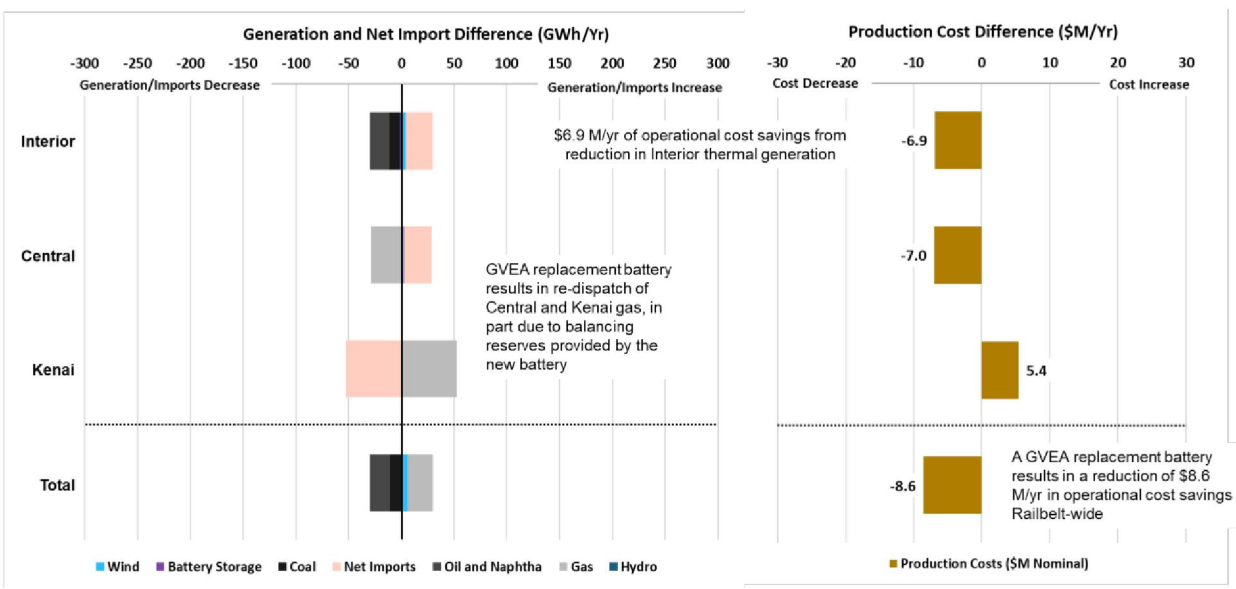


Figure 25: Generation, net imports, and production cost difference by zone: GVEA Battery Replacement Sensitivity - 300 MW New Wind Scenario

A replacement battery in GVEA reduces Railbelt-wide production costs by $8.6 M/yr in 2030. The production cost savings do not include the cost of the battery. The production cost savings are relative to the existing battery and do not represent full production cost value of the replacement battery. Much of the cost savings are a result of lower thermal generation in the Interior zone. The flexibility of the new battery in the Interior zone causes re-dispatch of Central and Kenai gas resources to reduce total system costs, resulting in more Kenai gas generation and less in Central relative to the 300 MW New Wind Scenario.

In the 300 MW New Wind Scenario, the existing GVEA battery does not charge or discharge; in the GVEA Battery Replacement sensitivity there is 7.1 GWh/yr of discharge. As shown in Figure 26, the replacement battery provides 5-minute regulation up and down reserves, which the current battery does not. The new battery is also able to provide day-ahead forecast error and within-hour regulation capacity in the day-ahead timeframe (not shown in Figure 26).

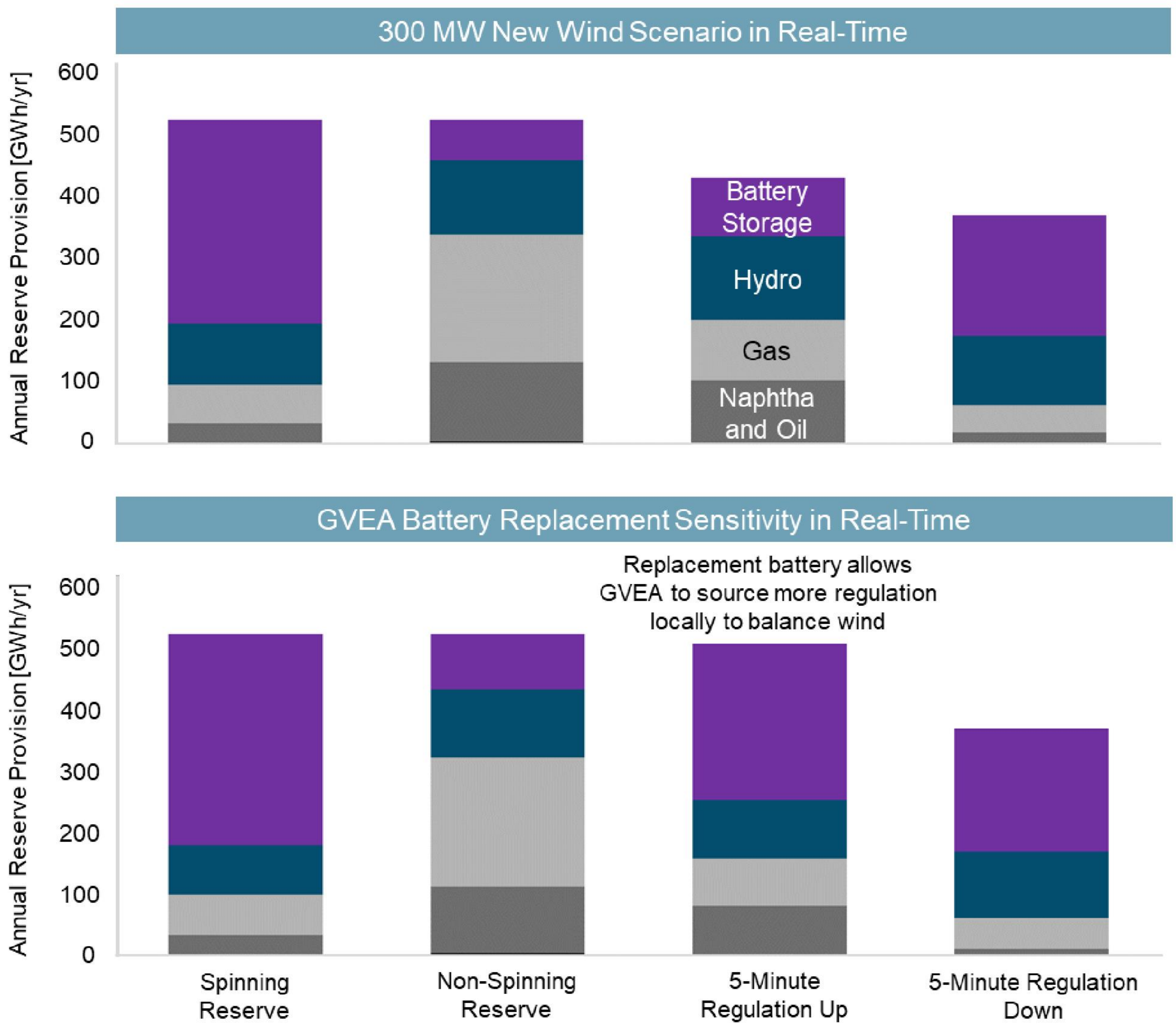


Figure 26: Reserve provision in the 300 MW New Wind Scenario (top) and GVEA Battery Replacement Sensitivity (bottom)

The value of replacing GVEA's battery can be impacted by many factors that are not explored in this sensitivity. We have modeled the Railbelt as a single load balancing area, but if the Interior zone were to be less able to interact with its neighbors than is modeled in PLEXOS, the incremental production cost savings from the replacement battery would likely be larger.

A replacement battery may be able to contribute to the reliability services that drive the need for commitment of naphtha generation to maintain system stability in the Interior zone. Studying the feasibility and potential costs savings of a GVEA replacement battery reducing or eliminating the Interior zone thermal commitment needs is outside the scope of E3's study but should be investigated.

4.3 Transmission Reinforcement Sensitivity

The Railbelt is exploring the possibility of expanding intertie capacity between zones. The **Transmission Reinforcement Sensitivity** increases transfer capacity between the Interior and Central zones, and also between the Central and Kenai zones. It also removes the Interior stability constraint on the assumption that it would not be required with higher voltages on the Alaska intertie.

4.3.1 Changes from 300 MW New Wind

- The Transmission Reinforcement Sensitivity increases the transfer capability between the Central and Interior zones from 78 MW to 200 MW in both directions, which reflects a voltage upgrade to 230kV on the Alaska Intertie. The Transmission Reinforcement Sensitivity also increases the transfer capability between the Central and Kenai zones from 75 MW to 175 MW in both directions, which reflects a new 100 MW DC line.
- The Transmission Reinforcement Sensitivity assumes that the Interior stability requirement (which requires commitment of at least one North Pole unit) is no longer necessary with higher voltage transmission between the Central and Interior zones. The removal of the stability requirement merits further study, especially in the context of higher levels of wind generation in the Railbelt.
- The results show the combined impact of both higher transmission capacity between zones as well as the removal of the Interior stability constraint.

4.3.2 Results

As shown in Figure 27, Kenai gas generation increases in the Transmission Reinforcement Sensitivity relative to the 300 MW New Wind Scenario, in large part due to the increase in generation from HEA's Nikiski combined cycle plant. In the 300 MW New Wind Scenario, reserves from Bradley and the HEA battery are frequently prioritized over energy on the Kenai Intertie, resulting in low levels of generation from the Nikiski combined cycle plant. In the Transmission Reinforcement sensitivity, there is enough transmission capacity between the Kenai and Central zones to simultaneously support generation from Nikiski combined cycle plant and reserves from Bradley and the HEA battery. As a result of increased output from the Nikiski combined cycle plant, transmission flows in the Kenai to Central direction increase in the Transmission Reinforcement Sensitivity (Figure 28).

Higher capacity on the Alaska Intertie and removal of the Interior stability constraint enables higher Central to Interior flows in ~25% of intervals. Lower levels of Interior naphtha and oil generation are observed in the Transmission Reinforcement Sensitivity relative to the 300 MW New Wind Scenario; the naphtha and oil generation is replaced with lower cost imports from Central.

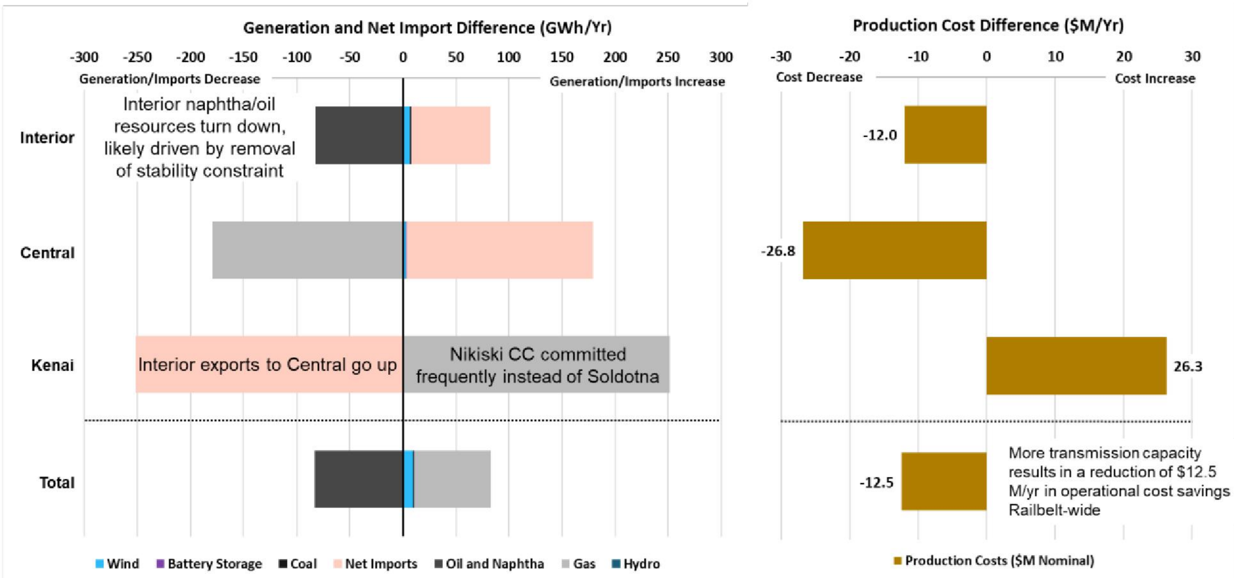


Figure 27: Generation, net imports, and production cost difference by zone: Transmission Reinforcement Sensitivity - 300 MW New Wind Scenario.

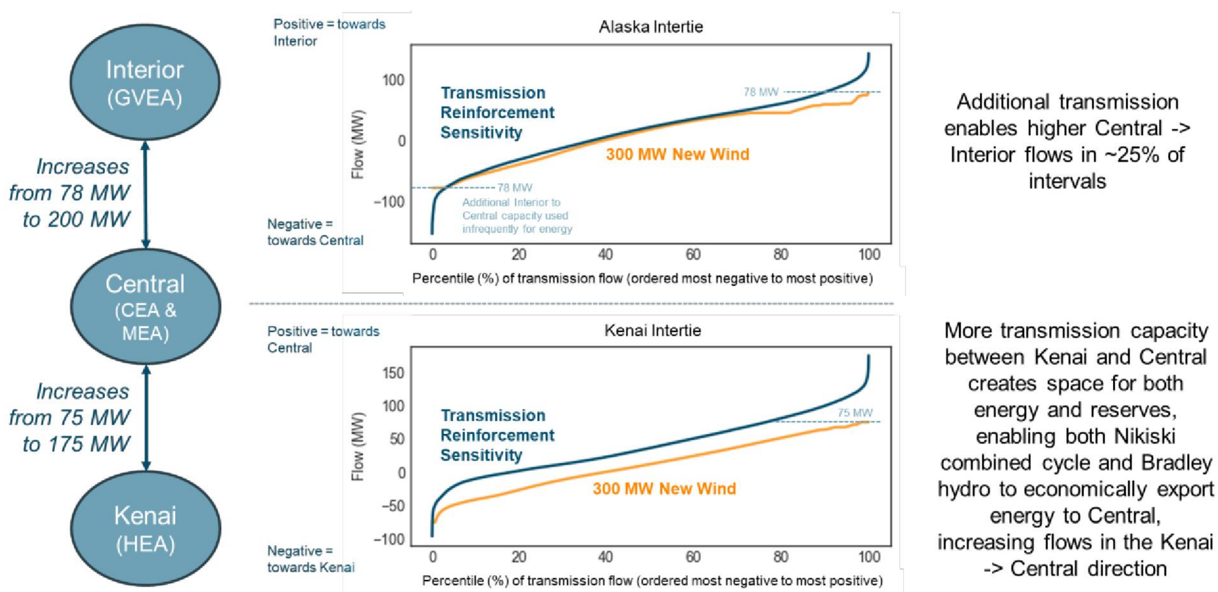


Figure 28: Real-time transmission flows in the 300 MW New Wind Scenario and Transmission Reinforcement Sensitivity

Figure 28 shows real-time energy flow on the transmission lines but does not show how the lines are used in the day-ahead timeframe for resource scheduling and reserves. When more transmission capacity is added to the Railbelt, the new capacity can lower production costs by allowing low cost energy sources to generate (especially the Nikiski combined cycle plant) while also allowing transmission to be reserved for balancing wind generation. As a result, the energy and reserve schedules in the day-ahead timeframe in the Transmission Reinforcement Sensitivity frequently exceed the line capacity in the 300 MW New Wind Scenario (Figure 29 and Figure 30).

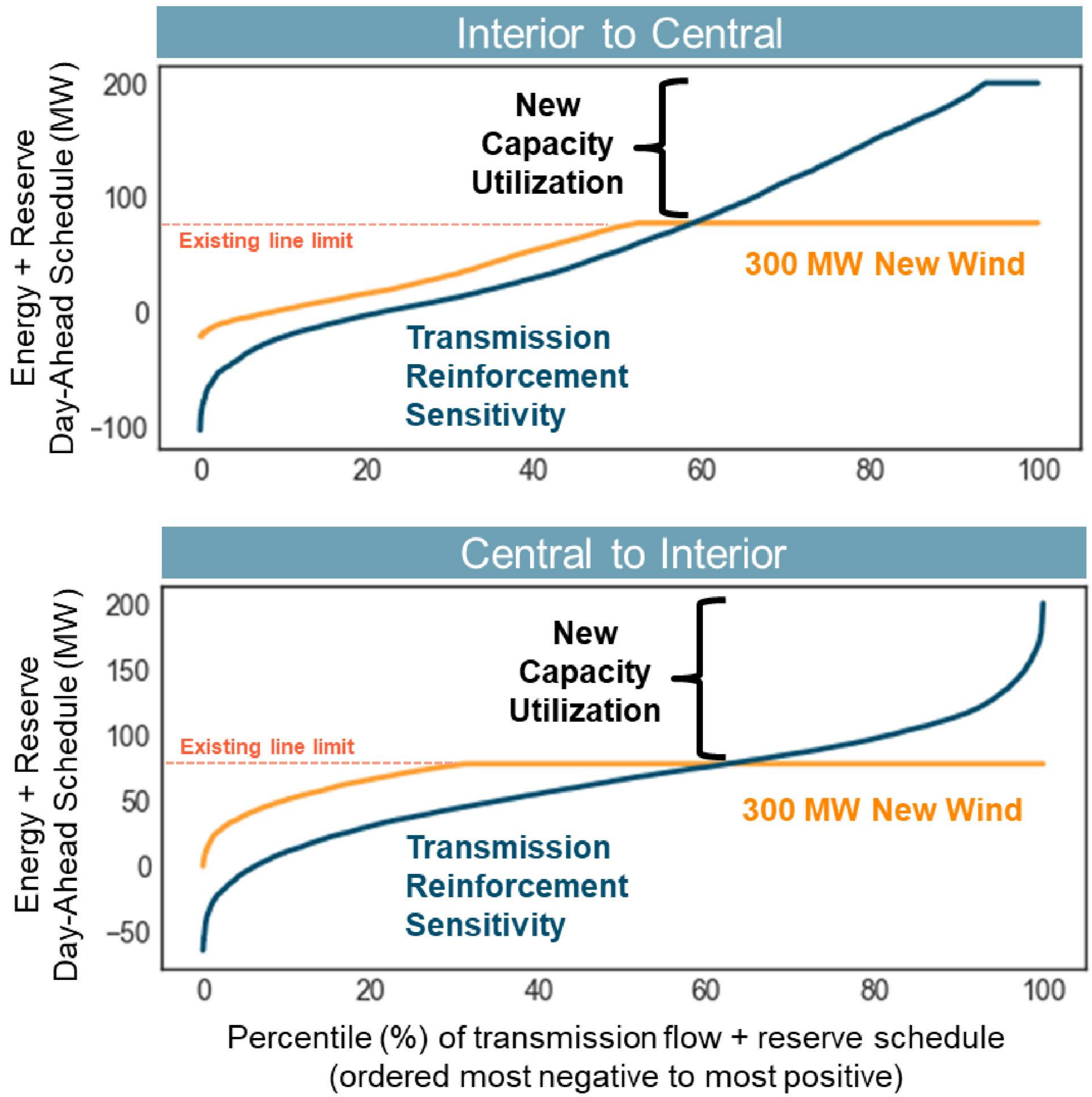


Figure 29: Day-ahead utilization of transmission in the 300 MW New Wind and Transmission Reinforcement Sensitivity between the Central and Interior zones in both the Interior to Central (top) and Central to Interior (bottom) directions.

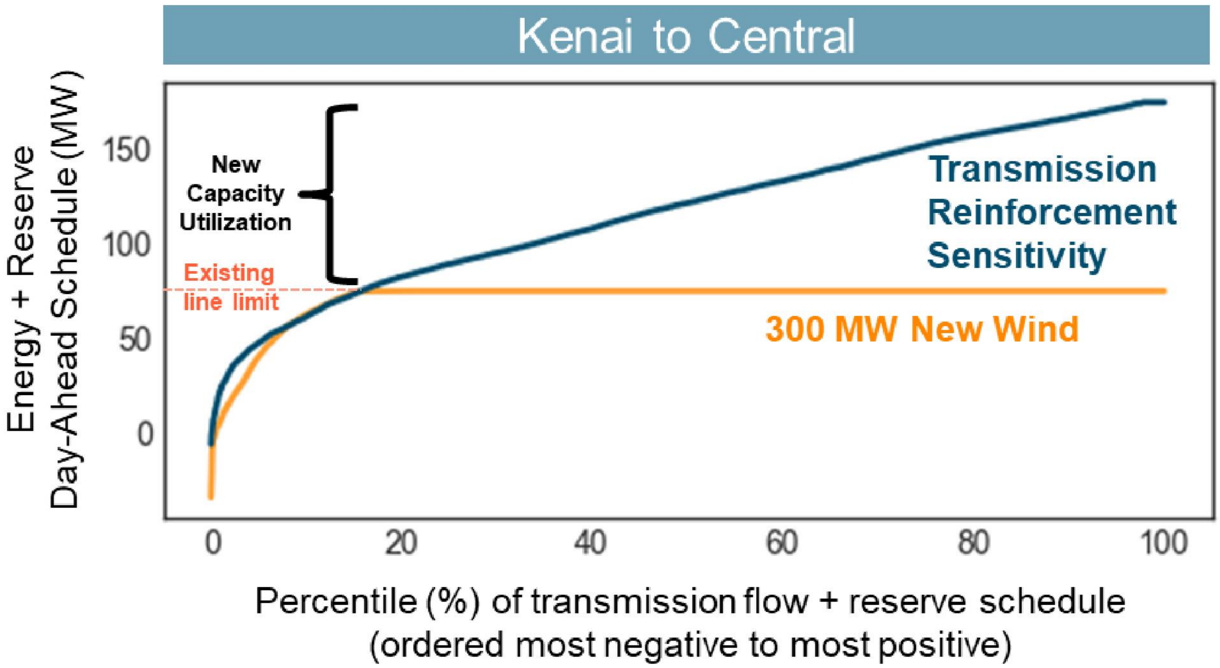


Figure 30: Day-ahead utilization of transmission in the 300 MW New Wind and Transmission Reinforcement Sensitivity between the Kenai and Central zones in the Kenai to Central direction. E3 did not model reserve-transmission limits in the Central to Kenai direction due to the low reserve needs in the Kenai zone.

Additional transmission capacity reduces Railbelt-wide production costs by $12.5 M/yr. This cost savings figure does not include the cost of the new transmission itself. Studies of other grids have typically shown that cost savings from new transmission depends strongly on the generation and storage resource mix considered when evaluating the transmission investment; the Transmission Reinforcement Sensitivity does not add new generation or storage resources to the 300 MW New Wind Scenario, so the combined impact of more transmission *and* additional resources is not quantified here.

The Transmission Reinforcement Sensitivity does not quantify the value of some of the potential reliability-related benefits of more transmission capacity, especially the resource adequacy value; consideration of additional reliability value would increase the benefits of new transmission capacity. The sensitivity does not model increased contingency reserves that may be needed when the upgraded lines are flowing at levels above their current rating. The need for more contingency reserves would decrease the operational benefits of more transmission capacity relative to the results presented here.

4.4 Gas Scheduling Flexibility Sensitivity

Technical specifications of the Railbelt natural gas generation units indicate that gas generators are capable of ramping up and down relatively quickly and many units can start quickly. However, the gas fuel supplied to these generators represents a significant limitation to the ability to use the operational flexibility of the gas generation units (Section 2.8) in real-time dispatch. The **Gas Scheduling Flexibility Sensitivity** removes the gas nomination limits to explore the cost and dispatch impact of gas fuel flexibility limits. While it may be possible to increase the flexibility of the natural gas fuel supply in the Railbelt, it is likely that physical and contractual limits will impose some restrictions on gas flexibility and therefore the results of this sensitivity should be considered as a bookend for the value of gas flexibility in the context of higher levels of wind in the Railbelt.

4.4.1 Changes from 300 MW New Wind

The gas nomination constraints that are removed in the Gas Scheduling Flexibility Sensitivity are:

- Real-time gas consumption must be within +/- 10% of the day-ahead nomination
- Day-ahead reserve constraints that limit forecast error and within-hour regulation reserve provision from gas plants to be at most 10% of their level of generation
- The day-ahead restriction that offline gas resources cannot contribute to forecast error reserve

4.4.1 Results

Relaxing gas nomination constraints allows more system flexibility to be provided by gas resources, reducing the reliance on other resources, especially expensive naphtha and oil for upward ramping (Figure 31). Gas generation is re-dispatched across the Kenai and Central zones to reduce total costs. Additional gas scheduling flexibility reduces production costs Railbelt-wide by $13.7 M/yr. The production cost reduction does not include any costs to increase gas fuel flexibility and is therefore a bookend to the value of more fuel supply flexibility. However, in the near-term, there may be additional savings from gas supply flexibility relative to those shown here if coordination between Railbelt utilities is not as efficient as modeled in this study.

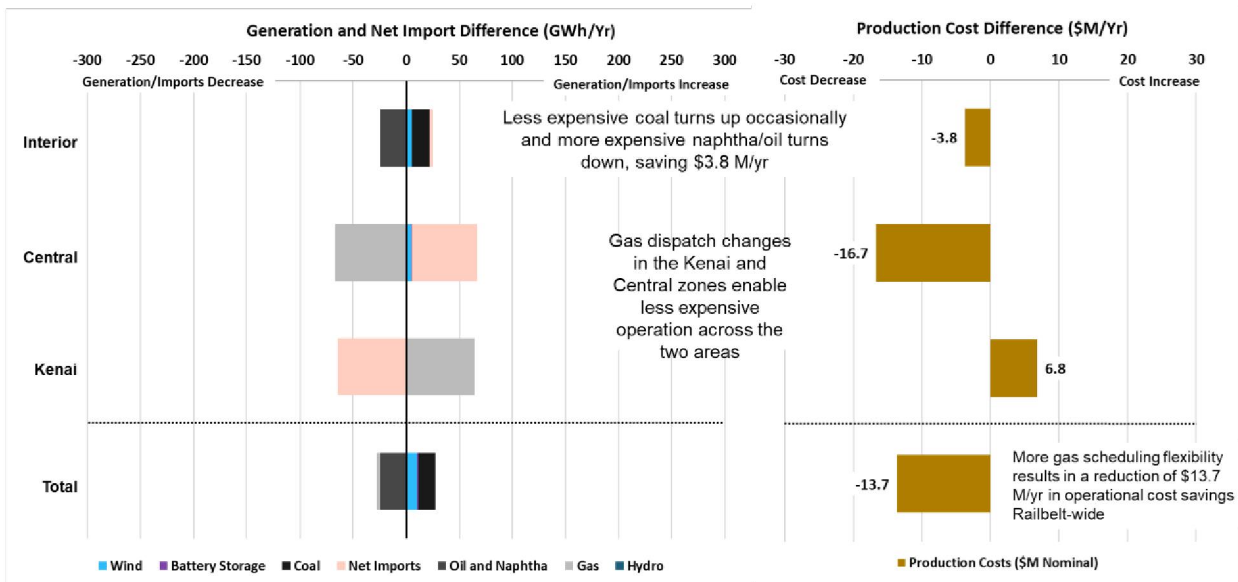


Figure 31: Generation, net imports, and production cost difference by zone: Gas Scheduling Flexibility Sensitivity - 300 MW New Wind Scenario

Figure 32 shows that gas generators with a flexible fuel supply can largely replace the role of naphtha and oil generators in providing backup for wind over-forecasts.

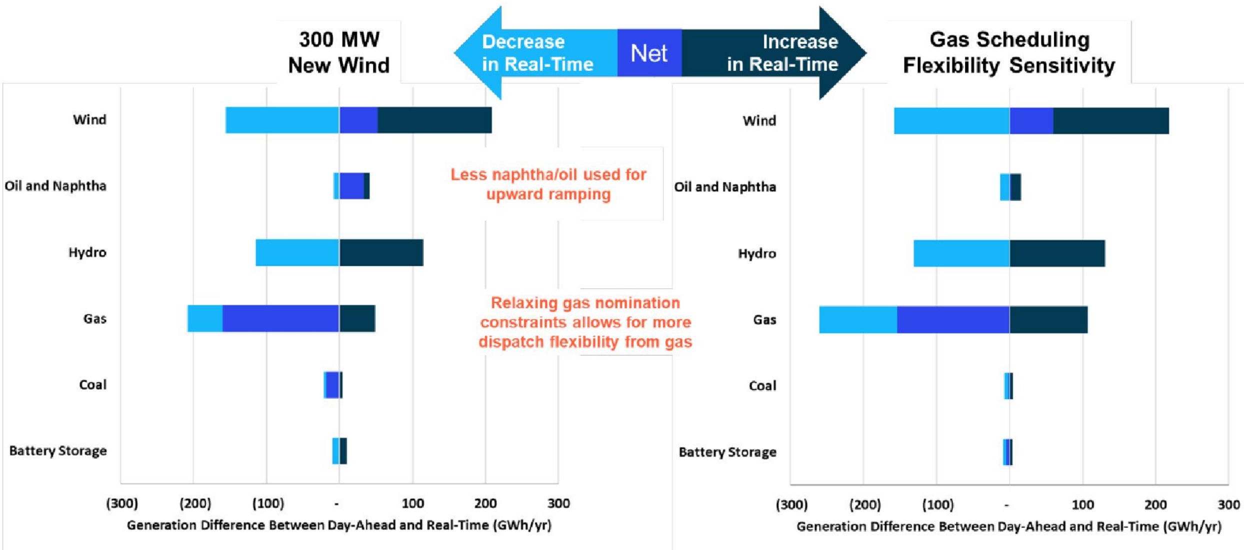


Figure 32: Difference between day-ahead schedule and real-time generation, grouped by fuel type: 300 MW New Wind Scenario (left) vs. Gas Scheduling Flexibility Sensitivity (right). Positive values indicate that generation increased in real-time relative to the day-ahead schedule. As indicated by the legend at the top of the figure, the dark and light blue bars indicate the gross amount of generation increase and decrease (respectively) across the year, while the bright blue bars indicate the net increase (gross increase – gross decrease).

4.5 Commit All Day-Ahead Sensitivity

Current Railbelt operational practice typically schedules units on an hourly basis, frequently using the day-ahead load forecasts. While operators can turn on quick start thermal in real-time if necessary, the frequency with which these units are turned on increases as more wind is added to the system (Section 3.7). As a bridge between present day operations and the evolution of operational practice modeled in this study, the **Commit All Day-Ahead Sensitivity** enforces the day-ahead unit commitment schedule for all thermal units in the real-time stage. This sensitivity explores the value of quick-start unit commitment in real-time in the context of higher levels of wind in the Railbelt.

4.5.1 Changes from 300 MW New Wind

+ In the 300 MW New Wind Scenario, the commitment of combined cycle and coal plants is determined in the day-ahead timeframe, but quick-start oil and gas plants can be turned on in real-time (though gas plants are limited in their ability to increase output by the amount of gas available in the day-ahead gas nominations). The Commit All Day-Ahead Sensitivity enforces day-ahead commitment schedules for *all* thermal units in the real-time stage. Because the day-ahead stage in E3's model is at hourly resolution, resources in the Commit All Day-Ahead Sensitivity do not change their commitment within the hour and cannot therefore respond to within-hour fluctuations of wind generation.

- Offline resources are not allowed to provide day-ahead forecast error and within-hour regulation reserve capacity in the Commit All Day-Ahead Sensitivity because offline resources would not be able to start up in real-time to provide the required response.

4.5.2 Results

Day-ahead commitment of all thermal resources results in a production cost increase of \$14.5 M/yr relative to the 300 MW New Wind Scenario. Wind curtailment increases from 13 GWh to 116 GWh (from 1% to 10% of the total wind production potential), and the total gas generation across the Railbelt increases to replace the lost wind generation. Minimal differences in Interior thermal unit generation are observed on an annual basis. Comparing the costs from the No New Wind Scenario to the Commit All Day-Ahead Sensitivity shows that production cost savings from 300 MW of new wind could be as low as \$97 M/yr (\$82 per MWh of wind production) in 2030 if thermal resource flexibility is limited.

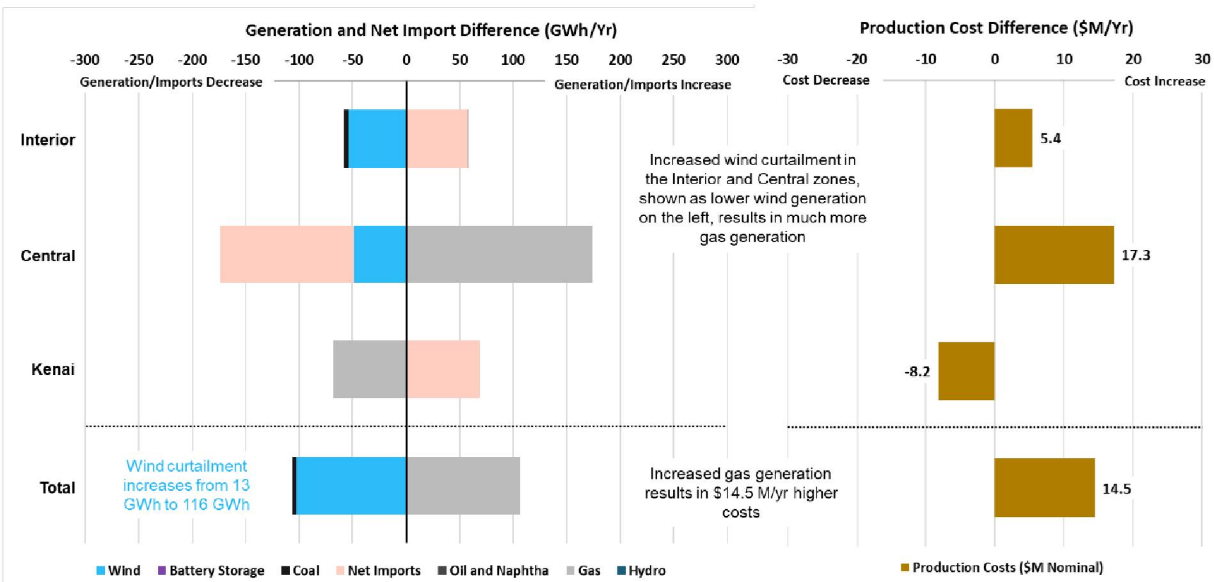


Figure 33: Generation, net imports, and production cost difference by zone: Commit All Day-Ahead Sensitivity - 300 MW New Wind Scenario

The Commit All Day-Ahead Sensitivity results indicate lower reliability than the 300 MW New Wind Scenario, highlighting the importance of unit commitment in real-time to balance wind. While the Commit All Day-Ahead Sensitivity does not show material loss of load, dump energy or spinning reserve shortages, there are increases in 5-minute regulation up shortages (1.7 GWh/Yr vs. 0.004 GWh/Yr in the 300 MW New Wind Scenario) and gas overconsumption relative to the day-ahead gas nomination (31 BBTU/Yr in Commit All Day-Ahead Sensitivity vs. 0.6 BBTU/Yr in the 300 MW New Wind Scenario). Higher gas nomination violations could potentially result in loss of load or other reliability issues if additional gas cannot be supplied in real-time.

The combined impact of higher production costs and lower reliability of the Commit All Day-Ahead Sensitivity demonstrate the importance of real-time unit commitment in the context of higher levels of wind in the Railbelt.

4.6 Kenai Intertie Outage Sensitivity

In the 300 MW New Wind Scenario, resources in the Kenai zone are frequently used to balance wind in the Central and Interior zones. In all simulations except for the **Kenai Intertie Outage Sensitivity**, the Kenai Intertie is modeled as in-service for all hours of the year. Input from Railbelt staff highlighted that the Kenai Intertie is usually out for maintenance and upgrades for at least 4 weeks per year; these outages is not captured in E3's runs. The Kenai Intertie Outage Sensitivity models an outage of 4 weeks per year, which shows the production cost and operational impact of outages relative to the 300 MW New Wind Scenario.

4.6.1 Changes from 300 MW New Wind

- The Kenai Intertie is taken out of service for four weeks: two consecutive weeks in February and two consecutive weeks in July. As a result, other components of the model are adjusted to simulate operations with the Kenai zone islanded from the rest of the Railbelt:
- Kenai contingency reserves change from 6.2 MW (HEA's load share of 60 MW) to 40 MW.
- 60 MW of contingency reserve is held in in the Interior and Central zones, divided between the two using their load share.
- Kenai resources (including Bradley) cannot contribute to reserves in the Interior and Central zones, including forecast error, within-hour variability, and 5-minute regulation reserve needs caused by wind variability and uncertainty.
- Reserve needs for the Kenai zone can only be met by Kenai resources (including Bradley hydro).
- The full capacity of the HEA battery is allowed to provide reserves.
- To ensure system stability, only one of the Bradley hydro units can be on.
- The Bradley hydro budget is reduced while the Kenai Intertie is out (when Bradley is only serving Kenai load), and energy production potential is shifted to adjacent periods within the same month when the Intertie is in service.

4.6.2 Results

Relative to the 300 MW New Wind Scenario, four weeks of Kenai Intertie outage per year increases production costs by $1.2 M/yr (Figure 34). Wind curtailment increases marginally by 1.5 GWh/yr (0.1% of the annual wind production potential), indicating that there may be a need to more frequently curtail wind when the Kenai Intertie is out of service. Gas generation increases by 5.8 GWh/yr with the Kenai Intertie out, and hydro generation from Bradley decreases by 3.7 GWh/yr.[17] It is likely that the displaced hydro generation observed in this sensitivity could be moved to other months, thereby mitigating the increase in gas generation and production costs.

The Kenai Intertie Outage Sensitivity exhibits acceptable reliability performance: no unserved energy, no overgeneration, no daily gas nomination violations, and minimal hourly gas nomination violations. A small

[17] During the periods in which the hydro daily budget is increased (from energy shifted out of the outage periods), the model is allowed to consume less than the daily budget to allow for dispatch flexibility within these periods.

amount (4 MWh) of 5-minute regulation reserve shortages in the Interior and Central zones are observed in the month of Kenai Intertie outage – E3 does not believe this to be a concerning amount of reserve shortage as it is still small compared to the reserve requirement itself. However, the amount of 5-minute regulation shortage observed in the month of the Kenai Intertie outage is roughly equivalent to the amount of reserve shortage observed in the entire year in the 300 MW New Wind Scenario, which suggests that it is more challenging to provide regulation with the Kenai Intertie out of service.

The February and July dates picked for the Kenai Intertie outage do not include a day with an extreme wind over-forecast, so the Kenai Intertie Outage Sensitivity does not test the system under a worst-case wind forecast situation. Operators will need to be more cautious when dispatching the system with the Kenai Intertie out and, if necessary, proactively under-schedule wind generation to avoid reliability issues related to extreme wind over-forecasts.

An example dispatch plot with the Kenai Intertie out of service is shown in Figure 35.

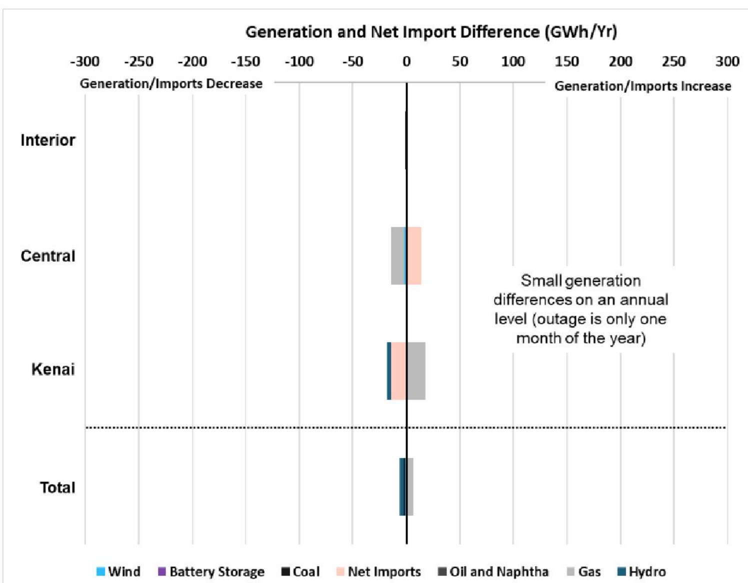


Figure 34: Generation, net imports, and production cost difference by zone: Kenai Intertie Outage Sensitivity - 300 MW New Wind Scenario

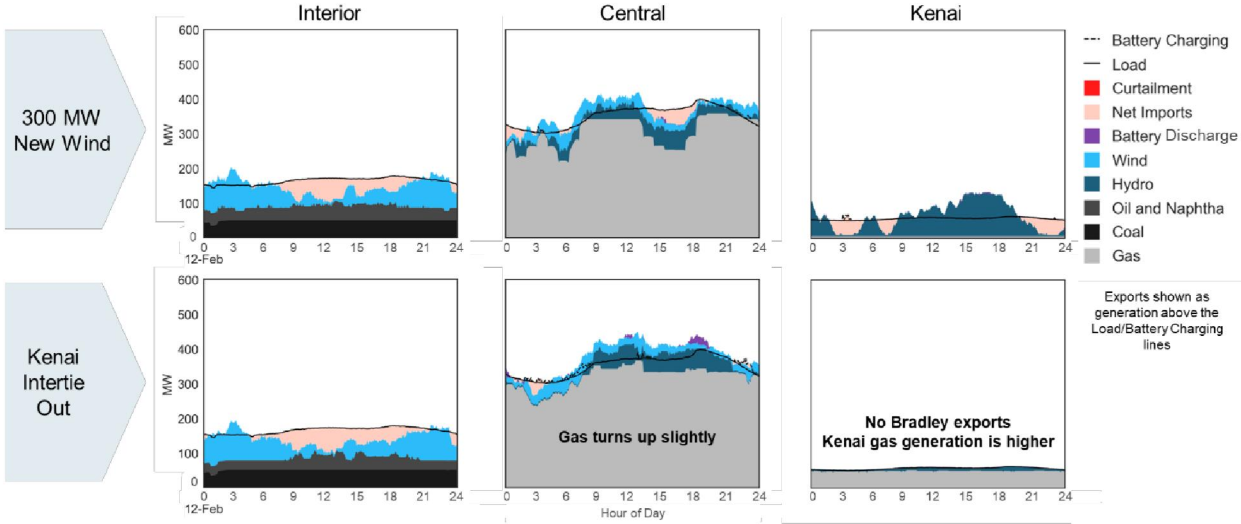


Figure 35: Dispatch plots from the 300 MW New Wind Scenario (top) and Kenai Intertie Outage Sensitivity (bottom) from the real-time dispatch stage on the example day February 12th. Generation is depicted based on the physical location of the resource.

4.7 Wind 5-Minute Regulation Sensitivity

Modern wind plants have the technical capabilities to curtail and un-curtail quickly (seconds to minutes) and can respond to automatic generation control (AGC) signals or operator dispatch. However, unlike conventional power plants, wind resources have a variable fuel supply, making control of this resource more complex. In the **Wind 5-Minute Regulation Sensitivity**, we explore the value of wind providing short-duration balancing services within each 5-minute dispatch interval. As discussed in Section 2.11, we have included the option to curtail wind in each real-time 5-minute interval in all simulations and have also included the option to under-schedule wind in the day-ahead stage if economical. The results of Wind 5-Minute Regulation Sensitivity should be interpreted in the context that wind is *already* performing balancing services in the 300 MW New Wind Scenario.

4.7.1 Changes from 300 MW New Wind

- In the Wind 5-Minute Regulation Sensitivity, Little Mount Susitna and Shovel Creek are modeled as being able to provide 5-minute regulation up and down, whereas in the 300 MW New Wind Scenario they are not able to do so.
    - To provide 5-minute regulation up, the wind must be curtailed such that there is headroom to dispatch wind up.
    - PLEXOS limits the amount of 5-minute regulation down that can be provided by wind to the wind output in each interval.

4.7.1 Results

Adding wind as an option to provide regulation within each 5-minute interval does not materially impact the generation mix or system costs (Figure 36). The Wind 5-Minute Regulation Sensitivity focuses narrowly on the value of wind providing within 5-minute balancing; the sensitivity does not quantify the value of wind providing flexibility via within-hour dispatch and day-ahead under-scheduling (i.e. pre-curtailment) of wind. In Section 3.8 we observe somewhat frequent under-scheduling of wind, but the value of wind flexibility from under-scheduling is captured in the 300 MW New Wind Scenario and therefore is not an incremental value in the Wind 5-Minute Regulation Sensitivity.

Reasons that 5-minute regulation from wind has a minimal impact on the generation mix and production costs include:

- To provide regulation *up*, wind must be curtailed. There is minimal wind curtailment in the 300 MW New Wind Scenario because it is cost-effective to integrate almost all of the wind generation. The low level of curtailment suggests that there are infrequent opportunities for wind to provide cost-effective regulation in the upward direction. If more new wind were to be modeled than the 300 MW of wind included in this study, or if the Railbelt grid were to be represented with less operational flexibility, curtailment would increase. Higher levels of curtailment would likely increase the value of wind providing 5-minute regulation up.
- Wind can provide regulation *down* without having to pre-curtail output. The 5-minute regulation down reserve is provided at minimal cost by batteries, hydro, and to a lesser extent thermal resources, and therefore there isn’t much additional value from wind providing regulation down. While wind does provide some 5-minute regulation down (Figure 37), the value of it providing this service is relatively low.

In the near-term, if coordination between Railbelt utilities is not as efficient as it is modeled in this study, there may be additional savings from wind providing regulation relative to the production cost difference shown in Figure 36.

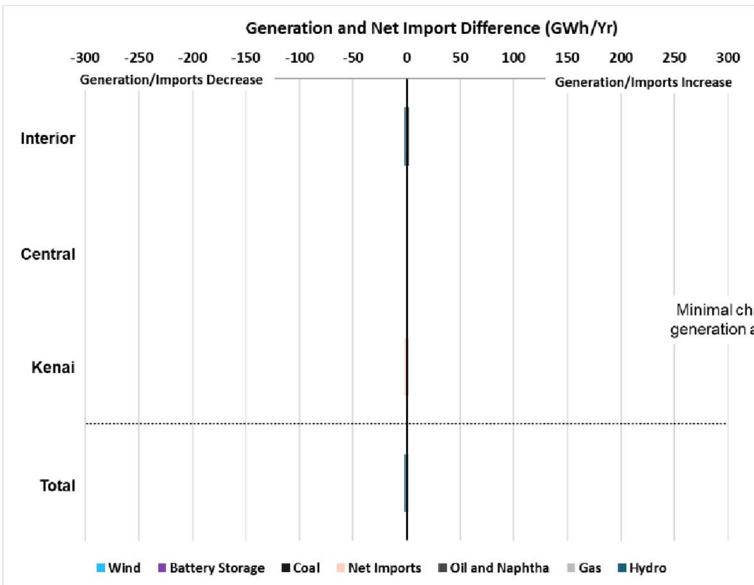


Figure 36: Generation, net imports, and production cost difference by zone: Wind 5-Minute Regulation Sensitivity - 300 MW New Wind Scenario.

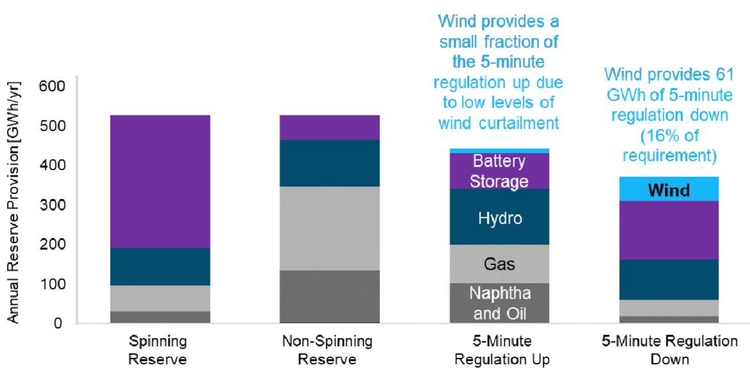


Figure 37: Reserves by resource type in the Wind 5-Minute Regulation Sensitivity

4.8 No Stability Commitment Sensitivity

Stability studies performed by EPS, Inc. identified dynamic stability issues (voltage and inertia) when operating the Railbelt grid with low levels of online thermal generation. The **No Stability Commitment Sensitivity** identifies possible cost savings if the stability-related grid services (voltage and inertia) could be provided without thermal commitments (i.e. from batteries, wind, power electronics, synchronous condensers etc.). We do not investigate the feasibility or cost of maintaining stability with lower levels of thermal commitment. Additional study and operational experience would be necessary to reliably operate the Railbelt with fewer commitment constraints than are outlined in the EPS report.

4.8.1 Changes from 300 MW New Wind

+ The No Stability Commitment Sensitivity removes (i.e. does not enforce) the stability commitment rules described in Section 2.7 from both the day-ahead and real-time model stages.

4.8.2 Results

Removing the stability commitment constraints decreases production costs by $14.2 M/yr relative to the 300 MW New Wind Scenario. While there are moderate cost savings ($2.9 M/yr) the Interior zone, most of the cost savings result from increasing utilization of the most efficient gas resources. Interior naphtha and oil units have expensive fuel costs but generation from these units cannot be entirely eliminated due to the limited capacity of the Alaska Intertie relative to Interior load, as well as the need to balance wind and load variability and uncertainty. The production cost savings results demonstrate that there may be material cost savings associated with lowering the level of thermal commitment required to maintain system stability.

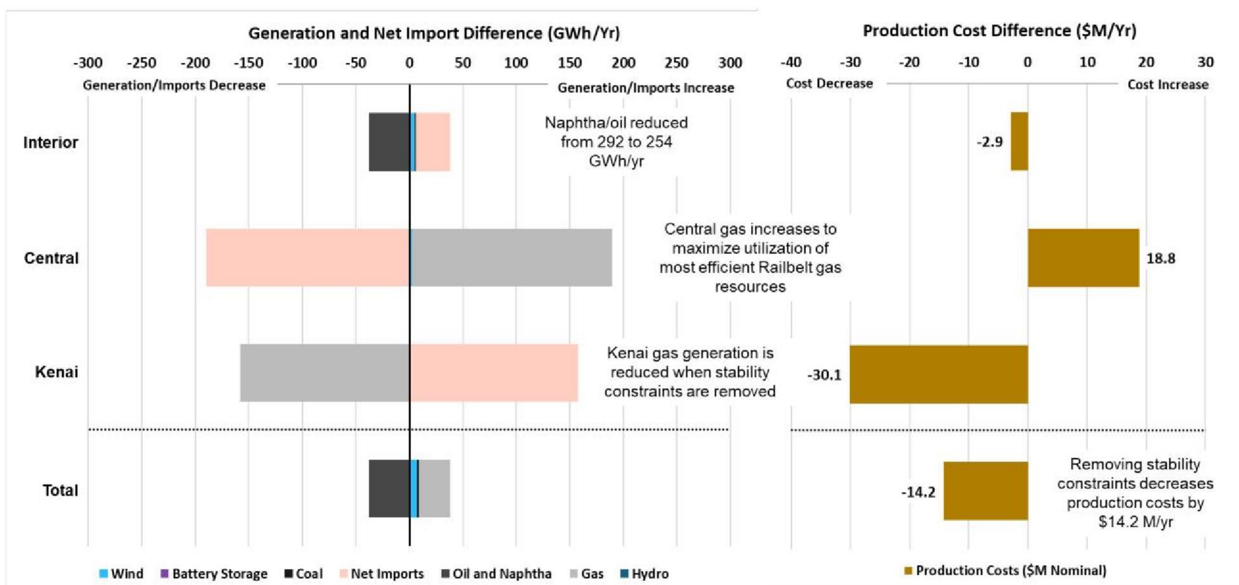


Figure 38: Generation, net imports, and production cost difference by zone: No Stability Commitment Sensitivity - 300 MW New Wind Scenario.

4.9 2025 Fuel Price Sensitivity

Future fuel prices are a key driver of the production cost savings from adding more wind. Impending natural gas supply challenges in the Railbelt make future natural gas fuel costs uncertain. As a default assumption, Railbelt staff advised E3 to use 2030 natural gas prices that assume that imports of Liquified Natural Gas (LNG) will be available, but also to run a sensitivity with non-LNG natural gas pricing. The **2025 Fuel Price Sensitivity** shows the impact of lower, near-term non-LNG pricing, as well as near-term pricing for oil, naphtha, and coal fuel.

4.9.1 Changes from 300 MW New Wind

- In the 2025 Fuel Price Sensitivity, the 2025 fuel prices in Table 2 are used instead of the 2030 fuel prices used elsewhere in this study. All other assumptions are kept the same as the 300 MW New Wind Scenario.
- A **No New Wind 2025 Fuel Price Scenario** is also simulated such that the production cost savings from additional wind with 2025 fuel prices can be quantified. The only difference in inputs between the No New Wind Scenario and the No New Wind 2025 Fuel Price Scenario is that the No New Wind 2025 Fuel Price Scenario uses 2025 fuel prices instead of 2030 fuel prices.

4.9.2 Results

Figure 39 demonstrates that lower, near-term fuel costs do not change the dispatch priority order in the Railbelt, resulting in very similar dispatch between the 300 MW New Wind Scenario and the 2025 Fuel Price Sensitivity. Using 2025 fuel prices, adding 300 MW of wind reduces production costs by $82.9 M/yr (calculated by comparing the production costs of the No New Wind 2025 Fuel Price and 2025 Fuel Price sensitivity), which is equivalent to a savings of $70/MWh of wind production potential. The production cost savings from adding 300 MW of wind are 26% lower in 2025 than in 2030 due to the lower avoided fuel prices in 2025. We assume a 2% inflation rate per year (10% over the 5 years between 2025 and 2030); inflation between 2025 and 2030 represents a portion of the difference in cost between the model runs.

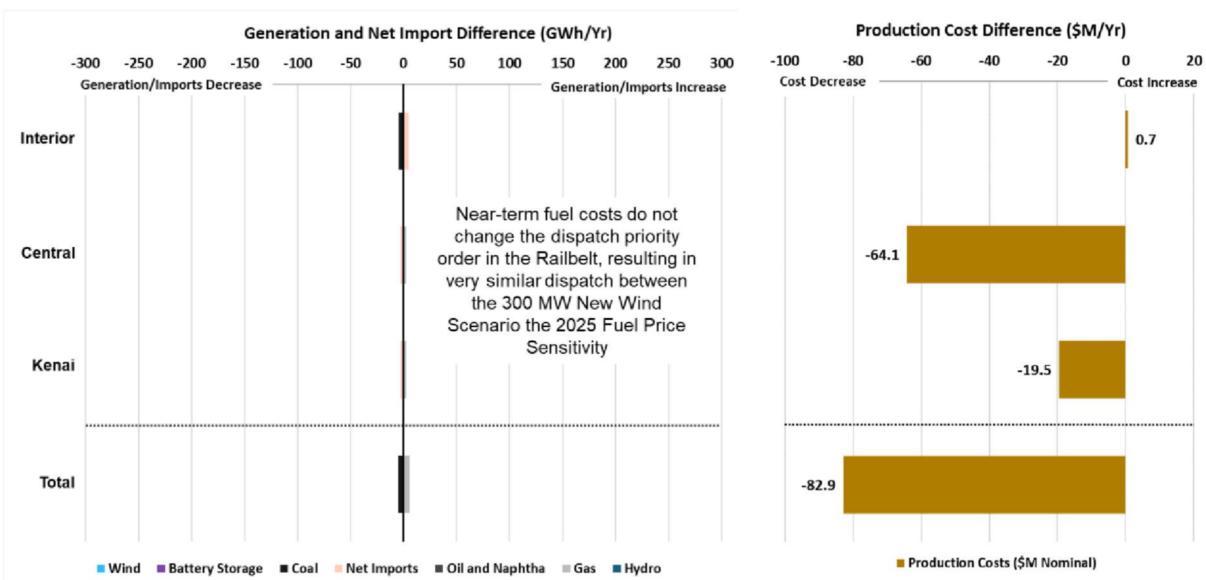


Figure 39: Generation, net imports, and production cost difference by zone: 2025 Fuel Price Sensitivity – 2025 No New Wind Scenario

As discussed in Section 3.4, fuel cost savings from additional wind are likely to grow as fuel price projections, especially for natural gas, increase over time.

4.10 Numerical results summary

Table 5: Annual generation by fuel type for all simulations (GWh/yr). Battery storage is reported as net generation (discharging – charging) and is slightly negative due to round trip efficiency losses.

Simulation Name	Wind	Battery Storage	Hydro	Gas	Oil and Naphtha	Coal
No New Wind	132	0	658	3,230	295	413
300 MW New Wind	1,299	-2	658	2,089	292	393
GVEA Battery Replacement	1,305	-2	658	2,112	273	383
Transmission Reinforcement	1,308	-2	658	2,161	209	394
Gas Scheduling Flexibility	1,309	-1	658	2,086	267	409
Commit All Day-Ahead	1,196	-1	658	2,194	292	389
Kenai Intertie Outage	1,297	-2	654	2,095	292	392
Wind 5-Minute Regulation	1,298	-2	658	2,089	293	392
No Stability Commitment	1,306	-2	658	2,118	254	394
No New Wind 2025 Fuel Price	132	0	658	3,233	293	413
2025 Fuel Price	1,298	-2	658	2,094	291	389

Table 6: Annual production costs by zone (and total) for all simulations. All costs are reported in nominal $M/yr. We do not allocate costs to utilities so the savings per zone does not directly translate into a rate impact for each zone; the allocation of import and export costs is out of scope for this study.

Simulation Name	Total	Interior	Central	Kenai
No New Wind	459.5	85.3	317.5	56.7
300 MW New Wind	347.7	86.4	230.9	30.3
GVEA Battery Replacement	339.1	79.4	223.9	35.7
Transmission Reinforcement	335.2	74.4	204.2	56.6
Gas Scheduling Flexibility	334.0	82.6	214.2	37.1
Commit All Day-Ahead	362.2	91.8	248.2	22.2
Kenai Intertie Outage	348.8	86.4	230.3	32.1
Wind 5-Minute Regulation	347.4	86.4	230.5	30.5
No Stability Commitment	333.4	83.5	249.7	0.2
No New Wind 2025 Fuel Price	348.5	71.4	235.2	41.9
2025 Fuel Price	265.7	72.1	171.1	22.4

Table 7: Annual CO_2 emissions by zone (and total) for all simulations ($MMtCO_2$/yr).

Simulation Name	Total	Interior	Central	Kenai
No New Wind	1.99	0.66	1.14	0.19
300 MW New Wind	1.50	0.65	0.83	0.03
GVEA Battery Replacement	1.49	0.62	0.81	0.07
Transmission Reinforcement	1.54	0.61	0.74	0.19
Gas Scheduling Flexibility	1.45	0.65	0.77	0.03
Commit All Day-Ahead	1.54	0.66	0.88	0.00
Kenai Intertie Outage	1.52	0.65	0.83	0.05
Wind 5-Minute Regulation	1.50	0.65	0.83	0.03
No Stability Commitment	1.53	0.64	0.90	0.00
No New Wind 2025 Fuel Price	1.99	0.66	1.14	0.19
2025 Fuel Price	1.52	0.64	0.83	0.05

Table 8: Annual fuel consumption by fuel type for all simulations (BBTU/yr).

Simulation Name	Natural Gas (Central)	Natural Gas (Kenai)	Oil and Naphtha	Coal	Landfill Gas
No New Wind	20,741	3,778	2,285	5,147	818
300 MW New Wind	14,955	2,010	2,362	4,959	752
GVEA Battery Replacement	14,555	2,379	2,120	4,842	762
Transmission Reinforcement	13,263	3,776	1,863	4,975	774
Gas Scheduling Flexibility	13,789	2,417	2,179	5,113	816
Commit All Day-Ahead	15,896	1,478	2,599	4,925	731
Kenai Intertie Outage	14,940	2,132	2,366	4,950	744
Wind 5-Minute Regulation	14,933	2,021	2,364	4,953	747
No Stability Commitment	16,259	16	2,219	4,974	756
No New Wind 2025 Fuel Price	20,758	3,789	2,273	5,144	818
2025 Fuel Price	14,960	2,031	2,358	4,915	745

5. Comparison of Historical to PLEXOS Dispatch

5.1 Introduction and motivation

E3's wind integration study assumes a single load balancing area across the Railbelt, including cost-minimizing procurement of regulation and balancing reserve capacity. The model results show that resources in one zone frequently help to balance load and resources in another zone, especially with higher levels of wind generation in the Railbelt. In addition, production simulation models do not represent many details of grid operations, and historical conditions differ from those modeled in production simulation. For all of the above reasons, the modeled dispatch is more optimized than is currently feasible in the Railbelt. To quantify differences between the production simulation results and historical operations, E3 performed a spreadsheet analysis to compare differences between 2022 historical operations and 2025 modeled results.

5.2 Data sources

2022 historical Railbelt data is sourced from each of the Railbelt utilities as well as from publicly available sources. The categories of data collected include: generation by generating station (net-to-grid), fuel costs, average unit heat rates, and total annual fuel consumption. To the extent that data of sufficient granularity is available directly from the utilities, then that data is used. Any data gaps are filled by generator level data reported to the United States Energy Information Agency (EIA). E3 reconciled the EIA Form 923 data with data provided by the individual utilities to identify any inconsistencies in the reported data before use. A detailed breakdown of data sources is found in Table 9. Average generator heat rates are derived by dividing total annual fuel consumption by total annual generation.

Table 9: 2022 Data sources by generating unit

Unit(s)	Generation (MWh) Net Station Service	Fuel Consumption (MMBtu)	Fuel Cost ($/MMBtu or $/MCF)
Anchorage 1 (Nikkels), Beluga, George M Sullivan 2 CC, George M Sullivan 2 GT, Southcentral	EIA-923 Generation Data	Derived using total CEA+MEA annual consumption and fuel cost in from CEA Exhibit 04	CEA Cost of Power Adjustment Filing Exhibit 04
Bradley Lake, Cooper Lake, Eklutna Hydro	EIA-923 Generation Data	N/A	N/A
Chena	EIA-923 Generation Data	EIA-923 Fuel Data	Hitachi Velocity Suite
Delta	EIA-923 Generation Data	GVEA 2022 Form 12/12c	GVEA 2022 Form 12/12c
Eklutna Generation Station	MEA	Derived using total CEA+MEA annual consumption and fuel cost in from CEA Exhibit 04	CEA Cost of Power Adjustment Filing Exhibit 04
Eva Creek Windfarm	GVEA 2022 Form 12/12c	N/A	N/A
Fire Island Wind	CEA 2022 Form 7	N/A	N/A
Healy 2	EIA-923 Generation Data	GVEA monthly Power Supply Reports	GVEA monthly Power Supply Reports
JBER Landfill Gas	EIA-923 Generation Data	EIA-923 Fuel Data	EIA-923 Fuel Data
Nikiski Combined Cycle, Soldotna, Bernice Lake	EIA-923 Generation Data	EIA-923 Fuel Data	Derived average $/mcf fuel cost from HEA 2022 financials multiplied by unit fuel consumption
North Pole CC, North Pole GT, Fairbanks Diesels, Fairbanks GT, Healy 1	GVEA 2022 Form 12/12c	GVEA 2022 Form 12/12c	GVEA 2022 Form 12/12c
UAF	EIA-923 Generation Data	GVEA 2022 Form 12/12c	GVEA 2022 Form 12/12c Derived from total delivered power costs
Zehnder	2022 data for Zehnder was not available		

5.3 Generation, fuel price, and heat rate comparison

First, we compare the 2022 historical generation, fuel costs, and generator efficiency (heat rate) to the PLEXOS No New Wind 2025 Fuel Price Scenario. As shown in Figure 40, Figure 41, and Figure 42, we find relatively close agreement between the two datasets, but also observe a number of differences that could drive differences in production costs.

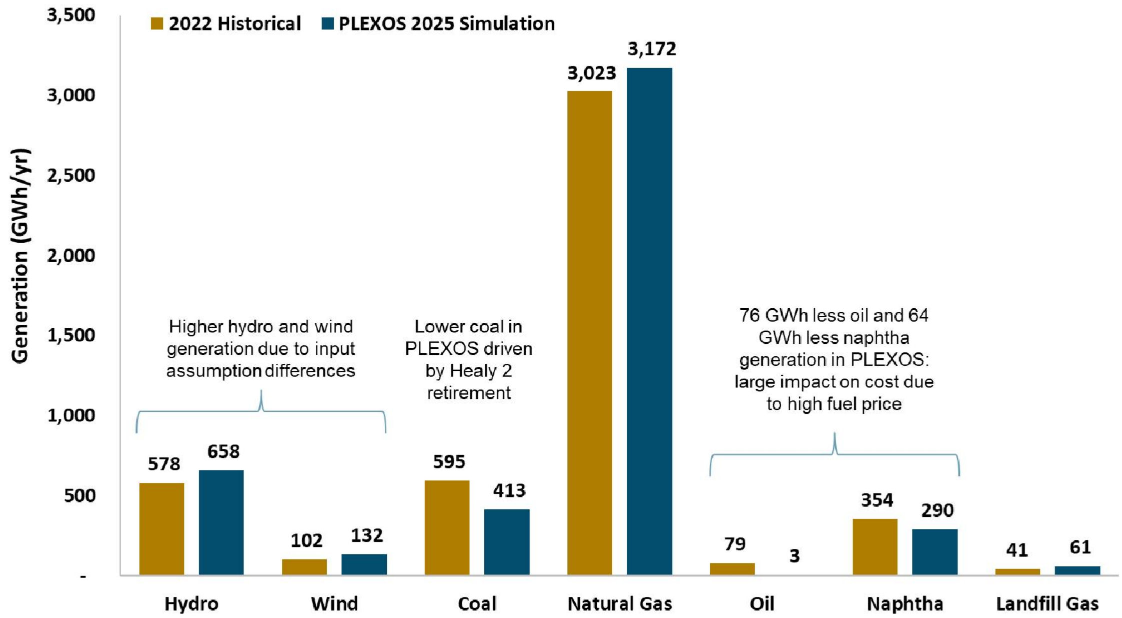


Figure 40: Annual generation comparison between 2022 historical Railbelt operations and 2025 operations simulated in PLEXOS, broken out by fuel type.

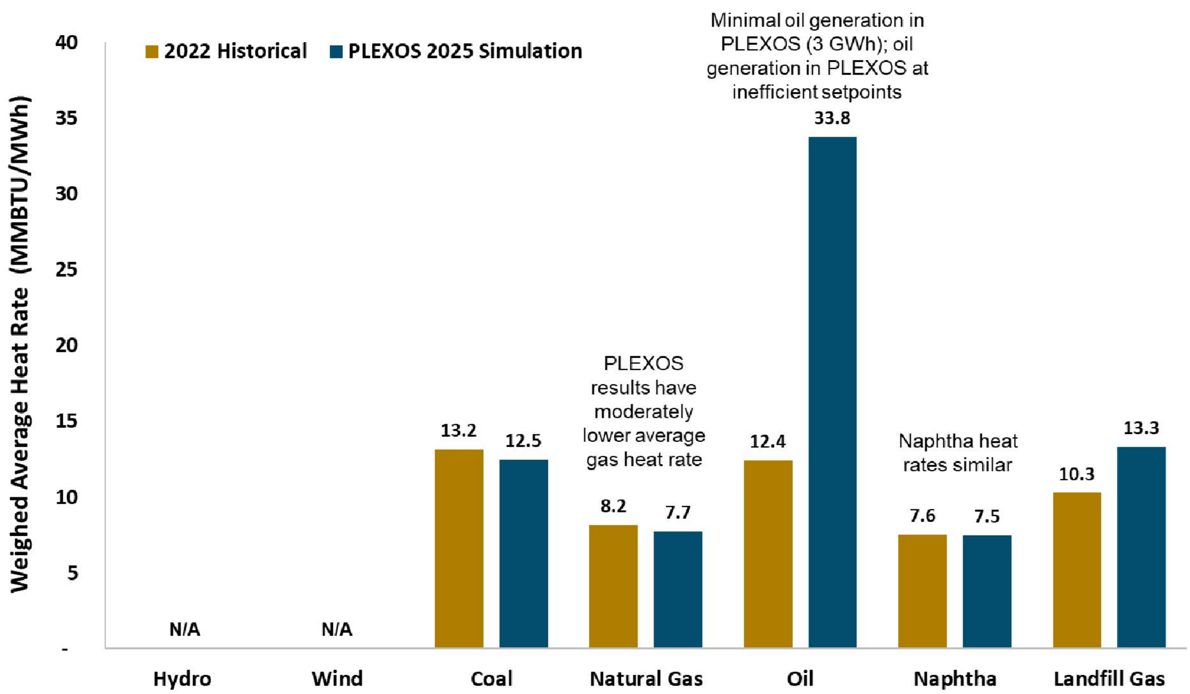


Figure 41: Weighted average heat rate comparison between 2022 historical Railbelt operations and 2025 operations simulated in PLEXOS, broken out by fuel type.

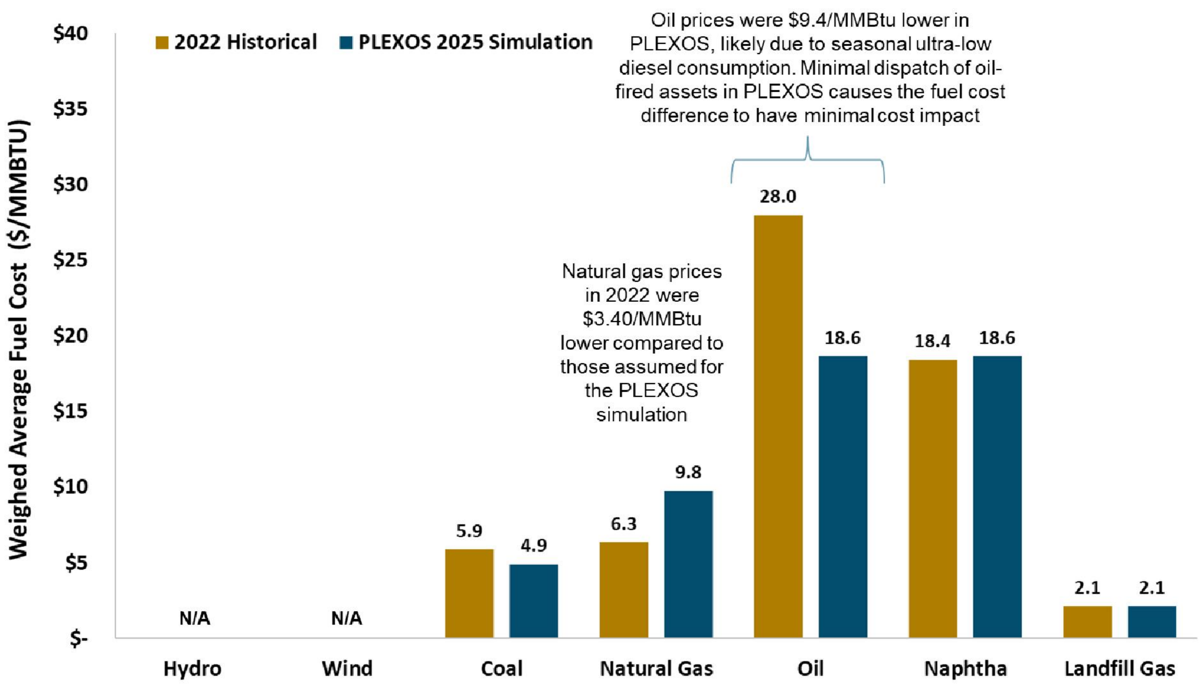


Figure 42: Weighted average fuel cost between 2022 historical Railbelt operations and 2025 operations simulated in PLEXOS, broken out by fuel type.

5.4 Waterfall analysis

Some of the differences between historical and PLEXOS operational results can be explained by differences in input data or changes in infrastructure between the 2022 historical data and the 2025 PLEXOS simulation. E3 performs a "waterfall" exercise to estimate the magnitude of fuel cost difference that could be attributable to differences related to inputs or changes in infrastructure. The goal of the waterfall analysis is to isolate possible impacts of the single load balancing area assumption and other ways in which the modeled results are more optimal or lower cost that was achieved in historical dispatch.

The analysis quantifies the fuel cost difference resulting from factors (the columns in Figure 43) that differ between the historical data and the modeled data. Each factor is represented as a "what-if" adjustment to the historical data until the two data sets are brought into line. For example, less hydro generation is observed in the historical data than is present in the PLEXOS model runs due to different hydro energy availability (2022 historical vs. 2018 modeled hydro year). E3 assumes that the difference in hydro energy would result in gas, naphtha, and oil resources turning down in PLEXOS to resolve the difference. The difference in thermal generation translates into a difference in fuel consumption and therefore costs. In this analysis, E3 compared the total fuel cost across the Railbelt but did not include other aspects of production costs such as variable operations and maintenance and start costs (both of which are much smaller than fuel costs).

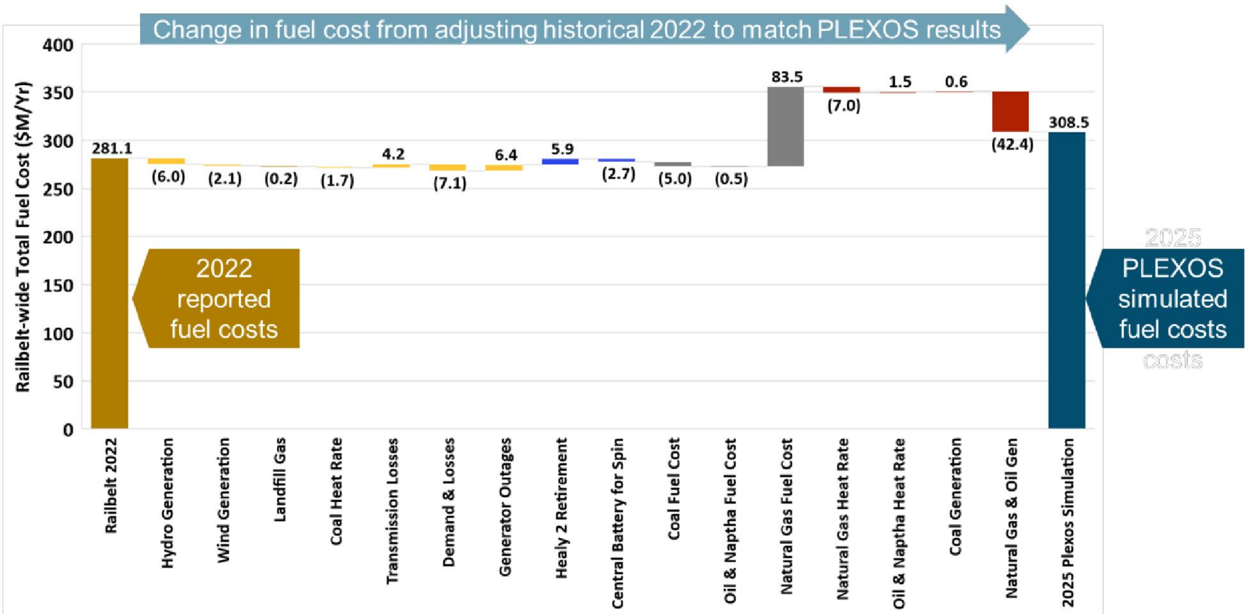


Figure 43: Fuel cost impact of differences between 2022 historical Railbelt operations and 2025 operations simulated in PLEXOS.

We find that:

- Differences that result from different PLEXOS inputs relative to historical 2022, colored yellow in Figure 43, have minimal net impact on the total Railbelt fuel costs.
- Differences that result from retirements and additions by 2025 relative to 2022, colored blue in Figure 43, also have minimal net impact on the total Railbelt fuel costs.
- Coal, oil, and naphtha fuel cost differences result in minimal differences in total Railbelt fuel costs, but natural gas fuel prices are the single largest difference between the 2022 and 2025 data. It was out of scope to determine the source of the difference in natural gas fuel costs between the datasets.
- The remaining differences that are not explained by other factors, colored red in Figure 43, account for a $47 M/yr difference in fuel cost between the two datasets. These differences result from model optimization, the single load balancing area assumption, and other ways in which historical dispatch differs from PLEXOS dispatch. While it is not possible to isolate the portion of $47 M/yr that is attributable to the single load balancing assumption, the results suggest that there may be significant fuel cost savings, potentially many millions of dollars per year, from optimizing scheduling and dispatch across the Railbelt.

6. Conclusions

- **Reliability:** At the resolution of 5-minute dispatch, the Railbelt system can be reliably operated with 300 MW of new wind. This study assumes operational practices similar to those that have been implemented by Independent System Operators (ISOs); E3 did not study system reliability with additional wind capacity and current Railbelt operational practices.
  - No loss of load events and minimal levels of regulation shortages are observed over an entire year of 5-minute operations.
  - Dynamic stability (voltage and inertia) is ensured by commitment of thermal and hydro units.
  - The study approximates the need for balancing within each 5-minute dispatch interval using simulated 5-minute wind production data; additional study and operational experience are required to determine the correct level of regulation reserves to balance wind fluctuations within each 5-minute interval. Higher levels of reserves to regulate wind fluctuations, if necessary, would be expected to decrease production cost savings from additional wind and/or increase the need for fast-ramping resources (especially batteries).
- **Fuel and Variable Operations and Maintenance (VO&M) Cost Savings :** Adding 300 MW of wind reduces fuel consumption and VO&M costs, decreasing production costs by $97 - $126 M/yr in 2030. While we observe material production cost savings from the addition of new wind, this study does not determine whether new wind is cost effective because we do not compare production cost savings from new wind to the cost to build, interconnect, and operate the new wind resources. To avoid increasing costs to Railbelt customers, the annual Power Purchase Agreement (PPA), infrastructure, and operational costs related to adding more wind would need to be less than $97 - $126 M/yr in 2030.
  - On average, each MWh of wind production decreases production costs by $82 - $106 per MWh in 2030, which is calculated by dividing the annual savings ($97 - $126 M/yr) by the annual production from 300 MW of wind (1,180 GWh/yr).
  - The production cost savings from wind are expected to scale with fuel prices and are lower with near present-day (2025) fuel prices. Savings are likely to increase over the lifetime of the wind power plants because Railbelt fuel costs are projected to increase over time.
  - The addition of more wind primarily reduces natural gas generation; it is this reduction in natural gas that is the main source of the cost reduction. Without new wind, the Interior zone frequently relies on natural gas imports from the Central and Kenai regions. With the addition of more wind, Interior imports decrease on an annual basis but become more variable.
- **CO_2 emissions:** Wind reduces CO_2 emissions by reducing predominantly gas generation. 300 MW of wind would reduce Railbelt-wide CO_2 emissions by roughly one quarter, from 1.99 to 1.50 $MMTCO_2$/yr. Adding 300 MW of wind reduces Railbelt-wide emissions intensity (CO_2 per MWh of demand) from 0.42 to 0.32 tCO_2/MWh.

- **Curtailment:** Wind curtailment is observed but does not represent a large fraction of the wind production potential. Our results indicate that as little as 1% of the wind production potential may need to be curtailed.
- **Resource operations:** Optimal dispatch of batteries, hydro, thermal, and transmission allows for almost all of the 300 MW of new wind to be absorbed. Each resource plays a different role in wind integration.
  - *Batteries* can help to balance short-duration fluctuations in wind output but are limited in their ability to balance multi-hour forecast error events due to their limited energy capacity.
  - *Hydroelectric* resources play a large role in balancing wind because energy stored in reservoirs enables dispatch flexibility. Using hydro resources to balance wind forecast errors is an important operational strategy to cost-effectively integrate wind generation in the Railbelt.
  - *Natural gas* resources have limited ability to respond to fluctuations in wind generation because gas fuel must be scheduled many hours in advance; much of the wind variability and forecast error occurs after gas fuel schedules have been determined and therefore must be managed with other resources.
  - *Naphtha and oil* resources in the Interior zone increase generation during wind over-forecast events (when less wind power is available in real-time relative to the day-ahead forecast). The oil and naphtha resources are expensive to operate relative to other Railbelt resources, so this strategy is used only when other forms of flexibility have been exhausted.
  - *Wind* under-scheduling (pre-curtailment) is used as a strategy to reduce the cost of integrating wind.
- **Transmission** between Railbelt zones is a crucial tool for managing wind variability and forecast errors. With Bradley hydro and the HEA battery in the Kenai zone, dispatchable naphtha and oil in the Interior, and fuel-constrained gas in the Kenai and Central zones, dynamic utilization of transmission between zones is important to access the diversity of Railbelt resources. Transmission flows change drastically with the addition of 300 MW of wind.
- **System Operations:** Railbelt system operations are represented in this study as more flexible than current practice. While we do not conclude that any single aspect of system flexibility is central to the ability to absorb more wind energy on the Railbelt system, our results are based on operational practices that are an evolution from current practice. Increasing system flexibility could reduce Railbelt production costs even without the addition of more wind generation, but the benefits of additional operational flexibility are likely to increase with more wind generation. The following enhancements to Railbelt operations should be considered:
  - Coordinated, Railbelt-wide unit commitment and dispatch
  - Transmission scheduling without wheeling charges
  - Co-optimization of energy and reserves on transmission lines
  - Use day-ahead wind forecasts in unit commitment
  - Scheduling upward and downward regulation reserve capacity on different resources
  - Differentiating wind balancing needs by the length of the balancing service required (day-ahead forecast error, within-hour variability, 5-minute regulation)

- Exploring opportunities to increase the flexibility of gas fuel nominations
- Exploring opportunities to ensure system stability with lower levels of thermal generation

7. Appendix: Operational Reserves Description

7.1 Balancing reserve introduction

Power system operators commit and dispatch resources in a way that prepares their system to operate reliably under a range of possible future conditions. Balancing reserves (Figure 44) hold capacity on resources to be able to manage expected levels of net load (load minus variable renewable production potential) forecast error and variability. While all power system operators hold capacity to balance their systems, practices vary regionally as to how grid operators implement balancing in their unit commitment and dispatch processes. Higher levels of variable renewable energy production will increase the need for balancing reserves and may require changes in Railbelt operational practices to ensure cost-effective and reliable operation.

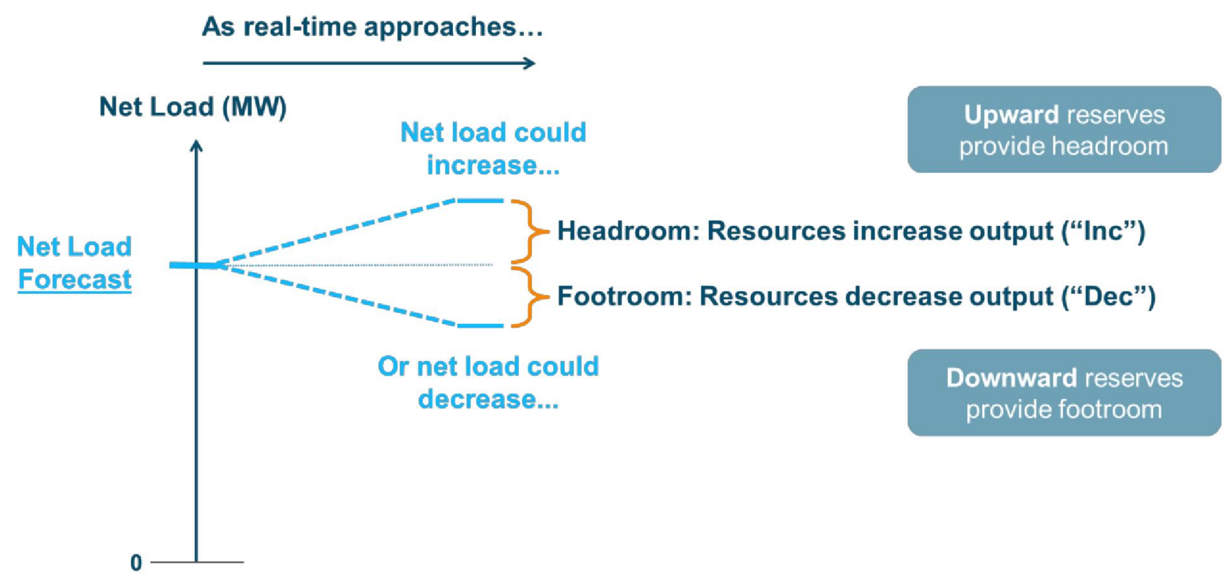


Figure 44: Balancing reserve terminology.

7.2 Balancing reserve types

As shown in Figure 45, E3 represents balancing reserves in this study by dividing balancing into three timeframes:

- Day-ahead to hourly real-time, which reserves capacity to handle large, persistent forecast errors between the day-ahead forecast and real-time net load.
- Hourly real-time to 5-minute dispatch interval, which prepares the system to navigate within-hour fluctuations of net load. Within-hour regulation capacity must be capable of ramping to meet within-hour changes in net load.
- <u>Within</u> each 5-minute dispatch interval, which ensures that fluctuations of net load within each 5-minute dispatch interval are covered by fast-ramping capacity.

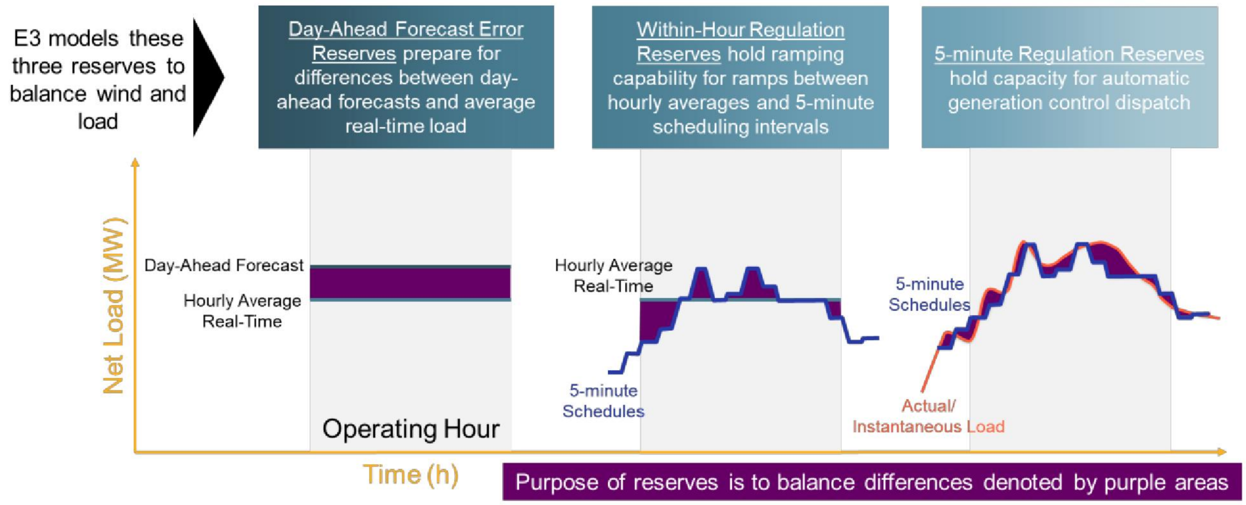


Figure 45: Balancing reserve conceptual diagram.

E3's implementation of system balancing represents an evolution of current Railbelt operational practice. E3 breaks balancing needs into the upward ("Inc") and downward ("Dec") components, which in some cases represents a change from current Railbelt operational practice. Representing separate upward and downward regulation requirements common among system operators in other jurisdictions. E3 does not model downward forecast error or downward within-hour regulation reserves on the assumption that there is adequate downward dispatchability in the day-ahead timeframe. Wind can be curtailed to address oversupply and as such the need for downward dispatchability for wind can be satisfied by the wind plants themselves if necessary. E3 does not observe overgeneration in any model run, which confirms that day-ahead downward forecast error and within-hour regulation reserves are not necessary to ensure reliability.

A summary of the balancing reserves modeled in PLEXOS is found in Table 10, along with important attributes related to each reserve. The capacity held for one type of balancing reserve cannot be used to also provide capacity to another balancing reserve or contingency reserve – each balancing reserve is mutually exclusive.

Table 10: Balancing reserve summary

Reserve Name >>	Forecast Error Reserves	Within-Hour Regulation	5-Minute Regulation Up	5-Minute Regulation Down
Function	Covers forecast errors between day-ahead and hourly average real-time net load	Covers from hourly average of 5-minute net load to 5-minute actuals	Addresses imbalances within the 5-minute dispatch interval in the headroom direction	Addresses imbalances within the 5-minute dispatch interval in the footroom direction
Direction	Upward (Headroom)	Upward (Headroom)	Upward (Headroom)	Downward (Footroom)
Included in Day-Ahead?	Yes	Yes	Yes	Yes
Included in Real-time?	No (capacity released for dispatch)	No (capacity released for dispatch)	Yes	Yes
Separate reserves for each zone, or Railbelt-wide	Railbelt-wide	Railbelt-wide	Separate reserves for each zone	Railbelt-wide
How are transmission constraints between zones addressed?	Reserve deliverability constraints ensure that reserves from resources in one zone could address the need for balancing in adjacent zones	Reserve deliverability constraints ensure that reserves from resources in one zone could address the need for balancing in adjacent zones	Interior and Central modeled as being able to share regulation up capacity, subject to transmission constraints	Transmission constraints are not addressed as transmission overloading is typically less of a concern with downward capacity than upward
Timeframe: How fast does the response need to be?	1 hour	15 minutes	5 minutes	5 minutes
Duration: How long does the response need to be sustained? See section 7.4	4 hours	1 hour	30 minutes	30 minutes
Can this reserve be provided by online units only, or can offline quick-start units also contribute?	Offline and online, but offline natural gas resources cannot contribute because of day-ahead natural gas nomination limits	Online only	Online only	Online only

Because gas consumption in the real-time model stage needs to be within 10% of gas consumption in the day-ahead unit commitment stage (Section 2.8), there is a risk that gas resources committed to provide forecast error or within-hour regulation reserves in the day-ahead stage would not have enough gas to ramp up in real-time to provide the service they were committed to perform. To avoid this situation, E3 includes a constraint that relates gas dispatch in day-ahead to forecast error and within-hour regulation reserve commitments. Specifically, for each of the Homer and Central zones in each hour of the day-ahead unit commitment model stage, the amount of gas capacity committed to provide forecast error and within-hour regulation reserves is limited to be at most 10% above the power output from gas-fueled units in that hour. This constraint ensures that commitment of balancing reserves in the day-ahead stage includes real-time limits on gas consumption. Spinning, non-spinning, and 5-minute regulation up and down reserves are not included in gas nomination constraints due to the short duration of the balancing need for these reserves.

7.3 Balancing reserve requirements

Production simulation models like PLEXOS ST require estimates of the expected level of forecast error and variability to study the operational behavior of future power systems. The need for each type of reserve is represented by analyzing the day-ahead and real-time load and wind data that are used as PLEXOS inputs (Section 2.4). Across the entire 2022 timeseries data, the difference in load and wind production potential between different timeframes is calculated (the purple areas depicted in Figure 45) and this data is used to set reserve requirements for wind and load. The specific calculations performed are described below and the results are summarized in Table 11. The load and wind reserve requirements are then added together in PLEXOS to create a final reserve requirement. This methodology conservatively ignores diversity between load and wind variations; in practice Railbelt operators may be able to reduce requirements relative to what is presented here if the diversity interactions between load and wind are considered.

The two-stage model tests whether the forecast error and within-hour regulation requirements held in the day-ahead stage are sufficient to ensure real-time reliability. If the requirements are insufficient, the real-time stage would not have adequate flexibility to balance load and resources, ultimately resulting in unserved energy, reserve shortages, or other constraint violations. As discussed in Section 3.6 and 3.10, the real-time stage of the 300 MW New Wind Scenario shows acceptable reliability, confirming that the day-ahead balancing reserves held for load and wind are appropriate.

Table 11 Balancing reserve requirements

Reserve Name >>	Forecast Error Reserves	Within-Hour Regulation	5-Minute Regulation Up	5-Minute Regulation Down
Load-based Requirement: MW of reserve needed	18.3 MW Railbelt-wide	15.0 MW Railbelt-wide	Separate reserve in each in each zone: 4.1 MW for Central, 4.1 MW for Interior, 0.8 MW for Kenai	5.2 MW Railbelt-wide
Wind-based Requirement: MW of reserve needed	All forecasted day-ahead wind is covered by reserve capacity except for wind that is scheduled to be curtailed. To avoid double-counting of reserve capacity, reserves held for the wind portion of within-hour regulation or 5-minute regulation up reduce the forecast error requirement for wind.	300 MW New Wind: 80.4 MW No New Wind: 18.3 MW The within-hour regulation requirement is reduced during periods of low wind production such that the total reserves held do not exceed the wind production potential.	300 MW New Wind: 39.2 MW No New Wind: 20.1 MW In the day-ahead stage the full MW requirement is held; In the real-time stage the 5-minute regulation up requirement is reduced during periods of low wind production such that the reserves held do not exceed the wind production potential.	300 MW New Wind: 37.2 MW No New Wind: 17.7 MW

7.3.1 5-minute regulation up requirements

It is not currently standard practice for Railbelt operators to quantify the need for balancing within a 5-minute interval as the need for regulation is frequently determined at an hourly resolution. E3 quantifies balancing needs within the 5-minute balancing interval because the real-time model stage has 5-minute dispatch granularity. To ensure reliable operation, operators would need to not only be able to balance the grid on each 5-minute timestep, but also hold additional capacity for net load deviations that occur within each 5-minute dispatch interval. E3 did not analyze data with a time interval faster than 5 minutes in this study and thus the ramps between 5-minute intervals are used as an approximation to variations that may occur within 5-minute intervals. [18] For wind, fluctuations of output within a 5-minute interval are essentially uncorrelated across long distances, so the 5-minute regulation up requirement is calculated as the largest change between 5-minute intervals in the headroom (upward) direction for a year of Shovel Creek windfarm simulated output (or the Eva Creek windfarm in the No New Wind Scenario). Due to infrequent data irregularities that cause occasional large ramping events in the Little Mount Susitna 5-minute timeseries, the Little Mount Susitna production profile is not used to calculate reserve requirements.

Operational experience with the Railbelt's current wind plants suggests that large drops in power output, approaching the wind plant's rated capacity, are possible within a 5-minute timeframe. New, larger wind projects will have a larger geographic extent than the existing wind plants and the speed at which sharp windspeed drops propagate across the larger area may result in lower drops in power output (as a % of rated capacity) over a 5-minute interval compared to existing wind plants. The synthetic 5-minute wind production data for new wind resources does not fully capture the windspeed and power output dynamics that determine an adequate level of regulation reserve capacity within each 5-minute interval. Additional within 5-minute regulation reserves for wind may be necessary in practice relative to what is modeled in this study, though this cannot be confirmed without further study or operational experience.

Because a large drop in wind production potential could occur in either the Interior or Central zones (both zones are modeled with similar amounts of wind capacity), the wind 5-minute regulation up requirement must be deliverable to either zone. Transmission-reserve constraints are implemented in PLEXOS, which ensure that a minimum of 39.2 MW of 5-minute regulation up (or 20.1 MW for No New Wind, see Table 11) is held across the Interior and Central zones, *and* that at least that amount of regulation capacity could be delivered to either zone if necessary. If capacity is reserved on the Alaska Intertie for 5-minute regulation up, the same capacity cannot be used to dispatch energy, potentially resulting in an opportunity cost of providing reserves across the transmission line. No 5-minute regulation up requirement for wind is modeled in Homer due to the lack of wind resources.

For load, the 5-minute regulation up requirement for each zone is calculated by taking the 99.5th percentile of load ramps in the headroom (upward) direction between 5-minute timesteps.

7.3.1 5-minute regulation down

The 5-minute regulation down requirement for wind is calculated as the largest change between 5-minute intervals in the footroom (downward) direction for a year of Shovel Creek windfarm simulated output (or the Fire Island windfarm in the No New Wind Scenario). For load, the 5-minute regulation down requirement is calculated by taking the 99.5th percentile of Railbelt-wide load ramps in the footroom (downward) direction between 5-minute timesteps.

[18] Additional study and operational experience with actual (i.e. non-synthetic) wind production is required to determine the correct level of regulation reserves to balance wind fluctuations within each 5-minute interval. Higher levels of reserves to regulate wind fluctuations, if necessary, would be expected to decrease production cost savings from additional wind and/or increase the need for fast-ramping resources (especially batteries).

7.3.2 Within-hour regulation

Within-hour regulation requirements for wind are determined by comparing the maximum difference between hourly averages and 5-minute production potential in the headroom direction for a year of Shovel Creek windfarm simulated output (or Eva Creek windfarm historical output in the No New Wind Scenario). The within-hour regulation reserve held in the day-ahead stage depends on the level of scheduled wind generation (See section 7.3.4).

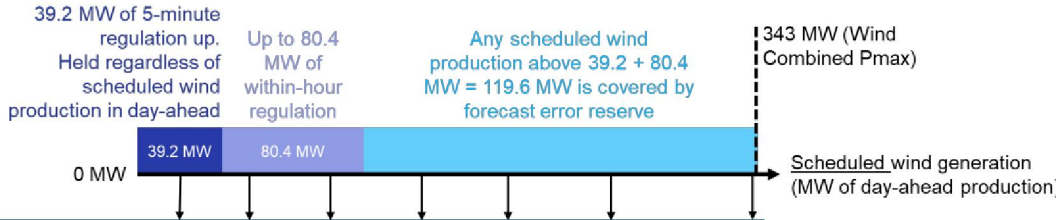
For load, the within-hour regulation requirement is calculated by comparing Railbelt-wide day-ahead and hourly-average real-time load profiles and taking the 99.5th percentile of load forecast error in the headroom (upward) direction between these profiles.

7.3.3 Forecast error

For wind, the forecast error reserve held in the day-ahead stage depends on the level of scheduled wind generation (See section 7.3.4). For load, the forecast error reserve requirement is calculated by comparing Railbelt-wide day-ahead and hourly-average real-time load profiles and taking the 99.5th percentile of load forecast error in the headroom (upward) direction between these profiles.

7.3.4 Wind reserves, production potential, and curtailment

As shown in Figure 46, E3 has implemented additional detail for wind reserve requirements in PLEXOS in the day-ahead timeframe. E3 assumes that all scheduled day-ahead wind production needs to be backed up by other resources and sets the forecast error reserve requirement for wind to perform this function. In addition to forecast error reserves, PLEXOS also holds reserve capacity for wind in the day-ahead stage in the form of within-hour regulation and 5-minute regulation up; the capacity held for these products is netted off of the forecast error reserve requirement to avoid holding redundant reserve capacity. If scheduled day-ahead wind production drops below the sum of the wind within-hour regulation and 5-minute regulation up requirements, the need for within-hour regulation is reduced and can go to zero if the scheduled wind production is low enough.



Example scheduled wind MW	20	50	100	150	200	250	343
5-minute regulation up	39.2	39.2	39.2	39.2	39.2	39.2	39.2
Within-hour regulation	0	10.8	60.8	80.4	80.4	80.4	80.4
Forecast error	0	0	0	30.4	80.4	130.4	223.4

Figure 46: Conceptual diagram of wind balancing reserves in the day-ahead simulation stage.

System operators do not need to hold flexibility for renewable production potential that is scheduled to be curtailed. E3's implementation of forecast error and within-hour regulation for wind allows the model to reduce balancing requirements for wind if there is a need to *schedule* wind curtailment in the day-ahead timeframe. Such a need may arise if there is not enough resource capacity to balance all of the wind, or if procurement of balancing capacity becomes more expensive than the value of additional wind generation.

Wind forecasts errors can also cause differences in wind-related reserve needs between day-ahead and real-time. It is appropriate for system operators to commit units in the day-ahead timeframe in a manner that could cover regulation needs that would be necessary for higher levels of wind production than are forecasted in the day-ahead timeframe. As a result, 39.2 MW of 5-minute regulation up (for 300 MW New Wind Scenario, or 20.1 MW for No New Wind Scenario) is held at all times in the day-ahead stage to balance wind, even if the forecasted day-ahead wind power production drops below the requirement for this grid service. Because it is not necessary to hold more regulation capacity than wind production potential in real-time dispatch, the wind component of the 5-minute regulation requirement is equal to the minimum of the production potential of all Railbelt windfarms combined and the 39.2 MW 5-minute regulation up requirement (or 18.3 MW for No New Wind) in the real-time model stage.

7.4 Battery reserve duration limits

For all reserves in this study, batteries are required to have energy available to provide the service if called upon. PLEXOS implements this through a "duration" for each reserve type, which dictates the amount of energy required in the battery to provide each MW of reserve. For example, for 5-minute regulation up, E3 has set the "duration" property to 30 minutes (0.5 hr), meaning a battery must have 1 MW * 0.5 hr = 0.5 MWh in the battery for every MW of 5-minute regulation up provided by that battery. Different duration assumptions are made for each balancing and contingency reserve. For example, forecast error reserves require the largest duration (4 hours) because forecast error events can span multiple hours; the 4 hour duration assumption restricts the amount of response that batteries can provide to the reserve. 5-minute regulation up and down reserves require the shortest duration (30 minutes) because 5-minute regulation is addressing short timescale fluctuations in net load.

For downwards reserves (only 5-minute regulation down in this study), the Duration property requires the battery to be partially un-charged (have headroom to charge) because providing a downward reserve will require the battery to charge.

For the Interior primary frequency response and spinning reserve requirements, duration is ignored for the current GVEA battery because GVEA staff confirmed that it is able to provide these services despite having minutes of discharge capability. This is because GVEA is able to bring on replacement resources fast enough to make the current battery duration adequate.

7.5 Contingency reserves

We model two types of contingency reserves in PLEXOS: spinning reserve and non-spinning reserve. Spinning reserves respond quickly to contingency events, whereas non-spinning reserves replace spinning reserves and can respond more slowly than spinning reserves. In every timestep of both the day-ahead and real-time model stages, E3 models a spinning reserve requirement of 60 MW. This 60 MW requirement for spinning reserves does not change with additional wind resources because the Railbelt plans to limit the largest contingency from wind farms to 60 MW by requiring multiple points of interconnection for large wind farms. In addition to spinning reserve, E3 includes a non-spinning reserve requirement that ensures that there is enough capacity available to replace spinning reserves in less than one hour. Resource capacity held for contingency reserves cannot also provide capacity towards balancing reserves. Spinning and non-spinning capacity must also be reserved on separate capacity.

A summary of the contingency reserves modeled in PLEXOS can be found in Table 12.

Because the Railbelt is an electrical island and has a relatively small amount of inertia relative to the larger North American interconnections, arresting frequency decline following a contingency is an important concern, especially in the context of additional wind power which can reduce the amount of synchronous inertia. The Railbelt is developing a primary frequency response policy to provide enough quick-responding capacity immediately following a contingency.[19] To ensure that the Railbelt always has enough primary frequency response, in every timestep 75% (45 MW) of the spinning reserve requirement is required to be delivered in the primary frequency response timeframe. In PLEXOS, the MW response of each generator towards the primary frequency response requirement is limited to the values in Appendix A of the Railbelt PFR Policy document. Combined cycle plants are modeled as a full plant in this study and therefore the primary frequency response available from the 1x1 configuration of combined cycles with more than one combustion turbine is used because the 1x1 configuration provides the least primary frequency response (i.e. is the most conservative representation). Because of the quick response time of batteries, all batteries are allowed to provide their rated power capacity towards primary frequency response.

[19] Railbelt PRF Policy V1 Rev 1-11_21_2023.

Table 12: Contingency reserve summary

Reserve Type>>	Primary Frequency Response	Spinning	Non-Spinning
Function	Arrest frequency decline before under-frequency load shedding occurs	Provide replacement energy for single largest contingency.	Spinning reserve replacement
Direction	Upward (Headroom)	Upward (Headroom)	Upward (Headroom)
Separate reserves for each zone, or Railbelt-wide	Separate reserves for each zone	Separate reserves for each zone	Separate reserves for each zone
How are transmission constraints between zones addressed?	Consistent with current Railbelt practice, contingency reserve requirements are divided across zones in load-ratio share. Transmission capacity is reserved if Bradley hydro (in the Homer zone) provides contingency reserves towards the GVEA or Central contingency reserve requirements. All other resources are modeled as only contributing to the contingency reserve of their own zone.		
Timeframe **(How fast does the response need to be?)**	N/A (Quick response ensured by using generator values from Railbelt PFR Policy)	5 minutes	45 minutes
Duration **(How long does the response need to be sustained? See section 7.4)**	10 minutes	1 hour	2 hours
Requirement (MW of reserve needed)	45 MW (75% of the 60 MW spinning requirement), held in load-ratio share across the three zones.	15 MW (25% of the 60 MW spinning requirement), held in load-ratio share across the three zones.	60 MW, held in load-ratio share across three zones.
Can this reserve be provided by online units only, or can offline quick-start units also contribute?	Online only	Online only	Offline and online

E3 does not model contingencies that can occur between the day-ahead unit commitment stage and real-time dispatch; contingency reserves are held in all intervals to prepare for contingency events, but the events themselves are not modeled.

Gas nomination constraints, which are only enforced in the real-time dispatch stage, are not modeled as constraining contingency reserve dispatch. In other words, it is assumed that gas would be available to increase generation on gas units that are holding contingency reserves, even if it would require consuming more gas than 110% of the day-ahead gas nomination for a short period of time (~1-2 hours). Railbelt utilities have a process by which they can request additional gas from their suppliers under emergency conditions.

The Bradley hydro resource is limited to provide at most 13.5 MW per turbine of spinning reserve; this capability is divided using the load ratio share for each zone. To limit fast response from Bradley, the provision of 5-minute regulation up from Bradley is also limited such that the sum of spinning reserve and 5-minute regulation is less than or equal to 13.5 MW per turbine. The 13.5 MW value originates from a stability study of unit and transmission capabilities in which the two Bradley units were found to be limited to 27 MW (13.5 MW * 2 = 27 MW) of spinning reserve.