CHUGACH
POWERING ALASKA'S FUTURE

INTEGRATED RESOURCE PLAN (IRP)

CHUGACH ELECTRIC ASSOCIATION, INC

APRIL 2024

PUBLIC VERSION

Cooper Lake Hydroelectric Power Plant

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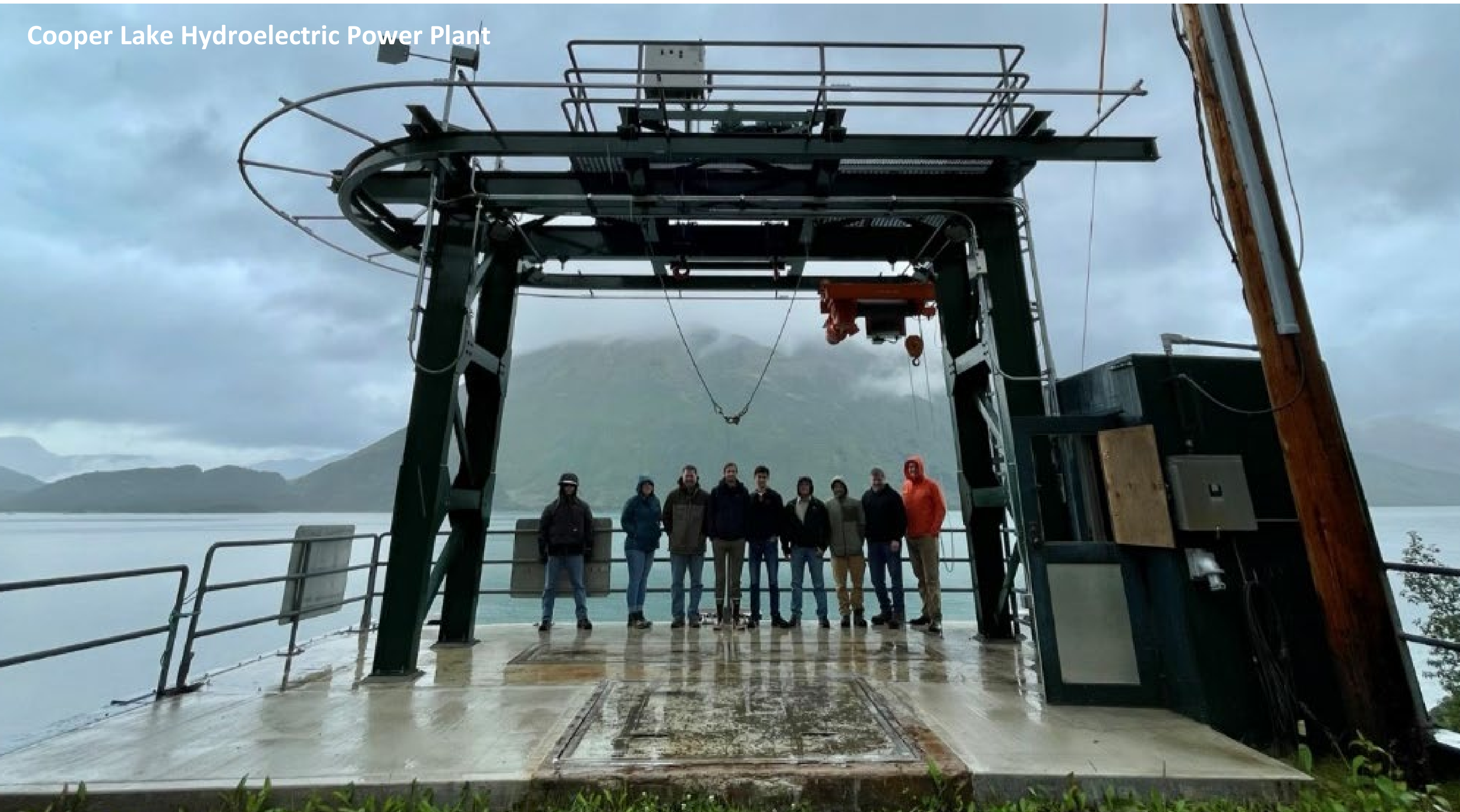
EXECUTIVE SUMMARY

Chugach Electric Association, Inc.'s (Chugach) mission is to provide safe, reliable and affordable electricity through superior service and sustainable practices, powering the lives of our members.   Chugach is a not-for-profit electric cooperative, and is the largest electric utility in the state. Chugach provides electric service to over 113,000 retail locations ranging from the Municipality of Anchorage to the northern Kenai Peninsula westward to Tyonek, including Fire Island, and eastward to Whittier. Chugach continues to proactively pursue growth and innovation.

The electric industry is undergoing a significant transformation as consumer preferences evolve and technology advances. How Chugach generates and delivers power for its members tomorrow will be vastly different today. Chugach embraces the opportunities and is rising to the challenges that these changes will bring. Chugach established decarbonization goals aligned with our vision for a clean, sustainable future for Alaska. This decarbonization strategic priority aims to reduce Chugach's carbon intensity by at least 35% by 2030 and at least 50% by 2040 with no material negative impact on rates or reliability.

The 2024 Integrated Resource Plan (IRP) is charting a course to meet and exceed these carbon reduction goals, doing so reliably and at the least possible cost. The IRP evaluated a wide range of technology options, timing and combinations to support a recommended Preferred Plan. Chugach's Preferred Plan includes adding 324 MW of utility scale wind, 340 MW of battery energy storage and increasing hydroelectric production by about 20% resulting in a 75% reduction in carbon emissions compared to 2012 levels while lowering the cost of power supply by 5% compared to the continued utilization of current generation assets.

This IRP sets a roadmap to achieve Chugach's vision of responsibly developing energy to build a clean, sustainable future for Alaska. Achieving these bold plans will require teamwork, collaboration, agility, planning and a sharp execution edge.



Cooper Lake Hydroelectric Power Plant

IRP SUMMARY

IRP OVERVIEW

An Integrated Resource Plan serves as a strategic framework for electric utilities, including Chugach, to effectively manage their power supply portfolios over both short-term and long-term planning horizons. Central to an IRP is the primary goal of providing an economic evaluation of the utility's power supply portfolio. This evaluation extends beyond immediate considerations, focusing on short-term decisions that position the utility for long-term success. By integrating economic assessments into the planning process, an IRP allows utilities to optimize resource allocation, balance costs with reliability, and mitigate risks while ensuring sustainability and resilience in the face of evolving energy landscapes and regulatory frameworks. Thus, for Chugach, an IRP is not just a planning tool but a strategic imperative that guides decision-making to achieve both immediate and future objectives while delivering reliable and cost-effective electricity to its members.

Chugach consulted with 1898 & Co., part of Burns & McDonnell, on its IRP. 1898 & Co. is recognized nationally for their work in power, transmission, and a variety of heavy industry and infrastructure planning, design and construction. In the formation of the IRP they reviewed transmission constraints, new supply resources, existing power supply, new demand side resources and various forecasts; including load, fuel and market products. Once the data was gathered, the development of scenarios and sensitives are reviewed. Through economic screen and cost-benefit evaluations identified scenarios outperform others and inform the preferred power supply plan. Chugach identified its 2024 IRP objective as outlined below.

Develop an economic evaluation of Chugach's power supply portfolio over both short-term and long-term planning horizons that meets our decarbonization goals at the lowest possible cost. Dynamically evaluate and consider key issues and critical questions including but not limited to impacts of fuel supply changes, future mission of aging thermal assets, carbon reduction levels off system sales, beneficial electrification/load changes, transmission additions, submarine cable retirements/replacements, renewable and clean energy additions, federal and state funding, and financial impacts on the business and member rates.

The IRP efforts directly tie into strategic priorities outlined in Chugach Electric's Business Planning & Economic Development, Decarbonization, and Natural Gas Supply initiatives.

The Chugach Integrated Resource Planning Team, comprised of ten Chugach subject matter experts, completed the IRP over an eight-month period guided by the Project's Executive Steering Committee. This committee, consisting of the entire executive team, ensured thorough oversight and alignment with strategic objectives throughout the planning process.

KEY QUESTIONS

Having established the IRP objective, the team proceeded to identify key questions essential to answer for achieving the set objectives. These key questions formed the backbone of the data acquisition and scenario modeling efforts and provided clear direction and focus for the planning process. Key questions also help to facilitate communication and alignment among internal stakeholders by providing a common understanding of the objectives and priorities of the IRP project.

Chugach staff identified several key questions which are tied closely to its decarbonization goals and existing generation asset utilization. As with any IRP development, new planning questions are identified in course of the analysis, and these additional key questions were captured to be considered in future IRP's including several potential growth and risk-related questions as outlined below.

Key Questions For 2024 IRP	Secondary Questions and Details
Are Chugach's carbon intensity reduction goals the optimum level and timing?	Evaluate various % reduction levels as well as Alaska's proposed legislative targets and resulting costs to understand the impacts of moving further, faster or at any different pace.
What is the priority of the decarbonization projects?	Which technologies and projects are most likely to achieve least cost, lower carbon future power supply?

Future IRP Questions	*Future Details*
What is the optimal thermal fleet portfolio (post-acquisition) and future of older, aging assets?	Rationalize Chugach's generating portfolio to maximize value and minimize risk.
What additional transmission investments are part of the least cost portfolio?	Evaluate undersea cable solutions as well as transmission expansion alternatives for the interties (north and south) and GRIP project impacts on the preferred plan.
What is the optimum way to serve additional wholesale electric loads where Chugach can bring value.	Evaluate asset utilization, asset addition and impact on cost if additional wholesale sales or other arrangements materialize.
How will Chugach's IRP be informed and impacted by the Railbelt – wide ERO led IRP?	Chugach's 2024 IRP will provide a foundation for understanding what impacts a Railbelt IRP may have compared to a stand-alone IRP.
What would a North Slope intertie and optimized generation look like at first blush? What are the cost-benefit insights?	Evaluate the concept of integrating with a North Slope intertie.

CHUGACH ELECTRIC OVERVIEW

Chugach was incorporated in Alaska on March 1, 1948, with funding under the Rural Electrification Act of 1936 (REA), as amended. The word "Chugach" comes from an Alaska Native name, which the Russians recorded as "Chugatz" or "Tchougatskoi." In 1898, U.S. Army Capt. W.R. Abercrombie spelled the name "Chugatch" and applied it to the mountains.

In 1991 Chugach refinanced and paid off its federal debt, leaving the REA program. Chugach is an electric cooperative, 501(c)(12), and formed to serve its member-owners. Owned and democratically controlled by its members, Chugach operates under a cooperative model, focused on keeping rates low and reinvesting excess revenue in infrastructure or returning it to members as capital credits.

SERVICE AREA

Chugach's service area extends from Anchorage to the northern Kenai Peninsula, while also encompassing regions westward to Tyonek, which notably includes Fire Island, and extending eastward to the City of Whittier. Chugach's service areas are part of the Alaska Railbelt region connected by the Alaska Railroad. Chugach's has an essential role in providing reliable energy services from the largest community in Alaska to rural communities across the Cook Inlet. The entire Chugach community is spread over a diverse landscape, facilitating the region's economic growth and development.

MEMBERSHIP

Chugach ranks among the largest of the nearly 900 electric cooperatives nationwide. As the largest electric utility in Alaska, Chugach supplies power to about 91,000 members across approximately 113,000 metered locations. Residential accounts make up approximately 85% of the metered locations, whereas small commercial and large commercial make up 12% and 3% respectively.

REGULATORY ENVIRONMENT

As a regulated utility, Chugach operates within the framework established by the Regulatory Commission of Alaska (RCA), which necessitates that any changes made to its billing rates, Chugach is mandated to seek approval from the RCA, a process that involves submitting detailed filings for regulatory scrutiny. Chugach's electric rates are made up of two primary components: "base rates" and "fuel and purchased power rates." Base rates provide recovery of fixed and variable costs related to providing electric service, while fuel and purchased power rates provide recovery of fuel and purchased power costs.

CHUGACH RESOURCES

FUEL SUPPLY

In 2023, 78.7% of Chugach's native electric energy, including Seward's territory, was generated from natural gas, which includes energy purchased from others. Chugach's primary sources of natural gas were Hilcorp Alaska LLC (Hilcorp) and Chugach's 2/3rd share of the Beluga River Unit ("BRU"). In April of 2022, Hilcorp announced it will not commit to renew existing Railbelt utility firm contracts at this time. Actual gas quantities produced are expected to vary on a year-by-year basis, with a steady underlying production decline rate during that period. The BRU gas and Chugach's current gas contracts are expected to meet 100% of Chugach's needs through March 31, 2028. At the end of this contract, Chugach is expecting to meet any gas shortfall with imported liquified natural gas (LNG).

Beluga River Unit ("BRU")

Chugach currently holds a two-thirds working interest ownership (WIO) in the BRU field. The Beluga River Field was discovered in 1962 and began gas sales in 1968 when Chugach Electric constructed the Beluga Power Plant adjacent to the field. As of year-end 2023, the field has produced 1.4 TCF of gas. Chugach became a two-thirds WIO in the field through the purchase of ML&P, with Hilcorp Alaska, LLC owning the remaining one-third. Hilcorp is also the Operator of the Field. Chugach's two-thirds WIO comprises the bulk of gas supply for Chugach's native load needs. Since 2016, Chugach has saved approximately $100 million with its ownership in BRU versus purchasing gas on the market. Chugach continues to invest in the field and over the past several years has seen an increase in production through those drilling efforts.

Hilcorp Alaska LLC (Hilcorp)

Chugach entered into a contract with Hilcorp to provide gas beginning January 1, 2015, and through multiple amendments, now extends through March 31, 2028. Chugach exercised a minor adjustment notice in 2021 increasing yearly base contract volumes by 1.8 Bcf, to 15 MMcf/day beginning on April 1, 2023, and extends through the remainder of the contract. Pricing for Year-11 of the contract, starting on April 1, 2024, is set at $7.78 per Mcf.

Future Gas Supply

Chugach is also actively involved in several efforts in securing long term gas supply. Chugach is actively evaluating multiple options at BRU including accelerating the drilling program to offset production declines in existing wells, working with the Hilcorp on a gas exchange agreement to utilize underlifted gas past the current Hilcorp gas contract, and evaluating potential gas storage options at BRU. Chugach is further working towards securing imported LNG and has engaged with consultants to determine pricing estimates. Imported LNG is expected to be available around the time of the end of our existing Hilcorp contract gas contract ends in first quarter 2028.

OWNED GENERATION ASSETS

Chugach owns four natural gas power generation plants, owns one hydroelectric power plant and is part-owner of another hydroelectric power plant. As of 2024, Chugach owned 923.1 MW of installed capacity (at 30 degrees Fahrenheit) consisting of 21 generating units at six power plants, or 790.7 MW (18 units at six power plants) net of mothballed facilities.

The installed capacity included 332 MW of installed capacity at Beluga Power Plant on the west side of Cook Inlet; 200.2 MW at Southcentral Power Plant, 66.5 MW at Hank Nikkels Power Plant, 293.5 MW at George M. Sullivan Power Plant in Anchorage, and 19.2 MW at the Cooper Lake Power Project, which is on the Kenai Peninsula. Beluga Unit 2 and 6 and Nikkels Unit 4 are the four units in mothballed (preservation maintenance) status. In January of 2024 Unit 4 was taken out of mothball status. Chugach also owns rights to 11.7 MW of capacity from the two Eklutna Hydroelectric Project generating units that we jointly own with MEA and the MOA. Additionally, we entered into a power purchase contract with the MOA for a proportionate share of their ownership interest of Eklutna's capacity.

Southcentral Power Project (SPP)

SPP began commercial operation in February 2013, contributing 200.2 MW of capacity (at 30 degrees Fahrenheit) provided by four generating units: 3 gas turbines (Unit 11, 12, and 13) and 1 steam turbine (Unit 10). Since they have been in commercial operation, SPP units have received preventive maintenance inspections consistent with Original Equipment Manufacturer recommendations and in accordance with a General Electric (GE) contractual service agreement.

Geroge M. Sullivan Power Plant (Plant 2 & 2A)

Chugach's second principal generation asset is the George M. Sullivan Power Plant (Sullivan), formerly known as Plant 2 and Plant 2A.

Originally known as Sullivan Plant 2, the combined cycle plant, which has 2 GE Frame 7E simple cycle turbines were built in 1979 (Unit 7) and 1984 (Unit 8) respectively.

Plant 2A shares the same campus as the original Plant 2 and became commercial in fall of 2016. It is a 2x1 combined cycle power plant with (2) LM6000PF gas turbines and a Siemens SST-400 bottoming cycle steam turbine. The gas turbines have water injection called SPRINT for power augmentation which when operating brings the plant to a rating of 126.7 MW. The Sullivan combined cycle also has a circulating water waste heat recovery system that transfers up to 100 MMBtu/hr to the cold city water supply.

Hank Nikkels Power Plant (Plant 1)

The Hank Nikkels Power Plant (Nikkels), formerly known as Plant 1 is a 70-year-old facility originating as a diesel plant for the Municipality of Anchorage. Generating units at that plant have been built, upgraded, and retired over the years. Nikkels plant currently consists of a 32.9 MW LM2500+ simple cycle turbine (Unit 3) built in 2007 and a 33.6 MW dual-fuel Westinghouse 251B simple cycle turbine (Unit 4) built in 1972. As of January 2024, Unit 4 available on diesel generation.. Nikkels units are primarily used for peaking.

Beluga Power Plant

Beluga Power Plant (Beluga) provides reserve and peaking capacity with six (6) natural gas fired simple cycle gas turbine generators, which were commissioned between 1968 through 1978. The plant is located on the west side of Cook Inlet near Tyonek. Currently, Units 2 and 6 are mothballed. With these units mothballed, Beluga has a current power rating of 233 MW. While the Beluga turbine-generators have been in service for many years, they have been maintained in good working order with scheduled inspections, periodic upgrades, and repairs as necessary. All Beluga units are inspected annually with combustion and hot gas path parts replaced according to their condition or on fired hours.

International Generation Turbines (IGT)

The International Generation Turbines (IGT), or also referred to as the International Generation Station, was a natural gas fired simple cycle gas turbine that was fully retired in May 2023. The site is still routinely inspected, especially because the Multi-Stage Energy Storage System is operated and maintained, which is located on the IGT campus. IGT is located off International Airport Road in Anchorage.

Cooper Lake Hydroelectric Project

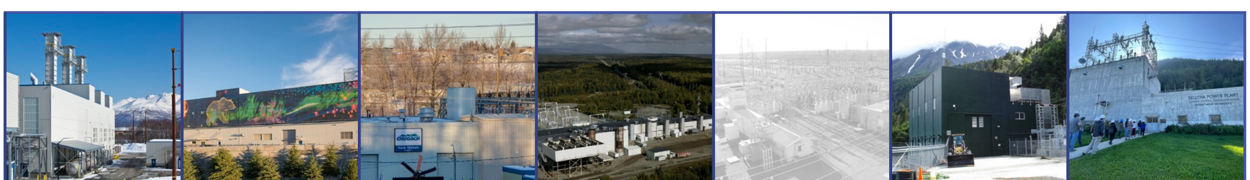
The Cooper Lake Hydroelectric Project (Cooper) is partially located on federal lands. Chugach owns, operates, and maintains the Cooper Lake project subject to a 50-year license granted to us by FERC in August of 2007. The two generating units at Cooper Lake, Units 1 and 2, have a combined capacity of 19.2 MW. Both hydro turbines as well as support equipment receive routine annual maintenance and condition assessments. A feature of the Cooper Lake Project includes a 36" siphon pipe that transports the water from Cooper Lake in to Cooper Creek. An upgrade project is underway to improve the operations of the facility to allow for load following operation.

Eklutna Lake Hydroelectric

The Eklutna Hydroelectric Project (Eklutna) is located on federal land subject to a United States Bureau of Land Management right-of-way grant issued in October of 1997. The facility is jointly owned by Chugach, MEA, and the MOA with ownership shares of 30%, 17%, and 53%, respectively. Chugach has access to an additional 34.29% of the project output through a Power Purchase Agreement ("PPA") with the Municipality of

Anchorage. Chugach has access to 25.7 MW effective total output of the plant when the plant is running at maximum capacity.

Power Generation Plant	Fuel	All Units (MW) Mothballed Units Grayed	Total Capacity (MW)	Chugach Current Capacity (MW)	2022 Carbon Intensity (CO2e MT/MWh)
Southcentral Power Project (SPP)	Natural Gas	Unit 10 – 57.4 Unit 11– 47.6 Unit 12 – 47.6 Unit 13 – 47.6	200.2	200.2	0.4198
Geroge M. Sullivan Power Plant (Sullivan)	Natural Gas	Unit 7 – 81.8 Unit 8– 85.0 Unit 9 – 48.9 Unit 10 – 48.9 Unit 11 – 28.9	293.5	293.5	0.4281
Hank Nikkels Power Plant (Nikkels)	Natural Gas (Diesel backup)	Unit 3 – 32.9 Unit 4 – 33.6	66.5	32.9	0.7397
Beluga Power Plant (Beluga)	Natural Gas (Diesel backup)	Unit 2 – 9.6 Unit 2– 19.6 Unit 3 – 64.8 Unit 5 – 68.7 Unit 6 – 79.2 Unit 7 – 80.1	332	233.2	1.6977
International Generation Turbines (IGT)	Natural Gas	Unit 1 – 14.1	Retired Asset as of 2023		
Cooper Lake Hydroelectric Project (Cooper)	Water	Unit 1 – 9.6 Unit 2 – 9.6	19.2	19.2	0.0000
Eklutna Lake Hydroelectric (Eklutna)	Water	Unit 1 – 23.5 Unit 2 – 23.5	47	25.7 (with PPA)	0.0000



SPP | Sullivan | Nikkels | Beluga | IGT Retired 2023 | Cooper | Eklutna

OWNED STORAGE ASSETS

Battery Energy Storage System

Chugach invested in a Battery Energy Storage System (BESS) that will primarily serve as a reliability and efficiency project, focused on improving the primary frequency response on the Railbelt Transmission System. The battery will enable Chugach to generate the same amount of power consuming less natural gas. Battery storage is also one of several technology options that allow flexibility in the power system and make it possible to integrate high levels of renewable energy, such as wind and solar. The BESS, a Tesla Megapack system, is rated at 40 Megawatts for two hours. It has been installed just south of the Chugach headquarters building on Electron Drive. Chugach will own a 75% interest and MEA will own the remaining 25% interest in the BESS project.

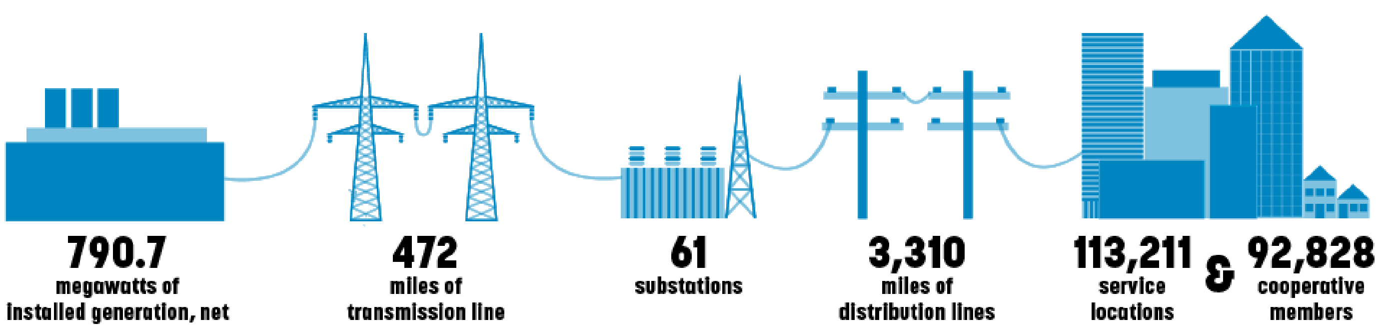
PURCHASED POWER

Bradley Lake Hydroelectric Project

Chugach is a participant in the Bradley Lake Hydroelectric Project (“Bradley Lake”). Bradley Lake was built and financed by the Alaska Energy Authority (“AEA”) through State of Alaska grants. Chugach and other participating utilities entered into take-or-pay power sales agreements under which shares of the project capacity have been purchased and the participants have agreed to pay a like percentage of annual costs of the project (including ownership, operation and maintenance costs, debt service costs and amounts required to maintain established reserves). Under these take-or-pay power sales agreements, the participants have agreed to pay all project costs from the date of commercial operation even if no energy is produced. Chugach has a 56.3% share, or 50.7 megawatts (MW), of the project’s capacity.

Fire Island Wind Project

Fire Island is located west of Ted Stevens Anchorage International Airport in Cook Inlet and is home to the Railbelt’s first commercial-scale wind farm. Fire Island Wind is comprised of eleven, 1.6 megawatt (MW) General Electric XLE wind turbines, which provide up to 17.6 MW of generation capacity and supplies approximately 47,500 megawatt hours (MWh) per year to Chugach retail members. Fire Island is connected to Anchorage via a double circuit 34.5 kV sub-transmission line. The sub-transmission line is comprised of submarine, overhead and underground segments. In 2011, the RCA approved a 25-year Power Purchase Agreement (PPA) between Fire Island Wind, LLC, a subsidiary of Cook Inlet Region Incorporated (CIRI), and Chugach Electric Association. Over the term of the PPA Chugach pays a fixed price of $97 per megawatt hour ($0.097 per kilowatt hour) for power made available by Fire Island wind generators.



CARBON INTENSITY GOALS

Chugach has identified a goal of reducing its carbon intensity, from a 2012 baseline year, by at least 35% by 2030, and by at least 50% by 2040, provided there is not a negative material impact to electric rates and/or reliability. Carbon intensity is the measure of emissions from the net generation to retail members. Emissions from any purchased power are included, and emissions associated with generation that is sold to other Railbelt electric utilities is removed from the calculation.

From 2012 through 2022, Chugach has seen a 53% reduction in its carbon emissions (CO2e) from its owned-generation. During this same time, Chugach has seen a 28% reduction in its carbon intensity (CO2e MT/MWh). To achieve this goal, Chugach's decarbonization plan supports the diversification of Chugach's generation portfolio while reducing dependency on natural gas. The plan also includes increasing clean energy generation, including renewable generation, and supports the development of new load growth through beneficial electrification, which aids in the reduction of carbon emissions within the community.

RENEWABLE ENERGY GOAL

To support Chugach's carbon intensity goals, it is aggressively seeking to add new renewable energy sources to its generation mix as soon as possible without a material negative impact on rates or reliability. This supports Chugach's goal of contracting for the addition of 100,000 MWh of new renewable energy by March 31, 2025.

LOAD FORECAST

The load forecast is a critical element of the IRP that drives many of the decisions of capacity expansion. The base load forecast used for the IRP was sourced from Chugach's Regulatory group's most recent filing with the Regulatory Commission of Alaska however additional considerations were made to account for future scenarios where expected peak demand and energy changes based on beneficial electrification, economic growth, and outside system power sales. In the development of the load forecast for the IRP, the reader's attention should be brought to the fact that ultimately these scenarios represent the best estimate of change to the system at the time of writing. Changes that are anticipated may materialize, or not, or other unconsidered events could occur. Even so, through the collaborative work of the various departments at Chugach, the IRP load forecast represents the best view we have currently of sensitivities to demands on the system.

The forecasted non-coincident peak of the Chugach is a representation of what our future instantaneous power demand on our system could be under various circumstances. Is it reasonable to expect a future where electric cars become much more popular, where a mass of customers begin charging their car after a cold winter's day at work at the same time heat pumps are starting, adding to our existing peak demand? The estimation of this growth of non-coincident peak is important for resource planning where our peak demand may grow at a different rate than energy. The IRP considers three scenarios where the non-coincident peak and energy from beneficial electrification including components from heat pumps and electric vehicles grow at a steady, aggressive, and delayed rate. These conditions help us understand the bounds of our resource expansion alternatives to serve potential new loads.

While additional peak demand is intrinsically linked to additional energy requirements, they may not grow at the same rate. For this reason, we model them independently in the IRP. Our energy forecast over the course of the IRP also includes sensitivity for changes in off system sales which could be system sales to an electric utility outside the power pool like GVEA that has set a goal of purchasing power, a new industrial customer, or opportunistic electric sales from gas available from development from the Beluga gas field.

Chugach received notification from Seward Electric System in December 2023 to terminate the existing wholesale power sales agreement between Chugach and Seward, effective January 1, 2025. The IRP does not include any power sales to Seward over the planning horizon beginning January 2025.

The Southcentral Power Pool (Power Pool) consisting of joint dispatch between Chugach and MEA is not considered in load projections of this IRP. As more operational experience is achieved within the Power Pool, a future IRP could evaluate the merits of the existing Power Pool. As well, as a Railbelt-wide IRP is developed by the Railbelt Reliability Council (RRC) in the future, this 2024 Chugach IRP will provide a valuable baseline to build from.

MODEL LIMITATIONS

Understanding the limitations and constraints of the modeling process is pivotal to understanding the context within which the IRP's conclusions and recommendations are framed.

MONTHLY HYDRO SCHEDULES

The hydro schedules were based on existing management practices, from eight-year averages by month, an assumption of a constant hydro input annually, was kept across each year of the study. This simplification, necessary for modeling feasibility, imposes an artificial limit on operational flexibility. As a result, the model may yield less economically optimal outputs than what could be achieved under real-time management. This limitation particularly affects the model's bias against selecting solar power due to its inability to model the true flexibility of hydro managed outside historic usage. This is interesting because in systems at lower latitudes solar power coincides with higher system loads due to AC cooling and winter hydro inflow.

EXCLUSION OF SOUTHCENTRAL POWER POOL DYNAMICS

The attribution of utility ownership of gas to generation without respect to ownership for economic dispatch, were beyond the capabilities of production cost modeling. This is a difficulty with production cost software in general and includes our power pool software including Gentrader and OSI Planner. Consequently, generalizations were made to model the system without considering the power pool dynamics.

GAS SUPPLY

The model incorporates natural gas availability and pricing based on Chugach's Hilcorp contract termination at the end of Q1 2028, BRU gas development and production forecasts from internal capital investment planning, and LNG import pricing based on collaborative work between NERA and Black and Veatch. The LNG availability was not constrained to a must take contract and gas storage costs were not included. Even without the inclusion of the cost of gas storage the avoided cost of reducing LNG imports heavily selected for renewable projects.

CARBON REDUCTION GOALS AND RENEWABLE PORTFOLIO STANDARDS (RPS)

Carbon reduction objectives, alongside RPS and Clean Energy Standards (CES), were evaluated post-hoc to ensure the model's project selections aligned with Chugach's strategic goals. This was done to affirm the model's alignment with Chugach's carbon reduction goals and benchmark various investment scenarios against potential legislation.

TECHNOLOGICAL SCOPE

The model considered a range of technologies, including solar, wind, small nuclear reactors, hydro projects, and Battery Energy Storage Systems. However, microgrids and other technologies were excluded or generalized due to specific financial and physical constraints. Coal was also excluded based on the utility's carbon reduction commitments and the undetermined costs of carbon capture technology.

ADDITIONAL CONSIDERATIONS

The model did not incorporate several potential investments and operational considerations, such as Chugach gas storage expansions, equity in LNG import facilities, transmission upgrades, and further BRU well developments. These elements represent areas for future investigation and potential inclusion in subsequent iterations of the IRP to enhance the comprehensiveness and accuracy of the modeling Chugach's future objectives.

REGULATION AND CONTINGENCY RESERVE

Contingency Reserves were modeled based on the largest single generation event (~60 MW). Chugach'sportion would equate to roughly 28 MW of contingency reserve. To effectively capture this in EnCompass the Peak Reserve Margin Requirement percentage (PRMR) was calculated by dividing the 28 MW reserve by the monthly peak load in each case in which the model would solve for. This approach would maintain the resultant reserve requirement of 28 MW in all load varying cases.

Regulating Reserve were modeled based on batteries, hydro, and thermal generation to maintain balance between Chugach load and non-dispatchable generation. For additional variable generation resources, an assumed 1:1 ratio of project power to BESS power was added to account for costing of managing renewable power.

ELECTRIC INTEGRATION ANALYSIS

The IRP cycle is an opportunity for Chugach to challenge assumptions, identify uncertainties, and weigh risks, ultimately resulting in a plan to meet the energy requirements of Chugach's system. Chugach's primary planning goal for its 2024 IRP is to provide for its members' electricity needs reliably and efficiently over the next 26 years through an appropriate mix of resources at the lowest reasonable cost by minimizing the net present value of the production and capital costs for serving the load. Chugach engaged 1898 & Co., a division of Burns & McDonnell Engineering Company, Inc., to provide additional expertise and analysis.

POWER PLANNING MODEL (ENCOMPASS)

1898 & Co. utilized the EnCompass Power System Optimization Software, Version 7.1.0, by Anchor Power Solutions to optimize the Chugach fleet of energy and capacity resources through the defined study period. EnCompass is an industry-standard chronological unit commitment and dispatch model with extensive presence throughout the power industry. The model employs Mixed Integer Programming to determine the optimal solution to capacity expansion, resource commitment, and economic dispatch problems with the application of real-world constraints like emission targets, generation and transmission limitations, mandatory portfolio targets and renewable energy availability.

The analysis objective is to minimize the net present value ("NPV") of capital and production costs considering, among other things, member energy needs, carbon emissions and environmental regulation. Capital and production costs can include compliance costs associated with existing generation, investments into capacity expansion, operation and maintenance costs, generation, and bilateral costs of energy to serve native member load, and the market revenues for energy sold from generation.

EnCompass was used for expansion planning and production cost modeling. The capacity expansion model was used to identify the recommended mix of generation resources expected to achieve a least-cost dispatch to meet electric load requirements. Expansion planning is typically conducted on a simplified dispatch horizon; in the case of the Chugach 2024 IRP, EnCompass was used to simulate a typical two-day week (one on-peak day, on off-peak day), fifty-two (52) weeks a year. Following expansion planning, a detailed economic dispatch mode (Production Cost Analysis) was utilized hourly for each year of the study period on a set of five portfolios across a set of sensitivities to understand better the cost risk of different paths for the Chugach power supply portfolio.

MODELING OVERVIEW

Chugach developed its Base Case using inputs, constraints, and assumptions based on the best information available at the time this IRP was prepared. This IRP includes a 26-year planning horizon (2024-2050). Multiple scenarios with multiple input variables were analyzed during portfolio development. Chugach started with assumptions previously developed from other recent studies as well as leveraging key subject matter experts and third-party consultants, to develop several new and revised assumptions including the following inputs as of early 2024:

- Member energy and load forecast
- Natural gas pricing and future LNG import capabilities & costs
- Unit cost and performance projections for new and existing generation resources.

This analysis assumes the following regarding Chugach's existing or approved generation resources:

- IGT is mothballed through the IRP study.
- Southcentral BESS online and operational.
- 10% energy derate on Cooper Hydro 1 and Cooper Hydro 2 in 2026.
- 10% energy derate on Eklutna Hydro in 2027.

A diverse range of renewable resources were evaluated in this IRP. The following lists potential resource options:

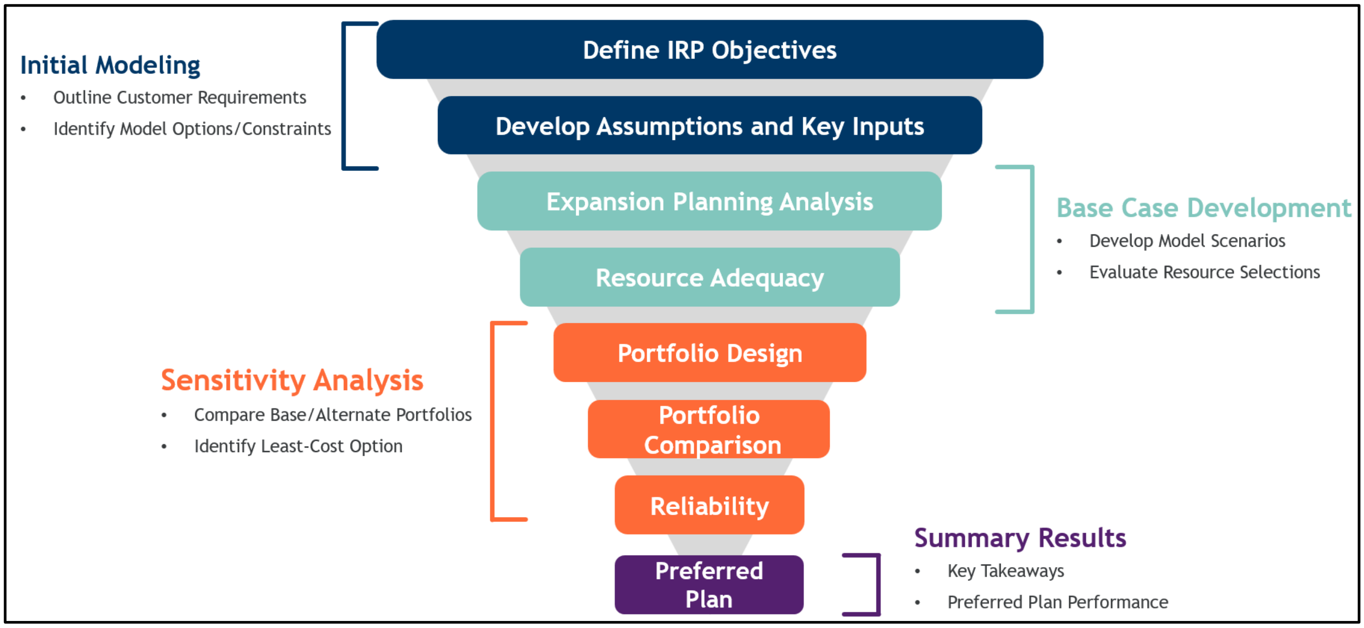
- 1 MW community solar in 2026
- 0.08 MW small-scale solar in 2026 at the SPP facility
- 0.085 MW small-scale solar in 2026 at the Sullivan facility
- 80 MW x 320 MWh Utility Scale standalone storage
- 40 MW x 80 MWh Utility Scale standalone storage
- 10 MW x 40 MWh Utility Scale standalone storage
- Various Sizes of Utility-scale solar
- Various Sizes of Utility-scale wind
- 70 MW Small Modular Reactor
- 190 MW of New Large-Scale Hydro

Operating Reserves were accounted for in EnCompass based on the largest single generation contingency event in the Railbelt Region, which is currently approximately 60 MW. Chugach's portion would equate to approximately 28 MW of contingency reserve.

It bears note that the EnCompass Model results included in this IRP do not represent a commitment by Chugach to a specific course of action. Additionally, it is important to understand that changes to the inputs, constraints and assumptions that impact this IRP result can, and do, occur rapidly, especially with the current uncertainties around inflation, environmental goals, technology advances, and fuel prices & availability, among other challenges. Consequently, Chugach has run sensitivities to the Base Case to evaluate the impact of changing inputs on the model determination of the least-cost option. Alaska specific trends and risk factors were considered when creating sensitivities with multi-variable inputs, including but not limited to changes to LNG fuel prices, load, capital costs, etc.

Chugach evaluated a total of eleven (11) sensitivities on the resource portfolios. These are designed to focus on the impact of changing one variable without subjecting that analysis to additional uncertainty. The single variable analysis shows points of impacts, i.e., the points when the change in a single variable causes a new result for the least-cost plan. Chugach ran sensitivities involving changes to the load forecast, LNG fuel prices, the amount of wind generation, and capital costs. This approach allowed for the exploration of several possible futures. Figure 1 illustrates the approach taken to refine resource selection and arrive at an economic and reliable portfolio, cognizant of environmental goals and related contingencies.

Figure 1
Portfolio Selection Process



PRE-IRP POSITION

To create a baseline for the analysis and have a clear scenario to compare to, Chugach's existing generation fleet was modeled to assess any energy or capacity shortfalls, verify costs, and establish a preliminary Existing Resource scenario. The Existing Resource scenario has sufficient capacity and energy generation to meet member demand and is financially competitive with other cases studied. Figure 2 and Figure 3 show Chugach's preliminary summer and winter installed capacity positions, respectively. Figure 4 shows Chugach's energy position over the study period.

Figure 2
Summer Capacity Position

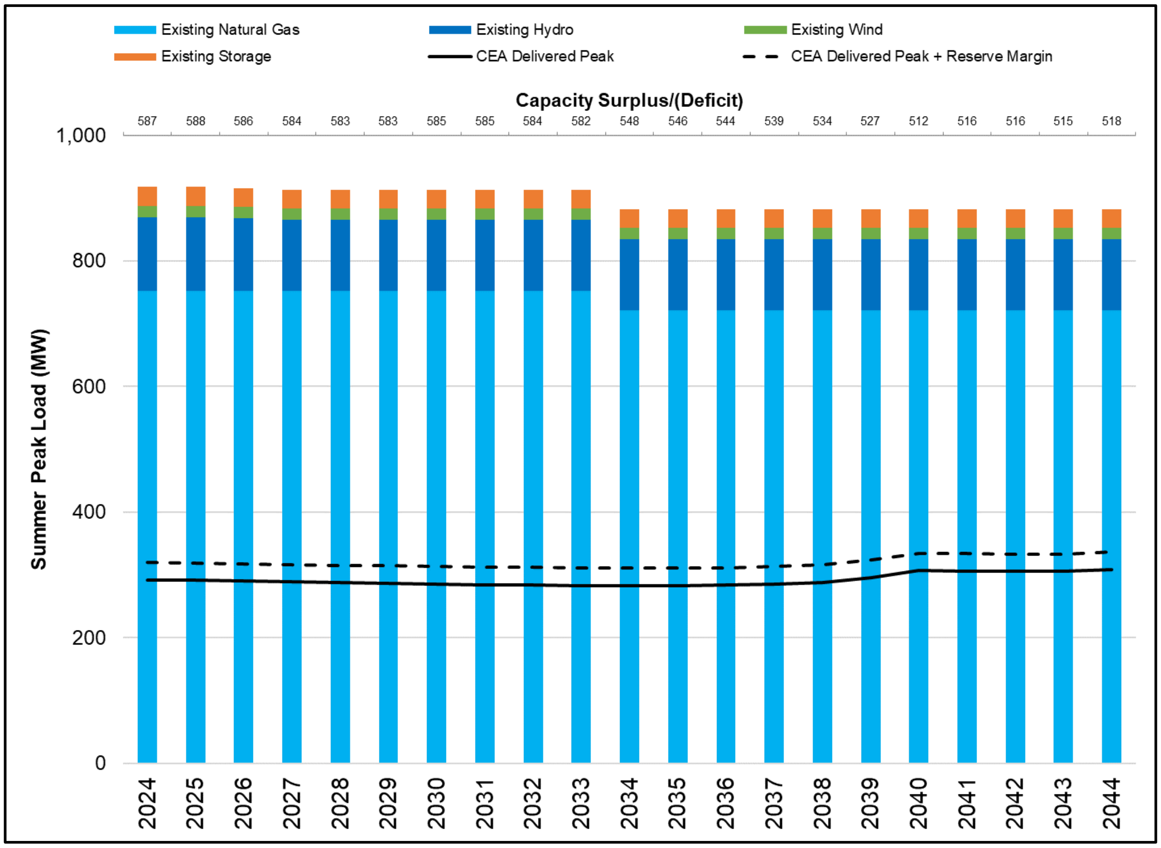


Figure 3
Winter Capacity Position

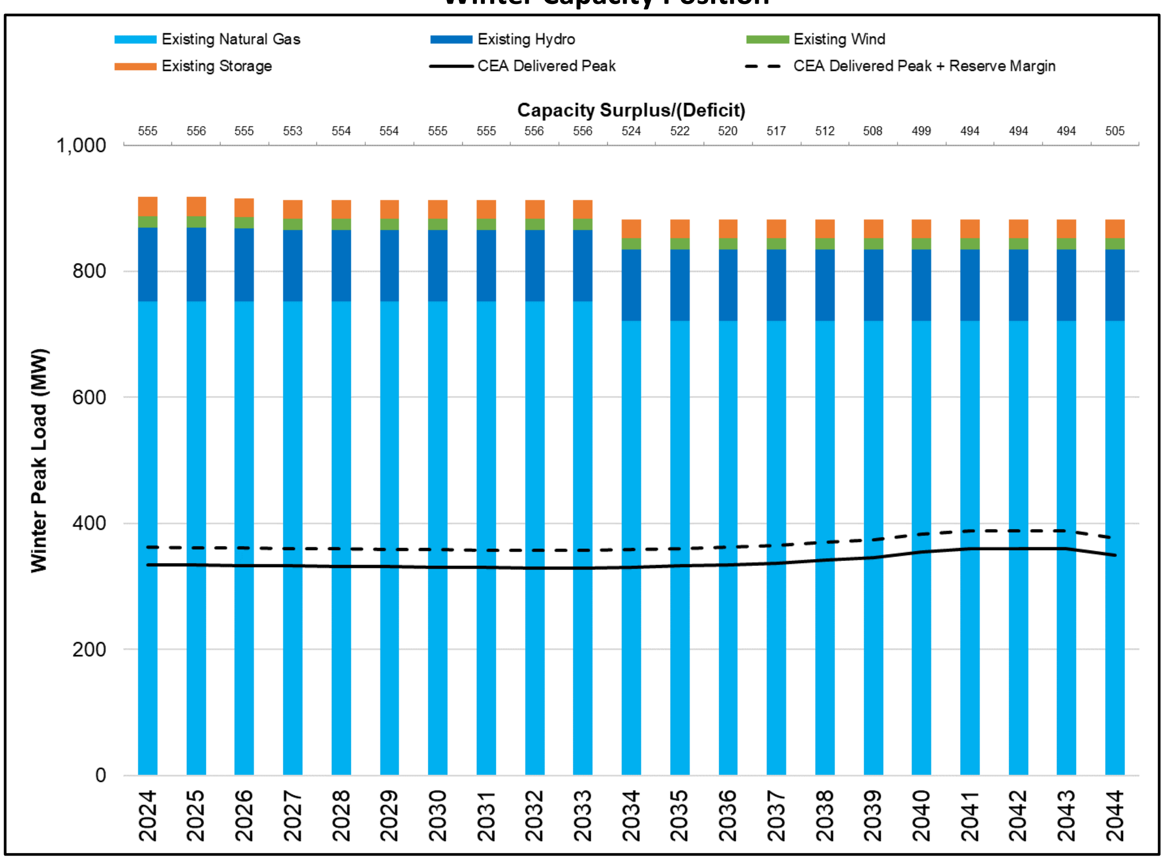
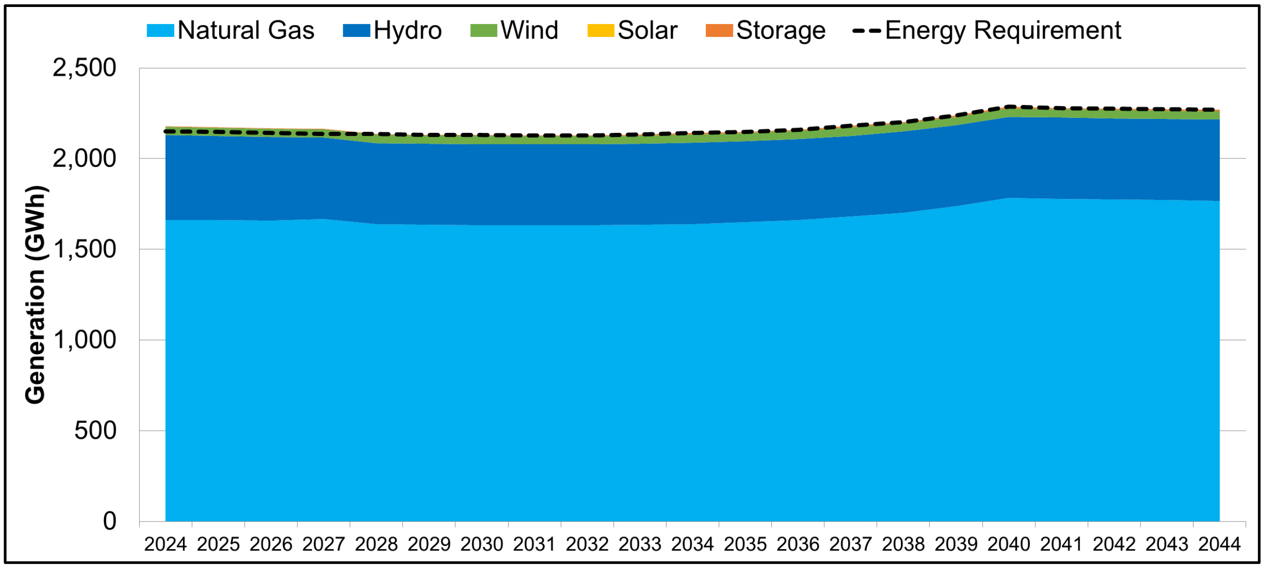


Figure 4
Existing Resource Energy Dispatch



The Existing Resource scenario is heavily reliant on natural gas (approximately 82%), therefore resulting in elevated carbon emissions throughout the study horizon. Figure 5 shows the annual fuel consumption by source. Due to the large amount of natural gas utilization, this scenario falls short of Chugach's Carbon Intensity Goals as well as the proposed Clean Energy Standard (CES) and Renewable Portfolio Standard (RPS) goals both near and long term. Figure 6 shows the carbon intensity of the Existing Resource scenario compared to Chugach's carbon intensity targets. Additionally, the annual power supply costs of the Existing Resource scenario is shown in Figure 7.

Figure 5
Fuel Consumption Existing Resource Scenario

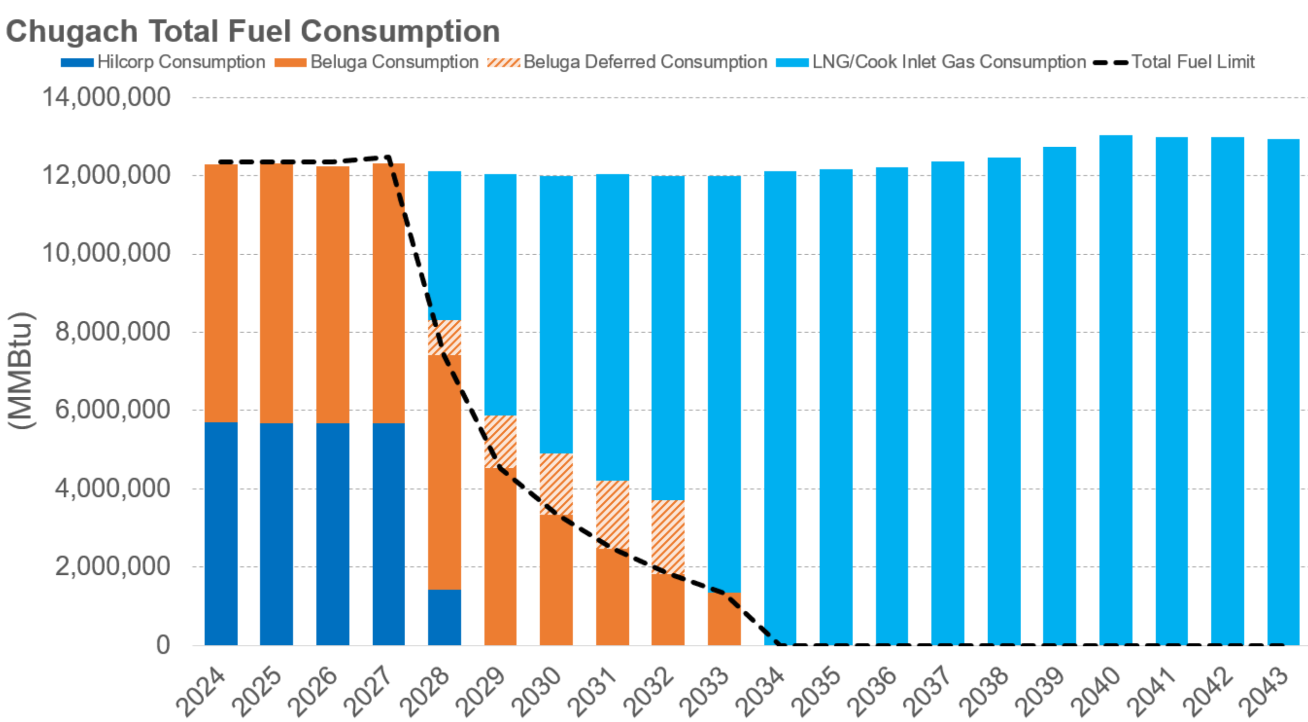


Figure 6
Carbon Intensity of Existing Resource Scenario

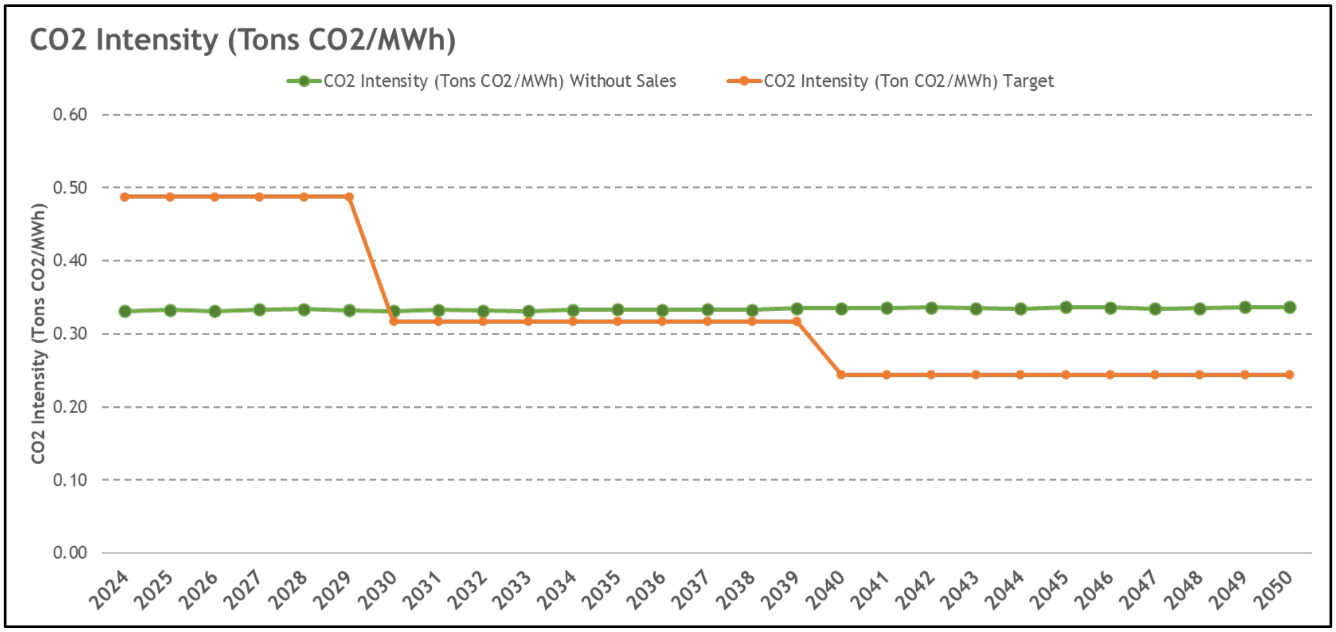
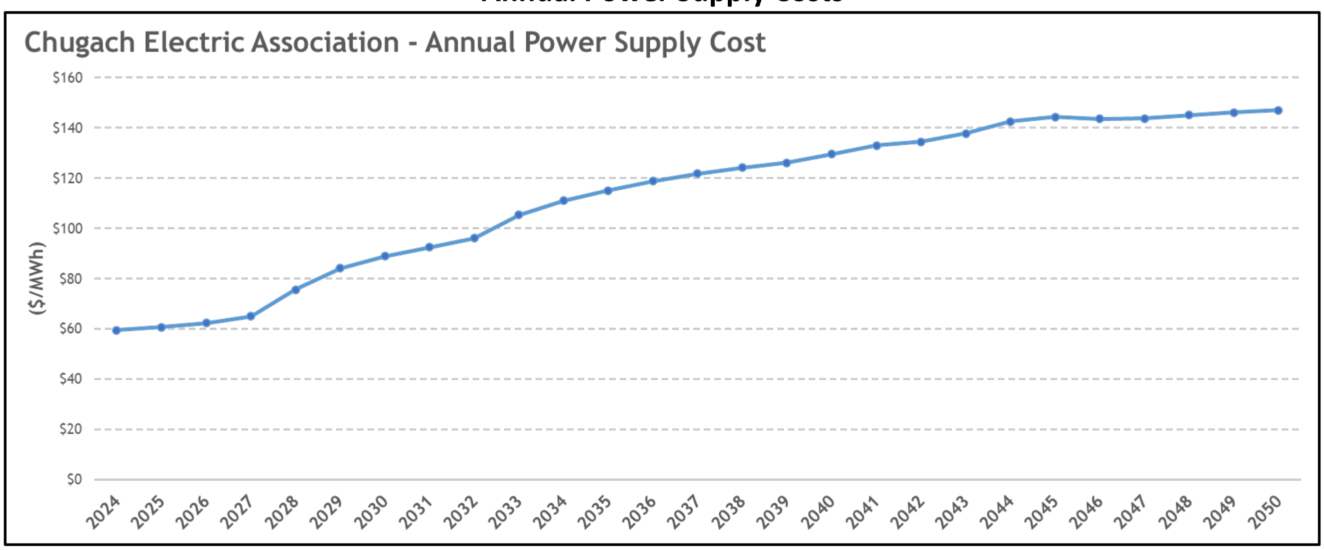


Figure 7
Annual Power Supply Costs



From a long-term planning perspective, without taking any action, Chugach has sufficient capacity and energy to meet its member obligations. Considering Chugach's environmental goals, further action and planning will be necessary to adequately meet capacity, energy, and environmental goals.

KEY ASSUMPTIONS

As mentioned above, 1898 & Co. worked with the staff at Chugach to source the assumptions used in this modeling, taking care to be consistent with other studies and work efforts ongoing at the utility.

Finance

Table 1 shows the financial inputs for the EnCompass model. The Debt Ratio represents the percentage of the total capital project costs to be financed with long-term debt. Chugach utilizes a Return on Equity ("ROE") of

3.66%.

Table 1
Financial and Budgeting Assumptions

Financial Metrics	
Metric	**Value**
Debt Ratio	83.3
Debt Rate	5.54
Tax Rate	0
Return on Equity(ROE)	3.66
Forward Discount Rate WACC	5.80

The general escalation rate was assumed to be 3.2% in the near term (2024-2033) and 2.25% long term (2034-2050). General escalation was applied to key costs such as capital, operations and maintenance expenditures, and fuel costs.

Resource Options

Table 2 shows the existing resource's annual fixed costs. Table 3 shows the existing resource's variable costs. Table 4 shows the heat rates for the existing thermal resources under the respective loading levels. Table 5 shows the resource alternative options made available within the model and some of the key parameters.

Table 2
Existing Resource Fixed Costs

	Fixed Costs ($000)																	
Year	Nikkels 3	Nikkels 4	Sullivan 7	Sullivan 8	Sullivan 1x1	Sullivan SC1	Sullivan SC2	SPP SC1	SPP SC2	SPP SC3	Beluga 1	Beluga 2	Beluga 3	Beluga 5	Beluga 6	Beluga 7	Eklutna	Cooper
2024	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237	$256	$704	$56	$354
2025	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237	$256	$704	$56	$354
2026	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$56	$354
2027	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$2,296	$354
2028	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$2,296	$354
2029	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$2,296	$354
2030	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$2,296	$354
2031	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$2,296	$354
2032	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$2,296	$354
2033	$824	$162	$971	$620	$993	$1,539	$1,532	$1,074	$1,516	$1,349	$91		$246	$237		$704	$56	$354
2034	$824				$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$354
2035	$824				$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$354
2036	$470				$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$354
2037					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$346
2038					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$346
2039					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$346
2040					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$346
2041					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$56	$234
2042					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$47	$234
2043					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$47	$234
2044					$993	$1,539	$1,532	$1,074	$1,516	$1,349							$47	$234
2045					$993	$1,539	$1,532	$1,037	$1,470	$1,306							$37	$234
2046					$993	$1,539	$1,532	$440	$450	$449							$35	$234
2047					$993	$1,513	$1,532										$35	$234
2048					$993	$1,149	$1,159										$35	$234
2049						$589	$598										$35	$234
2050							$9										$35	$234

Table 3
Existing Variable Costs

Existing Resource Costs			
Resource Name	Unit	Online Cost ($/Hr)	Variable O&M ($/MWh)
SPP	SPP 01-1 SC	$349	$0.36
	SPP 02-1x1	$349	$0.36
	SPP 03-2 SC	$697	$0.72
	SPP 04-1 CC 1 SC	$697	$0.36
	SPP 05-2x1	$697	$0.72
	SPP 06-3 SC	$1,046	$1.08
	SPP 07-1 CC 2 SC	$1,046	$0.72
	SPP 08-2 CC 1 SC	$1,046	$0.36
	SPP 09-3x1	$1,046	$1.08
	SPP 10-1x1 DF	$349	$0.36
	SPP 11-2x1 DF	$697	$0.72
	SPP 12-3x1 DF	$1,046	$1.08
Nikkels 3	Plant 1 Unit 3	$277	$0.36
Nikkels 4	Plant 1 Unit 4	$0	$0.00
Sullivan CC	Plant 2A 01-1 SC	$247	$0.93
	Plant 2A 02-1x1 CC	$247	$0.93
	Plant 2A 03-2 SC	$493	$0.93
	Plant 2A 04-1 CC 1 SC	$493	$0.93
	Plant 2A 05-2x1 CC	$493	$0.93
Beluga	Beluga 1	$245	$0.36
	Beluga 2	$245	$0.36
	Beluga 3	$245	$0.36
	Beluga 5	$245	$0.36
	Beluga 6	$0	$0.00
	Beluga 7	$245	$0.36
Sullivan 7	Sullivan 7	$508	$0.36
Sullivan 8	Sullivan 8	$1,854	$0.36
Eklutna	Eklutna	$0	$2.00
Bradley	Bradley	$0	$1.00
Cooper 1	Cooper 1	$0	$3.00
Cooper 2	Cooper 2	$0	$3.00
Fire Island Wind	FIWF	$0	$0.00
IGT	IGT 1	$0	$0.00
International BESS		$0	$0.00
Cooper Hydro Upgrade	Cooper 1 & 2	$0	$3.00

Table 4
Heat Rates for Existing Thermal Resource Loading Level

	Block 1		Block 2	
Resource Name	MW	HR	MW	HR
Nikkels 3	0	8,131	33	8,475
Nikkels 4	0	7,278	35	9,940
Sullivan 7	0	8,423	90	10,612
Sullivan 8	0	8,055	102	10,952
Beluga 1	0	7,822	20	12,276
Beluga 2	0	7,822	20	12,276
Beluga 3	0	7,567	72	10,118
Beluga 5	0	7,607	80	10,533
Beluga 6	0	7,607	80	10,533
Beluga 7	0	7,928	85	9,534
IGT	0	5,875	20	13,305
Sullivan 1x1	58	8,000		
Sullivan 2x1	58	7,000		
SPP 1x1	58	8,000		
SPP 2x1	58	7,000		
SPP 3x1	58	6,000		

Table 5
New Resource Alternatives

New Resource Alternatives					
Project	Resource Type	Max Capacity (MW)	First Available Year	PPA Cost	Project CapEx[1]
Retherford Solar	Solar	1	2025	-	-
SPP Solar	Solar	0.08	2025	-	<$1M
Sullivan Solar	Solar	0.085	2025	-	<$1M
CEA BESS	Battery Storage	40	2027	-	$30M
Proposed Project Solar (Pilot)	Solar	48	2027	Confidential	-
Proposed Project Wind (Pilot)	Wind	50	2027	Confidential	-
Generic BESS	Battery Storage	10	2027	-	$11M
Proposed Project Solar (Full Scale)	Solar	72 (120 Full)	2028	Confidential	-
Proposed Project Wind (Full Scale)	Wind	94 (144 Full)	2028	Confidential	-
Dixon Diversion (Bradley Upgrade)	Hydro	-	2028	-	$193M
Generic Wind	Wind	30	2030	-	$128M
Generic Solar	Solar	10	2030	$114/MWh	-
SMR	Nuclear	70	2035	-	$800M
Godwin Creek (Run of River)	Hydro	12.7	2038	-	$134M
Godwin Creek (Ponding)	Hydro	70	2038	-	$500M

[1]For Projects modeled with CapEx, the actual estimated costs are based on escalation from 2024 to the year of selection. (all costs shown in 2024$)

Tax Credits

Both Production Tax Credits (PTC) and Investment Tax Credits (ITC) were modeled in Encompass in accordance with the passage of the Inflation Reduction Act (IRA). Resources such as wind, solar, and battery energy storage systems were assumed to qualify for these credits. Wind was modeled as qualifying for the production tax credit on a $/MWh basis while solar and storage alternatives would qualify for the ITC. Wind qualified for a credit of $27.50 per MWh produced escalated throughout the study at the general escalation rate. In accordance with the IRA projects with COD of 2034 and 2035 would qualify for 75% and 50% of the full credit value respectively and would maintain the credit for a 10-year time horizon. The Investment tax credit was modeled at 30% of the capital cost for solar and storage assets with the same tax credit reduction schedule as the production tax credit.

Load Forecasts

Table 6 shows the four (4) load cases that were developed and utilized during this study. The Status Quo load forecast assumes a half percent (0.50%) annual decline. The Low, Base (Mid), and High load cases are all comprised of the native or base load plus various amounts of incremental heat pump load and Electric Vehicle (EV) adoption rates. The High Load case has an aggressive EV adoption rate, the Base Load has a steady EV adoption rate, and the Low Load case has a delayed EV adoption rate. The monthly peak forecast is shown in Figure 8 and the monthly energy forecast can be seen in Figure 9.

The EV adoptions and heat pump load impacts were forecasted with the best available data during the analysis window. The native load was forecasted through 2024 while the EV and heat pump adoption impacts were forecasted for model year 2040. A linear interpolation was done monthly between model year 2024 and 2040 to forecast the increase in both peak and energy demand over this time horizon. Post 2040 the demand was assumed to increase year-over-year at a 2% rate. The incremental peak and energy impacts were added to the base forecast such that the resultant curves would include low, mid, and high overall demand bands for load variation. The status quo load retail load assumes no incremental peak and energy additions.

Table 6
Load Forecast Across All Cases

	Status Quo Load Forecast		High Load Forecast		Base (Mid) Load Forecast		Low Load Forecast	
Date	Annual Peak (MW)	Annual Energy (MWh)	Annual Peak (MW)	Annual Energy (MWh)	Annual Peak (MW)	Annual Energy (MWh)	Annual Peak (MW)	Annual Energy (MWh)
2024	359	2,146,198	361	2,151,193	361	2,149,732	360	2,149,168
2025	358	2,135,467	361	2,148,023	360	2,144,545	360	2,144,112
2026	356	2,124,790	362	2,146,421	360	2,139,709	360	2,142,345
2027	354	2,114,166	363	2,146,938	359	2,135,302	361	2,140,536
2028	352	2,103,595	365	2,150,213	359	2,131,433	362	2,140,477
2029	350	2,093,077	369	2,156,929	359	2,128,233	364	2,141,932
2030	349	2,082,612	373	2,167,760	360	2,125,895	365	2,143,320
2031	347	2,072,199	380	2,183,846	360	2,124,750	367	2,145,745
2032	345	2,061,838	388	2,205,830	362	2,125,193	369	2,148,395
2033	344	2,051,529	398	2,233,439	364	2,127,575	371	2,151,098
2034	342	2,041,271	410	2,266,051	366	2,132,466	374	2,154,662
2035	340	2,031,065	423	2,302,147	370	2,140,603	376	2,158,277
2036	338	2,020,909	437	2,339,111	375	2,152,948	378	2,162,438
2037	337	2,010,805	449	2,373,170	382	2,170,751	381	2,166,650
2038	335	2,000,751	459	2,401,396	392	2,195,639	383	2,170,913
2039	333	1,990,747	466	2,417,789	404	2,229,728	385	2,173,201
2040	332	1,980,793	468	2,421,190	420	2,275,769	387	2,175,539
2041	330	1,970,889	469	2,420,094	420	2,271,765	387	2,169,530
2042	328	1,961,035	470	2,419,223	420	2,267,928	386	2,163,649
2043	327	1,951,230	471	2,418,582	420	2,264,261	385	2,157,896
2044	325	1,941,474	472	2,418,173	421	2,260,765	385	2,152,273
2045	323	1,931,766	474	2,418,000	421	2,257,444	385	2,146,782
2046	322	1,922,107	475	2,418,065	421	2,254,298	384	2,141,423
2047	320	1,912,497	477	2,418,374	422	2,251,332	384	2,136,199
2048	319	1,902,934	478	2,418,929	422	2,248,546	384	2,131,110
2049	317	1,893,420	480	2,419,734	423	2,245,943	383	2,126,159
2050	315	1,883,953	481	2,420,793	423	2,243,527	383	2,121,347

Figure 8
Monthly Peak Forecast

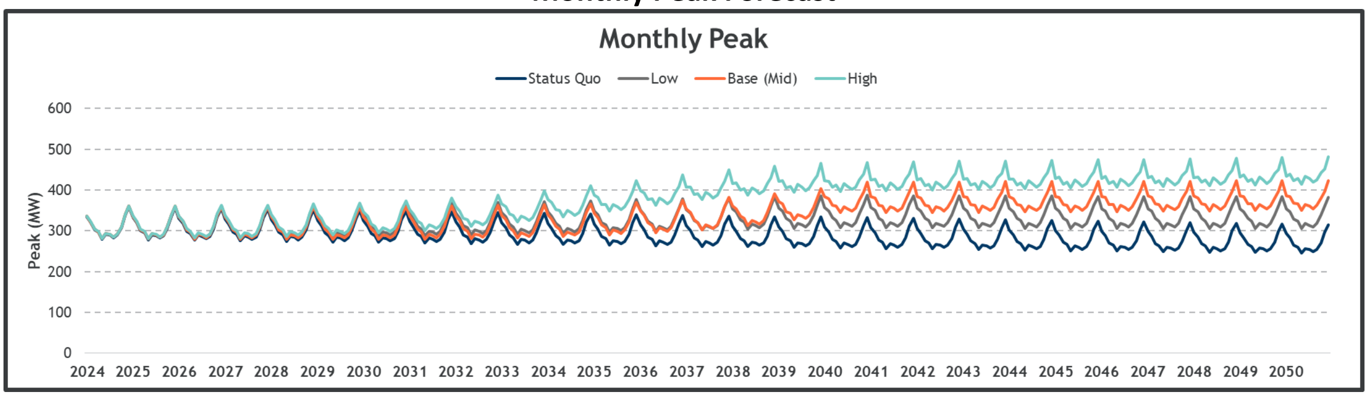
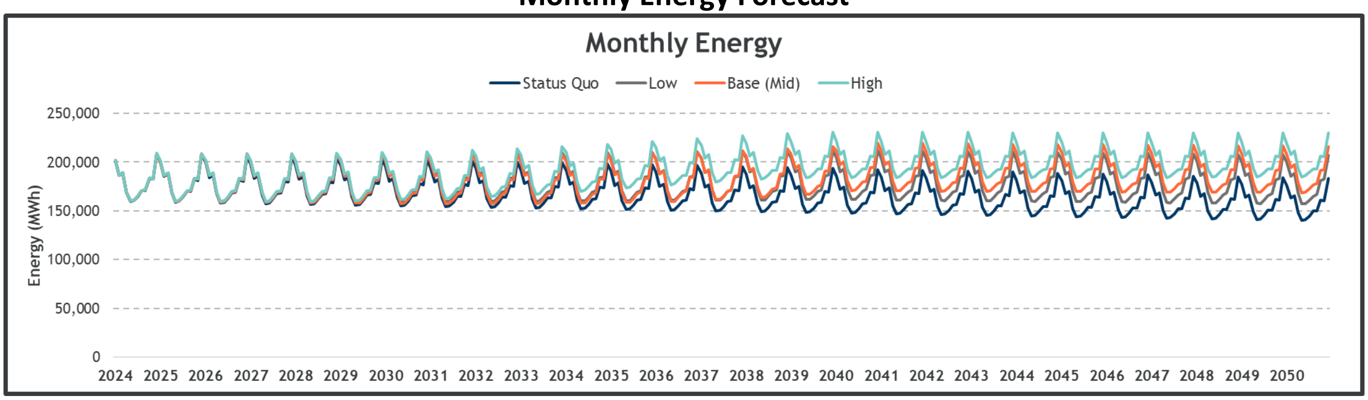


Figure 9
Monthly Energy Forecast



Fuel Forecasts

The EnCompass model had four separate fuel supply sources to utilize through the study. As described in the Fuel Supply section, gas powered thermal resources were priced using the BRU, the Hilcorp Alaska LLC contract, and LNG Imports. Additionally, the uranium supply costs for the SMR were sourced from the National Renewable Energy Laboratory (NREL) and escalated throughout the study at the general escalation rate. As shown in Figure 10 the BRU was available for use through 2038 and the Hilcorp contract was set to expire in 2028. The remaining gas supply would be subject to LNG pricing. Both the BRU and the Hilcorp contract were modeled with daily supply limits, and any excess Beluga River gas was carried forward for use between 2028 and 2032 as deferred gas availability. Figure 11 are the overall daily fuel limits in the EnCompass Model.

Figure 10
Fuel Supply Costs

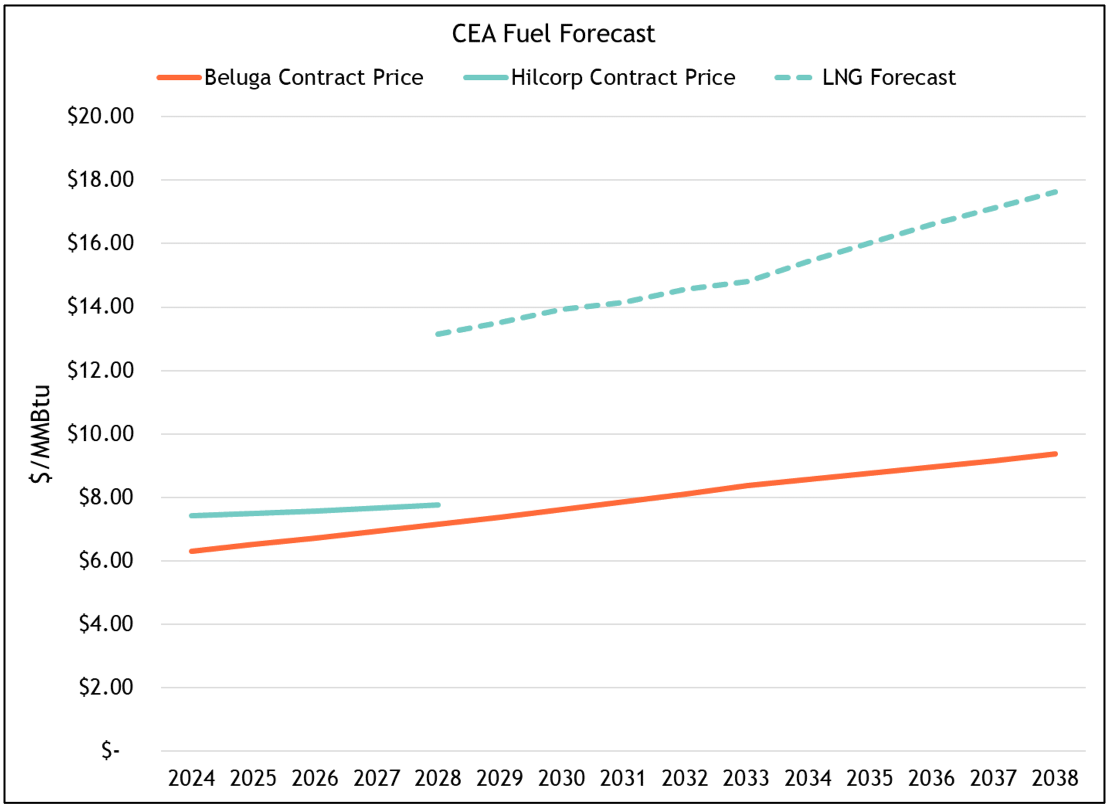
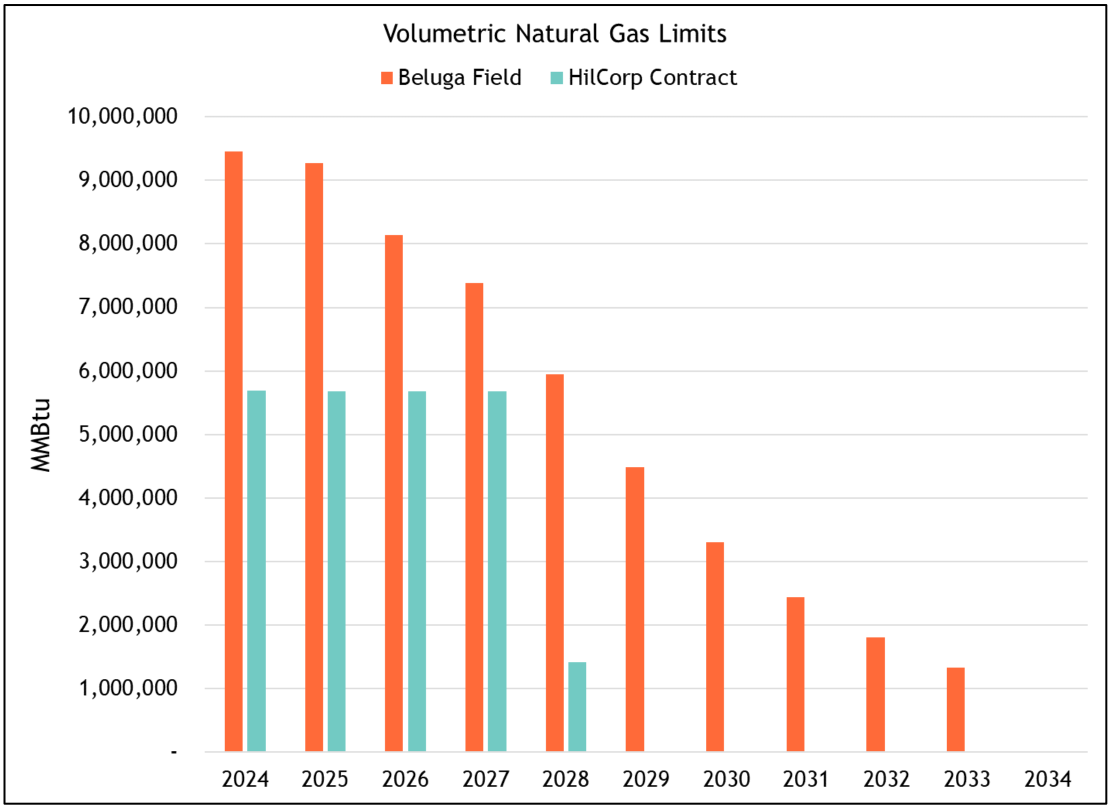


Figure 11
Fuel Supply Limits



EXPANSION PLANNING ANALYSIS

EnCompass was used to perform Expansion Planning analysis across the base assumptions with sixteen (16) scenarios discussed further in this section to inform portfolio development. All resource options were considered in this step to establish consistent portfolio selections across each sensitivity.

Chugach and 1898 & Co. developed the IRP expansion planning model with inputs and constraints using the best, currently, available information. The inputs, constraints, and justification for the Base Case assumptions are further explained below.

- **Generation Commit**: All-natural gas-fired generation units were modeled as economically committed according to startup characteristics and production costs. These characteristics include minimum up-time, minimum down-time, ramp rates and operating costs.
- **Generation Dispatch**: All-natural gas-fired generation units were modeled as economically dispatched within specific operating parameters provided for each unit, such as maximum and minimum capacity, heat rates, unit outage rates, and planned outages. The solar and wind units were modeled with a fixed hourly generation profile specific to the upper Cook Inlet area. The hydro units were modeled based on annual and monthly energy limits based on historical unit performance.
- **Generation Selection**: All new resource alternatives were evaluated based on project feasibility, i.e. the earliest reasonable COD for each alternative based on expectations for permitting and transmission interconnection. EnCompass was configured to allow the selection of resource alternatives in incremental steps over the study period. Constraints were incorporated in the model to keep an excessive amount of a single generic resource from being built. This approach to constraining the

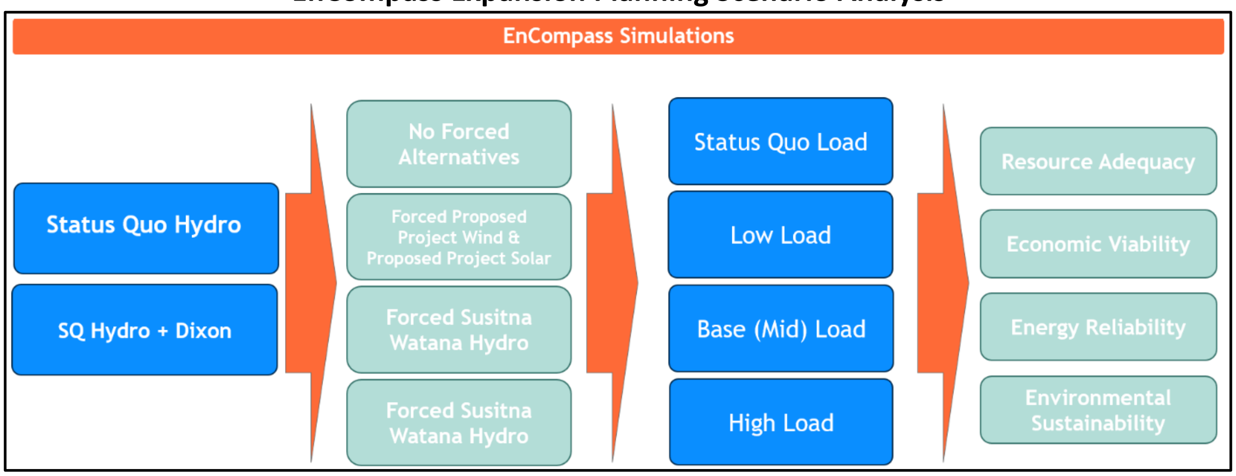
model is a typical practice in resource planning to liberally set limits around resource types to keep the model from exhibiting issues with solving the size of the computational problem.

- **Production Fixed Costs**: The production fixed costs that were utilized are provided above in Table 2 for existing resources.
- **Production non-fuel Variable Costs and Generator Operating Parameters**: The production non-fuel variable costs (online costs and energy costs) can be seen above in Table 3.

SCENARIO ANALYSIS

Thirty-two (32) model scenarios were analyzed using the EnCompass model. The focus of the scenario analysis is to determine the optimal resource selection across a range of inputs – varying one at a time – to assess the impacts to the least-cost resource plan selected by the modeling tool. The scenarios were conducted by varying load forecasts, different resource alternatives forced into the model, and the removal of a hydro resource. The resources chosen in the expansion planning across these scenarios were used to inform the development of the Base Portfolio and Alternative Portfolios. Figure 12 is a visual representation of the scenario analysis approach taken by Chugach and 1898 & Co.

Figure 12
EnCompass Expansion Planning Scenario Analysis



EXPANSION PLANNING RESULTS

Unit performance characteristics for new resource alternatives were sourced from feed studies that Chugach recently conducted with third-party experts. The information obtained from these were heat rates, max and min capacities, outage rates, and ancillary service capabilities. Financial assumptions such as capital costs, New Era financing and IPP/PPA costs were Chugach sourced.

The optimal plan from the EnCompass model under base case conditions resulted in: 1 MW of Retherford Solar being added in year 2025, 50 MW Proposed Project Wind Pilot added in year 2027, the remaining 94 MW of the Proposed Project Wind being built in 2028, 150 MW of Large-Scale Wind added in 2030, and 100 MW of Battery Energy Storage in 2033, an additional 20 MW of Battery Energy Storage in 2034, and finally 60 MW of Large-Scale Wind in 2034. Table 7 shows the optimal resource additions across the base or "No Forced Projects" and the other four Scenarios.

Table 7
Expansion Planning Project Selections

Project Selection Summary	Scenario			
Year	No Forced Projects	Existing Hydro with Dixon Diversion Forced in	SMR Forced in	Large Hydro & Dixon Diversion Forced in
2025	Retherford Solar (1 MW)	Retherford Solar (1 MW)	Retherford Solar (1 MW)	RetherfordSolar (1 MW)
2026	Cooper Upgrade	Cooper Upgrade	Cooper Upgrade	Cooper Upgrade
2027	Proposed Project Wind Pilot (50 MW)	Proposed Project Wind Pilot (50 MW)	Proposed Project Wind Pilot (50 MW)	
2028	Proposed Project Wind(94 MW)	Proposed Project Wind(94 MW)	Proposed Project Wind(94 MW)	
2029				
2030	Large Scale Wind (150 MW)	Dixon Diversion Large Scale Wind (150 MW)	Large Scale Wind (150 MW)	Dixon Diversion Large Scale Wind (150 MW)
2031				Large Scale Wind (60 MW)
2032		Generic BESS (10 MW)		
2033	Generic BESS (100 MW)	Generic BESS (80 MW)	Generic BESS (100 MW)	
2034	Generic BESS (20 MW) Large Scale Wind_2034 (60 MW)	Large Scale Wind_2034 (30 MW)		
2035			CEA SMR (70 MW)	
2040				Susitna Watana Hydro Block 1 (95 MW) Susitna Watana Hydro Block 2 (24 MW) Susitna Watana Hydro Block 3 (24 MW) Susitna Watana Hydro Block 4 (24 MW) Susitna Watana Hydro Block 5 (24 MW)

The results from the expansion planning analysis can be summarized into the following key themes:

- The Dixon Diversion project results in the lowest overall cost, and the flexibility of additional dispatchable generation.
- Large Scale Generic Wind was selected across all 32 scenarios.
- Proposed Project Wind was selected in approximately 44% of all expansion planning runs.
- Apart from the Retherford Solar project (selected in all scenarios), Large Scale Solar was not selected in any scenario where it was not a forced-in project.
- SMR was not selected in any scenarios where it was not forced in.
- New Large-Scale Hydro was not selected in any scenarios where it was not forced in.

Table 8 shows the number of times a project was selected and the percentage that it was selected across all 32 scenarios. Figure 13 displays the selections in a graphical form.

Table 8
Project Selection Statistics

Project Selections		
Selected Projects	**# of Selected**	**% Selected**
Large Scale Generic Wind	32	100%
Retherford Solar	32	100%
Generic BESS	24	75%
Proposed Project Wind	14	44%
Proposed Project Wind Pilot	14	44%
Large Scale Generic Wind_2034	12	38%

Figure 13
Project Selection Statistics

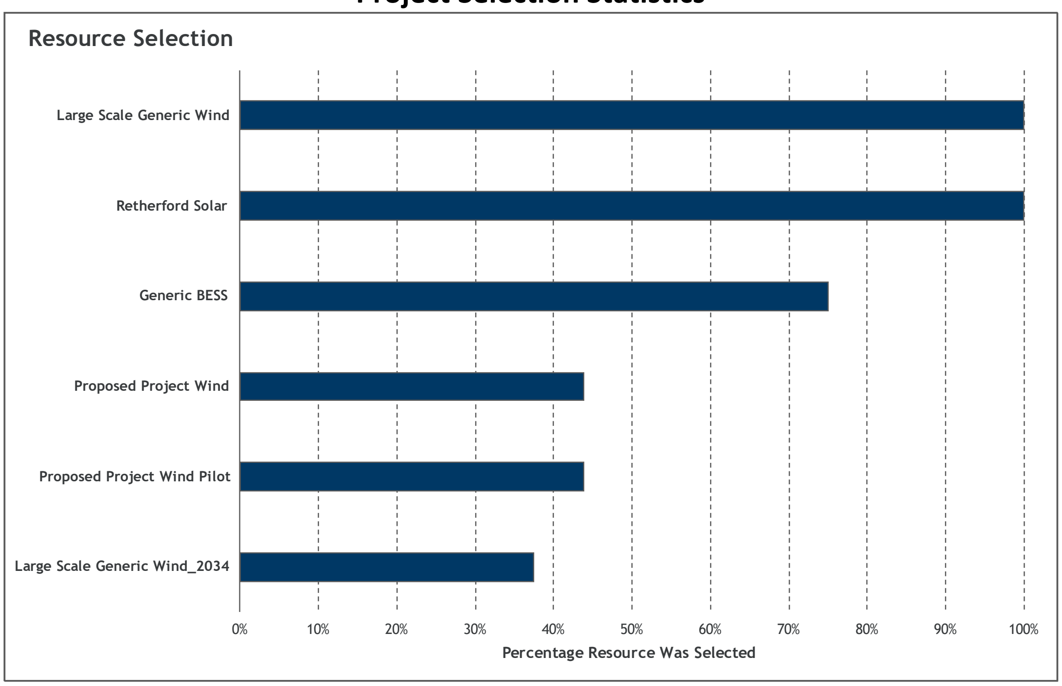


Table 9 shows the NPV of the 32 scenarios across two different swim lanes. A “traffic light” formatting was applied to help better visualize the trends between the scenarios. Lower costs are highlighted with a darker green and higher costs are highlighted with a dark red. The swim lanes and scenario naming structure are explained below:

- **SQH**: Status Quo Hydro
- **SQHDD:** Status Quo Hydro with Dixon Diversion project forced in

All the scenario names follow the same structure.

- **No Forced Projects**: Allows the model to select any resource option.
- **Large Hydro Forced**: Forces in large project modeled after Susitna-Watana Hydro.
- **PPS&PPW Forced**: Forces in Proposed Project Solar and Proposed Project Wind .
- **SMR Forced**: Forces in Small Modular Reactor.
- **No CO2 Limits**: There are no carbon emission constraints on the model.

Table 9
Summary of Expansion Plan NPVs

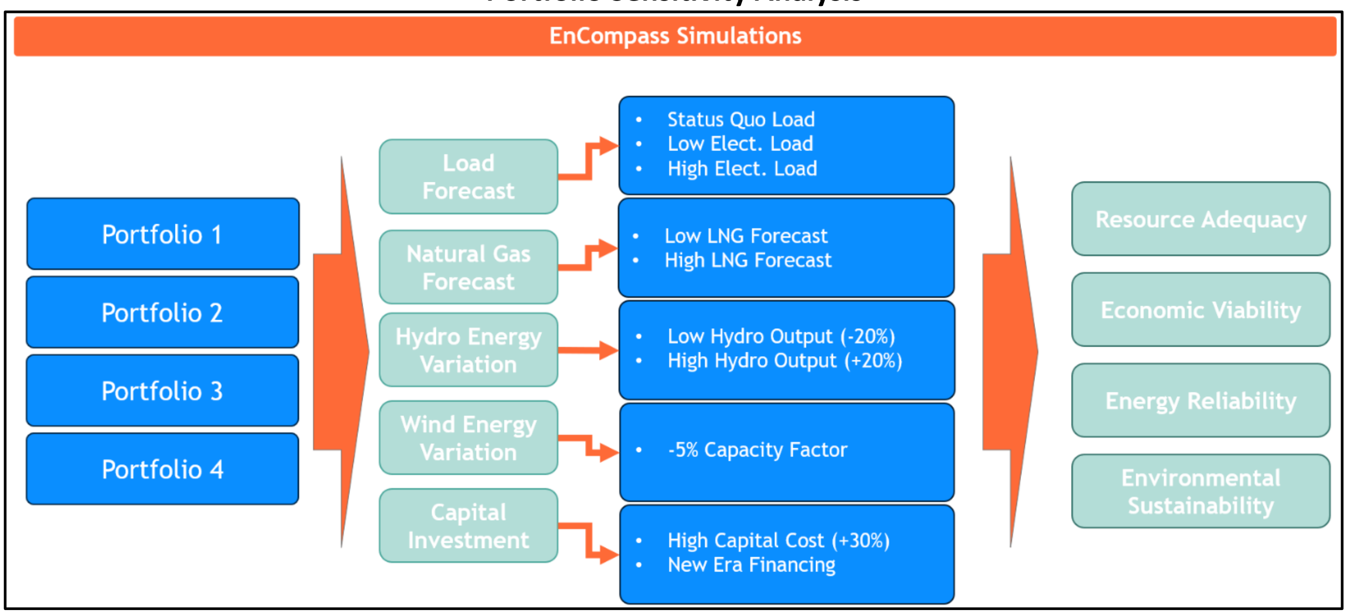
	NPV ($millions)	SQH	SQHDD
Base Load	Base Load - No Forced Projects - No CO2 Limits	$2,682	$2,634
	Base Load - Large Hydro Forced - No CO2 Limits	$3,227	$3,210
	Base Load - PPS&PPW Forced - No CO2 Limits	$2,681	$2,654
	Base Load - SMR Forced - No CO2 Limits	$2,927	$2,893
High Load	High Load - No Forced Projects - No CO2 Limits	$2,847	$2,797
	High Load - Large Hydro Forced - No CO2 Limits	$3,361	$3,342
	High Load - PPS&PPW Forced - No CO2 Limits	$2,839	$2,812
	High Load - SMR Forced - No CO2 Limits	$3,067	$3,042
Low Load	Low Load - No Forced Projects - No CO2 Limits	$2,623	$2,594
	Low Load - Large Hydro Forced - No CO2 Limits	$3,211	$3,198
	Low Load - PPS&PPW Forced - No CO2 Limits	$2,641	$2,596
	Low Load - SMR Forced - No CO2 Limits	$2,893	$2,874
SQ Load	Status Quo Load - No Forced Projects - No CO2 Limits	$2,443	$2,415
	Status Quo Load - Large Hydro Forced - No CO2 Limits	$3,081	$3,070
	Status Quo Load - PPS&PPW Forced - No CO2 Limits	$2,466	$2,444
	Status Quo Load - SMR Forced - No CO2 Limits	$2,719	$2,671
	95th Percentile	**$3,261**	**$3,243**
	Average	**$2,857**	**$2,828**

PORTFOLIO ANALYSIS

1898 & Co. worked with Chugach staff to identify key themes from the Expansion Planning phase of the study and distilled them into four different Portfolios to be analyzed through hourly production cost modeling in EnCompass. The rational for the individual portfolio buildout can be described by the following:

- **Portfolio 1:**
  - Establish a baseline for meeting carbon reduction goals with least cost renewable alternatives.
- **Portfolio 2:**
  - Study the impacts Dixon Diversion has on resource selections and overall portfolio cost.
- **Portfolio 3:**
  - Fuel Diversification with the addition of an SMR and study the impacts to cost and carbon goals.
- **Portfolio 4:**
  - Study a hydro-reliant portfolio with Susitna Watana and the Dixon Diversion in the energy mix.

Figure 14
Portfolio Sensitivity Analysis



The four portfolios outlined above were further studied using the Production Cost Modeling capabilities in EnCompass. Table 10 is a summary of resources added to the four alternative portfolios under base conditions. As stated, the Existing Resource scenario met the energy requirement and supplied enough capacity, the same exists for all four portfolios studied. The annual energy mix and Winter capacity positions are shown for further insight in Figure 16 and Figure 17 respectively

PORTFOLIO SENSITIVITIES

The four portfolios were simulated across the following eleven sensitivities. These sensitivities were particularly chosen to help evaluate and find potential vulnerabilities across Chugach's system. The base scenario is used as the constant so that the results from the other sensitivities can be easily compared.

Chugach is looking at different EV adoption rates as well as heat pump load, both impacts the load, therefore the study team wanted to understand what the effect of the varying load is on the portfolios.

Chugach projects continued heavy natural gas usage across the fleet, so the team studied a low and high LNG price forecasts.

Weather uncertainty as it pertains to hydro is a potential significant impactor to the Chugach power supply, the team wanted to see what impacts raising and lowering the hydro generation by 20% annually would have in the portfolios.

Due to data availability, the model only used a single production profile for all new wind additions. Different geographical locations could impact (and reduce) the projected capacity factor of a larger fleet of wind assets. The team decided to study lowering the capacity factor of all new wind resources by 5%.

Chugach has applied for grant funding for multiple new projects under the NewERA program. Should the grant funding be awarded to Chugach, the team wanted to include the potential cost reductions and see how they differed between portfolios. Finally, with inflation being high in recent years, the team wanted to look at capital costs with an assumed 30% increase from base levels.

The List of Sensitivities are listed below:

- Base Scenario (No Modifiers – Mid Electrification Load, Projected Gas, Projected Capital Expenditures)
- Status Quo Load
- Low Electrification Load
- High Electrification Load
- Low LNG Forecast
- High LNG Forecast
- Low Hydro Output on all units (-20% every year)
- High Hydro Output on all units (+20% every year)
- Low Wind Output on all new units (-5% capacity factor)
- New Era Funding on included projects (i.e. PPW)
- High Capital Costs (+30%)

PORTFOLIO RESULTS

All four portfolios studied met Chugach's carbon intensity goals in both the near and long term. The performance of the portfolios under the proposed Renewable Portfolio Standard (RPS) and the Clean Energy Standard (CES) was mixed, with the outcomes for each portfolio described below in their respective sections. The three target years that a pass/fail rating was assigned surrounding the Renewable Portfolio Standard were model years 2027, 2035, and 2040. The Clean Energy Standard pass/fail rating was targeted for the years 2036 and 2050.

Figure 15
Portfolio Carbon Intensity

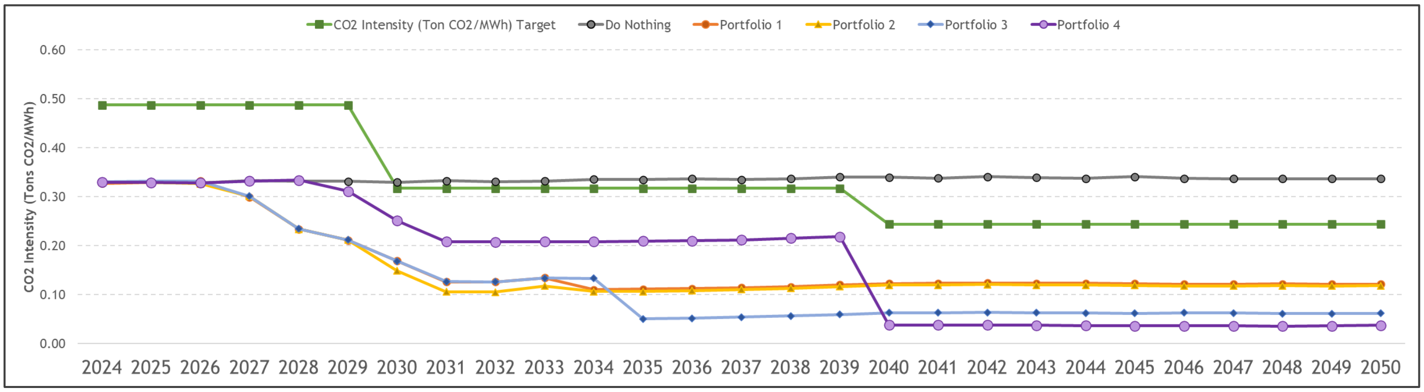


Table 10
Portfolio Buildout

Project Selection Summary	Scenario			
Year	P1: Status Quo Hydro	P2: SQH with Dixon	P3: SQH with SMR	P4: SQH, Dixon, Susitna-Watana
2025	RetherfordSolar (1 MW)	Retherford Solar (1 MW)	RetherfordSolar (1 MW)	RetherfordSolar (1 MW)
2026	Cooper Upgrade	Cooper Upgrade	Cooper Upgrade	Cooper Upgrade
2027	PPW Reg Package Proposed Project Wind Pilot (50 MW)	PPW Reg Package Proposed Project Wind Pilot (50 MW)	PPW Reg Package Proposed Project Wind Pilot (50 MW)	
2028	Proposed Project Wind (94 MW)	Proposed Project Wind (94 MW)	Proposed Project Wind (94 MW)	
2029	Generic Reg BESS Large Scale Generic Wind (30 MW)	Generic Reg BESS Large Scale Generic Wind (30 MW)	Generic Reg BESS Large Scale Generic Wind (30 MW)	LMSW Reg Package Large Scale Generic Wind (30 MW)
2030	Generic Reg BESS Large Scale Generic Wind (60 MW)	Generic Reg BESS Dixon Diversion Large Scale Generic Wind (60 MW)	Generic Reg BESS Large Scale Generic Wind (60 MW)	Dixon Diversion Large Scale Generic Wind (60 MW)
2031	Generic Reg BESS Large Scale Generic Wind (60 MW)	Generic Reg BESS Large Scale Generic Wind (60 MW)	Generic Reg BESS Large Scale Generic Wind (60 MW)	Large Scale Generic Wind (60 MW)
2032		Generic BESS (10 MW)		
2033	Generic BESS (100 MW)	Generic BESS (80 MW)	Generic BESS (100 MW)	
2034	Generic Reg BESS Large Scale Generic Wind_2034 (60 MW) Generic BESS (20 MW)	Generic Reg BESS Large Scale Generic Wind_2034 (30 MW)		
2035			CEA SMR (70 MW)	
2040				Susitna Watana Hydro Block 1 (95 MW) Susitna Watana Hydro Block 2 (24 MW) Susitna Watana Hydro Block 3 (24 MW) Susitna Watana Hydro Block 4 (24 MW) Susitna Watana Hydro Block 5 (24 MW)

Portfolio 1: Status Quo Hydro

This Portfolio established a baseline for meeting Chugach's carbon goals. This portfolio also implements least-cost renewable alternatives in a realistic and feasible timeline. Portfolio 1 passes the RPS across all sensitivities for the years 2027 and 2035. However, in 2040, Portfolio 1 does not meet the RPS standard. Portfolio 1 passes the CES for both years studied.

This portfolio contains a diversified mix of energy sources at modeled least cost to members. This portfolio has sufficient energy and capacity to meet the demand of Chugach's members and performed well across all environmental goals. This portfolio came in as the second overall least cost plan, coming in roughly $72 million higher than portfolio 3, suggesting further room for improvement from a portfolio cost perspective.

Figure 16
Annual Energy Mix Portfolio 1

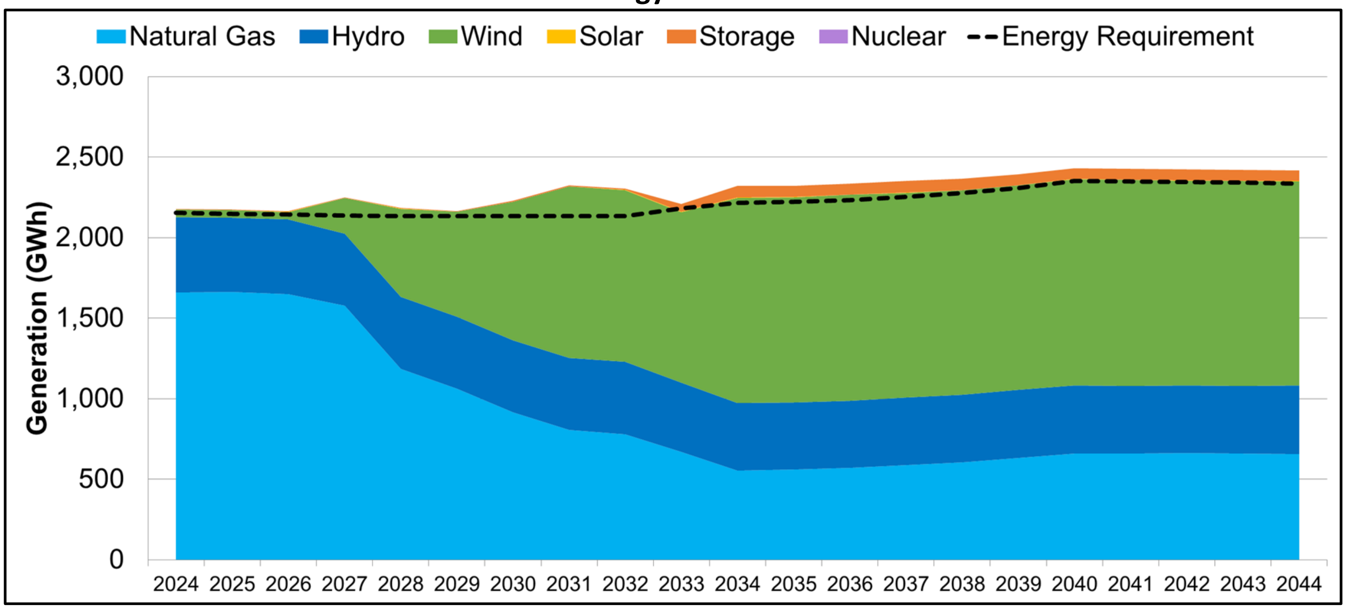
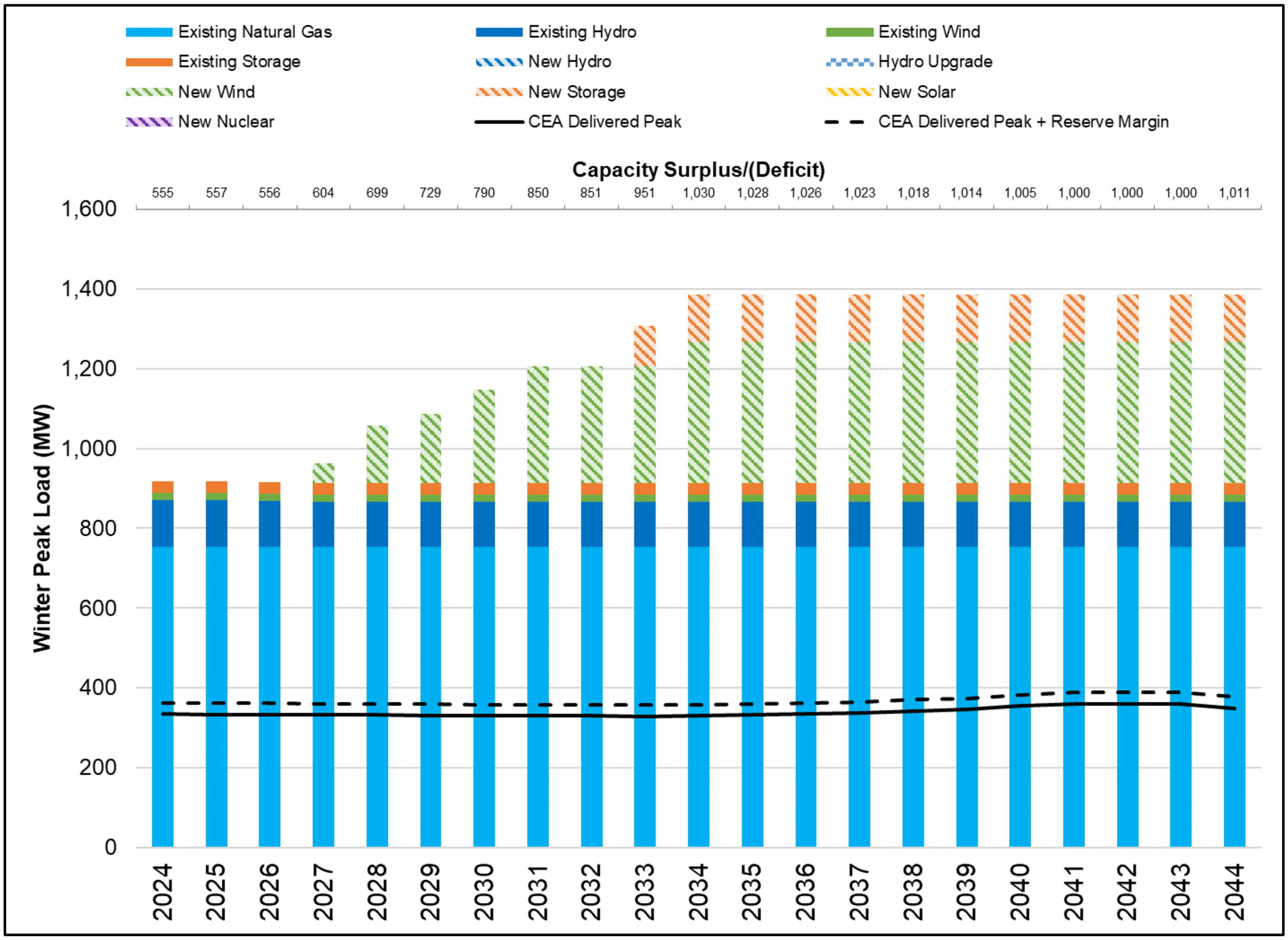


Figure 17
Winter Capacity Position Portfolio 1



Portfolio 2: Status Quo Hydro with Dixon Diversion

This portfolio investigates the key impacts the Dixon Diversion project has on the system. Portfolio 2 passes the RPS across all sensitivities in 2027 and 2035. However, in 2040, Portfolio 2 does not meet the RPS standard. Portfolio 2 passes the CES for both years studied.

Portfolio 2 highlights the necessity for diverse resource selections, and the role hydro facilities play in meeting both energy demand and regulation requirements. Portfolio 2 was the least overall cost plan across all sensitivities studied. This portfolio illustrates the benefit of upgrading an existing facility instead of securing funding for a new capital-intensive project. The diverse resource mix provides some safeguards against LNG volatility and project site selection risk.

Figure 18
Annual Energy Mix Portfolio 2

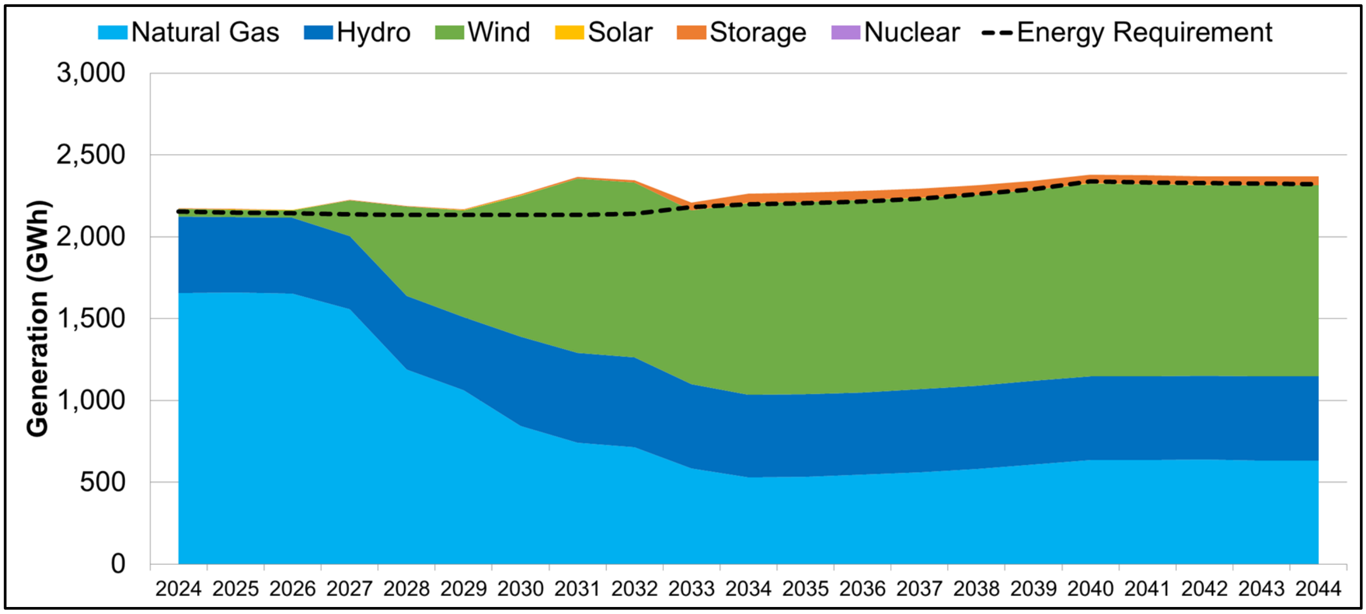
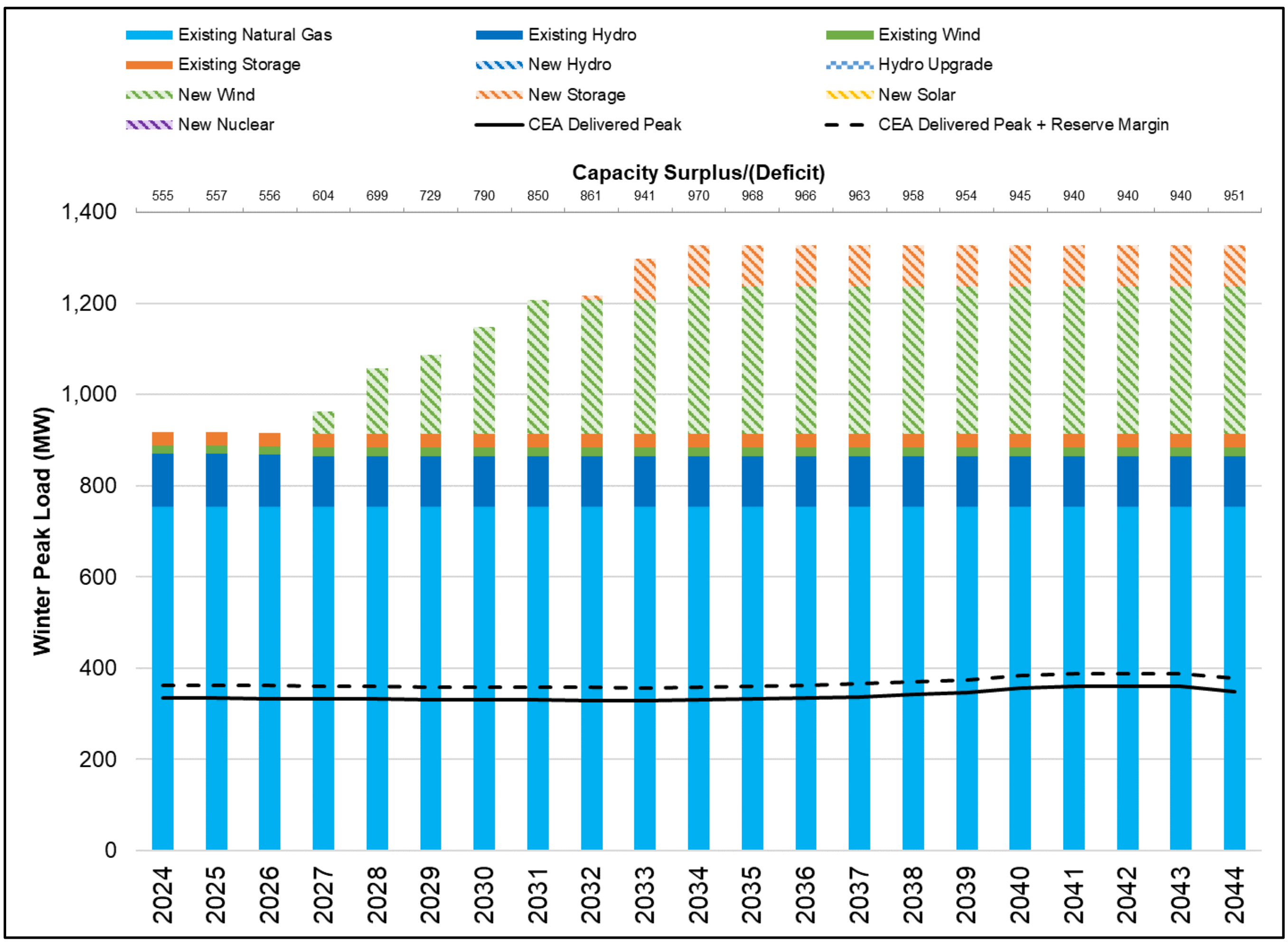


Figure 19
Winter Capacity Position Portfolio 2



Portfolio 3: Status Quo Hydro With A Small Modular Reactor

This portfolio looks at the effects of alternative ways to meet carbon goals with carbon free resources. Portfolio 3 passes the RPS across all sensitivities in 2027 and 2035. However, in 2040, Portfolio 3 does not meet the RPS standard. Portfolio 3 passes the CES in 2036 but fails in the "Low Wind Output" sensitivity in 2050. This is the only sensitivity that does not pass the Clean Energy Standard.

Portfolio 3 highlights the effects of exploring new technologies to meet carbon goals. This portfolio illustrates the benefits and risks of resource diversity to meet carbon goals at least cost. Though long-term LNG usage is minimized due to the base load production of the SMR, the capital costs pose a significant financial burden to the portfolio. This is illustrated in that Portfolio 3 came in as the Third highest overall portfolio cost even with the reduction in LNG usage. Additionally, permitting and licensing risks were not a metric studied in this analysis but certainly should not be overlooked. At the time of this report, no SMR has received a permit to operate from the Nuclear Regulatory Commission in the United States. Alaska also has some additional risk factors working against the construction of SMR including seismic potential and geographic location. The ability to implement projects in a feasible manner is crucial to portfolio development and the Small Modular Reactor is a relatively young technology with its own risks in development and project feasibility.

Figure 20
Annual Energy Mix Portfolio 3

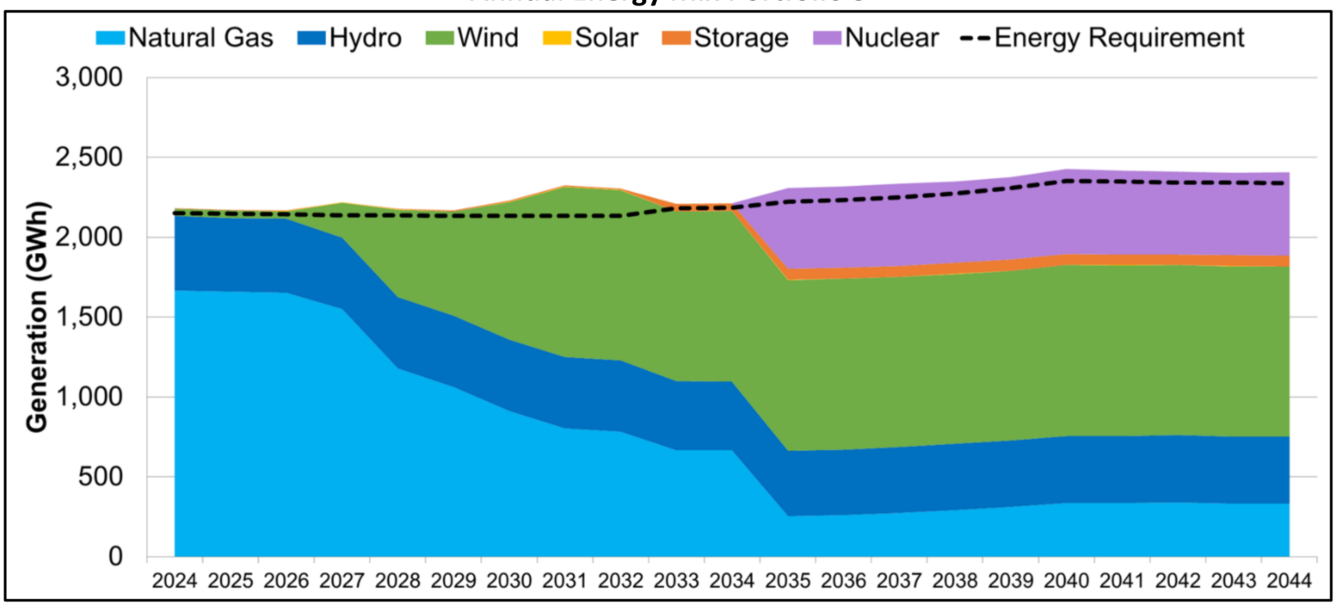
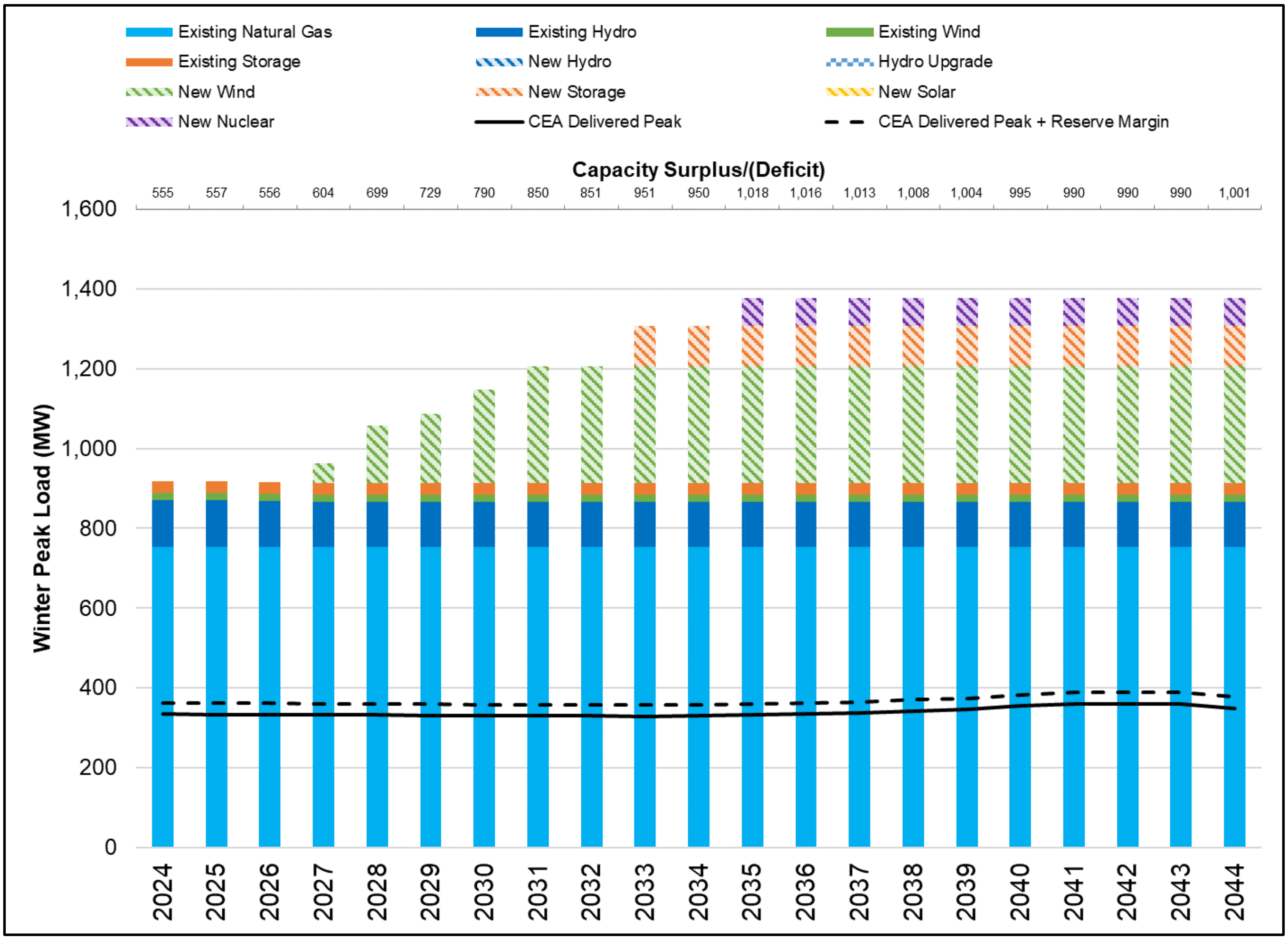


Figure 21
Winter Capacity Position Portfolio 3



Portfolio 4: Status Quo Hydro with Dixon Diversion and Large Scare Hydro

This portfolio looks at the effects of a hydro fleet and provides a "fringe" cost analysis. Portfolio 4 fails the RPS test across all sensitivities in 2027 and 2035 aside from the "High Hydro Output" sensitivity. However, in 2040, Portfolio 4 passes the RPS standard across all sensitivities. Portfolio 4 passes the CES for both years studied.

The impact hydro generation facilities have on meeting environmental, reliability and economic goals cannot be overstated. However, this does not mean all hydro-generating facilities are the same and do not pose a risk to Chugach. The study has highlighted the necessity for a diverse mix of resources, and the implementation of a large hydro facility like Susitna-Watana constrains Chugach's flexibility in perusing a diverse resource mix. The capital intensity and project timeline push the large hydro facility further out of the realm of feasibility. The model highlights delaying a large project addition to 2040 and committing to a project of this magnitude results in the second highest overall cost to Chugach, along with significantly reducing the flexibility Chugach has for a diverse mix of resources. Another aspect that was not quantified in this study but should not be ignored is the project site. The proximity to Denali Park for this large hydro facility could pose significant challenges in project permitting and construction.

Figure 22
Annual Energy Mix Portfolio 4

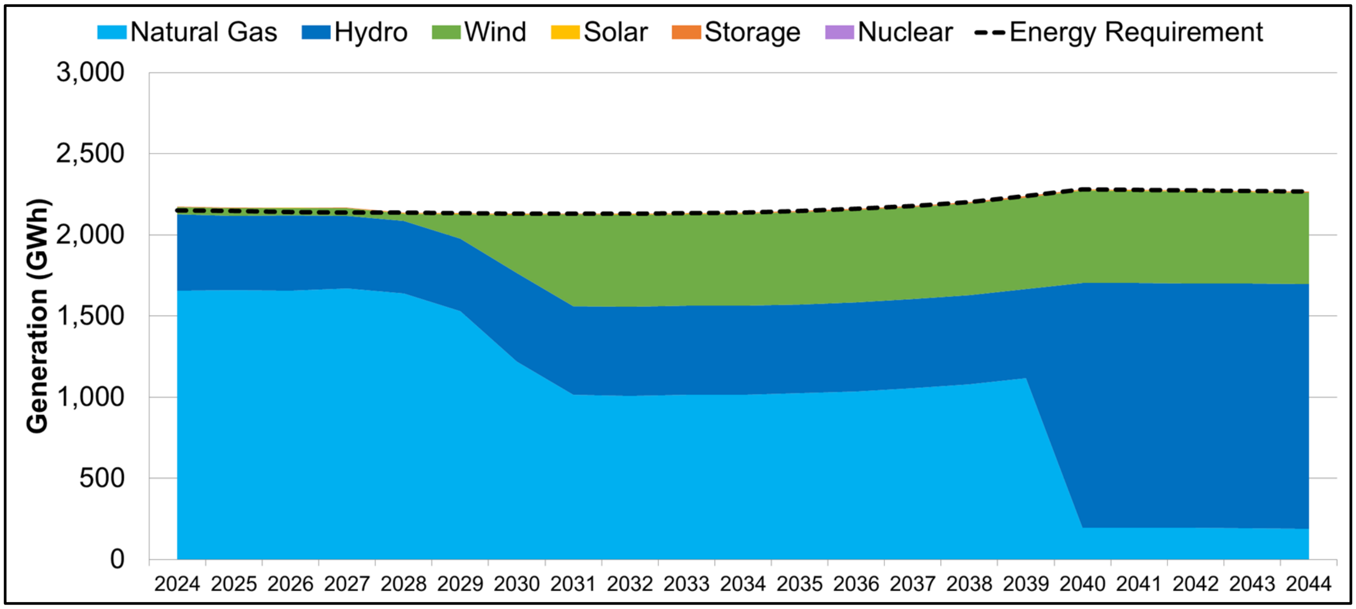
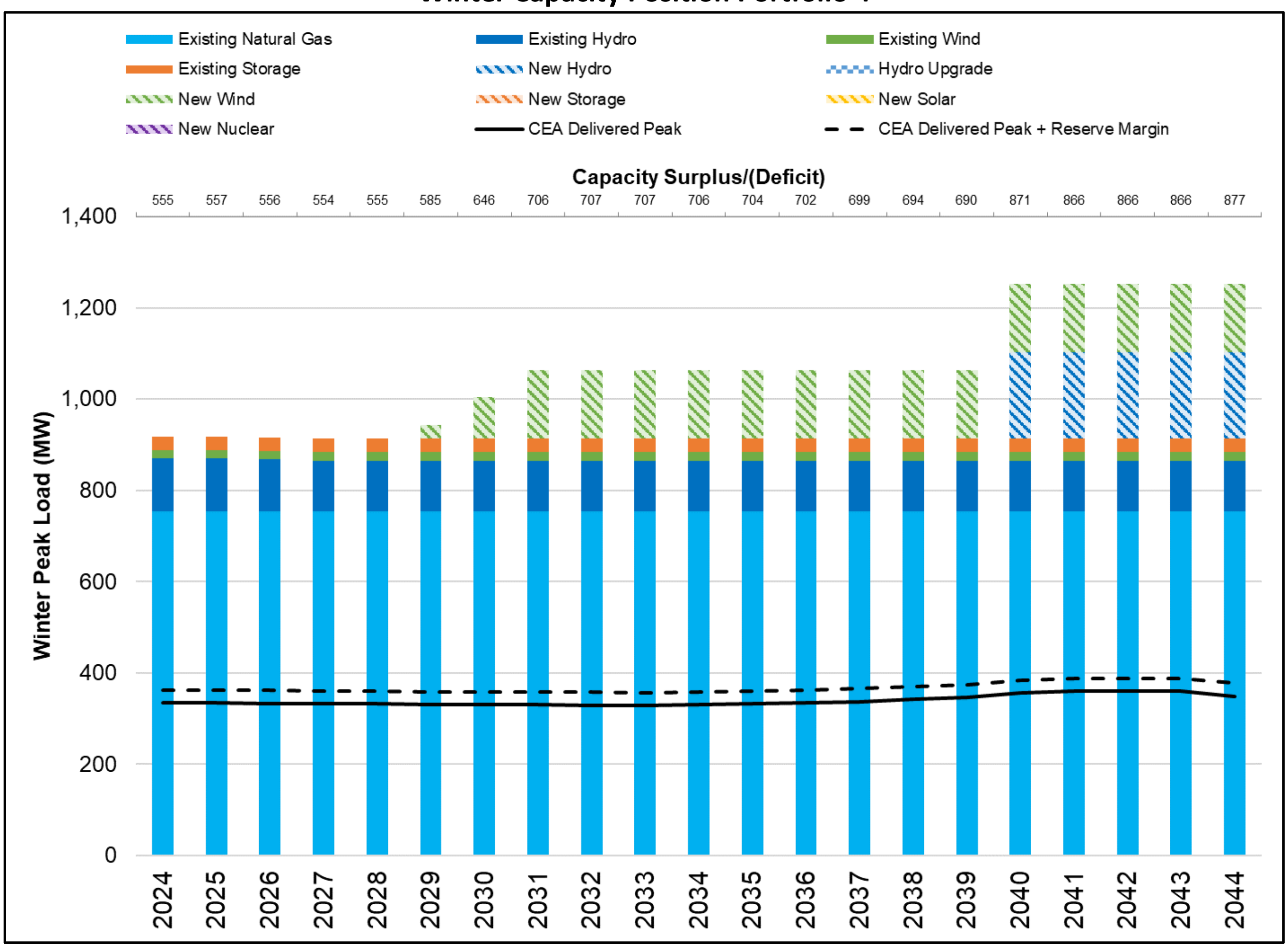


Figure 23
Winter Capacity Position Portfolio 4



Portfolio Production Cost Analysis

Encompass was also used to perform hourly production cost analysis for all five Portfolios – Status Quo Hydro, Status Quo Hydro with Dixon Diversion, Status Quo with Small Modular Reactor, and Status Quo Hydro with Dixon Diversion and a large hydro project. Table 11 shows the NPVs of each of the four portfolios across the 11 sensitivities. The chart has a "traffic light" formatting to display the low NPV's with a dark green and high NPVs with dark red. Looking at the average portfolio cost, Portfolio 1 and Portfolio 2 have the lowest NPV's. Table 12 shows the percentage difference from the Existing Resource portfolio to each of the portfolios. Figure 26 shows the carbon intensity for each portfolio as well as the Existing Resource portfolio and the carbon intensity targets.

Table 11
Summary of NPVs

NPV ($millions)	P1	P2	P3	P4
Base Scenario - No Modifiers	$3,206	$3,101	$3,365	$3,366
Low Load	$3,168	$3,061	$3,331	$3,346
High Load	$3,360	$3,254	$3,506	$3,526
Low LNG Forecast	$3,025	$2,926	$3,251	$3,161
High LNG Forecast	$3,448	$3,326	$3,516	$3,647
No Eklutna Derate (100% of production)	$3,190	$3,084	$3,350	$3,349
Low Hydro Output (-20% every year)	$3,451	$3,432	$3,623	$3,814
High Hydro Output (+20% every year)	$3,066	$2,953	$3,234	$3,168
Low Wind Output (-5% Capacity Factor)	$3,292	$3,184	$3,423	$3,460
New Era Funding on included projects	$3,079	$2,976	$3,240	$3,370
High Capital Costs (+30%)	$3,587	$3,471	$3,854	$3,821
Status Quo Load	$3,014	$2,903	$3,199	$3,200
95th Percentile	$3,519	$3,452	$3,739	$3,817
Average	$3,261	$3,161	$3,427	$3,457

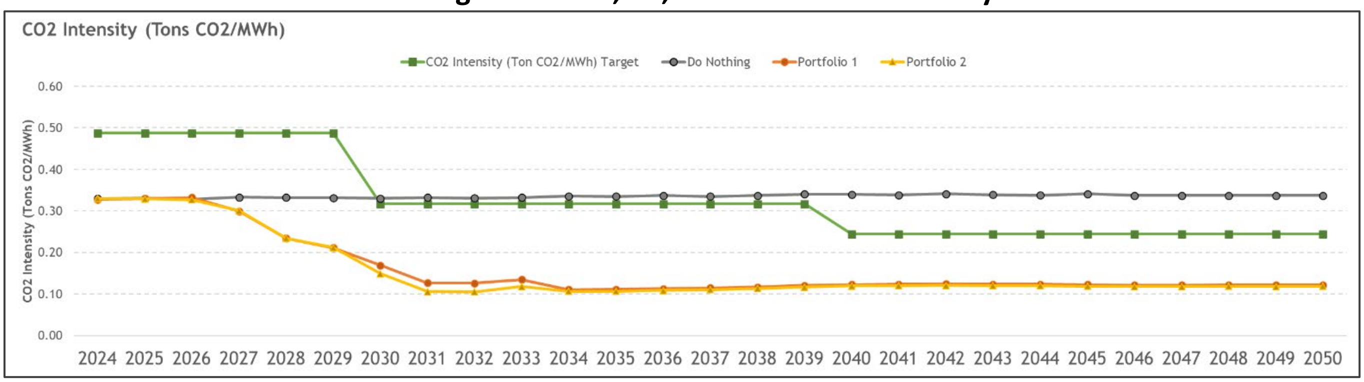
NPV ($millions)	P1	P2	P3	P4
Base Scenario - No Modifiers	$3,098	$2,993	$3,254	$3,258
Low Load	$3,057	$2,953	$3,220	$3,243
High Load	$3,250	$3,146	$3,393	$3,408
Low LNG Forecast	$2,915	$2,818	$3,139	$3,052
High LNG Forecast	$3,337	$3,218	$3,405	$3,540
Low Hydro Output (-20% every year)	$3,355	$3,325	$3,496	$3,672
High Hydro Output (+20% every year)	$2,958	$2,844	$3,126	$3,062
Low Wind Output (-5% Capacity Factor)	$3,183	$3,077	$3,311	$3,354
New Era Funding on included projects	$2,973	$2,867	$3,131	$3,251
High Capital Costs (+30%)	$3,444	$3,329	$3,713	$3,680
Status Quo Load	$2,907	$2,794	$3,087	$3,092
95th Percentile	**$3,399**	**$3,327**	**$3,604**	**$3,676**
Average	**$3,150**	**$3,050**	**$3,311**	**$3,342**

NPV ($millions)	P1	P2	P3	P4	P5
Base Scenario - No Modifiers	$3,098	$2,993	$3,254	$3,258	$3,358
Low Load	$3,057	$2,953	$3,220	$3,243	$3,314
High Load	$3,250	$3,146	$3,393	$3,408	$3,513
Low LNG Forecast	$2,915	$2,818	$3,139	$3,052	$3,133
High LNG Forecast	$3,337	$3,218	$3,405	$3,540	$3,648
No Eklutna Derate (100% of production)	$3,083	$2,975	$3,238	$3,245	$3,356
Low Hydro Output (-20% every year)	$3,355	$3,325	$3,496	$3,672	$3,563
High Hydro Output (+20% every year)	$2,958	$2,844	$3,126	$3,062	$3,257
Low Wind Output (-5% Capacity Factor)	$3,183	$3,077	$3,311	$3,354	$3,453
New Era Funding on included projects	$2,973	$2,867	$3,131	$3,251	$3,234
High Capital Costs (+30%)	$3,444	$3,329	$3,713	$3,680	$3,707
Status Quo Load	$2,907	$2,794	$3,087	$3,092	$3,152
95th Percentile	**$3,399**	**$3,327**	**$3,604**	**$3,676**	**$3,677**
Average	**$3,150**	**$3,050**	**$3,311**	**$3,342**	**$3,412**

Table 12
Delta from the Existing Resource Portfolio

Delta from "Existing Resource" Case	P1	P2	P3	P4
Base Scenario - No Modifiers	0%	-3%	5%	5%
Low Load	-1%	-5%	4%	4%
High Load	5%	1%	9%	10%
Low LNG Forecast	-6%	-9%	1%	-1%
High LNG Forecast	8%	4%	10%	14%
No Eklutna Derate (100% of production)	0%	-4%	5%	4%
Low Hydro Output (-20% every year)	8%	7%	13%	19%
High Hydro Output (+20% every year)	-4%	-8%	1%	-1%
Low Wind Output (-5% Capacity Factor)	3%	-1%	7%	8%
NewEra Funding on included projects	-4%	-7%	1%	5%
High Capital Costs (+30%)	12%	8%	20%	19%
Status Quo Load	-6%	-9%	0%	0%

Figure 24
Existing Resources, P1, and P2 Carbon Intensity



PREFERRED PLAN

Chugach has identified its Preferred Plan as Portfolio 2 through robust evaluation through a variety of combinations of possible projected changes in member demand growth, resource availability, and capital cost sensitivities. The Preferred plan identifies a recommended future resource mix and timing that is both the most economical portfolio to serve Chugach's members and achieves our carbon emission reduction goals at a cost lower than operating the current resource portfolio with projected future fuel costs. The Preferred Plan will leverage power purchase agreements with developers for new wind energy and battery energy storage projects, leveraging the potential federal Inflation Reduction Act funding and limiting Chugach's capital outlay requirements. Additional work with AEA and the Bradley Lake Management Committee to advance and finance the Dixon Diversion project will be required to execute this plan.

This Preferred Plan identifies that the next steps for Chugach are completing the Retherford solar project, continuing to develop the Proposed Project Wind, determining the system changes necessary to incorporate increasing amounts of variable energy, and advancing BESS integration. Beyond these first steps and moving into the 2030s, Chugach will need to find a way to repeat this process again by adding wind power and deploying the necessary regulation assets to manage the variability. This is the opportunity and, at the same time, a challenge that the IRP has identified for Chugach to bring cost-effective power to our members while we work to offset new and more costly Cook Inlet gas and LNG import alternatives.

The large volume of Lithium-ion utility-scale battery additions identified in this IRP for energy transfer transactions and batteries for regulation assets necessitates a fundamental shift in Chugach's power dispatch operations. Some changes have already been considered and are in place to be implemented in the next several years, but the scale necessary to incorporate large amounts of wind energy in our Preferred Plan will likely require further changes to operations, including system automation, employee training and new tools and systems to forecast weather-driven intermittent energy sources while ensuring reliable member service.

We are onboarding the IRP model and investing in training our team in Encompass to be nimble as technology and member demand change. This will also require us to update the model regularly, refine our answer, and test new potential projects as they are proposed internally ad hoc or presented by outside companies. This will help focus our effort to provide cost-competitive, reliable power for our members by testing different scenarios and optimizing our system. While the Preferred Plan spans to 2050, there is a need for further evaluation of new solar projects, a Fire Island Wind Project expansion, understanding the cost and benefit of PPA agreement vs. cooperative-financed projects, and working to solicit more projects for evaluation from developers. There may even be new technologies that are not yet commercially available that we will also consider in the future.

The status of existing assets in the Chugach portfolio will need additional study in the future. All the portfolios, including the Preferred Plan have significant amounts of surplus generation capacity when compared to Chugach's projected peak loads. Impacts from extreme weather and gas availability will require further analysis with modeling more granular and probabilistically based than can be performed in this IRP.

A review of the generation from Natural Gas fueled resources under the Base Sensitivity for the Preferred Plan (P2), reveals that apart from the SPP and Sulivan Combined Cycle units, the remainder of Chugach's natural gas fleet is called on for less than about 3,000 MWh of energy production per year. Since those other units combine for approximately 442 MW of installed capacity, the combined capacity factor of these resources is less than 0.1% annually. Determining which units may be candidates for mothballing will require the input of many core functions and departments of Chugach, along with further study.

It is a time of great change in the electric utility industry. Chugach's Preferred Plan sets an exciting and transformational roadmap for our future power supply to provide our members with a reliable power supply while achieving our strategic priority of reducing our carbon intensity by more than 50% in 2040 from 2012 levels at the lowest possible cost.