Alaska's Railbelt Electric System: Decarbonization Scenarios For 2050

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Technical Report
UAF/ACEP/TP-01-0003
January 2024

Suggested Citation:
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

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Acknowledgments

This work was made possible with support from numerous organizations and individuals through collaboration, input, data, and review as part of our technical advisory group. The analyses and interpretations presented in this report are the authors' alone. The reviewers provided ongoing feedback throughout the project but the views in the report are solely those of the authors and do not represent the views of reviewers or their employers.

- Alaska Energy Authority: Bryan Carey
- Chugach Electric Association: Dustin Highers, Hans Thompson, Mark Henspeter
- Golden Valley Electric Association: Dan Bishop
- Homer Electric Association: Larry Jorgensen, David Thomas
- Matanuska Electric Association
- Bradley Lake Project Management Committee: Brian Hickey

The authors also thank the following organization and individuals for their contributions through input, data, and comments:

- Information Insights Inc.: Jamie Hansen, Frana Burtness-Adams, and Lisa Baraff
- Alaska Microgrid Group: Brian Rogers
- Alaska Renewables LLC: Matthew Perkins and Andrew McDonnell
- Analysis North: Alan Mitchell
- Mark A. Foster, MAFA
- David Lockard
- Those who contributed at the Stakeholder Workshop and completed the Stakeholder Survey
- City of Seward, Alaska: Rob Montgomery

The following individuals from the Alaska Center for Energy and Power are also thanked and acknowledged for their comments and review throughout the process: Glen Woodworth, Ian MacDougall, Mariko Shirazi, Erin Trochim, Mohammad Heidari Kapourchali, Vanessa Raymond, Andrew Miles, Gwen Holdmann, Jeremy Kasper, and Peter Asmus. We are grateful to Fran Pedersen for her enthusiastic offer of editing and were saddened that she could not see the study to its end.

This project is part of the Arctic Regional Collaboration for Technology Innovation and Commercialization II Program - Innovation Network, an initiative supported by the Office of Naval Research (ONR) Award N00014-22-1-2049. This project is funded by state of Alaska fiscal year 2023 economic development capital funding. Additionally, this project has been supported by the Hawai'i Natural Energy Institute.

Acronyms

AC Alternating Current

ACEP Alaska Center for Energy and Power

ATB National Renewable Energy Laboratory Annual Technology Baseline

BAU business as usual

BESS battery energy storage system

CAPEX capital expenditure

CC combined-cycle

CCS carbon capture and storage/sequestration

CEA Chugach Electric Association

CHP combined heat and power

COS cost of service

CPI U.S. consumer price index

DC direct current

DERs distributed energy resources

DERMS distributed energy resource management systems

EIA Energy Information Administration

EMT electromagnetic transient

EV electric vehicle

FERC Federal Energy Regulatory Commission

G&T COS generation and transmission cost of service

Gas-CC combined- cycle gas turbine

Gas-CT simple-cycle gas turbine

Gas-IC internal combustion gas turbine

GFL grid following (inverter control scheme)

GFM grid forming (inverter control scheme)

GVEA Golden Valley Electric Association

GW gigawatt

GWh gigawatt-hour

HEA Homer Electric Assocciation

HVDC high-voltage direct current

Hz Hertz, a measure of frequency

IBR inverter-based resource

IRA Inflation Reduction Act

ITC investment tax credit

kWh kilowatt-hour, a measure of electrical energy and the unit of sale of electricity

LCOE levelized cost Of energy

LLC limited liability corporation

LNG liquified natural gas

MDPI Multidisciplinary Digital Publishing Institute

MEA Matanuska Electric Association

MJ megajoule

MMBtu one million British thermal units (a measure of heat energy)

ms microseconds

MSR minimum synchronous ratio

MSRHF minimum synchronous ratio with highest flows

MVA megavolt ampere

MW megawatt

MWh megawatt-hour

NG natural gas

NREL National Renewable Energy Laboratory

O&M Operations and Management

PNNL Pacific Northwest National Laboratory

PSS®E Power System Simulator for Engineering

pu per unit

PV photovoltaics

RPS renewable portfolio standard

s seconds

SES Seward Electric System

SMR small modular reactor

SR synchronous ratio

SV summer valley

S-W Susitna-Watana

TAG Technical Advisory Group

TWh terawatt-hour

UAF University of Alaska Fairbanks

UFLS Underfrequency Load Shedding

UNIFI Universal Interoperability for Grid-Forming Inverters

U.S. United States

WP winter peak

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1 Introduction

1.1 The Railbelt

The Railbelt is the largest regional electric grid in Alaska, spanning approximately 700 miles from Fairbanks to Homer. This Railbelt serves nearly 75% of Alaska's population.[1] Currently, approximately 80% of the Railbelt's electricity generation comes from fossil fuels, and 20% comes from renewable sources, mainly hydropower.

The Railbelt is operated by five load-serving electric utilities, as shown in Figure 1.1:

- Golden Valley Electric Association Golden Valley Electric Association (GVEA)
- Matanuska Electric Association Matanuska Electric Association (MEA)
- Chugach Electric Association Chugach Electric Association (CEA)
- Homer Electric Association Homer Electric Assocciation (HEA)
- Seward Electic System Seward Electric System (SES)

The first four electric utilities are member-owned cooperatives that own and operate generation, transmission, and distribution within their regions. The Alaska Energy Authority, which is the state's energy office, also owns some generation and transmission assets. Some independent power producers also operate generation in the region.

Energy and Power Basics Scientists and engineers define energy as the ability to do work. Alaskans use energy for a variety of things, such as to walk and ski, move cars along roads and boats through water, cook food on stoves and in ovens, warm our houses, light our homes and offices, manufacture products, and send astronauts into space. Energy can take many forms that can be changed between each other. For example, a diesel generator gets energy from chemical bonds in the diesel fuel and turns it into electrical and heat energy. Energy can be stored for later use.

Utility companies generate electric energy from a variety of sources. The amount of energy produced is called the "generation" of a specific component. Generation is typically measured in kilowatt hours (kWh), megawatt hours (MWh), and Million British Thermal Units (MMBtu). Batteries can be used to store electric energy.

Scientists and engineers define power as the rate at which energy is transferred. When more devices are drawing energy from the electric grid, grid operators have to ramp up the power output of generators. The maximum rated power output of a specific generator is called the capacity (also "nameplate capacity" or "peak capacity.") Capacity of individual power plants is typically measured in kilowatts (kW) or megawatts (MW). Transmission lines and transformers also have a capacity, which is the maximum amount of power that can flow through the device without causing damage.

Source: *Electricity explained - U.S. Energy Information Administration (EIA)*[a] and *Energy Explained - U.S. Energy Information Administration (EIA)*[b]

[a] *Electricity explained - U.S. Energy Information Administration (EIA)*. URL: https://www.eia.gov/energyexplained/electricity/ (visited on 12/13/2023).

[b] *Energy Explained - U.S. Energy Information Administration (EIA)*. URL: https://www.eia.gov/energyexplained/ (visited on 12/13/2023).

1.2 Study Objectives

Alaska is at a unique transition point within its energy landscape due to potential state policies such as a renewable portfolio standard or clean energy bill,[2] formation of the first regional electric reliability organization,[3] and the

[1] Gwen P. Holdmann, Richard W. Wies, and Jeremy B. Vandermeer. "Renewable Energy Integration in Alaska's Remote Islanded Microgrids: Economic Drivers, Technical Strategies, Technological Niche Development, and Policy Implications". In: *Proceedings of the IEEE* 107.9 (Sept. 2019), pp. 1820–1837. ISSN: 1558-2256. DOI: 10.1109/JPROC.2019.2932755. URL: https://ieeexplore.ieee.org/abstract/document/8801901 (visited on 12/13/2023).

[2] The Office of Governor Mike Dunleavy. *HB 301: Renewable Portfolio Standard FAQ*. URL: https://gov.alaska.gov/wp-content/uploads/RPS-FAQ.pdf (visited on 12/13/2023).

[3] *Additional Background on the RRC – Alaska RRC*. en-US. URL: https://www.akrrc.org/more-information/ (visited on 12/13/2023).

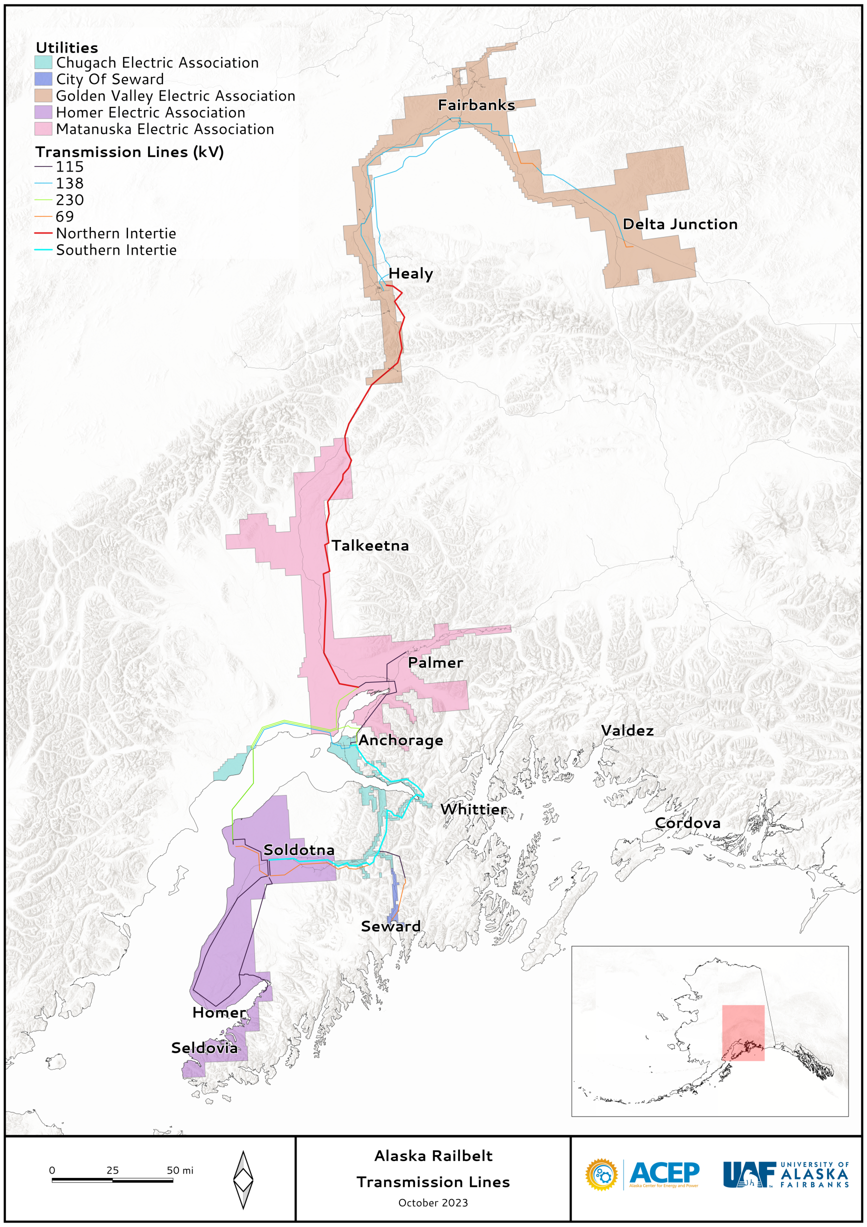

Figure 1.1. Alaska Railbelt transmission lines, load regions, and electric utility territories

pending loss of natural gas resources produced within the state.[4] These shifts are raising concerns about forward pathways for the Railbelt electric grid to secure affordable, reliable, and reduced carbon or carbon-free electricity.

The goal of this study is to explore and quantify decarbonization scenarios of Alaska's Railbelt electric grid by the year 2050. Decarbonization scenarios are developed and evaluated for reliability and affordability. These decarbonization scenarios are designed to be illustrative of potential 2050 decarbonized futures, and are not predictions of the future or suggestions of optimal pathways. Additionally, this study only evaluates decarbonization of the Railbelt electric grid, and not the other energy systems for this region such as heating and transportation. However, the impact of the forecasted electrification of these sectors is included. This study is policy and technology agnostic, meaning the identified scenarios are not designed to align with specific policies or favor specific types of technolo-

[4]Alaska Utilities Working Group, Berkeley Research Group, and Cornerstone Energy Services. *Phase 1 Assessment: Cook Inlet Gas Supply Project*. en. Tech. rep. June 2023. URL: https://enstarnaturalgas.com/wp-content/uploads/2023/06/CIGSP-Phase-I-Report-BRG-28June2023.pdf (visited on 12/13/2023).

gies beyond those that meet the project's goal. Energy resources that have been evaluated for and/or included in the scenarios are: wind, solar, geothermal [5], tidal, hydro, pumped storage hydropower, batteries, nuclear, and hydrogen. Carbon capture and storage/sequestration (carbon capture and storage/sequestration (CCS)) are not included in this study, although it is indicated that CCS might be required to achieve 100% decarbonization of the Railbelt.

This project aims to provide valuable information to the Alaskan public and decision makers on the economic and reliability implications of several decarbonization scenarios using established methods for evaluating Railbelt energy transitions. Additionally, a key intention of this work has been to build capacity within Alaska to perform the types of analyses needed to evaluate energy transitions. The information generated from this study includes general information such as resource availability and load forecasts, and information specific to the developed decarbonization scenarios such as stability and reliability of the system, and the impact to rates.

The outcomes of this study include:

- Evaluation of various resource mixes and quantities necessary to meet high-decarbonization objectives in the Railbelt,
- Quantification of the electric load impacts of electrification, including high electric vehicle and heat pump adoption,
- Characterization of the operational and reliability implications of decarbonization scenarios,
- Quantification of the potential capital costs and operational costs of a decarbonized power system,
- Creatation of information for Railbelt planning discussions and future studies, such as an Integrated Resource Plan,
- Training for students, staff, and faculty at the University of Alaska Fairbanks in the tools and methods to study energy transitions, including through the mentorship and collaboration of national and local industry experts.

[5] Geothermal energy was considered, but was not evaluated due to feedback on lack of identified viable resources.

2 Study Approach

2.1 Collaboration

A Technical Advisory Group was assembled to provide critical data, models, and information, advise the study team on current operations and conditions, and review the results of the study for technical feasibility and accuracy. Engineers and senior personnel from each of the Railbelt utilities participated in the technical advisory group, along with members from the Alaska Energy Authority and the Railbelt Reliability Council. The Technical Advisory Group met bi-weekly with the study team throughout the study period to provide continual technical advising.

Public engagement was performed throughout the study period in the form of workshops, presentations, and a survey. Feedback from the stakeholder survey was used to finalize the qualitative scenario descriptions and for the initial economic capacity sizing. Additionally, feedback from the presentations will be used to inform the direction of future relevant studies. A summary of the scenario description feedback has been published in an Alaska Center for Energy and Power (ACEP) technical report.[6]

The study team also coordinated with the National Renewable Energy Laboratory (NREL)'s team that performed the Renewable Portfolio Standard Assessment for Alaska's Railbelt.[7] Where appropriate, information was shared and assumptions were aligned, with the goal of creating complementary information. Table 2.1 outlines the key differences between this study and NREL's Renewable Portfolio Standard Assessment for Alaska's Railbelt.

2.2 Data Collection

The modeling relied extensively on publicly available datasets, largely based on information available from the United States Energy Information Agency (U.S. EIA). This included EIA Form 860 for information on plant capacities, installation dates, locations, and fuel types. EIA Form 923 was also levered to understand historical operating practices, fuel supply, costs, and plant efficiency (heat rates). Other sources included NREL's Renewable Portfolio Standard Assessment for Alaska's Railbelt,[8] reports from the Alaska Energy Authority, Railbelt utilities' Federal Energy Regulatory Commission (FERC) Form 1, annual reports, rate filings with the Regulatory Commission of Alaska, and public data from ACEP's 2020 analysis of carbon reduction for GVEA.[9]

Where necessary, the analysis also leveraged proprietary data provided by the Railbelt utilities through coordination and participation in the Technical Advisory Group. This included historical hourly load data for each utility, details regarding generator operating practices, reserve strategies, and transmission wheeling agreements. While simulations will never exactly replicate actual operations or utility procedures, the valuable input from the utilities helped the analysis to reflect, to the extent feasible, actual operating practices in the Railbelt.

Detailed power flow models, provided in Siemens Power System Simulator for Engineering (PSS®E), were also provided by the Railbelt utilities. These models included a detailed representation of network topology (transmission lines, busses, generator characteristics, and locations of load).

2.3 Methodology and Process

This study is a pre-feasibility study, which is an early stage of analysis valuable for evaluating the technical viability of the decarbonization scenarios proposed. To evaluate the changes to power system operations and grid stability with increasing renewable energy and electrification, this analysis leveraged detailed power system simulation and modeling software. In total, four scenarios were evaluated, identified in Section 3, to represent potential future power systems with increased renewable energy. Grid configurations were evaluated with additions of wind, solar, battery energy storage, hydropower, and nuclear technologies, as well as corresponding fossil-fuel generator retirements and increased electrification from electric vehicles (EVs) and heat pumps.

[6] Peter Asmus et al. *Railbelt Decarbonization Pathways Study Public Comment Summary*. en. ACEP Technical Report TP-01-0001. June 2023, p. 20. URL: https://www.uaf.edu/acep/files/media/ACEP_Railbelt_Decarbonization_Study_Public_Survey_Report_final.pdf.

[7] Paul Denholm et al. *Renewable Porftolio Standard Assessment for Alaska's Railbelt*. Technical Report. National Renewable Energy Lab. (NREL), Golden, CO (United States), Feb. 2022, p. 51. URL: https://www.nrel.gov/docs/fy22osti/81698.pdf.

[8] Denholm et al., *Renewable Porftolio Standard Assessment for Alaska's Railbelt*.

[9] Gwen Holdmann et al. *GVEA Carbon Reduction Study*. Tech. rep. Oct. 2020, p. 94. URL: https://www.gvea.com/wp-content/uploads/GVEA-Carbon-Reduction-Report-Final.pdf.

Table 2.1. Comparison between the Alaska Center for Energy and Power's Railbelt Decarbonization Pathways Study and the National Renewable Energy Laboratory's Renewable Portfolio Standard Assessment for Alaska's Railbelt.

Modeling Detail	ACEP	NREL
Overarching research focus	Sector-wide decarbonization	Specific policy evaluation of a renewable portfolio standard
Decarbonization target	100% by 2050	80% by 2040
Time horizon	2050 only	2024-2050, in 1-year increments
Technologies considered	Wind, solar photovoltaics, nuclear, hydropower, hydrogen, and ammonia, and thermal CCS	Only renewable technologies such as wind, photovoltaics, hydropower, and geothermal energy
Load growth projections	Includes EV, BTM solar, and heat pump growth	Using ACEP's load growth projections
Generation expansion scenario design	Partial optimization based on scenario assumptions	PLEXOS capacity expansion tool
Scope of operational modeling	PLEXOS production cost + PSS®E power flow analysis	PLEXOS production cost only
Financial impacts	Comparing electric rate impacts between scenarios	Comparing overall Railbelt-wide costs between scenarios

The software tools used in this analysis are available from third-party software vendors heavily used throughout the industry, and are the same ones leveraged by the Railbelt utilities and other global utilities. These grid planning tools allow for evaluation and simulation of a future power system using the same methods and processes used to operate and control today's grid to isolate the effects of integrating renewable energy, new technology, and operational changes.

When it comes to power system modeling, no one tool can provide a comprehensive analysis across the generation, transmission, and distribution segments of utility planning. In addition, no one tool can properly evaluate all the timescales of planning, which range from sub-seconds to an entire year, or years, of operation. To overcome this limitation, this study leveraged multiple power system planning tools with tight coupling between the different stages. This allows for each tool to properly evaluate its domain, while linking inputs, assumptions, and outputs between the tools to overcome seams in the analysis typically found between the generation and transmission analyses.

This study followed a six-step, interconnected process, as outlined in Figure 2.1

1. **Scenario Development:** Several scenarios were identified that highlighted different energy resources while including significant integration of wind and solar energy, to illustrate unique pathways to decarbonization. These scenarios were refined through public engagement and feedback during the early stages of the project.

2. **Load Forecasting and Electrification:** The ACEP team developed a load forecast for the Alaska Railbelt following current trends for electric load growth and the impact of electrification of other energy sectors, namely transportation and heating. Following best industry practice, the load forecast was developed for multiple layers, including an underlying economic forecast, rooftop solar photovoltaics (PV), electric vehicles (EVs), and heat pump adoption. This allowed for multiple forecasts to be developed to represent different levels of end-use electrification.

3. **Resource Selection and Sizing:** The energy resources considered in this study were identified by high resource availability near the existing Railbelt transmission system. The hourly availability of each new energy resource was collected for each location of new generation. Using the load forecast developed in Step 1, future renewable portfolios were developed with a custom-built resource sizing tool that selected resource combinations of wind, solar, battery storage, tidal and nuclear resources to meet modeled future demand.

4. **Generation Analysis:** Generation analysis involved both portfolio optimization and production cost analysis. Hour-to-hour operation of the grid was modeled using Energy Exemplar's PLEXOS production cost

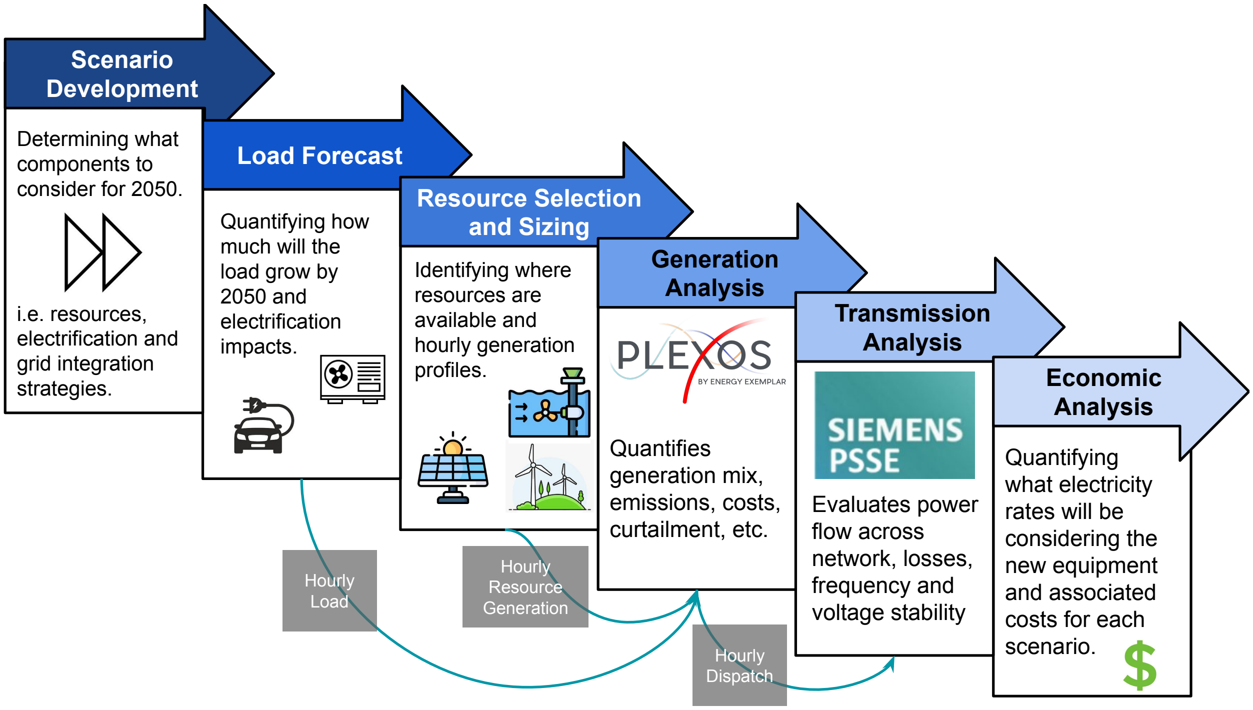

Figure 2.1. Project components flowchart

model. This tool matches load and generation in a least cost manner while meeting reliability constraints like regulation reserves, contingency reserves, and transmission constraints. PLEXOS inputs include initial economic capacity sizing, load forecasts, and energy resource information, such as availability and operating costs. The developed PLEXOS model incorporated reserves requirements as specified in the Alaska Reliability Standards[10] which were modified to account for high penetrations of variable renewable resources based on methods employed in other regions of the United States that currently have greater penetrations of variable renewable energy resources,[11],[12].[13] The output from the PLEXOS model used in this study is the hourly time series of the dispatch of pre-specified generation resources in the system. It is important to note that the generation dispatch created by PLEXOS assumes a single load balancing entity or transmission system operator, resulting in optimal dispatch for the system as a whole.

5. **Transmission Stability Analysis: PSS®E! (PSS®E!)** power flow modeling software was used to evaluate steady-state and dynamic stability on the transmission network (lines rated from 69 kV to 230 kV). This was built from the current **PSS®E!** model of the Railbelt, representing the present day system. The existing **PSS®E!** model was adapted to represent each of the scenarios using the resource sizes and locations, load forecasts, and economic dispatch generated in earlier steps. Stability and reliability analysis was performed in **PSS®E!** following key provisions of the Alaska Reliability Standard AKTPL-001-2. This process determined the additional equipment necessary to maintain voltage and frequency stability.

6. **Economic Analysis:** The cost of service (COS) to provide electricity on the Railbelt was determined for the

[10] *The Intertie Management Committees' Railbelt Operating and Reliability Standards*. Oct. 2017. URL: https://www.akenergyauthority.org/Portals/0/Programs/Railbelt%20Energy/Alaska%20Inertie/RailbeltOpratingRlbilityStndardsFinal2017.pdf?ver=2019-06-19-135947-740 (visited on 10/29/2023).

[11] Bartlett, Drake and Parks, Keith. *2020 Study of the Levels of Flex Reserve and Regulating Reserve Necessary for Reliable System Operation while Accommodating the Uncertainty of Wind and Solar Generation at Varying Levels of Installed Wind and Solar Generation Capacity within the Public Service Company of Colorado Balancing Area Authority*. en. Tech. rep. Public Service Company of Colorado, May 2022, p. 26. URL: https://www.xcelenergy.com/staticfiles/xe-responsive/Company/Rates%20&%20Regulations/Resource%20Plans/Clean%20Energy%20Plan/HE_114-KLS-3-Flex_Reserve_Study.pdf.

[12] *2019 Annual Report on Market Issues and Performance*. Tech. rep. California ISO, June 2020, p. 323. URL: https://www.caiso.com/Documents/2019AnnualReportonMarketIssuesandPerformance.pdf.

[13] Paul Denholm et al. *Summary of Market Opportunities for Electric Vehicles and Dispatchable Load in Electrolyzers*. en. Tech. rep. NREL/TP-6A20-64172. May 2015, p. 48. DOI: 10.2172/1215243. URL: http://www.osti.gov/servlets/purl/1215243/ (visited on 01/04/2023).

system build for each scenario based on 1) the capital cost of new generation, transmission upgrades, and additional equipment or system upgrades necessary for system stability; and 2) the variable operating costs (fuel and operations and maintenance Operations and Management (O&M)) of executing the hourly dispatch determined by the PLEXOS production cost model. The average cost per MWh of distribution and general and administrative services was assumed to remain constant at current levels. Margins were included as an element of the COS to determine average revenue requirements per megawatt-hour (MWh).

2.4 Methodology Limitations

The analysis performed in this study has several methodology limitations discussed here, inherent to a pre-feasibility study.

- Load Forecast and Cost Assumptions: The load forecast is generated using the best available data and information at the time of this study. Similarly, the generation analysis and rate analysis are performed using cost assumptions based on the best available data and information at the time of this study. The assumptions made in this study are outlined throughout the report and appendices. However, as policies change and new data becomes available both the load forecast and cost assumptions will be out of date. Future work will need to reevaluate and generate a new load forecast and cost assumptions.

- Stability Analysis Tool PSS®E: The power system simulation tool used in this study is Siemens Power System Simulator for Engineering (PSS®E). This is a common type of a power system simulator for evaluating large power systems at the level of detail for a planning study. This tool can accurately identify key stability challenges that are likely to create issues that will require mitigation. For detailed implementation studies and for small sections of electric grids with high amounts of inverter-based resources, electromagnetic transient (electromagnetic transient (EMT)) simulations are necessary, such simulations were beyond the scope of this report. For the level of analysis needed for this study, the simulation tool PSS®E provides informative results that identify key stability challenges. Additional details on the limitations and uses of the analysis tools and models employed are provided in Section 6.

3 Scenario Development

3.1 Scenario Overview and Objectives

The project focuses on technical feasibility and economic impact, using computer simulation models to explore the impacts of various technologies and their locations on the existing grid. Given the cost and policy uncertainties associated with new renewable technologies, this study evaluated four scenarios, each of which considers large, fundamentally different resource mixes to achieve similar decarbonization objectives.

A Business-as-Usual (business as usual (BAU)) scenario is used as a reference point, including only load growth and planned development, such as the Dixon Diversion hydroelectric project. Three additional low-carbon scenarios were evaluated. Each scenario considers significantly different resource mixes relative to the BAU. All three decarbonization scenarios included development of new solar and wind generation, batteries, and the planned development of the Grant Lake and Dixon Diversion hydroelectric projects. The scenarios differ by highlighting different new energy resources to illustrate a potential decarbonization scenario. Changes in the low-carbon scenarios relative to the BAU are indicative of major policy changes, large resource procurements, and/or technological advancements.

An overview of the four scenarios is provided in Figure 3.1, and key assumptions are outlined in Table 3.1. Scenarios are based on a target 2050 study year.

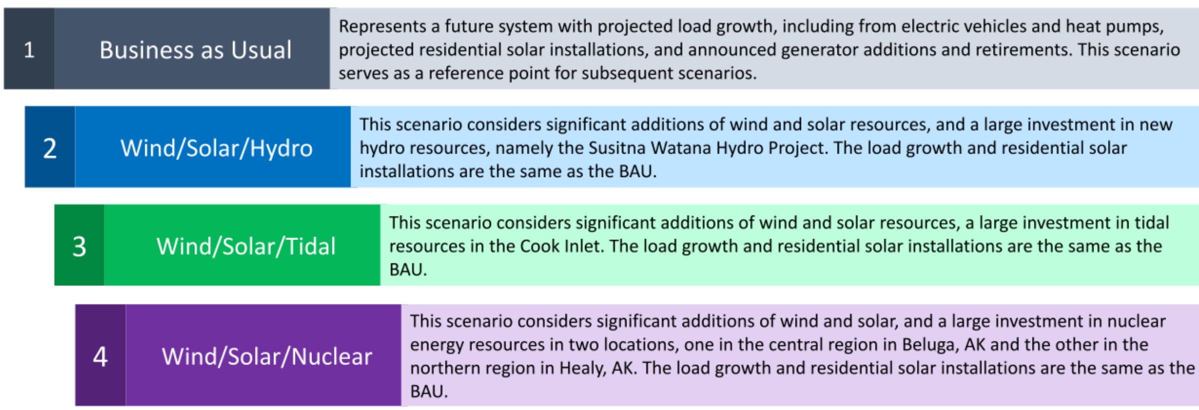

Figure 3.1. Scenario overview

3.1.1 Business as Usual

A business as usual (BAU) scenario was developed as a reference point for the three decarbonization scenarios. The BAU scenario assumes only incremental changes to the Railbelt power system, and is based only on firm announcements of new additions and retirements, and considers load growth, including load growth from EVs and heat pumps. This case was developed to represent how the current Railbelt system would operate given these near-term changes and allows a useful comparison for scenarios with higher levels of carbon-free energy. Announced changes include the Kenai Intertie transmission upgrade in the Railbelt electric grid, which will increase the voltage on existing lines from 115 kV to 230 kV. A high-voltage direct current (HVDC) subsea cable was added from Beluga, on the west side of Cook Inlet, to Bernice Lake, on the east side of Cook Inlet. This case also included the retirement of Healy 2 (60 MW), the addition of Houston Solar (8.5 MW) and Little Mount Susitna Wind (30 MW), and battery energy storage system (BESS) upgrades/additions based on Bradley Lake Project Management Committee proposals for a CEA/MEA BESS (70 MW/280 MWh) and a GVEA BESS (100 MW/200 MWh). This scenario also included the addition of the Dixon Diversion, allowing Bradley Lake to generate an additional 70 GWh over the course of the year from its existing two turbines[14].

3.1.2 Wind/Solar/Hydro Scenario

The Wind/Solar/Hydro scenario illustrates a low-carbon electric grid where hydroelectric projects provide a significant portion of the generation mix. This scenario was designed to study future high hydroelectric conditions,

[14] An increase of 70 GWh was calculated using 2021 hydrological data, which was a low water year. In a normal water year the Dixon Diversion would add much more generation, about 150 GWh, or around a 49% increase in energy from the Bradley Lake project.

Table 3.1. Key assumptions by scenario

	Business-as-Usual (BAU)	Wind/Solar/Hydro	Wind/Solar/Tidal	Wind/Solar/Nuclear
Load Growth	Economic load growth, electric vehicle and heat pump growth.	Economic load growth, electric vehicle and heat pump growth.	Economic load growth, electric vehicle and heat pump growth.	Economic load growth, electric vehicle and heat pump growth.
Behind-the-Meter PV	Growth following current trends	Growth following current trends	Growth following current trends	Growth following current trends
Retirements	Announced retirements only	All coal generators	All coal generators	All coal generators
Thermal Additions	As necessary for capacity purposes	As necessary for capacity purposes	As necessary for capacity purposes	As necessary for capacity purposes
Hydro Changes	Dixon Diversion	Susitna-Watana, Grant Lake, Dixon Diversion	Grant Lake, Dixon Diversion	Grant Lake, Dixon Diversion
Wind and Solar Additions	Central region wind project (30 MW)	BAU + several additional sites	BAU + several additional sites	BAU + several additional sites
Battery Storage	Chugach: 70 MW, GVEA: 100 MW, Soldotna: 47 MW	BAU + several additional sites	BAU + several additional sites	BAU + several additional sites
Transmission	Alaska Intertie: no changes, Kenai Intertie: 230 kV upgrade	BAU + Alaska Intertie: 230 kV upgrade, Kenai Intertie: new HVDC line, Susitna-Watana transmission	BAU + Alaska Intertie: 230 kV upgrade, Kenai Intertie: new HVDC line	BAU + Alaska Intertie: 230 kV upgrade, Kenai Intertie: new HVDC line

capturing the impacts of large increases in hydroelectric generation capacity to support load growth with the inclusion of EV and heat pump loads. This case included the addition of Susitna-Watana [15] and Grant Lake (5 MW) hydroelectric projects. It also included the addition of the Dixon Diversion. Wind, solar and battery capacity were also added based on the portfolio sizing. All coal capacity was retired, resulting in the removal of Aurora Energy (28 MW) and Healy 1 (26 MW) relative to the BAU scenario. The remaining fossil-fuel based generation was kept in place for reliability purposes.

Finally, to support the increase in hydroelectric generation and renewable capacity, as well as the additional load associated with EVs and heat pumps, it was assumed that both the Alaska and Kenai Interties were upgraded to 230 kV. Additionally a 100 MW rated HVDC cable was included connecting Beluga to Bernice Lake. These upgrades would support a maximum power flow of 300 MW between each region.

3.1.3 Wind/Solar/Tidal Scenario

The Wind/Solar/Tidal scenario illustrates a low-carbon electric grid where tidal energy provides a significant portion of the generation mix. The load growth is the same as for the other scenarios, including load growth from EVs and heat pumps. This scenario also included Grant Lake (5 MW) and the Dixon Diversion. Wind, solar and battery capacity were added based on the portfolio sizing. All coal capacity was retired, resulting in the removal of Aurora Energy (28 MW) and Healy 1 (26 MW) relative to the BAU scenario. The remaining fossil-fuel based generation was kept in place for reliability purposes.

Same as the other low-carbon scenarios, the Alaska and Kenai Interties were upgraded to 230 kV. A 100 MW rated HVDC cable was included connecting Beluga to Bernice Lake. These upgrades support a maximum power flow of

[15] 475 MW max monthly rating. Susitna-Watana would be technically capable of up to 620 MW of generation, however, max power was limited due to assumed downstream flow constraints.

300 MW between each region.

3.1.4 Wind/Solar/Nuclear Scenario

The Wind/Solar/Nuclear scenario illustrates a low-carbon electric grid where nuclear energy provides a significant portion of the generation mix. The load growth is the same as all the other scenarios, including load growth from EVs and heat pumps. This scenario also included Grant Lake (5 MW) and the Dixon Diversion. Wind, solar and battery capacity were also added based on the portfolio sizing. All coal capacity was retired, resulting in the removal of Aurora Energy (28 MW) and Healy 1 (26 MW) relative to the BAU scenario. The remaining fossil-fuel based generation was kept in place for reliability purposes.

As with the other low-carbon scenarios, the Alaska and Kenai Interties were upgraded to 230 kV. A 100 MW rated HVDC cable was included connecting Beluga to Bernice lake. These upgrades support a maximum power flow of 300 MW between each region.

The Wind/Solar/Nuclear scenario assumed there would be no liquified natural gas (LNG) imports. This meant the cheapest fossil-fuel in the system was either naphtha or continued Cook Inlet production, both of which are projected to be around $20/MMBtu[16]. This served two purposes. First, it illustrated an alternative to LNG imports. Second, as shown in the sensitivity analyses in Appendix H, the projected cost of nuclear energy meant that it could not compete with LNG, and so nuclear generation was not built by the sizing tool in Section 4.1 when LNG was available in the system.

3.2 Load Forecasting and Electrification

The first analytical step in developing the scenarios was to establish a load forecast for the Railbelt utilities. Following best industry practice, the load forecast was developed with multiple layers, including an underlying forecast based on population growth, behind-the-meter solar PV, EVs, and heat pump adoption. This allowed for multiple forecasts to be developed to represent different levels of end-use electrification.

There are three general load areas in the Railbelt: Northern, Central, and Southern. The Northern region consists of the GVEA service territory, the Central region consists of the MEA and CEA service territories, and the Southern region consists of the HEA service territory. These load areas, utility service areas, and the transmission network are illustrated in Figure 3.2

Two load forecasts were created: (1) a moderate adoption forecast based on projections from current adoption rates and comparisons to other regional and national projections and (2) an aggressive forecast, which provides an illustrative comparison of a high adoption rate of 90% for the included technologies. These load forecasts were published in Multidisciplinary Digital Publishing Institute (MDPI) *Energies*.[17]

The moderate load forecast was used in all of the scenarios in this study. The aggressive forecast provided a comparison of the current trends with a near total adoption of these technologies to illustrate impacts to the load; however it was only used as an illustrative comparison and was not implemented in the scenarios evaluated in this study.

The key characteristics and adoption rates of heat pumps, EVs, and Behind-the-Meter solar energy are summarized in Table 3.2.

The moderate forecast results in an 80% increase in total energy and a 113% increase in the peak load. The minimum load in the system was increased by 53%. The hourly demand change increased by 260%, which is significantly higher than the increases in total energy and peak load. This suggests that distributed energy resource management systems (distributed energy resource management systems (DERMS)) would be beneficial to control and smooth load fluctuations in the moderate forecast.

The aggressive forecast results in a 116% increase in total energy and a 219% increase in the peak load. In addition, due to the increase in Behind-the-Meter solar energy there was a reduction in the minimum load, which occurred in

[16] See Appendix H for more discussion of fuel prices

[17] Phylicia Cicilio et al. “Load, Electrification Adoption, and Behind-the-Meter Solar Forecasts for Alaska’s Railbelt Transmission System”. In: *Energies* 16.17 (2023). Publisher: MDPI, p. 6117.

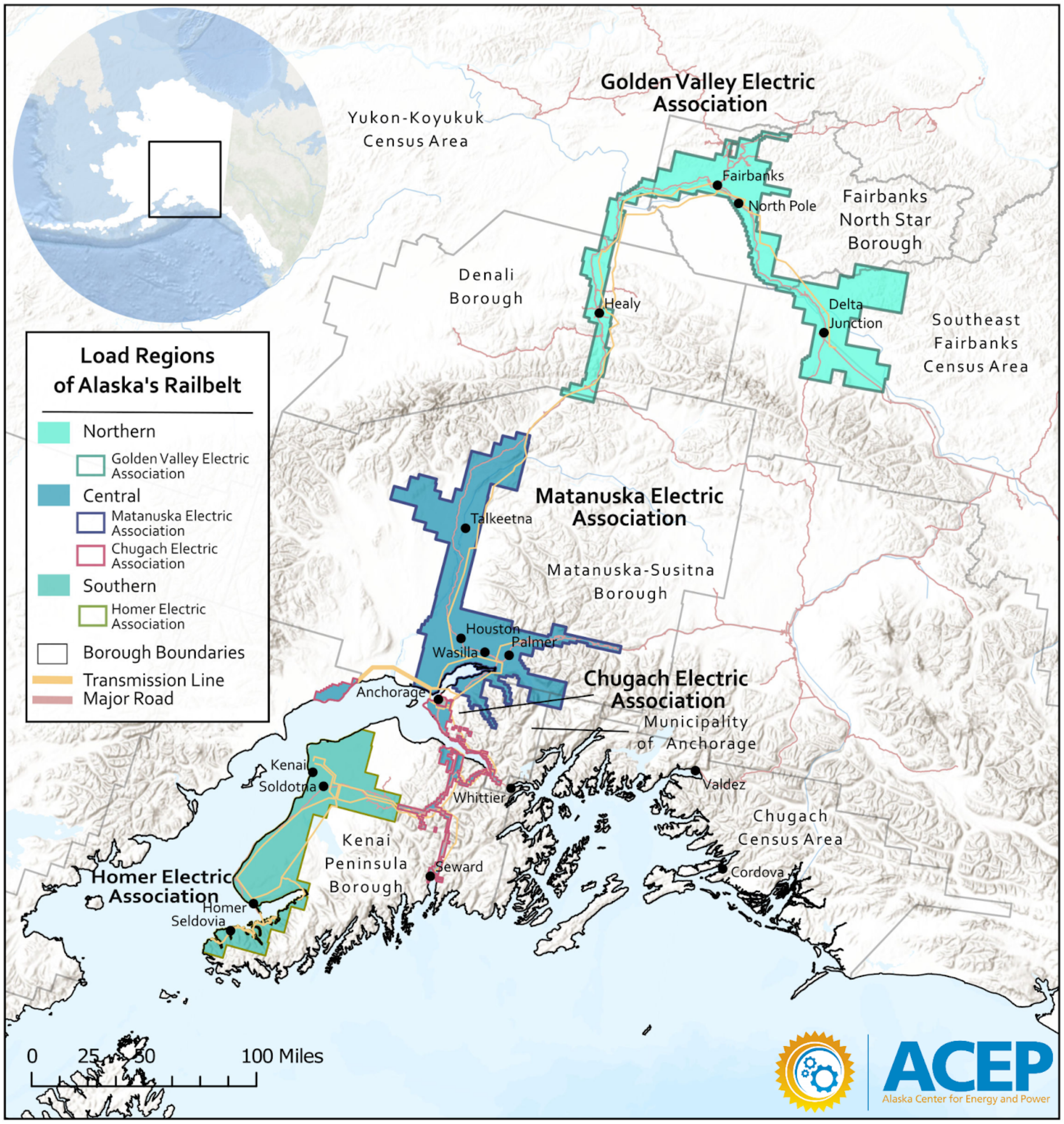

Figure 3.2. Alaska Railbelt transmission, load regions, and electric utility territories.

Table 3.2. Load characteristics for 2021 and the aggressive and moderate 2050 load forecasts.

Characteristic	2021	2050 Moderate	2050 Aggressive
Total Annual Energy [TWh]	4.72	8.48	10.2
Heat Pump Energy [TWh]	-	0.1	2
Electric Vehicle Energy [TWh]	-	3.1	4
Residential Solar Energy [TWh]	-	0.2	1
Peak Load Demand [MW]	765.3	1626	2403
Low Load Demand [MW]	381.1	580	144
Maximum Hourly Change [MW]	55.5	202	270
Number of Installed Heat Pumps	-	41,916	292,035
Number of Electric Vehicles	-	353,381	448,977
Behind-the-Meter Solar Installed Capacity [MW]	11	225	1111

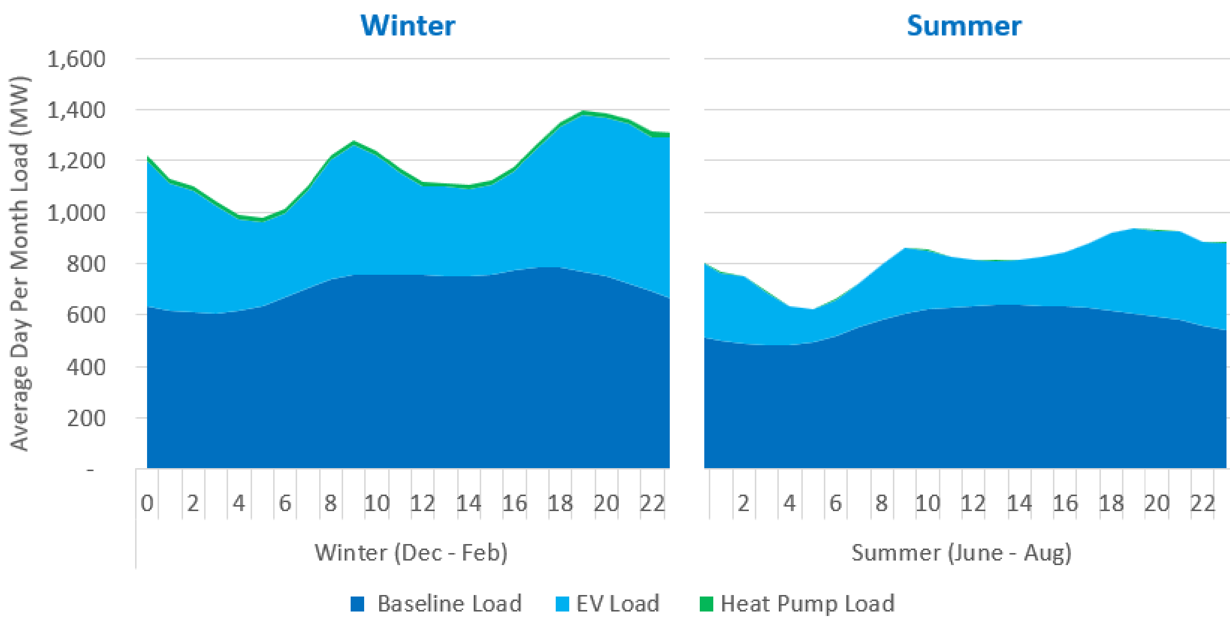

Figure 3.3. Components of Average Daily Load Per Season

the summer when solar production was high. The minimum load was decreased by 62%. The hourly demand change increased by 381%, which was also significantly higher than the increases in total energy and peak load. Additional action through demand management and DERMS, beyond those implemented in the methods of this study may be needed to manage load fluctuations.

Figure 3.3 shows the three components of the moderate load forecast (base load, EV load, and heat pump load) for an average day in winter (December through February) and summer (June through August). The impact of heat pumps on load is expected to be relatively small in the summer and most pronounced in the winter. EVs produce larger increases in load. This is most apparent during overnight periods when vehicle charging is expected. EV loads are also seasonal as a result of lower operating efficiency in colder temperatures. Additionally, no utility or DERMS-managed EV charging are implemented. Electrification results in greater seasonal variability in load (higher loads in the winter) and greater daily variability in load (higher loads overnight).

The net impact of these changes to load on monthly electricity demand and monthly peak loads for the Railbelt system are shown in Figures 3.4 and 3.5 . As discussed, the largest impacts of electrification are seen during the winter months.

These shifts result in a higher maximum and winter load with relatively lower minimum summer loads. This emphasizes the benefits of seasonal energy storage for the Railbelt system. Additionally, distribution system upgrades will

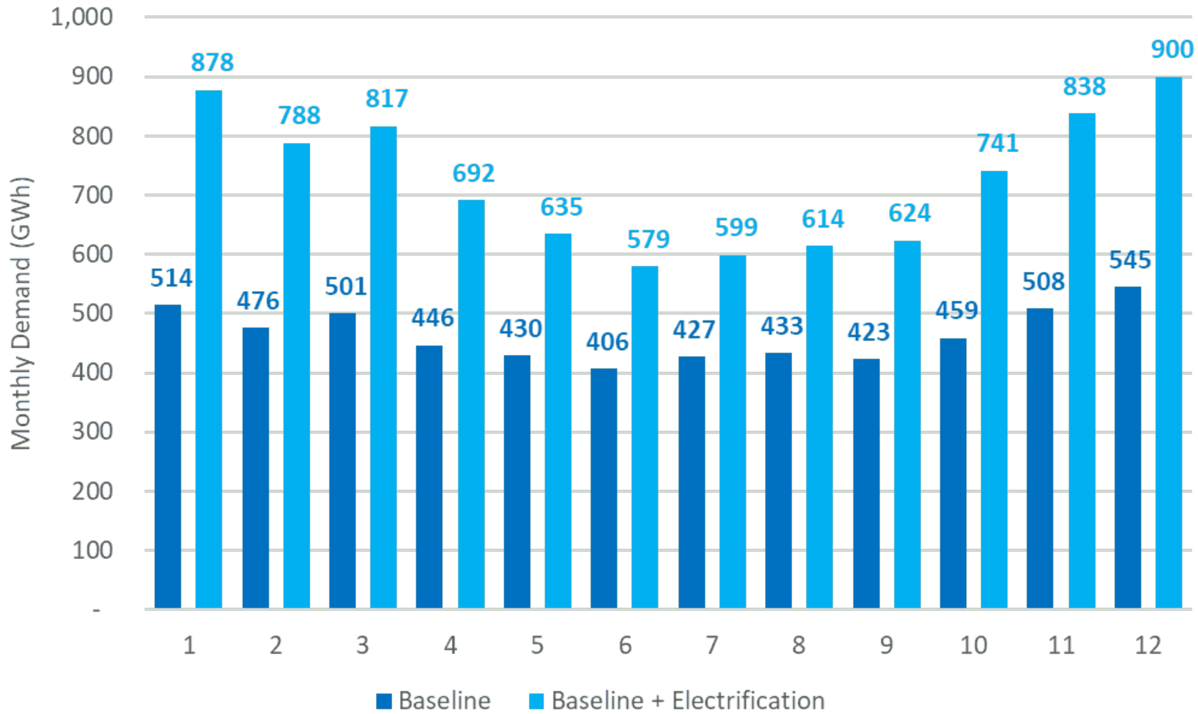

Figure 3.4. Monthly Electricity Demand

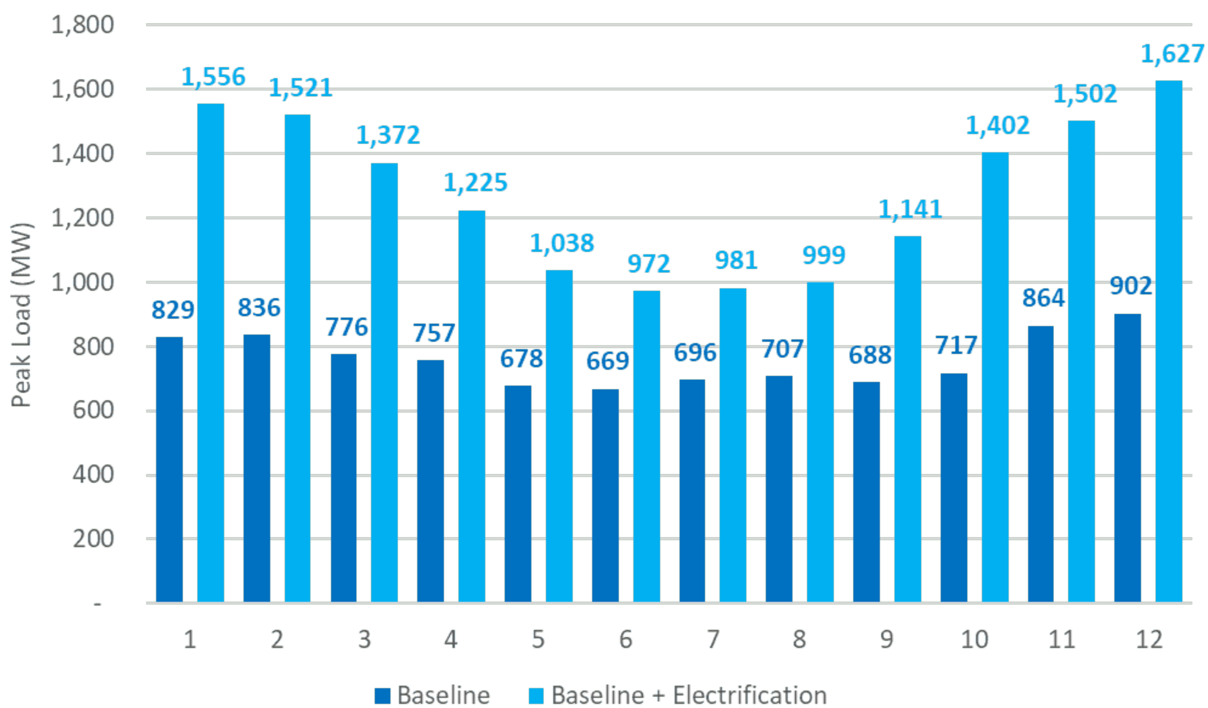

Figure 3.5. Monthly Peak Load

be necessary to facilitate this amount of Behind-the-Meter solar energy, EVs, and heat pumps. The costs associated with distribution system upgrades are not included in this study.

Since the release of the load forecast, which was developed using data and information from 2022, new data are available. However, incorporating this updated data is beyond the scope of this work. Load forecasts are typically updated on a yearly basis, and future studies of the Railbelt electric system should include an update of the load forecast using the best available data and information.

4 Resource Selection and Sizing

4.1 Resource Selection

Wind, solar, tidal, hydro, nuclear, fossil, battery energy storage, and pumped storage hydropower were all considered as possible new resources in this study. All with the exception of pumped storage hydropower were included in at least one scenario. This section describes the inputs, assumptions, and methods used to identify resource sites and/or technologies for each resource as well as their hourly available generation profile where applicable. Section 4 describes how capacity sizes were chosen for each resource in each scenario.

4.1.1 Solar Resources

Solar sites were chosen in each region based on expanding existing sites or as newly identified locations. The new solar resource sites were selected based on proximity to the transmission system and high irradiance from solar resources maps.[18] These sites, which are listed in Table 4.1, are meant to be representative of solar sites in the region and are not meant to propose a specific development project at these sites. The calculation of solar resource data is provided in Appendix E.

Table 4.1. Solar Resource Site Locations.

Site	Region	Latitude	Longitude	Annual Mean Global Horizontal Irradiance (kWh/m^2/day)	Annual Capacity Factor (%)
Nenana	Northern	64.55	-149.09	2.67	12.9
Point Mackenzie	Central	61.36	-149.97	2.57	11.8
Willow*	Central	61.76	-149.98	2.34	10.6
Houston*	Central	61.63	-149.80	2.34	10.6
Sterling	Southern	60.53	-150.76	2.92	14.3

* existing solar site

4.1.2 Onshore Wind Resources

Sites were selected in each region of the Railbelt. Sites that were already developed or that have existing plans for development were included. New wind sites were selected based on proximity to the transmission system and wind speeds viable for wind generation based on wind resource maps from the Global Wind Atlas.[19] These sites are meant to be representative of wind sites in the region and are not meant to propose a specific development project at these sites. Data for the selected wind sites are provided in Table 4.2.

An industry standard General Electric 3.4 MW turbine was selected to model power production at the sites, with an assumed 100-meter hub height. It was assumed that there would be an average of 15% loss in power output from the turbines. Wake losses of 10% are common in wind farms,[20] and 5% was assumed for additional losses, giving a total annual loss of 15%.

The annual capacity factors calculated for the Fire Island and Eva Creek wind sites are higher than current capacity factors. The increase in capacity factor is due to the study assuming taller wind towers that capture higher wind speeds and larger rotor diameters that capture more energy at lower wind speeds.

The calculation of onshore wind resource data is provided in Appendix F.

[18] Denholm et al., *Renewable Porftolio Standard Assessment for Alaska's Railbelt*.
[19] *Global Wind Atlas*. URL: https://globalwindatlas.info (visited on 12/07/2022).
[20] *Reducing Wind Turbine Wakes Could Save Wind Farms Millions*. en. National Renewable Energy Laboratory. Jan. 2022. URL: https://www.nrel.gov/news/program/2022/reducing-wind-turbine-wakes.html (visited on 12/13/2023).

Table 4.2. Wind Resource Site Locations and Assumptions.

Site	Region	Latitude	Longitude	Annual Mean Wind Speed at 100 m (m/s)	Annual Capacity Factor (%)
Eva Creek	Northern	64.055	-148.887	9.57	41
Delta Wind	Northern	64.014	-145.596	6.4	32
Shovel Creek	Northern	64.9528	-148.414	8.5	41
Fire Island	Central	61.139	-150.214	6.33	32
Little Mount Susitna	Central	61.451	-150.951	8.69	45
Houston	Central	61.727	-149.44	7.5	36
Homer	Southern	59.810	-151.574	7.72	39

4.1.3 Tidal Resources

A single tidal resource site was selected for this study in Cook Inlet.[21] NREL studies have identified hourly resource availability at several locations in Cook Inlet.[22] Hourly resource availability data for four sites in Cook Inlet were provided by NREL. The East Forelands site was selected for this study. This site location was chosen due to proximity to Nikiski and the transmission system. A generation capacity of 400 MW was chosen for this tidal site in the Wind/Solar/Tidal scenario to illustrate a high tidal resource scenario. The capacity factor at this location is 42% based on the available data. It is noted that this capacity factor is based solely on resource availability and will likely be lower after results are obtained from field deployments due to maintenance and individual generator capabilities, which would reduce the total yearly energy generation.

4.1.4 Nuclear Generation Sites

Two nuclear generation sites were selected, one in the Northern region in Healy, Alaska and one in the Central region in Beluga, Alaska, to be located near the largest load centers. We analyzed small modular reactor (SMR) and microreactor products from several companies including Oklo, Radiant Nuclear, Ultra Safe Nuclear Corporation, Westinghouse, Terrestrial Energy, and Nuscale Power. The nuclear generators modeled in this study were assumed to be SMRs, due to the greater availability of information and generation characteristics.

The ability to operate nuclear plants as combined heat and power (CHP) plants and extract economic value from the waste heat was not included in this study. Operating as a CHP plant has the potential to increase the economic viability of nuclear energy as well as help decarbonise and reduce costs for heating loads. Modeling how to do this would require a much more detailed investigation into where heating loads coincide with the transmission grid for optimal placement as well as co-optimizing operation to supply both heating and electric loads. Microreactors (under 60 MW) may be a better option for CHP applications. For example, Eielson Air Force Base near Fairbanks is planning to install a microreactor to operate as a CHP plant.

4.1.5 Hydropower Resources

Hydropower locations that were considered in this study were limited to existing sites and proposed sites from previous studies. Existing hydropower sites included Bradley Lake, Cooper Lake and Eklutna Lake. New projects in this study included Grant Lake, Dixon Diversion and Sustina-Watana. Grant Lake is on the Kenai Peninsula, has its final FERC permit, and is likely to be implemented.[23] The Dixon Diversion project would divert water into Bradley Lake and raise the height of its reservoir, which would increase both the amount of energy generated by Bradley Lake in a year by an estimated 49%, and increase the storage capacity of the reservoir from 275 GWh to around 320 GWh. At the time of this report, the Dixon Diversion appears to be likely to proceed and was therefore included in all low-carbon scenarios and BAU. Grant Lake was included in all low-carbon scenarios.

[21] Paul Denholm et al. *Renewable Portfolio Standard Assessment for Alaska's Railbelt*. Tech. rep. NREL/TP-5700-81698, 1844210, MainId:82471. Feb. 2022, NREL/TP–5700–81698, 1844210, MainId:82471. DOI: 10.2172/1844210. URL: https://www.osti.gov/servlets/purl/1844210/ (visited on 08/12/2022).

[22] *Turning the Tide for Renewables in Alaska*. en. Oct. 2021. URL: https://www.nrel.gov/news/features/2021/turning-the-tide-for-renewables-in-alaska.html (visited on 12/09/2022).

[23] *Final Environmental Impact Statement for Hydropower Licenses, Grant Lake Hydroelectric Project—FERC Project No. 13212-005*. en. Tech. rep. FERC/FEIS-0283F. Federal Energy Regulatory Commission, May 2019, p. 408. URL: https://www.ferc.gov/sites/default/files/2020-06/05-01-19-FEIS.pdf.

Susitna-Watana is a proposed large hydropower project that has been studied and debated for over 50 years. The project is controversial and there are strong proponents and opponents. This report does not take a position for or against the project, or any other hydropower project. The Susitna-Watana project was included in the Wind/Solar/Hydro scenario to illustrate the impact of adding a large hydropower project to the Railbelt electric grid.

Table 4.3. Summary of Hydropower Resources.

	Bradley Lake + Dixon Diversion	Cooper Lake	Eklutna Lake	Grant Lake	Susitna-Watana
Maximum Capacity (MW)	120	19.4	40	5	460 - 618[24]
Annual Energy (GWh)	500[25]	60	24	19	2800
Scenarios	All	All	All	low-carbon scenarios	Wind/Solar/Hydro

The generation available from hydropower sites is defined by the maximum capacity of the turbines (shown in Table 4.3) as well as the availability of water to flow through the turbines and generate power. Over the course of a year, water flows into the hydropower reservoir and is stored so that it can be used to generate power when needed. Table 4.3 provides the total annual hydropower energy available by plant that was used in the models. The amount of hydropower energy available at a particular time of year is a function of year-to-date water inflows and generation, limited by the amount of water that can be stored in the reservoir.

In Section 4 (Resource Sizing), all hydropower plants were modeled as having a monthly available energy. This is a common modeling simplification that is used as an alternative to modeling an actual reservoir with water inflows and outflows. In Section 5, Bradley Lake with the Dixon Diversion project was modeled using a reservoir model. Modeling the actual reservoir gave PLEXOS more freedom to optimize its operation.

4.1.6 Fossil-Fuel Generation

Existing fossil-fuels used on the Railbelt include natural gas, coal, diesel, and naphtha. These are burned to power steam turbines, combustion turbines (CTs), and internal combustion engines to generate electricity. Combined-cycle (CC) plants power a steam turbine from the exhaust of a CT to achieve higher efficiencies. Natural gas from Cook Inlet is the primary fossil-fuel in the Southern and Central regions. The Northern region does not have access to natural gas infrastructure and relies primarily on naphtha (a type of refined petroleum) which is produced at a local refinery in North Pole, Alaska and coal from coal mines in Healy, Alaska.[26] Diesel is the most expensive fuel and is rarely used.

Natural gas reserves in Cook Inlet that can be profitably extracted are running out. Hilcorp, the primary natural gas producer in Cook Inlet, recently informed Railbelt electric utilities that it did not have enough gas supply to renew gas contracts. Options to import LNG to replace dwindling supply from Cook Inlet are being investigated by Railbelt utilities. All scenarios with the exception of Wind/Solar/Nuclear scenario assumed natural gas comes from LNG imports. As described in Section 3, the Wind/Solar/Nuclear scenario assumed no LNG imports, with naphtha becoming the least expensive fuel.

In the low-carbon scenarios, all coal plants were assumed to be retired by 2050. The remaining existing installed fossil-fuel generators were assumed to still be available in 2050. In some scenarios new fossil-fuel generators were added. They were used when the new carbon-free resources were unavailable to meet the load and provide adequate reserves. To fully achieve the goal of 100% decarbonization by 2050, all fossil-fuel generators used in dispatch would have to be retrofitted with carbon capture and storage/sequestration capabilities. These retrofits were not included as part of the unit characteristics used by PLEXOS for production cost modeling. Low- or zero-carbon fuels are an alternative to CCS but were not included in this study.

Only announced retirements, such as Healy 2, were included in the BAU scenario, and new generators were added.

[26] *Glossary - U.S. Energy Information Administration (EIA) - Naphtha*. U.S. Energy Information Adminstration (EIA). URL: https://www.eia.gov/tools/glossary/index.php (visited on 12/14/2023).

4.1.7 Lithium-ion Battery Storage

Batteries are currently installed and in use by GVEA, CEA, and HEA. GVEA currently has a nickel-cadmium 25 MW battery capable of up to 40 MW for short periods of time.[27] GVEA has released a Request for Proposals for a new battery system to replace the 20 year old nickel-cadmium system. The Request for Proposals calls for a lithium-ion battery system of up to 100 MVA / 200 MWh or other sizes and capabilities that achieve GVEA's transmission services and renewable integration objectives.[28] CEA currently has a 1 MW / 16.5 MJ flywheel and a 2 MW / 0.5 MWh lithium-ion battery multi-energy storage system used to regulate the 17.6 MW Fire Island wind farm. Joint initiatives are underway to significantly expand CEA/MEA's battery storage capacity. HEA deployed a 46.5 MW / 93 MWh lithium-ion battery in 2022.[29]

Additional battery capacity was included in all scenarios at existing battery locations and at new battery locations depending on the scenario. Available battery durations were 0.5, 2, 6, and 10 hours. Battery power and energy capacities were increased as discussed in Section 4, Section 5, and Section 6 sections.

4.2 Resource Sizing

4.2.1 Methodology

The goal was to determine the generating capacities of candidate resources for each scenario. A Railbelt grid dispatch simulation was written in Matlab. Matlab's fminsearch nonlinear programming solver was used to find the portfolio of capacities that resulted in the lowest system cost by iteratively selecting generating capacities and running simulations. This code will be referred to as the "sizing tool".

The sizing tool was used to select the capacities of new solar, wind, fossil-fuel, nuclear, tidal, and battery energy storage sites. The hydropower projects that were included for each scenario were determined in Section 3 and not sized using the sizing tool. Section 3 determined that there would be significant generation contributions from tidal and nuclear power in the Wind/Solar/Tidal and Wind/Solar/Nuclear scenarios respectively. For the Wind/Solar/Tidal scenario, this was ensured by manually selecting a 400 MW tidal project. At the projected costs for tidal generation, this size of project would not have been built. Similarly for the Wind/Solar/Nuclear scenario, around 500 MW of nuclear energy was built in the sizing tool by artificially increasing the cost of natural gas to $25/MMBtu[30]

Additional details on the operation of the sizing tool are provided in Appendix G.

4.2.2 Financial Parameters

Market value, moderate projection values for the year 2030 from the 2022 NREL Annual Technology Baseline (ATB) were used as optimization inputs to size the various system components. Following completion of the resource sizing in this work, NREL released their 2023 ATB projections, which were generally higher than the projections in 2022. A sensitivity analysis was performed using the 2023 NREL ATB projections, available in Appendix H.

Costs associated with each source of generation and used by the sizing tool can be generally broken down into:

- Capital costs, which are associated with buying hardware and construction, have units of $ per unit of installed capacity ($/MW or $/kW).
- Variable costs, which increase with generation of energy, include fuel and certain maintenance costs. They have units of $ per unit of energy ($/MWh or $/kWh).

[27] *Battery Energy Storage Systems (BESS)*. en-US. URL: https://www.gvea.com/services/energy/sources-of-power/battery-energy-storage-systems-bess/ (visited on 12/16/2022).

[28] *Request for Proposal – EPC Project to Construct Battery Energy Storage System*. en-US. Aug. 2022. URL: https://www.gvea.com/bids/request-for-proposal-battery-energy-storage-system/ (visited on 12/14/2023).

[29] *Battery Energy Storage System (BESS)*. en-US. June 2022. URL: https://www.homerelectric.com/battery-energy-storage-system-bess/ (visited on 12/16/2022).

[30] $25/MMBtu was only used to size the system, while actual fuel cost projections were used in Section 5. This is much higher than the expected cost of natural gas. However, it allowed a significant amount of nuclear energy to be chosen by the sizing tool. It also resulted in a scenario that had the lowest consumption of natural gas, which aligned with the goal of no LNG imports.

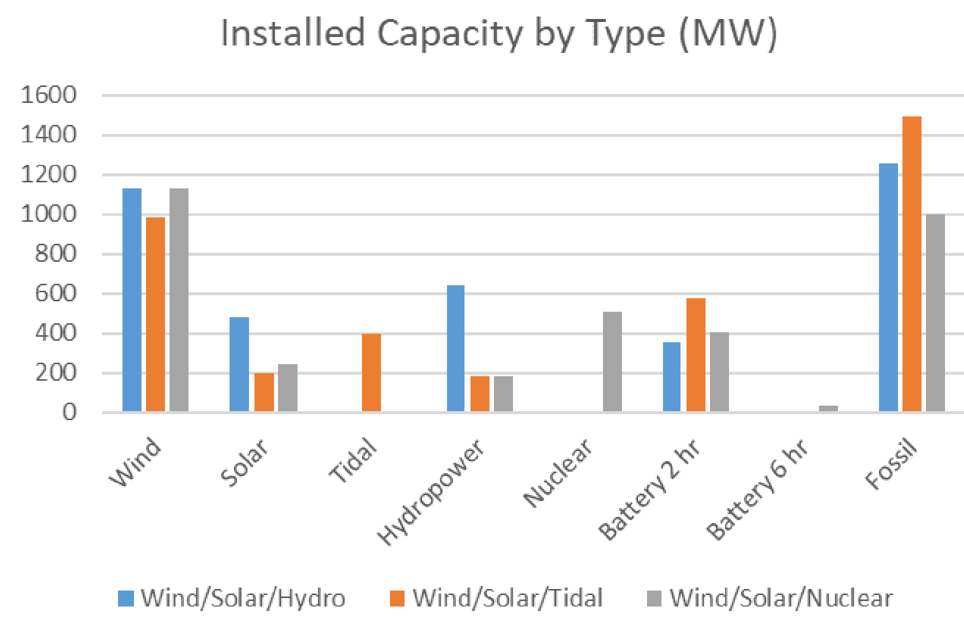

Figure 4.1. Installed system capacity by unit type for low-carbon scenarios.

- Fixed O&M costs are fixed annual amounts such as certain maintenance costs. They have units of $/MW-year, or $/year for a particular unit with a given amount of capacity.

The financial inputs used in this study are available in Appendix I.

4.2.3 Resource Sizing Method Limitations

The sizing of resources for each scenario should be interpreted as a first approximation of a reasonable system and not a fully optimized system. A limited number of technologies were included as available resources for each scenario. The sizing tool was only used to size a subset of available resources while other resources (such as hydropower, tidal energy, and transmission) were not optimized. A simplified methodology was used to size the resources compared to what would be done for actual system planning.

As described in Section 4.1, the wind and solar sites were not fully vetted for project viability and limited quality resource data was available. The sizes of wind and solar systems constructed at each site should not be used to interpret the value of the resource at those particular sites. Instead, they illustrate what a diverse portfolio of wind and solar sites could look like.

See Appendix G for a detailed list of the simplifications and limitations of resource sizing methods and inputs.

4.2.4 Results of Resource Sizing

Figure 4.1 shows the resource portfolios for each scenario by unit type. As noted previously, tidal, nuclear, and hydropower capacities were either predetermined or the sizing tool inputs manipulated in order to achieve the desired level of contribution from each of these resources in the different scenarios. Installed capacity does not directly correlate to share of generation, which will be discussed in Section 5. Fossil-fuel based generators were required in each scenario (this includes existing and new capacity) to serve load. Wind generation had the largest or second largest installed capacity in the scenarios, due largely to its correlation with the Railbelt winter peaking load.

As described in Appendix G, 2-hour batteries were only used to provide reserves to the system while 6- and 10-hour batteries were used to provide reserves as well as time shift excess renewable energy. With the lithium ion battery costs assumed, mostly 2-hour batteries were built, only a few 6-hour batteries were built, and no 10-hour batteries were built.

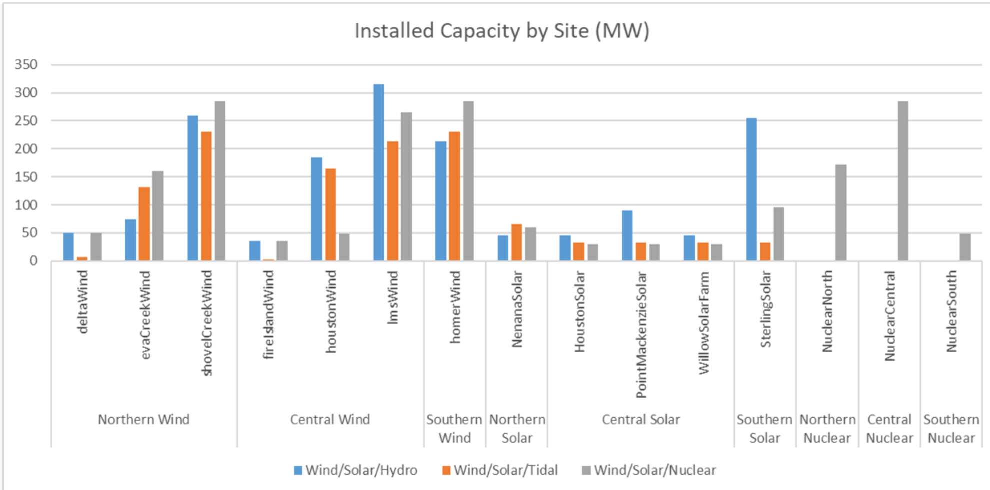

Figure 4.2. Installed system capacity by site.

As described in Section 3, the Wind/Solar/Nuclear scenario was unique in that it assumed no LNG imports. As a result, the cheapest fossil-fuel in the system was either naphtha or natural gas from continued Cook Inlet production, both of which have similar cost projections. This served two purposes. First, it illustrated an alternative to LNG imports. Second, as shown in the sensitivity analyses in Appendix H, the projected cost of nuclear energy meant that it could not compete with LNG, and no nuclear power was built by the sizing tool when LNG was available in the system.

There is a large degree of uncertainty when projecting costs out to 2050. Sensitivity analysis, shown in Appendix H, were conducted to determine the impact of wind, nuclear, tidal, and fuel costs on system sizing. The sensitivity analysis included different assumptions about the availability of an investment tax credit (ITC) for low-carbon technologies. The nuclear and tidal technologies included in the study are not mature technologies with no full-scale commercial deployments at the time of writing. As a result, the availability and cost projections for these technologies are more uncertain than for the other technologies.

Figure 4.2 shows the capacities of each wind, solar, and nuclear site that was sized by the sizing tool. Figure 4.3 plots the wind and solar site capacities against their capacity factors. In general sites with higher capacity factors have larger installed capacities. However, other factors beyond capacity factor impact the selection of resource sizing, including transmission constraints, location and timing of loads, and anti-correlation of resource availability with other sites. Note that these results are based on a rudimentary analysis of the resources-and costs associated with each site. A more detailed analysis may result in a different build out across the different resource sites.

The final sizes of all renewable and nuclear resources are outlined in Table 4.4. Battery and fossil-fuel-based generation capacities are listed in Section 5, where additional battery and fossil-fuel capacity are also added.

The resulting sizes of the various resources built by the sizing tool are due to the interactions of costs, such as capital and variable costs (including fuel costs), and resource characteristics, such as the variability of wind and solar resources and the total yearly energy available from hydropower.

The variable cost of wind and solar generation is close to zero. However, the energy provided is intermittent, so there needs to be enough firm (for example fossil-fuel-based generation, nuclear energy, and hydropower) generating capacity in the system to supply the load when wind and solar power are unavailable. To the extent that existing installed firm capacity can be used, capital costs can be avoided; installing new firm capacity results in additional capital costs.

The more wind and solar power there are in the system, the less energy will be produced from the firm sources of generation. This means the firm sources of generation will have lower variable costs due to decreased fuel usage.

Fossil-fuel-based generation has relatively low capital and fixed costs, but high variable costs. There is already

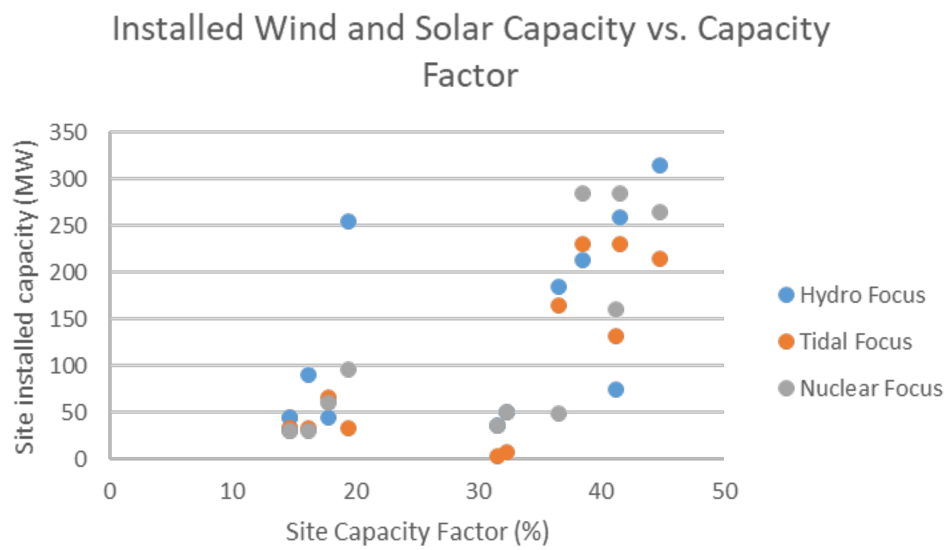

Figure 4.3. Installed wind and solar site capacity vs. capacity factor.

significant fossil-fuel-based generating capacity on the Railbelt that can be utilized as a source of firm power. These qualities make the existing, and in some cases new, fossil-fuel generation a cost-effective source of firm generating capacity to pair with large amounts of wind and solar power. The sizing tool relied heavily on fossil-fuel as a source of firm generation.

The annual amount of energy generation from a hydropower plant is limited by the amount of water that flows into the reservoir serving that plant. The storage supplied by the reservoir provides hydropower plants flexibility in when they generate. Thus, as long as the available water is used to generate electricity, it is cost effective to use constructed hydropower to balance intermittent renewable generation. The sizing tool was not used to decide whether to build new hydropower projects; thus these results only demonstrate the ability of constructed hydropower projects to balance renewable generation, and not the cost effectiveness of building new hydropower projects. Analysis of the system costs for each scenario is provided in Section 7.

Unlike fossil-fuel-based generation, nuclear energy has relatively high capital costs and low variable costs. Thus, running nuclear power at a low capacity factor in order to balance large amounts of variable renewables is not cost effective. Nuclear generation was not always economically viable to construct in the scenarios run in the sensitivity analysis. In the sensitivity scenarios where nuclear generation was constructed, it displaced both variable renewable and fossil-fuel-based generation. In other words, the sensitivity scenarios where more nuclear generation was built resulted in less variable renewable and fossil-fuel-based generation being built. The converse was also true: if less nuclear power was built, more variable renewable and fossil-fuel-based generation was built. This also meant that the sensitivity scenarios that had more nuclear generation had lower carbon emissions than sensitivity scenarios with less nuclear generation due to the reduction of fossil-fuel-based generation.

Energy storage was used to provide reserves and energy arbitrage (charging during periods of excess renewable generation and discharging during periods of low renewable generation). Both of these uses can displace some of the need for firm generation, such as fossil-fuel-based generation. Only lithium-ion batteries with different rated durations were considered. Other thermal, chemical, electro-chemical and mechanical storage technologies were not considered by the sizing tool.

4.3 Resource Selection and Sizing Key Findings

- **Wind and solar are the cheapest source of energy, but the cost of curtailment and energy storage limited their installed capacity.** For the range of costs considered in the system sizing sensitivity analysis, wind

Table 4.4. Final resource sizes (MW) for scenarios and a comparison to the current system.

Resource Type	Resource	Current System	BAU	Wind/Solar Hydro	Wind/Solar Tidal	Wind/Solar Nuclear
Hydro	Susitna-Watana	–	–	459-608**	–	–
	Grant Lake	–	–	5	5	5
	Bradley Lake	120	120	120	120	120
	Eklutna Lake	40	40	40	40	40
	Cooper Lake	19.4	19.4	19.4	19.4	19.4
Wind	Delta	1.9	1.9	50	7	50
	Eva Creek	24.6	24.6	74	132	160
	Fire Island	18	18	36	18	36
	Homer	–	–	213	231	285
	Houston	–	–	185	165	49
	Little Mount Susitna	–	30	315	214	265
	Shovel Creek	–	–	223	231	285
Solar Photovoltaics	Fairbanks	0.56	1	1	1	1
	Houston	8.5	8.5	45	33	30
	Nenana	–	–	45	66	60
	Point Mackenzie	–	–	90	33	30
	Sterling	–	–	255	33	96
	Willow	1.20	–	45	33	30
Behind-the-Meter Solar Photovoltaics	Northern	∼5*	43.3	43.3	43.3	43.3
	Central	∼10*	139.9	139.9	139.9	139.9
	Southern	∼4*	44.3	44.3	44.3	44.3
Tidal	Cook Inlet	–	–	–	400	–
Nuclear	Healy	–	–	–	–	231
	Beluga	–	–	–	–	308

* Estimated by the 2020 number of net meter customers and scaled by estimated growth from EIA Form 861.
** Susitna-Watana maximum power capability depends on the level of water in its reservoir.

and solar resources provided the lowest cost energy. However, they were not able to supply the full load and reliability needs of the system. In all scenarios, some amount of curtailment of wind and solar energy was necessary. In cases with high levels of curtailment the capital costs of wind and solar become prohibitively expensive. While lithium-ion batteries can mitigate some curtailment for use later, it is a relatively expensive upgrade.

- **Fossil-fuel and hydro power generation are more flexible and operate alongside variable wind and solar generation while nuclear generation, is better suited to supply baseload power.** Our analysis showed that the system could not be decarbonized using only variable renewable resources, such as wind and solar power. Some amount of firm source of generation is still required so that sufficient generation is always available. With the technologies considered in this study, fossil-fuel and hydro power generation were the most cost effective firm sources to pair with variable renewables. When nuclear generation was built into system sizing sensitivity analysis scenarios, it displaced both renewable and fossil-fuel sources of generation and was more expensive.

- **Inclusion of nuclear or tidal generation in the system sizing sensitivity analysis scenarios depended on their cost projections.** Nuclear and tidal generation were not built in all system sizing sensitivity analysis scenarios due to their projected costs. There is also significant uncertainty in the projected costs and future commercial availability of these technologies.

5 Production Cost Analysis

5.1 Methodology

The previous section developed portfolios of new energy resources to meet a 2050 decarbonized scenario.

Following the creation of the portfolios, production cost analysis was performed on each scenario for the following reasons:

- To confirm that the resource portfolios generated for each scenario were operable and reliable when considering system constraints and generator properties,
- To tabulate key metrics for renewable integration, including wind and solar curtailment, battery utilization, hydropower scheduling, and thermal generator cycling,
- To calculate variable production costs for further analysis of economic costs and rate impacts (Section 7), and
- To identify appropriate unit commitment and dispatch details for AC power flow stability simulations (Section 6).

The resource sizing process did not consider detailed operating characteristics such as a fully optimized dispatch and generating unit properties (polynomial heat rate curves, and startup and shutdown constraints).

To account for these properties, a PLEXOS production cost model was developed for each of the scenarios in this study. PLEXOS performs a direct current optimal power flow simulation to determine the least-cost dispatch of Railbelt generators for each hour over the year (i.e. 2050) while adhering to constraints on transmission capacity, load served, reserve provisions, generator constraints, maintenance intervals, hydropower availability, and other system characteristics described below. The tool co-optimizes both energy and reserve requirements.

NREL's PLEXOS model from their Railbelt Renewable Portfolio Standard study,[31] CEA's PLEXOS model, and GVEA's PLEXOS model were used as reference points, along with publicly available data from EIA and other sources, to develop a new model of the full Railbelt system in PLEXOS. This model included the grid-connected generators for the four interconnected Railbelt utilities: GVEA, CEA, MEA, and HEA.

5.2 Inputs and Assumptions

5.2.1 Network Topology and Transmission

This study relied on a simplified representation of the Railbelt's transmission network in PLEXOS, utilizing a 'pipe and bubble' model with the three load regions (the "bubbles", Northern, Central, and Southern) connected by the Alaska and Kenai Interties (the "pipes"). The model was constrained by a maximum power transfer (MW) and losses across each intertie. Wheeling charges of $10/MWh on both interties were included in all scenarios.

In the BAU scenario, only the Kenai Intertie was upgraded to 230 kV. This upgrade assumes a maximum thermal limit of 140 MW across the Kenai Intertie. In the low-carbon scenarios, more extensive transmission upgrades were assumed, with both the Alaska and Kenai Interties being upgraded to 230 kV. This creates a 230 kV backbone for the Railbelt. Additionally, a 100 MW HVDC connecting the Central and Southern regions was added in the low-carbon scenarios. A simplified transmission limit between the regions was assumed in PLEXOS in the low-carbon scenarios, with a maximum power transfer of 300 MW between the Northern and Central regiosn and the Central and Southern regions. Table 5.1 summarizes the transmission limits used in the generation analysis section of this study.

As the system is currently stability limited, and is expected to remain so due to the network layout, further analysis was needed to calculate the exact transfer limits of the interties based on system stability with the new generation and network changes of these scenarios. Analysis to evaluate the stability of the system is presented in Section 6.

[31] Denholm et al., *Renewable Porftolio Standard Assessment for Alaska's Railbelt*.

Table 5.1. Alaska and Kenai interties power transfer limits used in PLEXOS modeling.

Scenario	Alaska Intertie Maximum Flow (MW)	Kenai Intertie Maximum Flow (MW)
Current	78	75
BAU	78	140
Wind/Solar/Hydro	300	300
Wind/Solar/Tidal	300	300
Wind/Solar/Nuclear	300	300

5.2.2 Load Profiles

The load implemented in PLEXOS is the baseline load plus the load from EVs and heat pumps, as described in Section 3.2. The value of lost load in each bubble was set to $10,000/MWh to establish financial penalties in the optimization for unserved load.

A more detailed description of the Railbelt load forecast is published in MDPI *Energies*.[32]

5.2.3 Behind-the-Meter Generation

Behind-the-Meter solar energy was modeled as a generator that could not be curtailed. One generator was included in each region on the Railbelt and represented all Behind-the-Meter solar in that region.

5.2.4 Generator Characteristics

Generator characteristics and parameters from NREL's Railbelt Renewable Portfolio Standard study PLEXOS model,[33] CEA's PLEXOS model, GVEA's PLEXOS model, and input from the Technical Advisory Group were incorporated into the PLEXOS model for this study. These characteristics and parameters included assumptions for generator maximum capacity, minimum stable level, fuel type, heat rate, ramp up, ramp down, start cost, forced outage rates, maintenance rates, mean time to repair, hourly running costs, and variable O&M costs.

Unique polynomial heat rate curves were used in PLEXOS for thermal units if provided by stakeholder utilities. These curves allowed for a more accurate representation of a unit's variable costs as opposed to simply modeling the full load heat rate. Full load heat rates are used if polynomial heat rates were not provided. These are based on the NREL, CEA, and GVEA PLEXOS models.

New units were modeled for wind, solar, hydro, tidal, nuclear, storage and fossil-fuels. These varied based on scenario (See Section 4 for additional details).

5.2.5 Generator Retirements

The current Railbelt fossil-fuel-based generation fleet is aging, which can lead to a higher likelihood of generator failures and low flexibility. However, upgrades to components are common in order to allow units to operate for longer than typical lifespans is common. This study assumed few fossil-fuel generator retirements since a detailed unit-level retirement analysis was not performed. The fossil-fleet was used to maintain sufficient installed capacity for reliability as well as to help balance the intermittent generation from renewables.

The BAU scenario included the announced retirement of Healy 2. The remaining scenarios assumed that all coal generation was retired (Aurora Energy and Healy 1). All natural gas and oil generators were made available to serve load, excluding maintenance and forced outages. Existing fossil-fuel generators play an important role in providing sufficient generating capacity in the system, especially with projected load increases due to electrification.

5.2.6 Natural Gas Supply Flexibility

No constraints were modeled on natural gas' flexibility and its ability to meet variable and unscheduled demand. This is not currently the case on the Railbelt, and on any system there will be some constraints. Additional natural gas storage or pipeline flexibility may be needed to enable the flexibility of natural gas use assumed in this study.

[32] Cicilio et al., "Load, Electrification Adoption, and Behind-the-Meter Solar Forecasts for Alaska's Railbelt Transmission System".
[33] Denholm et al., *Renewable Porftolio Standard Assessment for Alaska's Railbelt*.

However, the level of supply flexibility for a LNG-based supply infrastructure is unknown and may provide more flexibility than is currently available.

5.2.7 Hydropower Resources

Hydropower resources at Bradley Lake, Cooper Lake, Eklutna Lake, and Grant Lake were included in all low-carbon scenarios. The Dixon Diversion was included in all scenarios. Susitna-Watana was included in the Wind/Solar/Hydro scenario.

The Susitna River is a major river with important environmental and infrastructure considerations that would limit maximum and minimum water flows throughout the year. Modeled Susitna-Watana dispatch results from Figure E.7-2 of the Alaska Energy Authority's December 2014 report[34] were used to estimate the maximum, minimum and average energy available for each month from Susitna-Watana. The resulting values are summarized in Table 5.2. Total capacity was split across three units of equal size and was sited along the Alaska Intertie.

Table 5.2. Susitna Watana Monthly Model Parameters

Month	Maximum Monthly Power (MW)	Minimum Monthly Power (MW)	Monthly Energy (GWh)
January	460	250	290
February	300	200	175
March	200	100	147
April	200	100	127
May	200	100	131
June	300	100	168
July	375	225	251
August	400	300	282
September	450	300	284
October	450	350	329
November	475	350	337
December	380	300	278
Total			**2,800**

For the Bradley Lake plus Dixon Diversion project, the actual reservoir and water inflows and outflows were modeled. This additional level of detail in the model allowed PLEXOS to more fully optimize the operation of the hydropower plant by using the increased water inflows and increased reservoir storage from Dixon Diversion to integrate large amounts of renewable generation and serve a much higher load than is currently seen on the Railbelt. All other hydropower plants were modeled using a fixed amount of energy available in each month.

5.2.8 Reliability Standards

The two Alaska Reliability Standards relevant for the PLEXOS modeling performed in this study are AKBAL-502-2 Planning Resource Adequacy Analysis, Assessment and Documentation and AKRES-001-2 Reserve Obligation and Allocation.[35] AKBAL-502-2 requires there to be sufficient installed generating capacity on the grid so that the load will be met. AKRES-001-2 requires that the system is operated in a manner that minimizes the risk of an outage. This requires different types of operating reserves that will respond over different time frames to imbalances in generation and demand. See Appendix J for a list of AKBAL-502-2 and AKRES-001-2 requirements.

Sections 5.2.10 and 5.2.11 describe the analyses that were performed to determine the reserves needed in order to meet the Alaska Reliability Standards. These analyses provide a first approximation of reserve requirements. A more detailed study would be required for actual planning purposes.

[34] *Engineering Feasibility Report Executive Summary*. Tech. rep. A11-022. Alaska Energy Authority, Dec. 2014. URL: https://www.susitna-watanahydro.org//wp-content/uploads/2015/01/Section-00-Executive-Summary.pdf (visited on 12/22/2022).

[35] *The Intertie Management Committees' Railbelt Operating and Reliability Standards*.

What are reserves in the context of electricity? Electric utilities need to change the output of their generators based on customer demand. Reserve requirements say how much more energy supply needs to be available than is currently in use. Different types of reserves are needed due to the fact that fluctuations in energy supply and demand happen in multiple timeframes.
The reserve margin is the capacity (ie, expected maximum available supply of electricity) minus the expected peak demand. Utility operators have many considerations at multiple timescales when planning system operation. They may consider weather conditions, the status of their generators, and customer behavior. The amount of unused capacity that operators must have at the ready is set by reliability standards agreed to by all of the Railbelt utilities.

5.2.9 Reserve Margin

A simplified capacity accreditation methodology was established to estimate the reserve margin of each region. This was used to size incremental 6-hour battery storage additions or VTs for reliability purposes to meet the AKBAL-502-2 requirement of a 30% reserve margin. The reserve margin target was set for each of the three regions separately and no credit was given to out-of-region generation to cover the potential loss of the Alaska or Kenai Interties.

This analysis was used as a proxy for a more robust and necessary probabilistic resource adequacy analysis that calculates loss of load expectation (LOLE) and expected unserved energy (EUE), which should be conducted in subsequent modeling and analyses. The reserve margin was calculated for each region as follows.

The reserve margin was calculated using the top 200 load hours (load less wind and solar power) for each region. Within these hours, the average available generation capacity was calculated for each thermal generator type and for hydropower. This became the effective capacity of that generator type. For example, if there were 100 MW of simple-cycle gas turbine (Gas-CT) units in a region, and during the top 200 net load hours only 95MW was available to be dispatched as a result of outages, the Gas-CT effective capacity would be 95 MW.

The 4-hour equivalent capacity was calculated for all batteries. For example, a 100 MW / 200 MWh '2-hour' battery could produce 50 MW for 4-hours if fully charged, therefore its 4-hour equivalent capacity would be 50 MW. The 4-hour equivalent capacity was compared against peak load, and a capacity credit was assigned to each incremental block of storage relative to this load. This was done to account for the impacts of storage saturation on reliability. The assumed capacity credit curve is shown in Table 5.3. For example, if peak load was 100MW and there was 30MW of 4-hour equivalent capacity, the first 20MW of storage (20% of peak load) would be assigned a 95% credit (19MW), while the remaining 10MW of storage (falling into the incremental 20-30% block of peak load) would be assigned a 75% credit (7.5MW). This results in a total effective storage capacity of 26.5MW.

The effective capacity of thermal energy plus hydropower was added to the effective capacity of storage to calculate the region's total effective capacity. The total effective capacity was divided by the region's net peak load to derive a reserve margin. A combination of 6-hour batteries and in some cases new thermal units were added to bring a region's reserve margin up to 30%, if needed. The new batteries were incorporated into the final PLEXOS simulations while the new thermal units were not, as they were assumed to be low capital expenditure (CAPEX), high marginal cost units that would not be called upon in normal dispatch and only required in abnormal situations. CAPEX are capital expenditures including interest during construction. The final battery and fossil-fuel capacities for each scenario are provided in the Sections 5.2.12 and 5.2.13.

Table 5.3. Storage Capacity Credit Curve

Storage Capacity Credit as a Percentage of Peak Load	
Incremental BESS Capacity as a Percentage of Peak Load	**Incremental Capacity Credit Assigned**
<20%	95%
20 - 30%	75%
30 - 40%	50%
40 - 50%	30%
50 - 60%	10%
60 - 70%	5%
70 - 100%	0%

Note that this analysis was used as a proxy for a more robust and necessary probabilistic resource adequacy analysis that calculates loss of load expectation and expected unserved energy,[36] which should be conducted in subsequent modeling and analyses.

This analysis uses each region's peak net load of the year to calculate capacity reserve margin requirements, where the net load is the regional load minus local wind or solar generation. This analysis could also be completed using the gross load in each region, and assume no capacity contribution from renewable energy sources. This is a more conservative approach. If the gross load, instead of net load, was used to calculate the required capacity reserve margin in each scenario, Table 5.4 shows the additional installed capacity that would be required in each region.

Table 5.4. Additional installed capacity required in each region when using the peak gross load to calculate capacity reserve margin.

Scenario	Region	Additional Capacity Required (MW)
Business-as-Usual	Northern	0
	Central	0
	Southern	0
Wind/Solar/Hydro	Northern	40
	Central	35
	Southern	0
Wind/Solar/Tidal	Northern	37
	Central	28
	Southern	0
Wind/Solar/Nuclear	Northern	0
	Central	0
	Southern	0

5.2.10 Regulation Reserves

Currently on the Railbelt there are only a few wind and solar sites and 100% of their generation is backed up with regulation reserves in order to cover uncertainty in their future generation. The low-carbon scenarios include a large amount of wind and solar generation spread over many sites along the Railbelt. Having many sites allows power to be aggregated between sites, and the result is that the net variability in the aggregated power output from those sites is significantly decreased compared to the current day operation. This section describes the updated regulation reserve requirements that were calculated for wind and solar generation in the low-carbon scenarios.

The regulation reserves were designed to cover drops in aggregated wind and solar generation within a 30-minute window. Fast start thermal units on the Railbelt take around 15 minutes to start and 30 minutes is the standard amount of time set aside to for startup. The regulation reserve requirement allows for sufficient dedicated online capacity to cover drops in wind and solar generation before a thermal unit can come online.

In each low-carbon scenario, the maximum drop in the aggregated output of wind and solar generation within a 30-minute window was identified for the entire year. This value was used as the maximum amount of regulation reserves that would be required. Below this value, 100% of wind and solar generation had to be covered with regulation reserves. Some additional analysis had to be performed to estimate this value since most wind and solar resource data was only available in 1-hour averages. This is described in Appendix K.

Figure 5.1 shows the minimum regulation reserve curve for the Wind/Solar/Hydro scenario as an example. The maximum identified drop in the aggregated wind and solar generation within a 30 minute window in the entire year was around 600 MW. Thus, below 600 MW, 100% of wind and solar generation is covered with regulation reserves. Above 600 MW, only 600 MW of regulation reserves is required. Results for all scenarios are in Appendix K.

5.2.11 Contingency Reserves

Contingency reserves are supplied by sources that can provide power when there is an unplanned fault in the system. For example if a generator trips offline, contingency reserves will provide power to the system to make up for the

[36] Derek Stenclick. *Five Principles of Resource Adequacy for Modern Power Systems - ESIG*. Aug. 2020. URL: https://www.esig.energy/five-principles-of-resource-adequacy-for-modern-power-systems/ (visited on 12/19/2023).

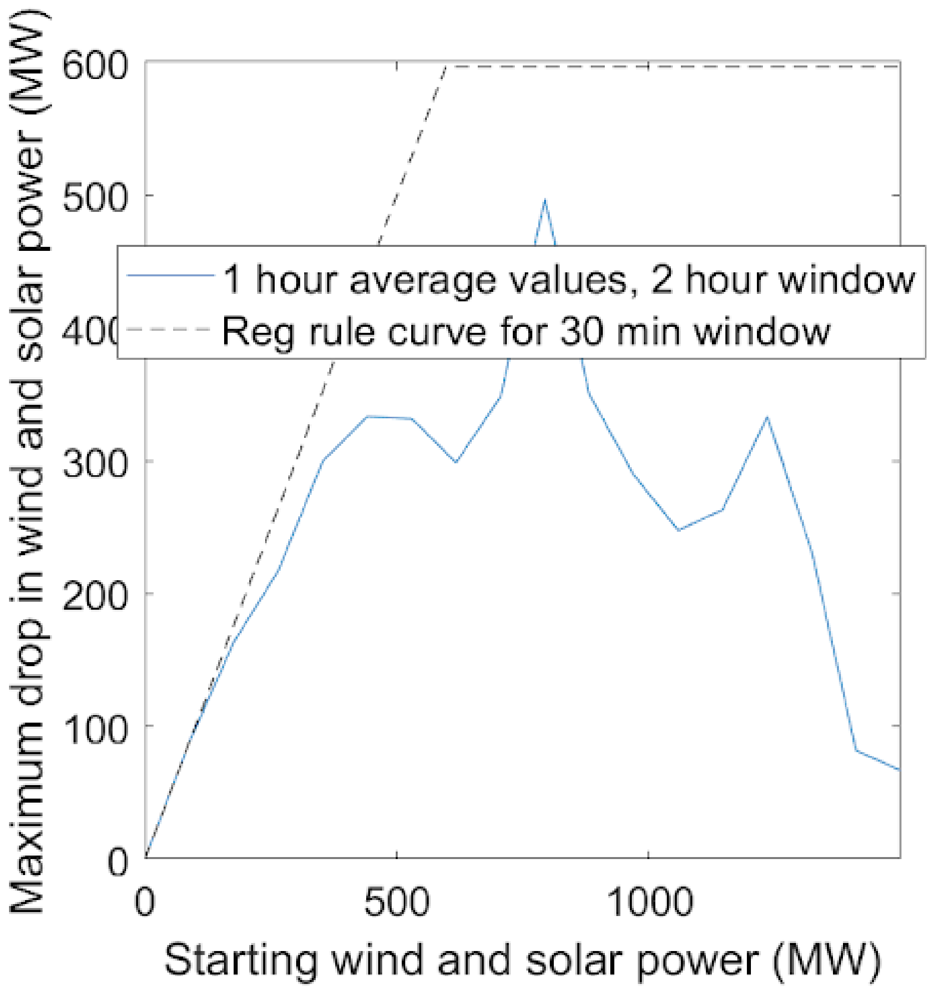

Figure 5.1. Regulation rule curve for the Wind/Solar/Hydro scenario.

lost generation and prevent the system from collapsing. Enough contingency reserves are required on the Railbelt to cover the capacity of the single largest generator (not plant) on the Railbelt. In the model, each region on the Railbelt was required to provide a share of the contingency reserves proportional to its load.

The BAU contingency reserve was set to 90 MW. This was 50% larger than the largest single generator and provided a little extra protection than required by AKRES-001-2. In the Wind/Solar/Hydro scenario, contingency reserves were sized on Susitna-Watana units (206 MW each). In the Wind/Solar/Tidal scenario, contingency reserves were sized on the tidal turbines (assumed to be 200 MW each). In the Wind/Solar/Nuclear scenario, the nuclear reactors were composed of multiple 77 MW modules and the contingency reserve requirements were kept identical to the BAU scenario at 90 MW.

Contingency reserves were not included in PLEXOS to cover transmission line contingencies. Additional battery capacity was added to the system in the Transmission Analysis in order to cover the transmission outages studied in that section.

The Railbelt is a low-inertia system and contingency reserves need to respond within 2 seconds in order to maintain system stability. This is a much shorter timeframe than on larger systems where 10 minutes is sufficient. Each scenario provided adequate response times of contingency reserves in the system by using batteries, which have rapid response times, and through testing contingencies discussed in Section 6.

Appendix L contains details on the implementation of contingency reserves.

5.2.12 Battery Storage

All existing and currently proposed BESS on the Railbelt were included in all scenarios. Section 4 added BESS capacity to provide reserves and time-shift excess renewable generation. Section 5 added BESS capacity (along with thermal capacity) to provide sufficient installed capacity within each region. Finally, Section 6 added BESS capacity to provide frequency and voltage stability. Table 5.5 shows the existing and proposed BESS capacities common to all scenarios. Table 5.6 lists the BESS capacities, which were added by Sections 4 and 5, modeled in PLEXOS. See Section 6 for a description of BESS that were added to the system for stability purposes, but were not modeled in PLEXOS.

Table 5.5. Current and proposed BESS resources that were modeled in Plexos.

BESS Resource	Power Capacity (MW)	Energy Capacity (MWh)
GVEA 2-hr BESS	100	200
CEA 4-hr BESS	70	280
HEA 2-hr BESS	46.5	93

Table 5.6. Capacities of new BESS resources that were modeled in PLEXOS.

Scenario	Region	BESS Name	Power Capacity (MW)	Energy Capacity (MWh)
Wind/Solar/Hydro	Northern	New 2hr GVEA BESS	7	14
		New 6-hr GVEA BESS	100	600
	Central	New 2-hr CEA BESS	78	156
		New 6-hr CEA BESS	200	1200
	Southern	New 2-hr HEA BESS	50	100
Wind/Solar/Tidal	Northern	New 2-hr GVEA BESS	0	0
		New 6-hr GVEA BESS	115	690
	Central	New 2-hr CEA BESS	0	0
		New 6-hr CEA BESS	165	990
	Southern	New 2-hr HEA BESS	80	160
Wind/Solar/Nuclear	Northern	New 2hr GVEA BESS	76	152
		New 6-hr GVEA BESS	96	576
	Central	New 2-hr CEA BESS	0	0
		New 6-hr CEA BESS	165	990
	Southern	New 2-hr HEA BESS	64	128

5.2.13 Installed Fossil-Fuel Capacity

The installed capacity of fossil-fuel-based generation is shown in Table 5.7. These include the existing fleet, excluding retirements and including additions. Natural-gas-powered CC units were added to the fossil-fuel fleet in the BAU scenario in order to meet the higher projected load in 2050 compared to today's load. Natural-gas-powered CTs were added to the Wind/Solar/Tidal scenario to meet the capacity reserve margin requirements. As described in Section 3, the Wind/Solar/Nuclear scenario assumed no LNG imports, and that naphtha, or an equivalently priced locally produced natural gas, was used in for gas-powered units.

Table 5.7. Capacities of installed fossil-fuel generation.

Scenario	**Installed Capacity (MW)**				
	Coal-powered generation	Gas/Naphtha-powered Combined Cycle (CC)	Gas-powered internal combustion (IC)	Gas-powered combustion turbines (CT)	Oil-powered generation
Business-as-Usual	54	1,095	171	568	198
Wind/Solar/Hydro	-	495	171	468	198
Wind/Solar/Tidal	-	495	171	872	198
Wind/Solar/Nuclear	-	495	171	468	198

5.2.14 Single Load Balancing Area

A unified dispatch for the whole Railbelt was used when modeling the scenarios in this study. A unified dispatch tries to minimize cost over the entire Railbelt. In the real world, this would most closely be represented by a single load balancing area for the entire Railbelt. This is different from current Railbelt operation, where each utility tries to minimize their own costs using assets that they own, or by purchasing lower cost power from other utilities. Presently the central region is operated as a power pool but this has not been expanded to other regions.

5.3 Power System Operations

5.3.1 Grid Operations with High Renewables

Modeled future grid operations change markedly between the BAU and the low-carbon scenarios. Figure 5.2 highlights how annual generation by unit type changes over the four scenarios. The most dramatic difference is the displacement of fossil-fuel-based generation with zero-carbon generation in the low-carbon scenarios. This and the following sections evaluate how this changes operation of the power system.

Zero-carbon resources provide between 70 and 96% of the total net energy generation in the low-carbon scenarios. This is a significant increase from the BAU scenario, where only 17% came from zero-carbon sources. Wind is the largest source of generation in each low-carbon scenario.

Small amounts of negative generation from batteries can be seen in the low-carbon scenarios. This is a result of the round trip efficiency losses from charge/discharge cycles. In the BAU scenario, battery storage is typically held at full charge to serve as a source of reserves.

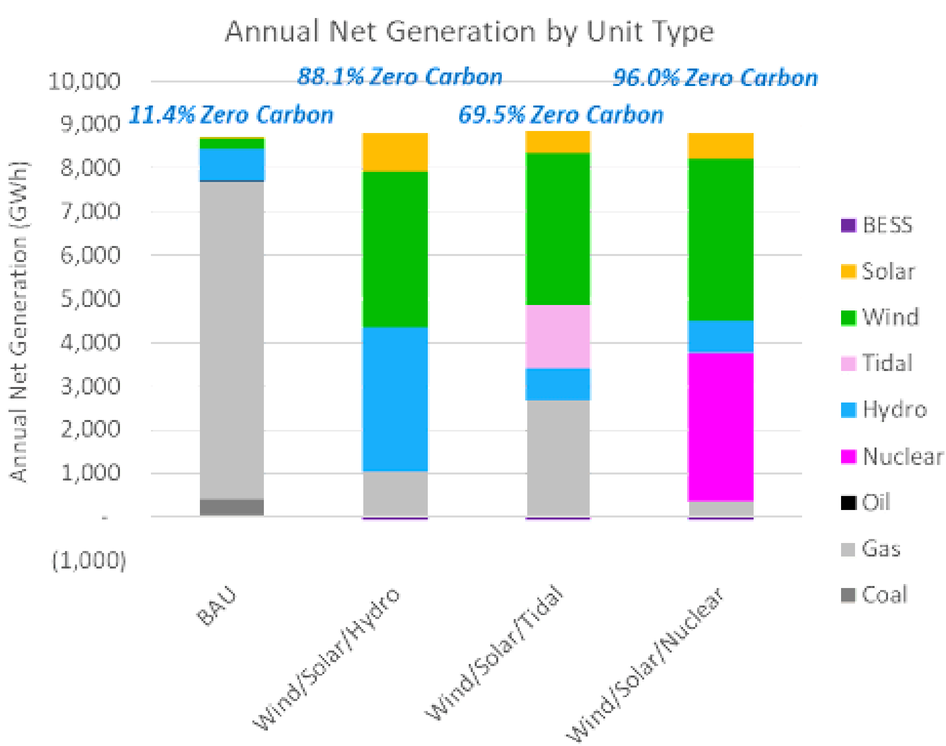

Figure 5.2. Annual Net Generation by Unit Type

Another way to highlight changes across the scenarios is to compare the net change in generation in each scenario, relative to BAU. This is shown in Figure 5.3. Resources that are increasing the amount of generation they contribute are positive (on the right side of thick black line) and those that are being displaced by new resources are negative (on the left side of black line). It is important to note that battery resources are on the left side due to the roundtrip efficiency losses inherent with the technology.

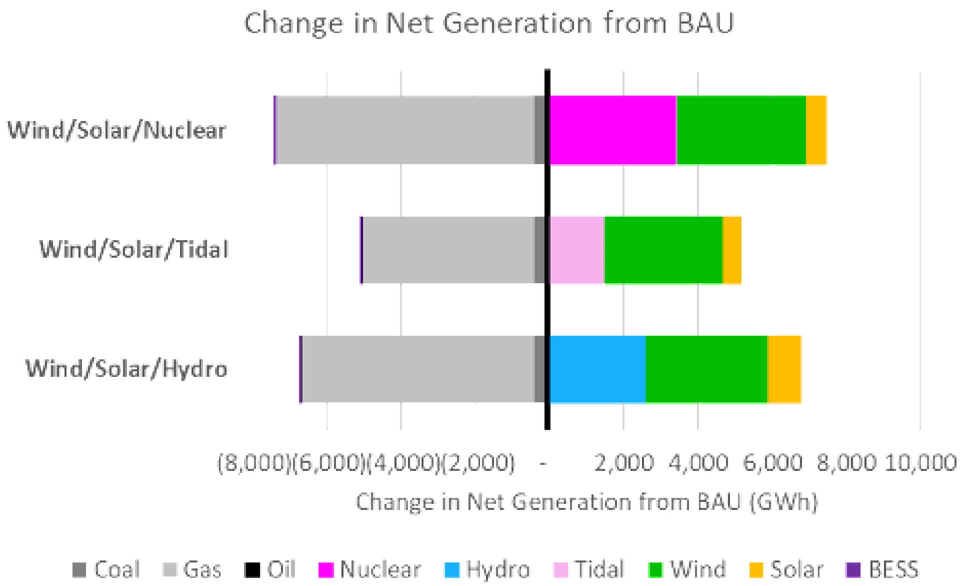

Figure 5.3. Change in Net Generation Relative to Business-as-Usual scenario

While annual generation and displacement values are important for public policy and long-term system planning, they provide little information on day-to-day operations. Because system load changes from hour to hour, and wind, solar and tidal resources are variable, understanding chronological generation by unit and resource type is critical. The production cost analysis performs a chronological commitment and dispatch evaluation of the power grid to minimize system cost – similar to what a grid operator would do on a real system. The commitment determines which units should be online while dispatch determines the MW output from each generator.

Figure 5.4 shows dispatch diagrams for a relatively "normal" winter day of operation for each scenario. The dashed black line shows the load level for each given hour. Battery storage is depicted as two shades; when the battery storage (light orange) is above the black line it is charging, and when it is directly below the black line (light purple) the battery storage is discharging.

There are noticeable shifts in the daily generation profiles between the scenarios, particularly when moving from BAU to the low-carbon scenarios.

For BAU the load is primarily served by fossil-fuel resources. Coal and combined-cycle gas turbines (Gas-CC) act as baseload resources. These resources represent the least cost form of fossil-fuel-based generation. Internal-Combustion gas turbines (Gas-IC) and Gas-CTs are ramped to follow the load. Hydroelectric generation, primarily from Bradley Lake, serves much of the remaining load while available onshore wind and solar PV serve the rest.

In the low-carbon scenarios, zero-carbon generation sources (onshore wind, solar PV, tidal, hydroelectric, and nuclear) supply most of the load. Hydroelectric, nuclear, fossil-fuel, and battery sources are firm sources of power and used to make up the difference between the load and the variable sources of generation. Fossil-fuel generators have the highest variable costs of generation and are used when the other firm sources of power are insufficient. Fossil-fuel-based generation is reduced in the low-carbon scenarios compared to BAU, with Gas-IC and Gas-CT only providing peaking power. Gas-CC is still sometimes used to provide baseload power, especially in the winter when there are high loads. Batteries take on a larger role as load shifting resources. These units are charged during the morning and middle of the day (when load is low and available renewable generation is high) and discharged overnight (when load peaks as a result of EV charging, and renewables generation is less available).

While the figures show a single day of operation across the four scenarios, commitment and dispatch decisions must take into account what occurred previously, and what will occur afterwards. To illustrate this, dispatch diagrams showing weeklong periods are provided in Figures 5.5 and 5.6. These two weeks were selected to highlight how the

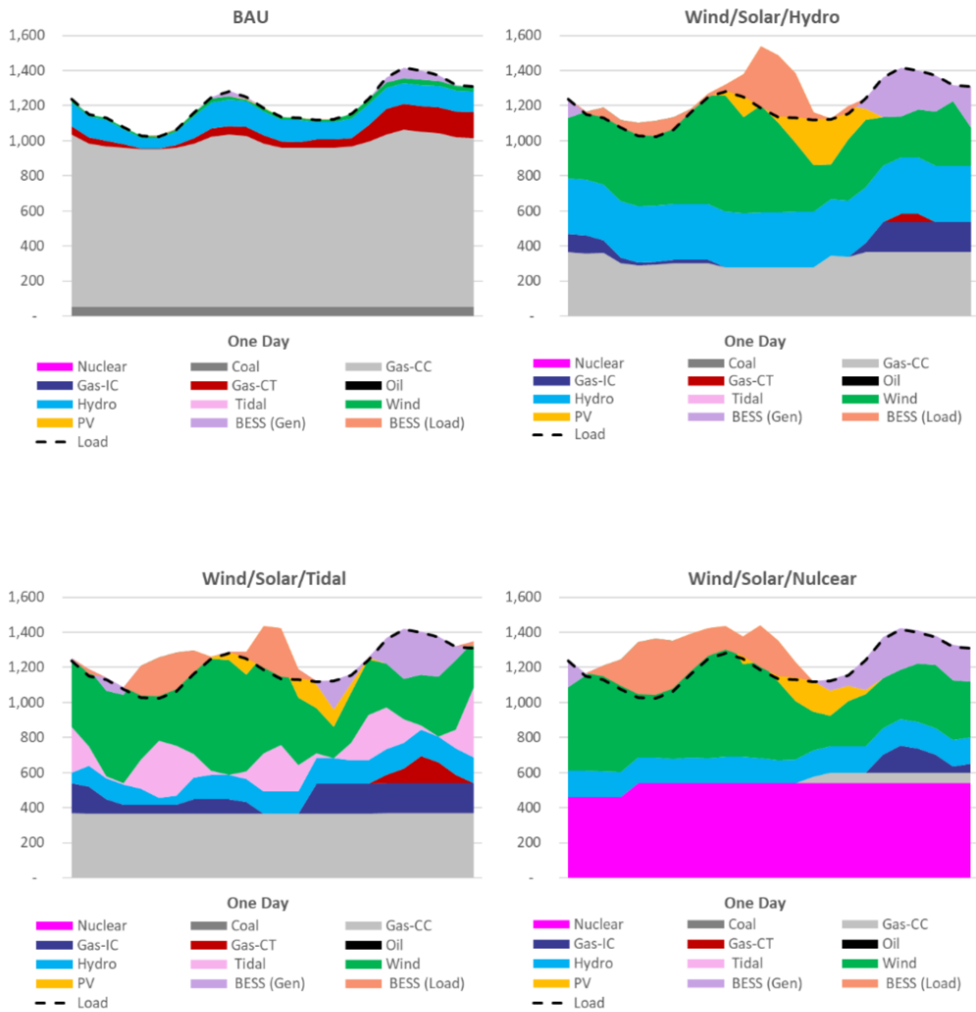

Figure 5.4. Normal Winter Day Dispatch (Wednesday, February 23rd)

system operates during the period of peak load and during the week with the most renewable generation.

These two weeks demonstrate times of little to no fossil-fuel-based generation in the low-carbon scenarios, especially the Wind/Solar/Hydro and Wind/Solar/Nuclear scenarios. This differs from BAU, as well as current system operation. Section 6 describes some of the resulting stability challenges and fixes.

As well as periods with little to no fossil-fuel-based generation, these two weeks demonstrate the variability of the fossil-fuel-based generation as it is used to make up shortfalls in low-carbon generation. This is different from BAU and current day operation, where there is limited flexibility in the natural gas supply. Generator cycling increases in the low-carbon scenarios and is described in Appendix M. It is assumed that the existing lack of flexibility with the natural gas supply is resolved in this study. Costs for this natural gas flexibility ability were not identified.

Hydropower plays a key role as a flexible firm source of power that can help integrate wind and solar resources into the grid while minimizing wind and solar curtailment. In the Wind/Solar/Hydro scenario, hydropower provides a large share of the load. More details on the operation of Sustitna-Watana and Bradley Lake plus Dixon Diversion hydropower sites are provided in Appendix Q.

5.3.2 Operating Reserves

Batteries were the major source of operating reserves in the system, as shown in Figure 5.7. Batteries have a low marginal cost to provide reserves and thus are chosen first in the reserve dispatch. They also have a rapid response

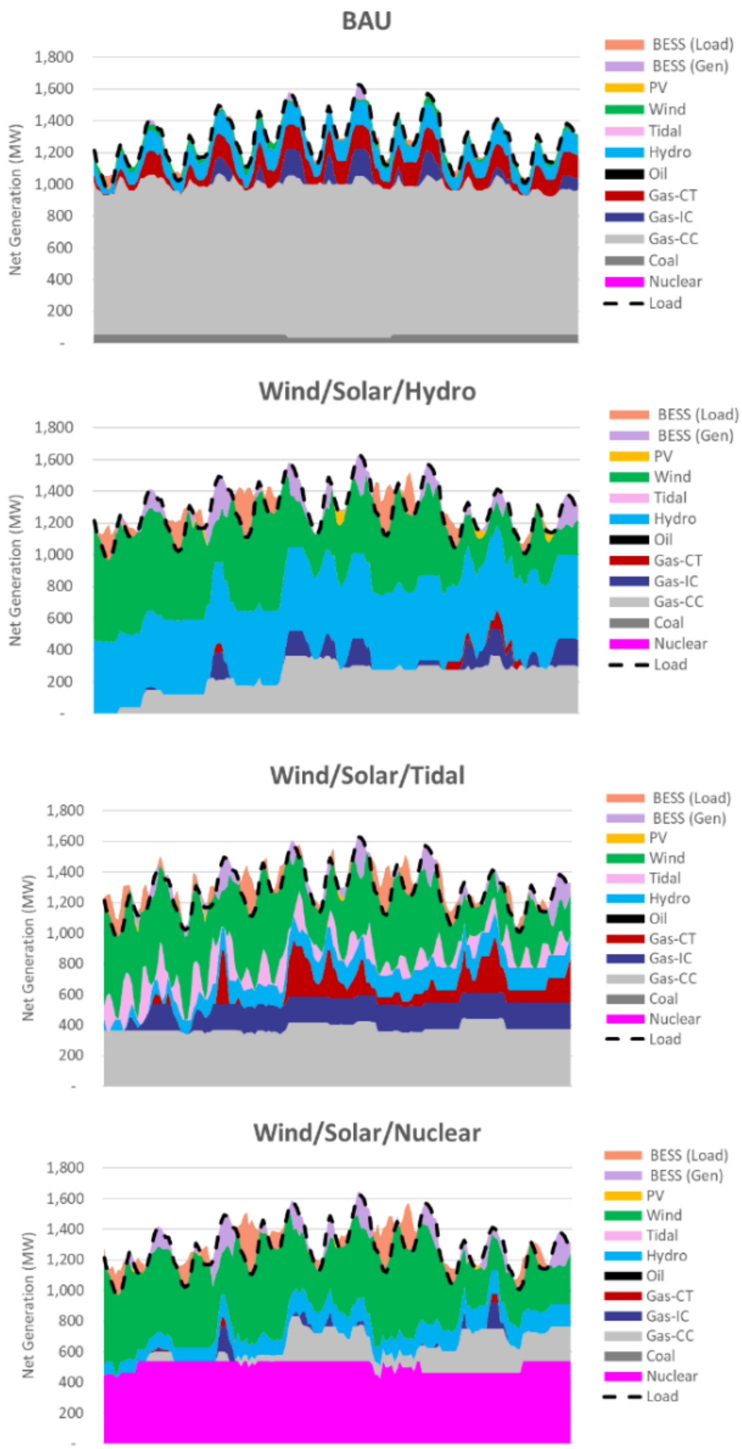

Figure 5.5. Peak Load Weekly Dispatch (Week of December 11th)

time, which is important when providing reserves in a low inertia system like the Railbelt. Even in the BAU, batteries are the main source of reserves. One notable difference between the BAU and low-carbon scenarios is that curtailed wind and solar resources provide some reserves in the low-carbon scenarios, as described in Appendix K.

Figure 5.8 shows the cumulative amount of reserves that is provided within the regions and the amount of reserves that is transferred between regions in each scenario. A notable difference between the BAU and the low-carbon sce-

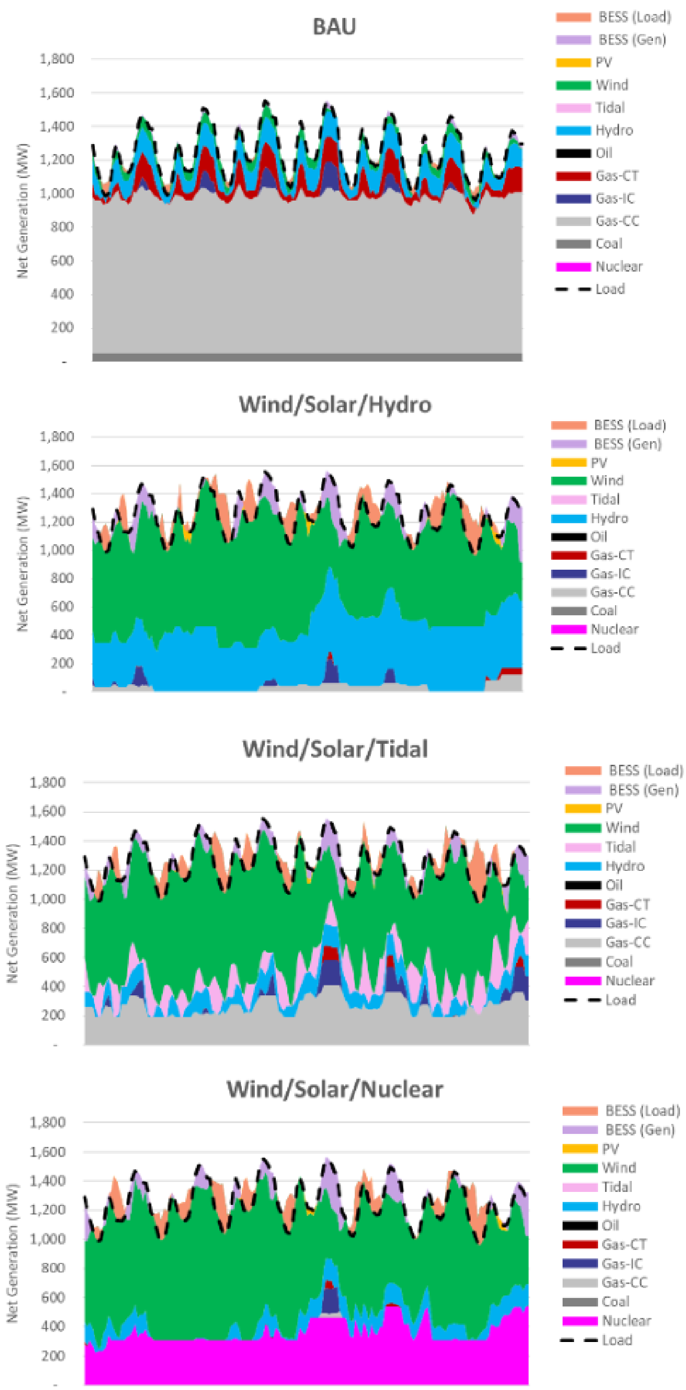

Figure 5.6. Peak Renewables Weekly Dispatch (Week of January 9th)

narios is the amount of imported reserves. Transmission constraints were taken into account when sharing reserves. However, requiring sufficient operating reserves and generation within each region to handle the loss of an intertie without loss of load was not explicitly modeled in PLEXOS. With the higher line rating, there are times when the largest contingency could be the loss of the line, especially if some of the Railbelt's spinning reserve was shared across the network. This potential contingency was evaluated further in Section 6.

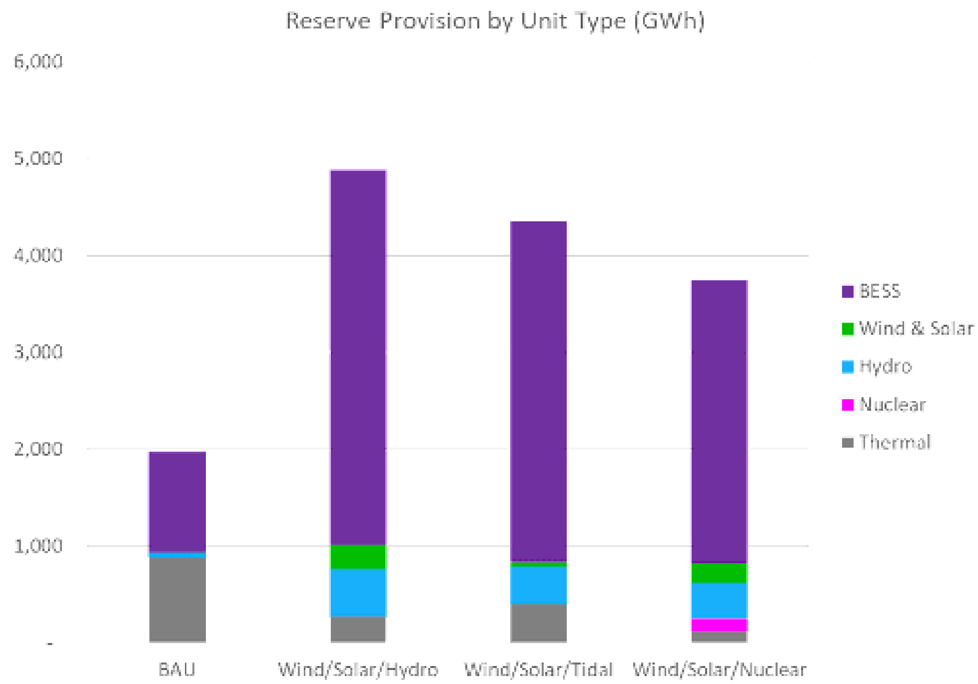

Figure 5.7. Contingency and regulating reserve provision by unit type.

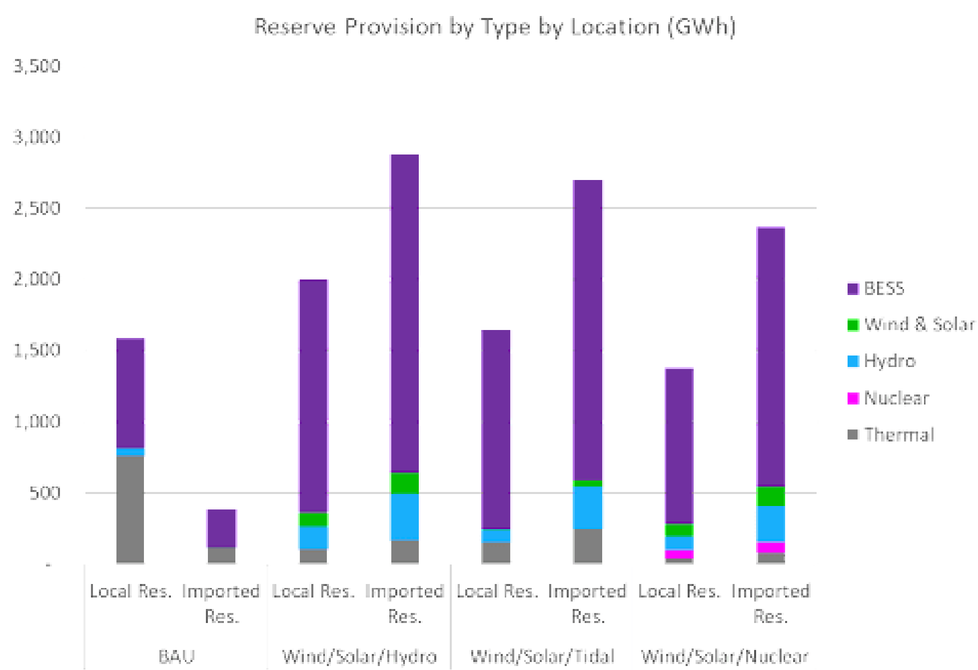

Figure 5.8. Contingency and regulating reserve provision by unit type and location

5.3.3 Renewable Curtailment

One important metric is the overall curtailment, which represents the amount of renewable generation that cannot be delivered to the grid due to oversupply and flexibility constraints. Curtailment can occur for wind, solar, hydro and tidal resources and is often presented as a percentage of total available generation.[37].

[37]Total available generation is calculated based on the resource available at each site, as described in Section 4

Figure 5.9 provides the annual curtailment of wind, solar, hydro and tidal resources, as a percentage of available energy. BAU is not shown given there is zero-curtailment in this scenario; the lower relative amount of zero carbon resources are able to be fully absorbed by the grid. The total curtailment in the low-carbon scenarios range from 1.2% to 7.4% of available generation.

Hydropower generation is said to be curtailed if the amount of energy generated from the hydropower does not match the amount of energy available. In effect, this represents the limited capacity of the reservoir to store water, where insufficient generation from a hydropower site will result in unused water being released down the spillway and not used to generate electricity. The Wind/Solar/Hydro scenario has the most hydropower curtailment, most of which comes from Susitna-Watana.

We assumed nuclear generation could load follow in order to accommodate additional wind and solar resources [38]. Over the course of the year, nuclear resources generated 911 GWh (21%) less than its total available generation in order to accommodate wind and solar generation. If SMR reactors will not be capable of load following and instead will need to operate as baseload generation, curtailment in the Wind/Solar/Nuclear scenario would increase to 27% for wind, 17% for solar, and 1.4% for hydro and be fully replaced with nuclear generation. Since nuclear energy also has a low variable cost of generation, similar to hydro, wind, and solar power, this would only slightly increase the total variable production cost for that scenario.

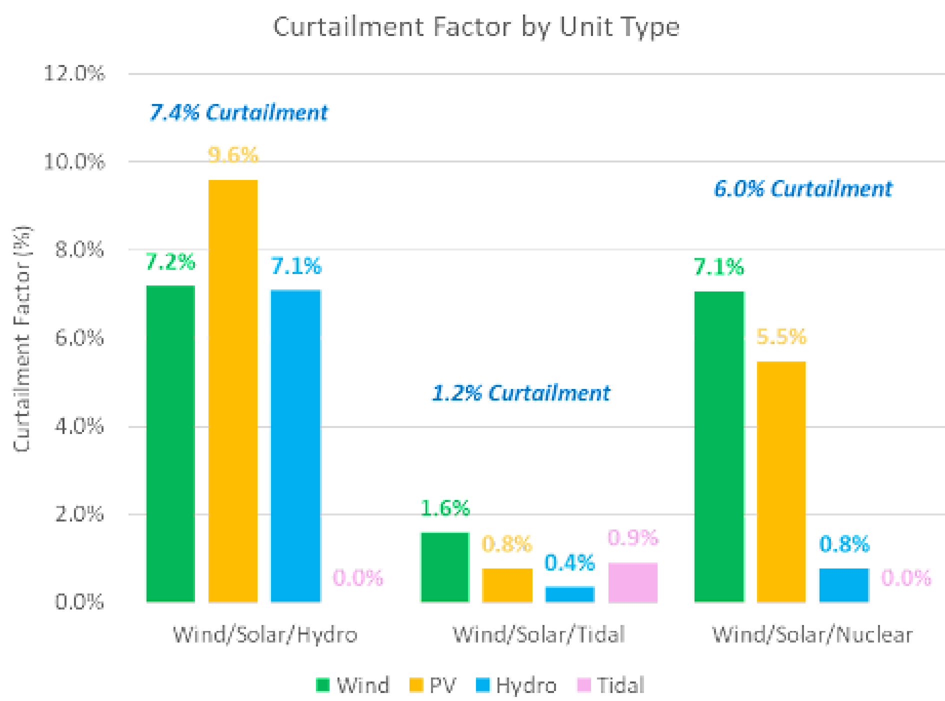

Figure 5.9. Curtailment Factor by Unit Type

Levels of curtailment are mitigated by the amount of battery storage that is added to the systems in the low-carbon scenarios. The charge and discharge cycles of battery storage can be seen in Figure 5.10 which shows the average daily net generation of the battery storage fleet over the course of the year. Positive numbers represent battery discharge and increased generation on the grid, and negative numbers represent charging (or increase in load). Batteries predominantly charge when the load is low and discharge when the load is high in order to displace the more expensive sources of fossil-fuel-based generation that are used to serve peak load. In the BAU scenario, this allows greater utilization of lower cost fossil-fuel-based generation while in the low-carbon scenarios it allows greater utilization

[38] Certain vendors are advertising this capability. For example Westinghouse's AP300 small modular reactor (SMR) is advertised as having "fast load-follow capabilities" which make it "ideally suited for integration with renewables sources." (*Westinghouse Unveils Game-Changing AP300™ Small Modular Reactor for Mid-Sized Nuclear Technology*. en-us. URL: https://info.westinghousenuclear.com/news/westinghouse-launches-ap300-smr [visited on 12/19/2023])

(and less curtailment) of renewable energy sources.

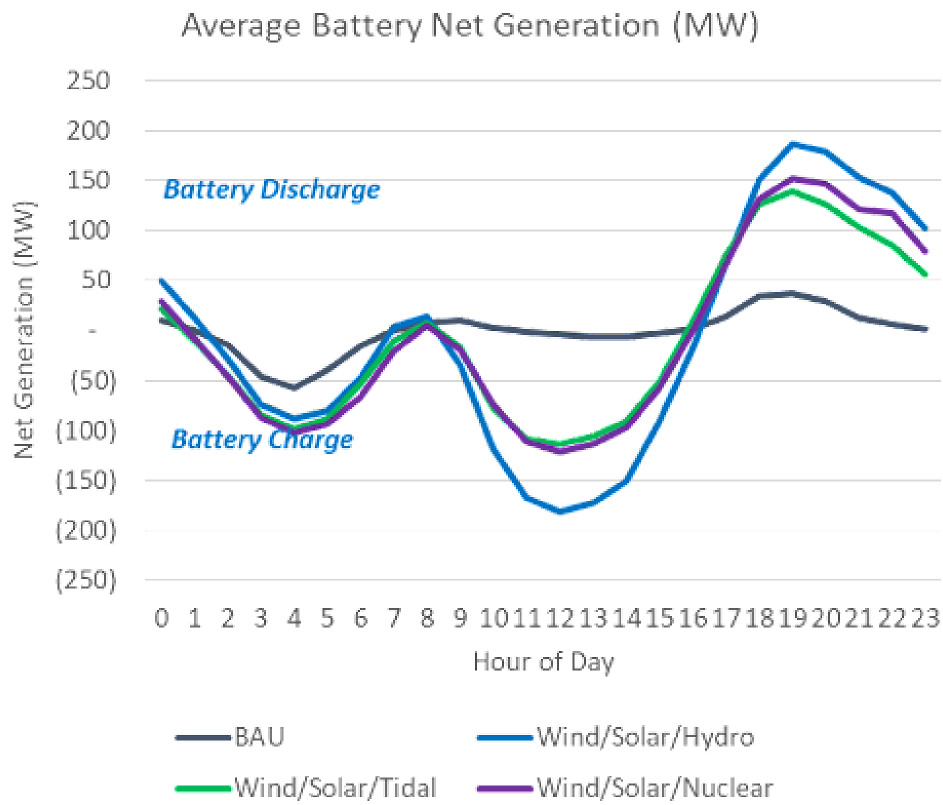

Figure 5.10. Average Daily Battery Net Generation

Figure 5.11 shows the amount of energy at each hour of the day, on average, that is stored in batteries across the Railbelt for use at a later time. The amount of stored energy increases during the low load periods early in the morning and around noon, when the batteries are charging and decreases during the evening peak when the batteries discharge. The greater capacity of installed battery storage in the low-carbon scenarios compared to BAU is seen by the amount of energy that is stored.

5.3.4 Capacity Factor

As discussed in the previous sections, a large amount of fossil-fuel-based generation was displaced by zero-carbon sources in the low-carbon scenarios. However, a significant amount of installed fossil-fuel-based generation capacity was still relied upon to provide power during periods of low generation from variable sources of power including wind, solar, and tidal resources. The result was that fossil-fuel-based generation in the low-carbon scenarios operated at lower capacity factors than BAU. This is especially true in the Wind/Solar/Hydro and Wind/Solar/Nuclear scenarios where the low variable cost of hydropower and nuclear units were given priority in the dispatch over fossil-fuel units. Figure 5.12 shows the annual capacity factor for each source of generation.

5.3.5 Instantaneous Generation from Inverter-Based Resources

While the previous section covers the annual generation and utilization of zero-carbon resources, it is critical to also evaluate the moment by moment operation of these resources across the entire year. This is because wind, solar, tidal and battery resources are IBRs, which connect to the grid through power electronics and rely on fast-acting controls to manage their behavior and provide stable operation. This is different than conventional forms of generation that connect to the grid using spinning synchronous generators which have some innate inertia that helps them maintain stable operation. Due to the variable nature of wind, solar and tidal resources, their maximum instantaneous power penetration (as a percent of total instantaneous load) can be much higher than their annual share of energy generation

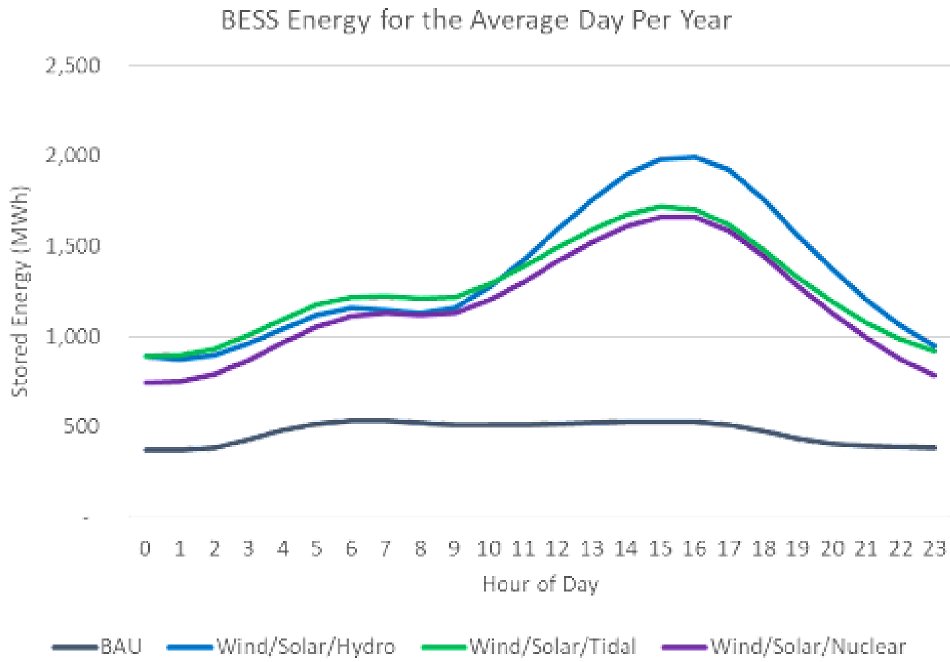

Figure 5.11. BESS Energy for the Average Day Per Year

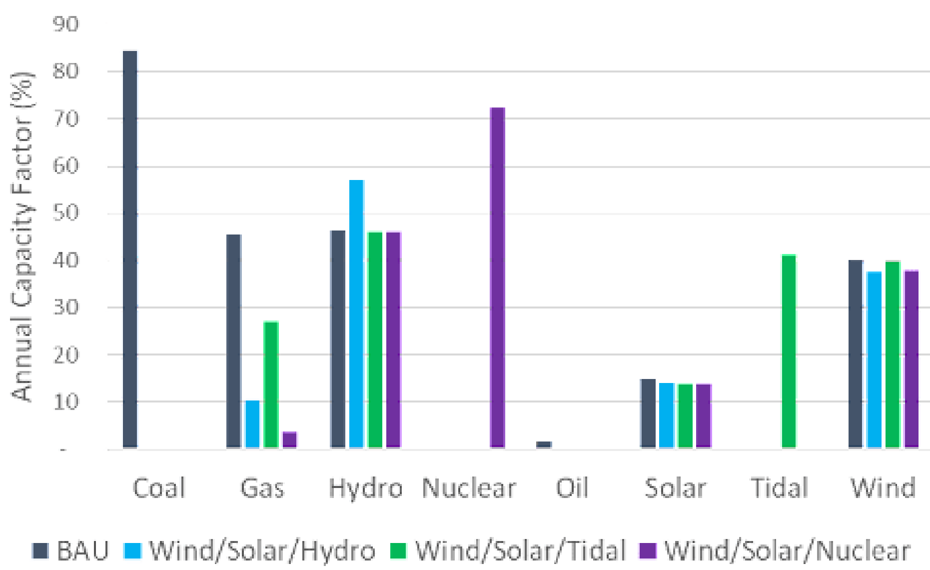

Figure 5.12. Annual Capacity Factor by Generation Source.

(as a percent of total annual load). This higher instantaneous power penetration is what needs to be planned for with additional measures to provide stable operation. These are addressed in Section 6.

Figure 5.13 shows the duration curves of hourly IBR generation (left) and as a percentage of total generation (right). The low-carbon scenarios have much more IBR generation than BAU and at times reach 100% of the total generation. The number of hours operating at or near 100% penetration levels are few. For example, the time spent operating above 90% IBR penetration is 75, 178, and 15 hours in the Wind/Solar/Hydro, Wind/Solar/Tidal, and Wind/Solar/Nuclear scenarios respectively. This suggests some operational changes, such as requiring a minimum amount of synchronous inertia, could be implemented that would mitigate the challenges of high IBR penetration with limited impact on production cost model results.

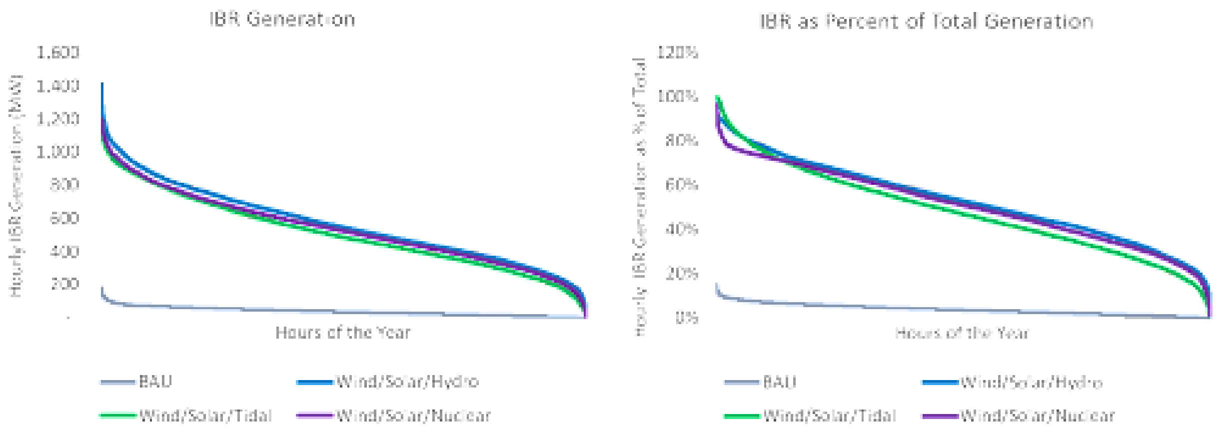

Figure 5.13. IBR Generation (left) & IBR as Percent of Total Generation (right)

Batteries are charged when there is excess renewable generation available. Additional renewable generation that cannot be used is curtailed to prevent overgeneration. Figure 5.14 shows the duration curve of wind and solar generation as a percentage of total load. At times wind and solar alone generate more than the entire load in order to charge batteries. This illustrates the extent to which the batteries are employed in the dispatch, to charge with excess renewable generation.

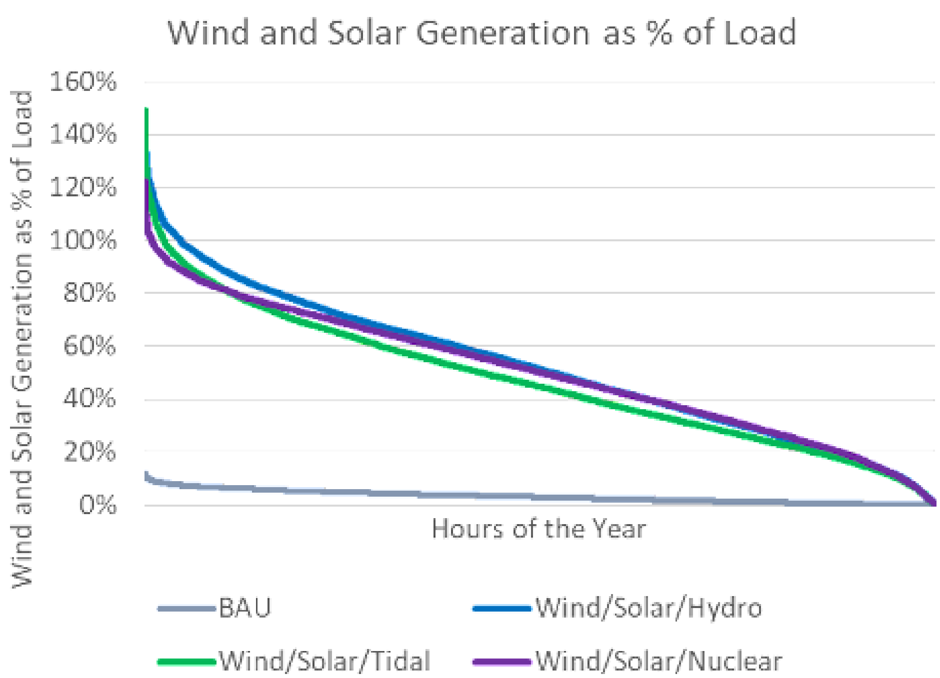

Figure 5.14. Wind and Solar Generation as % of Load for each hour of the year.

5.3.6 Regional Transmission Flows

Increasing the transmission capacity helps support both the higher loads and the greater number of variable sources of power in the low-carbon scenarios. As discussed in Section 5.2, the intertie capacity between regions in PLEXOS was increased to 300 MW in the low-carbon scenarios.

Annual regional flows between the three Railbelt regions are provided in Figure 5.15, where positive numbers represent net exports and negative numbers represent net imports. The net imports and exports increase significantly in the low-carbon scenarios compared to BAU. The increase in net imports and exports is driven by the locations of low variable cost, zero-carbon, resources on the grid. This is illustrated by Figure 5.16, which shows the annual zero-carbon generation in each region as a percentage of that regions annual load. These resources are used within the region first and excess generation is exported to other regions.

Net imports to the Central region increase in each low-carbon scenario, relative to BAU, supplied by an increase in combined net exports from the Northern and Southern regions. As described in Section 4, there is a benefit to distributing variable wind and solar generation somewhat evenly across the entire Railbelt to take advantage of anti-correlation in power generation between sites that are farther away from each other, instead of building most of the capacity in the Central region where the main load is located.

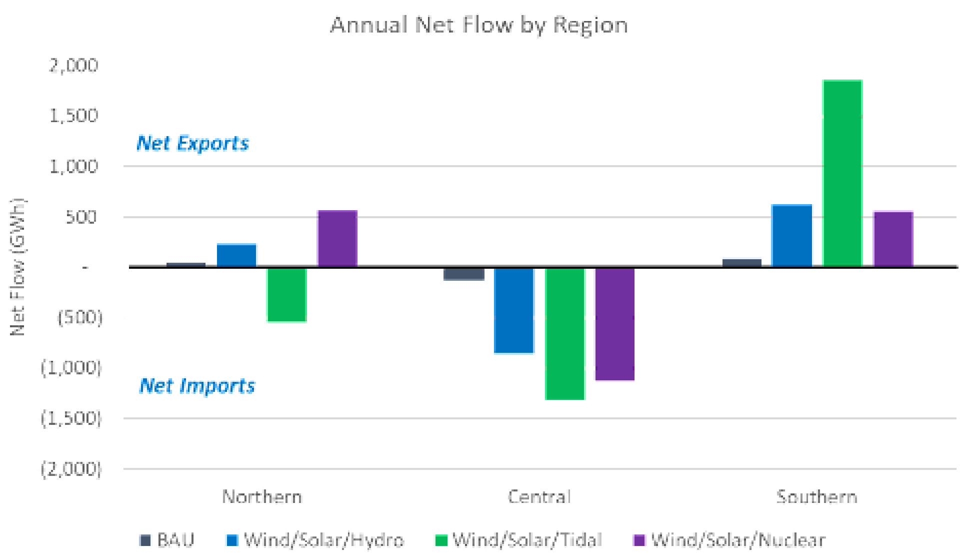

Figure 5.15. Annual net energy flow by region for the four scenarios.

While the total annual net flows by region are shown in Figure 5.15, the range of flows seen on the interties at each hour of the year is shown in Figure 5.17. The flows from each region are sorted from highest (exporting) to lowest (importing). The magnitude of power flows over the interties increases significantly in the low-carbon scenarios compared to BAU, as the Alaska Intertie capacity is increased from 78 MW to 300 MW and the Kenai Intertie capacity is increased from 140 MW to 300 MW.

In most low-carbon scenarios, there are not many hours in the year where the interties are operating near their maximum capacity. The exception is the Kenai Intertie in the Wind/Solar/Tidal scenario, which spends approximately one-third of the year operating at the maximum transmission capacity. This indicates that in the Wind/Solar/Tidal scenario there may be benefits of either adding additional transmission to neighboring regions, or siting other resources, like solar and wind, farther north in the Central and Northern regions. As described in Section 4, the economic value of transmission was not calculated when sizing transmission capacity upgrades in the scenarios to determine if they would lower system costs.

5.4 100% Decarbonization versus Low-carbon

In all of the scenarios evaluated, a percentage of the total energy generated comes from fossil-fuel-based generation. This is a result of the resource sizing which attempted to find the lowest cost system in each scenario. With the technologies and cost projections assumed in the resource sizing, reaching 100% decarbonization would have resulted in much more expensive systems. Therefore these scenarios have been called low-carbon scenarios.

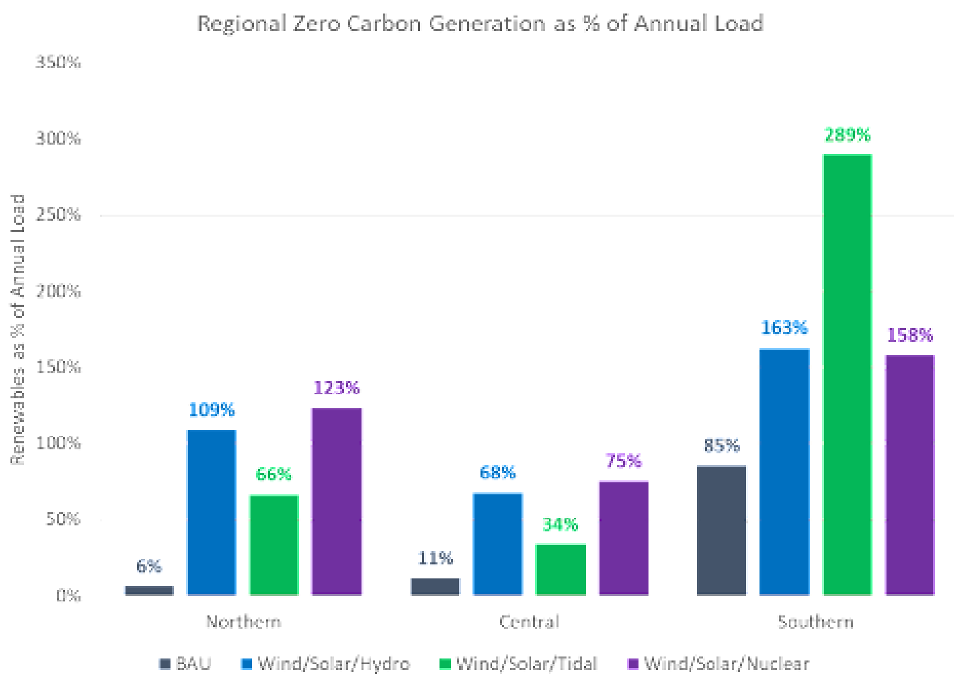

Figure 5.16. Wind and Solar Generation as % of Load for the whole year

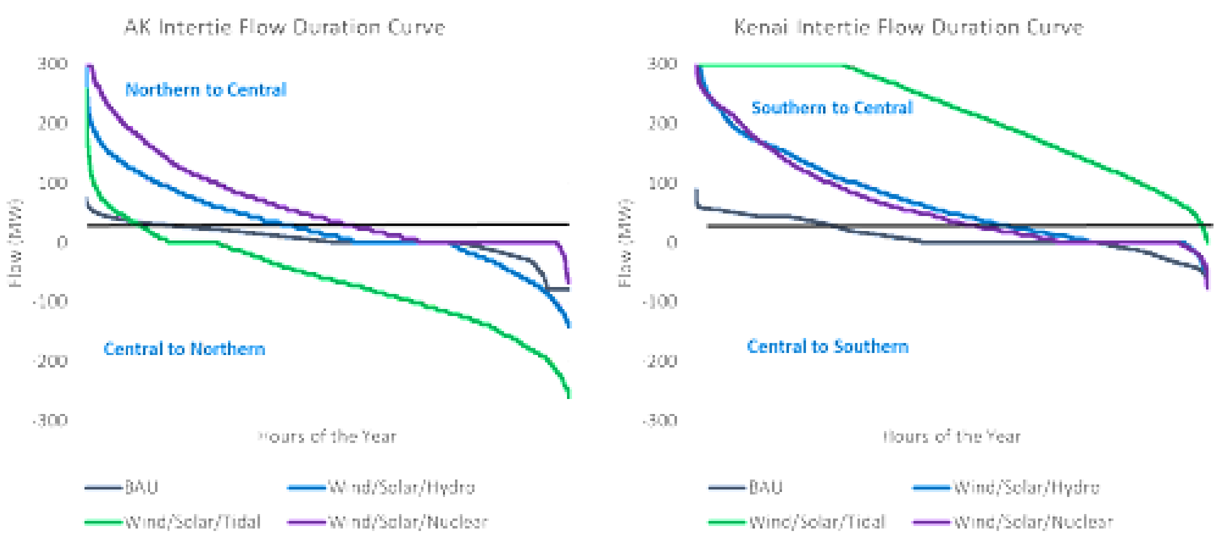

Figure 5.17. AK Intertie Flow Duration Curve & Kenai Intertie Flow Duration Curve

5.5 Production Cost Analysis Key Findings

- **In the low-carbon scenarios 70 - 96% of generation came from zero-carbon sources.** The rest came from fossil-fuel sources of generation. With the technologies and cost projections considered in this study, achieving 100% fossil-free generation would have been more expensive than the low-carbon scenarios in this study. CCS are not 100% effective, and including it would still not result in 100% decarbonization. Other potential options for this could include repowering with hydrogen, biofuels, or synthetic fuels, or using direct air capture, all of which have similar challenges.

- **Low-carbon scenarios represent a significant change in system operation compared to BAU and current day operation.** Due to the variable nature of wind, solar, and tidal energy, a high degree of flexibility must be readily available from firm sources of power. Fossil-fuel, hydropower, battery storage, and nuclear sources are leveraged to various degrees to meet this need. This results in a significant increase in the flexibility required from fossil-fuel sources to be able to serve unscheduled load compared to the BAU scenario and what is possible in the current system. This flexibility from thermal generators will also increase the flexibility needed from natural gas fuel production and transportation. The flexibility to be expected from a LNG import scenario in 2050 is not known and may be more than is in the current gas system on the Railbelt. This flexibility in natural gas production and transportation does not exist under current natural gas tariffs.

- **Increased transmission capacity allows greater power sharing between regions.** The capacities of the Alaska and Kenai Interties were increased to allow 300 MW in the low-carbon scenarios from 140 MW and 78 MW in the BAU scenario. The increased transmission allowed large projects such as Susitna-Watana hydropower, nuclear power plants, and Cook Inlet tidal to power loads across the Railbelt. It also allowed variable wind, solar, and tidal resource sites, spread over the hundreds of miles of the Railbelt grid, to help balance each other and deliver net generation with a lower degree of variability in each region. However, the economic value of transmission upgrades was not analyzed in this study to determine if they resulted in a lower cost system compared to a low-carbon scenario without the upgrades.

6 Grid Stability Analysis

6.1 Introduction

Like all major power systems, the Railbelt system is planned and designed to operate not only during normal operating conditions (all facilities in service) but also with the unexpected loss of any of the facilities. Furthermore, the system must make the transition from a pre-disturbance steady-state operating state to a post-disturbance steady-state operating state. The critical period from the onset of the disturbance to the new operating condition about 20 seconds later is the focus of dynamic stability analysis. In this period, resources must respond very quickly (within a few cycles, which last 1/60th of a second) and provide a consistent response over the ensuing seconds to maintain viability of the system, or multiple separated systems, in the new operating condition. Furthermore, resources across the system must be dispatched so they not only provide an appropriate response within a relevant time frame, but that their controls are aligned to create a stabilizing effect when working together. Achieving this feat for a system as dynamic as the Railbelt electric system requires careful orchestration of resources while respecting the limits of each resource and the transmission system, and consideration of the multitude of potential operating conditions. These stability challenges are amplified when the system runs on high levels of renewables. Achieving grid stability is a core tenant of creating a reliable future system with high levels of renewables.

Why is grid stability important? What do grid operators have to consider to make a system stable?
It's an icy day in Wasilla and your lights keep flickering. You hear that it is due to power lines getting pulled down by the extra weight of the ice. When the flickering gets bad enough, you may notice your television turns off. That flickering is due to grid instability. When a line in another neighborhood goes out, the generators serving the load that is now gone may increase the voltage and frequency output to your house. Your TV turns itself off because it is engineered to work within a narrow range of voltage and frequency, and it is trying to avoid damage by those fluctuations. Components of the electric system, such as generators and transformers, can also be damaged by fluctuations, so they may also disconnect themselves if the system is unstable.
Traditional generators are large, spinning machines. Due to the way that they work, all of the generators connected to a grid must be spinning at the same rate. If any one generator is spinning at a different rate, i.e. it is behaving asynchronously, that generator will damage itself and the other generators in the system. This is somewhat similar to how if you get stuck in snow or ice and one of your tires can't get traction, it will spin much faster than the other tires and your car won't go anywhere, except that instead of getting stuck, the large, spinning generator can tear itself apart.
Replacing damaged components of the electrical system is extremely expensive and can take a long time, increasing both consumer costs and the time your electricity is out. Electric utilities must plan for how they will protect these components from disturbances, whether through physical devices such as fuses and circuit breakers, software, or operational planning. These disconnections, whether due to forces of nature or human decisions, are called "contingencies". Utility operators work hard so that single contingencies don't cascade into multiple contingencies.

6.2 Key Stability Challenges

The primary stability challenges associated with working towards decarbonization on the Railbelt are:

- The transition from a synchronous-machine-dominant to an inverter-based resource IBR system, where the stability of the system depends on software-defined control systems. For significant periods of the year, the grid strength and inertia of the system will be negligible, requiring new means of providing stability to the system.

- The Railbelt's unique topology of three distinct parts of the system interconnected through long AC transmission lines makes major system separation events part of normal planning criteria.

- The Railbelt is a stability-constrained system versus a capacity-constrained system, as is found in larger more interconnected systems such as those in the contiguous United States. In a capacity-constrained system, the generation dispatch is limited by the amount of available resources. Instead, the Railbelt is more similar to other isolated, regional grids such as those in Hawaii. In a stability-constrained system, the operation and build-out of the system is restricted by voltage and frequency stability limits. Operation of the Railbelt and the integration of new resources are constrained by voltage and frequency stability limits.

6.3 Methods and Model Development

The stability analysis in this study was performed with the power system simulation tool Siemens PSS®E. This tool evaluates system stability under both steady-state and dynamic analytic conditions.

Steady-state analysis determines the voltage, voltage angle, reactive power setpoints, and active power setpoints accounting for AC power flows with respective power losses across the transmission system. Steady-state analysis evaluates the system before and after a disturbance to the system, but not during.

Dynamic analysis includes the dynamic machines models and evaluates the frequency, voltage, and other machine states throughout a disturbance. Steady-state analysis is much faster to perform and can be used to screen numerous disturbances, however it may not identify disturbances that the system may not survive due to the dynamic interactions of machines. Dynamic analysis is computationally slower to perform, and is typically performed for only a handful of disturbances such as those expected to cause the greatest disruption to system stability. Both types of analysis are performed for different sets of disturbances in this study.

The generation dispatch of the system is determined by the production cost modeling described earlier in this report. The hourly dispatch is screened for select critical stability hours. The generation dispatch for these selected hours is implemented in the PSS®E model as unique snapshots. The disturbances mentioned earlier are evaluated for each unique snapshot for each scenario.

New generators added to the system were added to the PSS®E model using Western Electricity Coordinating Council standard models. Details of the PSS®E models are outlined in Appendix A. Transmission upgrades were also added to the PSS®E model, following the upgrade lists provided in Appendix A. It is important to note that there are other planned transmission upgrades not included in this report due to either the timing of the upgrade announcement or status of the upgrade with respect to when analysis was performed for this report.

The following sections outline the case selection of critical stability hours, disturbance selection, results, and key findings and mitigating actions to maintain stability.

6.4 Case Selection

Due to significant changes to the load profile and generation resources for the 2050 scenario systems, it is expected that the current traditional summer valley, summer peak, and winter peak seasonal PSS®E models will not fully capture the critical stability snapshots as they do for the current system. The PSS®E models developed for the decarbonization scenarios of 2050 were created from snapshots of the hourly dispatch generated in Section 5 for each low-carbon scenario. The hourly dispatch was scanned to identify critical stability snapshots in times where grid conditions were particularly challenging for maintaining the stability of the system.

These critical stability snapshots include times when the frequency and voltage stability of the system are of concern, including when:

- system inertia is at its lowest
- inverter-based generation is at its highest relative to the amount of synchronous generation
- load is at its lowest and highest (same as traditional seasonal snapshots)
- smallest amount of spinning reserves available
- intertie flows are at their maximum power flow limits

The following metrics were used to screen for critical stability snapshots to implement in PSS®E. The critical stability snapshots are specific hours of the year, pulled from the dispatch created in the previous section. These target hours are those considered challenging from a system operations point of view, because in the event of contingencies the system might suffer large impacts or even collapse.

1. Low and High Load:
   - Summer Valley (SV) - lowest load of year (this is in summer)
   - Winter Peak (WP) - highest load of year (this is in winter)
2. synchronous ratio (SR): The total MVA rating of committed synchronous machines online relative to the total MW output of IBR generation, as seen in Equation 6.1. The lower the synchronous ratio, the higher the stability risk. The snapshot with the lowest synchronous ratio was selected for analysis, and called the minimum synchronous ratio (MSR).

$$SR = \frac{\sum P_{SG,MVA}}{P_{IBR,MW}} \tag{6.1}$$

3. Minimum Synchronous Ratio with Highest Flows (MSRHF) over the interties.

A PSS®E model was created for each critical stability snapshot (SV, WP, MSR, MSRHF).

A detailed breakdown and comparison of the synchronous ratio for each scenario are provided in Appendix D.

For the BAU scenario, only one PSS®E model representing one snapshot was created because the minimum changes resulted in a lower stability risk scenario. The snapshot selected was the MSRHF, with key values shown in Table 6.1. H538 denotes hour (H) number 538 out of 8760 hours in a year.

Table 6.1. Metric and intertie flows in the BAU case.

Metric and Power Flows	BAU at Hour 538
Synchronous Ratio	18.84
Alaska Intertie Flow (MW): Northern to Central	-78
Kenai Intertie Flow (MW): Southern to Central	57.5
Total Load (MW)	1137.2

Similarly, the Wind/Solar/Hydro scenario used both metrics in addition to the generation amount of Susitna-Watana hydropower plant (one hour with low generation and another hour with high generation) and also the direction of flow at the Alaska Intertie. The snapshots selected are summarized in Table 6.2. The hours selected for the Wind/-Solar/Hydro scenario focused on identifying potential stability challenges due to the unique, large Susitna-Watana hydro generator and high intertie flows. Though the SV and WP hours aren't explicitly modeled, H4158 approximates the SV hour and H8266 approximates the WP hour. The hour numbers (H1953, H4158, H7763, and H8266) corresponds to the date and time listed below the hour number in Table 6.2. For the Wind/Solar/Hydro scenario, the hour numbers are used as the name of the snapshot for the analysis performed in this section.

Tables 6.3 and 6.4 list the snapshots used for the Wind/Solar/Tidal and Wind/Solar/Nuclear scenarios, where the names of the snapshots are listed as SV, WP, MSR, and MSRHF.

6.5 Disturbance Selections

The draft Alaska Reliability Standards were used as a basis to assess the stability and reliability of the scenarios. The main standard referenced in this work is AKTPL-001-2.[39] This standard sets requirements to evaluate probable and impactful steady-state and dynamic contingencies to maintain system steady-state and transient stability under those contingencies. Therefore, this study performed limited stability analysis, and a full stability analysis would require analyzing all contingency events as outlined in AKTPL-001-2.

Two types of stability analyses were performed in this work: steady-state and dynamic analysis. A sample of steady-state and dynamic contingencies was identified from the list of planning and extreme events in AKTPL-001-2. This

[39] *The Intertie Management Committees' Railbelt Operating and Reliability Standards.*

Table 6.2. Synchronous ratio, intertie flows, and resource dispatch and capacities for each of the Wind/Solar/Hydro scenario's snapshots.

Resource and Intertie Flows	Snapshot and Dispatch (MW)				Capacity (MW)
	Hour 1953 3/23/2050 9:00:00	Hour 4158 6/23/2050 5:00:00	Hour 7763 11/20/2050 10:00:00	Hour 8266 12/11/2050 9:00:00	
Synchronous Ratio	0.92	0.99	1.49	1.14	-
Alaska Intertie flow: GVEA to CEA	-125.9	93.9	181.9	-114.1	-
Kenai Intertie and HVDC flow: Homer to CEA	261.7	202.7	239.4	233.8	-
Solar Photovoltaics	214.5	67.8	82.4	129.1	480
Wind	382.9	476.1	482.1	646	1199.5
Thermal	377.5	83	172.7	128.5	1296
Distributed Energy Resources	144.3	28.2	41.3	12.2	214.2
Hydro	66.7	77.8	435	380	459

Table 6.3. Synchronous ratio, intertie flows, and resource dispatch and capacities for each of the Wind/Solar/Tidal scenario's snapshots.

Resource and Intertie Flows	Snapshot and Dispatch (MW)				Capacity (MW)
	SV 2050-06-05 05:00:00	WP 2050-12-14 20:00:00	MSR 2050-08-10 17:00:00	MSRHF 2050-07-09 03:00:00	
Synchronous Ratio	1.22	0.24	0	0.01	-
Alaska intertie flow: GVEA to CEA	-95.9	2.9	42	300	-
Kenai Intertie & HVDC flow: Homer to CEA	139	99.8	300	300	-
Solar PV	31.8	0	68.6	0	198
Wind	457.2	377	526.4	720.7	998
Thermal	201	939.88	0	0	1296
DER	13.4	0	72.7	0.2	237.4
Tidal	187.2	0	400	220.4	400
Hydro	0.3	184.4	0	0.3	184.4

is not the full list of planning and extreme events specified and a planning study would need to evaluate the full list of events. As this is a pre-feasibility study, only a sample of events were evaluated. The events chosen are the most severe common events as listed in Table 6.5.

The critical elements referred to in Table 6.5 are listed below:

- Loss of Kenai Intertie: fault at line from Dave's Creek to Quartz
- Loss of Alaska Intertie: fault on the single-circuit line from Teeland to Douglas
- Largest loss of generation in the Southern region
- Largest loss of generation in the Central region
- Largest loss of generation in the Northern region

Table 6.4. Synchronous ratio, intertie flows, and resource dispatch and capacities for each of the Wind/Solar/Nuclear scenario's snapshots.

Resource and Intertie Flows	Snapshot and Dispatch (MW)				Capacity (MW)
	SV 2050-06-05 05:00:00	WP 2050-12-14 20:00:00	MSR 2050-09-16 12:00:00	MSRHF 2050-02-01 19:00:00	
Synchronous Ratio	0.81	0.14	0	0.34	-
Alaska Intertie flow: Northern to Central	34.6	187.7	0	161	-
Kenai Intertie and HVDC flow: Southern to Central	8.5	159.8	0	230	-
Solar Photovoltaics	35.3	0	120.7	0.5	198
Wind	434	464	462	991	998
Thermal	13	376.9	44.1	0	1296
Ditributed Energy Resources	13.5	14.5	15.5	16.5	237.4
Hydro	0.3	149.4	0	92	184.4
Nuclear	308	508	190.8	328	539

Table 6.5. Selected steady-state and dynamic contingencies for planning events for the decarbonization scenarios in 2050.

Steady-State Contingencies	Dynamic Contingencies
• N-1: removal of single transmission line or transformer	• N-1: Fault and clear the subset of known critical elements and those elements with limit violations from steady-state analysis ○ Critical elements: transmission lines connecting regions, largest online generator

The largest loss of generation is the largest generator or group of generators that could be lost due to a single point of failure. Therefore if a group of generators were connected to the grid through a single transformer, that group of generators could be considered to be the largest loss of generation. Currently the largest allowable generating contingency on the Railbelt is 60 MW. For this study, new generating facilities, such as wind and solar facilities, were assumed to have at least two points of interconnection to limit contingency size, however some new generators were larger than 60 MW. The largest generating contingency in this study, therefore, was not limited to 60 MW.

The stability of the system was evaluated by simulating the contingencies listed above and against the stability limits, which are listed below as identified from the 2017 Transmission Plan:[40]

- Voltage
  - ☐ >0.8 per unit (pu) after transient contingencies
  - ☐ > 0.95 pu at steady-state
  - ☐ < 1.05 pu at steady-state for load serving buses, and <1.1pu at steady-state for non-load serving buses
- Frequency
  - ☐ > 57 Hz and < 62 Hz
  - ☐ Oscillations must be damped

[40] David Meyer et al. *Alaska Energy Authority Railbelt Transmission Plan*. Tech. rep. Project #15-0481. Alaska Energy Authority, Electric Power Systems, Inc., Mar. 2017. URL: https://www.akenergyauthority.org/Portals/0/LibraryPublications/Final-transmission-plan-3-6-17.pdf?ver=2017-07-18-134154-497 (visited on 12/22/2022).

- Generation
    - ☐ No loss of synchronism
- Load
    - ☐ Single contingencies must not create loss of load

6.6 Steady-State Stability Analysis Results

Steady-state stability analysis was performed on the Railbelt system to assess its performance during N-1 steady-state contingencies, which includes the loss of each transmission line and transformer above 69 kV in the system. This analysis evaluates steady-state voltage stability and identifies thermal limit violations of transmission lines and transformers. The outcome of the steady-state stability analysis is the identification of necessary battery additions to address voltage limit violations, and line and transformer upgrades to address thermal violations.

Addressing Voltage Violations

Voltage limits are determined by the allowable voltage operating range of the equipment connected to transmission lines or transformers. Operation outside of voltage limits can cause damage to equipment. The voltage limit violations considered were < 0.95 pu and > 1.05 pu at steady-state after each contingency.

The following methods, in priority order, were implemented to eliminate voltage violations:

1. Adjusted the scheduled voltage and reference bus of existing, new, and online generators and shunts
2. Adjusted the HVDC line active power setpoint
3. Added shunt capacitors to the system at locations with consistent low voltage for all or most contingencies
4. Added batteries with only reactive power injection at locations where voltages switched between being too high or too low depending on the contingency
5. Changed the new battery's active power injection to shift power flow across transmission lines

If steady-state divergence and voltage violations persisted after the first two methods above, batteries were added as a reactive power compensation device. Numerous types of reactive power compensation devices are available, including fixed and switched shunts, static synchronous compensators, synchronous condensers, and batteries. There are advantages and disadvantages to each type of device. In this project, batteries were used to alleviate steady-state voltage violations from N-1 contingencies. Batteries were selected because they can provide multiple grid services. In addition to providing reactive power for voltage support, batteries can provide frequency support, and spinning reserves, and can adjust flow across transmission lines by changing the active power injection. Other types of reactive power compensation devices can only provide reactive power for voltage support, or both voltage support and frequency support through inertia for synchronous condensers.

Addressing Thermal Violations

Thermal limits are the power transfer rating for a transmission line based on the capacity and assumed temperature of the line. Increased power flow through a transmission line causes the temperature of that line to rise, which causes transmission lines to expand. Too much power flow can damage the line due to excessive heat and can also cause the line to touch the ground or a tree through expansion. Thermal limits are specific to each line conductor and transformer in the system, and are determined by the electric utilities and embedded in the PSS®E model. When thermal limit violations were identified, the sections of line or transformers were put on a list for upgrades whose costs were added to the total capital cost of the scenario.

Alaska Intertie Redundancy

Additional testing was performed to determine if the double 230 kV circuit was necessary for the Alaska Intertie. Through N-1 steady-state testing, it was determined that the system was N-1 secure with only one 230 kV line connecting the Northern and Central regions. Continued analysis throughout this section follows using a single 230 kV circuit for the Alaska Intertie.

6.6.1 All Low-Carbon Scenarios

In the low-carbon scenarios, transmission line thermal overloading occurred in all sections of the 115 kV Soldotna to Bradley Lake loop in the HEA service territory. This overloading is due to the placement of a large wind facility in the region around Homer, Alaska. The cost of updates was estimated for each of these sections of line. Reconductoring of the lines increased the ratings of the 115 kV lines to 275 MVA for all scenarios.

6.6.2 Business-as-Usual Scenario

Voltage violations were observed in the BAU scenario for contingencies in each region of the Railbelt. These voltage violations were primarily due to an increase in the 2050 load. To alleviate voltage violations, the following general adjustments and additions were made:

- Adjusted shunt and/or generator setpoints for nearby voltage violations
- Adjusted active power setpoint of HVDC line
- Added 50 MVA of voltage support batteries

The capacities of the voltage support batteries added in the BAU scenario are summarized in Table 6.6. Line and transformer upgrades identified as needed to address thermal violations are shown in Table 6.7.

Table 6.6. The capacity of batteries added for voltage support in each region in the BAU scenario.

Region	Battery Capacity (MVA)
Northern	30
Central	15
Southern	5
Total	50

Table 6.7. Total number of transmission line length and number of transformers in Areas with thermal mptioviolations for the BAU.

Area	Transmission Lines: total length (miles)	Number of Transformers
Northern	0	5
Central	1.9	15
Southern	0	0
Total	1.9	20

6.6.3 Wind/Solar/Hydro Scenario

Voltage violations were observed in the Wind/Solar/Hydro scenario in each region of the Railbelt. These voltage violations were due to: 1) an increased load, 2) new locations of large resources (such as wind and hydro) increasing power flows across the two main interties and other transmission lines across the system, and 3) reduction in power generation from fossil-fuel generators near load centers, reducing the available reactive power injection. To alleviate voltage violations, the following general adjustments and additions were made to eliminate violations:

- Adjusted shunt and/or generator setpoints for nearby voltage violations
- Adjusted active power setpoint of HVDC line
- Added 91 MVAR of shunt capacitors
- Added 365 MVA of voltage support batteries
- Added one transformer at Soldotna substation

The ratings of the capacitors and voltage support batteries added in the Wind/Solar/Hydro scenario are summarized in Table 6.8. Line and transformer upgrades identified, as needed, to address thermal violations are listed in Table 6.9.

Table 6.8. Capacity of capacitors and batteries added for voltage support in each region in the Wind/Solar/Hydro scenario.

Region	Battery Capacity (MVA)	Capacitor Capacity (MVAR)
Northern	80	22
Central	105	15
Southern	180	54
Total	365	91

Table 6.9. Total transmission line length and number of transformers for each area with thermal violations in the Wind/Solar/Hydro scenario.

Region	Transmission Lines: total length (miles)	Number of Transformers
Northern	12.4	9
Central	33.3	12
Southern	75.8	1
Total	121.5	22

6.6.4 Wind/Solar/Tidal Scenario

Voltage violations were observed in the Wind/Solar/Tidal scenario in each region of the Railbelt. Similar to the Wind/Solar/Hydro scenario, these voltage violations were due to 1) an increased load, 2) new locations of large resources (such as wind and tidal) increasing power flows across the two main interties and other transmission lines across the system, and 3) reduction in power generation from fossil-fuel generators near load centers reducing the available reactive power injection. To alleviate voltage violations, the following general adjustments and additions were made:

- Adjusted shunt and/or generator setpoints for nearby voltage violations
- Adjusted active power setpoint of HVDC line
- Added 75 MVAR of shunt capacitors
- Added 140 MVA of voltage support batteries Added one transformer at Soldotna substation

The capacities of the voltage support batteries for each snapshot of the Wind/Solar/Tidal scenario to secure N-1 contingency are summarized in Table 6.10. Line and transformer upgrades identified as needed to address thermal violations are shown in Table 6.11.

Table 6.10. Capacity of capacitors and batteries added for voltage support in each region in the Wind/Solar/Tidal scenario.

Region	Battery Capacity (MVA)	Capacitor Capacity (MVAR)
Northern	40	10
Central	50	60
Southern	50	5
Total	140	75

6.6.5 Wind/Solar/Nuclear Scenario

Voltage violations were observed in the Wind/Solar/Tidal scenario in each region of the Railbelt. Similar to the Wind/Solar/Hydro and Wind/Solar/Tidal scenarios, these voltage violations were due to 1) an increased load, 2) new locations of large resources (such as wind and nuclear) increasing power flows across the two main interties and other transmission lines across the system, and 3) reduction in power generation from fossil-fuel generators near

Table 6.11. Total transmission line length and number of transformers in each area with thermal violations in the Wind/Solar/Tidal scenario.

Region	Transmission Lines: total length (miles)	Number of Transformers
Northern	20.8	11
Central	30.9	17
Southern	172.5	2
Total	224.2	30

load centers reducing the available reactive power injection. To alleviate voltage violations, the following general adjustments and additions were made:

- Adjusted shunt and/or generator setpoints for nearby voltage violations
- Adjusted active power setpoint of HVDC line
- Added 185 MVAR of shunt capacitors
- Added 788 MVA of voltage support batteries
- Added one transformer at Soldotna substation

The capacities of the voltage support batteries for each snapshot of the Wind/Solar/Nuclear scenario to secure N-1 contingency are summarized in Table 6.12. Line and transformer upgrades identified as needed to address thermal violations are shown in Table 6.13.

Table 6.12. Total number and capacity of batteries added for voltage support in each area in the Wind/Solar/Nuclear scenario.

Region	Battery Capacity (MVA)	Capacitor Capacity (MVAR)
Northern	224	15
Central	548	145
Southern	16	25
Total	788	185

Table 6.13. Total transmission line length and number of transformers in areas with thermal violations in the Wind/Solar/Nuclear scenario.

Region	Transmission Lines: total length (miles)	Number of Transformers
Northern	6.8	13
Central	105.2	25
Southern	119	2
Total	231	40

6.7 Dynamic Stability Analysis Results

Dynamic stability analysis was performed on the Raibelt system to assess performance during critical events for the specified critical snapshots provided in Tables 6.1 through 6.4. Results of the stability analysis for each scenario are provided in the following sections.

6.7.1 Business-as-Usual Scenario

For the BAU scenario, Table 6.14 summarizes the specific list of contingencies applied to the MSRHF critical stability hour.

Table 6.14. Dynamic contingencies applied at BAU scenario.

Contingency Type	Location	Element
Line fault	Kenai Intertie	Dave's Creek to Quartz 230kV line
Line Fault	Alaska Intertie	Teeland to Douglas 138kV line
Loss of generation	Northern (GVEA)	North Pole Full CC) - Gas-generation
Loss of generation	Central (CEA)	Southcentral Power Project (CC) - Gas generation
Loss of generation	Southern (HEA)	Bradley Lake Unit 2 - hydro generation

Summary of Dynamic Analysis for BAU Scenario

No mitigations were required to create a stable system response for the contingencies for the MSRHF hour that was simulated. Only model adjustments were required to make the model better represent current system operations. The model changes included 1) adjusting the load-shedding scheme at the Chena substation to allow the connected generation to stay online and only the load to be shed during operation of the load-shedding relay, and 2) changing the dynamic model of the Wilson battery in the Northern region from a user-defined model to a generic model tuned to provide the necessary stable system response. A model adjustment for the Wilson battery would be expected with any updates to either the controls or design of the Wilson battery, which are currently planned under GVEA's Strategic Plan.

The detailed analysis for each contingency for the MSRHF hour is provided in Appendix O.

An example of the analysis, plots of the system response, and model changes made to verify stable operation for the loss of the Kenai Intertie are provided below.

Loss of Kenai Intertie

The loss of Kenai Intertie was simulated by applying a permanent fault to the Quartz to Dave's Creek line and then removing the entire line 0.1 seconds after the fault. With the onset of the fault, the Southern region was isolated from the rest of the Railbelt system. This separation is visible in the representative system frequencies in Figure 6.1, where, once the line is removed, the Southern region has a brief over-frequency deviation while the Central and Northern region have an under-frequency deviation before settling back to nominal.

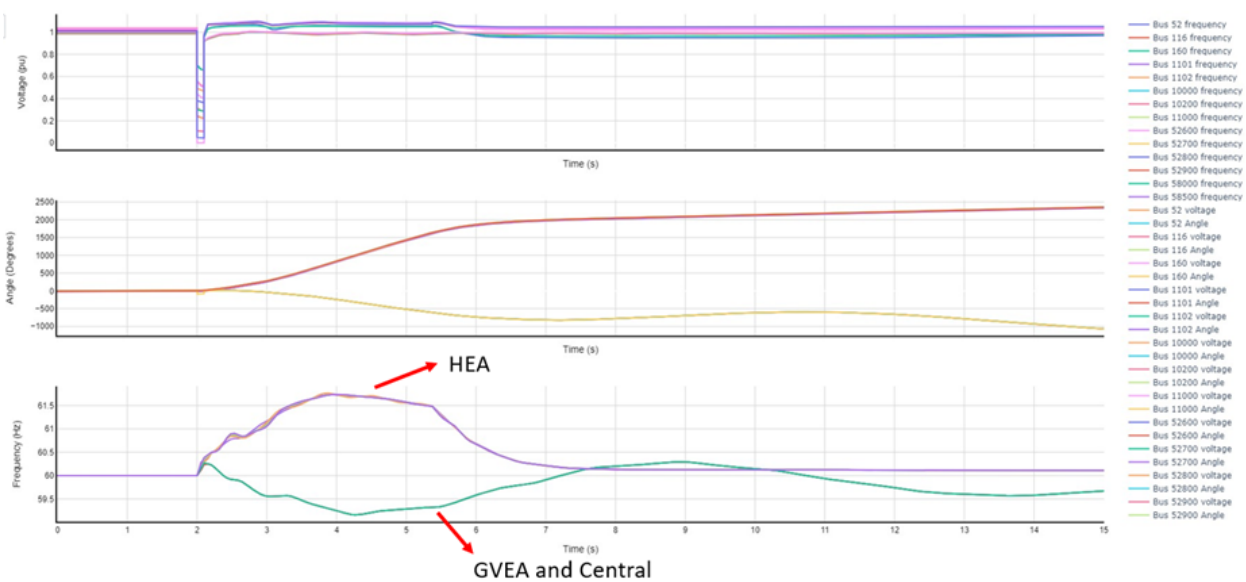

Figure 6.1. Loss of Kenai Intertie - Voltages, Angles, and Frequency

Before the disturbance, around 62 MW of power flowed through the Kenai Intertie, going south to north, and about 87 MW through the Alaska Intertie, also going south to north. Once the system separated, HEA, which was initially exporting power, reduced its generation to supply only the Southern region load, which is smaller than in the other regions. On the other hand, the Central and Northern regions, which were importing power from the Southern region, did not have enough local generation to supply their own load, making the load-shedding scheme act to reduce the load in those areas. The behavior of generation and load in the three regions can be seen in Figures 6.2 and 6.3.

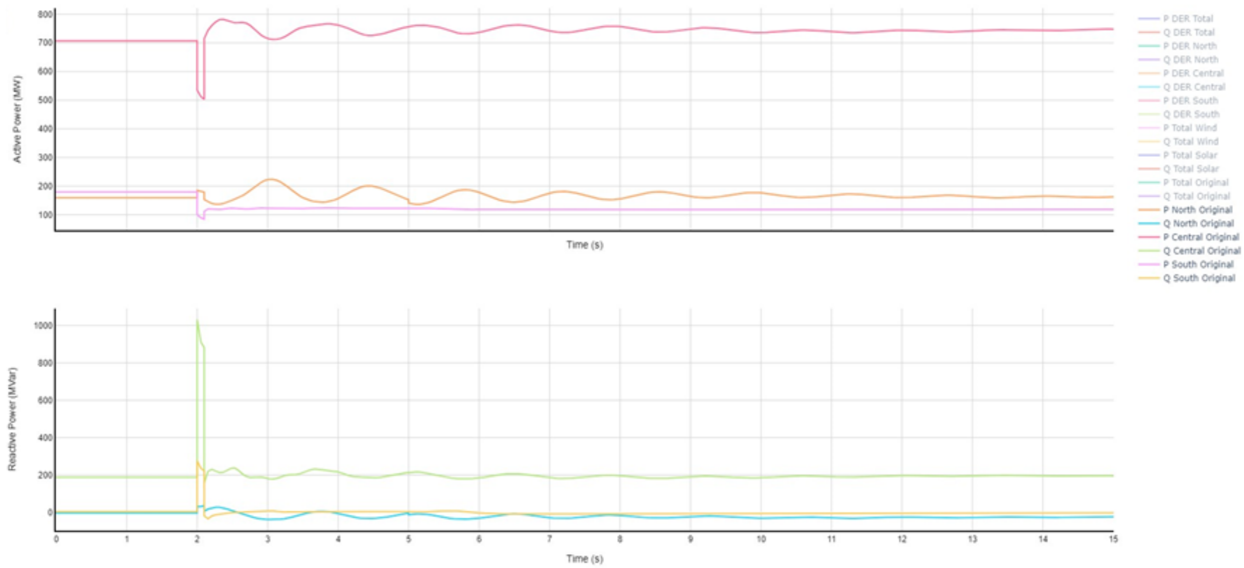

Figure 6.2. Loss of Kenai Intertie - Total generation in North, Central, and South

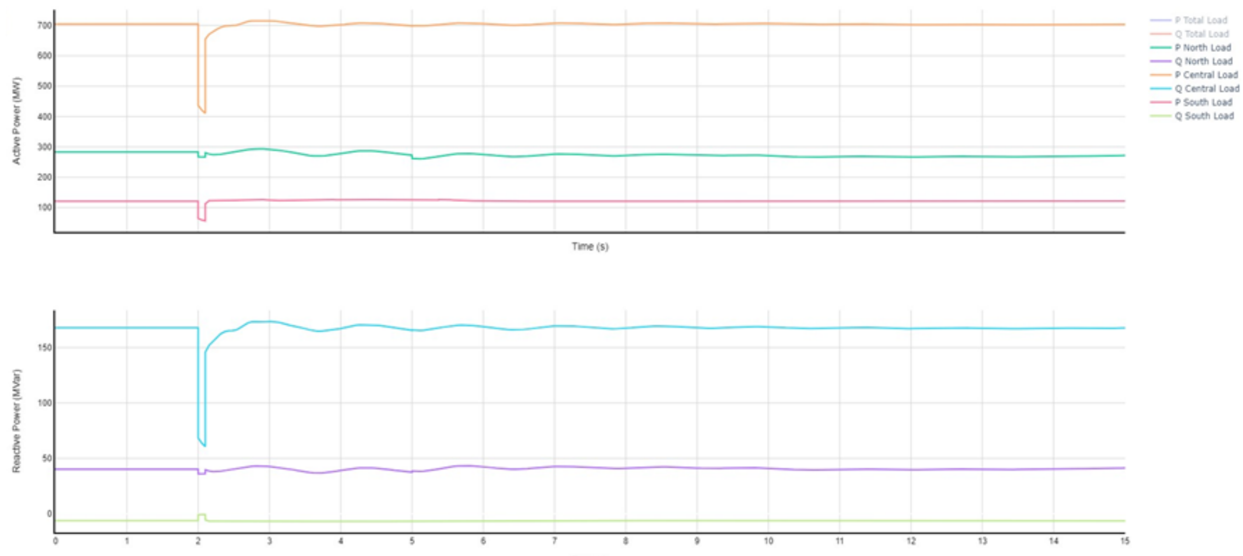

Figure 6.3. Loss of Kenai Intertie - Total load in North, Central, and South

It is possible to see that, although the system is operating in an N-1 scenario, after the load-shedding scheme acts we have a new generation/load balance, and the system survives the Kenai Intertie loss.

6.7.2 *Low-Carbon Scenarios Assessment of Grid-Following and Grid-Forming Inverters and Synchronous Condensers*

Initially, the new renewable generation (solar, wind and battery), was modeled to represent the IBRs that are typically being installed at the time of publishing this report. This IBR representation consists of grid-following (GFL) inverter control schemes with conventional frequency responses (several seconds of response time) and hierarchical voltage regulation at both the plant and the inverter levels.

The cases simulated in each of the low-carbon scenarios have significant periods of operation in which the Railbelt system is inverter-dominant, presenting stability challenges for power systems consisting only of conventional IBRs. In particular, for contingencies with the loss of the two interties, the exclusive use of conventional GFL IBRs results in system collapse after separation of the Northern or Southern regions.

This analysis evaluated applying mitigations including synchronous condensers, inverter tuning, and finally the use of the new GFM inverter technology. The analysis provided here was performed for the Wind/Solar/Hydro scenario; however, the findings were applicable to each of the low-carbon scenarios.

The loss of the Kenai and Alaska Intertie were simulated by applying a fault to the line segments specified in Table 6.19, followed by a trip of that line 0.1s after the fault. The loss of the interties were the most severe fault simulated out of the set of contingencies evaluated. This is because the loss of the interties results in either the Northern or Southern regions being synchronously or fully isolated from the rest of the system, with all generation in the isolated region being required to respond fast enough and with enough system strength for the region to operate independently. The HVDC line allows power transfer between the Central and Southern regions, but does not synchronously connect the two regions. Therefore when the Kenai Intertie is lost, only the HVDC line connects the Southern and Central region and that does not transfer the inertia or system strength from the Central to the Southern region.

As the most critical contingencies in the system, the loss of the Kenai and Alaska Interties were simulated with various mitigations applied to understand the effectiveness of each. These contingencies were simulated for each of the simulated hours for the Wind/Solar/Hydro scenario as outlined in Table 6.2. The sequence of tested mitigations and results is presented below.

Grid-following Inverters

The GFL inverters were initially modeled using the "REGCA1" generic model. With this system setup, not only did the system not survive the loss of both interties, the simulation was not numerically stable, as has been known to occur with the use of the REGCA1 model in weak systems. Voltages, angles, and frequency at the Kenai and Alaska Interties are shown in Figure 6.4 to illustrate the issue. Both sensitivities shown are for the hour H1953. For the loss of the Kenai Intertie (Figure 6.4), voltages and frequencies in the system reach implausible values in only a handful of simulation timesteps.

The results presented lead to the conclusion that because the system strength and inertia are insufficient for the system to restabilize after the disturbance, the system will collapse very quickly after the disturbance.

Addition of Synchronous Condensers

As an initial mitigation of the low grid strength and low-inertia problem observed previously, synchronous condensers were placed around the system in target areas and according to the necessity of the analyzed dispatch conditions. The synchronous condensers were simulated by turning on some synchronous generators that were off, but without dispatching active power. The selected generators are listed for each hour and region in Table 6.15.

A summary of the total MVA of synchronous condensers added to stabilize the system is provided below:

- Southern: 145 - 205 MVA
- Central: 142 MVA
- Northern: 277 MVA
- Total Railbelt: 564 - 624 MVA of synchronous condensers

For the hours H1953, H4158 and H8266, the commitment of a large level of synchronous condensers was required to maintain sufficient grid strength and inertia to enable the system to survive the challenging separation events when IBRs are configured in conventional ways. The voltages, angles, and frequencies for both intertie losses for hour H1953 are shown in Figure 6.5 for the Kenai Intertie loss and Figure 6.6 for the Alaska Intertie loss as example.

For the fault at Kenai Intertie at H7763, the addition of synchronous condensers solve the problem observed before.

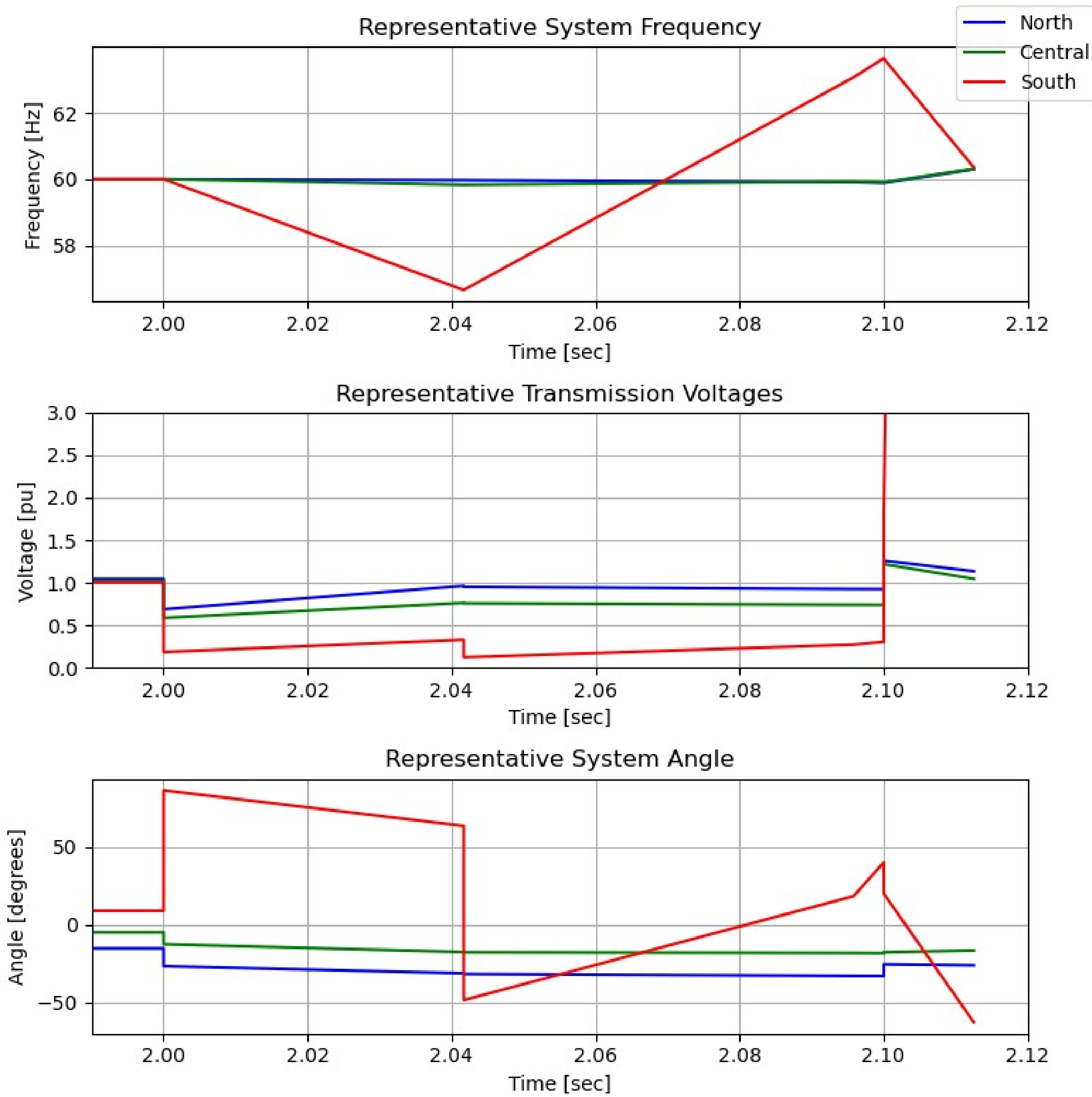

Figure 6.4. Loss of Kenai Intertie - Voltages, Angles, and Frequency Pre-mitigations - Hour 1953

However, for the fault at the Alaska Intertie, although the Central and Southern regions initially survive the event, the separation of the Northern region causes its frequency to increase to more than 66 Hz. After a few seconds, the frequency protection schemes in the Northern region start to act, tripping multiple generators in the area, and the system collapses. This is clearly observed in Figure 6.7.

Improved Tuning of Grid-following Inverter-based Resources with Fewer Synchronous Condensers

In order to solve the issue observed at H7763 and also reduce the need for synchronous condensers, the GFL generator model was changed to "REGCBU1", which has been developed more recently to address numerical divergence in PSS®E for simulations with weak grids by modifying the dynamic model's interface with the network solution. In addition, the electrical control and plant controller models of the IBRs were tuned to provide more aggressive voltage regulation and frequency response to help stabilize system voltages and frequencies during and after disturbances. This included enabling under-frequency response for BESS resources, such that a BESS with "headroom" would

Table 6.15. The addition of synchronous condensers as an initial mitigation approach.

AREA	Hour 1953	Hour 4158	Hour 8266	Hour 7763
South	• Bradley Lake ◦ 63 MVA • Soldotna Gas ◦ 71 MVA • Nikiski Full CC ◦ 45 MVA • Bernice Lake Gas Unit 4 ◦ 29.6 MVA	• Soldotna Gas ◦ 71 MVA • Nikiski Full CC ◦ 45 MVA • Bernice Lake Gas Unit 4 ◦ 29.6 MVA	• Soldotna Gas ◦ 71 MVA • Nikiski Full CC ◦ 45 MVA • Bernice Lake Gas Unit 4 ◦ 29.6 MVA	• Soldotna Gas ◦ 71 MVA • Nikiski Full CC ◦ 45 MVA • Bernice Lake Gas Unit 4 ◦ 29.6 MVA
Central	N/A	• Beluga Gas Unit 7 ◦ 85 MVA • Southcentral Power Project Unit 13 ◦ 57 MVA	• Beluga Gas Unit 7 ◦ 85 MVA • Southcentral Power Project Unit 13 ◦ 57 MVA	• Beluga Gas Unit 7 ◦ 85 MVA • Southcentral Power Project Unit 13 ◦ 57 MVA
North	• North Pole: ◦ Full CC (60 MVA) ◦ Oil Unit 1 (72 MVA) ◦ Oil Unit 2 (72 MVA) • Healy 2 Coal (73 MVA)	• North Pole: ◦ Full CC (60 MVA) ◦ Oil Unit 1 (72 MVA) ◦ Oil Unit 2 (72 MVA) • Healy 2 Coal (73 MVA)	• North Pole: ◦ Full CC (60 MVA) ◦ Oil Unit 1 (72 MVA) ◦ Oil Unit 2 (72 MVA) • Healy 2 Coal (73 MVA)	• North Pole: ◦ Full CC (60 MVA) ◦ Oil Unit 1 (72 MVA) ◦ Oil Unit 2 (72 MVA) • Healy 2 Coal (73 MVA)

quickly increase its output power in response to an under-frequency event. No other IBRs or distributed energy resources (DERs) were modeled with under-frequency response.

After implementing these improvements to the dynamic models, the stability of the system substantially improved, reducing the need for many of the synchronous condensers. Table 6.16 shows the condensers needed after the model improvements for each case.

Table 6.16. Synchronous Condensers needed after tuning inverter-based resource models.

Region	Hour 1953	Hour 4158	Hour 8266	Hour 7763
Southern	Nikiski CC (45 MVA) Bernice Gas Unit 4 (29.6 MVA)	Nikiski CC (45 MVA) Bernice Gas Unit 4 (29.6 MVA)	Nikiski CC (45 MVA) Bernice Gas Unit 4 (29.6 MVA)	Nikiski CC (45 MVA) Bernice Gas Unit 4 (29.6 MVA)
Central	N/A	Beluga Gas Unit 7 (85 MVA) Southcentral Power Project Unit 13 (57 MVA)	Beluga Gas Unit 7 (85 MVA) Southcentral Power Project Unit 12 (57 MVA)	Southcentral Power Project Unit 11 (57 MVA)
Northern	North Pole Oil Unit 2 (72 MVA) Healy 2 Coal (73 MVA)	North Pole Oil: Unit 1 (72 MVA) and 2 (72 MVA) Healy 2 Coal (73 MVA)	Healy 2 Coal (73 MVA)	North Pole CC (60 MVA) North Pole Oil: Unit 1 (72 MVA) and Unit 2 (72 MVA) Healy 2 Coal (73 MVA)

A summary of the total MVA of synchronous condensers added to stabilize the system is provided below:

- South: 75 MVA (reduction of 70-130 MVA)
- Central: 142 - 57 MVA (reduction of 0 - 85 MVA)

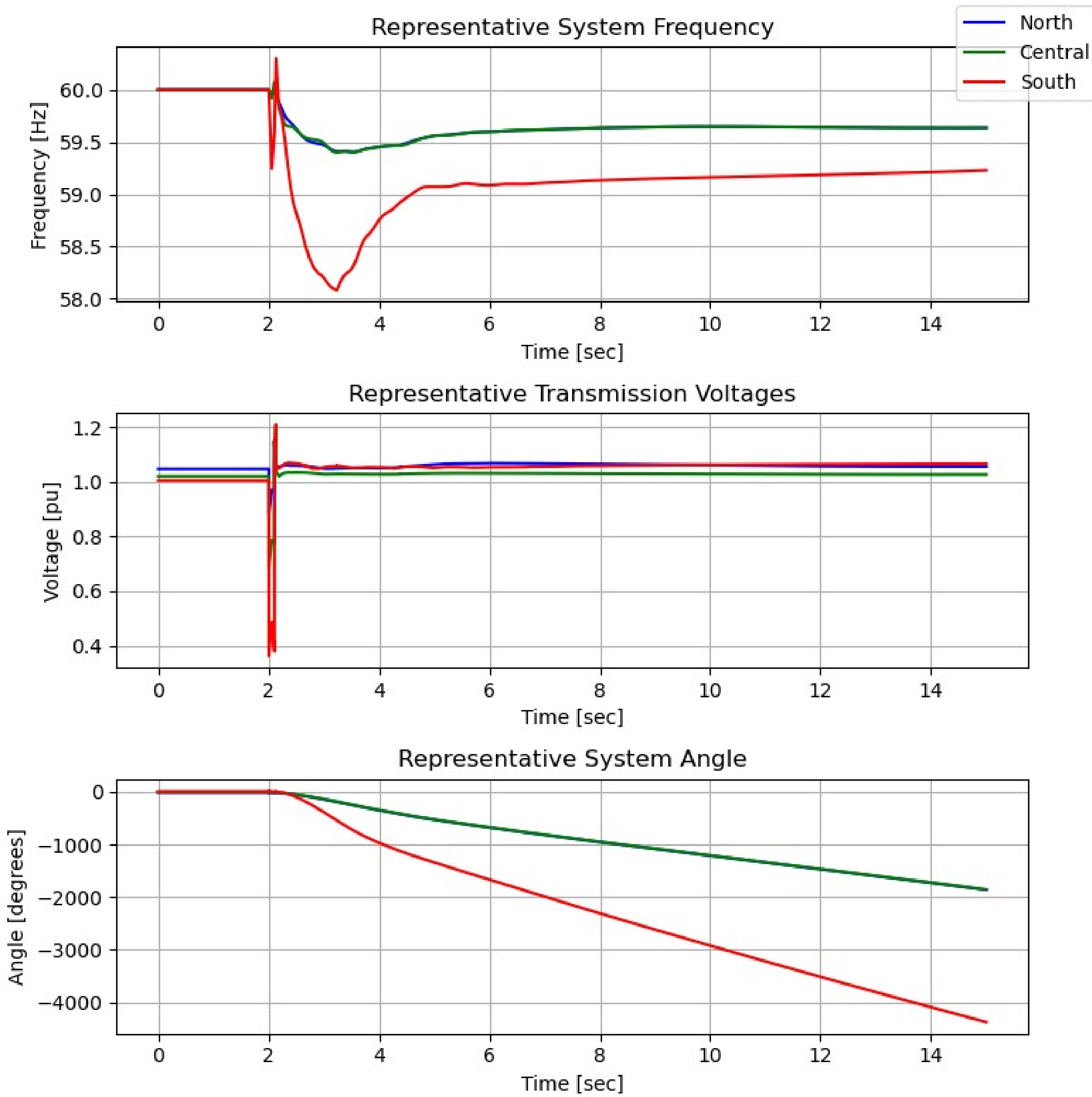

Figure 6.5. Loss of Kenai Intertie - Voltages, Angles, and Frequency with Synchronous Condensers - Hour 1953

- North: 277 - 73 MVA (reduction of 0 - 204 MVA)
- Total Railbelt: 290 - 494 MVA of synchronous condensers (reduction of 130 - 274 MVA)

All hours simulated showed good results for both faults with the new generator model. It was possible to remove some synchronous condensers in all cases. In addition, H7763 not only survived the faults with the new generator model, but it was possible to remove one synchronous condenser in the Central region and one in the Southern region. The improvement can be seen in Figure 6.8 for the Alaska Intertie fault, where the system does not collapse and the frequency in GVEA remains under 62 Hz. However, there is a damped voltage oscillation occuring after the fault.

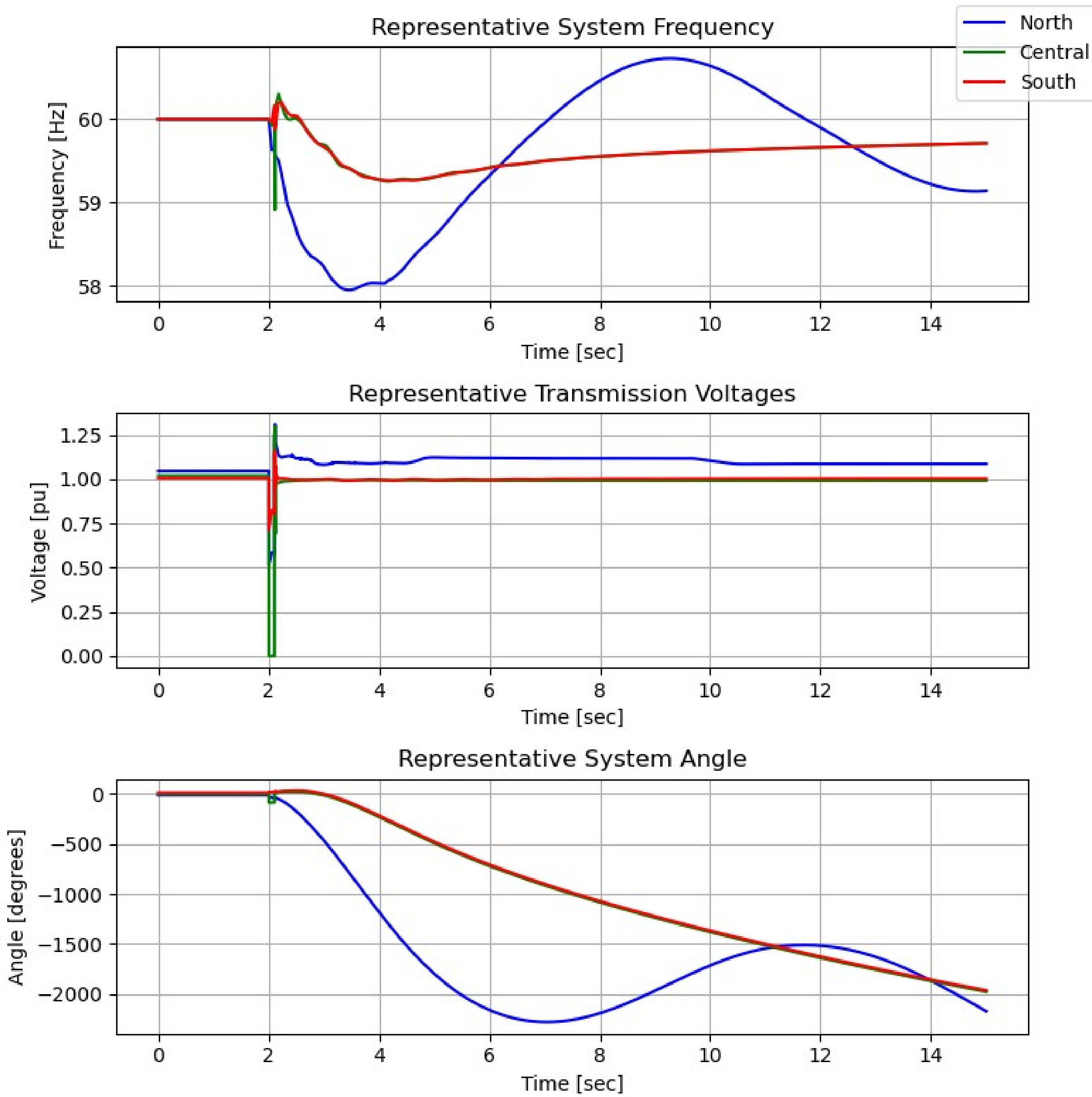

Figure 6.6. Loss of Alaska Intertie - Voltages, Angles, and Frequency with Synchronous Condensers - Hour 1953

Utilization of Grid-forming Inverters for Battery Resources with Improved Grid-following Inverter Tuning for Wind and Solar

To mitigate the voltage oscillation observed for H7763 and further reduce the need for synchronous condensers, all batteries in the system were modeled as GFM-resources using the latest "REGFM_A1" model developed by Pacific Northwest National Laboratory (PNNL) and approved by the Western Electricity Coordinating Council.[41]

GFM inverter technologies use the same hardware as conventional battery systems but instead use a control paradigm that controls the voltage phasor of the resource rather than attempting to control its current injection. This control approach provides improved stability in all timeframes in a manner similar to that of synchronous machinery.

Replacing the battery models with GFMs resulted in sufficient grid-strengthening and frequency response to stabilize

[41] Wei Du et al. *Model Specification of Droop-Controlled Grid-Forming Inverters-REGFM_A1.pdf*. Tech. rep. PNNL-32278. Pacific Northwest National Laboratory, Sept. 2023. URL: https://www.wecc.org/_layouts/15/WopiFrame.aspx?sourcedoc=/Reliability/Model%20Specification%20of%20Droop-Controlled%20Grid-Forming%20Inverters-REGFM_A1.pdf&action=default&DefaultItemOpen=1 (visited on 10/29/2023).

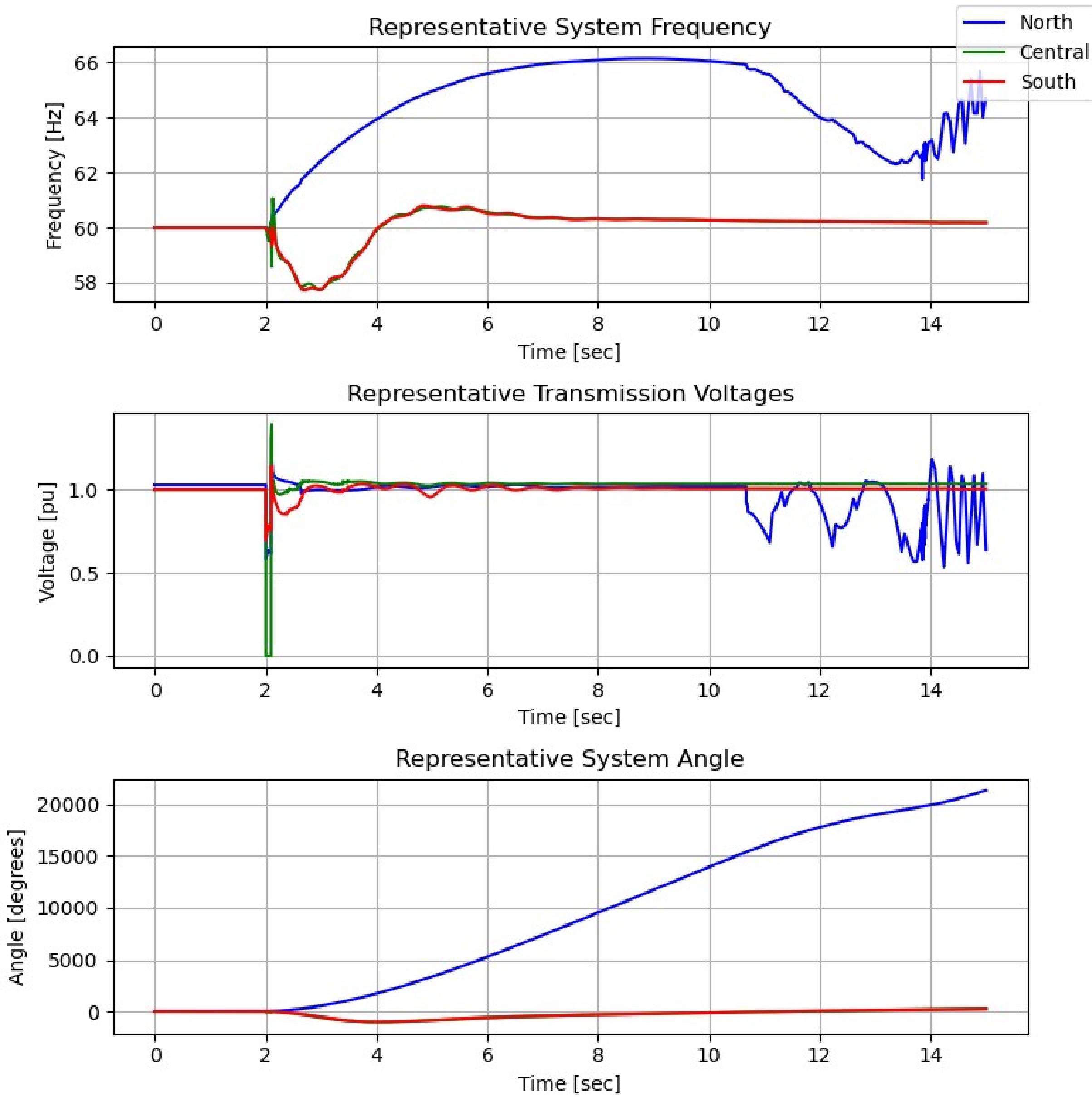

Figure 6.7. Loss of Alaska Intertie - Voltages, Angles, and Frequency with Synchronous Condensers - Hour 7763

the system in the event of all the faults without the need of synchronous condensers. This was observed for all four hours evaluated, including H7763, whose voltages, angles, and frequencies are shown in Figure 6.9. Compared to the case in Figure 6.8, the voltage oscillation observed is now eliminated.

Summary of Key Findings for the Assessment of Grid-following and Grid-forming Inverters and Synchronous Condensers

The greatest level of system performance was demonstrated by utilizing industry best practices for wind and solar resources modeled as GFL combined with using GFM IBR technology for all battery systems. From an operational perspective, the selected four target hours posed significant challenges due to the limited presence of online synchronous generators. However, the implementation of specific mitigations effectively maintained stable operation in all regions of the Railbelt during highly demanding fault and system separation events. Table 6.17 summarizes the key findings of each implementation.

The system experienced a collapse after the separation of the Northern or Southern region when modeling solar,

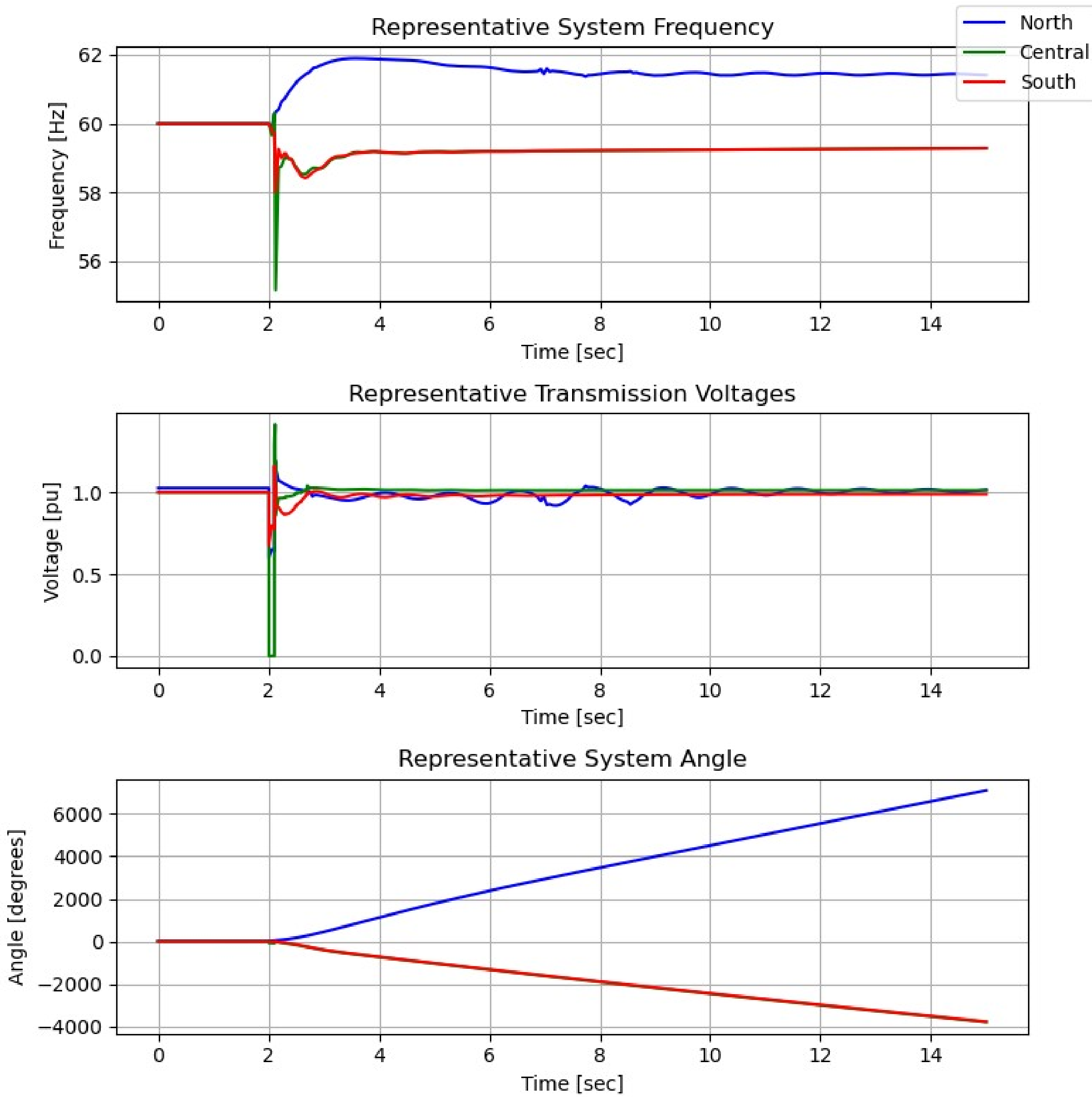

Figure 6.8. Loss of Alaska Intertie - Voltages, Angles, and Frequency with Synchronous Condensers and GFL tuning - Hour 7763

Table 6.17. Performance improvements across different mitigations applied.

Summary	**GFL only**	**SC addition**	**GFL tuned**	**GFM**
Stability	System collapsed	Stable except for Hour #7763	Stable	Stable
Synchronous MVA needed	System collapsed	564 - 624 MVA	290 - 494 MVA	No need for synchronous condensers
Worst case underfrequency load sheding	System collapsed	398.7 MW	282.2 MW	255.9 MW

wind, and batteries using GFL inverters with conventional frequency responses, which means they had response times of several seconds. As a first mitigation in response to the identified issues of low grid strength and low inertia, strategic placement of synchronous condensers was implemented within certain sections of the system. Better

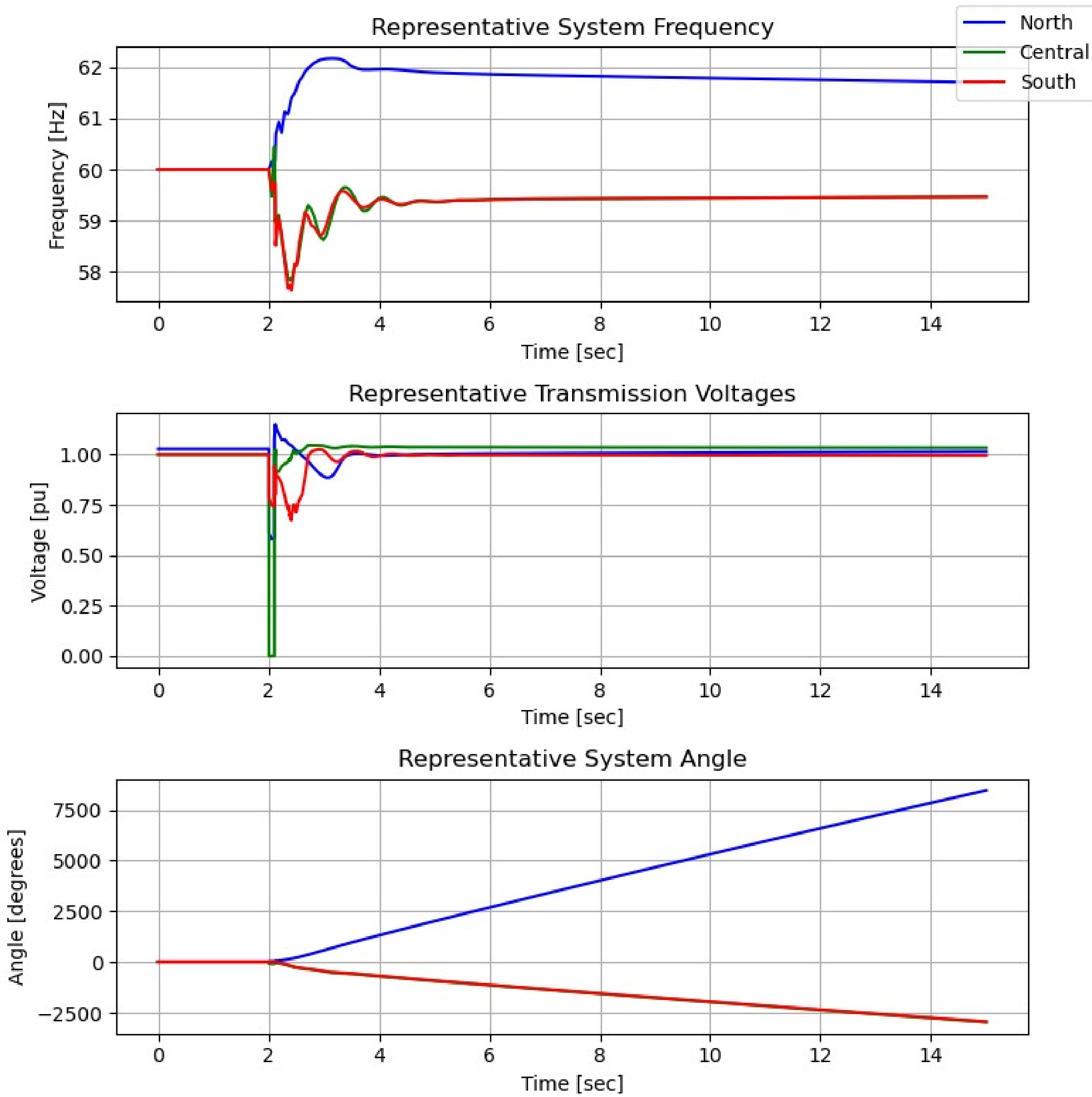

Figure 6.9. Loss of Alaska Intertie - Voltages, Angles, and Frequency with GFL tuning and GFM batteries - Hour 7763

performance was observed for this case, with the system being stable for three of the four target hours. However, in the case of the fault occurrence at the Alaska Intertie at H7763, while the system manages to withstand the event initially, disconnection of the Northern region leads to a subsequent rise in the frequency of the region. Following a brief interval, the frequency protection schemes inside the Northern region commence operation, resulting in the activation of several generator tripping events within the region, that ultimately lead to the system's collapse.

The system's performance was further enhanced by replacing the original GFL generating model with a more suitable model. Furthermore, the electrical control and plant controller models were fine-tuned to provide more aggressive voltage regulation and frequency response to aid in stabilizing system voltages and frequencies during and after disruptions. In addition to the better stability of IBRs, this mitigation allowed the removal of up to 274 MVA of synchronous condensers from the system. Load shedding was also reduced by the mitigations adopted.

The best performance obtained was with the use of GFM inverters, with no need for synchronous condensers and nearly a 65% reduction in the worst loading shedding (see Table 6.17). The substitution of battery models with GFMs offers adequate grid support and frequency response to stabilize the system during a fault event. This is due to the enhanced stability provided by the control method of GFMs throughout each time frame, such as that of synchronous machinery. The benefits of GFM application are also shown in Table 6.18, with the reduction of the total load shed, especially after the fault at the Alaska Intertie during high-flow periods.

Table 6.18. Total load shed after fault events.

Event	Hour #1953		Hour #4158		Hour #8266		Hour #7763	
	GFL + SC	GFM	GFL + SC	GFM	GFL + SC	GFM	GFL + SC	GFM
Kenai Intertie Loss	14.2 MW	13.4 MW	6.6 MW	7.2 MW	73.7 MW	91.1 MW	85.3 MW	19.4 MW
Alaska Intertie Loss	145.6 MW	82.3 MW	103.2	45.38 MW	282.2 MW	118.8 MW	262.1 MW	255.9 MW

6.7.3 Wind/Solar/Hydro Scenario

For the Wind/Solar/Hydro scenario, Table 6.19 summarizes the specific list of contingencies applied to the four simulated hours (H1953, H4158, H7763, H8266).

Table 6.19. Dynamic contingency events applied in the Wind/Solar/Hydro scenario.

Hour Index	Contingency Type	Location	Element
All simulated hours	Line fault	Kenai Intertie	Dave's Creek to Quartz 230kV line
All simulated hours	Line Fault	Alaska Intertie	Teeland to Douglas 230kV line
1953, 7763, and 8266	Loss of generation	Northern region (GVEA)	Susitna-Watana Unit 3 - Hydro generation
4158	Loss of generation	North (GVEA)	Houston Solar - Solar generation
1953 and 8266	Loss of generation	Central region (CEA)	Little Mount Susitna - Wind generation
4158 and 7763	Loss of generation	Central region (CEA)	Shovel Creek - Wind generation
All simulated hours	Loss of generation	Southern region (HEA)	Homer Wind - Wind generation

The Wind/Solar/Hydro analysis in the previous section for the loss of the Kenai and Alaska Interties identified that with the current batteries enabled with GFM inverter controls, and with some additional batteries, the system has a stable response for both contingencies for each of the hours simulated. When using the GFM BESS and wind and solar with advanced GFL features, the largest loss of generation for all regions results in a stable response for each of the hours simulated.

Table 6.20 provides a summary of the GFM batteries added in each region, in addition to the batteries used in the dispatch analysis from Section 5.

Table 6.20. Grid-forming inverter Batteries added to the Wind/Solar/Hydro scenario for grid stability.

Area	Grid-forming inverter Battery Capacity (MVA)
Northern	224
Central	47.6
Southern	171
Total	442.6

6.7.4 Wind/Solar/Tidal Scenario

The Wind/Solar/Tidal scenario built off of the dynamic models developed in the Wind/Solar/Hydro scenario. This included using GFM models for all of the batteries, and tuning the GFL models of the wind and solar generator models. The tidal generators were modeled using the same models as the wind and solar models, assuming a full-converter interface with the electrical grid.

The largest generators considered for contingencies in this scenario, were those whose loss would be the most impactful to stability, which are the synchronous generators or GFM batteries, as they provide the system strength critical to maintaining stability. The tidal generators were considered as two 200 MW generators, each individually connected to the system, and therefore also a large generating contingency. The wind and solar generators were not considered critical to stability, due to their lack of contribution to system strength and because they were connected with two interconnection transmission lines and transformers.

Table 6.21 summarizes the specific list of contingencies applied for the Wind/Solar/Tidal scenario. The largest generating contingency change in each region based on the simulated hour.

Table 6.21. Dynamic contingency events applied in the Wind/Solar/Tidal scenario.

Contingency Type	Location	Element
Line fault	Kenai Intertie	Dave's Creek to Quartz 230kV line
Line Fault	Alaska Intertie	Teeland to Douglas 230kV line
Loss of generation	Northern region (GVEA)	Healy Battery (MSRHF, SV) Wilson Battery (MSR) North Pole Plant Unit 3 Wind (WP)
Loss of generation	Central region (CEA)	Eklutna Generating Station Battery (MSRHF, MSR) Beluga Power Plant Unit 7 (WP) Southcentral Power Project Unit 10 (SV)
Loss of generation	Southern region (HEA)	Bradley Lake Hydropower Unit 1 (WP) Tidal Unit (MSRHF, MSR, SV)

Loss of Kenai and Alaska Interties

Synchronous condensers and GFM batteries were added to the system to mitigate the loss of the Kenai and Alaska Interties, in order to create a system able to survive these contingencies. For each hour and for each contingency different combinations of synchronous condensers and GFM batteries were assessed, and the lowest total MVA capacity combination was selected. The synchronous condensers and GFM batteries added for each simulated hour and for each contingency are summarized in Table 6.22.

The detailed assessment of each simulated hour for the loss of the Kenai and Alaska Interties, with plots demonstrating the response of the system, is provided in Appendix N.

Loss of Generation

With the mitigations that were previously added for the loss of the interties, each of the four hours simulated had stable responses to the loss of generation in each region.

Summary of Key Findings for Wind/Solar/Tidal Scenario

The Wind/Solar/Tidal scenario was built using the models that provided the most stable system for the Wind/Solar/Hydro scenario. Those GFM battery models and GFL wind and solar models were tuned specifically for this scenario, which was primarily operated with IBRs with minimal online synchronous generation online.

Stability mitigations were only required for the loss of the Kenai and Alaska Interties, no mitigations were required for contingencies involving loss of generation. Batteries and synchronous condensers were added to the model as needed to create a stable system response for the loss of the Kenai and Alaska Intertie contingencies. The batteries and synchronous condensers added to the scenario are summarized in Table 6.22.

6.7.5 Wind/Solar/Nuclear Scenario

The Wind/Solar/Nuclear scenario also built off of the dynamic models developed in the Wind/Solar/Hydro scenario. This included using the GFM models for all of the batteries, and the updated tuning of the GFL models of the wind and solar generator models. The nuclear generators were modeled using the same dynamic models as Healy Coal Plant #2, as they are both steam generators

Table 6.22. Synchronous condensers and batteries added to each simulated hour in the Wind/Solar/Tidal scenario for grid stability.

Region	Synchronous Condensers and Grid-forming inverter Battery Capacity (MVA)
Northern	None
Central	Eklutna Generation Station: Units 1-6 (21.34 MVA each) Sullivan Substation: Unit 8 (99.38 MVA) Unit 11 (36 MVA)
Southern	Bernice Substation: 250 MVA Grid-forming inverter Battery Nikiski Substation: Unit 1 (45 MVA) Unit 2 (50 MVA)
Total	608.5

The GFM and GFL models used for inverters in this scenario were tuned specifically for this Wind/Solar/Nuclear scenario, to improve stability with the synchronous nuclear generators. In particular, the regulatory gains of these models were adjusted to shift the strength of the response of the voltage and frequency controls.

Table 6.23 summarizes the specific list of contingencies applied for each of the hours simulated for the Wind/Solar/Nuclear scenario, as outlined in Table 6.4. The largest generating contingency change in each region based on the simulated hour.

Table 6.23. Dynamic contingency events applied in Nuclear scenario.

Contingency Type	Location	Element
Line fault	Kenai Intertie	Dave's Creek to Quartz 230kV line
Line Fault	Alaska Intertie	Teeland to Douglas 138kV line
Loss of generation	Northern region (GVEA)	Shovel Creek (MSRHF, MSR, WP) Eva Creek Wind (WP)
Loss of generation	Central region (CEA)	LMS Wind (MSRHF, MSR, SV) Nuclear Generator (WP)
Loss of generation	Southern region (HEA)	Homer Wind (MSRHF, SV, WP) Soldotna Battery (MSR)

Loss of Kenai and Alaska Interties

Synchronous condensers and GFM batteries were added to the system to mitigate the loss of the Kenai and Alaska Interties in order to create a system able to survive these contingencies. For each hour and for each contingency different combinations of synchronous condensers and GFM batteries were assessed, and the lowest total MVA capacity combination was selected. The synchronous condensers and GFM batteries added to the scenario are summarized in Table 6.24.

In addition to the GFM batteries and synchronous condensers added for grid stability, a high-voltage relay trip time setting was adjusted for the Shovel Creek Wind facility. This was due to the Shovel Creek Wind facility tripping offline due to the loss of the Alaska Intertie. The loss of this wind facility after the loss of the Alaska Intertie, caused the Northern region system to collapse. Adjusting the voltage relay setting to be delayed by 0.09 seconds (from 0.01 to 0.1 seconds) prevented the wind facility from tripping offline due to the high voltage, as the voltage recovered within the new trip time setpoint, creating a stable Northern region system response to the loss of the Alaska Intertie.

The detailed assessment of each simulated hour for the loss of the Kenai and Alaska Interties with plots demonstrating the response of the system, is provided in Appendix P.

Loss of Generation

In the MSR hour, the loss of the largest generator in the Central region, one of the nuclear units, caused a delayed (around 9 seconds after system recovery from the initial generator trip) undamped oscillation that resulted in system collapse. After investigating each of the generators' responses, it was determined that the remaining nuclear units online in the Central region were oscillating against each to cause an undamped system response. This interaction between the generators could be mitigated by tuning the controls of each of the nuclear generators, and this would be necessary for actual system operation. The purpose of studying this type of contingency is to evaluate the system's ability to survive a loss in generation. Based on the analysis conducted, the loss of the entire nuclear generating facility in the Central area was evaluated. The system had a stable response to the loss of the entire nuclear generation facility in the Central region. For actual operation of the system, the controls of each nuclear generator unit would need to be tuned to prevent the undamped oscillation; however, for the purpose of this analysis the loss of the entire nuclear generator station demonstrates the system's ability to survive the loss of a large generating facility.

All other loss of generation contingencies for each simulated hour resulted in stable system responses.

The detailed assessment of each simulated hour for the loss of generation in the Central region for the MSR hour is provided in Appendix P.

Summary of Key Findings for Wind/Solar/Nuclear Scenario

Stability mitigations were only required for the loss of the Kenai and Alaska Interties. Batteries and synchronous condensers were added to the model as needed to create a stable system response for the loss of the Kenai and Alaska Intertie. The voltage trip time setpoint for the Shovel Creek Wind facility was also adjusted to enable a stable system response.

The addition of batteries and synchronous condensers for each of the simulated hours is summarized in Table 6.24.

Table 6.24. Synchronous condensers and batteries added to each simulated hour for the Wind/Solar/Nuclear scenario for grid stability.

Region	Synchronous Condenser and Grid-forming inverter Battery Capacity (MVA)
Northern	Increased each battery MVA by 20%: 107 MVA
Central	Increased each battery MVA by 20%: 21.5 MVA
Southern	Increased each battery MVA by 20%: 200 MVA Nikiski Substation: Unit 1 (45 MVA) Unit 2 (50 MVA)
Total	418.5

6.8 Grid Stability Scenario Comparisons

Each of the scenarios required stability mitigations. The amounts and types of mitigations required for each type of stability issue for each scenario are summarized in Table 6.25.

Some scenarios required more mitigations than others, primarily due to two main factors:

1. the placement of large new generators
2. the amount of synchronous generation online

The placement of large new generators is impactful because it changed which transmission lines in the system had to transfer more power from these new generators to the load centers. In cases where large amounts of power are being transferred across 115 kV lines, such as the case with moving power from the Homer Wind facility to other loads in the Southern or Central regions, this causes high power losses in the 115 kV lines resulting in significant amounts of reactive power being needed to maintain voltage stability. This reactive power was provided by added capacitors and batteries as a mitigating measure. This stability issue generally happened where large new generation was added

Table 6.25. Summary of stability mitigations for each scenario for each type of stability issue.

Type	Region	BAU	Wind/Solar/Hydro	Wind/Solar/Nuclear	Wind/Solar/Tidal
Batteries (MVA) for Steady-State Voltage Stability	Northern	30	80	224	40
	Central	15	105	548	50
	Southern	5	180	16	50
	Total	50	365	788	140
Capacitors (MVAR) for Steady-State Voltage Stability	Northern	0	22	15	10
	Central	0	15	145	60
	Southern	0	54	25	5
	Total	0	91	185	75
Reconductored Lines (miles) for Steady-State Thermal Stability	Northern	0	12.4	6.8	20.8
	Central	1.9	33.3	105.2	30.9
	Southern	0	75.8	119	172.5
	Total	1.9	121.5	231	224.2
Transformers (MVA) for Steady-State Thermal Stability	Northern	5	9	13	11
	Central	15	12	25	17
	Southern	0	1	2	2
	Total	20	22	40	30
Transformers (MVA) for Steady-State Voltage Stability	Northern	0	0	0	0
	Central	0	0	0	0
	Southern	0	1	1	1
	Total	0	1	1	1
Batteries (MVA) for Dynamic Stability	Northern	0	224	107.24	0
	Central	0	47.6	21.45	0
	Southern	0	171	200	250
	Total	0	442.6	328.69	250
Synchronous Condensers (MVAR) for Dynamic Stability	Northern	0	0	0	0
	Central	0	0	0	263.42
	Southern	0	0	90	95
	Total	0	0	90	358.42

to the system in each scenario including the nuclear power plants, Susitna-Watana hydro power plant, large wind facilities, and large tidal facilities.

The less synchronous generation online, the more need there was for devices that could provide inertia and system strength such as synchronous condensers and GFM batteries. The need for these devices were prevalent in all low-carbon scenarios where there was fewer synchronous generation online. The Wind/Solar/Tidal scenario required less synchronous condensers and GFM batteries because there was more fossil-fuel-based generation throughout the system, as discussed in earlier sections of this report. The fossil-fuel-based generation in the Wind/Solar/Tidal scenario was more evenly distributed throughout the system as existing fossil-fuel-based generation was used. In the Wind/Solar/Nuclear and Wind/Solar/Hydro scenarios less of the existing fossil-fuel-based generation was in use, the nuclear and hydro generators were in use more often; however, they are located in fewer locations and therefore less evenly distributed throughout the system, resulting in pockets of the system without synchronous generation online, such as in the Anchorage and Mat-Su areas. Those pockets lacking synchronous generation required either synchronous condensers or GFM batteries to remain stable.

The mitigation measures employed in this section are consistently applied to each of the scenarios, however they do not necessarily represent the most cost effective mitigating measures. It is possible to iterate back and forth between generation analysis using PLEXOS and transmission analysis using PSS®E to identify more economical mitigations. Examples of this iteration could include:

- Refinement of interconnection locations for large projects, like Homer Wind. In general, distributing interconnections (more smaller projects rather than fewer large projects) is better for system reliability, but not necessarily for project cost.

- Redispatch/recommit the system with constraints to manage frequency stability risk. In this case a constraint could be set up that manages the battery state of charge so it is capable to either discharge quickly (under frequency response) or to charge (over frequency). This could be done by defining a new reserve requirement to maintain a minimum level of frequency stability services (through a combination of GFM battery headroom and/or synchronous generation commitment).

- Using the voltage violations in PSS®E you could develop operating nomograms or transmission interfaces that could resolve the voltage violations through unit commitment. If the violations are expected to be rare (i.e. only during peak load conditions or peak wind, etc.) it may be cheaper to commit a unit rather than build new infrastructure. In this case a constraint could be added to PLEXOS that says "if these conditions exist in the system, then take an action such as committing a specific unit, or limiting transmission flows in/out of a region, etc."

The magnitude of mitigation measures identified in this section do not necessarily relate to the viability of each specific resource in each scenario as further optimization of mitigations are possible. Instead, the value of this analysis is in demonstrating the types of stability challenges and when they occur, to provide context for the types of stability challenges that will arise as the Railbelt integrates new generation in the future.

6.9 Discussion on Grid-forming Inverter Technology

6.9.1 Simulation Models and Field Experience

The GFM inverters in this study play a major role in increasing the stability of the system in future scenarios. GFM is an emerging technology, and while there are some instances of it dating back decades, the current incarnation of utility-scale GFM technology is about 6-7 years old. While the installed base of GFM projects is still small today, the technology is rapidly gaining traction with several projects around the world that have been operating for years, and with many major utility-scale battery inverter manufacturers offering GFM products and detailed models of those products. However, the transition of a system reliant on synchronous machine technology for providing critical stability services to a system reliant on GFM technology for providing critical stability services should be handled with care and need not happen overnight. This section provides more context on the state-of-the-art of GFM technology and some of the steps for integrating it into the grid.

The stability analysis in this study was performed using Siemen's PSS®E, a decades-old mainstay of power system engineering software tools. It is a simulation platform that - like all simulations - makes some simplifying assumptions in the representation of the grid infrastructure and the connected resources. The simplifying assumptions made for representation of resources are particularly well-suited for synchronous machinery, where the behavior of these synchronous resources is dominated by the physical characteristics of the machine itself. Over the last 20 years, these models have been adapted to reflect the behavior of IBR - beginning with wind turbines, where the behavior of IBRs is dominated by the controls software running on the equipment. The control software on the equipment, having on the order of tens of thousands of lines of code would be simplified to a reduced-order model containing on the order of a few hundred lines of code. In many studies, such simplifications still result in a reasonably accurate representation of the equipment, and IBR representations in PSS®E are widely used and accepted. However, it is important that engineers know the limitations of the models and platform – where the simplifications can result in unacceptably large errors.

In this analysis using PSS®E, the GFM battery resources were represented by a recently-developed model from Pacific Northwest National Laboratory (PNNL) called the REGFMA1 model, which represents the core aspect of GFM technology in which there is a controlled internal voltage phasor that interfaces with the grid. In this way, the reduced-order model captures the essential behaviors and characteristics expected by practitioners familiar with GFM technology. As such, the representation of GFM technology is reasonable for a system-level analysis of a future scenario to show the nature of the stability challenges and how the new technology can address them.

The expectations of model fidelity for a system-level future scenario study are different from those of a near-term scenario study or a specific project-interconnection study. In such cases where specific equipment has been selected for integration to the grid and the size of the project is large (relative to the size of the system or region), then greater accuracy is expected. This means that the specific characteristics and nuances of the inverter controls selected for the project should be represented in the simulation models. Increasingly, the expectations of model fidelity for IBR-dominant systems cannot be met in a positive-sequence dynamic platform like PSS®E and force system operators to evaluate stability in a different simulation environment known as EMT simulation models. EMT simulation is a 3-phase time-domain simulation tool that uses microsecond time-steps and models derived - or in many cases, directly translated – from the firmware code running on the actual products. This is the closest to reality that the industry has in the desktop simulation environment and is widely accepted as the state-of-the-art for high-fidelity inverter and system simulations. The increased model fidelity and confidence in system planning and operations from EMT comes at a price. EMT model and simulation involves an order of magnitude more detail (input data), more computation, and more setup and specialized skills of practitioners. Furthermore, additional care must be taken to ensure the model is configured (typically hundreds of parameters must be set) in a way that matches the product in the field. Best practices also include demonstrations through benchmarking tests that show the response of the model closely matches the response of the product under laboratory or field tests on the actual hardware.

Positive-sequence dynamic simulation still has its place and will continue to play an important role in system studies. But increasingly, it will be augmented with EMT simulations where the stability challenges and stability risks demand higher levels of confidence in the behavior and performance of the connected equipment. As the grids evolves to become more renewable – and more IBR-dominant – it is worth noting that the transition is not a sudden jump but that it is best managed as a smooth and systematic transition from one technology to another in which there is a period in which both technologies (synchronous machinery and IBRs) will share responsibility for providing the critical stability services needed by the grid. In this period, grid operators will gain confidence that the new technology is configured correctly and is performing as expected, which can be proven through natural grid events or potentially through staged tests. As a means of ensuring proper performance, particularly during natural grid events, recent best practices include having digital fault recorders or similar high-resolution event-triggered data capture systems installed at each major project so that the performance during and after events can be reviewed and benchmarked against EMT models. In this way, the new technologies can prove itself and system operators can gain confidence in the new technology as they systematically shift away from fossil-fuel-based generation.

6.9.2 Industry Experience and References on Grid-forming Inverters

- Australian Energy Market Operator Report: Aug 2021 report, appendix cites several projects - BESS and Wind projects, where utility-scale GFM has been used on actual grids.[42]
- NREL Tests: March 2022 presentation, discusses laboratory tests on wind turbine drivetrains operating in GFM mode..[43]
- Electranix Report about Hawaii: Summer 2021, EMT study results for operating the islands of Oahu, Maui, and Hawaii at up to 95% IBR penetration, relying on GFM for stability. There is an additional challenge of large levels of legacy DER (rooftop PV) that will trip and/or cease current injection during planning events.[44]
- North American Electric Reliability Corporation: September 2023 Reliability Guideline recommending that all future battery projects deploy GFM technology. The appendix includes references to GFM projects around the world, including Kauai, Hawaiian Electric Company, and Australia.[45]
- Kauai, Universal Interoperability for Grid-Forming Inverters (UNIFI) Webinar: 2022, meeting with Cameron Kruse at Kauai Island Utility Cooperative and AES describing their experience with GFM integration. Today,

[42] *Application of Advanced Grid-scale Inverters in the NEM*. tech. rep. Australian Energy Market Operator, Aug. 2021, p. 40. URL: https://aemo.com.au/-/media/files/initiatives/engineering-framework/2021/application-of-advanced-grid-scale-inverters-in-the-nem.pdf (visited on 12/19/2023).

[43] V Gevorgian et al. *Grid-Forming Wind Power*. en. Mar. 2022. URL: https://www.nrel.gov/docs/fy22osti/82509.pdf.

[44] Kevin M Katsura. *Enclosure c; Division of Consumer Advocacy*. en. Tech. rep. Hawai'i Public Utilities Commission, June 2021, p. 60. URL: https://dms.puc.hawaii.gov/dms/DocumentViewer?pid=A1001001A21F14B62327F00172; Hawaiian Electric. *RFP Stage 2 IRS Island-Wide PSCAD Study*. en. June 2020. URL: https://www.hawaiianelectric.com/a/9272.

[45] *White Paper: Grid Forming Functional Specifications for BPS-Connected Battery Energy Storage Systems*. Tech. rep. North American Electric Reliability Corporation, Sept. 2023, p. 51. URL: https://www.nerc.com/comm/RSTC_Reliability_Guidelines/White_Paper_GFM_Functional_Specification.pdf (visited on 12/19/2023).

Kauai is reliant on GFM projects for stability and operates an IBR-dominant system.[46]

- Energy Systems Integration Group: March 2023 report appendix listed GFM projects around the world, including: General Electric in California, SMA Solar Technology AG in St. Eustatius, Siemens Wind in Scotland, Hitachi BESS in Dalrymple South Australia, Tesla BESS in Hornsdale South Australia, Tesla BESS in Wallgrove Australia and many others under construction in Australia, UK, and Hawaii.[47]

6.10 Grid Stability Analysis Key Findings

- **Grid reliability services must be provided by IBR as well as the remaining synchronous generation.** Reliability services like inertia and grid strength that have historically been supplied by online synchronous generation must still be provided for the grid to be stable and reliable. With IBRs displacing the synchronous resources for thousands of hours each year in the future scenarios, it is critical that IBRs provide sufficient levels of these services to enable the decommitment and/or retirement of fossil-fuel generators.

- **Improvements in inverter algorithms used on the Railbelt grid will be essential for future grid stability.** The GFM technology applied to the BESS resources plays a critical role in the stability of the future system. It is important that the GFM BESS resources are sized and distributed appropriately throughout the future system. The use of GFM inverter technology on BESS in combination with the most advanced GFL inverter technology for utility-scale wind and solar plants is instrumental in providing stability to the grid. These technologies enable the system to survive not only separation events, but also to reduce reliance on the under-frequency load-shedding scheme, resulting in a more resilient grid. GFM inverter technology is an emerging technology and more deployments, testing, and incremental GFM technology additions would need to be made to enable the successful broad deployment of this technology in the Railbelt as simulated in this study.

- **System stability is more difficult to achieve in the low-carbon scenarios.** This is due to the displacement of most of the thermal synchronous generators by IBRs and/or the addition of particularly large plants that could constitute a new most severe single contingency, such as the Susitna-Watana hydropower plant.

- **The loss of the interties were the most severe contingencies.** This is because the loss of the interties results in either the Northern or Southern regions being synchronously or fully isolated from the rest of the system, with all generation in the isolated region being required to respond fast enough and with enough system strength for the region to operate independently. The HVDC line allows power transfer between the Central and Southern regions, but does not synchronously connect the two regions. Therefore, when the Kenai Intertie is lost, only the HVDC line connects the Southern and Central regions, and that does not transfer the inertia or system strength from the Central region to the Southern region. The ability of the Northern and Southern regions to operate isolated from the rest of the system is critical, and is limited by the inertia and system strength available in those regions.

- **Significant steady-state voltage issues in Low-Carbon scenarios.** These voltage violations were due to 1) an increased load, 2) new locations of large resources (such as wind, hydro, and/or nuclear) increasing power flows across the two main interties and other transmission lines across the system, and 3) reduction in power generation from fossil-fuel generators near load centers reducing the available reactive power injection. These voltage violations were mitigated with the addition of shunt capacitors and batteries to provide reactive power, however other measures could be considered to reduce the demand for reactive power and voltage support, for instance, reducing the size of Homer Wind or distributing it to two different points of interconnection.

- **Stability considerations must be included when siting new generation.** For example, the large wind facility at Homer Wind was the main cause of the voltage and thermal violations in the Southern region for all low-carbon scenarios. Reducing the size of Homer Wind or locating the wind facility in the Southern region closer to the 230kV Kenai Intertie could have resolved or reduced this issue.

[46] Kruse, Cameron and Dcosta, Alston. *Cameron Kruse & Alston Dcosta: Lessons Learned from Inverter-Based Grid-Forming Operation*. Oct. 2022. URL: https://www.youtube.com/watch?v=2e5ET0L1j5g (visited on 12/19/2023).

[47] Julia Matevosyan. *Capturing the Reliability Benefits of Grid-Forming Batteries*. en. Tech. rep. Energy Systems Integration Group, Mar. 2023. URL: https://www.esig.energy/wp-content/uploads/2023/03/ESIG-GFM-batteries-brief-2023.pdf.

7 Economic Assessment

7.1 Introduction and Approach

The purpose of the economic assessment is to tabulate and highlight the major cost elements that differ across the four scenarios. Thus, the costs analyzed here are for generation and transmission in the year 2050. The total of these analyzed costs is the generation and transmission cost of service (G&T COS). The costs of distribution and general and administrative functions were assumed to remain constant on a per MWh basis and are not tabulated here.[48]

The G&T COS in year 2050 was determined for the total system build for each scenario as the sum of the following components:

- The variable operating costs (fuel and variable O&M) of executing the hourly dispatch, as determined by the PLEXOS production cost model;
- The annual fixed O&M (annual maintenance costs that do not vary with generation output levels) for generators and for new transmission;
- The debt service (annualized capital cost) payments for new generation, transmission upgrades, and additional equipment or system upgrades necessary for system stability; and
- The margins (revenues in excess of directly identified costs)[49].

The existing thermal fleet and existing transmission assets were assumed to be fully depreciated by 2050, so there are no capital charges associated with these assets. The capital charges for new resources were calculated as level nominal dollar debt service (the same kind of payment that a homeowner would make on a fixed rate mortgage). The margin was calculated as 10% of the debt service payment. This method of calculating the capital charges component of the cost of service (COS) is somewhat unconventional[50]. It is used here for several reasons:

- It reduces the front-loading effect of the depreciation plus interest method for plants built close to 2050 and is generally less sensitive to the year in which an electric plant is placed in service, which is important because this analysis only considers a single year and cannot take an average over time;
- The method has been suggested by the Alaska Energy Authority as a preferred approach to recovering the cost of large and long-lived hydropower projects.[51]
- This method corresponds to the capital recovery component of what an independent power producer might charge under a power purchase agreement if they based their pricing on recovering their own debt service and/or sought to offer a relatively flat price over time [52]. Since some future wind and solar generation is likely to be provided by independent power producers, it is appropriate to use a method that reflects this likely future reality.

The fixed O&M cost component, which is tabulated for both new and existing generators, is assumed to be sufficient to keep the existing thermal fleet running in all scenarios. In the BAU scenario, no specific allowance has been made for capital replacements of existing thermal units even though these units are run much more intensively in BAU than in the other three scenarios. Thus, the BAU COS might be biased down somewhat.

7.2 Key Assumptions

[48] Also, the cost of fixed O&M for existing transmission is not tabulated here.

[49] Margins were included because the Railbelt utilities collect margins to satisfy lender requirements and to provide a financial cushion against varying costs and revenues. The inclusion of margins can also be thought of as a proxy for profits that might be collected by an independent power producer in order to compensate that producer's equity investors.

[50] The Railbelt utilities currently calculate capital charges as depreciation plus interest on debt plus margin as a percent of interest. The margin is calculated such that the ratio of (interest + margin)/interest, known as the Times Interest Earned Ratio or TIER, achieves an approved target level that generally falls between 1.2 and 1.8.

[51] Susitna-Watana Hydro. *Susitna-Watana Hydro Cost of Power Alaska Energy Authority Compares Estimates to Dr. Colt's Report*. Tech. rep. Alaska Energy Authority, Sept. 2012. URL: https://www.arlis.org/docs/vol1/Susitna2/1/SuWa113.pdf (visited on 01/11/2024).

[52] Roughly speaking, a power purchase agreement built on recovering constant nominal-dollar debt service plus ongoing O&M expenses could break even for the IPP if their price included a fixed nominal dollar component plus an O&M component indexed to inflation.

7.2.1 General Parameters

Important general parameters that are constant across scenarios are as follows:

- Interest rate: 5%. This is based on assessment of historical rates paid by Alaska utilities for debt financing. It is also broadly consistent with a 3% real discount rate in conjunction with 2 - 2.5% inflation.
- Debt service coverage ratio: 1.1. This ratio is adopted as a mid-range or compromise between 1.2, which is typically thought of as a financially healthy ratio [53], and 1.0, which would be a break-even rate. A break-even rate reflects the fact that over the long-run, Railbelt cooperative member-owners recoup the margins they pay because they receive money returned to them as owners. (These disbursements are known as capital credits.)
- Inflation: 2.5% per year. This rate is consistent with recent results from the Cleveland Federal Reserve Inflation Expectations Model,[54] which currently projects 2.47% inflation over the next 30 years.
- Costs are adjusted to 2023 dollars (methods are discussed with particular resources).
- Fuel prices: $14/MMBtu for natural gas; $20/MMBtu for naphtha (oil); $4/MMBtu for coal, and $25/MMBtu for diesel
- ITC of 30% is taken where allowed, i.e., no additional bonuses beyond 30% are assumed in the base case. An allowed investment tax credit (ITC) of 30% is assumed for wind, solar, hydro (including Susitna-Watana,[55][56]), tidal, nuclear, and battery storage.[57]

7.2.2 Capital Cost Assumptions for Generation and Storage Used in Production Cost Modeling

Table 7.1 summarizes the assumed capital costs of generation and storage resources needed to support hourly energy production. (Additional resources were added after production cost modeling to provide power system stability; these are discussed below.) Most of these costs are based on the 2023 ATB published by NREL [58]. The variable name CAPEX is adopted in order to be consistent with ATB terminology. CAPEX amounts include interest during construction and could also be called the rate base capital costs since they reflect the amounts that must be recovered through rates. The assumed economic lifetime (also known as the capital recovery period) is 20 years for all generation and storage resources except hydro, which has an assumed 40-year economic life. The adjustment from 2021 to 2023 dollars was made using the Handy-Whitman Index of Public Utility Construction Costs (hereafter referred to as the Handy-Whitman Index) [59]. This index grew faster than the overall U.S. Consumer Price Index (CPI) and likely captures some of the recent increases in costs due to supply chain bottlenecks.

Further details regarding these parameters are provided in Appendix R. Specific considerations include the following:

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[53] See, e.g., Chugach Electric's prefiled testimony of Kurt Strunk, National Economic Research Associates, in the Chugach general rate case, TA 544-8, June 30, 2023, at page 11 of Exhibit KGS-02 (*In the Matter of the Tariff Revisions Designated as TA544-8 Filed by Chugach Electric Association, Inc.* Tech. rep. Chugach Electric Association, Inc., July 2023. URL: https://rca.alaska.gov/RCAWeb/ViewFile.aspx?id=b2932d36-0ef0-455c-ad52-a2267458e27d [visited on 01/11/2024])

[54] Federal Reserve Bank of Cleveland. *Inflation Expectations*. en. Inflation Expectations. Dec. 2023. URL: https://www.clevelandfed.org/indicators-and-data/inflation-expectations (visited on 01/11/2024).

[55] Department of Energy. *Inflation Reduction Act Tax Credit Opportunities for Hydropower and Marine Energy*. en. URL: https://www.energy.gov/eere/water/inflation-reduction-act-tax-credit-opportunities-hydropower-and-marine-energy (visited on 01/11/2024).

[56] LeRoy Coleman. *Unpacking the Inflation Reduction Act: What's In It For Waterpower?* en-US. Aug. 2022. URL: https://www.hydro.org/powerhouse/article/unpacking-the-inflation-reduction-act-whats-in-it-for-waterpower/ (visited on 01/11/2024).

[57] The White House. *Clean Energy Tax Provisions in the Inflation Reduction Act | Clean Energy*. en-US. Sept. 2023. URL: https://www.whitehouse.gov/cleanenergy/clean-energy-tax-provisions/ (visited on 01/11/2024).

[58] The 2023 ATB is used for the economic assessment because it provides the most current data (National Renewable Energy Laboratory. *Electricity Annual Technology Baseline (ATB) Data Download*. Annual Technology Baseline. 2022. URL: https://atb.nrel.gov/electricity/2022/data [visited on 12/16/2022]). The 2022 ATB was used for some of the sizing analysis because the 2023 ATB was not available when that analysis was done.

[59] The Handy-Whitman index values are copyrighted and cannot be reproduced here. The were obtained on 11/28/23 from the publicly-available web pages of the New England independent system operator ISO-NE (*FCM—Multiyear Rate Elections*. June 2023. URL: https://www.iso-ne.com/markets-operations/markets/forward-capacity-market/fcm-participation-guide/fcm-multiyear-rate-elections [visited on 01/11/2024]). Handy-Whitman publishes several more specific indexes related to utility costs, but only this one was used throughout this economic assessment.

Table 7.1. Capital costs used in the economic assessment, for generation and storage resources.

Category Description	NREL CAPEX (2021$/kW) (from 2023 ATB unless noted "Alaska cost")	Alaska cost multiplier	Alaska CAPEX in 2021$	Price level adjustment 2021 to 2023$	Rate base capital cost [=NREL CAPEX] before ITC (2023$/kW)	ITC multiplier	Rate base capital cost [=NREL CAPEX] after ITC (2023$/kW)
Onshore wind	1,263	1.94	2,450	1.200	2,940	0.7	2,058
Solar PV	1,038	1.5	1,557	1.200	1,868	0.7	1,308
Grant Lake	12,982	*	12,982	1.200	15,578	0.7	10,905
Tidal	8,459	*	8,459	1.200	10,151	0.7	7,106
Nuclear (SMR)	8,443	1.25	10,554	1.200	12,665	0.7	8,865
Gas-CC	1,161	1.25	1,451	1.200	1,742	1.0	1,742
Gas-CT	1,050	1.25	1,313	1.200	1,575	1.0	1,575
Battery energy storage (2-hr)	748	1.25	935	1.200	1,122	0.7	785
Battery energy storage (6-hr)	1,656	1.25	2,070	1.200	2,484	0.7	1,739

* Alaska Cost

- Susitna-Watana is costed separately (see Appendix R) because it is a unique project for which detailed cost estimates have been prepared. The assumed capital cost (pre-ITC) is 9.019 billion 2023 dollars and the assumed fixed O&M is 34.2 million 2023 dollars per year.
- The Grant Lake project capital cost in this table is specific to Grant Lake, since it is the only new hydro project other than Susitna-Watana that was included in the scenarios [60].
- The costs for tidal energy are not from the ATB. They are calculated from an assumed levelized cost of energy of 25 cents/kWh for Cook Inlet tidal [61]. Further details are provided in Appendix R.
- The Dixon Diversion, which is included in the BAU and low-carbon scenarios, has an assumed capital cost (pre-ITC) of 441 million 2023 dollars. It is assumed eligible for a 30% ITC. Further details are provided in Appendix R.

7.2.3 Capital Cost Assumptions for Transmission Upgrades

The southern transmission upgrade, which is assumed in all scenarios, includes the Bernice Lake-Beluga HVDC line and the upgrade of the Kenai Intertie to 230 kV. The northern transmission upgrade, which is assumed in the three low-carbon scenarios, includes the upgrade of the Douglas-Healy line to 230 KV. The capital costs of these upgrades are 2023 estimates provided by the Railbelt utilities, less a reduction of 50% of the HVDC line cost (50% x $329 million = $164.5 million reduction) due to u.S. Department of Energy grant funding. The resulting capital costs are

[60] The capital cost of $52.1 million in 2016 was taken from the FERC license application submitted by Kenai Hydro (*Grant Lake Hydroelectric Project (FERC No. 13212) Final License Application for an Original License*. Volume I: Public. Homer, AK: Kenai Hydro, LLC, Apr. 2016, p. 118. URL: http://www.kenaihydro.com/documents/FLA/GrantLkCvr-ExhDFinal.pdf [visited on 12/09/2022]) (page D-2). Escalation from 2016 to 2023 was done using the Handy-Whitman Index. See Appendix R for details.

[61] The 25-cent target was included in a presentation by NREL staff to the Cook Inlet Tidal Working Group in 2022. It was based on expert elicitation and was presented as 25 cents +or- 5 cents.

$467.5 million for the southern upgrades and $312 million for the northern upgrade. The assumed economic lifetime of transmission is 30 years.

7.2.4 Capital Cost Assumptions for Additional Resources Used for Stability and Grid Support

Table 7.2 summarizes the capital costs for the new assets added for stability by the **PSS®E!** analysis, as discussed in Section 6. These assets were not accounted for during the resource sizing step. Therefore, these capital costs are in addition to costs presented above for generation and storage assets. The price adjustment factors from 2017 or 2021 dollars to 2023 dollars use the Handy-Whitman Index. Further details are provided in Appendix R.

Table 7.2. Capital costs for transmission upgrades and stability resources.

Resource Description	Units	Unit cost (Alaska prices)	Year of unit cost	Price adjustment to 2023	Unit cost (2023 $000)	ITC multiplier	2023 $000 per unit
HVDC and Kenai Intertie 230kV upgrade	package	467,500,000	2023	1.000	467,500	1.0	467,500
Alaska Intertie 230kV upgrade	package	312,000,000	2023	1.000	312,000	1.0	312,000
Synchronous condensers	MVA	403,500	2023	1.000	404	1.0	404
Capacitors	MVAr	14,134	2023	1.000	14	1.0	14
Transformers	each	17,000	2017	1.435	24	1.0	24
Reconductored lines	mile	120,000	2017	1.435	172	1.0	172
Battery energy storage (30 min)	2021$/kW	509	2021	1.200	611	0.7	428

7.2.5 Assumptions about Fixed O&M

Table 7.3 shows the assumed fixed O&M costs for resources. Most values are based on the 2023 NREL ATB. The price level adjustment from 2021 to 2023 dollars was made using the U.S. consumer price index (CPI), reflecting the idea that much of the fixed annual O&M cost is for labor[62]. The fixed O&M for each transmission upgrade was assumed to be $2 million per year, which is approximately equal to the 2023 O&M expense budgeted for the existing Alaska Intertie.[63]

7.2.6 Assumptions about Year Placed in Service

The general assumption adopted for modeling cost was that new resources are placed in service in 2040 and are thus halfway through their economic lives in 2050. This assumption is a proxy for a broad mix of in-service dates, each of which would yield annualized capital costs that would be relatively high or low compared to the mid-life value. There are some exceptions to the year 2040 assumption:

- Grant Lake is assumed in service in 2030. It has been planned and licensed[64] and would likely not be delayed until 2040.
- Existing BESS resources are assumed to be rebuilt/replaced in 2043 because 2040 would be slightly early given that these existing resources are currently entering service.

[62] The change in the Alaska average monthly wage in the power generation industry was also considered. The U.S. CPI increased faster, so it was adopted. It is likely that wages will catch up to recent inflation as new labor contracts are negotiated.

[63] *7B. FY23 AK Intertie Proposed Budget*. Tech. rep. Alaska Energy Authority, 2023. URL: https://www.akenergyauthority.org/Portals/0/RailBeltEnergy/IMC/2022/2022.05.20/7B.%20%20FY23%20AK%20Intertie%20Proposed%20Budget%20Final.pdf?ver=2022-05-19-100141-943 (visited on 12/19/2023).

[64] Renewable Energy World. *FERC issues license for 5-MW Grant Lake Hydroelectric Project in Alaska*. Sept. 2019. URL: https://www.renewableenergyworld.com/baseload/hydropower/ferc-issues-license-for-5-mw-grant-lake-hydroelectric-project-in-alaska/ (visited on 01/11/2024).

Table 7.3. Fixed O&M costs used in the economic assessment.

Resource	Fixed O&M (2021$/kW-y) (from 2023 ATB unless noted as "Alaska Cost")	Alaska cost multiplier	Price level adjustment 2021 to 2023$ (CPI)	Fixed O&M (2023$/ kW-y)
Onshore wind	35	2.5	1.127	99
Solar PV	18	2.5	1.127	51
Grant Lake	38	*	1.127	43
Cooper Lake	-	-	**	69
Eklutna Lake	-	-	**	17
Bradley Lake	-	-	***	71
Tidal	70	2.5	1.127	197
Nuclear (SMR)	119	1.5	1.127	201
Gas-CC	29	1.5	1.127	49
Gas-CT	23	1.5	1.127	39
Gas-IC	35	*	1.127	39
Coal	163	*	1.127	184
Oil (diesel and naphtha)	39	*	1.127	43
Battery energy storage (2-hr)	19	1.5	1.127	32
Battery energy storage (6-hr)	41	1.5	1.127	69
Battery energy storage (30-min)	19	1.5	1.127	32
Transmission upgrade Southern region	-	-	-	2,000
Transmission upgrade Northern region	-	-	-	2,000

* Alaska cost
** Estimated from CEA 2022 FERC Form 1.
*** Estimated from Bradley Lake Project Management Committee fiscal year 2020, 2019 financial statements.

7.3 Generation and Transmission Cost of Service Results

7.3.1 Total Capital Expenditures

The total required amount of new investment in utility plant, or CAPEX, ranges from $2.3 billion under the BAU scenario to $11.8 billion under the Wind/Solar/Hydro scenario. Total amounts are shown in Table 7.4 and Figure 7.1.

7.3.2 Base Case Generation and Transmission Cost of Service

As shown in Table 7.5, in the base case the G&T COS is $119 per MWh generated under the BAU scenario and ranges from $128 to $134 per MWh generated across the low-carbon scenarios. Table 7.6 also shows the estimated cost per MWh sold, assuming 5% transmission and distribution losses. The costs of the low-carbon scenarios are remarkably similar: Given the large uncertainties in the input assumptions, they are essentially equal.

The relative contributions of fuel, O&M, and capital to the total COS vary widely and are shown in Figure 7.2. Fixed O&M is especially significant in the low-carbon scenarios.

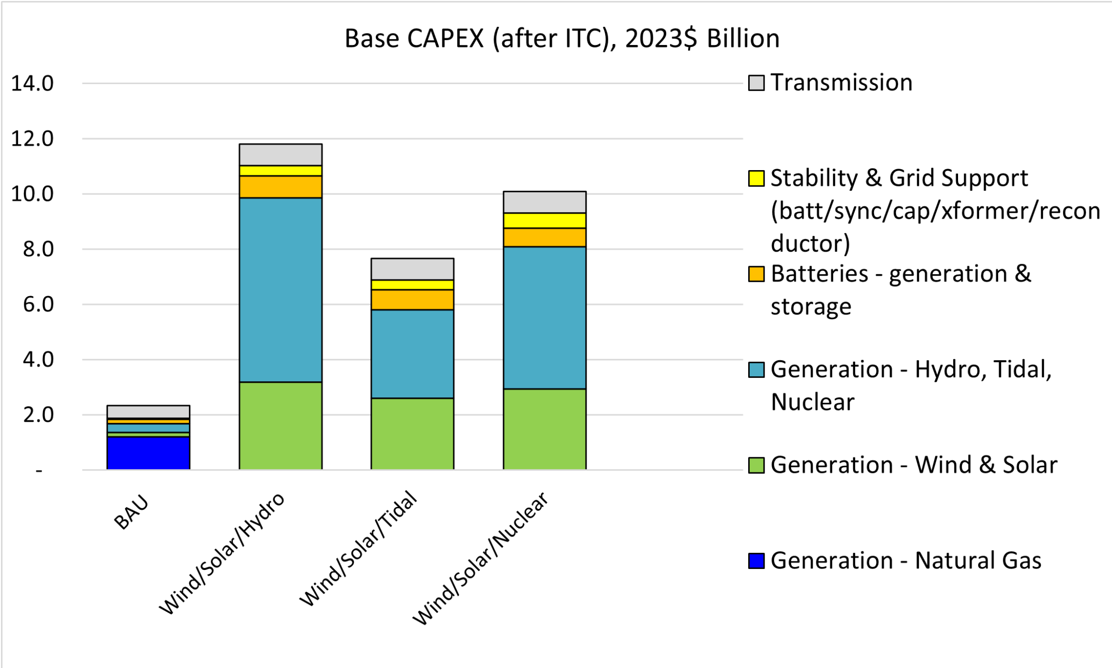

Figure 7.1. Base case CAPEX after ITC, 2023$ Billion

Table 7.4. Base Case capital investment costs, after applicable ITC, by scenario, 2023$ Billion

Resource	Wind/Solar/Hydro	Wind/Solar/Tidal	Wind/Solar/Nuclear
Generation - Natural Gas	-	-	-
Generation - Wind and Solar	3.2	2.6	2.9
Generation - Hydro, Tidal, Nuclear	6.7	3.2	5.1
Batteries - Generation and Storage	0.8	0.7	0.7
Stability and Grid Support (batteries, synchronous condensers, shunt capacitors, transformer, reconductored lines)	0.4	0.4	0.6
Transmission	0.8	0.8	0.8
Total	11.8	7.7	10.1

7.3.3 Sensitivity Cases

This section considers four sensitivity cases. In each case one or more key assumptions is varied up or down by 20% from the base values. Table 7.6 shows which key factors are varied to produce each sensitivity case. The CAPEX variations are for the listed projects only – Susitna-Watana, East Forelands tidal, and two nuclear reactors. The aim of these cases is to explore variation in the most uncertain cost components, which include fuel costs and the capital costs of the big projects (Susitna-Watana) and/or the immature technologies (tidal and nuclear). There is no variation among sensitivity cases in the CAPEX values for wind and solar PV (although the annualized capital cost of wind and solar is affected by the interest rate).

The variation in G&T COS is summarized in Table 7.7 and Figure 7.4, which groups the cases by scenario and gives a general sense of how the COS varies with fuel costs and capital costs within each scenario. As might be expected, the BAU scenario is exposed almost exclusively to fuel price risk, while the low-carbon scenarios are exposed to more varied risks. The Wind/Solar/Hydro and Wind/Solar/Nuclear scenarios show the greatest potential variability. In these scenarios the uncertainty would largely resolve itself after the large projects (Susitna-Watana hydro or nuclear SMR's) are placed in service and become "stably-priced" resources. However, prior to project completion, there could be great uncertainty about the eventual outcome.

Table 7.5. Base case G&T cost of service.

Cost component in 2023$ 000	**BAU**	**Wind/Solar/ Hydro**	**Wind/Solar/ Tidal**	**Wind/Solar/ Nuclear**
Fuel cost per Plexos	744,936	110,440	293,224	52,609
Fuel cost adjustment factor ($14/MMBtu =1.00)	1.00			
Adjusted fuel cost	744,936	110,440	293,224	52,609
Variable O&M	16,289	2,250	2,248	13,006
Startup & Shutdown	1,956	3,779	3,744	3,386
$/hr O&M cost	11,100	5,998	14,434	2,016
Total Variable Generation Cost	**774,280**	**122,468**	**313,649**	**71,017**
Generation fixed O&M	127,873	373,073	308,857	375,359
Generation debt service and margin	115,455	630,109	464,046	631,641
Total Generation COS	**1,017,608**	**1,125,650**	**1,086,553**	**1,078,017**
Transmission cost (O&M+debt service+margin)	22,415	41,856	41,856	41,856
Total G&T COS	**1,040,023**	**1,167,506**	**1,128,409**	**1,119,873**
Total Net Generation, GWh	8,708	8,731	8,785	8,744
Total Generation & Transmission $ per MWh generated	119	134	128	128
MWh sold @ 95% of generated	8,272	8,294	8,346	8,307
Total Generation & Transmission $ per MWh sold	**126**	**141**	**135**	**135**

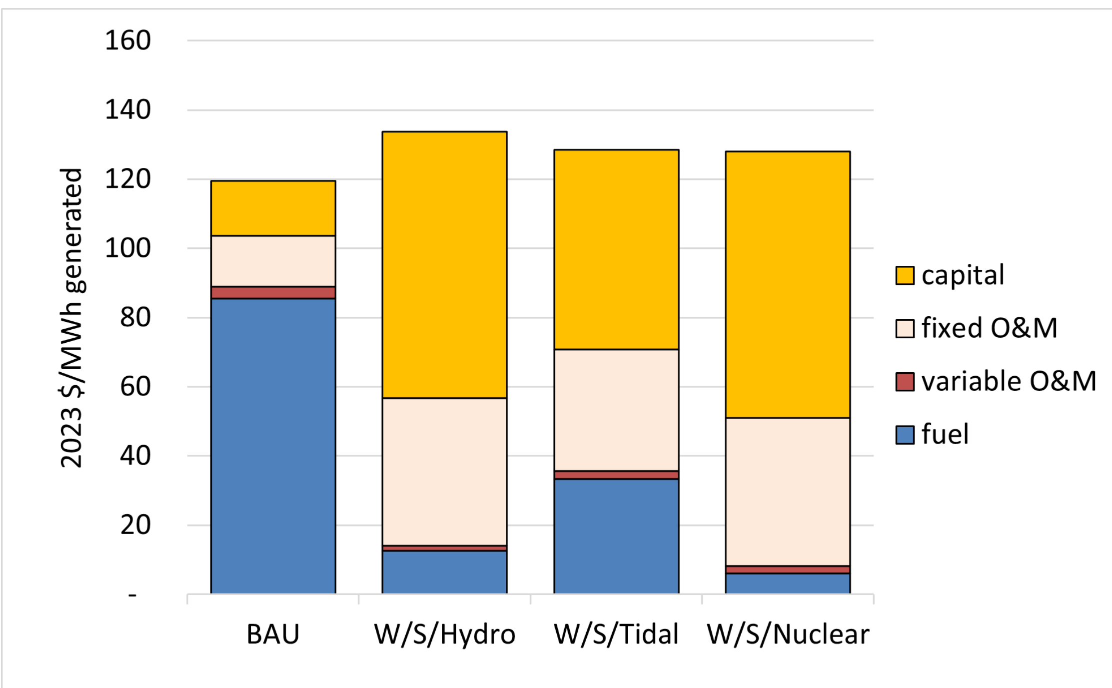

Figure 7.2. Base case G&T Cost of Service by component, 2023$ per MWh generated.

Figure 7.5 summarizes the COS analysis developed in this section. These charts reveals the many ways in which the scenarios differ and how their differing reliance on fuel, O&M, and capital inputs translates into changes in the COS when the costs of these input resources change.

How do changes to G&T COS impact my electric bill?
To provide some perspective on these reported costs, a G&T COS of service of $120/MWh equals $0.12/kWh. Figure 7.3 is an example of an electric bill from GVEA. There are several types of charges including, the Customer Charge, the Utility Charge, the Fuel & Purchased Power, the Regulatory Cost Charge, the ERO Surcharge, and the voluntary GVEA Goodcents program that rounds up the bill to the nearest dollar as a donation to nonprofit organizations.

Meter #	Billing Period		Days	Readings		Meter Multiplier	Usage	Rate
	From	To		Previous	Present			
[redacted]	11/01/23	12/01/23	30	40113	40573	1	460	RES1

Previous Account Activity		Current Activity			
Previous Balance	$120.00	Customer Charge			$22.50
Payment Received - Thank You	-$120.00	Utility Charge	460 KWH	@ 0.131090	$60.30
Balance Forward	$0.00	Fuel & Purchased Power	460 KWH	@ 0.117630	$54.11
		Regulatory Cost Charge	460 KWH	@ 0.001028	$0.47
		ERO Surcharge	460 KWH	@ 0.001010	$0.46
		Goodcents			$0.16
		Current Charges			$138.00

Figure 7.3. Example GVEA Electric Bill

The G&T COS corresponds to the “Fuel & Purchased Power” charge plus a portion of the “Utility Charge” on this sample bill. If the G&T COS increased by $10/MWh, the charges on the bill would increase by $0.01/kWh. Since the bill covers 460 kWh for a single month, the bill would increase by $4.60 for that month. Fuel is the dominant cost of today’s Railbelt G&T cost of service, and it would remain so in 2050 under the BAU scenario. As the current fleet of generation assets is paid off over time, capital costs under BAU would become a relatively minor cost component. By contrast, the three low-carbon scenarios require that large amounts of capital investment be paid off, but the annual fuel expense becomes relatively minor. Fixed O&M also plays a larger role in the cost of the low-carbon scenarios. Although renewable resources have zero fuel cost, they still require significant ongoing annual O&M.

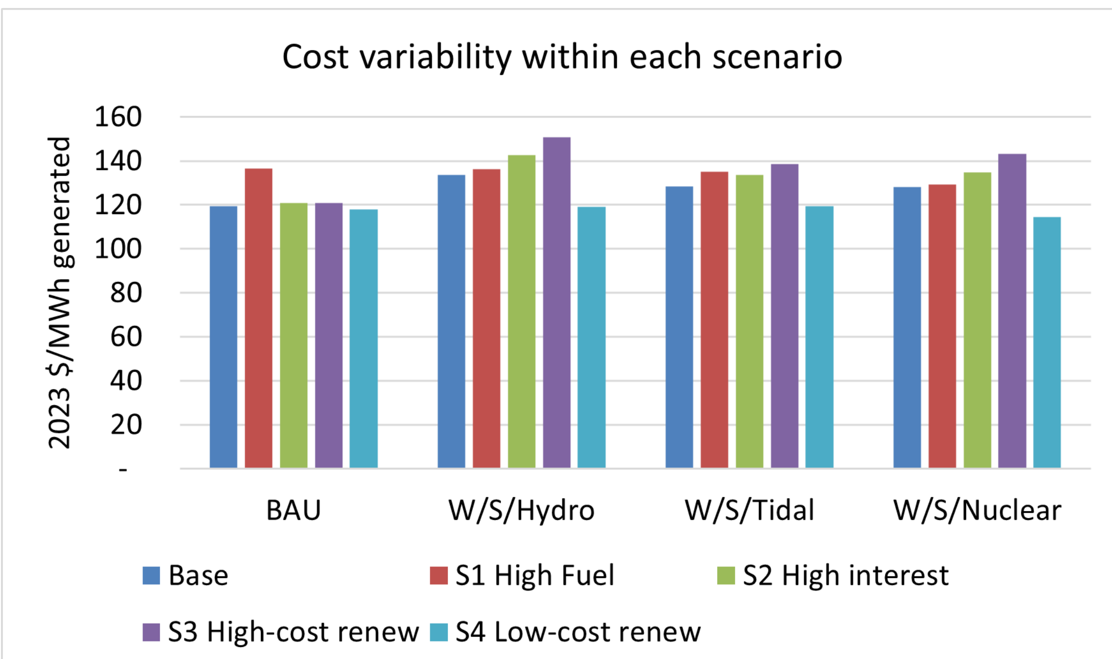

Figure 7.4. Variation in cost of service across sensitivity factors, within each scenario.

7.4 Economic Analysis Key Findings

- **The required capital investment to implement the low-carbon scenarios, after application of allowed ITC amounts, ranges from about 8 billion to about 12 billion in 2023 dollars under base case assump-**

Table 7.6. Components of four sensitivity cases showing variation in the G&T Cost of Service

		Sensitivity Case Name			
Case attributes	**Base**	**S1: High fuel**	**S2: High interest**	**S3: High-cost renewables**	**S4: Low-cost renewables**
Fuel price adjustment factor	Base	Base+20%	Base	Base	Base
Susitna-Watana CAPEX (pre-ITC)	Base	Base	Base	Base+20%	Base-20%
Tidal CAPEX per kW (pre-ITC)	Base	Base	Base	Base+20%	Base-20%
Nuclear CAPEX per kW (pre-ITC)	Base	Base	Base	Base+20%	Base-20%
Interest rate	Base	Base	Base+20%	Base+20%	Base-20%
Case values					
Fuel price adjustment factor	1.00	1.20	1.00	1.00	1.00
Susitna-Watana CAPEX (pre-ITC, 2023 $ billion)	9.02	9.02	9.02	10.82	7.22
Tidal CAPEX per kW (pre-ITC)	10,151	10,151	10,151	12,181	8,121
Nuclear CAPEX per kW (pre-ITC)	10,132	10,132	10,132	12,158	8,105
Interest rate	5%	5.0%	6.0%	6.0%	4.0%

Table 7.7. Summary of sensitivity cases, showing 2023 $/MWh generated

Cost per MWh generated	**BAU**	**Wind/Solar/Hydro**	**Wind/Solar/Tidal**	**Wind/Solar/Nuclear**
Base	119	134	128	128
S1 High fuel	137	136	135	129
S2 High interest	121	143	134	135
S3 High-cost renewables	121	151	138	143
S4 Low-cost renewables	118	119	119	115
Change from Base				
S1 High fuel	17	3	7	1
S2 High interest	1	9	5	7
S3 High-cost renewables	1	17	10	15
S4 Low-cost renewables	-1	-15	-9	-13
Percent change from Base				
S1 High Fuel	14%	2%	5%	1%
S2 High interest	1%	7%	4%	5%
S3 High-cost renewables	1%	13%	8%	12%
S4 Low-cost renewables	-1%	-11%	-7%	-11%

tions. These are large amounts, in part because significantly higher Alaska-specific capital and O&M costs were assumed, and in part because some specific high-cost projects were added to scenarios without first passing an economic screening test. These high up-front costs would be repaid through rates over the economic life of each project. For example, the annualized capital cost of the most capital-intensive scenario (Wind/Solar/Hydro) in 2050 would be about $630 million (for generation). By comparison, the annual fuel expense in 2050 under the BAU scenario equals $745 million.

- **The COS for the low-carbon scenarios, after application of allowed ITC subsidies, differs by -5% to 25% from the BAU scenario depending on varying fuel costs, hydro and nuclear capital costs, and interest rates.** Table 7.8 provides a numerical summary of the economic analysis. Under base case assumptions, which include a year 2050 natural gas price of $14/MMBtu (in 2023 dollars) and Alaska-specific (thus relatively high) capital and fixed O&M costs, the G&T COS for the low-carbon scenarios ranges from 7% to 12% higher than for the BAU scenario. However, if fuel prices were 20% higher (case S2), the low-carbon scenarios would cost from 5% less to the same as BAU, all else being equal. Similarly, if the interest rate and capital costs of the hydro, tidal, and nuclear projects were 20% lower (case S4), the low-carbon scenarios would cost from 3% less to 1% more than BAU.

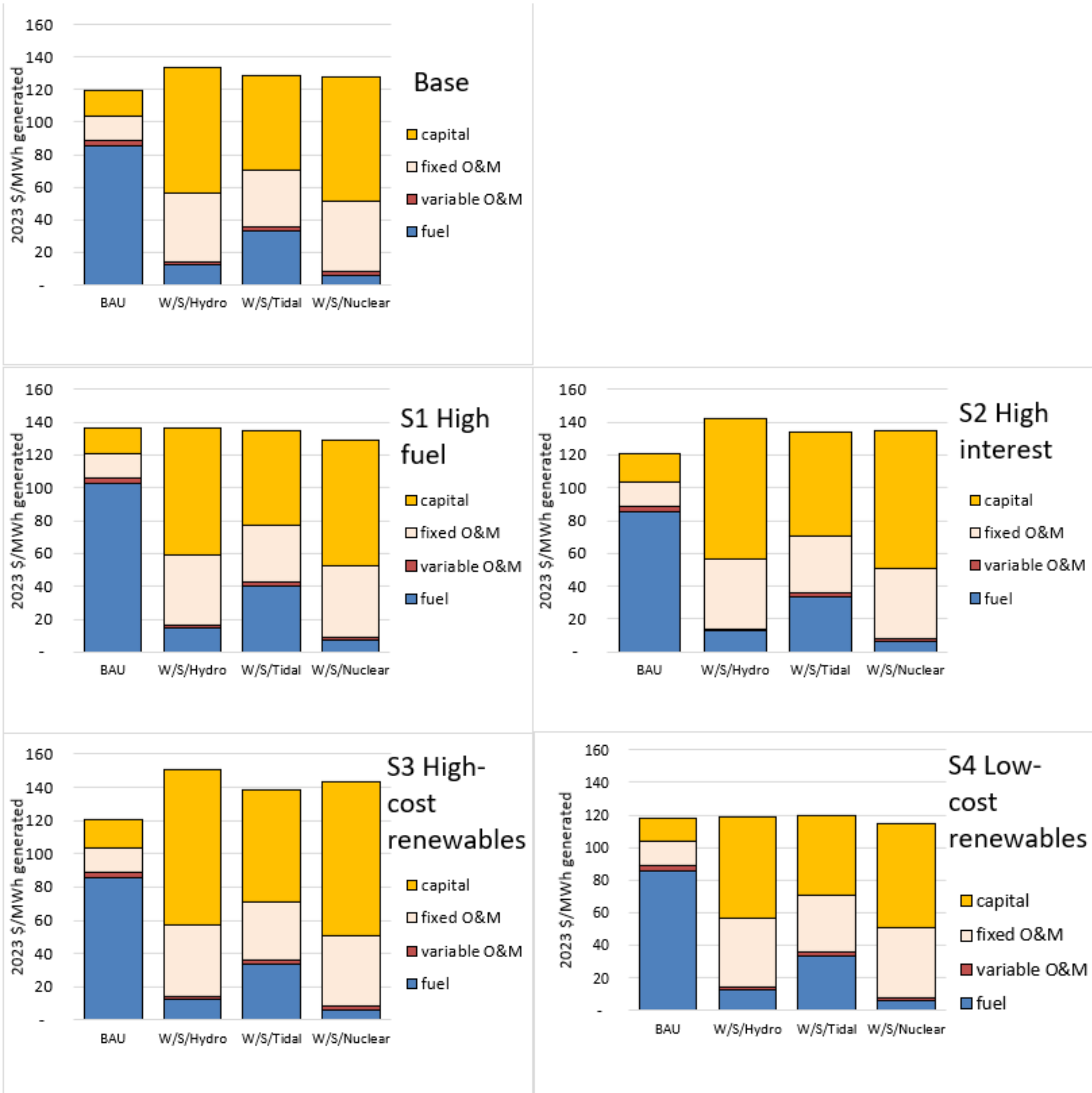

Figure 7.5. Summary of the cost of service, by component and scenario, under four sensitivity cases, in 2023 $ per MWh generated.

Table 7.8. Summary of G&T cost of service relative to BAU, for each scenario.

Percent change from BAU	Wind/Solar/Hydro	Wind/Solar/Tidal	Wind/Solar/Nuclear
Base	12%	8%	7%
S1 High fuel	0%	-1%	-5%
S2 High interest	18%	10%	12%
S3 High-cost renewables	25%	14%	18%
S4 Low-cost renewables	1%	1%	-3%

However, if interest rates and/or the capital costs of renewables were 20% higher than base case levels, the G&T COS of the low-carbon scenarios could exceed that of BAU by 18% to 25%[65].

- **Finally, this study did not evaluate the cost-effectiveness of near-term renewable additions. Instead it evaluated illustrative future high-decarbonization portfolios.** The cumulative cost of achieving high levels

[65] When considering these percentages, it is important to remember that a 25% percent increase in the cost of generation and transmission would not translate into a 25% increase in the overall COS, because other cost components (distribution, customer accounts, administration) would likely remain constant across the four scenarios).

of renewable penetration is non-linear, due to increased transmission and storage requirements. Additionally, from now till at least 2030, low-carbon projects will qualify for ITCs of 40-50%[66] of project capital costs. This creates an additional incentive to install renewable energy projects early. The values estimated here for 2050 should not be used to quantify the cost effectiveness of near-term wind and solar resource additions.

[66]All of Alaska qualifies as an energy community as defined by the US Department of Energy, which increases ITC from 30% to 40%. Projects that use domestically produced products qualify for an additional 10% for a total of 50%. The major wind manufacturers are producing enough components in the US to qualify for domestic content. Major solar and battery manufacturers are also qualifying for domestic content.

8 Conclusion

This study evaluates several decarbonization scenarios of the Railbelt electric grid in Alaska for the year 2050. The scenarios are meant to be illustrative examples as a pre-feasibility study, highlighting the ability of certain resources and resource mixes to create a low-carbon electric grid for evaluation based on affordability and reliability. Additional analysis is necessary for implementation of new resources, technologies, and transmission. What is presented in this work is neither a prediction of the future or a suggestion of an optimal low-carbon future.

This project aims to provide valuable information to the Alaskan public and decision makers on the economic and reliability implications of several decarbonization scenarios and to demonstrate methods for evaluating of Railbelt energy transitions. Additionally, a key intention of this work has been to build capacity within Alaska to perform the types of analyses needed to evaluate energy transitions. The information generated from this study includes general information such as resource availability and load forecasts, and information specific to the developed decarbonization scenarios such as stability and reliability of the system, and the impact to rates.

Through a multi-stage analysis process the project performed resource analysis to determine availability and sizing, load forecasting, economic dispatch of generation, stability analysis, and economic analysis. The accumulation of this analysis results in a set of resources for each scenario. The complete collection of resources in each of the scenarios is compiled in Table 8.1.

Economic analysis, including the assessment of capital costs, fuel costs, O&M costs, and financing provides insight into the potential cost implications of these scenarios. The COS for each scenario was calculated, and is presented in Figure 8.1. These charts reveal the many ways in which the scenarios differ and how their differing reliance on fuel, O&M, and capital inputs translates into changes in the cost of service when the costs of these input resources change.

These results are specific to the scenarios studied in this project, for the year 2050. What is presented in this work is neither a prediction of the future nor a suggestion of an optimal low-carbon future. These scenarios are illustrative and do not attempt to identify the lowest cost scenario for 2050. Additionally, this study did not evaluate the cost-effectiveness of near-term renewable additions. Instead it evaluated illustrative future high-decarbonization portfolios. The cumulative cost of achieving high levels of renewable penetration is non-linear, due to increased transmission and storage requirements. Additionally, from now untill at least 2030, low-carbon projects will qualify for ITCs of 40-50% [67] of project capital costs. This creates an additional incentive to install renewable energy projects early. The values estimated here for 2050 should not be used to quantify the cost effectiveness of near-term wind and solar resource additions.

This study provides value through demonstrating the process of evaluating decarbonization scenarios, illustrating the types of stability challenges and mitigations that can arise with the integration of IBRs such as wind, solar, and tidal, providing an example of how scenarios can be quantified in terms of COS, and developing valuable information that can be used by Railbelt stakeholders in future studies of real implementations of new resources and technologies.

[67] All of Alaska qualifies as an energy community as defined by the US Department of Energy, which increases ITC from 30% to 40%. Projects that use domestically produced products qualify for an additional 10% for a total of 50%. The major wind manufacturers are producing enough components in the US to qualify for domestic content. Major solar and battery manufacturers are also qualifying for domestic content.

Table 8.1. Summary of all resources in the current system and the scenarios developed in this study.

Resource Type	Resource	Current System	BAU	Wind/Solar/ Hydro	Wind/Solar/ Tidal	Wind/Solar/ Nuclear*
Hydro	Susitna-Watana	–	–	459-608 ****	–	–
	Grant Lake	–	–	5	5	5
	Bradley Lake	120	120	120	120	120
	Eklutna Lake	40	40	40	40	40
	Cooper Lake	19.4	19.4	19.4	19.4	19.4
Wind	Delta	1.9	1.9	50	7	50
	Eva Creek	24.6	24.6	74	132	160
	Fire Island	18	18	36	18	36
	Homer	–	–	213	231	285
	Houston	–	–	185	165	49
	Little Mount Susitna	–	30	315	214	265
	Shovel Creek	–	–	223	231	285
Solar Photovoltaics	Fairbanks	0.56	1	1	1	1
	Houston	8.5	8.5	45	33	30
	Nenana	–	–	45	66	60
	Point Mackenzie	–	–	90	33	30
	Sterling	–	–	255	33	96
	Willow	1.20	–	45	33	30
Residential Solar Photovoltaics	Northern	∼5**	43.3	43.3	43.3	43.3
	Central	∼10**	139.9	139.9	139.9	139.9
	Southern	∼4**	44.3	44.3	44.3	44.3
Tidal	Cook Inlet	–	–	–	400	–
Nuclear	Healy	–	–	–	–	231
	Beluga	–	–	–	–	308
Fossil-Fuel	Coal	114	54	-	-	-
	Natural-gas/Naphtha powered combined cycle	495	1,095	495	495	495
	Natural-gas powered internal combustion	171	171	171	171	171
	Natural-gas powered combustion turbines	468	568	468	872	468
	Oil power generation	198	198	198	198	198
Li-ion Batteries	30-minute	27	50	808	390	1,117
	2-hr	46.5	146.5	282	227	287
	4-hr	-	70	70	70	70
	6-hr	-	-	300	280	261
Synchronous Condensers		***	-	-	358	90
Shunt Capacitors		***	-	91	75	185

* The Wind/Solar/Nuclear scenario assumes that naphtha, or an equivalent priced fuel, replaces natural gas.

** Estimated by the 2020 number of net meter customers and scaled by estimated growth from EIA Form 861.

*** Reactive power compensation equipment such as shunt capacitors exist in the current system, but are not tabulated in this study. The scenarios in the study list the synchronous condensers and shunts added to the system, in addition to what is already present.

**** Susitna-Watana maximum power capability depends on the level of water in its reservoir.

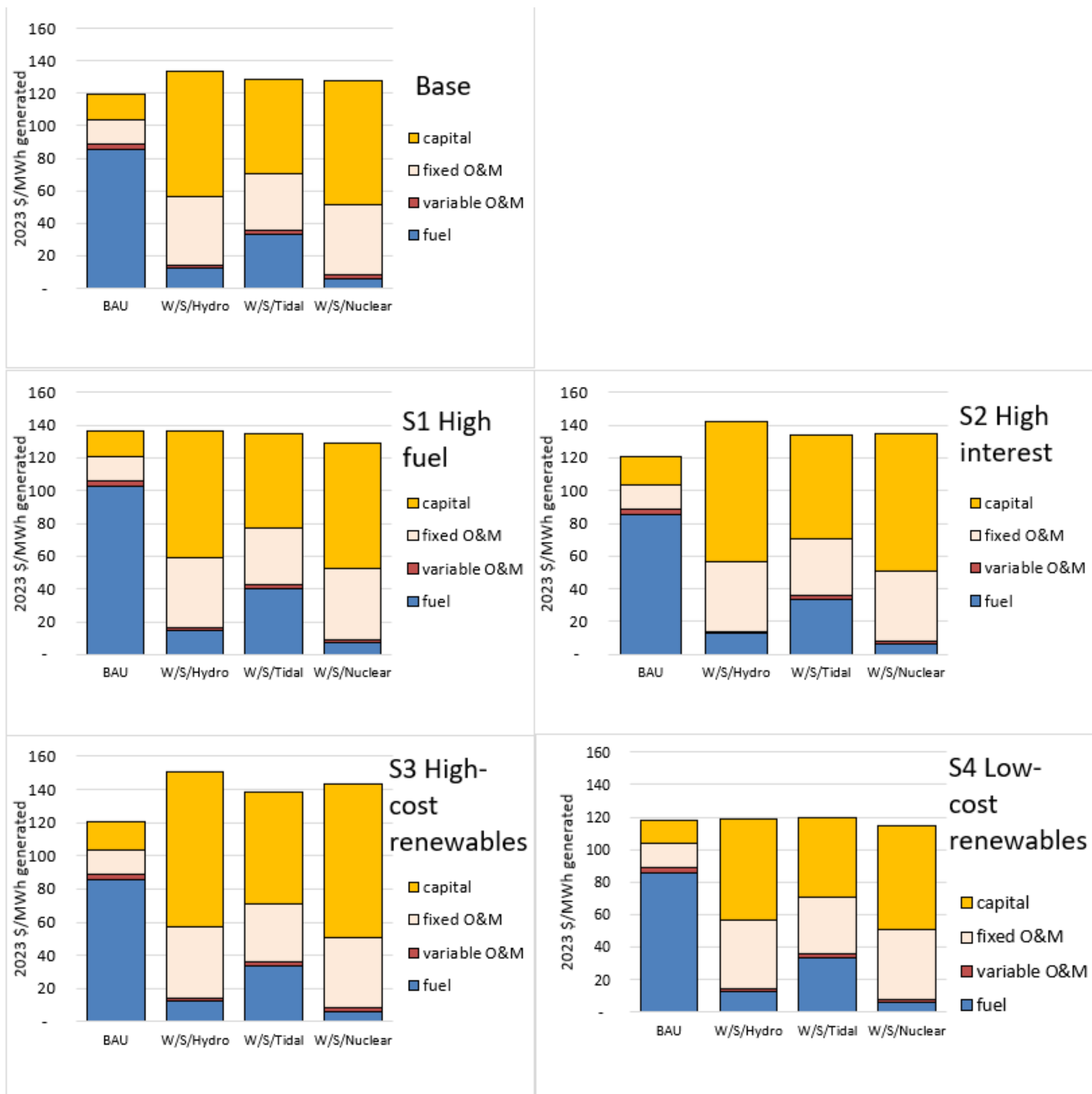

Figure 8.1. Summary of the cost of service, by component and scenario, under four sensitivity cases, in 2023 $ per MWh generated.

9 Next Steps

Over the course of this study, the team identified additional topics, challenges, and opportunities that were not included in this scope of work. Following is an unranked list of topics that should be further addressed.

Other Scenarios

- Wind and solar energy only scenario
- Fully optimized scenarios using capacity expansion modeling
- Evaluating year-by-year energy transitions

Reliability and Resource Adequacy

- The Railbelt poses unique challenges for reliability and resource adequacy. As a relatively small system, the loss of a single generator, especially larger synchronous generation units pose large contingencies and challenge reliability.
- Portfolios were designed to meet load across the entire year, but the evaluation did not include multiple years of weather conditions, extreme weather, or operations when the tie-lines are unavailable.
- While initial estimates of reserve margins were considered for each utility, further probabilistic resource adequacy analysis should be conducted to refine total capacity needs.
- For a more optimal evaluation of scenarios, identified grid stability challenges would inform dispatch decisions in the generation analysis section. The goal of this iteration would be to create more cost optimal mitigations to stability challenges.
- Wind and solar generation forecasting
- Demand response loads

Grid Stability

- Iterative Analysis: This study evaluated each step of the analysis sequentially as presented in Figure 1.2. A more optimal process would iterate back and forth between transmission analysis and generation analysis. In this iterative process, stability challenges identified in the transmission analysis would inform dispatch decisions in the generation analysis. The goal of this iteration would be to create more cost optimal mitigations to stability challenges. An iterative approach was beyond the scope of this report; however, it is recommended for future work.
- EMT analysis for detailed assessment of stability necessary for integration studies.
- Hosting capacity of DERs such as residential or commercial solar PV.

Policy, Regulatory and Ratemaking

- Opportunities created by federal incentives and grants
- Policies for creating an independent system operator or transmission system operator
- Effect of energy efficiency measures on building energy efficiency and impact on heat pump loads
- Utility rate structure impacts on decarbonization and energy equity
- Right-of-way and permitting challenges

Environmental Considerations

- Climate change impacts to renewable technologies in Alaska (e.g., the effect of precipitation, permafrost degradation, glacier melting and groundwater changes affecting hydro capacity, or of changing cloud cover affecting solar capacity)
- Effect of nuclear waste disposal on advanced micronuclear economics

Other Related Sources of Carbon Emission

- Carbon emissions from renewable energy technology construction (concrete used in large-scale hydroelectric projects, manufacturing of solar and wind technologies, mining of materials used for solar and wind technologies)
- Fugitive methane emissions in hydrogen and blue ammonia production

Emerging Technologies

- Thermal, chemical, or mechanical long-duration energy storage
- Hydrogen generation

Other Sector Decarbonization

- Heating
- Transportation
- Industrial Processes, mining and oil

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