Natural Gas-Fired Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska

Volume XIII

Ebasco Services Incorporated

August 1982

**Prepared for the Office of the Governor
State of Alaska
Division of Policy Development and Planning
and the Governor's Policy Review Committee
under Contract 2311204417**

Battelle
Pacific Northwest Laboratories

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The major portion of this report was prepared by the Bellevue, Washington, and Newport Beach, California, offices of Ebasco Services Incorporated. Their work includes the Introduction, Technical Description, Environmental and Engineering Siting Constraints, Environmental and Socioeconomic Considerations and Institutional Considerations. Capital cost estimates were prepared by S. J. Groves and Sons of Redmond, Washington, and reviewed by the Ebasco cost estimating department in New York City. Cost of energy estimates were prepared by Battelle, Pacific Northwest Laboratories of Richland, Washington.

PREFACE

The state of Alaska, Office of the Governor, commissioned Battelle, Pacific Northwest Laboratories (Battelle-Northwest) to perform a Railbelt Electric Power Alternatives Study. The primary objective of this study was to develop and analyze long-range plans for electrical energy development for the Railbelt Region (see Volume I). These plans will be used as the basis for recommendations to the Governor and Legislature for Railbelt electric power development, including whether Alaska should concentrate its efforts on development of the hydroelectric potential of the Susitna River or pursue other electric power alternatives.

The availability of low cost natural gas in the Cook Inlet Region has resulted in the development of an electric power system based largely on use of natural gas for electricity generation. Continued use of natural gas for electricity production may present operational system planning, cost and environmental advantages in comparison with alternative energy resources.

The operational system planning and potential cost advantages of continued natural gas use are related largely to the conversion technologies available for use with natural gas. Natural gas is suitable for use with combustion turbines and combined-cycle plants. These technologies provide good operational flexibility, being suitable for both baseload and load-following operation. Combustion turbines and, to a lesser extent, combined-cycle plants are available in relatively small unit capacities and are modular in nature. These characteristics, combined with relatively short construction lead times, facilitate capacity addition planning. Finally, capital costs of combustion turbines and combined-cycle plants are generally modest. This characteristic, combined with short construction lead times, results in low capital investment for natural gas-fired facilities.

Environmental advantages of continued natural gas use accrue from the clean products of natural gas combustion and from the relatively low waste heat rejected from certain natural gas-based conversion technologies. Natural gas combustion products contain no particulates or oxides of sulfur. Formation of nitrogen oxides is controlled in combustion turbines and combined-cycle plants by water injection. Combined-cycle plants operate at high conversion effectiveness, minimizing the waste heat rejected to the environment.

Continued use of natural gas for generation of electricity, while presenting the advantages discussed above, is also beset by potentially severe constraints. Chief among these is the continued availability of natural gas at prices competitive with other primary energy resources, and provisions of the Fuels Use Act restricting use of natural gas for electricity generation. An assessment of future natural gas availability and prices in the Railbelt Region, conducted in conjunction with the Railbelt Electric Power Alternatives Study (Battelle 1982), indicates that under certain conditions, natural gas supplies will continue to be available to the Railbelt Region, albeit at higher prices than in the past. It also appears that exemption from provision of the Fuels Use Act might be obtained under certain conditions.

Thus, in view of the potential advantages presented by contrived natural gas use for electricity generation, and because of the possibility of avoiding the chief constraints to future use of natural gas, it appeared to be desirable to examine in depth one or more of the electric generation technologies suitable for continued use of natural gas for electricity generation in the Railbelt Region.

Conversion technologies suitable for use with natural gas include steam-electric plants, combustion turbines, combined-cycle plants and fuel cells. A combined-cycle plant was selected for study for several reasons. Combined-cycle plants exhibit very favorable conversion efficiencies compared to combustion turbines or steam-electric units. The technology, though relatively new, is well established in the utility industry, including two Alaskan applications. Though greater than for combustion turbines, costs of combined-cycle plants are generally less than costs of comparable steam-electric facilities. Many plant components, such as the combustion turbines, are factory-assembled, minimizing the cost premiums and longer construction times often associated with Alaskan installations. Available plant sizes (90 MW and greater) are suitable for the modest growth in electrical demand forecast for the Railbelt Region. This report, Volume XIII of a series of seventeen reports, documents the findings of this study.

Other power-generating alternatives selected for in-depth study included pulverized coal steam-electric power plants, the Chakachamna hydroelectric project, the Browne hydroelectric project, large wind energy conversion systems and coal-gasification combined-cycle power plants. These alternatives are examined in the following reports:

Ebasco Services, Inc. 1982. Coal-Fired Steam-Electric Power Plant Alternatives for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Chakachamna Hydroelectric Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Browne Hydroelectric Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Wind Energy Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

Ebasco Services, Inc. 1982. Coal-Gasification Combined-Cycle Power Plant Alternative for the Railbelt Region of Alaska. Prepared by Ebasco Services Incorporated and Battelle, Pacific Northwest Laboratories for the Office of the Governor, State of Alaska, Juneau, Alaska.

SUMMARY

Potential operational, systems planning, cost and environmental advantages may accrue from continued use of natural gas for generation of electric energy in the Railbelt Region. The most promising currently available technology for future capacity addition using natural gas appears to be natural gas-fired combined-cycle plants. The purpose of this study is to examine the technical, economic, environmental and institutional characteristics of natural gas-fired combined-cycle plants of suitable capacity for the Railbelt Region.

The plant design selected for study is a nominal 200-MW natural gas-fired combined-cycle plant utilizing two combustion turbines of 74.5 MW capacity each and a heat recovery steam generator supplying a steam turbine generator of 50 MW rated capacity. Gross plant rating is thus 208 MW; net rating, less internal loads, is 198 MW at standard conditions. The annual average heat rate is estimated to be approximately 8200 Btu/kWh. A forced outage rate of 8 percent and a scheduled outage rate of 7 percent would provide an equivalent annual availability of 86 percent. Heat rejection is by mechanical draft wet/dry cooling tower. The plant would be located in the Beluga area, northwest of Cook Inlet. Natural gas is assumed to be supplied by pipeline from the Beluga Field. Power would be transmitted by 345-kV line approximately 75 miles to the proposed Anchorage-Fairbanks intertie.

Overnight capital cost for the proposed plant was estimated to be 1001 \$/kW. Working capital (30-day emergency distillate supply plus 30-day O&M costs) was estimated to be 52 \$/kW. Fixed and variable operation and maintenance costs were estimated to be 7.25 \$/kW/yr and 1.69 mills/kWh, respectively. Levelized busbar energy costs were estimated for various capacity factors and years of first commercial operation using forecasted Cook Inlet natural gas prices prepared elsewhere in the Railbelt Electric Power Alternatives Study. For a 1990 startup date and an 85 percent capacity factor, a levelized busbar power cost of 46.5 mills/kWh was estimated. All costs are in January 1982 dollars.

Environmental effects of the proposed plant are anticipated to be modest. NO_x emissions would be controlled to the applicable NO_x standard of 0.014 volume percent of total flue gas; the only other gaseous release of potential significance would be CO_2. Gross water requirements total 1060 gpm at full power, of which 870 gpm would be consumed and 190 gpm discharged. Estimated land requirements for the plant are 2-1/2 acres plus land required for transmission line, gas pipeline and access road right-of-ways.

The estimated peak construction work force of 400 personnel could produce severe boom-bust effects in the Beluga area.

Principal constraints to development include the continued availability of Cook Inlet natural gas, and Fuels Use Act prohibitions on use of natural gas for baseload electricity generation. Ample natural gas for the proposed plant appears to be available providing Pacific Alaska liquefied natural gas commitments are relinquished. Fuels Use Act exemptions could potentially be obtained if: a) waste heat from the plant were utilized for district heating or process heating; or b) if the State established statutory requirements favoring use of natural gas for electricity generation.

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1.0 INTRODUCTION

The use of combustion turbine generators in combination with steam turbine generators to generate electricity is a mature technology that has gained wide use within the past 15 years. A power plant of this type, called a combined-cycle plant, uses a combustion turbine generator to produce part of the plant total output. Combustion turbine exhaust, directed to a heat recovery boiler, generates high-pressure steam. This steam enters a steam turbine generator where additional power is produced. In a large plant of this type, several combustion turbine generators, each with individual heat recovery boilers, would generate steam for a single steam turbine generator.

Although steam turbine generators have been in utility service for over 60 years, and combustion turbine units since the late 1950s, the use of these units in a combined-cycle plant did not start until 1965. This type of plant is presently being used in the Railbelt at the Sullivan Station of Anchorage Municipal Light and Power and at the Beluga Station of Chugach Electric Association, Inc. Both of these plants utilize the plentiful supply of presently inexpensive local natural gas as fuel.

Among the advantages of this technology are:

- mature technology, proven equipment and systems
- relatively low capital cost
- high efficiency
- modular design
- relatively short construction time
- capable of cycling as well as base load service.

Disadvantages of this technology are:

- premium hydrocarbon fuels normally required
- combustion turbines limited in size - now up to 100 MW.

Combined-cycle plant sizes are a function of the size and number of combustion turbine units utilized. At the low end of the range, a combustion turbine of 10 MW size could be used while at the high end, a 100-MW unit could be used. For each 2 MW of combustion turbine capacity, a nominal 1 MW of steam turbine capacity can be provided. A combined-cycle plant with a total output of 100 MW, for example, could be built with two 35-MW combustion turbine generators and one 30-MW steam turbine generator.

In the alternative described in this document, a 200-MW nominal plant size was selected for a potential site in the Beluga area on the west side of Cook Inlet (Figure 1.1). This site is one of several gas fields located in the Cook Inlet area. This plant would include two 74.5-MW natural gas-fired combustion turbine generators, individual unfired heat recovery steam generators, and one 59-MW steam turbine generator. This design basis was used because it reflects the size of equipment that is presently available and expected to still be widely used in the 1985-1990 time period.

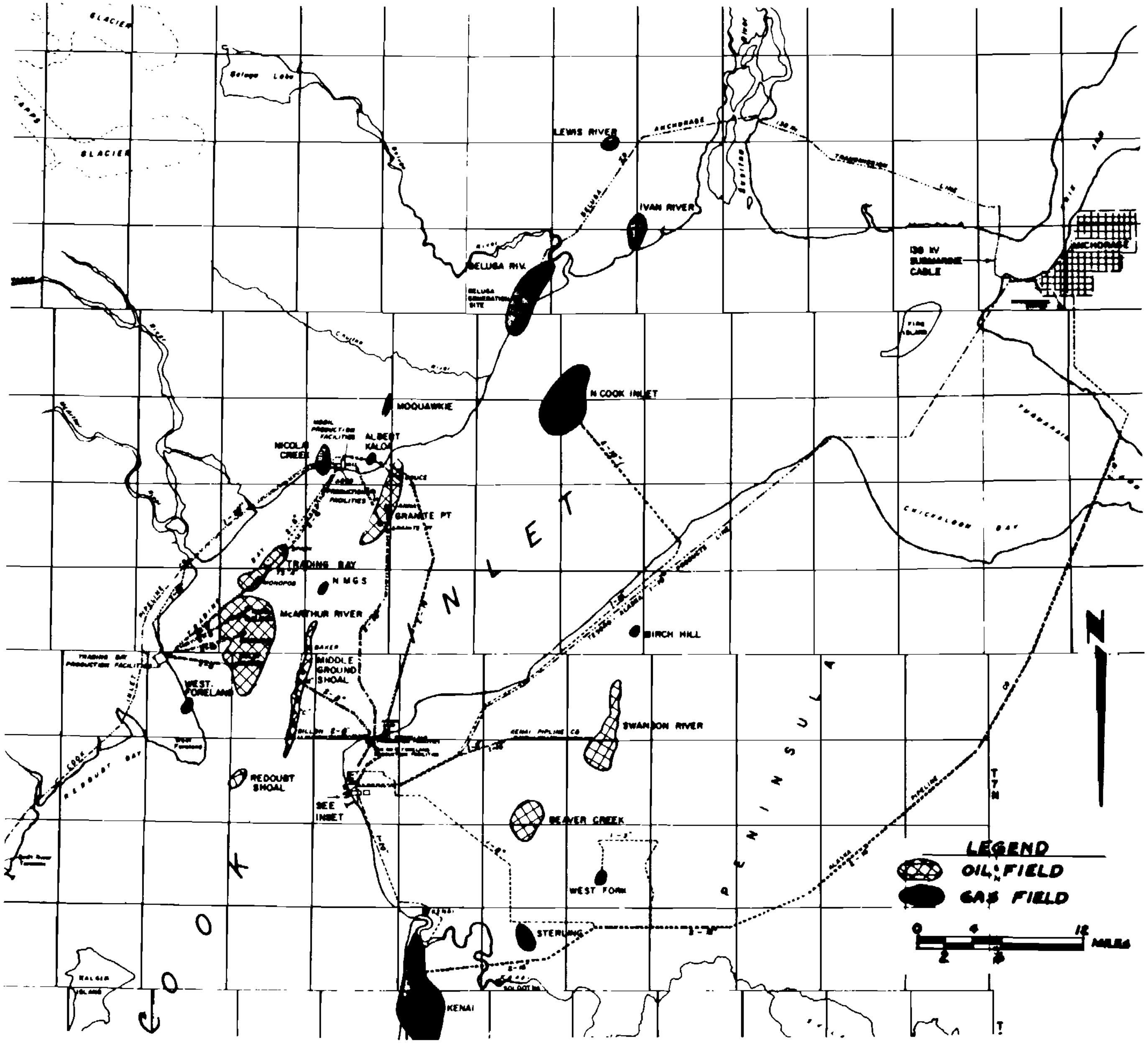

FIGURE 1.1. Study Area

2.0 TECHNICAL DESCRIPTION

2.1 PROCESS AND AUXILIARY SYSTEMS DESCRIPTION

The natural gas-fired combined-cycle turbine plant design envisioned is based on using two currently available General Electric gas turbine generators, rated approximately 74.5 MW each in combination with a General Electric steam turbine generator rated at approximately 59 MW. Other manufacturer's turbines of similar size could be used within the general concept of the design, but it must be pointed out that the specific plant output and various specific design parameters may be expected to change accordingly.

At International Standards Organization (ISO) referenced conditions (59°F and sea level), plant output in the combined-cycle mode will be 208 MW gross, of which approximately 10 MW will be utilized for internal auxiliary loads, resulting in a net plant output of 198 MW. The heat rate of the station will be approximately 8200 Btu/kWh.

The gas turbines can burn either natural gas, distillate oil or residual fuel oil. The plant design is based on using Alaska natural gas, with distillate oil as a suggested emergency standby back-up fuel.

Main steam of 850 psig, 900°F, has been selected for the steam cycle, based on the gas turbine exhaust temperature of 985°F. This design uses a conservative 85°F approach temperature for the main steam, and falls in the range of readily available steam turbine generator sets. For actual steam generation, a conservative 40°F approach temperature has been used on the feedwater heater, the economizer and the evaporator sections in the steam generator. A 1500 psig main steam system could also be used on a plant of this size; however, the actual steam production would be slightly lower at 1500 psig, 900°F, because the limiting factor on the steam generation is the heat available in the gas above the evaporator approach temperature, i.e., at the steam saturation temperature plus 40°F.

In an effort to more effectively utilize the lower temperature exhaust gases, a 50 psig saturated heating steam cycle has been included in the steam generator design. The steam turbine used for this design will be a full condensing turbine, bottom exhausting with the condenser mounted underneath.

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Nitrogen oxide (NO_x) control can be either by steam or water injection. Water injection has been selected for this design because steam injection would require 250 psig steam, which is not readily available.

The major process flows for this plant are shown in Figure 2.1. The natural gas supply (73,792 lb/hr) is compressed to supply 250 psig inlet gas at the combustors of each gas turbine unit. Combusted gas is expanded through the gas turbine driving both the 74.5-MW generator and the integral free-shaft gas turbine air compressor on each unit. Exhaust gas from each turbine flows through dual-pressure steam generators (one for each gas turbine, where the heat is utilized to generate 850 psig superheated steam used to drive the steam turbine generator, and 50 psig saturated steam for the building heating system. The gas is exhausted to the stack on exiting the steam generator. A bypass damper and stack are provided for each steam generator so that the combustion turbine can be operated independently of its waste heat boiler.

The combined main steam flow of 472,400 lb/hr at 850 psig and 900°F, is expanded through a common steam turbine driving a 59-MW generator. Exhaust steam from the turbine is condensed in a vacuum condenser, which in turn is cooled by the wet-dry cooling tower circulating water loop. The cooling tower can be operated either dry or wet, and is expected to operate in the dry mode during the winter months, eliminating the plume of fog and icing about the tower and reducing the plant makeup water requirements.

Condensate is pumped from the condenser through a feedwater heater section in each of the steam generators to the deaerator, which removes oxygen and other gases from the water and forms a small storage tank for the feedwater.

Feedwater pumps take suction from the deaerator to provide the steam generator with feedwater, where heat is absorbed from the hot gas turbine exhaust gas to convert the water to main steam, thus completing the closed feedwater cycle.

The heating steam operates on a completely separate cycle from the main steam, the low-pressure (LP) feed pumps taking suction from the heating steam deaerator and feeding the LP section of the steam generators or the auxiliary heating steam boilers that will be utilized in the event of a gas turbine or

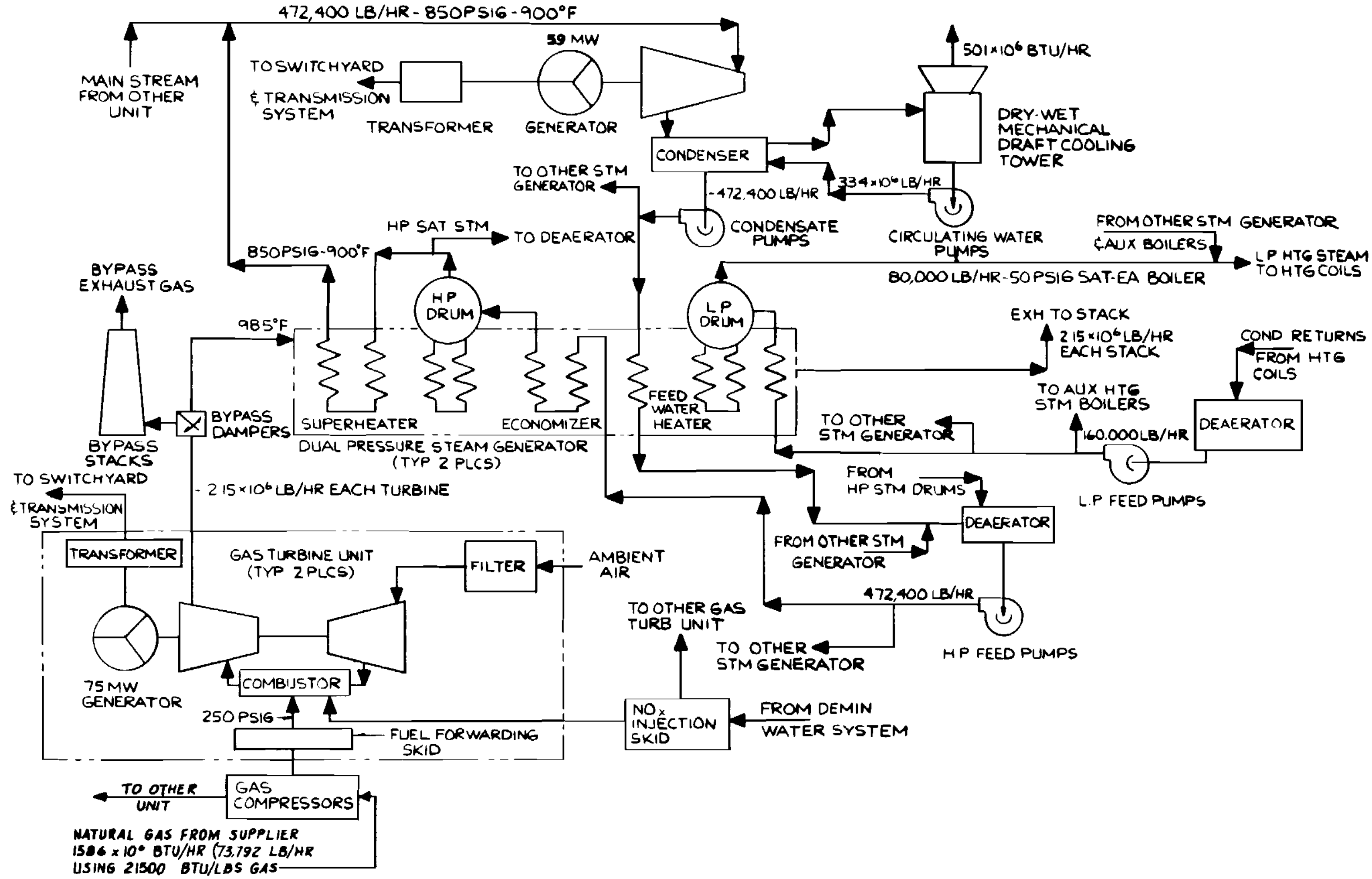


FIGURE 2.1. Process Flow Diagram

gas generator shutdown. The low-pressure, 50 psig, saturated steam is taken from the steam generator LP drums or auxiliary boilers to the building steam heating coils. Condensate returns from the heating coils are fed back to the heating steam deaerator.

Makeup water for both feedwater cycles is supplied from the condensate storage tank, which is steam heated to maintain a 40°F minimium condensate temperature. For the high-pressure (HP) cycles, make-up water will be supplied via the condenser hotwell; LP make-up water will be supplied to the deaerator storage tank. The condensate storage tank will be elevated slightly to provide gravity make-up feed to the condenser hot well. A 150 gpm net output, two-train demineralizer complete with demineralizer tank is used to supply turbine injection water and steam generator make-up.

Plant cold start is based on using distillate fuel from the emergency fuel tanks on one of the gas turbines. A diesel generator started on compressed air will provide the power for starting the gas turbine. The diesel generator can be sized to also power the gas compressors for cold start using gas fuel on the gas turbines if required or preferred; however, two or more diesel generators may be needed to meet such a requirement.

It should be noted that an incoming main gas pressure of 175 psig has been assumed in sizing the gas compressors. Larger compressors requiring more power will be required if the assumed gas mains pressure is not available.

2.1.1 Combustion Turbine Plant

Each combustion turbine is a large-frame industrial-type with an axial flow multi-staged compressor and power turbine on a common shaft. The combustion turbine is directly coupled to an electric generator, and can be started, synchronized, and loaded in about one-half hour under normal conditions.

Each combustion turbine generator package also includes an inlet air filtration system, fuel system, water injection system, lube oil cooling system, and various minor subsystems as required and furnished by the manufacturer. The design parameters for each combustion turbine with generator are presented in Table 2.1.

TABLE 2.1. Combustion Turbine with Generator Design Parameters (based on General Electric MS7001E or equal, two required)

Turbine Type: Simple-cycle, single-shaft, three bearing.

Generator Type: Hydrogen-cooled unit rated 110 MVA at 13.8 kV, 0.9 pf. with 30 psig hydrogen pressure at 10°C.

Performance: (Each Turbine)

Base Rating	74,450 kW at ISO Conditions (59°F, S.L.)
Heat Rate (LHV)	10,655 Btu/kWh
Air Flow	597 lbs/sec
Turbine Exhaust Temp	985°F
Turbine Inlet Temp	1985°F
Inlet Pressure Drop	5 in. water
Exhaust Pressure Drop	10 in. water
Dimensions (turbine generator only)	29 ft wide by 70 ft long by 13 ft high

Combustion Turbine Features:

Accessory compartment complete with starting motor, motor control center for all base-mounted motors, lubrication system, hydraulic control system, atomizing air system, and cooling water system.

Excitation compartment complete with static excitation equipment.

Switchgear compartment complete with generator breaker, potential transformers, disconnect link for auxiliary feeder, and a customer power takeoff.

Fuel system capable of utilizing natural gas, mixed gas fuel, or liquid fuel.

Fire protection system (low-pressure CO_2).

NO_x Control system utilizing water injection.

The inlet air filter is a high-efficiency glass fiber-type suitable for removing particulates from the inlet air. The use of an evaporative cooler has not been anticipated but a cooler could be added later if further study justifies the expenditure.

The fuel system includes the gas compressor (Table 2.2), the fuel oil forwarding skid and the fuel gas metering equipment. The combustion turbine is furnished with one liquid and one gas fuel nozzle in each of the ten annular combustors. Liquid fuel is pumped from the fuel forwarding skid to the combustion turbine, where a high-pressure pump forwards the fuel to the fuel nozzles. Gaseous fuel must be furnished to the combustion turbine at about 250 psig. Since only one gas fuel nozzle is furnished in each combustor, this requires that the heating value of the gas fuel be fairly constant (±10 percent).

TABLE 2.2. Gas Compressor Design Parameters

Type:	Barrel-type multistage centrifugal compressor complete with motor and gearing, frame mounted as a complete unit	
Number Required:	2-100 percent capacity	
Performance:	Capacity (each compressor) Inlet Pressure Discharge Pressure Service	30,000 SCFM 175[a] psig at 90°F 275 psig at 163°F Natural Gas
Compressor Features:	1,200 BHP 2-Stage Lube and seal oil system Tilting pad type journal bearings Kingsbury-type thrust bearing Balance piston Steel case Interstage seals and shaft end seals	
Motor:	4-kV, 3-phase, 60-hz, 1,500-HP rating	

(a) Assumed prevailing gas mains pressure.

The water injection system is used to limit the emissions of oxides of nitrogen (NO_x). Water is pumped from the demineralized water storage tank and injected directly into the combustors. This limits the peak flame temperature which in turn limits the formation of thermal NO_x. The injection rate is a function of load, ambient temperature, and the type of fuel. Typical water injection rates at base load are about 50 gpm for gas fuel and 75 gpm for oil per engine. Demineralized water is required to limit formation of deposits on the turbine blades.

Other miscellaneous systems furnished with the combustion turbine include: the starting package complete with electric motor and torque converter; a lube oil system for bearing lubrication; a cooling water system for cooling the lube oil system; a CO_2 system for fire protection and generator purge; and a controls system for controlling the entire gas turbine generator package.

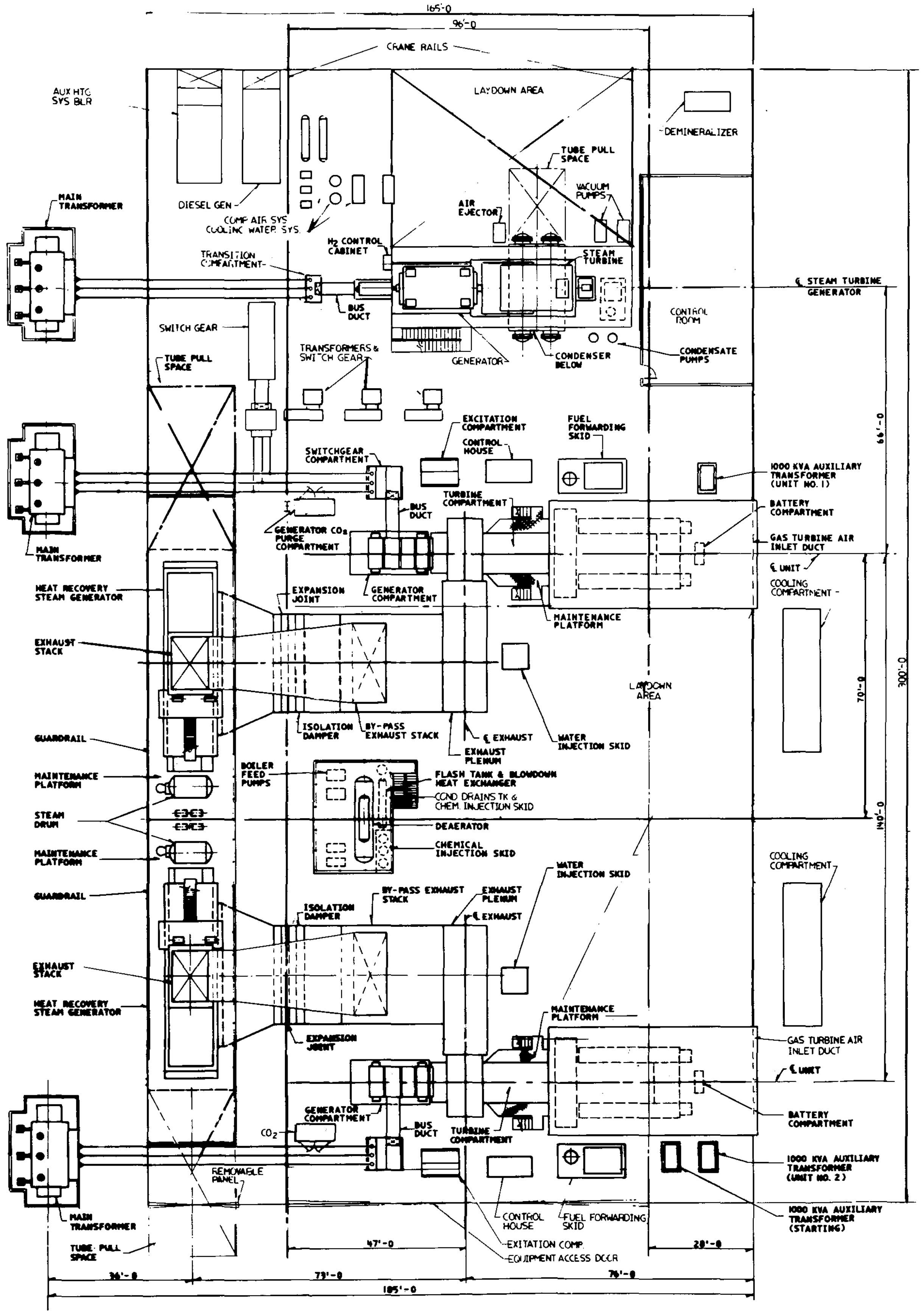
The combustion turbines are normally operated from a central control room, but controls provided with the unit allow either local or remote unattended operation. Operation of the combustion turbines is essentially an automated process, but operator presence is required to achieve proper coordination with boiler control functions. Under normal conditions, all combustion turbines are in operation at their base load rating.

The combustion turbines will be housed in a common building with the heat recovery steam generators and steam turbine to facilitate plant arrangement. The building will be 185 feet wide by 300 feet long and 90 feet high. The building will be of steel construction with aluminum sandwiched insulation siding, and will be served by an overhead crane. See Figure 2.2 for the plant arrangement.

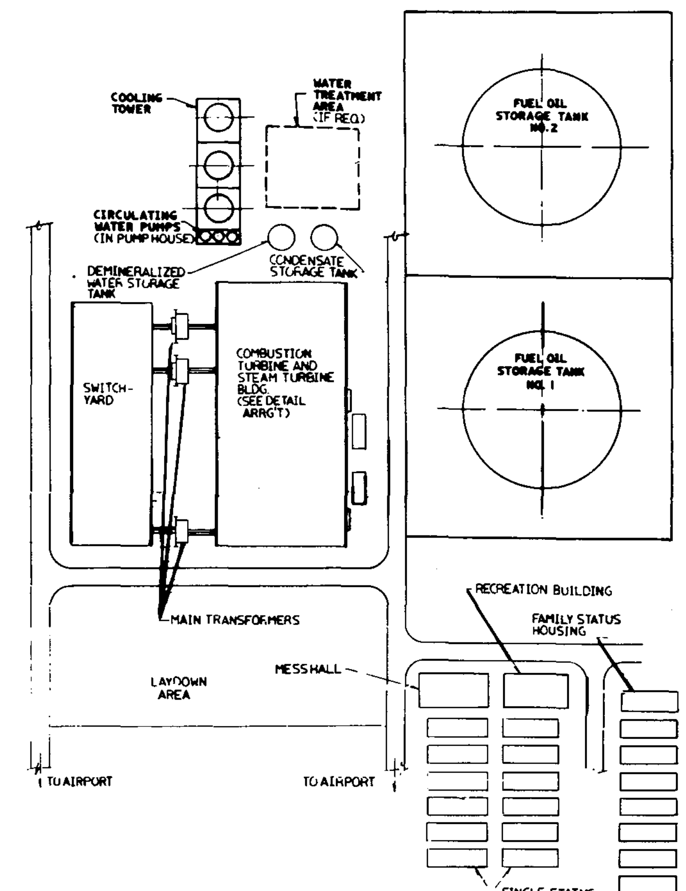
2.1.2 Steam Plant

The heat recovery steam generators are considered part of the steam plant, although physically the steam generators will be housed with the gas turbines in a common building.

The heat recovery steam generator package includes the steam generator complete with ductwork from the combustion turbine to the steam generator, a



CMBUSTION TURBINE & STEAM TURBINE ARRANGEMENT



PLOT PLAN

FIGURE 2.2. Plant Arrangement and Plot Plan

bypass damper and bypass stack, and a steam generator exhaust stack. The heat recovery steam generators are a dual-pressure design with a main steam outlet pressure of 850 psig at 900°F, and low-pressure outlet of 50 psig saturated steam. Each steam generator is designed to produce one-half of the plant's normal flow for steam, with a feedwater heater inlet temperature of 125°F. The heat recovery steam generators are designed for continuous operation. All steam generator controls will be located in a common area in the central control room.

During start-up and other load conditions, the bypass damper may be operated to provide operational flexibility. By closing the bypass damper, the combustion turbine exhaust is routed to the stack and does not reach the steam generator. Design parameters for the heat recovery steam generators are shown in Table 2.3.

The main steam produced in the heat recovery steam generators is conveyed to a common turbine generator set rated at a nominal 59,000 kW. The turbine generator will be a direct-connected multivalve, multistage condensing unit, mounted on a pedestal with a bottom exhaust for mounting the condenser under the turbine. The generator is designed for maximum capability of the turbine with a power factor of 0.9. Design parameters for the turbine generator are shown in Table 2.4. The turbine generator set will be furnished complete with lube oil and electrohydraulic control systems as well as the gland seal system, and the generator cooling and sealing equipment.

The turbine generator will be located on a pedestal at one end of the common combustion turbine and steam generator building. In addition to the combustion generators, steam generators, steam turbine and condenser, the building will contain the feedwater pumps, condensate pumps, vacuum pumps, deaerator, instrument and service air compressors, motor control centers, control room, house boiler and diesel generator (see Figure 2.2). The house boiler will be sized to provide building heating and freeze protection during periods of unfired steam generator shut down. The diesel generator will be sized for black start-up service.

The demineralizer will be used to supply both steam cycle make-up and turbine injection water for NO_x control. The demineralizer will be a

TABLE 2.3. Heat Recovery Steam Generator Design Parameters (two required)

Type: Watertube, forced circulation (General Electric) or two drum natural circulation (Deltak or Henry Vogt), dual pressure.

Performance: (Each Steam Generator)

Main Steam	
Outlet Condition	850 psig, 900°F
Quantity	236,200 lb/hr
Heating Steam	
Outlet Condition	50 psig, saturated
Quantity	80,000 lb/hr

Steam production under normal operation shall be achieved with an exhaust gas flow through the boiler of 2,149,200 lb/hr at 985°F. Feedwater will be supplied to the unit at 125°F to the feedwater heater. Low-pressure heating steam feedwater will be supplied to the unit at 125°F.

Heat Recovery Steam Generator Features:

H.P. Feedwater Heater
H.P. Economizer
H.P. Evaporator Section with Steam Drum
H.P. Superheater Section
L.P. Economizer
L.P. Evaporator Section with Steam Drum
Exhaust Gas Bypass Damper with Separate Stack

two-train unit, 150 gpm net output, and will be furnished complete with a 150,000-gallon demineralized water storage tank (see Table 2.5).

Heat is rejected from the steam turbine cycle at the condenser where circulating cooling water flowing through the condenser tubes absorbs heat from the exhaust steam. The cooling water discharged from the condenser is circulated through the cooling tower where the heat is dissipated to the atmosphere. The cooled cooling water is pumped back to the condenser forming the circulating cooling water cycle. A branch from the cooling water loop is used to dissipate the heat from the combustion turbine generators, steam turbine

TABLE 2.4. Steam Turbine Generator Unit Design Parameters (one required)

Turbine Type:	Multistage, straight condensing, bottom exhaust
Generator Type:	Hydrogen-cooled unit rated 59 MW at 13.8 kV 0.9 pf with 30 psig hydrogen pressure at 10°C
Performance:	Base Rating — 59 MW Steam Inlet Pressure — 850 psig Steam Inlet Temperature — 900°F Exhaust Pressure — 2 to 4" Hg Exhaust Temperature — 92°F Speed — 3600 rpm
Steam Turbine Generator Features:	Common base-mounted with direct-drive couplings. Accessories include multiple inlet control valves, electric hydraulic control system, lube oil system with all pumps and heat exchangers for cooling water hook-up, gland steam system and generator cooling. Excitation compartment complete with static excitation equipment. Switch-gear compartment complete with generator breaker potential transformers.

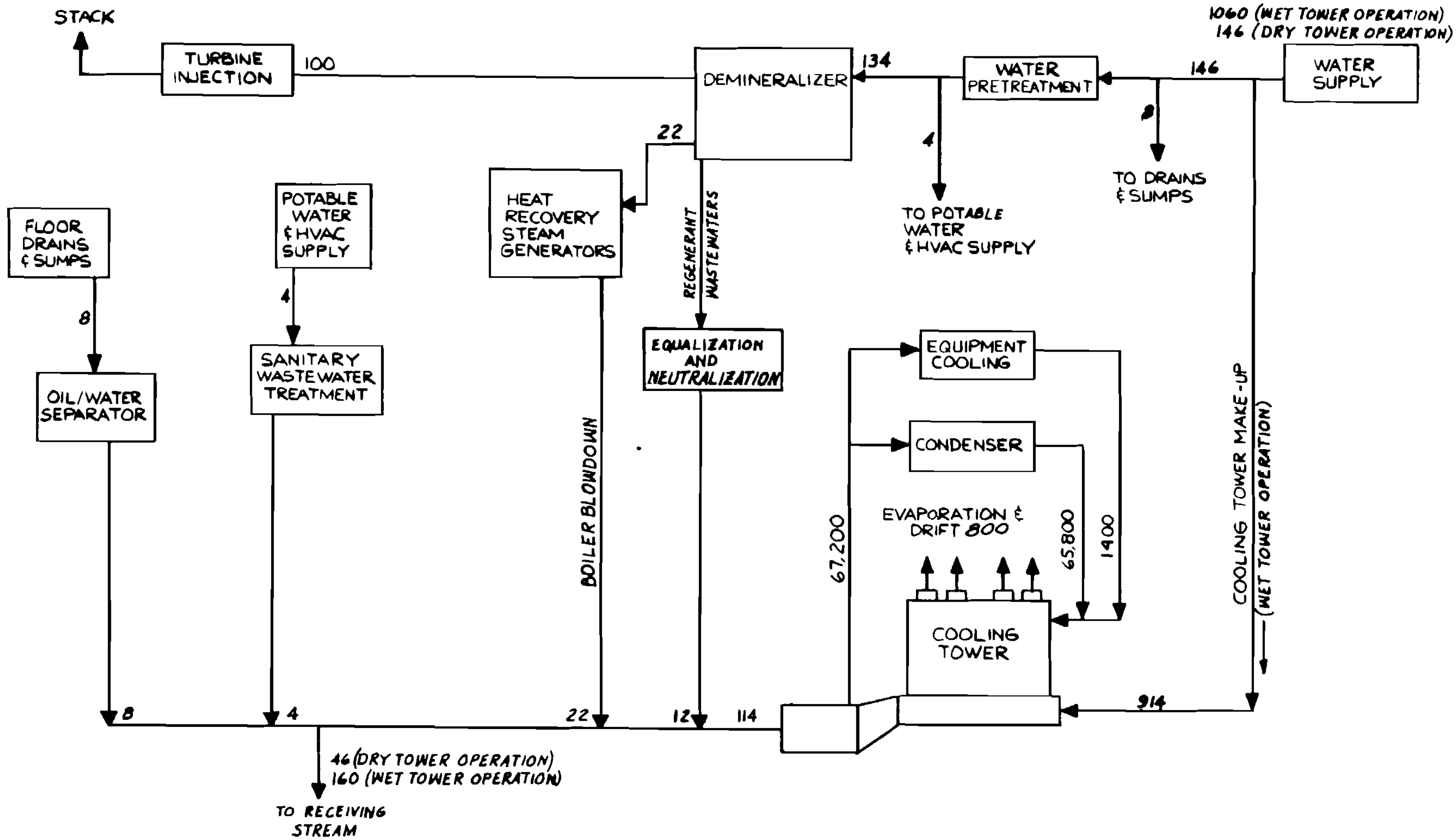
generator, air compressors, and other miscellaneous equipment heat exchangers in a similar manner (Figure 2.3).

The condenser design will be single shell, two pass, with a divided water box and hotwell. The hotwell will be designed to have sufficient storage to allow proper level control for surging and shall be properly baffled to keep the condensate at saturation temperature. Tube sheets should be Muntz metal, with inhibited Admiralty tubes except for 70-30 copper nickel tubes in air removal sections and impingement areas. The condenser design data is listed in Table 2.6.

The cooling tower will be the wet-dry-type mechanical draft design of material most suitable for the cold weather conditions found in the Beluga area of Alaska (see Table 2.7).

TABLE 2.5. Demineralizer System Design Parameters

Demineralizer		
Type:	Two single-train systems, each with cation, and anion, exchanger vessels	
Capacity:	75 gpm each train, including regeneration time	
Effluent Conditions:	pH at 77°F	7 ± 0.05
	Total dissolved solids	5 ppm
	Total metals	0.5 ppm
Demineralized Water Storage Tank		
Type:	Carbon steel, fixed dome roof, internal epoxy lining, steam heating coils, suitable insulation.	
Nominal capacity:	150,000 gal	
Acid Supply Tank		
Capacity:	Suitable for 40 regenerations between fill-up	
Material of Construction:	Carbon steel	
Caustic Tank		
Capacity:	Suitable for 40 regenerations between fill-up	
Material of Construction:	Carbon steel	
Recirculation and Booster Pumps		
Type:	Horizontal centrifugal, end suction, cast stainless casing.	
Capacity:	150 gpm at 150 TDH	



NOTES:
1. ALL FLOWS ARE EXPRESSED IN GALLONS PER MINUTE (GPM).
2. FLOWS ARE DAILY AVERAGES AT 100% CAPACITY FACTOR.

FIGURE 2.3. Plant Water Balance

TABLE 2.6. Condenser Design Parameters (one required)

Condenser Type: Single shell - 2 pass

Performance:	Heat Load	491×10^6 Btu/hr
	Saturation Temperature	92°F (1.5" Hg)
	Inlet Water Temperature	72°F
	Outlet Water Temperature	87°F
	Terminal Temperature Difference	5°F
	Cooling Water Flow	65,800 gpm

Features: Single shell, 2 pass - 1" - 18 BWG Admiralty Tubes

Divided water box and hotwell

TABLE 2.7. Wet-Dry Cooling Tower Design Parameters (one required)

Cooling Tower Type: Parallel Path Wet-Dry

Performance:	Heat Load	501×10^6 Btu/hr
	Cooling Water Flow	67,200 GPM
	Inlet Water Temperature	87°F
	Outlet Water Temperature	72°F

Design Basis - 15°F approach to 10 percent of the time wet bulb temperature of 57°F at Anchorage. Design coldest dry bulb 97.5 percent of time is -20°F at Anchorage.

Features: One fan required for each cell. Integral air cooled heat exchanger sections for "dry" cold weather use.

Three 50 percent capacity vertical pit-type circulating water pumps will be mounted in an enclosure at the cooling tower basin. The pumps will be mounted 4 feet above the water level and have self-lubricating, cutless rubber design shaft bearings (see Table 2.8).

TABLE 2.8. Pump Design Parameters

HP Boiler Feed Pumps:		(3) 50 percent pumps required	
Type:		Horizontal split-case, multistage, double-suction, frame-mounted complete with electric motor drive and lube oil system.	
Performance:	(Each Pump)	Capacity	480 GPM
		TDH	2615 ft at 250°F
		NPSH	20 to 24 ft
Cooling Water Circulating Pumps:		(3) 50 percent pumps required	
Type:		Vertical shaft pit pumps with submerged suction, discharge column complete with vertical-mounted electric motor.	
Performance:	(Each Pump)	Capacity	22,500 GPM
		TDH	45 ft
		Water Temperature	40 to 80°F
		Submerged Suction	
LP Heating Steam Boiler Feed Pumps:		(3) 50 percent pumps required	
Type:		Horizontal, single-stage centrifugal, double-suction frame-mounted complete with motor drive	
Performance:	(Each Pump)	Capacity	160 GPM
		TDH	250 ft
		Water Temperature	250°F
		NPSH	10 to 12 ft

Design parameters and other pertinent data on some of the major equipment previously referred to and other required equipment that has not been previously addressed is provided in Tables 2.2, 2.9, and 2.10.

TABLE 2.9. Miscellaneous Equipment Design Parameters

Air Compressors:	Two required
Type:	Reciprocating, single-cylinder, oil-free, water-cooled, frame-mounted with motor.
Performance:	50 ACFM each 115 psig discharge pressure
Diesel Generator:	One required
Type:	Air-start, skid-mounted, multicylinder diesel complete with 1-1/2 MW generator, 0.8 pf
Heating Steam Boiler:	One required
Type:	Drum-type, water-tube
Performance:	40,000 lb/hr 50 psig saturated
Condensate Pumps:	(3) 50 percent pumps required
Type:	Vertical-shaft single-stage centrifugal, complete with vertical-mounted motor.
Performance:	Vacuum suction, low NPSH, 480 GPM each pump, 150 ft TDH at 120°F

2.1.3 Electric Plant

Generating Systems

Two types of prime movers are utilized for electrical generation, as shown in Figure 2.4: two gas fired combustion turbines with generators rated at 74.5 MW and one steam turbine generation unit rated at 59 MW. Each gas turbine will deliver approximately 80 MVA to the switchyard. The steam turbine will add 50 MVA, resulting in a total of 210 MVA delivered to the switchyard.

TABLE 2.10. Fuel Oil and Condensate Tank Design Parameters

Fuel Oil Tanks:	Two required
Type:	Floating Roof per API 650
Size:	89,580 BBL per API standard 12C 5-96" courses, 120 ft diameter x 40 ft high (approximately 11 days supply)
Service:	Distillate fuel, specific gravity of 0.82 to 0.86
Features:	Stairway, platform, floating-roof, seal-fixed roof supports
Condensate Tank:	One required
Type:	Fixed Roof - carbon steel
Size:	150,000 gals (approx 5 days supply)
Service:	Condensate storage
Features:	Steam heating coils, suitable insulation, plastic lined
Deaerator and Storage Tank:	One required
Type:	Integral connected unit with deaerator mounted on top of 5-minute storage tank. Stainless steel troughs and baffle plates.
Size:	39,370 lb storage
Water Flow Out:	472,400 lb/hr
Steam Flow In:	50 psig
Design Pressure:	60 psig
Operating Pressure:	25 psia

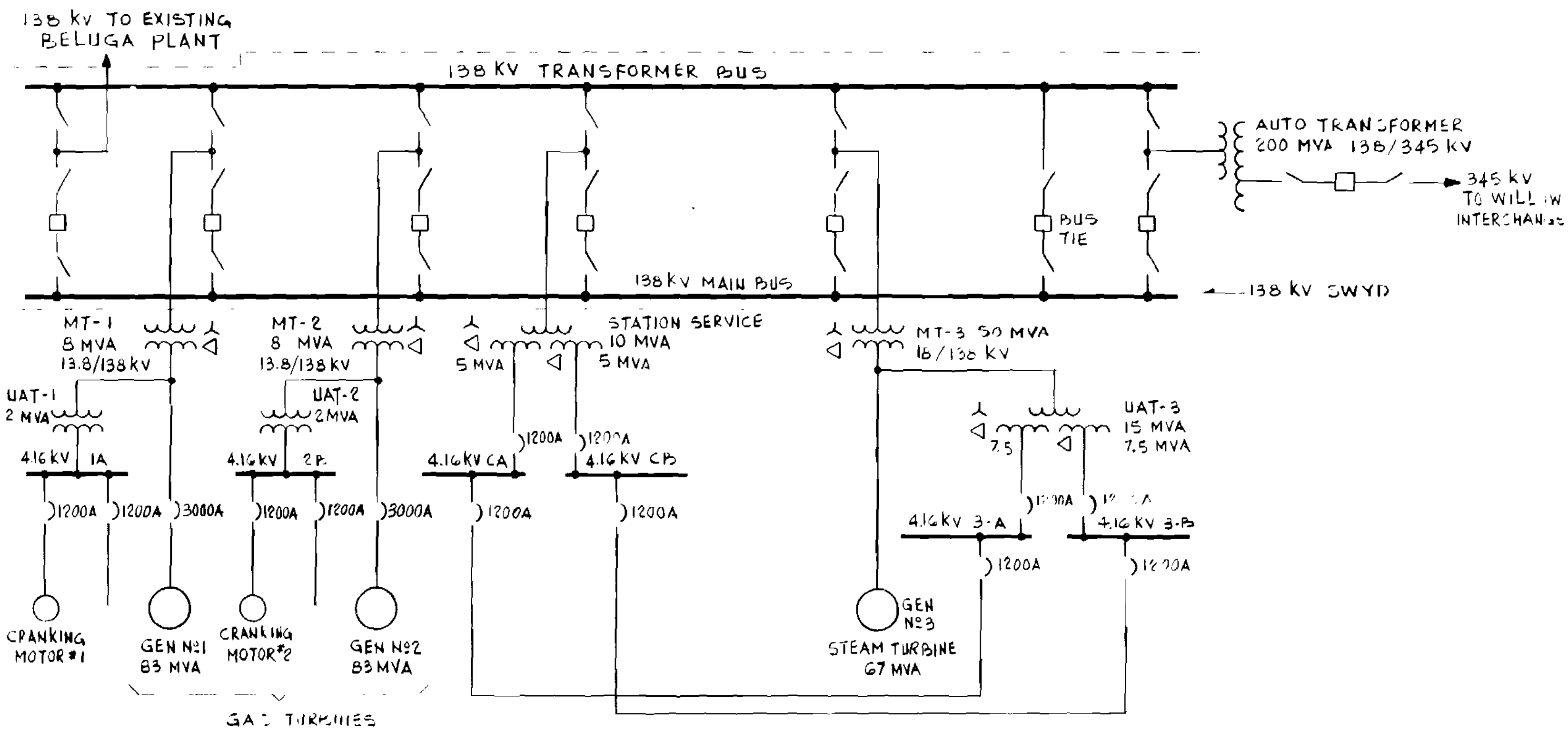


FIGURE 2.4. One-Line Diagram

Gas Turbine Generators. These are "packaged" units and as such include all equipment required to support the turbine generator. The generators are nominally rated at 74.5 MW, 0.9 PF, 83 MVA, with generation voltage at 13.8 kV.

The package generally includes:

1. 13.8-kV switchgear that houses the generator grounding transformer, and generator air circuit breaker.

2. Nonsegregated phase bus duct runs to the generator and main transformer.

3. A master control panel for overall operation and monitoring.

4. A unit auxiliary transformer 13.8/4.16 kV sized to support the ancillary load (assumed to be 2 MVA).

5. A 4.16-kV switchgear with air circuit breakers for other loads (e.g., 800-hp cranking motor). The largest load (gas compressor) is fed from the plant common 4.16-kV switchgear.

The step-up transformers for each gas turbine are rated 80 MVA, 13.8/138 kV.

Steam Turbine Generator. The generator is rated 59 MW, 0.9 P.F., 67 MVA, with generation voltage at 18 kV. The unit auxiliary transformer is a three-winding 15 MVA, 18-4.16/4.16 kV. The two secondary windings supply 4.16-kV busses 3A and 3B. The step-up transformer is rated 50 MVA, 18/138 kV.

Station Service Transformer

This transformer is used to supply power for the steam turbine generator auxiliaries required for startup. It is a three-winding, 10-MVA, 138-4.16/4.16-kV transformer. The two secondary windings feed 4.16-kV common switchgear busses CA and CB.

Switchyard

The switchyard is basically 138 kV consisting of seven bays, shown in Figure 2.5. One parameter for selecting this voltage was the inclusion of a tie line to the existing Beluga Combustion Turbine Plant that presently has a 138-kV tie line to Anchorage.

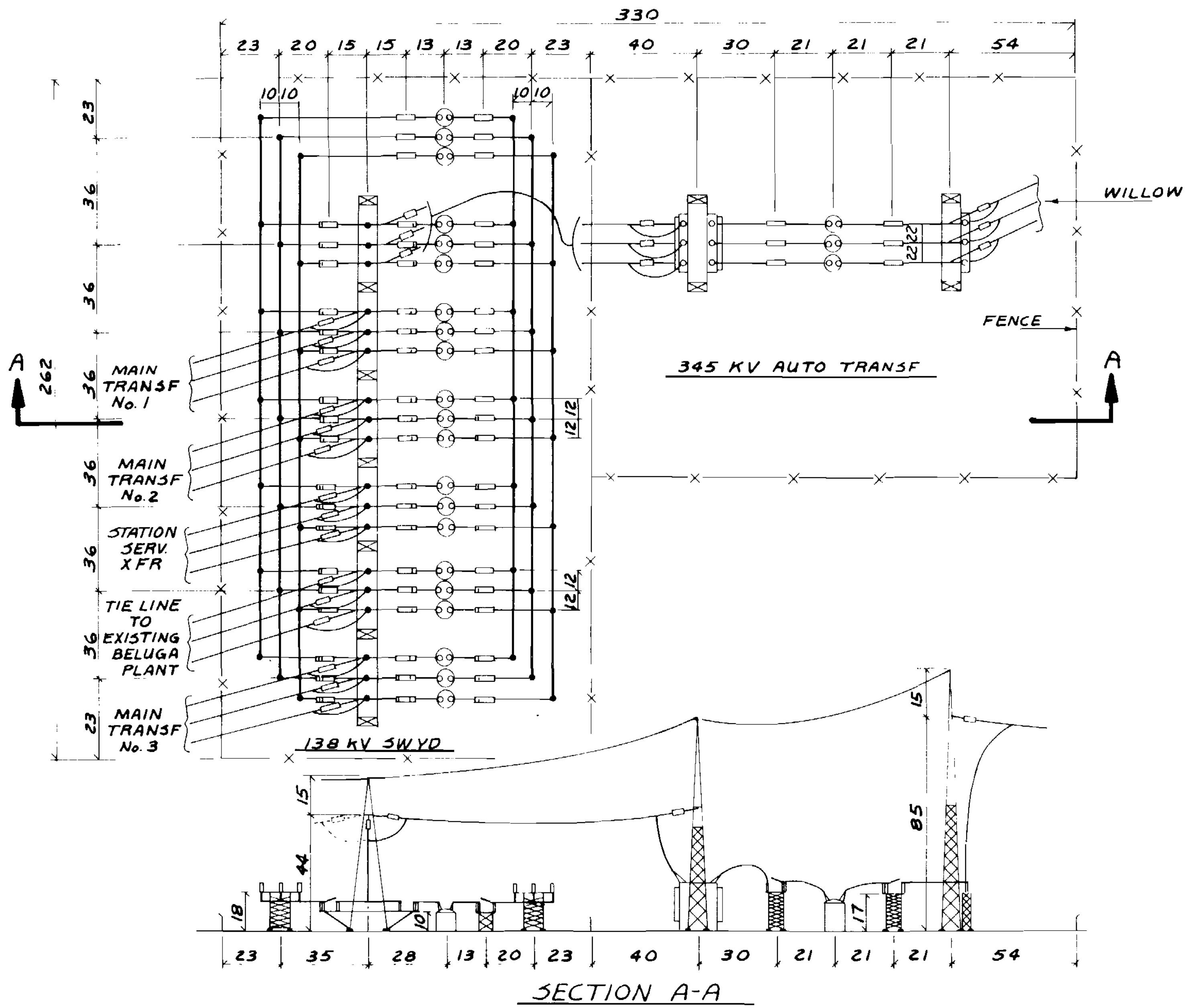


FIGURE 2.5. Beluga Area Station Switchyard

Basically, the switchyard is a two bus arrangement with a main and a transfer bus. Each bay has a 138-kV circuit breaker, three disconnect switches and a 138-kV tower. The bus tie bay has a 138-kV circuit breaker and two disconnect switches.

The transmission voltage is 345 kV for export of approximately 200 MVA. An autotransformer, 345-kV circuit breaker and two disconnect switches comprise this portion.

2.2 FUEL SUPPLY

The plant described in this report would be located in the Beluga area, northwest of Cook Inlet. Although a precise location is not specified, the plant would presumably draw upon natural gas supplied from the Beluga River Field, possibly supplemented by the nearby Lewis River and Ivan River Fields (Figure 1.1). The existing Beluga Station (Units 1-8) of the Chugach Electric Association is located at and supplied from the Beluga River Field.

The plant described in this report would require approximately 306 Bcf of natural gas if operated at maximum availability (86 percent) over its anticipated 25-year life. Although operation of maximum availability over the lifetime of the plant is unlikely, partial load operation would result in a higher heat rate, compensating for reductions in gas consumption attributable to operation at lower capacity factor than availability.

The 1980 recoverable natural gas reserves of the Beluga River Field are estimated to be 767 Bcf (Secrest and Swift 1982). Of these, 310 Bcf is committed to Chugach Electric Association and 624 Bcf to Pacific Alaska LNG Association, resulting in a 167 Bcf overcommitment of recoverable reserves. Two currently untapped smaller fields, the Ivan River Field and the Lewis River Field, lie in fairly close proximity to the Beluga River Field. The recoverable reserves of these fields are estimated to be 26 and 90 Bcf, respectively. Both are currently overcommitted to Pacific Alaska LNG, the Ivan River Field at 106 Bcf and the Lewis River Field at 99 Bcf.

Under the conservative assumption that the units of the existing Beluga Station are operated at maximum availability[a] for their remaining economic life, Chugach will require 396 Bcf of natural gas for continued operation beyond 1980 (Table 2.11).

Under these assumptions, sufficient gas for continued operation of the existing Beluga Station units for their remaining life does not appear to exist unless: 1) Pacific Alaska LNG commitments are released, or 2) the existence of additional recoverable reserves is established.

If, as thought probable, the Pacific Alaska LNG commitments are released, sufficient currently recoverable reserves would be available to support not only continued operation of the existing Beluga Station throughout its anticipated life, but also to support additional natural gas-fired generating units. Using recoverable reserves of the Beluga Field only, the surplus of 371 Bcf over that required to support continued operation of the existing Beluga Station would easily support the proposed plant. Development of the Ivan River and Lewis River Fields would provide an additional 116 Bcf of recoverable reserves for a total surplus beyond the needs of the existing Beluga Station of 487 Bcf, sufficient gas for approximately 300 MW of installed combined-cycle capacity.

In conclusion, this analysis suggests that with relinquishment of Pacific Alaska LNG commitments, ample gas is available from the Beluga Field alone to support the 200-MW combined-cycle plant of the capacity described in this report. Development of the Ivan River and Lewis River Fields would provide sufficient gas to support over 300 MW of baseloaded combined-cycle capacity. Without relinquishment of the Pacific Alaska LNG commitments, recoverable reserves from the Beluga Area Fields are insufficient to support operation of the plant described in this report.

(a) Except Unit 4, which is assumed to operate as a peaking unit at 10 percent capacity factor.

TABLE 2.11. Estimated Natural Gas Requirements: Chugach Beluga Station

Unit	Rated[a] Capacity (MW)	In-Service[a] Year	Estimated[a] Retirement	Remaining[b] Plant Life (Years)	Typical[a,c] Load Operation	Typical[a,c] Annual Capacity Factor (%)	Heat Rate[a,c] (Btu/kWh)	Estimated Natural Gas Requirements (Bcf)
1	14	1968	1988	8	Baseload	81	15,000	11.9
2	14	1968	1988	8	Baseload	81	15,000	11.9
3	51	1973	1993	13	Baseload	81	10,000	47.0
4	9.3	1976	1996	16	Cycling	10	15,000	2.0
5	60.0	1975	1995	15	Baseload	81	10,000	63.9
6	62.0	1976	2007[d]	27[d]	Baseload	81		
7	62.0	1979	2007[d]	27[d]	Baseload	81	8,760	259[e]
8	54	1982	2007	25	Baseload	81		
							TOTAL	396

(a) From Battelle 1982.
(b) Beyond 1980.
(c) Unit 4 is assumed to operate as a peaking unit, and Units 7 and 8 assumed to operate in conjunction with Unit 6.
(d) Units 6 and 7 are combustion turbines operating with Unit 8, a heat recovery steam generator and turbine. The operating life of Units 7 and 8 is assumed to extend until the end of life for Unit 8.
(e) Assumes that Units 6 and 7 operate at 81 percent capacity at 15,000 Btu/kWh prior to 1982.

2.3 TRANSMISSION SYSTEM

To transmit the 200 MW generated by this combined-cycle plant, preliminary calculations were made for a 75-mile, 345-kV transmission line from the Beluga area to Willow. The following assumptions were made for this preliminary estimation:

- This line was considered independent of the existing network.
- The line goes from Beluga to Willow, where the proposed Anchorage-Fairbanks intertie, which has sufficient capacity, will absorb the total generated power.
- The existing system at Willow will be a 345-kV system as recommended by Commonwealth Associates, Inc. (1981).

Three voltage levels were studied: 138 kV, 220 kV and 345 kV. A 138-kV voltage is too low to transmit the plant's power output the required distance; the surge impedance loading for this line would only be around 50 MW.

A 230-kV voltage line has a surge impedance loading of 135 MW. This type of line with VAR compensation and adequate conductor size could adequately transmit the plant output.

A 345-kV voltage line has a surge impedance loading of 300 MW. This line may need line reactors for open line and reclosing conditions. A double-circuit 230-kV transmission line may also be an attractive alternative. Initial investment may be higher than the 345 kV alternative because 230-345 kV transformation at Willow has to be built and transmission towers for a double-circuit 230 kV may be heavier than the 345-kV towers. However, I_2R losses may be lower. The results obtained from the preliminary study of these three alternatives are as follows:

Line Voltage (kV)	No. of Circuits	Type of Conductor	Size of Conductor (MCM)	Regulation	Losses I_2R (MW)	Reactive Support
230	1	ACSR	636	11.9 percent	14.5	Capacitors
345	1	ACSR	795	3.5 percent	4.5	Reactors
230[a]	2	ACSR	636	--	3.8	

(a) Estimated values.

From these preliminary calculations a 345-kV ACSR, single-circuit, 795 MCM is recommended. However, additional studies will have to be done to fully justify these parameters.

From an electrical point of view, interconnections with the transmission system may substantially modify the results. This line should not be studied independently (a complete system study is recommended). Capital investment and line losses of alternative line configurations will have to be fully evaluated.

The lowest initial investment will be the single-circuit 230-kV line, but excessive losses appear to negate this alternative. Differential losses of 10 MW between the 345-kV and 230-kV alternates may result in $2,000,000 per year, for a load factor of 80 percent and a cost of 3 cents a kWh for energy. The 345 kV will have the advantage of uniform voltages with the system recommended by Commonwealth Associates, Inc. (1981).

To incorporate the proposed combined-cycle plant output, a 345-kV substation at or near Willow (or some other convenient place) appears desirable and should have a configuration as depicted in Figure 2.6. The 345-kV lines to Anchorage, Beluga and Nenana would terminate here. This substation will provide flexibility and reliability to the system load flow.

Connecting this combined-cycle plant into the system at Willow avoids the underwater crossing of Knik Arm currently in use from the Chugach Beluga Station to Anchorage.

2.4 SITE SERVICES

The construction and operation of a 200-MW combined-cycle power plant will require a number of related services to support all work activities at the site. These site services could include the following depending upon the actual location of the power plant:

- access roads
- construction water supply
- construction transmission lines
- airstrip
- landing facility
- construction camp.

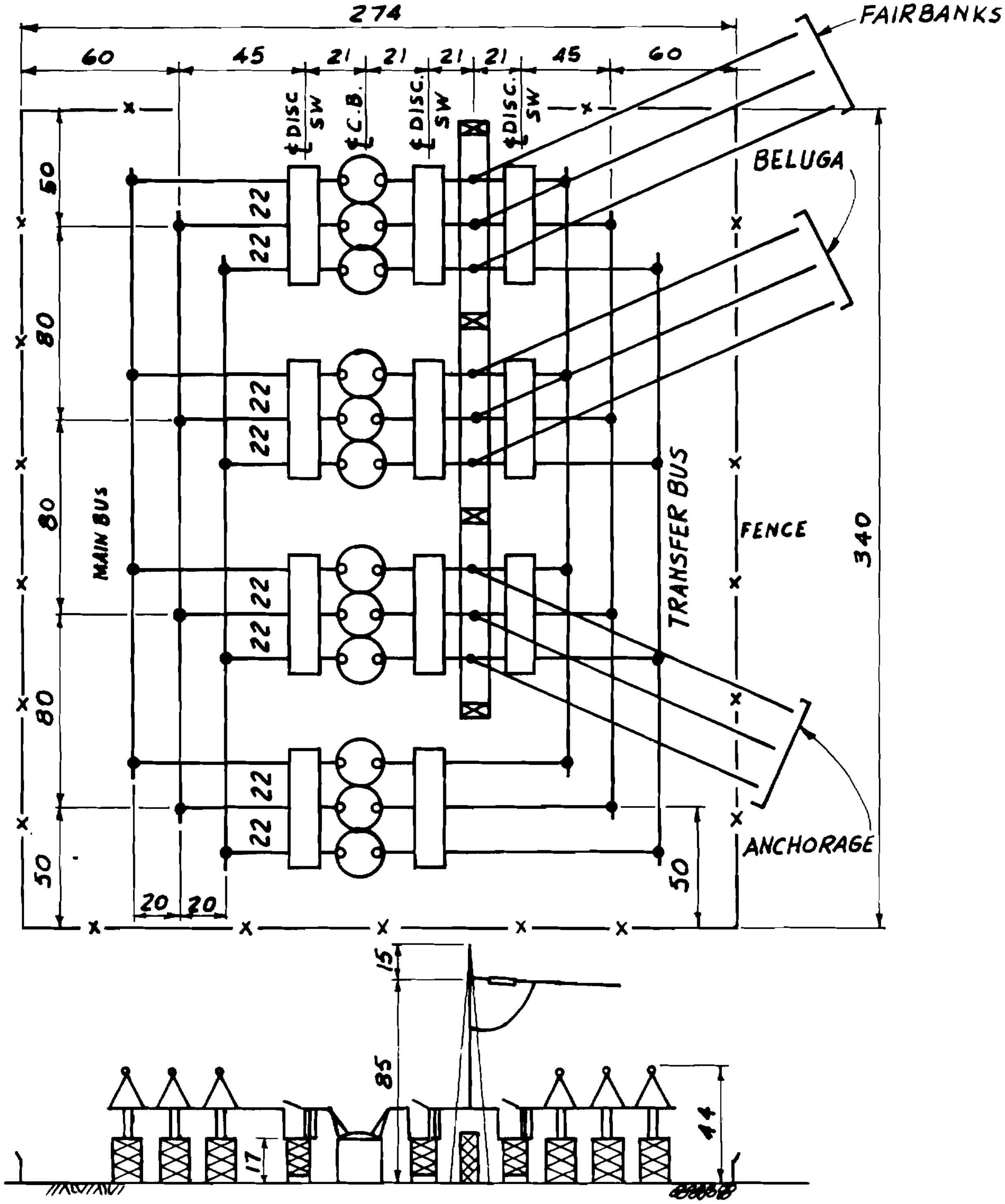


FIGURE 2.6. Willow Substation

2.4.1 Access Roads

Gravel roads with a 9-inch gravel base will be required to connect the plant site with the equipment landing facility in the Beluga area. To the extent possible, existing roads will be used. Hence, no more than 5 miles of new road construction is anticipated.

2.4.2 Construction Water Supply

A complete water supply, storage and distribution system will be installed. Due to the remote nature of a Beluga area site, a one million gallon water storage tank has been assumed with one-half of this storage capacity dedicated to fire protection purposes. Construction water supply to the project site should be at least 150 gpm.

2.4.3 Construction Transmission Lines

Power requirements during the construction phase will be supplied by constructing a 25-kV transmission line tapped from an existing transmission system. For a potential Beluga site, a transmission line length of 20 miles is assumed and will be derived from the existing Chugach Electric Association system at either the town of Beluga or Tyonek.

2.4.4 Airstrip

For the general power plant location, the existing airstrip will be used. It is anticipated that all personnel travel will be by air with prearranged commercial charter carriers. All perishable goods will be flown in. Equipment for construction will be flown in only under extraordinary circumstances. The largest airplane that will be able to land on the strip will be the size of a DC-3.

The airstrip will be lighted using an above-ground distribution system to provide for the possibility of night-time medical emergency traffic. A control tower will not be required. All air traffic will be on a Visual Flight Rule (VFR) basis only.

2.4.5 Landing Facility

The site will use the existing marine landing facility to receive all construction materials, equipment and supplies. A paved, fenced interim storage area will be provided. A heavy-duty haulage road will be provided from the landing area to the access road.

2.4.6 Construction Camp Facilities

A 500-bed labor camp will be provided. All personnel housed in this camp will be on single status. Provisions will be made to accommodate a work force containing females (separate bathroom and locker facilities).

The camp will have its own well water supply. A sewage treatment facility, waste incinerator, and garbage compactor will also be provided. The complex will also have a dining hall and recreation hall.

Since it is unlikely that all personnel will be willing to come to the job-site on single status only, a mobile home park will be provided for 16 supervisory personnel in family status. These mobile homes will be approximately 1000 ft^2 each and could remain after completion of construction to house vendor personnel for repair work during plant operation.

2.5 CONSTRUCTION

The number of workers necessary for construction of a 200-MW station will vary over the approximate 32-month construction period. Construction is estimated to peak in year two requiring a work force of approximately 400 personnel. The distribution of this work force over the schedule duration is shown in Figure 2.7.

Construction of this 200-MW station will follow normal acceptable construction methods. A program of this magnitude begins with orderly development of the following requirements:

1. construction camp and utility services, such as electric light and power, water for industrial and potable use and fire protection, sanitary facilities, telephone communications, etc.

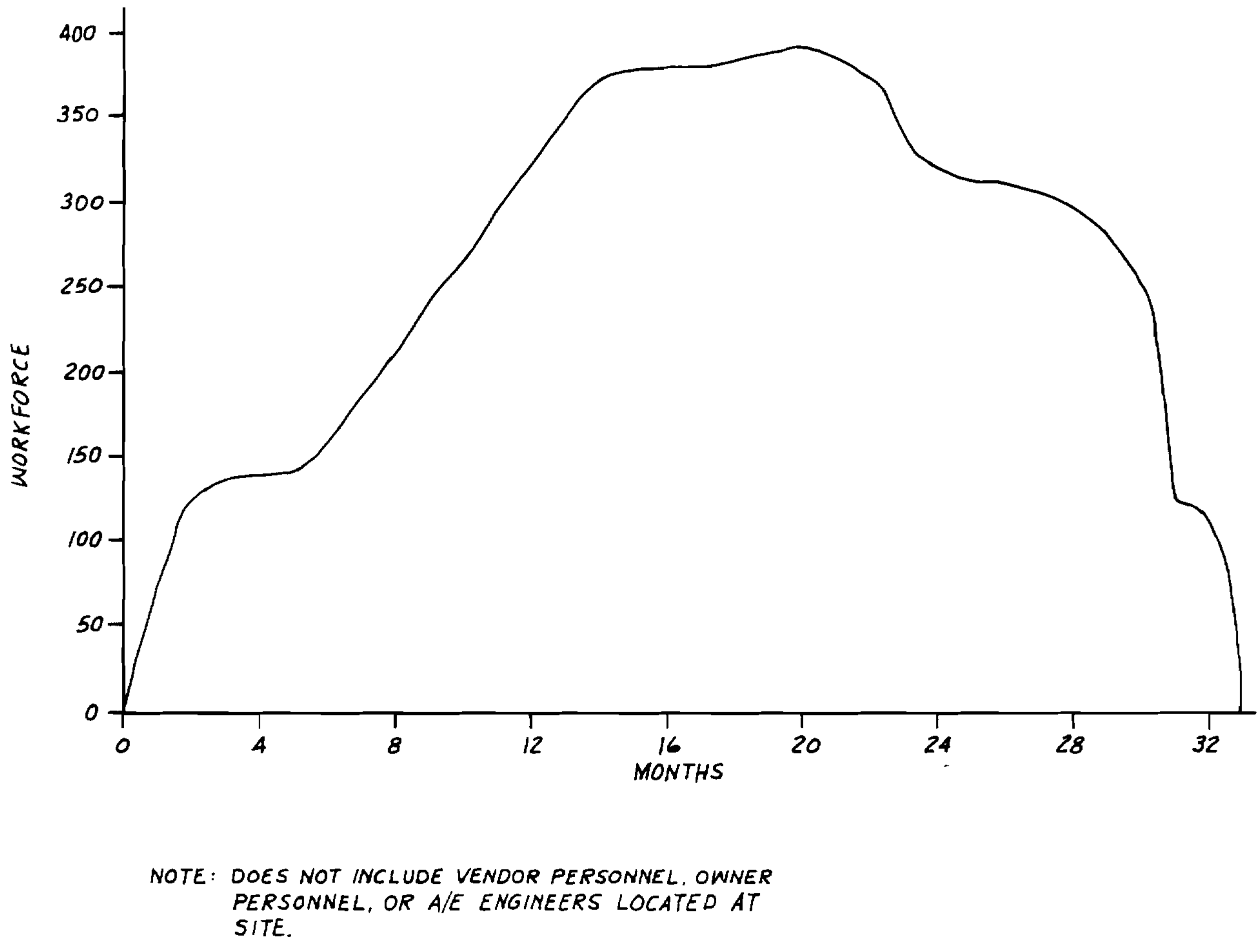


FIGURE 2.7. Construction Work force Requirements

2. temporary construction office facilities (with heating and ventilation furnished by contractors as required)
3. temporary and permanent access roads
4. temporary enclosed and open laydown storage facilities
5. delivery by landing craft of various types of construction equipment and vehicles, such as earth-moving equipment, concrete and materials hauling equipment, cranes, rigging equipment, welding equipment, trucks and other vehicles, tools, and other related types of construction equipment by landing craft
6. temporary office and shop spaces for various subcontractors

7. settling basins to collect construction area storm runoff
8. permanent perimeter fencing and security facilities
9. safety and first aid facilities in strict compliance with OSHA regulations.

Following completion of these site preparation activities, power plant systems construction will be initiated. The activities involved in the over-all construction process as well as the plant's detailed development schedule are presented in Figure 2.8.

2.6 OPERATION AND MAINTENANCE

2.6.1 General Operating Procedures

The plant has been designed for operation as a base loaded plant. Hot starts are accomplished by starting and synchronizing the first gas turbine. The heat recovery steam generator is then loaded and the steam turbine started. After the steam turbine is up to speed, the second gas turbine is started, the second steam generator is loaded and the plant is brought up to load.

Cold starts should be expected to take a minimum of 9 hours. The first gas turbine is started and synchronized with the bypass damper positioned to partially bypass the steam generator. The second gas turbine is started and synchronized in a similar manner. A vacuum is pulled in the condenser using the vacuum pumps and the steam turbine warmed through over the course of several hours in accordance with manufacturer's instructions. The by-pass dampers can be repositioned as required during the start-up period to control steam flow, and opened fully when the steam turbine is loaded.

Plant systems will be operated from the control room located in the main plant building. Some of the systems and equipment will also be controlled from local stations. In general, controls are automatic, although operators can override the automatic controls and operate the plant manually. To supplement the operational controls, the station will be equipped with an

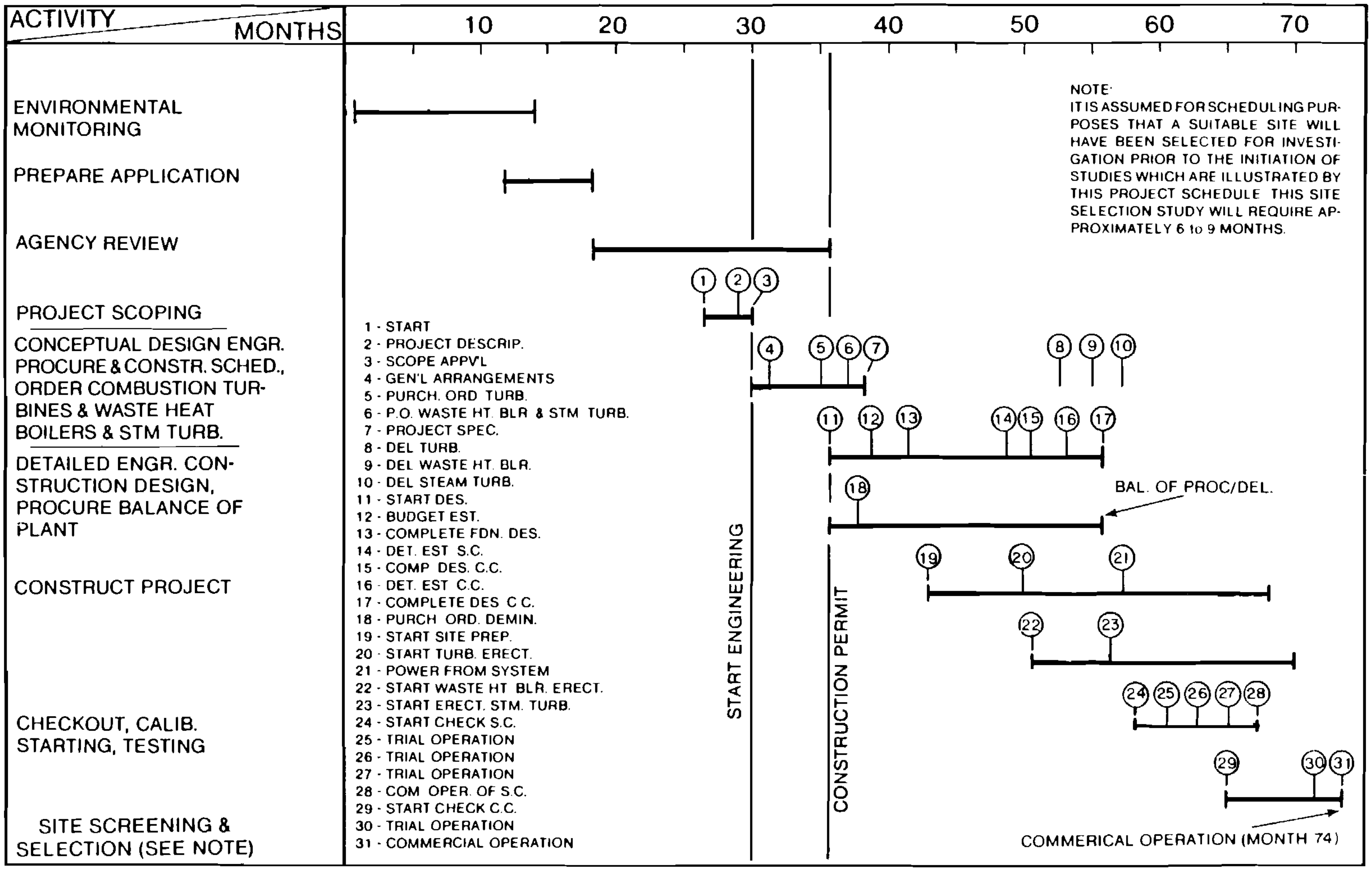


FIGURE 2.8. Project Schedule

alarm system, fire protection system, proper lighting, and a radiotelephone communication system. The diesel generator will be required to provide power for safe shutdown of the unit under trip and black-out conditions.

2.6.2 Operating Parameters

Operating experience on gas-fired combined-cycle plants is somewhat limited when compared to coal or oil-fired power plants. Conclusions on operating parameters are, therefore, based on the available data on gas-fired combined cycle plants supplemented by EPRI data (EPRI 1979) and experience on gas turbines and steam turbines.

It is expected that the forced outage rate will be about 8 percent. Operational experience on some earlier plants indicates higher forced outages in the first few years, but this is attributed to operational adjustments required for a new type of plant, and development of the current gas turbine design. It is expected that a slight increase in forced outages will occur as the plant ages, but the "technology development"-type outages experienced by some of the earlier plants are not anticipated. Variations in plant sizes should not affect the forced outage rate provided that the same "experience factor" is characteristic of the gas turbines used.

Cycling the plant will have a negative affect on all the plant machinery. Stress reversals encountered with peaking operation usually result in a higher forced outage rate.

Combined-cycle plant reliability is very dependent on an adequate preventative maintenance program, and scheduled outrage rates can be expected to be about 7 percent. Again, plant size will not affect the scheduled outage rate but cycling service will necessitate more frequent inspections, which will result in a higher scheduled outage rate.

An equivalent plant availability of approximately 86 percent should be obtained, with the forced and scheduled outage rates of 8 percent and 7 percent, respectively.

The plant heat rate of approximately 8,200 Btu/kWh is not expected to vary significantly with plant size within the range of 100 MW to 400 MW, but should rise slightly as the plant ages. The heat rate will, however, vary considerably with plant loading because as the efficiency of the gas turbines deteriorates rapidly as the load is reduced. At extremely low load conditions, in the 20 to 30 MW range, heat rates as high as 14,000 to 16,000 Btu/kWh should be anticipated. For a combined-cycle plant in load-following service, consideration should be given to using a steam turbine of relatively larger capacity and supplementary firing of the steam generators. Plant output could than be varied by adjusting the steam turbine output with duct burner firing. Duct-burner firing of the steam section will raise the heat rate, but offers a distinct advantage over heat rates obtained with part-load operation of the gas turbines.

2.6.3 Plant Life

The plant should have a 25-year life expectancy, based on the expected life of the gas turbine units. It is expected that the gas turbine units will be partially rebuilt a number of times during the scheduled (and unscheduled) outages.

2.6.4 Operating Work force

The plant will require an operating staff of approximately 43 employees. Of this total, approximately 25 represent operating staff and 18 are maintenance personnel. A list of the plant's staffing requirements is presented in Table 2.12. Employment of these personnel will continue throughout the life of the plant.

2.6.5 General Maintenance Requirements

To prevent mechanical failure, periodic maintenance will be performed on all pressure systems, rotating machinery, heat sensitive equipment, and other operating equipment to prevent malfunctions, leaks, corrosion and other such abnormalities. The periodic maintenance should be performed in accordance with an established maintenance program that will include the complete strip-down and major inspection of the turbines at intervals required or suggested by the equipment manufacturer. In addition, the maintenance programs will monitor the revegetation and erosion prevention programs initiated during the cleanup phase of construction. Trained maintenance crews will perform periodic maintenance and will correct malfunctions. In general, all major maintenance functions will be performed during the plant's annual scheduled outages.

TABLE 2.12. Plant Staffing Requirements

Job Title	200-MW Unit
Plant Superintendent	1
Operations Engineer	1
Shift Superintendent	4
Control Room Operators and Auxiliary Operators	4
Chemist	1
Results Engineer	1
Results Technician	1
Instrumentation and Controls Engineer	1
Instrumentation and Controls Technician	4
Storekeeper	1
Clerical	2
Maintenance Superintendent	1
Maintenance Engineer	1
Electrical/Mechanical Maintenance Foreman	2
Electrical/Mechanical Mechanics (6-Man Crews)	6
Instrumentation and Controls Maintenance Foreman	1
Instrumentation and Controls Mechanics (2-Man Crews)	2
Labor Foreman	1
Labor Crew	4
Fire Protection/Security Staff	4
TOTAL	43

NOTE: The above staffing is required for three 8-hour shifts and seven-days-a-week operation.

3.0 COST ESTIMATES

3.1 CAPITAL COSTS

3.1.1 Construction Costs

Construction costs in January 1982 dollars have been developed for the major bid line items common to natural gas-fired combined-cycle power plants. These line item costs have been broken down into the following categories: labor and insurance, construction supplies, equipment repair labor, equipment rental, and permanent materials. Results of this analysis are presented in Table 3.1. The equivalent unit capital cost of the plant is 1001 $/kW.

3.1.2 Payout Schedule

A payout schedule has been developed for the entire project and is presented in Table 3.2. The payout schedule was based on a 32-month basis from start of construction to project completion.

3.1.3 Capital Cost Escalation

Estimates of real escalation in capital costs for the plant are presented below. These estimates were developed from projected total escalation rates (including inflation) and subtracting a Gross National Product deflator series which is a measure of inflation.

Year	Materials and Equipment (Percent)	Construction Labor (Percent)
1981	1.0	0.5
1982	1.2	1.7
1983	1.2	1.7
1984	0.7	1.3
1985	-0-	-0-
1986	-0.1	-0.1
1987	0.3	0.3
1988	0.8	0.8
1989	1.0	1.0
1990	1.1	1.1
1991	1.6	1.6
1992 - on	2.0	2.0

TABLE 3.1. Bid Line Item Costs for a Natural Gas-Fired Combined-Cycle 200-MW Station[(a)] (January 1982 Dollars)

Bid Line Item	Construction Labor and Insurance	Construction Supplies	Equipment Repair Labor	Equipment Rent	Permanent Materials	Total Direct Cost
1. Improvements to Site	95,600		109,700	83,700	13,800	302,800
2. Earthwork and Piling	313,000	2,666,300	87,300	151,600		3,218,200
3. Circulating Water system	2,455,600	484,400	16,100	28,500	4,400,000	7,384,600
4. Concrete	3,450,700	348,000	372,700	226,600	1,496,000	5,894,000
5. Structural Steel and Lift Equipment	305,000				1,900,000	2,205,000
6. Buildings	192,200				491,000	683,200
7. Heat Recovery Boilers, Gas Turbines, and Generators	5,197,200	172,500		250,000	31,200,000	36,819,700
8. Steam Turbines and Generator	3,631,900	115,000		200,000	8,600,000	12,546,900
9. Other Mechanical Equipment	2,588,700	115,000		65,000	4,946,200	7,714,900
10. Piping	3,164,500	345,000		120,000	4,500,000	8,129,500
11. Insulation and Logging	126,500	86,300		50,000	250,000	512,800
12. Instrumentation	379,500	46,000		10,000	700,000	1,135,500
13. Electrical Equipment	4,586,000	57,500		15,000	5,250,000	9,908,500
14. Painting	632,600	11,500		2,500	500,000	1,146,600
15. Off-Site Facilities	2,451,400	211,100	3,621,100	2,693,600	979,200	9,956,400
16. Waterfront Construction	14,400		31,800	23,700	131,700	201,600
17. Substation	948,800	23,000		10,000	4,035,500	5,017,300
18. Construction Camp Expenses	4,292,400	12,362,000				16,654,400
19. Indirect Construction Costs and Architect/Engineer Services[(b)]	26,341,900	4,313,900	1,301,600	1,588,700		33,546,100
SUBTOTAL	61,167,900	21,357,500	5,540,300	5,518,900	69,393,400	162,978,000
Contractor's Overhead and Profit						15,000,000
Contingencies						22,224,200
TOTAL PROJECT COST						200,202,200

(a) The project cost estimate was developed by S. J. Groves and Sons Company. No allowance has been made for land and land rights, client charges (owner's administration), taxes, interest during construction or transmission costs beyond the substation and switchyard.
(b) Includes $14,816,200 for engineering services and $18,729,900 for other indirect costs including construction equipment and tools, construction related buildings and services, nonmanual staff salaries, and craft payroll related costs.

TABLE 3.2. Payout Schedule for a Natural Gas-Fired Combined-Cycle 200 MW Station (January 1982 Dollars)

Month	Cost per Month (Dollars)	Cumulative Cost (Dollars)
1.	2,155,800	2,155,800
2.	3,159,000	5,314,800
3.	3,159,000	8,473,800
4.	4,054,400	12,528,200
5.	3,904,000	16,432,200
6.	3,904,500	20,336,700
7.	4,840,700	25,177,400
8.	3,988,400	29,165,800
9.	3,814,400	32,980,200
10.	6,045,300	39,025,500
11.	5,730,800	44,756,300
12.	6,761,300	51,517,600
13.	6,761,300	58,278,900
14.	7,817,000	66,095,900
15.	8,869,200	74,965,100
16.	8,869,200	83,834,300
17.	8,869,200	92,703,500
18.	8,869,200	101,572,700
19.	8,869,200	110,441,900
20.	9,166,600	119,608,500
21.	9,166,600	128,775,100
22.	9,166,600	137,941,700
23.	8,237,300	146,179,000
24.	7,499,500	153,678,500
25.	7,499,500	161,178,000
26.	7,499,500	168,677,500
27.	6,738,400	175,415,900
28.	6,738,400	182,154,300
29.	6,248,400	188,402,700
30.	6,174,100	194,576,800
31.	2,885,800	197,462,600
32.	2,739,600	200,202,200

3.1.4 Economics of Scale

For combined-cycle systems, economies of scale can be realized for many site development costs, including temporary facilities, construction equipment, and construction labor. These savings, however, can only be brought about if facility capacity is increased through an increase in component capacity, and not through use of additional power generation units. For example, in the range of considered plant sizes (up to approximately 300 MW), utilization of 100-MW combustion turbines (current maximum unit size) and larger heat recovery boilers would necessitate only a slight increase in the construction work force over that required for smaller unit sizes and could be constructed within the same time frame. This would result in a cost reduction on a per-megawatt basis. If capacity was increased by use of additional power generation units, e.g., three 70-MW combustion turbines as opposed to two 100-MW units, this unit cost reduction would not be realized.

3.1.5 Working Capital

Working capital costs, including a 30-day emergency distillate supply and 30-day O&M cost, are estimated to be 52 $/kW. The cost of the emergency distillate supply was based on a forecasted 1990 price for No. 2 fuel oil at 8.45 $/MM Btu (Battelle 1982).

3.2 OPERATION AND MAINTENANCE COSTS

3.2.1 Operation and Maintenance Costs

The operation and maintenance costs for the 200-MW size plant, expressed in January 1982 dollars, are as follows:

Fixed Costs

Staff (43 Persons)	$1,450,600 (7.25 $/kW/yr)
Variable Costs	1.54 mills/kWh
Consumables	0.15 mills/kWh

3.2.2 Escalation

Estimated real escalation of fixed and variable operation and maintenance costs are as follows:

Year	Escalation (Percent)
1981	1.5
1982	1.5
1983	1.6
1984	1.6
1985	1.7
1986	1.8
1987	1.8
1988	2.0
1989	2.0
1990	2.0
1991	2.0

3.2.3 Economics of Scale

Costs associatea with personnel salaries are generally the major component of operation and maintenance costs for energy generating facilities. In light of this fact, economies of scale would result from larger unit capacities because the personnel requirements are more a function of items of equipment and, therefore, would not increase in direct proportion to additional capacity.

3.3 FUEL AND FUEL TRANSPORTATION COSTS

Estimated delivered costs for Cook Inlet natural gas to the Chugach Electric Association have been forecasted by Battelle, Pacific Northwest Laboratories (Battelle 1982). Cases with and without relinquishment of Pacific Alaska LNG commitments are developed in this report. In as much as it appears that insufficient recoverable reserves would be available in the Beluga area without relinquishment of the Pacific Alaska commitments, the "without" Pacific Alaska prices are used in the cost-of-energy estimates that follow. Forecasted natural gas prices to Chugach Electric Association through the time period considered in the Railbelt Electric Power Alternatives Study are shown in Table 3.3. Prices beyond 2010 are assumed to escalate at 2 percent per annum for the cost-of-energy calculations of this report. Note that the forecasted natural gas costs of Table 3.3 are weighted costs, comprised of gas from Beluga, Alaska Gas and service company supplies and supplemental gas supplies.

TABLE 3.3. Estimated Natural Gas Acquisition Cost for Chugach Electric Association Without Pacific Alaska LNG Plant, 1982 $, 0 Percent Inflation (Battelle 1982)

Year	Weighted Average Cost ($/Mcf)
1980	0.46
1981	0.45
1982	0.46
1983	0.46
1984	0.46
1985	0.51
1986	0.54
1987	0.66
1988	0.70
1989	0.78
1990	0.90
1991	1.53
1992	1.66
1993	1.87
1994	2.00
1995	.17
1996	4.46
1997	4.56
1998	4.68
1999	4.78
2000	4.91

3.4 COST OF ENERGY

The estimated busbar energy cost for the natural gas combined-cycle plant described in this report is 46.5 mills per kilowatt-hour. This is a levelized lifetime cost, in January 1982 dollars, assuming a 1990 first year of commercial operation and an 85 percent capacity factor. Estimated busbar energy costs for other capacity factors and other startup dates are shown in Figure 3.1. First and subsequent year energy costs and capital, O&M and fuel components are shown in Table 3.4. Year-of-occurrence costs are sensitive to escalating fuel costs.

These costs are based on the following financial parameters:

Debt Financing	100%
Equity Financing	0%
Interest on Debt	3%
Federal Taxes	0%
State Taxes	0%
Bond Life	25 years
General Inflation	0%

The escalation factors given in Sections 3.1 and 3.2 were employed. Weighted average capital cost escalation factors were derived using a labor/material ratio of 40 percent/60 percent.

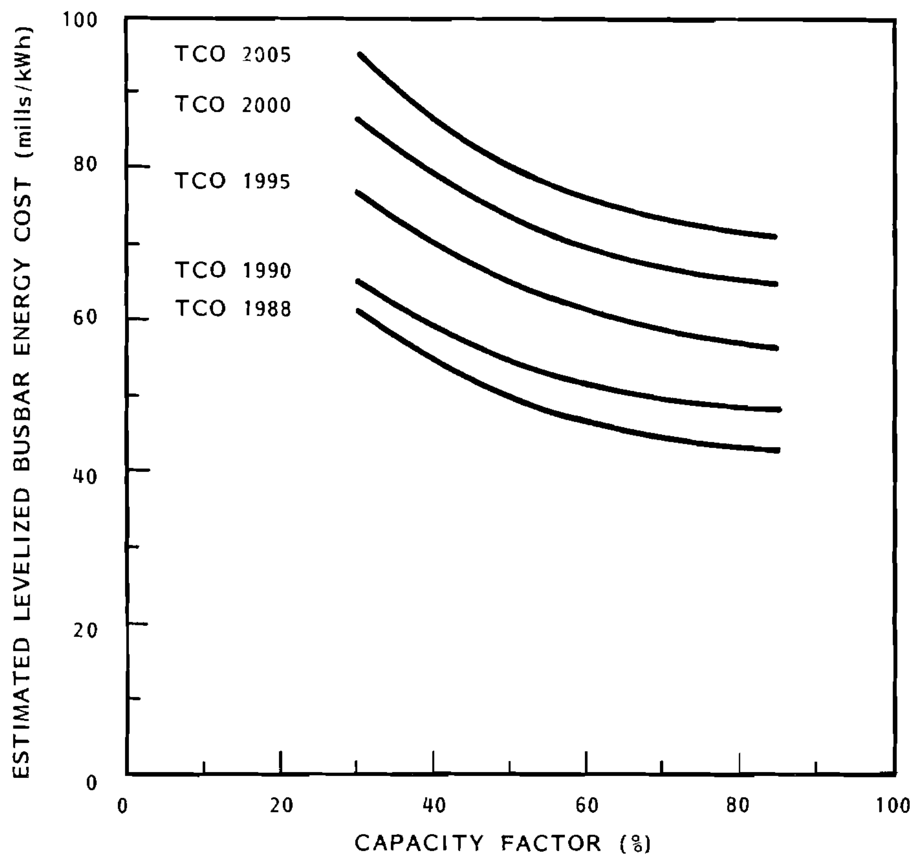


FIGURE 3.1. Cost of Energy Versus Capacity Factor and Year of First Commercial Operation (TCO) (January 1982 dollars)

TABLE 3.4. Year-of-Occurrence Energy Costs (1990 First Year of Operation; January 1982 dollars)

Year	Unit Capital Costs (mills/kWh)	Unit O&M Costs (mills/kWh)	Unit Fuel Costs (mills/kWh)	Total Unit Costs (mills/kWh)
1990	9.2	3.0	7.4	19.6
1991	9.2	3.0	12.5	24.7
1992	9.2	3.0	13.6	25.8
1993	9.2	3.0	15.3	27.5
1994	9.2	3.0	16.4	28.6
1995	9.2	3.0	17.8	30.0
1996	9.2	3.0	36.6	48.7
1997	9.2	3.0	37.4	49.6
1998	9.2	3.0	38.4	50.6
1999	9.2	3.0	39.2	51.4
2000	9.2	3.0	40.3	52.4
2001	9.2	3.0	41.1	53.3
2002	9.2	3.0	41.9	54.1
2003	9.2	3.0	42.7	54.9
2004	9.2	3.0	43.5	55.7
2005	9.2	3.0	44.4	56.6
2006	9.2	3.0	45.3	57.5
2007	9.2	3.0	46.2	58.4
2008	9.2	3.0	47.1	59.3
2009	9.2	3.0	48.1	60.3
2010	9.2	3.0	49.1	61.3
2011	9.2	3.0	50.0	62.2
2012	9.2	3.0	51.1	63.3
2013	9.2	3.0	52.1	64.2
2014	9.2	3.0	53.1	65.3

4.0 ENVIRONMENTAL AND ENGINEERING SITING CONSTRAINTS

Council of Environmental Quality regulations implemented pursuant to the National Environmental Policy Act of 1969 require an environmental impact statement for projects requiring licenses or permits issued by a federal agency. The combined-cycle plant described in this report would require several federal permits, as discussed in Section 6. The statement must include a discussion and evaluation of alternatives to the proposed action. This requirement is usually satisfied for power generating projects through the evaluation of alternative sites and alternative energy generating technologies. The purpose of such a study is to identify a preferred alternative and possibly viable alternative locations for the construction and operation of the generating station. This process can contribute to reduction in project costs through analysis of environmental and engineering siting constraints.

This section presents many of the constraints that will be evaluated during a siting study. Special attention was given to their applicability to the general location considered in this study. It should be realized that many of the constraints placed upon the development of a natural gas-fired combined-cycle power plant are regulatory in nature; therefore, the discussion presented in this section is complemented by the identification of power plant licensing requirements presented in Section 6.

4.1 ENVIRONMENTAL SITING CONSTRAINTS

Potential environmental siting constraints include effects on water resources, air resources, aquatic and marine ecology, terrestrial ecology and socioeconomic considerations.

4.1.1 Water Resources

Water resource sit ng constraints generally center about two topics: water availability and water quality. Water availability is important from two perspectives. First, the power plant requires a reliable source of water for efficient operation. Second, the withdrawal of water for plant uses should not adversely impact the source from which the water is drawn. Siting analyses generally attempt to minimize reduction in flow of potential water sources while maintaining plant reliability. For this reason, it is necessary to examine low flows as well as average yearly and monthly flows of potential water sources. Since combined-cycle technology minimizes water usage when compared with a similar-sized conventional steam-electric facility, water availability is not anticipated to be an overly constraining criterion.

Estimated plant makeup water requirements are 1060 gpm, of which 914 gpm are for heat rejection system makeup and 156 gpm are for steam system, domestic and miscellaneous (see Table 5.1 in Section 5). Water supply alternatives include use of fresh surface water sources, groundwater sources or seawater. Seawater utilization would be limited to heat rejection system uses and a fresh water source would be required for steam system and domestic uses.

Large rivers are not found at the Beluga location and therefore smaller streams will have to be examined to determine their suitability as a water source. Groundwater sources potentially exist in this area, with well yields estimated to be as high as 1000 gpm near the larger surface water bodies. Yields, however, range from 10 gpm to 100 gpm away from surface water bodies. Thus, it appears that adequate water supplies can be obtained from ground water near surface water bodies or by use of seawater for heat rejection system makeup and ground water for other uses. Investigation of specific streams may reveal sources of adequate magnitude.

Existing water quality can represent a significant siting constraint. First, receiving stream water quality standards, if particularly stringent, could prohibit plant effluent discharge. Second, makeup water quality requirements may mandate the provision of an extensive water treatment facility if the quality of the water source is inferior. This consideration should not prove restrictive at either potential plant location. The water quality of most other surface water resources is acceptable from a makeup water management viewpoint. However, if the plant utilizes a groundwater supply system, an extensive treatment system may be required since ground water is generally highly mineralized.

4.1.2 Air Resources

Combined-cycle gas-fired units emit only one atmospheric pollutant of major concern--oxides of nitrogen (NO_x). There are no PSD increments currently set for NO_x (see Section 6.1.1) and there are no nonattainment areas in the Railbelt Region with respect to the NO_x standards. Therefore, there is very little in the way of siting constraints due to atmospheric emissions from combustion-turbine combined-cycle units.

Nevertheless, regulatory compliance will be eased somewhat by judicious site selection. The regulatory issues discussed in Section 6.1.1 can be used to provide some guidance in this selection. Generally, areas designated as Class I for PSD purposes should be avoided when possible. The Tuxedni Wildlife Refuge and the Mount McKinley National Park are the only areas in the Railbelt Region currently designated as Class I. In addition, a nonattainment area designated for any pollutant should be avoided if reasonable alternatives are available. The Anchorage area is currently designated as nonattainment for carbon monoxide. Any potential for CO emissions must be analyzed carefully and controlled to the greatest extent possible. This may include potential emissions due to "upset" conditions when the facility is not operating at its most efficient levels, and it may also include CO emissions from secondary sources, such as construction and associated automobile traffic.

From a topographic point of view, enclosed areas with limited dispersion potential, such as deep valleys or sheltered basins, should also be avoided. The applicant will have to demonstrate that the ambient air quality standards (for NO_x) will not be violated by facility operation. Compliance with these standards is better assured in open, exposed locations.

4.1.3 Aquatic and Marine Ecology

Since the plant makeup and discharge requirements are relatively small (a maximum of 1060 gpm and 160 gpm, respectively), intake entrainment and impingement and wastewater discharge impacts will probably not be major site considerations. The major activity related to aquatic ecology performed during the siting process will, therefore, be an identification of exclusion and avoidance areas to be considered in association with intake and discharge structure development. The delineation of these areas will be based primarily upon an inventory of fish spawning habitat and upstream migration pathways, fish nursery habitat and downstream migration pathways, important benthic habitat and rare and/or endangered species and their critical habitats. Should a marine intake or discharge be considered, impacts to the significant marine populations, including Beluga whales, will be addressed, but should not represent a constraint due to the small intake and discharge flows expected.

4.1.4 Terrestrial Ecology

Since habitat loss is generally considered to represent the most significant impact on wildlife, the prime terrestrial ecology activity related to terrestrial ecology will be an identification of important wildlife areas, especially critical habitat of threatened or endangered species. Based upon this inventory, exclusion, avoidance and preference areas will be delineated and factored into the overall plant siting process.

A number of important and sensitive species inhabit the potential site area, including moose, caribou, brown and black bear as well as small furbearers, such as lynx, beaver and muskrat. Also present are significant bird species including bald eagles and colonial nesting birds, such as seagulls, puffins and cormorants. Appropriate consideration of these species and their habitats will be required during the plant siting process.

4.1.5 Socioeconomic Constraints

Major socioeconomic constraints center about potential land use conflicts and community and regional socioeconomic impacts of project activities. Two types of potential land use conflicts must be considered: exclusionary areas, where plant development would be prohibited; and avoidance areas, where plant development, while possible, is generally not desirable. Potential exclusionary land uses will consist of those areas that contain lands set aside for public purposes, areas protected and preserved by legislation (federal, state or local laws), areas related to national defense, areas in which a combined-cycle installation might preclude or not be compatible with local activities (e.g., urban areas or Indian reservations), or areas presenting safety considerations (e.g., aircraft facilities). Avoidance areas will generally include areas of proven archeological or historical importance not under legislative protection as well as prime agricultural areas.

Minimization of the boom/bust cycle will also be a prime socioeconomic consideration. Through the application of criteria pertaining to community housing, population, infrastructure and labor force, this consideration will be evaluated and preferred locations identified. Because of the potential for significant boom/bust-related impacts on small communities within the Beluga area, socioeconomic impact criteria will be heavily weighted in the overall site evaluation process.

4.2 ENGINEERING SITING CONSTRAINTS

Potential engineering siting constraints that should be considered in the site-selection process include site topography and geotechnical characteristics, road access, transmission line access, water supply and fuel supply considerations.

4.2.1 Site Topography and Geotechnical Characteristics

Principal topographic and geotechnical considerations include terrain, soil conditions, seismic activity and the availability of borrow material. In general, the power plant should be sited in relatively flat terrain. This will minimize the amount of required grading and excavation as well as minimize the potential for adverse environmental impacts due to rainfall runoff transport of suspended solids to nearby waterways. The plant should be sited above the 100-year floodplain of any major streams to avoid flooding.

Poor soil conditions can cause significant construction problems due to poor suitability as a foundation for structures. The presence of highly organic soil (muskeg) in the Beluga area will probably require that extensive piles be placed under major building and equipment foundations.

Potential seismic activity can also be an important site-differentiating factor, with preference given to those sites located in regions of low seismic activity. However, all potential Beluga sites fall within regions of high seismic activity (Zone 3). While this will not preclude development nor differentiate between the sites, it will increase construction costs because more material will be required to ensure plant foundation stability. The location and extent of all faults within the general Beluga area should be studied during the site-selection process because the plant should not be sited in close proximity to fault lines.

Finally, sites that contain an adequate supply of borrow material can be far less costly, especially if alternate sites would require haul of this material over long distances.

4.2.2 Access Road, Transmission Line and Fuel Supply Considerations

Siting the proposed power plant in close proximity to existing roads, transmission lines and gas pipelines would minimize the cost associated with these required connection links and also minimize the environmental effects associated with land disturbance. For roads, the selected route should comply with established safety and reliability standards. For example, the maximum allowable grade for roads is approximately 6 percent. Route selection of roads, pipelines and transmission lines will also be affected by soil and meteorological conditions because potential frost heave problems and other soil-related characteristics can significantly add to the cost of road and pipeline facilities. Additional considerations for transmission line routing include wind, temperature and prospective ice load; these factors can significantly affect transmission line design.

Accessibility to transmission is not expected to be a serious constraint for a Beluga site due to the presence of the transmission line serving the Chugach Electric Association Beluga Station.

4.2.3 Water Supply Considerations

The power plant requires a reliable water supply. To ensure that this requirement is met, two criteria are generally employed during the siting process:

- The plant should be sited within approximately 15 miles of an acceptable source of water, and
- The plant should be sited where the maximum static head between the water source and the end use facility (the plant itself or a makeup water reservoir) is less than approximately 1500 feet.

The first criterion reflects the need to minimize right-of-way acquisition; land disruption; associated construction-related environmental impacts; investment and operating costs; and the potential reliability problems associated with "pumps-in-series" operation. The second criterion reflects the limits on the reliability of high-lift pumping operations. Observance of this criterion will minimize the need for system redundancies (e.g., a duplicate pipeline) as well as minimize the operating costs associated with water pumping.

A discussion of potential water sources in the Beluga area is provided in Section 4.1.1.

5.0 ENVIRONMENTAL AND SOCIOECONOMIC CONSIDERATIONS

The construction and operation of a 200-MW natural gas-fired combined-cycle generating facility will create changes or impacts to the land, water and socioeconomic environments in which it is located. A summary of the primary impacts of the plant on the environment is presented in Table 5.1. Following preliminary plant design, these primary effects are then analyzed and evaluated in light of existing environmental conditions to determine the potential significance of the impact and the need for additional mitigative measures. Further discussion of the impacts listed in Table 5.1 is provided below.

5.1 WATER RESOURCE EFFECTS

Water resource impacts associated with the construction and operation of a combined-cycle power plant are generally mitigated through appropriate plant siting criteria and through a water and wastewater management program. The plant water system will normally employ water treatment and recycle to satisfy regulatory requirements on discharge and to minimize water consumption. Achievement of these water quality requirements will preclude adverse impacts on the water resource.

A favorable attribute of natural gas-fired combined-cycle power plants is that, on a per-megawatt-basis, these facilities require much less water for cooling purposes than conventional "all steam" systems. For example, the estimated makeup water requirement at a 200-MW direct coal-fired steam-electric plant is 1947 gpm (wet cooling) (Ebasco Services Incorporated 1982) compared with an estimated 1060 gpm for the 200-MW combined-cycle plant described in this report. The difference is attributable to the superior thermal efficiency of the combined-cycle plant and to the reduced steam system makeup requirements. In addition, natural gas-fired combined-cycle power plants produce little solid waste, and therefore minimize disposal and wastewater treatment requirements generally associated with combustion technology byproducts. Significant or difficult-to-mitigate water resource impacts should therefore not pose restrictive constraints on the development of this type of electric generating facility.

TABLE 5.1. Primary Environmental Effects

Air	
Particulate Emissions	Negligible.
Sulfur Dioxide Emissions	Negligible.
Nitrogen Oxide Emissions	Emissions variable - water injection controlled to meet calculated NO_x standard of 0.014 percent of total volume of gaseous emissions.
Water	
Plant Water Requirements	
Cooling Tower Makeup	914 gpm
Other Requirements	146 gpm
Plant Discharge Requirements	
Cooling Tower Blowdown	144 gpm
Demineralizer	12 gpm
Steam Generators	22 gpm
Total	178 gpm
Sanitary Treated Waste	4 gpm
Floor Drains	8 gpm
Aquatic and Marine Ecosystems	
Anadromous Fish	No impact anticipated.
Other	No significant impact anticipated.
Terrestrial Ecosystem	
Wildlife Habitat	Loss of habitat at the plant site and along access road corridor.
Food Chain	No significant impact anticipated.
Human Presence	Increased human presence at plant site and along access road corridor.
Land	
Plant Island	2 acres
Fuel Storage	1/2 acre
Transmission	75 miles at 345-kV line (could shave existing transmission corridor for much of this distance).
Road	5 miles of gravel road.
Gas Pipeline	Less than 10 miles of new corridor.
Socioeconomic	
Construction Work Force	Peak requirement of approximately 400 personnel.
Operating Work Force	43 personnel.
Relocations	None.
Land Use Changes	Increased access to plant site and along road, gas pipeline and transmission corridors.
Recreation	See land use changes above.
Capital Investment	70 percent within region. 30 percent outside region.
Operating Investment	84 percent within region. 16 percent outside region.
Fuel Investment	100 percent within region.
Aesthetics	
Maximum Structure Height	50 feet

5.2 AIR RESOURCE EFFECTS

Air quality impacts resulting from the operation of natural gas-fired combined-cycle facilities are generally limited to emissions of oxides of nitrogen (NO_x). Emissions of NO_x can be well controlled by reduction of peak combustion temperatures through water or steam injection. Sulfur oxides are not a significant pollutant because of the low sulfur content of natural gas. Achievement of regulatory requirements for New Source Performance Standards will generally preclude any significant impact from these emissions on the air resource.

Ice fog may be produced during cold weather conditions by water or steam injection; however, the requirement for water or steam injection may be eliminated when ice fog is deemed a traffic hazard. In addition, water vapor can be added to the air from the cooling tower. The formation of these plumes will be eliminated, however, by the use of a wet/dry cooling tower system. No offsite local climatic effects of system operation will be detectable. The assessment of impacts of this facility on broad-scale concerns, such as acid precipitation and CO_2 buildup, are not required from a regulatory viewpoint at this time, and such impacts may be deemed "not detectable."

As with other combustion-based technologies, operation of a natural gas-fired combined-cycle plant will release carbon dioxide to the atmosphere. Increasing concern has been expressed regarding long-term effects of the increase in atmospheric CO_2 apparently resulting from combustion of fossil fuels. Of particular concern is the potential "greenhouse" effect of increased atmospheric CO_2 concentration. No feasible measures are currently available for control of CO_2 production other than possible regulation of the global amounts of fossil fuels burned. No controls on CO_2 production, however, currently exist.

5.3 AQUATIC AND MARINE ECOSYSTEM EFFECTS

Potential impacts from water withdrawal and effluent discharge will be lowest on a per-megawatt basis for a combined-cycle plant in comparison with conventional steam electric plants. Proper design and location of the plant's intake and discharge structures should sufficiently mitigate any major adverse effects. Attainment of regulatory requirements on plant discharges through properly engineered systems will mitigate any potential effects.

5.4 TERRESTRIAL ECOSYSTEM EFFECTS

The greatest impact resulting from natural gas-fired combined-cycle power plants on the terrestrial biota is the loss of habitat due to human disturbance. The amount of land required is generally small, approximately 2 to 6 acres for a 200-MW plant, although a much larger area may be required for road access and transmission and pipeline corridors (see Table 5.1). Significant populations of moose, caribou, black bear and waterfowl are located in the Cook Inlet area. Therefore, siting studies for the actual plant location and for road, gas pipeline, and transmission corridors should be performed to minimize impacts to these species. A carefully selected site should not significantly impact these populations.

Some potential exists for the disturbance of the flora and fauna due to cooling tower drift emissions. Proper drift control devices should sufficiently mitigate this impact.

5.5 SOCIOECONOMIC EFFECTS

Many of the communities located near the Cook Inlet region are small in population and have an infrastructure that is not highly developed. In light of this, the construction and operation of a 200-MW natural gas-fired combined-cycle plant has a high potential to impact these local communities and cause a boom/bust cycle. These impacts can be lessened by siting a combined-cycle plant near a community with a population greater than 500, or by siting in a location remote from any existing population center. While a construction camp will mitigate this impact to some degree, disruption of the area's infrastructure must be anticipated if the facility is located near one of the smaller communities, such as Tyonek.

Since combined-cycle is a capital-intensive technology, the largest portion of expenditures outside the region will be attributed to equipment. Approximately 70 percent of the project capital expenditures will be spent in the lower 48 states, while 30 percent will be spent within the Railbelt. The allocation of operating and maintenance expenditures spent outside the Railbelt will be approximately 16 percent. All fuel will be obtained from Railbelt sources.

6.0 INSTITUTIONAL CONSIDERATIONS

This section presents an inventory of major federal, state of Alaska, and local environmental regulatory requirements that will be associated with the development of a 200-MW natural gas-fired combined-cycle power plant in the Beluga area of Cook Inlet. The inventory is divided into three sections, setting forth federal, state and local environmental licensing requirements. Federal requirements are summarized in Table 6.1; and state requirements in Table 6.2.

The discussion is limited to the major environmental regulatory requirements. The identification of more specific requirements can be accomplished only after detailed studies regarding project design and location are available. These requirements could be important in Alaska where much of the land is owned by the federal or state government.

6.1 FEDERAL REQUIREMENTS

6.1.1 Air

Air pollution controls are placed on new fuel-burning power plants through the provisions of the Clean Air Act (CAA). The CAA is implemented primarily through permitting programs that would ensure compliance with national ambient air quality standards (NAAQS) and that would prevent significant deterioration in areas where NAAQS are being met. To obtain a permit, a power plant may be required to restrict emissions in accordance with new source performance standards (NSPS), national emission standards for hazardous air pollutants (NESHAP), and other, more constricting programs, such as best available control technology (BACT) and lowest achievable emission rate (LAER).

The permitting program and controls to which a power plant will be subject is partially dependent upon its location. Since the general plant location is situated in an area in which air pollution levels are in compliance with NAAQS, the plant will be subject to the prevention of significant deterioration (PSD) permitting program administered by the Environmental Protection Agency (EPA) in accordance with CAA sections 160-169.

TABLE 6.1. Federal Regulatory Requirements

Agency	Requirement	Scope	Statute or Authority
U.S. Environmental Protection Agency	National Pollutant Discharge Elimination System	Discharges to Water	33 USC 1251 *et seq.*; section 1342
	Prevention of Significant Deterioration	Air Emissions	42 USC 7401 *et seq.*; section 7475
	Hazardous Waste Management Facility Operation Permit	Hazardous Waste	42 USC 6901 *et seq.*; section 6925
U.S. Army Corps of Engineers	Environmental Impact Statement	All Impacts	42 USC 4332; section 102
	Construction Activity in Navigable Water	Construction in Water	33 USC 401 *et seq.*; section 403
	Discharge of Dredged Fill Material	Discharges to Water	33 USC 1251 *et seq.*; section 1342
Federal Aviation Administration	Air Navigation Approval	Air Space for Transmission Lines	49 USC 1304, 1348, 1354, 1431, 1501
National Marine Fisheries Service/Fish and Wildlife Service	Threatened or Endangered Species Review	Air, Water, Land	16 USC 1531 *et seq.*
Advisory Council on Historic Preservation	Determination that Site is not Archeologically Significant	Land Use	16 USC 402 aa *et seq.*
	Determination that Site does not Infringe on federal landmarks	Land Use	16 USC 416 *et seq.*
Economic Regulatory Administration (Dept of Energy)	Exemption from Prohibition of Use of Natural Gas	Fuel Use	42 USC 8301 *et seq.*; section 201, 212
All Federal Agencies	Executive Order No. 11990	Development in Wetlands	
	Executive Order No. 11988	Development in Floodplains	

TABLE 6.2. State Regulatory Requirements

Agency	Requirement	Scope	Statute or Authority
Alaska Department of Environmental Conservation	State Certification that Discharges Comply with CWA and State Water Quality Requirements	Discharges to Water	33 USC 1251 et seq.; section 1341
	Air Quality Control Permit to Operate	Air Emissions	Alaska Statute 46.03.140
	Solid Waste Management Facility Operation	Solid Waste	Alaska Statute 46.03.100
Alaska Department of Natural Resources	Water Rights Permit	Appropriation of Water	Alaska Statute 46.15.030-185
Alaska Office of the Governor	Coastal Use Permit	Land Use	Alaska Statute 46.40
Alaska Department of Fish and Game	Anadromous Fish Protection Permit	Fish Protection	Alaska Statute 16.05.870
	Critical Habitat Permit	Fish and Game Protection	Alaska Statute 16.20.220 and .260

Currently, EPA retains authority to issue this PSD permit in the state of Alaska, although the state is now in the process of developing its own PSD permitting program which, when finalized, will transfer to the state this permitting authority. Until that time, EPA will continue to issue these permits based on rules found in 40 CFR 32.21.

Under these rules, major sources of pollution cannot begin construction until a PSD permit has been issued. A combined-cycle power plant is considered a major source if it has the potential to emit at least 250 tons per year of any air pollutant after controls have been applied. To obtain a PSD permit, an applicant must demonstrate that the source or modification will comply with the NAAQS, the NSPS, BACT, the NESHAP, and PSD increments. In addition, the applicant must conduct analyses relative to the effects of the source on soils, vegetation, visibility and area growth.

PSD increments are specified maximum allowable increases in the ambient concentrations of SO_x and particulate matter. Since gas-fired turbines emit essentially none of these two pollutants, the major concern relative to compliance with air quality standards are the New Source Performance Standards and the ambient air quality standards for NO_x.

Prevention-of-significant-deterioration regulations are based on classification of regions with respect to existing air quality. Class I areas are essentially pristine areas and receive greatest protection under the Clean Air Act. Class I areas in Alaska include the Denali National Park and the Tuxedni Wildlife Refuge. If the plant is located within 10 km of a Class I area, additional pollution controls must be applied. Under rules promulgated on December 2, 1980 (45 FR 80084), new sources that require PSD permits may be required to conduct additional studies to determine the source's effects upon the visibility in the Class I area. Note that Clean Air Act section 165 requires that PSD permits be denied for sources that would cause adverse air impacts on Class I areas.

6.1.2 Water

The preservation of the quality of the surface waters of the United States is accomplished in accordance with the Clean Water Act (CWA). There are two major regulatory programs mandated by this act with which a power plant incorporating a steam cycle must comply.

Controls will be imposed upon the discharge of pollutants by the power plant through the National Pollutant Discharge Elimination System (NPDES) permit. This permit is issued by the EPA pursuant to CWA section 402, and regulations for its issuance are found in 40 CFR 122. Application for an NPDES permit for a new source will trigger the environmental review requirements of the National Environmental Policy Act (NEPA). Because the discharge cannot take place without a permit being issued, an application must be filed at least 180 days before the discharge is scheduled to commence.

The EPA generally establishes effluent limitations for pollutant discharges on an industry-by-industry basis. Specific effluent limitations for natural gas-fired combined-cycle power plants have not, however, been issued. In cases such as this, the EPA generally applies the limitations from an industry that closely resembles the process in question. In light of this procedure, it can be expected that the effluent limitations for the steam-electric generating station point source category will be applied to similar waste streams occurring at a combined-cycle power plant. These waste streams would include cooling tower blowdown, boiler blowdown, metal cleaning wastewaters and low-volume waste discharges, such as demineralizer regeneration wastewater and floor drainage.

Pursuant to Section 404 of the CWA, a permit must be obtained from the U.S. Army Corps of Engineers (Corps) to discharge dredged or fill material into waters of the United States. A natural gas-fired combined-cycle power plant may need a Section 404 permit for construction of water intake or outfall structures, loading or unloading facilities and transmission lines.

With respect to the same activities, a power plant may also be required to obtain a permit under Section 10 of the Rivers and Harbors Act of 1899 for the placement of structures or the conduct of work in or affecting navigable waters of the United States. This permit is also issued by the Corps using the same application forms and processing procedures as that required for the Section 404 permit.

The processing of either of these permits can take 6 months or more, and requires that an environmental impact statement (EIS) be prepared according to the requirements of NEPA.

6.1.3 Solid Waste

The Resource Conservation and Recovery Act (RCRA), as amended in 1980, imposes controls upon the handling of solid waste in the United States. It should be realized that the definition of solid waste is very broad and includes all materials that are solid, semi-solid, liquid, or contained gases with a number of notable exceptions. At present, the major emphasis has been placed upon the control of hazardous solid waste. A formal hazardous waste management program is currently being administered by the EPA. The program sets forth identification and handling requirements for sources of hazardous waste; marking and manifesting requirements for transporters of hazardous waste; and a permitting program for hazardous waste treatment, storage and disposal facilities.

Natural gas-fired combined-cycle power plant waste that may be hazardous includes water treatment wastes, boiler blowdown, boiler cleaning wastes, cooling tower blowdown, floor drainage wastes, and sanitary and laboratory wastes. Accordingly, the owners and operators of the power plant may have to comply with the standards applicable to generators and transporters of hazardous waste, and may also be required to obtain an RCRA permit from the EPA to operate a hazardous waste treatment, storage or disposal facility.

The RCRA permit need only be obtained from the EPA if hazardous waste in amounts exceeding 1000 kg/month will be treated, stored or disposed of on the plant site. If the waste is transported offsite for disposal in a licensed facility (such as a municipal dump), a permit need not be obtained. Furthermore, certain types of facilities, such as neutralization tanks, transport vehicles, vessels or containers used for neutralization of wastes that are hazardous only due to corrosivity (40 CFR 264.1(g)), have been excluded from RCRA permit requirements. (This exclusion does not apply to surface impoundments.)

If an RCRA permit for operation of a hazardous waste treatment, storage or disposal facility is necessary, it must be obtained before construction of the hazardous waste management facilities can be commenced. EPA only recently began accepting applications for RCRA permits from new treatment, storage and disposal facilities. Although no such permits have been issued yet, EPA anticipates the processing of RCRA permits to take at least 1 year.

6.1.4 Power Plant and Industrial Fuels Use Act

A new natural gas-fired combined-cycle facility will be subject to the provisions of the Power Plant and Industrial Fuels Use Act of 1978 (FUA). Pursuant to Section 201 of the FUA, natural gas may not be used as a primary energy source in a new electric power plant unless special permission is obtained. Such permission is granted by the Economic Regulatory Administration (ERA) within the Department of Energy (DOE) in the form of an exemption from the FUA prohibition of the use of natural gas.

Thirteen conditions are set forth in the FUA, any one of which is a potential basis for an exemption. The conditions are as follows (10 CFR 503.30–503.43):

503.31 - An alternative fuel supply to natural gas or petroleum would not be available within the first 10 years of plant life.

503.32 - An alternative fuel supply is available only at a cost that substantially exceeds the cost of using imported petroleum.

503.33 - Site limitations are present that would impede the use of alternative fuels to natural gas or petroleum. Qualifying site limitations include: a) physical inaccessibility of alternate fuels; b) unavailability of transportation facilities for alternate fuels; c) unavailability of land or facilities for storing or handling alternate fuels; and d) unavailability of land for controlling and disposing of wastes resulting from use of alternate fuels.

503.34 - Inability to comply with applicable environmental requirements except by use of petroleum or natural gas.

503.35 - Inability to obtain adequate capital for plant construction except by use of petroleum or natural gas.

503.36 - State or local requirements (except for building codes, nuisance or zoning laws) rendering use of alternate fuels infeasible.

503.37 - Use of cogeneration, where electricity would constitute more than 10 percent and less than 90 percent of the useful energy output of the facility.

503.38 - Use of mixtures of natural gas or petroleum and alternate fuels.

503.39 - Use of the plant for emergency purposes only.

503.40 - Need for the plant to maintain reliability of service due to timing considerations.

503.41 - Use of the plant for peakload purposes (not greater than 1500 equivalent full-power hours per year).

503.42 - Use of the plant for intermediate-load purposes (not greater than 3500 equivalent full-power hours at a heat rate of 9500 Btu/kWh or less). This exemption applicable to petroleum-fired units only.

503.43 - Use of the plant to meet scheduled outages (less than or equal to 28 days per year on average over 3-year periods).

It appears unlikely that an exemption for the proposed facility could presently be justified on any of the conditions cited above. However, two approaches to obtaining exemptions for the proposed plant appear to exist. One would be to construct the proposed plant as a cogeneration facility. To meet the requirements of a cogeneration facility, as defined in the PUA, would require more than 10 percent of the energy production of the plant be usefully applied in nonelectrical form. One possibility would be a district heating application. Use of plant heat for district heating would likely qualify the plant for cogeneration exemption under the provision, allowing such an exemption to be obtained for "technically innovative" applications (10 CFR Part 503.37(a)(2)). A plant site much closer to a population center such as Anchorage would be required to develop a cost-effective district heating system.

A second possibility for obtaining an exemption to the FUA would be for the State to find it in the public interest to generate electricity by use of natural gas and to establish statutory provisions encouraging the use of this fuel. Such legislation may allow exemptions to be obtained for natural gas-fired power plants under the provisions of 10 CFR Part 503.36.

6.1.5 Other Federal Requirements

In reviewing federal environmental requirements to which a natural gas-fired combined-cycle power plant may be subject, it is necessary to consider certain additional regulatory programs. Although these programs may not include permitting requirements, they contain certain requirements that can affect location and/or construction of a power plant. These requirements are summarized in Table 6.1; a discussion of each is presented in Ebasco Services Incorporated (1982).

6.2 STATE REQUIREMENTS

To a large degree, the state requirements parallel and complement the federal requirements. They are summarized in Table 6.2.

6.3 LOCAL REQUIREMENTS

The Cook Inlet Region is controlled by some of the most sophisticated local requirements in the entire state of Alaska. This is largely due to its proximity to Anchorage, one of the major population centers in the state. As a result, the proposed plant will most likely be subject to rather detailed requirements on a local level.

The plant will likely be sited in either the Matanuska-Susitna Borough or the Kenai Peninsula Borough. The Matanuska-Susitna Borough is a second-class borough with powers of land use planning, platting and zoning with which development can be controlled. The Borough has acquired areawide powers for the regulation of ports and ambulances, and also controls education and the assessment and collection of taxes within its borders.

The Kenai Peninsula Borough has areawide powers of platting and zoning and can control local land use. Plans to develop land in the Borough must be approved by the local zoning board which can regulate land use, building location and size, the size of open spaces and population distribution. In addition, the Kenai Peninsula Borough has a solid waste disposal program and an air pollution control program with which the proposed power plant may be required to comply. Those programs do not have permit provisions, but they do require that the plans for a proposed facility be approved by the Borough prior to construction.

6.4 LICENSING SCHEDULE

It is expected that the licensing of the proposed plant would be completed in approximately 36 months from the time a specific site is chosen. However, two items of special concern should be recognized in reviewing the licensing schedule.

First, the exemption to the Fuels Use Act granted by the DOE for the use of natural gas as a fuel in a new electric power plant requires submission of a complete application, and approval of that application. Completion of the application could take as long as 2 years, after which approval can be expected in up to 6 months. Accordingly, this exemption may be obtained within the 36-month schedule.

Second, receipt of a permit to operate a hazardous waste treatment, storage or disposal facility as required by RCRA section 3005 may be slightly more complicated for a natural gas-burning facility than it is for coal-fired plant. The EPA has determined in a letter dated January 13, 1981, that, at least temporarily, hazardous wastes produced in conjunction with the combustion of coal can be treated or disposed of in combination with high-volume coal combustion wastes without complying with the requirements of EPA's hazardous waste management program.[a] The exemption from compliance with the hazardous waste management program was not extended by EPA to wastes produced in conjunction with a natural gas-fired combined-cycle power plant. The owners and operators of this type of facility should recognize, therefore, that they are more likely to be subject to the RCRA hazardous waste management program than the owners and operators of a coal-fired plant, who may treat and dispose of low-volume hazardous wastes in combination with high-volume coal combustion wastes and thereby avoid EPA's hazardous waste management program. Receipt of a RCRA permit was, however, included in the 36-month estimated schedule for a natural gas-fired plant. For a detailed discussion of the probable licensing schedule, consult Section 6, Institutional Considerations, of the Ebasco Services Incorporated (1982).

(a) Letter from Gary N. Dietrich, Associate Deputy Administrator for Solid Waste, to Paul Emler, Jr. Chairman, Utility Solid Waste Activities Group.

In Table 6.1, the requirement that an EIS be prepared as per the requirements of the National Environmental Policy Act of 1969 (NEPA) has been listed as a responsibility of the Army Corps of Engineers (Corps), even though more than one federal agency will impose regulatory requirements upon the project. As discussed in Ebasco Services Incorporated (1982), the lead agency is ultimately determined through negotiation between eligible agencies and the project owner. The final determination is usually based upon an examination of the following criteria: magnitude of agency's involvement, project approval/disapproval authority; expertise concerning the action's environmental effects; duration of the agency's involvement; and timing of the agency's involvement. Due to its involvement in the issuance of the dredge and fill permit and the permit for construction in navigable waterways, the Corps is generally selected as the lead agency for an EIS regarding a steam-electric power plant.

7.0 REFERENCES

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