Assemblymember Yundt IM 24-061 / RS 24-031

I MOVE to amend IM 24-061 by attaching the UAF Institute of Northern Engineering, Cook Inlet Region Low Carbon Power Generation With Carbon Capture, Transport, and Storace Feasibility Study.

This study was recently released and I did not have access to it when the resolution was being written.

COOK INLET REGION
LOW CARBON POWER GENERATION WITH CARBON CAPTURE, TRANSPORT, AND STORAGE FEASIBILITY STUDY

February 28, 2024

University of Alaska Fairbanks Institute of Northern Engineering

Energy & Environmental Research Center, University of North Dakota

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

Institute of Northern Engineering
University of Alaska Fairbanks

COOK INLET REGION LOW CARBON POWER GENERATION WITH CARBON CAPTURE, TRANSPORT, AND STORAGE FEASIBILITY STUDY

Topical Report

Low Carbon Emissions and Economic Analysis: Biomass-Coal versus Natural Gas Generation – Alaska Railbelt Electricity Grid and New Industrial Demand

Cooperative Agreement No. DE-FE0031838

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ACRONYMS AND ABBREVIATIONS

AAC	Alaska Administrative Code
AC	alternating current
ADNR	Alaska Department of Natural Resources
AEA	Alaska Energy Authority
AGDC	Alaska Gasoline Development Corporation
AIDEA	Alaska Industrial Development and Export Authority
ANSI	American National Standards Institute
AOGCC	Alaska Oil and Gas Conservation Commission
AOR	area of review
Bcf	billion cubic feet
BIF	Best Interest Finding
CAPEX	capital expenditure
CarbonSAFE	Carbon Storage Assurance Facility Enterprise
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CEA	Chugach Electric Association, Inc.
CFB	circulating fluidized bed
CFR	Code of Federal Regulations
CIRI	Cook Inlet Region, Inc.
CO_2	carbon dioxide
cP	centipoise
DAC	direct air capture
DOE	U.S. Department of Energy
DOG	Division of Oil and Gas
EERC	Energy & Environmental Research Center
EIA	U.S. Energy Information Administration
EOR	enhanced oil recovery
EPA	U.S. Environmental Protection Agency
FAST-41	Fixing America's Surface Transportation Act, Title 41
FEC	Flatlands Energy Corporation
FEED	front-end engineering design
FGC	flue gas cooler
FGD	flue gas desulfurization
FPP	fuel and purchased power
G&T	generation and transmission
GHGRP	Greenhouse Gas Reporting Program
GLO	Governor's Legislative Office
GVEA	Golden Valley Electric Association, Inc.
GWP	global warming potential
HEA	Homer Electric Association, Inc.
IEA	International Energy Agency
IRA	Inflation Reduction Act

Continued . . .

ACRONYMS AND ABBREVIATIONS (continued)

kg/m^3	kilogram per cubic meter
kWh	kilowatt-hour
lb	pound
lb/ft^3	pound per cubic foot
LNG	liquefied natural gas
mD	millidarcy
MEA	Matanuska Electric Association, Inc.
MHI	Mitsubishi Heavy Industries
MIT	mechanical integrity testing
MMBtu	million British thermal unit
MMscfd	million standard cubic feet per day
MRV	monitoring, reporting, and verification
MP	milepost
MMt	million metric tons
MW	Megawatt
MWe	Megawatts electric
MWh	megawatt-hour
NEPA	National Environmental Policy Act
NETL	National Energy Technology Laboratory
NGI	Natural Gas Intelligence
NIST	National Institute of Standards and Technology
O&M	operating and maintenance
OPEX	operating expenses
pc	pulverized coal
PCOR	Plains CO_2 Reduction (Partnership)
PISC	postinjection site care
POD	plan of development
PRA	Petrotechnical Resources of Alaska
psi	pound per square inch
R&D	research and development
ROD	record of decision
ROW	right of way
RRC	Railbelt Reliability Council
RTE	Red Trail Energy
Tcf	trillion cubic feet
T&S	transportation and storage
UAF	University of Alaska Fairbanks
UAF-INE	University of Alaska Fairbanks Institute of Northern Engineering
USDW	underground source of drinking water

COOK INLET REGION LOW CARBON POWER GENERATION WITH CARBON CAPTURE, TRANSPORT, AND STORAGE FEASIBILITY STUDY

EXECUTIVE SUMMARY

For approximately 70 years, Southcentral Alaska (Southcentral) has been dependent on natural gas produced and distributed from the Cook Inlet Basin for both direct heat use and electricity generation. Hilcorp Energy Company (Hilcorp) supplies approximately 85% of the natural gas to Southcentral utilities and in 2022 gave notice to utilities to consider alternative sources of energy because the depletion of Cook Inlet gas reserves prevents Hilcorp from renewing utility agreements beginning in 2025 (DeMarban, 2022). A dominant electricity producer in Southcentral, the Chugach Electric Association, Inc. (CEA), relies on gas for 80% of its electricity needs (Chugach Electric Association, 2022b). CEA states in its review of gas resources, "Absent sufficient production from the Cook Inlet, and with North Slope [gas] pipeline projects years away, the study concluded it may be necessary for Southcentral utilities to import either liquid or compressed natural gas to fill the gap" (Chugach Electric Association, 2022a). Imported liquefied natural gas (LNG) and other gas supply options including new Cook Inlet Gas or North Slope gas create significant fuel price risk and can substantially increase Southcentral electricity prices, already amongst the highest in the nation.

Biomass-Coal power generation with carbon capture and storage (CCS) presents a compelling alternative that can commence operation 6 and 8 years from start of a front-end engineering design (FEED) study. Beneficial use of both CO_2 and coal ash by-products from the power plant for agriculture, such as greenhouse growing or fertilizer production, and for other imported products such as cement, gypsum, and possibly critical minerals, can support the State's policy objectives of lessening "Alaska's dependence on external foods and supply chains" (DCCED, 2023). The State imports 95% of its food, 100% of its CO_2 supply, and the majority of its fertilizer.

Biomass-Coal power generation with CCS can also support the stated objectives of the Governor and of Alaska's Office of Energy Innovation in accessing a secure and diverse energy mix for safe, reliable, and affordable energy for Alaskans, and Alaska's desire for leadership in "both carbon capture, utilization, and storage and building the critical minerals of this state and nation" (Alaska Department of Natural Resources, 2022). The Governor's recent Administrative Order No. 340 places "policies that enable Alaska to capitalize on its vast energy potential in order to lower the cost of energy and enhance the stability of energy delivered to Alaskans" as the first listed purpose of the Office of Energy Innovation, and "development of a strong and responsible critical minerals mining program and investment in emerging energy technologies" as its fifth (State of Alaska and Office of the Governor, 2022). Low-cost electricity is a key enabler for establishing an Alaska-based critical minerals mining and refining industry.

In January 2024, the University of Alaska Fairbanks-Alaska Center for Energy and Power (ACEP) released a techno-economic report, *Alaska's Railbelt Electric System: Decarbonization Scenarios for 2050* (Cicilio 2024). That report found that "…the (Railbelt grid) 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. …fossil-fuel and hydro power generation were the most cost effective firm sources to pair with variable renewables." (p.22) That report also concluded that nuclear and tidal generation were both more expensive, and that "there is also significant uncertainty in the projected costs and future commercial availability of these technologies." That report's base case economic analysis showed that wind, solar, nuclear, tidal, or hydro power, i.e., re-activating the Susitna-Watana Dam project, would be more expensive than business-as-usual power costs. By extension, those options would be considerably more expensive than a biomass-coal or biomass-coal with CCS energy supply, which generates lower cost power than the current power system.

Study Approach

This study evaluates the economic and technical feasibility of a low CO_2 emissions biomass-coal-fueled power plant and compares it to current and future natural gas generation scenarios. The cost of electricity generated from a new biomass-coal power plant, with and without CCS, is compared with the cost of electricity generated from natural gas power plants, existing or newly constructed, with and without CCS, at current and expected future natural gas fuel prices.

A circulating fluidized-bed (CFB) biomass-coal fired power plant and Mitsubishi Heavy Industries (MHI)-based carbon capture plant were selected for evaluation in this study. These systems have recently been installed in analogous commercial industrial plants and are well understood. Both plants will be co-located at the Flatlands Energy Corporation (FEC) coal lease in the West Susitna region of the Northern Cook Inlet of Alaska for this study.

The selected CO_2 storage site for this study is the nearly depleted Beluga River on-shore gas field. This reservoir is forecast to be depleted within 10 years and has well-understood geology and pore space estimated to store more than 60 years of CO_2 captured from a 400-megawatt electric (MWe) biomass-coal power plant. For this multi-zone gas field, the Operator Hilcorp indicates a depletion plan can be developed where CO_2 injection begins during field gas depletion. Further geological and engineering study is planned for this area to calculate CO_2 storage capacity, to be led by University of Alaska. This storage capacity study, the Alaska Railbelt Carbon Capture and Storage (ARCCS) Project, was selected by the U.S. Department of Energy for a Carbon SAFE Phase II storage volume analysis including technical, economic, and community assessments for potential CO_2 storage (U.S. DOE FECM Nov.14, 2023).

CCS techno-economic models assume that the carbon capture, transport, and storage facilities are operated for all 30 years of the electricity generation project lifespan in all cases. Base-case 45Q tax credit assumptions are that the tax credits remain at $85/metric tonne through the entire 30-year project life, referred to as the "30-year tax credit" scenario, which is consistent with the history of U. S. Federal legislative extensions for both wind and CCS tax credits to date. As an alternate case, CCS economics are tested with 45Q credits that end after 12 years, consistent with current legislation and referred to as the "12-year tax credit" scenario. No economic benefits from value-added products, such as critical minerals or CO_2 sales, are considered in the economics in this report.

In order to assess the cost competitiveness of electricity from biomass-coal, three approaches are used to estimate the cost of natural gas power at current and higher future natural gas prices. First, the industrial rate offered by CEA is referenced. (Note: industrial rates are cited throughout this report. Retail electricity is ~12% higher than industrial rates.) A second approach estimates the avoided cost of electricity from the existing CEA fleet, representing the average operational cost to generate a megawatt-hour of power. A final approach evaluates new high-efficiency gas power generation using the same method used to evaluate biomass-coal, which enables assessing the lowest hypothetical cost of gas-based power versus a new biomass-coal power investment.

Conclusions and Recommendations

Biomass-coal energy supply with CCS provides lower cost energy than natural gas energy supply with or without CCS, and biomass-coal energy supply with CCS provides lower CO_2 emissions than the current natural gas energy supply without CCS. Further, CCS lowers the cost of electricity for biomass-coal generation because 45Q tax credit revenues exceed CCS cost, while CCS for natural gas increases electricity cost due to Southcentral's high gas prices. As the imminent gas supply shortfall further increases natural gas prices, gas-based electricity, *with or without CCS*, is more expensive than biomass-coal-based electricity *with CCS*.

This economic and technical evaluation of biomass-coal power generation with CCS located in Southcentral Alaska provides an attractive business, technical, public policy, and environmental case for meeting long-term regional electricity supply needs. Anticipated biomass-coal-fueled electrical generation costs are competitive with the current rates and much lower than future power costs for generation relying on uncertain new Cook Inlet gas, imported LNG, or North Slope gas. Biomass-coal generation with CCS can economically deliver low carbon power. It may even be possible to attain climate positivity in an already highly efficient CFB power plant, for example, using waste heat and CO_2 for beneficial use in greenhouse operations while sequestering the remaining CO_2.

Biomass-coal power generation would lower CO_2 emissions, lower the cost of electricity to the Railbelt and Southcentral, and, through Power Cost Equalization, lower the cost of Rural electricity across the State, all while adding new power generation capacity and providing in-state-sourced fuel security.

Considering the imminent regional natural gas shortage, the resulting higher gas and electricity prices, the abundant low-cost coal reserves in the region, and the competitive power cost delivered with low to negative CO_2 emissions, it is recommended to progress a new biomass-coal fired power plant with CCS for the Railbelt and Southcentral.

Specific recommendations are included at the end of the report.

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Institute of Northern Engineering
University of Alaska Fairbanks

COOK INLET REGION LOW CARBON GENERATION WITH CARBON CAPTURE, TRANSPORT, AND STORAGE FEASIBILITY STUDY

INTRODUCTION

This study evaluates the technical and economic feasibility of constructing a greenfield power generation plant in northern Cook Inlet region, Alaska, with carbon capture, transport, and geologic storage of carbon dioxide (CO_2) in a soon to be depleted Cook Inlet natural gas reservoir. The power plant is assumed to be located at the mine mouth of the Flatlands Energy Corporation's (Flatlands Energy) coal lease near the Railbelt electricity grid and near prospective CO_2 storage sites.

The pending depletion of the natural gas supply for the largest segment of Alaska's population, the Southcentral Alaska (Southcentral) region, from the largest regional gas supplier, Hilcorp Energy Corporation (Hilcorp), requires the evaluation of known energy reserves that can come into production in a compatible time frame (DeMarban, 2022). Flatlands Energy's existing proven reserves of clean (low ash, metal, and mercury content and ultralow sulfur content) coal, when coupled with well-understood biomass-coal power generation technology with carbon capture, can contribute to meeting the electricity needs of the Alaska Railbelt within the necessary time frame. A new biomass-coal fired power plant can displace natural gas used for power generation, thereby extending the remaining life of the declining natural gas supply. In addition to diversifying power generation sources and providing firm power, modern coal plants can respond to the challenges introduced to the grid by variable power generation sources. Plant design concepts and costs used for this study are benchmarked with the 405 MW Dry Fork, Wyoming coal power plant, the recently installed 17-MW coal power plant constructed at the University of Alaska Fairbanks, and recently designed carbon capture plants elsewhere in North America.

In this feasibility study, proven project options and technologies were selected for planning and cost estimation purposes. Competing alternatives have not been eliminated and should be evaluated in future evaluations.

Plains CO_2 Reduction (PCOR) Partnership
Energy & Environmental Research Center (EERC)

Study Team: University of Alaska Fairbanks and the EERC

Under the Plains CO_2 Reduction (PCOR) Partnership program, engineers from the University of Alaska Fairbanks Institute of Northern Engineering (UAF-INE) and the Energy & Environmental Research Center (EERC) at the University of North Dakota collaborated with coal power generation and permitting specialists.

The PCOR Partnership, funded by the U.S. Department of Energy (DOE) National Energy Technology Laboratory (NETL), the North Dakota Industrial Commission's Oil and Gas Research Program and Lignite Research Program, and more than 230 public and private partners is accelerating the deployment of carbon capture, utilization, and storage (CCUS) technology.

The PCOR Partnership region comprises ten U.S. states and four Canadian provinces in the upper Great Plains and north western regions of North America, including Alaska. It is led by the EERC, with support from the University of Wyoming and the UAF-INE. The goal of this joint government–industry effort is to identify and address regional capture, transport, use, and storage challenges facing commercial deployment of CCUS throughout the PCOR Partnership region.

The PCOR Partnership region is home to abundant and diverse sources of anthropogenic CO_2 (e.g., coal and natural gas power plants, gas-processing plants, ethanol plants), fitting geology for CO_2 storage and utilization, a history of CO_2 transport and expanding pipeline infrastructure, and an established industrial/energy commercial base. For nearly two decades, working with over 250 industry and government partners, the focus of the PCOR Partnership has been the integration of CCS/CCUS into commercial industries within the region. The PCOR Partnership partners include key industrial sectors with a stake in CCS/CCUS deployment; numerous state, regional, and federal governmental research entities; and several state and federal regulatory agencies.

The EERC has provided technical support for multiple CCUS injection project applications. For example, the EERC partnered with Red Trail Energy LLC (RTE) to pursue the first carbon storage facility permit approval in North Dakota, which occurred at RTE's ethanol production facility. Regulatory, subsurface engineering, and geologic experts oversaw the drilling of a stratigraphic test well with coring, logging, formation testing and downhole fluid sampling to characterize the storage complex and confirm the geologic suitability for storing CO_2 at RTE. EERC reservoir engineers used the characterized data from well drilling and a 3D seismic survey to build a geologic model of the storage complex in order to run numeric simulations that would be used to predict the expected CO_2 plume extent for the volumes of CO_2 captured at RTE's facility. The EERC in collaboration with RTE developed a site monitoring, reporting, and verification (MRV) plan compliant with both state and federal requirements, including the U.S. Environmental Protection Agency (EPA) Greenhouse Gas Reporting Program (GHGRP) MRV Plan, required to meet eligibility for the 45Q tax credit. EERC experts subsequently testified before regulatory authorities as to the high degree of geologic security and permanence at the site, and ultimately, RTE gained approval for injection and storage shortly thereafter.

For Project Tundra, the EERC installed a slipstream carbon capture system at the Milton R. Young power plant to demonstrate a proof of concept using two different commercial solvent options for actual plant flue gas. Subsurface engineering and geologic experts supported drilling, logging, coring, formation testing, sampling, completion, and injection testing of three stratigraphic test wells over two phases of the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) programs prior to pursuing site storage facility permits. They also conducted geologic modeling and fluid flow simulations to predict CO_2 plume growth during injection and stabilization during the postinjection period. Successful application for Project Tundra storage facility permits also required EERC regulatory groups to develop an adequate storage facility MRV plan to ensure safe and secure geologic CO_2 storage and provide risk analysis and remedial response plans for those risks among other long-term regulatory, legal, and operational planning. Upon completion of the storage facility permit applications, EERC staff again successfully testified that the site was safe and secure for CO_2 injection and storage, gaining storage approval shortly after RTE's storage facility permit approval.

Carbon Capture, Use, and Storage Technology Overview

Figure 1 shows a generalized schematic of CCS/CCUS. The CO_2 source in this feasibility study is combustion flue gas from a new biomass-coal fired power generation plant containing 11% to 14% CO_2 concentration by volume.

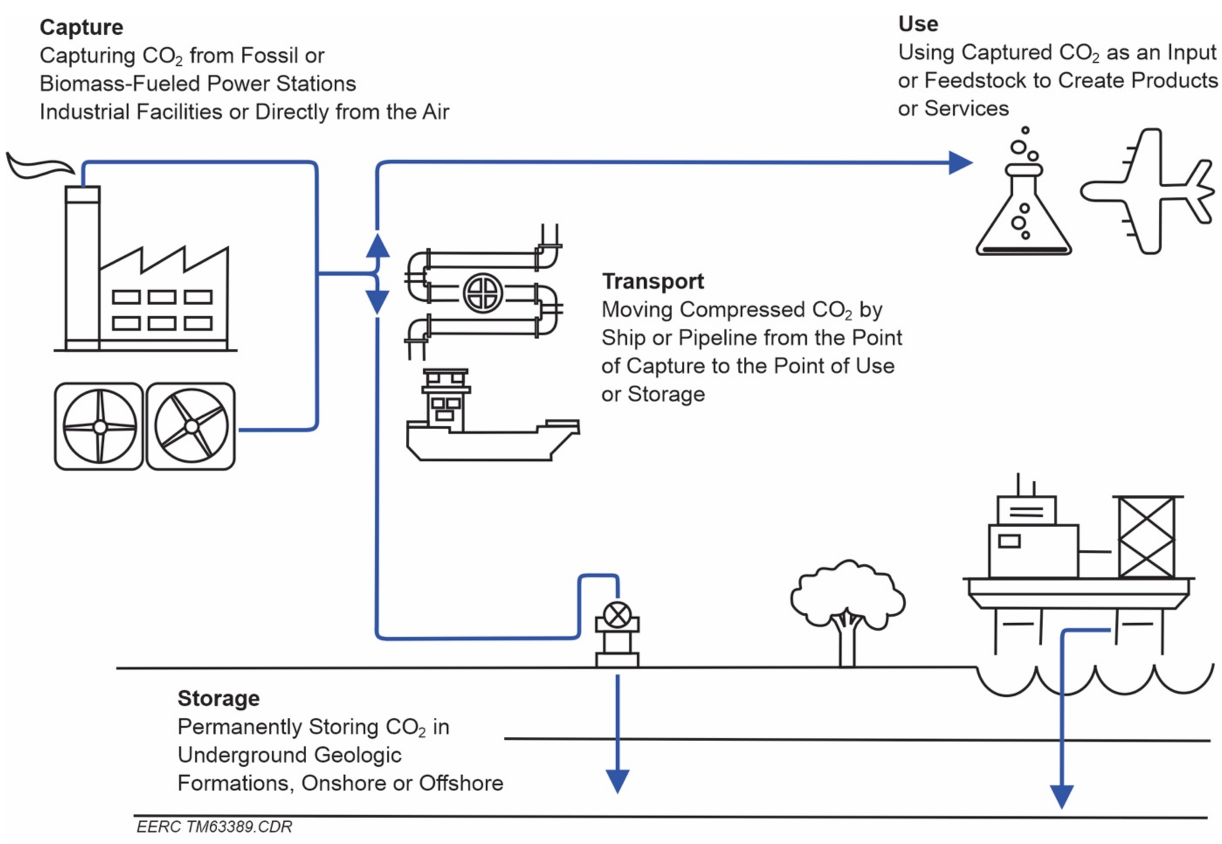

Figure 1. Generalized CCUS Schematic (International Energy Agency, 2022a).

With current carbon capture, 90% or more of coal power plant carbon emissions can be removed via amine-based solvent systems, resulting in lower CO_2 emissions than existing or new natural gas power plants without CCS. Most CCS projects compress CO_2 for increased density and lower volume and cost of transportation via pipeline to dedicated underground geologic storage in saline aquifers. Valuable by-product sales are also possible, including CO_2 for enhanced oil recovery (EOR), fly ash to the concrete market, critical minerals, or other products such as gypsum or sodium bicarbonate, allowing some coal plants with CCS and beneficial use to approach net-zero carbon emissions (International CCS Knowledge Centre, 2018).

Mine and Power Plant Location, Local Infrastructure, and Storage Potential

The Flatlands Energy coal reserve has sufficient proven reserves to supply electricity to prospective local industrial customers and the regional power utility grid for generations. This feasibility study considers electrical power generation with CCS from 25 to 500 MW (net) for local and regional power. Located in the northern Cook Inlet region, the Flatlands Energy coal lease is in an advantageous development location. A regional location map is shown in Figure 2. The lease:

1. Can access significant local and regional infrastructure:
    a. The existing West Susitna winter road, supporting development and construction.
    b. The all-season West Susitna Access Road, currently in permitting stage, for long-term operations.
    c. A permitted pipeline corridor connecting with known sequestration geology on the north shore of Cook Inlet which may be amended for electrical transmission and CO_2 transport.
    d. A regional 500+ MW-capacity power grid intertie at the Beluga power plant, or at an alternative tie-in near Port MacKenzie.
    e. Port MacKenzie, for delivery of large machinery and equipment and export of CO_2 value-added products such as greenhouse agricultural products, CO_2 for commercial use, ammonia, hydrogen, and other products.
    f. City of Anchorage, Southcentral, and Interior regions, with international airports, a strong relevant labor force, and materials and supplies.
2. Enjoys multiple local geologic storage options:
    a. Substantial, quantifiable geologic storage pore space onshore in the depleting Beluga River field and adjacent gas fields
    b. Potential saline aquifer storage space as close as 20 miles to Flatlands Energy site.

c. With additional nearby Northern Cook Inlet storage options including i) depleting or depleted oil or gas field nearby, ii) local or regional saline aquifer, e.g., the Hemlock Formation (Pantaleone and Bhattacharya, 2020) or iii) in local or regional unmineable coal seams (Shellenbaum and Clough, 2010) if other storage proves insufficient.

3. Can serve multiple new local and regional industrial customer/power demand, including the approved Donlin Gold mine (requiring ~200 MW) and other prospective mine developments underway nearby and enable the first low carbon to carbon neutral mining district in the world.

For this feasibility study, the selected electricity generation plant site is a mine-mouth power plant co-located at the Flatlands Energy coal lease, which is well-located for projected Railbelt growing power generation needs. Other locations can be considered in the future, but sites farther from the proposed mine site face longer, costlier coal truck haul, increased emissions related to the coal transport to the power plant, and possible combustion ash by-product backhaul to the mine site for disposal. Other considerations, such as location of greenhouse agricultural operations, may be considered in detail during future engineering and project optimization.

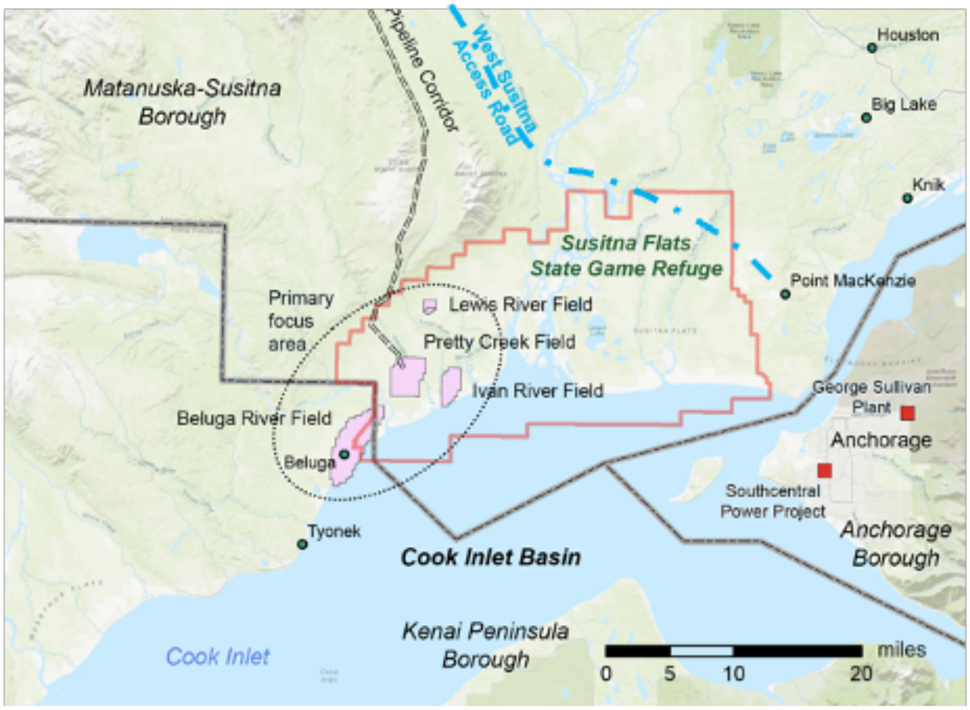

Figure 2. Northern Cook Inlet and Alaska Railbelt Carbon Capture and Storage (ARCCS) Map.

A geological and engineering study will calculate the CO_2 storage capacity in this region, the Alaska Railbelt Carbon Capture and Storage (ARCCS) Project by the University of Alaska awarded as DE-FE32453 (ref. Fig. 2). ARCCS was selected by the U.S. Department of Energy for a Carbon SAFE Phase II storage volume analysis including technical, economic, and community assessment for potential CO_2 storage (US DOE FECM press release, Nov. 14, 2023) “University of Alaska researchers plan to explore the viability of a new [biomass-]coal plant in the Susitna River valley that would inject its carbon emissions underground." (Northern Journal, Dec 2023).

Selected Storage Site, Grid Intertie, Transportation Route

For electricity intertie and CO_2 storage, the Beluga gas-fired power plant and on-shore Beluga River gas field were selected. The Beluga power plant is nearing the end of its service life and has an associated regional power grid intertie with 500- to 600-MW capacity that would allow the new proposed biomass-coal fired power plant to tie into the regional Railbelt grid. The Beluga River gas field has operated for five decades and has less than 10 years of remaining economical life (Stokes, 2017, and personal communication, Petrotechnical Resources of Alaska [PRA] staff). The operating and geologic technical data associated with the gas field were reviewed to assess pore space availability and economics. Viable CO_2 storage exists to support more than 60 years of CO_2 capture from a 300-MW-net plant with CCS.

The power and carbon capture plant site are planned to be located at the mine site. Road access to the site will be provided during construction by a winter access road and during operation by the proposed West Susitna Access Road. A 75-mile route (including an extra 5 miles for contingency) for CO_2 and electricity transportation runs 2 miles from the proposed plant to the permitted Donlin Gold natural gas pipeline Milepost (MP) 60, to the Beluga River power and pipeline corridor, then along the power and gas pipeline corridor to the Beluga River site. The Alaska Department of Natural Resources (ADNR) granted Donlin Gold the right to lease State land to build a pipeline to supply natural gas to the Donlin Gold mine to power its operations (KTOO, 2021). A CO_2 pipeline and power transmission line from the plant site to the Beluga River site could be co-located within the Donlin pipeline right of way (ROW) through approval from ADNR with a letter of nonobjection from Donlin. If Donlin objected to this infrastructure being placed within its ROW, then the CO_2 pipeline and power transmission line could be placed outside of the Donlin ROW in an abutting ROW that parallels Donlin's ROW.

Donlin Gold's intention to build a natural gas delivery pipeline connecting Cook Inlet gas supply to the mine was proposed and approved before Hilcorp's recent announcement that Cook Inlet gas reserves would be depleted in the coming years (Alaska Department of Natural Resources, 2022b; DeMarban, 2022). The Donlin Gold Mine is approaching the final investment decision stage for several billion dollars of capital commitment. Donlin Gold must now find an alternative energy source that provides approximately 30 years of secure, reliable, affordable, price-predictable energy. Donlin Gold is permitted for a peak electricity load of 180 MW, and is a potential industrial power consumer.

Generation Plant and Carbon Capture Technology Production Scenarios

The proposed new biomass-coal fired power plant at the Flatlands Energy coal lease would use circulating fluidized-bed (CFB) technology to generate electric power, similar to the recently completed power plant at UAF (Babcock & Wilcox, 2020). CFB technology generally allows for up to 30% biomass as fuel, though in this study 10% or lower biomass fuel is evaluated. For this study, plant power generation sizes were evaluated from 25- to 500-MW electricity. Gross electrical plant output includes power consumption associated with the carbon capture and transmission plant. Depending on the final power plant and CO_2 capture plant designs, operating conditions, and other factors, the CO_2 capture rate may be as high as 95% or more. The values in initial assessment will be refined during a future FEED (front-end engineering design) study. The power plant values include debt-financed CAPEX, no debt for OPEX, and exclude profit margins, tariffs, and other expenses. The accompanying CO_2 capture plant values include debt-financed CAPEX, debt-financed OPEX, and includes cost estimates for injection wells and pipeline construction. The CO_2 capture process selected for this feasibility study employs the proven Mitsubishi Heavy Industries (MHI) process.

Excluded Costs, Tax Structures, Grant Opportunities, and Loan Programs

The West Susitna Access Road is assumed to be funded by DOT and/or AIDEA in which case a toll may be charged for road use. This has yet to be determined. The existing winter road can be maintained and operated for a small annual cost. A short project access road which connects the West Susitna Access Road and winter road to the power plant site will need to be selected and costed.

The transmission construction cost of connecting from the power plant site to the Railbelt grid may be a grid cost or may be attributed to the power plant. Significant government funding may be available for new transmission lines that improve grid security and deliver low carbon power. This needs to be further evaluated and has not been included at this stage of study.

Transmission construction costs for industrial power supply are fully borne by the industrial project owners who pay for their transmission connection, e.g., the mine operator.

Beyond 45Q tax credits, additional Federal incentives, loans, and grants exist that, depending upon how the project is structured and operated, may apply but have not been included in this study.

COAL RESERVE LOCATION AND REGIONAL ELECTRIC GRID PROXIMITY

Location

The Flatlands Energy site contains an independently verified coal reserve. It is located on the lower east flank of Mount Dickason in the West Susitna Mining District in Southcentral Alaska. A regional location map is shown in Figure 2. The coal reserve is approximately 18 miles west-southwest of Skwentna which has a maintained airstrip to enable timely year-round site access. A winter road travels from Highway 3 west through Skwentna and onward to the Whisky Bravo airstrip, which supports the gold-critical minerals and gold–copper exploration operations of Nova Minerals and US GoldMining. The winter road passes within a few miles of the Flatlands Energy coal lease boundary. The lease is 67 miles northwest of Anchorage.

A multiuser all season resource road known as the West Susitna Access Road is in the construction approval process. The route will connect the existing road system near Port MacKenzie to the Whisky Bravo airstrip and pass within a few miles of the Flatlands Energy reserve. The route is proposed by the State, is exclusively on State land, and is anticipated to be approved in 2025. There are no native land claims.

The topography where the reserve is located is considered moderate at an approximate elevation of 1200 to 1600 ft above sea level. The area is covered with mixed shrubs and tundra. The area experiences cool summers and moderately cold winters, which are ideal year-round conditions for generating station operations.

Development History

Mobil Mineral and Coal Company, a division of Mobil Oil Company (Mobil), controlled the coal lease and undertook exploration mapping and drilling between 1972 and 1982. Mobil closed its Mineral and Coal division in the 1980s and merged with Exxon Oil Company (now ExxonMobil). Mobil returned the coal lease to the State of Alaska.

In 2012, Alaska Department of Natural Resources (ADNR) initiated a process to auction the historic coal lease. The lease carries with it a right to the coal contained in the lease lands for an unlimited term. A 2-year regulatory process, called the Best Interest Finding (BIF), was initiated. The BIF involved broad State regulatory review and comment as well as multiple rounds of community and municipal consultation.

The Final BIF Decision, recorded July 5, 2013, is a regulatory decision of ADNR, which found that use of the lease for coal mine development is in the best interest of the State. ADNR concluded that the potential environmental effects of coal mining can be largely avoided or mitigated.

In 2015, Flatlands Energy Corporation successfully bid into the State lease auction. Flatlands Energy subsequently performed its own drill program and data collection, and has been undertaking wetland, fish survey, water, air, and biota field evaluations. Since 2018 work along these lines has continued to progress toward the next stages of the project.

Coal Properties and Extraction

Coal in the Flatlands Energy reserve has properties comparable to the coal mined at Usibelli Mine in central Alaska. Usibelli Mine has supplied coal for power plant use in central Alaska for many decades. The Flatlands Energy coal energy quality is higher than the Usibelli coal, and similar to the Usibelli coal in that it is exceptionally clean with ultralow sulfur (0.15%) and low mercury and metals. It is a particularly clean (low contaminant) coal, similar to that being utilized in the new low emissions UAF combined heat and power generation station in Fairbanks, Alaska.

Because of the near-surface location of the coal, projected shallow mine extraction costs are competitive in comparison to industry averages. The site has sufficient coal to allow for low to reasonable extraction ratios an estimated 150 years or more. Site reclamation and restoration to original conditions are expected to present no material challenges. A shallow surface mine can fill in prior mined areas of the pit and begin the reclamation and vegetation regrowth process while operations continue elsewhere.

Delivered Cost of Coal

The proposed Flatlands Energy coal-fired power plant would utilize one of the lowest-cost and lower environmental impact forms of electricity generation, namely transportation of coal from a surface mine located adjacent to a generation station. This is known as a mine mouth generation station, where the mine operations are able to feed coal directly from the mine pit into the generation station. Assumptions for coal fuel cost for electricity generation economics are \$3.50/MMBtu.

EXISTING POWER GRID CURRENT AND FUTURE DEMAND

Current Status of Alaska Railbelt Utilities

Power for the Railbelt, the geographic area depicted in Figure 3, is supplied by the following utilities:

- Chugach Electric Association, Inc. (CEA)
- Golden Valley Electric Association, Inc. (GVEA)
- Homer Electric Association, Inc. (HEA)
- Matanuska Electric Association, Inc. (MEA)
- City of Seward (Seward)

These Railbelt electric utilities are interconnected by a bulk electric system that includes generation and transmission (G&T) components owned by the electric utilities and the State of Alaska through the Alaska Energy Authority (AEA) and smaller generation components owned by other entities. The Railbelt bulk electric system is also interconnected with Doyon Utilities, LLC (DU), which provides electric utility services to Fort Richardson, Fort Wainwright, and Fort Greely. The grid also ties-in UAF’s combined heat and power plant, which in addition to supplying all electricity and heat for the campus can provide excess power to GVEA (KTVF).

The southern portion of the Railbelt, serving about 50% of Alaska’s population in the Mat-Su Valley, Anchorage, and the Kenai Peninsula, is highly dependent on natural gas as a source of electricity and heat. The northern portion of the Railbelt, serving about 15% of Alaska’s population in Fairbanks and other interior communities, is highly dependent on coal and petroleum fuels for local generation in addition to natural gas and hydroelectric generation import from utilities in the south.

Figure 4a and 4b show the Cook Inlet natural gas demand and supply forecast presented by the Alaska DNR in July 2023. Shown are supply cases for high, mid, mean, and low production truncated to economic limits (4a), and existing proved developed plus proved undeveloped reserves forecasts (4b). These forecasts exclude known accumulations yet to be developed, such as those owned by Bluecrest, Furie/HEX and Vision. As shown, Railbelt

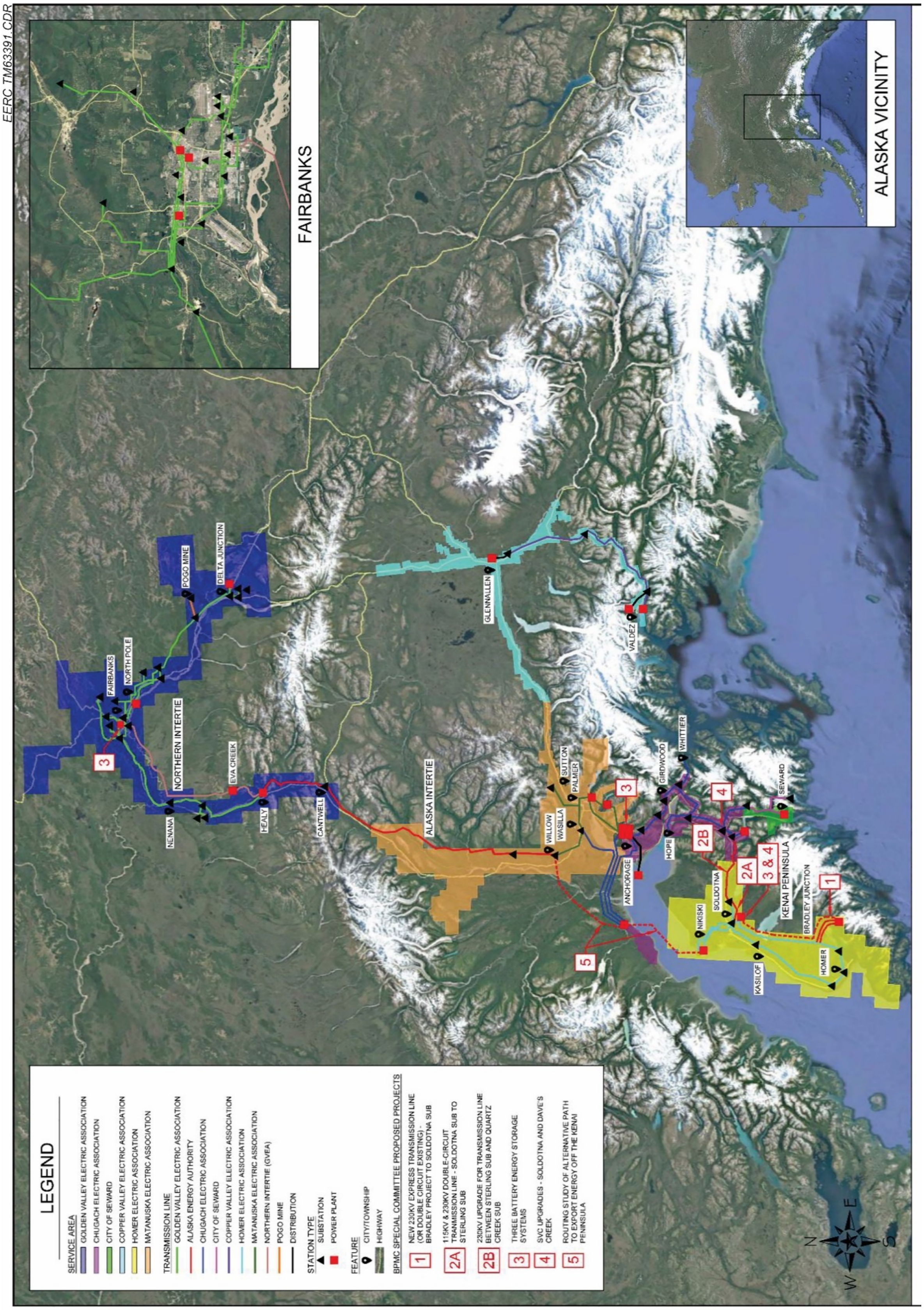

Figure 3. Alaska Railbelt Utilities.

utilities face an imminent shortfall of natural gas supply (AKDNR 2023). Until recently, all Alaska Railbelt utilities planned and met power supply needs separately, with no obligation to coordinate energy supply or generation development or consider grid impacts. The Railbelt Reliability Council (RRC) has recently been created to oversee all regional power supply and transmission planning. (Railbelt Reliability Council, 2022). In January 2024, the RRC directed all electric cooperatives to provide plans for meeting power demand to customers in the event of gas undersupply events (AETP). There is urgency to find alternative energy supply as a majority of the grid depends on natural gas.

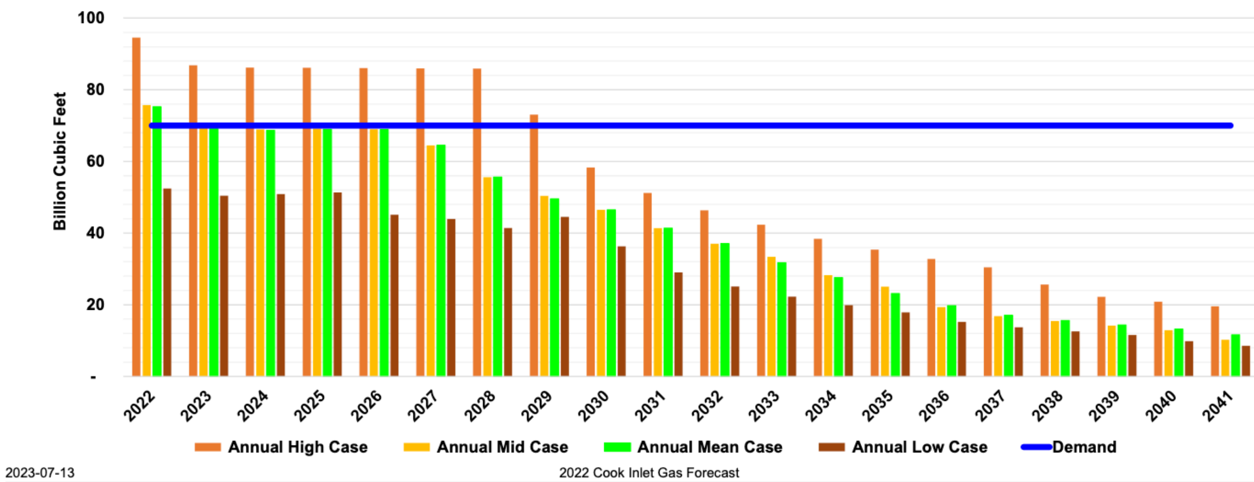

Figure 4a. Cook Inlet Annualized Gas Demand and Supply Forecast, Truncated, DNR.

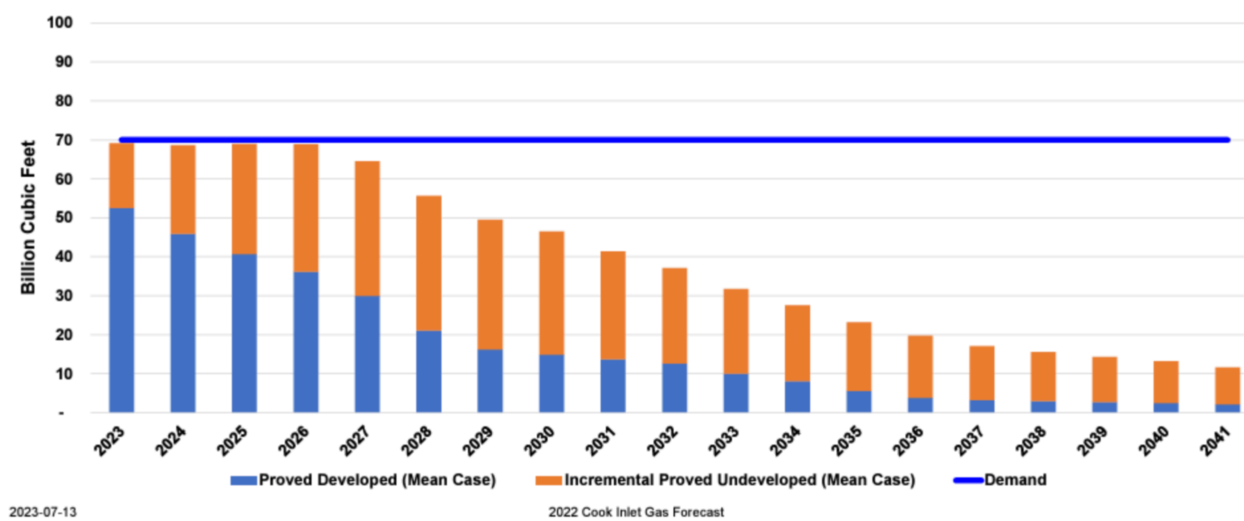

Figure 4b. Cook Inlet Proved Developed+Proved Undeveloped Mean Forecast, Truncated, DNR.

Potential Industrial Power Users

The Flatlands Energy coal reserve is approximately 25 miles from a large, advanced gold-rare earth elements Nova Minerals exploration project and the earlier stage US GoldMining gold-copper project, and approximately 200 miles from the Donlin Gold proposed mine development. Donlin has been approved and is now in the final investment decision stage.

These new mine developments have not been considered in future grid connection and electricity supply plans, with peak demand projected at more than 200 MW. In order to meet their power needs, these proposed mine developments will have to: (a) add their own generation, and along with that secure a new fuel supply; (b) contract with the Railbelt utilities, which would then need to build additional generation capacity and secure a new fuel supply; or (c) contract with an independent power producer, such as the project described herein, for power from the proposed, nearby biomass-coal plant with CCS.

Railbelt Power Generation Resources and Costs

Railbelt utilities currently have about 1600 MW of installed fossil fueled capacity. Only about 800 MW is considered fuel efficient, consisting of about 600 MW of modern natural gas-fueled plants (Southcentral utilities with fuel-related costs ranging from about $120 to $150/MWh) and about 200 MW of coal- and oil-fired plants (interior utilities with fuel-related costs ranging from about $100 to $400/MWh). Older, less heat-efficient units are used as emergency reserves and are more costly to operate.

In addition to fossil-fuel based generation, Railbelt utilities have about 200 MW of renewable capacity, predominantly hydro-power from Bradley Lake (NREL 2022 Table 2). Costs range from about $40 to $120/MWh with plans to expand. After expansion, costs are expected to exceed $150/MWh.

A recent analysis of the Railbelt's energy system by the National Renewable Energy Lab (NREL) found even with extensive new renewable energy sources including wind and solar, 75% of the current fossil energy-fueled power generation will have to be retained to meet demand when the weather is not conducive to supply renewable energy (NREL 2022).

In January 2024, the University of Alaska Fairbanks-Alaska Center for Energy and Power (ACEP) released a techno-economic report, *Alaska's Railbelt Electric System: Decarbonization Scenarios for 2050*. (Cicilio 2024) That report found that "…the (Railbelt grid) 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. …fossil-fuel and hydro power generation were the most cost effective firm sources to pair with variable renewables. (p.22)" That report also concluded that nuclear and tidal generation were both more expensive, and that "there is also significant uncertainty in the projected costs and future commercial availability of these technologies." That report's base case economic analysis showed that wind, solar, nuclear, tidal, or hydro power, i.e. re-activating the Susitna-Watana Dam project, would be more expensive than business-as-usual power costs.

In February 2024, Alaska Governor Dunleavy proposed legislation (HB307, SB217) that would, if passed, create a system allowing for the economic dispatch of lowest-cost power at all times. This creates an additional opportunity for low-cost biomass-coal CCS power supply in addition to power purchase agreements. The legislation would eliminate grid wholesale transmission fees and provide independent power producers the same exemption from local taxes that non-profit electric cooperatives receive (Alaska Office of Governor 2024).

OTHER POTENTIAL BIOMASS-COAL FIRED GENERATION OPPORTUNITIES

Beneficial Uses of CO_2 with Biomass-Coal Generation

A new biomass-coal fired power plant with CCUS is capable of making beneficial use of waste heat and CO_2 to manufacture other useful products, as shown in Figure 5. For instance, direct use of CO_2 and waste heat can enable year-round growing operations and increase product yield for some crops. This would reduce Alaska's dependence on importing food, as presently ~95% of all food is imported. The Alaska import cost for industrial CO_2 supply delivered to the customer is reported to be as high as $2,000/ton, but can be produced by a CCS biomass-coal plant for $50 to $60 per ton. These potential additional uses of heat, CO_2, and other by-products are potential up-sides that are not included in the techno-economic analyses in this report.

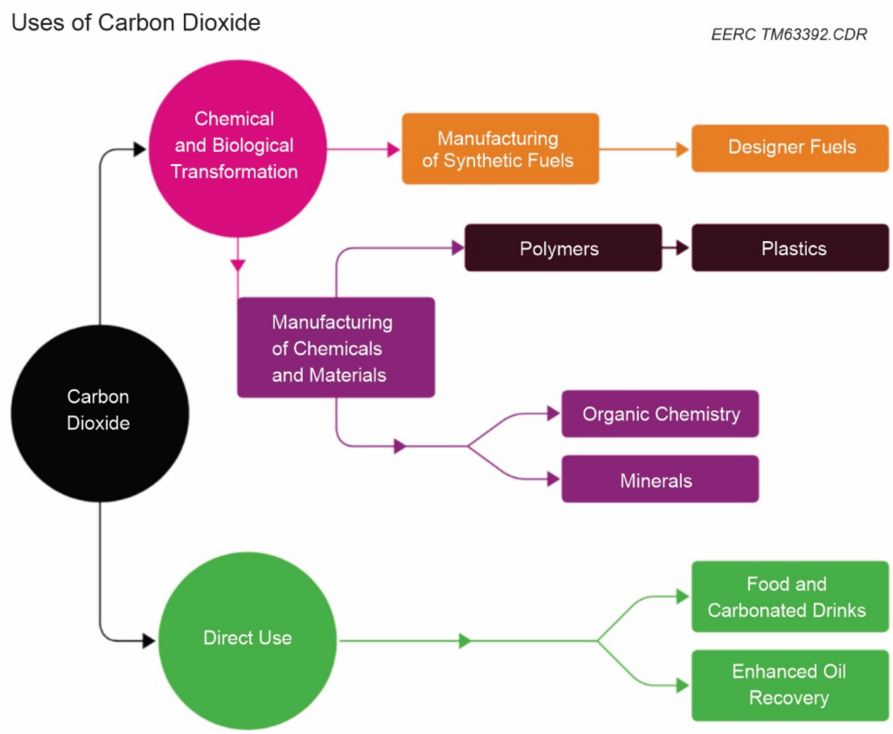

Figure 5. Beneficial Uses of CO_2.

Alaska's Food Security and Supply Chain Independence

Historically, less than 5% of Alaska's food needs have been met from in-state production. In 2022, Alaska Governor Dunleavy created the Food Security and Independence Task Force to proactively pursue measures and incentives for increasing in-state food production and external supply chain independence (Alaska Department of Commerce, Community, and Economic Development, 2023).

A biomass-coal-fueled power plant with carbon capture is capable of supplying the energy, heat (using waste heat), and CO_2 for greenhouse agricultural operations. In-Alaska greenhouse operations would provide local, secure fresh produce and replace produce grown elsewhere that can require 10–20 days of transportation with significant product waste and added costs. Alaska is also competitively located for North Asian markets. Fresh produce exported from Port MacKenzie would have a shipping advantage relative to some other producing regions.

Fertilizer, Ammonia, and Hydrogen

Potential exists for using the biomass-coal power plant to provide low-cost energy and CO_2 for the manufacture of fertilizer, ammonia, hydrogen, and synthetic fuels. Currently, Alaska imports nearly all of its fertilizer, ammonia, and CO_2 needs.

Concrete Additives and Critical Minerals

Potential exists for coal ash sales from the plant for by-products such as concrete additive, gypsum, and critical minerals, supporting external supply chain independence for Alaska. Currently, Alaska imports ash needed for concrete production. In addition to the potential for critical mineral resourcing from coal and ash itself, the Flatlands Energy location is approximately 50 miles from a USGS-identified high-prospect critical minerals region, in proximity for potential future power supply in the event critical minerals mining is developed in that vicinity (Mining News North, 2023; U.S. Geological Survey, 2015).

Net-Zero Scenarios – Beneficial CO_2 Use or Biomass Energy with CCS (BECCS)

With beneficial CO_2 use or BECCS, power generation can achieve net-zero or net-negative (climate positive) CO_2 emissions. Table 1 and Figure 6 discussed below illustrate net-zero and net-negative CO_2 emission power generation through inclusion of beneficial CO_2 use or biomass energy as a fuel supply. All emissions estimates in this report use only coal as fuel and exclude the emissions benefits from beneficial CO_2 use and biomass energy, except where noted.

Beneficial CO2 Greenhouse Use: Coal power plants can achieve low greenhouse gas emissions by implementing CCS to capture 90% or more of CO_2 emissions. Further, by using waste heat and CO_2, the greenhouse operations are able to enhance productivity and reduce additional coal use and associated CO_2 emissions from heating, which results in net-zero. As shown in Table 1, a 100-MW gross plant, net 75 MW with CCS, supporting a 57-acre greenhouse results in net-zero carbon operation. In this calculation, 90% of emitted CO_2 is captured and sequestered or beneficially used in the greenhouse. Rather than heating the greenhouse with coal, there is an emission reduction, -209 pounds CO_2 per MMBtu, from the beneficial use of power plant waste heat, 2176 MMBtu/day. This reduction is -223 pounds CO_2 per MWh generated, realizing net zero CO_2 emission. Note if CCS achieves 95% capture rather than 90%, emissions drop by half and the required greenhouse acreage for net zero decreases by half to 29 acres.

Table 1. Net-Zero Coal Plant with CCS and Greenhouse Food for Alaska
For a 100 MW gross, 75 MW net plant with CCS

Optionality for Achieving Net-Zero Carbon Operations Coal CO_2 Factors:	**Percentage of CO_2 Output**	**lb CO_2/ MMBtu**	**MMBtu/ MWh**	**lb CO_2/ MWh**
Power Plant Output		209	11	2,229
CO_2 Captured and Sequestered	80%			−1,783
CO_2 Captured and Beneficially Used	10%			−223
Reduction from Beneficial Use of Waste Heat	10%			−223
Net CO_2 Emissions				0

Making Beneficial Use of Waste Heat and CO_2 Coal CO_2 Factors:	**Electric Output, MWh/day**	**Greenhouse Use, Waste Heat, MMBtu/day**	**Greenhouse Use, Short tons/day**	**Greenhouse Use, per day per acre**	**Greenhouses, acres**
Waste Heat Production and Greenhouse Use	2040	2176		38 MMBtu heat	57
CO_2 Greenhouse Use			227 tons CO_2	4 tons CO_2	57

Assumptions:

a) Based on DOE CO_2 emissions rate for coal generation of 100 MW with 85% Capacity Factor with a CCS capturing 90% of emitted CO_2.
b) Based on estimated annualized average and peak waste heat for greenhouse use: 38 MMBtu/day/acre, 152 MMBtu/day/acre.
c) Based on estimated annualized average and peak CO_2 for greenhouse use: 4 tons/day/acre, 6 tons/day acre.
d) Excludes biomass emissions benefits.

Biomass Energy with Carbon Capture and Sequestration (BECCS): Southcentral has biomass suitable as a power plant co-fuel, including forest management, spruce bark beetle kill, agriculture, and/or municipal solid waste. Rather than allowing decomposition, biomass as power plant fuel with CCS reduces CO_2 emissions by capturing then sequestering their CO_2. To determine the net balance requires life cycle assessment of biomass fuel(s) including harvesting and handling, such as outlined in the Energy and Environmental Science Journal. (EESJ 2017)

"Because the biomass draws carbon from the atmosphere as it grows, BECCS can be a negative emissions technology when it is implemented well. That is, BECCS could serve to draw down the concentration of carbon dioxide (CO_2) in the atmosphere. However, care must be taken to ensure that emissions from the growing, harvesting, transporting, and processing of the biomass do not outweigh the captured carbon, and that the storage of captured carbon is reliable over long timescales." (American University Washington DC, 2020)

Net-negative power carbon intensity with BECCS can be achieved through system design including biomass type, supply chain, storage and handling, and burner considerations. Carbon intensity of generated power varies depending on biomass, net water use, pellet moisture content, carbon footprint (CF), supply chain emissions, and power plant cofiring and capture rate percentage as Figure 6 illustrates (from EESJ Figure 15). Carbon intensity improvements in Alaska may be substantially different, perhaps better, than illustrated in Figure 6 which is for cultivated miscanthus dried and pelletized for use as a fuel. Standing dead spruce bark beetle kill is low moisture content and an excellent fuel supply, for example. "Based on the overall rate of decomposition estimated (1.5% per year), it would take close to 200 years for beetle-killed trees to disappear…. Based on a simple model of forest regrowth, and assuming that beetles kill an entire stand of spruce trees, it is likely that this disturbance will cause forests to lose carbon to the atmosphere for 60 to 70 years. The rate forests are regenerated would have a very large impact on the amount of carbon released during this time, and even a 20-year lag in tree establishment could double these losses." (USDA Forest Service, 2005) Overflight of the region in summer 2023 showed substantial spruce bark beetle killed trees in the area. Depending on the harvest and transport supply chain, these make excellent biomass fuel.

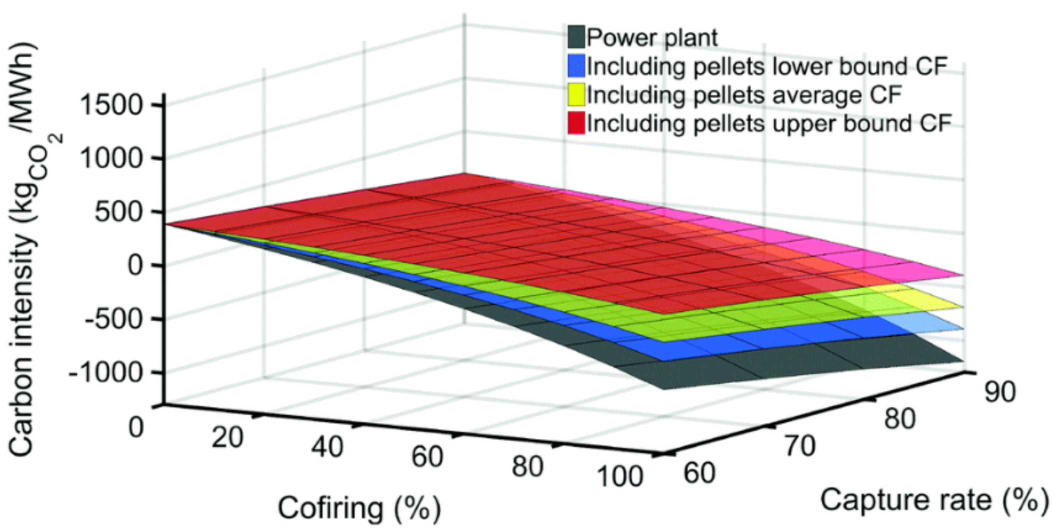

Figure 6. Carbon Intensity vs. Biomass Cofiring % and CO_2 Capture Rate % (from EESJ)

“BECCS typically refers to the integration of trees and crops that extract CO_2 from the atmosphere as they grow, the use of this biomass in power plants, and the application of carbon capture and sequestration via CO_2 injection into geological formations…. In its Fifth Assessment Report, the Intergovernmental Panel on Climate Change (IPCC) select[s] BECCS as the lowest cost option to reach the temperature objectives for the second half of the century (high confidence) and that BECCS plays an important role in many low-stabilization scenarios (with limited evidence and medium agreement).” (National Academy of Sciences, 2019, p.137). This study from the U.S. National Academy of Sciences estimates a global potential to sequester 3.4–5.2 $GtCO_2$ per year via BECCS without large adverse impacts. Biomass conversion technology readiness level (TRL) is Commercial, TRL greater than 10 (NAS, 2019, p.145).

POWER PLANT LOCATION, TRANSMISSION ROUTES, AND PROPERTIES

Transmission Intertie

The Flatlands Energy reserve is located approximately 46 miles in a straight line from the Beluga power plant and grid intertie. The Beluga power plant is reaching the end of its useful life. Two of the six natural gas turbine generators have been retired. The remaining four units are used solely for reserve power and meeting peak demand needs. The Beluga River power plant can provide power to the grid power via an intertie with 500+ MW capacity.

The Donlin Gold pipeline right of way passes within a few miles of the Flatlands Energy reserve and travels within a few miles of the Beluga power plant and crosses the electricity grid. This is a possible corridor for a high-line power transmission line from the Flatlands Energy reserve to the regional grid intertie.

With the Beluga River plant nearing its service life end, its intertie has capacity to deliver power to the Railbelt transmission system. This is one option to connect a major new power generation plant. Other interconnect points are at Milepost (MP) 0 of the Donlin Gold pipeline corridor, near the high-voltage lines of CEA, or at Point MacKenzie. Further study of interconnection points is needed to select the optimal electrical tie-in point.

Power customers are assumed to permit and install their own power lines independent of this project. Such costs and permitting are not addressed in this study.

CFB Advantages and Compatibility with Renewable Energy

The circulating fluidized bed (CFB) boiler system selected for this feasibility study is a commercially proven, well-understood system that provides several advantages. The CFB system, selected for the recent coal-fired combined heat and power generation station built at the UAF campus in Fairbanks, Alaska, is designed to achieve economy, reliability, and flexibility.

Modularization is key in construction-related cost savings. CFB systems can be built as a module, e.g. in 100 MW increments, for Southcentral needs and enable expansion for future developments. Additional generation capacity can be added in relatively small increments as new customer demand is identified. This is a significant change from a historical approach of overbuilding generating station capacity and anticipating that new demand will follow. Modularization is also key for the adjacent carbon capture plant, i.e., having large sections of the facility built off-site as modules would minimize on-site construction and result in significant cost savings (International CCS Knowledge Centre, 2018).

An advantage of CFB systems over historical coal-fired boiler systems is that CFB can be designed to load-follow, meaning that as electricity demand increases or decreases, CFB systems can ramp up or down. CFB systems can, therefore, work in concert with alternative energy sources such as solar and wind that provide variable power generation. Engineering analysis is required in order to determine if this system, when combined with CCS, can similarly be expected to load-follow.

Another key advantage of CFB technology is that pollution control is built into the combustion process. By adding low-cost limestone into the CFB, SO_x is captured and removed at the point where it is formed. The CFB's low combustion temperature, about 1000°F less than a conventional pulverized coal (pc) peak temperature, minimizes NO_x formation. The Flatlands Energy coal contains ultralow levels of sulfur and low levels of nitrogen, which support lower emissions in need of capture.

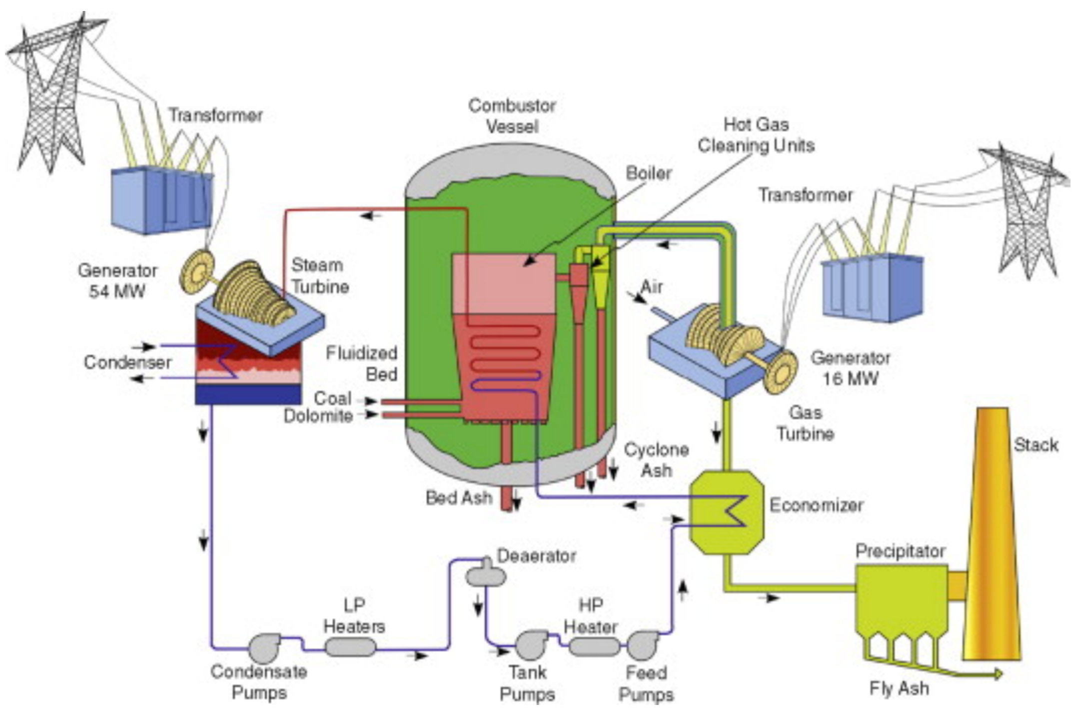

Figure 7. Coal CFB Combined-Cycle Process, Without CCS
www.sciencedirect.com/topics/engineering/circulating-fluidized-bed-combustion.

Figure 7 shows an example CFB combined-cycle power generation system without a CCS plant. Advantages of CFB systems include the following:

- Load-following; works in concert with alternative energy sources

- Modular and expandable
- Low emissions
- High combustion efficiency
- High reliability and availability
- Low maintenance costs
- Compact, economical design
- Reduced erosion
- Fuel flexibility
- Proven technology and performance
- Costs associated with CFB systems are well known.

POWER COSTS: NATURAL GAS (WITH PRICE SENSITIVITY) VS. BIOMASS-COAL

In this study, baseline Southcentral power costs are calculated using three separate approaches for natural gas-fired power. For each approach, electricity rates were calculated for \$7.07 (current), \$15, \$20, and \$25/MMBtu (future) natural gas prices. The future natural gas price range represents imported LNG, new Cook Inlet gas, or North Slope gas as described in the section Competitor Analysis. The first approach uses *CEA's approved pricing* for firm power service to large industrial and utility customers. The second approach estimates the *avoided cost* from all current producers, providing more of a common basis for electricity producers. The final approach applies the cost estimation methodology for the proposed biomass-coal fired power plant to a *new gas-fired power plant*, recognizing a new gas-fired plant may be more efficient than CEA's existing power fleet, thus providing the lowest hypothetical cost of gas-based power. Note this hypothetical gas-fired power cost is likely understated since it assumes a single generating turbine rather than multiple turbines that may be required for grid stability.

Current Approved Pricing

CEA's generation and transmission (G&T) rates are based on CEA's November 4, 2020, approved Schedule 760 tariff for limited all requirements service at primary voltage subject to availability. The G&T rate represents CEA's approved pricing for providing firm power service to large industrial and utility customers. It excludes additional costs that new industrial customers such as Donlin Gold and Nova Minerals would be required to pay, such as transmission costs outside of CEA's existing service area. CEA's residential and commercial service rates are ~12% higher than the G&T rates.

The CEA G&T electricity rates were calculated for \$7.07, \$15, \$20, and \$25/MMBtu natural gas prices, as shown in Table 2. These price scenarios are developed to assess how the G&T rates, currently with \$7.07/MMBtu natural gas based on CEA's most recent report, might be impacted with imported liquefied natural gas (LNG) based an Asia-Pacific LNG import futures market assessment. "Cook Inlet natural gas prices have not been static, rising 5% on average per year for the past decade and are now approximately \$8 per Mcf." (CEA 2023) These gas prices are also consistent with the "2040 blended fuel cost" estimate in the Renewable Portfolio Standard Assessment for Alaska's Railbelt (Denholm and others, 2022) and with the natural gas supply options discussed the *Competitor Analysis* section.

The low LNG import price, \$15/MMBtu, was derived from the DOE Office of Fossil Energy and U.S. Energy Information Administration (EIA) websites and industry websites such as Natural Gas Intelligence (NGI), Reuters, and AL FRED. The low and mid- LNG prices used here are also consistent with the \$16.6/MMBtu "2040 Blended Fuel Cost" that is assumed to be composed of 78% natural gas from the Renewable Portfolio Standard Assessment for Alaska's Railbelt report (Denholm and others, 2022). As of 2020 through 2022, the Asia-Pacific LNG market price is approaching \$30/MMBtu but is forecasted to come back down into the \$20 to \$25/MMBtu range. Europe's recent pivot from Russian gas supply makes this price range unpredictable, with some forecasters projecting higher prices. LNG-based electricity pricing may see substantial long-term upward pressures. Market disruptions in mid-2022 drove LNG spot above \$50/MMBtu for a short time (Federal Reserve Bank of St. Louis, 2022 and FRED data).

Table 2. CEA G&T Electricity Cost, \$/MWh

		CEA G&T Tariff Rates			
Description	**Units**	**\$7.07/MMBtu**	**\$15/MMBtu**	**\$20/MMBtu**	**\$25/MMBtu**
Capacity Charges	\$/MW-month	\$45,430	\$45,430	\$45,430	\$45,430
Capacity Factor	%	85%	85%	85%	85%
Average Capacity Charges	\$/MWh	\$74.2	\$74.2	\$74.2	\$74.2
Energy					
Energy Charge	\$/MWh	\$48.8	\$48.8	\$48.8	\$48.8
FPP Factor	\$/MWh	\$64.9	\$137.8	\$183.7	\$229.6
Total Energy	\$/MWh	\$113.7	\$186.6	\$232.5	\$278.4
Totals	**\$/MWh**	**\$188.0**	**\$260.8**	**\$306.7**	**\$352.7**

Assumptions:

a) Based on CEA November 4, 2020 approved Schedule 760 tariff for limited all requirements service at primary voltage subject to availability of generation capacity. Transmission costs not included for service outside of service area.
b) Residential and commercial service rates are ~12% higher than CEA G&T rates.
c) CEA would require new generation to provide estimated power service of large new mines in the 200-MW range, with new transmission provided and/or funded by others.
d) Capacity factor represents how much available capacity is used on average by customers.
e) Capacity Charge includes capital and fixed O&M costs.
f) Energy Charge is a mechanism to recover variable O&M and incidental costs.
g) FPP (fuel and purchased power) factor is a mechanism to recover fuel costs.
h) Average Heat-Rate, 9.185 MMBtu/MWh, is how much energy it takes to produce a unit of power. It is based on Exhibit 1 of CEA's Sep 29, 2023 COPA quarterly power adjustment filing.

Considering other natural gas supply options, the *Cook Inlet Gas Supply Project Phase I Assessment Report* commissioned by the Alaska Utilities Working Group assesses relative cost and availability of natural gas supply options. Berkeley Research Group (BRG) and Cornerstone Energy Services delivered the report June 28, 2023 (BRG 2023). Black & Veatch (BV) prepared the *Chugach Gas Supply Option and Market Assessment* for Chugach Electric Association, Inc., filed August 11, 2023 with the RCA. Six natural gas supply options are evaluated and found to supply gas at higher than today's price, a key driver for future electricity costs with natural gas.

From Table 2, the CEA G&T rate is \$188/MWh for fuel at \$7.07/MMBtu. Power cost increases 39%, 63%, and 88% for \$15, \$20, and \$25/MMBtu fuel, respectively (CEA 2020).

Avoided Cost

The CEA G&T rate discussed above represents a delivered cost of electricity to industrial consumers including non-generating expenses, installed capacity charges, and other fees. To provide another cost comparison to a new biomass-coal fired plant, these rates can be adjusted to an estimate avoided cost, i.e., the incremental cost an operator would avoid by not having to generate power, instead substituting or replacing it with power generated from another source. The avoided cost methodology provided here, while simplified, is expected to be sufficiently accurate for comparison purposes. The current avoided cost of electricity from gas is estimated to be $114/MWh as shown in Table 3, and escalates rapidly with increasing gas prices.

Table 3. Avoided Electricity Cost, $/MWh

		CEA G&T Tariff Rates Excluding Capacity Charge			
Description	**Units**	**$7.07/MMBtu**	**$15/MMBtu**	**$20/MMBtu**	**$25/MMBtu**
Capacity Charge	$/MWh	$0.0	$0.0	$0.0	$0.0
Energy					
Energy Charge	$/MWh	$48.8	$48.8	$48.8	$48.8
FPP Factor	$/MWh	$64.9	$137.8	$183.7	$229.6
Total Energy	$/MWh	$113.7	$186.6	$232.5	$278.4
Totals	**$/MWh**	**$113.7**	**$186.6**	**$232.5**	**$278.4**

Assumptions:

a) Same as Table 2, CEA G&T, except excludes Capacity Charge, i.e., excludes capital plus fixed O&M costs, to emulate an avoided energy cost comparison using existing power generation capacity. Included are Energy Charge and FPP, i.e., includes variable O&M and fuel costs.

New Gas Plant Scenario, Single Turbine, Without CCS

Tables 2 and 3 were generated from CEA's published rates, with avoided costs in Table 3 being estimated by zeroing-out capacity charge. As discussed, about half of the generation equipment can be considered efficient while the other half is more costly to operate and typically provides reserve capacity. Published rates represent the combined blended performance of these equipment. As such, a third and final gas-fired power cost estimating approach is provided to represent a hypothetical new, high efficiency gas fired plant, though no such proposal to install new gas-fired generation is known and may in fact be unlikely in the face of fuel supply shortfalls and cost uncertainty.

In this third approach for new gas-fired power cost estimating, a single turbine configuration was assumed for lowest capital and operating costs. However, if built for the Railbelt, a new gas plant would likely require multiple turbines to ensure that an unexpected loss of a unit would not cause a major system-wide power outage and to provide redundancy for unplanned outages. Thus, new gas plant costs may be higher than shown here.

Two new gas-fired power costs were estimated, a larger, 600 MWe, more efficient combined cycle plant and a smaller, 100 MWe, less efficient simple cycle plant. See GE Vernova for simple vs. combined cycle power discussion. A new large-scale, high-efficiency natural gas-fired combined cycle power plant operating at constant baseline conditions could be expected to produce less expensive electricity than a new biomass-coal fired power plant of similar size but only if (a) it is single turbine configuration, which likely does not meet grid reliability needs; (b) if current natural gas prices were to hold constant; and (c) CCS is not required. Smaller single-cycle natural gas power plant could produce electricity at a similar cost to those of a new biomass-coal power plant with present Cook Inlet gas prices. This is to be expected, as natural gas plants do not require solids handling, desulfurization, or ash disposal. However, as seen in Table 4, the cost for gas-based electricity rapidly increases with increasing gas prices and would rapidly exceed the costs for biomass-coal electricity discussed below. Even under the most favorable assumptions, gas-fired power is only cost competitive with biomass-coal in the short term given the Cook Inlet gas supply shortfall and increasing cost of other natural gas supply options for the region.

Power Cost Comparison CEA (Current Gas Price) vs. Biomass-Coal Without CCS

Biomass-coal power generation cases evaluated range from a small 25-MW generation unit to 500 MW, as shown in Table 5. Costs of plant capital, O&M, and fuel are shown, and electricity prices are calculated. The current G&T cost for CEA is shown for comparison. Biomass-coal fired generation without CCS delivers at substantially lower cost than current G&T industrial rates from CEA gas generation. The cost estimate uncertainty range is -30% low side to +50% high side, consistent with a Class 5 conceptual engineering estimate. (AACE RP 87R-14)

Power Cost Comparison: Natural Gas vs. Biomass-Coal Without CCS

In comparison with gas-fired power in Tables 2, 3, and 4, CEA G&T, avoided cost, and new gas plant, respectively, biomass-coal fired power is lower cost than CEA G&T at all gas fuel prices. Biomass-coal power from plants larger than 100 MW are cost-competitive with or cheaper than avoided costs for existing generation or for new single-cycle gas plants. While a new large-scale combined cycle gas plant could produce electricity at a lower cost than biomass-coal if gas prices were to hold constant over 30 years, gas-based electricity costs rapidly escalate with rising gas fuel price, so this cost advantage is expected to be short-lived in the face of the depleting local gas supply and a near-term need for securing additional gas.

Figure 8 compares three cases: At left is CEA G&T power for a range of fuel gas prices without any new generation. At center is for a new 600 MW high-efficiency combined cycle gas plant with the same variations in gas price. At right are for new biomass-coal fired generation at several a range of plant sizes.

The natural gas fuel price sensitivity range, in $/MMBtu, includes recent price ($7.07), and low ($15), mid- ($20), and high ($25) future natural gas prices.

Table 4. New Gas-Fired Electricity Cost, $/MWh

Description	**Units**	**Single Cycle, 100 MWe**				**Combined Cycle, 600 MWe**			
Capacity	MW	100				600			
Capital Costs	× 1,000,000	$195				$1701			
Capacity Charges	$/MW-mo	$10,462				$15,223			
Fixed O&M	$/MW-mo	$1,135				$1363			
Capacity Factor	%	85%				85%			
Average Variable O&M	$/MWh $/MWh	$19.0 $5.1				$27.1 $1.8			
Fuel	$/MMBtu	$7.07	$15.00	$20.00	$25.00	$7.07	$15	$20	$25
Av. Heat Rate	MMBtu/MWh	11.4				7.6			
Energy Cost	$/MWh	$80.4	$170.6	$227.5	$284.3	$53.6	$113.7	$151.7	$189.6
Total Energy	$/MWh	$85.5	$175.7	$232.6	$289.4	$55.4	$115.5	$153.5	$191.4
Totals	**$/MWh**	**$104.5**	**$194.7**	**$251.5**	**$308.4**	**$82.5**	**$142.6**	**$180.6**	**$218.5**

Assumptions:

a) CAPEX and fixed O&M costs are taken relative to biomass-coal CAPEX costs in Table 5, with the ratio of 2022 costs based on ranges published by NREL (https://atb.nrel.gov/electricity/2022/index)

b) CAPEX: $10,000,000/MWe (small biomass-coal estimate) × $0.922MM/MWe (gas, low) ÷ $3.075MM/MWe (biomass-coal, low) = $1,948,943/MWe, 100 MW case

c) CAPEX: $6,500,000/MWe (large biomass-coal estimate) × $2.324MM/MWe (gas, high) ÷ $5.327MM/MWe (biomass-coal, high) = $2,835,742/MWe, 600 MW case

d) 100 MW single-cycle gas plant is 30% efficient on an HHV basis, which is lower than LHV basis and also allows for some inefficiencies to load following.

e) 600 MW combined-cycle gas plant is 45% efficient on an HHV basis.

f) Variable O&M is based on 2022 values published by NREL (https://atb.nrel.gov/electricity/2022/index), with the upper range assumed for a small load-following single-cycle plant and the lower range assumed for a large combined-cycle plant operating at constant load.

g) Flatlands Energy power supply options exclude new transmission requirements and associated costs.

h) Capacity factor represents how much of the available capacity is being used on an average basis by customers.

i) Average Heat-Rate represents how much energy it takes to produce a unit of power output on an HHV basis.

j) CAPEX is debt financed at 5% over 30 years (same assumption used for biomass-coal)

k) 100 MW, $1,948,943/MW: −$1,046,235 per month debt service.

l) 600 MW, $2,835,742/MW: −$9,133,727 per month debt service.

Table 5. Biomass-Coal Fired Electricity Cost, $/MWh
For Plants from 25 MW to 500 MW. Two Sizes Highlighted Red have Corresponding CCS for Total Cost of Electricity Calculations

Description	**Units**	**CEA G&T, Current Price $7.07/MMBtu**	**Biomass-Coal Power Plant**						
Capacity	MW		25	50	**100**	200	300	**400**	500
Capital Costs	× 1,000,000		$250	$475	**$650**	$1235	$1760	**$2229**	$2647
Capacity Charges	$/MW-mo	$45,430	$53,682	$50,998	**$34,893**	$33,149	$31,491	**$29,917**	$28,421
Fixed O&M	$/MW-mo		$4500	$4275	**$4000**	$3800	$3610	**$3430**	$3258
Capacity Factor	%	85%	85%	85%	**85%**	85%	85%	**85%**	85%
Average	$/MWh	$74.2	$95.1	$90.3	**$63.6**	$60.4	$57.4	**$54.5**	$51.8
Energy									
Energy Charge	$/MWh	$48.8							
FPP Factor	$/MWh	$64.9							
Variable O&M	$/MWh		$12.0	$11.0	**$10.0**	$9.0	$8.5	**$8.0**	$7.5
Fuel	$/MMBtu		$3.5	$3.5	**$3.5**	$3.5	$3.5	**$3.5**	$3.5
Av. Heat Rate	MMBtu/MWh		11.0	11.0	**10.5**	10.5	10.5	**10.5**	10.5
Energy Cost	$/MWh		$38.5	$38.5	**$36.8**	$36.8	$36.8	**$36.8**	$36.8
Total Energy	$/MWh	$113.7	$50.5	$49.5	**$46.8**	$45.8	$45.3	**$44.8**	$44.3
Totals	**$/MWh**	**$188.0**	**$145.6**	**$139.8**	**$110.4**	**$106.2**	**$102.7**	**$99.3**	**$96.1**

Assumptions:

a) Based on CEA's November 4, 2020, approved Schedule 760 G&T tariff for limited all requirements service at primary voltage subject to availability of generation capacity with transmission costs not included for service outside its service area.
b) CEA's current residential and commercial service rates are ~12% higher than G&T rates.
c) CEA would require new generation to provide estimated power service needs of the large new mines in 200-MWe range and would require new transmission to be provided and/or funded by others.
d) Flatlands Energy power supply options exclude new transmission infrastructure requirements and associated costs.
e) Capacity factor represents how much of the available capacity is being used on an average basis by customers.
f) Energy Charge is a mechanism where CEA recovers its variable O&M and incidental costs.
g) FPP (fuel and purchased power) factor is a mechanism CEA uses to recover fuel costs.
h) Average Heat-Rate, 9.185 MMBtu/MWh, represents how much energy it takes to produce a unit of power output. It is based on Exhibit 1 of CEA's Sep 29, 2023 COPA quarterly power adjustment filing.
i) Constructed cost of CFB coal plants based on recent construction of similar 20-MW plant in interior Alaska of about $10,000,000/MW financed at 5% over 30 years.
j) 25 MW $10,000,000/MW $250 ×1,000,000: −$1,342,054 per month debt service. Discount for additional units: 95%.
k) 100 MW $6,500,000/MW $650 ×1,000,000: −$3,489,341 per month debt service. Discount for additional units: 95%.

New biomass-coal fired power is lower cost than the existing CEA G&T rate in every case, primarily owing to the fact that much existing CEA power is low-efficiency intermittent generation while new biomass-coal fired generation would be baseload power. CEA power, currently $188/MWh, could increase to $353/MWh, an 88% price increase, if the gas price is $25/MMBtu. While a large high-efficiency combined cycle gas plant could be cheaper than biomass-coal at current gas prices over 30 years if today's prices held, high future gas prices are expected to make even a small biomass-coal plant cost-competitive, while larger biomass-coal fired plants (with better economies of scale) would provide materially lower-cost electricity. Of note, even assuming long-term sustained current gas rates of $7.07/MMBtu, a large biomass-coal fired power plant with CCS could provide power at prices nearly on par with a new high-efficiency combined cycle natural gas plant but without CCS included. New biomass-coal fired generation with CCS provides new power generation infrastructure with a ~50-year lifespan to the grid at a lower cost of future power and with lower emissions than sourcing new gas for an existing gas fleet with declining lifespan (scenario at left).

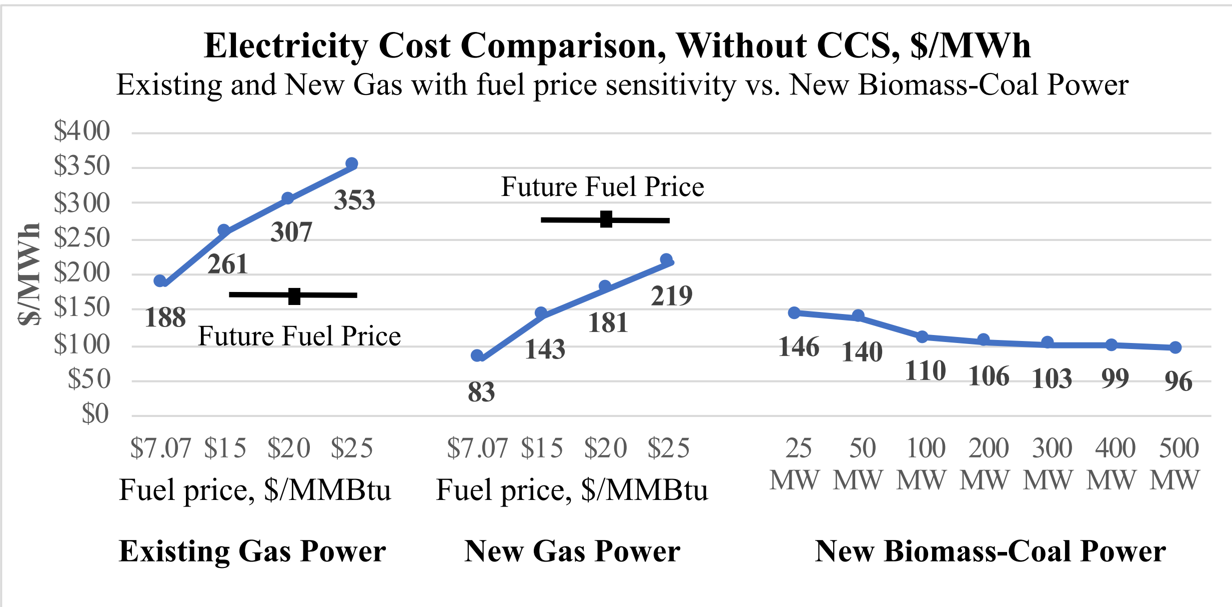

Figure 8. Electricity Cost Comparison, Without CCS, $/MWh
Existing CEA G&T Gas and New Gas with fuel price sensitivity vs. New Biomass-Coal Power.

CARBON CAPTURE PROCESS, TECHNOLOGY, AND DESIGN

Flue gas preconditioning is essential for the CO_2 capture process. Preconditioning cools and reduces flue gas impurities, which improves CO_2 absorption reaction kinetics and mitigates solvent degradation. As shown in Figure 9, flue gas preconditioning includes a flue gas cooler (FGC), flue gas desulfurization (FGD), and a flue gas quencher further cooling the gas and removing residual traces of sulfur. Within the FGD train, pulverized limestone is chemically converted to gypsum during the desulfurization process. Gypsum may be beneficially used to manufacture panel-grade drywall rather than being landfilled.

CO_2 is removed by contacting flue gas with an amine solvent which absorbs CO_2. The CO_2-rich solvent is regenerated for reuse by heating, which releases captured, concentrated CO_2. Captured CO_2 is then dehydrated and compressed for pipeline transport to the storage site.

One commercial option to capture the CO_2 emissions from a biomass-coal fired power plant is the MHI KM-CDR process. The MHI KM-CDR process has been used at the Petra Nova project, where it has demonstrated the ability to capture >90% of the CO_2 from the W.A. Parish coal-fired power plant. MHI touts the KM-CDR as featuring a modular and standardized design, allowing it to potentially scale with a similarly modular CFB for power generation that could be implemented in stages. The MHI process is the selected CO_2 capture technology for this study.

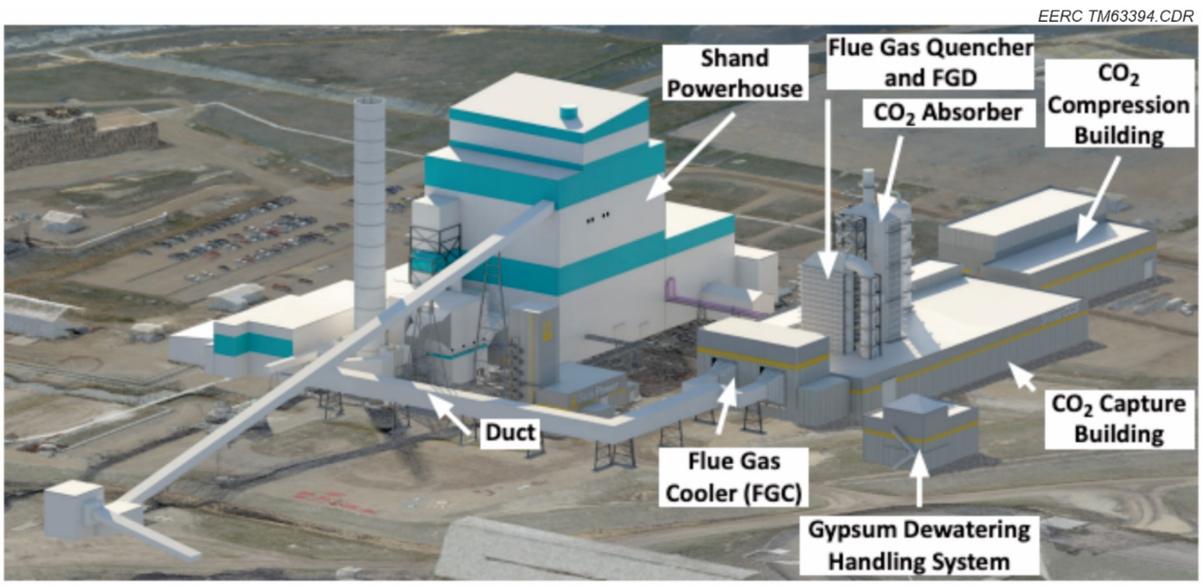

Figure 9. Power and Carbon Capture Plant Layout (International CCS Knowledge Centre, 2018).

CO_2 PIPELINE TRANSPORTATION AND ROUTE

This assessment assumes installation of an American National Standards Institute (ANSI) Class 900 spec CO_2 pipeline, designed for 2200-psig service, sized for plant capacity. Pipelines were sized such that no booster pump station was required. Pipeline transportation of CO_2 over longer distances is most efficient and economical when the CO_2 is in the dense (liquid) phase with pipeline pressures above 1080 psi. It is often preferrable and lower cost to size the pipeline large enough so a booster pump(s) is not required. CO_2 must be dehydrated to reduce the risk of pipeline corrosion. There are a few examples of existing pipelines converted to CO_2 service at lower pressure for low flow rates and/or short distances (less than 100 miles). CO_2 transport by truck and rail cost ranges from three to ten times more expensive per ton than by pipeline (National Petroleum Council, 2019).

This project's pipeline and power line are proposed to share the same corridor for cost estimation purposes, which has a nominal distance of ~75 miles including 5 miles for contingency. The route follows the Donlin Gold pipeline corridor from the mine site to tidewater, then westward to the Beluga River gas field and electrical grid intertie. The route runs alongside the West Susitna Access Road from the Flatlands Energy reserve to Donlin Gold pipeline's MP30. At MP30, the pipeline and transmission line head south to tidewater, while the West Susitna Access Road heads east to the port. A local ANSI Class 900 spec distribution network at the Beluga River gas field would be constructed to tie in individual CO_2 injection wells. No CO_2 booster pump station was required for this project. Other potential CO_2 storage locations will be evaluated by the pending ARCCS Project. (U.S. DOE FECM press release, November 14, 2023)

CARBON STORAGE LOCATION OPTIONS

A high-level screening of reservoirs found the Cook Inlet Basin is one of the areas with the highest potential for CO_2 storage in Alaska (Shellenbaum and Clough, 2010). For this study, the target geologic CO_2 storage formation is a depleted gas or oil field. Such fields have a proven seal that has stored gas over geologic time with well-defined storage capacity. Several such fields exist in the northern Cook Inlet region. Based on volumes of natural gas produced to date, a preliminary estimate of the geologic CO_2 storage capacity in the area is sufficient for ~60 years of injection of CO_2 in the Beluga River Unit, highlighted by the purple arrow in Figure 10, for the project's 300-MW-net biomass-coal fired power plant with CCS. Alternative storage sites include secure saline aquifers or unmineable coal seams, but these require geologic and geophysical study, and possibly new appraisal data, to assure their capacity and ability to permanently store CO_2. An example of a study of a saline aquifer close to the proposed project area is Pantaleone and Bhattacharya (2021).

A pending geological and engineering study will calculate the CO_2 storage capacity in this region, the Alaska Railbelt Carbon Capture and Storage (ARCCS) Project by University of Alaska. This Project was selected by the US DOE for a Carbon SAFE Phase II storage volume analysis including technical, economic, and community assessments for potential CO_2 storage complexes (U.S. DOE FECM, November 14, 2023 and Northern Journal, Dec 2023).

Figure 10, a Cook Inlet Basin location map, is taken from a geologic storage assessment for several oil and gas fields and the Hemlock Formation generally. Figure 11 shows the Hemlock in relation to the Beluga Formation in the stratigraphic column. For the overall basin, the saline aquifer Hemlock Formation has 0.91 to 16.61 Gt (P_{10} to P_{90}) storage capacity, with a P_{50} capacity close to the mean of 4.33 Gt, equivalent to 1800 years of carbon storage capacity for a 200-MW-net plant (Pantaleone and Bhattacharya, 2021). Hemlock Formation storage is one alternative to the selected CO_2 storage site discussed below, and underlies the Beluga River Field.

Depleted Oil and Gas Reservoirs

For Alaska-based CO_2 storage projects, storage in depleted gas reservoirs may be preferred as these have more available data sets formations to understand the subsurface than saline and oil and gas reservoirs have proven cap rock integrity. Developed field well data helps characterize geologic properties, including gas storage capacity, reservoir properties, and cap rock seal integrity. Therefore, this study considered as primary CO_2 storage targets the natural gas reservoirs in the Cook Inlet region, many of which are forecast to be nearly depleted.

One of the larger fields available for storage in the near future is the Beluga River Unit (Beluga/Sterling). Beluga River has an added benefit of onshore access, resulting in lower injection well costs than offshore wells. The Beluga River Unit is highlighted by the purple arrow in Figure 10. Discussion with the field Operator, Hilcorp, indicates remaining natural gas production can continue while initiating CO_2 sequestration in this multi-zone reservoir.

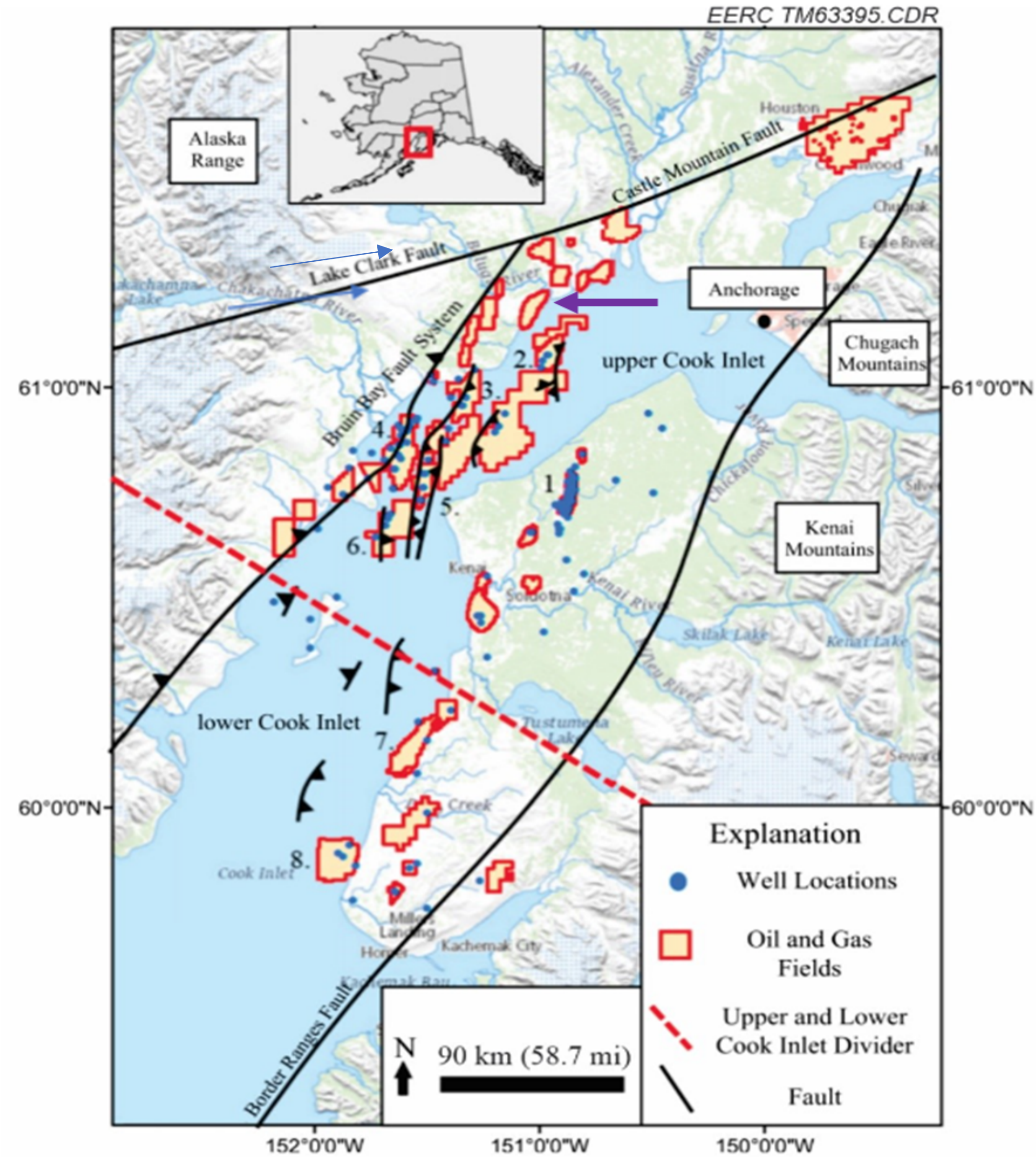

Figure 10. Location Map of Cook Inlet Basin with Beluga River Field Indicated by Purple Arrow (Pantaleone and Bhattacharya, 2021)

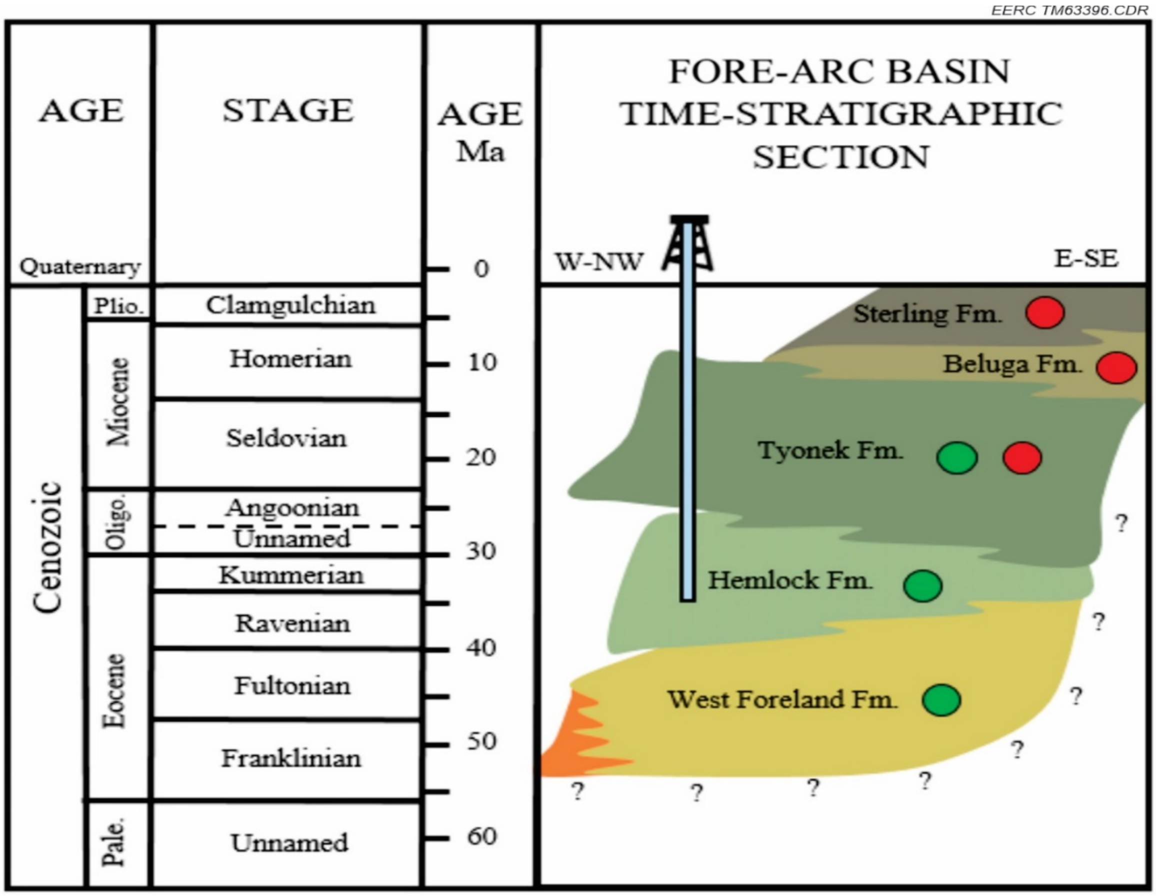

Figure 11. Chronostratigraphic and Petroleum System Chart for the Cook Inlet Basin (Pantaleone and Bhattacharya, 2021). Red and green dots note formations associated with natural gas and oil production, respectively.

Historical production data from the Beluga River Unit, Figure 12, show a strong p/z relationship that indicates the reservoir acts as a nearly static “tank” with no change in gas pore volume or formation damage occurring as gas is produced and reservoir pressure decreases. Assuming no significant reservoir damage occurs during production, volumetric calculations of the reservoir pore space available for CO_2 storage versus reservoir storage pressure is possible. This study assumed with CO_2 injection the reservoir will not exceed the original discovery gas reservoir pressure of ~ 2500 psi (Thomas and others, 2004). According to the same report, the volume of gas produced at depletion is approximately 1.3 Tcf of natural gas (Thomas and others, 2004), corresponding to a reservoir pressure of approximately 300 psi. The reservoir is located at an approximately 4000-foot depth. Assuming a surface temperature of approximately 60°F with a geothermal gradient of 15°F per 1000 feet results in a reservoir temperature of approximately 120°F. Under these reservoir conditions, natural gas has a density of approximately 7.8 lb/ft^3 (125 kg/m^3) compared to a density of approximately 0.044 lb/ft^3 (0.7 kg/m^3) under standard conditions (Unitrove, 2022) and results in a total reservoir volume available of approximately 7.3 Bcf.

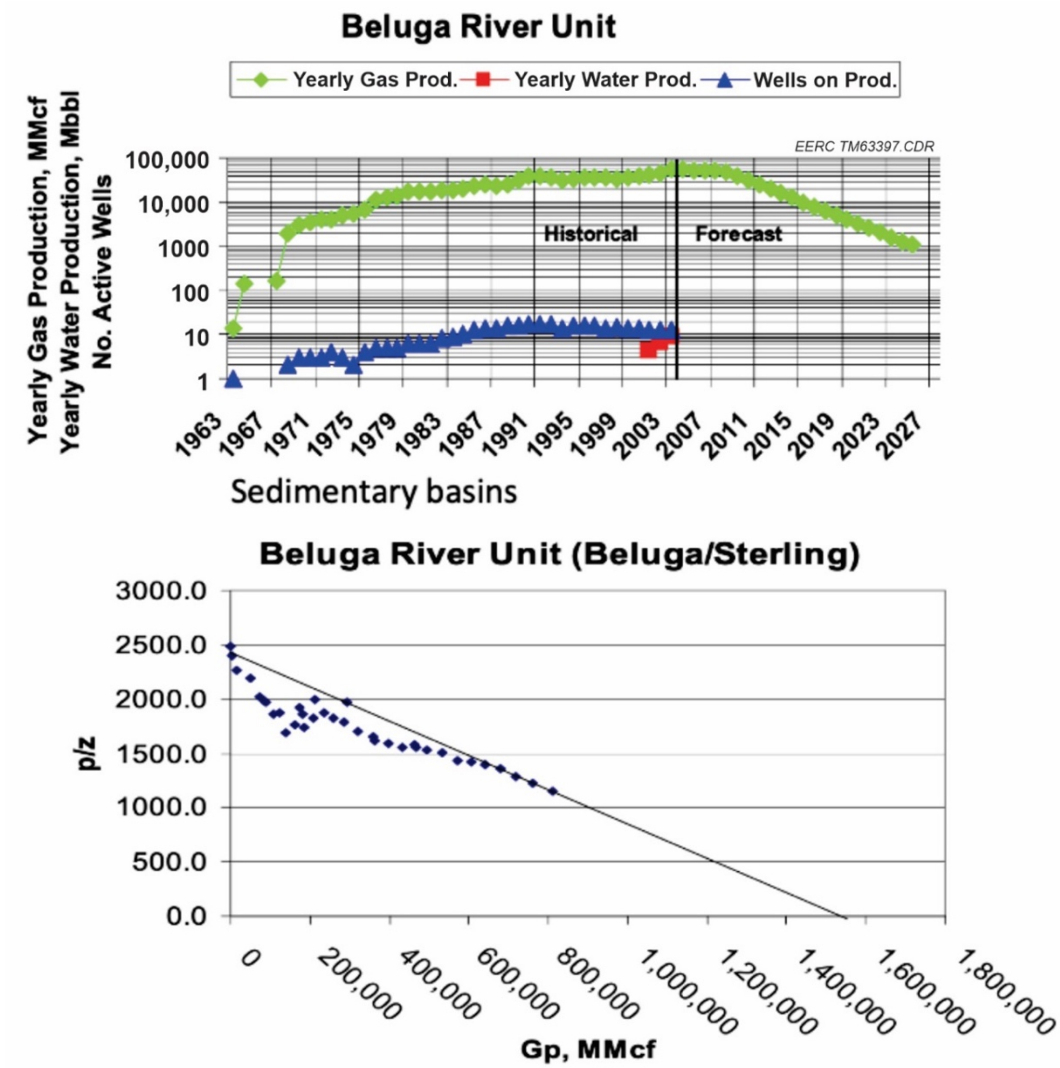

Figure 12. Beluga River Unit Production and Pressure History (Thomas and others, 2004).

Under the same reservoir conditions, CO_2 has a density of 46.8 lb/ft^3 (749 kg/m^3) (MegaWatSoft Inc., 2022). The same 7.3 Bcf of reservoir volume could be occupied by approximately 344 billion pounds, or 157 MMt, of injected CO_2. At CO_2 capture rates associated with a 400-MW gross power plant of 2.6 million metric tons per year, this provides approximately 60 years' worth of storage volume.

Achievable injection rates in a CO_2 injection well were estimated for the Beluga River gas field to determine whether it represents an economic target for CO_2 storage. To do this, the productivity index of the gas wells was converted to an approximate injectivity index. The Beluga River Unit for the month of December 2003 was approximately 4.8 Bcf from 13 production wells (Thomas and others, 2004). This rate is equivalent to 369 MMscf per month per well, or approximately 12 million standard cubic feet per day (MMscfd) per well. Reservoir pressure at this time is approximately 1200 psi. A conservative assumption is that the bottomhole pressure of the producing wells is nearly atmospheric (14.7 psi), inferring a productivity index of 10,000 scf per psi of pressure drawdown.

Average per well rates of 12 MMscfd from the Beluga River Unit are confirmed in well-by-well historical production data from a 2017 Cook Inlet gas study conducted by PRA (Stokes, 2017). Some Beluga River Unit wells peaked at rates as low as 3.5 MMscfd, while others peaked at rates of 30 MMscfd or higher.

Using Darcy's law to convert natural gas production rates to CO_2 injection rates, the main differences are the density and viscosity of the fluids. Under reservoir conditions of 1200 psi and 120°F, natural gas has a density of 3.6 lb/ft^3 (57 kg/m^3) and a viscosity of 0.01 cP (Petrowiki, 2022). Meanwhile, CO_2 under the same conditions has a density of approximately 14.7 lb/ft^3 (235 kg/m^3) and a viscosity of approximately 0.02 cP (Fenghour and others, 1998). Under bottomhole injection conditions of up to 2500 psi, the density and viscosity of CO_2 may both be as high as 46.8 lb/ft^3 (749 kg/m^3) and 0.066 cP (Fenghour and others, 1998). Based on the differences in both viscosity and density, it is estimated that the mass flow rate of the CO_2 will be approximately twice that of natural gas, assuming a similar 1200-psi difference in pressure between the reservoir and well. This translates from roughly 500,000 lb of natural gas per day at 12 MMscfd to approximately 480 metric tons of CO_2 per day (or 175,000 metric tons per year) per injection well.

Finally, to inform the most likely peak performance of injectors, if the bottomhole pressure never exceeds the initial reservoir pressure of 2500 psi and the reservoir is depleted to 300 psi prior to CO_2 injection, that would imply an initial pressure difference between the well and reservoir pressure of 2200 psi. With this higher increased bottomhole injection pressure, initial injectivity of CO_2 injection wells in the Beluga River Unit is expected to average approximately 320,000 metric tons per year. This would require approximately one injection well into the Beluga River Unit per 25 MW of net electricity generation capacity. The number of injection wells varies depending on plant size as shown in Table 6.

The conservative injectivity estimate based on analog wells in the Beluga River Unit is strengthened based on an analog of a new CO_2 storage project. According to the storage facility permit for Project Tundra to store CO_2 in the Broom Creek Formation near Center, North Dakota, the Broom Creek Formation has an average permeability of 439 mD and estimated maximum CO_2 storage injection well rates of 2 MMt per year (Minnkota Power Cooperative, 2021). Meanwhile, the Sterling Formation of the Beluga River Unit was characterized as having an average permeability of 119 mD, which would result in an adjusted injectivity of approximately 500,000 metric tons per year under comparable injection limits (Levinson, 2013). However, this study does not push the bottomhole injection pressure to the same 90% of fracture propagation pressure as Project Tundra.

Local Saline Aquifers

Storage reservoirs in the Cook Inlet region are not limited to depleted oil and gas reservoirs. Stratigraphic columns and descriptions of the Cook Inlet region show that the volcanic bedrock in the region was formed in the late Triassic or early Jurassic period (U.S.

Department of Interior National Park Service, 2022; Buthman, 2017; Dallegge, 2003). Since the volcanic bedrock, multiple vertically stacked sedimentary reservoirs have accumulated in the Cook Inlet Basin. Fewer oil or gas accumulations are associated with the deeper reservoirs prior to the Paleogene period (Gillis, 2022), making the deeper Cretaceous and Jurassic period sediments a likely significant pore space resource.

The Cook Inlet sedimentary basin extending east of Skwentna may be amenable to CO_2 storage, but any potential storage site would require characterization to verify storage security and capacity. Geologic uncertainties are associated with this formation, including its local depth, thickness, and quality; the seal continuity and capacity of overlying strata; and the impact of seismic events, including the Castle Mountain fault, which requires further evaluation.

Since pipeline CO_2 transport to the Beluga River Unit would be an expensive capital project, geologic appraisal including an exploration well and/or a seismic survey to characterize local saline aquifers near the project site could provide valuable information and potentially significant project cost savings. Geologic appraisal of this type has been subsidized in other regions by the federal government in order to enhance CCS projects (Peck and others, 2020).

The Hemlock Formation, part of the Cook Inlet basin shown in the cross-hatched blue region in Figure 13, is considered one of the most prospective CO_2 storage locations in Alaska, sufficient for 1800 years of 200-MW-net power plant CO_2 storage (Pantaleone and Bhattacharya. 2020). In the Cook Inlet, specific reservoirs within the Hemlock Formation have been characterized, but outside of the explored oil and gas reservoirs there is significant uncertainty in the distribution of formation and reservoir properties (Ellett and others, 2022).

Unmineable Coal Seams

Finally, deep (>2600-ft) unmineable coal seams are a third possible storage resource in the area. Within the Cook Inlet Basin are multiple unmineable layers of coal distributed among the other sedimentary rock in the stratigraphic column (Dallegge, 2003). Since development of the unmineable coal seams of the Cook Inlet region have a similar or greater amount of uncertainty and cost compared to local saline aquifers, they are unlikely to represent a significantly more attractive target for CO_2 storage. Injection into saline aquifers has an established successful history compared to the relatively untested history of mineable coal seams.

Water Demand and Disposal for Power Generation and CCS

Zhai and others (2011) investigated water use at a pulverized coal-fired power plant with post combustion CCS, finding the amine carbon capture system water use similar to the stand-alone coal power plant. The biomass-coal power plant with CCS is thus assumed need a water permit twice that of the power plant alone. The power and CCS plant can be designed for zero water discharge employing water-saving measures, water cycling and reuse, and on-site evaporative ponds. Further study is needed to estimate water demand and disposal needs, if any.

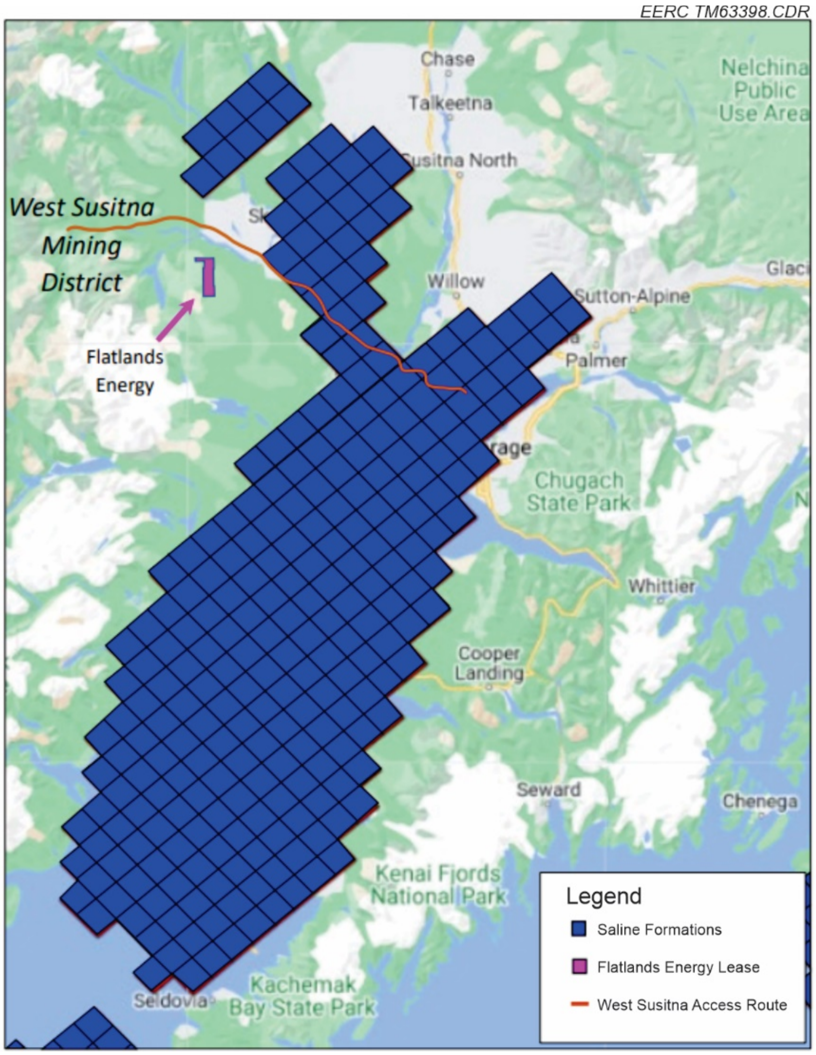

Figure 13. Cook Inlet Basin Saline Formations with West Susitna Access Road (https://simccs.org/maptool/).

If zero discharge is not possible, significant water disposal necessitates Class I wastewater disposal well(s) at or near the generation plant. This may make the case for an exploration well near the mine site for wastewater and/or CO_2 injection, to characterize the local geology of many stacked storage reservoir horizons. Local CO_2 injection would reduce CO_2 pipeline transportation costs, lowering the overall project cost.

CCS FINANCIAL ANALYSIS

CCS costs are evaluated for both biomass-coal and for natural gas fired power. All economic and financial analyses of the CCS systems presented in this report assume that the 45Q tax credits are the only source of revenue. Therefore, the assumptions of the duration and value of the 45Q tax credits are important to the economic analysis of this report and are discussed below. These revenue assumptions are then fed into the CCS cost model to estimate the total cost to generate electricity and capture and store the CO_2 associated with electricity generation for the 30-year project life.

45Q Federal Tax Credits – History and Long-Term Expectations

The study team expects that CO_2 capture and storage 45Q tax credits may be extended (and perhaps increased again) during the project life, i.e., beyond the Inflation Reduction Act's (IRA's) current \$85/metric ton and 12-year capture period. The base-case economic assumption for this feasibility study is that 45Q tax credits remain at \$85/metric ton through the entire 30-year project life, referred to as the "30-year tax credit" scenario. As an alternate case, CCS economics are tested with 45Q credits that end after 12 years (consistent with current legislation) while CO_2 capture, transport, and storage continue for the full 30-year electricity generation facility life despite the lack of the tax credit in the out years. This case is referred to as the "12-year tax credit" scenario.

The history of 45Q, summarized briefly below, is the reason the 30-year tax credit scenario was chosen as the base case presented in the tables and figures of this report. Consistent with the 30-year tax credit scenario, the history of federal wind tax credits, which goes back to 1992, has been renewed and extended numerous times (Institute for Energy Research, 2019).

First introduced in 2008, Section 45Q of the U.S. Internal Revenue Code provides a tax credit for CO_2 capture and storage. The policy is intended to incentivize commercial deployment of CCUS.

The Bipartisan Budget Act of 2018 made the credits more valuable, increasing the tax credit from \$20 to \$50/metric ton for dedicated geologic storage and from \$10 to \$35/metric ton for associated CO_2 storage from EOR for projects that begin construction by January 2026.

In 2022, the IRA again expanded and extended the 45Q tax credit to \$85/metric ton of dedicated CO_2 storage and \$60/metric ton of associated CO_2 storage from EOR. The credit also addresses biologic sequestration and direct air capture (DAC) projects. The 2022 changes include a 7-year extension to qualify for the tax credit, meaning projects have until January 2033 to begin construction. The credit is currently available to qualified facilities for 12 years after they begin capturing and storing CO_2 (International Energy Agency, 2022b; BrownWinick Law, 2022).

Long-term expectations for continued 45Q tax credits through the project life (the 30-year tax credit scenario) are consistent with recommendations in *A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*, which outlines a pathway through three phases: activation, expansion, and at-scale deployment. (National Petroleum Council, 2019) The 2019 study "recommended expanding current policies to a level of ~\$90/metric ton to provide incentive for further economic investment during the expansion phase." It also mentions that "achieving CCUS deployment at scale (i.e., additional 350 to 400 Mtpa) within the next 25 years will require substantially increased support driven by national policies…. Congressional action should be taken to bring cumulative value of economic policies to about \$110 per tonne".

CCS Cost Model

A CCS techno-economic assessment cost model developed by the EERC was adapted for this analysis, which reflects costs as of May 2022 for Lower 48 construction that are uplifted with an Alaska cost differential. Results are provided for both a new biomass-coal fired power plant and a representative CEA-region gas-fired power plant to enable financial and carbon intensity comparisons between these systems.

For this study, CCS capital expenditures (CAPEX) and operating expenses (OPEX) were raised 25% to reflect possible Southcentral cost differentials, reflecting that Alaska statewide average building costs are 23% above the national average (estimationqs.com, 2022). For smaller CCS systems, 75-MW-net generation with CCS, a further 25% continency was added to CCS CAPEX only, given the limited ability to optimize costs with smaller construction projects. Further cost estimation work is needed.

The techno-economic assessment model includes these costs and benefits:

1) CO_2 Capture capital costs
2) CO_2 Capture OPEX
   a) Electricity use (pumps, compressors, refrigeration units)
   b) Fuel gas/heat use (mainly for amine regeneration)
   c) Water costs (mainly for cooling)
   d) Compressor maintenance/rebuilds/compressor oil
3) Injection well capital costs
4) Well maintenance
5) Pipeline capital costs
6) Pipeline OPEX
7) Pipeline and site monitoring, inspections, and testing
8) Seismic monitoring program
9) Site development costs
   a) Storage facility permit
   b) EPA monitoring, reporting, and verification (MRV) plan
10) Storage fees (per EERC)
11) 45Q tax credits

The Inflation Reduction Act increased 45Q tax incentives to $85/metric tonne for carbon storage projects that begin construction before January 1, 2033. In addition, billions of dollars of U.S. federal government loans and grants are available for advancing CCS and power projects, as discussed in Appendix A, government engagement and funding opportunities. For this study, government loans, grants, or other incentives outside of 45Q credits are not considered in the economics.

For this analysis, all CCS costs presented in tables and figures assume 30 years of revenue equivalent to 45Q tax credits from capturing and storing CO_2. This assumes that the current 12-year eligibility for 45Q tax credits will be extended, or CO_2 markets will become established to provide equivalent income to 45Q tax credits following the 12 years 45Q eligibility, or other incentives will emerge to provide continued revenue for the remainder of the 30-year CO_2 capture facility life expectancy. Discussion is also provided for insight on the sensitivity of CCS and projected electricity costs assuming current 45Q legislation remains unchanged at current levels of 12 years of tax credit eligibility, no other revenue sources emerge, while the CCS system is operated for all 30 years of projected biomass-coal generation facility life, i.e., operates the last 18 years with CCS operational but without earning 45Q revenue.

Tax credit is given to the taxpayer or company that owns the carbon capture equipment placed into service in accordance with 45Q regulations. Therefore, if an electricity generation company owns the CCS equipment, excess tax credit generated from CCS could be applied to reduce the tax liability of the electricity generation side of the business, resulting in a net reduction in the cost of the electricity.

For this financial modeling, inflation was set to zero and the discount rate to 3%/year. This is effectively consistent with current National Institute of Standards and Technology (NIST) interagency report guidance (Kneifel and Lavappa, 2022):

- Real rate (excluding general price inflation): 3.0%
- Nominal rate (including general price inflation): 2.0%
- Implied long-term average rate of inflation: −1.0%

To test and validate the CCS financial model, carbon capture costs for a biomass-coal and natural gas power plant were compared with DOE NETL published estimates. For this benchmarking exercise, a $3.50/MMBtu natural gas price was used to be consistent with Lower 48 fuel prices. Transportation and shipping costs are excluded from these benchmarking estimates. CO_2 capture costs for a 300-MW-net power plant with CCS, a biomass-coal-fueled plant and natural gas-fueled power plant were estimated to cost $54.94 and $69.84/metric ton, respectively, to capture the CO_2 using the EERC CCS financial model. These are very close to published DOE NETL estimates: CO_2 capture cost for a subcritical coal-fired power plant is $56.20/metric ton and for natural gas combined cycle is $71.10/metric ton (U.S. Department of Energy National Energy Technology Laboratory, 2015). This benchmarking validated the CCS financial model for application in this study.

CCS Financial Results for Biomass-Coal Power Generation

Economic results are compiled in Table 6 for CCS associated with 25- to 500-MW-net with CCS power generation for a biomass-coal fired power plant. CAPEX includes the carbon capture plant, CO_2 transport pipeline, and wells to inject CO_2 into the storage reservoir. The plant has an annual operating CAPEX of 2.5% of the initial plant cost per year. OPEX for the CCS plant and pipeline are also major contributors to long-term project cost.

Table 6 shows only CCS system costs and benefits for clarity. Biomass-coal power plant costs are shown separately in Table 5. Two cases, highlighted red, have corresponding power plants with matching capacity for total cost of electricity calculations shown later.

Table 6. Biomass-Coal Power Plant CCS Financial Model Results for Various Plant Sizes
30-year Tax Credit Scenario. Two Sizes Highlighted Red have Corresponding Power Plant Costs for Total Cost of Electricity Calculations

	Units								
Power Plant Net Generation Without Carbon Capture	MW	33	67	**100**	133	267	**400**	533	667
Power Plant Net Generation with Carbon Capture	MW	25	50	**75**	100	200	**300**	400	500
Carbon Capture Plant Cost[1]	Net present US$MM	99.1	197.4	**295.7**	315.3	629.9	**944.4**	1259.0	1573.6
Carbon Capture Plant Ongoing CAPEX (30 years at 2.5% plant cost per year)	Net present US$MM	48.6	96.7	**144.9**	154.5	308.7	**462.8**	616.9	771.1
Carbon Capture OPEX (30 years)	Net present US$MM	162.4	275.8	**389.2**	502.5	956.1	**1409.7**	1863.2	2316.8
Pipeline Diameter, inches[2]	inches	6	8	**12**	12	12	**16**	20	20
Pipeline Capital Cost (75 miles)	Net present US$MM	68.8	77.0	**97.1**	97.1	97.1	**132.8**	171.8	171.8
Pipeline OPEX (30 years)	Net present US$MM	16.9	16.9	**16.9**	16.9	16.9	**16.9**	16.9	16.9
Well Costs[3]									
Total Number of Injection Wells (30 years)		1	2	**4**	5	11	**22**	43	105
Total Number of Storage Reservoir Monitoring Wells		1	1	**1**	1	1	**1**	1	1
Unit Cost of Wells	US$MM	10	10	**10**	10	10	**10**	10	10
Additional for Underground Source of Drinking Water (USDW) Monitoring Well and Monitoring Equipment	US$MM	0.6	0.6	**0.6**	0.6	0.6	**0.6**	0.6	0.6
Well Cost	Net present US$MM	20.6	30.6	**45.1**	56.1	108.4	**185.8**	315.4	628.3
Monitoring Costs	Net present US$MM	32.1	32.1	**32.1**	32.1	32.1	**32.1**	32.1	32.1
Seismic Costs	Net present US$MM	5.3	5.3	**5.3**	5.3	5.3	**5.3**	5.3	5.3
CCS Storage Facility Development Cost	Net present US$MM	6.3	6.3	**6.3**	6.3	6.3	**6.3**	6.3	6.3
Storage Fee Cost ($0.16/metric ton base)	Net present US$MM	1.2	2.4	**3.7**	4.9	9.8	**14.6**	19.5	24.4
Inspection and Testing Cost	Net present US$MM	3.5	7.0	**14.0**	17.5	38.5	**77.0**	150.5	367.5
Captured CO_2 (85% capacity factor, 90% CCS on-time, 95% capture rate)	MMt/y	0.22	0.44	**0.65**	0.87	1.74	**2.62**	3.49	4.36
Total CO_2 Stored (30 years, no discount factor)	MMt	6.54	13.08	**19.62**	26.16	52.33	**78.49**	104.65	130.82
CO_2 Captured (30 years, 3% discount)	Net present MMt	4.27	8.55	**12.82**	17.09	34.18	**51.28**	68.37	85.46
Power Generated (30 years, 85% capacity factor)	MWh	5,584,500	11,169,000	**16,753,500**	22,338,000	44,676,000	**67,014,000**	89,352,000	111,690,000
Net Present Power Generated (30 years, 85% capacity factor, 3% discount)	Net present MWh	3,648,354	7,296,708	**10,945,062**	14,593,415	29,186,831	**43,780,246**	58,373,662	72,967,077
Net Present Cost for CCS									
Total Cost for 30 years of Carbon Capture, Transport, and Storage	Net present US$MM	465	747	**1050**	1208	2209	**3288**	4457	5914
Total Cost for CCS per metric ton of CO_2 (30 years)	Net present US$/metric ton	108.76	87.46	**81.93**	70.70	64.62	**64.12**	65.19	69.20
Total Cost for CCS per MWh of Electricity (30 years)	Net present US$/MWh	127.39	102.44	**95.96**	82.81	75.69	**75.09**	76.35	81.05
Total Value of CCS with 30 years of 45Q Tax Credit ($85/metric ton)	Net present US$/metric ton	−23.76	−2.46	**3.07**	14.30	20.38	**20.88**	19.81	15.80
Total Value of CCS with 30 years of 45Q Tax Credit ($/MWh)[4]	Net present US$/MWh	−27.83	−2.88	**3.60**	16.74	23.87	**24.46**	23.20	18.50
Total Project Value with 30 years of 45Q Tax Credit ($85/metric ton)	Net present US$MM	−101.54	-21.03	**39.35**	244.36	696.61	**1070.88**	1354.53	1350.17

Assumptions:

[1] Net present costs assume 3% discount rate.

[2] Pipeline note: No additional pump stations required. Line sized for maximum 95% capture rate 100% on-time.

[3] Well count assumes only Beluga River Unit reservoir available. First-year wells accommodate 95% capture rate with 100% capacity factor and capture plant on-time. Later wells assume pressure buildup of average 85% capacity factor and 90% on-time of capture plant with 95% capture rate.

[4] Negative values add to electricity price, positive values lower electricity price.

Table 7. Natural Gas Power Plant CCS Financial Model Results for Various Fuel Gas Prices
30-year Tax Credit Scenario

	Units	$7.07 Natural Gas		$15 Natural Gas		$20 Natural Gas		$25 Natural Gas	
Power Plant Net Generation Without Carbon Capture	MW	400		400		400		400	
Power Plant Net Generation with Carbon Capture	MW	300		300		300		300	
Carbon Capture Plant Cost	Net present US$MM	213.8		213.8		213.8		213.8	
Carbon Capture Plant Ongoing CAPEX (30 years at 2.5% plant cost per year)	Net present US$MM	104.7		104.7		104.7		104.7	
Carbon Capture Plant OPEX (30 years)	Net present US$MM	422.9		627.7		764.2		900.7	
Pipeline Diameter	inches	8		8		8		8	
Pipeline Cap Cost (75 miles)	Net present $MM	77.0		77.0		77.0		77.0	
Pipeline OPEX (30 years)	Net present $MM	16.9		16.9		16.9		16.9	
Well Costs									
Total Number of Injection Wells (30 years)		3		3		3		3	
Total Number of Storage Reservoir Monitoring Wells		1		1		1		1	
Unit Cost of Wells	US$MM	10		10		10		10	
Additional for USDW Monitoring Well and Monitoring Equipment	US$MM	0.6		0.6		0.6		0.6	
Well Cost	Net present US$MM	35.0		35.0		35.0		35.0	
Monitoring Costs	Net present US$MM	32.1		32.1		32.1		32.1	
Seismic Costs	Net present US$MM	5.3		5.3		5.3		5.3	
CCS Storage Facility Development Cost	Net present US$MM	6.3		6.3		6.3		6.3	
Storage Fee Cost ($0.16/metric ton base)	Net present US$MM	2.6		2.6		2.6		2.6	
Inspection and Testing Cost	Net present US$MM	10.5		10.5		10.5		10.5	
Captured CO_2 (85% capacity factor, 90% CCS on-time, 90% capture rate)	MMt/y	0.45		0.45		0.45		0.45	
Total CO_2 Stored (30 years, no discount factor)	MMt	13.44		13.44		13.44		13.44	
CO_2 Captured (30 years, 3% discount)	Net present MMt	8.78		8.78		8.78		8.78	
Power Generated (30 years, 85% Capacity Factor)	MWh	67,014,000		67,014,000		67,014,000		67,014,000	
Power Generated (30 years, 85% capacity factor, 3% discount)	Net present MWh	43,780,246		43,780,246		43,780,246		43,780,246	
Net Present Cost for CCS			**Without T&S[1]**		**Without T&S**		**Without T&S**		**Without T&S**
Total Cost for 30 years of Carbon Capture, Transport, and Storage	Net present US$MM	915	729.7	1132	946.2	1268	1082.7	1405	1219.2
Total Cost for CCS per metric ton of CO_2 (30 years)	Net present US$/metric ton	104.25	83.10	128.91	107.76	144.46	123.31	160.00	138.86
Total Cost for CCS per MWh of Electricity (30 years)	Net present US$/MWh	20.91	16.67	25.85	21.61	28.97	24.73	32.09	27.85
Total Value of CCS with 30 years of 45Q Tax Credit ($85/metric ton)	Net present US$/metric ton	–19.25	1.90	–43.91	–22.76	–59.46	–38.31	–75.00	–53.86
Total Value of CCS with 30 years of 45Q Tax Credit ($/MWh)[3]	Net present US$/MWh	–3.86	0.38	–8.81	-4.57	–11.92	–7.68	–15.04	–10.80
Total Project Value with 30 years of 45Q Tax Credit ($85/metric ton)	Net present US$MM	–169.03	16.66	–385.56	–199.87	–522.06	–336.37	–658.56	–472.87

Assumptions:

[1] Transportation and storage.

[2] Well count assumes only Beluga River Unit reservoir available. First-year wells accommodate 90% capture rate with 100% capacity factor and capture plant on-time. Later wells assume pressure buildup of average 85% capacity factor and 90% on-time of capture plant with 90% capture rate.

[3] Negative values add to electricity price, positive values lower electricity price.

CCS systems require electricity and heat from the power plant for CO_2 capture and transport, consuming 25% to more than 30% of the gross power plant generation. Since systems initially designed with CCS are more efficient than plants retrofitted for CCS, this study assumed 25% of plant power is used by CCS. A 100-MW power plant thus corresponds to 75 MW net with CCS power generation. The carbon capture OPEX estimate includes the cost of electricity and heat provided by the power generation plant. In a combined economic analysis, not shown here and depending on the project business model, the power plant may be compensated by the carbon capture plant for the electricity and process heat consumed by the CCS plant.

Table 6 lists net present costs for carbon capture, transport, and storage, total cost per metric ton of CO_2 stored, and total cost per MWh for a range of power generation sizes. Net present costs are calculated over a 30-year project life, consistent with traditional utility power cost calculations. As a result of the 30-year horizon used for utility-scale power generation, 30 years of CCS was also assumed in the economic estimates. In these cases, it was assumed that 45Q tax credits were extended or emerging revenue sources such as a regional CO_2 market or other incentives (e.g., sale of carbon credits) provide continued income for CCS operation for the 30-year facility life. Economics for the 12-year tax credit scenario are discussed below.

Carbon capture units such as the MHI KM-CDR process can be designed to capture carbon from relatively small-scale operations; however, per unit costs will be higher. To account for reduced economies of scale, this study increased carbon capture plant initial capital cost by 25% for plants designed to capture CO_2 from sources generating under 1 MMt per year of CO_2. This cost increase was, therefore, applied to 75-MW-net generation with CCS and smaller plants. For reference, a 25-MW biomass-coal power plant facility generates ~300,000 metric tons per year of CO_2.

The final rows in Table 6 show total net present cost for CCS and net present value including 45Q tax credit benefit assuming 45Q tax credits for all 30 years. These are reported in terms of US$ per metric ton of captured CO_2 and net present power cost US$ per MWh.

When net present cost drops below $85/metric ton, CCS adds economic value since costs are more than offset by tax credits. The CCS breakeven point is between 50- and 75-MW power generation with carbon capture, assuming 30 years of revenue equivalent to current 45Q tax credits. As will be discussed later, when assuming only 12 years of tax credits that are available in current legislation, the CCS capital cost and 30 years of CCS operations costs exceed the tax credits, and the cost of electricity with only 12 years of 45Q (followed by 18 years of operating the CCS plant without tax credits) is higher than the base cost of electricity without CCS. While it would be economically unattractive to operate the CCS plant without tax credits, a plant operator may still choose to do so.

Larger plants realize substantial economic gain from economies of scale. For example, the 300-MW plant net with carbon capture realizes a $20.88/MMt tax credit benefit if 30 years of 45Q tax credits are available. $1.1 billion in net present value beyond capital and operating costs is realized after 30 years of CCS operation and 30 years of revenue equivalent to current 45Q tax credits. As plant size increases, the most significant economy of scale realized is in the CO_2

transport pipeline. From the smallest- to largest-sized pipelines, 6 to 20 inches diameter, installed pipeline cost increases 2.5 times, but this, in turn, enables transporting 20 times the CO_2 mass.

Larger plant sizes, while realizing some economies of scale, do have an offsetting increase in cost when it comes to CO_2 storage. Assuming only a single storage reservoir, well costs increase in the larger CO_2 volume cases because of the need for more wells to maintain the injection rate as reservoir pressure buildup occurs. In the case of the Beluga River gas field, with an approximate storage capacity of 157 MMt, twice the number of injection wells will be needed to maintain injection by the time 79 MMt is stored. So, in the case of 400 MW of generation capacity (300-MW net with carbon capture), twice as many wells will be needed by 16 years into the project compared to at the start of injection. In cases over 400 MW generation, the large number of injection wells necessary to maintain injection rates into the Beluga River gas field cause the net present cost per metric ton of CO_2 stored to increase compared to smaller projects.

Reducing CO_2 transportation costs by co-locating CO_2 storage at the Flatlands Energy reserve instead of ~75 miles away improves project economics in all scenarios. Smaller power generation options particularly benefit economically. This presents an opportunity for project optimization: an investment to test local storage options to reduce CO_2 transportation costs. This may also simplify pore space acquisition by avoiding existing hydrocarbon-leased acreage and by judiciously selecting storage acreage with a single pore space owner, the State of Alaska, versus three owners in the currently producing Beluga River gas field (State, Federal, and Cook Inlet Region, Inc., CIRI) (ref. Figure 15).

The Flatlands Energy reserve is located within a sedimentary basin that may have a suitable saline aquifer for CO_2 storage. However, site geologic characterization using a geophysical seismic survey and at least one exploratory well would be required to determine local CO_2 storage capacity and suitable injectivity. For example, a stratigraphic test well, at an estimated $15 million, site-specific geologic studies, and study of local seismic and fault hazards could be needed. Federal funding via CarbonSAFE or other CCS funding may be able to offset a portion of these costs. Shortening the pipeline to 15 miles or eliminating the pipeline completely in the case of on-site storage saves $81 million to $114 million for a 75-MW-net power plant and $111 million to $150 million for a 300-MW-net power plant, respectively. These cost savings are equivalent to $6 to $9 per net present metric ton of CO_2 stored for the 75-MW-net power plant and $2 to $3 per net present metric ton of CO_2 stored for the 300-MW-net power plant, assuming 30 years of operation. If local storage proves to be available, project cost reductions make a smaller-capacity power plant attractive.

These financial results are sensitive to the discount factor since long-term value of 45Q tax credits decreases with increasing discount rate. For a 3% discount rate per NIST guidance, the breakeven plant size is between 50 and 75 MW with CCS.

CCS Financial Results for Natural Gas Power Generation

The CCS cost model was also applied to evaluate CCS for natural gas power generation with the same assumptions as the coal cases (30-year project life and 30 years of revenue equivalent to 45Q tax credits). Table 7 shows financial results for a 300-MW-net natural gas power plant with CCS. CCS costs are estimated for the recent natural gas price ($7.07/MMBtu) and future low ($15/MMBtu), mid ($20/MMBtu), and high ($25/MMBtu) range of gas prices in light of supply shortfalls discussed above.

The CO_2 capture rate assumed is 90% from a natural gas plant compared to 95% assumed for biomass-coal fired power plants. Carbon capture is more difficult from a natural gas power plant because of the significantly lower CO_2 flue gas concentration compared to a biomass-coal plant, ~3-4% vs. ~14% CO_2 concentration, respectively (U.S. Department of Energy National Energy Technology Laboratory, 2015). The lower starting and ending concentration of CO_2 in natural gas power plant flue gas requires the injected amine CO_2 capture solvent to be significantly lower in CO_2 concentration, or "leaner," which requires higher amine regeneration temperatures. Higher amine required regeneration temperatures increase natural gas power plant CCS operating costs, especially with natural gas fuel price increases. While no commercial natural gas post-combustion flue gas CCS projects are currently operational, at least six are in advanced development with operational start dates of 2026 and beyond. (Global CCS Institute)

CO_2 captured rates and volumes from a natural gas plant are lower than a biomass-coal fired plant of similar power generation capacity, so natural gas plants have smaller CCS system sizes and costs to process and handle captured CO_2 per unit of electricity. On a per-ton basis, however, capture costs are higher for natural gas since costs are divided by a small number of tons CO_2. Natural gas capture costs in Southcentral, driven by locally high gas fuel price, are calculated to be much higher than in the lower 48 states or on the North Slope of Alaska which have low-cost natural gas fuel available to power the CCS processes.

For a natural gas plant, as shown in Table 7, the cost per ton of CO_2 ranges from $104 to $160/metric ton for capture, transport, and storage, increasing with fuel cost. Using Southcentral's fuel prices, in all cases the cost for natural gas CCS exceeds $85/metric ton, the 45Q credit amount, so CCS increases the electricity cost for natural gas power. Fortunately, while the cost per ton CO_2 is higher than the 45Q credit, relatively few tonnes of CO_2 are generated, so the cost increase per MWh is comparatively low for natural gas with 45Q tax credit revenue included. For similar reasons, CCS capture does not as dramatically increase natural gas-fired power cost as it would for biomass-coal fired power in the absence of 45Q tax credits.

Combined Project Cost: Low Carbon Biomass-Coal Power with CCS

Table 5 list biomass-coal power plant costs while Table 6 list corresponding CCS system costs. Table 8 brings these together for two project sizes: the 75- and 300-MW net with CCS power generation. Table 8 lists, in net present U.S. dollars, project total initial capital (bold), followed by operating capital cost and total expense costs for 30 years of operation. Note power transmission costs are excluded since customer location(s) is uncertain, e.g., industrial use or regional power grid. The customer is customarily responsible for power tie-in costs.

Table 8. Combined Project Cost, Low Carbon Biomass-Coal Power Generation with CCS, 30-yr

	Units	Power Plant with CCS	
Power Plant Generation Net with CCS	MWe net with CCS	75	300
Total Capital: Power Plant, CCS Plant, Pipeline, Well, Storage	Net present US$MM	**1149**	**3627**
Total Operating Capital Cost (30 years, 2.5% plant cost/yr)	Net present US$MM	464	1555
Total Expense Cost (30 years)	Net present US$MM	1657	6129
Power Plant Capital Cost (excluding power transmission)	Net Present US$MM	650	2229
Power Plant Ongoing CAPEX (30 years, 2.5% plant/yr)	Net present US$MM	319	1092
Power Plant OPEX (30 years)	Net present US$MM	1190	4567
Carbon Capture Plant Capital Cost	Net present US$MM	296	944
Carbon Capture Plant Ongoing CAPEX (30 years, 2.5% plant cost/yr)	Net present US$MM	145	463
Carbon Capture Plant OPEX (30 years)	Net present US$MM	389	1410
Pipeline Capital Cost	Net present US$MM	97	133
Pipeline OPEX (30 years)	Net present US$MM	17	17
Well Cost	Net present US$MM	45	186
Storage (monitoring, facility fees, inspection, and testing)	Net present US$MM	61	135

Biomass-Coal vs. Natural Gas Power Cost With and Without CCS

Figure 14 compares electricity costs for two natural gas power cases and for biomass-coal. Power costs are shown with and without CCS for comparison. For natural gas, the CEA G&T rate and a new combined-cycle natural gas plant are shown, both for a range of gas fuel prices. Biomass-coal is shown for two plant sizes, 75-MW-net and 300 MW-net with CCS. The natural gas fuel price range and the biomass-coal plant sizes described previously are shown here. In all these cases, CCS increases natural gas power cost, while CCS decreases biomass-coal fired power cost when assuming 30 years of revenue equivalent to 45Q tax credits.

When assuming the 12-year tax credit scenario, the 75-MW-net biomass-coal case has an average forecast electricity cost of $156 per net present MWh, while the 300-MW-net biomass-coal power plant with CCS has an average forecast electricity rate at $124 per net present MWh. These 12-year cases assume the CCS system operates for the full 30-year plant life. These findings are generally in line with DOE baseline studies, which estimated the cost of CO_2 capture for coal to be in the $50/metric ton range. If 45Q tax credits are earned only in the first 12 years, the net present impact of CO_2 capture on electrical costs in the following years are expected to be less $50/tonne but greater than zero.

The 12-year tax credit scenario with a 300-MW-net biomass-coal power plant has an average rate that is still less expensive than current CEA industry and retail rates and is comparable to the estimated average avoided cost in the CEA region of $114/MWh while delivering that power with greater stability, security, and superior environmental impact (lower CO_2 and methane intensity). Considering future natural gas prices, the 300-MW remains more cost-effective than new high-efficiency gas generation ($143/MWh at $15/MMBtu natural gas and increasing with fuel price). The only case in which gas could be more cost-effective than biomass-coal with CCS is when: (a) 45Q credits are not renewed after 12 years, and (b) 30-year natural gas prices for a new high-efficiency gas plant are guaranteed at or below current prices.

Low carbon biomass-coal power with CCS is predicted to be lower cost than natural gas power at comparable 300-MW-net generation capacity, especially for higher future natural gas prices. Since existing CEA natural gas power plants do not require CCS to operate, considering the shortfall of natural gas supply and the expectation of higher future fuel prices, and since CCS increases electricity costs, CEA may not add CCS to its natural gas power plants. Considering the case of adding CCS to a new high-efficiency combined-cycle gas plant, CCS still increases power cost and is not competitive with a new biomass-coal fired plant employing CCS.

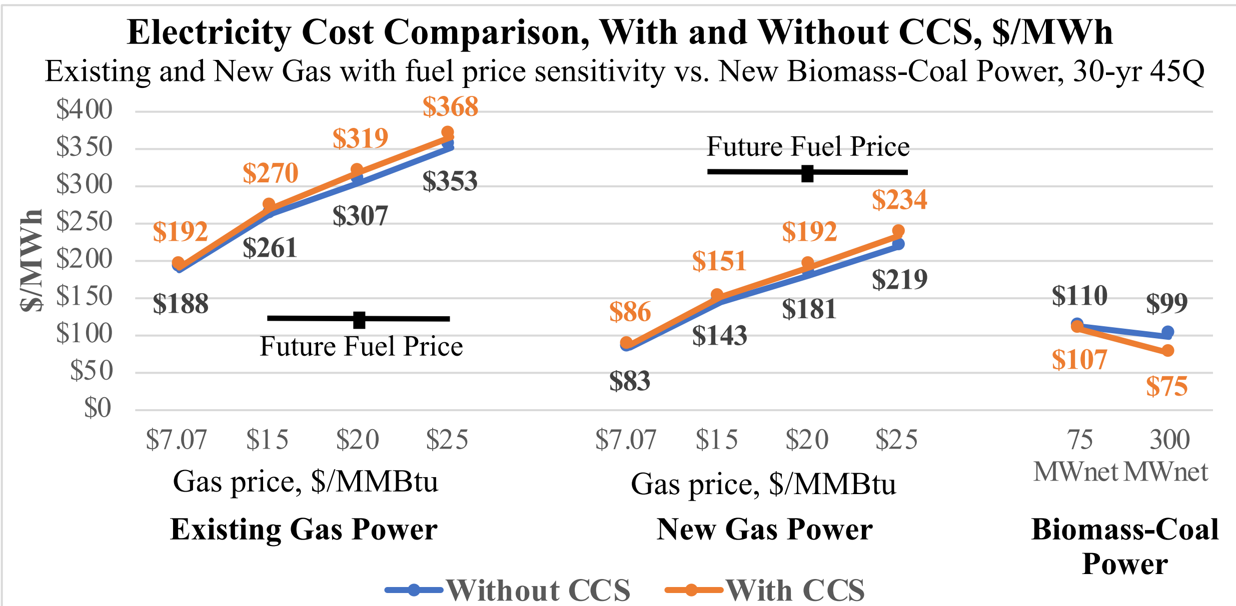

Figure 14. Electricity Cost Comparison, With and Without CCS, $/MWh
Existing CEA G&T Gas and New Gas Power with fuel price sensitivity
vs. New Biomass-Coal Power, 30-year tax credit scenario.

Biomass-Coal vs. Natural Gas: Generated Power Carbon Dioxide Intensity and Cost

As shown in Table 9, a low carbon biomass-coal power plant with CCS produces power at a much lower cost than the current CEA G&T rate for existing natural gas plants with or without CCS. Existing natural gas plants are unlikely to be retrofit with CCS, as CCS for natural gas is not required to operate and does not appear to be economically attractive. Table 9 shows power costs for natural gas at the gas price range low and high and for two biomass-coal sizes.

A biomass-coal power plant with CCS has less than half the carbon dioxide emissions of a natural gas generation station without CCS. Natural gas carbon dioxide emission intensity per unit of power generated for natural gas is 0.44 metric tons of CO_2 per MWh, more than double a low carbon biomass-coal power plant with CCS generating 0.20 metric tons CO_2/MWh or less. Note these carbon dioxide intensities are calculated for efficient gas power generation. For less efficient systems, natural gas can be as carbon dioxide intense as coal-fired-power without CCS.

Table 9. Carbon Dioxide Intensity and Power Cost: Natural Gas vs. Biomass-Coal Assuming 30-year Tax Credit Scenario

Source	**Units**	**Existing Natural Gas Power Plant Without and With CCS**				**Biomass-Coal Power Plant with CCS**	
Power Plant Size Before CCS	MW	400	400	400	400	100	400
Dispatched Power with CCS	MW	N/A[1]	300	N/A	300	75	300
Fuel Type	US$	\$7.07/MMBtu without CCS	\$7.07/MMBtu with CCS	\$25/MMBtu without CCS	\$25/MMBtu with CCS	\$3.5/MMBtu Coal	\$3.5/MMBtu Coal
EIA[2] CO_2 Intensity	lb/kWh	0.44		0.44			
Notes			90% capture		90% capture	95% capture	95% capture
Electricity Generated (85% capacity factor)	MWh/year		2,233,800		2,233,800	558,450	2,233,800
CO_2 Generated	MMt/year		653,000		653,000	765,000	3,060,000
CO_2 Captured	MMt/year		529,000		529,000	654,000	2,620,000
CO_2 Intensity	**metric tons/MWh**	**0.44**	**0.06**	**0.44**	**0.06**	**0.20**	**0.20**
Power Plant Electricity Cost	US\$/MWh					110.4	99.3
CO_2 Capture Plant Net Present Value with 30 years of 45Q Tax Credits[3]	US\$/MWh		−4.1		−15.0	3.6	24.5
Expected Electricity Cost	**US\$/MWh**	**188**	**192**	**353**	**368**	**107**	**75**

[1] Not applicable.
[2] U.S. Energy Information Administration (2022).
[3] Negative values add to electricity price, positive values lower electricity price.

A further environmental advantage is that the Flatlands Energy coal extraction is expected to produce little if any methane since the coal is all located near to the surface, and any associated methane has long since desorbed because of exposure to air over geologic timescales. Meanwhile a natural gas plant has associated methane (natural gas) extraction and thus possible fugitive methane emissions. Methane (CH_4) is a powerful GHG that in 2018 contributed 17% of global anthropogenic emissions on a CO_2 equivalent basis (PCOR Partnership Atlas, 2021). Methane is a significantly more damaging GHG than CO_2, with 84 times the global warming potential (GWP) of CO_2 over 20 years and 28 times more GWP over 100 years (Rosselot and others, 2021). According to the International Energy Agency (IEA), new research shows global methane emissions from the energy sector may be understated by as much as 70% (International Energy Agency, 2022a). Fugitive methane emissions can include sources such as venting and flaring.

COMPETITOR ANALYSIS: NATURAL GAS FUEL SUPPLY OPTIONS

Prior discussion in the section *Power Cost Comparison* concluded LNG import would result in higher natural gas prices to Southcentral Alaska. There are other, in-state options available to deliver gas to the region being evaluated in response to the imminent shortfall. The delivered cost of gas and avoided cost of electricity were developed for each gas option and compared to biomass-coal power total cost.

Berkeley Research Group (BRG) and Cornerstone Energy Services prepared the *Cook Inlet Gas Supply Project Phase I Assessment Report* for the Alaska Utilities Working Group to assess the cost and availability of natural gas supply options, dated June 28, 2023 (BRG 2023). Black & Veatch (BV) prepared the *Chugach Gas Supply Option and Market Assessment* for Chugach Electric Association, Inc., filed August 11, 2023 with the Regulatory Commission of Alaska (RCA). The CEO for Enstar Natural Gas, the largest natural gas utility in Southcentral Alaska, testified to the State Legislature that future gas supplies will cost at least $16/MMBtu. (Enstar, 2024)

Considered together, the BRG study, the BV study, and Enstar testimony are in-line with expectations for higher future natural gas prices, with a range approximately consistent with the $15 to $25/MMBtu discussed above.

Electricity from a biomass-coal fired plant remains the lowest cost option, $.10 per kWh average, and with CCS would have an even lower cost, $.075/kWh, and emit one-half to one-quarter the carbon dioxide emissions of the current CEA fleet. While a new large, high-efficiency, combined-cycle gas plant could potentially produce lower cost electricity, this is *only true* if (a) gas prices remain at or below current values for 30 years; (b) a single turbine configuration is built, which is unlikely given the need for the Railbelt grid to have multiple turbines in order to provide firm energy supply reliability; and (c) the cost of installing and operating CCS is not included. Under every other scenario examined, the cost of electricity from a new gas plant exceeds the cost of electricity from a new biomass-coal fired power plant. Further, a new gas plant without CCS would have higher CO_2 and methane emissions than a new biomass-coal fired plant equipped with CCS.

Biomass-coal fired power generation is the lowest cost to customer solution relative to all gas supply options considered.

If a natural gas line can be financed and constructed from the North Slope, AGDC projects the Alaska LNG project in-state natural gas price delivered to Southcentral would be $4 to $5/MMBtu, resulting in CEA electricity prices of $160 to $169/MWh using the CEA G&T rate methodology in Table 2 (Alaska Gasline Development Corporation, 2022). In-state gas sales would be small compared to the gas exported as LNG, which contemplates delivering 20 million tonnes per annum LNG, equivalent to ~3 Bcf/d gas. Unfortunately for Alaskan customers, North Slope LNG export depletes known gas reserves in ~25 years, potentially re-creating the present in-state natural gas supply crisis for the next generation. As Cook Inlet LNG exports left the region gas-poor, might the same occur with North Slope major gas sales? The Alaska LNG project appears to rely on yet-to-find gas during the latter years of a 30-year export project desired by potential customers. No substantial North Slope gas discoveries have been made in Alaska since the Pt. Thomson field discovery in 1977, so yet-to-find gas may prove difficult to discover or not be of sufficient volume for in-state demand plus export demand for future generations of Alaskans. The projected cost of approximately $40B for the AGDC pipeline is an additional major barrier.

A smaller, in-state Alaska "bullet line" could be built primarily for in-state use. In-state gas use could include restarting the existing, small-scale LNG export facility mothballed on the Kenai Peninsula, as it would reduce overall fuel costs. Smaller scale export would not rapidly deplete North Slope gas resources, which could be supplied from Pt. Thomson alone for decades. A 2011 bullet line project cost was estimated at $7.5 billion, down from a prior estimate of $11.8 billion. These estimates require inflation adjustment to today's dollars.

Yet-to-find gas from the Cook Inlet Region, which has not seen exhaustive exploration, would be expected to deliver gas at higher than recent natural gas prices. The Cook Inlet region is viewed as a high-cost, high-risk exploration area that is seeing limited exploration activity but active infill drilling and development (Thomas, 2004).

In comparison, a biomass-coal fired plant supplies electricity at a lower cost, $75/MWh with CCS, for the 30-year tax credit scenario. This rises to an average of $124/MWh in the 12-year tax credit scenario. A biomass-coal fired plant also has ~ 150 years of known reserves for a 400-MW plant from Flatlands Energy's currently explored lease areas alone.

GOVERNMENT ENGAGEMENT AND FUNDING OPPORTUNITIES

To accelerate CCUS deployment, the U.S. federal government is increasing CCUS project funding, mostly through DOE. Some of the potentially applicable funding opportunity announcements are listed in Appendix A: Government Funding Opportunities. The project should consider which, if any, FOAs, loans, or grants to apply for in future phases. While this information is dated, it is provided to illustrate the nature of potential FOAs.

PERMITTING, ENVIRONMENTAL, AND REGULATORY CONSIDERATIONS

Mine permitting is expected to follow all required regulatory processes including public comment periods, agency reviews, and mitigation of environmental impacts. From application to record of decision is expected to take approximately 2 years. The mine could then commence operation extracting coal in 1-2 years, i.e., prior to CO_2 storage facility permit approval.

Mine, road, power plant, carbon capture plant, CO_2 pipeline, and power transmission line permitting requirements are considered to be well understood and typical for this scale of project. The National Environmental Policy Act (NEPA) process, required to acquire federal permits, is likely to take 2 years, plus another 3 months to issue a record of decision (ROD). This project qualifies for the federal FAST-41 permitting process (described below), which can compress the permitting timeline.

The EPA aspires for the CO_2 storage permitting duration to take 2 years, but has taken 3 to 5+ years for other projects. The Alaska Legislature authorized the AOGCC in 2023 to seek Class VI CO_2 injection permitting primacy from the EPA, which if approved devolves permitting authority to the State, with continued EPA oversight, to regulate Class VI CO_2 injection well permits. Other states with primacy have approved carbon storage projects in as little as 8 months. Primacy transfer from the EPA would likely take ~ 2 years. The Legislature is considering new CCS omnibus carbon storage legislation for State lands, HB50 and SB49, with at least 14 committee hearings to date. This report considers two CO_2 storage permitting timelines, EPA and State, in the Timeline section of this report.

The EPA was consulted regarding approval expectations for a new coal fired plant. In summary, under the current 2015 EPA point source/generator emitter rule, as long as CO_2 emissions are kept below a certain carbon intensity, detailed below, a new coal plant of any size can be permitted, and permitted without CCS or hydrogen fuel switching being required. To achieve permittable carbon intensity, abatement may be necessary, e.g. biomass, CCS, or both. The 2023 EPA proposed rule does not change this nor does it require CCS to be added. Large existing coal plants that undertake major modifications have to implement CCS or switch to hydrogen as a condition of modifications. New coal plants that meet the 2015 rule do not have to add CCS or hydrogen. For gas-fired plants, the 2023 proposed rule requires all large gas plants, existing and future builds, to move to CCS or hydrogen fuel switching by 2040 or be shut down.

U.S. climate envoy John Kerry stated, "Now is the time for all of us to join together and take a more critical step - there should be no more permitting of any new unabated coal-fired power anywhere in the world. Period," according to a transcript of his speech at an event in Edinburgh. (Reuters 2023) Regarding abatement, the International Energy Agency stated, “Bringing down emissions from the existing global coal fleet requires a broad-based and dedicated policy effort. In our scenarios, coal plants are either retrofitted with CCUS, reconfigured to be co-fired with low emissions fuels such as biomass … repurposed … or retired.” (IEA 2023)

Current and proposed U.S. Federal policy regarding coal fired power, the Center for Climate and Energy Solutions states the following (*italicized*). Note per Table 1, the proposed power plant is estimated to emit 2,229 lbs *CO_2*/MWh without biomass or CCS.

"In December 2018, EPA proposed GHG emission regulations for new, modified, and reconstructed power plants. [Federal Register 2018] The proposed rule would replace EPA's 2015 "Carbon Pollution Standard for New Power Plants" which established New Performance Source Performance Standards (NSPS) to limit carbon dioxide emissions from fossil fuel-fueled power plants. The 2015 rule determined new coal power plants can emit no more than 1,400 pounds CO_2/MWh, which almost certainly requires the use of carbon capture and storage (CCS) technology.

The proposed 2018 rule would:

- *Set the best system of emissions reduction for newly constructed large units equivalent to a super-critical coal plant, which has an emissions rate of 1,900 lbs CO_2/MWh and would set the best system of emission reductions for small units to 2,000 lbs CO_2/MWh.*
- *Set separate performance standards for newly constructed and reconstructed coal refuse-fired units at an emissions rate at 2,200 lbs CO_2/MWh.*
- *Revise the standards of performance for reconstructed power plants to be consistent with the emission rates of newly constructed units.*

This standard was adopted under Section 111(b) of the Clean Air Act, which applies to new, modified, and reconstructed power plants, and requires EPA to set a numerical performance standard based on the best available technology that has been adequately demonstrated. States have little flexibility in applying the standard." (C2ES)

Three permitting matrices were developed, located in Appendix B. Table B-1 is a NEPA and federal permit matrix. Table B-2 is a State permit matrix. Table B-3 is a lands, right of way, and pore space leasing obligations and permit matrix. These tables address many of the major requirements but are not exhaustive.

Lands and Right of Way

Placement of CO_2 transport and storage infrastructure will require a right of way from affected landowners. Landowners on approach to the depleting Beluga River gas field include the State of Alaska, CIRI, and Chugach Electric Association. A CO_2 pipeline and power transmission line from the plant site to the Beluga River site could be co-located within the Donlin pipeline right of way (ROW) through approval from ADNR with a letter of nonobjection from Donlin. If Donlin objected to this infrastructure being placed within its ROW, then the CO_2 pipeline and power transmission line could be placed outside of the Donlin ROW in an abutting ROW paralleling Donlin's ROW.

Geologic Pore Space Leasing – Landownership and Availability

Acquiring the legal right to access and use the pore space of a geologic formation for permanent CO_2 storage is required for commercial CCS projects (Peck and others, 2022). The owner(s) of the overlying surface estate and the mineral estate are each important considerations for CO_2 injection and storage. In Alaska, a hydrocarbon lease does not convey pore space ownership. The State's proposed legislation provides ownership certainty for pore space leasing and a carbon storage regulatory framework in Senate Bill 49 and House Bill 50. These bills define certain rights for existing oil and gas operators for pore space leasing within an existing hydrocarbon lease, akin to a first right of refusal. Conflicts or shared interests between an oil and gas leaseholder and the carbon storage pore space leaseholder may arise, including project upsides for working with the producing field owner, e.g., rather than abandoning certain equipment upon cessation of production, some may be repurposed for the storage project.

The State, Federal government, and CIRI hold hydrocarbon leases in the Beluga River Unit, as shown in Figure 15.

Geologic Storage, Enhanced Oil Recovery, and 45Q Tax Credits

This project assumed the Beluga River gas field for storage. Evaluation of other storage options in the area is recommended, including other depleted fields and local and regional saline aquifers which may provide economic storage alternatives. The ARCCS project will determine carbon storage volume available in the area.

CO_2 storage can be dedicated storage in deep saline formations or storage through EOR. Two different tax credit values are available. The EOR-related 45Q tax credit is \$60/metric ton of CO_2 stored; while in saline formations, the 45Q tax credit is \$85/metric ton of CO_2 stored. Current legislation provides 12 years of 45Q tax credits, but, as discussed in section *45Q Federal Tax Credits – History and Long-Term Expectations,* these may be extended and/or increased in value to incentivize additional, large industrial CCS/CCUS project operations.

Geologic data are needed to characterize potential storage sites, develop storage permit applications, and prove to the regulating authority the storage reservoir is suitable for permanent storage and CO_2 will not escape the intended formation. It can be challenging to prove complete geologic containment of CO_2, especially in a seismically active region away from well-characterized oil and gas reservoirs, including the likely vast, but less well characterized, saline aquifer storage resources of the Cook Inlet region. The primary target of CO_2 storage in a depleted Cook Inlet gas field has the advantage of considerable geologic data and certainty of a secure storage resource once well integrity of existing well penetrations into the storage formation are ensured.

Permitting geologic storage at the Beluga River gas field, nearly depleted by production, has the advantage of a historic data set and understanding of the reservoir. Estimates have placed its remaining productive life at less than 10 years, i.e. by 2033. The presence of natural gas confirms the presence of a secure seal, and the field has proven, enduring storage capacity.

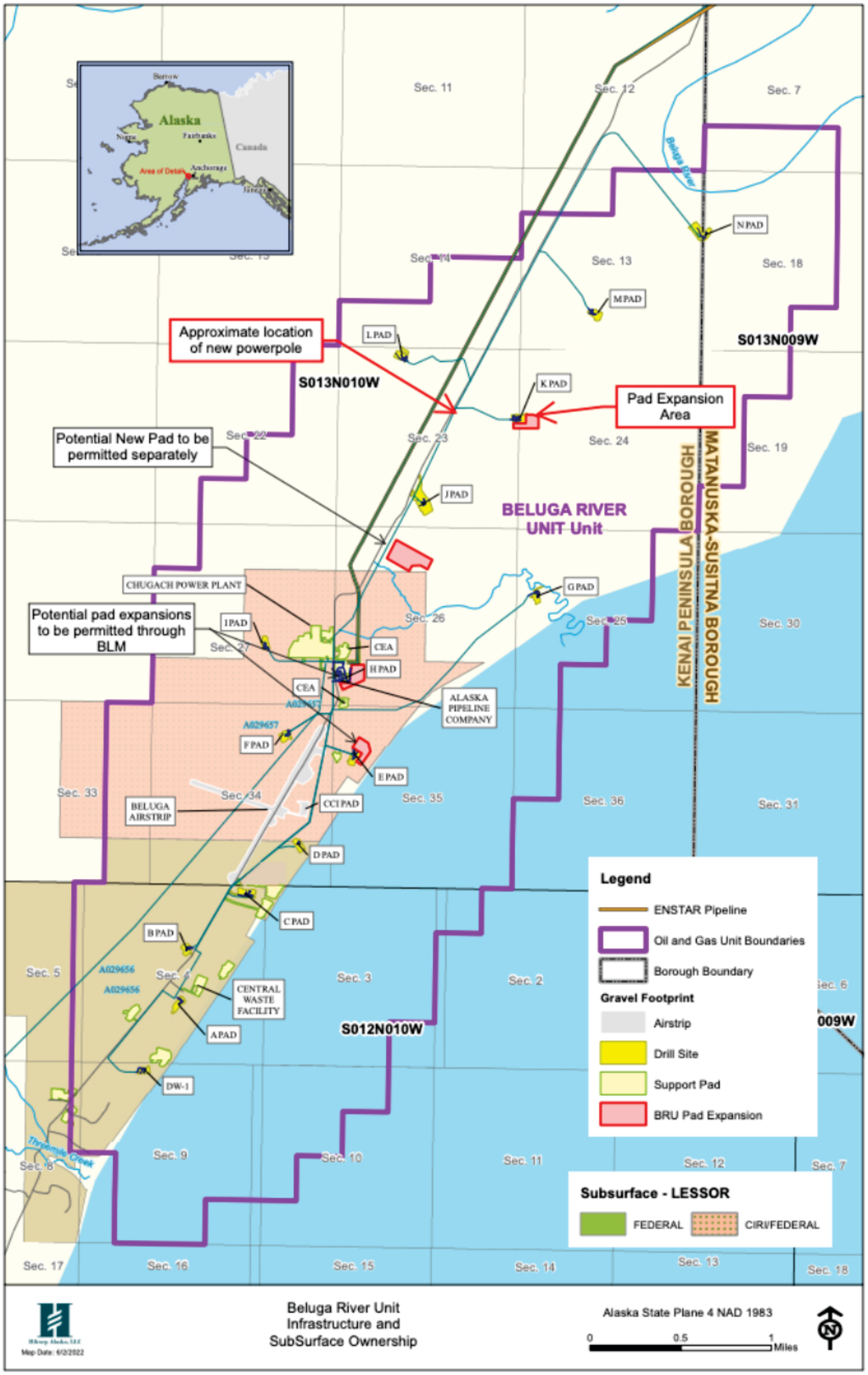

Figure 15. Beluga River Unit Infrastructure and Subsurface Lease Ownership (Alaska Department of Natural Resources, 2022b).

Class VI CO_2 Injection Well Permitting, EPA, and the State

Jurisdiction for Class VI CO_2 injection wells in Alaska is with the EPA. The EPA is processing 64 carbon storage applications, but has permitted a handful of CO_2 storage wells to date; one took 3 years and the other 5 years. (EPA Permit Tracker) To date, no applications have been made in EPA Region 10, which includes Alaska, for a carbon storage project.

The Alaska State Legislature approved in 2023 the Alaska Oil and Gas Conservation Commission (AOGCC) to seek Class VI primacy from EPA. The Governor proposed in 2023 Senate Bill 49 and House Bill 50 that would, with Legislative approval perhaps in 2024, establish Alaska's regulatory and legal carbon storage framework.

The AOGCC has begun preparing application for primacy. Once submitted, EPA review is expected to take at least 2 years, so the State may gain primacy by ~ 2026. Projects can apply simultaneously to EPA and the State, as projects have in Louisiana, which may enable Class VI permitting for applications filed in 2024 (if any) to be approved as early as 2026. In addition, Class VI permits can transfer from EPA to the State if primacy is achieved.

Class VI Injection Well Permit Criteria

If the State gains primacy, its regulations can be no less stringent than those of EPA in the protection of underground sources of drinking water. Class VI permit criteria include:

- Permitting
- Geologic site characterization
- Area of review (AOR) and corrective action
- Financial responsibility
- Well construction
- Operation
- Mechanical integrity testing (MIT)
- Monitoring
- Well plugging
- Postinjection site care (PISC)
- Site closure

Regulations address the unique nature of CO_2 injection, including:

- Relative buoyancy of CO_2
- Subsurface mobility
- Corrosivity in the presence of water
- Large injection volumes anticipated at geologic storage projects

Expedited Federal Review under FAST-41

The Fixing America's Surface Transportation (FAST) Act establishes coordinated oversight procedures for infrastructure projects being reviewed by federal agencies. It is intended to facilitate early consultation and coordination among government agencies, increase transparency through public timetables, and increase accountability through consultation and reporting on projects (Energy.gov, 2022). To be eligible, a proposal must be subject to NEPA; likely to require a total investment of more than $200,000,000; and not qualify for abbreviated authorization or environmental review processes under any applicable law.

Projects establishing CCS infrastructure may qualify for FAST-41 status and expedited federal review. A CCS project seeking to establish a CO_2 transport pipeline (or regional gathering line) for storage in Cook Inlet may be deemed critical transportation infrastructure, similar to other FAST-41 pipeline projects. Applying for FAST-41 status may help to expedite permitting for this project.

Monitoring, Reporting, and Verification Plan (MRV) for Sequestered CO_2

An EPA greenhouse gas reporting program (GHGRP) (40 CFR Part 98) approved MRV Plan is required by the IRS in order for CCS projects to receive the 45Q tax credit. Regardless of whether the State gains primacy for Class VI well permitting, the EPA maintains oversight for the monitoring, verification and accounting of the stored CO_2. The CCS techno-economic cost model (see CCS cost model discussion and Table 6) includes MRV costs for the life of the project, including seismic acquisition, monitoring well, State monitoring storage fees, inspection, and testing costs.

Area Injection Order and Plan of Development

If the project progresses under EPA jurisdiction, then a plan of development is expected to be required for approval by the State Division of Oil and Gas (DOG), but no area permit by the Alaska Oil and Gas Conservation Commission (AOGCC) is required. If the State gains Class VI primacy from the EPA, then the project must seek an AOGCC area injection order approval for underground injection of fluids (CO_2 in a nongaseous state) for an area basis rather than for each well individually, in accordance with Alaska Administrative Code (AAC) Title 20, § 25.460. Injection of CO_2 into a depleted gas field is also likely to require a plan of development (POD) submitted to the DOG and AOGCC to ensure compliance with State laws.

PROJECT TIMELINE

Power generation and CCS is expected to commence 6 to 7 years from the start of a FEED study, which is year 00 in Figure 16. The schedule reflects 30 months for project engineering. Timelines are aligned so completion of all construction occurs simultaneously.

Permitting the power and capture plants and CO_2 transport can begin 6 months after engineering starts. Permitting for the mine and power plant takes 2 years plus 3 months to issue the record of decision. Coal mine and road construction take 36 months. Flatlands Energy has most environmental baseline data gathering underway or completed and can move into the permitting process as soon as project development plans are finalized.

Carbon storage permitting is estimated to take 4 years with EPA, which has jurisdiction, completed by year 6. If the State achieves Class VI primacy or the EPA approves rapidly, it reduces CO_2 storage permitting from 4 to 2 years, i.e., end of year 4 as shown.

Pipeline and electric power transmission line construction take 12 to 18 months, as do injection well drilling, completion, and tie-in, including site preparations and production well abandonment. These activities can begin earlier if needed. Winter access roads have been built annually in recent years and would be available to support the project during construction. The regional access road WSAR is already in the pre-permitting process with the Alaska Department of Transportation and is expected to be available to support operations.

The schedule reflects 3 years for power plant and CCS plant construction.

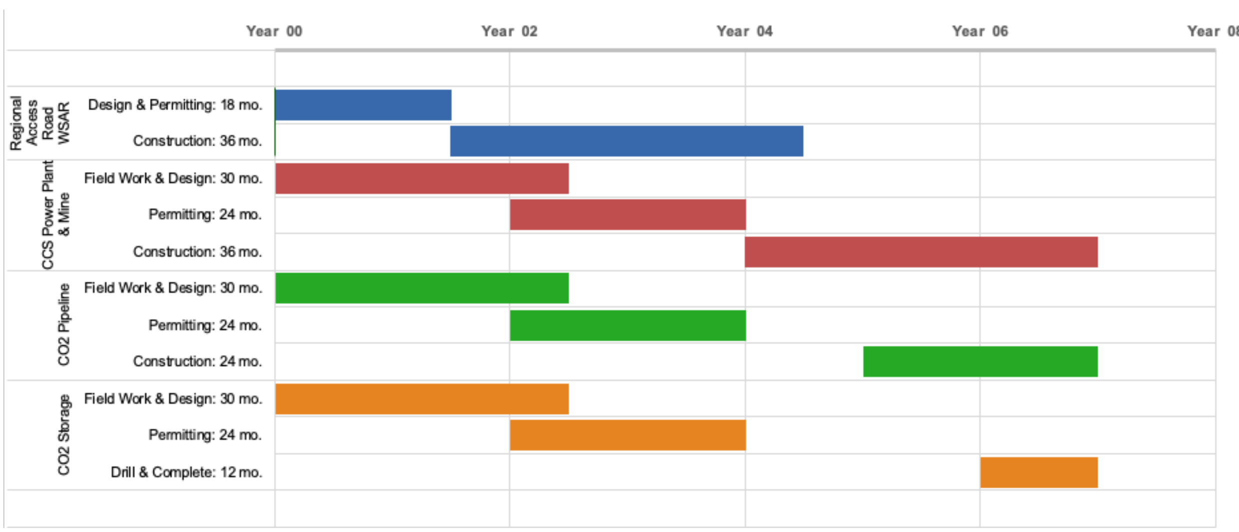

Figure 16. Project Timeline (created with Vertex42©).

KEY STUDY ASSUMPTIONS

Key assumptions include the following:

- 85% power plant capacity factor – represents how much capacity is used by customers on an average basis and includes all downtime, scheduled and unscheduled.
- 90% CCS plant uptime.
- 95% carbon capture rate for biomass-coal plant and 90% for natural gas plant.
- All economics assume 30 years of CO_2 capture, transport, and storage operations expenses during the expected life of the electricity generation facility.
- Power and carbon capture plants are located at the mine, with transmission of CO_2 and electricity along the permitted Donlin pipeline and Beluga River pipeline corridors to the nearly depleted Beluga River gas field and grid intertie.
- CCS capital and operating expenditure costs were uplifted 25% above the CCS model cost (which is based on the contiguous U.S. states) to reflect possible Alaska construction cost differentials.
- The capital cost estimate uncertainty range for this study is -30% on the low side to +50% on the high side, consistent with a Class 5 Conceptual Engineering estimate.
- To account for reduced economies of scale, carbon capture plant initial capital costs were increased by an additional 25% for 75-MW-net generation with CCS and smaller plants.
- Number of wells and CO_2 capture and pipeline facilities sized to handle maximum 95% CO_2 capture rate with 100% power plant capacity and 100% CO_2 capture plant on-time.
- Power transmission line cost was excluded for both a new power generation station and for utility cost comparisons; new customers are customarily required to pay for these costs, e.g., for industrial uses or the regional power grid. Also, the customer location(s) is currently uncertain.
- Power plant would commence operations ~ 7 years from beginning of engineering.
- Use of well-understood CFB plant technology and MHI or similar technology for the carbon capture plant.
- Carbon storage projects beginning construction before 1/1/2033 can earn 45Q tax credits.
- $85/metric ton 45Q tax credit applies for dedicated CO_2 storage in a depleted gas field.
- Economics in tables and figures assume the most likely 30-year tax credit scenario because of expectations of growing carbon (CO_2) markets, extended or enhanced 45Q tax credits, or creation of new incentives to ensure continued CCS operation beyond current 12-year 45Q eligibility.
- Sensitivity economics are calculated for the 12-year tax credit scenario, as per current legislation, with 30 years of continued CCS operations.
- 3% discount rate, consistent with NIST guidance.

CONCLUSIONS

This study concludes a new biomass-coal power plant with CCS in Southcentral is attractive and can deliver affordable, reliable, clean, long-term energy security.

For affordable energy, the biomass-coal generation project would:

1) Be competitive economically with existing utility electricity rates and materially lower than future higher-priced gas provided locally, from imported LNG, or the North Slope.
2) Decrease the cost of electricity to the Railbelt, and through Power Cost Equalization, decrease the cost of Rural electricity across the State, while adding power capacity and providing in-state sourced fuel security.
3) Outperform alternative new firm power projects that appear more costly and challenging timewise, per the recent UAF report, *Alaska's Railbelt Electric System: Decarbonization Scenarios for 2050* for micro-nuclear and the Susitna Watana Dam. (Cicilio 2024).
4) Be competitive with theoretical new natural-gas fired baseload generation and materially lower cost than theoretical new gas generation with future higher-priced gas.
5) For larger biomass-coal plants, realize substantial economic gain from economies of scale, especially for CO_2 transportation costs.

For reliable energy, the biomass-coal generation project would:

1) Diversify the regional fuel supply with respect to power generation.
2) Provide new, firm baseload power for new industry consumers, the Railbelt grid, or both.
3) Enable replacement of aging regional power equipment, and result in lower cost, lower emissions power generation.
4) Outperform new gas supply options available to Southcentral, which have risks of supply shortfalls, supply chain uncertainties, and material cost uncertainties.
5) Outperform wind and solar power, which may to have a valuable but limited role to play given the need for dispatchable base load power when the weather is not amenable for wind or solar power generation. This is shown by the NREL analysis that concluded significant fossil-energy power generation would be retained to provide energy security.

For clean energy, the biomass-coal generation project would:

1) Be environmentally superior to current natural gas power-generating stations by inclusion of CCS. Biomass-coal power with CCS generates one-half to one-quarter the CO_2 emissions and has lower fugitive emissions of methane, a powerful greenhouse gas.
2) Through biomass co-firing, reduce or realize net-zero or better carbon emissions with thoughtful biomass supply chain management.
3) Achieve net-zero or better carbon emissions while increasing regional food security through beneficial use of CO_2 and heat for greenhouse.

For long-term energy security, the biomass-coal generation project in Southcentral would have:

1) The Flatlands Energy site with sufficient proven coal reserves to supply electricity for generations, sufficient to enable low to reasonable extraction ratios for 150 years or more.

2) Substantial biomass resources regionally, including spruce bark beetle kill.
3) The storage site selected in this study, Beluga River Unit gas field, has estimated capacity for 60+ years for a 300-MW-net biomass-coal fired power plant with CCS.
4) Other possible carbon storage formations are available regionally that the ARCCS Project will evaluate, but these may require additional geologic data gathering.

Other cost-related conclusions include:

1) Adding CCS to biomass-coal generation lowers electricity cost, due to positive 45Q tax credit revenue.
2) Adding CCS to natural gas power generation increases electricity cost, due to 45Q tax credit revenue insufficient to cover costs of CO_2 capture and sequestration.
3) Biomass-coal power cost without CCS is lower cost than natural gas without CCS.
4) Biomass-coal power cost with CCS is lower cost than natural gas power with or without CCS.

RECOMMENDATIONS

Considering the imminent regional natural gas shortfall and high cost for new gas, diverse energy sources should be sought for the Railbelt and Southcentral.

Moving a low carbon biomass-coal with CCS power generation Project forward to its next step is warranted based on the favorable findings in this Feasibility Study, using technologies ready for commercial industrial deployment.

An expeditious decision to proceed is recommended, as the energy supply crisis becomes more challenging each passing month, seasonal fieldwork for permitting-related data collection is short, service providers are busy, and the 45Q tax incentives for carbon storage, worth an estimated $2.7B for a 400MW plant, are conditional upon CCS facilities construction commencing by December 31, 2032.

Specific recommendations include:

- The State should establish the legal and regulatory framework to enable carbon storage, i.e., progress bills currently with the Legislature into law.
- The AOGCC should seek and gain Class VI permitting primacy from the EPA.
- UAF should perform the Alaska Railbelt Carbon Capture and Storage (ARCCS) Project, which is contingent on State Legislative approval of matching funds that are included in the associated UA budget submission.
- The State and the Regional utilities should form a power purchasing buyers group and confirm the amount of firm power to be purchased which is required to meet both Railbelt and prospective mining development needs such as the Donlin Gold

project. The Utilities working with the State should enter into Power Purchase Agreements ideally through the Alaska Energy Authority which will enable Project funding of the appropriately sized power plant, perhaps along the lines of the successful Bradley Lakes Power project previously negotiated through the AEA.

- Enabling legislation for the Alaska Energy Authority should be amended to enable the Authority to enter into firm power purchase agreements with independent power producers and to enter into power sale agreements with electric utilities and industry as well as to enable the Authority to finance or support the financing of firm power purchase agreements.

- The Project owners, the State, and Utilities should jointly seek funding, including U.S. DOE loans and grants for FEED and/or CCS demonstration funding, which may be available in amounts as high as $500M.

Public investment in the Project will foster transparency, build trust, and promote alignment among stakeholders, which is crucial for project acceptance and long-term success. Public investment also ensures a platform for meaningful stakeholder engagement, allowing for the incorporation of feedback from regulators, local communities, and other relevant parties. Detailed engineering and cost estimation will provide accurate project cost projections, enabling stakeholders to make informed financial decisions. Additionally, risk assessments will identify potential challenges and uncertainties, allowing for proactive risk mitigation strategies to be implemented.

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APPENDIX A

GOVERNMENT FUNDING OPPORTUNITIES AS OF OCTOBER 1, 2022

Reference No.	Description	Due Date	Notes
DE-FOA-0002804 (Released 9/8/2022) EERE Advanced Manufacturing Office BIL NOI 2803 (Issued 6/29/2022)	**Industrial Efficiency and Decarbonization FOA** Awards will be made at one of two funding levels with max award amount by tier and topic: 1 - Decarbonizing Chemicals 2 - Decarbonizing Iron and Steel 3 - Decarbonizing Food and Beverage Products 4 - Decarbonizing Cement and Concrete 5 - Decarbonizing Paper and Forest Products 6 - Cross-sector Decarbonization Technologies	10/12/2022 Concept paper 12/20/2022 Full application	Up to $104M total Tier 1 up to $3M-$4M per award; 20% cost share Tier 2 up to $5M-$10M per award; Phase 1 or 2 20% cost share, Phase 3 50% cost share 20-38 awards anticipated 1 entity concept paper & application per topic area https://eere-exchange.energy.gov/Default.aspx#FoaId9809abda-a152-49e7-8ca3-4cc34d57ea18
DE-FOA-0002738 (Released 9/2/2022) DOE OCED BIL From NOI - 2806 (Issued 7/13/2022) FOA was anticipated Aug/Sept 2022	**BIL: Carbon Capture Demonstration Projects Program** The goal of the BIL Carbon Capture Demonstration Projects Program is to de-risk integrated CCS demonstrations and catalyze significant follow-on investments from the private sector for commercial-scale, integrated CCS demonstrations on carbon emissions sources across industries in the U.S. DOE intends to issue two FOAs to fulfill the requirements of the Program. This first FOA (DE-FOA-0002738) will provide funding for up to 20 FEED studies for integrated CCS, submission of permit applications (i.e., Underground Injection Control (UIC) Class VI permit to construct, if necessary), preparation of an Environmental Information Volume (EIV), and the initial CBP work and analysis, which will address the first Phase of an integrated CCS demonstration project. FOA 2 is expected to be initially released in late 2022. TA-1.1 FEEDs for Integrated CCS Systems at Coal Electric Generation-Only Facilities TA-1.2 FEEDs for Integrated CCS Systems at Coal CHP Facilities TA-2.1 FEEDs for Integrated CCS Systems at NGCC Electric Generation Facilities or NG SMR Facilities Producing H2 for Electricity Generation TA-2.2 FEEDs for Integrated CCS Systems at NG Simple Cycle Electricity Generation Facilities or NG CHP Facilities TA-3.1 FEEDs for Integrated CCS Systems at Ammonia Facilities Not Purposed for Electric Generation TA-3.2 FEEDs for Integrated CCS Systems at Industrial Facilities Not Purposed for Electric Generation	10/21/2022 Mandatory LOI 12/5/2022 Full application Anticipated selection date ~3/31/2023	~$189M total available $5.5M–12.5M per award up to 20 awards 50% cost share required up to 24 months period of performance https://oced-exchange.energy.gov/Default.aspx#FoaId82c73432-65b4-4d82-b03c-d61a6fcfe2a0
DE-FOA-0002400 Amendment 8 (Released 8/26/2022) DOE FECM NOI - 2822	**Clean Hydrogen Production, Storage, Transport and Utilization to Enable a Net-Zero Carbon Economy** Amendment to previously released FOA 2400. Advances in hydrogen technologies capable of improving performance, reliability, and flexibility of existing and novel methods to produce, transport, store, and/or use hydrogen will enable the United States to greatly reduce its carbon footprint associated with energy use. The amended FOA is make funding available for these areas of interest: AOI-4: Advanced Air Separation for Low-Cost H2 Production via Modular Gasification AOI-14: Clean Hydrogen Production and Infrastructure for Natural Gas Decarbonization 14a: Methane pyrolysis/decomposition, in situ conversion, or cyclical chemical looping reforming 14b: Hydrogen Production from Produced Water AOI-15: Technologies for Enabling the Safe and Efficient Transportation of Hydrogen Within the U.S. Natural Gas Pipeline System AOI-16: Fundamental Research to Enable High Volume, Long-term Subsurface Hydrogen Storage	10/25/2022	Up to $32M available $1.25-$5M per award 20% or 50% cost share required https://www.grants.gov/web/grants/view-opportunity.html?oppId=330950

DE-FOA-0002779 (Released 9/22/2022) DOE OCED BIL From NOI - 2768 (Issued 6/6/2022) FOA was anticipated Sept/Oct 2022	**Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs** This $8 billion effort will catalyze investment in the development of H2Hubs that demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen. Each H2Hub will include multiple partners that will bring together diverse hydrogen technologies to produce and utilize large amounts of hydrogen in different ways. These clean hydrogen demonstrations will balance hydrogen supply and demand, connective infrastructure, and a plan for long-term financial viability. The H2Hubs will also include substantial engagement of local and regional stakeholders, as well as Tribes, to ensure that they generate local, regional, and national benefits. DOE has defined a four-phase structure for the H2Hubs. Phase 1 will encompass initial planning and analysis activities to ensure that the overall H2Hub concept is technologically and financially viable, with input from relevant local stakeholders. Phase 2 will finalize engineering designs and business development, site access, labor agreements, permitting, offtake agreements, and community engagement activities necessary to begin installation, integration, and construction activities in Phase 3. Phase 4 will ramp-up the H2Hub to full operations including data collection to analyze the H2Hub's operations, performance, and financial viability. This FOA will solicit plans for all four phases of proposed H2Hub activities; however, DOE will only initially authorize funding for Phase 1.	11/7/2022 Concept paper 4/7/2023 Full application	$8.0B available over 5 years ($6–$7B in first FOA launch for 6–10 H2Hubs) $400M–$1.25B per award 8–12 year period of performance 50% cost share https://oced-exchange.energy.gov/Default.aspx#FoaId4dbbd966-7524-4830-b883-450933661811
DE-FOA-0002711 (Released 9/21/2022) DOE FECM BIL From NOI - 2729 (Issued 4/29/2022) FOA was anticipated FY22 Q3 (Apr–Jun)	**Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative: Phases III, III.5, and IV** The overall objective of this FOA is to accelerate the development of new or expanded commercial-scale geologic carbon storage projects and associated carbon dioxide transport infrastructure, through a focus on detailed site characterization, permitting, and construction stages of project development. This FOA is expected to remain open for five years to facilitate expeditious development of secure geologic carbon storage facilities. As required by the BIL, the selection process will give priority to projects with substantial carbon dioxide storage capacity and projects that will store carbon dioxide from multiple carbon capture facilities. It is anticipated that multiple closings will follow through quarter 4 of fiscal year 2026 with the frequency based upon the number of applications received and the availability of funding. This FOA will be amended a minimum of 4 weeks in advance of subsequent closings to provide applicants notice of the next closing date. Phase III – Site Characterization and Permitting (15–40 awards) ($15M–$110.5M/award) (no more than 36 months) Phase III.5 – NEPA, FEED Studies, and Field Development Plan Only (0–10 awards) ($100k–$4.55M/award) (no more than 24 months) Phase IV – Construction (5–20 awards) ($30M–$195M/award) (no more than 30 months)	11/28/2022 Selection notifications ~3/13/2023	$2.25 billion available across all closings through FY26 Q4 20% cost share for Phases III and III.5. 50% cost share for Phase IV.
DE-FOA-0002730 (Released 9/22/2022) DOE FECM BIL From NOI - 2780 (Issued 7/13/2022) FOA was anticipated FY23 Q1 (Oct–Dec)	**BIL: Carbon Capture Technology Program, Front-End Engineering Design for Carbon Dioxide (CO_2) Transport** This FOA is focused on FEED studies of commercial-scale CO2 pipeline projects that transport CO2 from anthropogenic sources to CO2 conversion plants and/or to secure geologic storage facilities, with an emphasis on FEED studies in different geographic regions that will provide DOE with increased understanding of CO2 transport costs; transport network configurations; and technical, regulatory, and commercial considerations to inform DOE's research, development, and demonstration (RD&D) strategy and to encourage fully commercial-scale deployment of CCUS and CDR. The intent of this FOA is to award projects with consideration for the creation and integration of a hub and cluster configuration, rather than a standalone CCUS/CDR pipeline(s). Applicants are also encouraged to propose projects that will repurpose existing pipeline(s) into CO2 service. Area of Interest: Front-End Engineering and Design Studies for CO2 Pipeline Infrastructure (Onshore and Offshore)	11/28/2022 Selection notifications March 2023	$92M to be available for a 5-yr period with 6 or more awards per year $750k–$3M per award 20% cost share required 1–2 year period of performance https://www.grants.gov/web/grants/view-opportunity.html?oppId=342284

NOI - 2746 for DE-FOA-0002735 (Issued 5/13/2022) DOE FECM NETL BIL	**Bipartisan Infrastructure Law (BIL): Regional Direct Air Capture (DAC) Hubs** Section 40308 of the BIL requires DOE to provide funding for eligible projects that contribute to the development of four (4) regional DAC Hubs. Each of the DAC Hubs: (i) facilitates the deployment of direct air capture projects; (ii) has the capacity to capture and sequester, utilize, or sequester and utilize at least 1,000,000 metric tons of carbon dioxide from the atmosphere annually from a single unit or multiple interconnected units; (iii) demonstrates the capture, processing, delivery, and sequestration or end use of captured carbon; and (iv) could be developed into a regional or interregional carbon network to facilitate sequestration or carbon utilization. 2 project timelines: AOI-1: Standard timeline - Phase 1 funding with this FOA. AOI-2: Accelerated timeline - Phase 1 (equal to AOI-1 Phase 1) funding with this FOA.		FOA anticipated FY22 Q4 (July–Sep) $3.5B available Likely 20% cost share for AOI-1 Phase 1. Likely 50% cost share for AOI-2 Phase 2. All subsequent phases 50%. https://www.grants.gov/web/grants/view-opportunity.html?oppId=340319
NOI - 2798 for DE-FOA-0002799 (Issued 7/21/2022) DOE FECM	**Regional Initiative to Accelerate Carbon Management Deployment: Technical Assistance for Large Scale Storage Facilities and Regional Carbon Management Hubs** If released, the overall objective of this FOA will be to accelerate the deployment of carbon management by establishing a consistent, effective mechanism for providing technical assistance to develop multiple large scale storage facilities and regional carbon management (CM) hubs that could store hundreds of millions of tons and inject over 5 million metric tons per year. DOE views this FOA as an opportunity to (a) expand, refine, and enhance the 'technical assistance' aspects of the RI effort to directly support development of large scale storage facilities (5MMT+/year) and regional carbon management hubs; and (b) attract applications from other organizations that may be equally capable of providing the same type of technical assistance to large-scale storage facilities and regional carbon management hubs under development as the existing RI projects. The two intended Areas of Interest in this FOA will result in awards that can work separately or in tandem to provide the desired technical support. • Area of Interest 1 - Technical Assistance for Geologic CO_2 Storage and Transport for Large Scale Storage Facilities and within Prospective Regional CM Hubs • Area of Interest 2 - State Geological Data Gathering and Analysis to Support Large Scale Storage Facilities and Regional CM Hub Development		FOA anticipated FY23 Q1 (Oct–Dec) If released, not <$20M to be available for a 5-yr period 20% cost share required Max 2 years https://www.grants.gov/web/grants/view-opportunity.html?oppId=342628

Reference No.	Description	Due Date	Notes
DE-FOA-0002804 (Released 9/8/2022) EERE Advanced Manufacturing Office BIL NOI 2803 (Issued 6/29/2022)	**Industrial Efficiency and Decarbonization FOA** Awards will be made at one of two funding levels with max award amount by tier and topic: 1 - Decarbonizing Chemicals 2 - Decarbonizing Iron and Steel 3 - Decarbonizing Food and Beverage Products 4 - Decarbonizing Cement and Concrete 5 - Decarbonizing Paper and Forest Products 6 - Cross-sector Decarbonization Technologies	10/12/2022 Concept paper 12/20/2022 Full application	Up to $104M total Tier 1 up to $3M-$4M per award; 20% cost share Tier 2 up to $5M-$10M per award; Phase 1 or 2 20% cost share, Phase 3 50% cost share 20-38 awards anticipated 1 entity concept paper & application per topic area https://eere-exchange.energy.gov/Default.aspx#FoaId9809abda-a152-49e7-8ca3-4cc34d57ea18
DE-FOA-0002738 (Released 9/2/2022) DOE OCED BIL From NOI - 2806 (Issued 7/13/2022) FOA was anticipated Aug/Sept 2022	**BIL: Carbon Capture Demonstration Projects Program** The goal of the BIL Carbon Capture Demonstration Projects Program is to de-risk integrated CCS demonstrations and catalyze significant follow-on investments from the private sector for commercial-scale, integrated CCS demonstrations on carbon emissions sources across industries in the U.S. DOE intends to issue two FOAs to fulfill the requirements of the Program. This first FOA (DE-FOA-0002738) will provide funding for up to 20 FEED studies for integrated CCS, submission of permit applications (i.e., Underground Injection Control (UIC) Class VI permit to construct, if necessary), preparation of an Environmental Information Volume (EIV), and the initial CBP work and analysis, which will address the first Phase of an integrated CCS demonstration project. FOA 2 is expected to be initially released in late 2022. TA-1.1 FEEDs for Integrated CCS Systems at Coal Electric Generation-Only Facilities TA-1.2 FEEDs for Integrated CCS Systems at Coal CHP Facilities TA-2.1 FEEDs for Integrated CCS Systems at NGCC Electric Generation Facilities or NG SMR Facilities Producing H2 for Electricity Generation TA-2.2 FEEDs for Integrated CCS Systems at NG Simple Cycle Electricity Generation Facilities or NG CHP Facilities TA-3.1 FEEDs for Integrated CCS Systems at Ammonia Facilities Not Purposed for Electric Generation TA-3.2 FEEDs for Integrated CCS Systems at Industrial Facilities Not Purposed for Electric Generation	10/21/2022 Mandatory LOI 12/5/2022 Full application Anticipated selection date ~3/31/2023	~$189M total available $5.5M–12.5M per award up to 20 awards 50% cost share required up to 24 months period of performance https://oced-exchange.energy.gov/Default.aspx#FoaId82c73432-65b4-4d82-b03c-d61a6fcfe2a0
DE-FOA-0002400 Amendment 8 (Released 8/26/2022) DOE FECM NOI - 2822	**Clean Hydrogen Production, Storage, Transport and Utilization to Enable a Net-Zero Carbon Economy** Amendment to previously released FOA 2400. Advances in hydrogen technologies capable of improving performance, reliability, and flexibility of existing and novel methods to produce, transport, store, and/or use hydrogen will enable the United States to greatly reduce its carbon footprint associated with energy use. The amended FOA is make funding available for these areas of interest: AOI-4: Advanced Air Separation for Low-Cost H2 Production via Modular Gasification AOI-14: Clean Hydrogen Production and Infrastructure for Natural Gas Decarbonization 14a: Methane pyrolysis/decomposition, in situ conversion, or cyclical chemical looping reforming 14b: Hydrogen Production from Produced Water AOI-15: Technologies for Enabling the Safe and Efficient Transportation of Hydrogen Within the U.S. Natural Gas Pipeline System AOI-16: Fundamental Research to Enable High Volume, Long-term Subsurface Hydrogen Storage	10/25/2022	Up to $32M available $1.25-$5M per award 20% or 50% cost share required https://www.grants.gov/web/grants/view-opportunity.html?oppId=330950

DE-FOA-0002779 (Released 9/22/2022) DOE OCED BIL From NOI - 2768 (Issued 6/6/2022) FOA was anticipated Sept/Oct 2022	**Bipartisan Infrastructure Law: Additional Clean Hydrogen Programs (Section 40314): Regional Clean Hydrogen Hubs** This $8 billion effort will catalyze investment in the development of H2Hubs that demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen. Each H2Hub will include multiple partners that will bring together diverse hydrogen technologies to produce and utilize large amounts of hydrogen in different ways. These clean hydrogen demonstrations will balance hydrogen supply and demand, connective infrastructure, and a plan for long-term financial viability. The H2Hubs will also include substantial engagement of local and regional stakeholders, as well as Tribes, to ensure that they generate local, regional, and national benefits. DOE has defined a four-phase structure for the H2Hubs. Phase 1 will encompass initial planning and analysis activities to ensure that the overall H2Hub concept is technologically and financially viable, with input from relevant local stakeholders. Phase 2 will finalize engineering designs and business development, site access, labor agreements, permitting, offtake agreements, and community engagement activities necessary to begin installation, integration, and construction activities in Phase 3. Phase 4 will ramp-up the H2Hub to full operations including data collection to analyze the H2Hub's operations, performance, and financial viability. This FOA will solicit plans for all four phases of proposed H2Hub activities; however, DOE will only initially authorize funding for Phase 1.	11/7/2022 Concept paper 4/7/2023 Full application	$8.0B available over 5 years ($6–$7B in first FOA launch for 6–10 H2Hubs) $400M–$1.25B per award 8–12 year period of performance 50% cost share https://oced-exchange.energy.gov/Default.aspx#Foald4dbbd966-7524-4830-b883-450933661811
DE-FOA-0002711 (Released 9/21/2022) DOE FECM BIL From NOI - 2729 (Issued 4/29/2022) FOA was anticipated FY22 Q3 (Apr–Jun)	**Carbon Storage Assurance Facility Enterprise (CarbonSAFE) Initiative: Phases III, III.5, and IV** The overall objective of this FOA is to accelerate the development of new or expanded commercial-scale geologic carbon storage projects and associated carbon dioxide transport infrastructure, through a focus on detailed site characterization, permitting, and construction stages of project development. This FOA is expected to remain open for five years to facilitate expeditious development of secure geologic carbon storage facilities. As required by the BIL, the selection process will give priority to projects with substantial carbon dioxide storage capacity and projects that will store carbon dioxide from multiple carbon capture facilities. It is anticipated that multiple closings will follow through quarter 4 of fiscal year 2026 with the frequency based upon the number of applications received and the availability of funding. This FOA will be amended a minimum of 4 weeks in advance of subsequent closings to provide applicants notice of the next closing date. Phase III – Site Characterization and Permitting (15–40 awards) ($15M–$110.5M/award) (no more than 36 months) Phase III.5 – NEPA, FEED Studies, and Field Development Plan Only (0–10 awards) ($100k–$4.55M/award) (no more than 24 months) Phase IV – Construction (5–20 awards) ($30M–$195M/award) (no more than 30 months)	11/28/2022 Selection notifications ~3/13/2023	$2.25 billion available across all closings through FY26 Q4 20% cost share for Phases III and III.5. 50% cost share for Phase IV.
DE-FOA-0002730 (Released 9/22/2022) DOE FECM BIL From NOI - 2780 (Issued 7/13/2022) FOA was anticipated FY23 Q1 (Oct–Dec)	**BIL: Carbon Capture Technology Program, Front-End Engineering Design for Carbon Dioxide (CO2) Transport** This FOA is focused on FEED studies of commercial-scale CO2 pipeline projects that transport CO2 from anthropogenic sources to CO2 conversion plants and/or to secure geologic storage facilities, with an emphasis on FEED studies in different geographic regions that will provide DOE with increased understanding of CO2 transport costs; transport network configurations; and technical, regulatory, and commercial considerations to inform DOE's research, development, and demonstration (RD&D) strategy and to encourage fully commercial-scale deployment of CCUS and CDR. The intent of this FOA is to award projects with consideration for the creation and integration of a hub and cluster configuration, rather than a standalone CCUS/CDR pipeline(s). Applicants are also encouraged to propose projects that will repurpose existing pipeline(s) into CO2 service. Area of Interest: Front-End Engineering and Design Studies for CO2 Pipeline Infrastructure (Onshore and Offshore)	11/28/2022 Selection notifications March 2023	$92M to be available for a 5-yr period with 6 or more awards per year $750k–$3M per award 20% cost share required 1–2 year period of performance https://www.grants.gov/web/grants/view-opportunity.html?oppId=342284

NOI - 2746 for DE-FOA-0002735 (Issued 5/13/2022) DOE FECM NETL BIL	**Bipartisan Infrastructure Law (BIL): Regional Direct Air Capture (DAC) Hubs** Section 40308 of the BIL requires DOE to provide funding for eligible projects that contribute to the development of four (4) regional DAC Hubs. Each of the DAC Hubs: (i) facilitates the deployment of direct air capture projects; (ii) has the capacity to capture and sequester, utilize, or sequester and utilize at least 1,000,000 metric tons of carbon dioxide from the atmosphere annually from a single unit or multiple interconnected units; (iii) demonstrates the capture, processing, delivery, and sequestration or end use of captured carbon; and (iv) could be developed into a regional or interregional carbon network to facilitate sequestration or carbon utilization. 2 project timelines: AOI-1: Standard timeline - Phase 1 funding with this FOA. AOI-2: Accelerated timeline - Phase 1 (equal to AOI-1 Phase 1) funding with this FOA.		FOA anticipated FY22 Q4 (July–Sep) $3.5B available Likely 20% cost share for AOI-1 Phase 1. Likely 50% cost share for AOI-2 Phase 2. All subsequent phases 50%. https://www.grants.gov/web/grants/view-opportunity.html?oppId=340319
NOI - 2798 for DE-FOA-0002799 (Issued 7/21/2022) DOE FECM	**Regional Initiative to Accelerate Carbon Management Deployment: Technical Assistance for Large Scale Storage Facilities and Regional Carbon Management Hubs** If released, the overall objective of this FOA will be to accelerate the deployment of carbon management by establishing a consistent, effective mechanism for providing technical assistance to develop multiple large scale storage facilities and regional carbon management (CM) hubs that could store hundreds of millions of tons and inject over 5 million metric tons per year. DOE views this FOA as an opportunity to (a) expand, refine, and enhance the 'technical assistance' aspects of the RI effort to directly support development of large scale storage facilities (5MMT+/year) and regional carbon management hubs; and (b) attract applications from other organizations that may be equally capable of providing the same type of technical assistance to large-scale storage facilities and regional carbon management hubs under development as the existing RI projects. The two intended Areas of Interest in this FOA will result in awards that can work separately or in tandem to provide the desired technical support. • Area of Interest 1 - Technical Assistance for Geologic CO_2 Storage and Transport for Large Scale Storage Facilities and within Prospective Regional CM Hubs • Area of Interest 2 - State Geological Data Gathering and Analysis to Support Large Scale Storage Facilities and Regional CM Hub Development		FOA anticipated FY23 Q1 (Oct–Dec) If released, not <$20M to be available for a 5-yr period 20% cost share required Max 2 years https://www.grants.gov/web/grants/view-opportunity.html?oppId=342628

APPENDIX B

PROJECT PERMITTING MATRICES

Table B-1. NEPA and Federal Permitting Requirements

	NEPA Document (EA / EIS)	NHPA Sec. 106 Consultation	EFH & ESA Sec. 7 Consultation	CWA 404	RHA 10	RCRA Hazardous Waste Permit	PHMSA Authorization Letter	Title VI Injection Well Permit	BGEPA and MBTA
	USACE-Led	*USACE-Led*	*NMFS / USFWS*	*USACE*	*USACE*	*EPA*	*US DOT PHMSA*	*EPA*	*USFWS*
Construction Activities									
Clearing, Grubbing, Grading, and Ground Prep. at Mine Site	X	X		X					X
25MW - 500 MW Power Plant Options	X	X		X		X			X
Elevated AC overhead transmission line	X	X		X					X
Buried CO2 Transport Pipeline	X	X	X	X	X		X		X
Pipeline Compressor(s)	X	X		X					X
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)	X							X	
Operational Activities									
Mining of Carbon Ore to Fuel the Power Plant	X	X		X		X			X
25MW - 500 MW Power Plant Options	X	X		X		X			X
Elevated AC overhead transmission line	X	X		X					X
Buried CO2 Transport Pipeline	X	X	X	X	X		X		X
Pipeline Compressor(s)	X	X		X					X
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)	X							X	

Table B-2. State of Alaska Permitting Requirements

	APMA	CWA 401 Cert. & Antideg. Analysis	CWA 402 APDES Const. GP, SPCC, and SWPPP	CWA 402 Non-Contact Cooling Water GP	CWA 402 Domest. WW Trtmt. Plant GP	TWUP	Certificate of Appropriation (Water Right)	Title 16 Fish Habitat Permit	PSD Permit Minor or Major Source	Title V CAA Operating Permit	Area Injection Order	POD	PA	CRMP	RRC Authorization
	ADNR DMLW	*ADEC Water*	*ADEC Water*	*ADEC Water*	*ADEC Water*	*ADNR DMLW*	*ADNR DMLW*	*ADFG Habitat*	*ADEC Air*	*ADEC Air*	*AOGCC*	*ADNR DOG*	*ADNR SHPO*	*ADNR SHPO*	*RRC RCA*
Construction Activities															
Clearing, Grubbing, Grading, and Ground Prep. at Mine Site	X	X	X		X	X			X				X	X	
25MW - 500 MW Power Plant Options		X	X		X				X				X	X	
Elevated AC overhead transmission line		X	X										X	X	X
Buried CO2 Transport Pipeline		X	X			X		X					X	X	
Pipeline Compressor(s)		X	X						X				X	X	
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)									X			X			
Operational Activities															
Mining of Carbon Ore to Fuel the Power Plant	X	X	X		X	X	X		X	X			X	X	
25MW - 500 MW Power Plant Options		X	X	X	X				X	X					
Elevated AC overhead transmission line		X	X												X
Buried CO2 Transport Pipeline		X	X												
Pipeline Compressor(s)		X	X						X	X					
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)									X	X	X	X			

Table B-3, Lands, Right of Way, and Pore Space-Leasing Requirements

	State (< 75 mi)	ANC (< 4 mi)	Private (< 0.5 mi)	Federal	State	ANC
	ADNR (DMLW)	*CIRI*	*Chugach Electric*	*EPA*	*ADNR (DOG)*	*CIRI*
Construction Activities						
Clearing, Grubbing, Grading, and Ground Prep. at Mine Site	X					
25MW - 500 MW Power Plant Options	X					
Elevated AC overhead transmission line	X	X	X			
Buried CO2 Transport Pipeline	X	X	X			
Pipeline Compressor(s)	X					
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)			X			
Operational Activities						
Clearing, Grubbing, Grading, and Ground Prep. at Mine Site	X					
25MW - 500 MW Power Plant Options	X					
Elevated AC overhead transmission line	X	X	X			
Buried CO2 Transport Pipeline	X	X	X			
Pipeline Compressor(s)	X					
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)			X	X	X	X

	State (< 75 mi)	ANC (< 4 mi)	Private (< 0.5 mi)	Federal	State	ANC
	ADNR (DMLW)	*CIRI*	*Chugach Electric*	*EPA*	*ADNR (DOG)*	*CIRI*
Construction Activities						
Clearing, Grubbing, Grading, and Ground Prep. at Mine Site	X					
25MW - 500 MW Power Plant Options	X					
Elevated AC overhead transmission line	X	X	X			
Buried CO2 Transport Pipeline	X	X	X			
Pipeline Compressor(s)	X					
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)			X			
Operational Activities						
Clearing, Grubbing, Grading, and Ground Prep. at Mine Site	X					
25MW - 500 MW Power Plant Options	X					
Elevated AC overhead transmission line	X	X	X			
Buried CO2 Transport Pipeline	X	X	X			
Pipeline Compressor(s)	X					
CO2 Injection Wells - Onshore at Existing Beluga Power Plant Pad(s)			X	X	X	X