Nome Region Energy Assessment

DOE/NETL-2007/1284

Final Report

March 2008

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CITY OF NOME–2007

Ed Englestadt, Wyatt Earp and John Clum
at Nome, Alaska in 1900

THREE OF NOME'S EARLY CITIZENS

NOME REGION ENERGY ASSESSMENT

EXECUTIVE SUMMARY

The purpose of this assessment is to present an analysis of technologies available to the City of Nome for electric power production. Nome is a city of 3,500 people located on the Bering Sea coast of the Seward Peninsula 539 air miles northwest of Anchorage, 102 miles south of the Arctic Circle and 161 miles east of the Russian coast.

Typical of most of Alaska's rural communities, Nome is totally dependent upon diesel generators for electricity. The current load range for the city is 1.8 MWe to 5.2 MWe (yearly average of 3.35 MWe). All power is supplied by diesel generation. Diesel fuel is also required by the residents for residential and commercial space and water heating. The addition of industrial activity, the Rock Creek Mine, increased the load by about 9 MWe for an average load of 12.35 MWe. The mine, which began initial operations in late 2007, is estimated to be in operation for 7 to10 years.

Recovered heat is currently used for heating the plant site and the potable water system for the City. The diesel generators require 1.8 to 2.0 million gallons of fuel each year. The consumer power rate has held steady in Nome since 2001. It ranges from $0.165 to 0.185/kWh depending upon usage. However, the fuel surcharge has risen to $0.075/kWh in 2006, making the current effective rate from $0.24 to 0.26/kWh. The continuing increase in diesel fuel costs has caused the City to look at alternative power sources to offset the total reliance on diesel.

Scope and Approach

Alternatives to the city's dependence on diesel generators analyzed in this assessment are:

- A barge-mounted coal-fired power plant using coal from: (1) the Usibelli mine near Healy, AK and transported by rail to Seward, AK and then by barge to Nome; or (2) British Columbia coal transported by barge to Nome.
- Wind power with the wind turbines located on Anvil Mountain approximately 1 mile north of Nome.
- Geothermal power plant at Pilgrim Hot Springs located 60 miles north of Nome with a power transmission network to Nome.
- Natural gas from the Norton Sound delivered to Nome from a sub-sea development with a pipeline to shore and conversion of one of the new diesel engines to burn natural gas.

Tidal/wave energy, hydroelectric dams, and coalbed natural gas were also considered, but these options did not appear viable and were not included in the final analysis. Tidal/wave energy technology is less mature than the other technologies considered and its applicability at Nome could not be assessed under current budget restrictions. The hydroelectric power option was not considered feasible and was not analyzed. Coalbed natural gas is not expected to be present in the vicinity of Nome and was not evaluated beyond some initial inquiries.

Coal resources are known to exist on the Seward Peninsula, specifically at Chicago Creek on the north side of the Seward Peninsula and other coal resources are known to exist on the Seward Peninsula and in the Northwest. However, none of the Northwest Alaska resources are being actively mined and would require significant capital investment to start operations. This start-up cost would not be justified to supply coal for a small power plant. Hence, the coal plant design and economics contained within this report are based on coal available from within Alaska and from British Columbia.

Infrastructure requirements, environmental regulations and the status of technology development for the coal plant, wind, geothermal, and natural gas options were assessed and compared with the existing diesel generation system on an equivalent economic basis.

Economic Results

The economic analysis model calculates the total cost of providing electric power to the Nome Joint Utility electrical distribution system (the "busbar cost"). Total cost is the cost of all capital and operating costs, including distribution and administrative costs, and the cost of providing heat energy on a Btu basis to residential and commercial residents. The analysis runs for thirty years, from 2015 to 2044. All existing electrical and thermal loads currently served by the system are treated as firm; that is, fully and continuously supplied throughout the period. A reasonable expectation of electrical load growth over the 30-year period is included to account for increases in population and economic activity of the city.

For each alternative case, the model estimates the electrical load requirement for each day of the year and computes how much energy is supplied by the primary generation source (e.g., diesel, coal, wind/diesel, geothermal, or natural gas). It also estimates how much must be delivered from diesel units as a backup resource. The model calculates the net present value of all annual costs, including current system fixed costs and the carrying cost of investments in new resources, to determine the total system life-cycle cost of power to the utility. The present values for each energy option are shown in Table 1.

Table 1. Present Value of Busbar Electricity, $Millions

Present Value of Busbar Electricity, $Millions						
Diesel Cost Escalation	Scenario					
	Diesel System	Wind & Diesel	Geothermal	Coal @ $63/ton	Coal @ $78/ton	Natural Gas
Mid	116	111	90	134	117	107
High	140	128	92	137	120	107
	Present Value Savings Residential/Commercial Heat, $ Millions					
Mid						5
High						13

The model also computes the approximate average electric rate necessary to cover each year's annual cost of providing electrical service, which includes estimated distribution and administration costs, based on recent financial statistics. The savings to residential and commercial consumers from an alternative source of heating fuel is estimated on a per Btu basis for the natural gas option. The average electricity rates for each energy option are shown in Table 2.

Table 2. Average Electric Rates and Space Heating Rates

Year	2015	2020	2025	2030	2035	2044	Avg. 2015 to 2044
Diesel System	**$/kWh**						
Mid-range diesel escalation	0.30	0.31	0.31	0.31	0.31	0.32	0.31
High-range diesel escalation	0.30	0.32	0.34	0.36	0.38	0.43	0.36
Coal Scenarios							
Coal $63/ton, Mid-Range Diesel	0.35	0.34	0.33	0.32	0.32	0.31	0.33
Coal $63/ton, High-Range Diesel	0.35	0.34	0.33	0.32	0.32	0.33	0.33
Coal $78/ton, Mid-Range Diesel	0.32	0.31	0.30	0.29	0.29	0.28	0.30
Coal $78/ton, High-Range Diesel	0.32	0.31	0.30	0.29	0.29	0.30	0.30
Wind/Diesel							
Mid-Range Diesel escalation	0.30	0.30	0.30	0.30	0.30	0.30	0.30
High-Range Diesel escalation	0.30	0.31	0.32	0.33	0.35	0.39	0.34
Geothermal							
Mid-Range Diesel escalation	0.29	0.28	0.26	0.25	0.24	0.24	0.26
High-Range Diesel escalation	0.29	0.28	0.27	0.26	0.25	0.25	0.26
Natural Gas							
Mid-Range Diesel Escalation	0.32	0.31	0.29	0.28	0.27	0.27	0.29
High-Range Diesel Escalation	0.32	0.31	0.29	0.28	0.27	0.28	0.29
Natural Gas Water and Space Heating—Relative Costs ($/MMBtu)							
Mid-Range Diesel Escalation	24	24	25	26	26	27	25
High-Range Diesel Escalation	24	26	28	31	33	39	31
Natural Gas	25	24	23	22	21	19	22

All costs are expressed in *real* dollars that have purchasing power at a constant reference point, in this case 2007.

Diesel fuel cost increases in real terms (i.e., price increases over and above general inflation rates) are the same in all scenarios. For the purposes of estimating future costs of diesel fuel, the Alaska Energy Authority (AEA) prepares projections of delivered fuel prices for a number of locations in Alaska, including the city of Nome. These projections are used for analysis of a variety of energy issues throughout the state, including evaluation of wind-diesel hybrid systems and other alternative generation options. For consistency with statewide energy planning, the diesel fuel rate of change over time (other than general inflation) for the city of Nome was drawn from the Alaska Energy Authority estimates and applied to the price of diesel delivered to Nome in 2007.

- Diesel Fuel Initial Price: $2.54/gal
- Diesel Fuel Escalation (real)
  - Mid-Range case 0.58%/yr
  - High-Range case 2.12%/yr

These diesel fuel escalation rates result in estimates of diesel costs of $3.00/gal by 2044 for the mid-range case, and to as much as $4.67/gal in the high-range case. A low-range case, which assumes an average decline in diesel prices of over 1%/yr over the AEA analysis period, was not examined for the purposes of this screening analysis.

The net present values are derived with a real discount rate of 4%, corresponding to the effective interest rate for borrowing by municipal electric systems such as Nome.

For each case, the life-cycle cost of providing electricity is the discounted present value of all annual costs for the 30-year period of analysis. In the natural gas case, where natural gas is made available for utility requirements, a net present value is estimated for the electric utility that compares directly with other electric production options, and a separate estimate is provided for the savings from the availability of natural gas for space and water heating,

Diesel System

The generating efficiency of the two new units recently installed by the Nome Joint Utility System will average 16 kWh/gallon of diesel fuel, an efficiency that is expected to remain unchanged year-to-year, so diesel consumption will vary directly with changes in electric load requirements. For the Nome system in 2006, with fuel costs at an average of $1.99/gallon, diesel fuel constituted 50% of the average cost of electricity in Nome. The cost of fuel used for generation reached $2.54/gallon (Nov. 2007), significantly increasing the share of electricity costs attributable to generation.

The fixed costs of the generation facilities are “sunk costs” that will not be diminished by the addition of alternative generation facilities. Those fixed costs, along with administrative expenses are assumed not to vary with load changes and are held at a constant level throughout the analysis. Distribution system costs, however, will likely vary as system loads increase, due to the need to add and maintain new services. Distribution system costs are estimated on a per kWh basis. The total cost of distribution system ownership, operation and maintenance will increase as the distribution load increases.

The results of the economic analysis for the operation between 2015 and 2044 of the diesel generation system installed at Nome indicate system operating costs of between **$116 million** in present value under the expectations of a mid-range diesel fuel cost escalation to **$140 million** present value under conditions of a high-range escalation of diesel fuel costs.

The results indicate that the existing diesel system is fully available to meet energy requirements for the electric system at a stable cost, net of fuel cost increases. The greatest risk to the system is the potential variability in the cost of diesel delivered to Nome, or the additional or extended load requirements associated with local mining activities.

Wind-Diesel System

As part of this analysis, the Alaska Energy Authority (AEA) performed an analysis of the availability of wind energy to supplement the existing diesel generation. .A wind generation system of 3 MW, consisting of two 1.5 MW units installed on Anvil Mountain near Nome appeared to provide annual electric energy at a cost slightly less than the current cost of diesel generation. The wind source, however, is intermittent and provides energy as a function of wind velocity rather than electricity requirements, and cannot be relied upon for energy at any particular point in time. Integrating wind units with diesel generation systems requires specialized control systems that respond to the variation in wind energy production and electric load requirements to ensure that maximum efficiency is made of the combination of wind and diesel units.

The wind turbine installation is expected to provide about 8,988 MWh/year or about 30% of the initial year load of the Nome electric system. For the purposes of the economic analysis, it was assumed that the energy provided by the wind turbines will be contributed throughout the year, displacing that amount of diesel generation each and every year of the analysis period. Nome's new power plant controls were designed to integrate alternative and intermittent sources so no additional costs for integration hardware and software are expected to be required for the two wind turbines of 1.5 MW each.

Adding wind turbine capacity adds cost to the system. Thus, the installed cost of $4,000/kW is recovered in electric rates over the analysis period, as well as the expected fixed operating costs of 3% of the installed costs and variable operating costs of slightly less than 1 cent/kWh. Initially, the installation of new wind turbines is expected to require 1 additional staff member to adequately maintain the wind system.

The installation of two 1.5 MW wind turbines near Nome, producing at a 34% capacity factor that offset diesel generation, results in system operating costs for the 30-year period of **$111 million** in present value under conditions of a mid-range escalation in diesel fuel costs. In the case of high-range escalation in diesel fuel costs, the total present value would increase to **$128 million**. In both cases, the total cost of providing electricity under these assumptions is several million dollars less than the cost of continuing to operate the system with only diesel generation. If green tag sales are available and successful at the time of installation and throughout the life of the wind system approximately $4.7 million in credits may contribute to a further reduction in the cost of electricity to the residents

With proper siting and mitigation measures, most impacts from wind energy development would be negligible. Obtaining required permits in accordance with federal and state regulations is anticipated to be routine.

Geothermal System

A geothermal installation located at Pilgrim Hot Springs, approximately 60 miles north of Nome, was evaluated as an option with the potential to displace a very large portion of the diesel generation in the initial years of operation. The analysis, described in Section 6, suggests the possibility of a 5 MWe geothermal installation providing about 41,600 MWh/yr, 33% more than required in 2015. The generating capability of the geothermal facility is just slightly less than the 41,633 MWh/year expected to be required in 2044.

If successfully developed, the geothermal facility can provide nearly all of the electric load requirements, and with the load shape of the electric system, maintenance activities can be scheduled during low load periods without significantly impacting system operating costs. The existing diesel system will be available for backup service in the event of unscheduled outages or transmission failures. Further, the existing diesels will be available to meet short-term and intermittent peaking requirements (although a diesel generating unit may be selected to operate during high load periods for reliability, but not necessarily economic, purposes).

The installed cost of the geothermal system, including all exploratory activities, construction costs and the transmission system to interconnect with Nome, is assumed to be $12,800/kW for a system with a lifetime of at least 30 years. A geothermal installation, while generally robust, will require specialized staff to operate and maintain the installation, increasing personnel costs, particularly in the initial years of operation (and perhaps toward the later years), while the increase in miles of transmission lines may increase line worker requirements. For the screening analysis, two additional staff members are estimated to be required over the analysis period, but it may be possible that generation facility staff currently operating the diesel system could be redeployed. The diesel system must be maintained for backup (or high load reliability service), and some personnel will remain assigned to the power house.

The geothermal operating costs would consist primarily of manpower and supplies. Very little is currently known about the cost of operating and maintaining a geothermal facility of that magnitude in the Nome region, but information from other geothermal investigations suggests that annual supplies, such as chemicals, lube oil, etc. will amount to about 1.5% of the installed cost of the facility. That cost is considered a fixed annual cost recovered in power rates in similar fashion to the acquisition cost.

The displacement of the diesel generation with a geothermal power source eliminates, for the most part, the availability of water-jacket heating for the Nome city water supply. Consequently, in the early years of the geothermal scenario, the city water heat is assumed to be supplied by the direct-fired boilers. In later years, as more supplemental diesel generation will be required, the diesel engines will contribute to the city water heating load.

Installation of a geothermal power generation facility at Pilgrim Hot Springs would significantly reduce the cost of electricity for the Nome Joint Utility System. The cost for 30 years of energy supply to Nome would drop to **$90 million** in present value with a mid-range diesel fuel cost escalation and to **$92 million** for the high-range diesel cost escalation. Generation costs increase in the latter years as a result of the increasing component of diesel generation as loads increase, and the contribution of geothermal energy declines as a proportion of generation.

The low cost associated with the geothermal option must be weighed against the risk that the geothermal resource will not prove to be adequate to support the generation capability of scenario described.

The lack of a steam phase in binary geothermal power systems prevents the airborne release of CO_2 and other gases, which remain in solution and are reinjected back into the reservoir to help sustain resources. The permitting process should only involve standard permits related to land use.

Coal Plant

A conceptual design was completed for a barge-mounted coal plant that would provide 4.655 MW of coal-fired electrical power to the city upon installation in 2015. A barge-mounted coal plant has the advantage that it could be constructed in an existing ship yard in the Lower 48, tested, and then towed to Nome reducing on-site construction time and costs. In addition to the coal plant capability, the design of barge mounted system includes a 1 MW diesel generation unit for startup power and auxiliary loads in order to accomplish a self-contained system. For the purposes of the Nome system evaluation with the addition of a barge-mounted coal plant, the diesel unit will provide only a backup power source for black-start conditions or other system emergencies and not be routinely operated or included in the net capability.

Other than the estimated capital cost ($14,100/kWe based on the 4.655 MWe output only), the most significant cost element for the evaluation of a coal plant in Nome is the fuel cost. The fuel cost of the coal system is a function of the delivered cost and quality (i.e., heat content) of the coal and the efficiency of the coal boilers. The coal units were designed to accommodate a variety of coal, but with emphasis on the character of the coal available within Alaska. The Usibelli coal source in central Alaska provides an available source of coal at a somewhat lower cost than coal obtained elsewhere, but it has a heat, or energy, content lower than some other coals. Coal obtained in British Columbia that is readily transportable to Nome will have a higher cost and heat content than the coal currently available in Alaska. Usibelli coal is estimated to cost $63/ton delivered to Nome, whereas British Columbia coal is estimated to cost $78/ton. Considering the Btu content of the coal, the British Columbia coal will provide for the needs of the plant at $2.82/MMBtu. Usibelli coal on an equivalent basis will cost about $4.06/MMBtu.

Coal unit net efficiency (electric output/coal input) is a function of a variety of factors, most notably the size of the units relative to the auxiliary loads. The operation of boiler feed water pumps, fans and other ancillary equipment will have a significant impact on the net efficiency in converting the energy of coal into electric power. The barge-mounted coal system designed for the Nome installation has a net efficiency of 16%, which is relatively low compared to larger coal-fired power plants in operation or planned for construction.

Regardless of the source of coal, the delivered cost is estimated to *remain constant in real terms, including transportation*. Coal price projections available for review have indicated a trend of stable prices for both the commodity and transportation for the foreseeable future as a result of supply and demand characteristics worldwide. Consequently, no real increase is expected above general inflation for coal delivered to Nome.

The barge-mounted coal fired generation alternative introduces a cost of production that will vary dramatically as a function of the assumptions regarding the coal fuel purchased and delivered to the Nome location. Assuming Usibelli coal at $63/ton delivered, the cost of operating the system for 30 years will be **$134 million** in present value under conditions of mid-range diesel fuel escalation. With the same coal fuel, but a presumed high-range escalation of diesel costs, the present value cost of operating the system rises to **$137 million.**

If British Columbia coal at $78/ton is assumed to be used to fuel the coal generation facility the present value for the midrange case will be about **$117 million** and high-range case will be about **$120 million**.

The displacement of the diesel generation with a coal plant eliminates, for the most part, the availability of diesel unit water-jacket heating for the Nome city water supply. The coal plant, however, would be capable of providing a source of heat to replace that provided by the diesel units if a steam or hot water interconnection is constructed between the coal plant and the existing power house. In the absence of an interconnection, the city water heating requirement would need to be supplied by the direct-fired boilers. In later years as more supplemental diesel generation is required, the diesel engines could contribute to the water heating load.

The diesel fuel required by the direct-fired boilers to provide the heat required for the city water system is estimated to cost $6 million in present value for the mid-range escalation case and $7 million for the high-range case. A steam line that could be installed and operated at a lower cost over the 30-year period for installation and ownership would provide additional benefits to the coal scenario. A withdrawal of steam from the coal plant at the rate required would, however, introduce a loss of about 2% of the coal plant's electric capability and result in more supplemental diesel generation.

As long as the project can avoid triggering Hazardous Air Pollutants (HAP) major status (10 tons per year (tpy) of a single HAP or 25 tpy of multiple HAPs), then the permitting process and applicable limits associated with operation of a coal-fired boiler would be relatively straightforward with no red flags. In this instance, the boiler would not be subject to the boiler maximum achievable control technology (MACT) because it was not HAP major, and it would not be subject to the Clean Air Mercury Rules since it would be rated at only 4.655 MWe.

Because coal will be stockpiled from one delivery per year, the Alaska Department of Environmental Conservation will most likely require reasonable precautions to prevent emissions of particulate matter (*e.g.*, fugitive dust). Coal slag and fly ash from the boiler and elemental sulfur could be disposed of at an approved landfill or monofill. Mercury content of slag and fly ash could become a regulatory issue for reuse or disposal in the future.

Permitting as described in Section 7 will be required for siting, water use, etc. but is expected to be straight forward.

Natural Gas

An entirely new fuel source for Nome is potentially possible from a Norton Sound natural gas drilling and production investment, described in Section 6. Successful exploration and development of a Norton Sound resource would provide for both the electric energy needs and the space and water heating requirements of the community. The economic analysis of the natural gas scenario requires consideration of the investment costs of the natural gas system, both to deliver fuel to the utility, and to the commercial and residential business sectors. In addition to the investment in the system of production and delivery, costs will be incurred to convert generation units to operate on natural gas, as will space and water heating equipment.

The assessment includes an evaluation of the shared costs of the investment in the off-shore production facilities and pipeline costs for delivery to the city gate. Of the total investment of $62.7 million overall required to provide the fuel supply, $56.2 million will be committed to the installation of the production and primary delivery systems. Annual fixed costs estimated at $4 million/year associated with the operation of the system and variable operating costs will add significantly to the costs, such that initial-year total costs of the production and primary transmission of gas are estimated at $7.3 million. These costs are assumed to be shared between the electric utility and the gas distribution system customers on the basis of the relative shares of natural gas volumes consumed for each purpose.

A distribution system to provide access to gas, along with the conversion of heating equipment from fuel oil to natural gas, is estimated to cost about $4.2 million and require about 1.0% of that amount in annual variable operating costs for maintenance and repairs. All of the annual costs of the distribution system are assumed to be paid by the users of the commercial and residential service.

For the electric utility to operate on natural gas, it is assumed that one of the newest installed units will be changed out for a unit that will operate on natural gas. Each of the two recently installed diesel units will provide 5.2 MW of electrical energy, individually meeting nearly all of the energy requirements of Nome. For the purposes of screening, the analysis assumes that all of the annual electrical energy is provided from natural gas, while some diesel fuel will undoubtedly continue to be required for emergency purposes and during short periods of natural gas unit outages. An investment in a second unit to operate on natural gas would add a modest cost to the analysis, or about $2 million.

A $2 million investment represents about 787,000 gallons of diesel fuel, enough to produce over 400,000 kWh of electricity each year, providing for several outage days a year during low load periods. If the natural gas system proves feasible, the change out of an additional unit may be appropriate, since other units will remain in place to operate on diesel fuel for emergency purposes.

A significant economic factor associated with the investment in a natural gas system is that the sole cost of the natural gas for the utility and other users will be embodied in the capital and operating costs of the production and delivery systems. There are no taxes or commodity costs assumed for the volumes of gas delivered by the system by which to compare directly with the cost of diesel fuel that is sold on a gallon-by-gallon basis. Consequently, unlike the electric utility for which average power costs may be compared, the economic evaluation of the space and heating requirement is a comparison of the relative cost of thermal energy on a Btu basis.

The installation of a natural gas system allows the displacement of nearly all diesel fuel used by the Nome electric utility system. The present value of system operating costs includes full recovery of all investment costs necessary to both obtain and deliver natural gas.

For the electric system, the present value of the busbar cost of electricity using natural gas fuel is estimated at between **$107 million**. This is about $10 million less than operating the diesel system at mid-range fuel escalation, and about $33 million less under a high-range escalation assumption. Different assumptions of diesel cost escalation for the system operating on natural gas has very little effect on the economics, because so little diesel generation is likely to occur until late in the analysis period. (Only emergency and maintenance requirements will be met with diesel.) Thus, electric rates between the mid-range and high-range cases will be nearly identical until the last few years.

The permitting process and applicable limits of a gas-fired engine or turbine would be relatively straightforward with no red flags. However, caution should be used when selecting a turbine to ensure compliance with the federal limit.

Natural Gas Space Heating

The installation of a natural gas system for Nome would provide a source of fuel as an alternative to diesel fuel for the provision of commercial and residential space and water heating. The economic evaluation of the impact of the installation of the gas system indicates a present value savings for the thermal requirements for space and water heating, in the instance of a mid-range fuel price escalation, of about **$5 million**. Under a high-range cost escalation, the economic benefit to the community will reach slightly more than **$13 million.** The impact on heating consumers is described in terms of the cost per Btu for energy providing space and water heat and is shown in Table 2.

Conclusions

The energy technologies analyzed for Nome fall into two categories, (a) technologies that rely upon known energy resources—diesel, wind, and coal; and (b) technologies that would rely upon hypothetical (or untested) resources—geothermal and natural gas. Geothermal and natural gas resources are known to exist based on limited evaluation, but will require expensive exploration to prove the resources exist in sufficient quantity and deliverability to meet the requirements. The exploration and development costs for geothermal and natural gas are not well established and will require additional analysis to confirm the estimates. The natural gas options assumed that a drill ship would be available at day rates only and that the costs to obtain and move a ship to and from Norton Sound would not have to be borne by the project.

The present value comparisons indicate that for the assumptions incorporated in the analysis regarding each of the alternatives, the wind/diesel, geothermal plant, barge-mounted coal plant using high BTU coal, and natural gas exploration and development are all economically equal or better than continued reliance on diesel for both mid-range and high-range diesel price escalation. The lower Btu coal option is slightly better in the instance of a high-range diesel price escalation. The development of a natural gas resource, in addition to showing a strong potential for savings in the operation of the electric utility, would provide an economical option by providing natural gas for water and space heating throughout the community.

Of the alternatives investigated, the most likely prospect of immediate savings gain is the installation of wind turbines to offset diesel generation for the electric utility. Wind units are commercially available, and the Nome utility system has already anticipated the advent of wind by including integration capability in the construction of the new power house.

The geothermal and natural gas prospects both indicate potential savings greater than the wind resource, but will require additional investment in exploration and development to verify the resource potential. Nevertheless, the potential gain from each is significant, with the natural gas prospect in particular providing the additional benefit of displacing fuel oil for space and water heating.

The coal plant prospect with high-Btu coal provides savings to the electric system, but to a lesser extent than the other alternatives. With low-Btu coal, savings would only be available under a high rate of diesel price escalation, and under conditions of coal prices remaining constant in real terms. In either case, the savings associated with the prospect of a coal power plant are based on an engineering estimate of costs to construct an initial unit. Economies of scale from construction of multiple units of a similar design could reduce the capital cost of the system and improve the economics of a coal-based alternative.

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The study was prepared at the request of the mayor of Nome and is intended to provide information for planning and decision-making by city officials and state agencies regarding power and space heat strategies for Nome and other similarly situated communities.

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A Steering Committee was formed to review assumptions and price forecasts, and provide guidance to the study team responsible for preparing this assessment. The committee members are listed below.

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ACRONYMS AND ABBREVIATIONS

AAC	Alaska Administrative Code
ACMP	Alaska Coastal Management Program
ADEC	Alaska Department of Environmental Conservation
ADFG	Alaska Department of Fish and Game
ADNR	Alaska Department of Natural Resources
AEA	Alaska Energy Authority
As	Arsenic
B	Boron
B.C.	British Columbia
Btu	British thermal unit
CAA	Clean Air Act
CAAA	Clean Air Act Amendments
C/BFB	Circulating/bubbling fluidized bed
CFR	Code of Federal Regulations
Cl	Chlorine
CO	Carbon Monoxide
CO_2	Carbon Dioxide
COST	Continental Offshore Stratigraphic Test Well
CPQ	Coastal Program Questionnaire
CWA	Clean Water Act
DG	Diesel generator
DNR	Department of Natural Resources
DOE	Department of Energy
EA	Environmental Assessment
EIS	Environmental Impact Statement
EPA	Environmental Protection Agency
EPRI	Electrical Power Research Institute
ESA	Endangered Species Act
FAA	Federal Aviation Administration
FDOT	Federal Department of Transportation
FERC	Federal Energy Regulatory Commission
FGR	Flue gas recirculation
gr/dscf	Grains per dry standard cubic foot

GWe-hr	giga-watt hour (electric)
HAP	hazardous air pollutant
HCl	Hydrogen Chloride
Hg	mercury
Hga	mercury atmospheric
HHV	Higher heating value
hp	horsepower
hr	hour
ISO	International Standards Organization
kWe	kilowatt (electric)
kWh	kilowatt hour
kV	kilo volts
lb	pound
MACT	Maximum Achievable Control Technology
MMBtu	Million British thermal units
MMS	Minerals Management Service
MMscf	millions of standard cubic feet
Mscf	thousands of standard cubic feet
MWe	mega-watt (electric)
MWh	Megawatt hour
NAAQS	National Ambient Air Quality Standards
NEPA	National Environmental Policy Act
NESHAPs	National Emission Standards for Hazardous Air Pollutants
NMFS	National Marine Fisheries Service
NO_x	Nitrogen Oxide
NPDES	National Pollutant Discharge Elimination System
NSPS	New Source Performance Standards
NSR	New Source Review
OCS	Outer Continental Shelf
OCSLA	Outer Continental Shelf Lands Act
PM-10	Particulate Matter
ppm	parts per million
PSD	Prevention of Significant Deterioration
psig	pounds per square inch gage
RCRA	Resource Conservation and Recovery Act

RICE	Reciprocating Internal Combustion Engines
ROW	Right-of-Way
scf	Standard cubic foot
SO_2	Sulfur Dioxide
tons	2,000 lbs
tonnes	metric ton–2,204.62 lbs
tpy	tons per year
TSCA	Toxic Substance Control Act
Tscf	trillion standard cubic feet
UIC	Underground Injection Control
USACE	United States Army Corps of Engineers
USDOI	United States Department of the Interior
USFWS	United States Fish and Wildlife Service
USC	United States Code
USEPA	United States Environmental Protection Agency
UTC	United Technologies Corporation
VOC	Volatile Organic Matter

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NOME REGION ENERGY ASSESSMENT

1 INTRODUCTION

The purpose of this assessment is to present an analysis of options available to the city of Nome for electric power production and space heating. Typical of most of Alaska's rural communities, Nome is totally dependent upon diesel generators to generate electricity for its citizens. As with all communities that rely primarily (if not exclusively) upon diesel generation, Nome is facing increasing costs for the diesel for electric generation and space heating. Alternatives to the city's continued dependence on diesel generators analyzed include power generating options based on coal, natural gas, wind, and geothermal. Coalbed natural gas, hydropower, tidal/wave energy were also considered, but these options did not appear viable and were not included in the detailed analysis. The economic analysis contained in this report is based upon the interrelated technical, economic and environmental factors for each alternative considered.

The study was prepared at the request of the mayor of Nome and is intended to provide information for planning and decision-making by city officials and state agencies regarding power and space heat strategies for Nome and other similarly situated communities.

1.1 BACKGROUND

Nome is a city of 3,500 people located on the Bering Sea coast of the Seward Peninsula 539 air miles northwest of Anchorage, 102 miles south of the Arctic Circle and 161 miles east of the Russian coast. The location and a photo are shown in Figure 1.1. Currently, all of Nome's electrical needs are provided by the Nome Joint Utility Systems (NJUS). The current load range for the City is 1.8 MWe to 5.2 MWe (yearly average of 3.35 MWe). All power is supplied by diesel generation. Diesel fuel is also required by the residents of Nome for residential and commercial space and water heating. The addition of industrial activity, the Rock Creek Mine, increased the load by about 9 MWe for an average load of 12.35 MWe. The mine, which began initial operations in late 2007, is estimated to be in operation for no more than 7 to 10 years.

The power plant that served Nome was built in 1963 and initially consisted of three 0.6 MW diesel generator units. Additional generation was added as the city's demand for electricity increased. Primarily as a result of the anticipated load growth, a new power plant has been constructed and was put into operation at eh end of 2007. The $21 million project involved construction of a new building at a new location not far from the old power plant, but, unlike the old plant, the new building is above the 100-year flood plain and outside the runway protection zone (RPZ) of Nome's international airport. The new plant will have two new 5.2 MWe generator units and the existing 3.66 MWe and 1.875 MWe generator units will be relocated to the new facility for a total capacity of 16 MWe. The distribution system is 4.16 and 12.47 kV. The replacement project is projected to assure reliable power to the City for the foreseeable future with power to support the Rock Creek Mine, which increases the load range to 10.8 MWe to 14.2 MWe as shown in Figure 1.2.

Figure 1.1. City of Nome, Alaska—Location and Photo

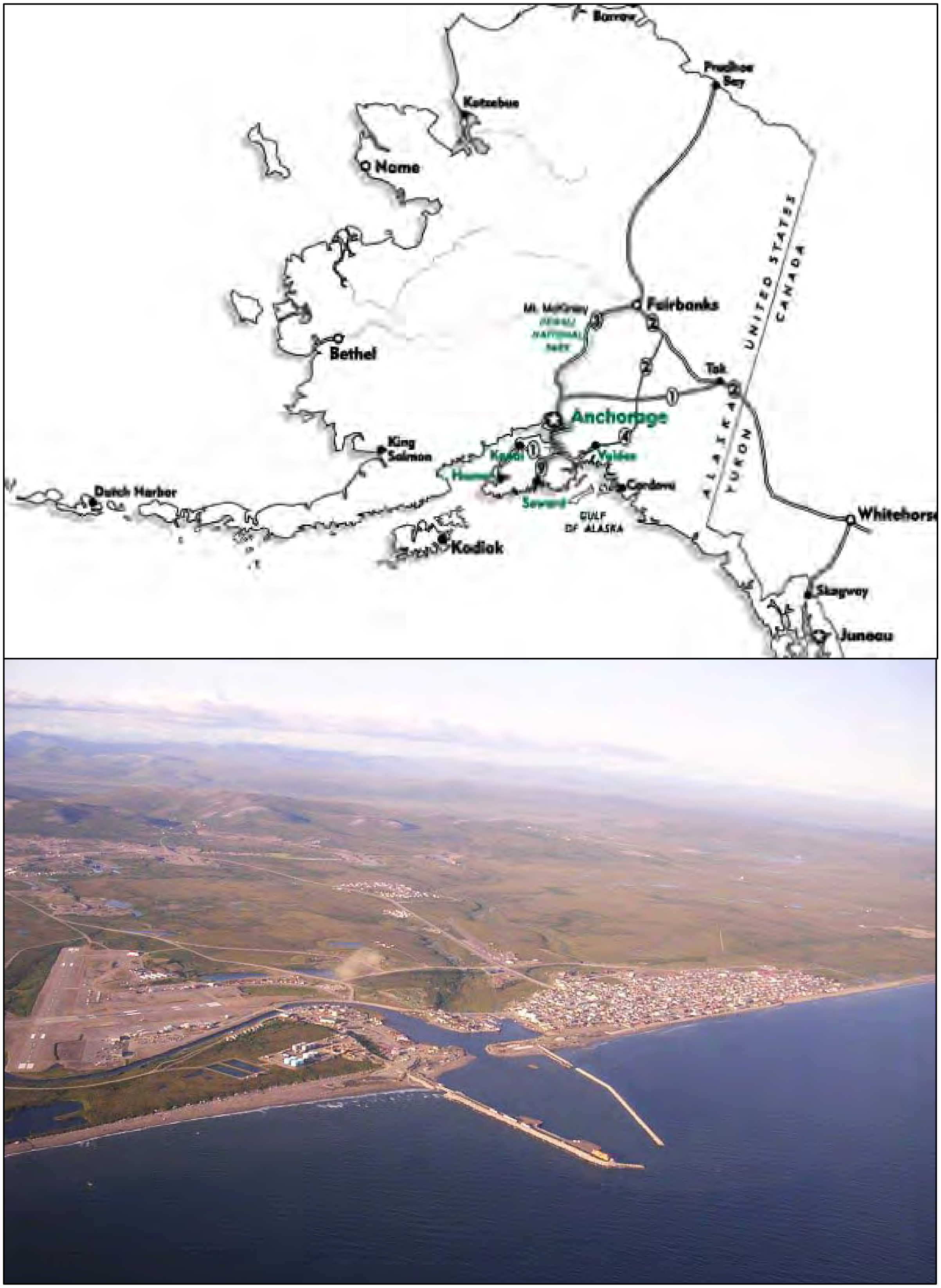
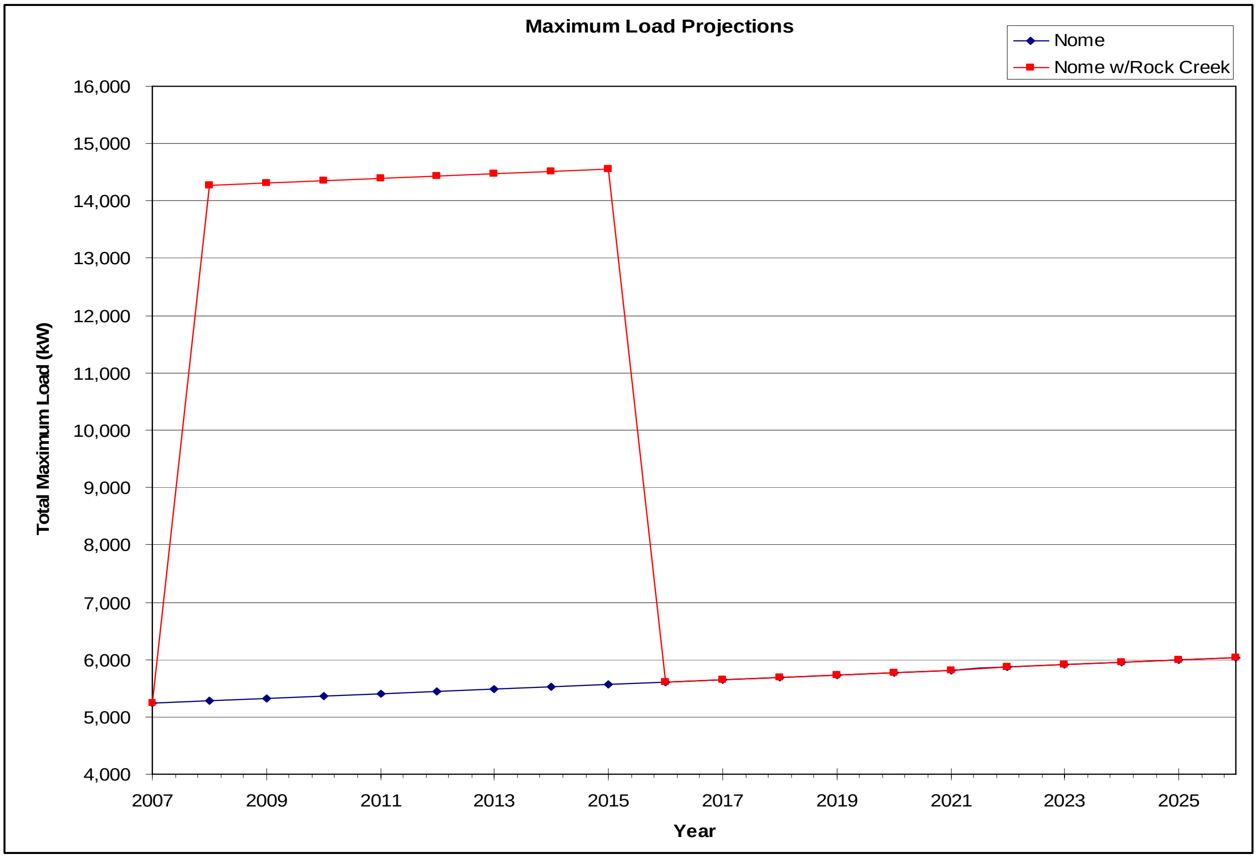


Figure 1.2. City of Nome Electric Load Profile



Recovered heat is currently used for heating the plant site and the potable water system for the City. The diesel generators require 1.8 to 2.0 million gallons of fuel each year. The consumer power rate has held steady in Nome since 2001. It ranges from $0.165 to 0.185/kWh depending upon usage. However, the fuel surcharge has risen from nil to $0.075/kWh in 2006, making the current effective rate from $0.24 to 0.26/kWh. The continuing increase in diesel fuel costs has caused the City to look at alternative power sources to offset the total reliance on diesel.

1.2 SCOPE AND APPROACH

The possible alternate energy sources and technologies analyzed in detail in this study are:

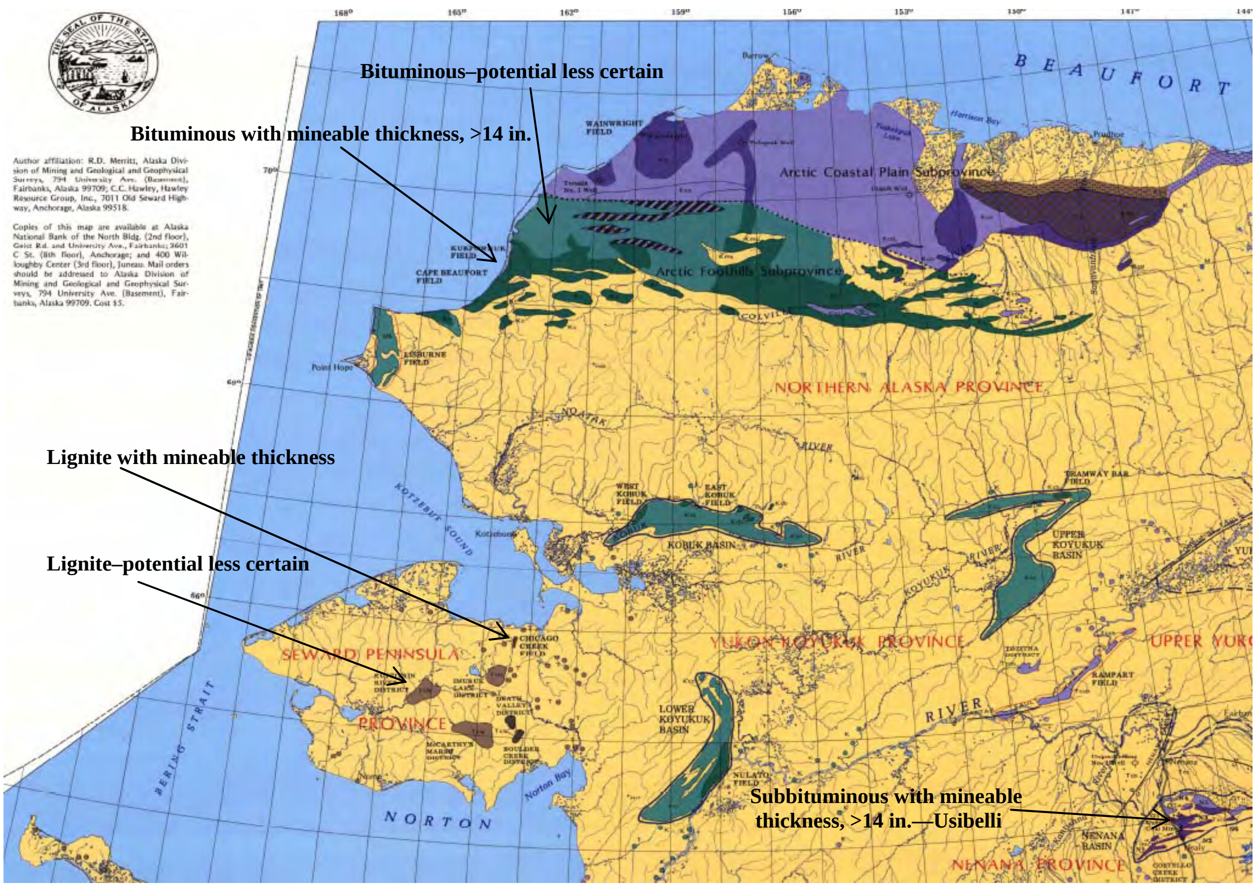
- A barge-mounted coal-fired power plant using coal from either the Usibelli mine near Healy, AK and transported by rail to Seward and then by barge to Nome or British Columbia coal transported by barge or ship to Nome.
- Wind power with the wind turbines located on Anvil Mountain approximately 1 mile north of Nome.
- Geothermal power plant at Pilgrim Hot Springs 60 miles north of Nome with a power transmission network to Nome.
- Natural gas from the Norton Sound delivered to Nome from a sub-sea development with a pipeline to shore and conversion of a diesel engine to burn natural gas at Nome.

Tidal/wave energy technology is less mature than the other alternates listed above and its applicability at Nome has not been assessed. Hence, its potential is not analyzed in this assessment but it may become on option that should be evaluated in the future.

The hydroelectric power option is not considered feasible and is not analyzed as part of the economic comparisons. .

Coal resources are known to exist on the Seward Peninsula, specifically at Chicago Creek on the north side of the Seward Peninsula. Other coal resources are known to exist on the Seward Peninsula and in the Northwest Arctic as shown in Figure 1.3. The coal on the Seward Peninsula is lignite. Beds with mineable thickness are shown in dark brown; i.e., Chicago Creek and Boulder Creek (ADGGS 1990, USGS 2004). None of the Northwest Alaska resources are being actively mined and would require significant capital investment to start operations. This start-up cost would not be justified to supply coal for a small power plant. Hence, the coal plant design and economics are based on coal from the Usibelli Mine in Healy, Alaska and from British Columbia.

Figure 1.3. Northwest Alaska Coal Resources



Coalbed natural gas is not expected to be present in the vicinity of Nome. The geological assessments to date indicate that coal beds do not exist near Nome with the potential to provide viable coal bed natural gas resources for the city ADGGS 1990, USGS 2004). Coalbed natural gas is not evaluated further in this assessment.

The interaction of infrastructure, environmental regulations and advanced technology development for the coal plant, wind, geothermal, and natural gas options are assessed and compared to the existing diesel generation system on an equivalent economic basis.

1.2.1 REPORT ORGANIZATION

The report is organized as follows:

Section 2 is a description of the current utility status for Nome and the load profiles expected for the forecast period of the analysis.

Section 3 is a description of a barge-mounted coal plant. A detailed conceptual design for a self-contained barge-mounted nominal 5 MWe coal-fired plant is described and included in the economic evaluation.

Section 4 is an assessment of the potential for developing a Norton Sound natural gas resource to provide natural gas for use in a shore-based natural gas engine for electric generation and would offer the opportunity to use natural gas for space heating throughout Nome.

Section 5 is a description and analysis for the wind/diesel option based on a modeling study performed by the Alaska Energy Authority (AEA).

Section 6 is a description and analysis of the geothermal resource and power plant option at Pilgrim Hot Springs commissioned by AEA and performed by HDL Engineering Consultants

Section 7 describes the environmental assessments for the alternate energy options.

Section 8 contains the integrated economic evaluation of the energy options referenced to the existing Nome diesel-based power system.

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2 CITY OF NOME–CURRENT UTILITY STATUS AND LOAD PROFILES

The City of Nome provides electric utility service throughout the community. The energy assessment compares alternatives to the current utility system based on diesel generators, which are described in this section. Current and forecast load profiles for electric power and thermal loads for the City of Nome are described. The loads and load-shape profiles are used in the economic analysis for all the energy alternatives.

2.1 CURRENT UTILITY OVERVIEW

The Nome electric utility system has undergone significant capital improvements over the last several years. In anticipation of future load requirements and to improve operating efficiency, the city of Nome undertook installation of two new diesel generating units. A completely new powerhouse was constructed that was sized to accommodate, in addition to the two new generating units, the relocation of up to two of the existing generating units. The new powerhouse that went into full operation in December 2007 has two new 5.2 MWe Wartsila generating units, providing 10.4 MWe of generation capability. The power station construction included upgraded fuel storage and substation equipment. The existing 3.66 MWe and 1.875 MWe generator units will be relocated to the new facility. With the availability of 5.6 MWe provided by the most efficient of the previously installed diesel engines, the system can meet peak loads of up to 16 MWe. A schematic view of the new plant is shown in Figure 2.1.

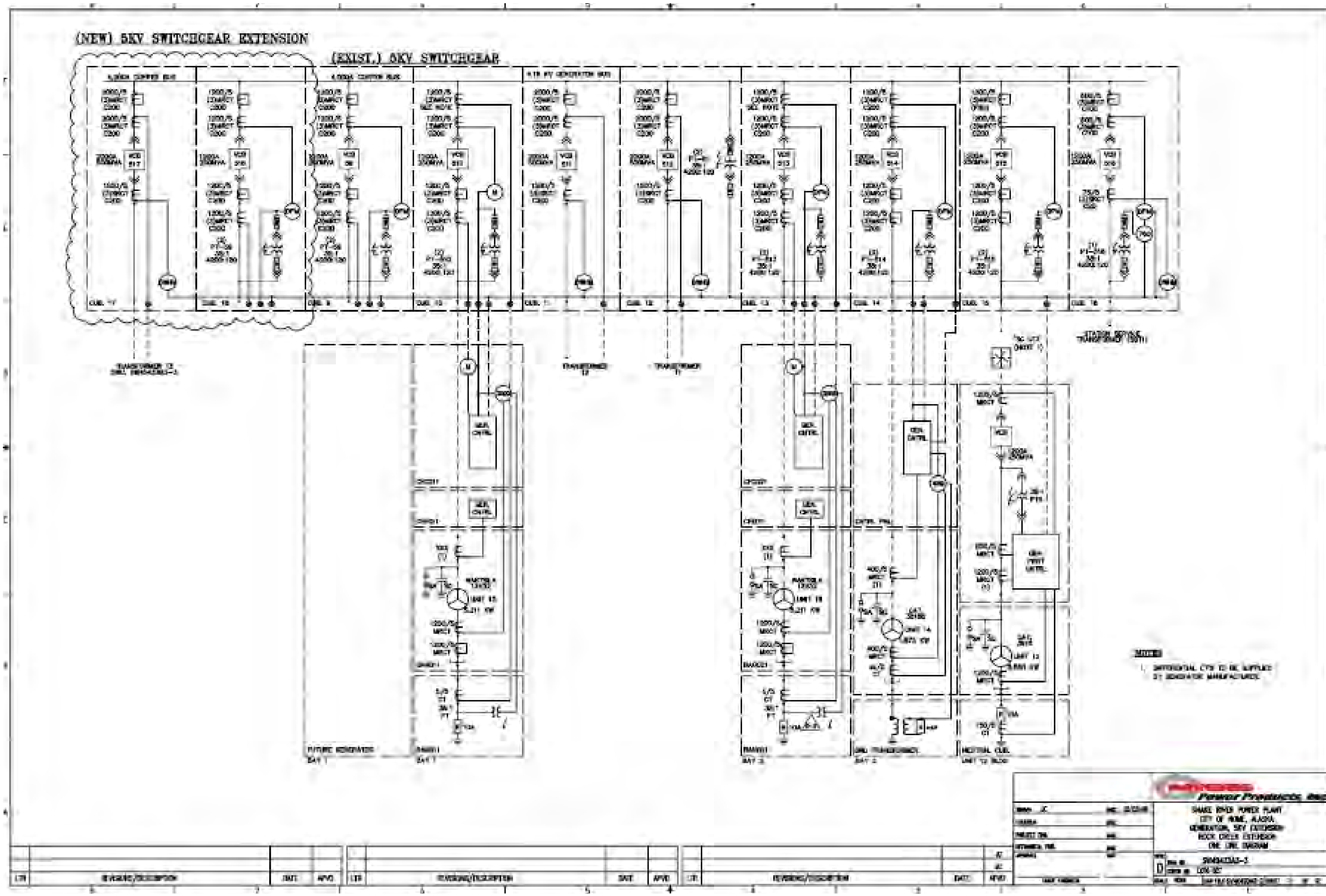
In addition to the new powerhouse and auxiliary systems, a transmission extension was provided to interconnect the electric system with a mining operation at Rock Creek scheduled to being operation in early 2008. The mine is expected to be in full, continuous production by 2009, and require a continuous supply of electricity at a fairly constant level.

As a result of the system improvements, the electric utility is currently capable of meeting all of the capacity and energy requirements of the system for the foreseeable future. The load impact of the mine has been estimated to increase the average MW load from between 3.5 and 4 MW to as much as 12 MW. Instantaneous peak loads for the system are estimated to reach as much as 14.5 MW, but still well within the capability of the electric system. While the mine is expected to operate continuously, it has a reported expected lifetime of only several years. The mine has announced the expectation to operate at least through 2015, and there has been no reported determination of continued operation beyond that date.

The economic analysis begins in the year 2015. This is the first reasonable date that any of the examined generation alternatives can become available except the wind/diesel option, which could possibly be started a few years sooner. The 2015 start date for the analysis corresponds with the date at which the incremental load imposed by the Rock Creek mine is expected to terminate, or, if extended, could be served separately from the available capacity of the existing system. The effect of the future date for the start of operation of new resources and the termination of the mining load is that any new generation alternative will serve only to reduce the amount of generation from the existing diesel units.

A reduction in generation from existing units will reduce diesel fuel requirements and some maintenance costs. It has been assumed that even if the Rock Creek load continues beyond 2015, the existing units will remain in operation. Therefore, new generation facilities will be dispatched on the basis of daily energy requirements and the installed capacity will be adequate to cover any short-term peak load requirements.

Figure 2.1. One-line Schematic of New Power Plant

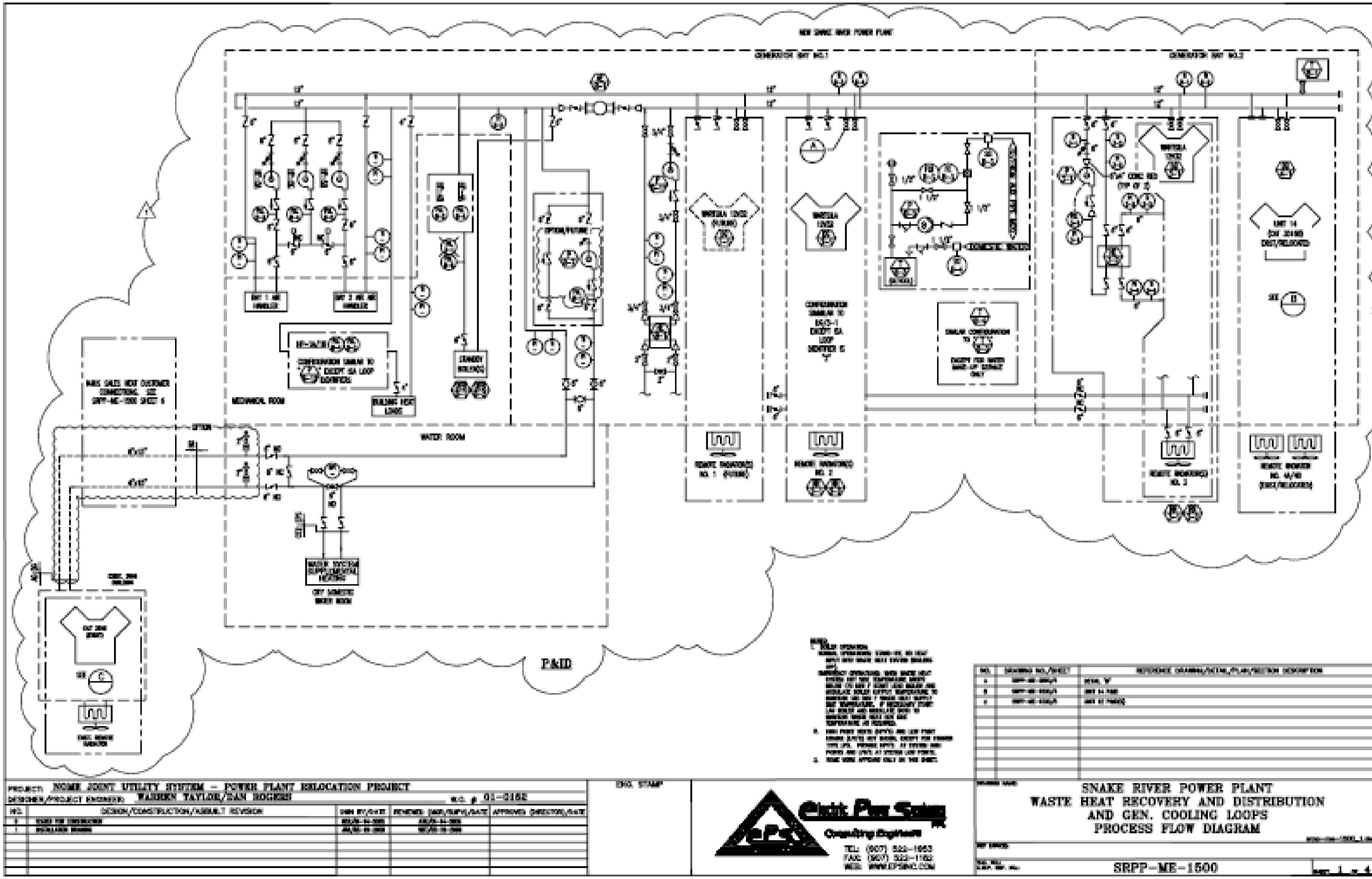


A feature of the existing and new power plant is the operation of a waste heat recovery system and supplemental direct-fired boilers to heat the city water system, the building and potentially other thermal loads. Water from the supply wells located outside of the city gate is warmed several degrees to provide adequate thermal capability to distribute throughout the city at all times of the year. Water-jacket heating from diesel units has been used to provide the source of thermal energy to heat the water. The direct-fired diesel fuel boilers are available as a heat source for the water system, designed initially for backup service.

Currently waste heat from the NJUS power plant is used for freeze protection heating of the NJUS public water system (see Figure 2.2) and power plant facilities (NJUS 2002). The public water system uses the equivalent of approximately 140,000 gallons of fuel oil annually for water system freeze protection. Other thermal load options described in the NJUS–EPS report depended on where the plant is located and included heating the power plant building and associated facilities, the U.S. Postal Service Facility and NJUS offices, the airport facilities, and the Nome Beltz High School, DOT&PF Maintenance Shop and the Anvil Mountain Correctional System.

The average annual heat requirement for the city water system is 17.6 B Btu/year, and must be provided to ensure that the water distribution system remains fully operational at all times. The existing diesel system will contribute to the heat load when diesel units are operated at adequate output levels, but during times when much of the diesel generation may be displaced by an alternative generation source, heat for the water system must be provided by the alternative generation source or the boilers must be in operation. Thus, while new generation alternatives may displace diesel fuel for electricity generation, the reduction is offset somewhat by the amount of diesel fuel required by the boilers.

Figure 2.2. Power Plant Waste Heat Recovery System



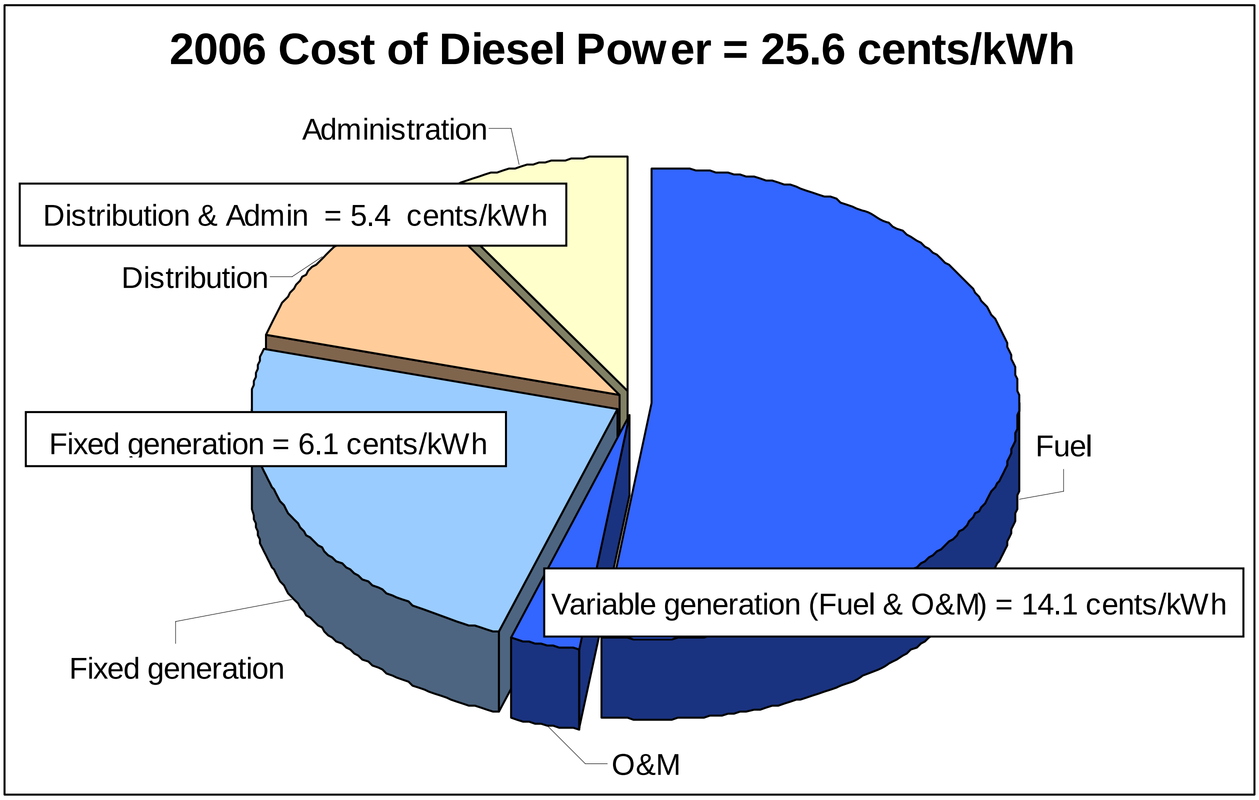
2.1.1 CURRENT SYSTEM LOADS AND COSTS

Sales of electricity for the Nome electric system in 2006 were just over 28,000 Megawatt-hours (MWh). This required approximately 30,200 MWh of diesel generation to provide for sales and system losses. The rate of growth in generation over the last several years has averaged approximately 1.1%, while sales have increased by an average of 1.9%. Diesel fuel efficiency has improved continually, but system losses have varied from year-to-year as a function of changing load patterns.

The average annual cost of providing the electric power for the Nome Joint Utility System, derived from 2006 operating statistics, is approximately $0.256/kWh. Of this total cost, $0.141 is attributable to the variable cost of generation. The fixed costs of generation add $0.061, resulting in a cost of producing electrical energy at the powerhouse of $0.202, nearly 80% of the cost of providing electricity to the city. The balance is the cost of distribution system ownership and operation and the administrative services of the utility and city personnel. The relative proportions of the major components of system operating costs can be seen in Figure 2.3.

Variable generation costs are the only costs that will be displaced by energy producing alternatives. Therefore, the fixed generation costs will continue to be recovered in electric rates as will all other costs of owning and operating the electric system. Effectively, any energy producing generation alternative coming into operation in 2006 would have had to provide electric energy for less than $0.141/kWh to be competitive at that load level.

Figure 2.3. 2006 Cost of Diesel Power

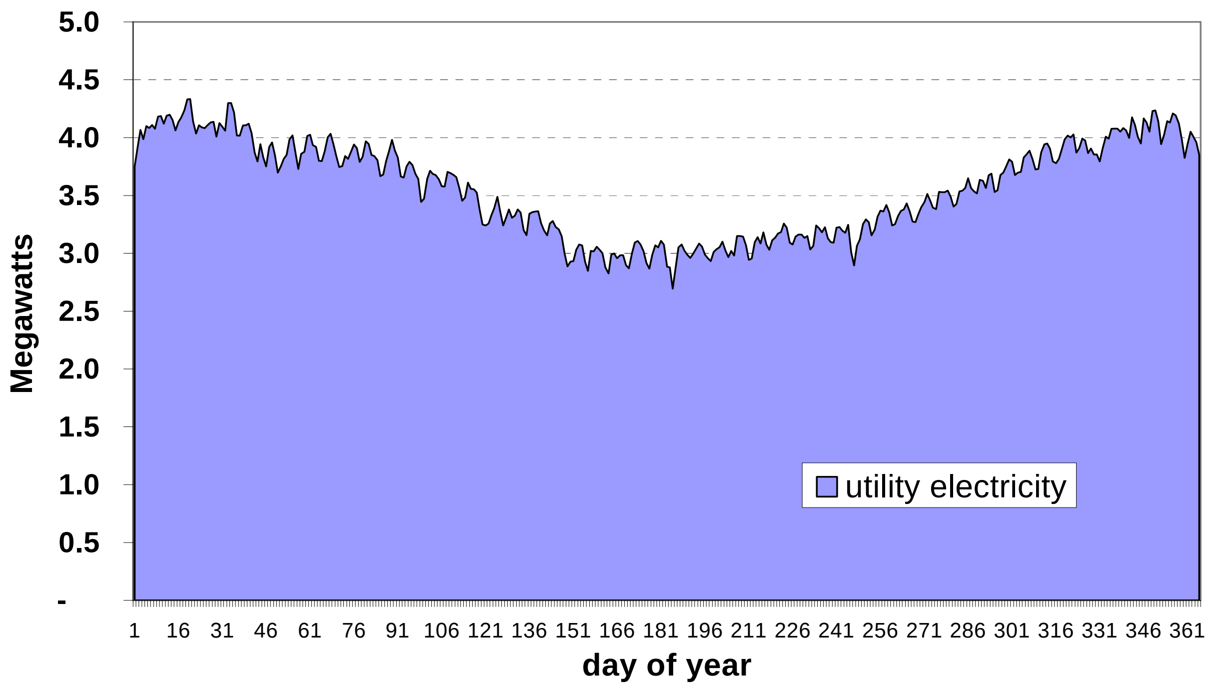


2.1.2 ASSUMPTIONS ABOUT FUTURE LOADS

The economic evaluation of the alternatives available to provide for the electric load of the Nome system is based on the displacement of energy from the existing system, including the newly installed generating units. For both electric generation and commercial and residential space and water heating, the assessment includes a replacement of diesel fuel with natural gas. The key factors for the evaluations are the annual of electrical energy requirements in MWh and the thermal energy requirements in Btu.

Forecasts of electric load were prepared for the city for the purposes of evaluating the timing and size of the newly installed generating units, including the impact of the Rock Creek mine. For the purposes of the screening analysis, those expectations were retained; such that the forecasted city loads (net of Rock Creek) will increase by slightly over 3% between 2006 and 2015. Generation requirements will be 31,198 MWh/yr in 2015, and increase about 1%/yr thereafter. The daily loads throughout 2015 will vary from about 4.3 MW to around 2.7 MW, as illustrated in Figure 2.4.

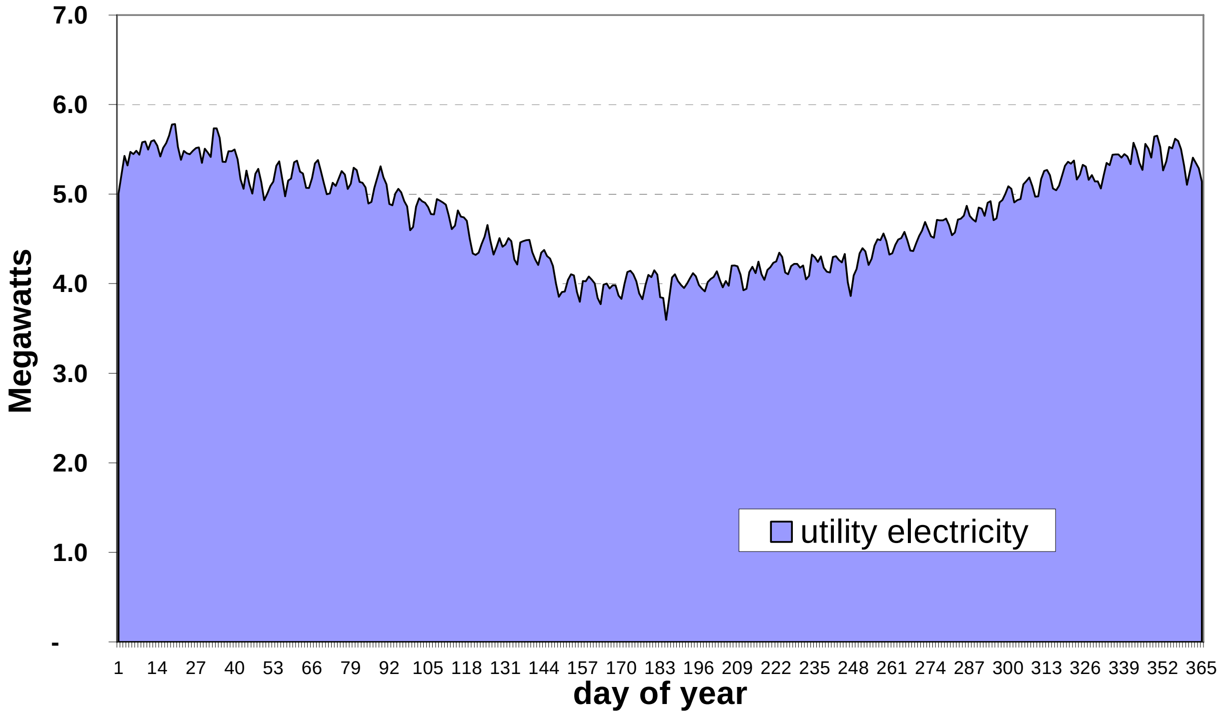
Figure 2.4. Nome Daily Loads–year 2015



The shape of the daily loads throughout the year is significant from the standpoint of the dispatch of the alternative generation units and the existing generating units. The use of the existing system for backup energy provision will be necessary for any period in which the load exceeds that of the alternative provided in a scenario, or whenever the alternative generation facility is shutdown for maintenance or repair. For example, referring to Figure 2.4, if an alternative generation facility is sized at 2.0 MW, it is certain that one or more of the existing generation units available to Nome will be operated for some period of time. If the alternative is sized at 4.5 MW, then existing units would be significantly reduced. If a new facility is sized at 3.5 MW, then existing units would be operated for part of the year, and partially displaced for part of the year. If the sizing is appropriate, maintenance could be undertaken on the new unit during the times that energy requirements are less than the optimal operating level of the new unit.

At the forecasted rate of growth of 1.0%/yr, system electric energy requirements will reach 41,633 MWh/yr in 2044, and the daily loads will move upward accordingly, as illustrated in Figure 2.5, which shows the utility electricity requirements throughout the year.

Figure 2.5. Nome Daily Loads–year 2044



By 2044, the average daily load for the Nome electric system reaches upwards of 5.8 MW in the winter months, and drops to around 3.6 MW on the lowest load day of the year. The load forecast assumes that the annual load shape remains relatively constant from year-to-year, an assumption that may change as energy prices increase and additional conservation efforts are undertaken in response to the higher costs.

Recovered heat is currently used for heating the plant site and the potable water system for the City. The diesel generators require 1.8 to 2.0 million gallons of fuel each year.

2.1.3 THERMAL LOAD

In addition to the recovered heat from the new power plant for the plant site and potable water system for the City, thermal requirement exist for the space and water heating of commercial and residential buildings in Nome. The thermal load requirement is estimated to grow with increases in Nome's population and economic activity. If natural gas is available, the gas may be used as an alternative fuel to displace diesel used for space and water heating.

Annual fuel oil requirements for space and water heating were estimated at 630,606 gal/yr in 2007, increasing to 682,856 gal/yr for 2015, the start year of the economic analysis. Annual increases of 1%/year were assumed, consistent with the growth rate of electric requirements, resulting in an annual diesel fuel requirement for commercial and residential purposes of over 911,000 gal/yr by 2044.

The location of the coal plant will determine the potential for supplying these thermal loads, and would be subject to further engineering and economic evaluation. The character, size, and location of the electric generation alternatives for the city will determine the potential for supplying these thermal loads, and would be subject to further engineering and economic evaluation. Generation alternatives that produce steam, such as a coal plant, could be expected at a minimum to have the capability to supply the thermal energy demand for the city water system and the plant facilities, although with some reduction in electric power capability. Other heating load could be potentially supplied. In the early years of the analysis, some of the electric production alternatives may have surplus generation capability that could supply thermal loads through resistance heating, but not for the term of the analysis.

3 COAL POWER SYSTEMS FEASIBILITY ASSESSMENT

Fluidized-bed combustion systems are the leading edge technology for small scale coal-fueled power systems in the size range from 20 to 300 MWe. However, a plant of this size would be inappropriately large for a community the size of Nome, so NETL commissioned a conceptual engineering design for a barge-mounted coal fired power plant sized appropriately for the community's needs. Fuel choices include sub-bituminous coal, lignite, waste coal, coke, biomass, and sewage sludge. A fluidized-bed system can accommodate a broad range of fuel quality—from 14,000 Btu/lb of bituminous coal down to 1,000 Btu/lb of combustible waste materials.

3.1 COAL SOURCES AND CHARACTERISTICS

Local coal seams are exposed and have been mined at Chicago Creek on the north side of the Seward Peninsula. Other coal resources are known to exist on the Seward Peninsula and in the Northwest Arctic as shown in Figure 1.3 (Section 1). None of these coal resources are being actively mined and would require significant capital investment to begin mining operations. Start-up costs would not be justified to supply coal for a 5 MWe coal-fueled power plant.

At the present time, the most promising sources of coal are the Usibelli Mining Company in Healy, Alaska and major coal fields in British Columbia.

3.1.1 ALASKA COAL

The Usibelli Coal Mine, located in the Alaska Range near the town of Healy, is the only coal mine in Alaska. It has a work force of about 95 employees, operates year-round, and mines about 1.5 million tons of coal per year. Today, UCM supplies six interior Alaska power plants as well as exports coal to South Korea and several other Pacific Rim destination..

Reserves for Usibelli are an estimated 250 million tons of in-place surface mineable coal exist at Usibelli, as shown in Table 3.1 (NETL 2007).

Table 3.1. Coal Reserves at the Usibelli Mine

USIBELLI COAL MINE	Indicated Reserves (million tons)	Proven Reserves (million tons)	Permitted for Mining (million tons)
	250	100	50

The 100 million tons of proven reserves are more than sufficient to sustain current production levels if selected as the source. At 2 million tons per year production, the Usibelli Mine has permits to continue production for 25 years, with more coal available in the future.

The properties of Usibelli coals in the currently mined areas are shown in Table 3.2.

Table 3.2. Properties of Usibelli Coals in Currently Mined Areas

Proximate Analysis Moist (As-Received) (%)	
Moisture	27.0
Ash	8.0
Volatile Matter	36.0
Fixed Carbon	29.0
TOTAL	100.0
Ultimate Analysis (without moisture or ash)	
Carbon	69.5
Hydrogen	4.5
Nitrogen	0.9
Chlorine	--
Oxygen	24.8
Sulfur	0.3
TOTAL	100.0
Heating Value (Btu/lb)	7,800

3.1.2 BRITISH COLUMBIA COAL

Coal in British Columbia varies in rank from lignite to anthracite and is distributed through out the province (Ryan 2002). There is estimated to be an ultimate coal resource available for surface or shallow underground mining of over 22 billion tons in the province. About 50% of the coal exported goes to Japan and most of the rest to Europe, Korea, and South America. The province uses very little coal internally as most electricity in the province is generated by hydropower.

A typical coal for this region is a medium-volatile bituminous coal produced at the Bullmoose Mine owned by Teck-Cominco located in the Gates formation in the Peace River Coal Field. The coal is low in sulfur and phosphorus as shown in Table 3.3.

Table 3.3. Properties of British Columbia Bullmoose Mine Coal

	As shipped quality
Moisture (%)	8.0
Volatile Matter (%)	26.6
Fixed Carbon (%)	56.9
Ash (%)	8.5
Sulfur (%)	0.4
Btu/lb Dry	13,800
MJ/kg	30.18
FSI	5.5 – 7
Hardgrove index	70 – 80
Rmax %	1.1
Calc. HHV as fired (Btu/lb)	12,593

3.2 LIMESTONE SOURCE AND CHARACTERISTICS

A sorbent supply (limestone or other suitable calcium-bearing material) is required for the operation of the coal plant and will be delivered by barge. Alaska Lime Company operates the only limestone mine in Alaska, near Cantwell (DOE 2006). The sorbent is assumed to have the composition shown in Table 3.4.

Table 3.4. Limestone Analysis

	Dry Basis, %
Calcium Carbonate, $CaCO_3$	80.4
Magnesium Carbonate, $MgCO_3$	3.5
Silica, SiO_2	10.32
Aluminum Oxide, Al_2O_3	3.16
Iron Oxide, Fe_2O_3	1.24
Sodium Oxide, Na_2O	0.23
Potassium Oxide, K_2O	0.72
Balance	0.43

3.3 ANALYSIS OF COAL AND LIMESTONE DELIVERY AND COST

For the nominal 5 MWe plant described in Section 3.5, the total annual coal demand at 92% capacity is 41,722 tons/yr of Usibelli sub-bituminous coal from Healy compared to 23,610 tons/yr using bituminous coal from British Columbia. The only method to supply coal to Nome is by barge or larger shipping vessel. The Nome harbor is frozen about eight months per year leaving a four-month window for shipping and the need to store nine months' worth of coal near the power plant.

An attempt was made to obtain a barge estimate from an Alaska shipping firm, but the firm declined to make an estimate because they determined that 36,000 tons/yr could be handled in one trip per year and that it would be uneconomical to position a vessel on the west coast to make this single, annual trip. Therefore, estimates of coal shipping costs used in this study were based on prior studies by NETL (NETL 2006) and Nuvista (Nuvista 2004). All costs from the previous studies were updated to 2007 $s. The Nuvista study contemplated a coal plant located in Bethel, located approximately 300 miles south of Nome. No allowance in shipping distance was made for the difference in distances from Bethel to Nome. These results are shown in Table 3.5.

Table 3.5. Coal Shipping Cost Estimates

Basis	NETL 2006 Study	Nuvista Study	Estimated For Nome	Nuvista Study	Estimated For Nome
Year of Estimate	2006	2003	2007	2003	2007
Origin & Destination	Usibelli to Kenai	Usibelli to Bethel	Usibelli to Nome	British Columbia to Bethel	British Columbia to Nome
Minemouth Price,	$16.9/ton	$15.3/ton	$17.2/ton	Included below	Included below
Land transport	$8.2/ton	$1.9/ton	$8.3/ton	Included below	Included below
Price to Port	$25.1/ton	$17.2/ton	$25.5/ton	$31.8/ton	$35.6/ton
Shipping cost Load-ship-unload	$14.5/ton	$33.7/ton	$37.8/ton	$37.7/ton	$42.3/ton
Total delivered price	$39.6/ton	$50.9/ton	$63.3/ton	$69.5/ton	$77.9/ton
Coal Heating Value	7,800 Btu/lb	7,800 Btu/lb	7,800 Btu/lb	13,800 Btu/lb	13,800 Btu/lb
Total delivered price	$2.54/MMBtu	$3.26/MMBtu	$4.06/MMBtu	$2.52/MMBtu	$2.82/MMBtu

The Alaska Lime Company mine owner projected that limestone could be shipped for similar handling costs as those for coal. The mine-mouth cost was estimated to be $98/ton. Thus, the total delivered price at Nome is estimated to be about $144/ton. (The land transport and shipping costs from column 4 of Table 3.5 are $46.10/ton). The sorbent consumption rate is a small fraction of the coal consumption rate, depending on the sulfur content of the coal and the available calcium content of the sorbent. For the Usibelli coal used as the basis for the designs in this report, the limestone consumption rate is less than 1 percent of the coal-firing rate.

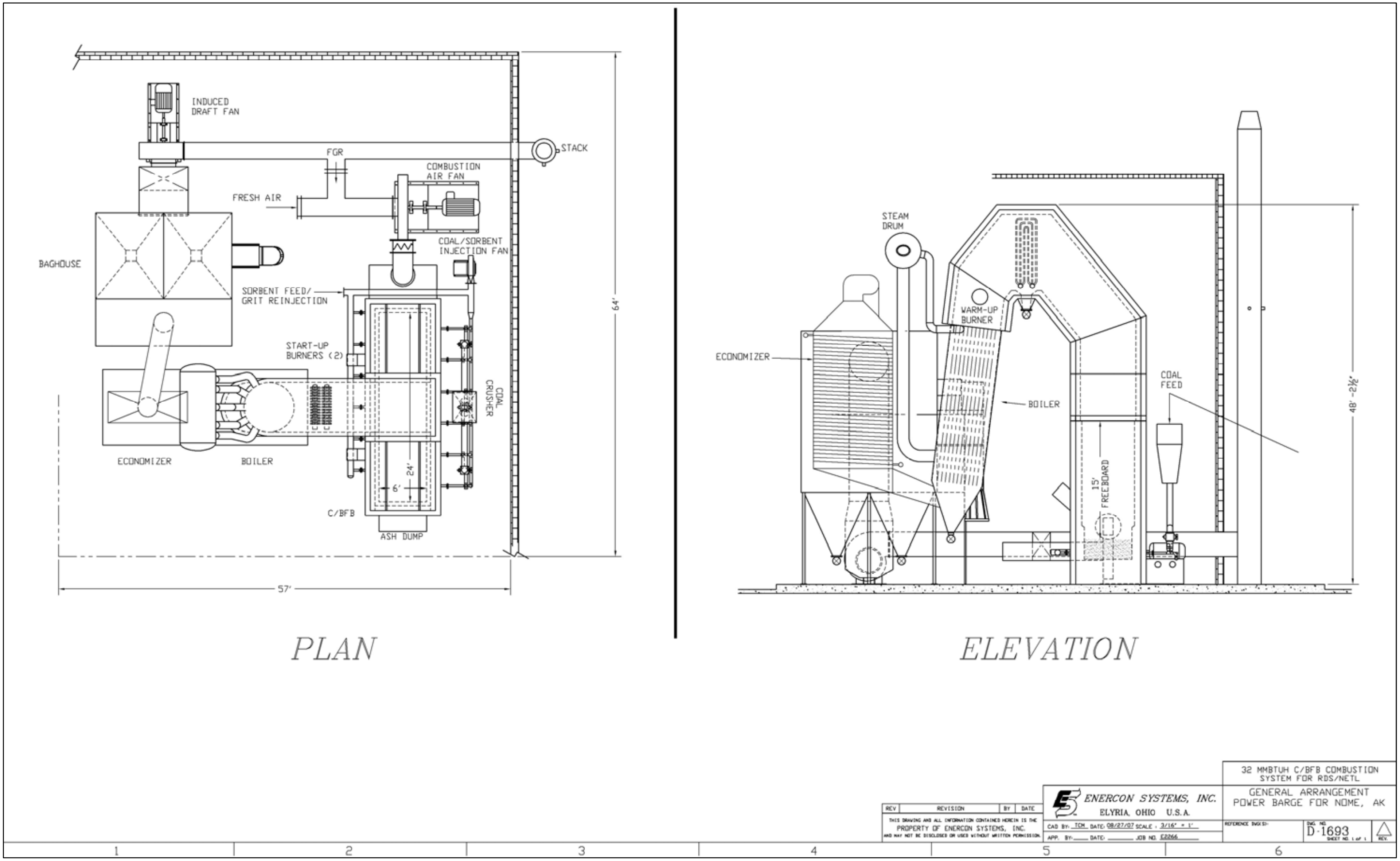
3.4 5 MWe BARGE-MOUNTED COAL PLANT

The nominal 5 MWe coal-fired unit designed for this study is capable of combusting a wide range of coals; the case described herein reflects performance with Alaska Usibelli subbituminous coal. Performance of the power plant will vary (power output, heat rate) depending on the fuel combusted.

This unit utilizes three modular design circulating/bubbling fluidized bed (C/BFB) combustors; each with a fire tube boilers, steam superheaters, economizers, and ancillary equipment. The three boilers generate steam for one steam turbine generator set, similar to those used in industrial applications. The estimated performance for the coal-fired power plant is a net electrical output of 4,655 kWe, and a net heat rate of 20,885 Btu/kWh, on a higher heating value (HHV) basis. The barge is also provided with an onboard diesel generator rated at a nominal 1 MWe. The diesel generator is fueled with No. 2 oil, and can be used as a peaking unit and as backup for the coal fired modules to support critical loads that may be identified on shore. *However, for the purpose of this assessment*, it is assumed that the existing diesel generators already existing within Nome will provide this service and that the 1 MWe onboard generator would be used rarely.

Figure 3.1 is a schematic diagram of the process flows for each of the three boilers required for this 4,655 kWe coal fired power plant.

Figure 3.1. 32 MMBtu/hr C/BFB Clean Coal Combustion System Schematic Flow Diagram



Coal is crushed and pneumatically injected into the C/BFB. The bed depth can be up to 36 inches deep (expanded). Limestone and recycled char and limestone are also pneumatically injected into the bed such as to promote some lateral mixing with the injected coal in the bed.

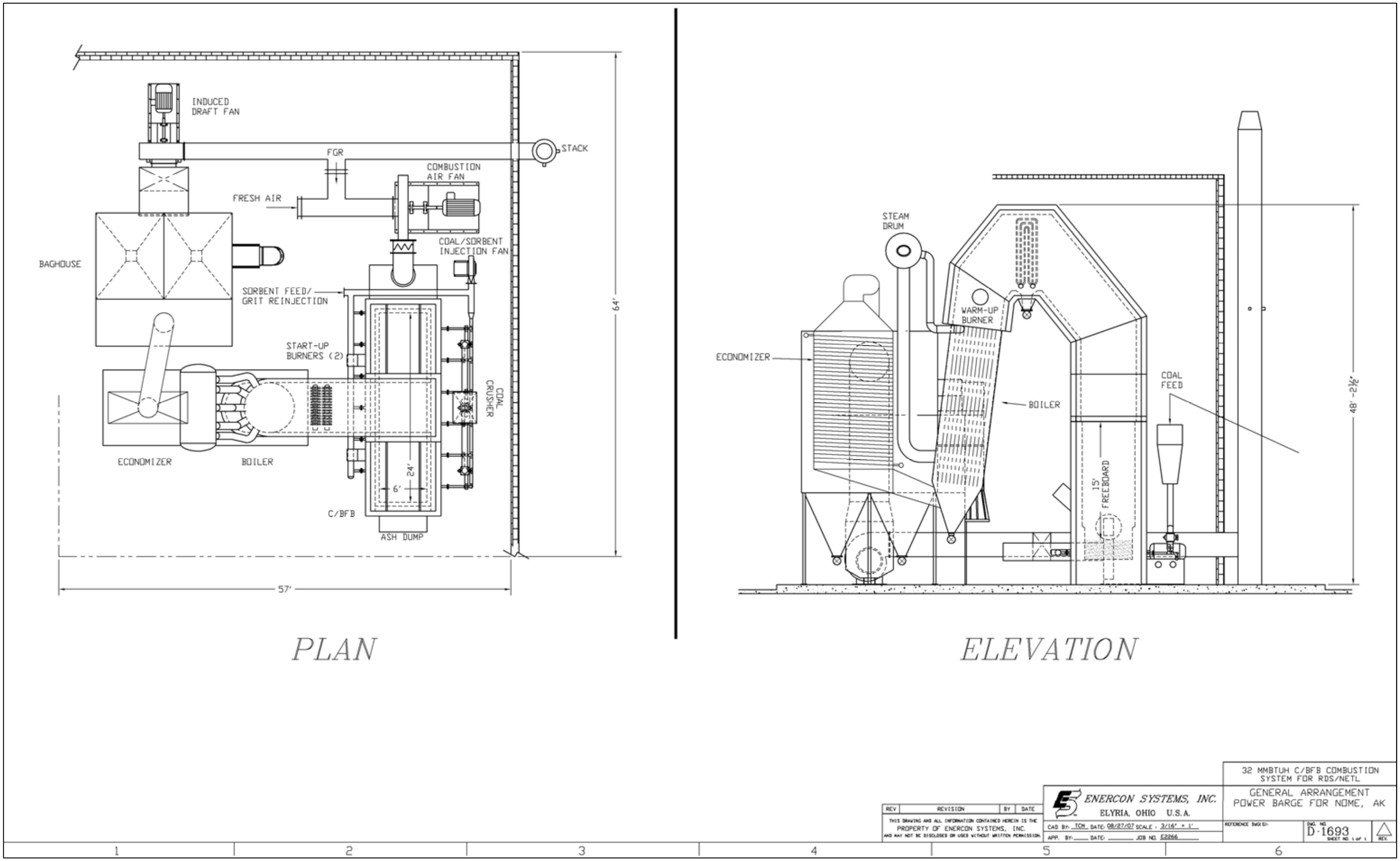
A unique feature of the C/BFB is the utilization of flue gas recirculation (FGR) for bed temperature control and to minimize the use of excess air, which would reduce thermal efficiency. The products of combustion leave the bed at 1,575ºF, enter the freeboard section and pass through a pendant superheater on route to the boiler. A hopper under the superheater collects large particles of limestone and char for re-injection into the bed for improved combustion efficiency and sorbent utilization. The gases leaving the superheater pass in a down-flow manner through the fire tube boiler, then up-flow through an economizer section. The economizer exit gas at 370ºF enters a baghouse for particulate removal. An induced draft fan, ducting, and stack complete the gas circuit.

Each of the three modular C/BFB combustion systems is provided with a combustion air fan, an induced draft fan, and coal/sorbent injection blowers. The scope of each modular system includes the following equipment:

- Coal Crusher and Feed Hopper
- Coal Injection Blowers
- Sand Loader
- C/BFB Combustor
- Freeboard Chamber
- Superheater
- Firetube Boiler and Steam Drum
- Economizer
- Baghouse, including air compressor for backpulse
- Combustion Air Fan and Induced Draft Fan
- Solids Recycle and Ash Screw Conveyors
- Startup and Warmup Burners
- All ducting (up to the stack) and structural steel for support of the above listed components
- Instrumentation
- Smart MCC
- Control Room Skid with integrated PLC control system and a PC for data management.

The three superheater outlets are headered together to provide up to 66,700 pounds/hr of steam at 250 psig/700ºF (at the turbine throttle) to the single condensing steam turbine. Figure 3.2 presents plan and elevation views of one of the three modular C/BFB coal combustion systems.

Figure 3.2. 32 MMBtu/hr C/BFB Coal Combustion System General Arrangement—Plan and Elevation



3.4.1 HEAT AND MASS BALANCE

The overall performance of this coal fired power plant is evaluated by consideration of the following three aspects:

- Boiler efficiency in converting fuel input into steam
- Steam turbine efficiency converting steam into power at the generator terminals
- Auxiliary electrical loads that are subtracted from the generator output to arrive at a net electrical output.

The boiler efficiency is dependent on the fuel that is fired. In particular, when efficiency is determined on a higher heating value (HHV) basis, high moisture coals will reduce efficiency due to losses from the moisture in the stack gas. The efficiency of the three C/BFB combustors and boilers is summarized in Table 3.6.

Table 3.6. Plant Performance–Two Coals

Coal	British Columbia	Usibelli
Thermal Input (fuel), Btu/hr	97,200,000	97,200,000
Thermal output (steam), Btu/hr	78,521,622	76,046,412
Boiler Efficiency (FW at 250ºF)	80.8%	79.1%
Moisture	8%	27%
Fuel HHV as Fired (calculated)	12,593	7,800

Overall performance for the coal fired plant is summarized in Table 3.7, which includes auxiliary power requirements. The steam cycle design parameters were selected to maximize output and efficiency, while remaining within the limits of the modular combustor and fire tube boiler design. Loads are presented for three modular combustor/fire tube boilers, and one steam turbine driven generator.

Table 3.7. Plant Performance Summary–100 Percent Load

STEAM CYCLE	
Throttle Pressure, psig	250
Throttle Temperature, °F	700
Reheat Outlet Temperature, °F	n/a
POWER SUMMARY (Gross Power at Generator Terminals, kWe)	
Gas Turbine	n/a
Steam Turbine	5,705
Total	5,705
AUXILIARY LOAD SUMMARY, kWe	
Coal Handling/Coal Crushing	20
Limestone Handling & Preparation	Neg.
Induced Draft Fans (3@ 70 hp)	165
Fluidization Blowers (3 @ 270 hp)	640
Condensate/ Feed Pump	30
Miscellaneous Balance of Plant (Note 1)	20
Heat Sink (Condenser) Fans	150
Transformer Loss	25
TOTAL AUXILIARIES, kWe	1,050
Net Power, kWe	4,655
Net Efficiency, % HHV	16.34
Net Heat Rate, Btu/kWh (HHV)	20,885
CONDENSER COOLING DUTY, 10^6 Btu/hr	60
Condenser Backpressure, in. Hga	2.0 to 4.0
CONSUMABLES	
As-Received Coal Feed, lb/hr, Usibelli	12,465
Sorbent, lb/hr	100
Note 1--Includes plant control systems, lighting, HVAC, etc. Note 2--Soot blowing medium is steam. Electric power consumption is negligible.	

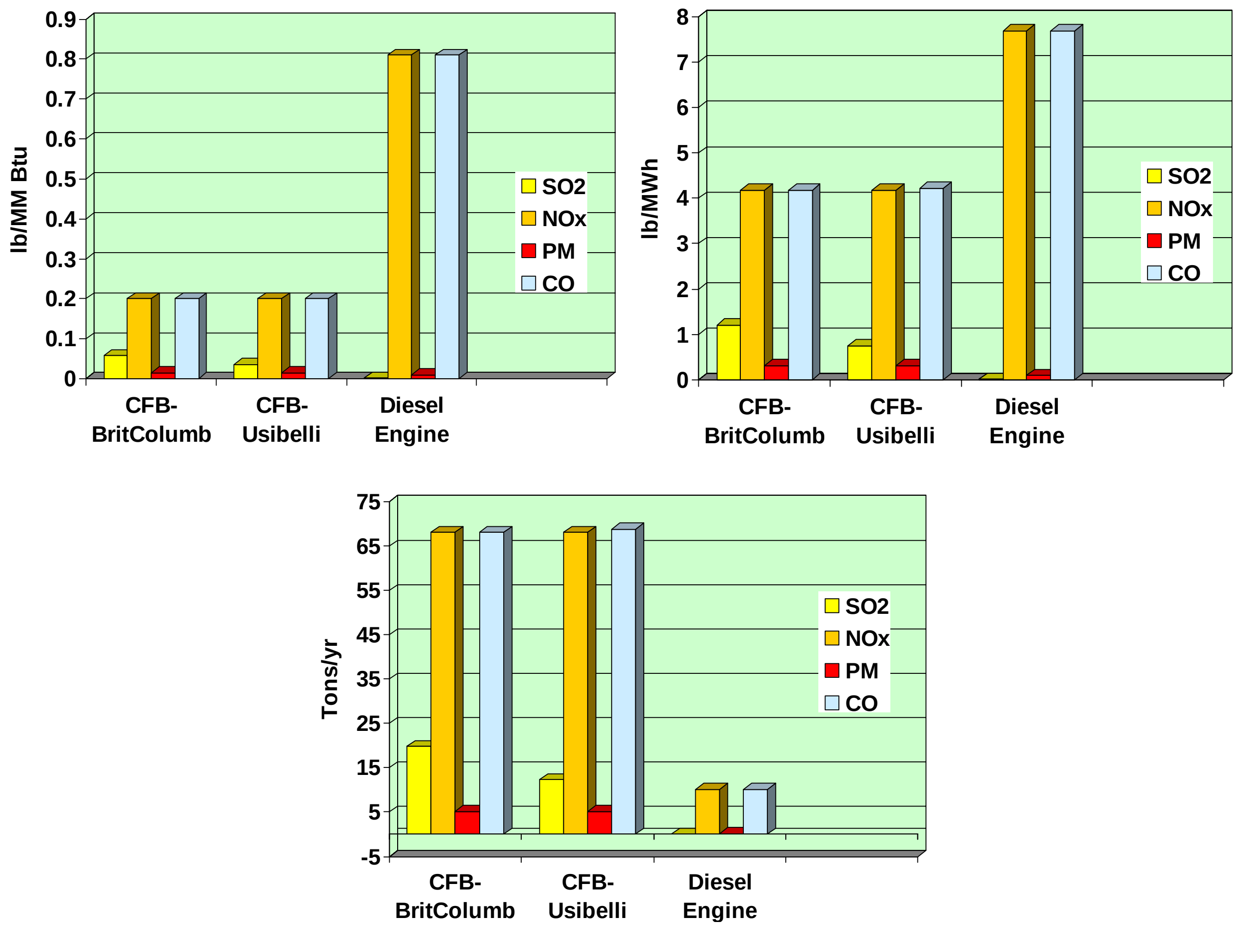
For the 4.655 MWe coal-fired portion of the plant, the total annual coal demand at 80% capacity is 35,240 tons/yr of Usibelli sub-bituminous coal from Healy compared to 18,900 tons/yr using bituminous coal from British Columbia.

The coal fired power plant generates power using a conventional steam (Rankine) cycle that is based on a 250 psig/700°F non-reheat configuration. In this unit, a single geared, condensing steam turbine drives an open frame, air cooled machine electric generator at 3,600 rpm. The turbine exhausts to an air cooled direct condenser that operates as an evaporative unit at ambient temperatures above about 38 ºF dry bulb, and operates dry at lower ambient temperatures. Condenser backpressure varies from 2.0 to 4.0 inches Hga depending on the mode of operation and the ambient conditions. The feedwater train consists of a single closed feedwater heater and one open feedwater heater (deaerator). Final feedwater temperature into the economizer section of the modular boilers is 250ºF.

3.5 EMISSIONS PERFORMANCE

The 5 MWe (nominal) power barge is projected to generate emissions of NOx, SO_2, CO, and particulates as presented in Figure 3.3.

Figure 3.3. Projected Coal Plant Emissions



The low level of SO_2 emissions is achieved by capture of sulfur in the bed by calcium in the limestone sorbent. The nominal design basis SO_2 removal rate is 85% with a Ca/S ratio of 2.4 for the fluid bed.

The low production of NOx is achieved by controlling the temperature and percent oxygen for combustion in the fluid bed. The design bed gas exit temperature of 1,575ºF optimizes sulfur capture, provides good carbon burnout and is a significant contributor to reducing formation of NOx in the bed, since the kinetics of NOx formation are significantly retarded at these relatively low combustion temperatures. The techniques of selective catalytic reduction (SCR) or selective non-catalytic reduction (SNCR) can further reduce NOx emissions, but are not applied to the subject plant.

Particulate discharge to the atmosphere is reduced by the use of modern state of the art bag filters, which provides a collection efficiency greater than 99.99%.

CO emissions are kept relatively low by tuning the amount and distribution of excess air in the fluid bed. .

3.6 CAPITAL COST ESTIMATE

The capital costs of the barge system have been estimated in two subtotals, one for the barge itself and the second for the supporting land based facilities. The estimates for these two entities were prepared using a combination of cost estimating models, input from equipment suppliers, and limited material take-off quantities. The estimate is broken down into line item summaries in accordance with Electrical Power Research Institute (EPRI) Technical Assessment Guide methodology. The estimate breakdown shows labor hours and costs, and material (bulks and equipment) costs.

The final estimate for this study shows the land based facilities at just under $15 million on a bare erected cost basis, and the power barge at $37 million on the same basis. The power barge is estimated based on construction in a U.S. west coast shipyard, with towing or transportation by heavy lift ship to Nome, Alaska. The barge is completely assembled and tested (hydro-test, system functional testing, first steam generation, etc.) in the shipyard prior to release for transportation.

The total direct construction cost for the entire barge system is just under $52 million. Potential exists to reduce this amount by a more detailed conceptual design of the land-side facility, particularly the coal unloading and storage system. An option that was not evaluated was using the barge for transport only, unloading pre-assembled modules onto prepared foundations on shore at the power plant site. The barge may then be released for other duties (general cargo, etc.). This removes the barge cost of $12 million from the capital cost, to be replaced by foundation costs, barge rental (in lieu of purchase). Further optimization of the power plant is also possible, during more detailed design. The barge estimate is shown in Table 3.11 below.

The estimated total direct construction costs (capital and labor costs) of just under $52 million results in a cost on a Total Plant Cost (TPC) basis of just under of $9,200/kWe based on the total output of the plant of 5,655 kWe. The addition of engineering (10% of TPC) and contingency (15% of TPC) results in a total project cost of $65.5 million or just under $11,600/kWe. The cost per unit of electricity delivered is presented in Section 8—Economics Evaluation and is based on the 4.655 MWe output from the coal powered portion of the plant only, which results in the use of $14,100/kWe in the economics.

Table 3.8. Summary Capital Cost for 5 MWe Barge Power Plant

CLIENT:	Department of Energy -NETL	ESTIMATED :	Weiss	DATE :	17-Sep-07
PROJECT:	City of Nome Alaska - 5 ME Barge Mounted PP	CHECKED :		DATE :	
DESCRIPTION:	Barge Mtd ,Bubbling Fluidized Bed Boilers	APPROVED :		DATE :	
W. O. NO:		REVISED :		DATE :	16-Oct-07
	CONCEPTUAL ESTIMATE				

[ ] SUMMARY
[x] C/S/A
[x] MECHANICAL
[x] PIPING
[x] ELECTRICAL
[x] I/C

ITEM NO.			DESCRIPTION	QUANTITY	UNIT	TOTAL MAN-HOURS	MATERIAL COST	LABOR COST	TOTAL COST
					ATTACHMENT				
				S U M M A R Y -					
		ON SHORE							
	L	1A	COAL RECEIVING AND HANDLING			22,765	4,546,700	2,817,700	7,364,400
	L	1B	LIMESTONE HANDLING			5,346	557,700	661,700	1,219,400
	B	3a	CONDENSATE AND FEED WATER			-	-	-	-
	B	3B	BALANCE OF PLANT SYSTEMS			-	-	-	-
	B	4	AFBC BOILERS AND ACCESSORIES			-	-	-	-
	B	5	FLUE GAS CLEANUP			-	-	-	-
	B	7	DUCTING AND STACK			-	-	-	-
	B	8	STEAM TURBINE GENERATOR AND ACCESSORIES			-	-	-	-
	B	9	AIR COOLED (EVAPORATIVE) CONDENSER			-	-	-	-
	L	10	ASH HANDLING			9,413	1,310,000	1,165,000	2,475,000
	S	11	ACCESSORY ELECTRICAL PLANT			3,650	449,200	452,500	901,700
	S	12	INSTRUMENTATION AND CONTROL			1,161	133,100	144,000	277,100
	L	13	IMPROVEMENTS TO SITE			5,737	1,248,000	710,100	1,958,100
	S	14	STRUCTURES AND BARGE			771	554,300	95,400	649,700
			Subtotal Land based scope			48,843	$ 8,799,000	$ 6,046,400	$ 14,845,400
		ON BARGE							
		1A	COAL RECEIVING AND HANDLING			-	-	-	-
		1B	LIMESTONE HANDLING			-	-	-	-
		3a	CONDENSATE AND FEED WATER			9,340	849,800	1,127,600	1,977,400
		3B	BALANCE OF PLANT SYSTEMS			6,634	1,323,500	821,100	2,144,600
		4	AFBC BOILERS AND ACCESSORIES			26,755	7,164,000	3,311,500	10,475,500
		5	FLUE GAS CLEANUP			3,973	1,569,300	491,800	2,061,100
		7	DUCTING AND STACK			230	120,000	28,500	148,500
		8	STEAM TURBINE GENERATOR AND ACCESSORIES			6,798	2,395,300	841,400	3,236,700
		9	AIR COOLED (EVAPORATIVE) CONDENSER			7,089	1,019,800	877,400	1,897,200
		10	ASH HANDLING						
		11	ACCESSORY ELECTRICAL PLANT			8,790	1,239,300	1,087,200	2,326,500
		12	INSTRUMENTATION AND CONTROL			2,797	367,200	345,900	713,100
		13	IMPROVEMENTS TO SITE			-	-	-	-
		14	STRUCTURES AND BARGE (BARGE)			-	12,000,000	-	12,000,000
			Subtotal Barge based scope			72,406	$ 28,038,200	$ 8,932,400	$ 36,970,600
			Total Direct Construction Costs			121,249	36,837,200	14,978,800	51,816,000
			Engineering						5,181,600
									56,997,600
			Contingency	15%					8,549,640
			Total project (September 2007 dollars US)						65,547,240

3.7 BALANCE OF PLANT DESCIRIPTOIN AND EQUIPMENT LISTS

Descriptions of the Balance of Plant and equipment lists for the auxiliary components and systems on and off the barge required to support operation of the barge-mounted coal plant are provided in Appendix A, B, C, and D. Appendix A contains the balance-of-plant descriptions for the combustor and boiler support systems. Appendix B contains the balance-of-plant descriptions for the steam cycle. Appendix C contains description of the plant site, structures and systems integration, which includes the barge design and layout. Appendix D contains the equipment lists for the components.

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4 NATURAL GAS

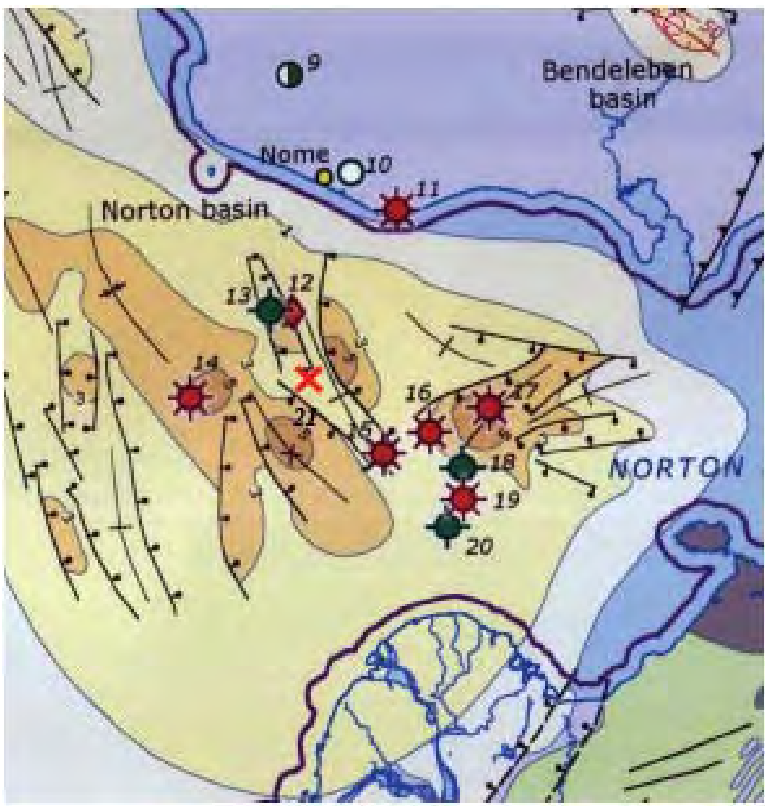
The possibility of developing of a subsea production system providing natural gas for onshore electricity generation, and distribution of natural gas for home and business heating, is assessed in this section. The analysis relies heavily on the information published by the U.S. Department of Interior (DOI), Minerals Management Service (MMS) Alaska Outer Continental Shelf (OCS) Region in two reports: *Undiscovered Oil and Gas Resources, Alaska Federal Offshore as of 2006* (MMS 2006), and *Engineering and Economic Analysis of Natural Gas Production in the Norton Basin* (Reitmeier 2005).

4.1 NORTON BASIN NATURAL GAS RESOURCE POTENTIAL

Natural gas is known to exist in the Norton Basin, approximately 30 miles offshore of Nome. A number of exploratory wells were drilled and are presented in Figure 4.1 and described below.

ARCO Alaska Inc. drilled two Continental Offshore Stratigraphic Test (COST) wells in the Norton basin, one in 1980 and the other in 1982. COST Well No. 1 (#14) is located 54 miles southwest of Nome and was completed in September 1980. COST Well No. 2 (#18) is located 68 miles southeast of Nome and was completed August 1982. COST Well No. 1 (#14) mud logs indicated strong shows of methane at depths of 3,000 to 6,000 ft. COST Well No. 2 (#18) showed only minor shows of gas (Reitmeier 2005).

Figure 4.1. Norton Basin Exploration Wells



During the summer of 1984 three wells were drilled. Exxon Corporation drilled exploratory wells OCS Y-0414 (#15), Y-0430 (#19) and ARCO drilled exploratory well OCS Y-0436 (#13).

Exxon's OCS Y-0414 (#15) and ARCO's OCS Y-0436 (#13) wells showed strong shows of methane in the 1,200 to 3,600 ft interval. These wells were later plugged and abandoned.

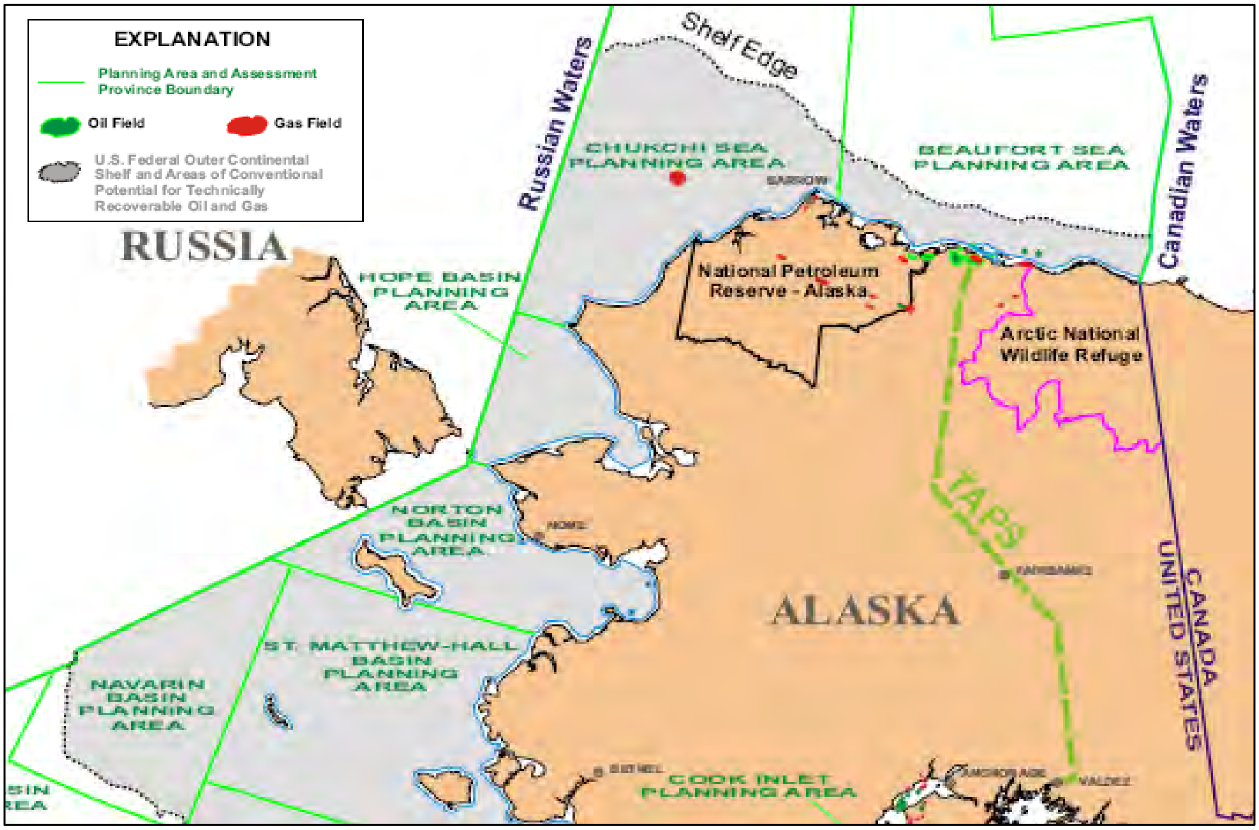
Exxon drilled three more exploration wells in 1985, OCS Y-0407 (#16), OCS Y-0398 (#17), and OCS Y-0425 (#19). Wells OCS Y-0407 (#16) and OCS Y-0425 (#19) showed moderate to strong gas shows in the 1,000 ft to 3,000 ft interval. These three wells were also plugged and abandoned.

Exploration targets at the time were for oil and the assumption was that commercial gas development would require a large scale liquefied natural gas (LNG) project designed for exportation, which was uneconomic at that time (Reitmeier 2005).

In 2006 the MMS estimated that the mean risked, undiscovered, technically recoverable gas for the Norton Basin is 3.06 trillion standard cubic feet (Tscf) of natural gas—a modest resource from a commercial perspective (is this an accurate characterization of the resource base?). The MMS assessment provinces (see Figure 4.2) include three northern Bering Sea Basins—Hope, Navarin and Norton Basins—and concludes that commercial development of the area is highly unlikely. The requirement for successful exploration and development in all three basins, the low potential for commercially sufficient quantities of gas, and geological and economic risks are cited by MMS in support of its conclusions. Hence, a <u>commercial</u> scenario for gas development in the Norton Basin that could provide lower-cost natural gas to the Nome Region has a very low probability of occurring and is not included in this analysis.

However, the strong gas shows in the exploration wells suggests that enough natural gas can be developed in the Norton Basin to supply the needs of the Nome region, just not enough to export out of the region on a commercial basis. Therefore, this study includes an analysis that assumes that some government entity or perhaps the utility will explore and develop a natural gas resource to support the energy needs of Nome.

Figure 4.2. MMS 2006 Alaska OCS Assessment Provinces (source: MMS 2006)



For the purpose of this study, the prospect evaluated is located 30 to 40 miles directly south of Nome with a water depth of 50 feet. The MMS (2006) assessment for the Mid-Tertiary West Subbasin Fill Play resulted in an estimate of mean risked, undiscovered, technically recoverable gas of 1.944 Tscf. This estimate indicates that gas resources adequate to meet the needs of the Nome region may exist in this play. However, this potential natural gas resource has not been confirmed except for natural gas shows described above. It is important to note that no production tests were performed, making this a highly speculative scenario for economic analysis.

4.2 NOME GAS SUPPLY REQUIREMENTS

For Fiscal Year 2006 (July 1, 2005 to June 30, 2006) the city of Nome used 1,907,272 gallons of No. 2 diesel for electrical generation (AEA 2006 PCE Report). Total electricity generated in FY 2006 was 30,392,934 kWh. This results in a heat rate for the diesel generators of 8,472 Btu/kWh or an efficiency of 40.3% efficiency. The forecasts used in the economic analysis as described in Section 2 are 31,198 MWh in 2015 increasing to 41,633 MWh in 2044.

The existing diesel engines are not designed for dual fuel application and cannot be converted to run on natural gas. Therefore, this analysis incorporated the cost of exchanging one of the existing Wartsilla engines for a duel-fuel Wartsilla 32 (or similar) with the characteristics shown in Table 4.1.

Table 4.1. Heat Rates for Wartsilla Dual-Fuel Engine

Model	Power (kWe)	Heat rate (Btu/kWh)
Wartsilla 32 reciprocating engine	5819	7,653 (natural gas mode) 7,709 (fuel oil mode)

Norton Basin gas is assumed to contain 10% CO_2 by volume resulting in an energy density of 900 Btu/scf (Reitmeier 2005). Hence, the volumes of Norton Basin natural gas required for fiscal years 2006, 2015, and 2044 utilizing the Wartsilla 32 engine operating on natural gas. are illustrated in Table 4.2.

Table 4.2. Natural Gas Requirements for Nome Electric Generation

	2006	2015	2044
Quantity of No. 2 used for generation	$1.91X10^6$ (gal/yr)		
No. 2 Diesel heat equivalent	138,000 (Btu/gal)		
Btu Used for power generation	263 (MMBtu/yr)		
Nome Electricty Use	30,393 (MWh/yr)	31,198 MWh/yr	41,633 MWh/yr
Wartsilla 32--Gas Mode			
Btus required to generate 1 kWh	7,653 (44.6% eff.)		
Natural Gas Supply Requirement (900 Btu/scf)	258 MMscf/yr [708 Mscf/day]	265 MMscf/yr [727 Mscf/day]	354 MMscf/yr [907 Mscf/day]

The estimated volumes for residential and commercial heating are shown in Table 4.3.

Table 4.3. City of Nome District and Commercial Heating Fuel Use

	2015	2044
Quantity of No. 2 used for heating	682,856 gal/yr	911,274 gal/yr
No. 2 Diesel heat equivalent	138,000 Btu/gal	138,000 Btu/gal
Btu Used for heating	94,234 MMBtu/yr	125,756 MMBtu/yr
Natural Gas (900 Btu/scf)	105 MMscf/yr (287 Mscf/day)	140 MMscf/yr (383 Mscf/day)

The estimate for the total natural gas required to replace diesel generation with natural gas with a Wartsilla dual-fuel engine and residential/commercial heating is shown in Table 4.5.

Table 4.4. Natural Gas Required for Electric Generation and Residential Heating

Year	2015	2044
Electrical (Mscf/day)	727 Mcf/day	907 Mcf/day
Heating (Mscf/day)	287 Mcf/day	383 Mcf/day
Total	1,014 Mdf/day	1,290 Mcf/day

Therefore, a gas field capable of producing at sustained rates of from 1,000 Mscf/day up to almost 1,300 Mscf/day is required for transition to natural gas for electric generation and residential and commercial heating.

Capital and operating costs will be estimated for these two cases in the next section and used in the economic evaluation for comparison with the other energy alternatives.

4.3 ENGINEERING & ECONOMIC ASSUMPTIONS

The Norton Basin undiscovered natural gas resource prospect used as the model for this evaluation is assumed to be 30 to 40 miles directly south of Nome in 30 to 50 feet of water, as described in the MMS study (Reitmeier 2005).

In order to deliver this gas to Nome, a subsea production system would be installed. It would consist of a subsea module for the well heads, pipe manifolds, and control cables that run from a shore control center to the field and is estimated to cost about $16 million. The subsea facilities may require partial burial to prevent ice-scouring and may require a protective shell that will allow for fast maintenance. An alternative to subsea facilities would be an arctic-hardened platform or structure. However, structures of this type for a small development would be excessively expensive, perhaps costing as much as $300 million (Reitmeier 2005).

Assumptions used in the evaluation of this scenario are:

- A jack-up drilling rig similar to those used to drill the exploration wells in 1980 and 1982 will be used to drill all the wells. It is assumed that mobilization and demobilization cost will not have to be paid because a drilling rig will be available in the region for drilling in the Beaufort Sea or Chukchi Sea. Therefore, only day rates would be required.
- Two production wells, each capable of producing a sustained rate of between 1.35 and 2.0 MMscf/day, will be needed in order to provide redundancy. Peak production rates of over 2 MMscf/day could be needed during peak use periods. Seismic evaluation,

exploration wells, and production testing will be required to prove that the natural gas resource is capable of being developed to providing the required volumes and rates.

- A bottom-founded subsea production system will be used to produce the wells and the raw gas will be transported to shore untreated.
- In addition to a 30-mi pipeline to shore, 10 miles of flowlines to the production template and associated offshore facilities will be required.
- All required gas treatment will occur onshore near the power plant.
- Operating costs include production startup, facilities maintenance and repair, fuel, labor, supplies, well workovers, pipelines, transportation, communication, and project management. These costs are composed of two components, a fixed-cost based on cost per well per year, and a variable component based on production rates. The fixed operation costs are estimated to be about $2 million per well per year (Thomas et al. 2007, p. 3.18). The variable operating costs are estimated to be 1 MMscf/day or about $55,000 per year increasing to $58,000 per year at 1.29 MMscf/day (Thomas et al. 2004, p. 128; Thomas et al. 2007 p. 3-146).
- Royalty and severance taxes are assumed to be zero for a natural gas development in the Norton Sound for use in Nome.
- Operating costs for the onshore natural gas generation plant is 1% of the amortized capital cost of the onshore plant and gas distribution system.
- A pipeline to shore and an umbilical cord for control cables needed to monitor and control the wells and manifold.
- As-produced-gas is transported to shore and processed in a gas processing plant to make the gas suitable for fuel in the reciprocating engine generator sets and suitable for consumption for residential and commercial heating.
- CO_2 in exhaust gases will be vented.
- The capital costs include drilling three wells–one exploration well, a delineation well and a second production well (it is assumed that either the exploration well or the delineation well will be capable of completion as a second production well).
- The gas processing plant would consist of a gas dehydration and compression unit to supply gas for the natural gas engine and gas distribution for district and commercial heating.

4.3.1 GAS DISTRIBUTION COSTS FOR HOME AND BUSINESS CONVERSION

The gas distribution and home and business conversion is calculated as follows:

Approximately 50,000 feet of pipe will be required based on a digitized map of Nome. At $30/ft this results in $1.5 million dollars. There are about 350 homes in Nome and 50 other businesses or facilities for a total of 400 hookups required. At $3,000 per hook up this will be $1.5 million dollars. Three pressure regulation stations at $500,000 each for a total of $1.5 million. The resulting total estimated capital cost for conversion to natural gas heating is $4.2 million.

The estimated capital costs are presented in Table 4.5.

Table 4.5. Converted Diesel Generator Capital Costs

Capital costs items	Year	Capital Costs ($1,000)
Geology and Geophysical exploration	2010	$500
Exploration Well[1,2]	2011	$10,000
Delineation and Prod. Well[2]	2011	$14,000 (2 wells @ $7,000)
Subsea facilities	2012	$16,000
Pipelines	2013	$14,000
Gas Processing Plant	2013	$2,000
Reciprocating engine replacement	2013	$2,000
Gas Distribution System	2014	$4,200
Well Workovers		Included in O&M
Total Capital Cost		**$62,700**

1. Includes all lease and drilling costs.
2. Mobilization and demobilization costs are not included. It is assumed that a jack-up rig or drill ship will be available as a result of exploration in the Chukchi OCS or Beaufort Sea OCS areas and the company will be able to make the rig available while enroute to or from those areas. Hence, only day rates and logistical support will be required.

4.4 CONCLUSIONS

It is possible that the Norton Basin contains natural gas resources are more than adequate to provide the volumes and rates of production needed for supplying natural gas for Nome but this cannot be determined without drilling wells. It was assumed for these initial estimates that it will be possible to use a drill ship enroute to or from the Beaufort or Chukchi Sea and only have to pay day rates for drilling the three wells. Theses are aggressive assumptions requiring that there will be no dry holes and will result in two wells capable of production to provide redundancy for production and to meet peak heating loads in winter. The peaking required for electrical needs can be provided by the existing diesel generators.

The use of gas turbines was not analyzed because a preliminary investigation suggests it is more cost effective to exchange one of the existing Wartsilla engines for a dual-fuel unit that can run on natural gas. However, gas turbines can be run on lower quality gas and may be worthy of consideration before a final decision is made should it be determined that pursuit of natural gas will occur.

5 WIND RESOURCES

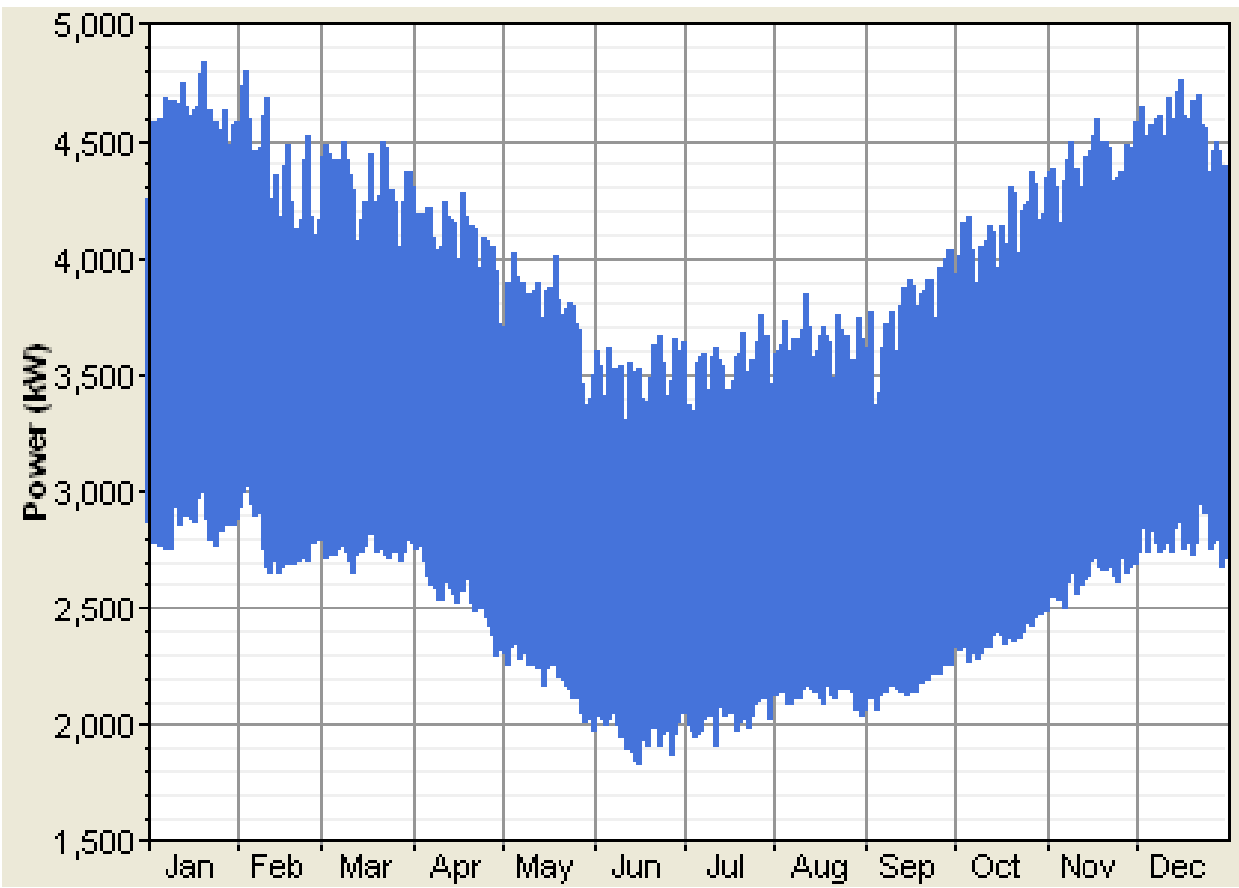
5.1 INTRODUCTION

Excellent wind resources are known to exist very near Nome at Anvil Mountain and the potential for offsetting a major portion of the diesel fuel used for power generation in a cost effective manner by developing this resource is described in this section.

5.2 ELECTRICAL LOAD PROFILE

The electric load profile was generated by importing hourly load data provided by the Nome Energy Assessment Group into the economic optimization software HOMER, developed by the National Renewable Energy Laboratory.[1] A graphic overview of year 2007 is show in Figure 5.1.

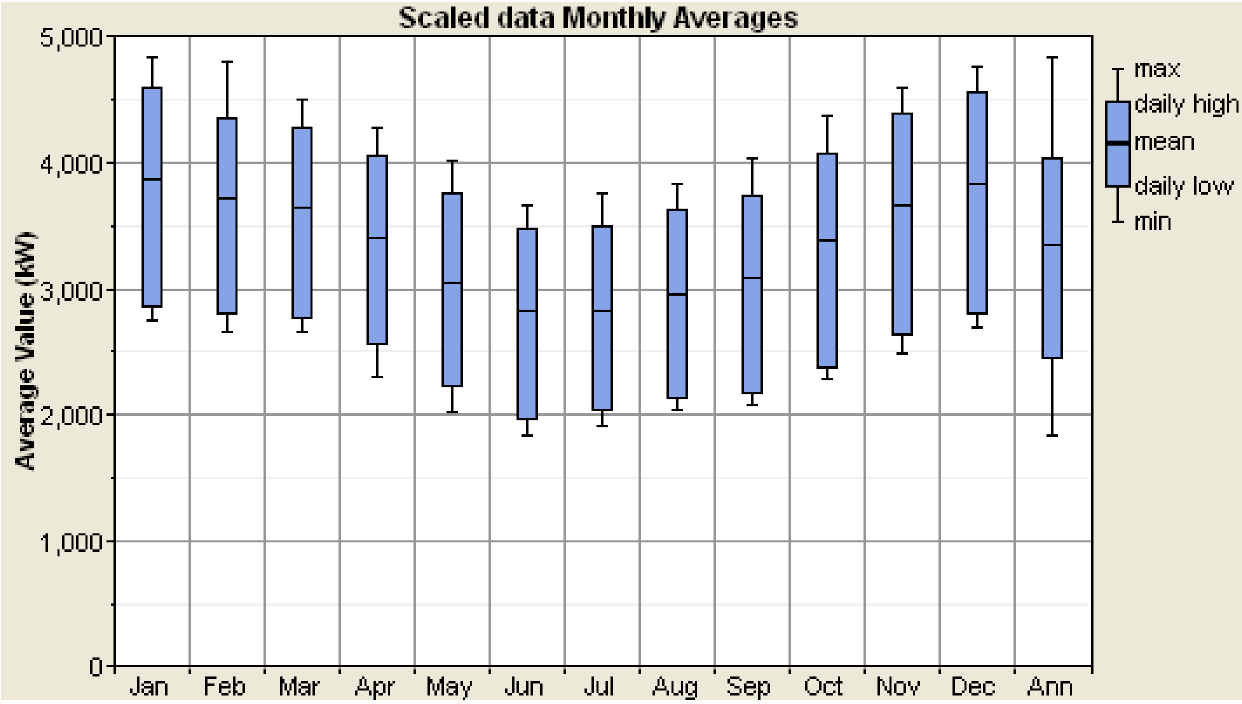
Figure 5.1. Hourly load profile for year 2007



[1] https://analysis.nrel.gov/homer/includes/downloads/HOMERBrochure_English.pdf

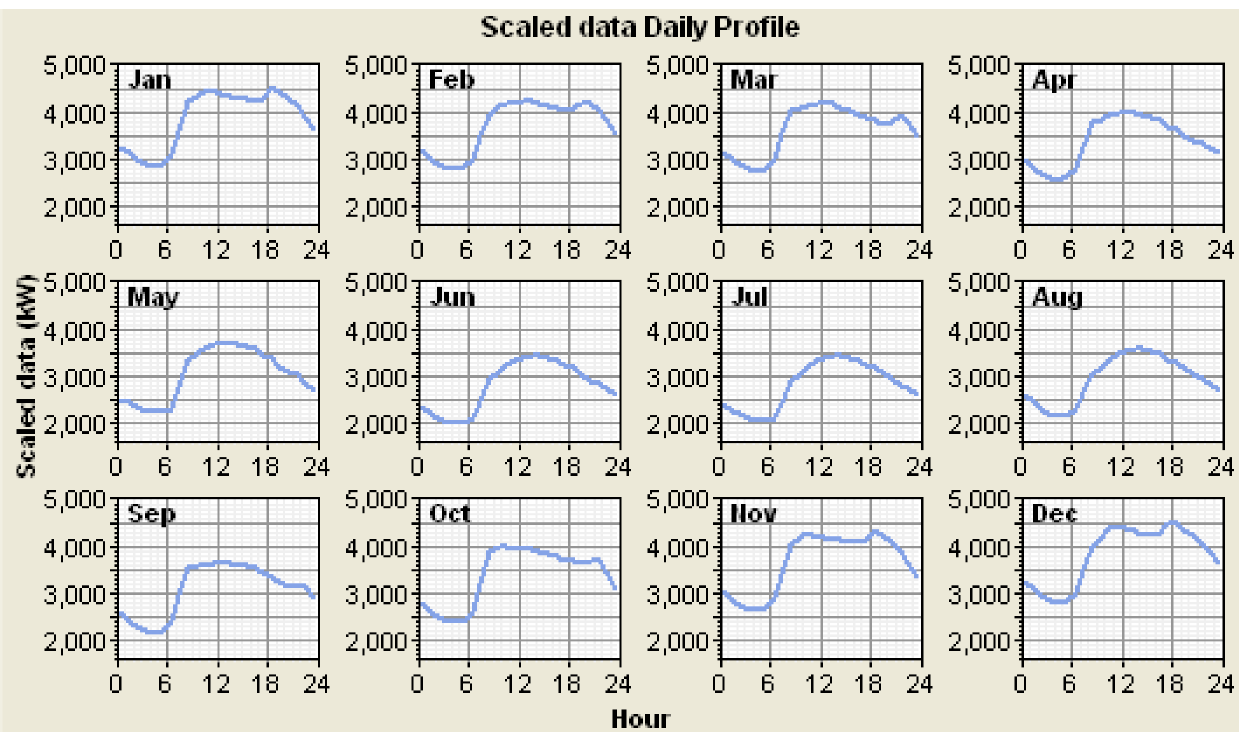
The monthly scaled averages for 2007 are shown in Figure 5.2.

Figure 5.2. Nome scaled averages for year 2007



A scaled daily profile for year 2007 is shown in Figure 5.3.

Figure 5.3. Nome scaled daily load data for year 2007



5.3 WIND RESOURCE

In September 2005, wind monitoring equipment was installed in Nome on Anvil Mountain. The purpose of this monitoring effort is to evaluate the feasibility of utilizing utility-scale wind energy in the community (Dolchok 2006). The site is described in Figure 5.4.

Figure 5.4. Nome Anvil Mountain Site summary.

Site #:	7310
Latitude (NAD27):	64° 33’ 50.2” N
Longitude (NAD27):	165° 22’ 40.5” N
Magnetic Declination:	13° 34’ E
Tower Type:	Telephone pole
Sensor Heights:	12 m
Elevation:	328 m (1076 ft)
Monitor Start:	9/15/2005 4:00
Monitor End:	3/14/2006 15:50

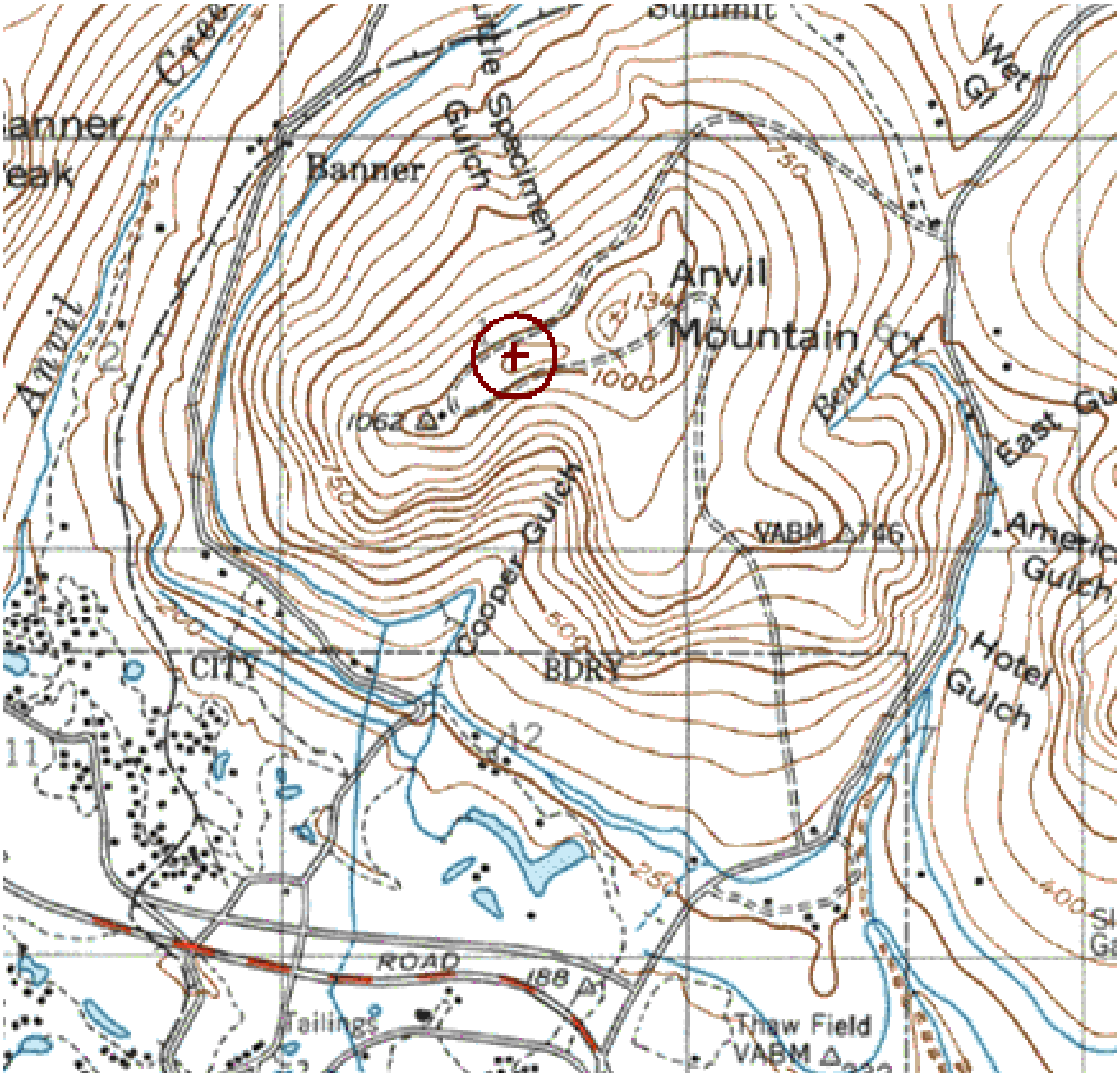
A one-year synthesized wind-data set was developed by filling the data gaps due to icing by using probability methods that calculate the most likely scenario for this time period.

The site has the following beneficial factors:

- The potential wind site is in slightly mountainous terrain, which enhances terrain induced wind acceleration from certain wind directions.
- Existing roads and transmission lines are in the proximity of the site.
- No living quarters or other housing within a safe ice-throw distance (≥250m) (Bossani and Morgan 1996).
- Visible intrusion is assumed to be minimal from main developments. Viewshed analysis has to be performed to confirm.

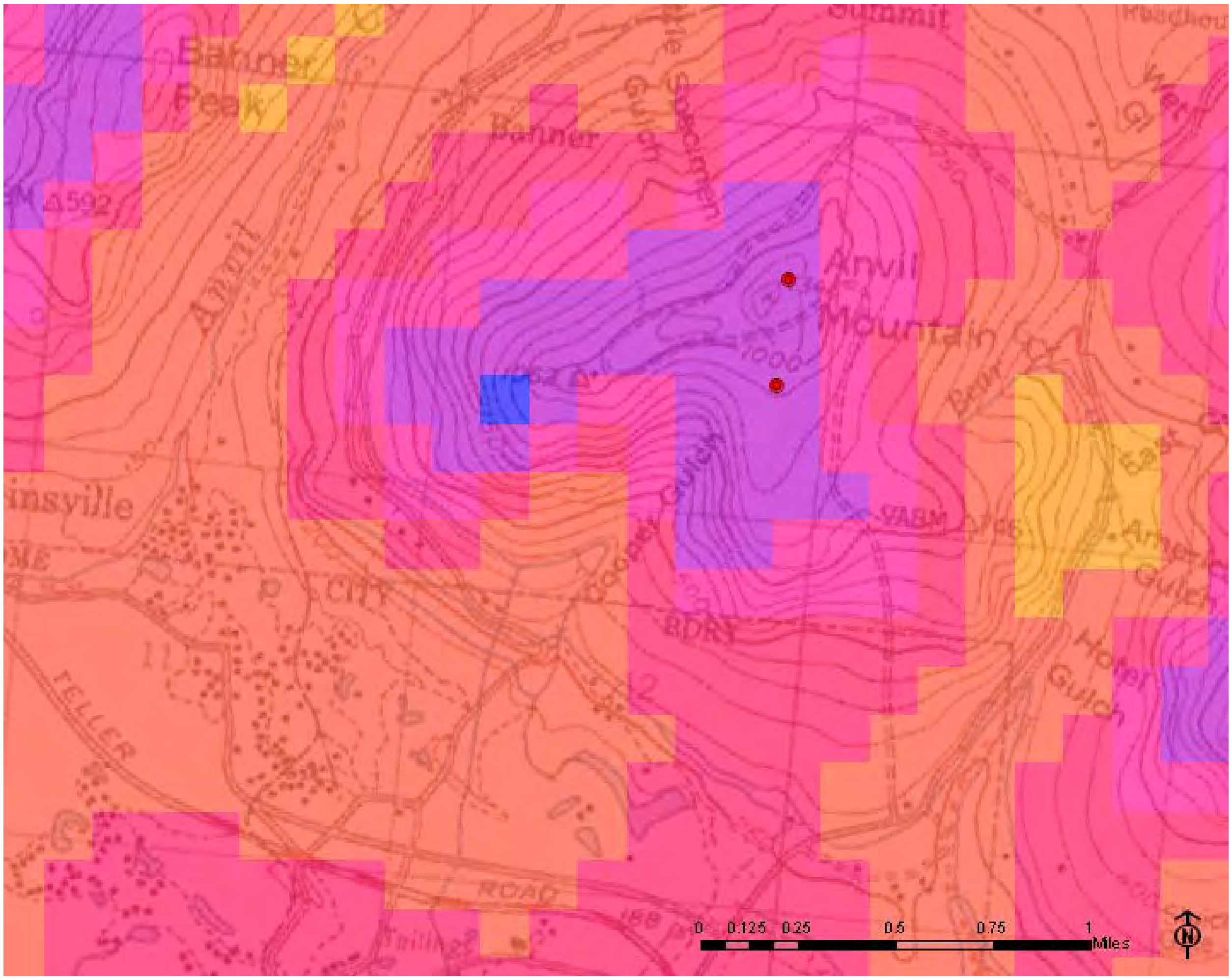
A topographic map indicating the Met-tower location is shown in Figure 5.5.

Figure 5.5. Nome–Met Tower location, Anvil Mountain



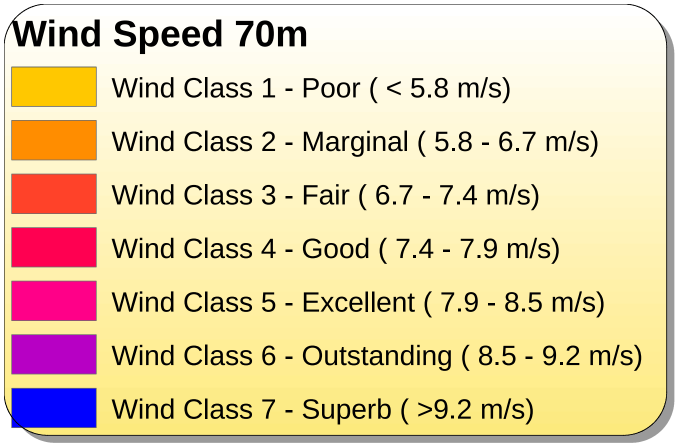
A map that combines high-resolution wind modeling results with topographic information is shown in Figure 5.6. The red marks indicate potential turbine locations.

Figure 5.6. Nome—High Resolution wind map, Anvil Mountain



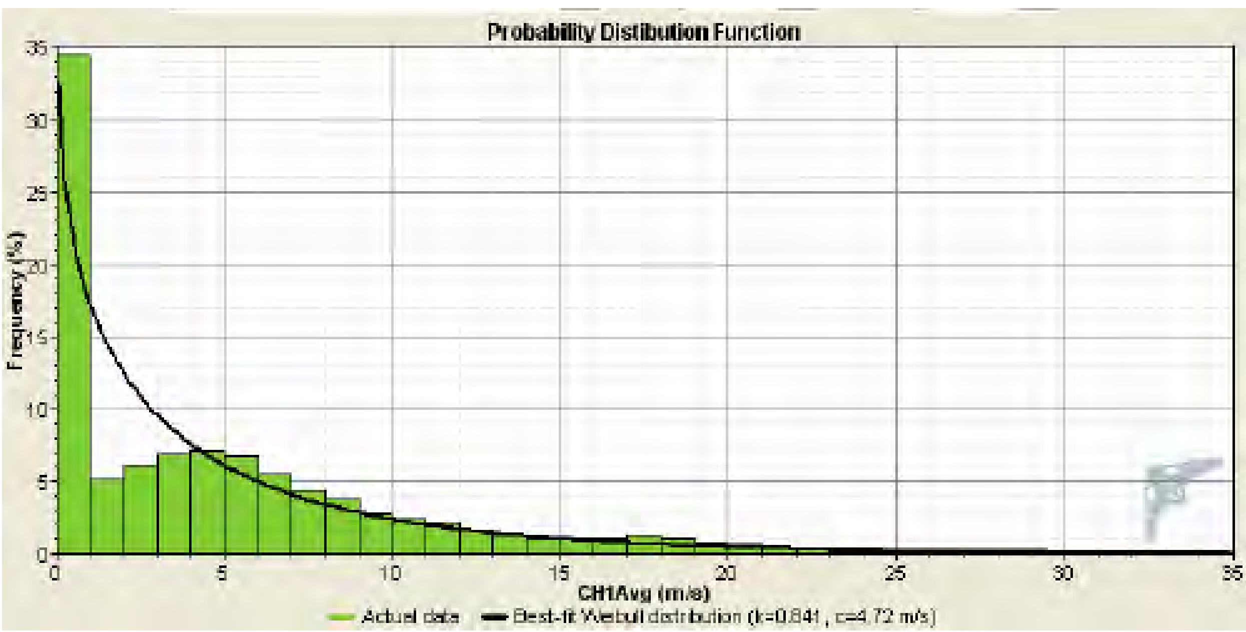
Color coding for the high resolution wind map is shown in Figure 5.7

Figure 5.7. High Resolution wind map color coding



The collected data were evaluated with the Windographer software.[2] An unfiltered wind probability profile is shown in Figure 5.8. Icing events appear as calm periods.

Figure 5.8. Nome Anvil Mountain wind probability profile.



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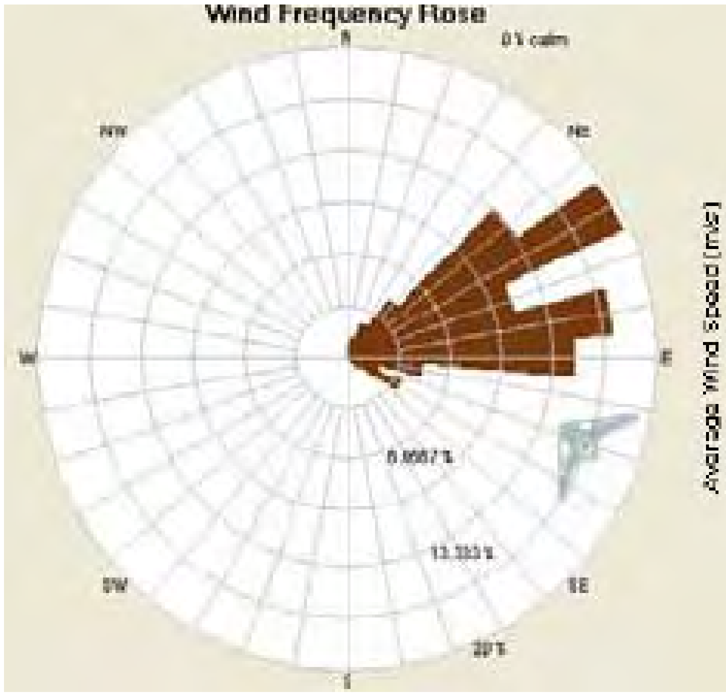
[2] Mistaya Engineering Inc. http://www.mistaya.ca/products/windographer.htm

A wind frequency rose is shown in Figure 5.9.

Figure 5.9. Nome Anvil Mountain wind frequency rose.



During the monitoring period, time periods with severe icing occurred. The collected data showed time gaps with no events recorded, attributable to ice coated sensors. In Figure 5.10 the ice built-up on the Met-Tower is shown.

Figure 5.10. Nome Anvil Mountain, Met-Tower after icing event.

In order to obtain a more complete picture of the wind resource, it is recommended that a 60 to 80 meter ice-rated Met-tower be installed to measure wind speed at the hub height of large size wind turbines. The data collection period is recommended to be at least twelve continuous months. The current data collection at 30 meters will most likely not satisfy the needs for an industry standard wind feasibility study for large size wind turbine development.

5.4 WIND MODELING

5.4.1 GENERAL INFORMATION

The wind modeling was performed using a Clean Energy Project Analysis Software from RetScreen[3] and provided data which was then used to develop the comparative economics described in Section 8. For the purpose of this screening report, no optimization between different wind-diesel system designs was performed due to different integration design possibilities such as available equipment and its costs, controls, switchgear, and interconnection.

A detailed engineering study is necessary to evaluate the feasibility, costs, and performance of an integrated wind-diesel system. This is outside the scope of this study.

For maximum utilization of investment only the high penetration scenario is described. This increases the complexity and integration cost compared to a medium or low penetration system. However, it is assumed that the increased wind absorption rate and resulting diesel fuel savings will justify the higher cost for integration. The cost estimation for the different integration controls (low, medium, high penetration) are outside the scope of this study. For preparation of a final design study the different scenarios should be taken into consideration and a cost comparison should be made.

5.4.2 WIND RESOURCE

An annual average wind speed of 6.0 m/s at 10 meter (class 5) was used to conservatively compensate for uncertainty in the high-resolution wind map and the monitoring data gaps. The wind speed distribution is calculated as the Weibull probability density function. A wind shear component of 0.16 was estimated to take moderate rough terrain features like hills or cliffs into account. The model calculated the average wind speed at hub height to be 8 m/s with a wind density of 580 W/m^2.

5.4.3 ATMOSPHERIC CONDITIONS

The standard atmosphere of 101.3 kPA was used for modeling, although local average pressure data are likely to be more favorable for wind density.

The annual average temperature of 27.1°F or -3°C was used. [4]

5.4.4 SYSTEM CHARACTERISTICS

Several models runs were performed by AEA. The recommended wind generation system was a 3 MW central-grid system using two 1.5 MW or similar-sized turbines. A project life of 20 years for the wind turbines was used.

The model calculates the wind plant capacity factor (%), which represents the ratio of the average power produced by the plant over a year to its rated power capacity. It is calculated as the ratio of the renewable energy delivered over the wind plant capacity multiplied by the total hours in a year. The wind plant capacity factor will typically range from 20 to 40%. The lower end of the range is representative of older technologies installed in average wind regimes while the higher end of the range represents the latest wind turbines installed in good wind regimes.

A wind farm capacity of 34% is used in the economic assessment.

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[3] http://www.retscreen.net/ang/d_o_view.php
[4] http://climate.gi.alaska.edu/climate/Temperature/mean_season.html

5.4.4.1 WIND TURBINES

The power curve for the wind turbine was modeled after the specifications of the GE 1.5se turbine with a hub height of 65 meters, a swept area of 3,904 m^2, and a rotor diameter of 70 meters. The electricity output is 1,500 kW at a rated wind speed of 13 m/s. The cut-in wind speed for this model is set at 4m/s and the cut-out wind speed is 25 m/s. The rotor speed is 12 to 22.2 rpm.

5.4.4.2 TURBINE LOSS FACTORS

Following turbine loss factors were taken into account:

- Array losses: 5%
- Icing losses: 10%
- Other downtime losses: 5%
- Miscellaneous losses: 10%
- Total Losses: 30%
- The current industry estimate for turbine loss factor is in the range of 15 to 33%.

5.4.5 COST DATA

The turbine costs are estimated to be $4000/kW installed. A recent study undertaken by the Berkeley National Laboratory (Harper et al. 2007) states the installed cost for utility scale, grid connected wind turbines in the U.S. market (lower 48) are $1,725 to $1,829 per installed kW. The higher installed cost used in this evaluation is warranted due to Alaska's high transportation and construction cost according to wind developers in Alaska, and verified by AEA experience with past wind projects. This assumption results in an initial capital cost for the 3 MW system of $12 million.

The amount of displaced diesel was calculated by dividing the 8,992,503 kWh/year produced by the wind generators by the diesel system efficiency number of 16 kWh/gal. This results in displacement of 562,031gal/year.

The cost for operation and maintenance is a combination of fixed and variable cost. The fixed cost used is 3% of installed cost and the variable cost is 0.975¢/kWh per year. These annual costs are applied throughout the estimated project life of the wind turbines and include repair and replacement costs. The variable cost was determined by applying a 5% annual increase of 1996 industry data of 0.65¢/kWh.[5] Planners consider adding variable cost to take wear and tear that increases with project life into account. The resulting annual operation and maintenance cost is $447,677.

A price for environmental attributes, renewable energy credits or green tags, may be available. The price for the green tag calculation is $0.03/kWh for 20 years. This price is based on price information from Bonneville Environmental Foundation's Denali Green Tag Program.[6] The actual price depends on project parameters and can be negotiated in individual contracts. The typical range is between $0.03 to $0.05/kWh.

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[5] http://www.awea.org/faq/cost.html

[6] www.greentagsusa.org/greentags/denali.cfm.

5.4.6 TIME FRAME

- Met-data collection: at least one year from starting point.
- Site development: 1.5 years from starting point.
- Turbine Selection/Procurement: 2 years from starting point.
- Construction: 6 to 12 months from point app. 1.8 years after starting point
- Final commissioning: 2 to 6 months after construction start.
- Full commercial operation: App. 1 year after final commissioning.

5.4.7 GREENHOUSE GAS ANALYSIS

Green House Gas (GHG) emissions were calculated based on 100% energy mix of diesel #2 generation using the following default values:

- CO_2 74.1kg/GJ;
- CH_4 0.0020 kg/GJ;
- NO_2 0.0020 kg/GJ;
- Fuel conversion efficiency 30%
- To obtain a more accurate emission analysis, actual energy mix data have to be applied.

5.5 CONCLUSION AND RECOMMENDATION

Current turbine development in the wind industry is targeted to multi-megawatt wind generators. For smaller applications the equipment choice is limited. Two emerging trends for the Alaska market are visible.

One market sector supply caters towards used, refurbished wind turbines. These machines are decommissioned at existing wind projects ('Lower 48' or Europe) and are remanufactured, rebuilt, and often upgraded to meet modern standards. However, the lifetime of these re-manufactured turbines is uncertain, since not enough performance data have been collected to make a valid statement. The overall industry consensus is that the lifetime of a re-manufactured wind turbine is about 15 years. Another uncertainty is the spare part supply and service support. Vendors or re-manufactured turbines, in general, do not offer warranty contracts over one year and service, technical support, and maintenance contracts are unusual. However exceptions exist, warranty and service contracts are a negotiation point that should be considered when re-manufactured turbines are the project choice.

The second market sector is the small to medium size wind turbine sector. Manufacturers offer new turbines with warranty contracts between 1 to 2 years, and extended warranty periods of 5 years are negotiable. The spare part supply is usually guaranteed by the manufacturer throughout the lifetime of the turbine, which ranges from 20 to 25 years. Service contracts and technical support are available. The capital costs for these turbines are generally higher. However, the levelized maintenance, replacement and repair costs are believed to be equal to or lower than those of the re-manufactured turbines. Due to limited data a firm statement in regard to the operation costs cannot be made. Operation and maintenance costs are in general an uncertainty, especially with the limited data for Alaska installations.

Recently a commitment from a large turbine manufacturer was made to install 2 megawatt size turbines in Alaska, on Kodiak Island. It is uncertain if this presence will guarantee the deployment of additional large size turbines into the Alaska market and the necessary technical, spare part, and service support for further machines. The application for these machines in Alaska is limited due to electrical load demand requirements, construction equipment requirements, and maintenance requirements. However, the selected large size wind turbines for this screening report are believed to be an appropriate choice for Nome due to the relatively large current and projected load demand as well as the local skilled workforce, a well run and organized utility, and the ability to support large construction projects. However, special attention should be given to the fact that Nome's met data collection showed moderate to severe icing conditions. This might limit the ability to obtain a large size wind turbine without modifying the manufacturer's standard model. Usually the offered cold climate packages are not suited to withstand the climatic conditions of Nome. It will be dependent on the manufacturer's willingness to modify the standard turbine model and the structural limitations thereof.

The number of installed turbines per project in rural Alaska applications can differ due to a number of reasons. The intended installed capacity can usually be met with the choice of a number of smaller turbines or one or two larger turbines. The benefit of fewer turbines is the reduced cost of foundation, transmission line and construction time, to a limited extend. The disadvantage is the risk of losing a higher percentage of electricity output if a turbine fails or downtime occurs, than with a higher number of smaller turbines. The repair skill, spare part availability, remoteness of location, complexity of system (medium or high penetration system), and responsiveness of technical support are factors that have to be taken into consideration in the decision making process. A good general rule of thumb is that the less certain the above stated factors are, the recommendation is to install more, smaller turbines in order to avoid a large percentage reduction of production capability.

Another important factor for wind-diesel installations in Alaska is the integration design and integration controls. Low, medium, and high penetration systems are currently installed in Alaska. Low penetration systems require only a minimum of control function on the diesel generation side, but displace only a minimal amount of diesel. Medium penetration designs require a more advanced level of integration and switchgear design and are capable of displacing up to ~25% of the annual diesel consumption. High penetration systems are highly complex designs that require experienced engineers and operators to develop a successful wind-diesel system. It also displaces the largest amount of diesel. High penetration wind-diesel systems are still in the pilot project phase and experience data for Alaska installations is minimal.

When trying to determine the desired level of wind penetration in a specific village application one must balance the potentially greater diesel savings of higher penetration systems against the higher costs and risks associated with the greater complexity of the system. Local conditions such as availability of skilled technicians and remoteness of location should help to determine where along the risk/reward continuum a project should be selected.

The owner and operator of the system as well as the utility have to be aware of the risk involved in installing a high penetration system in a remote location in Alaska and have to evaluate the benefits and disadvantages in terms of reliability and quality of energy supply, diesel savings, and environmental attributes.

5.5.1 FURTHER STUDY NEEDS

If the comparison with other energy scenarios should be favorable for wind development in Nome, the following studies are suggested before a final decision is made for implementing the proposed wind generation system, or variations thereof:

- Met-data collection with 60 to 80 meter ice rated tower

- Detailed system integration design
- Turbine availability for Nome including O&M options
- Environmental assessment
- Potential funding sources and/or business structure
- Detailed economic and financial analysis

5.5.2 RECOMMENDATION

Based on the modeling results the preferred wind generation system would be comprised of two 1.5 MW or similar sized turbines. We think that wind development could potentially be considered as a viable option for the citizens of Nome to displace a significant amount of diesel fuel and thus have the potential to reduce the price of energy as well as the dependency on diesel as a fuel source.

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6 GEOTHERMAL POWER—PILGRIM HOT SPRINGS, ALASKA

This section contains the Preliminary Feasibility Study of Pilgrim Hot Springs, Alaska performed by Lorie M. Dilley of HDL Engineering Consultants for AEA. The complete HDL report is contained in this section without change except for minor editing for compatible formatting with this report (Dilley 2007).

6.1 INTRODUCTION

This study presents the results of our preliminary feasibility study of Pilgrim Hot Springs, Alaska. The purpose of this preliminary study was to evaluate the previous scientific studies conducted in the area and to indicate the feasibility of developing Pilgrim Hot Springs into an active geothermal resource. Alternatives were developed as to the power plant type and geothermal well requirements. A decision matrix, the benefits and faults, and order of magnitude costs are provided for each alternative. This report is based entirely on the literature review conducted and no field studies or additional evaluation of the geothermal resource has been conducted. This is a preliminary study to indicate the potential feasibility of developing Pilgrim Hot Springs into an active geothermal resource for power generation

6.2 LOCATION

Pilgrim Hot Springs is located on the Seward Peninsula, Alaska, approximately 60 road miles north of Nome and 80 miles south of the Arctic Circle. The area is located at Latitude 65° 06' N, Longitude 164° 55' W. Vicinity maps are presented in Figures 6.1 and Figure 6.2, and a site map in Figure 6.3, and photos of the area in Figure 6.4. The area is accessible by air via a small landing strip. A 7.5 mile rugged dirt road leading off from MP 53 of the Nome-Taylor Road accesses the area. Pilgrim Hot Springs stands out as an approximately two square mile "thawed zone"; an area of warm soil, dense underbrush and tall cottonwoods seemingly out of place within the harsh conditions of frozen soil and stunted vegetation in the surrounding subarctic tundra.

Pilgrim Hot Springs lies in an area of low relief in the wide flat valley of the Pilgrim River, which meanders generally east to west approximately a half mile to the north. Figure 6.3 presents a site map. Pilgrim River is a tributary of the Kuzitrin River to the north. Several low flowing springs and seeps flow into the Pilgrim River from the underlying alluvial sands and silts. Water temperature near the springs ranges from 145° to 160°F (63° to 71°C). In 1918-19, a worldwide pandemic flu epidemic struck Mary's Igloo and Pilgrim Hot Springs area and killed every Alaska native adult and a majority of the children living there. Most of the surviving orphans were raised by the Catholic Jesuit priests and Ursuline nuns at the orphanage constructed at Pilgrim Hot Springs. The children and grandchildren (approximately 150 descendants) now comprise the tribe of Mary's Igloo, a federally recognized Alaska Native Tribe. They were moved to surrounding villages when the children's orphanage closed in the 1930's.

The surface ownership of Pilgrim Hot Springs is in the Catholic Church, which has leased the area to Pilgrim Springs Limited. It is reported that Mary's Igloo Native Corporation (MINC) owns the surrounding area and the subsurface rights as shown in Figure 6.5. Currently there is a caretaker on the property and occasional visitors.

Figure 6.1. Pilgrim Springs Vicinity Location Map

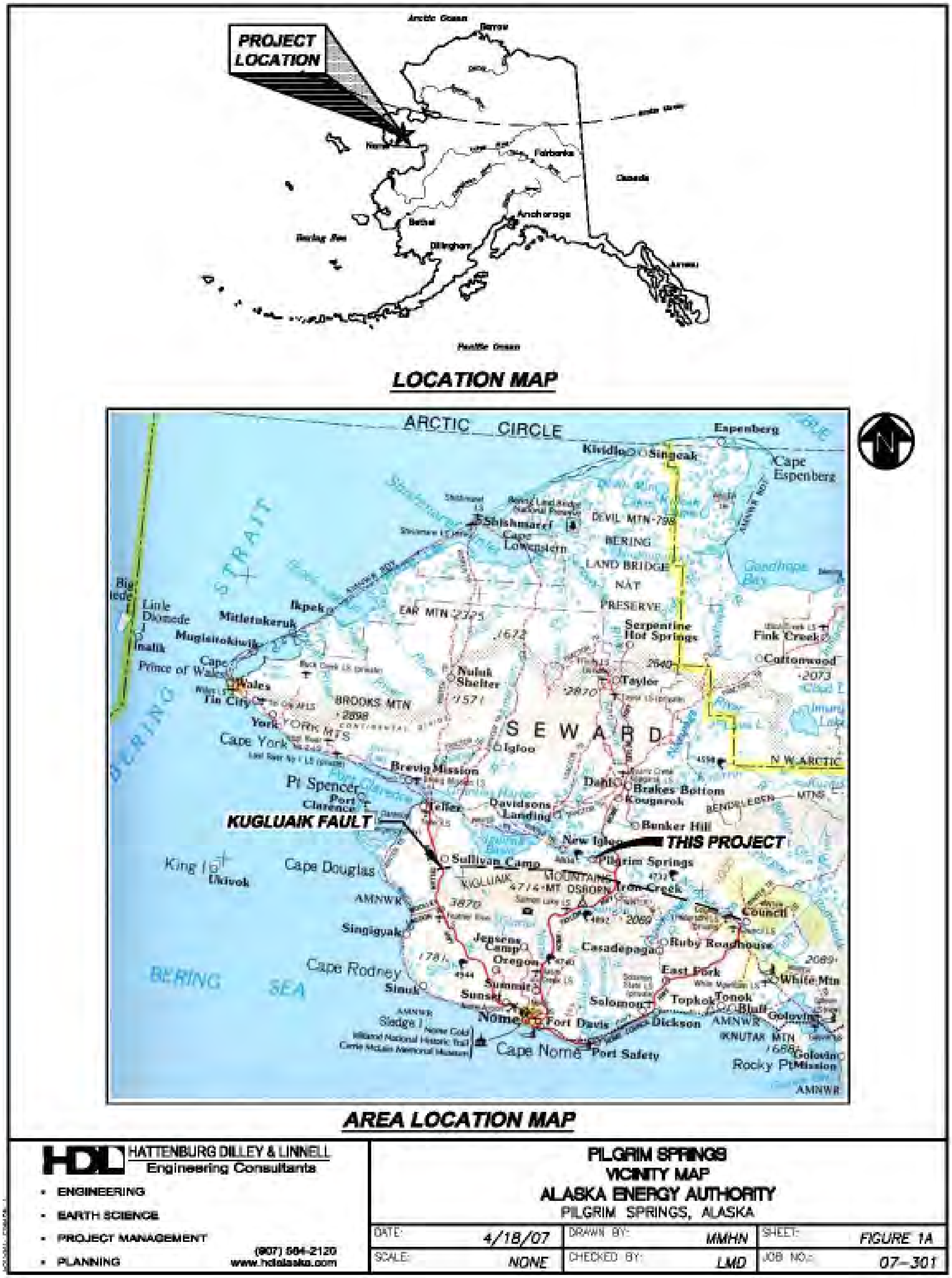


Figure 6.2. Pilgrim Springs Vicinity Map—Surrounding Topography (Dilley 2007)

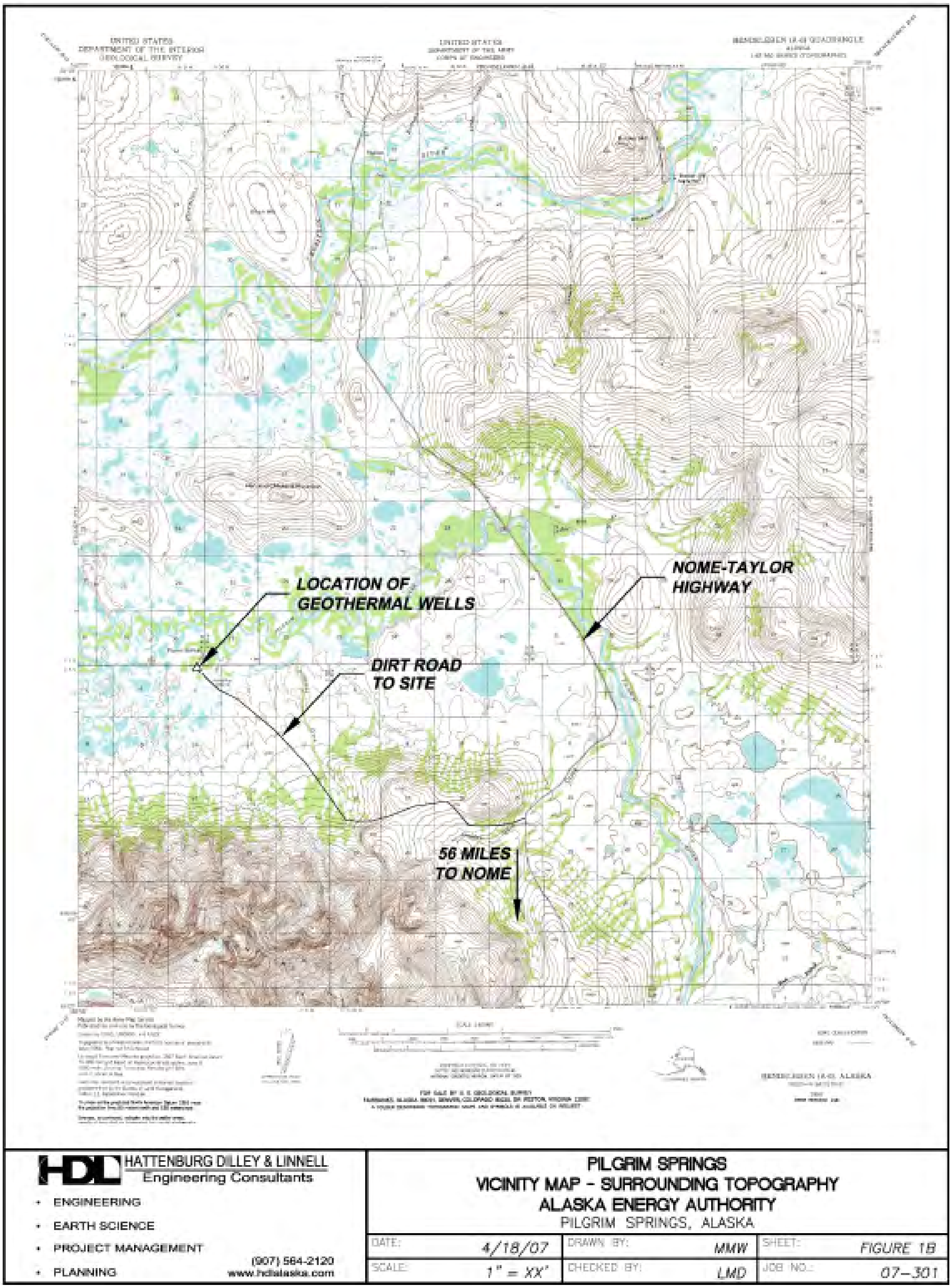


Figure 6.3. Pilgrim Springs Site Map

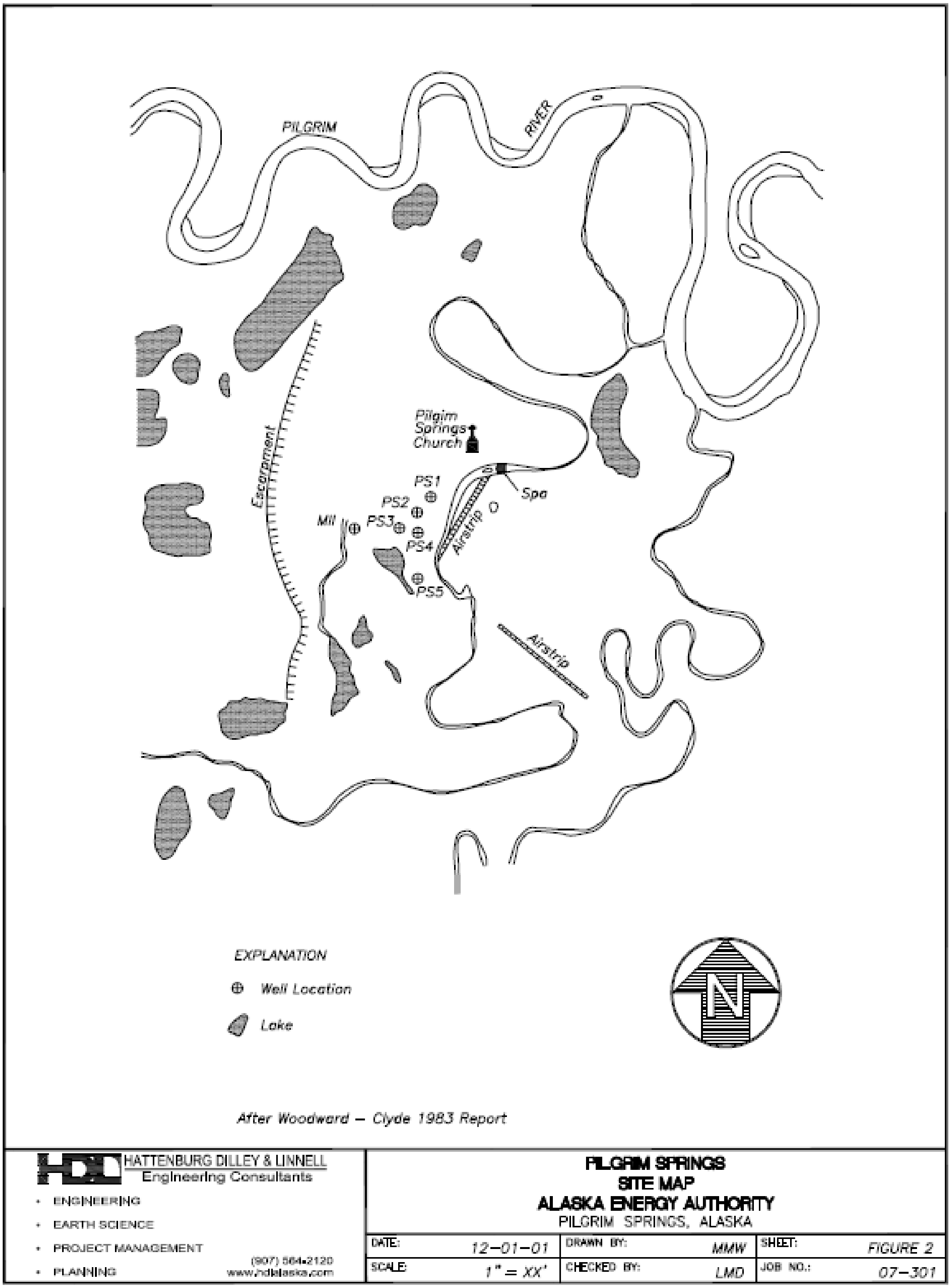
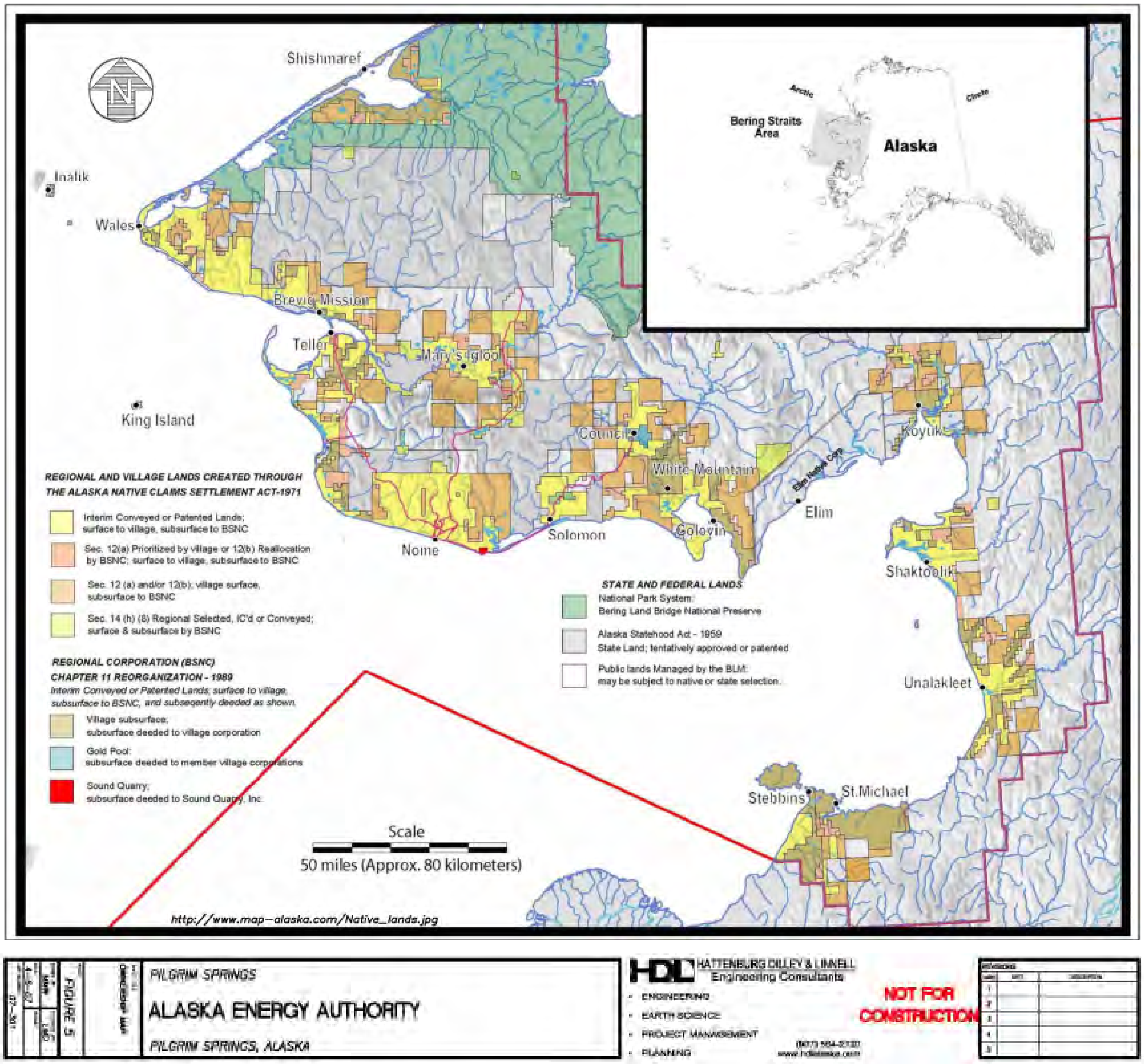


Figure 6.4. Pilgrim Springs Photos (Dilley 2007)

Pilgrim Hot Springs. Catholic Church built 1918-1920 and Mission grounds. View facing mostly north.

The 7-1/2 mile access road from Road Marker 53 of the Nome-Taylor Road.

Figure 6.5. Surface and Subsurface Ownership



6.3 PREVIOUS STUDIES OF THE PILGRIM SPRINGS AREA

The most recent and comprehensive investigation of the geothermal characteristics of Pilgrim Springs was a cooperative investigation begun in 1979 by the State of Alaska, Geophysical Institute of the University of Alaska and Woodward Clyde Consultants (WCC). The study, done in two phases and completed in 1982, included the drilling of six test wells to depths between 150 and 1001 feet. In addition, surveys of soil helium and mercury, gravity, and electrical resistivity; surficial geology and bedrock mapping, seismic refraction, geomagnetic profiling, shallow thermal conductivity measurements, hydrologic measurements, and geochemistry analysis were undertaken.

While this program was able to confirm a significant geothermal resource at Pilgrim Springs, the exact location, depth, and characteristics of the source of the geothermal activity remains to be identified.

6.4 GEOLOGY

The Kigluaik Fault, a range-front fault trending east-west several miles to the south, separates the northern edge of the Kigluaik Mountains from the down-dropped (graben) Pilgrim River valley (Figures 6.1 and 6.2). This seismically-active fault has experienced displacement within the past 10,000 years. These mountains, rising to elevations of generally 3500 to 4000 feet, are composed of various metamorphic rocks of Precambrian age, including granitic gneisses and amphibolites. A remnant of similar Precambrian metamorphic rock outcrops several miles north of Pilgrim Springs in the Hen and Chicken Mountains. Local Cretaceous intrusives consisting of biotite granite and diabase are found in a belt from the Seward Peninsula to the Kobuk valley; geothermal springs in this belt appear to be associated with these intrusive plutons. Geologic mapping indicates a number of north trending faults, with one projected underneath the Pilgrim valley fill approximately 1.5 miles east of Pilgrim Springs.

Based on seismic and gravity surveys, the Pilgrim River valley is filled with sediments at least 1500 feet thick. Surface soils consist of alluvium deposits of the Pilgrim River. A vicinity map showing the topographical features surrounding Pilgrim Springs is presented in Figure 6.2, and a geologic map of the Seward Peninsula is presented in Figure 6.6.

6.5 HYDROGEOLOGY

Six wells were installed by WCC in 1982 ranging in depth from 150 to 1001 feet. They were clustered in the hottest part of the anomaly approximately ¼ mile southwest of the historic Pilgrim Springs Church; see Figure 6.3. One well was located on MINC property. Flow rates for the wells ranged from 30 to 250 gallons per minute. All six wells penetrated an extensive shallow geothermal system, having fluid temperatures of 194ºF (90ºC), were under artesian pressure of six feet above the land surface, and appeared to feed the surface springs and seeps in the local vicinity of Pilgrim Springs, principally to the southwest of the church. Temperature profiles of the two deepest drill holes indicate the thermal gradient of sediments below the surficial groundwater zone to be increasing about 4ºF (2.2ºC) per 100 feet of depth.

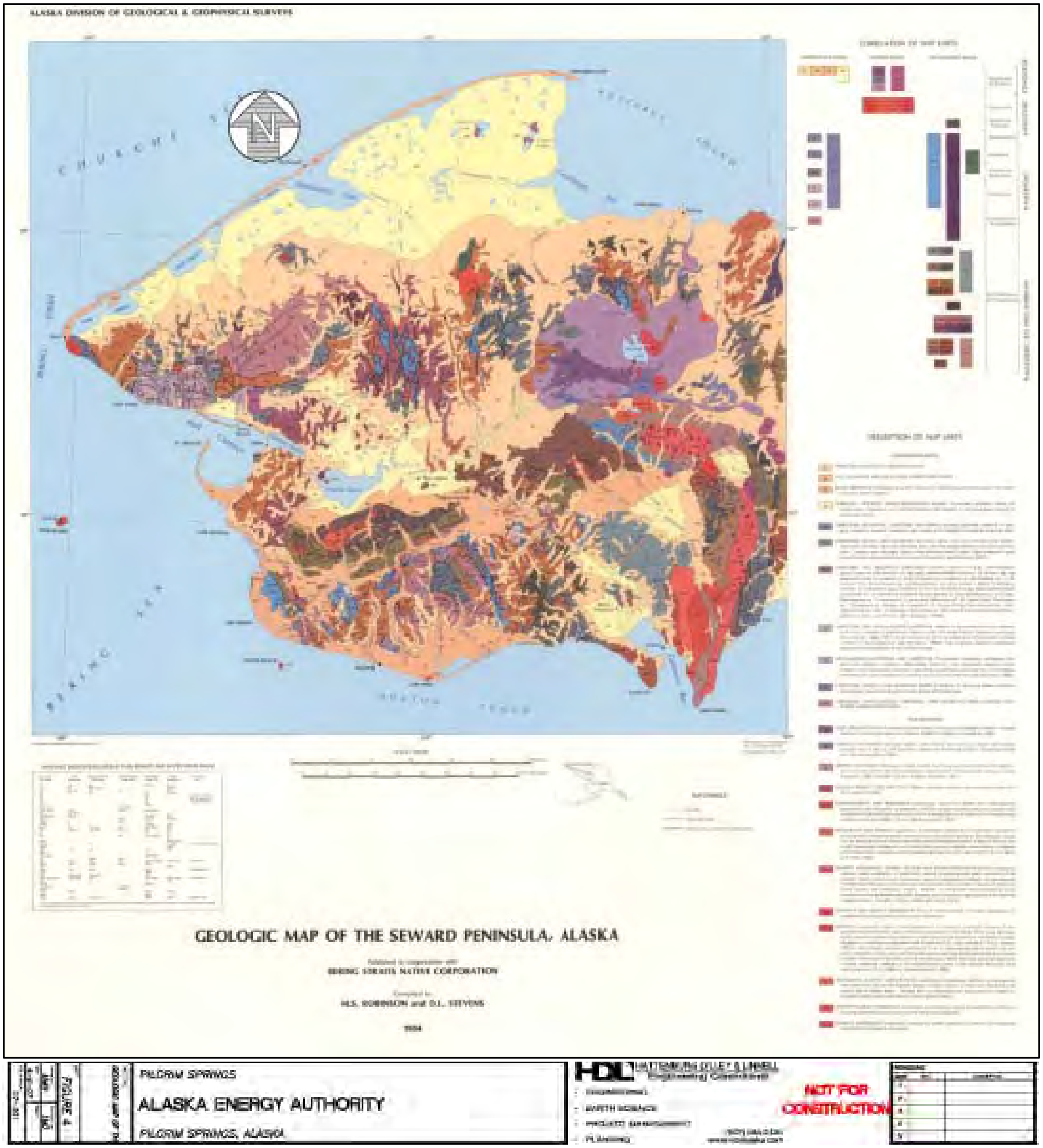
6.6 GEOCHEMISTRY

Pilgrim Springs can be characterized as an alkali-chloride spring, a type often associated with areas of recent volcanism. Saline waters can also be associated with Tertiary sedimentary rocks, which may compose some of the extensive depth-of-fill in the Pilgrim River valley.

Geochemical analysis of Pilgrim Springs was undertaken by the Alaska Division of Geological and Geophysical Surveys, on samples taken from the six wells. In general, water from wells PS-1 and PS-2 was hot 198 to 205ºF (92 to 96ºC), high in dissolved solids, low in salinity, and low pH. Well MI-1, which is tapping water that lies below the shallow thermal aquifer, is cooler 75ºF (24ºC), low in dissolved solids and salinity, and has high pH.

Available geochemical data of Pilgrim Spring's exploration wells and springs imply contradictory evidence of a deep, but diluted thermal fluid and a more saline, shallow aquifer. Geothermometry of waters indicate maximum deepwell temperatures (Fournier 1981) of 266ºF (~130ºC) yet these values are not consistent with the mixing curves provided by the existing major chemistry.

Figure 6.6. Geologic Map of Seward Peninsula



Despite extensive exploration in the Pilgrim Spring's valley by previous researchers, "neither the heat source nor the water source of the circulating geothermal system have been identified (Lofgren, 1983)." Deep drilling (Well PS-5) into the intersection of two high angle faults propagating through the Pilgrim Spring's property was unsuccessful in identifying a conduit connecting deeper thermal waters with the shallow artesian aquifer, yet the resulting temperature profile confirmed the possibility for high temperature thermal waters 248ºF (120+ ºC) at depths greater than 2,600 feet. However, testimony of past researchers implies additional grounds for locating such a structural conduit. Economides (1982) and Wescott (1981) agreed that a thermal aquifer containing fluids of 300ºF (150ºC) at 4,800 feet depth are supplying heat to the surface waters near the present-day well field. Forbes (1979) however recommended further investigation 2 miles to the northeast along the thawed fault-bounded foothills of Hen & Chickens Mountain.

A geothermal reservoir is dependent upon the hydrology of the reservoir and the heat balance. The conceptual geothermal reservoir model developed by WCC, 1982 was developed considering the inflow and outflow of fluids and heat into an idealized reservoir area. The model indicates that there could be a continuous supply of 19 to 24 megawatts (MW) of geothermal energy fed into the reservoir from some yet unidentified source. The 19 to 24 MW of energy fed into the reservoir is balanced by outflow from the reservoir of 6 MW to the atmosphere, 2 MW to the thermal springs, and 11 to 16 MW into the groundwater. A 20-year supply of energy at a use rate of 1.5 MW is believed stored in the shallow thermal aquifer system. More than 90 percent of the resource available is from the as-of-yet unidentified source. The useable part of the resource is estimated to be 13 to 18 MW or the energy in the thermal springs and the groundwater. This is prior to any energy conversion into power production.

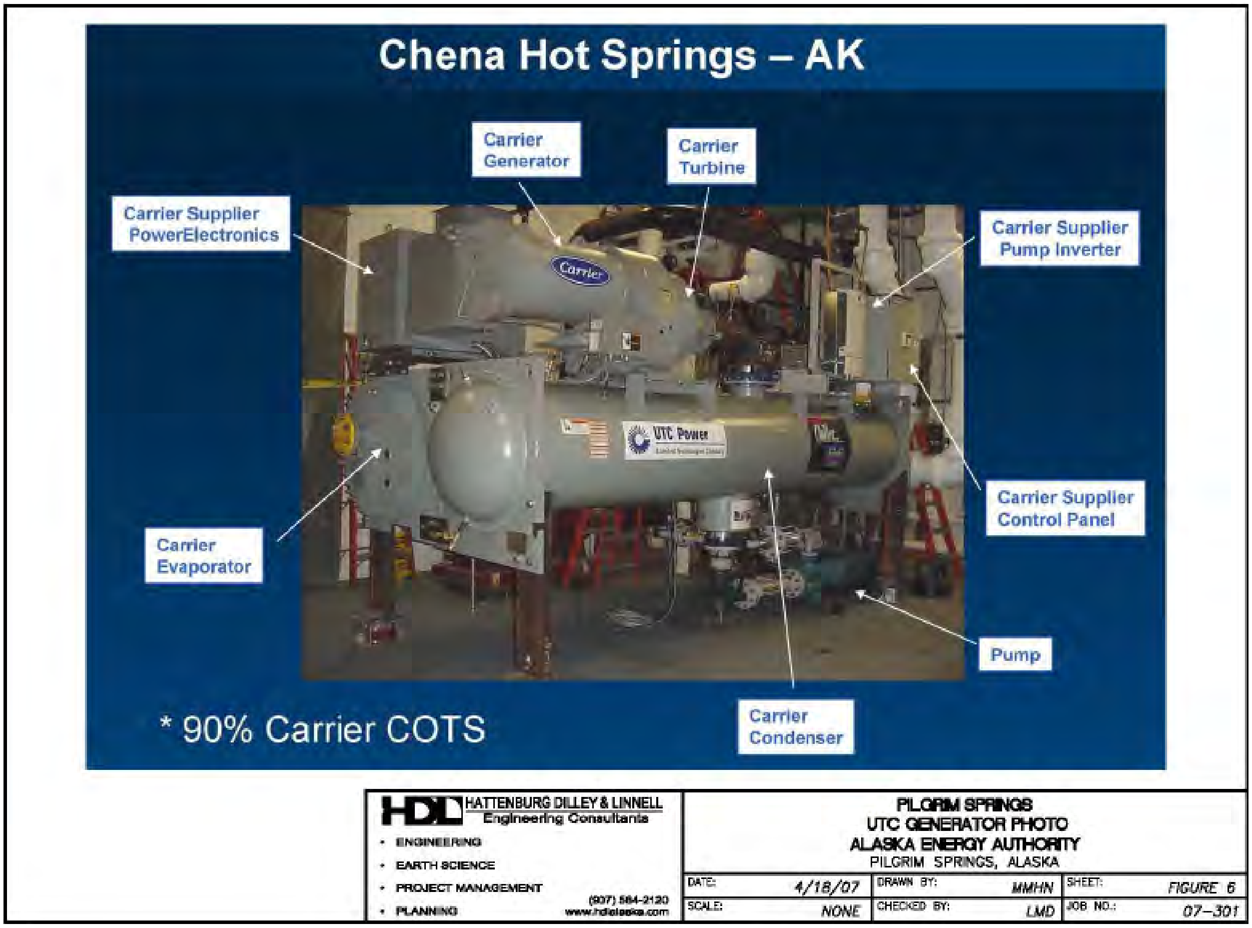
6.7 POWER PLANTS

Corresponding to progressively lower resource temperature, geothermal energy is used for electric power generation, direct heating, and geothermal heat pumps. Two main types of geothermal systems are utilized for electric power generation: steam dominated and hot water systems. Steam dominated systems have pure high temperature steam that is greater than 455ºF (235ºC) and typically have production wells 3,000 to 13,000 feet in depth. The steam is brought to the surface and it is used directly to spin the generators to create electricity. Hot water geothermal systems in production have a typical temperature range of 300 to 570ºF (150-300ºC) (DOE 2003). A flash steam power plant is most common in these systems. The geothermal fluids are brought to the surface through production wells as deep as 13,000 feet. They are highly pressurized; up to 40 percent of the water flashes or in a series of steps boils explosively and turns to steam. The steam is then separated and is fed to the turbine generator unit directly to produce electricity.

For hot water systems with lower temperature reservoirs, those between approximately 255ºF and 430ºF (125ºC and 225ºC) a binary cycle power plant instead of a flash steam plant is required. In the binary cycle plant the geothermal waters are passed through a heat exchanger to heat a secondary working fluid that vaporizes and that vapor is then used to turn the turbines.

United Technologies Corporation (UTC) has developed a binary geothermal power plant currently operational at Chena Hot Springs which produces power from even lower temperature fluids. A reverse-engineered refrigeration unit is used as the binary plant and only requires a 100ºF (38ºC) temperature differential between heat source and sink to generate power. At Chena Hot Springs, this differential is achieved by using 164ºF (73ºC) water from the geothermal wells and 40 to 45ºF (4 to 7ºC) water from a local cold water source. This system is currently only produced by UTC and hereafter will be referred to as the UTC system (See Figure 6.7 for a photo of a UTC system at Chena Hot Springs).

Figure 6.7. United Technologies Corporation Binary Geothermal Plan—Chena Hot Springs



6.8 ENERGY EFFICIENCY

Based on the conceptual model there is approximately 13 to18 MW of energy available prior to power production. The amount of energy that can be produced is based upon the energy available at the well heads, losses in the hot water delivery system, and the efficiency of the generators. Losses in the transmission line to Nome would also impact the amount of power that reaches the customer. The energy available at the well heads is based upon the flow rate and the temperature of the fluid. Table 6.1 provides an estimate of well productivity or the amount of energy available per reservoir temperature. For the low temperature source (90 ºC) the energy available is approximately 0.4 MW per well. For the higher temperature source (150 ºC) the energy available is approximately 2.5 MW per well. Flow rates for each alternative to produce 5 MW of power are presented in Section 6.7 for each alternative.

One of the most important concepts about the operation of a power plant is that the efficiency of the process is determined by the temperature difference between the boiler and the condenser. In a conventional fossil fuel power plant the temperature of the steam leaving the boiler may be 1,000 ºF and the condenser may operate at 100 ºF. Theoretical efficiency of the cycle is about 60 percent. Due to losses in equipment, heat transfer processes, the actual efficiency might be on the order of 40 percent. In addition, boiler, combustion, and generator all have efficiencies less than 100 percent therefore a traditional fossil fuel power plant operates at about 30 to 35 percent efficiency. Geothermal resources produce temperatures far less than those of a traditional fossil fuel plant. Geothermal power plants conversion efficiency of heat to electricity is generally less than 10 percent (Rafferty, 2000). This impacts the feasibility of producing geothermal power by increasing the quantity of heat needed thereby increasing costs for resource development. Furthermore the higher heat requires more waste heat requiring more cooling and therefore a larger parasitic load on the plant.

Table 6.1. Confirmation Program Components and Unit Costs

Method	Unit	Cost per unit ($)	For 500 ft deep/90ºC	For 5000 ft deep/150ºC
Administration	project	7.5 % of total confirmation costs	0.2 M$	0.3 M$
Drilling : Full diameter hole	foot	Cost = 240,000 + 210 (depth in feet) + 0.019069 (depth) 2	0.3 M$/Well	1.8 M$/Well
Drilling : Hole productivity	°F	MW/Well = reservoir Temp. (°F)/50 – 3.5	0.4 MW/well	2.5 MW/well
Drilling : Unsuccessful hole factor	%	40%	5 wells needed* =1.5 M$	2 wells needed* =3.6 M$
Other	project	20,000	0.02 M$	0.02 M$
Regulatory Compliance (includes permitting and environmental compliance)	project	5 % of drilling	0.08 M$	0.2 M$
Reporting document: (data integration/analysis/modeling)	project	5 % of drilling	0.08 m$	0.2 M$
Well Test: Full diameter hole, 3-10 days	well	70,000	0.2 M$	0.07 M$
Well Test: Multi-well field test, 15-30 days	project	100,000	0.1 M$	0.1 M$
Source: GeothermEx, “New Geothermal Site Identification and Qualification” (Table IV-1), 2004. * Number of wells needed to confirm 25% of the production capacity, which in our case is 25% of 5 MW = 1.25 MW. Note that in the case of the deep, 5000 ft resource, one successful well at 2.5 MW/well will confirm 50% of the capacity as modeled in this paper.				

In binary plants, discussed in Section 6.7, the temperature of the vapor leaving the boiler is always less than the temperature of the geothermal fluid. Binary power plant efficiency is based the entering temperature of the geothermal fluid and the leaving temperature of the fluid. Most plants are capable of achieving leaving geothermal water temperatures of approximately 160 ºF (70ºC). By knowing the plant efficiency and the resource temperature, the quantity of water flow required can be determined. Given the reservoir temperature of 300ºF (150ºC) and assumed plant efficiency of 10 percent, the required geothermal water flow is about 2,400 gallons per minute (gpm) for a 5 MW plant. The calculation conducted to determine flow for a given plant efficiency and reservoir temperature breaks down below a temperature of about 200ºF (95ºC) and therefore does not work for the shallow source identified at Pilgrim Springs.

6.9 ALTERNATIVES

Given the identified shallow source of geothermal fluids at Pilgrim Hot Springs near 195ºF (90ºC), and the presumed deeper source of up to 300ºF (150ºC) geothermal water, we modeled three possible alternatives to generate electricity. Because of the relatively cool temperatures of the two possible sources, we considered options using either the UTC system or a traditional binary power plant. If the lower, hotter reservoir exists, the temperatures are believe to range from 250ºF to 300ºF (120ºC to 150ºC) which is too cool for a flash steam power plant. The alternatives modeled in this report are as follows:

Alternative 1: Shallow Source; UTC System.

Alternative 2: Deep Source; UTC System.

Alternative 3: Deep Source; Binary Plant.

For each alternative, we assumed that there was a developable resource able to produce 5 MW of electricity, which needs to be proven by drilling. Because so little is known about the nature of the resource, including total size, or the sustainable flow rates of the geothermal fluids, this assumption may prove to be either much lower or higher than the real potential of the resource. This can only be verified by more onsite investigation of the resource. A resource capable of producing 5 MW's may be more likely to hold for the deep, higher temperature, geothermal source. The current peak power needs of Nome are in the neighborhood of 5 MW, and they are projected to exceed this by around 9 MW with the Rock Creek Gold Mine on line. Table 6.1 presents components and costs associated with confirming the existence of the geothermal reservoir. Table 6.2 presents a summary of the alternatives. The order of magnitude cost estimates for each alternative are based on a completed 5 MW capacity power plant, with enough geothermal wells drilled for supplying the necessary fluids and providing for reinjection wells in order to maintain reservoir pressures. Schematic diagrams of the alternatives are presented in Figures 6.8 to 6.10. The cost estimates are an order of magnitude costs and should only be used to compare costs between the alternatives and as an assessment of the feasibility of the models, should further research prove out the resource. Further analysis of the components of the cost estimates follow in Sections 6.9.1 to 6.9.3.

Table 6.2. Summary of Alternatives

Alt	Temp	Depth	# of Wells	Flow Rate	# Generators	Costs (M$)
1	195 °F 90 °C	500 Feet	13~20 + 4 reinjection	6,000 gpm	25 UTC @ 200 kW 5 UTC @ 1 MW	48-92
2	300 °F 150 °C	5,000 Feet	2 -3 production 1 reinjection	1,750 gpm – 2,400 gpm	5 UTC @ 1 MW	54-103
3	300 °F 150 °C	5,000 Feet	2 -3 production 1 reinjection	1,750 gpm – 2,400 gpm	1 Binary @ 5 MW	64 – 116
gpm: gallons per minute: kW: kilowatt, MW: megawatt						

6.9.1 ALTERNATIVE 1: SHALLOW SOURCE; UTC SYSTEM

In this alternative we modeled tapping the shallow, 195ºF (90ºC) geothermal waters. This temperature is well suited to the temperature differential utilized in a Chena Hot Springs-style UTC system; assuming cooling is achieved by winter air or local, cold stream waters used in the power plant. The Pilgrim River runs nearby, and would provide the necessary cooling water. We assume a depth of 500 feet below the surface for wells utilizing this source.

According to Chena Power, LLC, a flow rate of approximately 1200 gallons per minute (gpm) would be necessary to generate 1 MW with the assumed 195ºF (90ºC) fluid. For the 5 MW, a flow rate of about 6,000 gpm would be necessary. The efficiency of the larger 5 MW system may require additional flow, which is unknown at this time. If the attainable flow rate for each well was near 300 gpm, approximately 20 production wells would be necessary. Simple calculations based on fluid temperature (Hanse, 2005) give a productivity of 0.4 MW per well (see Table 6.1). This calculation results in 13 wells necessary to generate 5 MW of power. The number of wells with this low-temperature resource was set at between 13 to 20 wells. This number of wells may be unfeasible in such a small area, leading to well interference among other problems. At least one reinjection well, and likely more, would be necessary to maintain the pressure and fluid flow within the reservoir.

The existing UTC power plant technology as utilized at Chena takes advantage of a temperature range very similar to that found in the shallow resource at Pilgrim. The geothermal waters utilized at Chena are 164ºF (73ºC), and the cooling river waters are 40ºF (4ºC). The generators at Chena are 200 KW units. Twenty-five of these units would be required to produce 5 MW. UTC is reported to be developing a 1 MW generator, in which case this rather unwieldy number of generators would be cut to 5.

6.9.2 ALTERNATIVE 2: DEEP SOURCE; UTC SYSTEM

In this alternative we consider the as yet to be determined deeper, hotter, geothermal source. We model this source using the 300ºF (150ºC) fluid temperature and well depths at 5000 feet below the ground surface. Alternative 2 investigates the costs associated with using a UTC power plant with this source. According to Chena Power LLC, the flow rate of geothermal fluids necessary to generate 1 MW at this temperature is approximately 350 gpm, much lower than the preceding alternative. Using an assumed plant efficiency of 10 percent, we calculated the flow rate at about 480 gpm per 1 MW. Therefore to produce 5 MW of electricity the geothermal fluid flow rate would be between 1,750 to 2,400 gpm. Drillhole productivity calculations from Table 6.1 indicated each well in this alternative would produce about 2.5 MW. For the anticipated 5 MW, 2 wells would be needed. However, based on the high flow rates needed three wells may be necessary. For this alternative we have assumed two to three production wells would be necessary.

The existing UTC technology would have to be modified to take advantage of this higher temperature source. The larger temperature differential would at least require a different secondary fluid to maximize the efficiency of power generation. Assuming this technological problem is adequately solved, the greater temperature differential should help increase the power available, perhaps lowering the cost per MW.

6.9.3 ALTERNATIVE 3: DEEP SOURCE; TRADITIONAL BINARY PLANT

In this alternative we again consider the inferred deeper, hotter, geothermal source. We modeled this source assuming 300ºF (150ºC) fluids at 5000 feet depth below the ground surface. Alternative 3 investigates the costs associated with using a traditional binary power plant. As with Alternative 2 above, calculations in Table 6.1 give us roughly 2.5 MW per well, necessitating two wells to produce 5 MW. Flow rates would be similar to those in Alternative 2 therefore we have assumed two to three wells would be needed to achieve the necessary flow rates at the assumed plant efficiency of 10 percent. The temperature of this source is in the range of fluid temperatures that have proved to be economically exploitable by traditional binary power plants. Ormat is a major supplier of this type of power plant with generators in the 5 MW range.

Figure 6.8. Alternative 1: Shallow Source UTC Power Plant

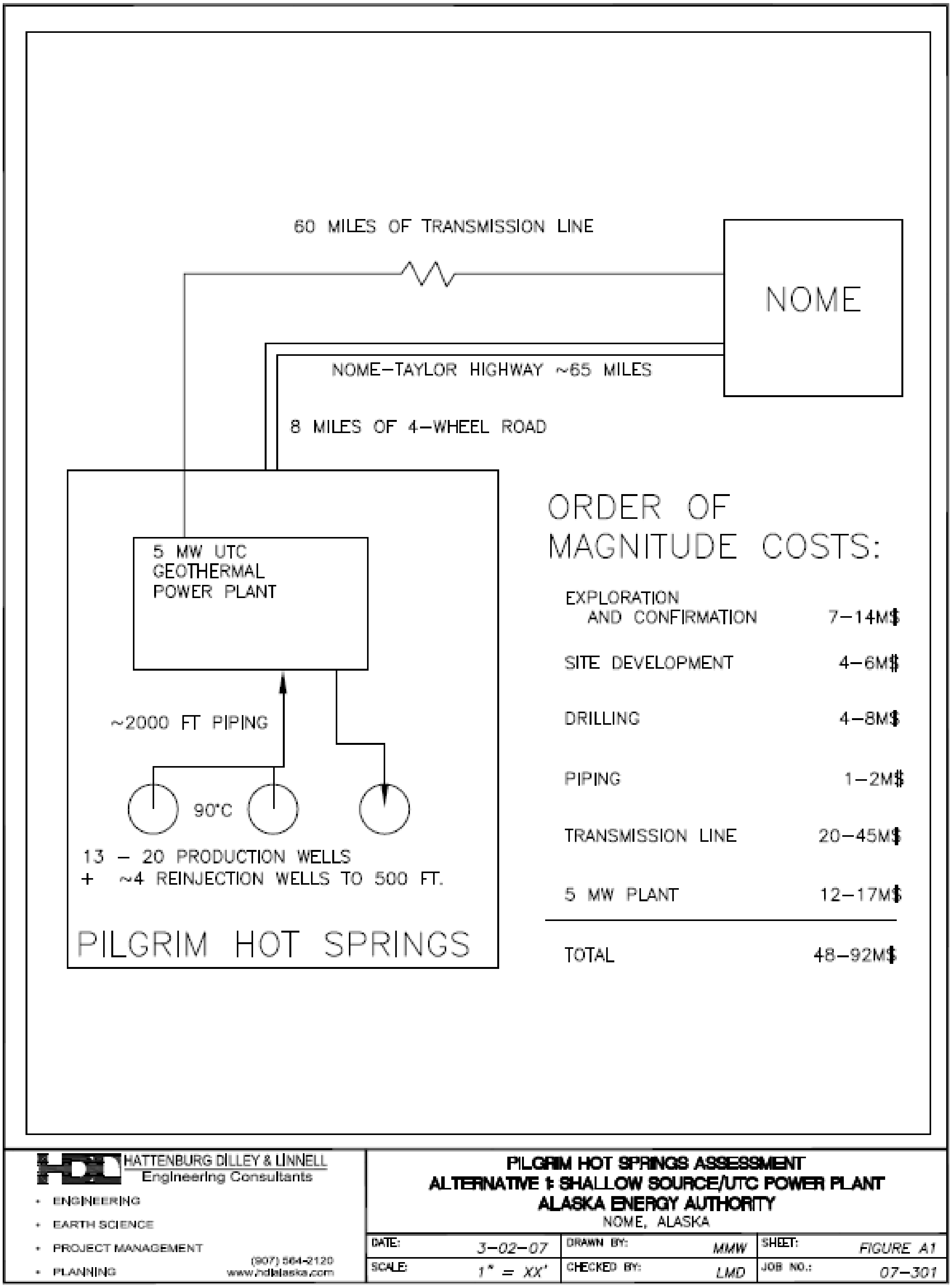


Figure 6.9. Alternative 2: Deep Source UTC Power Plant

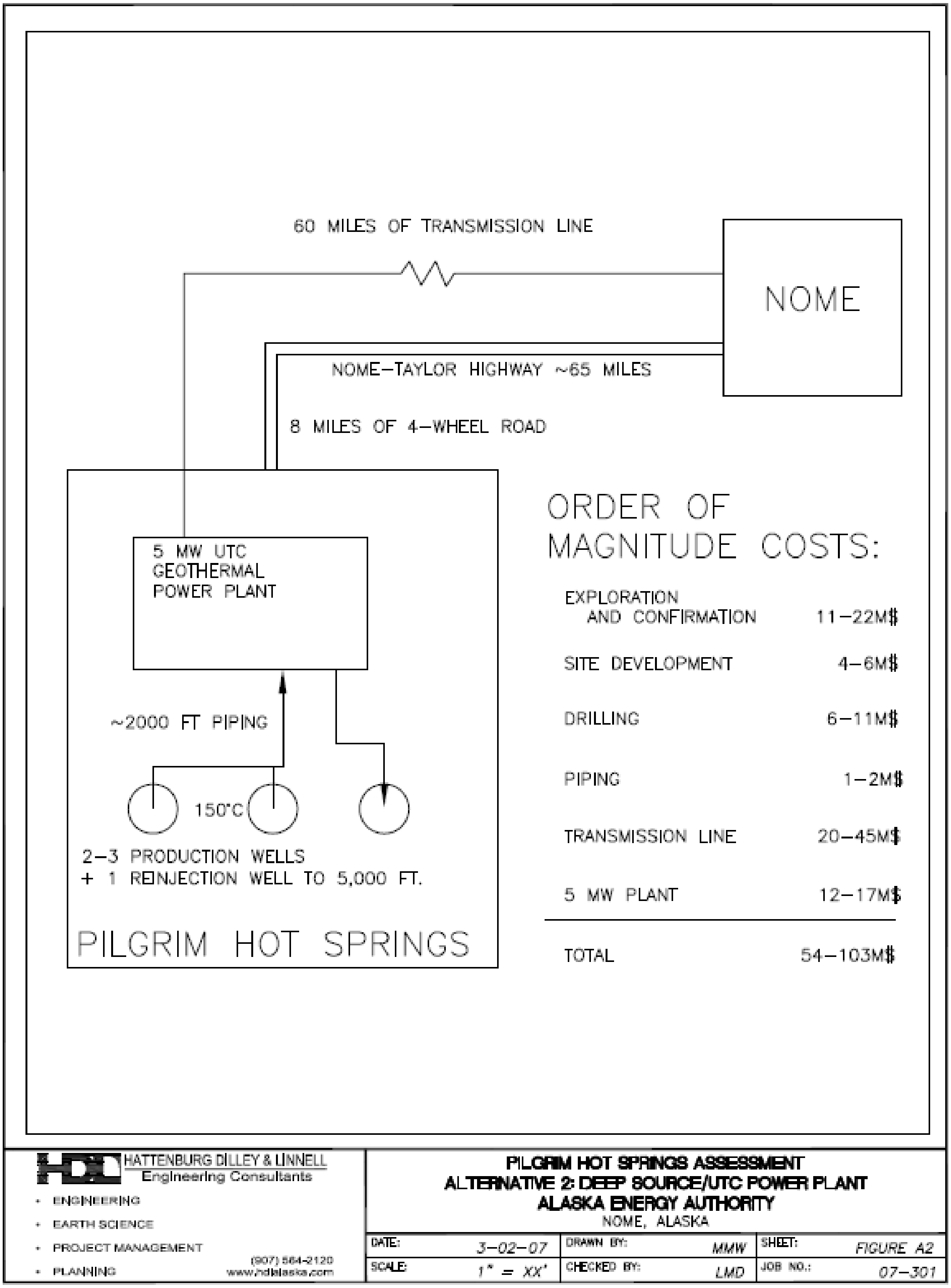
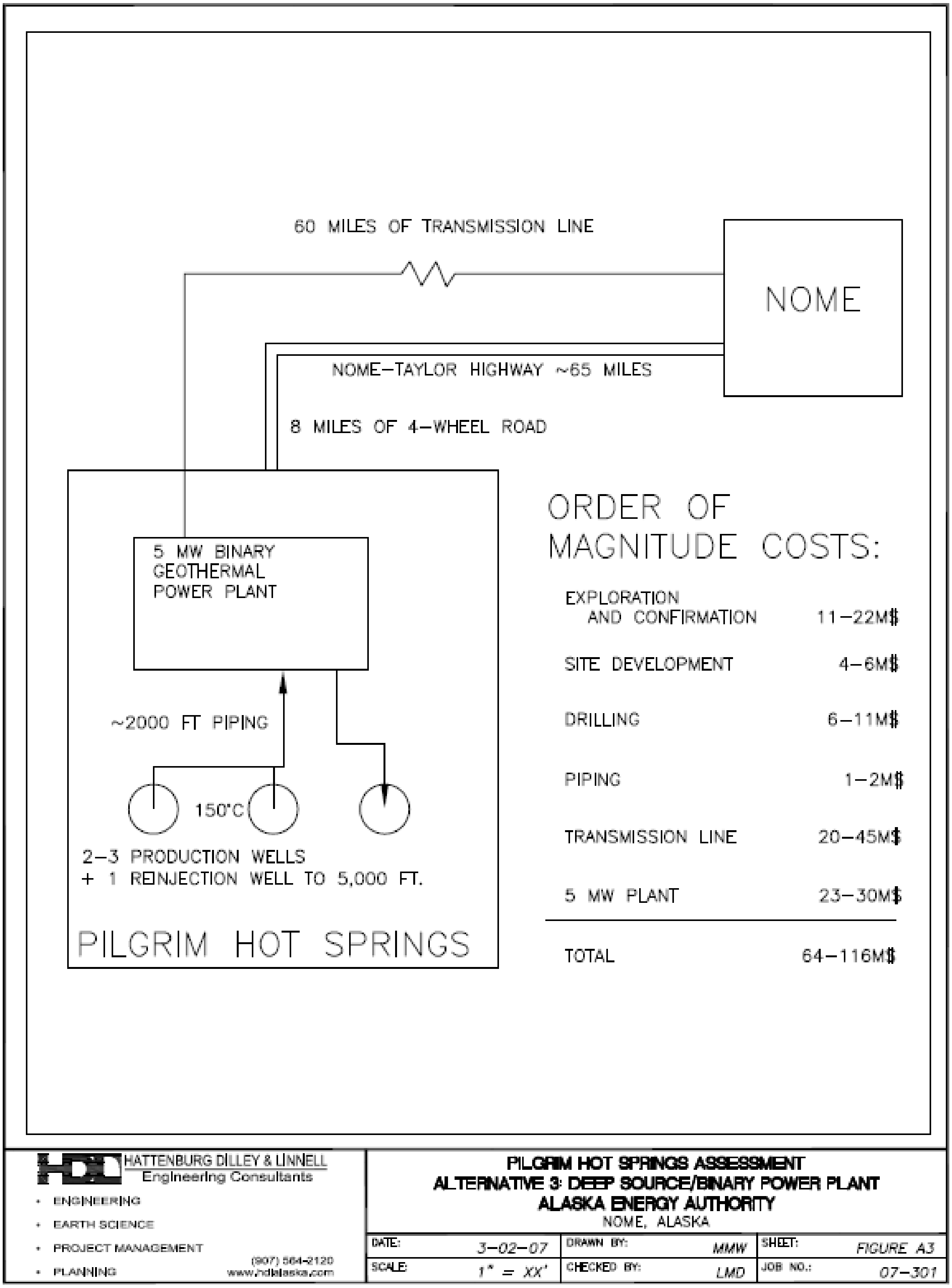


Figure 6.10. Alternative 3: Deep Source Binary Power Plant



6.10 CAPITAL COST COMPONENTS

Presented are the components of the capital cost for the alternatives discussed. All costs detailed are order of magnitude only. Summaries of these costs are found on the schematics of the alternatives in Figures 6.8 through 6.10 and in Table 6.2. All costs are based on 2008 construction with no inflation. The large capital costs required for these types of projects necessarily involve borrowing money and long delays in construction can add significant costs to any of the projects. The components considered were the following:

- Site Development
- Exploration & Confirmation
- Permitting
- Production Well Drilling
- Power Plant and Gathering System
- Transmission Line

For the geothermal components such as exploration and confirmation, and well drilling, we relied on calculations in Table 6.1 developed by Hanse, 2005. Site development and transmission line costs were developed based on experience of local engineers, the new Nome Power Plant, and contacting suppliers. Power plant costs were based on Hanse and quotes from suppliers of the power plants.

6.10.1 SITE DEVELOPMENT

Site development would include upgrading the gravel access road and developing an area for the power plant site and well pads. An existing, approximately 7.5-mile, 4-wheel drive road that connects the Nome-Taylor Highway to Pilgrim Springs would need to be upgraded to provide access for drill rigs and other equipment (see photo in Figure 6.4). The last 200 yards of this road is especially swampy and difficult for vehicles according to the on-site caretaker. Costs for this improvement will depend on a number of factors, including number and type of stream crossings necessary, size and adequacy of existing road section, availability and grading of local materials, subsurface conditions at the site, etc. For our cost analysis we assume that the current 4-wheel drive road is approximately 16 feet wide and has a 2-foot thick section and will be upgraded to 24 feet wide and 3-foot thick section. We assume that adequate gravel will be available from quarries near Nome. Bid tab estimates were used plus additional increase in the cost for hauling material to Pilgrim; we estimated approximately $40 to $80 per cubic yard for gravel. These numbers are on the low end for rural Alaska projects, but Nome generally has a reasonably available source of gravel from local mining operations. We further assume that two stream crossings will be necessary, and that these will be provided by road culverts at approximately $200,000 per crossing. This gives a total range for the road upgrade of about 3 to 5 million dollars (M$).

Based on the new Nome Power Plant size and scaling for the size and number of generators that would be used at Pilgrim we estimated a building size of about 15,000 square feet. Pad development for the power plant will be on the order of $250,000 to $500,000 assuming a 15,000 square foot building and cost for gravel of $40 to $80 per cubic yard. Well sites and additional upgrades to on-site roads will probably add an additional $250,000 to $400,000 in gravel to the project. Site development would add an additional 0.5 to 1 M$. This assumes that the power plant would not need a specialize foundation. The new Nome Power Plant needed a specialize foundation with a cost of about 1 to 1.2 M$ for the foundation alone.

6.10.2 EXPLORATION & CONFIRMATION

The exploration phase consists of investigating the geothermal resource, beginning with prospecting and field analysis, and ending with the drilling of the first full-scale commercial production well. Some of this work has already been accomplished. For example, a full regional reconnaissance is not necessary as the focus has already been narrowed to the region of apparent geothermal activity at Pilgrim. Some district exploration has already been accomplished in the 1979 study of Pilgrim Springs. However, much work does remain to be done to characterize reservoir morphology, flow rates and temperature for both the shallow and deep resource. It is expected that exploration of the shallow resource, (though it may be less likely to satisfy the power generating needs of Nome) would be less costly due to being nearer the surface and better characterized at this time than the deeper source. According to Hanse (2005), exploration costs typically run in the range of \$100 to \$200/kW depending on the nature and size of the project, the amount of information already available, and the technologies employed in exploration.

Factors affecting drilling costs also greatly influence exploration. The size of drill rig will also affect the drilling costs. For the proposed shallow wells, a shallow gas drill rig may be preferred to a large oil drill rig. The shallow gas drill rigs are capable of drilling depths on the order of 3,000 feet and are transported on a single, heavy duty truck. Support trucks are used for carrying supplies, mud tanks, and some associated gear however the drilling footprint is much smaller than the large oil drill rigs. The deeper depth of 5,000 feet is near the cut off for some of the more advanced shallow drill rigs and it may still be possible to use this type of drill rig for this depth. Currently, drilling costs are expected to be high because of the high cost of oil and the high demand for rigs for petroleum exploration projects. Figure 6.11 presents drilling costs of oil and gas wells in 2003. The costs for the shallower depths use the smaller drill rigs. If one doubles these numbers to account for the current (2007) level of exploration, and then doubles the cost again as a rough “Alaska factor” to try to compensate for remoteness, a range of about 0.8 to 2 M\$ per well results

Confirmation costs are those costs necessary to confirm 25 percent of the total project capacity. Table 6.1 provides the costs for administration, unsuccessful drill holes, regulatory compliance for exploration drilling, reporting documents, and well testing. These costs are needed to confirm a geothermal reservoir prior to production drilling. If the costs from Table 1 are added up for the two sources and multiplied by an Alaska factor of 2, this gives a low-end total confirmation cost of around 5 M\$ for the shallow resource and 9 M\$ for the deeper resource. If we double these numbers again to give a rough estimate to the high end of the expected range (to allow mainly for more expensive drilling costs due to the competition for drilling equipment with the petroleum industry, etc.), and add on the range above for the exploration costs we get the numbers listed on Figures 6.8 through 6.10 for the costs of exploration and confirmation of 7 to 14 M\$ for the shallow resource and 11 to 22 M\$ for the deeper resource. This is the range of costs needed to confirm that the resource is actually there.

6.10.3 PERMITTING

Permitting costs are necessary for compliance with state and federal regulations. Hanse gives a range of typical project costs for permitting of from about 0.2 M\$ with a completion time for permitting of less than a year (best case scenario) to over 1 M\$ with a permitting time of over 3 years, mostly depending on the stringency of local regulations. Air permitting on the Nome Power Plant was extensive and required two years of monitoring data before permitting would take place. However geothermal power plants generally have better air quality than traditional fossil fuel plants and therefore air permitting will probably be less rigorous. Additional permitting issues may arise particularly with transmission lines and migratory birds as well as discharge of waters into the surrounding environment. These costs are included into the Exploration and Confirmation costs on Figures 6.8 through 6.10.

Figure 6.11. Average drilling costs for oil and gas wells in 2003

Drilling Costs

Average Costs of Onshore Oil & Gas Drilling for 2003 from Joint Association Survey on Drilling (Augustin, 2006).

Drilling Interval (feet)	Average Depth (meters)	Average Depth (feet)	Average Cost (Year 2003 US M$)
1250-2499	557	1826	0.227
2500-3749	964	3162	0.267
3750-4999	1329	4359	0.3
5000-7499	1912	6272	0.543
7500-9999	2613	8572	1.01
10000-12499	3380	11087	2.033
12500-14999	4092	13424	2.949
15000-17499	4868	15969	5.168
17500-19999	5648	18526	11.177

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PILGRIM SPRINGS
DRILLING COSTS
ALASKA ENERGY AUTHORITY
PILGRIM SPRINGS, ALASKA

DATE:	4/18/07	DRAWN BY:	MMHN	SHEET:	FIGURE 7
SCALE:	NONE	CHECKED BY:	LMD	JOB NO.:	07-301

6.10.4 PRODUCTION WELL DRILLING

Although some well drilling is included above in costs to confirm the resource, additional wells would need to be drilled to complete the development of the resource to 5 MW.

Drilling costs are affected by depth of hole, availability of equipment, how well the resource is characterized, temperature, chemistry and permeability of the resource, and cost of construction materials, among other factors. A little over half of the drilling costs are explained solely by the depth of the well. Assuming the brine in this resource is not corrosive and given that the relatively low temperatures of these resources should not result in high pressure, the drilling conditions at Pilgrim should not be unduly adverse. One method for assessing base cost for drilling each well is that given by Table 6.1. This value is significantly higher, however, than drilling costs averaged from onshore oil and gas drilling (Augustin, 2006) (see Figure 6.11). Either of these costs must be multiplied by an “Alaska Factor” to take local conditions and remoteness into account, as well as availability and cost of drilling equipment in the current market.

The number of wells that need to be drilled depends most strongly on the productive capacity of each well, which has been estimated in Section 6.8. The success rate of holes drilled during this phase is in the range of 80 percent. It is strongly recommended to drill at least one extra production well during this phase to help offset the common occurrence of well productivity decline. Reinjection wells will also be necessary to maintain the resource.

Taking all of these factors into account, a range for the cost of drilling is around 4 to 8 M$ for the shallow resource and 5.5 to 11 M$ for the deep source, keeping in mind that 25 percent of the production capacity for the shallow resource and 33 percent of the production capacity for the deep resource was developed in the confirmation phase. Competition for drilling services from the oil and gas industry could drive these figures up even higher.

6.10.5 GATHERING SYSTEM/POWER PLANT

In costs for the power plant we include costs for the generators and generator building and pumps and piping to bring the geothermal fluids to the generators.

The hot water gathering system includes the pipes and pumps. Under a reasonable assumption that our geothermal fluids are not too highly corrosive, we can start with the industry average of around $250 per kW from Hanse(2005), which gives about 1 M$ for a 5 MW project. Doubling this for the Alaska factor, one obtains a range of roughly 1 to 2 M$. The number of pipes necessary to develop the shallow resource will undoubtedly be greater, as we require a greater number of wells in our model.

At the new Nome Power Plant, a traditional fossil fuel plant, building costs were on the order of 5 to 7 M$, with the final project costs approaching 30 M$. Geothermal power plant costs include the cost of land, and physical plant, including buildings and power generating turbines. Geothermal plants are relatively capital-intensive, with low variable costs and no fuel costs. Plant lifetimes are typically 30 to 45 years. Financing is often structured such that the project pays back its capital costs in the first 15 years. Costs then fall by 50 to 70%, to cover just operations and maintenance for the remaining 15 to 30 years that the facility operates. In the case of the traditional binary power plant, we use numbers from Hanse, multiplied by a factor of 2 (“Alaska Factor”) to estimate a range of from 23 M$ to 30 M$ for a 5 MW power plant, assuming a resource temperature of 150ºC. According to the Renewable Energy Policy Project (REPP) in Washington DC, capital cost for geothermal power plants in the 5 MW range using a medium quality resource ranges from $1600 to $2400 per installed kW. Applying a factor of 2 for the remoteness of the project, construction cycles and Alaska weather the REPP numbers are in the same range as Hanse.

Chena Power, LLC gives a cost of $1300 per KW for the UTC generators. Based on conversations with Chena Power, LLC, this cost is expected to hold for the currently produced 200 kW generators and the 1 MW generators they are developing. Shipping for the 200 kW generator to Chena Hot Springs was around $50 per kW. We also assume the construction of a 15,000 square foot building to house the generators, shops, and apartment space at around $350 to $500 per square foot. Using these values we get a cost of roughly 12 to 17 M$ for the UTC plant.

6.10.6 TRANSMISSION LINE

To bring the power produced to Nome, approximately 60 miles of transmission line would be necessary. For a single pole structure, Dryden and LaRue (personal communication) provided a rough estimate of $500,000 to $750,000 per mile. This assumes winter construction for tundra protection, and further assumes that topography is gentle along the path of the transmission line. This gives a total cost of between 30 to 45 M$. Hanse reports costs for construction lines of from $164,000 to $450,000 per mile, doubling these numbers for the Alaska Factor we get a total of around 20 M$ to 54 M$. We take a middle range to be a reasonable rough cost estimate, and assume transmission costs to be approximately 20 M$ to 45 M$.

6.11 CONCLUSIONS

6.11.1 ALTERNATIVE DISCUSSION

The following presents a summary of the alternatives and associated costs.

Table 6.3. Summary of Alternatives and Costs

ALTERNATIVE	PROJECT COSTS ($M)
1. Shallow Source; UTC System	48 - 92
2. Deep Source; UTC System	54 - 103
3. Deep Source; Binary Plant	64 - 116

Based on cost alone, it seems that Alternative 1 would be the preferred alternative. It is possible that this alternative would not produce 5 MW. We do not know the total capacity of either resource for power generation. It is more plausible that the inferred deeper source would be able to generate power in the range of 5 MW. The shear number of wells and generators needed to generate power may also preclude the use of the UTC system. Well interference may also be a major problem with Alternative 1.

Alternatives 2 and 3 utilize a source that while less well characterized than the shallow source, has greater theoretical potential for power generation due to its higher inferred temperature (150ºC versus 90ºC) and potentially greater heat capacity. Using a UTC system may have cost advantages because of the small size of the plant and relatively low temperature of the source. However, the UTC system currently utilized in geothermal setting at Chena Hot Springs runs off of a lower temperature source and the technological problems of working with the hotter fluid at Pilgrim will need to be overcome. This may delay the time until a working plant is available, thus raising the cost.

Although projected to be slightly more expensive than the other options, Alternative 3 at this time seems to be the option most likely to succeed. Prior to more research into the characteristics of the resource, this appears to be the best option. If the deeper resource proves to have greater than 5 MW capacity then the cost per megawatt will decrease. Many of the costs are fixed and therefore additional power capacity beyond the 5 MW would provide a lower cost per megawatt which could benefit the mine coming on line.

6.11.2 FOLLOW ON STEPS

At this time neither of the resources has been confirmed. The shallow source has been identified however its full character has not been confirmed. The deep source is only known through limited geochemistry and modeling the shallow source. An exploration phase followed by a confirmation phase needs to be conducted prior to any decisions about type of power plant and number of wells.

We would recommend that the exploratory phase focuses initially on both the shallow and the deep source. A better characterization of each would help immensely in refining the feasibility estimates of the available options. We would recommend the following for assessing the resources:

1. Identifying the regional thermal and hydrologic gradient;
2. Repeat equilibrium temperature profiles for existing wells;
3. Accurately and uniformly characterize the chemistry of the well, spring and river waters;
4. Complete mapping of regional geothermal system;
5. Characterizing regional aqueous geochemistry; and
6. Quantifying thermal budget and environmental impacts.

In addition to these items, a conceptual model of the shallow and deep geothermal reservoirs with our improved understanding of structurally controlled geothermal systems should be developed. Based on the exploratory phase one or both of the sources will be identified and a more thorough understanding of the sources will be achieved. After the exploratory phase a decision can be made as to which source to pursue and a confirmation phase can begin. The costs associated with exploratory and confirmation phases including the drilling of test holes and well tests is on the order of 7 to 22 M$.

6.12 LIMITATIONS

If substantial time has elapsed between submission of this report and the start of work at the site, or if conditions have changed because of natural causes or construction operations at or adjacent to the site, we recommend that this report be reviewed to determine the applicability of the conclusions and recommendations considering the time lapse or changed conditions.

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7 ENVIRONMENTAL ASSESSMENTS OF ENERGY OPTIONS

The purpose of this Section is to identify environmental issues associated with each of the identified power system options that have some measure of feasibility based upon technical and economic considerations, to identify associated environmental issues and outline the applicable regulatory framework and requirements.

The facilities defined in this report would require a number of federal and state environmental construction and operation permits. A summary of several regulatory requirements applicable to all of the energy options is followed by a discussion of each power system relative to specific environmental concerns. These discussions are organized into the following natural resource components: Air, Solid and Hazardous Waste, Water and Wastewater, Fish and Wildlife, Land Use. When permits and authorizations are described in the text by the responsible agency and type of permit (e.g., Alaska Department of Natural Resources (ADNR), temporary water use permit), the specific authorities and titles are listed at the end of this section in Table 7.7.

7.1 REGULATORY REQUIREMENTS APPLICABLE TO ALL ENERGY OPTION

Nome and the surrounding are within Alaska's Coastal Zone. All projects within the coastal zone must undergo a determination of consistency with the Alaska Coastal Management Program (ACMP) (AS 46.40). The process is initiated by filing a Coastal Project Questionnaire (CPQ) with ADNR.

The identified power systems also must comply with the National Environmental Policy Act (42 U.S.C. § 4321 et seq.), (NEPA) assures that information on the environmental implications of a federal or federally-funded action is available to public officials and citizens before making decisions or taking actions.

Actions having the potential to significantly impact the environment must be evaluated by federal agencies to determine the environmental consequences, identify reasonable alternatives and document the environmental analysis. Federal agencies could be required to prepare an Environmental Assessment (EA) or Environmental Impact Statement (EIS) prior to issuing permits or other approvals for the project. Federal actions that could trigger the preparation of an EA/EIS include:

- Federal funding or loan guarantees by the DOE,
- Issuance of a National Pollution Discharge Elimination System (NPDES) permit to accommodate facility construction and surface water discharges of treated effluent and/or permitting of injection wells under Underground Injection control (UIC) regulations (Environmental Protection Agency),
- Permits to excavate or place fill in wetlands and waters as necessary for project development (United States Army Corps of Engineers).
- Federal Energy Regulatory Commission (FERC) license to construct and operate a hydroelectric project

When preparing an EA or EIS, the federal agency must consider the Proposed Action, Connected Actions and Cumulative Impacts that are related to the project.

- **Connected Actions:** Actions by others that are required for the proposed project to operate, and actions that will result from construction and operation of the proposed project.

- **Cumulative impacts:** Impacts resulting from other past, present, and reasonably foreseeable actions in the project area.

The lead agency must also consult with the United States Fish and Wildlife Service (USFWS) and National Marine Fisheries Service (NMFS) to assure compliance with the Section 7 of the Endangered Species Act and the State Historic Preservation Officer to assure compliance with Section 106 of the National Historic Preservation Act.

7.2 COAL

The coal power option for Nome would involve construction and operation of coal fired boilers and steam turbines. Coal would be delivered to the Port of Nome by ocean going barge. The source of the coal would be existing operating mines in Alaska and/or British Columbia. The coal power facility would be located in the vicinity of Nome, and would utilize existing surface or ground water for cooling purposes.

7.2.1 AIR QUALITY

The Clean Air Act (CAA), 42 USC 7401 et seq. amended in 1977 and 1990, is the basic federal statute governing air pollution. The provisions of the CAA that are potentially relevant to the proposed projects include the following:

- **New Source Review (NSR) / Prevention of Significant Deterioration (PSD)**
  The NSR permitting program was established as part of the 1977 Clean Air Act Amendments (CAAA). New Source Review is a preconstruction permitting program that ensures that air quality is not significantly degraded from the addition of new or modified major emissions sources.[7] In poor air quality areas, NSR ensures that new emissions do not inhibit progress toward cleaner air. In addition, the NSR program ensures that any large new or modified industrial source will be as clean as possible, and that the best available pollution control is utilized. The NSR permit establishes what construction is allowed, how the emission source is operated, and which emission limits must be met.

  If construction or modification of a major stationary source located in an attainment area would result in emissions greater than the significance thresholds, the project must be reviewed in accordance with PSD regulations. Construction or modification of a major or, in some jurisdictions, non-major stationary source in a nonattainment or PSD maintenance (Section 175A) area requires that the project be reviewed in accordance with nonattainment NSR regulations. The Alaska Department of Environmental Conservation (ADEC) regulates air emissions as set out by 18 AAC 50, and is the delegated authority for preparing air quality permits in Alaska.

- **New Source Performance Standards (NSPS)**
  The NSPS, codified at 40 CFR Part 60, establish requirements for new, modified, or reconstructed units in specific source categories. NSPS-requirements include emission limits, monitoring, reporting, and record keeping.

- **National Emission Standards for Hazardous Air Pollutants (NESHAPs) / Maximum Achievable Control Technology (MACT)**
  NESHAPs, codified in 40 CFR Parts 61 and 63, regulate hazardous air pollutant (HAP)

[7] A major stationary pollutant source in a nonattainment area has the potential to emit more than 100 tons per year (tpy) of any criteria pollutant. In PSD areas, the threshold level may be either 100 or 250 tpy, depending on the source.

emissions. Part 61 was promulgated prior to the 1990 CAAA and regulates only eight types of hazardous substances (asbestos, benzene, beryllium, coke oven emissions, inorganic arsenic, mercury, radionuclides, and vinyl chloride).

The 1990 CAAA established a list of 189 additional HAPs, resulting in the promulgation of Part 63. Also known as the MACT standards, Part 63 regulates HAP emissions from major sources of HAPs and specific source categories that emit HAPs. Part 63 considers any source with the potential to emit 10 tons per year (tpy) of any single HAP or 25 tpy of HAPs in aggregate as a major source of HAPs.

- **Title V Operating Permits.**
  Title V of the federal CAA requires individual states to establish an air operating permit program. The requirements of Title V are outlined in 40 CFR Part 70 and 71, and the permits required by these regulations are often referred to as Part 70 or 71 permits. The ADEC regulates air emissions as set out by 18 AAC 50, and is the delegated authority for preparing air quality permits in Alaska.

7.2.2 5 MW BARGE MOUNTED COAL-FIRED POWER PLANT

The first assessment provides the permitting triggers, permitting requirements, and limits that would be applicable to a nominal 5 MWe barge mounted coal-fired power plant. The plant includes a 4.655 MWe coal-fired boiler system with circulating fluidized bed combustors and a 1 MWe diesel-fired engine (described in Section 3).

7.2.2.1 EMISSIONS

The estimated emissions from the 4.655 MWe coal-fired boiler with circulating fluidized bed combustors using both British Columbia (B.C.) and Usibelli coal, in units of tpy, are given below in Table 7.1.

Table 7.1. 4.655 MWe Coal Plant Emissions

Emissions	Emission Factors	4.65 MWe B.C. Coal-Fired Boiler	4.65 MWe Usibelli Coal-Fired Boiler
Nitrogen Oxides (NO_x)	0.20 lb/MMBtu	85.1 tpy	85.1 tpy
Carbon Monoxide (CO)	0.20 lb/MMBtu	85.1 tpy	85.1 tpy
Sulfur Dioxide (SO_2)	0.06 lb/MMBtu - BC 0.08 lb/MMBtu - Usibelli	25.5 tpy	34.1 tpy
Particulate Matter (PM-10)	0.015 lb/MMBtu	6.4 tpy	6.4 tpy
Volatile Organic Compounds (VOC)	0.11 lb/ton	1.0 tpy	1.9 tpy

Notes:
(1) Based on a thermal input of 97.2 MMBtu/hr.
(2) Based on full load and year round operations.
(3) VOC emission factor was estimated using AP-42, and coal demand of 18,900 tpy for B.C. and 35,240 tpy for Usibelli.
(4) All others emission factors are based on design basis

The coal-fired boiler would also produce HAPs. Organic HAPs include carcinogenic dioxins, furans, and polycyclic aromatic hydrocarbons. Because these compounds result from incomplete combustion, as does carbon monoxide, measures to prevent the release of CO also generally limit organic toxins. In addition to organic HAPs, combustible fuel may contain small quantities of toxic metals and other inorganic pollutants. These substances leave power plants as airborne particles or vapor. They also concentrate in bottom ash and collect in pollution control devices. Measures to limit particulate emissions also generally control inorganic HAPs. Volatile metals such as mercury and selenium represent important exceptions; only about 10% of mercury emitted from power plants takes a particulate form. The remainder takes either an ionic or an elemental form. However, according to EPA's AP-42 emission factors (Table 1.1-17 and 18), a coal boiler would emit less than 1 tpy of mercury.

Hydrogen chloride (HCl) emissions are generally the primary source of HAP emissions from a coal-fired boiler. According to EPA's AP-42 emission factors (Table 1.1-15), a fluidized bed combustor would emit approximately 1.2 pound of hydrogen chloride (HCl) per ton of coal combusted. This equates to approximately 11 to 21 tpy of HCl for B.C. and Usibelli coal use, respectively. *Emissions at this level would trigger classification of the facility as HAP major, triggered at 10 tpy of a single HAP or 25 tpy of cumulative HAPs.* Therefore, controls should be implemented to avoid this classification, which would trigger several federal requirements.

A 1 MWe diesel generator is included on the barge for startup and limited backup power. Emissions are given in Table 7.2.

Table 7.2. 1 MWe Diesel Generator Emissions

Emissions	Emission Factors	1 MW Diesel Generator
Nitrogen Oxides (NO_x)	0.81 lb/MMBtu	33.3 tpy
Carbon Monoxide (CO)	0.81 lb/MMBtu	33.3 tpy
Sulfur Dioxide (SO_2)	Mass Balance w/ 0.0015% S (0.002 lb/MMBtu)	0.06 tpy
Particulate Matter (PM-10)	0.10 lb/MMBtu	4.1 tpy
Volatile Organic Compounds (VOC)	0.09 lb/MMBtu	3.7 tpy

Notes:
(1) Calculations used conversations of 19,300 Btu/lb fuel, 7.1 lb fuel/gal, and 7,000 Btu/hp-hr.
(2) VOC emission factor was estimated using AP-42 Table 3.4-1; all others based on design basis.
(3) Based on full load and year round operations since no enforceable limit would be necessary.

Therefore, total coal project emissions are as shown in Table 7.3.

Table 7.3. Total Emissions for the 5MWe Barge-Mounted Coal Plant

Emissions	5 MW B.C. Coal-Fired Power Plant	5 MW Usibelli Coal-Fired Power Plant
Nitrogen Oxides (NO_x)	118.4 tpy	118.4 tpy
Carbon Monoxide (CO)	118.4 tpy	118.4 tpy
Sulfur Dioxide (SO_2)	25.6 tpy	34.1 tpy
Particulate Matter (PM-10)	10.5 tpy	10.5 tpy
Volatile Organic Compounds (VOC)	4.7 tpy	5.6 tpy

7.2.2.2 PERMITTING

A Title I minor permit would be required by the ADEC prior to construction as set out by 18 AAC 50.502(c)(1)(B): The owner or operator must obtain a minor permit under this section before commencing construction of a new stationary source with a potential to emit greater than 40 tpy of NO_x.

The permit application would entail the following:

- Demonstration of compliance with applicable emission limits—the demonstration may include emissions calculations, source testing, and other monitoring; and
- Ambient air quality modeling to ensure protection of standards—the analysis would demonstrate that potential stationary source emissions would not interfere with projection of the ambient standards for NO_x.

ADEC regulations and statutes maintain the minor permits should be issued within 150 days of submittal, assuming a complete application. *(Note – if the plant has a coal preparation plant, a minor permit would also be triggered by 18 AAC 50.502(b)(5) and other permit requirements may be applicable.)*

PSD major sources are triggered at 250 tpy of a regulated pollutant, in most instances, as set out by 18 AAC 50.306 and 40 CFR 52.21 as adopted by reference in 18 AAC 50.040. PSD can be triggered at 100 tpy for specific sources, including but not limited to fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input (project is currently rated at 97.2 MMBtu/hr), and coal cleaning plants with thermal dryers (*not aware that the project has a coal cleaning plant*). Subsequently, this project does not appear to trigger Title I PSD construction permitting requirements.

In the instance that HAPs cannot be reduced to under the major HAP threshold of 10 tpy for a single HAP or 25 tpy for cumulative HAPs and as a result the power plant is subject to a standard under 40 CFR 63, then a construction permit would be required under 18 AAC 50.316.

A Title V operating permit would be required by the ADEC as set out by 18 AAC 50.326(a) and 40 CFR 71: The owner or operator must obtain an operating permit for operation of a major source with the potential to emit 100 tpy or more of a regulated air pollutant, 10 tpy or more of a single HAP, or 25 tpy or more of cumulative HAPs.

The permit application must be submitted within 12 months after commencing operation or on or before such earlier date as the permitting authority establishes, and would entail the submitting information as set out by 40 CFR 71.5. If the Title I minor permit requested operational limits to avoid 100 tpy of a regulated air pollutant, a Title V permit would not be required.

7.2.2.3 APPLICABLE LIMITS

The limits shown in Table 7.4 would be applicable to the coal-fired boiler.

Table 7.4. Emissions Limits

	SO_2	PM-10	Opacity
Boiler Emission Estimates	0.06 to 0.08 lb/MMBtu	0.015 lb/MMBtu	NA
State Emission Limits	500 ppm sulfur compounds emissions, expressed as SO_2	0.1 gr/dscf corrected to standard conditions	20% averaged over any 6 consecutive minutes
	18 AAC 50.055(c)	18 AAC 50.055(b)	18 AAC 50.055(a)(1)
Federal Emission Limits	0.20 lb/MMBtu to 1.2 lb/MMBtu heat input	None if under 8.7 MW	None if under 8.7 MW
	40 CFR 60 Subpart Dc	40 CFR 60 Subpart Dc	40 CFR 60 Subpart Dc

- **The boiler would be subject to 40 CFR 60 Subpart Dc for Small Industrial-Commercial-Institutional Steam Generating Units** because it would be constructed after June 9, 1989 and has a maximum design heat input capacity of 29 MW (100 million British thermal units per hour (MMBtu/hr) or less, but greater than or equal to 2.9 MW (10 MMBtu/hr). Applicable limits are noted in the table above. Heat input means heat derived from combustion of fuel in a steam generating unit and does not include the heat derived from preheated combustion air, recirculated flue gases, or exhaust gases from other sources (such as stationary gas turbines, internal combustion engines, and kilns).
- The engine would be subject to 40 CFR 60 Subpart IIII for Stationary Compression Ignition Internal Combustion Engines.
- The plant may also be subject to **40 CFR 60 Subpart Y for Coal Preparation Plants** for processes more than 200 tons per day of coal. This subpart limits particulate emissions and opacity from thermal dryers, pneumatic coal cleaning equipment, coal processing and conveying equipment, coal storage system, or coal transfer and loading system processing coal.
- The plant may also be subject to **40 CFR 60 Subpart J for Petroleum Refineries** if it contains a Claus sulfur recovery plant rated greater than 20 long tons per day (i.e., long ton equals 2,240 pounds).
- The engine may also be subject to **40 CFR 63 Subpart ZZZZ for Stationary Reciprocating Internal Combustion Engines** if the stationary source is classified as HAP major (i.e., RICE Rule—encompasses formaldehyde and CO emission limits).

- The boiler <u>may also</u> be subject to **40 CFR 63 Subpart DDDDD for Industrial, Commercial, and Institutional Boilers and Process Heaters** (i.e., *<u>Boiler MACT</u>*—currently being rescinded/revised but appears still in effect) if the stationary source is classified as HAP major (i.e., encompasses CO, PM, HCl, and Hg emission limits).
- The boiler <u>is not</u> subject to **40 CFR 60 Subpart HHHH for Coal-Fired Electric Steam Generating Units** (i.e., *<u>Clean Air Mercury (CAM) Rule – Cap and Trade Program</u>*) since the unit is rated less than 25 MW.
- The boiler <u>is not</u> subject to **40 CFR 60 Subpart Da for Electric Utility Steam Generating Units** (i.e., *<u>Clean Air Mercury (CAM) Rule – New Source Limits for PM, SO_2, NOx, and Hg</u>*) since the unit is rated less than 73 MW.
- The boiler <u>is not</u> subject to 40 CFR 60 Subpart Db for Industrial, Commercial, Institutional Steam Generating Units since the unit is rated less than 29 MW.

7.2.2.4 GREENEHOUSE GASES

Currently, there are no federal limits for the emission of greenhouse gases. However, several states require sources to mitigate greenhouse gas emissions as part of an environmental impact statement.

In May 2007, the President directed the EPA, the Department of Transportation, the Department of Energy, and the Department of Agriculture to work together to protect the environment with respect to greenhouse gas emissions from motor vehicles, non-road vehicles, and non-road engines, in a manner consistent with sound science, analysis of benefits and costs, public safety, and economic growth. Furthermore, on October 18, 2007, a Senate blueprint for tackling global warming was proposed to require power plants and vehicles to reduce their greenhouse gases by 70 percent. A chief sponsor said President Bush's approach of voluntary action will not meet the goal. The plan would set a mandatory cap on greenhouse gases, principally carbon dioxide, from electric power, manufacturing and transportation sources. Its goal is to cut annual emissions by 15 percent in 2020 and 70 percent by 2050 from 2005 levels.

Therefore, although greenhouse gases are not currently regulated, it should be noted that regulations could come into play in the near future.

7.2.2.5 CONCLUSION

As long as the project can avoid triggering HAP major status (i.e., 10 tpy of a single HAP or 25 tpy of cumulative HAPs), then the permitting process and applicable limits associated with operation of a coal-fired boiler and standby diesel generator would be relatively straightforward with no red flags. In this instance, the boiler would not be subject to the boiler MACT (40 CFR 63 Subpart DDDDD) because it was not HAP major, and it would not be subject to the Clean Air Mercury Rules since it would be rated only 4.655 MWe.

Because coal will be stockpiled from one delivery per year, the ADEC will most likely require reasonable precautions to prevent particulate matter (i.e., fugitive dust), such as implementation and approval of a plan to control dust.

7.2.3 SOLID AND HAZARDOUS WASTE

The project will generate several new solid and hazardous waste streams during construction and operation, and will require handling and storage of non-hazardous and hazardous materials. Regulations for waste handling and disposal will have to be complied with as established by EPA, FDOT and ADEC.

Non-hazardous wastes include the following:

Construction debris (grubbing, packaging, litter, etc.) generated by constructing new land based support facilities. This debris can be disposed of as a solid waste at existing permitted solid waste disposal facilities.

Coal slag and fly ash from the boiler and elemental sulfur could be disposed of at an approved landfill or monofill. Mercury content of slag and fly ash could become a regulatory issue for reuse or disposal in the future.

The coal power facility would require storing and handling several hazardous materials and will also generate several new hazardous wastes. Hazardous materials to be used at the facility include anhydrous ammonia, chilled methanol, sodium hydroxide, sulfuric acid, caustic soda ash and potassium permanganate. All will require transporting, storing and tracking as hazardous materials in accordance with USEPA (RCRA), FDOT and ADEC regulations.

Potential hazardous wastes include:

- Spent filter elements and media including spent carbon containing mercury (some are hazardous);
- Spent catalyst wastes for unspecified disposal (hazardous); and
- Metals, salts, and sludge from cooling water treatment, as well as amines used to capture CO_2 (potentially hazardous).

7.2.4 WATER AND WASTEWATER

The proposed project has water supply and wastewater disposal requirements that would require a number of Federal and State environmental permits:

- Process and Cooling Water Supply—water is available from City of Nome wells or surface water from Snake River. Surface water withdrawal from Snake River as a potential source of water for the project would require water use and fisheries passage and habitat permits from ADNR, and a dredge and fill from the U.S. Army Corps of Engineers (USACE) for intake structures.

- Wastewater Discharges—Discharge of treated wastewater to surface waters (e.g. Snake River) would require a NPDES permit form USEPA. Proposed facilities and operations that could result in surface water discharges to be reviewed under NPDES regulations include, storm water runoff, coal, and slag storage facility effluent and cooling blow down. These effluents typically contain salts, minerals, sulfide, chloride, ammonium and cyanide (RDS 2006). The exact composition of wastewater discharges is unknown at this time. In general, wastewater streams would be treated to remove oil and solids prior to discharge. Advanced treatment for some contaminants may be required.

7.2.5 FISH AND WILDLIFE

The proposed project would be located on undeveloped lands and submerged lands in close proximity to the Port of Nome. Vegetative cover in the area is predominantly alpine tundra. There are no threatened or endangered plant species known to exist in the area. The status of wildlife utilization would be specific to the site chosen for development. The barge mounted power facility could require permits form the U.S Army Corps of Engineers for structures in navigable waters, and from ADNR for habitat and fisheries impacts, particularly if the barge is to permanently moored or rests on submerged lands. Also, overland cables present electrocution and collision barriers for birds, especially large raptors.

7.2.6 LAND USE

The project site and transmission line corridor should be screened for contaminants (Phase I Environmental Investigation), fish and wildlife habitat characteristics, presence of wetlands and cultural resource sites. The presence of these features could result in environmental permit requirements as summarized in Table I. If the proposed barge occupies state owned submerged lands or the transmission lines state owned lands, a Right-of-Way authorization from ADNR would also be required.

7.3 NATURAL GAS

The natural gas power option would involve development of gas production wells in Norton Sound approximately 30 to 40 miles offshore of Nome, a sub-sea or platform based production system, sub-sea pipelines to deliver the gas on shore, on-shore gas processing facility, and a 5 MWe output gas-fired engine or gas turbine for power production. Gas turbines could also be used but were not analyzed in favor of the natural gas engines option (see section 4). Development of gas resources in Norton Sound would an independent project requiring compliance with federal and state oil and gas leases and compliance with environmental laws, regulations, and lease stipulations applicable to development of oil and gas resources. If gas could be discovered, produced and delivered to Nome by pipeline, a gas-fired power facility could be considered. The environmental issues and regulations associated with a gas-fired power facility are discussed herein.

7.3.1 AIR QUALITY

The permitting triggers, permitting requirements, and limits that would be applicable to a 5 MWe gas-fired engine or a 5 MWe gas-fired turbine are discussed herein.

7.3.1.1 EMISSIONS

The estimated emissions from a 5 MWe gas-fired engine, in units of tons per year (tpy), are given in Table 7.5.

Table 7.5. Natural Gas Engine Emissions

Emissions	Emission Factors	5 MW Gas Engine
Nitrogen Oxides (NO_x)	8 kg/hr	77.2 tpy
Carbon Monoxide (CO)	11 kg/hr	106.2 tpy
Sulfur Dioxide (SO_2)	Mass Balance w/ 50 ppm H_2S	1.6 tpy
Particulate Matter (PM-10)	0.00991 lb/MMBtu	2.0 tpy
Volatile Organic Compounds (VOC)	40 kg/hr	386.2 tpy (23.3 tpy – see note 5)

Notes:
(1) Based on a thermal input of 45 MMBtu/hr.
(2) Calculations used conversation of 1,020 Btu/scf.
(3) Based on full load and year round operations.
(4) Emission factors were estimated using data obtained by Wartsilla, except for PM-10 emission factors that came from AP-42.
(5) Using an AP-42 emission factor for VOC rather than Wartsilla yields 23.3 tpy rather than 386.2 tpy.

The estimated emissions from a 5 MW gas-fired turbine, in units of tons per year (tpy), are given in Table 7.6.

Table 7.6. Natural Gas Turbine Emissions

Emissions	Emission Factors	5 MW Gas Turbine
Nitrogen Oxides (NO_x)	0.099 to 0.32 lb/MMBtu	27.3 to 88.2 tpy
Carbon Monoxide (CO)	0.082 lb/MMBtu	22.6 tpy
Sulfur Dioxide (SO_2)	Mass Balance w/ 50 ppm H_2S (0.01 lb/MMBtu)	2.3 tpy
Particulate Matter (PM-10)	0.0066 lb/MMBtu	1.8 tpy
Volatile Organic Compounds (VOC)	0.0021 lb/MMBtu	0.6 tpy
Notes: (1) Based on a thermal input of 62.9 MMBtu/hr for typical turbine operation. (2) Calculations used conversation of 1,020 Btu/scf. (3) Based on full load and year round operations. (4) Emission factors were estimated using AP-42.		

7.3.1.2 PERMITTING

A Title I minor permit would be required by the ADEC prior to construction as set out by 18 AAC 50.502(c)(1)(B): The owner or operator must obtain a minor permit under this section before commencing construction of a new stationary source with a potential to emit greater than 40 tpy of NO_x.

The permit application would entail the following:

- Demonstration of compliance with applicable emission limits—the demonstration may include emissions calculations, source testing, and other monitoring; and
- Ambient air quality modeling to ensure protection of standards—the analysis would demonstrate that potential stationary source emissions would not interfere with projection of the ambient standards for NO_x.

ADEC regulations and statutes maintain the minor permits should be issued within 150 days of submittal, assuming a complete application.

PSD major sources are triggered as 250 tpy of a regulated pollutant, in most instances, as set out by 18 AAC 50.306 and 40 CFR 52.21 as adopted by reference in 18 AAC 50.040. PSD can be triggered at 100 tpy for specific sources, including but not limited to fossil fuel-fired steam electric plants of more than 250 million British thermal units per hour heat input (project is currently rated at 45 MMBtu/hr). Subsequently, <u>as long as VOC emissions are restricted to under 250 tpy</u>, neither source appears to trigger Title I PSD construction permitting requirements.

A Title V operating permit would be required by the ADEC as set out by 18 AAC 50.326(a) and 40 CFR 71: The owner or operator must obtain an operating permit for operation of a major source with the potential to emit 100 tpy or more of a regulated air pollutant.

The permit application must be submitted within 12 months after commencing operation or on or before such earlier date as the permitting authority establishes, and would entail the submitting information as set out by 40 CFR 71.5. If emissions are less than 100 tpy of a regulated air pollutant, a Title V permit would not be required.

7.3.1.3 APPLICABLE LIIMITS

The limits shown in Table 7.7 would be applicable to the gas-fired turbine:

Table 7.7. Gas-Fired Turbine–Applicable Emissions Limits.

	NOx	SO_2	PM-10	Opacity
Turbine Emission Estimates	0.099 to 0.32 lb/MMBtu (estimated at 1.2 to 4.0 lb/MWh)	0.01 lb/MMBtu	0.0066 lb/MMBtu	NA
State Emission Limits for Turbine (and Engine)	NA	500 ppm sulfur compounds emissions, expressed as SO_2 18 AAC 50.055(c)	0.05 gr/dscf corrected to standard conditions 18 AAC 50.055(b)	20% averaged over any 6 consecutive minutes 18 AAC 50.055(a)(1)
Federal Emission Limits for Turbine	1.2 lb/MWh 40 CFR Subpart KKKK	0.060 lb/MMBtu heat input 40 CFR Subpart KKKK	NA	NA

- **The turbine would be subject to 40 CFR 60 Subpart KKKK for Stationary Gas Turbines** because it would be constructed after February 18, 2005, and have a heat input at peak load equal to or greater than 10.7 gigajoules (10 million Btu) per hour, based on the higher heating value of the fuel fired. Stationary combustion turbines regulated under this subpart are exempt from the requirements of Subpart GG. Heat recovery steam generators and duct burners regulated under this subpart are exempted from the requirements of Subparts Da, Db, and Dc. Applicable limits are noted in the table above.

As can be seen from Table 7.7, EPA's emission factor estimates that the turbine shows that NOx emissions will be very close to the applicable federal emission limit. Therefore, caution should be used when selecting a turbine, to ensure compliance with the federal limit.

- The engine would be subject to 40 CFR 60 Subpart IIII for Stationary Compression Ignition Internal Combustion Engines.

7.3.1.4 CONLCLUSION

The permitting process and applicable limits of a gas-fired engine or turbine would be relatively straightforward with no red flags. However, caution should be used when selecting a turbine to ensure compliance with the federal limit.

7.3.2 SOLID AND HAZARDOUS WASTE

A gas-fired boiler facility would not produce solid or hazardous wastes.

7.3.3 WATER AND WASTEWATER

The primary water use for a gas fired facility would be for cooling. Water supply and water discharge would be similar to that required for the coal plant as previously discussed.

7.3.4 FISH AND WILDLIFE

The proposed project would be located on undeveloped lands in the vicinity of Nome. Vegetative cover in the area is predominantly alpine tundra. There are no threatened or endangered plant species known to exist in the area. The status of wildlife utilization would be specific to the site chosen for development. Also, overland cables present electrocution and collision barriers for birds, especially large raptors.

7.3.5 LAND USE

The project site and transmission line corridor should be screened for contaminants (Phase I Environmental Investigation), fish and wildlife habitat characteristics, presence of wetlands and cultural resource sites. The presence of these features could result in environmental permit requirements as summarized in Table 7.7.

7.4 WIND

The wind power option would be located on Anvil Mountain, less than 1 mile north of Nome's city boundary. It will involve installation of wind turbines, upgrades and/or alterations to existing roads, and installation or connection to existing transmission lines located in the proximity of the site. The principal components for a wind turbine generator include the rotor (blades and hub), turbine assembly (gearbox and generator), tower, and foundation or support structure. A facility with an electric service platform would provide a common electrical interconnection for all of the turbines and provide transmission of the generated electricity to a substation.

Three wind farms sizes are being analyzed: a 3 MW capacity comprised of two 1.5 MW turbines, a 7.5 MW capacity comprised of five 1.5 MW turbines, and a 15 MW capacity with 10 turbines. The 15 MW capacity wind farm could not be accommodated at Anvil Mountain due to spacing requirements. Each of the GE 1.5se turbines has a height of 213 ft and a rotor diameter of 230 ft, outputting 1,500 kW of electricity.

Currently, Federal or State regulations specific to the development of wind energy projects do not exist. Each project has been addressed individually, at a state and local level. However, the construction of any project on state lands requires the necessary permits and regulations as cited in Table 1. The USFWS Wind Turbine Siting Working Group issued interim guidelines in 2003 concerning the avoidance and minimization of wildlife impacts from wind turbines (USFWS, 2004). For projects on BLM-administered land, ROW authorizations are required in accordance with the terms and conditions of the BLM's Wind Energy Development Policy (BLM 2002a).

For offshore projects, the Minerals Management Service (MMS) has the authority to issue leases, easements, or rights-of-way on the Outer Continental Shelf (OCS) for wind energy projects not otherwise authorized by the Outer Continental Shelf Lands Act (OCSLA) (43 USC 1337) (MMS EIS 2007). The MMS of the U.S. Department of the Interior (USDOI) is currently developing an Alternative Energy and Alternate Use Program on the OCS to approve and manage potential energy-related activities.

With proper siting and mitigation measures, most impacts from wind energy development would be negligible. Potential impacts are highest during the construction phase due to an increase in the amount of traffic, noise generation, and air emissions. Coordination with USFWS and ADFG could result in plans to minimize or avoid impacting animal species or their habitats. Siting facilities away from sensitive areas would reduce turbine impacts to wildlife as well as mitigate potential visual impacts.

7.4.1 AIR QUALITY

There are very few emissions related to an operating wind energy project. Any emissions would be subject to the Clean Air Act (CAA) (42 U.S.C. s/s 7401 et seq.).

7.4.2 SOLID AND HAZARDOUS WASTE

There are no wastes associated with this energy source other than human refuse and construction debris. The refuse and all debris generated from constructing the turbine pads can be disposed as solid waste at existing permitted solid waste disposal facilities.

7.4.3 WASTE AND WASTEWATER

Water usage is minimal with wind systems. In comparison with other energy sources, wind uses less than 1/1600 as much water per unit of electricity produced as does nuclear, and approximately 1/1500 as much as coal. The small amount of water used is for the cleaning of the turbine blades and any general facility operations.

Turbine pads on or near water sources have the potential to cause sediment plumes during construction or cable burying operations, potentially affecting plant and wildlife species. Further pollution of water sources may occur from accidental equipment spills or un-controlled run-off during construction activities.

7.4.4 FISH AND WILDLIFE

Bird and bat strikes are a common concern with wind energy projects. Collisions occur with the propeller like blades or turbines that are placed atop towers 100 feet or more in the air and with meteorological monitoring towers and their supporting guy wires. Clustering towers, utilizing enclosed towers, and choosing locations away from known daily flight and migratory movements of bird and bat populations helps reduce the number of collisions. Overland cables also present electrocution and collision barriers for birds and bats, especially large raptors.

Indirectly, wildlife are impacted by avoidance, habitat disruption and displacement caused by the presence of infrastructure, access roads and human activity. Neglected or improper disposal of animal carcasses resulting from turbine collisions, have the potential to attract predators (bears, raptors, etc.), resulting in habituation and other wildlife management issues. Disrupting the soil during the construction phase may encourage the establishment of small burrowing mammals, attracting raptors and other predatory species.

Noise issues concerning wind power occur as broadband, tonal, impulsive, or low frequency from the turbine operation. If the proposed site is located near a water source, fish and other species sensitive to noise may be affected.

State and Federal agencies exercise their authority when projects are sited on or may affect state or federal natural resources or endangered species. The placement of turbine pads, towers, access roads, parking areas, and/or fences do not fragment important native vegetation or the feeding, breeding, nursery, or migration corridors of important wildlife. The State of Alaska currently has no wind-specific guidelines; however, in states that have passed guidelines, reference to post-construction monitoring to ensure that not threatened or endangered species, nor their habitats are affected by development of wind energy. The U.S. Fish and Wildlife Service maintains the list of threatened and endangered species and provides for the conservation of threatened and endangered plants and animals and the habitats in which they are found. The USFWS regulations are described in Table 7.7.

7.4.5 LAND USE

State and Federal agencies exercise their authority when projects are sited on or may affect state or federal lands or natural resources. The state of Alaska has not passed any guidelines dealing with wind-specific projects. The project site and transmission corridor should be evaluated prior to construction to ensure that the area is free from contaminants, characterize fish and wildlife habitats, and identify wetlands or cultural resources present. If present, it could result in the environmental permitting identified in Table 7.7. The ADNR would require a Right-of-Way authorization if transmission lines cross state-owned lands. Any type of construction or industrial activity has the potential to impact the soil, sand, gravel resources and other rock sources resulting from excavation, grading, road construction, and structural foundations. The specific type and thickness of the soil will determine the degree of potential erosion and/or compaction problems.

Typically, excavation activities and construction of access roads related to wind farms are limited. The installation of the turbines, monitoring towers and equipment requires some clearing and grading; the impact on soil and geologic resources is minimal, reducing erosion potential and seismicity concerns.

Tower height is regulated by the Federal Aviation Administration (FAA) through the issuance of permits for structures over 200 feet in height. Towers more than 200 feet tall requires lighting and markings approved by the FAA.

7.5 HYDROELECTRIC

The hydropower power option would involve a dam at Buster Creek or a watercourse with similar characteristics located northeast of Nome, a reservoir, water powered turbines, and power transmission lines connecting the facility to Nome. This scenario is a concept at this time and very little is known about the specific features that would be required for a hydropower project at Buster Creek or a similar location.

Hydroelectric projects require a license to construct and operate from the Federal Energy Regulatory Commission (FERC). Under authority of the Federal Power Act (16 USC 791a, et seq.), FERC has the exclusive authority to license most nonfederal hydropower projects located on navigable waterways or federal lands, or connected to the interstate power grid. Small hydropower projects of 5 MW power capacity or less are exempt from licensing by FERC when an approved state regulatory program is in place. To date, Alaska has not adopted regulations for small hydroelectric power projects, therefore at the present time FERC has jurisdiction over all non-federal hydroelectric power projects in Alaska. FERC's Integrated Licensing Process is a multi-year process that includes per-filing, studies, filing, NEPA compliance, tribal and interagency coordination, license issuance and monitoring. In addition, the State of Alaska requires a number of permits and authorizations for water rights, water use, fisheries and habitat impacts, land use and dam safety as listed in Table 7.7.

7.5.1 AIR QUALITY

Air quality impacts may occur from fugitive dust emissions and from construction equipment exhaust during construction. Impacts would not occur during operation.

7.5.2 SOLID AND HAZARDOUS WASTE

There are no solid or hazardous wastes generated, other than those related to construction activities and land clearing activities

7.5.3 WATER AND WASTEWATER

ADNR permits for water rights and water use would be required. Water quality issues associated with hydroelectric projects relate to physical parameters that could affect fish. Impoundment of waters in a reservoir and release through turbines could alter temperature, turbidity and dissolved oxygen conditions.

7.5.4 FISH AND WILDLIFE

In general, the major issues surrounding hydro power include impacts to fisheries resources, aquatic habitats, riparian and terrestrial habitats, water quality (particularly thermal regime), dam safety and flooding. These impacts occur as a result of creating a dam and reservoir, and diverting flow through power turbines. ADNR fish passage and fish habitat permits would be required for creation of a reservoir as the natural characteristics of a flowing stream would be permanently altered by reservoir construction.

7.5.5 LAND USE

The project footprint includes the hydroelectric facility, dam and reservoir. The reservoir could displace a large area of upland. The dam and structures would require section 404 permits from the USACE and Dam Safety Permits from ADNR. If the stream bottoms are state owned, a right-or-way or land lease could also be required by ADNR.

7.6 TIDAL AND WAVE

The City of Nome's location on the shores of Norton Sound allows ready access to tidal or wave energy alternatives. A variety of technologies have been proposed to capture the energy from waves. The two main types of tidal power are classified as potential or kinetic energy systems. Potential energy systems manipulate the water column, moving it up and down like a piston to spin a turbine or utilize surface reservoirs filled by impinging waves; releasing the reservoir water to drive hydroturbines or other conversion devices. These systems rely on barrages that create a difference in height between high and low tides. Kinetic energy systems utilize the movement of water currents to power turbines, similar to wind mills and their reliance upon air movement. Kinetic energy systems have fewer environmental issues and generally cost less than potential energy systems. All types would require connection to a transformer as part of the existing power grid. Most impacts from wave energy occur during the construction phase; however, proper siting and mitigation measures can reduce them.

Barrage tidal power is a potential energy system involving a barrage of caissons, embankments, sluices, turbines (connected to generators), and ship locks, similar to a hydro dam. Caissons house the sluices, turbines and ship locks with embankments used to seal in a basin. This system in effect places a dam across an estuarine system, thereby altering the ecosystem. Although these systems have higher civil infrastructure costs, they are more commonly considered than kinetic energy systems, which are gaining popularity due to lower costs with fewer ecological impacts.

Currently, there are no field demonstrated environmental effects available because there are no operating tidal power projects that have been developed in North America. The only tidal power plant currently producing electricity is located on an estuary of the Rance River, in Bretagne, France.

The following environmental effects could result from potential energy systems (i.e. barrages):

7.6.1 AIR QUALITY

Air quality impacts may occur from fugitive dust emissions and from construction equipment exhaust during construction. Impacts would not occur during operation. There would be no output of greenhouse gases.

7.6.2 SOLID AND HAZARDOUS WASTE

There are no solid or hazardous wastes generated, other than those related to construction activities.

7.6.3 WATER AND WASTEWATER

The water quality in the basin or estuary may be affected. Turbidity, or the amount of particulate matter suspended within the water, decreases due to less water exchanged between the basin and the sea, encouraging phytoplankton by allowing sun to penetrate deeper waters. This change would spread up the food chain. With less water exchange, the average salinity within the basin would also decrease. Placing a barrage into an estuary has the potential to block any sediment flow that may have taken place from the rivers to the sea, resulting in sediment accumulation within the barrage. All of these would result in changes to the local ecosystem.

During construction, the potential exists for construction equipment to release oil or other pollutants or that activities associated with deployment of tidal structures or trenching associated with deploying the transmission cable could result in sediment suspension or increased turbidity. The potential contamination depends upon the number and size of the structures, sediment characteristics and the amount of disturbed sediment. The equipment and methods used for underwater construction are similar to established processes used for construction of other marine development projects, including dock and pier construction and deployment of underwater transmission lines.

7.6.4 FISH AND WILDLIFE

During construction, coastal habitats (e.g., wetlands, barrier beaches) containing nesting and foraging habitats for birds and native vegetation may be disrupted, requiring the avoidance of sensitive areas and mitigation. Noise impacts to marine fauna that could also occur from construction activities.

During operation, safe fish passage is possible when the sluices are open; however, when they are closed fish will seek out turbines and attempt to pass through them. The water speed near a turbine may suck some fish through the turbine resulting in mortality.

The change in water levels near the shoreline has the potential to impact the vegetation around the coast as well as the aquatic and shoreline ecosystems. These changes would affect the types of birds that utilize the area, forcing them to migrate to other more favorable areas.

The benthic community will be physically disturbed during the construction phase from the installation of the barrage and related structures and the transmission cable with indirect effects from the re-distribution of fine sediment. In turn, aquatic life may be displaced or habitats on the seabed and intertidal zone may be altered. An increase in mortality in less mobile species in the immediate footprint may occur during construction as well as loss of seabed habitat.

Another potential effect common to all marine construction projects is noise and vibration. This includes noise from the cable deployment and the operation of boats and other equipment. Specific sources includes: engines, propeller cavitation, continuous machinery equipment and impulse equipment, and the construction of pilings (i.e. foundations). Noise and construction disturbances have the potential to cause marine mammals, fish and birds to avoid the project area during construction; disrupting their feeding, migration, and breeding/nesting behaviors. These disturbances are considered short-term behavioral responses that do not necessarily change biologically important behaviors.

Proper siting to avoid sensitive species and their use areas can mitigate habituation and stress leading to their avoidance of the project area. Management or conservation areas, such as submerged aquatic vegetation should be identified early in the siting process and avoided if possible.

7.6.5 LAND USE

Footprint issues relate to loss of shoreline and seabed habitat for the foundations, pilings and other turbine structures (i.e. anchoring, etc.). The transmission cable can be laid along and anchored to the seafloor; however, cable burial is preferred. The different methods for installing the transmission cable depend upon site selection and seabed conditions. Most land use issues arise from the method of cable installation (underwater trenching, horizontal directional drilling for open trenching, seafloor anchoring, etc.).

It is assumed that existing transmission line corridors on shore are available for connection to the power grid. If overhead transmission lines are necessary, the construction of a ROW and installation wires and poles may be required. Access to the shoreline near the project area may be restricted for safety reasons during construction. Typically, construction effects are considered temporary effects to the environment.

7.7 GEOTHERMAL

The geothermal power option would require exploratory prospecting and analysis, construction of a power plant containing generators, production wells, injection wells, and a power transmission network to Nome. The geothermal source is located 60 miles north of Nome, in Pilgrim Hot Springs. The power plant facility would be located within the vicinity of the hot springs with construction of power transmission lines leading to Nome. Existing surface or groundwater for plant cooling processes would come from nearby Pilgrim River. Currently, a 7.5 mile 4x4 gravel road provides access to Pilgrim Hot Springs; this would need to be upgraded for plant construction and operation. The construction of power transmission lines and a permanent access road would require the crossing of several small streams and rivers.

Three alternatives are being considered, all are considered to be binary power plant systems: a shallow source United Technologies Corporation (UTC) system, a deep source UTC system, and a deep source binary power plant. Due to the projected range of geothermal temperatures, all of the alternatives use a binary geothermal power plant, instead of steam dominated systems that require higher water temperatures. Each alternative was assumed to be a developable resource capable of producing 5 MW of electricity. The extent of impact from each differ, however, the general impacts are the same.

7.7.1 AIR QUALITY

The potential for air pollution to occur exists from the operation of construction equipment and related activities, as well as from geothermal power plant operations. However, the amount of air pollution from the plant would not approach air quality permitting levels. Small amounts of carbon dioxide (CO_2) and sulfur dioxide (SO_2) would be emitted as natural, minor constituents related to the geothermal reservoirs; these gases would naturally be released into the air, although at a slow rate. Geothermal fluids may also release hydrogen sulfide (H_2S), causing a sulfurous odor that humans can easily detect at levels less than 1 part per million (ppm). Typical emissions from a geothermal plant are less than 1 part per billion (ppb), below the level people can smell. Hydrogen sulfide gas can present a potential pollution problem; however, this gas is only present in steam systems. Geothermal plants lack the nitrogen oxides (NO_x) emissions typical of most fossil-fuel fired power plants because they lack high pressure combustion. Geothermal systems are also known to contain small amounts of ammonia. Binary geothermal power plants have little to no air emissions because they use a self-contained cycle, or closed system. The lack of a steam phase in binary systems prevents the airborne release of CO_2 and other gases, which remain in solution and are reinjected back into the reservoir to help sustain resources.

7.7.2 SOLID AND HAZARDOUS WASTE

Geothermal plants generate no appreciable solid waste; however, geothermal fluids contain solid byproducts or wastes. The composition of geothermal reservoirs ranges from 0.1 to over 25 weight percent dissolved solutes. The reservoir rock type, temperature, and pressure determine the composition and concentrations of geothermal fluids. Generally, the higher the geothermal fluid temperature, the higher the concentration of solutes: possibly, requiring remedial action to protect the environment. Potentially hazardous elements (Hg, B, As, and Cl) produced in geothermal brines are largely injected back into the producing reservoir.

The amount of byproduct waste produced can be reduced by recycling valuable minerals and metals. The plant would be storing and using hazardous organic compounds and produce a corrosive brine, requiring transport and disposal. The removal of non-hazardous materials such as precipitated silica and hydrogen sulfide from geothermal waters requires recycling or disposal. Clarifying and thickening tanks are used to remove solids from the injection water; the output is a slurry of brine and amorphous silica. The RCRA and ADEC regulations would apply to the transport, handling and storing of both hazardous and non-hazardous materials.

All solid and hazardous wastes would be handled and disposed of in accordance with EPA, FDOT, and ADEC regulations.

All construction debris from the new power plant facility, etc. can be disposed of as solid waste at an existing permitted solid waste facility.

7.7.3 WATER AND WASTEWATER

The proposed project would require thermal water and would dispose of wastewater by underground injection, requiring UIC permits from USEPA.

All waters are saturated in silica with the potential to precipitate upon cooling. A settling pond can be used to allow the silica to settle from the water and then the water can be pumped to an injection well. Precipitated silica is removed so it doesn’t clog the injection well or underground reservoir. Other species that have precipitated are washed from the silica and reinjected with the wash water.

In the U.S., only lower-temperature geothermal waters that meet safe drinking water quality standards are allowed to flow back into lakes and streams. Otherwise, cooled water must be injected back into the underground reservoir. Potable groundwater in shallow aquifers is protected by lining the production and injection wells with steel casing pipe that is cemented to the surrounding rock in the aquifer and confining layers. Sonic logging instruments are used to detect any leaks within the casing or cement.

The closed production and injection systems prevent contamination of surface waters. Geothermal plants use cooling towers to condense turbine exhaust fluid, dumping no heat into surface waters.

No waste heat is disposed into rivers or surface water, the heat is dispelled into the atmosphere. Lining injection wells with steel or titanium casing and cement, isolate fluids from groundwater sources. Spent fluids can be injected back into the geothermal reservoir, prolonging the reservoir use by replenishing fluids. Recycling wastewater extends the life of the geothermal reservoir, conserving water resources.

Disposing of spent geothermal fluids depends upon the quality of the fluids, local hydrological conditions, and environmental regulations. All discharges will adhere to the Clean Water Act. This act regulates the discharge of pollutants into U.S. waters through EPA control programs and established water quality standards.

7.7.4 FISH AND WILDLIFE

The use of land for placement of the power plant and transmission lines has the potential to impact fish and wildlife. Any wetlands crossed would require the permitting and construction of bridges and/or culverts. If there are any known threatened or endangered species within the project vicinity, mitigation measures would need to be implemented to conserve the ecosystem, as related to the Endangered Species Act (ESA).

Permanent facility structures such as turbine bases, parking, access roads, fences, unburied or overland transmission lines, all may fragment native vegetation and wildlife habitats. The migratory, feeding and breeding behavior of certain species may be disrupted, along with the destruction of important nesting grounds. Overland cables present electrocution and collision risks for birds and bats, especially large raptors. This includes the Migratory Bird Treaty Act, the Bald and Golden Eagle Protection Act and the Endangered Species Act.

7.7.5 LAND USE

Compared to coal power plants, geothermal plants require small footprints. A geothermal field uses 1-8 acres per MW versus 19 acres per MW for coal. A geothermal plant requires wells and drilling, impacting the land. Other industries, such as agriculture, can exist in proximity to the roads, wells, pipelines, and power plants. Directional or slant drilling helps alleviate this impact on the land. This drilling method allows several wells to be drilled from one location, reducing the amount of land needed for drilling pads, access roads, and geothermal fluid piping. Exploratory drilling using slimhole-drilling, further reduces the environmental impact during exploration, also reducing the amount land needed for site preparation and road construction.

Any type of construction or industrial activity has the potential to impact the soil, sand, gravel resources and other rock sources resulting from excavation, grading, road construction, and structural foundations. The specific type and thickness of the soil will determine the degree of potential erosion and/or compaction problems.

Land subsistence may occur from the removal of large amounts of geothermal fluid from beneath the earth’s surface. To prevent this, spent geothermal fluids are reinjected back into reservoirs. Removing large amounts of fluid and injecting it back into the subsurface raises concerns for induced seismicity. If induced seismicity occurs, it’s typically less than a magnitude of 2.5 on the Richter scale; most earthquakes are not felt below 3.5.

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
FEDERAL								
U S Environmental Protection Agency (EPA)								
National Pollutant Discharge Elimination System (NPDES): Point Source and Stormwater Discharges	Section 402, Clean Water Act (22 U.S.C. § 1251 et seq.)	Point source and stormwater discharges to surface waters including sanitary and domestic wastewater, gravel pit and construction dewatering, process/cooling water, hydrostatic test water, storm water discharges.	stormwater, process/cooling water discharges	stormwater, process/cooling water discharges	stormwater from construction area disturbance	stormwater from construction area disturbance	stormwater from construction area disturbance	stormwater from construction area disturbance
Discharge of Fill Material	Sec. 404, Clean Water Act (CWA): (33 USC § 1251 et seq.)	USEPA reviews and comments on USACE Section 404 permit applications for compliance with the Section 404(b)(1) guidelines and other statutes and authorities within its jurisdiction (40 CFR 230).	Permanent mooring of barge, intake/discharge structures.	intake/discharge structures.	unlikely	Wetland filling and structures	Intake/discharge structures	Wetland filling and structures
SPCC Plan	Section 311 of the CWA (33 USC §1251 et seq.)	USEPA requires a spill prevention, control, and countermeasure (SPCC) plan to be developed by owners or operators of any facility storing a total capacity of 1,320 gallons of fuel in aboveground storage tanks.	Fuel storage tanks for backup generators	Fuel Storage Tanks for backup generators	unlikely	unlikely	Fuel Storage Tanks for backup generators	Fuel Storage Tanks for backup generators
Underground Injection Control (UIC)	Safe Drinking Water Act (42 USC §300)	Regulates implementation of injection wells in Alaska for injection of non-hazardous and hazardous waste	unlikely	unlikely	unlikely	unlikely	Injection of brine and reinjection of geothermal waters	unlikely

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Cultural and Historical Resource Preservation	Section 106, National Historic Preservation Act of 1966 (NHPA) (16 USC 470 et seq.)	Ensure consideration of the values of historic properties in carrying out federal activities, and to make efforts to identify and mitigate impacts to significant historic properties	Review of NPDES activity	Review of NPDES activity	unlikely	unlikely	Review of UIC activity	unlikely
Hazardous Waste Generator and Transporter	Sections 3001 through 3019 of the Resource Conservation and Recovery Act (RCRA) (42 USC 3251 et seq.)	Establishes criteria governing the management of hazardous waste	Management of hazardous waste	Management of hazardous waste	unlikely	Management of hazardous waste	Management of hazardous waste	unlikely
U S Army Corps of Engineers (USACOE)								
Dredge and Fill Permit	Section 10 of the Rivers and Harbors Act (33 USC § 403)	Regulates and permits dredging, filling and structures in, on, over, or under navigable waters of the United States	Permanent mooring of barge, intake/discharge structures.	intake/discharge structures.	unlikely	Fill and structures in waters	intake/discharge structures.	Fill and structures in waters
Discharge of Fill Material	Section 404, Clean Water Act (33 USC § 1251 et seq.)	Placement of dredge and fill material (including structures) in waters of the United States, including wetlands.	Permanent mooring of barge, intake/discharge structures.	intake/discharge structures.	unlikely	Wetland filling	intake/discharge structures.	Wetland filling

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Section 106, National Historic Preservation Act	Section 106, National Historic Preservation Act of 1966 (NHPA) (16 USC 470 et seq.)	During construction, ensures consideration of the values of historic properties in carrying out federal activities, and to make efforts to identify and mitigate impacts to significant historic properties	Review of Section10/404 activity	Review of Section10/404 activity	Unlikely	Review of Section10/404 activity	Review of Section10/404 activity	Review of Section10/404 activity
U S Coast Guard (USCG)								
Construction Permit for a Bridge Across Navigable Waters	Rivers and Harbors Act of 1899 (33 USC § 403)	Regulates and permits construction of any bridges and causeways across navigable waters to ensure safe navigability of waterways.	unlikely	unlikely	unlikely	Causeways (dams) in tidal waters	Bridges associated with access roads.	Bridges associated with access roads.
U.S. Department of Transportation (USDOT)								
Hazardous Materials Registration Number	Hazardous Materials Transportation Act (49 CFR)	Transportation of hazardous materials to or from facilities	Hazardous waste disposal from operations.	unlikely	unlikely	unlikely	Hazardous waste disposal from operations.	unlikely
National Marine Fisheries Service (NMFS)								
Endangered Species Act (ESA) Sec. 7 Consultation, Marine Mammals, Fish	Endangered Species Act (ESA) (16 U.S.C. § 1531)	Protects wildlife, fish, and plant species in danger of becoming extinct, and conserves the ecosystems on which endangered and threatened species depend	Construction and operations	Construction and operations	operations	Construction and operations	Unlikely	Construction and operations

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Essential Fish Habitat Consultation.	Magnuson-Stevens Fishery Management and Conservation Act (M-SFMCA) (16 U.S.C. § 1801-1883)	Protects Essential Fish Habitat from adverse impacts	Construction and operations	Construction and operations	Unlikely	Construction and operations	Unlikely	Construction and operations
Fish & Wildlife Coordination Act Consultation, Marine Mammal Protection Act Consultation	Fish and Wildlife Coordination Act (FWCA) (16 USC § 661 *et seq*) Marine Mammal Protection Act (MMPA) (16 U.S.C. § 1361-1407)	Protection of wildlife resources and habitat. Ensuring that marine mammals are maintained at, or in some cases restored to healthy population levels.	Construction and operations	Construction and operations	operations	Construction and operations	Unlikely	Construction and operations
Marine Mammal Protection Plan	Marine Mammal Protection Act (16 USC § 1361 *et seq*)	Protection of marine mammals	Waterside Construction and Operations	unlikely	unlikely	Waterside Construction and Operations	unlikely	unlikely
Federal Energy Regulatory Commission (FERC)								
License to Construct and Operate a Hydroelectric Facility	Federal Power Act (16 USC § 791a *et seq*)	FERC's Integrated Licensing Process applies to all non-federal hydroelectric facilities in Alaska	NA	NA	NA	unlikely	NA	License to Construct and Operate

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
U S Fish and Wildlife Service (USFWS)								
ESA Sec. 7 Consult.	Endangered Species Act (ESA) (16 U.S.C. § 1531)	Protects wildlife, fish, and plant species in danger of becoming extinct, and to conserve the ecosystems on which endangered and threatened species depend	If listed species are present on site	If listed species are present on site	If listed species are present on site	If listed species are present on site	If listed species are present on site	If listed species are present on site
Bald Eagle Protection Act Clearance	Bald and Golden Eagle Protection Act (16 U.S.C. § 668)	Makes it unlawful to take, pursue, molest, or disturb bald and golden eagles, their nests, or their eggs	Construction and operations (if present)	Construction and operations (if present)	Construction and operations (if present)	Construction and operations (if present)	Construction and operations (if present)	Construction and operations (if present)
Migratory Bird Protection Act Consultation	Migratory Bird Treaty Act (Title 16 U.S.C. § 703)	Protect birds that have common migration patterns between the United States and Canada, Mexico, Japan, and Russia	Construction and operations	Construction and operations	Construction and operations	Construction and operations	Construction and operations	Construction and operations
Fish & Wildlife Coordination Act Consultation	Fish and Wildlife Coordination Act (FWCA) (16 USC § 661 *et seq*)	Protection of wildlife resources and habitat	Construction and operations	Construction and operations	Construction and operations	Construction and operations	Construction and operations	Construction and operations

Table 7.7. Applicable Federal and State Permitting Activities

Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Federal Aviation Administration (FAA)								
Permit for objects affecting navigable air space and obstruction lighting	Federal Aviation Administration (14 CFR Part 77)	Tower height is regulated by the Federal Aviation Administration (FAA) through the issuance of permits for structures over 200 feet in height. Towers more than 200 feet tall requires lighting and markings approved by the FAA.	unlikely	unlikely	Permit for towers and lighting	unlikely	unlikely	unlikely
STATE								
Alaska Department of Natural Resources (ADNR)								
Alaska Coastal Management Program (ACMP) Consistency Review	Alaska Statutes (AS) 46.39 and 46.40	Nome and surrounding area is within Alaska's Coastal Zone. Therefore, it will be reviewed for consistency with the ACMP'Coastal Management Program's enforceable policies, including coastal district policies. The review is a coordinated review of federal and state authorizations, all of which require a positive consistency determination before issuance of permits. Coastal Consistency Reviews are conducted by ADNR Office of Project Management and Permitting (ADNR/OPMP)	Within coastal zone.	Within coastal zone	Within coastal zone	Within coastal zone	Within coastal zone	Within coastal zone
Coastal Plan Questionnaire (CPQ)	AS 46.39 and 46.40	The CPQ is the regulatory checklist that will be the guiding document during the ACMP review for permits to be acquired for the project. A project plan of operations, and permit applications will be attached to the CPQ.	Must be done as part of ACMP review	Must be done as part of ACMP review	Must be done as part of ACMP review	Must be done as part of ACMP review	Must be done as part of ACMP review	Must be done as part of ACMP review

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Upland or Tideland (Competitive) Leases.	AS 38.05.070 and 075; AS 38.05.05	For use of state-owned tidelands, an ADL tideland lease is issued for marine facilities such as docks. Likewise, for use of state-owned uplands, an ADL lease is required for facilities such as transportation and staging facilities. The ADNR Division of Mining, Land and Water/Lands Section (ADNR/MLW/Lands Section) issues these leases.	May require a lease for the barge mooring site	unlikely	unlikely	May require a lease for tidelands use	unlikely	Lease for use of state owned lands
Right-of-Way for Access and Utilities.	AS 38.850	For projects on state land, a right-of-way is required for infrastructure such as roads, pipelines, and powerlines. The ADNR/MLW/Lands Section issues this approval.	unlikely	unlikely	unlikely	Required for power lines	Required for power lines	Required for power lines
Alaska Department of Natural Resources (ADNR)								
Dam Safety Certification. A	*AS 46.17 and 11 AAC 93.3*	A Certificate of Approval to Construct and a Certificate of Approval to Operate must be obtained for any significant dam. These certificates involve a detailed engineering review of the dam's design (prepared a professional engineer registered in Alaska), construction (as-built drawings and completion report), and operation (operations and maintenance manuals as well as an emergency action plan). The certificates are issued by the ADNR/MLW/Dam Safety Unit issues both certificates	*Required for dry tailings/overburden dam construction and then for operation.*	*unlikely*	*unlikely*	*Required for dry tailings/overburden dam construction and then for operation.*	*unlikely*	*Required for dry tailings/overburden dam construction and then for operation.*

Table 7.7. Applicable Federal and State Permitting Activities

Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Temporary Water Use Permit (TWUP)	*AS 46.15*	Temporary uses of a significant volume of water, for up to 5 years during development or operation of a project requires a Temporary Water Use Permit. The permit is issued by the ADNR/MLW/Water Section	*TWUP for process and cooling water*	*TWUP for process and cooling water*	*unlikely*	*unlikely*	*TWUP for process and cooling water*	*unlikely*
Permit to Appropriate Water (Water Rights)	*AS 46.15*	Appropriation of a significant amount of water on other than a temporary basis requires authorization by a Water Rights Permit. A water rights permit is a legal right to use a specific amount of surface or groundwater from a specific source. This water can be diverted, impounded, or withdrawn for a specific use. When a water right is granted, it becomes appurtenant to the land where the water is being used for as long as the water is used.	unlikely	unlikely	unlikely	unlikely	unlikely	Stream diversion
Material Sale	*AS 38.05 and 020*	If materials such as sand, gravel, or rock, are needed from state lands off a millsite lease or road right-of-way, then a separate material sale is issued by the ADNR/MLW/Lands Section.	unlikely	unlikely	unlikely	Sand, gravel and rock will be required for constructio n.	unlikely	Sand, gravel and rock will be required for construction.

Table 7.7. Applicable Federal and State Permitting Activities

Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Cultural Resource Protection.	National Historic Preservation Act Section 106, Alaska Historic Preservation Act (AS 41.35)	Clearance must be obtained to ensure that a project will not significantly impact cultural and archaeological resources. If significant disturbance cannot be avoided, then a compensation strategy is developed. Cultural resource clearances are obtained from ADNR/State Historic Preservation Office.	Required for site development	Required for site development	Required for site development	Required for site development	Required for site development	Required for site development
Title 41 Permit	AS 16.05.840 or 16.05.870	This permit, regardless of land ownership, is required for any activity conducted within fish-bearing waters, such as bridges, culvert installation, fords and crossings (both winter and summer), material sites, tailings facilities, and water-withdrawal structures. The ADNR/OHMP issues this permit.	Required for construction and operation.	Required for construction and operation.	Unlikely	Required for construction and operation.	Required for construction and operation.	Required for construction and operation.

Table 7.7. Applicable Federal and State Permitting Activities								
			Potential Applicability to Project Components					
Permit/Activity	Authority	Description	Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Fish Passage	AS 16.05.840 (Fishway Act) and AS 41.14	The Fishway Act requires that an individual or governmental agency notify and obtain authorization from the Alaska Department of Natural Resources (ADNR) for activities within or across a stream used by fish if the department determines that such uses or activities can represent an impediment to the efficient passage of fish. Culvert installation; stream realignment or diversions; dams; low-water crossings; and construction, placement, deposition, or removal of any material or structure below ordinary high water all require approval from the ADNR. Although approval is by the ADNR/OHMP, an ADF&G Fish Habitat Biologist will review and make recommendation.	unlikely	unlikely	unlikely	Required for construction and operation.	Required for access road construction and improvements.	Required for construction and operation.

Table 7.7. Applicable Federal and State Permitting Activities									
Permit/Activity	Authority	Description	Potential Applicability to Project Components						
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Alaska Department of Natural Resources (ADNR)									
FISH Habitat Permit	AS 16.05.870 (Anadromous Fish Act)	Alaska Statute 41.14.870 (Anadromous Fish Act) requires that an individual or governmental agency provide prior notification and obtain approval from the ADNR "to construct a hydraulic project or use, divert, obstruct, pollute, or change the natural flow or bed" of a specified anadromous waterbody or "to use wheeled, tracked, or excavating equipment or log-dragging equipment in the bed" of a specified anadromous waterbody. All activities within or across a specified anadromous waterbody and all instream activities affecting a specified anadromous waterbody require approval from the ADNR, including construction; road crossings; gravel removal; placer mining; water withdrawals; the use of vehicles or equipment in the waterway; stream realignment or diversion; bank stabilization; blasting; and the placement, excavation, deposition, disposal, or removal of any material. Recreational boating and fishing activities generally do not require a permit. Although approval is by the ADNR/OHMP, an ADF&G Fish Habitat Biologist reviews plans and notifications.	unlikely	unlikely	unlikely	unlikely	Required for access road construction and improvements.	Required for construction and operation.

Table 7.7. Applicable Federal and State Permitting Activities

Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Alaska Department of Environmental Conservation (ADEC)								
Solid Waste Permits	AS 44.46, AS 46.03, AS 46.04, and AS 46.06	May require solid waste disposal permits for, inert waste, wood waste, industrial solid waste, hazardous waste, and construction waste. .	Construction wastes, Ash and slag disposal	Construction wastes	unlikely	Construction wastes.	Construction wastes.	Construction wastes.
Section 401 Certification	Section 401 of the Clean Water Act (CWA)	Storm water discharges are regulated under the NPDES program and certain storm water discharges require an NPDES permit from EPA. Under the NPDES program the state of Alaska does not have permitting and enforcement authority. However, pursuant to Section 401 of the Clean Water Act (CWA) the state of Alaska certifies EPA general permits both construction activities and during operational phases. This is commonly known as "401 Certification". The facility may have separate NPDES permits to cover waste water and storm water discharges, or the requirements may be combined into one permit.	Required for construction and operation.	Required for construction and operation.	Required for construction and operation.	Required for construction and operation.	Required for construction and operation.	Required for construction and operation.

Table 7.7. Applicable Federal and State Permitting Activities								
Permit/Activity	Authority	Description	Potential Applicability to Project Components					
			Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Certificate of Reasonable Assurance for 402 and 404 Permits.	Section 402 and 404 CWA	Activities involving discharge of wastewater or fill material into waters of the United States are not only governed by the terms and conditions of a CWA Section 402 NPDES Permit from EPA, and a CWA Section 404 Permit from the COE, but also require a Certificate of Reasonable Assurance from the State of Alaska. These certificates can only be issued if ADEC/Division of Water can state that the proposed activity will comply with Section 401 of the CWA and that any discharge will comply with applicable state water quality standards.	Required for constructio n and operation	Required for constructio n and operation	Required for constructio n and operation	Required for constructio n and operation	Required for construction and operation	Required for construction and operation
Alaska Department of Environmental Conservation (ADEC)								
Plan Review for Non-Domestic Wastewater Treatment System.	*18 AAC 72 or Section 401 Certification*	Plans for treatment of wastewater from non-domestic wastewater sources must be submitted to the ADEC/Division of Water. Approval follows, either as an ADEC Wastewater Disposal Permit (18 AAC 72) or an NPDES Permit (ADEC reviews plans under CWA Section 401).	Required for constructio n and operation of camp and mine.	Required for constructio n and operation of terminals.	Unlikely	Unlikely	Unlikely	Unlikely
Spill Prevent, Control and Countermeasu re (SPCC) Plan Review	40 CFR 112.1-7.	ADEC will use its CWA Section 401 certification authority to review the SPCC Plan required by EPA for storage of large quantities of oil.	Fuel storage tanks for backup generators	Fuel Storage Tanks for backup generators	unlikely	unlikely	Fuel Storage Tanks for backup generators	Fuel Storage Tanks for backup generators

Table 7.7. Applicable Federal and State Permitting Activities								
			Potential Applicability to Project Components					
Permit/Activity	Authority	Description	Coal	Natural Gas	Wind	Tidal and Wave	Geothermal	Hydroelectric
Air Quality Control Permits to Construct and Operate.	*18 AAC 50*	Air Quality Permits. The construction, modification, and operation of facilities that produce air contaminant emissions require a state Air Quality Control Permit to Construct, and a separate Air Quality Control Permit to Operate. The determination to require a permit is based on the source location, total emissions, and changes in emissions for sources specified in 18 AAC 50.300(a). Generally, air quality must be maintained at the lowest practical concentrations of contaminants specified in the Ambient Air Quality Standards of 18 AAC 50.020(a).	Construction and operation will require permits.	Construction and operation will require permits.	unlikely	unlikely	unlikely	unlikely

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8 ECONOMIC EVALUATON OF POWER GENERATING OPTONS

Evaluating various energy alternatives involves technology, environmental factors and economics. Previous sections of this report addressed the status of the various technologies and the environment impacts of the alternatives. Central to the evaluation of competing technologies is the economic value of generating useful energy from the various resources available.

The economic analysis presented here examines the economic value of the alternatives by comparing the impact on energy costs of the various power generating options identified for Nome. The comparison is made by estimating the cost of providing energy from the alternatives against the cost of using the existing generation, transmission and distribution system for serving electric loads and providing thermal energy over the period 2015 through 2044.

8.1 OVERVIEW OF METHODOLOGY

The economic analysis model calculates the total cost of providing electric power to the Nome Joint Utility electrical distribution system (the “busbar cost”). Total cost is the cost of all capital and operating costs, including distribution and administrative costs, and the cost of providing heat energy on a Btu basis to residential and commercial residents. The analysis runs for thirty years, from 2015 to 2044. All existing electrical and thermal loads currently served by the system are treated as firm; that is, fully and continuously supplied throughout the period. A reasonable expectation of electrical load growth over the 30-year period is included to account for increases in population and economic activity of the city.

For each alternative case, the model estimates the electrical load requirement for each day of the year and computes how much energy is supplied by the primary alternative generation source (diesel, coal, wind/diesel, geothermal, and natural gas). It also estimates how much must be delivered from diesel units as a backup resource. The model calculates the net present value of all annual costs, including current system fixed costs and the carrying cost of investments in new resources, to determine the total system life-cycle cost of power to the utility. The model also computes the approximate average electric rate necessary to cover each year’s annual cost of providing electrical service, which includes estimated distribution and administration costs, based on recent financial statistics. The savings to residential and commercial consumers from an alternative source of heating fuel is estimated on a per Btu basis.

The uncertainty associated with different expectations of the changes in the cost of diesel fuel over time is treated by testing one or more expected annual increases in the price of diesel fuel delivered to Nome. Other variations in assumptions may be tested, as well, to derive the sensitivity of the results to changes in the fundamental variables.

All costs are expressed in *real* dollars that have purchasing power at a constant reference point, in this case 2007. Diesel fuel cost increases in real terms—i.e., price increases over and above general inflation rates - are the same in all scenarios. The net present values are derived with a real discount rate of 4%, corresponding to the effective interest rate for borrowing by municipal electric systems such as Nome.

For each case, the life-cycle cost of providing electricity is the discounted present value of all annual costs for the thirty year period of analysis. In the natural gas case, where natural gas is made available for utility requirements, a net present value is estimated for the electric utility that compares directly with other electric production options, and a separate estimate is provided for the savings from the availability of natural gas for space and water heating.

8.1.1 EXAMPLES OF THE MODEL CALCULATIONS

The economic model includes a number of basic steps. These steps are illustrated by the following example for estimating the cost of providing electric power.

Assume the total firm load to be served on January 1, 2015, is four megawatts (4 MW) of electricity measured at the bus bar–the point of interconnection with the transmission and distribution system–and that the primary generation resource is diesel.

- The busbar energy requirement for that day is:
  - 4 MW x 24 hours = 96 megawatt-hours (MWh), or 96,000 kilowatt-hours (kWh)
- The amount of diesel required is:
  - 96,000 kWh / (16 kWh/gallon) = 6,000 gallons/day
- The cost of the fuel is:
  - 6,000 gallons times $2.54/gallon = $15,240/day
- Additional variable operating costs (such as lube oil and overhauls) are:
  - 96,000 kWh times $0.02 = $1,920/day
- The total variable cost of generation for this one day is:
  - $15,240 + $1,920 = $17,160/day

The total variable cost for other days differs because more or less electricity is produced. The model adds all of these daily variable costs together; the total variable cost for one year may then be on the order of $5.5 million.

- The annual fixed generation cost is:
  - $1,200,000 (for labor) + $500,000 (for generation equipment) = $1,700,000.
- Therefore, the total annual cost of generation for the year 2015 is $7.2 million.

If the annual cost of ownership and operation of the distribution system is $0.8 million, and the annual cost of the administration of the system is $0.6 million, then the total cost of electric service for the year is approximately $8.6 million.

- The total electric sales for the year are based on an annual energy load of 32,000 MWh:
  - 32,000 MWh x 0.9 = 28,800 MWh

where the factor 0.9 accounts for the 10% losses between the point of generation and the customers' meters.

To cover the total cost of generation, the average electric rate for the system must be:

- $8,600,000 / 28,800,000 kWh = $0.30/kWh

Of this, $0.19/kWh is for the variable costs of generation (fuel, lube and overhaul) and the remaining $0.11/kWh covers the fixed ownership costs of the generation, transmission and distribution system, the distribution system operating costs, and all of the administrative expenses attributable to providing electric service. In subsequent years, as the load grows and costs increase, the electric rate may go up or down over time.

In the instance of an alternative fuel source for generation that will displace the current primary use of diesel for electric generation, the model also considers the impact of sales of the fuel for other purposes. Another simple example illustrates the steps in the model to evaluate an impact of a natural gas alternative for generation that also may be used to displace diesel fuel for commercial and home heating applications.

As before, a 4 MW load corresponds to 96,000 kWh of electricity to be generated daily.

The amount of natural gas required to provide generation for the kWh load is:

- 96,000 kWh x (7,653 Btu/kWh) (See Table 4.3) = 735 MMBtu per day.

Over the course of a year, the electric system natural gas requirement may reach as much as 238 Billion Btu just to meet the electric load requirements.

However, if the natural gas fuel is available, a portion of the gas may be available to displace the fuel oil normally used for space and water heating. The residential and commercial fuel oil used throughout the year must be estimated on an equivalent energy content basis.

The amount of natural gas that is required annually to displace the fuel oil needed for residential and commercial space and water heating is:

- (683,000 gal/yr) x (138,000 Btu/gal) = 94 Billion Btu/yr;

Other potential heating loads may add a billion Btu or so a year, for a total natural gas energy requirement of about 333 Billion Btu.

Delivery from a natural gas source to Nome, however, will require an investment in the infrastructure to extract the gas from underground sources and deliver the natural gas to the initial point of use. The annual carrying cost of the investment in the infrastructure, and the variable cost of operating the natural gas system could reach $7.3 million, shared on the basis of volume of gas required.

The annual cost for the availability of a natural gas supply source by user would be:

- Utility: $7.3 million x (238 B Btu / 333 B Btu) = $5.2 million,
- Res/Comm: $7.3 million x (95 B Btu / 333 B Btu) = $2.1 million.

In addition, the electric system would incur the capital cost of converting the generation equipment to operate on natural gas, adding about $116,000/year of amortization expenses to the cost of generating power. The variable generation cost for lube and overhaul of $0.7 million would remain as in the earlier example, as would the $1.7 million for labor and other fixed costs, for a total annual generation cost of $7.7 million. The electric distribution system costs and administrative costs would add an additional $1.4 million for a total system cost of $9.1 million.

The average electric rate for the system to cover the total generation cost would be:

- $9.1 million / 28,800,000 kWh = $0.32/kWh.

For the commercial and residential natural gas users, the difference in cost between operating on diesel fuel and natural gas can be expressed as the difference in dollars per Btu of energy provided for space and water heating. Heating fuel must be distributed to the end user, however, resulting in a higher cost than diesel supplied in bulk to the utility. And, since a distribution system is required to deliver the natural gas to the end user, an investment in distribution pipe and meters, and the equipment to convert existing water and space heaters will result in an annual distribution system cost of about $285,000.

The average annual cost per Btu for fuel oil for the commercial and residential users is:

- (683,000 gal/yr) x ($2.50/gal + $0.75/gal) x 138,000 Btu/gal = $24/MMBtu.

The average annual cost per Btu for natural gas for space and water heating would be:

- \$2.1 million + \$0.3 million / 95 B Btu = \$25/MMBtu

The actual year-by-year costs will vary with the relative change in costs of operating the system, the growth in electric and natural gas requirements, and the expected increase in costs of fuels supplied to meet the electrical and thermal loads.

8.1.2 ECONOMIC MODEL LIMITATIONS

The methodology of the economic analysis is a comparison of scenarios. The scenarios are structured to identify the costs of operating the electric utility system and meet the electric requirements of the Nome system over a period of time 30 years into the future. The annual production and operations costs of the system are estimated for each year to obtain the present value of the life-cycle costs for providing electricity and, in one case, fuel for commercial and residential space and water heating. The scenarios compare current system operations projected into the future with alternative generation or fuel opportunities.

A benefit of scenario analysis using the economic model is that the assumptions are clearly defined and a clear comparison may be made of the benefits and costs between scenarios. However, there are limitations. Some of those limitations are:

- The validity of each scenario depends on the validity of the assumptions.
- No probabilities are assigned to the outcomes of the scenarios, nor are a range of probabilities provided for the assumptions (such as, for example, the success of a natural gas drilling program).
- Feedback loops are not included, so there are no estimates of changes in electric or thermal load forecasts as a consequence of changes in the cost of electricity or the price of fuel for space and water heating.
- Other impacts to Nome, such as higher costs for delivery of smaller volumes of fuel, and the resultant economic impact on users of diesel other than for electric power production, are not considered.
- There is no explicit estimation of the risk associated with any of the scenarios, either financial or economic.

The results obtained from the scenario analysis therefore provides an indication (“screening”) of the relative economic value of the generation alternatives and alternative fuel source for the Nome electric system and for space and water heating. The model is very effective as a system for developing a ranking of alternatives. The limitations of the methodology, however, suggest that further and more detailed investigation of any one scenario may be required prior to investing in the development of any particular alternative.

8.2 ECONOMIC INTEGRATION

The basic assumptions for each of the energy options (diesel system, wind-diesel, geothermal, coal plant, and natural gas) are described in this section.

8.2.1 NOME DIESEL SYSTEM ASSUMPTIONS

The electric generation system of Nome has recently been upgraded with two new generating units and improved interconnection and auxiliary systems. With the advent of the new generation facilities, the diesel-based system is expected to provide adequate capacity and energy for the foreseeable future. With appropriate routine maintenance and periodic overhauls, the existing units are likely to be available for operation throughout the entire period of the analysis.

The generating efficiency of the new units will average 16 kWh/gallon of diesel fuel, an efficiency that is expected to remain unchanged year-to-year, so diesel consumption will vary directly with changes in electric load requirements. For the Nome system in 2006, with fuel costs at an average of $1.99/gallon, diesel fuel constituted 50% of the average cost of electricity in Nome. The cost of fuel used for generation reached $2.54/gallon (Nov. 2007), significantly increasing the share of electricity costs attributable to generation

For the purposes of estimating future costs of diesel fuel, the Alaska Energy Authority (AEA) prepares projections of delivered fuel prices for a number of locations in Alaska, including the city of Nome. These projections are used for analysis of a variety of energy issues throughout the state, including evaluation of wind-diesel hybrid systems and other alternative generation options. For consistency with statewide energy planning, the diesel fuel rate of change over time (other than general inflation) for Nome was drawn from the Energy Authority estimates and applied to the price of diesel delivered to Nome in 2007.

- Diesel Fuel Initial Price: $2.54/gal
- Diesel Fuel Escalation (real)
    - Mid-Range case 0.58%/yr
    - High-Range case 2.12%/yr

These diesel fuel escalation rates will result in estimates of diesel costs of $3.00/gal by 2044 for the mid-range case, and to as much as $4.67/gal in the high-range case. A low-range case, which assumes an average decline in diesel prices of over 1%/yr over the AEA analysis period, was not examined for the purposes of this screening analysis.

Other assumptions regarding the current electric system costs include the estimates of the new unit maintenance on a “per/kWh” basis. The maintenance includes all routine lubrication and component replacements over a 20-year maintenance cycle recommended by the manufacturer. Effectively, the costs of operating the units in addition to fuel costs are recovered on the basis of the energy produced rather than availability.

The fixed costs of the generation facilities are “sunk costs” that will not be diminished by the addition of alternative generation facilities. Those fixed costs, along with administrative expenses are assumed not to vary with load changes and are held at a constant level throughout the analysis. Distribution system costs, however, will likely vary as system loads increase, due to the need to add and maintain new services. Distribution system costs are estimated on a per kWh basis. The total cost of distribution system ownership, operation and maintenance will increase as the distribution load increases.

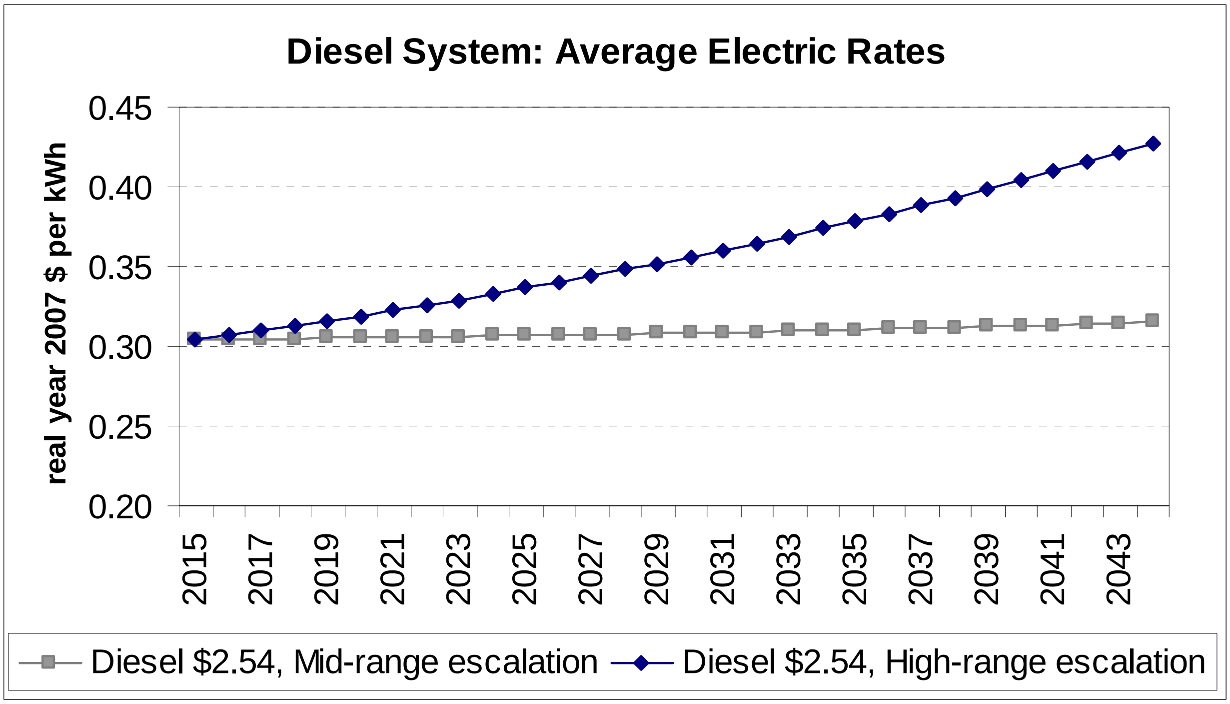
8.2.2 DIESEL SYSTEM ECONOMIC ANALYSIS RESULTS

The results of the economic analysis for the operation between 2015 and 2044 of the diesel generation system indicate system operating costs of between **$116 million** in present value under the expectations of a mid-range diesel fuel cost escalation to **$140 million** present value under conditions of a high-range escalation of diesel fuel costs.

The average electric rates (2007$) are shown in Figure 8.1. The rates reflect the expected increase in diesel prices. For the mid-range escalation of 0.58%, the increase in electric rates from 2015 to 2044 is small, from $0.30 to $0.32/kWh as compared to the increase to $0.43/kWh for the high-range escalation in diesel prices.

The results indicate that the existing diesel system is fully available to meet energy requirements for the electric system at a stable cost, net of fuel cost increases. The greatest risk to the system is the potential variability in the cost of diesel delivered to Nome, or the additional or extended load requirements associated with local mining activities.

Figure 8.1. Diesel System–Electric Rates.



8.2.3 WIND-DIESEL SYSTEM ASSUMPTIONS

As a part of this study the AEA completed an initial screening analysis of the availability of wind energy to supplement the current generating sources of the Nome utility. The results of the screening analysis, described in Section 5, included an assessment of possible wind turbine configurations available for the wind energy regime of Anvil Mountain, located just north of Nome.

The results indicate that a wind system of 3 MW, consisting of two 1.5 MW units, could provide electricity at a cost slightly less than the current cost of diesel based generation. The wind source, however, is intermittent and provides energy as a function of wind velocity rather than electricity requirements, and cannot be relied upon for energy at any particular point in time. Integrating wind units with diesel generation systems requires specialized control systems that respond to the variation in wind energy production and electric load requirements to ensure that maximum efficiency is made of the combination of wind and diesel units. The load requirements will have an effect on the operation and the choice of diesel units that may be dispatched to meet the load unmet by the wind generators.

The wind turbine installation is expected to provide about 8,988 MWh/year or about 30% of the initial year load of the Nome electric system. For the purposes of the economic analysis, it was assumed that the energy provided by the wind turbines will be contributed throughout the year, displacing that amount of diesel generation each and every year of the analysis period. Nome's new power plant controls were designed to integrate alternative and intermittent sources so no additional costs for integration hardware and software are expected to be required for the two wind turbines of 1.5 MW each.

However, adding wind turbine capacity adds cost to the system. Thus, the installed cost of $4,000/kW is recovered in electric rates over the analysis period, as well as the expected fixed operating costs of 3% of the installed costs and variable operating costs of slightly less than 1 cent/kWh. Initially, the installation of new wind turbines is expected to require 1 additional staff member to adequately maintain the wind system.

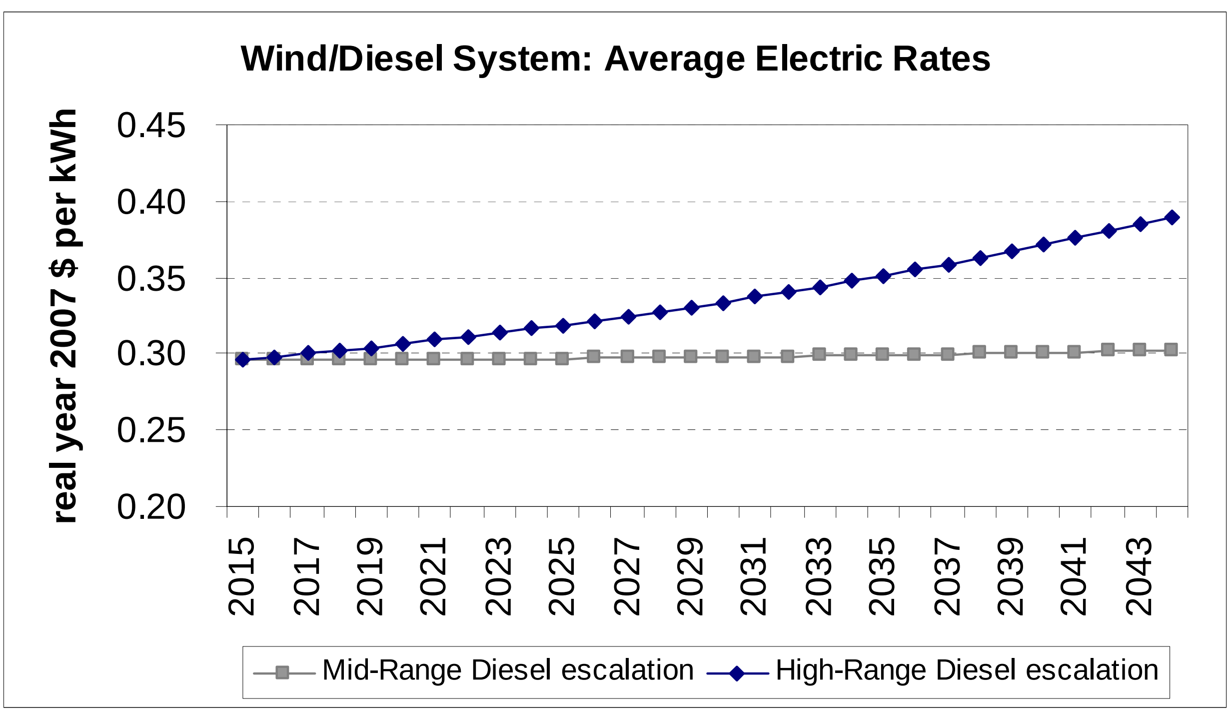
A simplifying assumption is that the units installed in 2015 will operate over the analysis period with routine maintenance. The actual availability of the turbines suggested for installation, with a forecasted effective lifetime of 20 years, is not certain. It is also possible that more robust units with greater operating efficiency and longer lifetimes may become available over the analysis period as a result of the rapid advances that are being routinely achieved in wind turbine technology. Replacing units after 20 years with more efficient turbines would likely increase the economic benefits of a wind-diesel system, as would adding more turbine capacity over time as electric load requirements increase. (See Section 5 for more on this.)

8.2.4 WIND/DIESEL SYSTEM ECONOMIC ANALYSIS RESULTS

The installation of two 1.5 MW wind turbines producing at a 34% capacity factor that offsets diesel generation results in system operating costs for the 30-year period of **$111 million** in present value under conditions of a mid-range escalation in diesel fuel costs. In the alternative case of high-range escalation in diesel fuel costs, the total present value would increase to **$128 million**. In both cases, the total cost of providing electricity under these assumptions is several million dollars less than the cost of continuing to generate electricity with only diesel generators. If green tag sales are available and successful at the time of installation of the wind system, approximately $4.7 million in credits may contribute to a further reduction in the cost of electricity (See Section 5.4.5).

The rate of change of the average electric rates is shown in Figure 8.2. For this case, the rates remain almost constant for the mid-range escalation case and increase about 30% to $0.39/kWh for the high-range escalation.

Figure 8.2. Wind/Diesel system: Average Electric Rates



8.2.5 GEOTHERMAL SYSTEM ASSUMPTIONS

A geothermal installation at Pilgrim Hot Springs has the potential to displace a very large portion of the diesel generation in the initial years of operation; however there is considerable uncertainty as to the size of the geothermal resource. The Hattenburg, Dilley & Linnell Engineering Consultants (HDL) analysis described in Section 6 suggests the possibility of a 5 MW geothermal installation providing about 41,600 MWh/yr, 33% more electricity than what is expected to be required by the Nome utility in 2015. The generating capability of the geothermal facility is just slightly less than the 41,633 MWh/year expected to be required in 2044.

If successfully developed, the geothermal facility can provide nearly all of the electric load requirements, and with the load shape of the electric system, maintenance activities can be scheduled during low load periods without significantly impacting system operating costs. The existing diesel system will be available for backup service in the event of unscheduled outages or transmission failures. Further, the existing diesels will be available to meet short-term and intermittent peaking requirements (although a diesel generating unit may be selected to operate during high load periods for reliability, but not necessarily economic, purposes).

The installed cost of the geothermal system, including all exploratory activities, construction costs and the transmission system to interconnect with Nome, is assumed to reach $12,800/kW for a system with a lifetime of at least 30 years. A geothermal installation, while generally robust, will require specialized staff to operate and maintain the installation, increasing personnel costs, particularly in the initial years of operation (and perhaps toward the later years), while the increase in miles of transmission lines may increase line worker requirements. For the screening analysis, two additional staff members are estimated to be required over the analysis period, but it may be possible that generation facility staff currently operating the diesel system could be redeployed. The diesel system must be maintained for backup (or high load reliability service), and some personnel will remain assigned to the power house.

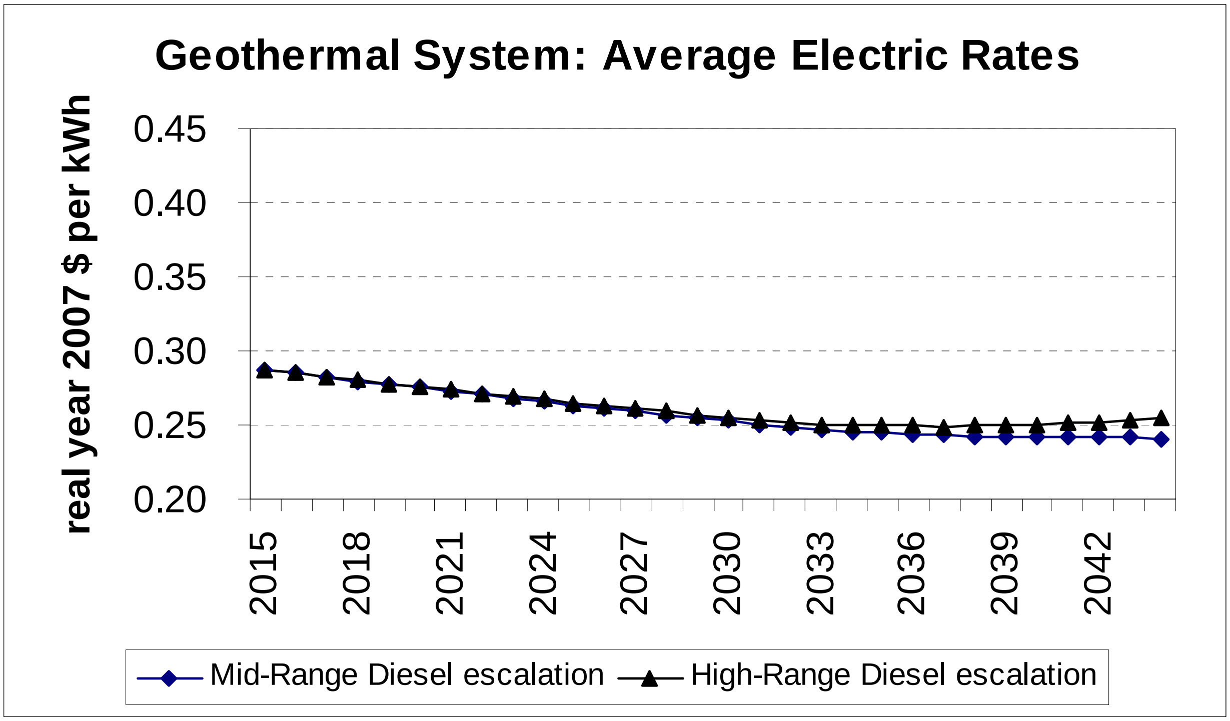
The geothermal operating costs are estimated to consist primarily of manpower and supplies. Very little is currently known about the cost of operating and maintaining a geothermal facility of that magnitude in the Nome region, but information from other geothermal investigations suggests that annual supplies, such as chemicals, lube oil, etc. will amount to about 1.5% of the installed cost of the facility. That cost is considered a fixed annual cost recovered in power rates in similar fashion to the acquisition cost.

The displacement of the diesel generation with a geothermal power source eliminates, for the most part, the availability of water-jacket heating for the Nome city water supply. Consequently, in the early years of the geothermal scenario, the city water heat is assumed to be supplied by the direct-fired boilers. In later years, as more supplemental diesel generation will be required, the diesel engines will contribute to the city water heating load.

8.2.6 GEOTHERMAL SYSTEM ECONOMIC ANALYSIS RESULTS

Installation of a successful geothermal power generation facility at Pilgrim Hot Springs would significantly reduce the cost of electricity for the Nome Joint Utility System. The cost for 30 years of energy supply to Nome would drop to **$90 million** in present value with a mid-range diesel fuel cost escalation and to **$92 million** for the high-range diesel cost escalation. The rate of change of the average electric rates can be seen from Figure 8.3. The increase in generation costs of the latter years result from the increasing component of diesel generation as loads increase, and the contribution of geothermal energy declines as a proportion of generation.

Figure 8.3. Geothermal System Average Electric Rates.



The low cost associated with the geothermal option must be weighed against the risk that the geothermal resource will not prove to be adequate to support the generation capability scenario described.

8.2.7 COAL PLANT ASSUMPTIONS

As part of this study, NETL prepared a conceptual design for a barge-mounted coal plant to provide 4.65 MW of electricity.. The design of barge mounted system also includes a 1 MW diesel generation unit for startup power and auxiliary loads in order to accomplish a self-contained system. For the purposes of the Nome system evaluation, the 1 MW diesel unit will provide only a backup power source for black-start conditions or other system emergencies and will not be routinely operated.

The coal power system designed for the Nome location has a three-unit configuration, providing flexibility in both dispatch and in maintenance scheduling. Each unit of the configuration may be operated independently, allowing variations in level of electrical output throughout the year, and the ability to sequence maintenance to reduce the amount of diesel generation required during maintenance activities. The availability of the coal generation facility overall is estimated as a result to be 92% each year.

The installed cost of $14,100/kW (based on the 4.655 MWe output) provides a coal system with a life of more than the 30-year study period. About $0.028/kWh is assumed to be required for variable operating costs and routine consumables. The specialized systems of the barge-mounted coal plant will require additional power plant staff. Four additional personnel are estimated to be needed to operate and maintain the barge-mounted coal plant and provide 24-hour plant coverage with appropriate skills.

Other than the capital cost, the most significant cost element for the evaluation of a coal plant in Nome is the fuel cost. The fuel cost of the coal system is a function of the delivered cost and quality (i.e., heat content) of the coal and the efficiency of the coal boilers.

The coal units were designed to accommodate a variety of coal, but with emphasis on the character of the coal available within Alaska. The Usibelli coal source in central Alaska provides an available source of coal at a somewhat lower cost than coal obtained elsewhere, but it has a heat, or energy, content lower than some other coals. Coal obtained in British Columbia that is readily transportable to Nome will have a higher cost and heat content than the coal currently available in Alaska. Usibelli coal is estimated to cost $63/ton delivered to Nome, whereas British Columbia coal is estimated to cost $77/ton. Considering the Btu content of the coal, the British Columbia coal will provide for the needs of the plant at $2.82/MMBtu. Usibelli coal on an equivalent basis will cost about $4.06/MMBtu.

Coal unit net efficiency (electric output/coal input) is a function of a variety of factors, most notably the size of the units relative to the auxiliary loads. The operation of boiler feed water pumps, fans and other ancillary equipment will have a significant impact on the net efficiency in converting the energy of coal into electric power. The barge-mounted coal system designed for the Nome installation has a net efficiency of 16%, which is relatively low compared to larger coal-fired power plants in operation or planned for construction.

Regardless of the source of coal, the delivered cost is estimated to *remain constant in real terms, including transportation*. Coal price projections available for review have indicated a trend of stable prices for both the commodity and transportation for the foreseeable future as a result of supply and demand characteristics worldwide. Consequently, no real increase in coal costs above general inflation was considered for coal delivered to Nome.

As with the geothermal plant, installation of the coal-fired units provides the opportunity to displace the vast majority of the diesel generation, reducing the availability of the thermal contribution of the diesel units for the heating of the Nome water supply. In the early years of the coal resource scenario, the city water heat is assumed to be supplied by the direct-fired boilers, replaced by water jacket heating as more supplemental diesel generation is provided in the latter years of the scenario.

8.2.8 COAL SYSTEM ECONOMIC ANALYSIS RESULTS

The barge-mounted coal fired generation alternative introduces a cost of production that will vary dramatically as a function of the assumptions regarding the coal fuel purchased and delivered to the Nome location. Assuming Usibelli coal at $63/ton delivered, the cost of operating the system for 30 years will be **$134 million** in present value under conditions of mid-range diesel fuel escalation. With the same coal fuel, but a presumed high-range escalation of diesel costs, the present value cost of operating the system rises to **$137 million.**

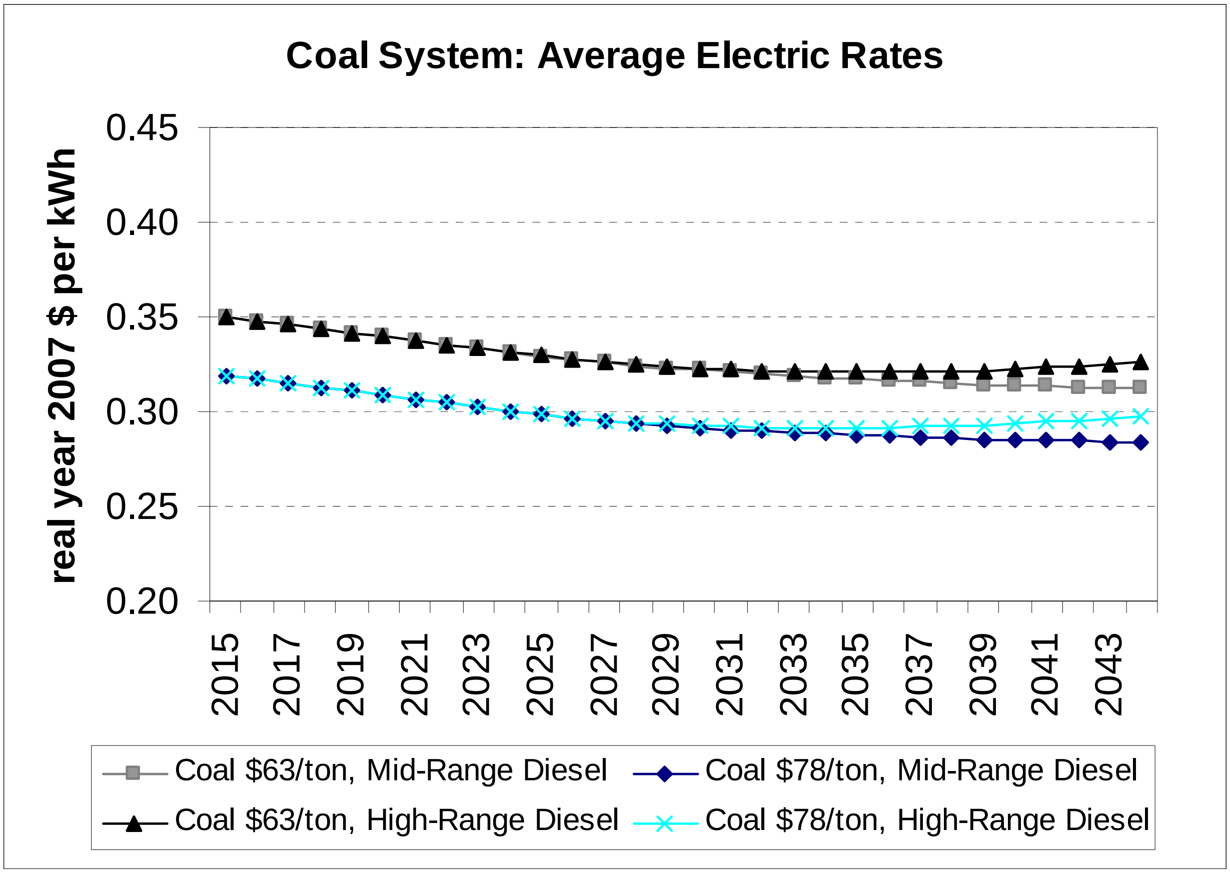
If British Columbia coal at $78/ton is assumed to be used to fuel the coal generation facility the present value for the midrange case will be about **$117 million** and high-range case will be about **$120 million**.

While the displacement of the diesel generation eliminates much of the availability of diesel unit water-jacket heating for the Nome city water supply, the coal plant would be capable of providing a source of heat if a steam or hot water interconnection is constructed between the coal plant and the existing power house.

The diesel fuel required by the direct-fired boilers to provide the heat required for the city water system is estimated to cost $6 million in present value for the mid-range escalation case and $7 million for the high-range case. A steam line that could be installed and operated at a lower cost over the 30-year period for installation and ownership would provide additional benefits to the coal scenario. A withdrawal of steam from the coal plant at the rate required would, however, introduce a loss of about 2% of the coal plant's electric capability and result in more supplemental diesel generation.

The rate of change of the average electric rates for each coal source is shown in Figure 8.4.

Figure 8.4. Coal System Electric Rates.



8.2.9 NATURAL GAS SUPPLY ASSUMPTIONS

As noted in Section 6, successful exploration and development of a Norton Sound natural gas resource would provide for both the electric energy needs and the space and water heating requirements of the community. The economic analysis of the natural gas scenario requires consideration of the investment costs of the natural gas system, both to deliver fuel to the utility, and to the commercial and residential business sectors. In addition to the investment in the system of production and delivery, costs will be incurred to convert generation units to operate on natural gas, as will space and water heating equipment.

The economic model includes an evaluation of the shared costs of the investment in the off-shore production facilities and pipeline costs for delivery to the city gate. Of the total investment of $62.7 million overall required to provide the fuel supply, $56.2 million will be committed to the installation of the production and primary delivery systems (See Section 6). Annual fixed costs estimated at $4 million/year associated with the operation of the system and variable operating costs will add significantly to the costs, such that initial-year total costs of the production and primary transmission of gas are estimated at $7.3 million. These costs are assumed to be shared between the electric utility and the gas distribution system customers on the basis of the relative shares of natural gas volumes consumed for each purpose.

A distribution system to provide access to gas, along with the conversion of heating equipment from fuel oil to natural gas, is estimated to cost about $4.2 million and require about 1.0% of that amount in annual variable operating costs for maintenance and repairs. All of the annual costs of the distribution system are assumed to be paid by the users of the commercial and residential service.

For the electric utility to operate on natural gas, it is assumed that one of the newest installed units is changed out for a unit that will operate on natural gas. Each of the two recently installed diesel units will provide 5.2 MW of electrical energy, individually meeting nearly all of the energy requirements of Nome. For the purposes of screening, the analysis assumes that all of the annual electrical energy is provided from natural gas, while some diesel fuel will undoubtedly continue to be required for emergency purposes and during short periods of natural gas unit outages. An investment in a second unit to operate on natural gas would add a modest cost to the analysis, or about $2 million.

A significant economic factor associated with the investment in a natural gas system is that the sole cost of the natural gas for the utility and other users will be embodied in the capital and operating costs of the production and delivery systems. There is no assumed commodity cost for the volumes of gas delivered by the system by which to compare directly with the cost of diesel fuel that is sold on a gallon-by-gallon basis. Consequently, unlike the electric utility for which average power costs may be compared, the economic evaluation of the space and heating requirement is a comparison of the relative cost of thermal energy on a Btu basis.

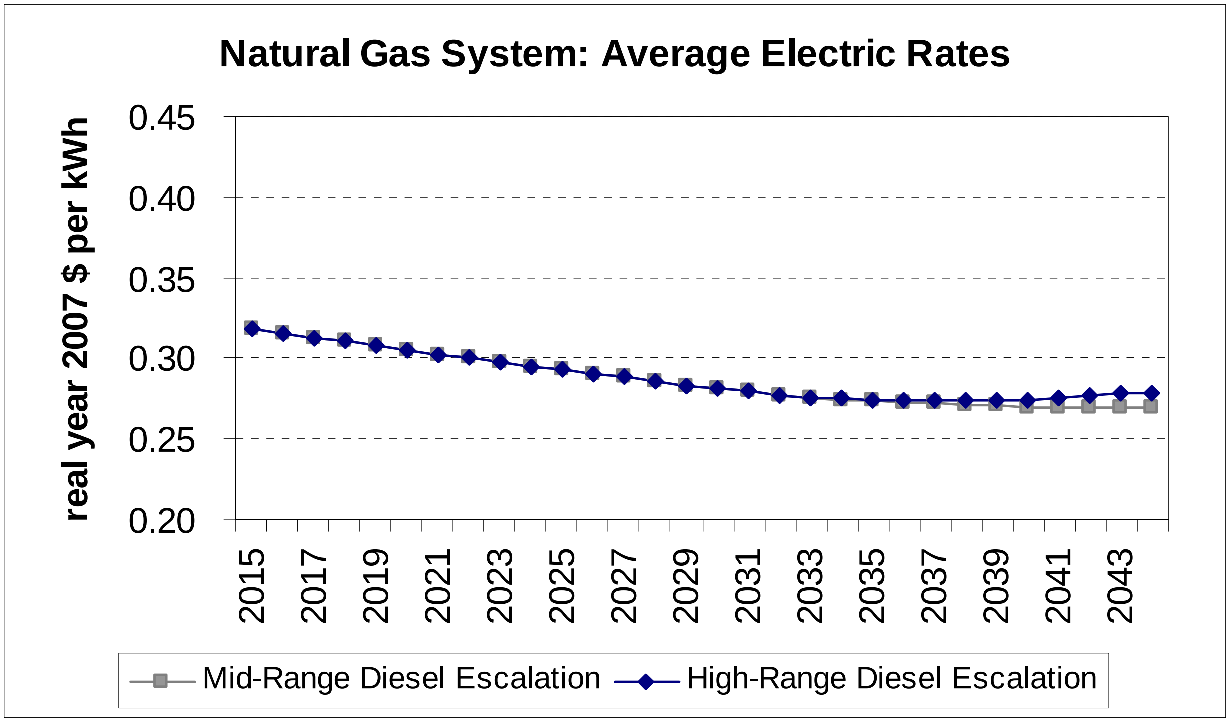
8.2.10 NATURAL GAS SYSTEM ECONOMIC ANALYSIS RESULTS

The installation of a natural gas system allows the displacement of nearly all diesel fuel used by the Nome electric utility system. The present value of system operating costs include full recovery of all investment costs necessary to both obtain and deliver natural gas.

For the electric system, the present value of the busbar cost of electricity using natural gas fuel is estimated to be **$107 million**. This is about $10 million less than operating the diesel system at mid-range fuel escalation, and about $33 million less under a high-range escalation assumption. Different assumptions of diesel cost escalation for the system operating on natural gas has very little effect on the economics, because so little diesel generation is likely to occur until late in the analysis period. (Only emergency and maintenance requirements will be met with diesel.) Thus, electric rates between the mid-range and high-range cases will be nearly identical until the last few years.

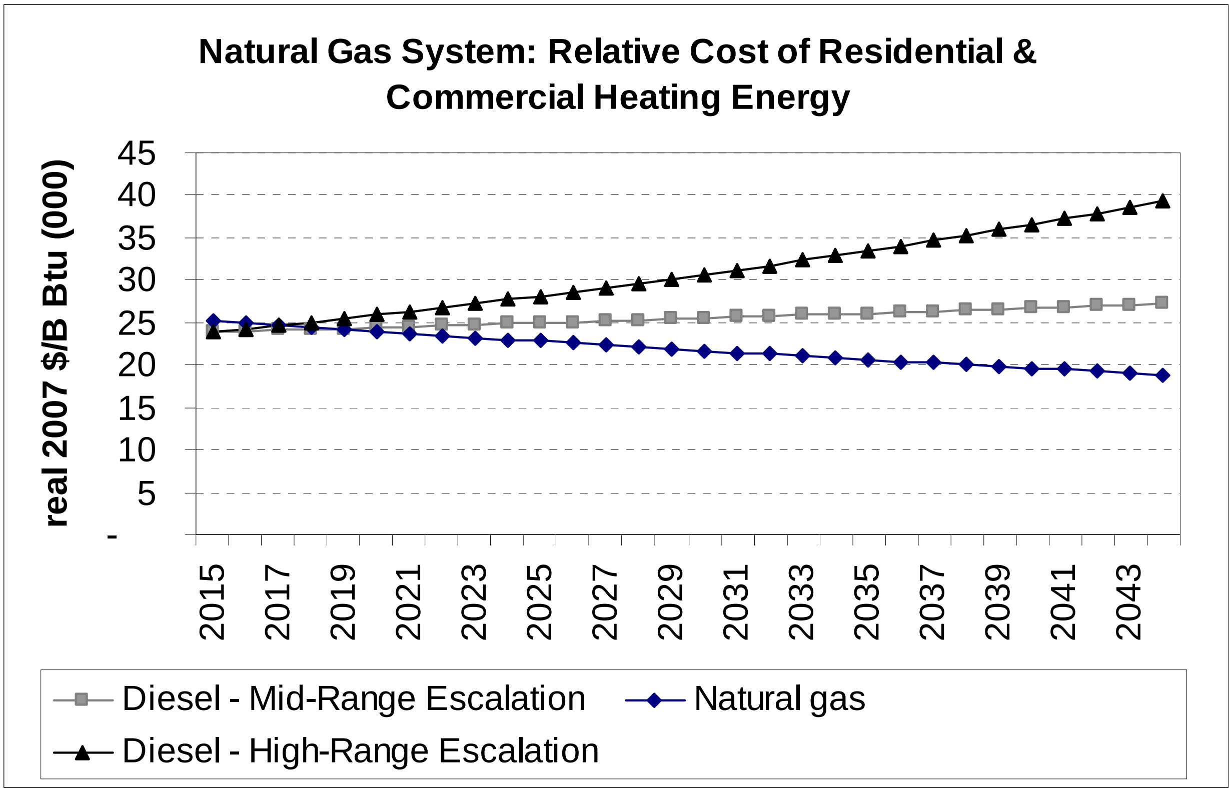
The rate of change of the average electric rates is shown in Figure 8.5.

Figure 8.5. Natural Gas System Average Electric Rates.



As described in the discussion of the assumptions for the natural gas scenario, the installation of a natural gas system will provide a source of fuel as an alternative to diesel fuel for the provision of commercial and residential space and water heating. The economic evaluation of the impact of the installation of the gas system indicates a present value savings for the thermal requirements for space and water heating, in the instance of a mid-range fuel price escalation, of about **$5 million**. Under a high-range cost escalation, the economic benefit to the community will reach slightly more than **$13 million.** The impact on heating consumers is described in terms of the cost per Btu for energy providing space and water heat and is shown in Figure 8.6.

Figure 8.6. Natural Gas System Heating Scenario



8.3 SUMMARY OF ECONOMIC ANALYSIS

The scenario analysis for the energy options analyzed from Nome provides a representation of the relative costs of providing electricity, and space and water heating for commercial and residential consumers in Nome. The estimated present value cost of each option is compared in Table 8.1 and the average electric rates are compared in Table 8.2.

Table 8.1. Present Value Comparison of Busbar Electricity

Present Value of Busbar Electricity, $Millions						
Diesel Cost Escalation	Scenario					
	Diesel System	Wind & Diesel	Geothermal	Coal @ $63/ton	Coal @ $78/ton	Natural Gas
Mid	116	111	90	134	117	107
High	140	128	92	137	120	107
	Present Value Savings Residential/Commercial Heat, $ Millions					
Mid						5
High						13

Table 8.2. Nome Energy System Average Electric Rates Comparison

Year	2015	2020	2025	2030	2035	2044	Avg. 2015 to 2044
Diesel System	**$/kWh**						
Mid-range diesel escalation	0.30	0.31	0.31	0.31	0.31	0.32	0.31
High-range diesel escalation	0.30	0.32	0.34	0.36	0.38	0.43	0.36
Coal Scenarios							
Coal $63/ton, Mid-Range Diesel	0.35	0.34	0.33	0.32	0.32	0.31	0.33
Coal $63/ton, High-Range Diesel	0.35	0.34	0.33	0.32	0.32	0.33	0.33
Coal $78/ton, Mid-Range Diesel	0.32	0.31	0.30	0.29	0.29	0.28	0.30
Coal $78/ton, High-Range Diesel	0.32	0.31	0.30	0.29	0.29	0.30	0.30
Wind/Diesel							
Mid-Range Diesel escalation	0.30	0.30	0.30	0.30	0.30	0.30	0.30
High-Range Diesel escalation	0.30	0.31	0.32	0.33	0.35	0.39	0.34
Geothermal							
Mid-Range Diesel escalation	0.29	0.28	0.26	0.25	0.24	0.24	0.26
High-Range Diesel escalation	0.29	0.28	0.27	0.26	0.25	0.25	0.26
Natural Gas							
Mid-Range Diesel Escalation	0.32	0.31	0.29	0.28	0.27	0.27	0.29
High-Range Diesel Escalation	0.32	0.31	0.29	0.28	0.27	0.28	0.29
Natural Gas Space Heating—Relative Costs ($/MMBtu)							
Mid-Range Diesel Escalation	24	24	25	26	26	27	25
High-Range Diesel Escalation	24	26	28	31	33	39	31
Natural Gas	25	24	23	22	21	19	22

8.4 CONCLUSIONS

The energy technologies analyzed for Nome fall into two categories, (a) technologies that rely upon known energy resources—diesel, wind, and coal; and (b) technologies that would rely upon hypothetical (or untested) resources—geothermal and natural gas. Geothermal and natural gas resources are known to exist based on limited evaluation, but will require expensive exploration to prove the resources exist in sufficient quantity and deliverability to meet the requirements. The exploration and development costs for geothermal and natural gas are not well established and will require additional analysis to confirm the estimates. The natural gas options assumed that a drill ship would be available at day rates only and that the costs to obtain and move a ship to and from Norton Sound would not have to be borne by the project.

The present value comparisons indicate that for the assumptions incorporated in the analysis regarding each of the alternatives, the wind/diesel, geothermal plant, barge-mounted coal plant using high BTU coal, and natural gas exploration and development are all economically equal or better than continued reliance on diesel for both mid-range and high-range diesel price escalation. The lower Btu coal option is slightly better in the instance of a high-range diesel price escalation. The development of a natural gas resource, in addition to showing a strong potential for savings in the operation of the electric utility, would provide an economical option by providing natural gas for water and space heating throughout the community.

Of the alternatives investigated, the most likely prospect of immediate savings gain is the installation of wind turbines to offset diesel generation for the electric utility. Wind units are commercially available, and the Nome utility system has already anticipated the advent of wind by including integration capability in the construction of the new power house.

The geothermal and natural gas prospects both indicate potential savings greater than the wind resource, but will require additional investment in exploration and development to verify the resource potential. Nevertheless, the potential gain from each is significant, with the natural gas prospect in particular providing the additional benefit of displacing fuel oil for space and water heating.

The coal plant prospect with high-Btu coal provides savings to the electric system, but to a lesser extent than the other alternatives. With low-Btu coal, savings would only be available under a high rate of diesel price escalation, and under conditions of coal prices remaining constant in real terms. In either case, the savings associated with the prospect of a coal power plant are based on an engineering estimate of costs to construct an initial unit. Economies of scale from construction of multiple units of a similar design could reduce the capital cost of the system and improve the economics of a coal-based alternative.

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APPENDIX A—BALANCE OF PLANT: COMBUSTOR/BOILER SUPPORT SYSTEMS

This section describes the Balance of Plant—the auxiliary components and systems on and off the barge—required to support operation of the barge-mounted coal plant.

A-1 Coal Handling System

The function of the balance-of-plant coal handling system is to unload, convey, prepare, and store the coal delivered to the plant. The design and configuration of the system is outside the barge-mounted power plant battery limits, and is located on shore, on an adjacent pier or on a separate barge. The design of this system is dependent on site and coal delivery factors. For this conceptual design, fuel delivery is assumed to be by barge or ship. The land side power plant support facility is provided with a traveling unloader. The fuel is transferred from the delivery vessel to a series of conveyors leading to an enclosed domed storage building.

A domed storage building is assumed that will house a one year supply of fuel in a weather protected space, allowing reclaim to proceed under all weather conditions. A radial stacker/reclaimer inside the dome stacks the coal in a torus shaped storage pile. In the reclaim mode of operation, the coal is loaded onto a conveyor to the primary crusher house where the coal is broken into a size (2" X 0) suitable for feed to the secondary crushers supplied with the boiler packages.

A-2 Limestone Handling and Preparation System

The function of the balance-of-plant limestone handling and preparation system is to receive, store, and convey the limestone delivered to the plant for feeding to the fluid bed boiler sorbent injection system. The scope of the barge-mounted system is from the storage day bins up to the sorbent injection system lock hopper inlets. The bulk limestone receiving and storage system is located on shore.

A-3 Ash Handling

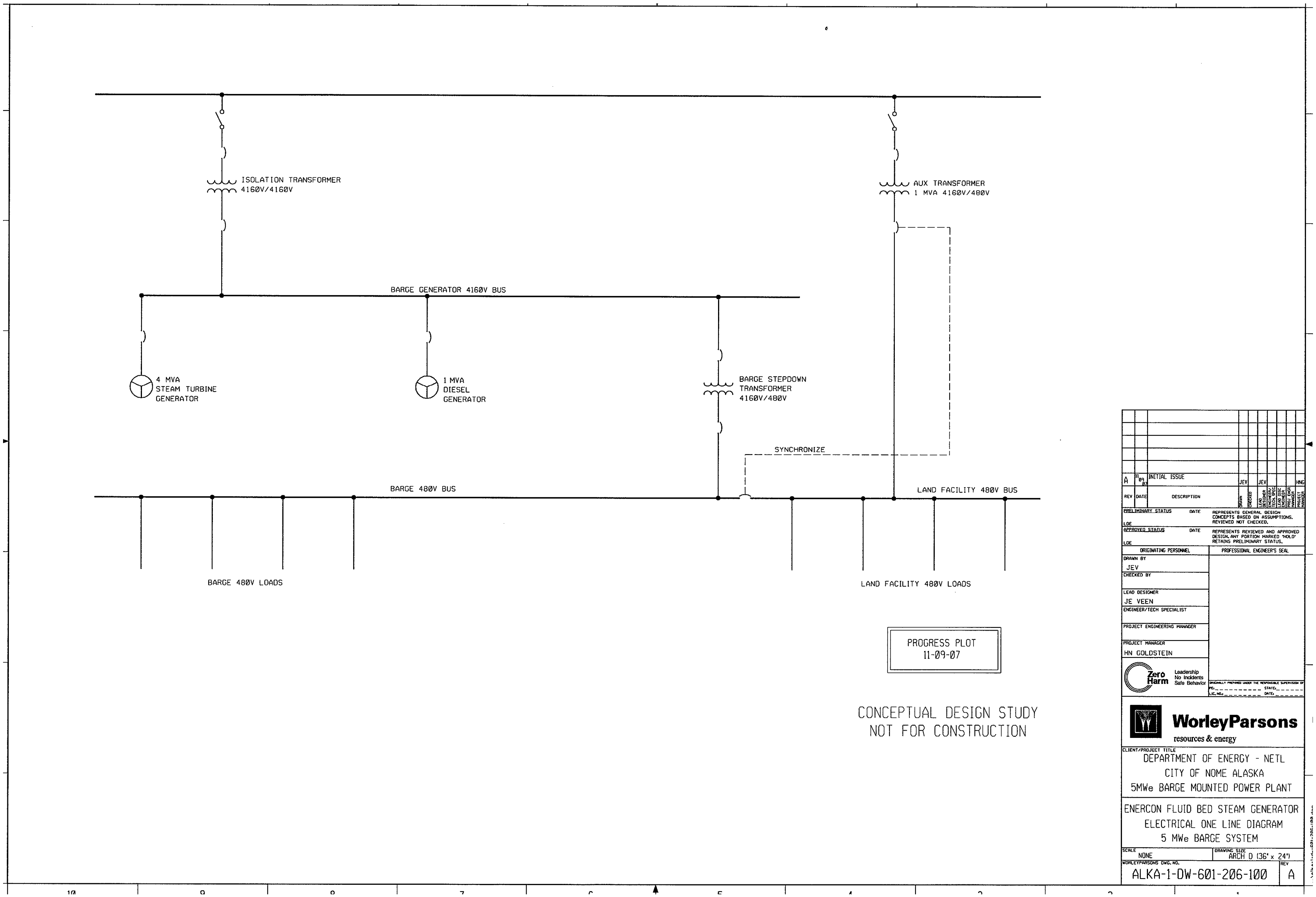
The ash handling system conveys, stores, and disposes of ash removed from the fluidized bed (spent bed material, or bottom ash), and from the bag filters (fly ash). The design basis ash handling rate is a nominal 1 ton/hour (based on an ash production rate of ½ ton/hour firing Usibelli coal at the design point).

A slide gate valve at the bottom outlet of the hopper regulates the flow of material from the hopper to a screw cooler, which cools and transports the ash out and onto a system of drag chain conveyors. The conveyors transport the ash to a pair of storage silos located on the adjacent pier or on shore for temporary holdup. The silos are sized for a nominal holdup capacity of approximately 36 hours of full load operation per each. At periodic intervals, the ash is removed from the silos for ultimate disposal. The system includes telescoping unloaders and fluidizing blowers at each silo for transfer of the ash to transport to an off-site location. The barge-mounted system includes drag chain conveyors to transfer the ash to the shore-based silos and remaining equipment.

A-4 Electrical System Description

The electrical system supporting the barge and onshore operations is described in this section and a single line diagram is shown in Figure 3.4

Figure A-1. Single Line Diagram



A.4.1 General

The electrical power system, including the motor-generator unit, is designed with adequate auxiliary equipment, standby power, and protection to provide maximum continuity of service, and thus ensure operating of the essential equipment during all normal and emergency conditions. The auxiliary electrical power system is divided into the following major subsystems:

- Motor-generator terminal system
- 4,160-volt ac power supply system including the emergency diesel generator
- Low voltage (480- and 120/208-volt) power supply system
- Dc and vital ac systems

High-voltage switchyard system

A.4.2 Motor-Generator Terminal System

Function – The function of the motor-generator terminal system is to provide for power transfer from the generators to the bulk power system, and from the bulk power system to the unit auxiliary power transformer.

Major Components – The motor-generator terminal system consists of the following major components:

- Generator isolation transformer
- Non-segregated phase bus ducts
- Generator neutral grounding equipment
- Generator line-side cubicles

Excitation system (assumed to be a brushless exciter)

System Description – The generator terminal system provides for power flow from the steam turbine generator and the diesel generator to the bulk power system, and from the bulk power system to the unit auxiliary power transformer. Under black start conditions, it also provides for power flow between the diesel generator (DG) and the barge service bus (4160V). Under normal operation, the DG may be run at full load to supply additional power to the system for export to the grid.

Under normal operating conditions, power is generated at 4160V at the generator terminals and routed to the switchyard on land. (The local power grid in Nome operates at 4160V). Under normal startup and shutdown conditions, the power to the 4,160-volt bus will be obtained by backfeeding the power from the bulk power system through the isolation transformer when the GCB is open. The generator will be started and will attain its rated voltage and frequency and then be synchronized by closing its GCB.

The two-winding isolation transformer is oil-filled with OA/FA/FA type cooling. The isolation transformer land-side winding is wye connected with a solid ground. The barge-side winding is delta connected. The generator neutrals are high impedance grounded.

A.4.3. 4,160-Volt AC Power Supply System

Function – The function of the 4,160-volt ac power supply is to provide power to 4,000-volt motor loads and 4,160-480-volt transformers.

Major Components – The 4,160-volt ac supply system consists of the following major components:

- Unit auxiliary transformer
- Materials handling transformer
- 4,160-volt circuit breakers
- 4,160-volt motor starters

System Description

On-Barge System – The on-barge 4,160-volt ac power supply system provides power from the unit auxiliary transformer (UAT) and the diesel generator to a small unit substation that steps the voltage down to 480V to feed the various electrical loads on the barge. A separate unit substation performs the same function to support the land based equipment.

The 4,160-volt switchgear is a double-ended type with two incoming circuit breakers, each connected to the UAT and bus tie breaker. This allows for greater operating flexibility and removing a 4,160-volt bus for maintenance when needed.

Auxiliary Diesel Generator – The diesel generator for this 4.65 MWe barge mounted power plant is sized at a nominal 1,000 kWe, at a prime power rating. If power from the shore-based grid is not available, the diesel generator operates to start the fluid bed boiler plant. For the purposes of this conceptual design, the following description is representative of a diesel generator that may be selected.

The diesel generator set comprises an in-line or V-type multi-cylinder turbocharged diesel engine directly driving an electric generator at 900 rpm. Generator output is at 4,160 volts at 60 Hz. The engine is a unit of a type manufactured by several major manufacturers.

The engine is provided with a sealed jacket water system that is cooled by an air-cooled radiator, which also cools the turbocharger aftercooler and the engine lube oil cooler. Each engine is started by a self-contained starting air system, which stores air at 250 psig in a 100-cubic-foot-capacity air receiver tank, and supplies this air to the engine cylinders in a timed sequence. A dedicated air compressor and air receiver tank are supplied with the engine.

Engine intake air is ingested through an air filter and inlet silencer. An inlet pipe of 12 in. diameter is estimated for this application. Engine exhaust is piped outside each engine room to a vertically mounted, bottom entry exhaust silencer, with the discharge pipe extending up the side of the deckhouse to a point 7 ft above the deckhouse roof. One exhaust pipe with a diameter of 12 in. is estimated for this application.

Off-Barge System – The off-barge system consists of the materials handling transformer that takes power from the switchyard and transforms it to 480 volts AC, which feeds a lineup of motor control centers. The two-winding material handling transformer is oil-filled with OA or OA/FA type cooling, depending on the final load requirement. The materials handling transformer high-voltage winding is delta connected. The low-voltage winding is wye connected. The medium-voltage system is low resistance grounded at the material handling power transformer’s wye-side winding.

A.4.4 480-Volt AC Power Supply Systems

Function – The function of the on-barge and off-barge 480-volt ac power supplies is to provide power to loads requiring power at 480-volt ac single or three-phase.

Major Components – The 480-volt ac supply system consists of the following major components:

- 4,160 – 480-volt unit substation transformers
- 480 -volt switchgear
- 480 -volt motor control centers

System Description – The 480-volt ac power supply system provides power to all electrical loads requiring electrical power at 480 volts. Two 100 % redundant transformers transform power from 4,160 volts to 480 volts to feed the double-ended switchgear. The main incoming and bus tie circuit breakers are electrically operated, and the feeder circuit breakers are manually operated. The switchgear supplies power to 480-volt motor control centers (MCCs). The 480-volt system will be solidly grounded, three-phase, four-wire.

A.4.5 120/208-Volt AC Power Supply Systems

Function – The purpose of the on-barge and off-barge 120/208-volt ac power supplies is to provide power to loads requiring power at 208 volts, single- or three-phase, or 120 volts, single-phase.

Major Components – The 120/208-volt ac supply system consists of the following major components:

- 120/208-volt, three-phase, four-wire panelboards
- 480 – 120/208-volt, three-phase dry-type transformers

System Description – The 120/208-volt ac power supply system generally supplies power to the small loads that are not essential to plant operation, and loss of these loads would not have direct impact on the operation of the facility. Normal loads include the following:

- Receptacles
- General area lighting
- Fractional hp motors (nonessential)
- Communications

The 120/208-volt power supply will be derived from a 480-volt MCC through a 480-120/208-volt dry-type step-down transformer. Each MCC will have provision for at least one such transformer with a panelboard suitably rated to serve the 120/208-volt equipment.

A.4.6 On-Barge DC and Critical AC Power Supply System

Function – The dc and critical ac power systems provide reliable and regulated sources of power for the control, indication, protection, and monitoring of the plant equipment. In addition, it provides power supply to the emergency oil pumps, emergency lighting, and critical control and instrumentation system.

DC Power System – One 125-volt battery and two chargers will be provided for on-barge plant services. The battery will have the capacity equal to 100 percent of the barge only dc plant load for one hour. The battery chargers will be supplied from the MCCs.

Critical AC Uninterruptible Power Supply (UPS) System – One 120/208-volt output UPS system will be provided. The system includes a dc/ac static inverter, static transfer switch, manual bypass switch, alternate source regulating transformer, and distribution panel board. The UPS and the alternate source transformer will be supplied from MCCs.

A.4.7 Protection System

Function – The function of the protection system is to provide protection of the electrical system during abnormal conditions.

Major Components – Protective relays

System Description – The protective relay system is designed to provide protection for the electrical equipment and systems. Most protective relaying is provided with the particular equipment by the suppliers as required in the specifications. Additional metering is specified as required to provide a comprehensive system. Protective relaying protects equipment and systems from overloads, short circuits, ground faults, and over temperature. Conditions that can wait to be corrected or controlled by operations or maintenance intervention are alarmed. Severe conditions initiate breaker trips to isolate equipment and systems to reduce the damage.

- A fully integrated relay scheme for the protection of the generator, auxiliary power distribution equipment, step-up transformer, and high-voltage switchyard equipment is provided. The protective relaying scheme provides a rapid and coordinated response to electrical and mechanical faults so as to minimize equipment damage, while maintaining continuity of service of unaffected systems. Safety of personnel and of the general public, whenever involved, is considered of paramount importance in the design.
- Comprehensive protective device coordination and associated calculations are the basis for specific settings of all protective relays and devices.
- Relays for protection of the motor-generator, step-up transformer, and unit auxiliary transformer are mounted on a panel in the electrical/control building.
- Relays for protection of the auxiliary system are located on the appropriate switchgear or motor control center.
- All protective relays are utility grade, semi-flush-mounted on panel fronts with draw-out cases with suitable testing facilities. All protective relays are provided with re-settable targets or indicators to facilitate troubleshooting. Auxiliary relays have dust covers and are mounted in panel interiors. All protective relays operate independently of the distributed control system (DCS), programmable logic controllers (PLCs), and unit control systems.
- Breaker failure/backup protection is provided for all high-voltage circuit breakers (if switchyard included).
- Motor-generator protective relaying includes protection against inadvertent energization.

A.4.8 Lighting Systems

Function – The function of the on-barge and off-barge lighting systems is to ensure the availability of necessary illumination during normal and emergency operations.

Major Components – Lighting fixtures

System Description – In general, the normal ac systems shall be supplied power from a 400-volt MCC. A three-phase transformer with a 480-volt primary and a 120/208-volt secondary may be used. Each system will have its own separate supply source and lighting fixtures. Individual lighting fixtures will be suitable for the environment in which they are located (i.e., indoor, outdoor, and hazardous classified area). The outdoor and indoor area lighting system will be 120, 208, or 277 volts. Outdoor lighting fixtures will be generally high-pressure sodium type. The lighting system power is distributed to the fixture circuits by circuit breaker panelboards. Lighting panels will be logically located and accessible, and all circuits are clearly identified in each panel. Except in offices or special areas, the circuit breakers serve as lighting switches. Emergency lighting generally consists of individual self-contained battery packs; in standby charge from the normal ac system and operating at 12 volts dc. Dc emergency lights from the barge 125-volt dc battery are provided only in a few strategic areas, e.g., battery room, control room.

The lighting systems design includes consideration of maintenance factors, manual controls, and normal and emergency conditions.

A.4.9 Grounding System

Function – The function of the on-barge and off-barge grounding systems is to provide safety grounding for systems and equipment.

Major Components – The ground system consists of the following major components:

- Ground rods (on-shore)
- Ground cable
- Bonded raceways
- Building/barge steel

System Description – The grounding system is designed to provide personnel safety and protection to electrical equipment. The grounding system consists of ground rods (off-barge) and an integrated installation of ground cable, steel raceways, and building and barge steel to establish a low resistance ground grid.

A main grid of interconnected bare copper cable is established throughout the barge and site. Structural columns and major equipment are connected to the main grid by bare copper cables. Steel raceway rather than separate ground conductors provides the grounding for most equipment. Isolated signal grounding for the sensitive electronic systems is provided.

A.4.10 Lightning Protection System

Function – The function of the on-barge and off-barge lightning protection system is to provide lightning protection for the plant structures and buildings, etc.

Major Components – The lightning protection system consists of the following major components:

- Lightning air terminals
- Ground conductors

System Description – The lightning protection system consists of vertical air terminals, bonding conductor, and ground electrodes (off-barge). The system is designed and installed by a contractor according to a performance specification to meet National Fire Protection Association (NFPA) requirements.

Lightning protection is provided in accordance with NFPA No. 780, UL96, UL96A, Lightning Protection Institute Standards 175, 176, and 177, and per manufacturer recommendations. Air terminals, conductors, and other related accessories are UL listed and labeled.

A.5 Fire Protection

The fire protection system for the barge-mounted power plant is in compliance with NFPA 850 for electric generating plants and various NFPA codes for marine vessels, including NFPA 301, 306, and 1405. System components are discussed in the following sections.

A.5.1 Fire Pumps and Fire Main System

The fire main is looped around the barge, with isolation valves provided at intervals to limit the amount of pipe taken out of service in the event of a pipe break. The fire loop supplies fixed fire protection systems and hose stations.

The fire main is supplied by two fire pumps, one electric motor-driven and one diesel engine-driven. Both pumps take suction from the sea chest provided for the circulating water pump intake. The motor-driven pump is powered by the 480-volt electric bus, through the 4,160-volt bus. The 4,160-volt bus is supplied by the unit auxiliary transformer in normal operation, with backup by the diesel generators in the event that main power is lost. The diesel-driven pump is independent of the plant electrical system, and auto-starts on loss of pressure in the fire main.

A.5.2 Automatic Sprinklers

Automatic sprinklers of the wet pipe type are provided for the maintenance shop, warehouse, crew quarters, startup oil burner area, diesel fire pump area, oil-fired auxiliary boiler area, and corridors and stairways in support building. Preaction type sprinklers are for steam turbine bearings.

A.5.3 Carbon Dioxide

Local CO_2 systems are provided for the steam turbine lube oil reservoir, which is located below the main deck near the machine.

A.5.4 Fire Hose Stations and Fire Extinguishers

Fire hose stations and fire extinguishers are provided throughout the barge. Each fire hose station is provided with foam induction nozzles and a supply of foam concentrate in gallon containers, which are used in conjunction with the hose stations to apply foam, where needed in a fire situation.

A.5.5 Fire Alarm

The entire barge and power plant are provided with comprehensive fire detection and alarm systems. A fire alarm control panel in the control room monitors the status of all fire alarm devices and controls the release of the CO_2 and preaction systems. The fire alarm control panel indicates a water flow alarm for all sprinkler systems and fire hose stations and monitors the status of the fire pumps. In addition to thermal fire detectors, manual alarm stations and evacuation alarms are provided throughout the unit.

A.5.6 Wet-Chemical System

A wet-chemical system is provided specifically for the galley area in the deckhouse.

A.5.7 Fire Barriers

Fire-rated bulkheads are provided for the following areas:

- Sleeping/crew quarters.

- Diesel fire pump.
- Lube oil storage areas.
- Oil-filled transformers.
- Auxiliary diesel generator rooms.

Tanks are provided within the hull to contain the volumes of oil that may leak from transformers, diesel generator fuel oil day tanks, and other fuel and lube oil points of use.

A.6 Heating, Ventilating, and Air Conditioning (HVAC)

A.6.1 General

The barge power plant is constructed as an open outdoor type structure. The deckhouse areas are enclosed to protect equipment within from the elements and provide an environment suitable for personnel and/or equipment operations. The HVAC system functions to maintain acceptable levels of temperature, humidity, filtration, fresh air supply, and air movement, and to exhaust contaminated air.

A.6.2 Codes and Standards

The following United States codes, standards, and handbooks are applicable:

- American Society of Heating, Refrigerating, and Air-Conditioning Engineers (ASHRAE) 1997, Handbook of Fundamentals.
- ASHRAE 15, Safety Code for Mechanical Refrigeration.
- ASHRAE 34, Number Classification and Safety Designation for Refrigerants.
- ASHRAE 55, Thermal Environmental Conditions for Human Occupancy.
- ASHRAE 62, Ventilation for Acceptable Indoor Air Quality.
- American Conference of Governmental Industrial Hygienists (ACGIH) Industrial Ventilation, A Manual of Recommended Practice.
- Sheet Metal and Air Conditioning Contractors National Association (SMACNA).
- National Fire Protection Association (NFPA).
- Air Movement and Control Association (AMCA).
- Air Conditioning and Refrigeration Institute (ARI).

A.6.3 Design Conditions

HVAC design conditions are specified on Table A.1.

Table A.1. HVAC Design Conditions

Area	Temperature (dry bulb / wet bulb)	Level
Outside ambient (summer)	75 °F DB /65 °F WB	
Outside ambient (winter)	-35 °F DB	
Diesel generator room	95 °F DB / 79 °F WB	1
Water treatment room	95 °F DB / 79 °F WB	1
Electrical equipment room	86 °F DB / 72 °F WB	2
Control room	75 °F DB / 63 °F WB	2
Chiller room	86 °F DB / 72 °F WB	2
Office	75 °F DB / 63 °F WB	3
Dining/conference	75 °F DB / 63 °F WB	3
Galley	75 °F DB / 63 °F WB	3
Bunk/sleep area	75 °F DB / 63 °F WB	3
Battery room	75 °F DB / 63 °F WB	3
Toilet/shower rooms	75 °F DB / 63 °F WB	3

A.6.4 System Descriptions

HVAC systems are described in the following sections.

A.6.4.1 Diesel Generator Rooms/Water Treatment Room Level 1 – HVAC

The auxiliary diesel generator is located in a separate room within the deckhouse structure. Exhaust from the diesel generator is routed to the outside. Combustion air for the diesel generator is from the outside and is not taken directly from the room.

A dedicated pair of air handling units supplies air to each diesel generator room and the centralized water treating room on the first level. Each air handling unit will handle 100 percent of the Level 1 cooling load with the other unit serving as a spare. The air handling units will be provided with a mixing box, filter section, hot water coil, and fan section. No cooling will be provided by these units.

During normal operation, sufficient air will be supplied to each room to maintain a slightly positive pressure and maintain design temperature and conditions. When the diesel generators are energized, the supply airflow to the diesel generator rooms will be increased to compensate for the heat radiated from the diesel generator. A relief louver is placed in the wall of each diesel generator room. Air is not returned from the diesel generator rooms to the air handling units, but is returned to the air handling units from the water treatment room. The air handling units are controlled by a room thermostat located in each room. The air handling units are operated on an alternating schedule to equalize wear.

The outside air intake louver for the air handling units will be on a wall opposite the diesel generator exhaust. Fire dampers will be installed on duct penetrations through the walls that separate the diesel generator rooms from the water treating room.

A.6.4.2 Electrical Equipment Room / Control Room/Crew Quarters Levels 2 and 3 – HVAC

A dedicated pair of air handling units supplies air to the electrical equipment room, control room, office, dining room/conference room, galley, and bunk/sleeping area. Each air handling unit will handle 100 percent of the combined Levels 2 and 3 load, with the other unit serving as a spare. The air handling units are each provided with a mixing box, filter section, steam heating coil, and fan section. No cooling will be provided on these units.

During normal operation, sufficient air will be supplied to each room to maintain a slightly positive pressure and maintain design temperature and conditions. Variable air volume (VAV) boxes will be provided in the different areas to maintain the specific room design conditions. Individual room temperatures will be controlled by room thermostats.

A.6.4.3 Battery Room Level 2 – HVAC

An exhaust fan is located in the battery room to limit the potential buildup of hydrogen to below 2 percent by volume. Room air is exhausted to the outside. A flow switch in the duct will activate an alarm when there is no flow in the exhaust duct.

A.6.4.4 Bunk Area, Galley, Dining/Conference Room, Office Level 3 – HVAC

HVAC for this level is provided by the same pair of air handling units that service Level 2. Ductwork is routed between the Level 3 areas and the air handling units, with VAV boxes provided for each room on Level 3.

A.6.4.5 Galley, Toilet, Shower Rooms Level 3 – HVAC

Individual exhaust fans are provided in the galley, toilets, and shower room. Exhaust air is drawn in from the surrounding areas.

Compartments within the barge hull that contain mechanical or electrical equipment are ventilated to control ambient temperature and prevent the buildup of explosive mixtures of oil vapor and air. These areas include the lube oil reservoirs for the steam turbine generator set, and the No. 2 fuel oil tankage.

A.7 Fuel Oil Storage and Distribution

The barge-mounted power plant is provided with a supply of No. 2 fuel oil that is consumed by several functions, as follows:

- Diesel Generator – The auxiliary diesel generator is provided with a nominal 7-day supply of fuel oil in a dedicated pair of hull tanks. This enables the barge to operate in a standby mode to perform repairs or await a command to restart. In addition to the bulk oil supply within the hull tanks (3,500 gallons per each of two tanks), the engine is provided with a 550-gallon day tank. The bulk tanks contain sufficient fuel oil to enable the engine to operate for 7 days at about 70 percent load. The bulk tanks are also used to provide fuel oil to top off the day tank provided for the diesel-driven fire pump.
- Start-Up Burners for the B/CFB boilers.
- The hull tanks are horizontal cylindrical type vessels, mounted on saddles in compartments within the hull, which act as a secondary containment in the event of a tank rupture or leaks. A pair of vertical centrifugal-type pumps mounted in the top of the hull tanks distributes the oil to the points of use.

A.8 Water Treatment

The barge-mounted PFBC power plant requires supplies of treated makeup water for several purposes, each demanding specified quality levels. The needs for makeup water for this unit are as follows:

- Cycle Makeup – The steam power cycle requires approximately 10 gallons per minute of deionized water on a continuous basis during normal operation. This water replaces fluid lost from the cycle by boiler blowdown, leaks from valve stems and pump seals, deaerating heater vent, and miscellaneous leakage paths.
- Potable Water – A supply of potable water is required for support of the operating crew for drinking, cooking, and sanitary purposes. Approximately 150 gallons per day of potable water are required on a continuous basis, on average.
- Air Cooled Condenser Makeup-A supply of filtered fresh water is required to support operation of the air cooled steam condenser in the evaporative mode of operation. This requirement is estimated at 75 gpm at the summer design condition.

The water requirements described above are provided by a water treating plant contained on the barge. The water treatment plant design is based on the assumption that a source of fresh water is available for makeup to the barge. This water can be supplied by a well, or the local municipal water system.

The water treating plant comprises state-of-the-art equipment that provides the following functions:

- Pretreatment Chemical Injection – A pre-piped and pre-wired chemical injection skid containing pumps and tanks of chemicals is provided. This unit injects chemicals such as permanganate, sodium hypochlorite, and a polymer to oxidize iron and manganese for downstream removal by a filter.
- Greensand Filter – A pair of greensand filter vessels containing anthracite and manganese greensand are provided. The system is pre-packaged and equipped with necessary valves and controls to allow one unit to filter, while the second unit is on standby or in a backwash mode.
- Cartridge Filter – A cartridge filter is provided downstream of the greensand filter vessels to remove fine particulate matter (down to 5 microns). Two filter vessels, each containing a number of replaceable cartridges, are skid-mounted together, along with valves, piping, etc.
- Reverse Osmosis Pretreatment Chemical Injection – A second skid-mounted chemical injection unit provides antiscalant to inhibit formation of mineral scale on the reverse osmosis membranes, and sodium metabisulfate to scavenge chlorine.
- Reverse Osmosis (RO) System – A two-stage reverse osmosis system is provided to produce high purity water for feed to the final stage of purification, which is electro-deionization. The RO system uses two product staged RO systems in series. The permeate from the first stage is passed to the second stage, with the reject of the second stage recirculated to the feed of the first stage. The RO units utilize tubular fiberglass-reinforced plastic membranes in a packaged skid-mounted unit, complete with valves, controls, etc.

The product of the RO unit is used as makeup to the steam cycle, well as the potable water system. Chlorine is added to the RO-supplied water to render the water fit for human consumption. Water for the air cooled condenser is taken from the filtered water supply upstream of the RO units. RO units are used in lieu of softeners or resin type deionization units to minimize consumption of chemicals, resins, and other consumables.

A.9 Service Air and Instrument Air

Compressed air for use by the power plant is provided by two 100 percent redundant, oil-free, two-stage rotary screw air compressors. The air compressors are pre-packaged units, complete with controls, inter- and after-cooling, and inlet air filtration. The inter- and after-coolers are air cooled. Each compressor is rated at a nominal 75 cfm, free air delivery, at 125 psig, and is driven by a 15 hp, 480-volt, three-phase, 60 Hz electric motor.

The compressed air system includes two 100 percent capacity air dryers of the adsorbent type. Each dryer is a twin tower unit, with one tower providing the drying function, while the other tower is regenerating. Downstream of the dryer units, cartridge type air filters remove particulate matter from the dry compressed air.

An air receiver of 40-cubic-foot capacity is provided to buffer the system against large pressure swings and to compensate for large changes in air demand. Oilers are provided at selected locations in the system where air is supplied for use by power tools, or other applications where oil-free air is not required. The air receiver is a carbon steel, ASME Code stamped (Section VIII) vessel, lined with epoxy. System piping is copper, with brass valves and fittings.

A.10 Barge Closed-Loop Cooling Water System

A closed-loop cooling water system provides cooling water for components requiring that cooling water be clean and of high quality. A typical list of components served by this system, along with approximate flow rates, is presented in Table A.2.

Table A.2. Closed Loop Cooling Water Systems Duty

Component	No.	Full Power Q*, Btu x 10^6/hr	Full Power, gpm
Steam Turbine Lube Oil Cooler	2	0.15	30
Steam Turbine EHC Fluid Cooler	1	0.05	15
Feed Pump Lube Oil Cooler	2	0.05	12
Feed Pump Motor Cooler	2	0.05	10
Isolated Phase Bus Duct Cooler	1	0.02	5
Sample Coolers	5	0.02	5
* Q = thermal duty, Btu x 10^6/hour			

The closed-loop cooling water system comprises two evaporative tube bundles, two circulating water pumps, a head/expansion tank, and necessary piping, valves, and instruments. The evaporative tube bundles are mounted in the air cooled condenser support structure, and operate on the same principle.

The closed-loop cooling water system utilizes two 100 percent capacity circulating water pumps of the horizontal centrifugal, double-suction type. The pumps are rated at 80 gallons per minute at 50 feet TDH, and are of all iron construction. The head/expansion tank is a 100-gallon atmospheric vessel, located at an elevation above the highest component served by the system. Piping and valves are carbon steel.

A.11 Potable Water System

The potable water system distributes potable water from the water treatment system (Section 3.7.8) to plumbing fixtures, safety showers, eyewashes, and hose bibs throughout the barge. The system is sized to provide 100 gallons per day, on average, for an anticipated crew of four full-time individuals who are housed on board the vessel. The system can supply water at a much higher rate in response to demand from a safety shower, which is provided in the battery room, the water treating equipment room, and any other location storing or using hazardous chemicals. A 120-gallon, electrically heated, fast-recovery domestic hot water tank is provided to maintain a supply of hot water at 140 °F for showers and sanitary use.

A.12 Sanitary Waste Disposal System

The sanitary waste disposal system collects drains from plumbing fixtures (heads, lavatory and galley sinks, shower drains) in a 500-gallon holdup tank. At periodic intervals, the contents of the tank are pumped through a macerator to a tie-in with the local sanitary sewage system.

APPENDIX B—BALANCE OF PLANT: STEAM CYCLE

This section describes the steam turbine and related steam cycle equipment for this barge-mounted first-generation PFBC electric generating unit.

B.1 Steam Turbine Generator

The steam turbine is a geared condensing machine manufactured by a number of domestic manufacturers. The turbine section exhausts axially into the air cooled condenser. The turbine drives a 60 Hz synchronous generator through a speed reducing gearbox. The generator is an open frame air cooled type, and is equipped with a static exciter. The standard turbine auxiliaries, including gland steam condenser, lube oil reservoir and conditioner, oil coolers, electrohydraulic control system, etc. are provided on ancillary skids and packages.

B.2 Condensate and Feedwater Systems

Condensate is defined as fluid pumped from the condenser hotwell to the deaerator inlet. Feedwater is defined as fluid pumped from the deaerator storage tank to the boiler economizer inlets.

The condensate system comprises two motor-driven condensate pumps, each rated at 100% capacity. The pumps take suction from the condenser hotwell, and pump the condensate through the gland steam condenser, two low pressure feedwater heaters, and then into the deaerating heater.

The feedwater system comprises two motor-driven feedwater pumps, each rated at a nominal 100 percent of maximum continuous rated power. The feedwater discharged from the pumps passes through a high-pressure feedwater heater, and then to the economizer inlets of the boilers.

B.3 Condenser

The condenser is a bare tube air cooled evaporative unit. When the ambient temperature is above about 38F, the unit operates with water sprayed on the tubes for evaporative cooling. At lower temperatures, the unit operates dry to reduce annual water consumption, eliminate the potential for icing up, and to eliminate the plume. The condenser is provided with steam jet air ejectors, each rated at 100 percent capacity for continuous operation at the design condensing backpressure of 2.5 inches Hga.

B.4 Steam Cycle Piping

Table B.1 presents design information describing the piping required to connect the steam turbine cycle with the boiler and heat recovery unit.

Table B.1. 4,655 kWe Fluidized Bed Combustor Steam Cycle Piping Required
(To connect steam turbine cycle with boiler and HRU)

Pipeline	Flow, lb/hr	Press, psia	Temp, °F	Material	OD, in.	Wall Thickness
Condensate to Deaerator	63,000	75	116	A106 Gr. B	3	Sch. 40
Feedwater to Boiler Economizer Inlet	67,400	325	250	A106 Gr. B	3	Sch. 40
Main Steam/Boiler to Steam Turbines	66,700	275	700	A106 Gr. B	6	Sch. 40

APPENDIX C—SITE, STRUCTURES, AND SYSTEMS INTEGRATION

This section contains the description of the plant site, structures, and systems integration.

C.1 Plant Site and Ambient Design Conditions

This section describes the design of the barge that houses and supports the coal fired power plant. As presently conceived, the unit is designed to be relatively self-sufficient for operation and routine maintenance at remote and primitive sites under harsh environmental conditions. The power plant rating is defined and calculated at ISO ambient conditions. However, the range of anticipated ambient conditions is expected to reflect the Nome climate, per the following:

- Ambient temperatures up to from -35°F to 75°F dry bulb (up to 55°F wet bulb)
- Salt and/or freshwater spray.
- Heavy rainfall or snow conditions.
- Cyclonic winds (up to 100 mph).

The barge is designed to be moored at a permanent pier, with some of the systems and equipment required for operation located on-shore or on an adjacent auxiliary barge. The tie-ins to these necessary services are assumed as follows:

- Coal supply is brought to the power barge mooring site by means of barge. A primary crusher is provided to reduce the coal size to no large than 2X0. The secondary crushing and drying to suit the B/CFB feed requirements will be performed on the power barge. The storage dome provided at the land-based facility that supports the barge can store up to a one year supply of Usibelli coal, and about a one and one-half year supply of British Columbia coal (the BC coal has significantly higher Btu content per unit weight). It is assumed that a coal delivery occurs once per year. The coal is off-loaded, and the delivery barge is returned to the supplier.
- Sorbent supply (limestone or other suitable calcium-bearing material) is also delivered by barge. The sorbent consumption rate is usually a small fraction of the coal consumption rate, depending on the sulfur content of the coal and the available calcium content of the sorbent. For the Usibelli coal used as the basis for the designs in this report, the limestone consumption rate is less than 1 percent of the coal-firing rate. It is assumed that the sorbent is delivered in a run-of-quarry condition, and requires grinding to meet B/CFB boiler feed requirements. Necessary grinding equipment is provided at the land based facility supporting the barge. A storage capability of one to two years of limestone is maintained at the land based facility.
- Ash is stored on shore or on an auxiliary barge. If stored on shore, the storage requirement is based on the time interval between transports of ash to an ultimate disposal area. Ash removal can be by truck or barge. It is also possible to establish an intermediate ash storage area immediately adjacent to the power barge mooring site, if local conditions warrant. Storage capability for up to one year of ash production firing Usibelli coal is maintained at the land based facility.

Electric power is conveyed from the barge at transmission voltage levels to a switchyard on shore adjacent to the barge. The main power step-up transformer is located on the barge, so that the conductors connecting the barge to the shore facility require the capability to adapt to tidal changes in elevation, while maintaining adequate clearances relative to the high-voltage lines.

The barge is designed to be self-sufficient for water needs, except for makeup of fresh water. The barge is equipped with primary, cycle makeup, and potable water treating equipment. Occasional deliveries of chemicals are required.

The barge is equipped with a small sanitary sewage treatment unit, adequate to handle waste produced by the permanent crew. The waste is discharged to the local sanitary waste system.

The power barge requires periodic deliveries of No. 2 fuel oil for startup and standby power and steam generation. In addition, other consumables such as chemicals, small parts and tools, food for the galley, and routine business supplies will require periodic replenishment.

C.2 Structures and Systems Integration

The general arrangement of the 5 MWe (nominal) barge-mounted PFBC power units considers the overall spatial restrictions imposed by the barge dimensions, and attempts to fit virtually all of the equipment required for a self-contained, functioning power plant on one integral barge that is 90 feet wide and 350 feet long as shown in Figure C.1 and Figure C.2.

The barge hull is designated as a seagoing barge by the American Bureau of Shipping (ABS), and is designed and constructed in accordance with ABS rules for this class of vessel. The hull is of all-welded construction, using mild steel plate and structural shapes. It is designed for a minimum maintenance-free working life of 25 years. The hull is designed to take the bottom at each low tide (twice per day) for the specified working life. The barge is designed for transport on a semi-submersible heavy lift transport vessel, therefore no bilge keels or other protuberances are permitted to be attached to the hull below the waterline.

The barge is sub-divided into watertight compartments by a system of transverse and longitudinal bulkheads so that stability and buoyancy are maintained under specified damage conditions.

The barge is painted with various types of corrosion-resistant coatings, generally including high build epoxy primers and top coats. The underwater portions of the hull receive three coats of tin-free, antifouling vinyl suitable for stagnant brackish water. In addition, a cathodic protection system is provided based on replaceable high-purity aluminum anodes.

Figure C.1. Barge Site Layout

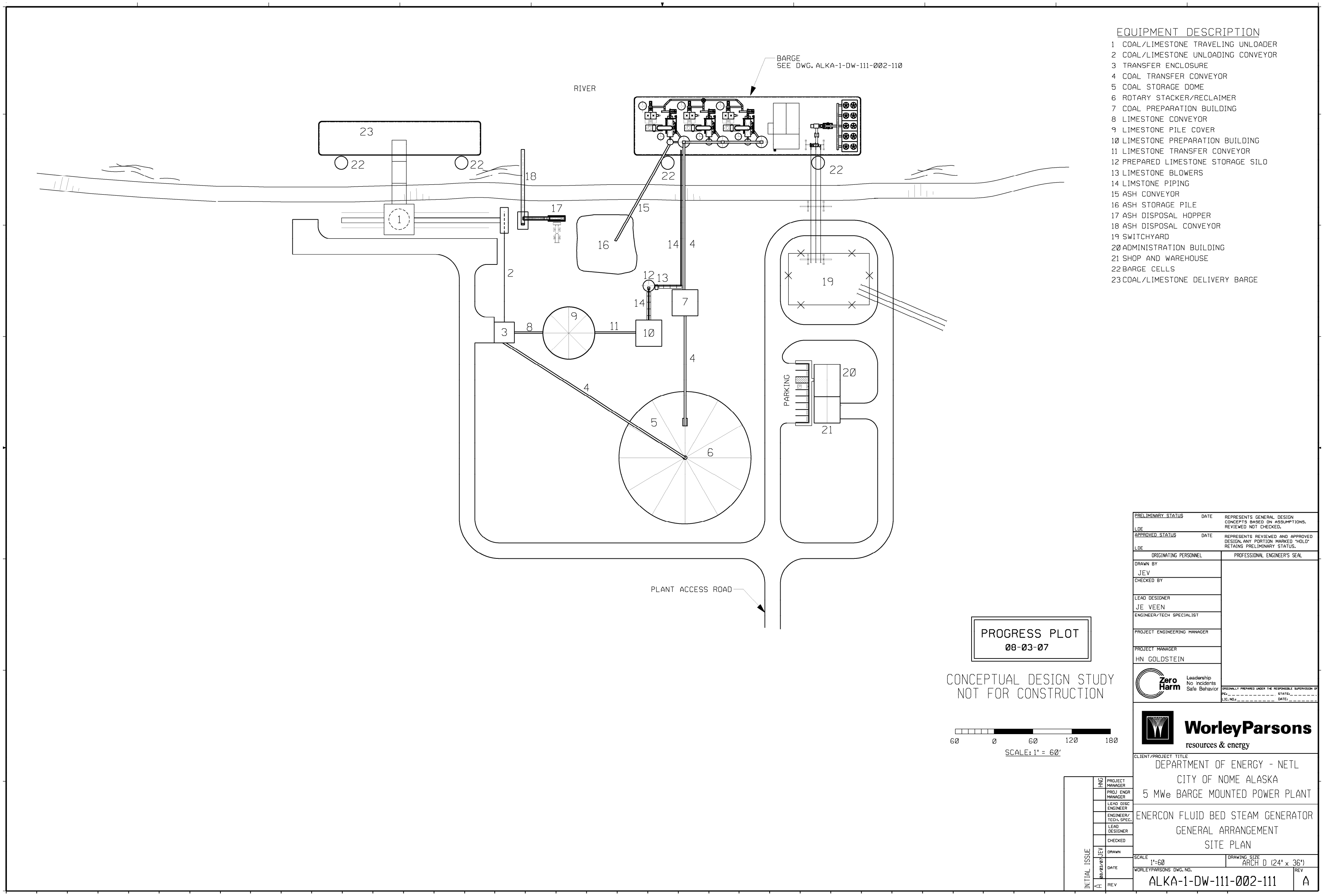
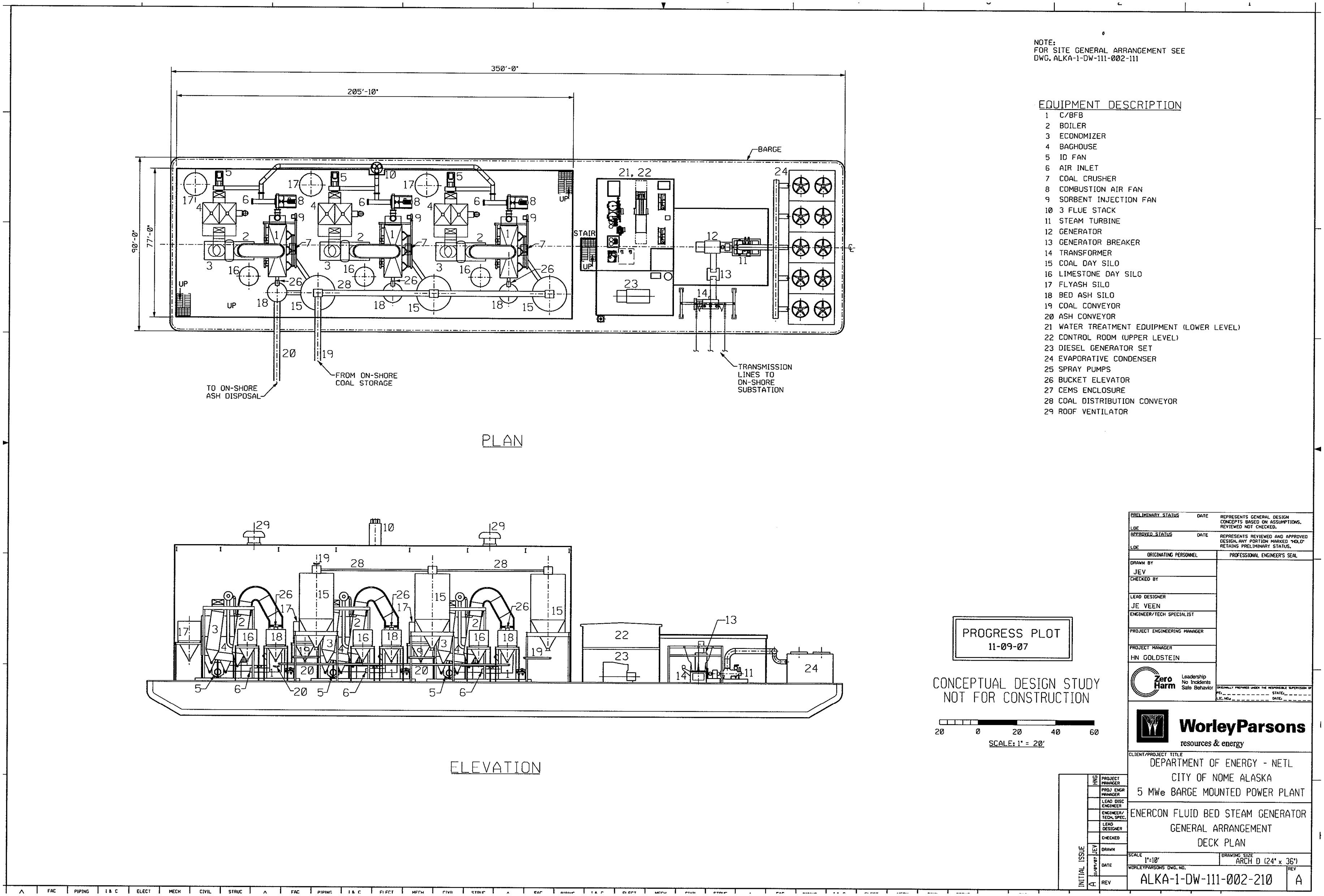


Figure C.2. Barge General Arrangement, Deck Plan



The barge is provided with suitable weather doors and hatches for all hull openings, and includes appropriate lifesaving equipment and safety features such as handrails around the entire deck perimeter, lifebuoys, lines, and ladders.

The principal interface between the power plant and the barge is the main deck (sometimes referred to as the strength deck). The top of steel of this deck represents a spatial plane that corresponds to the top of finished concrete of the main foundation slab for an equivalent land-based unit. Although most of the power plant equipment and structure are located above the main deck, a number of equipment items and pipe runs are located below the deck in order to reduce the overall height of the complete unit.

Although the barge is designed on a single hull, the power plant equipment and structures are grouped into four basic areas, when viewed in plan. Starting at one end of the barge, an area 225 feet long is occupied by the three fluid bed boilers and their ancillary equipment. The next area (about 40 ft along the barge in the longitudinal direction) is occupied by the deckhouse sheltering miscellaneous mechanical and electrical equipment, control room, and crew quarters.

The next barge area, also about 40 feet in length, is devoted to the steam turbine generator. Finally, the last 25 feet of the barge length is occupied by the air cooled condenser.

APPENDIX D—EQUIPMENT LISTS FOR THE 5MWE/60 HZ BARGE-MOUNTED C/CFB

ACCOUNT 1 - COAL AND SORBENT HANDLING

ACCOUNT 1A - COAL RECEIVING AND HANDLING (Equipment in this account is part of the land-side barge support facility)

Equipment No.	Description	Type	Design Condition	Qty
1	Barge Unloader	Traveling	300 tph, 50 hp motor	1
2	Conveyor 1	Flat Belt	36-inch-wide belt, 300 tph, 20 hp motor	1
3	Conveyor 2	Flat belt	0°, 250 fpm, 36-inch-wide belt, 300 tph, 20 hp motor	1
4	Transfer House			1
5	Stackout Conveyor	Flat Belt	60°, 250 fpm, 36-inch-wide belt, 300 tph, 25 hp motor	1
6	Radial Stacker/Reclaimer	Radial	300 tph, 25 hp motor	1
7	Reclaim Conveyor	Flat Belt	0°, 200 fpm, 24-inch-wide belt, 100 tph, 10 hp motor	1
8	Coal Geodesic Dome	Modular Construction	120-foot ID, 72 feet high, 15,000 tons of coal	1
9	Coal Primary Crusher	Impact	100 tph, 100 hp motor	1
10	Crusher Surge Bin		100 tons	1
11	Barge Feed Conveyor	Flat Belt	100 tph, 24 inch, 10 hp motor	1
12	Crusher	Impact Crusher	100 tons per hour, 200 hp motor	2
13	Sampling Subsystems		100 lb/hr	2

ACCOUNT 1B - LIMESTONE HANDLING AND PREPARATION (Equipment in this account is part of the land-side barge support facility)

Equipment No.	Description	Type	Design Condition	Qty
1	Limestone Stackout Conveyor	Flat Belt,	75 tph, 24 inch belt, 10 hp motor	1
2	Limestone Storage Cover	Bolted steel plate construction	26-foot diameter x 45-foot straight wall, 935 tons capacity	1
3	Limestone Reclaim Conveyor	Flat Belt	25 tons/hr, 24 inch belt, 5 hp	1
4	Rod Mill Surge Hopper	Carbon steel, 25 tons		1
5	Limestone Grinding Mill	Rod mill	25 tons/hr, 15 hp	1

Equipment No.	Description	Type	Design Condition	Qty
6	Limestone Transfer to Day Bin Blowers	High-pressure blower unit with inlet and outlet silencers and inlet filter	40 hp, belt drive, 900 cfm, 25 tons transfer per hour	2

ACCOUNT 2 - COAL AND SORBENT INJECTION

Not Applicable

ACCOUNT 3 - CONDENSATE, FEEDWATER AND MISCELLANEOUS SYSTEMS

ACCOUNT 3A - CONDENSATE AND FEEDWATER SYSTEM ***(Equipment in this account is on-barge)***

Equipment No.	Description	Type	Design Condition	Qty
1	Condensate Pumps	Vertical dry pit centrifugal pump, 100% capacity	140 gpm, 260 TDH, 15 bhp	2
2	Condensate Storage Tank	Vertical cylindrical steel tank, carbon steel, plasite-lined, AWWA construction	10,000 gallons, floating diaphragm	1
3	Condensate Low-Pressure Heater No. 1	U-tube closed-type horizontal heaters with roller supports on the shell for tube removal, stainless steel U-tubes, ASME VIII	4,000,000 Btu/hr, entering condensate 130°F, outlet temperature 196°F, shell design pressure/temperature vacuum to 50 psig/230°F, tube design pressure/ temperature 215 psig/230°F	1
4*	Condensate Low-Pressure Heater No. 2	U-tube closed-type horizontal heaters with roller supports on the shell for tube removal, stainless steel U-tubes, ASME VIII	3,000,000 Btu/hr, entering condensate 196°F, outlet temperature 232°F, shell design pressure/temperature vacuum to 50 psig/ 260°F, tube design pressure/temperature 215 psig/260°F	1
5*	Condensate Deaerator and Storage Tank	Horizontal storage tank with deaerator mounted on top of it, ASME VIII for D/A and tank	3,000,000 lb/hr, 232°F, extraction steam flow 4,000 lb/hr @ 45 psig, extraction enthalpy 1276 Btu/lb, heater drain flow 17,000 lb/hr, heater drain enthalpy 288 Btu/hr, storage tank capacity 2000 gallons, design pressure full vacuum to 75 psig, design temperature 320°F, operating pressure 45 psia	1
6	Feedwater Pumps	Horizontal split case multi-stage centrifugal type, 100% capacity	140 gpm, 850 TDH, inlet 4-inch diameter/ 150 lb, outlet 4-inch diameter/300 lb, 50 bhp	2

ACCOUNT 3B - MISCELLANEOUS EQUIPMENT

Equipment No.	Description	Type	Design Condition	Qty
2	Reverse Osmosis Units - Makeup Water Treatment	100% RO units in FRP pressure vessels to include booster pumps, valves, controls, skid-mounted FRP CIP solution tank, 5 micron filter, tank-mounted immersion heater for CIP tank, etc.	30 gpm each, minimum 75% recovery and 99% removal of TDS. LSI will not exceed 1.5 in the reject water, 10 hp booster pumps, 10 kW immersion heater	2
4	Sodium Bisulfite Feed System - Makeup Water Treatment	Metering feed of bisulfite into line upstream of cartridge filter. Complete prefabricated unit with two 100% diaphragm type chemical metering pumps.		1
5	Antiscalant Feed System - Makeup Water Treatment	Metering feed of antiscalant into line upstream of cartridge filter. Complete prefabricated unit with two 100% diaphragm type chemical metering pumps.		1
6	Demineralized Water Storage Tank - Makeup Water Treatment	Vertical cylindrical, 304L stainless steel, AWWA construction	15,000 gallons	1
7	Demineralized Water Pumps - Makeup Water Treatment	Horizontal centrifugal pumps, end suction ANSI, FRP construction	100% capacity, 30 gpm, 100 psig, 70°F, 1 hp motor	2
8	Waste Water Neutralization Tanks - Waste Water Treatment System	Vertical cylindrical, FRP construction	Sized for 25 gpm processing rate with 9.4 seconds reaction time, pH 6 to 9, temperature 150°F maximum.	2
9	Tank Agitators - Waste Water Treatment System	Tank-mounted mixer	Sized to keep small particles in suspension	2
10	Acid Metering Pumps - Waste Water Treatment System	Diaphragm	Sized to meter acid from tote for pH greater than 9	2
11	Caustic Metering Pumps - Waste Water Treatment System	Diaphragm	Sized to meter caustic from tote for pH less than 6	2
12	Oil/Water Separation Tank - Waste Water Treatment System	Below grade, FRP construction	Maximum 25 gpm	1
13	Waste Oil Pump - Waste Water Treatment System	Gear type	5 gpm, ½ hp	1

Equipment No.	Description	Type	Design Condition	Qty
14	Cooling Water Tube Bundles (mounted on evap condenser structure) - Closed Cycle Cooling Water System -	Tube size 2 inches OD, 304L stainless steel / 18 BWG, with water box on inlet and outlet	Duty 1 MMBtu/hr	2
15	Closed Cycle Cooling Water Pump - Closed Cycle Cooling Water System	Horizontal centrifugal, end suction ANSI, ductile iron	Capacity 100 gpm, 70 TDH, 3 bhp	2
16	Cooling Water Head Tank - Closed Cycle Cooling Water System	Vertical cylindrical, carbon steel	50 gallons, atmospheric pressure	1
17	Chemical Tank and Pump Skid - Closed Cycle Cooling Water System	Polyethylene tank and metering pump	Corrosion inhibitor	1
18	Auxiliary Boiler - Auxiliary Boiler System	Package type water tube design, pressurized construction, forced draft fan, full capacity burners for natural gas or No. 2 fuel oil, one steam drum, no superheater, fully insulated tube water walls with a steel casing, soot blowing system	15,000 lb/hr of 125 psig steam	1
19	Auxiliary Boiler Deaerating Feedwater Heater - Auxiliary Boiler System	Deaerating and storage unit	2,500 lbs/hr of 5 psig steam, inlet 100 to 160°F, steam to heat feedwater to 228°F, oxygen less than 0.005 cc/liter	1
20	Auxiliary Boiler Feed Pumps - Auxiliary Boiler System	Horizontal centrifugal, split case, two-stage	20 gpm, 400 TDH, 5 hp	2
21	Fuel Oil Supply Pump - Auxiliary Boiler System	Centrifugal	2 gpm, 100 TDH, ¼ hp	2
22	Auxiliary Boiler Forced Draft Fan - Auxiliary Boiler System	Centrifugal fan	5 hp	1
23	Auxiliary Boiler Oil Boost Pump - Auxiliary Boiler System	Centrifugal	1 hp	2
24	Instrument Air Dryer - Auxiliary Boiler System	Twin tower heatless desiccant type	75 scfm	2
25	Instrument/Service Air Compressors - Auxiliary Boiler System	Rotary screw	75 scfm, 115 psig, 20 hp	2

Equipment No.	Description	Type	Design Condition	Qty
27	Diesel-Driven Fire Pump	Horizontal centrifugal	75 hp	1
28	Motor-Driven Fire Pump	Horizontal centrifugal	75 hp	1
29	Fire Jockey Pump	Horizontal centrifugal	1 hp	1
30	Fuel Oil Transfer Pump	Gear positive displacement	2 hp	2

ACCOUNT 4 – C/BFB BOILERS AND AUXILIARIES *(EQUIPMENT IN THIS ACCOUNT IS ON-BARGE)*

Equipment No.	Description	Type	Design Condition	Qty
1	Solid Fuel Fired Steam Generator	Atmospheric Bubbling Bed Combustor	22,226 lb/hr @ 275 psig/705°F	3
2	C/BFB Fluidization Blower	Centrifugal type with inlet screen, inlet vanes, silencer, electric motor drive	300 hp, XX,000 cfm	3
3				
4	C/BFB Induced Draft Fan	Centrifugal type with inlet damper, electric motor drive	100 hp, XX,000 cfm	3
5				
6	C/BFB Weigh Belt Feeder		3 hp	3
7	C/BFB Limestone Transport Blowers	Roots high pressure blowers	3 hp	3
8	C/BFB Baghouse Backpulse Air Blowers	Positive displacement	5 hp	3

ACCOUNT 5 - FLUE GAS CLEANUP (EQUIPMENT IN THIS ACCOUNT IS ON-BARGE)

Equipment No.	Description	Type	Design Condition	Qty
1	Baghouse	Low pressure, high volume	XX,000 acfm, 6” H_2O pressure drop, 400 lb/hr particulate removal	3
2	Continuous Emissions Monitoring System	Three flues, multi-channel		1

ACCOUNT 6 – COMBUSTION TURBINE AND ACCESSORIES

Not Applicable

ACCOUNT 7 - DUCTING, AND STACK (EQUIPMENT IN THIS ACCOUNT IS ON-BARGE)

Equipment No.	Description	Type	Design Condition	Qty
1	Stack	Self Supporting Carbon Steel		1
2	Flue Gas Duct	Galvanized carbon steel		3

ACCOUNT 8 - STEAM TURBINE AND AUXILIARY EQUIPMENT *(EQUIPMENT IN THIS ACCOUNT IS ON-BARGE)*

Equipment No.	Description	Type	Design Condition	Qty
1	Steam Turbine Generator and Accessories	Geared, condensing, extraction (uncontrolled)	66,700 lb/hr 250 psig/700F 5705 kWe 3 phase AC at 4160V	1

ACCOUNT 9 – AIR COOLED EVAPORATIVE CONDENSER *(EQUIPMENT IN THIS ACCOUNT IS ON-BARGE)*

Equipment No.	Description	Type	Design Condition (per each)	Qty
1	Evaporative Condenser	Five 20% capacity modules with fan assembly (one 20 hp cooling fan per each module), two 1,200 gpm, 60 TDH, 10 hp spray pumps per condenser, 304L stainless steel condensing tube bundles	Design wet bulb 65°F, dry bulb 74°F, steam flow 58,000 lb/hr, condensing pressure 1.7 psia,	1
2	Evaporative Condenser Spray Pumps	Vertical mixed flow wet pit type pump	10 hp	2
3	Condensate Collection Tank (Hot Well)	Horizontal cylindrical, carbon steel with plasite lining, ASME VIII	Sized for 3 minutes condensation, 50 psig positive pressure to full vacuum	2
4	Air Ejector System	Steam jet ejector and after condenser	Use 125 psig steam, 50 lb/hr of non-condensable gases and water vapor, condenser pressure 0 – 0.7 psia or higher	2
5	Basin Water Heating Coil	Located in the spray water basin	Receives 15 psig steam with 50° superheat	2

ACCOUNT 10 - ASH HANDLING (EQUIPMENT IN THIS ACCOUNT IS ON-BARGE)

Equipment No.	Description	Type	Design Condition*	Qty
1	Bed Ash Silos	Carbon steel shell plate including: fittings for bin vent filter and pressure relief, manhole cover, ladders/stairs, platforms to unloading platform and silo roof	20 tons, 18-foot-diameter, 10-foot straight wall, 60° cone bottom	3
2	Fly Ash Silos	Carbon steel shell plate including: fittings for bin vent filter and pressure relief, manhole cover, ladders/stairs, platforms to unloading platform and silo roof	20 tons, 18-foot-diameter, 14-foot straight wall, flat bottom, 3 hp vent fan	3
3	Fly Ash Cyclone Separator / Receiver	Carbon steel shell plate	1000 lb/hr, 2-foot-diameter, 3-foot straight wall, 60° cone bottom	3
4	Fly Ash Conditioner	Motor, gearbox, fluid coupling, and chain drive, 5 hp	4,000 lb/hr	3
5	Pug Mill	Motor, gearbox, fluid coupling, and chain drive, 5 hp, including watering headers, cleanout system, zero speed switch, rotary feed discharge	4,000 lb/hr	3
6	Telescopic Chute		4,000 lb/hr	3
7	Pressure Vessel for Fly Ash Recycle Outlets	Carbon steel shell plate	1,000 lb/hr	3
8	Bin Vent Filter (for fly ash silos)	Bag filters, delta P gauge, bird screen, discharge to fly ash silo, NEMA electricals	300 cfm, maximum 3:1 air to cloth ratio, sized for 80 psi plant air supply	3
9	Bin Vent Filter for Bed Ash Silos	Bag filters, delta P gauge, bird screen, discharge to fly ash silo, NEMA electricals	300 cfm, maximum 3:1 air to cloth ratio, sized for 80 psi plant air supply, 10 hp fan	3
10	Pressure/ Vacuum Relief Devices for Bed Ash Silos			3
11	Bed Ash Conveying Blower Units	Roots pressure blowers with inlet and outlet silencers and an inlet filter, check valves, pressure switch, motor and drive	200 cfm, 15 psi, 25 hp	3
12	Fly Ash Conveying Blower Units	Roots pressure blowers with inlet and outlet silencers and an inlet filter, check valves, pressure switch, motor and drive	200 cfm, 15 psi, 25 hp	3

Equipment No.	Description	Type	Design Condition*	Qty
13	Rotary Air Lock Valves for Bed Ash Silos	Valves with zero speed switch, motor, and drive	0.20 cubic feet per revolution, 3 hp, 25 rpm (1 for each bed ash silo)	3
14	Air Lock Feeds	NUVA feeders, cast iron housing	LATER (2 for each fly ash bag-house)	6
15	Fly Ash Silo Fluidizing Blower	Rotary positive displacement	5 hp	3
16	Fly Ash Fluidizing System	LATER	LATER	