POLICY ANALYSIS PAPER 82-14

Potential for Industrial Development in the Railbelt Region of Alaska Based on the Availability and Cost of Electric Power

December 1982

STATE OF ALASKA
OFFICE OF THE GOVERNOR
Division of Policy Development and Planning
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POTENTIAL FOR INDUSTRIAL DEVELOPMENT IN THE RAILBELT REGION OF ALASKA BASED ON THE AVAILABILITY AND COST OF ELECTRIC POWER

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December 1982

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EXECUTIVE SUMMARY

The potential of new Alaskan hydroelectric and tidal power projects to provide large amounts of electrical power suggests that such hydroelectric capacity might serve as a magnet for industrial development and would help expand Alaska's economy. To assist the Office of the Governor in evaluating the potential for industrial development in Alaska based on inexpensive power, SRI International has reviewed available information on the proposed hydroelectric and tidal power projects and examined the issues related to an Alaskan location for a group of identified electrically intensive industries.

In addition to addressing particular industrial segments, SRI has examined other nonindustrial uses for low-cost electrical energy. These include electrification of the Alaskan Railroad, the possibility of an intertie to electrical grids in the lower 48 states, and expansion of electric space heating.

To determine the scope and timing of the proposed facilities, SRI used several studies on electric power development in the Railbelt region of Alaska. These include:

- Preliminary Assessment of Cook Inlet Tidal Power (Acres American/Governor's Office).
- Susitna Feasibility Study (Acres American/Alaska Power Authority) (Final Draft).
- Railbelt Electric Power Alternatives Study (Battelle Northwest Laboratories/Governor's Office) (Comment Draft).
- Energy Intensive Industry for Alaska (Battelle Northwest Laboratories/Division of Energy and Power Development).
- Various feasibility, engineering, and design studies on the Railbelt region by the Alaska Power Authority.
- Economic Development in Alaska--A Sectoral Analysis (Arthur D. Little/Alaska Department of Revenue).

In reviewing these studies of the Susitna hydroelectric and Cook Inlet tidal power projects, SRI collected data by project and in total for the following factors:

(a) Project location, likely completion date, power output, and other relevant system characteristics.

(b) Estimated project cost range.

(c) Forecast of service area demand.

(d) Estimated electric power price based on a, b, and c above.

(e) Nonutilized or surplus power availability through 2010, including a definition of "surplus" power and analysis of the impact of load growth on surplus power availability over time.

(f) Surplus or nonutilized power price ranges, including four cases: 100% market financing, 50% market financing and 50% state grants, 100% state loans with the rate of return equal to the inflation rate, and 100% state grants. The effect of potential wholesale and retail rate structures on surplus power price ranges was considered.

In addition, to place the hydroelectric and tidal power projects in perspective, SRI tabulated information about hydroelectric and other electric power developments worldwide that affect Alaska's competitive position compared to alternative industrial locations.

After reviewing the reports listed above, SRI concludes that for many of the proposed financing methods and demand scenarios, the projected capacities and price of power of electricity from the Susitna and Eagle Bay projects will not be major incentives for electrically intensive industries to locate in the Railbelt region.

Energy projects are usually phased to balance supply with expected demand. Significant quantities of nonutilized power are unlikely to be available as an inducement for industry to locate in Alaska unless the state chooses to adopt a construction schedule and plant mix that result in excess capacity.

More importantly, even though the annual operating costs of these projects may be low relative to alternative power sources, the high carrying costs associated with the initial construction of these projects, financed at prevailing interest rates, will offset such savings. As a result, unless the state is able to obtain low interest rates or provide the majority of capital costs at no or very low interest rates, the cost of excess power, even if available, will not be sufficiently low to attract industry.

Table 1 summarizes the pertinent data of the reviewed reports and to indicate the likely completion dates. The actual completion dates will depend on the demand for electric power and the potential for financing the projects.

Table 1

CHARACTERISTICS OF HYDROELECTRIC AND TIDAL POWER PROJECTS

Project Location	Earliest Completion Date, Medium Demand Forecast	Installed Capacity (MW)	Energy (GWh)	Capital Costs (billion 1982 $)	Projected Electricity Cost (mills/kWh)	Forecasts for Nonutilized Energy, 2000-2010 (GWh) Medium Demand	Low Demand
Hydroelectric							
Susitna--Watana	1993	680					
Subtotal				$3.647		0	0
Susitna--Devil Canyon	2002	600		$1.470		0	900-1,300
Total		1,280	6,790	$5.117	58		
Tidal							
Eagle Bay	2010	1,440	4,000	$3.825[2]	48	4,000	4,000
Directly usable power			1,600		121		
Available power for retiming			2,400		79		

[1]Actual costs will include any additional interest to finance each project.

[2]Does not include any costs for retiming or storage.

To identify potential industries that might be attracted to Alaska by the long-term availability of inexpensive electrical energy, SRI compared U.S. Department of Commerce data on the value of purchased electrical energy with the value of shipped product for over 960 4-digit Standard Industrial Classification (SIC) code industries.

The screening process identified nine industries that might benefit from inexpensive power. Four are in Category I, for which electricity costs exceed 10% of product value. Two are in Category II, for which electricity costs are between 5% and 10% of product value; these were combined with three in Category III, for which total energy costs are greater than 10% of product value and electricity may be substituted for thermal energy sources.

In addition to the Category I, II, and III industries retained for further screening, four other potential large-scale electrical energy uses were considered as specified in the statement of work. The list of industries and "other industrial applications" evaluated are listed in Table 2.

Of the nine potential candidate industries and four additional application areas considered, only residential space heating and processing of certain primary metals are likely to take advantage of the low-cost power in the Railbelt region. Expanded space heating usage has the best potential to utilize any excess power produced in the Railbelt. Investment in an aluminum plant appears to be likely only if the construction costs of the hydroelectric projects are subsidized by the state, and then it is questionable that there will be sufficient excess power available to serve a single "world-class" plant. Although the tidal project might provide sufficient power, the power from this project will not be low cost. Other metal processing plants are likely to be considered only if feedstocks are found in Alaska. The construction of an intertie with the Lower 48 does not appear to be cost-effective without state grants to finance the power projects, but there is no rationale for Alaska to subsidize power delivered to other states.

SRI's findings are predicated on 10% interest rates, continued high Alaskan labor costs, and little real increase in petroleum prices during the next 25 years.

The major findings of the study are:

- The cost of power from the Susitna project will not be competitive without a very substantial state subsidy, in the form of either grants or subsidized interest rate (until the capital cost obligation is paid off in 2010).

- The Cook Inlet project will not produce power at competitive rates because of the intermittent nature of tidal power.

Table 2

INDUSTRIES AND OTHER INDUSTRIAL APPLICATIONS EVALUATED AS POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL POWER

Category I

- The Aluminum Industry (SIC 3334, Primary Production Aluminum)
- The Chlor-Alkali Industry (SIC 2812, Alkalies and Chlorine)
- Industrial Gases (SIC 2813, Industrial Gases)
- Ferroalloy and Miscellaneous Metal Alloy Production (SIC 3313, Electrometallurgical Products)

Categories II and III

- Pulp and Paper Industry (SIC 2661, Building Paper and Building Board Mills; 2611, Pulpmills; and 2621, Papermills, Excluding Building Paper)
- Cement Industry (SIC 3241, Hydraulic Cement)
- Chemical Industry (2719, Industrial Inorganic Chemicals, NEC)
- Primary Metals Industry (SIC 3339, Primary Smelting and Refining of Nonferrous Metals, NEC; SIC 3333, Primary Zinc)
- The Fertilizer Industry (SIC 2873, Ammonia Production, Nitrogenous Fertilizers; 2874, Phosphate Fertilizers)

Other Applications

- Agglomerations of Small Industrial Facilities
- Residential Space Heat
- Electrification of Alaskan Railroad Intertie with the Lower 48
- Intertie with the Lower 48.

- There is not likely to be excess power available from Susitna alone unless the Alaskan economy stagnates or declines.

- There is unlikely to be sufficient excess power to serve a single world-class aluminum plant.

- Other than aluminum, electrically intensive industries are unlikely to derive sufficient cost savings from subsidized power to consider an Alaskan site on the basis of low-cost electricity alone.

- The availability of low-cost power might improve the economics of processing materials, provided the major feedstocks are native to Alaska.

- Without a tiered rate structure to discourage use for residential space heating, subsidized power is likely to increase electric space heating use sufficiently to absorb any excess power from the Susitna project.

- The relatively high state corporate income tax is a barrier to industrial development in the state.

- Although the SRI study is predicated on stable energy prices through 2002, the findings of the study are not greatly affected by an increase in fuel prices of 50%, since transportation costs will escalate commensurately.

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I PROPOSED RAILBELT HYDROELECTRIC AND TIDAL POWER PROJECTS

The potential of new Alaskan hydroelectric and tidal power projects to provide large amounts of electrical power suggests that such hydroelectric capacity might serve as a magnet for industrial development and would help expand Alaska's economy. To assist the Office of the Governor in evaluating the potential for industrial development in Alaska based on inexpensive power, SRI International has reviewed available information on the proposed hydroelectric and tidal power projects and examined the issues related to an Alaskan location for a group of identified electrically intensive industries.

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In addition, to place the hydroelectric and tidal power projects in perspective, SRI tabulated information about hydroelectric and other electric power developments worldwide that affect Alaska's competitive position compared to alternative industrial locations.

The economics of the proposed hydroelectric and tidal power plants are highly dependent on future oil prices and lower interest rates. Increasing oil prices will provide more state revenue, enabling the Legislature to consider grants or low-interest loans. More importantly, increased oil prices are more likely to force electric energy costs higher and induce electric-energy-intensive industries to build new facilities in regions with low-cost electric power. Industry is also more likely to finance the construction of new plants if interest rates are low.

After reviewing the reports listed above, SRI concludes that for many of the proposed financing methods and demand scenarios, the projected capacities and price of power of electricity from the Susitna and Eagle Bay projects will not be major incentives for electrically intensive industries to locate in the Railbelt region.

Energy projects are usually phased to balance supply with expected demand. Significant quantities of nonutilized power are unlikely to be available as an inducement for industry to locate in Alaska unless the state chooses to adopt a construction schedule and plant mix that result in excess capacity.

More importantly, even though the annual operating costs of these projects may be low relative to alternative power sources, the high carrying costs associated with the initial construction of these projects, financed at prevailing interest rates, will offset such savings. As a result, unless the state is able to obtain low interest rates or provide the majority of capital costs at no or very low interest rates, the cost of excess power, even if available, will not be sufficiently low to attract industry.

SRI International prepared Table I-1 to summarize the pertinent data of the reviewed reports and to indicate the likely completion dates. The actual completion dates will depend on the demand for electric power and the potential for financing the projects.

Susitna Hydroelectric Development

Project Location

The Susitna basin development plan recommended by Acres American, Inc., indicates that the proposed 1,280 MW Watana-Devil Canyon dam project is the optimum plan from an economic, environmental, and social point of view. The proposed plan develops approximately 91% of the total basin potential.

The Susitna River system is the sixth largest in Alaska. The main stream of the Susitna River originates about 90 miles south of Fairbanks, where melting glaciers contribute much of its summer flow. For more than 30 years, the vast hydroelectric potential of this river has been recognized and studied. Strategically located in the heart of the south central Railbelt, the Susitna could be harnessed to produce more than twice as much electrical energy per year as is now being consumed in the Railbelt. Figure I-1 illustrates the location of the proposed Watana and Devil Canyon dams.

The main Watana dam is projected to be an earth/rockfill structure constructed primarily with locally excavated materials. The maximum height of the dam above the foundation will be approximately 880 feet, and the crest elevation will be 2,225 feet. The overall volume of the dam is estimated at approximately 63 million cubic yards.

The main Devil Canyon dam is currently proposed as a thin concrete arch structure with an overall height of 650 feet and developed crest length of 1,230 feet. The crest width will be 20 feet, and the base width at the crown cantilever will be 90 feet. The geometry of the arch corresponds to a two-center configuration compatible with the asymmetric transverse profile of the valley. The development at Devil Canyon will be located at the upper end of the canyon at its narrowest point.

Table I-1

CHARACTERISTICS OF HYDROELECTRIC AND TIDAL POWER PROJECTS

Project Location	Earliest Completion Date, Medium Demand Forecast	Installed Capacity (MW)	Energy (GWh)	Capital Costs (billion 1982 $)	Projected Electricity Cost (mills/kWh)	Forecasts for Nonutilized Energy, 2000-2010 (GWh): Medium Demand	Low Demand
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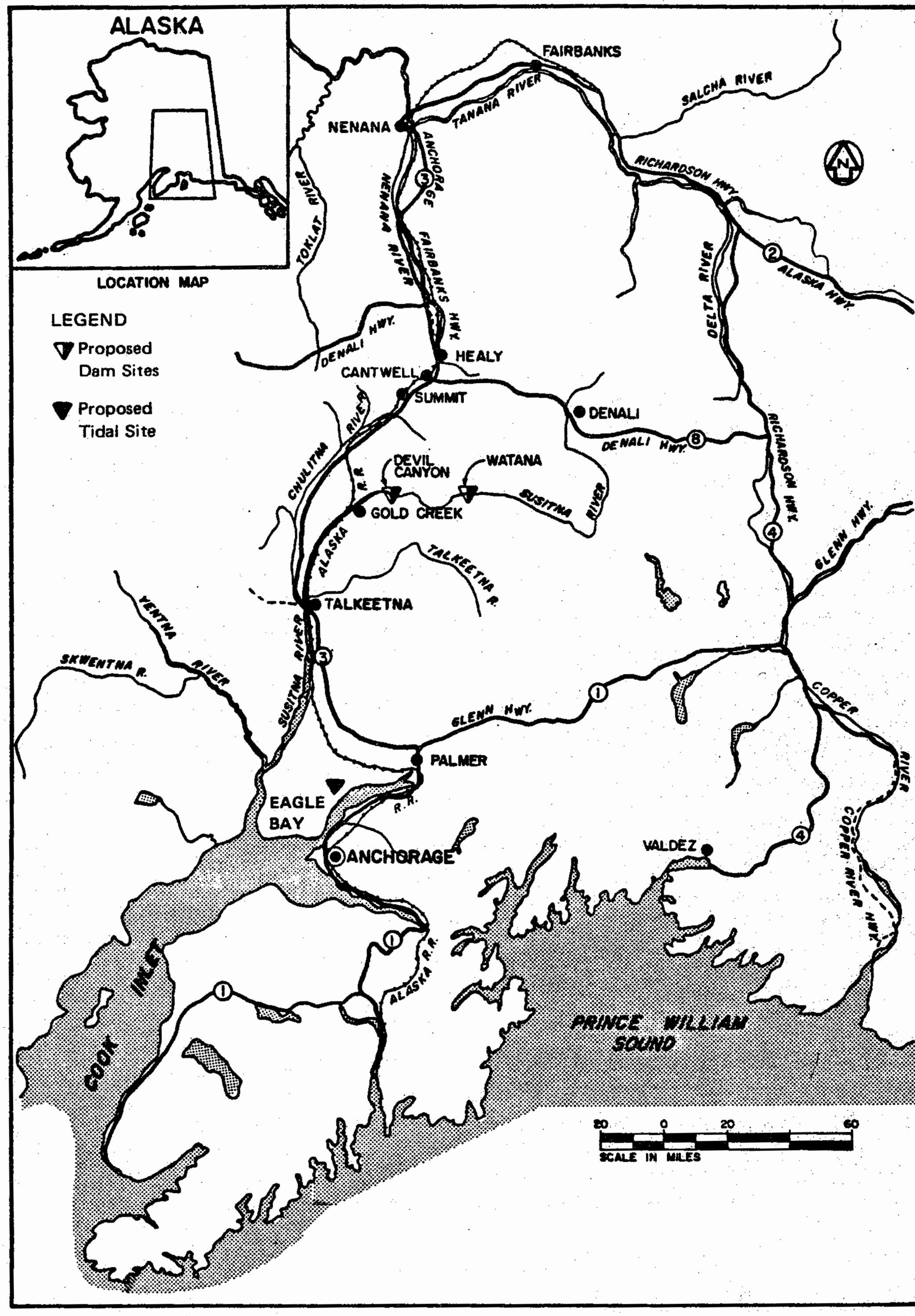

SOURCE: Acres American Incorporated, *Susitna Hydroelectric Project, Task 11: Economic, Marketing and Financial Evaluation*, prepared for Alaska Power Authority (March 1982)

FIGURE I-1 LOCATION OF PROPOSED PROJECTS

Completion Dates

The Watana rockfill dam is expected to take approximately 11 years to complete from the start of the access road to the testing and commissioning of all generating units. The earliest date that power production from the Watana dam could start is January 1993, based on construction of the access road beginning in early 1985 as soon as the Federal Energy Regulatory Commission (FERC) license is received. The Devil Canyon thin arch dam will take approximately 9 years and will be completed by 2000 at the earliest.

Power Output

The selected Susitna Basin development plan involves the construction of the Watana dam with a 680-MW powerhouse scheduled to commence operation by 1993, the earliest that a project of this magnitude can be brought on line. The final stage involves the construction of the Devil Canyon dam with an installed capacity of 600 MW.

Should the load growth rate increase more slowly than the current medium growth forecast, then Alaska would have to consider postponing both the capacity expansion proposed at Watana and the construction of the Devil Canyon dam to the year 2002 or later. If Watana were delayed to the late 1990s, Devil Canyon would be delayed to 2010. This slippage corresponds to the low load forecast with an increased level of load management and conservation. For actual load growth rates higher than the medium load forecasts, construction of the Devil Canyon dam could be advanced to 1998.

Although this development plan is economical for a wide range of possible future energy growth rates, the actual scheduling for the various stages should be continuously reassessed. In addition, the dam heights and installed capacities should be considered representative at this stage of project planning.

Project Cost Estimates

The total projected capital cost (1982 dollars) for the selected Susitna hydroelectric development project is $5.117 billion, with Watana costing $3.647 billion and Devil Canyon an additional $1.470 billion. The annual operating costs are projected to be $10 million for Watana and $5.42 million for Devil Canyon--a total of $15.42 million per year. Other forecast financial parameters are shown in Table I-2.

Cook Inlet Tidal Power Development

Tidal power was selected for consideration in Railbelt electric energy plans because the substantial Cook Inlet tidal resource is among the largest in the world and because of the renewable character of this energy resource.

Tidal power plants typically consist of a tidal barrier extending across a bay or inlet that has substantial tidal fluctuations. The barrier contains sluice gates to admit water on the incoming tide and turbine-generator units through which the outgoing tide passes to generate power. Tidal power is intermittent, requiring a power system with an equivalent amount of installed capacity capable of cycling its output. Hydroelectric plants and/or energy storage facilities (pumped hydro, compressed air, storage batteries) could be used to regulate the power output of the tidal facility.

Project Location

The Acres American study, "Preliminary Assessment of Cook Inlet Tidal Power" (September 1981), evaluated three tidal power plant alternatives, identifying Eagle Bay in Knik Arm northeast of Anchorage as the most economically attractive site based on preliminary results of its technical evaluation. SRI analyzed the price and availability of power only at the Eagle Bay site because of its compatibility with Railbelt load projections and avoidance of some environmental problems common to sites farther down the Knik Arm in Cook Inlet. The other two sites, Rainbow and Point Mackenzie-Point Woronzof, are not included in the SRI comparative analysis.

Completion Date

The overall tidal project at Eagle Bay is estimated to require 10 years to complete once the FERC license application is received. A license probably would not be awarded by FERC before late 1989 at the earliest. The process could be accelerated by performing the detailed design and engineering specifications (with a model of the test turbines) during the federal license process. Although construction could begin as early as 2000, the State of Alaska is unlikely to undertake the tidal project until the Susitna project is nearing completion. The phasing of economic cycles, in combination with the financial drain of the large capital outlays required by both tidal and hydroelectric projects, precludes them from being constructed concurrently. In light of the periodic nature of tidal energy output, the hydroelectric projects at Susitna built before the development of the Cook Inlet tidal basin could assist in leveling the output of a tidal generation facility by idling Susitna generators during tidal plant output periods. Alternatively, thermal power plants could be disengaged while the tidal power plant was generating. However, even with Susitna on line, not all tidal power would be used. With the Devil Canyon dam being completed by 2000 at the earliest, the Eagle Bay project would be ready to start up by 2010.

Table I-2

FORECASTS OF SUSITNA FINANCIAL PARAMETERS

	Watana	Devil Canyon	Total
Project completion date	1993	2002	
Costs (1982 $)			
Capital costs (billion $)	$ 3.647	$ 1.470	$ 5.117
Operating costs (million $/year)	$10.0	$ 5.42	$15.42
Provision for capital renewals* (million $/year)	$10.94	$ 4.41	$15.35
Operating working capital	15% of operating costs plus 10% of revenue		
Reserve and contingency fund	100% of operating costs plus 100% of provision for capital renewals		
Real rate of increase in operating costs			
1981 to 1987	1.7% per annum		
1986 to 1992	1.0% per annum		
1993 on	2.0% per annum		

*0.3% of capital costs.

Power Output

The planned Eagle Bay tidal plant could have an installed capacity of 1,440 MW and could produce about 4,000 GWh annually when the project is in full operation. In the Railbelt system, the value of the installed capacity of a tidal power plant operating strictly on tidal cycles cannot be fully realized. The periodic nature of the tidal plant's generation cycle and the very substantial output of energy in comparison to the Railbelt demand provides a unique problem in fitting the supply to match the pattern of demand.

Previous tidal power studies estimated that, in theory, the energy output from a tidal plant must be less than 10% of the total system requirements for it to be directly absorbed without "retiming" of energy. The 4,000 GWh produced at Eagle Bay would be as much as 90% of total system energy needs in the Railbelt projected by Battelle for the year 2010. SRI is not aware of any major industrial users of electricity that could utilize the intermittent power. Some type of retiming or energy storage is necessary if the full tidal power plant output is to be absorbed effectively.

If the energy usable in the system is defined as that portion of the tidal power plant production that meets system demand, the usable portion varies from about 30% of the total energy produced in summer months, to about 35% in the spring and fall months, to more than 50% in the winter months. Overall, about 1,600 GWh, or 40% of the Eagle Bay plant total of 4,000 GWh, can be classified as directly usable in the system.

Because of the magnitude of the directly unusable energy--about 2,400 GWh--three options should be considered to increase utilization of the tidal power: (1) installation of an energy storage system designed to balance the tidal fluctuations, (2) providing a balancing power supply source, or (3) attracting an industrial base to take advantage of unretimed tidal output. The penalty for not using the full output of tidal power is major. The cost of the usable energy goes up by a factor of 2.5 at Eagle Bay if the unretimed and directly unusable energy is not utilized.

Project Cost Estimates

Cost estimates for the tidal project of Eagle Bay are taken from the study prepared by Acres American. The Eagle Bay project is expected to have a capital cost of $3.825 billion (1982 dollars), which does not reflect the additional costs for retiming or any other costs associated with integration of the intermittent phased output pulses of tidal power.

II RAILBELT FORECASTS OF ANNUAL PEAK LOAD AND ELECTRIC ENERGY REQUIREMENTS

Historical Electricity Demand Profiles

Between 1940 and 1978, electricity sales in the Railbelt grew at an average annual rate of 15.2%, roughly twice the national average. However, the gap between national and Alaskan energy consumption has been narrowing due to the maturing of the Alaskan economy. Growth in the Railbelt has exceeded the national average for two reasons: the population growth in the Railbelt has been higher than the national rate, and the proportion of Alaskan households served by electric utilities was initially lower than the U.S. average so that some growth in the number of customers occurred independently of population growth.

The 1980 annual energy requirement of the Railbelt utility system was estimated to be 2,790 GWh and the peak demand 515 MW. Near-term future demands can be satisfied by the existing generating system, the committed expansion at Bradley Lake (hydroelectric), and the combined-cycle (gas-fired) plant at Anchorage. These facilities are expected to meet the demand until 1993, provided an Anchorage-Fairbanks intertie of adequate capacity is constructed.

Demand Forecasting

The feasibility of a major hydroelectric project depends partly on the extent to which the available capacity and energy are consistent with the needs of the market to be served by the time the project comes on line. Therefore, load forecasts are a most important factor in selecting the type and timing of generation units.

The Battelle Northwest study, "Railbelt Electric Power Alternatives Study" (February 1982), produced forecasts of annual electric energy and peak electric demand requirements for the Railbelt region and its three principal load centers: the Anchorage-Cook Inlet area, the Fairbanks-Tanana Valley area, and the Glennallen-Valdez area. These forecasts are designed as internally consistent estimates of power needs that take into account the following effects on the Railbelt region:

- Future economic and population growth.
- Future changes in the age, size, and energy-use characteristics of households.
- Future growth in commercial building stock.
- Future price and availability of fuel oil, natural gas, and wood.
- Cost of power from specific combinations of conservation and electrical generation that could be used to meet power demands.

- Public policy actions directly affecting energy demand or the cost of power.
- Possible new major uses of electric power, such as industrial use in manufacturing.

Because groups of these factors may interact in complex ways to produce a range of possible (but not equally plausible) forecasts, computer models of the interaction process were developed to determine how these factors individually and jointly affect demand estimates. The models, together with certain key assumptions concerning Alaska's economy, Alaskan public policy, and world prices for fossil fuels, produced contingent forecasts of electricity demand at 5-year intervals beginning from 1980. The demand forecasts were used as the basis for power plant planning in the Battelle study.

The forecasting process consisted of two steps: (1) combining sets of consistent economic and policy assumptions (scenarios) with economic models from the University of Alaska Institute of Social and Economic Research (ISER) to produce forecasts of future economic activity, population, and households in the Railbelt region and its three load centers; and (2) combining these forecasts with data on current end uses of electricity in the residential sector, data on the size of the Railbelt commercial building stock, data on the cost and performance of conservation, assumptions concerning the future prices of electricity and other fuels, and future new uses of electricity to produce demand forecasts.

Specifically, three basic scenarios for private economic activity and state spending were combined to give three overall economic scenarios: (1) high private economic activity and high state spending (high economic growth case); (2) medium private economic activity and medium state spending (medium economic growth case); and (3) low private economic growth and low state spending (low economic growth case). Increased industrialization and unsustainable state spending were investigated by Battelle but are not included in the three major growth scenarios. The Battelle forecasting model, the Railbelt Electric Demand (RED) model, is based on the linkage between economic growth scenarios and electricity consumption.

Peak demand and annual energy forecasts for the low, medium, and high economic growth cases, as developed by Battelle, are presented in Table II-1.* The medium growth scenario is established in the Battelle

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*Note that the forecasts used by Acres American, Inc., in the Susitna hydroelectric project were initial projections derived from December 1981 computer runs of the various scenarios. The final forecasts produced in February 1982 by Battelle are approximately 20% lower. The result is that the Acres American low growth case corresponds to the latest Battelle medium growth forecast.

study as the base-case. The projected annual growth rate in base-case demand for electric energy is approximately 3.0% between 1980 and 2010, for an increase in per capita use of approximately 0.9% per year. Demand in the low economic growth case increases at 2.2% per year. Demand in the high economic growth case shows an average increase of 4.3% per year. The corresponding Railbelt system peak load (expressed in megawatts) corresponds basically to growth rates in annual energy demand.

Table II-1

PEAK DEMAND AND ANNUAL ENERGY REQUIREMENTS FOR THE LOW, MEDIUM, AND HIGH ECONOMIC GROWTH CASES*

	Low Economic Growth		Medium Economic Growth		High Economic Growth	
Year	Peak (MW)	Energy (Gwh)	Peak (MW)	Energy (Gwh)	Peak (MW)	Energy (Gwh)
1980	520	2,550	520	2,550	520	2,550
1985	620	3,030	640	3,140	670	3,240
1990	800	3,850	880	4,260	1,060	5,414
1995	840	4,060	990	4,880	1,180	6,060
2000	820	3,990	1,020	5,030	1,230	6,380
2005	870	4,280	1,090	5,420	1,440	7,430
2010	1,000	4,940	1,260	6,260	1,760	9,010

*The peak demand and annual energy requirements in this table do not assume a subsidy of the electric rate. The demand for electricity would increase if rates were subsidized.

III ELECTRIC POWER PRICE RANGES

Susitna Project

Electricity cost estimates depend directly on the ability to correctly forecast electricity demand. If electricity consumption drops by one-third, the cost per kilowatt-hour more than doubles. As the unit price of power increases (decreases), consumption rates tend to decrease (increase). This elasticity of demand for electric power has proven to be a major factor in the economic health of domestic utilities. Clearly, to assure an economical match between electricity production and consumption, the timing of a major project like Susitna and the cost of power are extremely critical. The issue of full utilization of Susitna capacity is complicated by the present system of decentralized independent utilities which can be expected to bargain for rates no higher than the cost of energy from the best thermal option available to them.

Unless Susitna is completely financed by the state, residual bond financing will be required, at interest rates determined by complex political and economic forces. Acres American developed a financing plan based on interest rates of 10% to 12% to arrive at estimates of project financing characteristics. Analysis of this plan indicates that the costs of supporting the Susitna project on a 100% market-financed basis are higher than its projected revenues during the early years of the project. The cost of 100% market financing would result in electric rates which vary over time but are 9 to 15 times the level that would result from 100% state grants. These multiples result from high debt-servicing costs associated with the 100% market-financed scenario.

Table III-1 illustrates overall power costs, and the fraction of those costs attributable to operational costs and debt servicing for the four basic scenarios under consideration for the year 1995 (2 years after Watana's earliest power production), 2003 (2 years after Devil Canyon's earliest power production), and 2010 (at which point Susitna power costs should be relatively level). Price ranges were taken directly from published Acres American financial data, except for the 100% state loan scenario. The power price for this scenario was calculated from yearly plant expenses in the absence of capital cost debt servicing as determined by the 100% state grant case, and from debt-servicing data used in the 100% market-financed case.

With 100% state grants and a total capital cost of $5.1 billion (in 1982 dollars), the price for hydroelectric power of $.01 per kWh would be very competitive worldwide. This plan represents the simplest financing option.

Table III-1

ELECTRIC POWER PRICE RANGES
(Mill/kWh, Constant 1982 Dollars)

Scenario	Amount of Power Cost Attributable to Debt Servicing			Annual Operational Expense*			Total Cost		
	1995	2003	2010	1995	2003	2010	1995	2003	2010
100% state grant	N/A	N/A	N/A	8.24	8.84	8.35	8.24	8.84	8.35
100% state loan	78.47	49.05	26.72	8.24	8.84	8.35	86.71	57.89	35.07
50% market financing 50% state grant	47.14	51.06	25.11	8.24	8.84	8.35	55.38	59.90	33.46
100% market financing	112.10	70.07	38.17	8.24	8.84	8.35	120.34	78.91	46.52

*Assumed constant for all scenarios; see Table II-1.

Source: Acres American Susitna Feasibility Study

If Susitna is built with 100% state grants, the implication is that only the relatively small annual costs necessary for successful operation would be charged as the cost of output. The energy developed by Susitna would thus be supplied to utilities at a fraction of the cost of power from alternative sources. It has been assumed that no financing or marketing problems will exist for this case. The major problem may be arriving at an equitable allocation of the low-cost power among the consuming utilities whose normal demand may well exceed the supply of heavily subsidized power. The 100% state grants case would result in rates of about $.01/kWh (in 1982 dollars), which are comparable to but slightly lower than the $.0125 industrial rates for Le Grande Complex in Canada.*

Another possible scenario is for the state to provide 100% of the capital costs in the form of a state loan to be repaid at an interest rate based on inflation. Assuming repayment at an average interest rate of 7%, this scenario would result in a rate of $.09/kWh in 1995, which decreases to $.035/kWh by 2010 (in 1982 dollars). If the state provides about half ($2.3 billion) of the capital costs as a grant, with the remaining portion being market financed, the electric rate would vary from $.05/kWh in 1995 to $.06 in 2003 and then decrease to $.033/kWh by 2010, somewhat higher than the current industrial rates in the Pacific Northwest. This rate is fractionally lower than the state loan case, reflecting the effect of the $2.3 billion grant. If the Susitna hydroelectric project is 100% market financed, then the rates would be $.12/kWh in 1995, decreasing to $.08/kWh in 2003 and $.046/kWh by 2010.

Cook Inlet Tidal Project

As illustrated in Table III-2, estimated production costs of an unretimed tidal power facility ($.048/kWh) would be competitive with principal alternative sources of power, such as coal-fired power plants, but this cost can be realized only if all the available power could be used effectively by a specialized industry established to absorb the predictable but cyclic output of the plant. Alternatively, if it is assumed that only the portion of the power output that could be absorbed by the Railbelt power systems could be classified as usable, the cost of this energy ($.121/kWh) would be extremely high relative to other power-producing options because only a fraction of the raw energy production could be used. An additional alternative would be to construct a retiming facility, such as a pumped storage facility. Because of the increased capital costs and power losses inherent in this option, busbar power costs ($.079/kWh) would still be substantially greater than for nontidal generating alternatives.

If the power production capability of the proposed 1,440-MW Eagle Bay plant were halved, using 30 instead of 60 turbines, the energy costs, when the excess energy cannot be used, are still relatively high.

*LeGrande Complex rates for small power users vary between $.026/kWh and $.045/kWh.

Table III-2

TIDAL GENERATION ENERGY COSTS AT EAGLE BAY
($/kWh)

Installed Capacity (MW)	Production Cost of Unretimed Energy	Energy Cost*	
		Excess Energy Not Used	Excess Energy Retimed
1,440	.048	.121	.079
720	.058	.087	.076

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*Assumes a 3% real rate of return on the capital invested.

Source: Preliminary Assessment of Cook Inlet Tidal Power, Phase I Report, Acres American, Incorporated, September 1981.

IV AVAILABILITY OF NONUTILIZED POWER THROUGH 2010

Nonutilized power can be the result of seasonal variations, insufficient demand in the short term (3 to 5 years), or long-term low energy demand. The actual demand for electricity in the Railbelt varies seasonally. The capacity of new generation facilities is designed to meet peak loads, even if some surplus capacity results during certain time periods. Little can be done with short-term excess capacity when the normal demand growth will consume it within a few years. Only long-term surpluses of a generation system like the Susitna hydroelectric or the Eagle Bay tidal project would have the potential for attracting electrically intensive industry. These industries require reliable energy sources at low cost for periods exceeding 10 to 15 years.

According to Table I-1, in their final configuration the proposed Susitna hydro projects at Watana and Devil Canyon are expected to produce 6,790 GWh of energy annually. Under the Battelle-derived medium demand electric energy forecast, all of this energy will be consumed through normal load growth and displacements of existing generation facilities. Nonutilized power would only become available if the low growth forecast occurs. Should the low growth scenario prevail, approximately 1,200 to 1,800 GWh of nonutilized power, when Devil Canyon comes on line in 2002, could then be consumed annually by electrically intensive industries.

The mere availability of inexpensive electrical energy is not sufficient to ensure that the managers of electrically intensive industries will elect to locate new facilities in Alaska. Companies are reluctant to invest the required capital in a new plant to take advantage of inexpensive electric energy if large quantities of electricity cannot be guaranteed beyond 10 to 15 years. For example, the Acres American report states that even under their medium demand scenario some Susitna energy output (about 350 GWh) will not be used during the summer in 2010 (medium demand, summer). This seasonal energy output could be available to industry in the summer months. However, since most manufacturing processes require year-round operation, this power would not be attractive to most industries and cannot really be classified as a "surplus." In addition, the projected cost of the power from the unsubsidized facility is high when compared to other large hydroelectric power facilities like Le Grande Complex in Canada. If the state provides 100% of the capital for the project and does not expect any return on capital, then the cost of electricity will be very low, but this lower rate is likely to increase domestic demand significantly, resulting in little power availability for industry.

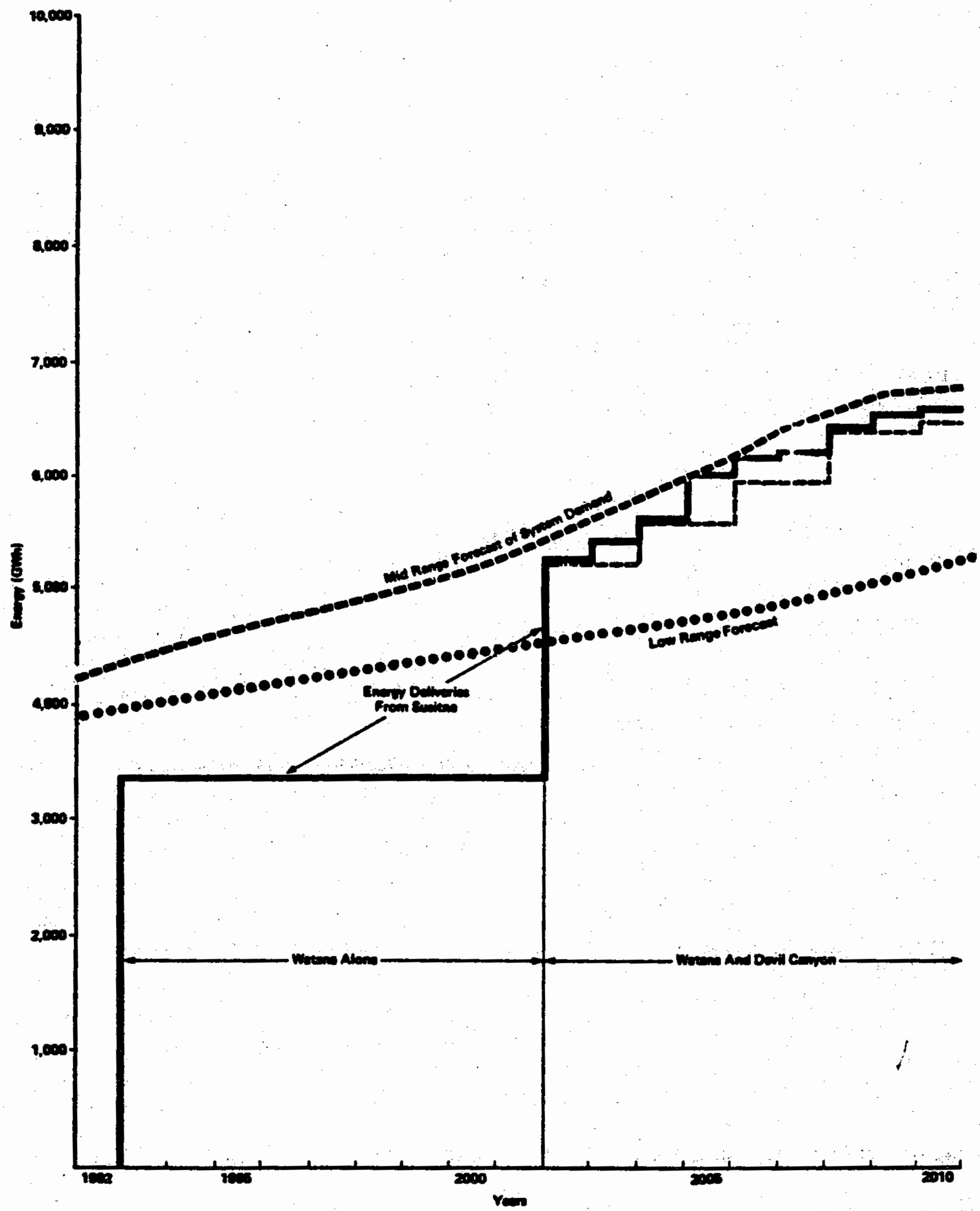
If the proposed Eagle Bay tidal power facility is approved, construction is expected to begin after 2000, when the Susitna project is about ready to go on line. This schedule would most effectively use Alaskan labor supply and is not likely to overtax the Alaskan economy. The required 10 years of construction would bring the tidal-generated power on line in 2010 or 2012. Even for the medium demand forecast, very little if any Eagle Bay output is expected to be required in 2010-2012. All of the output of this facility could be available, therefore, for additional industrial consumption. Because the generation of tidal power is intermittent, the energy produced will be in excess of the demand at certain periods, resulting in power that is not directly usable by the power grid without a large energy storage facility for retiming. The additional costs for retiming would make the project uneconomical. If only the directly usable power is included in the overall project, the cost for Eagle Bay power is estimated at $0.12/kWh.

Optimum economic use of the Watana and Devil Canyon hydroelectric plants requires that they be operated as close as possible to full capacity. Large users of electric power could be offered blocks of power at a reduced rate to encourage full utilization of the capacity of the dam with maximum payback on the high capital costs and fixed operation and maintenance.

Potential for Nonutilized Electric Power

By comparing the forecast of system demand for the Railbelt with the energy deliveries from Susitna and Eagle Bay, the projected quantity of nonutilized electric power can be derived. The medium forecast of system demand and capacity is used as the base case in most of the studies that were compared. This comparison is shown in Figure IV-1 for both the medium and low case scenarios used by Acres. The wholesale energy cost from the hydroelectric and tidal plants is assumed to be less than the cost of the best thermal option and also less than the avoided operating costs of electricity supplied by existing equipment so that existing facilities are displaced. These assumptions would result in Railbelt utilities purchasing the majority of their power requirements from the hydroelectric and tidal projects. If the wholesale energy cost from the hydroelectric and tidal plants is not competitive with the cost of the thermal options, then there is little justification to undertake the large water projects. If the wholesale price is substantially less than the thermal alternatives because of financing subsidies, then the quantity of nonutilized power (excess capacity) would decrease as a higher "normal" demand consumes the lower-cost energy.

Figure IV-1 compares energy demand projections from Acres and projected deliveries from the Susitna hydroelectric projects. When Watana comes on line in 1993, the total energy output would not exceed the expected demand. No surplus is expected to be available for large-scale industrial usage, at least until Devil Canyon comes on line in



SOURCE: Acres American Incorporated, *Susitna Hydroelectric Project, Task 11: Economic, Marketing and Financial Evaluation,* prepared for Alaska Power Authority (March 1982)

FIGURE IV-1 ENERGY DEMAND AND DELIVERIES FROM SUSITNA

2000-2002. Under the medium growth forecast, little if any nonutilized power would be available. However, the low range forecast projects that 1,200 to 1,800 GWh of energy would be available annually for at least 10 years.

If the Eagle Bay tidal power plant comes on line in 2010, then the complete output of the project would be available for industrial use in the near term, although only 1,600 kWh would be directly usable.

The State of Alaska and the Corps of Engineers are considering two additional hydroelectric projects, Chackachamna and Bradley Lake. Chackachamna would be completed no earlier than 1995; its installed capacity of 330 MW would produce 1,500 GWh of energy annually. The 90-MW Bradley Lake project, which could be completed in 1988, would produce 350 GWh of energy annually. This plant has a 90-MW base load and 135-MW peak load capacity. By 1995 these plants would make an additional 1,850 GWh available for industrial use.

Fiscal Crisis Scenario

The various scenarios that have been discussed assume that any non-utilized or excess power capacity above normal reserve margins is the general result of a conscious decision to build such capacity for attracting industry and that massive excess capacity will not occur unintentionally. One additional scenario that SRI was asked to address concerns a worst-case fiscal crisis situation in which dams are constructed and even the low growth economic projection fails to materialize. This scenario is similar to the situation in which the utilities that make up the Washington Public Power Supply System found themselves when building what turned out to be excess nuclear capacity. They were forced to terminate at least two plants of five under construction, one of which was more than 24% complete. Under the fiscal crisis scenario, the state would have approximately 3,800 GWh available to attract industry.

In all financing scenarios except the 100% state grant, the ability or nonability to repay financing debt has serious consequences. In cases with fixed capital costs and falling demand, management is likely to increase power prices to maintain revenue. In any event, this scenario would result in an increase in the range of power available for industrial development if capacity is built before the Alaskan economy enters stagnation or downturn.

Summary of Potential for Surplus Energy

Table IV-1 summarizes the potential for surplus energy that might develop in the Railbelt. The data in the table indicate that if all the contemplated projects are built and if the Railbelt region experiences a low growth rate (2.2% per year), up to 5,350 GWh of annual output could be available by 2010 to attract electrically intensive industries. Even if the Cook Inlet and Chackachamna facilities are not built, 2,000 GWh of annual output could be available by 2000 if Devil Canyon is built and the "fiscal crisis" scenario develops.

Table IV-1

SUMMARY OF POTENTIAL SURPLUS ENERGY*

	2000	2010
Watana/Devil Canyon[1]	1,300 GWh	
Watana/Devil Canyon and Cook Inlet Tidal[1]	1,300 GWh	5,300 GWh
Watana alone[2]	2,500 GWh	
Watana/Devil Canyon[2]	3,800 GWh	

*Without consideration of project financing.

[1]Assumes Acres low demand case.

[2]Assumes Battelle "Fiscal Crisis" case.

V WORLDWIDE POWER PROJECTS COMPETITIVE WITH ALASKA'S HYDROELECTRIC DEVELOPMENT

Roughly half of the world's hydropower potential (approximately 1,200 GW) is in developing countries. Only 10% of the potential projects have been developed. Tables V-1 and V-2 show the status of worldwide hydroelectric development. Given the large increases in oil prices, many previously uneconomical hydroelectric sites have become more attractive. Developing countries are funding hydropower surveys and feasibility studies to explore these possibilities, but because of the long lead time for such projects and high financing cost, very few large projects will be completed during the present decade. Nevertheless, about 100 GW of hydroelectric capacity are expected to be completed over the next decade in some 60 developing countries. At fuel oil prices of $20-$25 per barrel, hydropower costing $2,500 to $3,000 per kilowatt of installed capacity can be competitive with oil-fueled steam units or large diesels. At this investment cost, assuming financing at 10%, hydroelectricity would cost about $0.07/kWh. Several sites, particularly in Canada and Brazil, have projected rates of about $.015/kWh. With power costs of $.0125/kWh for large industrial users, Le Grande Complex in Quebec will be a competitor of the Railbelt for electrically intensive industries. Moreover, significant amounts of power are expected to be available for industrial use from this facility.

Industry is a major user of commercial energy in the developing world. In countries for which data are available, the industrial sector accounts for one-fifth to two-thirds of total commercial energy consumption, with an average at around 35%.

Those developing countries with relatively high levels of energy consumption are also major producers of the more energy-intensive industrial products, such as steel (Brazil, India, Republic of Korea, Mexico, Romania, Turkey, Yugoslavia), cement (Brazil, India, Republic of Korea, Romania, Turkey), ammonia (India, Indonesia, Republic of Korea, Mexico, Romania), aluminum (Brazil, India, Yugoslavia), pulp and paper (Brazil, Republic of Korea, Mexico, Romania), fertilizers (India, Brazil, Romania, Turkey), and chemicals (Brazil, India, Portugal, Romania). These countries are potential competitors of Alaska as industrial sites.

Table V-1

HYDROELECTRIC DEVELOPMENT STATUS
(MW)

Country	Installed Capacity	Under Construction	Planned	Other Probable
Australia (1981)	6,113	-	2,350	9,765
Argentina (1979)	3,900	3,872	33,717	8,340
Brazil (1979)	23,842	26,163	14,096	100,000
Chile (1979)	1,480	950	6,595	6,781
Venezuela (1979)	3,000	2,620	13,565	-
India (1979)	9,908	6,820	1,978	42,000
Indonesia (1979)	450	-	2,500	31,000
Nepal (1979)	37	90	80,000	-
Colombia (1979)	3,120	1,150	23,350	23,600
Iceland (1979)	3,069	-	-	28,000
Honduras (1979)	69	600	-	3,000
Nigeria (1979)	600	1,145	1,200	8,000
Guatemala (1977)	121	600	1,635	4,000
Thailand (1977)	910	185	19,602	-
New Zealand (1978)	3,766	-	-	-

Table V-2

INTERNATIONAL DEVELOPMENT STATUS OF HYDROELECTRIC POWER SITES--INSTALLED OR INSTALLABLE CAPACITY (MW)

Country	Operating	Under Construction	Planned	Other Probable	Total
World	402,294	122,137	247,105	457,850	1,229,386
Canada	40,810	17,522	4,050	37,397	99,779
U.S.	68,933	8,200	2,013	103,477	182,623
Asia and Pacific					
Australia	5,695	1,660	2,350	-	9,705
New Zealand	3,617	868	1,320	5,000	10,805
Nepal	36	-	-	-	36
Philippines	725	2,085	-	4,778	7,588
Sri Lanka	335	-	-	-	335
Thailand	910	185	19,602	-	20,697
India	9,353	6,820	1,978	-	18,151
Indonesia	976	-	2,500	28,500	31,976
Malaysia	350	348	838	1,150	2,686
Latin America					
Argentina	1,945	5,872	33,717	8,340	49,874
Brazil	19,038	26,163	14,096	44,734	104,031
Chile	1,474	950	6,595	6,781	15,800
Colombia	2,801	1,150	23,350	23,600	50,901
Guatemala	121	20	1,635	4,881	6,657
Honduras	69	-	-	-	69
Paraguay	265	-	-	-	265
Peru	1,412	488	-	37,140	39,040
Uruguay	236	1,245	20	42,520,	1,926
Venezuela	2,353	2,620	13,565	0	18,538
Africa					
Angola	368	80	300	9,000	9,748
Ghana	792	-	140	527	1,459
Madagascar	40	-	-	-	40
Mozambique	937	3,700	2,500	5,000	12,137
Nigeria	420	440	3,930	-	4,790
Zaire	1,159	289	-	32,000	33,448
Zambia	1,669	-	-	-	1,669

Source: Yearbook of World Energy Statistics, United Nations (1979).

VI INDUSTRIAL LOCATION DECISIONS

General

Business location decisions depend on a variety of site-specific factors, the objectives of the particular company involved, and the changing business environment and health of the relevant industry. Justification for specific facilities is an outgrowth of specific corporate strategies. The compelling reasons behind the search for new sites include:

- Expansion of existing production capacity
- New product manufacturing
- Cost reduction of production and distribution
- Expansion of market area
- Replacement of obsolete facilities.

Table VI-1 lists typical site selection criteria. Five broad categories--labor costs, transportation costs, utility costs, construction and other occupancy costs, and tax costs--represent about 90% of the total geographically variable cost factors associated with a typical plant location study. Usually treated as recurring expenses, these costs are therefore annualized; their totals represent a major input into locational decisions by most companies.

Usually a number of noncost, or subjective, factors are investigated during the course of a facility location project. The list may be as short as a half-dozen or as long as 100 or more. However, most company lists include at least labor issues (unionism, attitudes, availability), electric power and natural gas availability and dependability, physical site suitability, community attitude toward business development, and living conditions.

The specific measures used by an industry to determine each location's degree of compliance with the general location criteria consist of two types of screens: (1) thresholds or minimum requirements that must be met by any location to be considered suitable for a plant, such as those relating to environmental regulations or availability of required utilities, transportation facilities, and land and buildings; and (2) relative measures that provide a basis for comparing locations that meet all minimum requirements, such as those relating to production factors and quality of life issues.

Once the list of alternative locations is narrowed, specific cost analyses of total facility costs attributed to labor, transportation, amortization, utilities, taxes, and other costs are often conducted.

Table VI-1

GENERAL SITE SELECTION CRITERIA

Financial Considerations

- Overall cost of living
- Cost of transportation for feedstock and parts to plant and for product to marketplace
- Cost of direct and indirect labor
- Utility costs
- Salary levels
- Taxes on industry
- Availability of industrial development assistance
- Availability of capital
- Overall operating costs
- Employee relocation costs
- Cost of land and buildings
- Construction costs, including expense of added time for permit approval

Locational Considerations

- Availability and reliability of utilities
- Proximity to transportation, including airports, rail lines, trucking, shipping, and mass transit
- Proximity to like industries
- Proximity to materials, vendors, and services
- Start-up training and facilities
- Stability of regulatory and political climate
- Labor union presence
- Environmental sensitivities
- Recruitment potential and labor availability
- Legal status of land ownership

Quality of Life Considerations

- Quality of public schools
- Availability and cost of housing; potential neighbors
- Cultural activities
- Presence of major university--4-year, 2-year, vocational
- Recreational activities
- Climate
- Community attitudes
- Alternative employment potential
- Proximity to resource centers for professional development

Compromises are almost always necessary in locating a new facility. For example, a company may have extensive requirements for electricity that would cause it to select a second-best site. Many site selections result from arbitrary corporate decisions that contradict purely economic analyses. This situation most often occurs when economic variations between competing sites show few significant differences and personal preferences by corporate management become the deciding factor. A list of the site selection factors considered by industry in analyzing energy issues is presented in Table VI-2.

Electrically Intensive Industries*

The cost of electric power, like the cost of any input to production, will affect Alaska's attractiveness as a location for new production facilities, but low-cost electricity by itself is insufficient to attract industry. For example, although a typical aluminum plant incurs electrical energy costs from 14% to 18% of product value, the extra construction costs (1.6 times U.S. average) and other additional expenditures associated with an Alaskan location may outweigh the benefit of reduced electricity costs.

Plant Location Factors

New forces are emerging that are shifting the weight of the relative measures for comparing locations. Cost factors are changing significantly, making future cost projections difficult. Figure VI-1 shows that transportation, electric power, and occupancy costs have increased much more dramatically during the past 10 years than the cost of labor or local property taxes.

Changes in transportation costs during the past 10 years have been closely linked to escalating fuel costs. As transportation costs increase, the importance of strategic markets and raw material availability increases for new plant sites.

Electric power costs have escalated rapidly during the past 10 years and can be expected to continue to increase over the next 10 years. Electricity rates for large industrial users rose by 18% between 1980 and 1981 alone, and recent increases in the Northwest have dramatically shifted the economics of existing plants.

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*Derived from A. R. Tussing in "Introduction to Electric Power Supply Planning," Tussing and Associates, May 1980.

Table VI-2

SITE LOCATION FACTORS RELATING TO
ELECTRIC ENERGY AND UTILITIES

<u>Power Source</u>

- Thermal--coal, natural gas, propane, fuel oil, lignite
- Hydroelectric
- Other--nuclear, geothermal, solar

<u>Electric Power Supply</u>

- Company or public agency serving area
- Interconnection with other systems
- Capacity--present and planned
- Recent record of shortages or interruptions
  - Average number of interruptions per year
  - Maximum duration
- Vulnerability to natural disasters
- Location of nearest electric substations and whether interlocking
- Voltage, phase, and cycle available
- Size of connection at proposed site
- Two-way feed
- Rates based on demand for services
  - Lighting
  - Machine operation
  - Air conditioning
  - Welding
  - Furnaces
- Cost of extending service
- Typical residential rates
- Off-peak possibilities
- Fuel adjustment provisions

<u>Potential for On-Site Independent Energy Source</u>

- Gas well
- Coal mine
- Nuclear reactor
- Cogeneration
- Waste burning

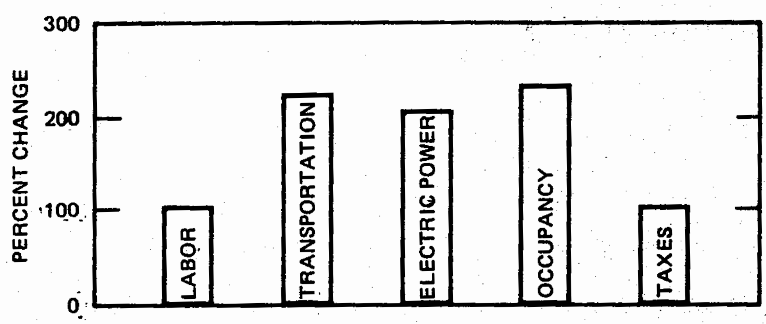

FIGURE VI-1 PERCENT CHANGE IN KEY COST FACTORS, 1970-1980

As competition among the states for new facilities increases, more and more states are seeking to improve their business climates to attract new industries. Although median tax rates have increased from about 2% to 4% of total investment during the past 10 years, more states are granting full or partial exemption to various classes of property to lure new facilities. Similarly, state levies on corporate income have remained relatively stable. Only two states have increased corporate income taxes during the past 5 years.

Occupancy costs have risen faster than any other costs during the 1970s. Both of the key elements that make up this cost, construction costs and interest rates, have doubled during the past 10 years. A $2 million building in 1970 cost $4,444,000 in 1980. A typical revenue bond interest rate in 1970 of 7% nearly doubled to 13% by 1980. The annual cost to amortize a 25-year loan jumped more than 250% between 1970 and 1980.

A review of site location studies written during the early 1970s reveals a concern with unionism, natural gas availability, proximity to interstate highways, and proximity to various support services. By 1980, additional factors such as state and community attitude toward industry, environmental concerns, living conditions, airline and truck service, and electric power availability and reliability are equally important.

Companies are becoming more concerned, in making their siting decisions, about living conditions, community attitudes, and political stability. In addition to forecasting geographically variable costs, corporations will become more adept at evaluating noncost or subjective factors. These concerns could become significant when comparing an Alaskan site to a site in a developing country with competing low-cost hydroelectric power. The relative political stability offered by Alaska represents a real asset when compared to the political uncertainty in many developing countries, although this asset may be offset by the economic uncertainty resulting from the expected decline in oil revenues in the 1990s.

During the next 10 years, additional issues such as water availability are expected to increase in importance. The availability of grants, subsidies, and inducements will also be a major locational criterion. The aggressive worldwide competition for new industry, exemplified by Japanese aluminum smelters in Brazil and by U.S. microelectronics industry in Scotland, are becoming increasingly important as U.S. manufacturers look in both developed and developing countries for sites which lower their production costs.

VII CHARACTERISTICS, RESOURCES, AND LIMITATIONS OF THE RAILBELT REGION

Characteristics of the Railbelt region critical to industry-specific location decisions are:

- Labor costs and supply
- Taxation
- Construction costs
- Transportation cost and infrastructure
- Land status
- Climate
- Environmental considerations and land use plans
- Basic services and secondary industry
- Natural resources
- Existing industry
- Geographical location and proximity to markets

Alaska's principal economic attractions are its potential supply of undeveloped raw materials and fuel and its power availability. These attractive features must be weighed against those factors of the Alaskan economy which will prevent certain types of development in the state for the foreseeable future.

Labor Costs and Supply

As indicated in Table VII-1, the Railbelt has only limited supplies of labor in the construction, mining, and manufacturing (industrial) sectors. Any major developments in those sectors would require a significant labor influx. The most recent, accurate data concerning labor supplies in the Railbelt region are the employment figures for the third quarter of 1980. The data in Table VII-1 represent the averages for that year and are given by sector and by subregion (census division).

Table VII-1

NUMBER OF EMPLOYEES BY SECTOR IN THE RAILBELT

Sector	Anchorage	Kenai	Mat-Su	Subtotal South Central	Fairbanks/ SE Fairbanks	Cordova/ Valdez	Total Railbelt	Percent Total
Government	20,356	1,169	1,281	22,806	7,460	1,100	31,366	26%
Services	17,182	1,023	511	18,716	4,554	686	23,956	20
Retail trade	13,324	1,048	792	15,164	3,662	332	19,158	16
Transportation, communication, utilities	8,318	671	306	9,295	2,882	608	12,785	11
Construction	7,190	902	267	8,359	2,374	360	11,093	9
Finance, insurance, real estate	4,900	203	115	5,218	698	123	6,039	5
Manufacturing	2,532	2,022	27	4,581	502	532	5,615	5
Wholesale trade	4,230	272	53	4,555	679	51	5,285	4
Oil & gas extraction	2,671	793	--	3,464	6	--	3,470	3
Other mining	244	--	53	297	74	152	523	--
Other	804	82	36	922	103	--	1,025	1
Total	81,751	8,185	3,441	93,337	22,994	3,944	120,315	100%
Percent Total	68%	7%	3%	78%	19%	3%	100%	

Source: U.S. Bureau of Labor Statistics

Alaskan wage rates for industrial occupations tend to be substantially above U.S. averages. For example, in 1982 the average construction worker's weekly wage in Anchorage was approximately 1.52 times the average of 27 other U.S. metropolitan areas (Table VII-2). Other industries such as services and manufacturing are somewhat closer to national averages. Hourly manufacturing wage rates in Alaska in 1980 were about 1.37 times higher than those for the U.S. as a whole and are expected to remain at least 1.3 times higher in most sectors throughout the study horizon of 1982-2010. In the specific industry analyses, which are contained in Section IX, labor data for the individual industries are used where available.

Not only are prevailing wage rates in Alaska relatively high, but Alaska does not have a large pool of highly skilled workers. Many of the recent unemployed are construction workers. Workers with specific skills in the oil industry and other specialized skills are generally recruited outside of the state.

In general, extractive and primary processing operations are less labor intensive than final product manufacture. In addition, the increased use of automation and robotics in manufacturing will decrease the importance of labor in this sector. Nevertheless, labor costs, especially for construction, will remain an inhibiting factor to any industry that does not gain an offsetting economic advantage from an Alaskan location (e.g., lower material or energy costs).

Taxation

Recent changes in Alaskan taxation policies have made the state more attractive to both individuals and corporations, although corporate income taxes remain high.

Most states levy corporate income and/or corporate franchise taxes as significant sources of state revenues. For 1982, the income tax rate for large corporations was significantly reduced in Alaska, to 9.4% from the previous maximum rate of 11%. This reduction makes Alaska more competitive with states such as California (9.6%), but the rate remains high relative to many Sunbelt states which have either no corporate income tax (Nevada, Texas) or rates in the 5% to 6% range (Alabama, Florida, Georgia, South Carolina, North Carolina, etc.). Alaska is also high relative to Pacific Northwest states. Washington has a business occupation tax of 1%, and Oregon has a 7.5% corporate tax rate.[2]

The retroactive repeal of personal income tax, in combination with the absence of a general sales tax, is a significant attraction to individuals and may eventually have a positive impact on Alaskan labor rates.

Table VII-2

HOURLY AVERAGE WAGE RATES IN CONSTRUCTION
FOR ANCHORAGE AND 27 U.S. METROPOLITAN AREAS
($ 1982/hr)

Albuquerque	15.10	Indianapolis	17.78
Anchorage	27.28	Kansas City	18.13
Atlanta	13.89	Miami	15.74
Baltimore	15.49	Minneapolis	17.52
Birmingham	13.41	New Haven	17.70
Boston	18.31	New York	19.33
Buffalo	18.39	Philadelphia	17.33
Chicago	19.25	Phoenix	19.28
Cincinnati	19.05	Pittsburgh	17.88
Cleveland	19.24	Portland, OR	20.51
Dallas	16.21	St. Louis	17.63
Denver	16.19	San Diego	22.30
Detroit	19.71	San Francisco	22.96
Houston	17.73	Seattle	21.06

Source: Engineering News-Record, September 23, 1982.

Construction Costs

Location adjustment factors computed to account for added construction costs in Alaska typically range from 1.5 to 2.0. Location adjustment factors increase as site locations move inland and northward. They are also dependent on the extent to which prefabrication can be performed in the lower 48 states.

Many estimates of Alaskan construction escalation factors were based on pipeline construction experience and reflect the high rates of inflation which occurred during that period. There is evidence that the Alaskan labor rate differential is moderating. Cost of living indexes for various Alaskan areas are not growing as rapidly as some other U.S. regions.[3] Nevertheless, 1982 hourly construction labor rates in Anchorage are approximately 1.52 times those of 27 other U.S. metropolitan areas (see Table VII-2).

Material costs also contribute to high construction costs in Alaska because of the necessity to import many materials. Some materials, such as sand and gravel, may be at or below national average prices because of their availability in Alaska. However, cement prices are approximately 2 times higher in Anchorage than in Seattle due to transportation charges. A general materials cost factor of 1.7 was assumed by SRI and is reasonable for the Railbelt region during the time frame of the study. Labor costs generally constitute about 1/3 of direct construction costs, with materials and project management costs accounting for the remainder. An overall construction factor of 1.5 can be derived for the Railbelt region based on current rates.

This factor is consistent with recent estimates obtained by SRI for specific plant construction cost factors in the Railbelt region. The engineering firm C. F. Braun recently quoted 1.5 as the construction offset factor, and Chevron (a component of Standard Oil of California) suggested 1.6 as a construction factor for a hypothetical ammonia/urea plant constructed in the Railbelt. Wherever possible, construction cost factors for specific plants have been used in the SRI study. These location factors would probably decrease over time, assuming that Alaska economic development continues.

Transportation Costs and Infrastructure

The Railbelt region has the only comprehensive transportation system in the state. All of the urban centers are connected by air, rail, and highway links and have good access to ocean shipping. Specialized oil ports exist in Valdez and Cook Inlet. A coal terminal is planned for Seward, and grain terminals are being planned for Seward and Valdez. A specialized coal terminal is also contemplated for the Beluga coal fields.* Specific areas set aside for energy, industrial, and port development activities include the Port of Anchorage, Point MacKenzie (Mat-Su Borough), and the Port of Seward.

Transportation costs are high both within Alaska and between Alaska and its markets and suppliers. Because the state's transportation infrastructure is limited, low-cost intrastate transportation is scarce. Many areas can only be reached by air, or by sea in ice-free months. The costs of transportation to areas outside of the Railbelt are high because of their remoteness and because of the small quantities shipped and lack of backhaul. The cost of shipping equipment to or product from a mine or plant off the established transportation routes places the additional burden of road construction on any prospective developer.

Until additions to this infrastructure are made, most development will be limited to the coastal and immediate Railbelt areas. Only projects with immense economic potential will be able to finance their own transportation facilities (e.g., the oil/gas pipelines, coal facilities) and those projects will occur only as dictated by world market and national policy considerations. Beyond the Anchorage/Fairbanks corridor, little infrastructure is available to serve industries and their employees. Any mining or manufacturing activities outside of the Anchorage/Fairbanks corridor will have to provide housing and other population-serving infrastructure--either temporary camps or permanent new towns--for workers.

Because of the lack of a major inland waterway transportation infrastructure, locations in Alaska near coastal areas can be expected to be favored for process plants. Pulp, chemicals, and primary metals are all industries that typically require waterborne transport access.

Industries whose transportation costs are low relative to the value of product have more flexibility in location decisions than those with comparatively high transportation costs. Industries that produce high-value, low-weight products may choose locations that minimize power, labor, or other costs.

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*The transportation network is described in detail in ISER, Alaska's Unique Transportation System (June 1980), and Booz, Allen, Strategic Marketing Plan for Port of Anchorage, Chapters II and III and Appendix B (February 1981).

In summary, transportation costs will remain a major factor in Alaska's future economic development because of the costs involved in transporting natural resources and feedstocks to processing facilities and the costs of transporting goods to international markets.

Land Status

A great deal of important land in the Railbelt is still under federal ownership, a fact that will limit certain resource extraction and industrial activities. Much of the Anchorage coastline, for example, is owned by the Alaska Railroad (a federal entity) and the Department of Defense. The Fairbanks area also has large military reservations and other federal holdings.

Land status is currently in flux because of the slow pace of selection by, and conveyance to, the state and native corporations. Site-specific information about particular land areas is available from federal, state, and local authorities for areas under their respective jurisdictions and from private holders, including native corporations.

Although land availability is a negative factor for firms seeking to exploit mineral resources, most land that might be desired for industrial development in the Railbelt region could be leased for the economic life of the facility, which should be a satisfactory arrangement to most firms.

Climate

Not only is the Railbelt region's climate severe, but Fairbanks often has extensive ice smog created by air inversions trapping sediments and particles from burning fuels in the river valleys of the area, and active volcanoes are located in the Cook Inlet region. Permafrost is a unique subsurface characteristic of the Arctic that poses special problems for construction.

Alaska's climate limits most construction and extraction activities to the summer months and curtails transportation to northern parts of the state in winter. The limitations imposed by the weather raise the overall cost of doing business in the state (e.g., creating a need for substantial summer overtime hours and premiums in construction or for costly air freight transport in the winter). Weather conditions in the Railbelt region are a severe inhibitor to the location of manufacturing industries in Alaska, not only because of construction and operating cost considerations but also because it restricts freedom of movement for personnel and material during much of the winter.

Environmental Considerations and Land Use Plans

Uncertainty over the state's future environmental policies, especially for pristine wilderness areas, may inhibit new industry. An example of such uncertainty is the state's mineral tax policy. The question of whether royalties and severance taxes (similar to those on oil and gas) should be imposed on hardrock minerals and the rates of such taxes remain unsolved. In addition, opinions on what the state should seek to gain through industrial development are contradictory and unresolved.

The Anchorage and Matanuska-Susitna boroughs (Mat-Su) have standards for energy facility siting. Anchorage has a formal coastal management plan. Mat-Su, Kenai/Cook Inlet, and Valdez have written plans which are currently being reviewed and are in the approval process. All permit--and encourage--industrial location in designated areas. The state also has a natural resources plan for its lands. Most intermediate product manufacturers and bulk material producers require large sites to accommodate plants and facilities. The effect of land use plans must be considered on a project-by-project basis once the initial threshold requirements have been met.

Basic Services and Secondary Industry

Local representation of major infrastructure (e.g., insurance firms, repair services, banking) and secondary industry firms (e.g., emergency resupply for mechanical or electrical failure) can be an important factor in plant location decisions. The perceived lack of secondary support facilities is likely to be a major inhibiting factor for the location of new industries in Alaska.

Many aspects of developed industrial infrastructure, such as specialized industrial supplies and services, apart from petroleum extractors and transportation services, do not currently exist in Alaska. Repair services, machine shops, parts depots, and other complementary firms will have to be established concurrently with industrial development, or such supplies and services will have to be imported at high cost.

Natural Resources

The major natural resources of the Railbelt include coal, minerals, and metal ores (although no bauxite reserves for aluminum production), oil and natural gas, fish and shellfish, forests (soft and hardwood), nonfuel minerals; and water (for hydroelectric generation and for consumption). Historically, economic development in any region has usually begun with some type of resource extraction. Mineral resources that have not yet been extensively developed can become the basis for primary processing industries, including mining and smelting. Timber and fishing resources have supported most of Alaska's manufacturing activity to date, and it is likely that manufacturing based on these resources can be expanded.

A special category of natural resources includes hydrocarbons, which can serve as raw materials as well as fuels for manufacturing processes. Industries such as food processing, pulp and paper, petrochemicals, primary and fabricated metals, and electrometallurgical processes require stable and/or low-cost supplies of oil, gas, or coal as process fuels or as feedstocks as well as the appropriate materials, minerals, and metals for processing. The potential of Alaskan oil and gas as industrial feedstocks is widely recognized and proposals for in-state processing of royalty oil have been considered. If oil and natural gas (including LNG) become more expensive and scarce, the availability of petroleum feedstocks will become an increasingly attractive factor.

While oil and particularly natural gas have traditionally been used as industrial process fuels, this use will become less widespread as costs continue to increase and regulatory actions encourage use of other fuels (primarily coal). In this regard, Alaska also has vast quantities of low-sulfur steam coal available for industrial use. The ready avail- ability of water in the south central region could be particularly important for those industries that require significant amounts of process water (e.g., food products, particularly beverages, pulp and paper, chemicals), particularly in view of the shortfalls in water availability predicted for many regions of the U.S.

The presence of important natural resources is not sufficient to guarantee development. For example, extensive high-grade strategic metals and minerals are present in the Brooks Range, but development of the transportation infrastructure for extraction is economically prohibitive.

Existing Industry

Government is the major employer in the Railbelt (see Table VII-1), and most of the employment in the region is associated with services. Although relatively small, the petroleum industry has the character of a true basic industry in that the Railbelt includes the people and facilities for administration (primarily in Anchorage), transportation (primarily in Valdez and Kenai), and processing (North Pole refinery near Fairbanks and Tesoro and Chevron Oil refineries, Phillips LNG plant, and Union Chemicals nitrogen fertilizer plant, all located at Nikiski, Kenai), as well as exploration and development.

Employment statistics for the petroleum industry are aggregated by reporting agencies to avoid disclosure of individual business reporting units. The labor force in the petroleum sectors is estimated, however, to include about 3,650 to 4,900 persons.

Petroleum production capacities are as follows:

	Capacity (barrels/day)
Kenai	
Tesoro oil refinery	48,000
Chevron oil refinery	22,000
Fairbanks	
Mapco North Pole refinery	47,000

Another major plant is the Union chemical fertilizer plant, which produces 1 million tons of liquid ammonia per year and 800,000 tons of urea per year. The Phillips LNG plant produces 140 million cubic feet of LNG per year for the Japanese market.

Other than those associated with the petroleum industry, there are few industry groupings already in Alaska to naturally attract similar firms or suppliers.

Geographical Location and Proximity to Markets

Alaska's remoteness and the requirement to use U.S. registered ships for U.S.-bound goods results in high shipping costs between Alaska and the rest of the United States. The state's vastness also increases the likelihood of future developments being remote from the state's population centers or from the principal resource base. If a primary processing facility is located near a mine to minimize ore handling and shipping, for example, provisions will have to be made to provide housing and related facilities for workers. Alternatively, a firm performing processing near the population centers will have to transport bulk ores from the mine. Similarly, the distance from Anchorage, the commercial center, to the many outlying towns and villages will make it very difficult for even an Anchorage-based producer to supply the in-state market at reasonable prices. In addition, Alaska's remoteness from the Lower 48 may discourage small or medium-sized firms from even considering Alaska as a potential site.

Alaska's local market is quite small (approximately 400,000 people) and is further limited by the difficulties of distributing products to the more remote areas. Furthermore, unlike other states with relatively small markets, no neighboring states can absorb excess production of local market-oriented goods. The most basic local market industries do exist in Alaska--bakeries and newspapers, for example--but the population is too small to support other consumer-product makers. The need to ship excess production at possibly high cost will inhibit development of locally oriented consumer or industrial suppliers until local demand is sufficiently sustained to support such industries.

Service industries, which are the fastest growing segment of the U.S. economy, locate near the population centers or companies they serve. Intermediate product industries, such as concrete producers, metal forgers, commercial printers, and glass container makers, tend to locate near industrial or commercial purchasers of their products. In many of these industries, industrial development must occur sequentially. For example, a plastics manufacturer may logically locate near a petrochemical complex as long as product transportation costs to the marketplace are relatively low. The sequencing or downstream integration of production facilities depends on upstream materials being available.

Alaska's geographic location on the Pacific Ocean is tantalizing. As the international procurement of materials and the international manufacturing of products increase, Alaska's location may be more beneficial than previously assumed. The ports in the south central region of the Railbelt are closer to Japan and Korea than the Lower 48 ports; unfortunately, this factor is currently largely offset by higher construction, labor, and operating costs in the Railbelt region.

Summary

The major advantages of developing an Alaskan industrial site are the state's vast supplies of natural resources and its fuel and feedstocks for extraction and initial processing industries. As natural resources and fuel or power shortages develop, Alaska will become an increasingly attractive site. Alaska is also favorable in comparison to many developing countries, which have the potential for political instability.

Deterrents to an industry's siting its facilities in Alaska arise from the state's economic environment, as well as industry-specific resource development constraints. Inhibiting factors are generally those that raise the costs of operating in Alaska, making Alaska-produced goods less competitive in U.S. and world markets, or that contribute to an adverse business climate (e.g., highly publicized environmental lawsuits and Teamsters Union activities have had a detrimental effect on corporations contemplating expansion into Alaska).

The principal inhibitors to development in Alaska are:

- High labor costs (1.3 to 1.5 times U.S. average) and lack of skilled labor.

- Lack of transportation and other infrastructure.

- High construction costs (1.5 times U.S. average is typical).

- Remoteness from major markets (transportation costs--highly dependent on product and destination).

- Limited local market.

- Institutional and regulatory issues:

  - Uncertain land status
  - Environmental constraints
  - Federal government influence.

- Climate.

- Relatively high corporate taxes.

The relative importance of inhibiting factors to economic development and industry-specific location decisions varies, depending on the proposed industrial facility, the economic health of the industry, and world market trends. Most of the Railbelt characteristics that presently inhibit industrial development increase the operating costs for industry. The advantages of an Alaskan location, such as proximity to specific resources and Pacific markets, are insufficient to offset these additional operating costs for most industries. The special case of electrically intensive industries will be examined in the next section.

VIII IDENTIFICATION OF POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL POWER

To identify potential industries that might be attracted to Alaska by the long-term availability of inexpensive electrical energy, SRI compared U.S. Department of Commerce data on the value of purchased electrical energy with the value of shipped product for over 960 4-digit Standard Industrial Classification (SIC) code industries. The four SIC industries for which electrical energy costs exceed 10% of the value of the shipped product are listed in Table VIII-1. Firms in these Category I industries are considered the most likely to consider an Alaskan site for new plant facilities if long term, low cost electrical power becomes available in the Railbelt region.

Additional industries considered as secondary candidates are listed in Table VIII-2. For these Category II industries, electrical power costs range between 5% and 10% of the value of shipped product. The lure of inexpensive energy will generally be less important for firms participating in the industries listed in Table VIII-2 than those in Category I.

Finally, the value of total (not just electrical) energy used was compared with the value of shipped product for all 4-digit SIC code industries to identify energy-intensive industries that might consider substituting inexpensive electrical energy for other forms of energy. These Category III industries identified during this process are listed in Table VIII-3, which does not include industries already listed in Table VIII-1 and Table VIII-2. Firms participating in Category III industries are considered to be less likely candidates for a Railbelt location than firms from the industries listed in Table VIII-1 and Table VIII-2, because of the largely unexplored issues associated with energy substitution.

Based on this initial screening, all four Category I industries were further evaluated to determine the potential additional costs of a Railbelt location for new plants in these industries. Of the Category II industries, manufactured ice, hydraulic cement, iron foundries, and reclaimed rubber were not considered likely candidates because of the obvious tradeoff between low product value and high transportation costs associated with these industries. An analysis of the transportation costs for cement is included in the study for comparison purposes and is considered to be representative of these low-value products. Malleable iron foundries and reclaimed rubber both depend on close proximity to associated industries (e.g., heavy machinery, automobile) and are unlikely to consider any locations which lack these supporting industries.

Table VIII-1

CATEGORY I: ELECTRICALLY INTENSIVE INDUSTRIES
(Electrical Energy Costs as Percentage of Product Value, 1980)

SIC Code	Description
2812	ALKALIES AND CHLORINE (18.8)

Establishments primarily engaged in manufacturing alkalies and chlorine.

Alkalies	Potassium hydroxide
Carbonates, potassium and sodium	Sal soda
Caustic potash	Soda ash
Caustic soda	Sodium bicarbonate
Chlorine, compressed or liquefied	Sodium carbonate (soda ash)
Potassium carbonate	Sodium hydroxide (caustic soda)

SIC Code	Description
2813	INDUSTRIAL GASES (23.3)

Establishments primarily engaged in manufacturing gases for sale in compressed, liquid, and solid forms. Establishments primarily engaged in manufacturing fluorine and sulfur dioxide are classified in Industry 2819, household ammonia in Industry 2842, and other ammonia in Industry 2873, and chlorine in Industry 2812. Distributors of industrial gases and establishments primarily engaged in shipping liquid oxygen are classified in trade. Ammonia and chlorine production are considered separately. Fluorine, sulfur dioxide, and liquid oxygen are expected to have production economics similar to the gases listed in SIC 2813.

Acetylene	Helium
Argon	Hydrogen
Carbon dioxide	Neon
Dry ice (solid carbon dioxide)	Nitrogen
Gases, industrial: compressed, liquefied, or solid--mfpm	Nitrous oxide
	Oxygen, compressed and liquefied

Table VIII-1 (Concluded)

SIC Code	Description
3313	ELECTROMETALLURGICAL PRODUCTS (14.1)

Establishments primarily engaged in manufacturing ferro and nonferrous additive alloys by electrometallurgical or metallothermic processes, including high-percentage ferroalloys and high-percentage nonferrous additive alloys.

- Additive alloys, except copper: not produced in blast furnaces
- Electrometallurgical products, except aluminum, magnesium, and copper
- Ferroalloys, not made in blast furnaces
- Ferrochromium
  - Ferromanganese, not produced in blast furnaces
  - Ferromolybdenum
  - Ferrophosphorus
  - Ferrosilicon, not produced in blast furnaces
- Ferrotitanium
- Ferrotungsten
- Ferrovanadium
- High-percentage ferroalloys, not produced in blast furnaces
- Manganese metal, not produced in blast furnaces
- Molybdenum silicon, not produced in blast furnaces
- Nonferrous additive alloys, high percentage: except copper
- Steel, electrometallurgical

SIC Code	Description
3334	PRIMARY PRODUCTION OF ALUMINUM (15.4)

Establishments primarily engaged in producing aluminum from alumina, and in refining aluminum by any process. Establishments primarily engaged in rolling, drawing, or extruding aluminum are classified in Industries 3353, 3354, and 3355 and are not classified as electrically intensive.

- Aluminum ingots and primary production shapes, from bauxite or alumina
- Extrusion ingot, aluminum: primary
- Pigs, aluminum
- Slabs, aluminum: primary

Source: U.S. Commerce Department Data

Table VIII-2

CATEGORY II: ELECTRICALLY INTENSIVE INDUSTRIES
(Electrical Energy Costs as Percentage of Product Value, 1980)

SIC Code	Description
2097	MANUFACTURED ICE (8.0)

Establishments primarily engaged in manufacturing ice for sale. Ice plants operated by public utility companies are included in this industry when separate reports are available. (Establishments primarily engaged in manufacturing dry ice are classified in Industry 2813 and have not been analyzed.)

Block Ice
Can ice
Ice cubes
Ice, manufactured or artifical: except dry ice
Ice plants, operated by public utilities

SIC Code	Description
2661	BUILDING PAPER AND BUILDING BOARD MILLS (5.6)

Establishments primarily engaged in manufacturing building paper and building board from wood pulp and other fibrous materials. Pulp mills combined with building paper and building board mills, and not separately reported, are also included in this industry; where separately reported, they are classified in Industry 2611.

Asbestos paper and asbestos-filled paper, mitse
Asphalt board and sheathing, mitse
Asphalt paper: laminated--mitse
Board, building: composition, cellular fiber, and hard pressed--mitse
Board, building; except gypsum--mitse
Building board, mitse
Building paper: sheathing, insulation, saturating, and dry felts--mitse
Construction paper, mitse
Dry felts, mitse
Felts, building: unsaturated--mitse
Fiber board, wood or other vegetable pulp: mitse
Insulating siding, paper or board, mitse
Insulation board, cellular fiber or hard pressed (without gypsum): mitse
Kraft sheathing paper, mitse
Lath, fiber: mitse
Paper, building: mitse
Paperboard, building (containing no gypsum): mitse
Roofing board and felt stock, unsaturated: mitse
Roofing, wood fiber: mitse
Saturated felts, mitse
Tar paper, building and roofing: mitse
Wall tile, fiber board: mitse
Wallboard, except gypsum: cellular fiber or hard pressed--mitse

Table VIII-2 (Continued)

SIC Code	Description
2819	INDUSTRIAL INORGANIC CHEMICALS, NEC (8.7)

Establishments primarily engaged in manufacturing industrial inorganic chemicals, not elsewhere classified. Important products of this industry include inorganic salts of sodium (excluding refined sodium chloride), potassium, aluminum, calcium, chromium, magnesium, mercury, nickel, silver, tin; inorganic compounds such as alums, calcium carbide, hydrogen peroxide, sodium silicate, ammonia compounds (except fertilizers), rare earth metal salts and elemental bromine, fluorine, iodine, phosphorus, and alkali metals (sodium, potassium, lithium, etc.). Establishments primarily engaged in mining, milling, or otherwise preparing natural potassium, sodium, or boron compounds (other than common salt) are classified in Industry 1374, which is not electrically intensive. Establishments primarily engaged in manufacturing household bleaches are classified in Industry 2842, which is not electrically intensive; phosphoric acid in Industry 2874; and nitric acid, anhydrous ammonia, and other nitrogenous fertilizer materials in Industry 2873 are discussed separately.

Activated carbon and charcoal
Alkali metals
Alumina
Aluminum chloride
Aluminum compounds
Aluminum hydroxide (alumina trihydrate)
Aluminum oxide
Aluminum sulfate
Alums
Ammonia alum
Ammonium chloride, hydroxide, and molybdate
Ammonium compounds, except for fertilizer
Ammonium perchlorate
Ammonium thiosulfate
Barium compounds
Bauxite, refined
Beryllium oxide
Bleaching powder
Borax (sodium tetraborate)
Boric acid
Bromine, elemental
Cesium metal
Calcium carbide, chloride, and hypochlorite
Calcium compounds, inorganic
Calcium metal
Calomel
Carbide
Catalysts, chemical
Cerium salts
Charcoal, activated
Chlorosulfonic acid
Chromates and bichromates
Chromic acid
Chromium compounds, inorganic
Chromium salts
Cobalt chloride
Cobalt 60 (radioactive)
Cobalt sulfate
Copper chloride
Copper iodide and oxide
Copper sulfate
Cyanides

2819 INDUSTRIAL INORGANIC CHEMICALS, NEC (8.7) (Continued)

Boron compounds, not produced at mines
Borosilicate
Brine
Fissionable material production
Fluorine, elemental
Fuel propellants, solid: inorganic
Fuels, high energy: inorganic
Glauber's salt
Heavy water
High purity grade chemicals, inorganic: refined from technical grades
Hydrated alumina silicate powder
Hydrochloric acid
Hydrocyanic acid
Hydrofluoric acid
Hydrogen peroxide
Hydrogen sulfide
Hydrosulfites
Hypophosphites
Indium chloride
Inorganic acids, except nitric or phosphoric
Iodides
Iodine, elemental
Iodine, resublimed
Iron sulphate
Isotopes, radioactive
Laboratory chemicals, inorganic
Lead oxides, other than pigments
Lead silicate
Lime bleaching compounds
Lithium compounds
Lithium metal
Luminous compounds, radium
Magnesium carbonate
Magnesium chloride
Magnesium compounds, inorganic
Manganese dioxide powder, synthetic
Mercury chlorides (calomel, corrosive, sublimate), except U.S.P.
Mercury compounds, inorganic
Mercury oxides
Mercury, redistilled
Metals, liquid
Desiccants, activated: silica gel
Dichromates
Ferric chloride
Ferrocyanides
Potassium iodide
Potassium metal
Potassium nitrate and sulfate
Potassium permanganate
Propellants for missiles, solid: inorganic
Radium chloride
Radium luminous compounds
Rare earth metal salts
Reagent grade chemicals, inorganic; refined from technical grades
Rubidium metal
Salt cake (sodium sulfate)
Salts of rare earth metals
Scandium
Silica, amorphous
Silica gel
Silicofluorides
Silver bromide, chloride, and nitrate
Silver compounds, inorganic
Soda alum
Sodium aluminate
Sodium aluminum sulfate
Sodium antimoniate
Sodium bichromate and chromate
Sodium borates
Sodium borohydride
Sodium bromide, not produced at mines
Sodium chlorate
Sodium compounds, inorganic
Sodium cyanide
Sodium hydrosulfite
Sodium, metallic
Sodium molybdate
Sodium perborate
Sodium peroxide
Sodium phosphate
Sodium polyphosphate
Sodium silicate
Sodium silicofluoride

Table VIII-2 (Continued)

2819 INDUSTRIAL INORGANIC CHEMICALS, NEC (8.7) (Concluded)

Mixed acid
Muriate of potash, not produced at mines
Nickel ammonium sulfate
Nickel carbonate
Nickel compounds, inorganic
Nickel sulfate
Nuclear cores, inorganic
Nuclear fuel reactor cores, inorganic
Nuclear fuel scrap reprocessing
Oleum (fuming sulfuric acid)
Oxidation catalyst made from porcelain
Perchloric acid
Peroxides, inorganic
Phosphates, except defluorinated and ammoniated
Phosphorus and phosphorus oxychloride
Potash alum
Potassium aluminum sulfate
Potassium bichromate and chromate
Potassium bromide
Potassium chlorate
Potassium chloride and cyanide
Potassium compounds, inorganic: except potassium hydroxide and carbonate
Potassium cyanide
Potassium hypochlorate
Sodium stannate
Sodium sulfate--bulk or tablets
Sodium tetraborate, not produced at mines
Sodium thiosulfate
Sodium tungstate
Sodium uranate
Stannic and stannous chloride
Strontium carbonate, precipitated, and oxide
Strontium nitrate
Sublimate, corrosive
Sulfate of potash and potash magnesia, not produced in mines
Sulfides and sulfites
Sulfocyanides
Sulfur chloride
Sulfur dioxide
Sulfur hexafluoride gas
Sulfur, recovered or refined, including from sour natural gas
Sulfuric acid
Tanning agents, synthetic inorganic
Thiocyanates, inorganic
Tin chloride
Tin salts
Uranium slug, radioactive
Water glass
Zinc chloride

Table VIII-2 (Continued)

SIC Code	Description
3031	<u>RECLAIMED RUBBER</u> (6.9) Establishments primarily engaged in reclaiming rubber from scrap rubber tires, tubes, and miscellaneous waste rubber articles by processes which result in devulcanized, depolymerized, or regenerated replasticized products containing added ingredients. These products are sold for use as a raw material in the manufacture of rubber goods with or without admixture with crude rubber or synthetic rubber. Establishments primarily engaged in the assembly and wholesale sale of scrap rubber are classified in trade industries. Reclaimed rubber (reworked by manufacturing processes)
3241	<u>CEMENT, HYDRAULIC</u> (7.4) Establishments primarily engaged in manufacturing hydraulic cement, including portland, natural, masonry, and pozzolan cements. Cement, hydraulic: portland, natural masonry, pozzolan
3322	<u>MALLEABLE IRON FOUNDRIES</u> (5.6) Establishments primarily engaged in manufacturing malleable iron castings. Castings, malleable iron Foundries, malleable iron Pearlitic castings, malleable iron

Table VIII-2 (Concluded)

SIC Code	Description
3339	PRIMARY SMELTING AND REFINING OF NONFERROUS METALS, NEC (5[illegible]4)

Establishments primarily engaged in smelting and refining nonferrous metals, not elsewhere classified. Establishments primarily engaged in rolling, drawing, and extruding these nonferrous primary metals are classified in Industry 3356, which is not electrically intensive, and the production of bullion at the site of the mine is classified in the mining industries.

Antimony refining, primary
Beryllium metal
Bismuth refining, primary
Cadmium refining, primary
Chromium refining, primary
Cobalt refining, primary
Columbium refining, primary
Germanium refining, primary
Gold refining, primary
Ingots, magnesium
Iridium refining, primary
Magnesium refining, primary
Nickel refining, primary
Nonferrous refining, primary: except copper, lead, zinc, and aluminum
Pigs, magnesium
Platinum-group metals refining, primary
Precious metal refining, primary
Primary refining of nonferrous metal: except copper, lead, zinc, aluminum
Primary smelting of nonferrous metal: except copper, lead, zinc, aluminum
Refining of nonferrous metal, primary: except copper, lead, zinc, aluminum
Rhenium refining, primary
Selenium refining, primary
Silicon, epitaxial (silicon alloy)
Silicon, pure
Silicon refining, primary (over 99% pure)
Silver refining, primary
Slabs, magnesium: primary
Smelting of nonferrous metal, primary: except copper, lead, zinc, aluminum
Tantalum refining
Tellurium refining, primary
Tin base alloys, primary
Tin refining, primary
Titanium metal, sponge and granules
Zirconium metal, sponge and granules

Source: Commerce Department Data

Table VIII-3

CATEGORY III: ENERGY-INTENSIVE INDUSTRIES
(Total Energy Costs as Percentage of Product Value, 1980)

SIC Code	Description	Energy Costs As Percent of Product Value
2046	Wet Corn Milling	8.7
2063	Beet Sugar	8.3
2083	Malt	6.7
2261	Finishing Plants, Cotton	7.4
2492	Particleboard	6.8
2611	Pulpmills	10.1
2621	Papermills, Excl. Building Paper	10.3
2631	Paperboard Mills	14.4
2816	Inorganic Pigments	8.8
2822	Synthetic Rubber	5.1
2823	Cellulosic Manmade Fibers	8.0
2824	Organic Fibers, Noncellulosic	5.2
2861	Gum and Wood Chemicals	7.1
2865	Cyclic Crudes & Intermediates	6.9
2869	Industrial Organic Chemicals, NEC	7.1
2873	Nitrogenous Fertilizers	18.2
2874	Phosphatic Fertilizers	6.0
2895	Carbon Black	10.7

Table VIII-3 (Continued)

SIC Code	Description	Energy Costs As Percent of Product Value
2951	Paving Mixtures and Blocks	6.4
3211	Flat Glass	9.8
3221	Glass Containers	10.3
3229	Pressed and Blown Glass	8.1
3251	Brick & Structural Clay Tile	20.1
3253	Ceramic Wall & Floor Tile	6.2
3255	Clay Refractories	8.0
3259	Structural Clay Products	17.3
3261	Vitreous Plumbing Fixtures	5.5
3263	Fine Earthenware Food Utensils	6.8
3269	Pottery Products, etc.	6.3
3274	Lime	31.3
3275	Gypsum Products	9.3
3295	Minerals, Ground or Treated	7.7
3296	Mineral Wool	9.1
3297	Nonclay Refractories	6.1
3312	Blast Furnaces & Steel Mills	9.7
3321	Gray Iron Foundries	7.5

Table VIII-3 (Concluded)

SIC Code	Description	Energy Costs As Percent of Product Value
3325	Steel Foundries, NEC	5.4
3333	Primary Zinc	10.3
3398	Metal Heat Treating	6.9
3624	Carbon & Graphite Products	6.6

The three remaining industries in Category II are building paper and building board mills; industrial inorganic chemicals, not elsewhere classified; primary smelting and refining of nonferrous metals, not elsewhere classified. These industries were considered further as potential candidates because of possible Alaskan feedstocks.

Industries identified in the Category III screening that are associated with food processing (e.g., wet corn milling, beet sugar, malt); textile finishing (e.g., cotton finishing plants, man-made fibers); or heavy, low-value materials (e.g., paving mixtures, lime, glass containers, brick and structural clay tile and clay products) are unlikely candidates because of the remoteness of an Alaskan location from both feedstocks and markets for these commodities. Carbon black production is energy intensive only because petroleum-based feedstocks are used in the manufacturing process and is therefore precluded from further consideration. Although ammonia production is energy intensive for the same reason, electrically driven compressors can be substituted for gas-fired turbines in the production process. Furthermore, the major feedstock for ammonia production, natural gas, is available in Alaska. For these two reasons, ammonia production was selected for limited consideration. The construction of new processing facilities of most primary metals (e.g., copper, steel) is unlikely in the Railbelt region primarily because these industries are dependent on nearby feedstocks and are likely to remain depressed in the U.S. economy in the foreseeable future. In addition, the consequences of energy conservation (e.g., automobile downsizing) have caused the heavy manufacturing industries that are supplied by the primary metal industries to permanently reduce their requirements for feedstock. Although selected primary metals (e.g., zinc) might benefit from the combination of Alaskan feedstocks and low-cost electrical energy for thermal processes, most of these industries are unlikely candidates for expansion throughout the remainder of this century. The only industries in Category III that were retained for further consideration were ammonia production, nonferrous metals, and paperboard mills.

In addition to the Category I, II, and III industries retained for further screening, four other potential large-scale electrical energy uses were considered as specified in the statement of work. The list of industries and "other industrial applications" evaluated in Section IX are listed in Table VIII-4.

Table VIII-4

INDUSTRIES AND OTHER INDUSTRIAL APPLICATIONS EVALUATED AS POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL POWER

Category I

- The Aluminum Industry (SIC 3334, Primary Production Aluminum)
- The Chlor-Alkali Industry (SIC 2812, Alkalies and Chlorine)
- Industrial Gases (SIC 2813, Industrial Gases)
- Ferroalloy and Miscellaneous Metal Alloy Production (SIC 3313, Electrometallurgical Products)

Categories II and III

- Pulp and Paper Industry (SIC 2661, Building Paper and Building Board Mills; 2611, Pulpmills; and 2621, Papermills, Excluding Building Paper)
- Cement Industry (SIC 3241, Hydraulic Cement)
- Chemical Industry (2719, Industrial Inorganic Chemicals, NEC)
- Primary Metals Industry (SIC 3339, Primary Smelting and Refining of Nonferrous Metals, NEC; SIC 3333, Primary Zinc)
- The Fertilizer Industry (SIC 2873, Ammonia Production, Nitrogenous Fertilizers; 2874, Phosphate Fertilizers)

Other Applications

- Agglomerations of Small Industrial Facilities
- Residential Space Heat
- Electrification of Alaskan Railroad Intertie with the Lower 48
- Intertie with the Lower 48.

IX EVALUATION OF POTENTIAL LARGE USERS OF RAILBELT ELECTRICAL ENERGY

To evaluate the real potential of the candidate users of electrical energy, the likely characteristics of representative process plants in the selected industries must be considered. Because of the increasing importance of energy costs in recent years, much of the research and development in the candidate industries is devoted toward reducing process energy costs. The effect of these efforts should be to increase the likelihood of the construction of new process facilities in the candidate industries, but to reduce the importance of a regional location based on low cost electrical energy. The industry averages used to select candidate industries undoubtedly overestimate the importance of the costs of electrical energy for new facilities because they include marginal facilities that might be replaced by more efficient plants during a period of economic expansion. In the specific industry analyses which follow, the most recent available data on plant efficiency were used to evaluate the attractiveness of low-cost electrical energy. In each case the reduced costs of an Alaskan location attributable to inexpensive power must be balanced against the increased costs associated with an Alaskan location.

A range of electric energy rates, including a most probable competing energy rate (where possible), was assumed when comparing energy savings with additional transportation, construction (e.g., capital) and labor expenses associated with a Railbelt location. Because of industry infrastructures and market locations, the competitiveness of given electrical energy prices to attract new industry varies with the industry. Aluminum smelters are typically sited in lower-cost energy locations than chlor-alkali plants, which are more dependent on local resources. Since the availability of the low-cost electric power is highly dependent on the demand scenario associated with Alaskan population growth and petroleum-derived state revenues, SRI assumed for the purposes of the study that sufficient capacity would be available for at least one "world-class" plant in each category (e.g., 2,700 GWh annually for an aluminum smelter).

In addition to energy requirements, a major consideration for prospective Alaskan industries is the cost of transporting raw materials to Alaska and the resultant products to user markets. Materials and products which are subject to mass handling techniques and bulk shipment are preferable because lower handling costs associated with such materials reduce the overall cost of transportation. Transportation costs were considered for a "typical" facility to determine the additional expense of this factor associated with an Alaskan location. Related to transportation costs is the important consideration of the ability of the candidate industries to utilize indigenous Alaskan raw materials.

Primary industries with relatively simple input requirements may be most easily sited initially. As will be described in the industrial analyses which follow, however, synergistic relationships can form as an industrial base develops and industries are able to utilize locally produced materials. As an example, caustic soda from chlor-alkali production is an important input to alumina production, or facilities producing bulk commodities such as caustic soda might provide a partial return cargo for Alaska-bound alumina carriers serving aluminum smelters in the state.

Other important factors are the relatively high costs for labor and construction in the state, the degree of labor intensiveness of candidate industries, the relative proximity of markets, and the overall projected demand for candidate industry products.

The Aluminum Industry

Of the industries which have been examined, aluminum has, at .154, the third highest ratio of purchased electrical energy costs to value of shipped product. In spite of the high energy costs associated with aluminum production, the metal increasingly contributes to energy efficiency in other products, particularly in the transportation sector. As a result, projections for aluminum demand indicate annual growth of 4-6%[4,5] over the next decade. As the aluminum industry continues to expand, areas offering low-cost electricity will be considered as locations for new plants.

Currently, the industry is dominated by six multinational corporations which collectively account for over 66% of the world's bauxite/alumina production and 54% of aluminum metal production.[6] As shown in Table IX-1 and Table IX-2, these corporations are:

- The Aluminum Company of America (Alcoa, U.S.A.)
- Pechiney Ugine Kuhlmann (France)
- Swiss Aluminum (Alusuisse, Switzerland)
- Aluminum Company of Canada (Alcan, Canada)
- Reynolds Metals Company (U.S.A.)
- Kaiser Aluminum and Chemical Corporation (U.S.A.).

Table IX-1

INVESTORS IN THE ALUMINUM INDUSTRY: ALUMINA REFINERIES, 1979
(Thousands of Tons; Percentage)

	Capacity in Developed Countries	Capacity in Developing Countries	Total Capacity: Thousands of Tons	Total Capacity: As Percentage of Market Economy Countries' Capacity	Total Capacity: As Percentage of World Capacity
Six Major Transnational Corporations					
Alcan	2,208	1,344	3,552	12.2	10.3
Alcoa	4,135	1,966	6,101	20.9	17.8
Alusuisse	1,265	36	1,301	4.5	3.8
Kaiser	2,645	471	3,116	10.7	9.1
Pechiney	2,169	130	2,299	7.9	6.7
Reynolds	2,318	430	2,749	9.4	8.0
Total	14,740	4,377	19,118	65.6	55.7
Other TNCs with Private Investors in Developed Market Economy Countries	5,772	738	6,510	22.3	18.9
Governments of Developed Market Economy Countries	1,569	18	1,587	5.4	4.6
Governments of Centrally Planned Countries	5,208	-	5,208	—	15.2
Governments of Developing Countries	-	1,590	1,590	5.5	4.6
Private Investors in Developing Countries	-	355	355	1.2	1.0
World Total	27,289	7,078	34,368	100.0	100.0

Source: United Nations Centre on Transnational Corporations, as published in Transnational Corporations in the Bauxite/Aluminum Industry, United Nations, 1981, p. 37.

Table IX-2

INVESTORS IN THE ALUMINUM INDUSTRY: ALUMINUM SMELTERS, 1979
(Thousands of Tons; Percentage)

			Total Capacity		
	Capacity in Developed Countries	Capacity in Developing Countries	Thousands of Tons	As Percentage of Market Economy Countries' Capacity	As Percentage of World Capacity
Six Major Transnational Corporations					
Alcan	1,355	154	1,509	11.2	8.6
Alcoa	1,673	131	1,804	13.4	10.3
Alusuisse	649	-	649	4.8	3.7
Kaiser	884	227	2,222	8.2	6.3
Pechiney	973	71	1,044	7.7	6.0
Reynolds	1,043	82	1,125	8.3	6.4
Total	6,577	665	7,242	53.6	41.3
Other TNCs and Private Investors					
Europe	686	13	699	5.1	4.0
United States and Canada	1,218	32	1,251	9.3	7.1
Other	1,652	26	1,678	12.4	9.6
Total	3,556	71	3,628	26.8	20.7
Governments of Developed Market Economy Countries	1,569	-	1,569	11.6	9.0
Governments of Developed Centrally Planned Economies	3,732	-	3,732	-	21.2
Developing Country Governments	-	979	979	5.2	5.6
Developing Country Private Investors	-	378	378	2.8	2.2
Market Economy Countries, Total	11,703	1,821	13,522	100	
World, Total	15,434	2,093	17,528		100

Source: United Nations Centre on Transnational Corporations, as published in *Transnational Corporations in the Bauxite/Aluminim Industry*, United Nations, 1981, p. 37.

Collectively, these corporations have aluminum smelters in virtually all developed countries. Historically, smelting facilities have been located in developed countries, which have imported bauxite (or alumina), the primary feedstock for aluminum production. As energy prices have risen, smelters are being built with increasing frequency in countries with indigenous bauxite and lower-priced electric power.

The effect of high energy costs on aluminum production is particularly evident in both Japan and the United States, as is the effect of worldwide recession on the demand for aluminum. It is estimated that Japan's internal smelting capacity will decrease 40% by mid decade from the level of 1,204,000 metric tons of 1981, largely as a result of increased electricity costs in Japan. In 1981, Japanese smelters were facing electrical rates 2 to 23 times those available in the United States and Canada. As production has decreased in Japan, Japanese companies have increasingly participated in joint refinery projects overseas and are building smelters in Australia, Brazil, and Indonesia.[7] In the United States, aluminum producers have also been faced with escalating electrical energy costs at a time when plants are operating at approximately 40-60% of capacity, largely due to the current recession. In the Northwest, for example, the Bonneville Power Administration indicated that electrical rates for aluminum smelters would increase 49.7% to 25.9 mills/kWh, up from 17.3 mills, effective October 1, 1982. Initial industry reaction has been to indicate that such rate increases will seriously affect plans for capital investment and plant modernization in the area, which currently accounts for about 1/3 of U.S. production capacity.[8]

The most recently constructed U.S. aluminum smelter, the Alumex plant at Mt. Holley, South Carolina, is reported to use 6.24 kWh/lb of metal produced. A representative of Kaiser Aluminum indicated, during a telephone interview, that major breakthroughs in electricity usage are not expected and that 6.24 kWh/lb should be regarded as representative for plants which will come on line in the early 1990s.

In spite of the rising cost of energy in the developed nations, some experts believe that a large-scale shifting of aluminum production to developing countries will not occur. Indigenous electrical energy needs of the developing countries will compete for available power and may make other energy sources in developed countries, such as U.S. western coal reserves, economically attractive. There are also concerns about political stability in some of the developing countries, the higher costs associated with construction in remote areas, and the distance of such facilities from aluminum markets.

As noted in a recent United Nations report on the aluminum industry, "finance charges contribute about as much as do alumina and power to the cost of a ton of aluminum metal for a new smelter. Cheap power will not make a smelter competitive."[9] Since Alaska offers the potential combination of political stability and low-cost power, it remains to examine the importance of other costs which may be pivotal in decisions to site aluminum production facilities in the state.

Foremost among these other costs is the cost of transporting both raw materials to Alaska and aluminum ingot or finished products to markets in the United States and the Pacific basin. Primary aluminum production consists of two steps. The first is the mining and subsequent refining of bauxite into alumina, which is followed by smelting into primary aluminum ingots. The principal producers of bauxite are Australia, Guinea, and Jamaica as shown in Table IX-3. These countries, however, produce only a small fraction of the world's aluminum. Aluminum production is dominated by the United States, the U.S.S.R., Japan, and Canada (Table IX-4). Thus, the aluminum industry has historically transported bauxite/alumina over long distances to smelting facilities.

Transportation Costs

Both bauxite and alumina can be shipped using bulk handling procedures. Although alumina transportation costs are generally higher than for bauxite, there are advantages to refining bauxite into alumina at the mine since 2 to 2.5 tons of bauxite are required to produce 1 ton of alumina. This process requires only small amounts of caustic soda and other materials and consumes only 300 to 350 kWh of electrical energy per ton of alumina, as compared to the refining of aluminum, which requires 14 to 16 MWh (industry average) of electrical energy per ton of aluminum produced (Table IX-5 and Table IX-6).

Many exporting countries are increasingly shipping alumina rather than unrefined bauxite. Australia is an example of this trend. Approximately 74% of alumina imported by the United States is obtained from Australia, but no bauxite has been imported from Australia in recent years. It should also be noted that relative sizes of world-class alumina plants and aluminum smelters are significant in determining the structure of the industry which might develop in Alaska. Most new alumina plants have capacities in excess of 500,000 tons/year, and at least 10 have capacities in excess of 1,000,000 tons. Aluminum smelters tend toward capacities above 100,000 tons, usually around 200,000 metric tons. As a result, a single world-class alumina facility can support a number of smelters. This fact, in combination with the distances which bauxite would have to be transported, suggests that one or more aluminum smelters, as opposed to alumina processing plants, would be the most likely facilities located in Alaska, with alumina feedstocks coming from Australia.

Although our analysis indicates that the Alaskan smelting site might incur increased transportation charges compared to the Pacific Northwest, Alaskan sites may not incur significantly higher charges than most other U.S. smelting sites. Alaska is closer to Australia than east coast smelters such as the newly completed Mount Holly plant in South Carolina, which is importing alumina from Alcoa of Australia. In addition, Alaska is less than 1,600 miles above smelters in the Pacific

Table IX-3

BAUXITE AND ALUMINUM PRODUCTION IN 1980
(Metric Tons x 1000)

	Bauxite	Aluminum
Australia	27,584	369
Guinea	14,000	-
Jamaica	12,261	-
USSR	4,600	2,167
U.S.	1,460	5,463
Japan	-	1,323
Canada	-	1,295
World Total	89,933	16,940

Source: 1980 Minerals Yearbook

Table IX-4

1980 ALUMINUM PRODUCTION PERCENTAGE

U.S.	30.3
Canada	6.9
Japan	7.1
Western Europe	23.3
Eastern Europe	16.2
Australia & New Zealand	3.0
Rest of World	13.2

Source: 1980 Minerals Yearbook

Table IX-5

REPRESENTATIVE INPUTS FOR 1 METRIC TON OF ALUMINA

Bauxite, dry	2.0 to 2.5 tons
Caustic soda	0.07 to 0.17 tons
Fuel oil (steam and calcinating)	0.28 to 0.38 tons
Electric energy	300 to 350 kWh
Total labor and supervision	2.5 to 5 hours

Source: United States Bureau of Mines, Mineral Commodity Profile, May 1978, as reported in Transnational Corporations in the Bauxite/Aluminum Industry, United Nations, 1981.

Table IX-6

REPRESENTATIVE INPUTS FOR 1 METRIC TON OF ALUMINUM

Alumina	1.92 - 1.95 tons
Calcined petroleum coke	0.40 - 0.45 tons
Pitch	0.14 - 0.16 tons
Fluoride salts (with dry scrubbers)	0.02 - 0.03 tons
Electric energy	14 - 16 MWh
Labor and supervision	10 - 20 hours

Source: Transnational Corporations in the Bauxite/Aluminum Industry, United Nations, 1981, p. 17.

Northwest. Transportation costs on a per mile basis tend to decrease with distance, because the relatively fixed costs of time spent in terminals and handling charges are spread over the larger distances. Thus, the added expense associated with this extra distance may not be significant compared to the cost savings of inexpensive power.

Transportation charges for bauxite to the U.S. mainland averaged $5.77 per metric ton in 1980, although charges from some countries were in excess of $10.00 per ton. Alumina shipping charges averaged $16 per ton; however, as a fraction of product value, bauxite transportation charges averaged 18% as opposed to 9% for alumina, reflecting the added value associated with alumina.

An analysis of the additional transportation costs associated with an Alaskan location is complex. A major consideration is the suitability of harbor facilities in Alaska. Although 35,000-ton shipments are common, bauxite vessels are projected to increase in size to 60,000-100,000 dwt because efficiencies increase for bulk materials as vessel size increases and because of bauxite's low value per unit weight. Alumina vessel capacities are expected to remain under 50,000 dwt. Harbor facilities at Kenai, for example, might accommodate such tonnages, but it is not clear that access to these private harbor facilities is possible. Use of the port of Anchorage would require the smaller 35,000-ton vessels, while construction cost for a new port would be on the order of $28,000,000.[10]

Weather is another important factor. In the 1960s, Alcoa stockpiled materials during the ice-free season on the St. Lawrence and subsequently developed a large shipping business in Canada to effectively utilize its shipping capacity during the off-season. Thus, potential delays associated with use of the port of Anchorage or other harbors due to dredging or ice formation could affect overall transportation costs.[11]

Other factors which influence transportation cost calculations are the degree to which carriers are owned by the aluminum companies and their accounting practices. Rates can also vary markedly depending on the destination of the shipping run, independent of the distance traveled. For example, lack of return cargos can have a significant effect on shipping costs.[12]

Even more important than feedstock transportation costs are the costs associated with transporting aluminum metal. Approximately 90% of aluminum is produced in the developed countries where it is consumed. On a per weight basis it is estimated that aluminum transportation is 4 to 5 times more costly than bauxite or alumina because of added handling costs associated with the discrete ingots. Thus, the location of smelting facilities geographically close to metal users in the developed countries may have helped to offset rising electrical energy costs. As aluminum smelters are located near bauxite resources, overall transportation charges can increase.

Based on current U.S. averages for transportation costs in the aluminum industry, SRI estimates that transportation costs are approximately 7% of the primary aluminum value.[13] While Alaska may be more distant from U.S. aluminum users than other smelters in the U.S., it is closer to Japanese and other Pacific basin markets. As such, Alaskan transportation costs may not be higher than those of other U.S. smelters. Some increase in transportation costs may result from the need for additional alumina storage and delays associated with weather. SRI estimates that a transportation adjustment factor of 0% to 10% of the average U.S. rate is appropriate for computing additional transportation costs associated with an Alaskan site.

Capital Cost

An estimate of the capital costs for a smelter in Alaska can be made by using a location adjustment factor and data on cost of construction for a similar facility operating in the Lower 48. As stated previously, SRI estimates an adjustment factor of approximately 1.5 for construction of plants in the Anchorage area relative to the Lower 48. Only one new smelter facility has been constructed in the United States since 1973. This is the Mt. Holly plant, built by Alumax, Inc., at Mt. Holly, South Carolina, which went into operation in 1980. This plant cost $350,000,000, of which $40 million was attributed to environmental controls (that might be inadequate for an Alaskan location). The plant occupies 300 acres, receives over 35,000 short tons of alumina from Australia per month, and produces approximately 197,000 metric tons of aluminum product annually. It has an alumina storage capacity of approximately 40,000 tons and is located 14 miles from its port facility in North Charleston. The plant employs approximately 700 persons.[14]

Labor Costs

Since there are no nonferrous metal smelters in operation in Alaska, the differential in labor cost to be expected, relative to other U.S. sites, must be computed by comparison with other published industry labor data. The method used compares the ratio of hourly wages for primary metal production to general manufacturing, modified by specific plant data published for the Mt. Holly facility. As shown in Table IX-7, primary metal workers' hourly earnings are consistently higher than general manufacturing workers'. The variation is highest in the southern states at about 40% but decreases in the Northwest to less than 20%. Total annual payroll reported for the Mt. Holly plant in 1980 was $16,000,000 or an average hourly rate per employee of $10.98. This average, unlike Table IX-7 data, includes salaried professions. Based on an average 42% higher salary paid primary metal workers over general manufacturing in the Southeast, the average hourly rate for the Mt. Holly plant is estimated at $7.94 using the data in Table IX-7 on general manufacturing labor rate in South Carolina. The additional $3.04 ($10.98 minus $7.94) per employee in South Carolina accounts for the salaried management component of the overall plant payroll.

Table IX-7

1980 AVERAGE HOURLY MANUFACTURING WAGES FOR PRIMARY METALS AND MANUFACTURING
($ in Millions)

	Manufacturing	Primary Metals	Ratio (Primary Metals/Manufacturing)
U.S. Total	7.27	9.77	1.34
Alaska	10.22	-	-
South Carolina	5.59	-	-
Washington	9.41	10.74	1.14
Oregon	8.65	10.24	1.18
Texas	7.15	8.99	1.26
Kentucky	7.34	10.44	1.42
Tennessee	6.08	8.58	1.41
West Virgina	8.08	11.73	1.45

Source: U.S. Bureau of Labor Statistics as reported in the "Geo-Economic Index," Site Selection Handbook, May 1982, Conway Publications, Inc.

Although average U.S. hourly rates are 42% higher than in the Southeast, it is assumed that the Mt. Holly plant is paying above the prevailing wage in the region. Assuming that the U.S. rate is only one-third greater than the Mt. Holly rate. It is estimated that a hypothetical 1980 overall hourly rate in the U.S. for Mt. Holly type plants would have been $14.64. Overall plant payroll in Alaska, assuming a similar percentage of management personnel as at Mt. Holly and a factor of 1.4 (ratio of Alaska to U.S. average labor rates in Table IX-7), would thus be:

(1.4) x (700 employees) x ($14.64) x (1,920 hours) = $27.5 million.

Adjusted for inflation, this would amount to $30.3 million in 1982 dollars for an Alaskan smelter as opposed to $17.6 million in the Mt. Holly facility. (A hypothetical U.S. average plant would have a $21.6 million payroll.) Thus, the additional labor cost for an Alaskan smelter would be approximately $12.7 million annually. If a lower differential of 1.3 is used for Alaska labor costs, the additional labor costs would be only $10.5 million annually.

Construction Costs

If a Mt. Holly type plant were constructed today, it is estimated that it would cost between $450 million and $500 million. In Alaska, a similar plant would cost approximately $675 million to $750 million, assuming a construction adjustment factor of 1.5. The cost differential is between $225 million and $250 million. Over 30 years, assuming a 10% interest rate, this differential produces an additional annual cost of approximately $25 million per year.

Electricity Rates

Average U.S. industrial electrical power costs have been escalating rapidly since 1970. After many years of constant real costs, large power user rates jumped from an average of about $0.015/kWh in 1970 to an average of $0.046/kWh in 1980 and $0.054/kWh in 1981.[15]

Aluminum smelters are generally located in regions with industrial electricity rates well below the average. Using the published electricity rates for aluminum smelters plus other published rate data, it is estimated that Alaskan power must compete with average current rates of $0.026/kWh to $0.029/kWh (1982 dollars).

Alaskan Site Sensitivity Summary

In Table IX-8 are summarized some of the major additional-cost differentials which are expected to be incurred in siting an aluminum smelter in the Railbelt region near an existing port facility. Additional construction expenses associated with taxes, housing, or harbor modification are not included.

Table IX-8

ANNUAL COST DIFFERENTIALS ASSOCIATED WITH ALASKAN SMELTER
($ 1982)

	Increase
Labor	$10.5 to $12.7 million
Construction	$25 million
Transportation	$0-$2.2 million
Total	$35.5-$39.9 million

Table IX-8 indicates that electrical power savings associated with Susitna power must be in excess of $35-$40 million annually to offset other higher costs associated with location in the state. Based on plant usage of 6.24 kWh per pound of product and 197,000 metric tons of output, the plant requires 2,700 GWh annually. Susitna power must therefore be $.014/kWh to $.016/kWh cheaper than competing sites to reach "break-even" against the added differential costs computed above. Table IX-9 shows the maximum prices at which Susitna power can be sold to achieve "break-even." Thus only the 100% state grant case could provide power at a sufficiently low price to compete effectively (see Table III-1). It is questionable that sufficient power (2,700 GWh) would be available for a single large aluminum facility at this rate since demand would increase significantly from domestic users at this low rate.

Table IX-9

POWER COST SENSITIVITY OF SMELTER FACILITY*
($/kWh)

Competing site power rates	.029	.035	.050
Susitna power rates at "break-even"	.015	.021	.036

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*Assumes $40 million must be saved to offset costs.

The Chlor-Alkali Industry

The ratio of purchased electricity to value of shipments for the chlor-alkali industry in 1980 was 18.8%. The primary electrically intensive products of the chlor-alkali industries are sodium hydroxide (NaOH) and chlorine (Cl_2). Chlorine is produced commercially through the electrolysis of brine, with sodium hydroxide (also known as caustic soda) as a byproduct. Table IX-10 contains a comparison of U.S. chlorine capacity and production. Sodium hydroxide production follows a pattern similar to chlorine production, with some variation.[16] Sodium hydroxide capacity and production are compared in Table IX-11.

The top five producers, shown in Table IX-12, account for over 65% of U.S. capacity. Dow Chemical, the major producer of chlorine, accounts for almost one-third of U.S. production. In the world production of chlorine, the U.S. share, second to Europe, is 36% (see Table IX-12). Approximately 54% of total U.S. chlorine production is liquefied for sale or in-plant transport; the remainder is used captively by producers to make chlorinated products or transferred via pipeline as a gas. Geographic distribution of chlorine production is listed in Table IX-14.

Table IX-10

U.S. CHLORINE CAPACITY AND PRODUCTION
(Thousands of Metric Tons)

Year	Capacity	Production	Operating Rate (Percent)
1977	14,281	11,630	80.9
1978	15,243	12,157	79.8
1979	15,725	13,520	86.0
1980	15,815	12,563	79.4
1981	15,860	11,615	73.2

Source: Current Industrial Reports,
U.S. Department of Commerce

Table IX-11

U.S. SODIUM HYDROXIDE CAPACITY AND PRODUCTION
(Thousands of Metric Tons)

Year	Capacity	Production	Operating Rate (Percent)
1977	12,532	9,979	79.6
1978	13,082	10,275	78.5
1979	13,604	11,242	82.6

Source: Current Industrial Reports,
U.S. Department of Commerce

Table IX-12

THE TOP FIVE U.S. CHLORINE PRODUCERS

	Percent
Dow Chemical U.S.A.	31.3
PPG Industries, Inc.	10.4
Diamond Shamrock Corp.	8.8
Occidental Petroleum Corp.	7.9
Olin Corp.	6.8
Others	34.8

Source: SRI

Table IX-13

WORLD PRODUCTION OF CHLORINE

	Percent
Europe	47
United States	36
Asia	11
Canada	4
South America, Oceania, and Africa	2
Total	100

Source: Encyclopedia of Chemical Technology

Table IX-14

U.S. CHLORINE PRODUCTION
BY GEOGRAPHIC AREA

Geographic Area	Metric Tons (000s)	Percentage
New England	656.2	5.0
Middle Atlantic	505.9	3.9
North Central	858.3	6.6
South Atlantic	942.2	7.2
East South Central	1,531.1	11.7
West South Central	7,640.1	58.5
Mountain & Pacific	935.2	7.2

Source: The Chlorine Institute

Chlorine is primarily used for the manufacture of organic chemicals. Other uses include pulp, paper, and textile bleaching, the production of inorganic chemicals, water and waste treatment, cleaning and sanitation products, and metallurgical processing (see Table IX-15). Of the 12,563,000 metric tons of chlorine produced in 1980, 564,058 tons (4.5%) was shipped as a gas. Out of the 7,774,565 tons produced as a liquid, 4,621,980 tons were commercially shipped; of this, only 128,626 tons were exported.[17] This low figure is primarily due to the risk of chlorine transportation.

Though the pulp and paper industry has been a significant user of chlorine, there is a trend to move away from chlorine dependence by way of substitutions. Due to a tightening of Cl_2 and NaOH supply,[18] prices have risen faster than inflation. The imbalance has became worse as pulp and paper producers (who spend $600 million on bleaching chemicals a year) substitute other bleaching agents for chlorine. For example, the replacement of conventional Cl_2 processes by oxygen-using processes is one trend. Another trend is the substitution of chlorine dioxide, which possesses 2.63 times the oxidizing equivalent of chlorine. Mills using hardwood feeds are said to decrease chlorine consumption by almost 30%. In addition, chlorine-base products also face competition from hydrogen peroxide.

According to the data in Table IX-16, chemical manufacturers consume almost half of the sodium hydroxide used (in 1979 this amounted to approximately 5 million metric tons). The production of alumina from bauxite by the Bayer process is one of the major chemical uses of sodium hydroxide. The volume of NaOH is approximately 9% of the alumina produced; in 1979, for example, 540,000 metric tons were consumed to produce 6 million tons of alumina. A large portion of sodium hydroxide exports in liquid form has been to countries that are major manufacturers of alumina (e.g., Australia, Jamaica, and Surinam). Destinations for most caustic exports will continue to be tied to trends in alumina production. Unfortunately, because it is more economical to produce alumina at the site where it is mined, it is unlikely that this potential infrastructural synergism could develop between the two industries in Alaska.

The pulp and paper industry, however, may provide a potential interaction. Because of the limited supplies and high prices, the pulp and paper industry (which consumed over 2 million tons of caustic soda in 1979) has turned to other sources. Several mills, for example, are using sodium sulfate as a substitute. Now, however, partly due to regional shifts to alternative chemicals such as sodium sulfate and soda ash, caustic supplies have become more plentiful and prices have fallen. As a result, production rates have dropped from 80.2% in June 1981 to as low as 65% in June of 1982.[19]

Table IX-15

U.S. CONSUMPTION OF CHLORINE
(1979)

	Metric Tons Consumed	Percent
Organic Chemicals	7,834,000	71.1
Pulp & Paper Production	1,215,000	11.0
Inorganic Chemicals	648,000	5.9
Water Treatment	500,000	4.5
Other	830,000	7.5

Source: SRI International

Table IX-16

U.S. CONSUMPTION OF SODIUM HYDROXIDE
(1979)

	Metric Tons Consumed	Percent
Chemical Manufacturing	5,000,000	49.7
Pulp & Paper Manufacturing	2,050,000	20.4
Cleaning Products (Soaps, Bleaches, etc.)	634,000	6.3
Petroleum & Natural Gas	495,000	4.9
Cellulosics (Rayon, etc.)	267,000	2.6
Cotton Mercerizing	170,000	1.7
Other		14.4

Source: SRI International

Another contribution to the decrease in price has been the contribution of energy-saving production technology. Previous chlor-alkali production has been dependent on various designs based on the diaphragm or mercury intermediate electrode. A new generation of electrolytic cells is now being developed which promises to cut energy consumption by 20% and more.[20]

PPG is converting the diaphragm chlor-alkali cells to the more efficient (by 25%) bipolar electrolyzer technology that the company has developed.[21] (Other companies, such as Diamond Shamrock, Chemetics, and Occidental Research, are also installing electricity-cutting technologies involving new catalysts and separation membranes.) These new methods can be expected to reduce the importance of the cost of electricity.

In the economics of the production process, investment costs for a 1-billion lb-per-year chlorine plant in the U.S. are approximately $260 million. Based on the typical escalation factor for construction in Alaska, the investment in a Railbelt site would be expected to be approximately $395 million in 1982 dollars. At 10% interest, the annualized cost differential for an Alaskan location would be approximately $14 million. Electricity consumption using diaphragm cells is approximately 1.28 kWh/lb of Cl_2 produced. For each pound of Cl_2 produced, approximately 1.128 lb of NaOH is produced. For a typical plant producing 1 billion lb of Cl_2 annually, electricity consumption is equal to 1,280 GWh annually. At the current average price of $0.045/kWh, annual electricity costs are $57.6 million.

Labor operating costs for the facility will be approximately $7.5 million annually. For an Alaskan location, the operating labor cost differential would be $2.25 million based on an adjustment factor of 1.3. Estimates of the costs associated with transporting the product to market were obtained from shipping firms. The cost of transporting the Cl_2 and NaOH from Anchorage to Seattle by container ship range from $0.042/lb to $0.059/lb for Cl_2 and $0.031/lb to $0.043/lb for NaOH (50% solution). If the additional cost of transporting salt from Baja to Anchorage and distributing the product from Seattle is ignored, the annual transportation penalty for an Alaskan location would be approximately $92 million.

Table IX-17 summarizes the pertinent data for a large Cl_2 plant. Table IX-18 summarizes the cost differential for an Alaskan location. The $108 million cost penalty can only be offset if Alaskan electricity is $0.084/kWh below the prevailing rates in competing regions. The high cost of transportation makes the production of Cl_2 an unlikely candidate industry for an Alaskan location.

Table IX-17

DATA FOR A LARGE (1 BILLION LB/ANNUALLY) Cl_2 PLANT LOCATED IN ALASKA

Capital Cost	$260 million
Electricity Usage	1,280 GWh
NaOH Product	1.13 x 10^9 lb
Raw Material Costs	$.75 million
Direct Operating Costs (including Labor)	$15.4 million
Indirect Operating Costs	$41.9 million
Electricity Costs	$57.6 million
Other Utility Costs	$16.7 million

Source: SRI International

Table IX-18

COST SAVINGS AND PENALTIES
ASSOCIATED WITH AN ALASKAN LOCATION FOR A Cl_2 PLANT

Construction Differential	$ 14 million
Labor Differential	$ 2.25 million
Transportation Differential	$ 92.0 million
Total	$108.25 million

Source: SRI International

The Industrial Gases Industry

As a group, industrial gases had the highest ratio of electrical energy purchases to product value, .233. Gases within this classification include:

Acetylene	Neon
Argon	Nitrogen
Carbon dioxide	Nitrous oxide
Helium	Oxygen
Hydrogen	

Based on the value of U.S. shipments, oxygen and nitrogen are the most economically significant, as shown in Table IX-19.

Acetylene, carbon dioxide, and hydrogen are all made from hydrocarbon refining processes. Carbon dioxide and hydrogen are both largely produced by steam reforming of natural gas. Nitrogen, oxygen, and argon are more energy intensive and are produced by the cryogenic separation of air into its elemental constituents.

The primary producers of industrial gases are:

- Airco Industrial Gases Division of Airco Inc.
- Industrial Gases Division of Air Products and Chemicals, Inc.
- Linde Division of Union Carbide Corp.

Currently, Alaska has a 30-ton/day air separation plant owned by Liquid Air Corporation. Acetylene is also produced in the state. Production of the other hydrocarbon-derived gases in Alaska was not confirmed but is certainly feasible with the abundant feedstocks available.

After World War II, large air separation plants were constructed in the United States, primarily to supply oxygen to the steel industry. Most large facilities are near their primary users and utilize pipelines for product transportation. Until recently, the synfuels industry seemed likely to emerge as a major oxygen consumer. Based on SRI energy price projections, it now seems unlikely that the synfuel industry will emerge as a major user of oxygen by the year 2000.

The co-product of air separation, nitrogen, is expected to show continued strong growth for secondary oil recovery. At least one company, Ingersoll-Rand Enhanced Recovery Company, builds cryogenic air separation plants with compression capability at oil and gas field sites substituting hydrocarbon-based energy for electricity. Table IX-20 shows a breakdown of market share for various oxygen and nitrogen producers.

Table IX-19

1979 VALUE OF U.S. SHIPMENTS OF INDUSTRIAL GASES
(In Millions of Dollars)

Oxygen	502.4
Nitrogen	407.3
Acetylene	175.2
Argon	136.5
Carbon Dioxide	130.4
Hydrogen	119.0

Source: U.S. Department of Commerce, 1979 Industrial Gases Report issued November 1980.

Table IX-20

OXYGEN AND NITROGEN
ON-SITE AND MERCHANT CAPACITY
(Tons per Day)

	Oxygen Gas	%	LinLox	%	Oxygen Gas	%	LinLox	%
Linde	27,158	43.3	13,000	36.0	50,000[a]	34.6	26,700	35.6
Airco	8,935	14.3	6,100	17.0	20,500[b]	13.8	13,000	17.3
Air Products	10,180	16.3	5,900	16.3	25,000[c]	17.3	14,000	17.7
Big Three	7,883	12.6	3,600	10.0	15,000	10.4	6,500	8.4
Liquid Air	4,000	6.3	3,600	10.0	7,000	4.8	8,000	10.7
Liquid Carbonic	0	0.0	1,400	3.9	3,000	2.1	2,500	3.3
Burdox	630	1.0	800	2.2	1,000	0.8	1,500	2.0
Burdett	400	0.6	1,200	3.3	1,500	1.0	2,000	2.7
Others	3,465	5.5	500	1.3	22,000	15.2	800	1.0
Capacity (billion cubic feet)	397		263		916		520	
Demand (billion cubic feet)	292		163		780		410	
Operating Rate	73%		62%		85%		80%	

Note: Oxygen gas: on-site. LinLox (liquid nitrogen and oxygen): merchant.

[a]6,000 tpd synfuel on-site.

[b]6,000 tpd synfuel on-site.

[c]8,000 tpd synfuel on-site.

Source: Smith Barney Harris Upham & Co., as quoted in Chemical Business, May 4, 1981.

In the last two decades, two trends have been in evidence in the industrial gas industry. The first is a shift toward bulk liquefied gas transportation with a commensurate decrease in the use of small gas cylinders as a major transportation mode, and the second is an increase in the number of small plants and on-site production facilities. Both of these trends are brought about by the high cost of transporting compressed and liquefied gases. Currently, no industrial gas is shipped from Alaska. Nationwide, the industry is operating below capacity, particularly in the Pacific Northwest.

Since there are no bulk shipments of industrial gases from Alaska, precise transportation charges are not available. Using current classification rates for liquid nitrogen, however, transportation costs relative to product value were examined.

All industrial gases are subject to widely varying prices depending on the quantity of gas required, location of the user, length of contract, supplier competition, and availability of feedstocks. Prices on the west coast for nitrogen are approximately \$.40 per 100 ft^3 of gas based on a 3-year contract and usage of 700,000 ft^3 per month. This figure does not include vaporization charges or storage tank leasing fees. Currently, rail barge service is available from Anchorage to Seattle, and it is assumed that liquid nitrogen could be transported by railcar. An average tank car weighs approximately 111,000 lb and has a liquid nitrogen capacity of 82,000 lb (or 840,000 ft^3 of gas when vaporized). Southbound transportation costs, Anchorage to Seattle, for 80,000 lb of nitrogen are quoted, using class rates, at \$4.60/100 lb. Thus, for a typical rail car, the ratio of transportation costs to product value would be 1.10.[22]

Given regular shipments, this class rate could be greatly reduced; however, even if it were reduced by 50%, transportation costs alone would outweigh the advantage of inexpensive electricity, even if it cost as little as \$0.005/kWh. Thus, while indigenous Alaskan gas producers would certainly benefit from lower industrial power rates, even free energy would not overcome the cost of transportation outside the state.

The Ferroalloy Industry

The production of ferro and nonferrous additive alloys is electrically intensive (electric energy/shipped product value ratio of .141). These alloys are primarily utilized in steel production to remove undesired elements and to form alloys with improved strength and corrosion properties. These additives also are used to form alloys with improved temperature performance and to neutralize undesirable characteristics of other elements within the metal. Alloys within this group are listed in Table IX-21.

Table IX-21

SIC CODE 3313 ELECTROMETALLURGICAL PRODUCTS

Additive alloys, except copper: not produced in blast furnaces	Ferrotitanium
Electrometallurgical products, aluminum, magnesium, and copper	Ferrotungsten
Ferroalloys, not made in blast furnaces	Ferrovanadium
Ferrochromium	High percentage ferroalloys, not produced in blast furnaces
Ferromanganese, not produced in blast furnaces	Manganese metal, not produced in blast furnacnes
Ferromolybdenum	Molybdenum silicon, not produced in blast furnaces
Ferrophosphorus	Nonferrous additive alloys, high percentage: except copper
Ferrosilicon, not produced in blast furnaces	Steel, electrometallurgical

The ferroalloy industry, like other metals industries in the developed countries, is being adversely effected by high energy and labor costs. Ferroalloys are not end products, but are in turn dependent on the health of the steel industry they support. In recent years, both the U.S. steel industry and the ferroalloy industry have been under continual pressure from foreign imports and the economic recession.

In 1980, ferroalloy imports into the United States were valued at $644 million while U.S. exports were only $93 million, a 6 to 1 ratio of imports to exports. The principal imported alloys are manganese alloys, ferrosilicon, chromium alloys, and ferronickel alloys as shown in Table IX-22.

The availability of feedstock ores in Alaska will be a major factor in any decision to locate a ferroalloy processing plant there.

From 1917 to 1957 chromite was produced at three main sites: the Star and Chrome Queen claims at Red mountain, and the Reef mine at Claim Point in Seldovia, all on the Kenai Peninsula.

There has been no domestic production of chromium since 1961, and no production of manganese since 1973. The United States currently imports chromium from the Republic of South Africa (44%), the Philippines (16%), and the Soviet Union (18%).

Red Bluff Bay, in southeast Alaska, contains high-grade deposits with a good chromium-to-iron ratio. Reserves of 570 tons of more than 40% chromium and 29,000 tons of 18-35% chromium have been noted. These deposits could be valuable national reserves; however, they are not major occurrences on the world scale.

Manganese is imported from Gabon (40%), Brazil (19%), Australia (15%), and South Africa (14%).

Approximately 40% of mined tungsten is consumed by ferrous alloys; when added to iron or steel it improves high-temperature strength and hardness. 38% of all tungsten produced is used as tungsten carbide in many die and drilling applications. On Gilmore Dome, east of Fairbanks, the Yellow Pup mine has produced tungsten concentrates at its small gravity mill.

Molybdenum is a strategic metal used in the production of high-strength alloy steels where minimum weight is required. Reserves of molybdenum have been either proved or inferred at Bond Creek (500 Mt at .03%), Stepovak Bay (100 Mt at .03%), and Nunatak (8.5 Mt at .125%). The most widely known and important reserves, however, can be found in Alaska at Quartz Hill, 45 miles east of Ketchikan. This deposit, discovered in 1974 by U.S. Borax and Chemical Corp., contains an orebody of 1.5 billion tons of ore and a gross value of $18 billion; it is believed to be one of the largest molybdenum deposits in the world. Quartz Hill will produce 40 million lb of molybdenum a year, and is expected to come on stream in late 1987. U.S. Borax estimates that half its output will be exported to markets in the Pacific Basin and Europe.

The United States is heavily dependent on external sources for many of the vital elements listed in Table IX-21, as shown in Table IX-23. There were 32 U.S. ferroalloy producers in 1980 (Table IX-24), many of which are foreign owned. The pattern of plant locations in the United States is an indication that proximity to markets is a more important factor in this industry than electricity costs.

An estimated 15,000 to 20,000 kWh is needed to produce 1 ton of ferroalloy. Based on industry averages, a "typical" ferroalloy plant might produce 1,600 tons of product annually. Pertinent data for a representative ferroalloy production facility are listed in Table IX-25. The differential costs associated with an Alaskan facility are listed in Table IX-26. Because of the varying points of origin of feedstocks, average transportation costs will vary widely, but based on the parameters estimated in Table IX-25, Railbelt electricity would have to be $0.0625/kWh less expensive than competing sites before the region would be considered on the basis of inexpensive electricity alone. Transportation costs for input feedstocks and product would make an Alaskan plant site less competitive than in the eastern U.S. Unless Alaskan producers can identify and economically process local feedstock resources, there is little potential for ferroalloy production in the state based on inexpensive electricity alone.

Even if plants are built, this industry is unlikely to utilize significant quantities of electrical energy, based on the total average annual electrical energy usage for individual plants (32 GWh) in this industry. Such plants would be candidates for the agglomeration of small facilities discussed later in this section.

Table IX-22

1980 U.S. IMPORTS OF FERROALLOYS
AND METALS USED IN FERROALLOYS
($ in Thousands)

Manganese alloys	240,833
Ferrosilicon	42,639
Chromium alloys	155,803
Ferronickel	104,156
Ferromolybdenum	243
Ferrophosphorus	10
Ferrotitanium and Ferrosilicon titanium	1,679
Ferrotungsten and Ferrosilicon tungsten	4,039
Ferrovanadium	3,477

Source: 1980 U.S. Minerals Yearbook.

Table IX-23

1980 NET IMPORT RELIANCE AS A PERCENTAGE OF APPARENT CONSUMPTION

Manganese	98%
Chromium	90%
Silicon	20%
Nickel	73%
Titanium	Data withheld by the Bureau of Mines to avoid disclosing company proprietary data
Tungsten	52%

Source: "Mineral Commodity Summaries 1982," U.S. Department of Interior, Bureau of Mines

Table IX-24

PRODUCERS OF FERROALLOYS IN THE UNITED STATES IN 1980

Producer	Plant Location	Products[1]	Type of Furnace
FERROALLOYS (EXCEPT FERROPHOSPHORUS)			
Alabama Alloy Co., Inc.............	Bessemer, AL	FeSi	Electric
Aluminum Co. of America, Northwest Alloys, Inc.	Addy, WA	Si, FeSi	Do.
Autlan Manganese Corp..............	Mobile, AL	SiMn	Do.
AMAX Inc., Climax Molybdenum Co. Div.............................	Langeloth, PA	FeMo	Metallothermic
Cabot Corp., KBI Div. Penn Rare Metal Div.	Revere, PA	FeCb	Do.
Chromasco Ltd., Chromium Mining & Smelting Corp. Div.	Woodstock, TN	FeCr, FeSi	Electric
Dow Corning Corp...................	Springfield, OR	Si	Do.
Engelhard Minerals & Chemicals Corp., Minerals and Chemicals Div.	Strasburg, VA	FeV	Metallothermic
Foote Mineral Co., Ferroalloys Div.	Cambridge, OH Graham, WV Keokuk, IA	FeSi, FeV, silvery pig iron, other[2]	Electric
Hanna Mining Co., The:			
Hanna Nickel Smelting Co.........	Riddle, OR	FeNi, FeSi	Do.
Silicon Div......................	Wenatchee, WA	Si, FeSi	Do.
Interlake, Inc., Globe Metallurgical Div.	Beverly, OH Selma, AL	FeCr, FeCrSi, Si FeSi, SiMn	Do.
International Minerals & Chemical Corp.,	Bridgeport, AL	FeSi	Do.
Industry Group, TAC Alloys Div.	Kimball, TN	Do.	Do.
Macalloy Inc.	Charleston, SC	FeCr, FeCrSi	Do.
Metallurg, Inc., Shieldalloy Corp.	Newfield, NJ	FeAl, FeB, FeCb, FeTi, FeV, other[2]	Metallothermic
Ohio Ferro-Alloys Corp.............	Montgomery, AL Philo, OH Powhatan Point, OH	FeB, FeMn, FeSi, Si, SiMn	Electric
Pennzoil Co., Duval Corp...........	Sahuarita, AZ	FeMo	Metallothermic
Pesses Co., The.....................	Newton Falls, OH Solon, OH Pulaski, PA Fort Worth, TX	FeAl, FeB, FeCb FeMo, FeNi, FeTi, FeV, FeW, other[2]	Electric, metallothermic

Table IX-24 (Concluded)

Producer	Plant Location	Products	Type of Furnace
FERROALLOYS (EXCEPT FERROPHOSPHORUS)			
Reactive Metals and Alloys Corp.....	W. Pittsburgh, PA	FeTi, other[2]	Electric,
Reading Alloys, Inc................	Robesonia, PA	FeCb, FeV	Metallothermic
Reynolds Metals Co.................	Sheffield, AL	Si	Electric
Satra Corp., Satralloy, Inc. Div....	Steubenville, OH	FeCr, FeCrSi	Do.
SEDEMA S.A., Chemetals Corp.........	Kingwood, WV	FeMn	Fused-salt electrolytic
SKW Alloys, Inc.....................	Calvert City, KY.. Niagara Falls, NY.	FeMn, FeSi, SiMn	Electric
South African Manganese Amcor, Ltd.. Roane Ltd.	Rockwood, TN	FeMn, SiMn	Do.
Teledyne, Inc., Teledyne Wah Chang, Albany Div	Albany, OR	FeCb	Metallothermic
Union Carbide Corp., Metals Div.....	Alloy, WV Ashtabula, OH Marietta, OH Niagara Falls, NY Portland, OR Sheffield, AL	FeB, FeCr, FeCrSi FeMn, FeSi, FeV, FeW, Si, SiMn, other[2]	Electric
Union Oil Co. of California, Molycorp, Inc.	Washington, PA	FeB, FeMo, FeW	Electric and metallothermic
FERROPHOSPHORUS			
Electro-Phos Corp.................	Pierce, FL	FeP	Electric
FMC Corp., Industrial Chemical Div	Pocatello, ID	Do.	Do.
Monsanto Co., Monsanto Industrial Chemicals Co.	Columbia, TN Soda Springs, ID	Do. Do.	Do. Do.
Occidental Petroleum Corp., Hooker Chemical Co., Industrial Chemicals Group	Columbia, TN	Do.	Do.
Stauffer Chemical Co., Industrial Chemical Div.	Mt. Pleasant, TN Silver Bow, MT Tarpon Springs, FL	Do.	Do.

[1]FeAl, ferroaluminum; FeB, ferroboron; FeCb, ferrocolumbium; FeCr, ferrochromium; FeCrSi, ferrochromium-silicon; FeMn, ferromanganese; FeMo, ferromolybdenum; FeNi, ferronickel; FeP, ferrophosphorus; FeSi, ferrosilicon; FeTi, ferrotitanium; FeV, ferrovanadium; FeW, ferrotungsten; Si, silicon metal; SiMn, silicomanganese.

[2]Includes specialty silicon alloys, zirconium alloys, and miscellaneous ferroalloys.

Source: U.S. Minerals Yearbook, 1980.

Table IX-25

DATA FOR REPRESENTATIVE 1600-TON/YEAR FERROALLOY PLANT

Investment Costs for New Plant Construction	\$10-\$20 million
Labor Costs (200 employees)	\$4 million
Electricity Costs (\$0.045/kWh)	\$1 million

Source: SRI International

Table IX-26

ANNUALIZED DIFFERENTIAL COSTS ASSOCIATED WITH AN ALASKAN SITE FOR A FERROALLOY FACILITY

Construction Costs	\$0.5 - \$1.0 million
Labor	\$1.2 million
Transportation Costs	\$0.2 - \$0.3 million
Total	\$1.9 - \$2.5 million

Source: SRI International

The Pulp and Paper Industry

In 1979, paper mills (excluding building paper) ranked as the fourth largest energy-consuming industry in the United States, using 592.2 trillion Btu costing $1.689 billion. Of this total, 32% ($536.7 million) was for electric power. For the building board and building board mills, purchased electrical energy represented 5.6% of the value of shipped product in 1980. Much of this industry produces a major portion of its own electricity through cogeneration. The United States ranks first in the world in both production and consumption of paper, board, and pulp. In 1981, the U.S. produced over 57 million metric tons of paper and board alone. A breakdown by grade of U.S. paper and board production for 1970-1981 is given in Table IX-27. The increase in annual demand expected by SRI through the 1980s, though far below growth in the 1950s and 1960s, will be about 65 million tons, or an annual increase of 3.3% per year. Growth of demand in developing countries is expected to be greater than in the U.S. U.S. exports have been increasing from 65,000 metric tons in 1979 to 159,000 in 1980 and 245,000 in 1981.[23,24]

The paper/forest products industry, like many other industries, is currently depressed by the recession and high interest rates. Some of the biggest companies, such as Boise Cascade, Champion International, and Crown Zellerbach are having a difficult time meeting interest payments.[24] Although the industry is currently depressed (see Table IX-28), it can be assumed that the economic recovery will lead to expansion of the industry comparable to historic trends. In the timeframe of interest (1990-2010), the industry can be expected to add capacity, particularly if new markets are developed, such as the People's Republic of China.

Because a newsprint facility[25] using thermomechanically processed pulp (TMP) possesses the least ability to generate its own internal sources of electricity, and because it is representative of the predominant paper commodities, this segment of the industry was selected by SRI as an example of the most likely of the pulp and paper industry segments to benefit from low-cost Alaskan electricity.

Industry estimates of plant energy costs vary from 12% to 30% of shipment value. Canadian plants, which produce the preponderance of newsprint, report purchased energy costs at 12% of the value of shipment. An Alaskan site would compete with the most efficient alternative sites, so the Canadian data are the most pertinent for comparison purposes. Based on industry averages, electricity costs

Table IX-27

PAPER AND BOARD PRODUCTION IN THE UNITED STATES
(Thousands of Short Tons)

	Paper							Paperboard				Construction[1]			
Year	News-print	Coated Printing	Publicat. & Print.[2]	Writing & Relat.	Coarse[3]	Sani-tary	All Paper Total	Other Bleached Paper-board	Corru-gating Material	Unbleached Kraft[4]	All Paper-board Total	Wet Ma-chine Board	Con-struc-tion (Paper)	All Cons-struction Total	Total All Types
1970	3,345	3,279	2,646	2,937	5,439	3,548	23,625	1,856	4,332	11,436	25,477	139	1,594	4,276	53,516
1971	3,321	3,251	2,758	2,996	5,442	3,660	23,811	1,938	4,596	11,700	26,135	138	1,837	5,001	55,086
1972	3,451	3,546	3,010	3,329	5,713	3,796	25,435	1,964	4,992	13,030	28,522	148	1,915	5,352	59,457
1973	3,459	3,814	3,116	3,817	5,694	3,726	26,483	1,971	5,285	13,139	29,267	149	1,858	5,406	61,304
1974	3,395	3,974	2,832	4,102	5,731	3,800	26,674	1,957	5,093	12,755	28,017	144	1,845	5,118	59,930
1975	3,476	3,318	2,400	3,244	4,805	3,669	23,306	1,792	4,411	11,170	24,452	115	1,616	4,648	52,521
1976	3,400	3,967	2,984	3,910	5,661	3,936	26,612	1,894	5,045	12,501	27,840	130	1,771	5,316	59,898
1977	3,525	4,215	3,316	4,170	5,930	4,045	28,096	1,968	5,485	105,902	29,006	N.A.	1,852	5,492	62,722
1978	3,489	4,513	3,507	4,277	5,778	4,036	28,506	1,634	5,792	N.A.	30,033	N.A.	1,915	5,625	64,300
1079	3,778	4,580	2,048	4,596	5,708	4,403	29,580	1,841	5,918	13,857	31,168	144	1,868	5,436	66,329
1980[5]	4,660	4,751	2,127	4,793	5,327	4,298	30,164	1,794	5,864	14,249	31,143	138	1,369	4,390	65,834
1981[6]	5,000	4,900	2,000	4,900	5,700	4,600	31,500	1,900	6,000	14,800	32,000	150	1,200	4,600	68,000

[1]Paper and Board. [2]Prior to 1979 data are for book paper, uncoated. [3]Packaging & industrial converting paper. [4]Prior to 1979 data are for linerboard. [5]Preliminary. [6]Estimate.

Source: Bureau of the Census

Table IX-28

U.S. PAPER/FOREST PRODUCTS FIRST-QUARTER RESULTS
($000)

Paper Companies	Sales	Change 1982/81	Earnings[1]	Change 1982/81
Chesapeake	$ 59,600	-6.6%	$ 1,900	-67.8%
Clevepak	31,079	5.9	949	0.1
Consolidated	135,816	-1.1	10,905	-29.7
Crown Zellerbach	725,000	-5.3	5,600	-69.6
Diamond	264,979	-14.4	2,204	-73.1
Federal Paper	123,015	8.0[2]	5,348	8.1[2]
Fort Howard	120,295	8.4	21,803	10.2
Glatfelter	68,696	29.3	5,774	150.7
GN Nekoosa	367,900	0.5	22,000	3.8
Hammermill	325,916	5.7	7,080	-34.1
Intl. Paper	1,002,700	-23.2	60,000[3]	-59.3
James River (1/24)[4]	184,250	-1.6	4,391	-5.9
Kimberly-Clark	734,300	0.1	57,700	-4.2
Longview (1/31)[4]	92,912	11.0	(2,185)	n.m.
Mead	689,866	2.6	13,803	-54.0
Mosinee	22,021	-6.1	1,022	-41.6
Pentair	67,865	17.0	2,223	-19.5
St. Regis	672,230	9.8	19,430	-61.0
Scott	580,156	2.5[2]	18,639	-27.9[2]
Socono	122,953	-4.2[2]	6,667	-13.8[2]
Sorg	19,932	-8.8	(98)	n.m.
SW Forest	144,948	-27.6	(4,603)	n.m.
Stone Container	105,442	2.3	2,556	-58.6
Union Camp	372,433	-10.6	32,241	-19.4
Wausau (2/18)[4]	44,833	-5.6	(864)	n.m.
Westvaco	342,644	-5.4	8,323	-57.4
Willamette	214,305	-12.2	(4,652)	n.m.
Total	$7,906,086	-3.1%	$298,156	-42.3%

Table IX-28 (Continued)

Forest Products	Sales	Change 1982/81	Earnings[1]	Change 1982/81
Boise Cascade	$ 713,960	-9.0%	$ 5,560	-85.2%
Champion Intl.	905,913	-9.5	617	-97.8
Georgia-Pacific	1,199,000	-11.1	15,000	-51.9
Louis.-Pacific	196,570	-26.4	(11,750)	n.m.
Popo & Talbot	59,633	-4.0	857	39.3
Potlatch	201,308	-7.9	4,485	-43.6
Weyerhaeuser	1,057,457	-3.7	56,952	-0.1
Total	$ 4,333,841	-9.3%	$ 81,721	-59.3%
U.S. Total	12,239,927	-5.4	379,877	-47.1

CANADIAN PAPER INDUSTRY RESULTS

Abitibl	C$414,618	0.9%	C$22,019	-21.5%
B.C. Forest	198,300	-2.9	(4,700)	n.m.
B.C. Resources	143,200	-35.9	(13,000)	n.m.
Con-Bathurst	362,600	1.6	17,600	-32.8
Donam	30,600	-1.0	(7,700)	n.m.
Fraser	102,734	8.4[2]	143	-97.0[2]
Great Lakes	132,275	-4.7	12,179	-42.0
Mac/Bloedel	505,000	-17.5	(10,400)	n.m.
Scott	52,900	9.3	2,200	10.0
Weldwood	99,700	-23.2	(4,047)	n.m.
Total	C$2,041,927	-9.2%	C$14,294	-87.1%

Note: n.m. = not meaningful

1. Income after taxes, from continuing operations, excluding most significant nonrecurring items in both years.

2. 1981 figures restated by company.

3. 1982 results include after-tax gain of $17.2 million from sale of tax benefits. 1981 results include after-tax gain of $57 million from land transactions.

4. Period ended. Figures for James River are for third quarter, Wausau for second quarter.

Source: Pulp and Paper, June 1982

are approximately 32% of energy costs, and the cost per metric ton (based on a production cost of $425.25/Mt) in Canada is equal to $16.33. For marginal plants where electricity is 20% of the total operating costs of an integrated facility, the costs might be as high as $85/ton. Alternatively, if electricity were substituted for all other energy uses, costs might be as high as $50/ton, even for a Canadian plant.

Average costs for construction of new forest products facilities are given in Table IX-29. Construction of a typical large newsprint facility is estimated at $330 million with a capacity of approximately 200,000 metric tons per year. At 10% interest over 30 years, finance charges on such a plant are approximately $712 million, for a total cost of $1,042 million. A similar plant in Alaska using a 1.5 location adjustment factor is estimated to cost $1,564 million over 30 years, of which $1,068 million is interest. These costs represent an annual cost differential for an Alaskan location of $17.3 million (1982 dollars).

Although input feedstock transportation costs are expected to be comparable to those for competing sites, output transportation costs will be greater for an Alaskan location than for an average site in Canada or the Pacific Northwest. At bulk shipment rates, annual costs for shipment of 200,000 tons of newsprint from Anchorage to Oakland, California, are expected to be $33.6 million (see Table IX-30). This value represents an added expense of approximately $168/ton, compared to average U.S. transportation charges of $64.50/ton. For a 200,000-ton production plant, the annual transportation differential is approximately $20.6 million (1982 dollars). Although export to Asia might be comparable for an Alaskan site and a U.S. west coast site, competing low-cost Asian labor rates make shipment of finished paper products to Asian users unlikely for all U.S. sites.

The labor cost differential can be calculated using published pulp and paper hourly rates for the Northwest and the United States as a whole and using the assumption that Alaskan labor rates are approximately 1.2 times higher than in the Northwest, and approximately 1.68 times higher than the U.S. average for the paper and pulp industry.[25] This results in an overall labor differential for an Alaskan plant of $13.5 million.

As shown in Table IX-31, the overall annual cost differential for a typical plant, which must be offset by energy rates, is $51.4 million, or $257/ton, which compares unfavorably with the $85/ton cost of electricity for even marginal plants.

Using an average of $.02/kWh price for electricity in Canada, the energy usage per pound of product can be estimated at approximately 1.28 kWh. Based on this estimate, Susitna power would have to be approximately $.09/kWh cheaper than competing sites in order to achieve a break-even with the annualized added cost of construction, labor, and transportation associated with an Alaskan site. An analysis of other

Table IX-29

TYPICAL U.S. MILL CONSTRUCTION COSTS

Grade	Capacity (metric tons/day)	Costs (million $)
Newsprint	550	330
Linerboard	1,100	Less than 200
Kraftboard	550	300
Printing & Writing Paper	550	600
Tissue	550	300

Source: Composite taken from interviews with industry officials.

Table IX-30

NEWSPRINT TRANSPORTATION COSTS

	Mode	Annual Cost (million $)
Newsprint from Anchorage to Seattle; $116.38/metric ton x 200,000 tons	Container vessel	23.3
Newsprint from Seattle to Oakland; $51.70/metric ton x 200,000 tons	Rail	10.3
Solid wood from British Columbia to Anchorage; $20/cubic meter x 483,000 cubic meters	Container vessel	9.7
Total Transportation Costs		43.3

Source: SRI International

Table IX-31

ANNUAL COST DIFFERENTIAL ASSOCIATED WITH AN ALASKAN SITE FOR A PULP AND PAPER PLANT

	Total	$/Ton
Construction	$17.3 million	86.5
Labor	13.5 million	67.5
Transportation	20.6 million	103.0
Total	$51.4 million	257.0

Source: SRI International

segments of the pulp and paper industry can be expected to produce similar results, since newsprint production is characteristic of the energy intensity of the pulp and paper industry processes, and this segment of the industry is less able to take advantage of cogeneration.

The Cement Industry

Because of the low value-to-weight ratio of cement, transportation charges are a major factor in its production. Most cement is used within 150 miles of where it is produced. Overall, cement industry capacity has not changed in recent years, but because of extreme competition within the industry, numerous older, obsolete plants have been retired and new, more efficient plants constructed. In the period 1980 through 1981, 22 plants were closed while 9 million tons of capacity were added in 1981.[26]

Four companies dominate the current cement industry.[27] These are:

- Lone Star Industries
- Ideal Basic
- Kaiser Cement
- Texas Industries.

Overall, there are 48 companies and 159 plants producing cement in 39 states. Most energy (90%) associated with cement production is used in the drying of cement clinker, which is then ground into the final product. There are two processes, wet and dry, which are used in the industry, although most new plants employ the dry process. Dry process plants typically are 20% lower in energy consumption than wet process plants.[28,29]

Although the cement industry is a high user of electrical energy, the preponderance of energy usage is from fossil fuels. In 1979, 76% of kiln energy was fueled by coal, 16% was natural gas, and 8% was oil. Since low-cost hydropower might be used to displace fossil fuel in thermal processes, the cement industry could be a candidate for energy substitution.[30]

Currently, there are no cement plants in Alaska. Product is shipped at a cost of approximately $60/ton from plants in Seattle which receive their raw materials from British Columbia.[31] Because of these added transportation costs, the cost of cement in Anchorage is twice the cost relative to the average U.S. price. Fifty percent of U.S. cement production currently comes from six states: Texas, California, Pennsylvania, Michigan, Missouri, and Florida. In general, the high cost of transportation from Alaska (approximately 100% of product value) appears to overshadow any possible energy saving associated with Alaskan cement production.

The Chemicals Industry

The industrial inorganic chemicals in SIC 2819 are a potpourri of diverse products and dissimilar industries. Contained within this group are a number of materials discussed in this report in conjunction with other industrial processes, such as alumina and bauxite as feedstocks to the aluminum industry. Of the remainder, the importance of energy costs varies markedly. The classification of this group as electrically intensive is somewhat misleading, since uranium production is included in this classification group.

The U_{235} isotope occurs in small concentrations in uranium ore, and the ore must be enriched in this isotope to produce nuclear fuel. In the currently used diffusion process, uranium oxide (U_3O_8) is converted into uranium hexafluoride (UF_6). This gas is then passed through diffusion tubes in an iterative process resulting in an increase in the concentration of the fissionable isotope. The entire process is extremely electrically intensive. Production of uranium fuel is controlled by the federal government, and no new diffusion plants are planned. Future isotope separation plants will utilize either centrifuge or laser separation techniques, both of which are less energy intensive.

Many of the other energy-intensive products are associated with production of low volumes of elemental metals, propellants, and elemental gases, which do not require large facilities. This SIC code also contains a number of high-volume, low-energy products. Eight chemicals within this SIC code are among the top 50 chemical products in the United States on a weight basis, as shown in Table IX-32. The production of these chemicals is, however, not very electrically intensive. Sulfuric acid production is an example of this class. Phosphate fertilizer production accounts for about 2/3 of sulfuric acid production, but other uses could be significant to Alaska. Its use in chloro-alkali production has been discussed previously. About 1.8 million metric tons is used annually in petroleum refining, and 1.7 million tons is used annually in recovering copper from low-grade ores.

In the production of sulfuric acid, sulfur dioxide reacts with excess air in an exothermic reaction which requires cooling. The resultant sulfur trioxide reacts with water to form sulfuric acid. The energy produced in this exothermic reaction can be used in a cogeneration steam process to produce electrical energy. Plants built in the 1980s will be able to generate 1.3 lb of steam per pound of acid. Significantly, this will occur at higher pressures (900 psi as opposed to 300 psi) and thus be more suitable for energy recovery than in older plants. Addition of a turbo generator to recover this energy would add $5,000,000 to the plant capital costs of $25,000,000 but would generate 15,000 kWh of energy.[32]

Table IX-32

RANKING OF SELECTED U.S. INORGANIC CHEMICALS
ON PRODUCTION BASIS

	Rank	1980 Production (billions of pounds)
Sulfuric acid	1	80.7
Sodium hydroxide	7	22.6
Sodium carbonate	12	16.6
Hydrochloric acid	26	5.5
Sodium sulfate	35	2.5
Aluminum sulfate	37	2.4
Calcium chloride	40	2.0
Sodium tripolyphosphate	47	1.4

Source: Standard & Poor's Industrial Surveys, "Chemicals," November 5, 1981

Three general conclusions can be made concerning SIC 2819 industries. Energy usage is heavily skewed by radioactive material production; many other high-volume chemicals are actually not energy intensive; and finally, of those that remain, most represent small markets and are secondary products associated with developed industry infrastructures and not primary industries, a factor which SRI regards as important in identifying candidate industries for Alaska. SRI has not identified any candidate industries within the group which appear to be likely candidates to benefit from low-cost Alaskan power.

The Primary Metals Industry (Excludes Steel, Copper, and Aluminum)

Five metals (gold, silver, zinc, nickel, and tin) within these SIC codes either are in production in Alaska, are the subject of exploration, or are known to exist in potentially significant quantities. In the case of precious metals, Alaska has approximately 13 principal producers working placer gold deposits within the state. Overall, about 65,000 troy ounces of gold were recovered by over 200 operators in 1979. Approximately 6,500 troy ounces of silver were also recovered alloyed with the placer gold. At least 3 tin mining facilities are operating within the state. Zinc and nickel are the subject of exploration by a variety of multinational corporations, and various reserves have been reported. Unfortunately, of 244 known major mineral areas catalogued by Resource Associates of Alaska, over 80% are in closed lands. Of the 13 most economically viable deposits identified by RAA, 9 are closed to exploitation by the Alaska National Lands Interest Conservation Act.

Some of the larger known deposits that contain economically recoverable metals are:

- Lik - sulphides of Pd (8.5%), Zn (25.5%), Ag, Cd (0.25%)
- Cominco - very similar to Lik
- Artic - sulphides of Cu (4.0%), Zn (5.5%), Pg (1.0%), Ag
- Picnic Creek - similar to Artic
- Lost River - tin, fluorite, tungsten, and beryllium
- Brady Glacier - Ni-Cu
- Bohemia Basin - Ni (0.4%), Cu (0.25%), Co (0.04%)
- Green's Creek - Pb (1.94%), Zn (7.71%), Cu (0.4%), Ag, Au
- Quartz Hill - molybdenite (0.15% MoS_2).

Zinc, copper, and silver ores are the most prevalent, but significant deposits of strategically important cobalt, chromite, titanium, molybdenum, and tungsten ores are located throughout Alaska.

Nickel is used in the production of stainless steel and other corrosion-resistant alloys. The deposit at Brady Glacier, at Glacier Bay National Park, is considered to be a major nickel reserve for the U.S. Probable reserves are estimated to be between 100 million and 300 million tons of 0.5% Ni. On Yakobi Island, Inspiration Development Co. has conducted drilling and geological detailing at its claims covering the Bohemia Basin and Takanis deposits. These deposits, together with the Flapjack deposit, contain in excess of 20.7 million tons of 0.33-0.51% Ni and up to 0.04% Co.

Tin concentrates are produced as a by-product of molybdenum mining in Colorado and from placer deposits in Alaska. Only one tin smelter is in operation in the U.S., at Texas City, Texas. Although the U.S. is 80% dependent on tin imports and Alaska contains the primary U.S. reserves, the U.S. reserves are only 0.5% of the world total. Tin is, however, available from a number of world suppliers, including Southeast Asia, Australia, Bolivia, Brazil, Mainland China, and the USSR. Overall, U.S. tin usage is expected to grow at less than 1% annually through 1990.[34]

Zinc mining in the U.S. was a $306-million industry in 1981, with 25 mines producing 99% of total output. Tennessee, Missouri, New York, and Idaho accounted for 79% of total production. Although the United States is a net importer, its reserve base is approximately 20% of the world total. Demand is expected to grow at about 1.1% annually through 1990.

Energy costs for processing these ores as a percent of value are generally less than 10% of the final product value. The unknown costs of extraction in an Alaskan setting and transportation of finished products are expected to be a significant fraction of the final cost for these metals. Low-cost Alaskan electricity would enhance the economies of extraction of these minerals but is not likely to be an overriding factor in the decision to exploit them. Detailed economic analysis is required for each site before the impact of low-cost electricity can be determined, especially since many of these deposits are precluded from exploitation in the foreseeable future.

It is not practical to examine the economies of processing at all the sites for minerals in this category, but zinc smelting is representative of the group and will be examined in some detail.

Commercially valuable zinc-bearing ores occur predominantly in sulfide form. Valuable impurities in zinc ores, from which the zinc is extracted via specific metallurgical operations, include lead, iron, copper, silver, gold, antimony, and occasionally tin.

The process of extracting zinc from the ore takes place in three operational steps:

- Concentrating - where ores, after being mined, are separated into a concentrated mineral and a waste rock.

- Smelting - where the concentrate is reduced to the metal in a metallurgical works.

- Refining - where the metal is further refined and alloyed to commercially usable form.

The concentration of zinc sulfide ores usually takes place adjacent to the mine site. First, the ore must be crushed and ground in order to free the mineral lattices from those of the waste rock (gangue). Next, the finely divided ore is mixed into a slurry with water, and the mineral and gangue particles are separated utilizing the effect of gravity. This separation usually takes place by way of the froth flotation process, where the gangue is discarded as waste (tailings). During the last step in concentration (or beneficiation), the mineral slurry is separated into solids and water via a filtration process. The resulting zinc sulfide concentrates contain 50% to 64% zinc.

The preparation of the concentrate for smelting involves a process (roasting, sintering, or pyroconcentration) in which the source material is made into a crude zinc oxide form and specified particle size. During roasting, the sulfide is heated and burned with oxygen to form ZnO and gaseous SO_2 (which is generally converted to sulfuric acid). Sintering may take place to further treat the ZnO to increase density and particle size before feeding into the smelter. In pyroconcentration, the zinc-bearing material is mixed with coal, heated, and turned into a vapor, which is carried via a gas stream to a baghouse (filter) and condensed.

In the reduction step, the zinc is reduced from its oxide to its elementary form. Several different thermal processes may be used: horizontal retort, vertical retort, electrothermic furnace, and blast furnace (all of which use carbon as a reducing agent). The electrolytic process uses the passage of electric current for reduction to metal from a liquid bath. This hydrometallurgical (electrolytic) process for zinc smelting, rather than using heat for the reduction, relies on electrodeposition of the metal from a zinc sulfate solution prepared from the crude zinc oxide and sulfuric acid. Virtually all impurities remaining from the preparation step are eliminated in this process.

The quality of zinc produced by the various carbon reduction processes mentioned is suitable for hot-dip galvanizing, continuous-line galvanizing, and in some cases for brass manufacture and rolled (wrought) zinc. For sizable usage in die-casting alloys, however, output from this type of smelter must undergo a refining step. The major method of upgrading the lower-purity zinc metal is fractional distillation in reflux refining columns, which is capable of producing 99.995% pure zinc.

Sulfuric acid, one of the major byproducts of the zinc industry, is used by the chemical and oil industries (e.g., for chemical cleaning of steel; in making phosphates for fertilizers).

Identified world resources of zinc are estimated to be about 1.8 billion tons. (Metal Statistics, 1980, American Metal Market, Fairchild Publications, New York, 1980). Canada, the largest producer of zinc, is also the country with the largest known reserves. Other important producers are Peru, Australia, the U.S., and Mexico. In 1980, Peru produced 72,000 Mt; Australia, 300,000 Mt; United States, 325,300 Mt; Mexico, 165,000 Mt; and Canada 550,000 Mt. Major U.S. companies producing zinc include:

- Amax, Inc. (Greenwich, Conn.).
- Asarco, Inc. (New York).
- Bunker Hill Co. (Kellogg, Idaho), a unit of Gulf Resources and Chemical Corp.).
- National Zinc Co. (Bartlesvillle, Okla.; a unit of Engelhard Minerals and Chemicals Corp.).
- New Jersey Co. (Nashville; a unit of Gulf and Western Industries, Inc.).
- St. Joe Zinc Co. (Pittsburgh; a unit of St. Joe Minerals Corp., which closed its Monaca, Pa., electrothermic zinc smelter at the end of 1979).

A zinc smelter employing the electrolytic reduction process can be expected to use about 3,500 kWh per ton of finished product. Free electricity might produce a savings of $200 per ton, but this would be offset by $60 per ton in additional capital costs ($180 million for an Alaskan site) and $54 a ton for additional labor costs (300 workers) associated with an Alaskan location. Transportation costs cannot be evaluated without consideration of a specific site. In conclusion, the availability of inexpensive electricity makes an Alaskan zinc smelter more favorable but is clearly not a deciding factor.

The Fertilizer Industry

Although the chemical fertilizer industry is currently suffering from overcapacity, SRI projects a growth rate of 2% to 3% over the next 20 years for this industry, and there is potential for expansion of the industry in the 1990s. The industry has reduced the electric energy "content" of its product in recent years and has generally converted from mechanical compressors to the reforming process, which involves combustion of natural gas at 1,800°F to produce H_2 and steam for turbines. Siting issues are primarily associated with the availability and price of natural gas, which is used as feedstock for these plants. A new ammonia plant produces a product with an electric energy content of only 25 kWh/ton, compared to 1,000 kWh/ton for a plant using mechanical compressors. To determine the value of conversion back to electricity, the cost of the displaced gas ($28/ton of product, assuming $3.75 per million Btu) must be balanced against the electricity cost and the other costs associated with an Alaskan location.

Electrical energy (compressors) would only be substituted for natural gas (gas-fired turbines) if the electric energy content of the product did not exceed $25 to $30 per ton. SRI estimates the investment required to build a 1,500-metric-ton-per-day plant in Alaska at $259 million, based on an investment of $166 million for a similar facility at a Gulf Coast site. Differential carrying costs associated with the capital investment in an Alaskan site are therefore approximately $10 per ton. Differential transportation costs can be expected to add another $35 to $45 per ton. Based on the increased construction costs and transportation costs of an Alaskan site, inexpensive energy alone will not attract investors to Alaska interested in siting a new ammonia plant.

If, however, an Alaskan location is considered because of economically priced natural gas, a decision between the gas-fired plant and a mechanical plant will be made on the tradeoff between the cost of displaced gas (7 billion Btu) and the electricity costs. Electricity prices below $0.026/kWh would be required before the mechanical plant would have lower operating costs than a gas-fired plant, assuming a gas cost of $3.75 per million Btu. If operation of the reciprocating-compressor ammonia plant proved economical, it would require approximately 550 GWh annually.

Electric Space Heat in the Residential/Commercial Markets of the Railbelt

In addition to major industrial development and activity, commercial and residential space heat offer market opportunities for utilizing low-cost electrical energy. Electric pricing policies and marketing programs could provide incentives to displace a portion of fuel oil and gas space heaters in both existing and new units. If electric rates were low enough relative to other space heating options, there would be a shift from fossil fuel to electric-generated space heating.

At present, electricity supplies approximately one-third of all residential end-use energy in the Railbelt. Commercial use is also large. The current and forecast use in both markets by fuel type predicted by Applied Economics Associates, adjusted and amplified by SRI as noted, are shown in Table IX-33.

Residential Electricity Demand

Total demand for residential energy (taken here as heat demand) is shown as growing to 57.844 trillion Btu by 2010 (see Table IX-33, Table IX-34). Likely conservation factors, estimated as reducing overall demand by 10%, 20%, and 30% in 1990, 2000, and 2010, respectively, result in a demand of approximately 40.5 trillion Btu in 2010 (see Table IX-34). If it is assumed that all savings are in the fossil fuel component, the fossil fuel usage after conservation would be approximately 30 trillion Btu (equivalent to approximately 18 trillion Btu of electricity). This quantity must be added to the original forecast for electricity of 12.5 trillion Btu. Accounting for conservation, this gives a total potential residential all-electric demand of approximately 30.5 trillion Btu. Assuming a favorable price advantage for electricity, conversion of existing facilities and the total electrification of all new construction in the Railbelt can be expected to approximate the conversion from coal to natural gas for space heating that occurred in the Midwest and Northeast during the late 1940s and 1950s. Because of transmission and distribution limitations, market penetration of approximately 80% is assumed at equilibrium in the Railbelt. The estimated potential residential electrical usage in 2010 is therefore approximately 24 trillion Btu (7,000 GWh). For 1990 it was assumed that the price differential between electricity and fossil fuels would be smaller, leading to a smaller equilibrium market share; that the market would be half way to equilibrium; and that only 90% of the potential market can be reached because of geographical factors. These assumptions imply that 25% of residential demand would be met by electricity. Similar considerations lead to a 45% share in 2000.

Table IX-33

ENERGY CONSUMPTION IN THE RAILBELT:
RESIDENTIAL/COMMERCIAL[1,2]
(10^9 Btu)

	1979	1990	2000	2010
Electric				
Residential	3,572	5,427	8,240	12,500 (3)
Commercial	2,544 (4)	3,998	6,618	10,060
Petroleum				
Residential	14,355	18,533	23,722	
Commercial	3,481	5,345	6,231	
Natural gas				
Residential	7,178	9,266 (5)	11,861 (5)	
Commercial Heat	3,221	4,810 (6)	5,608 (6)	
Total liquid fuels				
Residential				45,300
Commercial				17,800
Total energy				
Residential	25,105	33,226	43,823	57,844 (1)
Commercial	9,246	14,153	18,457	27,860

[1]Basic data from Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

[2]Coal excluded.

[3]Extrapolated by SRI International.

[4]Taken from energy balances, Long Term Plan, as 2,544 x 10^9 Btu. Other figures in row extrapolated at rate indicated on p. C-66 (4.2%).

[5]Inferred by SRI from 1979 data as 50% of petroleum use.

[6]Inferred by SRI from 1979 data as 90% of petroleum use.

Table IX-34

ESTIMATES OF POTENTIAL ELECTRIC DEMAND FOR RAILBELT RESIDENTIAL END USE
(10^9 Btu Unless Otherwise Noted)

	1979[1]	1990	2000	2010[2]
Forecast usage				
Electricity	3,573	5,427	8,240	12,500
Fossil	21,533	27,799[3]	35,583[3]	45,346
Total	25,106	33,226	43,823	57,846
Total with conservation	25,106	29,903	35,058	40,492
Energy demand if all electric	16,493	20,113	24,331	29,295
Likely fraction of demand electric	0.217	0.25	0.45	0.8
Resulting electricity usage				
Btu	3,573	5,028	10,949	23,730
GWh	1,047	1,474	3,209	6,955

[1]Actual.

[2]Extrapolated by SRI International.

[3]Natural gas taken as 50% of petroleum values.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

Commercial Electricity Demand

Similar considerations apply to commercial conversion to electricity and total potential electricity use. For the commercial sector it is assumed that some activities preclude the use of electricity, resulting in an arbitrary limit of 70% maximum market penetration. If the same market share approach* used in the residential estimates is assumed, the fractional shares indicated in Table IX-35 can be calculated. These values lead to the electricity demand forecasts presented at the bottom of Table IX-35.

Supply and Demand

The forecast[20] generation and generation capability are contrasted with the potential residential and commercial electricity use projected above in Table IX-36.

It is apparent that unless use for space heating is discouraged by a tiered rate structure, increased residential and commercial use of electricity could result in near saturation of the proposed Susitna-based generation system without any increase in industrial demand above the current 600 GWh per year. If long-term favorable electric rates are offered to residential and commercial consumers, a substantial substitution of electricity for fossil fuels will occur since electrical space heating equipment is generally less expensive than fossil-fuel-fired space heating equipment. The conversion will take place over a 20-year period as old space heating equipment is replaced. Electrical heating equipment will be specified in both the new construction and replacement markets, if the prospect for long-term favorable electric rates is widely perceived and accepted.

If the same analysis is performed for the fiscal crisis scenario, where the population is assumed to grow only by a factor of 1.25 by 2010 and conservation reduces per capita demand so that total usage is comparable to 1980 usage, the projected demand is reduced accordingly (approximately 3,900 GWh). In this scenario, substantial excess capacity is projected.

Agglomerations of Small Industrial Facilities

One alternative to attracting a single enterprise that utilizes large quantities of electric power is to attract a group of small energy-intensive businesses to an industrial park. The industrial park setting has been widely adopted as a way to attract business development to a region and to provide planned commercial development. As a job creation mechanism, there are advantages to a strategy that attracts small

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*With slightly different equilibrium share and penetration figures.

Table IX-35

ESTIMATE OF POTENTIAL ELECTRIC DEMAND FOR
RAILBELT COMMERCIAL END USE
(10^9 Btu Unless Otherwise Noted)

	1979[1]	1990	2000	2010[2]
Forecast usage				
Electricity	2,544	3,998	6,618	10,060
Fluid fuels	6,702	10,155[3]	11,839[3]	17,800
Coal	825	na	na	na
Total	10,071	14,153[4]	18,457[3]	27,860[3]
Total after conservation		12,738	14,766	19,502
Energy demand if all electric	7,060	9,242	11,507	20,740
Fraction of demand electric	0.360	0.400	0.441	0.567
Electricity use				
Btu	2,544	3,697	5,075	11,759
GWh	746	1,084	1,487	3,447

[1]Actual.

[2]Extrapolated by SRI.

[3]Natural gas taken as 90% of petroleum.

[4]Without coal.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

Table IX-36

POTENTIAL ELECTRICITY USE IN THE
RESIDENTIAL AND COMMERCIAL SECTORS COMPARED TO SUPPLY
(GWh)

	1990	2000	2010
Residential	1,474	3,209	6,955
Commercial	1,084	1,487	3,447
Total projected demand[1]	2,558	4,696	10,402
Projected demand[2]	2,440	3,100	3,921
Projected supply[3]	4,846	5,107	7,031
Projected supply[4]	5,578	9,473	12,383

[1]4.2% annual growth.

[2]Fiscal crisis scenario.

[3]Battelle (4.2% annual growth in population).

[4]Arbitrary retention of all existing and projected fossil capacity operating at previous maximun yearly rate.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, State of Alaska: Long-Term Energy Plan, p. 30, Appendix p. C-66 (August 1981).

businesses rather than large process plants. Large capital-intensive process plants tend to require fewer workers than small businesses per dollar invested. Moreover, large businesses are less likely to expand further in a single location than smaller businesses, which have a better potential for growth. Finally, large plants based on a single commodity are vulnerable to worldwide market changes, whereas a diversified business base can more easily adjust to changing market realities.

There are negative aspects of an agglomeration strategy. Large process plants can be planned as independent entities with waste treatment facilities, fire protection, and other services designed to satisfy the needs of the plant. For planned industrial parks, these services are often provided by the surrounding community. It will be more difficult for Alaska to provide the support facilities for a group of small businesses in an economically timed development program since the first tenant will require full services and it might take 20 years to fill the development. The projected energy requirements for a typical industrial park are not large, and it is difficult to envision any strategy (short of extremely favorable industrial development bonds for financing) that would enable Alaska to compete effectively with the large number of regional industrial development programs and commercially developed industrial parks in a way that would fill a large number of industrial parks.

The successful development of industrial parks designed for energy-intensive small businesses might be feasible if other aspects of an Alaskan location are exploited in addition to the potential availability of inexpensive electrical power. Materials processing, especially of Alaskan minerals, is the most likely type of business activity to be attracted to an Alaskan industrial park setting. The secondary processing of scarce high-value minerals is usually feasible only on a small scale. One approach for an integrated processing park would be to target the processing of critical or strategic materials like cobalt, chromium, molybdemum, manganese, zinc, nickel, tin, and fluorspar, and this possibility has been briefly discussed under "Ferroalloy Production."

SRI has found no meaningful way to quantitatively assess the potential for the development of small business industrial parks based on inexpensive electrical energy. SRI could find no examples of such parks that have been attracted to existing regions by the availability of inexpensive hydroelectric power. Since electrically intensive potential candidates, large or small, are considered throughout Section IX, potential candidates for the agglomeration strategy have been considered during the study. Based on this screening process, the most likely candidates appear to be associated with electrometallurgical processing (SIC 3313) or the processing of inorganic chemicals (SIC 2819).

Electrification of the Alaskan Railroad

Electrification of the Alaskan Railroad might be an attractive alternative to continued use of diesel-electric locomotives if low-cost plentiful electrical power becomes available. Two questions must be answered to determine the viability of electrification of the Alaskan Railroad:

- What approximate quantity of electric power would be consumed each year?

- What annual savings in the cost of energy would be available to repay the capital cost of electrification plus a return on investment?

Facilities and Equipment

The Alaskan Railroad has 654 miles of mainline, branch, yard, and other track for which traction power must be supplied. At present, the railroad owns 65 diesel-electric locomotives, including 21 classed as switchers. Thirty-eight locomotives are in service, 9 are undergoing heavy repair, 13 are stored in serviceable condition, and 1 is leased.[35]

If electrification were undertaken, some tracks such as yards and some branch lines would not be converted. Also, the Portage-Seward mainline has very low traffic density and would probably not be converted. For present purposes we will assume that 450 miles of track would be considered for electrification. This includes 419 miles of single track mainline between Whittier and Fairbanks and unspecified branch lines.

Construction of overhead electric lines, substations, and power distribution lines account for most of the capital cost of electrification. Electric locomotives would have to be purchased, but in the long run electric and diesel-electric locomotive fleets have similar capital costs.

Operations

Traffic on the Alaskan Railroad has varied greatly from year to year. In FY 1980 the railroad carried 271 million revenue ton-miles. In FY 1981 the traffic increased to 407 million revenue ton-miles, mainly because of increases in shipments of sand and gravel.[36]

Electrification is usually regarded as an interesting possibility only on lines that carry many trains each day and have high traffic densities--e.g., 40 million gross tons per year. The mainlines of the Alaskan Railroad have a low rate of utilization (Reference 3). In summer there are only 14 freight and passenger trains per week, each way, between Anchorage and Fairbanks, and the most heavily traveled line--between Anchorage and Matanuska--carries a total of only 37 round-trip trains per week. Traffic densities for mainline links in FY 1981 were as follows:

	Million Gross Tons Per Year
Fairbanks - Menana	3.1
Menana - Healy	3.2
Healy - Matanuska	2.2
Matanuska - Anchorage	5.9
Anchorage - Portage	1.8
Portage - Whittier	1.0
Portage - Seward	0.3

Energy Requirements

The Alaskan Railroad consumed 3,060,000 gallons of diesel fuel in 1981. In April 1981, at about midpoint in FY 1981, the average price paid for diesel fuel by U.S. railroads was $1.04 per gallon.[37] If we assume that the Alaskan Railroad paid $1.04 per gallon throughout FY 1981, its fuel cost was about $3.2 million.

In Reference 38, SRI developed factors for diesel fuel and electric power which indicate that an electrified system would require about 10.4 kWh to do the work of 1 gallon of diesel fuel in a diesel-electric system. Thus, in FY 1981, 100% conversion of the Alaskan Railroad would have generated a demand for about 32 million kWh of electric power. Actual demand would be somewhat less because some track would not be converted. If electric power had been available for $0.01/kWh, the cost of electric power would have been less than $320,000, or about 1/10 the cost of diesel fuel.

The difference between the costs of diesel fuel and electric power is the principal economic advantage of electrification. According to the foregoing estimates, the potential saving from 100% conversion would be about $2.9 million per year for the volume of freight carried in 1981 and at the price of diesel fuel in 1981. Savings from conversion of 450 miles would be somewhat less, of course. In future years savings would be higher if more freight were carried or if the difference in the prices of electric power and diesel fuel were higher.

Economics of Electrification

SRI's assessment of railroad electrification[38] indicates that the average cost of electrifying single track mainline without automatic signaling equipment was about $100,000 per mile at 1974 price levels. Costs in Alaska would be higher, and inflationary factors from 1974 to the 1990s would further increase costs. If these two factors are included, it would cost, on average, approximately $250,000 per mile for 450 miles, for a total cost of $110 million for electrification. If it is further assumed that the investment should be recovered in 40 years at a return of 10% per year, annualized capital costs will be approximately $11.2 million per year. This amount compares unfavorably with the estimate of the potential savings from electrification, which are estimated at less than $2.9 million per year.

It seems unlikely that the conclusions of the analysis will be altered in the future by changing conditions. Savings in operating costs would increase if the cost of diesel fuel increased or if the volume of traffic increased. However, based on the rough estimates presented above, the annualized capital cost of electrification would barely be recovered if the average cost of diesel fuel increased to $4 per gallon (in 1980 dollars) or if the average volume of freight increased to 1.6 billion revenue ton-miles. Neither event is considered likely by SRI in the time frame of interest (i.e., 1990-2010). The price of electricity has little influence. The merits of electrification would not be changed greatly if the cost of electricity were $.02/kWh or if it were free.

Electric Intertie to the Lower 48

Exporting electric power from the proposed Alaska hydroelectric and/or tidal power plants to the Lower 48 is one option in utilizing the full production capacity of these plants. As shown in Figure IX-1, the overland route would run from Fairbanks or Anchorage to Everett, Washington, where it could tie into the Pacific Northwest power grid. Since the electric power systems of the Pacific Northwest are now interconnected with those of British Columbia, another option for consideration is to interconnect Alaskan, Canadian, and Pacific Northwest power sources and markets through exchange and load displacement. However, since additional transmission capacity through British Columbia and the Pacific Northwest would be required, the costs associated with an interconnection to British Columbia are expected to be comparable with the costs associated with a direct intertie to the Lower 48, if the ultimate destination of the power is the Lower 48.

Physical Factors

Routes considered for the intertie involve an impressive variety of terrain, geology, and climate settings. Most route locations lie in remote, sparsely settled areas.

A potential 1,810-mile route from Fairbanks to Everett, Washington, involves only two elevations greater than 3,000 ft.

Canadian portions of the route are map locations for study purposes only. Generally, use is made of protected mountain trenches and relatively low inland plateaus, thus avoiding the rugged, wet coastal mountains. Existing roads and railroads now use predominantly these terrain features.

Several studies have been made of road and rail routings through Northern British Columbia and the Yukon Territory.

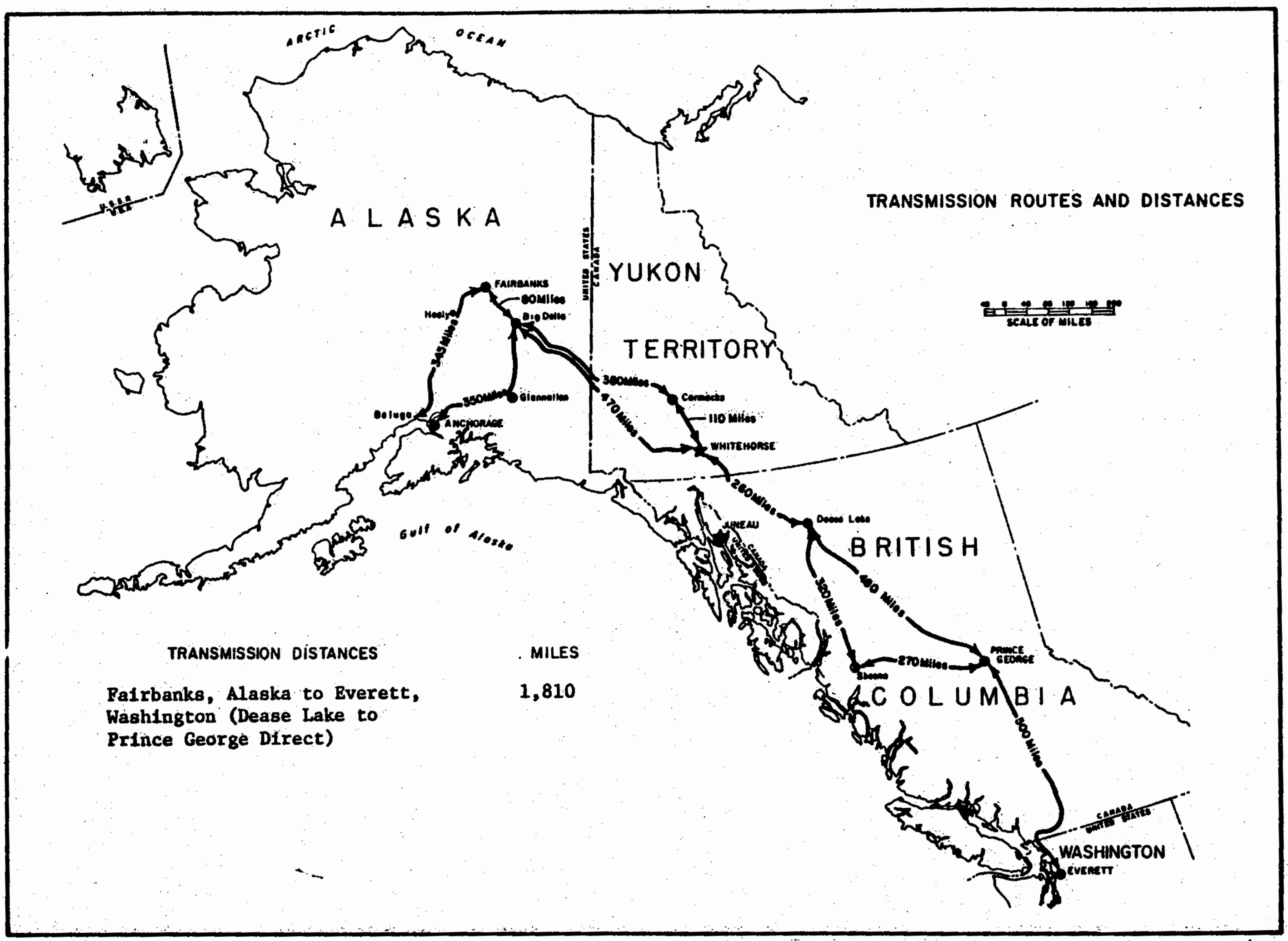

FIGURE IX-1 TRANSMISSION ROUTES AND DISTANCES

Existing 138-kV transmission systems near Fairbanks and Whitehorse, plus the extensive B.C. Hydro system extending as far North as the Peace River Project, provide an invaluable experience base. The Healy-Fairbanks 138-kV line experiences many of the environmental factors expected for the intertie, including exposure and operation in -70°F weather and tower foundations in fragile, discontinuous permafrost. From a design viewpoint, the southern portions of British Columbia may have the most difficult combination of terrain, snow, and icing problems encountered in the entire route.

Permafrost is known to exist as far south as the Yukon-British Columbia border and is a factor in foundation and access road design. Except for extremes of cold and duration of cold, the available climate data indicate few unusual design problems. Winds, snow, icing, and electrical storms all seem well within the range of climate conditions routinely handled in transmission systems in the Lower 48.

The route areas appear unusually free of earthquake dangers, considering the proximity to active areas of the Pacific Rim. Of the regions involved, the Puget Sound area has the most severe earthquake hazard.

Limited access presents problems for construction, operation, and maintenance. Routing generally along existing and developing transportation corridors should meet these concerns.

In summary, the available data support a tentative conclusion that no physical impediments exist which preclude construction of high voltage electric transmission lines along the routes considered. Careful attention to foundations and full use of existing knowledge of Arctic conditions appears to ensure physical feasibility.

A detailed study would involve careful consideration of the actual route selection, including soils and terrain, plus study of critical points such as the divides and mountain passes and full attention to the unique operation and maintenance situations in the Arctic.

Technology

Significant advances in high voltage transmission capabilities have been made in the last decade. Extensive alternating current transmission systems now exist at 500 kV, and some major Canadian and U.S. lines are operational at 735 and 765 kV.

Parallel advances in high voltage direct current (HVDC) technology include the 846-mile dc circuit of the Pacific Northwest-Southwest Intertie, which has a rated capacity of 1,440 MW. The Russian government has under study 1,500- and 1,800-mile lines at 750 kV dc for capacities up to 6,000 MW.

Existing and assured near-future transmission technology is adequate. This appears to be no technical barrier for the contemplated intertie.

Transmission towers would likely be of steel. Environmental effects of possible concern include esthetic impacts, direct effects of construction, increased activities in presently remote areas, and potential health effects of high voltage transmission lines. Interception of wildfowl by transmission lines has been experienced in some areas.

Transmission line clearing and weed control programs would be of possible concern. Differences would be expected in vegetation patterns and snow accumulation in cleared areas. Possible effects on wildlife, such as availability of feed, would need to be anticipated in location and clearing design.

It is assumed that any Canadian decisions on possible transmission routes in Canada would reflect full consideration of environmental effects. At this time, no environmental aspects of the transmission line preclude its development.

<u>International Aspects</u>

Transmission of the electric power would involve an international element in the feasibility of exporting Alaskan surplus power to the Lower 48. We assume appropriate arrangements with Canada can be reached if the U.S. and Canada determine there is a mutual interest. It should be noted, however, that B.C. Hydro is presently undertaking studies concerning exporting surplus electricity from British Columbia to potential markets in the Pacific Northwest and California. The interest by British Columbia in selling its own hydroelectric-generated power may place it in a competitive position with Alaska-generated electricity.

<u>Design and Cost Assumptions</u>

Adapting the Department of Interior North Slope Transmission Study Analysis,[39] the costs of an intertie with the Lower 48 were scaled according to the differences in transmission distances between the North Slope and the Railbelt (i.e., 2,249 miles vs. 1,810 miles). All estimates are based on routes and distances shown in Figure IX-1.

The analysis was based on Pacific Northwest construction costs, adjusted by a factor of 1.9 to reflect higher labor and transportation costs for Alaskan and northern Canadian construction. The transmission routes generally follow existing and planned roads and railroads, so no added costs were assumed for access roads or right-of-way. Costs were included for a service road suitable for 4-wheel-drive vehicles along those portions of the route where soil conditions permit. The service road would be used for construction and operation and maintenance.

For permafrost areas, such primitive service roads would be suitable only where soil conditions are ideal. For frost-susceptible soils and suspected high-ice-content permafrost, it is assumed that overland access for both construction and operation and maintenance would be limited to winter transport on frozen soils. Helicopters would be used extensively.

Tower foundations in permafrost areas require a departure from normal practice. Estimates for this study assume free-standing structural steel towers with foundations on timber grillage and gravel pads for permafrost areas, based on successful Canadian experience with this design.

Rough estimates of clearing costs were based on regional forest cover types and required width of rights-of-way. The costs do not include any allowance for right-of-way acquisition. System voltage and conductor configurations were selected by rule-of-thumb methods, and rough approximations were made of line capabilities, losses, and series compensations.

The estimates include substation (or terminal) costs to deliver power to regional transmission systems. The costs do not include subtransmission or distribution facilities within the regions. Unit transmission costs reflect assumptions of 50-year life for transmission lines and 30 years for terminals and substations, and an assumption of public financing. The estimated costs for transmission of electricity from the Railbelt region to the Lower 48 are expected to average $0.022/kWh in 1981 dollars (Table IX-37).

Under the proposed bulk transmission of electric power to the Pacific Northwest, the power must satisfy an unmet demand and be cost competitive in the potential market areas.

The increased cost of transmission to the Lower 48 compares unfavorably with current industrial market prices, which range from $0.01/kWh to $0.025/kWh in the Pacific Northwest. Although the price of subsidized Alaskan electricity transported to the Northwest ($0.035/kWh) might compare favorably with the projected prices of electricity in the Northwest and California in the 1990s, Alaska would have to assure power availability throughout the lifetime of the transmission line, and there seems to be little incentive for Alaska to subsidize power delivered to the Northwest.

Established HV and EHV transmisson grids in the Pacific Northwest interconnect the region's federal and investor utility generating plants and load centers. A recent report on potential markets in the Pacific Northwest and California for surplus electricity from British Columbia in the late 1980s concluded that:

Table IX-37

ESTIMATED COSTS FOR TRANSMISSION OF ELECTRICITY FROM RAILBELT TO LOWER 48 FOR 4,000 MW WITH 90% LOAD FACTOR AND 7% LOSSES (2.6×10^{10} kWh at market)

Construction cost (1981$)	$\$4.7 \times 10^9$
Interest during construction $\left(\frac{\text{cost} \times 10\% \times 4 \text{ yrs}}{2}\right)$	$\$0.9 \times 10^9$
Investment	$\$5.6 \times 10^9$
Annualized cost (10%)	$\$0.56 \times 10^9$
Operation and maintenance	$\$ .01 \times 10^9$
Total cost	$\$0.57 \times 10^9$
Energy cost for transmission	$0.022/kWh

> Utility forecasts indicate that the Pacific Northwest states will have a net SURPLUS of electrical energy under most foreseeable circumstances through the mid-1990s.
>
> ...the Pacific Northwest is NOT a promising market for surplus British Columbia electricity, except under extremely infrequent (and certainly unpredictable) "critical" water conditions.*

In the 1990-2010 time frame, power from Alaska would be a supplement to the hydro-thermal program in lieu of nuclear installation near the Pacific Northwest load centers. There are many uncertainties as to probable future costs of new baseload electric energy in the Pacific Northwest. Increasing construction costs, siting questions, and a range of environmental considerations all point to higher cost of energy from future plants. Independent analyses by SRI of the supply and demand in the Pacific Northwest confirm that supplies should be adequate in this region through the 1990s. There is some potential to market Alaskan electricity in California if it can be made available below prevailing industrial rates.

The export to the Pacific Northwest of power generated with the proposed hydroelectric or tidal facilities through a direct bulk power delivery system is fully feasible from a physical and engineering standpoint. However, it is unlikely at this time to have sufficiently favorable financial feasibility to merit priority consideration in the use of surplus hydroelectric power. More detailed investigations of transmission systems to deliver energy generated by hydroelectric or tidal power in the 1982-1995 time frame do not seem merited. Potential delivery to California markets on a regular basis through the Pacific Northwest grid may be feasible beyond 1995.

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*A. R. Tussing, S. A. van Vactor, C. C. Barlow, "Potential Markets in the Pacific Northwest and California for Surplus Electricity from British Columbia." ARTA, Inc., Seattle, Washington, November 1981.

X CONCLUSIONS

SRI has evaluated the potential of low-cost power in the Railbelt region to attract energy-intensive industries. Of the nine potential candidate industries and four additional application areas considered, only residential space heating and processing of certain primary metals are likely to take advantage of the low-cost power in the Railbelt region. Expanded space heating usage has the best potential to utilize any excess power produced in the Railbelt. Investment in an aluminum plant appears to be likely only if the construction costs of the hydroelectric projects are subsidized by the state, and then it is questionable that there will be sufficient excess power available to serve a single "world-class" plant. Although the tidal project might provide sufficient power, the power from this project will not be low cost. Other metal processing plants are likely to be considered only if feedstocks are found in Alaska. The construction of an intertie with the Lower 48 does not appear to be cost-effective without state grants to finance the power projects, but there is no rationale for Alaska to subsidize power delivered to other states.

SRI's findings are predicated on 10% interest rates, continued high Alaskan labor costs, and little real increase in petroleum prices during the next 25 years.

The major findings of the study are:

- The cost of power from the Susitna project will not be competitive without a very substantial state subsidy, in the form of either grants or subsidized interest rate (until the capital cost obligation is paid off in 2010).
- The Cook Inlet project will not produce power at competitive rates because of the intermittent nature of tidal power.
- There is not likely to be excess power available from Susitna alone unless the Alaskan economy stagnates or declines.
- There is unlikely to be sufficient excess power to serve a single world-class aluminum plant.
- Other than aluminum, electrically intensive industries are unlikely to derive sufficient cost savings from subsidized power to consider an Alaskan site on the basis of low-cost electricity alone.

- The availability of low-cost power might improve the economics of processing materials, provided the major feedstocks are native to Alaska.

- Without a tiered rate structure to discourage use for residential space heating, subsidized power is likely to increase electric space heating use sufficiently to absorb any excess power from the Susitna project.

- The relatively high state corporate income tax is a barrier to industrial development in the state.

- Although the SRI study is predicated on stable energy prices through 2002, the findings of the study are not greatly affected by an increase in fuel prices of 50%, since transportation costs will escalate commensurately.

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10. Ibid., pp. 4-27.

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12. Ibid.

13. Average U.S. price of aluminum ingot in 1980 = 71.6¢/lb
= $1,575 $/metric ton

Average shipping cost for alumina = $16/ton

2 tons alumina/ton aluminum = $16 x 2 = $32/ton input shipping charge

Export shipping of ingot = 4.5 x $16 = $72/ton

Total average shipping charge per ton aluminum = $72 + $32
= $104

Fraction of value attributable to shipping = $104/ton shipping
÷ $1,575/tons value
= 6.6%

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