ALASKA LEGISLATURE COMMITTEE FILES 1983-1984

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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, <u>Mineral Commodity Profile</u>, May 1978, as reported in <u>Transnational Corporations in the Bauxite/Aluminum Industry</u>, 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	1.13×10^9 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
- Argon
- Carbon dioxide
- Helium
- Hydrogen
- Neon
- Nitrogen
- Nitrous oxide
- Oxygen

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
Electrometallurgical products, 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 furnacnes
Molybdenum silicon, not produced in blast furnaces
Nonferrous additive alloys, high percentage: except copper
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.

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[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-truction 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.	1,652	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	65,034
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

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[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]
Socomo	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.
Pope & 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

Abitibi	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 $239 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,[illegible] (5)	
Commercial Heat	3,221	4,810 (6)	5,[illegible] (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

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[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

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[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

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[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

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[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 maximum yearly rate.

Source: Department of Commerce and Economic Development, Division of Energy and Power Development, <u>State of Alaska: Long-Term Energy Plan</u>, 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.

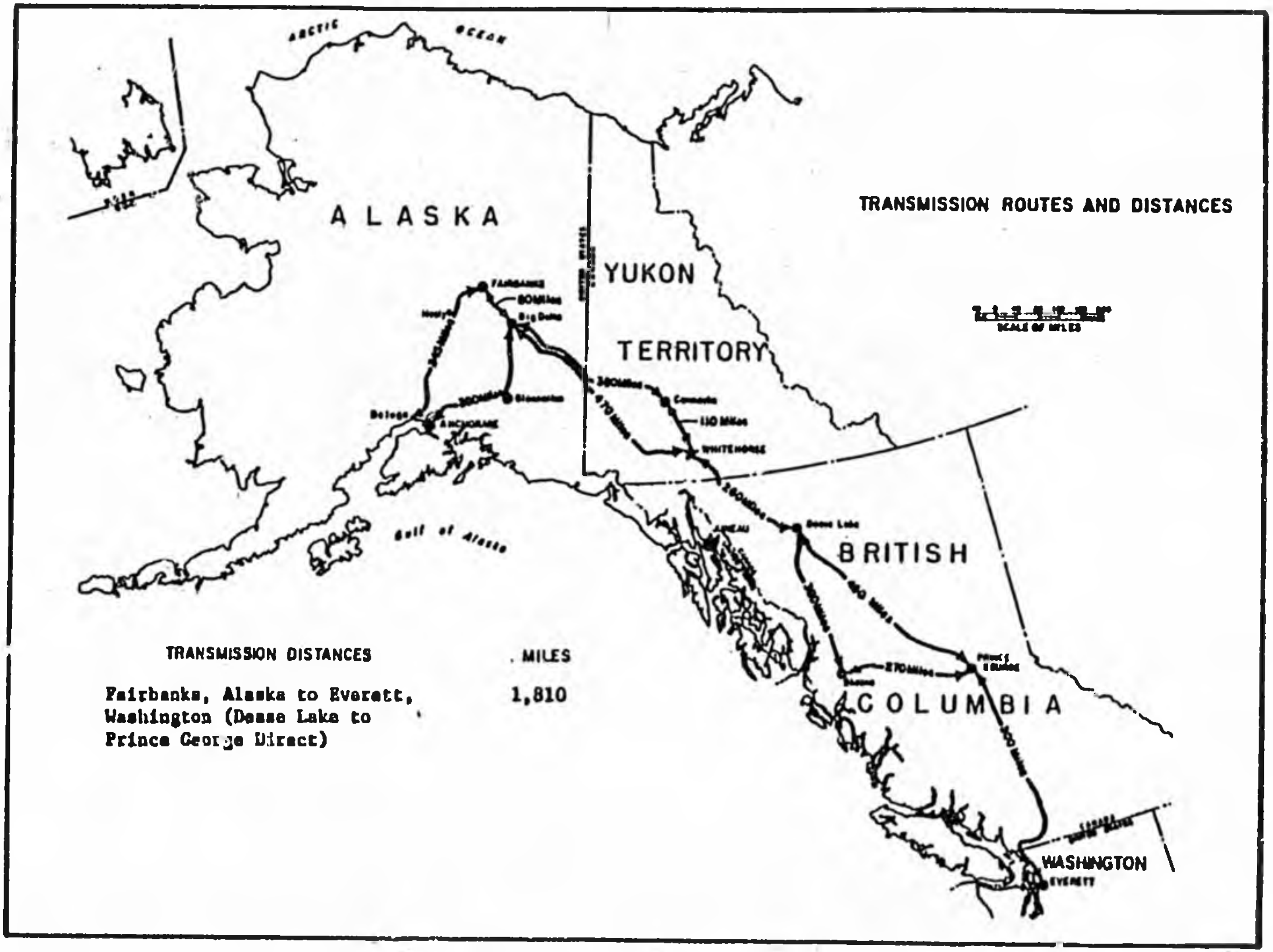
Physical Factors

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.



TRANSMISSION DISTANCES	MILES
Fairbanks, Alaska to Everett, Washington (Dease Lake to Prince George Direct)	1,810

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.

International Aspects

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.

Design and Cost Assumptions

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. 1,310 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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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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SUSITNA
HYDROELECTRIC
PROJECT

SUMMARY
REPORT

MARCH, 1982

DRAFT

ACRES

ALASKA POWER AUTHORITY

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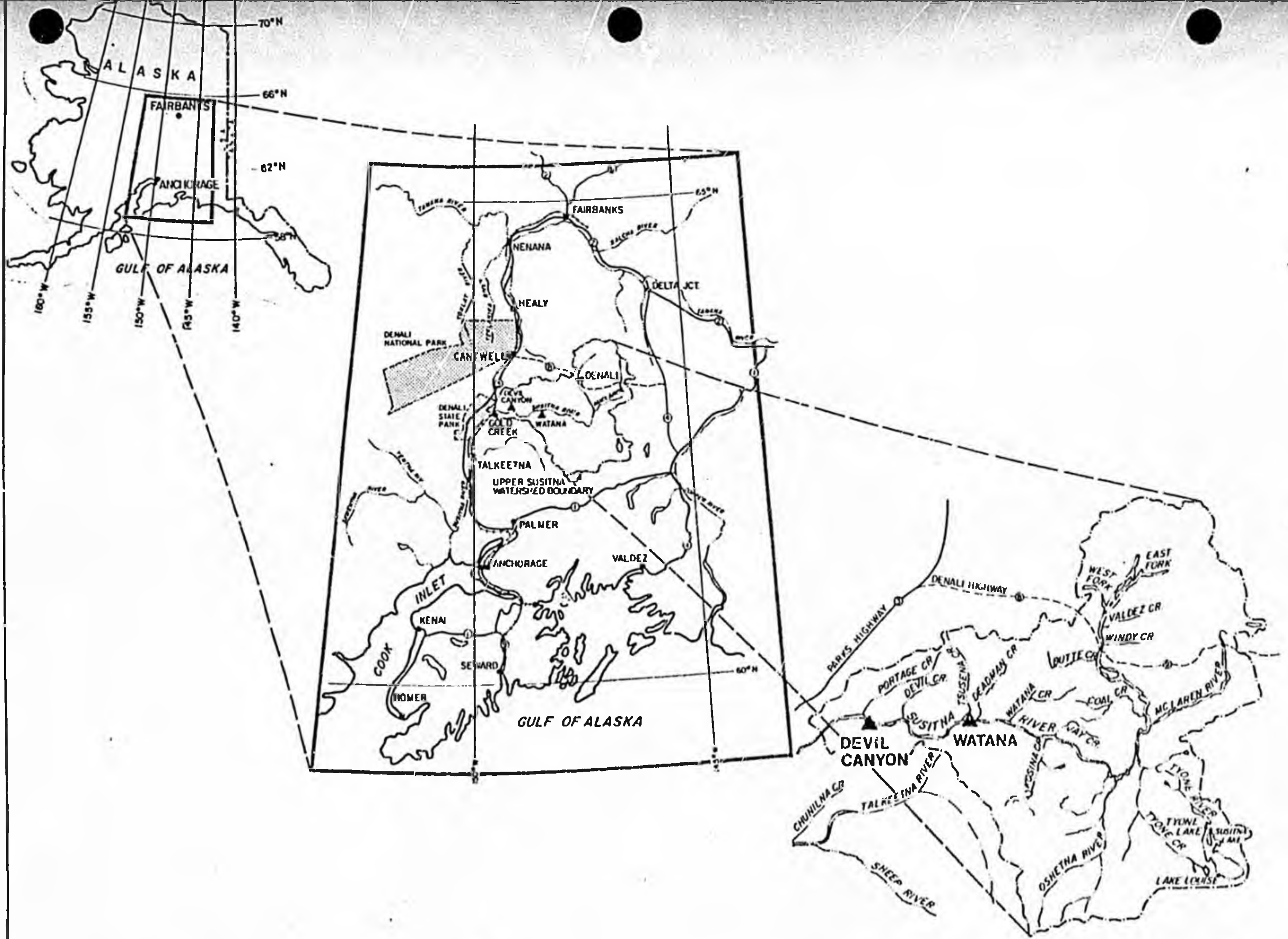


PLATE 1 **LOCATION PLAN**

INTRODUCTION

1

The Susitna River, with a drainage area of more than 19,000 square miles, is the sixth largest in Alaska. (See Plate 1.) Rising in the glacier-topped mountains of the Alaska Range about 90 miles south of Fairbanks, the river meanders across a broad alluvial fan for about 50 miles in a southerly direction before it turns westward and begins a 75-mile plunge between essentially continuous canyon walls. Turning once again to the south, it flows for another 125 miles before discharging into the upper reaches of Cook Inlet west of Anchorage. An important and productive fishery resource, the Susitna also contributes to the support of significant wildlife populations in the virtually untouched and relatively inaccessible lands across which it flows.

Contained entirely within the southcentral Railbelt region, the Susitna basin is strategically situated between the two largest Alaskan population centers of Anchorage and Fairbanks.

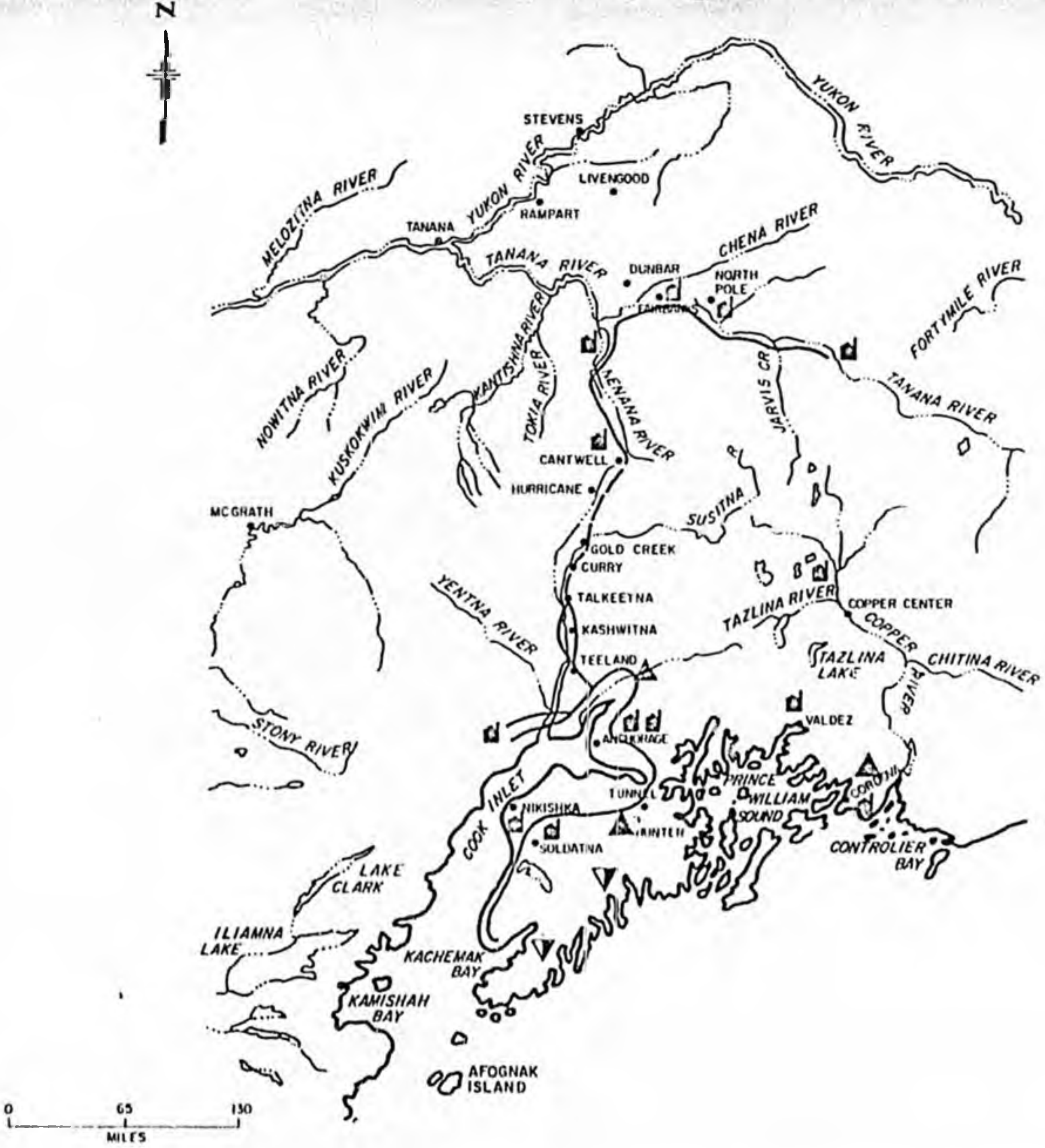
The extensive hydroelectric potential of the Susitna River first came to public attention in 1948 when the Bureau of Reclamation issued a report of its initial investigations there. Since that time, various development schemes have been advanced by public agencies and private organizations. A common thread in the many earlier reports is a virtually unanimous agreement that some project should proceed.

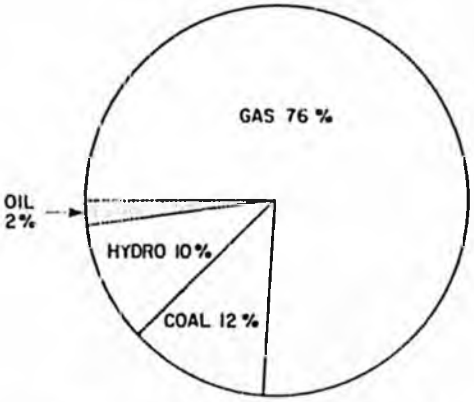
Acres American Incorporated was commissioned by the Alaska Power Authority, in December 1979, to conduct a detailed feasibility study in order to determine technical feasibility, economic viability, and environmental impacts of an optimal development in the basin. A rigorous program of field investigations, alternative plan evaluations, design studies, environmental studies, and economic analyses led to the production of a final draft feasibility report issued for public comment in March 1982. This document provides a summary of the detailed report.

Throughout the study period, an agressive public participation program was conducted by the Alaska Power Authority. Comments from interested organizations and individuals have greatly influenced the work. In addition, coordination with federal and state resource agencies has resulted in the selection of design criteria, project features, and operation plans which appear to offer balanced solutions to sometimes conflicting objectives.

A separate and independent study of alternatives to the Susitna project has been prepared by Battelle Pacific Northwest Laboratories under the terms of an agreement with the Office of the Governor, State of Alaska. Both the Battelle Report and the detailed feasibility study are available for public review at libraries throughout the Railbelt.

THE EXTENSIVE HYDROELECTRIC POTENTIAL OF THE SUSITNA RIVER FIRST CAME TO PUBLIC ATTENTION IN 1948...





NET GENERATION BY TYPES OF FUEL

PLATE 2 **GENERATING AND TRANSMISSION FACILITIES**

NEEDS

2

Current Generation System

About 90 percent of the current total net generation of electricity in the Railbelt depends upon the use of fossil fuels. Anchorage and other communities in the south now enjoy relatively low-cost energy because of their proximity to Cook Inlet gas fields and to existing small hydroelectric plants. In the north, the Fairbanks-Tanana Valley area depends primarily upon coal (which is mined near Healy) and a small amount of oil. Plate 2 provides a breakdown of generation by fuel types.

At the present time, the northern and southern load centers are not interconnected. Thus, generating systems have evolved independently over the years in these two areas. The total installed capacity in the Railbelt, exclusive of military generation, is nearly 1000 MW.

Five electric utility companies serve the Anchorage-Cook Inlet area. The two largest, Achorage Municipal Light and Power and Chugach Electric Association, operate the bulk of the generating resources. Alaska Power Administration, a federal agency, operates the 30-MW Eklutna hydroelectric plant, marketing wholesale power to several of the utility companies. Aside from the Eklutna plant, most generating resources in the south are concentrated around urban areas or near Beluga, west of Anchorage, where natural gas is piped from various wells. Transmission interconnections between utility systems generally exist in the Anchorage-Cook Inlet area.

The Fairbanks-Tanana Valley area is served by two utility companies: Golden Valley Electric Association and Fairbanks Municipal Utilities System. A coal-fired plant operated near the mine mouth at Healy supplies energy to communities to the north through a 138-kV transmission line.

Military bases in the Railbelt independently operate generating units, as does the University of Alaska at Fairbanks. The Glennallen-Valdez area, east of Anchorage, is served by the Copper Valley Electric Association.

Scheduled Additions

An intertie permitting transfer of up to 70 MW of power between Anchorage and Fairbanks is currently planned by the Alaska Power Authority. It will provide an opportunity for economic interchange of energy and will permit sharing reserve capacity. Provisions have been made for integrating the intertie into a future larger transmission system in the event that the Susitna project or other regional-scale facility is constructed.

> **THE TOTAL INSTALLED CAPACITY IN THE RAILBELT, EXCLUSIVE OF MILITARY GENERATION, IS NEARLY 1000 MW.**

Five new generating units are currently planned in the Railbelt. Two hydroelectric plants will provide about 97 MW with perhaps another 45 MW of spinning reserve. The larger of these is the Bradley Lake Project east of Homer, now being considered at alternative capacities of either 90 MW or 135 MW. Grant Lake would add a further 7 MW. One gas-fired combined-cycle unit and two gas turbines will add another 160 MW. When scheduled retirements and new additions are accounted for, the total system capacity in the early 1990s is expected to be about 1200 MW.

Historical Trends

Between 1940 and 1978, electricity sales in the Railbelt grew at an average annual rate of 15.2 percent - roughly twice that of the nation as a whole. Plate 3 illustrates the historical growth in electric energy demand between 1965 and 1980. Although the rate of demand increase in the Railbelt has consistently exceeded the national average, the gap has narrowed in recent years as the Alaskan economy has matured. Past high growth rates can be attributed both to rapid population increases and to installation of electric service in households which had not previously been served.

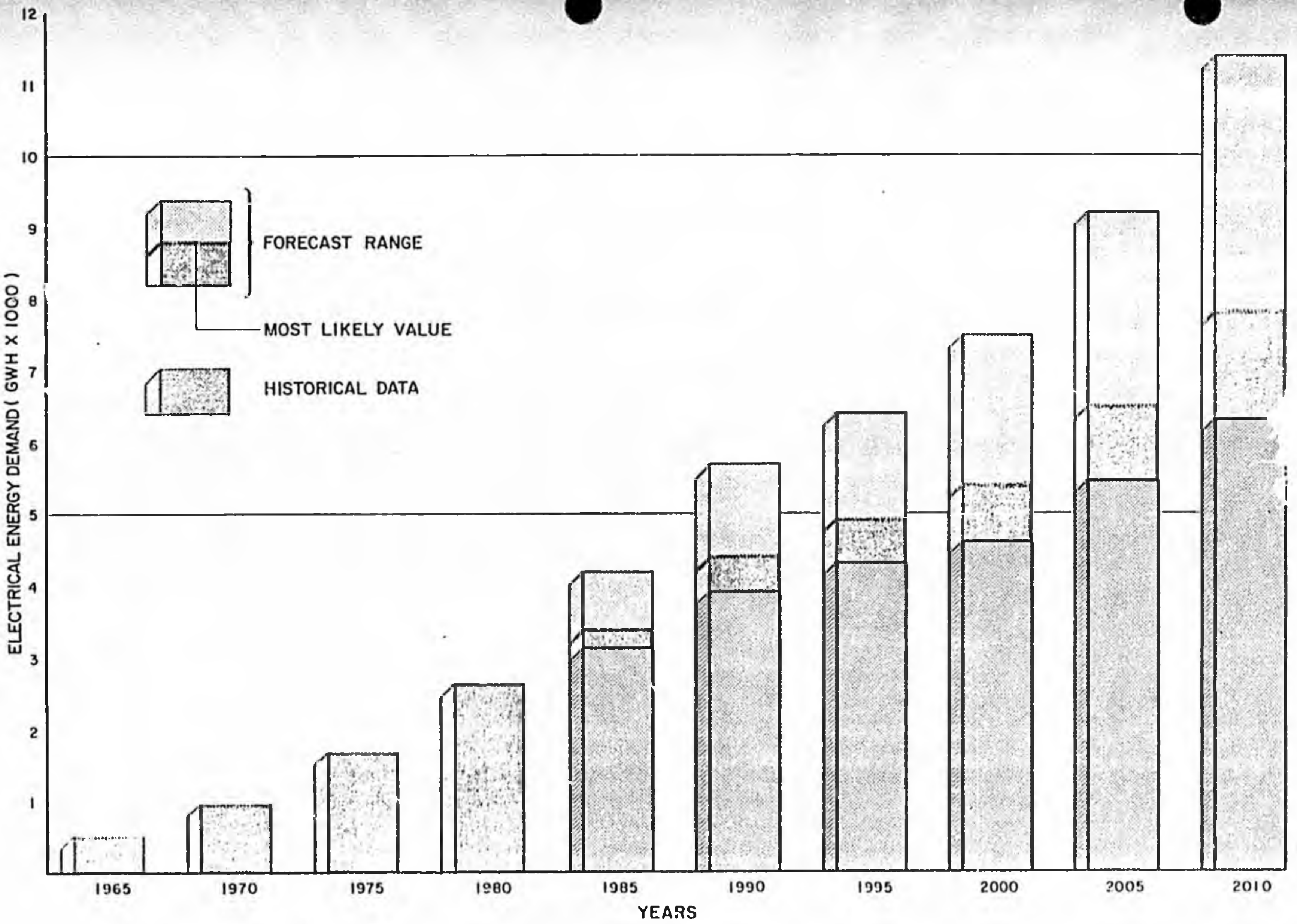


PLATE 3

RAILBELT ENERGY DEMANDS

Currently, about 47 percent of utility sales are to residential customers, 1 percent for miscellaneous use (e.g. street lighting), and the remaining 52 percent to the commercial-industrial-government sector. This split has been relatively constant during the past decade.

Forecasts of Future Demand

A great deal of uncertainty is necessarily associated with the preparation of demand and load forecasts. Population growth, industrial activity, government expenditures, energy prices, conservation measures and a variety of other factors will affect — and are frequently affected by — future demand. To ensure objectivity, a range of load forecasts was independently derived. Initial work accomplished by the institute for Social and Economic Research, University of Alaska, was subsequently updated by Battelle Pacific Northwest Laboratories (Battelle). Plate 3 illustrates the December 1981 Battelle forecasts used in the final evaluation of Susitna project viability. Between 1981 and 2010, the mid-range forecast suggests that electrical and energy demand will grow at an annual rate of about 3.5 percent, with the high and low range limits at about 4.6 percent and 2.8 percent, respectively. The mid-range value was selected as the base case for planning future generation needs in the Railbelt. Sensitivity tests were conducted for the high and low cases (see Section 10).

All forecasts include substantial electricity conservation due to the cost of power. In the low case, industrial developments such as mining Beluga coal, U.S. Borax mining, a petrochemical plant, and a Valdez refinery are assumed not to occur. These developments do appear in the high case, but no additional major capital projects for which planning has not yet commenced are assumed. In each case, demand was sensitive to energy costs. Thus, more energy demand is assumed to occur for the least cost alternative than for higher cost alternatives.

Military bases and self-supplied industries are assumed to continue to generate electricity for their own needs and they are not included in the demand forecast.

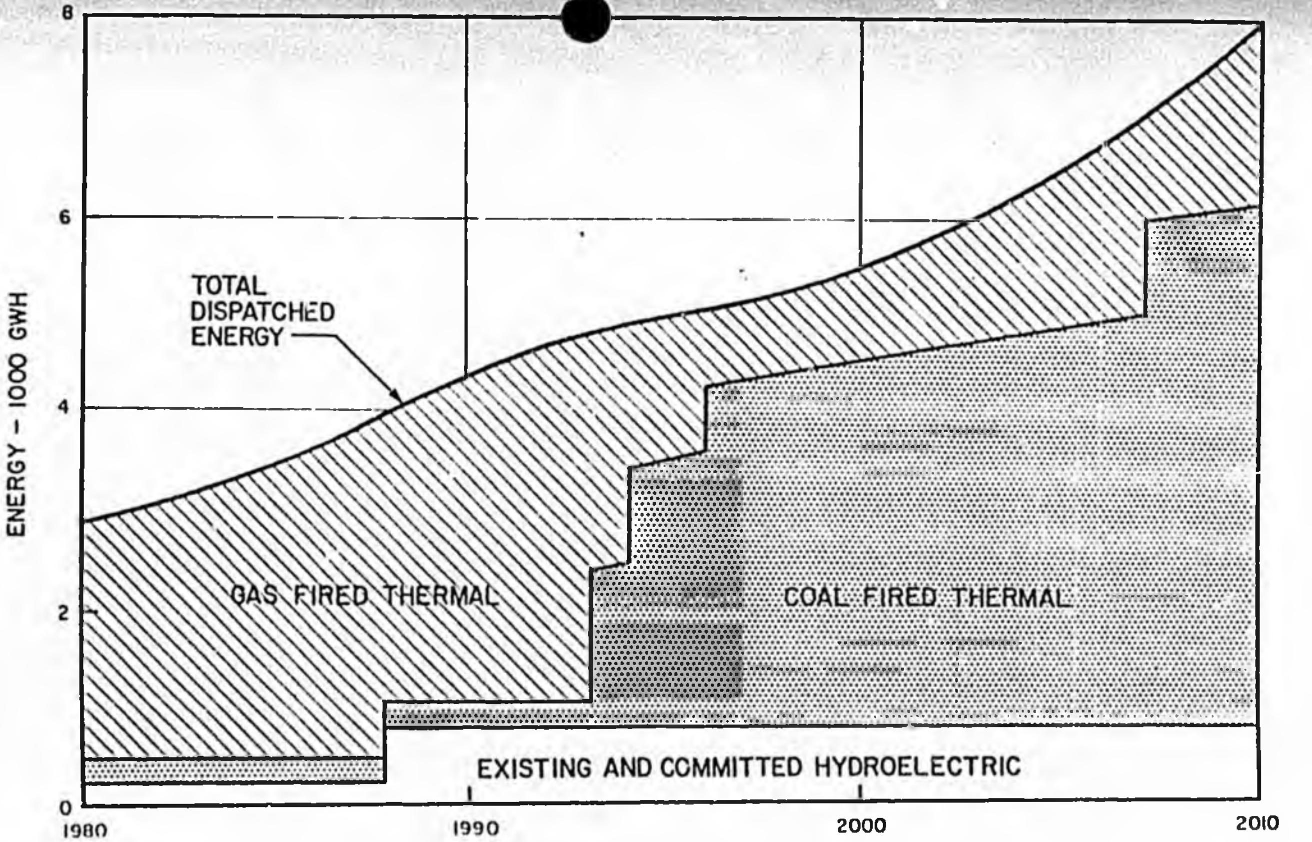
Electric space heating which now warms about 21 percent of the households in Anchorage and 9 percent in Fairbanks is assumed to change in relation to price differences between electricity and alternative heating fuels. Growth in population and tourism varies from case to case. Battelle indicated that the chances of realizing lesser and greater demand than the mid-range forecast are equal.

Requirements for Additional Capacity[1]

Under the mid-range forecast, currently scheduled additions are sufficient until 1993 to meet rising demand as well as to replace aging units which must be retired. Between 1993 and 2010, about 1400 megawatts of capacity must be added to the system to meet additional demand as well as to replace aging units.

...THE MID-RANGE FORECAST SUGGESTS THAT ELECTRICAL ENERGY DEMAND WILL GROW AT AN ANNUAL RATE OF ABOUT 3.5 PERCENT.

If required system expansion occurs by continued use of the thermal generating plants, a shift toward increased use of coal will be necessary not only because the Cook Inlet gas reserves may be insufficient to sustain long-term reliance upon natural gas in the face of increased demand but also because sharp increases in gas prices will occur in the next decade as old supply contracts expire. The installation of thermal (coal- or gas-fired) plants to meet the demand would offer the consumer no protection against rising costs, since fuel prices will continue to be exposed to inflation and to extraordinary escalation occasioned by world market conditions. Thus, it is appropriate to consider what other options may exist, as well as to ponder important implications and risks which might be associated with them.



VALUES OF SELECTED PARAMETERS

	200 MW COAL - FIRED PLANT (BELUGA)	70 MW GAS-FIRED COMBUSTION TURBINE
FUEL PRICE (1982 $/MMBTU)	$1.43	$3.00
ANNUAL FUEL PRICE ESCALATION:		
1982-2000	2.6%	2.5%
2000-2010	1.2%	2.0%
CAPITAL COSTS (1982 $/KW)	$2,242	$636
ANNUAL CAPITAL COST ESCALATION	1.8%	1.8%
INFLATION RATE	0%	0%
DISCOUNT RATE	3%	3%
ANNUAL OPERATING AND MAINTENANCE COSTS		
FIXED (1982 $/KW)	$16.83	$2.70
VARIABLE (1982 MILLS/KWH)	0.60	4.84
ASSUMED USEFUL LIFE (YEARS)	30	30

PLATE 4

BASE CASE INSTALLATION SEQUENCE