STATE OF ALASKA

DEPARTMENT OF NATURAL RESOURCES

DIVISION OF GEOLOGICAL AND GEOPHYSICAL SURVEYS

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This report is preliminary and has not been edited or reviewed for conformity with Alaska Division of Geological and Geophysical Surveys standards.

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ECONOMIC AND GEOLOGIC STUDIES OF THE BELUGA-CAPPS AREA AND GEOLOGIC RESOURCE OCCURRENCES IN OTHER AREAS OF THE PROPOSED COOK INLET LAND TRADE

By P.L. Dobey, D.L. McGee, and DGGS Staff

January 1976

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INTRODUCTION

This report is in response to a need to have geologic information about the Federal-State-Cook Inlet Region Incorporated proposed land exchange consolidated under one cover.

The report is divided into three parts.

I Coal Resource Appraisal of the Beluga-Capps Glacier area (McGee)

II Potential Revenues from Coal Royalties in the Capps Glacier area (Dobey, Welch, and O'Connor)

III Resource Appraisal of Land Exchanges Outside of the Beluga-Capps Glacier area (DGGS staff)

For completeness, I have included "The Potential for Developing Alaskan Coals for Clean Export Fuels" by the Stanford Research Institute. This study uses the Beluga area as a model for a feasibility analysis of a coal conversion facility and contains much statistical data about the coals of this region.

Part I, Coal Resource Appraisal of the Beluga-Capps Glacier Area, by Don McGee, is a summary of the known geology of the region. A geologic map accompanies the report (pocket) and several stratigraphic sections are included. Coal reserve estimates are based on this work.

In order to avoid semantic confusion, a brief glossary of terms defined as they are used in this text is included in the report.

Conclusions reached by McGee begin on page 9. Of the known coal reserves in the Beluga-Capps land trade area, approximately 95% are located in the Capps Glacier lease block. Hypothetical reserve estimates in the Beluga-Capps land trade area by their very nature are elusive quantities owing to information gaps. It is estimated that approximately 2 billion tons of hypothetical coal lie outside the proven coal areas but within the land trade area, Hypothetical coal reserve estimates vary from author to author for obvious reasons. In this report, the hypothetical coal estimates within the boundaries of the Beluga-Capps land trade area were based on an average of 10 feet of commercially extractable coal. A simple doubling of the extractable coal footage doubles the total hypothetical coal reserve estimates.

Known coal resources within the Beluga Mental Health lands are 1.6 billion tons and are not considered in this report.

Physical and chemical qualities of the coal, if needed, may be found in tabulated form in DGGS OFR #51 by McGee and O'Connor.

Part II, Potential Revenues from Coal Royalties in the Capps Glacier Area, by Dobey, Welch, and O'Connor, is an attempt to project direct royalty dollar losses to the State from relinquishing these lands. Dollar losses related to land sales, rental losses, etc., are not considered. Lease rentals become $1.00/acre at the beginning of the 6th year (1976). However, with initiation of production the royalty paid offsets the lease rental and presumably the latter declines to zero. Variables such as initial production rates are difficult to anticipate because of other variables and must be considered as arbitrary.

Regardless of total recoverable coal quantities, royalty income to the State will be a function of production rates within a given time period. Theoretical production schedules reflect a low of 6 million tons per year and a high of 21 million tons per year. It should be noted that the largest coal mine today, the Navajo Mine, New Mexico, produces 7.4 million tons/year (USBM). The economic analysis projects royalty income to the year 2025 with readjusted royalties in 1991. Discount factors of 8% and 10% were applied to bring projected revenues to present dollar values.

The assumption is made that the State's present policy of a fixed royalty (10¢/ton with 10 or 20 year adjustments) will remain in effect until 1991. Scenario II assumes a percentage royalty exists thereafter of 1/10, 1/8, and 1/6.

Part III, Resource Appraisal of Land Exchanges Outside of the Beluga-Capps Glacier Area, by the DGGS staff, is provided for the sake of completeness inasmuch as these lands were a part of the three-way exchange. Known mineral and energy resources are plotted on regional maps and a brief summary of the geology and developmental activities is provided. A bibliography accompanies the text of each region.

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Part I

COAL RESOURCE APPRAISAL OF THE BELUGA-CAPPS GLACIER AREA

D.L. McGee

1976

Part I

COAL RESOURCE APPRAISAL OF THE BELUGA-CAPPS GLACIER AREA

By Don L. McGee

INTRODUCTION

Purpose of Report

This investigation was completed to review the coal resources within the boundaries of the area proposed for a three-way land trade between the State of Alaska, Cook Inlet Region Inc., and the federal government. Map compilation was limited to areas underlain by the coal-bearing Kenai formation of Tertiary age that lie within the area of proposed trade lands.

Because the coal deposits of this region (fig. 1) are undeveloped and are largely covered by surficial deposits, a thorough understanding of their stratigraphy and structure can be obtained only with the aid of a large amount of subsurface exploration. The primary purpose of this report is to indicate the areas where coal outcrops are sufficiently dense to enable a determination of measured and indicated coal resources and to also indicate where the most favorable areas are for probable future coal resources.

Location

The area selected for the land trade (fig. 2) is outlined on the attached map, and includes about 18 townships, from which the Cook Inlet Region Inc. will be allowed to select 13-1/2. Nearly the entire area is underlain by either middle or lower Kenai Tertiary sediments.

Geology

Rocks within the trade area include an undifferentiated assemblage of metasedimentary rocks of Jurassic and Cretaceous age, intrusive medium to

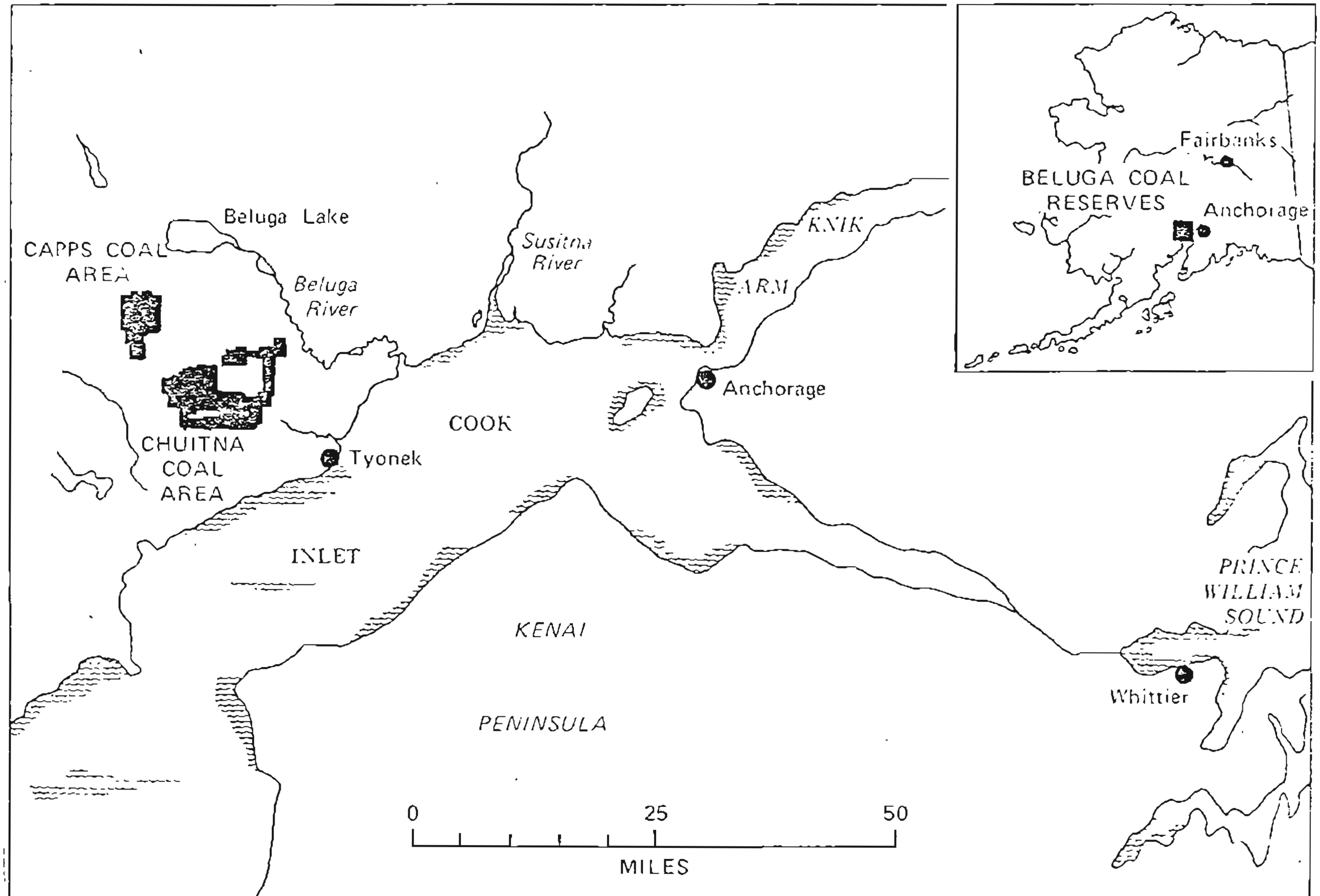


Figure 1. Index map for the resource analysis of the Capps Glacier-Beluga trade area.

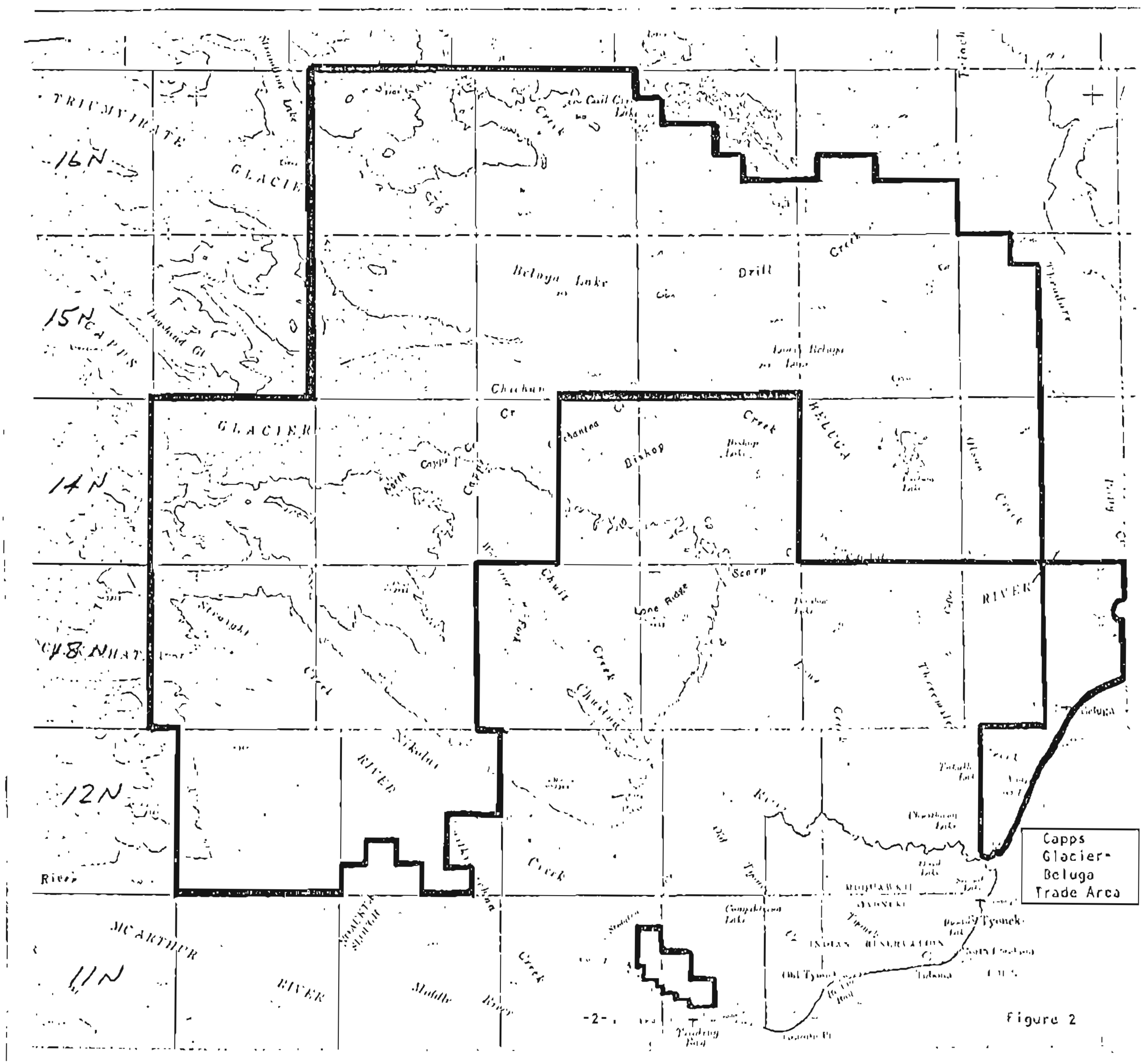


Figure 2. Capps Glacier-Beluga trade area.

coarse-grained granitic rocks presumably intruded into the older bedded rocks, Tertiary sedimentary rocks (the Kenai Formation) which Barnes (1966) has divided into a lower and middle group, tuff and volcanic breccia south of Capps Glacier, and rocks of Quaternary age consisting of glacial deposits, alluvial deposits, talus, colluvium, and landslide masses.

Nearly all the coal deposits are in rocks of the middle Kenai Formation.

Coal Resources

The major known coal resources within the trade area are located south of Capps Glacier, where approximately 13 square miles are under coal leases. Resources based on known geological parameters and a section-by-section examination (from cross sections constructed from the geological parameters) are 550 million short tons. Much of this coal can be considered as measured and indicated, and a large part of it has a stripping ratio of less than 10 to 1.

A single area of about 1 square mile on Drill Creek, east of Beluga Lake, has proven resources of about 20 million tons of coal. This area was drilled by the U.S. Bureau of Mines in 1959-1961.

There are four other areas which appear favorable for coal extraction based on sections measured by Barnes (1966):

1. An area of about 7 square miles south of the leased area at Capps Glacier.

2. About 6 square miles east of the leased area at Capps Glacier.

3. A small area underlain by the Beluga coal deposits, which lies within the proposed trade area east of Felts Lake.

4. The area along Coal Creek extending from Coal Creek Lake as far east as the Drill Creek lease area which has outcrops of middle Kenai Formation with known coal sections. This area of about 50 square miles contains hypothetical coal deposits of 500 million short tons (based on a predicted 10 feet of coal and consistent low-angle dips).

CONCLUSIONS

Coal resources in much of the proposed land trade area are unknown. The two areas of greatest interest and where geological data are available, the Capps Glacier and Drill Creek areas, contain 570 million short tons of coal. The four other areas indicated on the map probably contain an equal amount of coal listed as hypothetical. The corridor area south of the Chuitna coal field is covered by unconsolidated sediments and it is not known if coal is present or not.

As near as can be determined from widely separated and only roughly correlated stratigraphic sections, coal beds are uniformly distributed through the middle member of the Kenai Formation, but are rare or lacking in the conglomeratic lower member. For this reason the most favorable locations for coal exploration are the areas underlain by the middle Kenai Formation. No mention has been made of hydrocarbon potential, although much of the area is underlain by Kenai Formation sediments that are hydrocarbon productive to the south (in the Cook Inlet area) and to the east (in the Beluga gas field).

The coal resources described in this report and used in the royalty analysis are limited to known recoverable reserves and restricted to the Capps area, about 13 square miles and Drill Creek, about 1 square mile. These coal resources based on outcrop and cross-section geological information, represent the minimum quantity of coal expected to be recovered from these areas.

This report specifically excludes the known coal resources outside the land trade area in the Beluga area. These resources exceed 1.6 billion short tons of coal classified as known and because of the favorable geology there probably are several billion additional tons.

Specific areas outside the Capps Glacier area have high potential for coal. These areas are south of the Capps Glacier coal area, northeast of the Capps Glacier, along the Beluga River just north of the land trade boundary and a 50 square mile area along Coal Creek. Elsewhere there is a probability of middle Kenai sediments containing coal under the glacial overburden. Coal resources in these areas must be considered as hypothetical until proven by drilling. However it is estimated that there are in excess of 2 billion tons of hypothetical coal outside the proven coal areas but still within the land trade area.

It is very important to distinguish between known coals and hypothetical coals. Known coals in this report include both measured (coals that have been blocked out by drilling) and indicated (coals that are outlined by proximity to outcrop or drill holes). There is a very high probability, that these resources are accurate. In this report these are the resource values used in the economic considerations.

The term hypothetical is used to indicate that geological parameters are favorable. The area along Coal Creek where coal-bearing middle Kenai sediments outcrop at varying intervals is a good example of an area of hypothetical coal. There are sufficient middle Kenai exposures along Coal Creek to indicate the probability that much or all of the area is underlain by coal-bearing middle Kenai sediments. These exposures all contain coal and can be extrapolated with some certainty from exposure to exposure. By calculating the probable size of the areas and average thickness of the coals in the exposures, an estimate can be made of the hypothetical coal resources. However, until the coals are outlined by drilling, they remain questionable.

Brief references have been made in the report to areas where coal extraction may occur at some future date. These areas include about 50 square miles along Coal Creek (500 million tons hypothetical coal), south of the leased area at Capps Glacier (8 square miles underlain by middle Kenai sediments containing coal), hypothetical resources for this area are in excess of 150 million tons, east of the area under coal leases (about 6 square miles with probable hypothetical resources in excess of 150 million tons), and the area north of the Mental Health lands along the Beluga River (hypothetical coal of 30 to 50 million tons). In addition, the large area between Capps Glacier and extending to Coal Creek is covered with unconsolidated deposits probably overlying at least in part middle Kenai coal-bearing sediments (about 60 square miles and if an effective thickness of 10 feet is used, the area could be underlain with sediments containing 600 million tons of coal). Northeast of Drill Creek is an area of about 50 square miles that may contain coal-bearing sediments with 500 million tons hypothetical coal. The area along the Chakachatna River and Chuitkilnach and Nikolai Creeks southeast of the Castle Mountain fault and within the land trade area is also possibly coal-bearing (25 square miles containing perhaps 250 million tons coal). Hypothetical coal within the boundaries of the land trade area would be in excess of 2 billion tons based on an average of 10 feet of commercially extractable coal. This value is easily doubled to 4 billion tons by increasing the coal thickness to an average 20 feet. It is highly probable that this figure is excessively high and that if large tonnages of coal are actually in place, much of it will not be commercially extractable because of excessive overburden or thinness of beds.

REFERENCES

Barnes, F.F., 1966, Geology and coal resources of the Beluga-Yentna region, Alaska: U.S. Geol. Survey Bull. 1202-C, 54 p.

McGee, D.L., 1973, Coal reserves, Beluga and Chuitna Rivers and Capps Glacier areas, Alaska: Alaska Div. of Geol. and Geophys. Surveys open-file rept. 30

Warfield, R.S., 1963, Investigations of a subbituminous coal deposit suitable for open cut mining, Beluga River coal field, Alaska: U.S. Bur. Mines Rept. Inv. 6238

Part II

POTENTIAL REVENUES FROM COAL ROYALTIES IN THE CAPPS GLACIER AREA

P.L. Dobey, J. Welch, K.M. O'Connor

1976

Part II

POTENTIAL REVENUES FROM COAL ROYALTIES IN THE CAPPS GLACIER AREA

By P.L. Dobey, J.K. Welch, K.M. O'Connor

INTRODUCTION

An economic analysis of the direct monetary value to the state for coal resources in the Capps Glacier-Beluga state-land trade area was completed for the Division of Lands, and refined for open file status. In this analysis, it is important to remember that the only direct dollar losses to the state from relinquishing these lands would be from the absence of royalties, fees, and rentals. Of these, a loss of royalty from coal would be the major economic factor. If the state does not obtain royalty from the coal it will still have taxing options for revenue from the coals, e.g., a severance tax, which could be considered in addition to the normal business taxes. Therefore, the question of importance is: How significant are the potential revenues from coal royalties in this area?

In this analysis, a development model is used to show the possible royalty revenues the state would expect from the coal in the zone considered for trade. Conservative parameters were used, and the economic analysis was completed only on the measured and indicated coal reserves of the Capps Glacier area (550 million short tons). The Beluga coal reserves to the southeast might be developed before any of the coal in the trade zone; this could create a much longer time to the start of development than our model, resulting in an even lower net present value of the measured and indicated coals of the trade zone.

RESULTS AND SUMMARY

The development and economic models have the following significant results:

1. In the remaining 16 years of the present lease contract, the State's potential royalty revenues from coal resources in the trade zone at 10¢ per ton are estimated to range from a pessimistic low of around $7,000 to a high of approximately $4,000,000.

2. It is disadvantageous to the State to lease a resource on a fixed dollar value during inflationary times. During the remaining 16 years of this lease contract the inflationary effect upon the 10¢ royalty reduces the real future income to the State by approximately 50% in the optimistic case to over 75% in a high inflation pessimistic case.

3. Assuming that the State renegotiates for a higher royalty in 1992, an analysis for three new royalty cases gives the following results:

Pessimistic Case (1/10 royalty)	
Future cumulative revenue	$84.0 million
Present value (discounted 10%)	$ 3.7 million
Present value (discounted 8%)	$ 6.5 million
Medium Case (1/8 royalty)	
Future cumulative revenue	$177.0 million
Present value (discounted 10%)	$ 9.2 million
Present value (discounted 8%)	$ 15.4 million
Optimistic Case (1/6 royalty)	
Future cumulative revenue	$633.1 million
Present value (discounted 10%)	$ 38.9 million
Present value (discounted 8%)	$ 62.9 million

4. Future total estimated cumulative revenue to the State to the year 2025 could range from $84 million to $650.9 million.

5. Total estimated present value income could be:

	Discounted 10%	Discounted 8%
Pessimistic	$ 3.7 million	$ 6.5 million
Medium	$ 10.5 million	$ 15.9 million
Optimistic	$ 42.2 million	$ 67.0 million

6. The optimistic production scenario of 21 million tons per year is three times the present annual production of the largest operating coal mine in the United States. These dollar values are therefore very optimistic and should be considered a low probability maximum income.

CONCLUSION

Because of the probable extremely low royalty revenues resulting under the present State contract and the long time delay for income under more favorable royalties, the present dollar value of the trade zone (with respect to royalty income) is very low per acre. The total present value of the theoretical royalty income discounted 10% would be $11.90 per acre in the pessimistic case, $33.76 in the medium case, and $137.60 in the optimistic case.

THE ANALYSIS

Coal reserves in the trade zone are divided into the known quantities in the Capps Glacier area and the relatively unknown but possible reserves in other areas. This analysis is based upon the estimates of recoverable economic measured and indicated coal provided by Don L. McGee of the Division of Geological and Geophysical Surveys. The production model uses three production estimates to generate a range of probable revenues. A pessimistic one to 6 million tons per year, a most likely of 5 to 10 million tons per year, and an optimistic 5 to 15 million tons per year. Our study is based on a fifty-year projection with a cut-off date of year 2025. Present dollar values of the produced coal are very low after this long period. A development scenario was then derived (Chart I) for the three production cases and royalty revenues derived for the existing State contract in the amount of 10¢ per ton for the 1971-1991 contract period. Next, real dollar values were calculated for the

THEORETICAL PRODUCTION SCHEDULES

Coal Production in Millions of tons

Year	Pessimistic	Medium	Optimistic
1975			
1976			
1977			
1978			
1979			
1980			
1981			1
1982			5
1983			10
1984		.5	15
1985		5	21
1986		5	21
1987		5	21
1988		5	21
1989		5	21
1990	.5	5	21
1991	1	5	21
1992	1	5	21
1993	1	5	21
1994	1	5	21
1995	1	5	21
1996	1	5	21
1997	1	5	21
1998	1	5	21
1999	3	5.5	21
2000	3	8	21
2001	3	8	21
2002	3	8	21
2003	5	8	21
2004	5	8	21
2005	5	8	21
2006	5	8	21
2007	5	8	21
2008	5	8	21
2009	5	8	21 - Depletion of known coals (550 MM)
2010	6	10	21
2011	6	10	21
2012	6	10	21
2013	6	10	21
2014	6	10	21
2015	6	10	21
2016	6	10	21
2017	6	10	21
2018	6	8	21
2019	6	8	21
2020	6	8	21
2021	6	8	21
2022	6	8	21
2023	6	8	21
2024	6	8	21
2025	4.5	8	21
Total Cumulative Production	150 MM	300 MM	891 MM
Producing Years	36 yrs.	42 yrs.	45 yrs.

Chart 1

future royalty income using constant inflation rates of five, eight, and ten percent (Chart 2). The inflationary effect upon the constant 10¢ royalty drastically reduces the real future income to the State. This reduction ranges from approximately 50% in the low inflation optimistic case to over 75% in the high inflation pessimistic case ($150,000 -vs- $33,750). It is apparent that leasing a resource for a fixed amount during inflationary times is not a very viable approach.

The present value of the coal revenues were then calculated using a discount rate of 10% for the three cases (Charts 3, 4, and 5). Total present value income to the State from the remaining 16 years of this contract period is estimated to range from $7,608 in the most pessimistic case to $3,303,217 in the most optimistic. These figures, although derived on a theoretical basis, should reflect the economic benefits fairly closely.

After 1991 the contracts can be renegotiated and, because of the many uncertainties involved, it is very difficult to guess what income will be. An attempt was made using a hypothetical model that assumes 1/10, 1/8 and 1/6 royalties plus some possible future coal prices obtained from the Bureau of Mines (Chart 6) and the Stanford Research Institute study (Appendix).

The results of Scenario II are present 1975 dollar values of hypothetical future coal production for pessimistic, medium, and optimistic cases using a 10% discount factor. A discounted present value income range of $3.7 million to $38.9 million with a medium of $9.1 million resulted. Using an 8% discount factor the results range from $6.5 million to $62.9 million with a medium of $15.4 million.

Adding Scenario I and II for a hypothetical income total we have:

	Discounted 10%	Discounted 8%
Pessimistic	$ 3.7 million	$ 6.5 million
Medium	$ 10.5 million	$ 15.9 million
Optimistic	$ 42.2 million	$ 67.0 million

Chart 2

POTENTIAL REAL VALUE OF STATE'S ROYALTY INCOME FROM COAL IN THE PROPOSED TRADE AREA UNDER EXISTING LEASES - (TO YEAR 1991)

YEAR	PESSIMISTIC					MEDIUM					OPTIMISTIC				
	PRODUCTION IN MM TONS	NOMINAL $ VALUES ROYALTY 10¢ TON	Real dollar values @ constant rate of inflation 5%	8%	10%	PRODUCTION IN MM TONS	NOMINAL $ VALUES ROYALTY 10¢ TON	Real dollar values @ constant rate of inflation 5%	8%	10%	PRODUCTION IN MM TONS	NOMINAL $ VALUES ROYALTY 10¢ TON	Real dollar values @ constant rate of inflation 5%	8%	10%
1975															
1976															
1977															
1978															
1979															
1980															
1981											1MM	100,000	74,620	63,020	56,450
1982											5MM	500,000	355,350	291,750	256,600
1983											10MM	1,000,000	676,800	540,300	466,500
1984						500 M	50,000	32,250	25,000	21,200	15MM	1,500,000	966,900	750,300	636,150
1985						5MM	500,000	307,000	231,500	193,000	21MM	2,100,000	1,289,190	972,720	809,550
1986								292,500	214,500	175,000			1,227,870	900,690	736,050
1987								278,500	198,500	159,500			1,169,280	833,910	669,060
1988								265,000	184,000	145,000			1,113,630	772,170	608,370
1989								252,500	170,000	131,500			1,060,710	715,050	552,930
1990	500 M	50,000	24,050	15,750	11,950			240,500	157,500	119,500			1,010,100	661,920	502,740
1991	1MM / 1.5 MM	100,000 / 150 M	45,800	29,200	21,800	5MM / 35.5 MM	500,000 / 3.55 MM	229,000	146,000	109,000	21MM / 177MM	2,100,000 / 17,800,000	962,010	612,990	456,960
1992			- END OF CONTRACT -												
TOTAL INCOME			$69,850	$44,950	$33,750			$1,897,250	$1,327,000	$1,053,700			9,906,460	7,114,820	5,751,360

SCENARIO I

PRESENT VALUE OF COAL ROYALTIES IN REAL 1975 DOLLARS
DISCOUNTED @ 8% AND @ 10% WITH 5% CONSTANT RATES OF INFLATION TO YEAR 1991

YEAR	PESSIMISTIC CASE			MEDIUM CASE			OPTIMISTIC CASE		
	REAL $ VALUE @ CONSTANT 5% INFLATION	PV_8	PV_{10}	REAL $ VALUE @ CONSTANT 5% INFLATION	PV_8	PV_{10}	REAL $ VALUE @ CONSTANT 5% INFLATION	PV_8	PV_{10}
1975									
1980									
							74,620	47,026	42,123
							355,350	207,347	182,366
							676,800	365,675	315,727
				32,250	16,132	13,674	966,900	483,643	410,062
1985				307,000	142,202	118,502	1,289,190	597,153	496,983
				292,500	125,453	102,375	1,227,870	526,633	430,368
				278,500	110,592	88,842	1,169,280	464,321	372,533
				265,000	97,441	76,850	1,113,638	409,485	322,621
				252,500	85,976	66,408	1,060,710	361,172	279,285
1990	24,050	7,581	5,748	240,500	75,806	57,480	1,010,100	318,384	241,818
1991	45,800	13,369	9,984	229,000	66,845	49,922	962,010	280,811	209,333
				--- END OF CONTRACT ---					
TOTAL INCOME	$69,850	$20,950	$15,732	$1,897,250	$720,447	$574,053	$9,906,468	$4,061,650	$3,303,219

Chart 3

SCENARIO I

PRESENT VALUE OF COAL ROYALTIES IN REAL 1975 DOLLARS
DISCOUNTED @ 8% AND @ 10% WITH 8% CONSTANT RATES OF INFLATION TO YEAR 1991

YEAR	PESSIMISTIC CASE REAL $ VALUE @ CONSTANT 8% INFLATION	PESSIMISTIC CASE PV_8	PESSIMISTIC CASE PV_{10}	MEDIUM CASE REAL $ VALUE @ CONSTANT 8% INFLATION	MEDIUM CASE PV_8	MEDIUM CASE PV_{10}	OPTIMISTIC CASE REAL $ VALUE @ CONSTANT 8% INFLATION	OPTIMISTIC CASE PV_8	OPTIMISTIC CASE PV_{10}
1975									
1980									
							63,020	39,715	35,575
							291,750	170,236	149,726
							540,300	291,924	252,050
				25,000	12,505	10,600	750,300	375,300	318,202
1985				231,500	107,231	89,359	972,720	450,564	374,984
				214,500	91,999	75,075	900,690	386,306	315,692
				198,500	78,824	63,322	833,910	331,146	265,684
				184,000	67,657	53,360	772,170	283,927	223,698
				170,000	57,885	44,710	715,050	243,475	188,273
1990	15,750	4,964	3,764	157,500	49,644	37,643	661,920	208,637	158,464
1991	29,200	8,524	6,366	146,000	42,617	31,828	612,950	178,932	133,387
				--- END OF CONTRACT ---					
TOTAL INCOME	$44,950	$13,488	$10,130	$1,327,000	$508,362	$405,897	$7,114,820	$2,960,162	$2,415,735

Chart 4

SCENARIO I

PRESENT VALUE OF COAL ROYALTIES IN REAL 1975 DOLLARS
DISCOUNTED @ 8% AND @ 10% WITH 10% CONSTANT RATES OF INFLATION TO YEAR 1991

YEAR	PESSIMISTIC CASE			MEDIUM CASE			OPTIMISTIC CASE		
	REAL $ VALUE @ CONSTANT 10% INFLATION	PV_8	PV_{10}	REAL $ VALUE @ CONSTANT 10% INFLATION	PV_8	PV_{10}	REAL $ VALUE @ CONSTANT 10% INFLATION	PV_8	PV_{10}
1975									
1980									
							56,450	35,575	31,866
							256,600	149,726	131,687
							466,500	252,050	217,622
				21,200	10,604	8,989	636,150	318,202	269,791
1985				193,000	89,398	74,498	809,550	374,984	312,082
				175,000	75,058	61,250	736,050	315,692	257,986
				159,500	63,337	50,881	669,060	265,684	213,163
				145,000	53,317	42,050	608,370	223,698	176,245
				131,500	44,776	34,585	552,930	188,273	145,586
1990	11,950	3,767	2,856	119,500	37,666	28,561	502,740	158,464	120,356
1991	21,800	6,363	4,752	109,000	31,817	23,762	456,960	133,387	99,435
				--- END OF CONTRACT ---					
TOTAL INCOME	$33,750	$10,130	$7,608	$1,053,700	$405,973	$324,576	$5,751,360	$2,415,735	$1,975,819

Chart 5

Chart 6

PRICE REQUIRED FOR COAL AT 20% DISCOUNT FACTOR*

Annual production (tons)	Power generation	f.o.b. tidewater Cook Inlet
5,000,000	$5.36 per ton (37¢/MMBtu's)	$ 8.47/ton (56¢/MMBtu's)
3,000,000	$6.57 per ton (44¢/MMBtu's)	$11.01/ton (73¢/MMBtu's)
1,000,000	$10.20 per ton (68¢/MMBtu's)	$22.12/ton (147¢/MMBtu's)

Optimistic production scenario uses price of $5.32 from Stanford Research Institute report, "The Potential for Developing Alaska Coals for Clean Export Fuels".

*Changing Economics of Alaskan Coals Robert Bottge, Mining Engineer, Alaska Field Operation Center, U.S. Bureau of Mines, Juneau, Alaska;

A paper presented at the Alaskan Conference on Coals, University of Alaska Fairbanks, October 15-17, 1975.

It is possible that the Beluga coal reserves to the south, outside of the trade zone, will be developed before the Capps Glacier coals. This would result in a much longer time to development in the economic analysis and an even lower present value of the trade coal reserves. It should also be noted that the hypothetical coal reserves in the trade zone could be as great as two billion tons (Don McGee). The development of these reserves may lie beyond the extreme limit of this analysis (the year 2025), and the present value of the hypothetical reserves become meaningless under these circumstances.

Coal Production Scenarios

The attached coal production assumptions are a result of the opinions given by experts of the U.S. Bureau of Mines, the State Geological and Geophysical Surveys, knowledgeable industrial sources, and a report by Robert Bottge of the U.S. Bureau of Mines presented to the Alaskan Coal Conference of October 15-17, 1975. We have also compared the assumptions with analogous producing areas of the Lower 48.

Coal Production Assumptions (Electric Generation Only)

	Pessimistic	Medium	Optimistic
Time to production	15 yrs.	9 yrs.	6 yrs.
1st year's production	500 M tons	500 M tons	1 MM tons
2nd year's production	1 MM tons	5 MM tons	5 MM tons
3rd year's production (see Production Schedule, Chart 6)	1 MM tons	5 MM tons	10 MM tons
Total Cumulative Production	150 MM tons	300 MM tons	891 MM tons
Life of project	year 2025	year 2025	year 2025

Other Assumptions

For scenario II (years 1992 to 2025), the following assumptions were made:

1. Coal prices will be based on Robert Bottge's estimated price necessary for a 20% DCF rate of return to the producer in 1975 dollars and the SRI study.

2. Royalties will be estimated from the prices in (1) above. It will be assumed that other taxes (severance, etc.) will hold corporate income around the 20% DCF rate. These taxes would apply with or without mineral ownership of the land, therefore, they do not apply as income to the State in this analysis. It should be noted that a very high market value for Alaskan coals could result in higher royalty income to the State then calculated by this analysis if the excess income above 20% DCF return to the seller were not absorbed by additional taxation.

3. The pessimistic scenario assumes small or nonexistent external economic coal market and coal production is used primarily for electric generation.

4. The optimistic production scenario of 21 million tons per year is three times the present annual production of the largest operating coal mine in the United States. These dollar values are therefore very optimistic and should be considered a low probability maximum income.

REFERENCES

Bottge, Robert. Changing Economics of Alaskan Coals, a paper presented at the Alaskan Conference on Coals, University of Alaska, Fairbanks, October 15-17, 1975

The Potential for Developing Alaskan Coals for Clean Export Fuels, Stanford Research Institute, December 1974

SCENARIO II

THEORETICAL ROYALTY INCOME TO THE STATE IN 1992-2025

In 1991, the State renegotiates its coal permits using a percent royalty based on the price of coal at the mine (for power generation). Prices used will be the theoretical model prices developed by Robert Bottge, U.S. Bureau of Mines for his October 1975 study (Chart 6). Coal prices are in 1975 dollar estimates at a 20% DCF before taxes. Theoretical royalty values of 1/10, 1/8, and 1/6 are used for estimated pessimistic and optimistic income calculations. These royalty values, when related to Bottge's theoretical price chart, represent a royalty of approximately five times the present 10¢ royalty in the lowest calculations and over ten times in the highest. The present value of the theoretical estimated royalty revenue was then calculated using 8% and 10% discount factors.

SCENARIO II

THEORETICAL ESTIMATES OF STATE INCOME FROM TRADE AREA COAL YEARS 1992-2025

	PESSIMISTIC CASE				MEDIUM CASE				OPTIMISTIC CASE			
Year	Production MM Tons Coal	Future Value Of Coal @ Chart 6 Royalty Million $	Revenue @ 1/10 Royalty Million $	PV_{10} Million $	Production MM Tons Coal	Future Value Of Coal @ $ 5.36/Ton Million $	Revenue @ 1/8 Royalty Million $	PV_{10} Million $	Production MM Tons Coal	Future Value Of Coal @ $ 5.32/Ton Million $	Revenue @ 1/6 Royalty Million $	PV_{10} Million
1992	1	10.2	1.0	.198	5	26.8	3.35	.663	21	111.72	18.62	3.68
1993	1	10.2	1.0	.180	5	26.8	3.35	.603	21	111.72	18.62	3.35
1994	1	10.2	1.0	.164	5	26.8	3.35	.549	21	111.72	18.62	3.04
1995	1	10.2	1.0	.149	5	26.8	3.35	.499	21	111.72	18.62	2.77
1996	1	10.2	1.0	.135	5	26.8	3.35	.452	21	111.72	18.62	2.52
1997	1	10.2	1.0	.123	5	26.8	3.35	.412	21	111.72	18.62	2.29
1998	1	10.2	1.0	.112	5	26.8	3.35	.375	21	111.72	18.62	2.08
1999	3	19.7	2.0	.203	5.5	29.5	3.69	.375	21	111.72	18.62	1.89
2000	3	19.7	2.0	.184	8	42.9	5.36	.494	21	111.72	18.62	1.72
2001	3	19.7	2.0	.168	8	42.9	5.36	.449	21	111.72	18.62	1.56
2002	3	19.7	2.0	.153	8	42.9	5.36	.409	21	111.72	18.62	1.42
2003	5	26.8	2.7	.187	8	42.9	5.36	.370	21	111.72	18.62	1.29
2004	5	26.8	2.7	.170	8	42.9	5.36	.338	21	111.72	18.62	1.17
2005	5	26.8	2.7	.155	8	42.9	5.36	.307	21	111.72	18.62	1.07
2006	5	26.8	2.7	.141	8	42.9	5.36	.279	21	111.72	18.62	.97
2007	5	26.8	2.7	.123	8	42.9	5.36	.254	21	111.72	18.62	.88
2008	5	26.8	2.7	.116	8	42.9	5.36	.231	21	111.72	18.62	.80
2009	5	26.8	2.7	.106	8	42.9	5.36	.210	21	111.72	18.62	.73
2010	6	32.2	3.2	.114	10	53.6	6.70	.239	21	111.72	18.62	.66
2011	6	32.2	3.2	.103	10	53.6	6.70	.216	21	111.72	18.62	.60
2012	6	32.2	3.2	.094	10	53.6	6.70	.197	21	111.72	18.62	.55
2013	6	32.2	3.2	.085	10	53.6	6.70	.179	21	111.72	18.62	.50
2014	6	32.2	3.2	.077	10	53.6	6.70	.163	21	111.72	18.62	.45
2015	6	32.2	3.2	.070	10	53.6	6.70	.148	21	111.72	18.62	.41
2016	6	32.2	3.2	.064	10	53.6	6.70	.135	21	111.72	18.62	.37
2017	6	32.2	3.2	.059	10	53.6	6.70	.123	21	111.72	18.62	.34
2018	6	32.2	3.2	.053	8	42.9	5.36	.089	21	111.72	18.62	.31
2019	6	32.2	3.2	.048	8	42.9	5.36	.081	21	111.72	18.62	.28
2020	6	32.2	3.2	.044	8	42.9	5.36	.073	21	111.72	18.62	.26
2021	6	32.2	3.2	.040	8	42.9	5.36	.067	21	111.72	18.62	.23
2022	6	32.2	3.2	.036	8	42.9	5.36	.060	21	111.72	18.62	.21
2023	6	32.2	3.2	.033	8	42.9	5.36	.055	21	111.72	18.62	.19
2024	6	32.2	3.2	.030	8	42.9	5.36	.050	21	111.72	18.62	.18
2025	4.5	24.1	2.4	.020	8	42.9	5.36	.046	21	111.72	18.62	.15
TOTAL	148.5	$ 844.9	$ 84.3	$ 3.737	264.5	$ 1418.1	$ 177.24	$ 9.191	714.0	$3,798.48	$633.08	$35.90

Chart 7

Table 1

THEORETICAL ESTIMATES OF STATE ROYALTY INCOME FROM TRADE AREA COAL

YEARS 1971-2025

	Present Value Discount Factor 10%
Pessimistic Case	
Future value of coal royalties	$ 84.4 million
Present value of coal royalties	$ 3.7 million
Medium Case	
Future value of coal royalties	$180.8 million
Present value of coal royalties	$ 9.76 million
Optimistic Case	
Future value of coal royalties	$650.9 million
Present value of coal royalties	$ 42.2 million

	Present Value Discount Factor 8%
Pessimistic Case	
Future value of coal royalties	$ 84.4 million
Present value of coal royalties	$ 6.5 million
Medium Case	
Future value of coal royalties	$180.8 million
Present value of coal royalties	$ 15.9 million
Optimistic Case	
Future value of coal royalties	$650.9 million
Present value of coal royalties	$ 67.0 million

The above listed values are the sum of the 1971-1991 contract figures and the projected 1992-2025 scenario figures.

Part III

RESOURCE APPRAISAL OF LAND EXCHANGES OUTSIDE OF THE BELUGA-CAPPS GLACIER AREA

DGGS Staff

1976

PROPOSED COOK INLET LAND TRADE

Lands Given by the State to CIRI

AREA	ACREAGE TO BE SELECTED
Pt. MacKenzie	3,200
Knik-Willow	8,320
Kashwitna	38,400
Chickaloon	5,730
Alexander Ck.	4,560
Salamatof	5,945
Kenai Penin.	117,315
Beluga Area	Treated Separately

PT. MacKENZIE AND KNIK-WILLOW AREAS

Oil and Gas

These areas are part of the Cook Inlet sedimentary basin. A number of exploratory wells have been drilled in the area, but no production has been found. Exploration in the area will probably continue, but the chance of discovery of significant reserves is low because of complex geologic structure.

Coal

No outcrops of coal are known to exist in these areas. Well logs indicate that coal exists in the subsurface, although most of the beds appear to be very thin (less than 5 feet). Methods that make feasible the production of energy or gas from coal in the subsurface may be developed in the foreseeable future. There are an estimated 20 billion tons of hypothetical coal reserves between the surface and a depth of 2000 feet in the South Willow area and 7.9 billion tons of hypothetical reserves in the Pt. MacKenzie area that might be produced by such methods. Such production is considered unlikely in this area because so much of the coal is in thin beds.

Metallic Minerals

There are no known deposits of metallic minerals in the area.

Uranium

Sedimentary deposits of uranium might exist in the area. No investigations of this resource have been carried out.

Geothermal

The area has no known geothermal resources.

Gravel

A large part of the area is covered by various types of glacial deposits, many of which would be excellent sources of gravel. Expansion of urban development around Anchorage into this area will require large amounts of gravel for construction. Gravel is probably the most valuable natural resource in the area. Investigation will be necessary to delineate deposits of gravel suitable for such use.

References

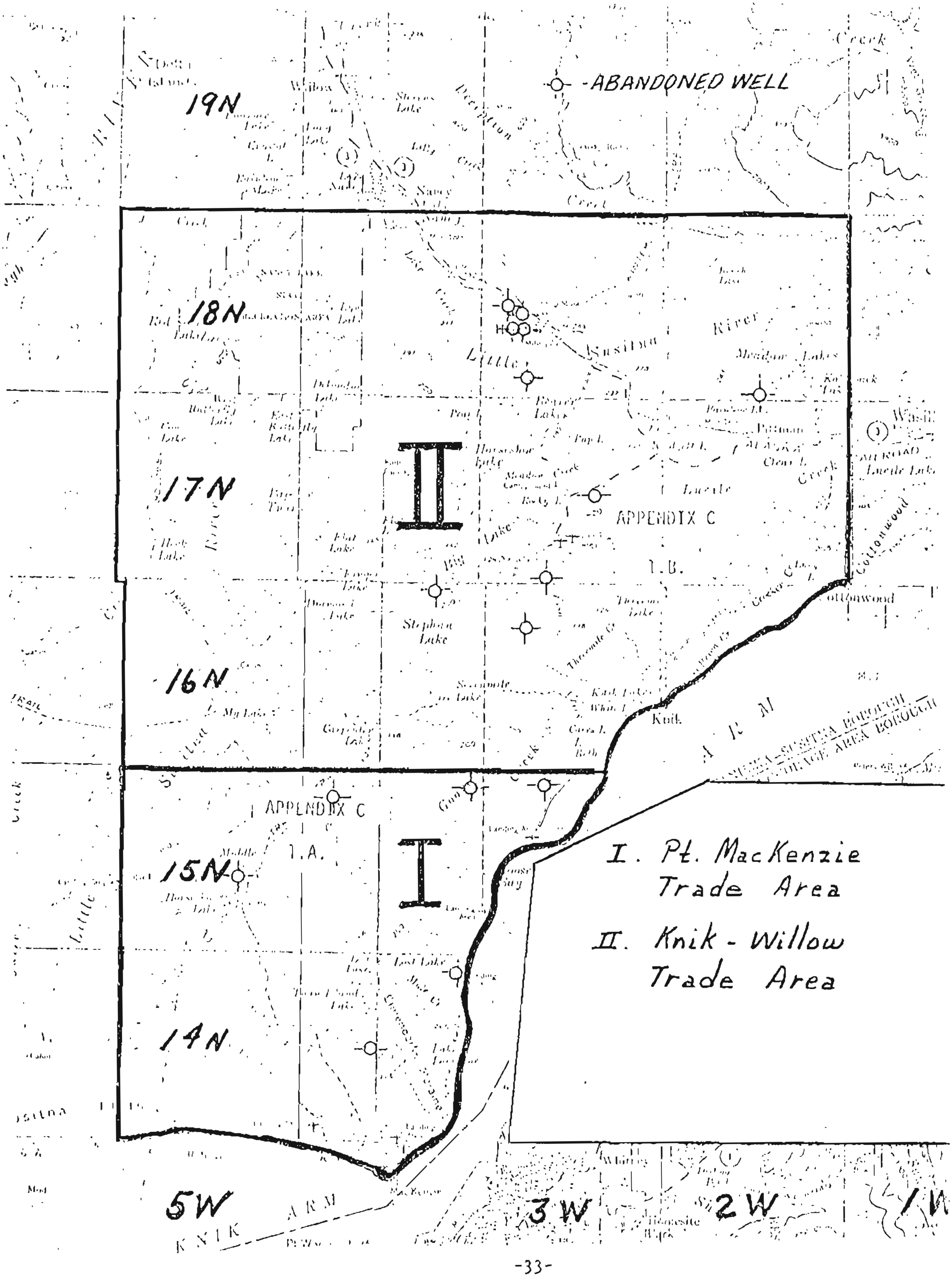
Cobb, E.H., 1972, Metallic mineral resources map of the Anchorage quadrangle, Alaska: U.S. Geol. Survey map MF-409

Cobb, E.H., 1972, Metallic mineral resources map of the Tyonek quadrangle, Alaska: U.S. Geol. Survey map MF-385

Hartman, D.C.; Pessel, G.H.; and McGee, D.L., 1972, Preliminary report on stratigraphy of Kenai Group, Cook Inlet, Alaska: Alaska Div. of Geol. Survey Spec. Rept. 5

McGee, D.L.; and O'Connor, K.M., 1975, Mineral resources of Alaska and the impact of federal land policies on their availability, coal: Alaska Div. of Geol. Survey Open File Rept. 51

____________, 1975, Cook Inlet basin subsurface coal reserve study: Alaska Div. of Geol. and Geoph. Surveys Open File Rept. 74


ABANDONED WELL
19N
18N
17N
16N
15N
14N
5W
3W
2W
II
I
APPENDIX C
I.B.
APPENDIX C
I.A.
Stephan Lake
Knik
Little Susitna River
I. Pt. MacKenzie Trade Area
II. Knik - Willow Trade Area

KASHWITNA AREA

Oil and Gas

The area is not favorable for accumulation of oil and gas.

Coal

The area does not contain any known or hypothetical reserves of coal.

Metallic Minerals

There are no known deposits of metallic minerals in the area.

Uranium

No uranium deposits are known in the area, and the geology is not favorable for the occurrence of such deposits.

Geothermal

There are no known geothermal resources in the area.

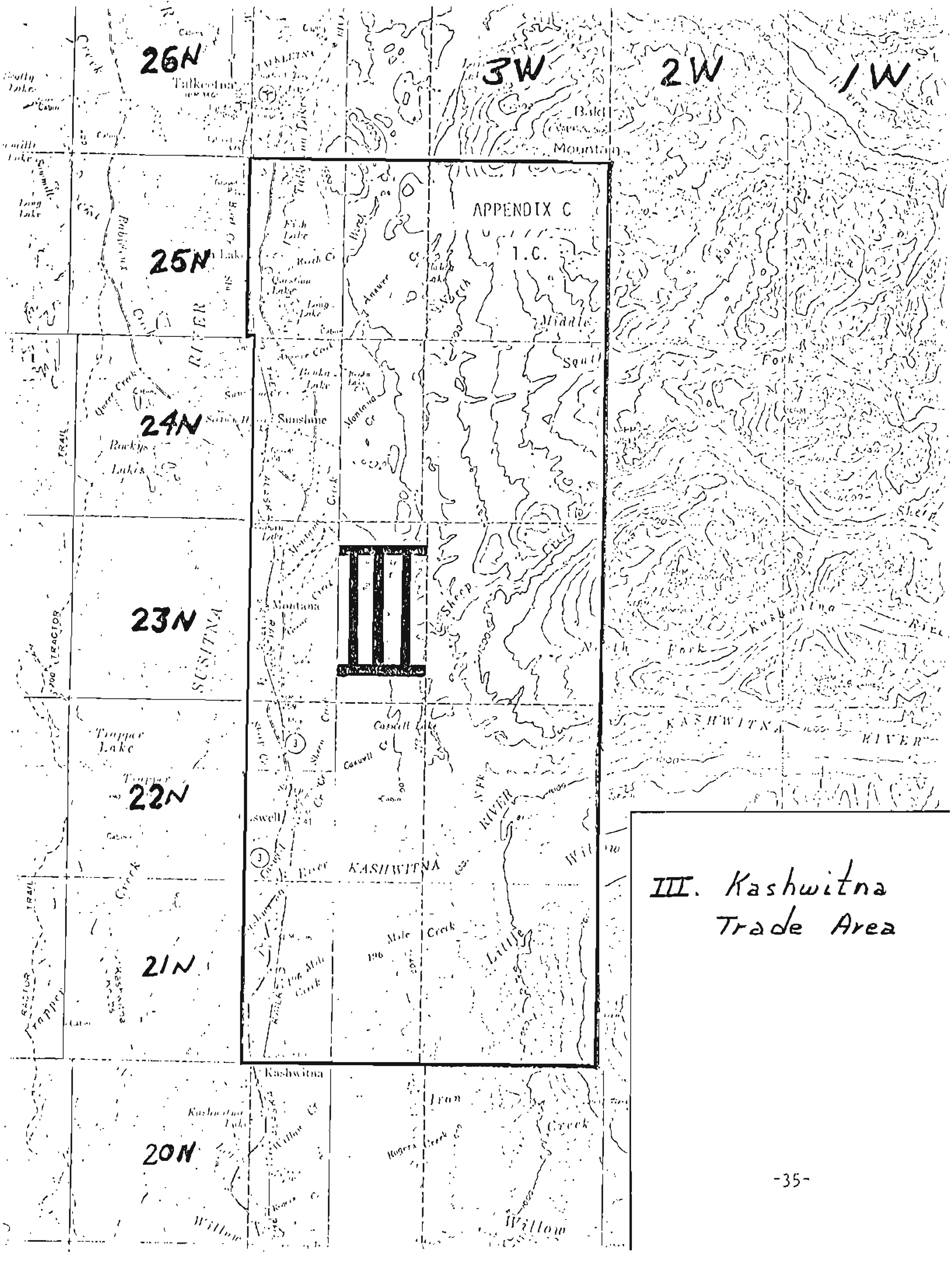
Gravel

Various types of glacial deposits exist in the area that would be sources for gravel. Development along the rail belt, and possibly near a new capital, will require large amounts of this resource. Investigation will be necessary to delineate deposits of gravel that would be suitable for such use.

References

Cobb, E.H., 1972, Metallic mineral resources of the Talkeetna quadrangle, Alaska: U.S. Geol. Survey map MF-369

Karlstrom, T.N.V., 1964, Quaternary geology of the Kenai lowland and glacial history of the Cook Inlet region, Alaska: U.S. Geol. Survey Prof. Paper 443



III. Kashwitna Trade Area

CHICKALOON AREA

Oil and Gas

The geology of the area is generally unfavorable for accumulations of oil and gas. An exploratory well was drilled many years ago at Drill Lake near Chickaloon, but was unsuccessful.

Coal

Part of the coal reserves of the Matanuska province are found in this area. Demonstrated reserves are estimated at 25 million tons, and there are hypothetical reserves of about 25 million tons. Geologic structure in the area is complex, and large scale coal production is not probable in the future.

Metallic Minerals

Placer gold deposits were worked in the latter part of the 19th century on Chickaloon River and Schoonoven Creek (see map). These deposits were not extensive, and there are probably no significant deposits in the area.

Uranium

There are no uranium deposits known in the area. Investigations for this resource have not been carried out in the area.

Geothermal

There are no known geothermal resources in the area.

Gravel

There are a few stream gravels and glacial deposits in the area that could be sources of gravel. The size of the deposits is not extensive enough to be important for anything but limited local use.

References

Barnes, F.F.; and Payne, T.G., 1956, The Wishbone Hill district, Matanuska coal field, Alaska: U.S. Geol. Survey Bull. 1016

Cobb, E.H., 1972, Metallic mineral resources map of the Anchorage quadrangle, Alaska: U.S. Geol. Survey map MF-409

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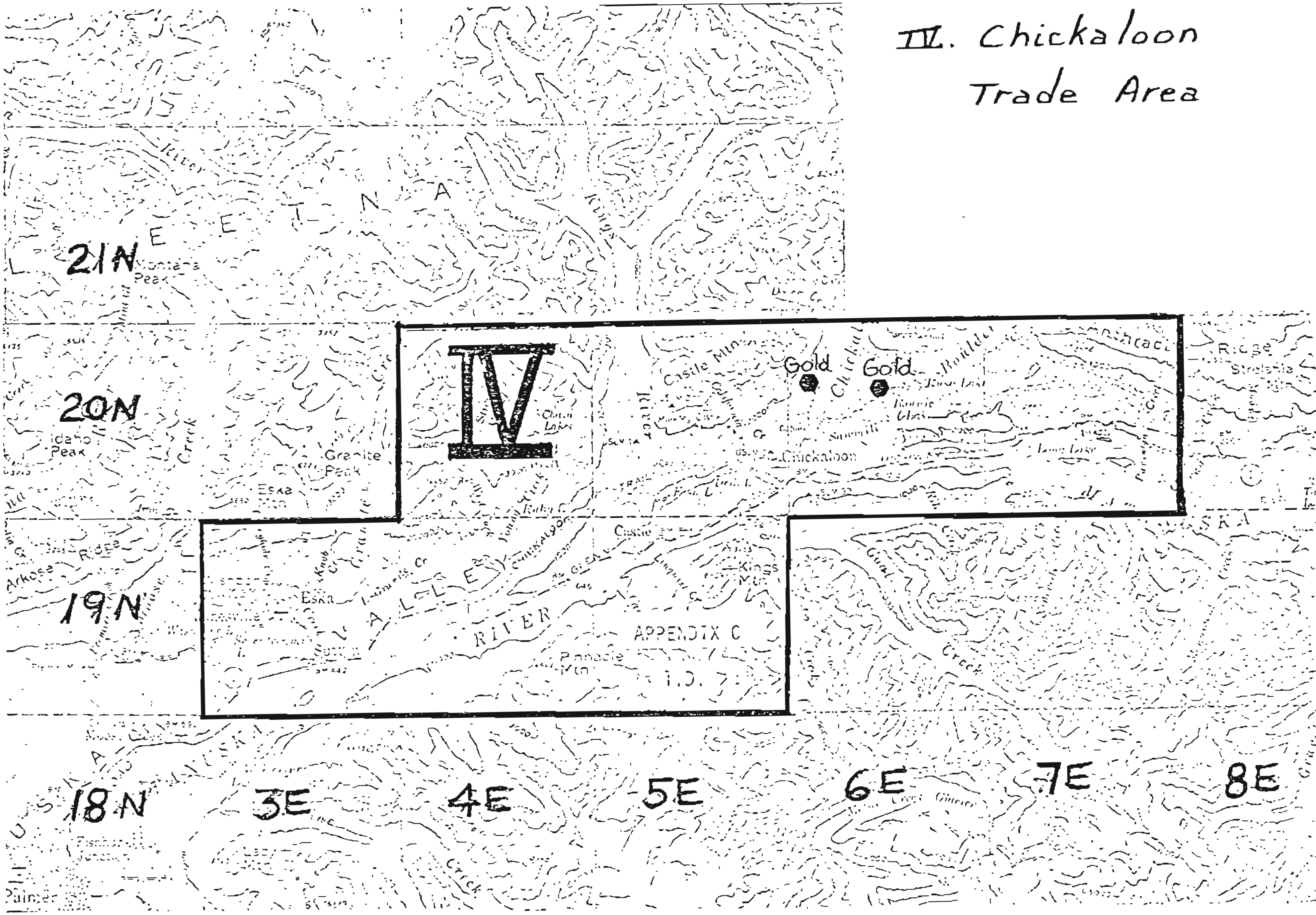
Mendenhall, W.C., 1900, A reconnaissance from Resurrection Bay to the Tanana River, Alaska: U.S. Geol. Survey Annual Report of 1900

IV. Chickaloon Trade Area



ALEXANDER CREEK AREA

Oil and Gas

Most of the area east of Alexander Creek is part of the Cook Inlet sedimentary basin. An exploratory well was drilled just south of the area, at Bell Island, but was not productive. The area is close to the boundary fault for the basin, the geologic structure is complex, and there is not much chance that significant reserves of oil and gas will be found in the area.

Coal

No outcrops of coal exist in the area. Coal exists in the subsurface, but the beds are thin and sparse, and probably do not constitute an economic resource.

Metallic Minerals

Gold placers are found along about six or seven miles of the Lewis River, on the flanks of Mt. Susitna. The deposits were worked and prospected in the early part of this century, but are not currently active.

Uranium

Sedimentary deposits of uranium might exist in this area. No investigations of this resource have been carried out.

Geothermal

Geothermal resources are not known to exist in the area.

Gravel

Glacial and stream deposits in the area would be a source for gravel. The importance of these deposits would depend on the proximity of development and construction creating a need for such materials.

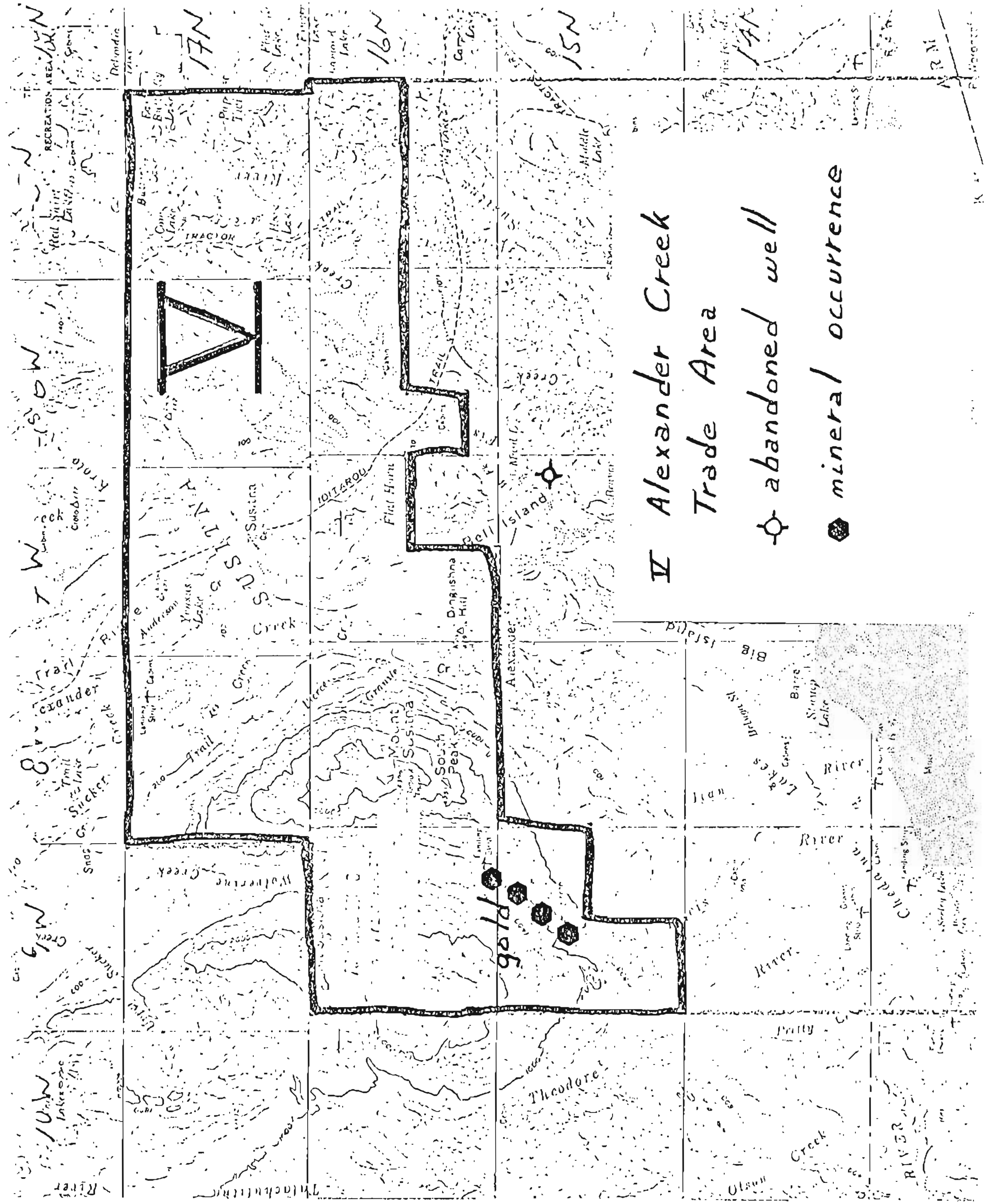
References

Brooks, A.H., et al, 1918, Mineral resources of Alaska: U.S. Geol. Survey Bull. 662

Cobb, E.H., 1972, Metallic mineral resources map of the Tyonek quadrangle, Alaska: U.S. Geol. Survey map MF-385

Hartman, D.C.; Pessel, G.H.; and McGee, D.L., 1972, Preliminary report on stratigraphy of Kenai Group, Upper Cook Inlet, Alaska: Alaska Div. of Geol. Survey Spec. Rept. 5

McGee, D.L.; and O'Connor, K.M., 1975, Cook Inlet basin subsurface coal reserve study: Alaska Div. of Geol. and Geoph. Surveys Open File Rept. 74


II Alexander Creek
Trade Area
abandoned well
mineral occurrence
Susitna
Mount Susitna
Bell Island
Alexander
Theodore
River
Creek

SALAMATOF AREA

Oil and Gas

The area is in the productive part of the Cook Inlet basin, and several oil and gas fields are in and adjacent to the area (see map). However, the history of exploration in this area would indicate a low probability for the discovery of additional significant reserves. A summary of production through October 1975 is given below:

	Gas (MCF)	Oil (bbls)
McArthur River Field	91,005,864	287,406,542
Middle Ground Shoal	45,105,913	94,758,645
Sterling Gas Field	1,839,770	3,397
Kenai Gas Field	622,305,684	8,139,075

Coal

There are some coal outcrops in the area, but no estimate of reserves is available. Well logs indicate that some coal exists in the subsurface at a depth less than 2,000 feet, but the total thickness of such coals is generally less than 10 feet. Coal production from such sources is not considered likely in this area.

Metallic Minerals

There are no known deposits of metallic minerals in the area.

Uranium

Sedimentary deposits of uranium might exist in the area. No investigations of this resource have been carried out.

Geothermal

No geothermal resources exist in the area. The geology is not favorable for the presence of such resources.

Gravel

Various types of morainal deposits and deltaic deposits cover part of the area and these would be good sources of gravel. Development of housing, roads and industry in the Kenai area will require large amounts of this resource. Investigation will be necessary to delineate deposits of gravel suitable for such use.

References

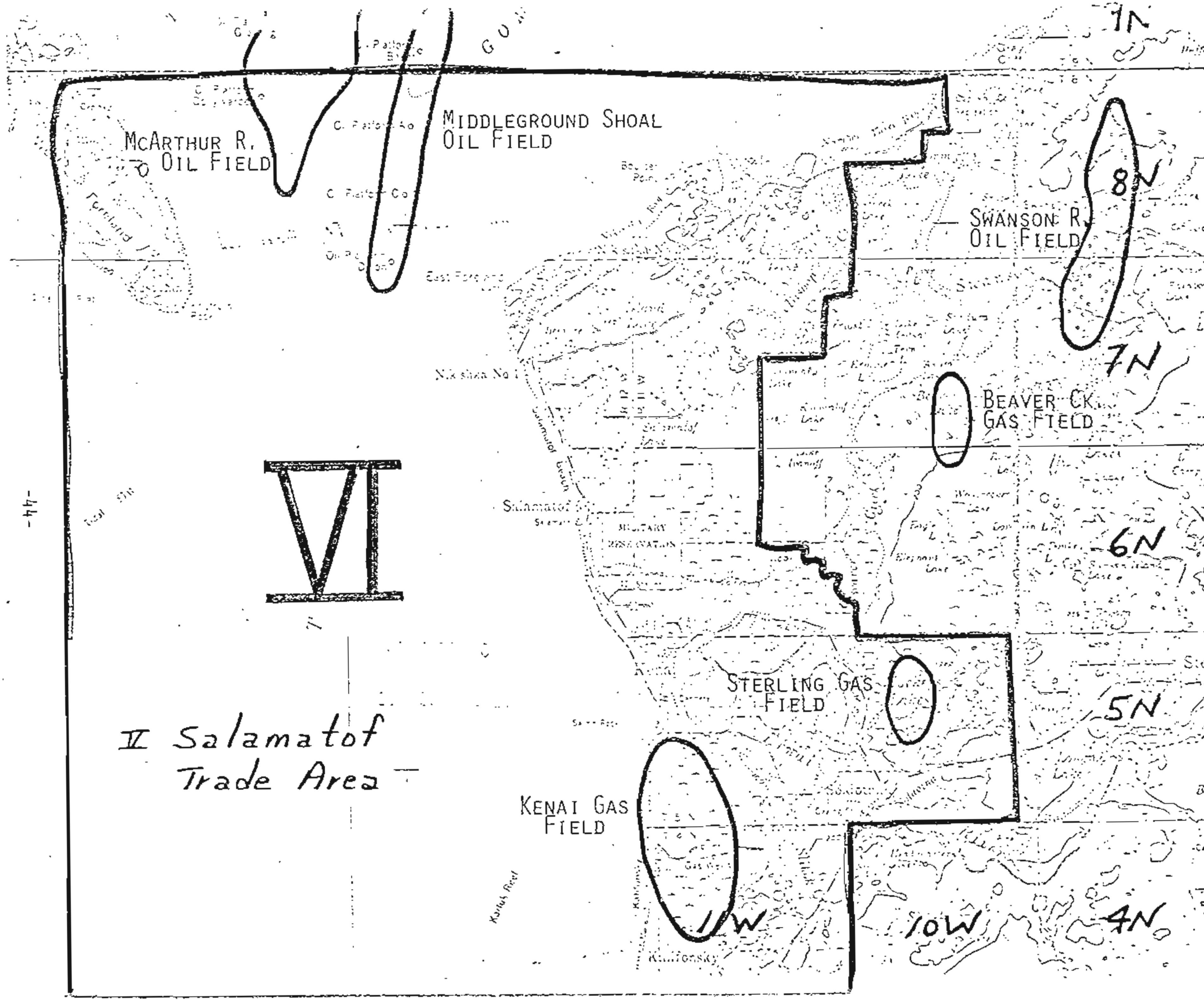
Cobb, E.H., 1972, Metallic mineral resources of the Kenai quadrangle, Alaska: U.S. Geol. Survey map MF-377

Hartman, D.C.; Pessel, G.H.; and McGee, D.L., 1972, Preliminary report on stratigraphy of Kenai Group, Upper Cook Inlet, Alaska: Alaska Div. of Geol. Survey Spec. Rept. 5

Karlstrom, T.N.V., 1964, Quaternary geology of the Kenai lowland and glacial history of the Cook Inlet region, Alaska: U.S. Geol. Survey Prof. Paper 443

McGee, D.L.; and O'Connor, K.M., 1975, Mineral resources of Alaska and the impact of federal land policies on their availability, coal: Alaska Div. of Geol. and Geoph. Surveys Open File Rept. 51

______________, 1975, Cook Inlet basin subsurface coal reserves study: Alaska Div. of Geol. and Geoph. Surveys Open File Rept. 74


McArthur R.
Oil Field
Middleground Shoal
Oil Field
Swanson R.
Oil Field
Beaver Ck.
Gas Field
Sterling Gas
Field
Kenai Gas
Field
VI
VI Salamatof
Trade Area
8N
7N
6N
5N
4N
11W
10W
Nikishka No 1
Salamatof
Military
Reservation
East Foreland
Kalifonsky

SOUTH KENAI

Oil and Gas

The area is part of the Cook Inlet sedimentary basin, and contains two known gas fields, neither of which has been put on production. A number of exploratory wells have been drilled in the area, and exploration will undoubtedly continue in the future. Additional reserves of oil and gas will probably be found.

Production test results on the two gas fields are given below:

Falls Creek:	300 to 680 MCF/day
North Fork:	1770-4360 MCF/day

Coal

Coal outcrops are found in many of the shoreline cliffs in this part of the Kenai peninsula. Most of the coal reserves that could be produced by modern mining methods probably lie in a narrow zone near the shore.

Demonstrated reserves within the area are 300 million tons, and there are hypothetical reserves of 2.4 billion tons (McGee and O'Connor, 1975). Methods may be developed that make feasible the production of energy or gas from coal in the subsurface in the foreseeable future. The area contains an estimated 24 billion tons of hypothetical reserves that might be produced by such methods between the surface and a depth of 2000 feet.

Metallic Minerals

There are several recorded placer deposits of fine gold on the beaches at Anchor Point and north of Ninilchik that were worked early in this century (Cobb, 1972). The deposits were very small, and are not significant. The area probably does not contain significant deposits of metallic minerals.

Uranium

Sedimentary deposits of uranium might exist in the area. No investigations of this resource have been carried out.

Geothermal

The area has no known geothermal resources.

Gravel

Various types of morainal and deltaic deposits cover part of the area, and these would make excellent sources of gravel. Development in the Homer area would require large amounts of gravel. Investigation will be necessary to delineate deposits of gravel suitable for such use.

References

Cobb, E.H., 1972, Metallic mineral resources map of the Kenai quadrangle, Alaska: U.S. Geol. Survey map MF-377

____________, 1972, Metallic mineral resources map of the Seldovia quadrangle, Alaska: U.S. Geol. Survey map MF-397

Hartman, D.C.; Pessel, G.H.; and McGee, D.L., 1972, Preliminary report on stratigraphy of Kenai Group, Upper Cook Inlet, Alaska: Alaska Div. of Geol. Survey Spec. Rept. 5

Karlstrom, T.N.V., 1964, Quaternary geology of the Kenai lowland and glacial history of the Cook Inlet region, Alaska: U.S. Geol. Survey Prof. Paper 443

Martin, G.C.; Johnson, B.L.; and Grant, U.S., 1915, Geology and mineral resources of Kenai Peninsula, Alaska: U.S. Geol. Survey Bull. 587

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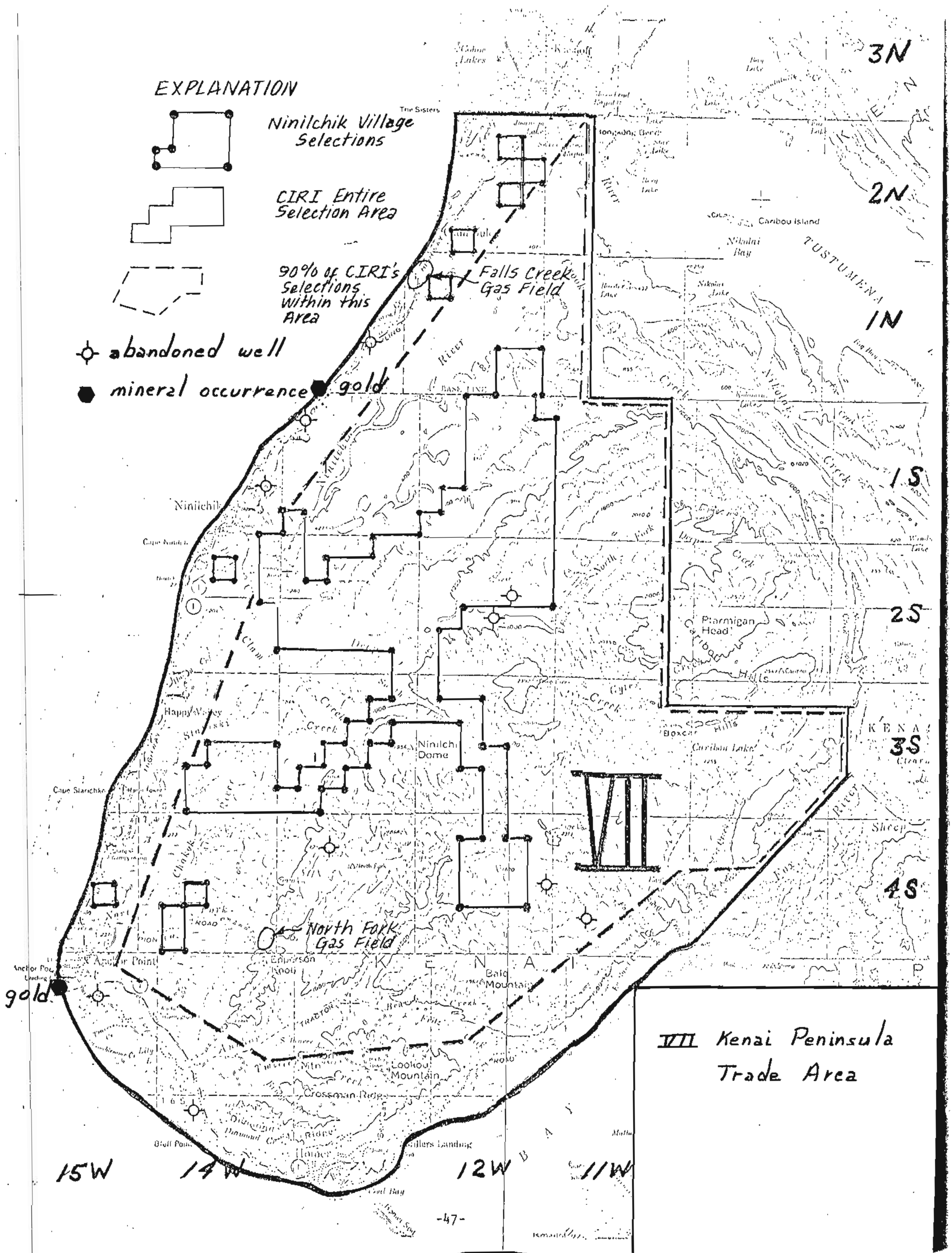

EXPLANATION
Ninilchik Village Selections
CIRI Entire Selection Area
90% of CIRI's Selections within this Area
abandoned well
mineral occurrence
gold
Falls Creek Gas Field
North Fork Gas Field
Ninilchik
Ninilchik Dome
Happy Valley
Anchor Point
Caribou Island
Tustumena
Ptarmigan Head
Caribou Hills
Boxcar Hills
Caribou Lake
Bald Mountain
Lookout Mountain
Crossman Ridge
Emerson Knoll
3N
2N
1N
1S
2S
3S
4S
15W
14W
12W
11W
VII
VII Kenai Peninsula Trade Area

PROPOSED COOK INLET LAND TRADE

Lands Received by State from Federal Government

AREA	ACREAGE TO BE RECEIVED
Lake Iliamna	576,000
Talkeetna Mtns.	184,320
Kamishak Bay	506,480
Tutna Lake	161,280

ILIAMNA AREA

Oil and Gas, Coal

The geology of the area is unfavorable for accumulations of these resources.

Metallic Minerals

A magnetite iron deposit is located in the area near Frying Pan Lake. Iron content runs from 16% to 24% with about 1.3% titanium. The deposit is about one square mile in extent, and is probably not economically significant.

The area lies in a metal province containing copper, lead, zinc, gold and silver (Clark, et al, 1975), and deposits of these metals might be found in the area in the future.

Uranium

No uranium deposits are known to exist in the area. Investigations for this resource have not been carried out.

Geothermal

No geothermal resources are known in the area.

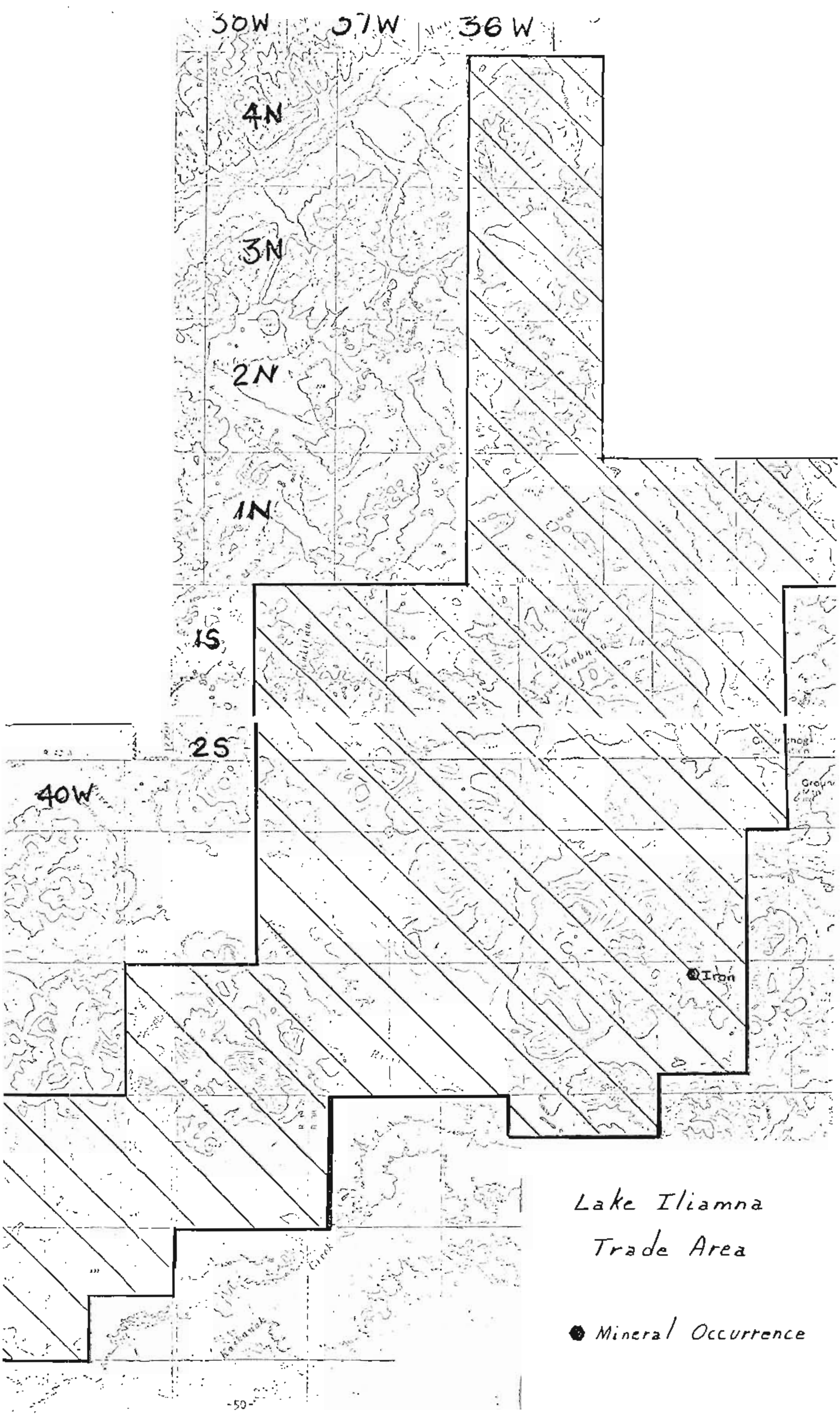
Gravel

Stream gravels and glacial deposits in the area probably contain a small amount of gravel. Because of the remoteness of the area and the lack of foreseeable development in the future, these deposits are unimportant.

References

Cobb, E.H., 1972, Metallic mineral resources of the Iliamna quadrangle, Alaska: U.S. Geol. Survey map MF-364

Reed, B.L.; and Detterman, R.L., 1965, A preliminary report on some magnetite bearing rocks near Frying Pan Lake, Iliamna D-7 quadrangle, Alaska: U.S. Geol. Survey open file rept. 260



36W
4N
3N
2N
1N
1S
2S
40W
Iron
-50-
Lake Iliamna
Trade Area
Mineral Occurrence

TALKEETNA MOUNTAINS

Oil and Gas

The geology of the area is not favorable for the accumulation of oil and gas.

Coal

The area contains no known deposits of coal.

Metallic Minerals

The area contains no known deposits of metallic minerals.

Uranium

The geology of the area is not favorable for the occurrence of uranium deposits.

Geothermal

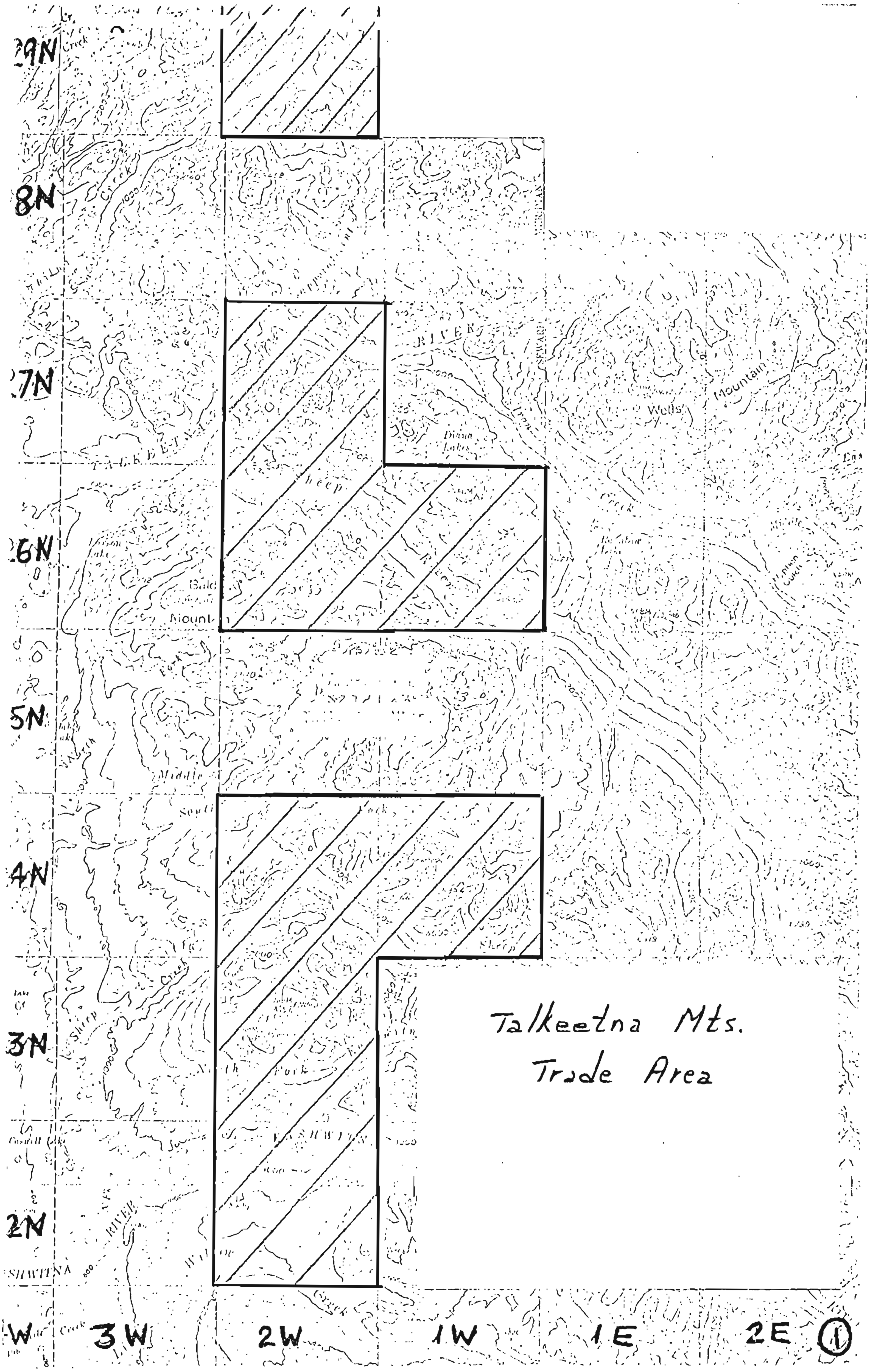
The area has no known geothermal resources.

Gravel

The area contains a few glacial and stream deposits, but these are small, and not important compared to the large areas of glacial deposits in the lowlands.

References

Cobb, E.H., 1972, Metallic mineral resources map of the Talkeetna Mountains quadrangle, Alaska: U.S. Geol. Survey map MF-370



Talkeetna Mts.
Trade Area
29N
28N
27N
26N
25N
24N
23N
22N
3W
2W
1W
1E
2E
1
Wells
Mountain
Diana Lakes
Sheep
Bald
North Fork
Middle
Creek
RIVER

KAMISHAK AREA

Oil and Gas

The geology of the area is unfavorable for the accumulation of oil and gas.

Coal

There are no known coal deposits in the area.

Metallic Minerals

Several large, low-grade iron deposits are known in the area. These deposits consist of lenses and disseminated grains of magnetite.

A few deposits of copper and gold are known in the area, but these appear to be small and are probably not big enough to mine.

The area is in a metal province containing copper, lead, zinc, gold, silver, iron, titanium, chromium and platinum. Deposits of these metals may be found in this area in the future.

Uranium

No uranium deposits are known to exist in the area. Investigations for this resource have not been carried out.

Geothermal

No geothermal resources are known to exist in the area.

Gravel

There are small glacial and stream deposits in the area that would probably be a source of gravel. Because of the remoteness of the area and the lack of foreseeable development in the future, these deposits are unimportant.

References

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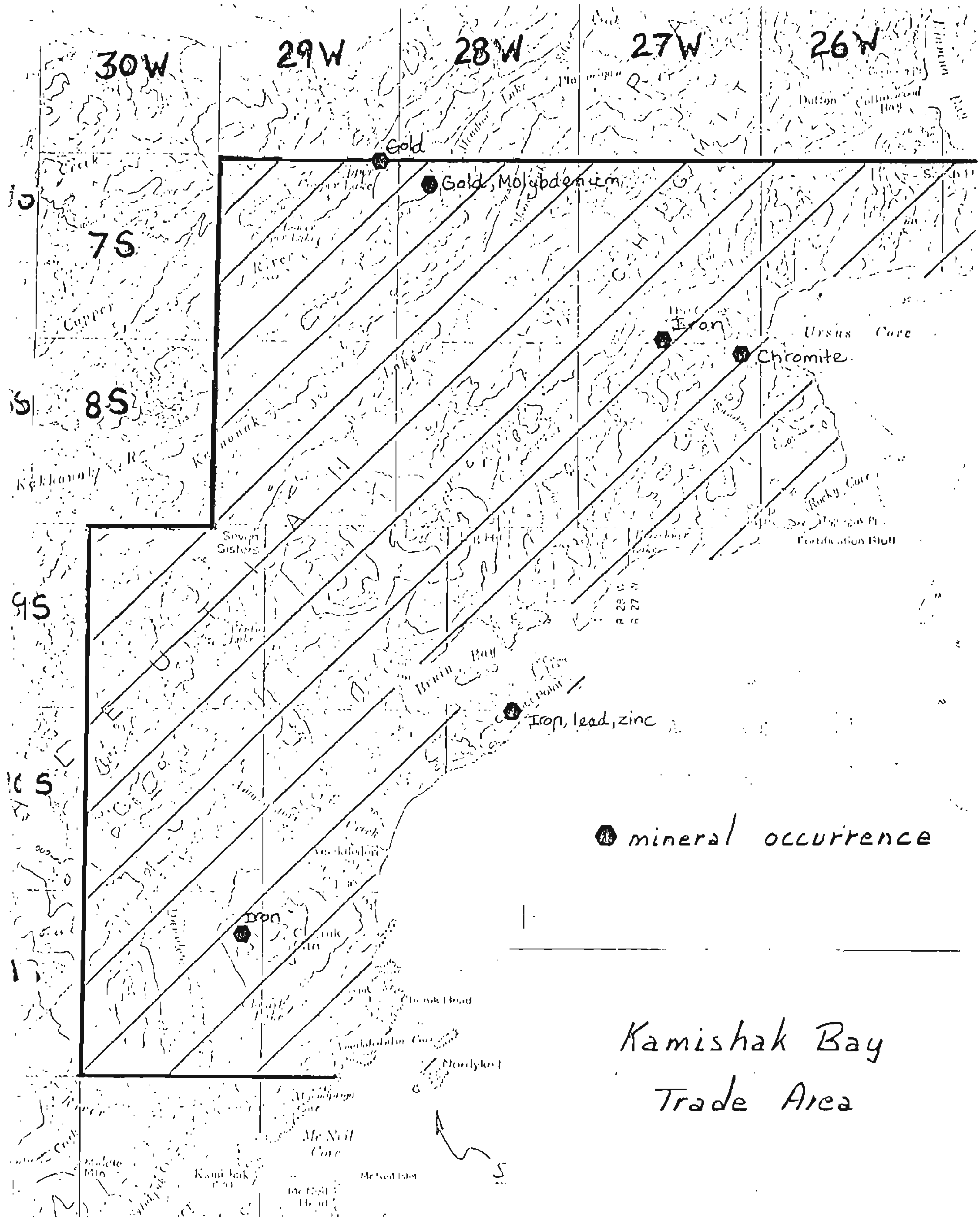

30W
29W
28W
27W
26W
7S
8S
9S
Gold
Gold, Molybdenum
Iron
Chromite
Iron, lead, zinc
Iron
Ursus Cove
Rocky Cove
Fortification Bluff
Bruin Bay
Seven Sisters
Dutton
mineral occurrence
Kamishak Bay
Trade Area

TUTNA LAKE

Oil and Gas, Coal

The geology of the area is unfavorable for resources of this type of resources.

Metallic Minerals

There are no known deposits of metallic minerals in the area. The area is in a metal province containing copper, lead, zinc, silver and gold (Clark, et al, 1975), and deposits of this type might be discovered in the future.

Uranium

There are no known deposits of uranium in the area. No investigations for this resource have been carried out.

Geothermal

There are no known resources of this type in the area.

Gravel

There are small deposits from glaciers and streams in the area. However, the remoteness of the area and the lack of any foreseeable development makes any gravel resources unimportant.

References

Clark, A.L.; Berg, H.C.; Cobb, E.H.; Eberlein, G.D.; MacKevett, E.M.; and Miller, T.P., 1974, Metal provinces of Alaska: U.S. Geol. Survey map I-834

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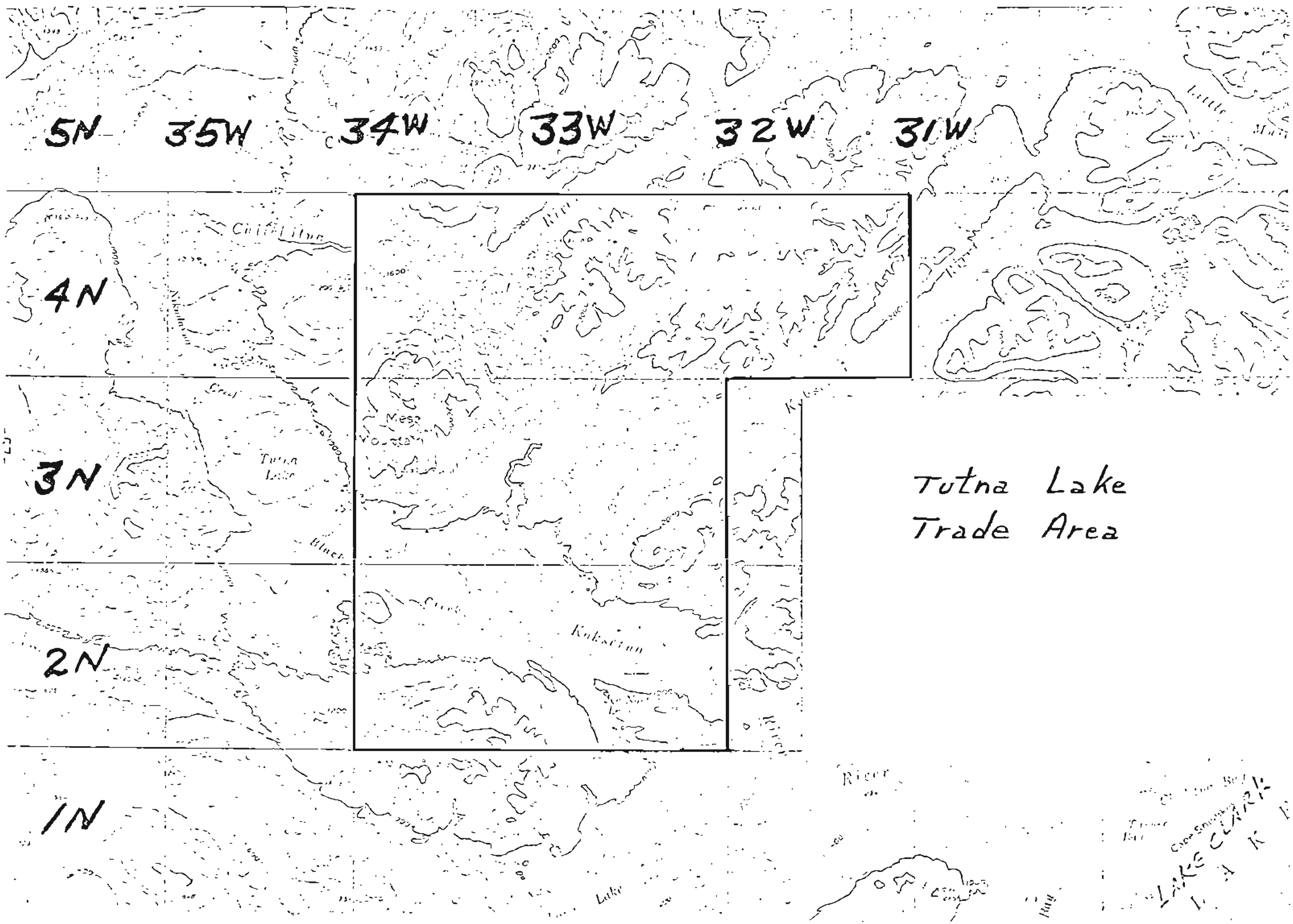

5N
35W
34W
33W
32W
31W
4N
3N
2N
1N
Tutna Lake
Trade Area
Mesa
Tutna
Lake
Kokrtuun
River
LAKE CLARK
Lake

GLOSSARY

Known Coal

Known coal as used in the report is a common term for demonstrated coal. These two terms represent the same coal resources. Known coal is a collective term for the sum of materials in both measured and indicated resources which are described below.

1. Measured - material for which estimates of the quality and quantity have been computed within a margin of error of less than 20 percent, from sample analysis and measurements from closely spaced and geologically well-known sample sites.

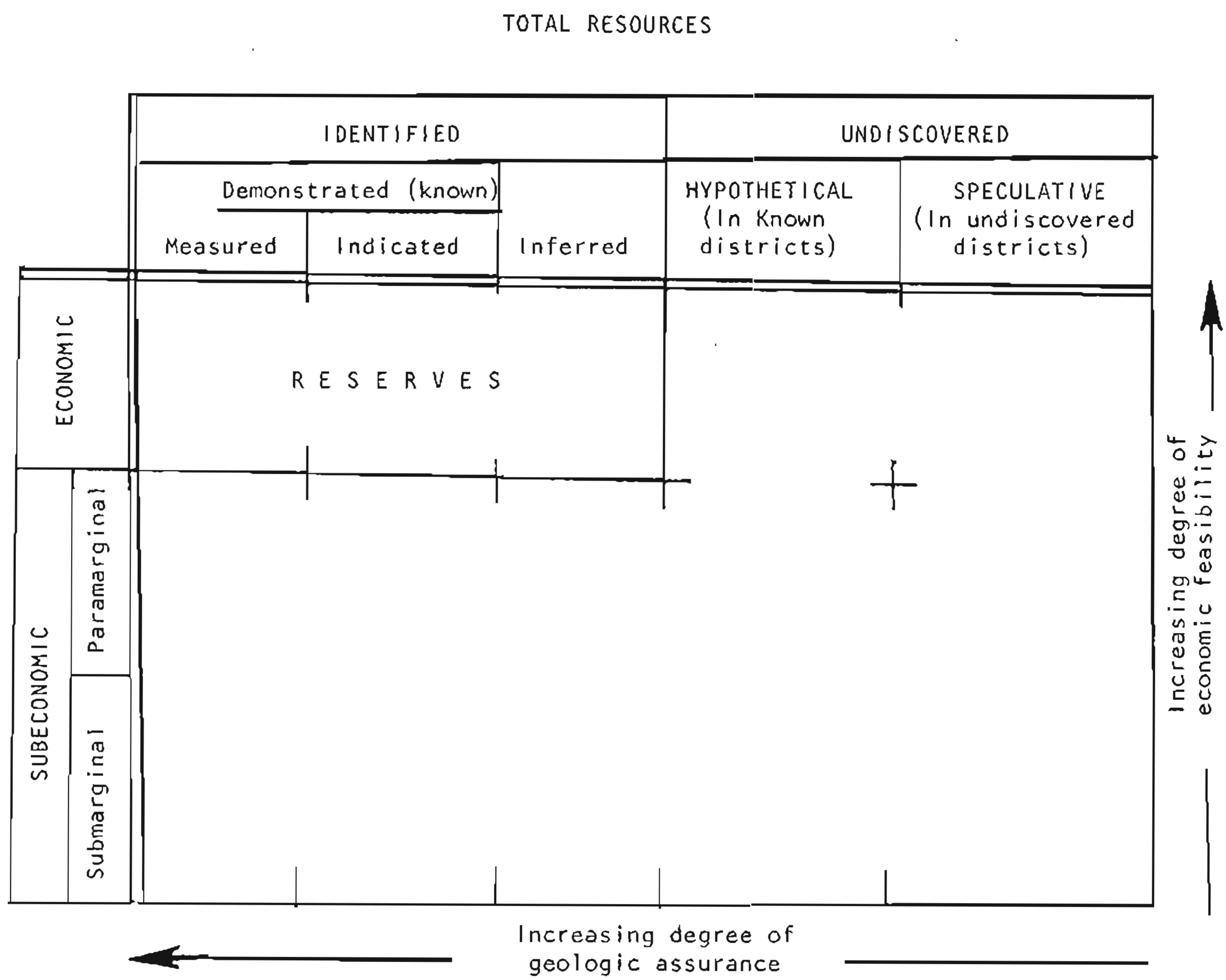
2. Indicated - material for which estimates of the quality and quantity have been computed partly from sample analysis and measurements and partly from reasonable geologic projections.

Inferred coal - material in unexplored extensions of demonstrated (known) resources for which estimates of the quality and size are based on geologic evidence and projection.

Hypothetical coal - undiscovered materials that may reasonably be expected to exist in a known mining district (a basin containing known coal) under known geologic conditions. Exploration that confirms their existence and reveals quantity and quality will permit their reclassification as a reserve or identified subeconomic resource.

The above definitions are from the Joint USGS-US Bureau of Mines Resource Classification and Operational Procedures. Figure 1A is a graphical display of the terms.

Figure 1A --Classification of Mineral Resources



Stripping ratios - a stripping ratio is a simple method of comparing the amount of overburden (material above the coal bed) with the thickness of the coal bed. An example of this is as follows:

50' coal, 100' of soil, gravel, and sand above the coal. The stripping ratio is 2 to 1. There are no rigid rules as to what constitutes an economic stripping ratio. The consolidation of the overburden, thickness of the coals and grade of the coal are all part of this consideration. However, stripping ratios of less than 5 to 1 are generally considered favorable and ratios of 10 to 1 may be economic.

Short tons - a short ton is the unit of weight used for coal. A short ton (avoirdupois) is 2000 pounds (0.907 metric tons). A long ton is 2240 pounds (1.016 metric tons). Long tons may be converted to short tons by multiplying the long tons by 1.120 and conversely short tons may be converted to long tons by multiplying by the factor of .8929.

Present value - a cash-flow in the future discounted to present dollar value at an assumed rate of interest.

Real dollar value - a value expressed in terms of a dollar with a purchasing power of a given year (i.e., 1975 dollars). That is, a dollar with a given constant purchasing power, particular to a given year.

Future value - a cash-flow in the future expressed in real dollar values.

Present value discount factor - that factor which is used to bring to the present a future real dollar value.

COAL LEASE AND PROSPECTING PERMIT

Permit Conversion to Lease

At any time while a Coal Prospecting Permit (page 62) is in effect, if the Permittee shows to the satisfaction of the director that the land covered by the permit contains coal in commercial quantities and submits a satisfactory mining plan, the Permittee is entitled to a noncompetitive Coal Lease (page 63) on all or part of the land covered by the permit.

If more than 300 tons of coal are used or marketed in any three-month period, the prospecting permit shall be converted to a lease.

Royalties are fixed before offering the lease and shall be effective for a period of not more than 20 years. Note - the latest attachments (page 62 and 63) indicate a move by the State to reduce the time period to 10 years for royalties and rental rates adjustments.

Rental - $0.25/acre for the first year, $0.50+/acre for the 2nd, 3rd, 4th and 5th years and $1.00/acre for each year thereafter.

The lease is for an indeterminate period of time.

Lease Information

Sec. 38.05.145 Leasing Procedure, Coal

1. Deposits of coal and State lands containing these deposits are subject to disposition under rules and regulations recommended by the director and adopted by the Commissioner and the provisions contained within the law.

   Prospecting Permits

2. On undeveloped areas requiring exploration work, the Commissioner may issue to qualified applicants prospecting permits for a term of two years not exceeding 5,120 acres.

If within the period of two years, satisfactory proof of commercial quantities of coal and a satisfactory mining plan is submitted, the Permittee shall be entitled to a lease for all or part of the land in his permit.

A coal prospecting permit may be extended for two years if the Permittee has been unable, with the exercise of reasonable diligence, to determine the existence of workable coal deposits and desires to do additional exploration.

a. Filing fee $20.00

b. No stipulated rental fee

c. Stipulations for royalty while under this lease.

For further information regarding Alaska coal and leasable minerals, the reader is referred to the Department of Natural Resources publication "Regulations and Statutes Pertaining to Coal and Other Leasable Minerals on Alaska Lands as Contained in the Alaska Administrative Code and the Alaska Statutes".

APPENDIX

THE POTENTIAL FOR DEVELOPING ALASKAN COALS FOR CLEAN EXPORT FUELS

Work Performed Under Contract With

Stanford Research Institute
Menlo Park, California

for

Office of Coal Research
Department of the Interior
Washington, D. C. 20037

OCR Contract No. 14-32-0001-1516

(The data and conclusions presented in this report are essentially those of the contractor and are not necessarily endorsed by the Office of Coal Research, Department of the Interior)

CONTENTS

ILLUSTRATIONS

TABLES

TABLES (continued)

THE POTENTIAL FOR DEVELOPING ALASKAN COALS FOR CLEAN EXPORT FUELS

Foreword

The Phase I study objective is to determine the economic feasibility of a coal conversion facility using the large Beluga coal reserves of Alaska. Although this study is site-related and one of a kind research, the data generated should have general application to coal resource development in other western regions. Since development of the vast Alaskan coal reserves faces some unusual problems, as can be seen from related activities in the lower 48 states, the Office of Coal Research deemed it valuable to gain perspective for such a development. Even though the Alaskan coal reserves are somewhat remote from markets for coal and coal-derived fuels, the proximity of the recoverable coal reserves to deep water ports--unique to Alaska and Washington--promises some interesting and potentially low-cost transportation options for development. Since the Alaskan coal reserves have been relatively unexplored and since it might be expected that the size of the resource base will be very large, the Office of Coal Research has sponsored this program to look at the potential for the development of this valuable U.S. resource.

Introduction

The Beluga fields of south central Alaska, which are being studied as an example, contain a large quantity of low-sulfur, subbituminous coal that has, to date, remained undeveloped. The new technologies that are being developed for coal conversion could provide the process for converting this coal into a liquid or solid fuel that could satisfy part of the growing demand in Japan and the western United States for a clean fuel. This analysis should be helpful in the assessment of coal conversion projects in other coal mining areas.

In order to demonstrate the feasibility of this coal conversion project, four major areas must be investigated:

- Coal reserves--research size, coal quality, mining costs, environmental regulations, etc.
- Coal conversion plant--process design, product yields, process economics, site-related items, etc.
- Product transportation--port survey in Alaska, economics of overland transportation between mine mouth and processing plant, economics of sea transportation of refined product to Pacific rim countries, etc.
- Market survey--demand for clean fuels in Pacific rim countries, costs of competitive fuels in these markets, etc.

Based on the analysis of these four areas, the feasibility of the development of the entire energy complex can be determined.

Coal Mining

The Beluga coal fields lie about 50 air miles west of Anchorage on the northwest side of the Cook Inlet. Two important deposits within the Beluga fields, Capps and Chuitna, are shown in Figure 1. According to the U.S. Geological Survey, the reserves of the Beluga field are estimated to be more than 1.5 billion tons at a stripping ratio of 10:1. Since a coal conversion facility producing 100,000 barrels per stream day of liquid or solid products requires a 20-year reserve of about 300 million tons of subbituminous coal, it would seem that the Beluga reserve could supply one or more large coal conversion facilities. However, more exploratory data are needed to more accurately describe the size of this coal reserve so that the optimal conversion facilities can be determined.

Several analyses have been made on Beluga coal to determine its composition. These analyses are incomplete but an approximate average composition, formed from data from several sources, is shown in Table 1. This shows that the coal is relatively low in sulfur (.2 percent) and high in water (24.9 percent). These average values are used in the following section for design and analysis of the conversion plant, although more accurate coal quality data are needed for a more precise design.

Mining costs are determined primarily by the geophysical characteristics of the coal deposit and its overburden. Climatological conditions and mine location also have economic effects. In order to estimate mining costs in the Beluga area, the project staff has conducted extensive literature review, has conducted an on-site inspection in Alaska, and has conducted interviews with mine operators, mining equipment suppliers, mine labor organizations, and Alaskan state officials.

2

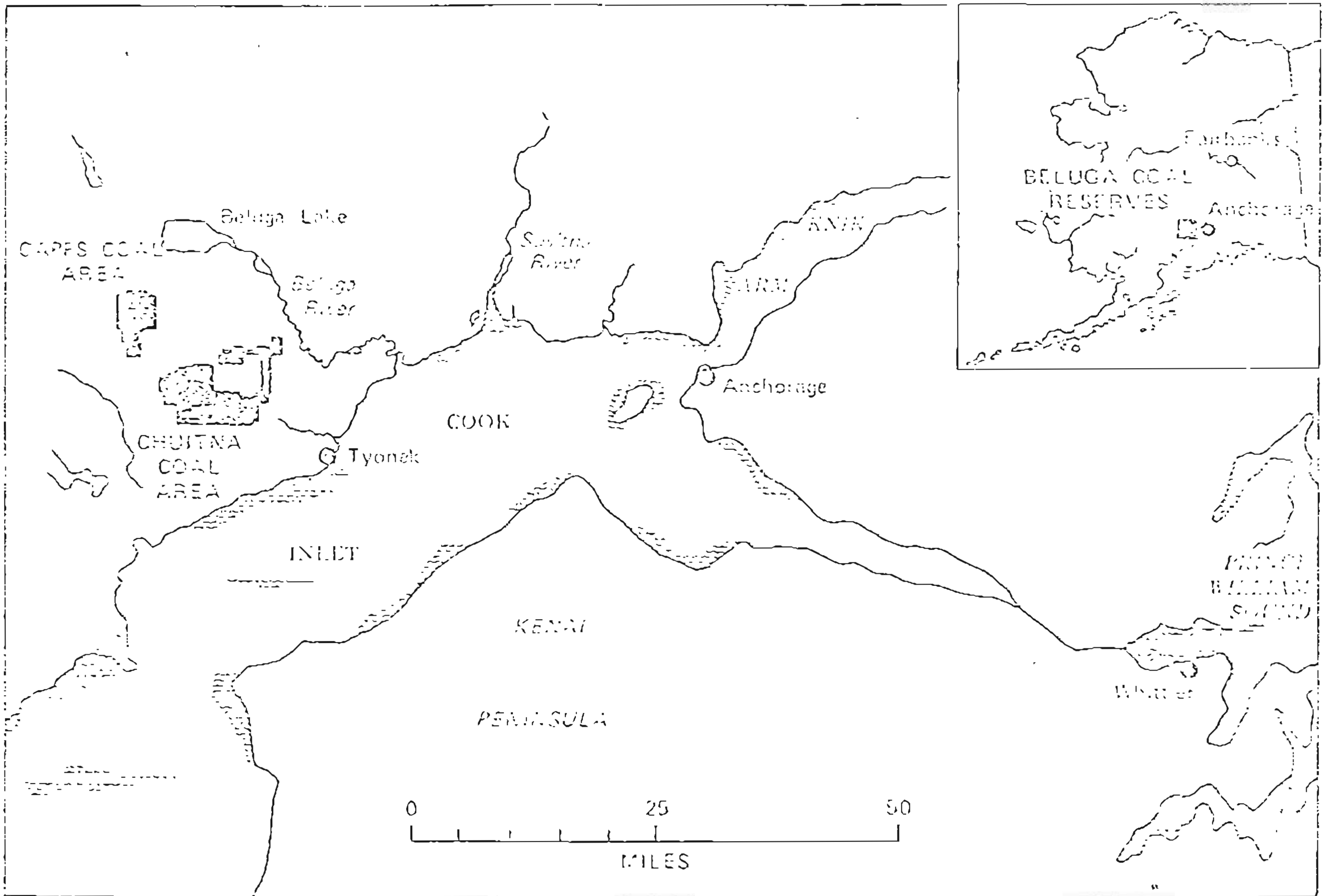

Beluga Lake
CAPES COAL AREA
Beluga River
Susitna River
KNIK ARM
Anchorage
COOK
CHUITNA COAL AREA
Tyonek
INLET
KENAI
PENINSULA
Whittier
BELUGA COAL RESERVES
Fairbanks
Anchorage
0
25
50
MILES

Table 1

COAL QUALITY
BELUGA AREA COAL

Average Capps-Chuitna Run-of-Mine Coal Analysis

	Weight Percent
Carbon	44.7
Hydrogen	3.8
Nitrogen	0.7
Oxygen	15.8
Sulfur	0.2
Ash	9.9
Water	24.9

Average As-Mined Btu Content = 7,200 Btu/lb

Inorganic sulfur = 30%
Organic sulfur = 70%

The Beluga coal deposits lie in a relatively flat, sloping region with the altitude ranging from 1,300 to 2,500 feet. Investigation has shown that, although winter weather conditions seem severe compared with the conditions in most of the lower 48 states, it should be possible to utilize existing mining techniques at Beluga. Preliminary data indicate that the coal deposits lie in two or three horizontal seams, each of which vary in thickness from 6 to 40 feet. These factors have been used to design a surface mining operation and subsequent land reclamation for the Beluga coal. Estimates have been made of the amount, type, and cost of equipment and labor. It should be pointed out that environmental regulations for surface coal mines will undoubtedly apply in this region and may, in fact, become stricter during the period of this operation. The cost of such thorough reclamation has been included in the preliminary mining cost estimates.

The results in Table 2, obtained from the preliminary geological data, show that the initial estimate of the base cost of the mined coal will be $5.32 per ton based on 15 percent per year DCF. This cost estimate will be improved when better data are available on reserves versus stripping ratio and on overburden characteristics. Reclamation costs can also be refined when federal strip mine legislation is finalized.

Coal Conversion

Although the Beluga coal is a possible fuel in its as-mined form, there are several reasons to consider converting it to an alternative form before shipping. The coal composition, as shown in Table 1, is nearly 35 percent water and ash by weight. In shipment to a market, these noncombustibles represent dead weight, thus higher cost. At the point of use, the ash content (about 10 percent), which appears as a residue after combustion, can result in a disposal expense.

Table 2

MINING COSTS
BELUGA PROJECT

Area	Dollars per Ton
Capps	$4.07
Chuitna	5.79
Average	4.93

Capital investment: $74,035,000
Production: 61,000 tons per day
Mine operation: 350 days per year
Mine life: 20 years (reserves available for longer life)
Cost of coal based on 15% DCF: $5.32 per ton

The ability to supply a clean fuel in either a solid or liquid form might well be attractive to those who are currently being forced to switch fuel forms to satisfy environmental constraints. It is reasonable, therefore, to investigate the feasibility of converting the mined coal into a form that is lower in water and ash and to compare the economics of shipping the untreated coal with that of the derived fuel, both as a solid and as a liquid.

Though there are several possible processes to produce liquid and/or solid fuel from coal, this study has centered on the use of one of the more developed ones, the solvent refined coal (SRC) process, developed through OCR funding by the Pittsburg and Midway Coal Mining Company. This process has reached the pilot plant stage. A 6 ton-per-day pilot plant has been built in Wilsonville, Alabama, and a 50 ton-per-day pilot plant is under construction at Fort Lewis, Washington.

The SRC process can be designed to produce a light liquid product and either a solid or liquid solvent refined coal. In addition, the solvent refined coal product might be combined with the light liquid fraction to make a transportable product. Otherwise, the light liquid product might be marketed separately. Also of interest for this study is the fact that the solvent refined coal may well have a unique application as a coking feedstock for Japan; low-sulfur liquid products would be produced as well as valuable metallurgical grade coke for the steel industry. In this case, the combined solvent refined coal/light liquid product would probably be marketed.

Project staff members have visited both of the previously mentioned SRC pilot plants to gain a better understanding of the current state of SRC technology, particularly in the areas of operating reliability and product quality. One of the process elements requiring careful study is the filter system used to remove ash from the product. Its performance is a key to product quality. The Southern Services SRC plant at Wilsonville, Alabama, uses a Funda leaf filter system, while the OCR plant at Ft. Lewis, Washington, will use Goslin-Birmingham rotary pressurized precoat filters. Insufficient studies have been made to date on these filters, so that future work at these pilot plants will more closely examine filter performance. These two plants differ considerably in the extent to which each provides support services. While the Southern Services' plant is not equipped with many of the supporting processing units, the Fort Lewis plant includes a hydrogen and inert gas generating unit, a Stretford sulfur removal unit, SRC solidification facilities, and a coal grinding unit.

For the purpose of making economic and product quality studies of the SRC process as it might be used on a production scale with Alaskan coal, a conversion plant was designed to produce 100,000 barrels per day of solvent refined coal product, including the light liquids. Previous studies at SRI have indicated that coal processing plants of this general size tend to yield more economical performance than smaller ones. Economic and product quality estimates were made using traditional and SRI developed cost estimating methods using results from bench scale SRC units. An estimate of product yield, which is based on a bench scale run of a similar Alaskan coal, is shown in Table 3. This result shows that 89.5 percent of the coal is converted on an ash free coal basis.

The important properties of the two marketable products from the SRC process are shown in Table 4. A comparison of the SRC product with the as-mined coal, Table 1, shows that the ash has been reduced from 9.9 percent to 0.1 percent and that the heating value has been more than doubled from 7,200 Btu per pound to 15,700 Btu per pound. It is stressed that these product quality estimates are preliminary because they are based on limited data of Beluga-area coals and on the performance of only a bench-scale SRC process unit.

In order to estimate the cost of the SRC process, the costs of the input raw materials, primarily coal and hydrogen, must be known. Coal costs were previously estimated to be about $5.32 per ton (Table 2) at the mine mouth. The necessary hydrogen, 2,000 to 2,300 scf per barrel of product (Table 3), would be supplied most economically from natural gas by steam reforming. Current estimates indicate that there are about 2.4 trillion cubic feet of uncommitted reserves of natural gas in the Cook Inlet near this project area. (This is a relatively unique picture compared with the gas shortage in the lower 48 states.) Over the life of this development, between .45 and .50 trillion cubic feet of natural gas would be needed, so that as of this time sufficient hydrogen resources exist.

The economic analysis has assumed that coal delivered to the conversion plant will cost $5.67 per ton (see following section) and that natural gas at the conversion plant will cost 65 cents per 1,000 cubic feet. The plant will operate 347 days per year and will produce 100,000 barrels per day of total product.*

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* For total liquid product, daily production is 69,100 barrels of liquid solvent refined coal and 30,900 barrels of light liquids. For mixed solid/liquid product, daily production is 15,000 tons of solid refined coal and 30,900 barrels of light liquids.

Table 3

PILOT PLANT YIELDS
BELUGA AREA COAL

	Dried Feed Coal Basis (weight percent)
Heavy SRC	43.8
Light liquids	12.2
Ash plus carbon residue	26.6
H_2S	Trace
CO_2	3.1
C_1-C_4 gases	6.4
Water phase	8.6
Total	100.7

Coal converted (% feed coal basis)	73.4%
Coal converted (% MAF coal basis)	89.5%
Hydrogen consumption	2,000 to 2,300 scf/barrel

Table 4

ESTIMATED PRODUCT PROPERTIES

	Light Liquids	Solvent Refined Coal
Gross heating value, Btu/lb	19,400	15,700
Density, lbs/barrel	270-280	430-440
Sulfur, wt%	0.1	0.2
Nitrogen, wt%	0.2	1.9
Ash, wt%	--	0.1
Boiling range, °F	100-450	450'
Viscosity, CP at 300°F		~ 10

8

The necessary support facilities have been included in the cost analysis of the coal conversion complex. Electrical power for both the conversion process and to power a train to bring coal from the mine is produced by a steam turbine generating facility. Sulfur is recovered by Claus units. For the case of a solid solvent refined coal product, belt coolers are used for the solidification step. For liquid solvent refined coal products, tanks that are steam heated and insulated are used for storage.

Construction and labor costs in remote, climatically harsh locations, such as the Beluga site, can increase the uncertainty in the economic analysis. Construction and operating cost estimates are based on SRI experience from past studies, on interviews with firms currently operating in Alaska, and on information gathered from state and federal agencies in Alaska. However, these estimates should only be considered to be preliminary results whose accuracy can be significantly improved as additional operating and construction experience is accumulated in Alaska.

The results of this economic analysis are shown in Table 5 for both a nonregulated producer (at 10 percent and 15 percent DCF) and a regulated producer (whose gross return is 10.5 percent of average rate base).* The regulated producer can produce the refined coal product for $1.15 per million Btu for total liquid product and $1.17 per million Btu for solid solvent refined coal/light liquid product. These prices include mining and transporting coal to the processing site.

Conclusions of this preliminary analysis show that plant and support facilities for a liquid solvent refined coal product require an investment of between $470 and $480 million, while plant and support facilities for a solid solvent refined coal product cost $485 to $495 million. This capital-intensive venture results in a product whose costs are very sensitive to the capital market conditions and to the type of financial structure (regulated versus nonregulated) of the developer.

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* A regulated producer is one operating as a public utility. Because it is granted certain market concessions by the government, it can operate at lower costs. A nonregulated producer is one that operates in a competitive market.

Table [illegible]

SUMMARY OF BASE CASE RESULTS
SOLVENT REFINED COAL

	Liquid (100,000 B/day)	Solid (19,300 T/day)
Nonregulated producer		
15% DCF return		
Required selling price*		
Cents/million Btu	171¢	174.5¢
Dollars/ton	$49.9	$50.9
Dollars/barrel	$10.8	--
10% DCF return		
Required selling price*		
Cents/million Btu	142¢	144¢
Dollars/ton	$41.3	$42.1
Dollars/barrel	$8.95	--
Regulated producer		
Required selling price*		
Cents/million Btu	115¢	117¢
Dollars/ton	$33.6	$34.1
Dollars/barrel	$7.26	--

Coal price: $5.67/ton

Natural gas price: $0.65/1,000 cubic feet

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* Total product basis.

Site and Transportation

Because the area of the Beluga coal deposit is currently undeveloped, there is considerable choice in the location of the processing plant and shipping dock. Since no transportation facilities currently exist in the region, the transportation mode(s) between mine and processing plant and between processing plant and dock are also open to selection.

Figure 2 shows several of the plant and dock sites considered, as well as possible transportation links. Five possible locations were considered: the North Foreland-Granite Point area, the Kenai Peninsula-Nikiski area, the Anchorage-Port MacKenzie area, the Seward area (including sites at Fourth of July Creek and at the head of the fjord), and the Whittier area (north side of fjord and Shotgun Cove). A number of modes were considered to move coal to each of these sites including railroad (new and/or existing), slurry pipeline, trucks, and belt conveyors.

The location of the processing site should be based on many factors in addition to transportation economics. A suitable townsite (new or existing) needs to be available to workers in the processing plant. Because it will be necessary to ship large quantities of solvent refined coal product, the ability of the dock and ship channel to accommodate large ships is important. The coal conversion and docking facility will have a 20-year life, so it ought to be located in an area that is not exposed to excessive earthquake damage. Such factors were studied by a team of transportation specialists during an inspection trip to Alaska.

North Foreland, on the northern shore of Cook Inlet, has been selected as the preliminary site for the coal conversion plant and marine terminal. The aerial photograph in Figure 3 shows the North Foreland area in the foreground. The coal deposits lie to the north near the foot of the mountains.

It was determined that a single track railroad employing high voltage AC locomotives with regenerative braking might be used to carry to coal from the mine to the processing plant. On return trips to the mine, the train can carry fuel, supplies, equipment, and ash (from the SRC plant). This railroad system, which will cost about $45 million, will haul coal to the processing plant for about 35 cents per ton.

A marine loading terminal was designed for ocean going vessels. This facility would load liquid or solid solvent refined coal into ships for

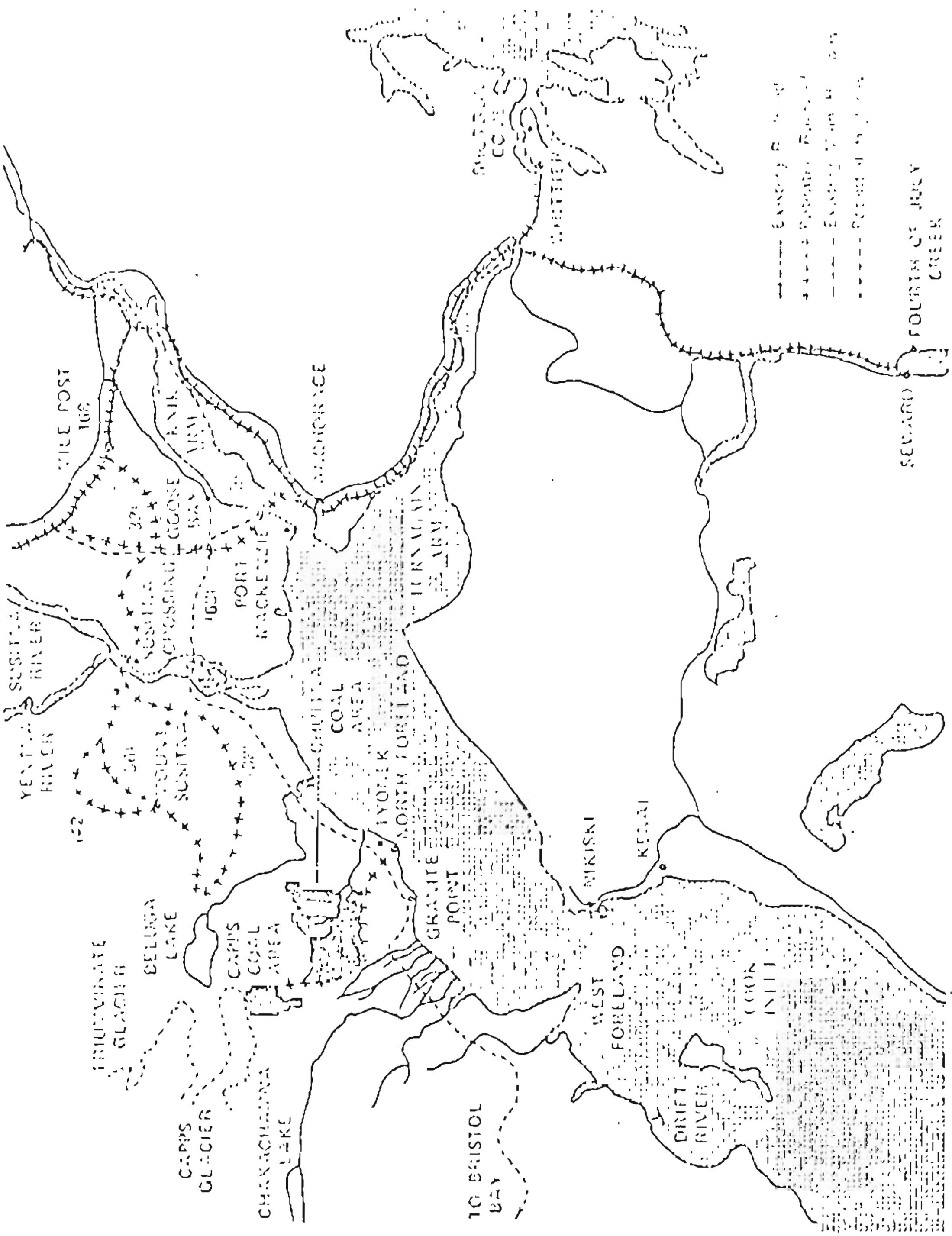

FIGURE 2 BELUGA PORT AND TRANSPORTATION ALTERNATIVES

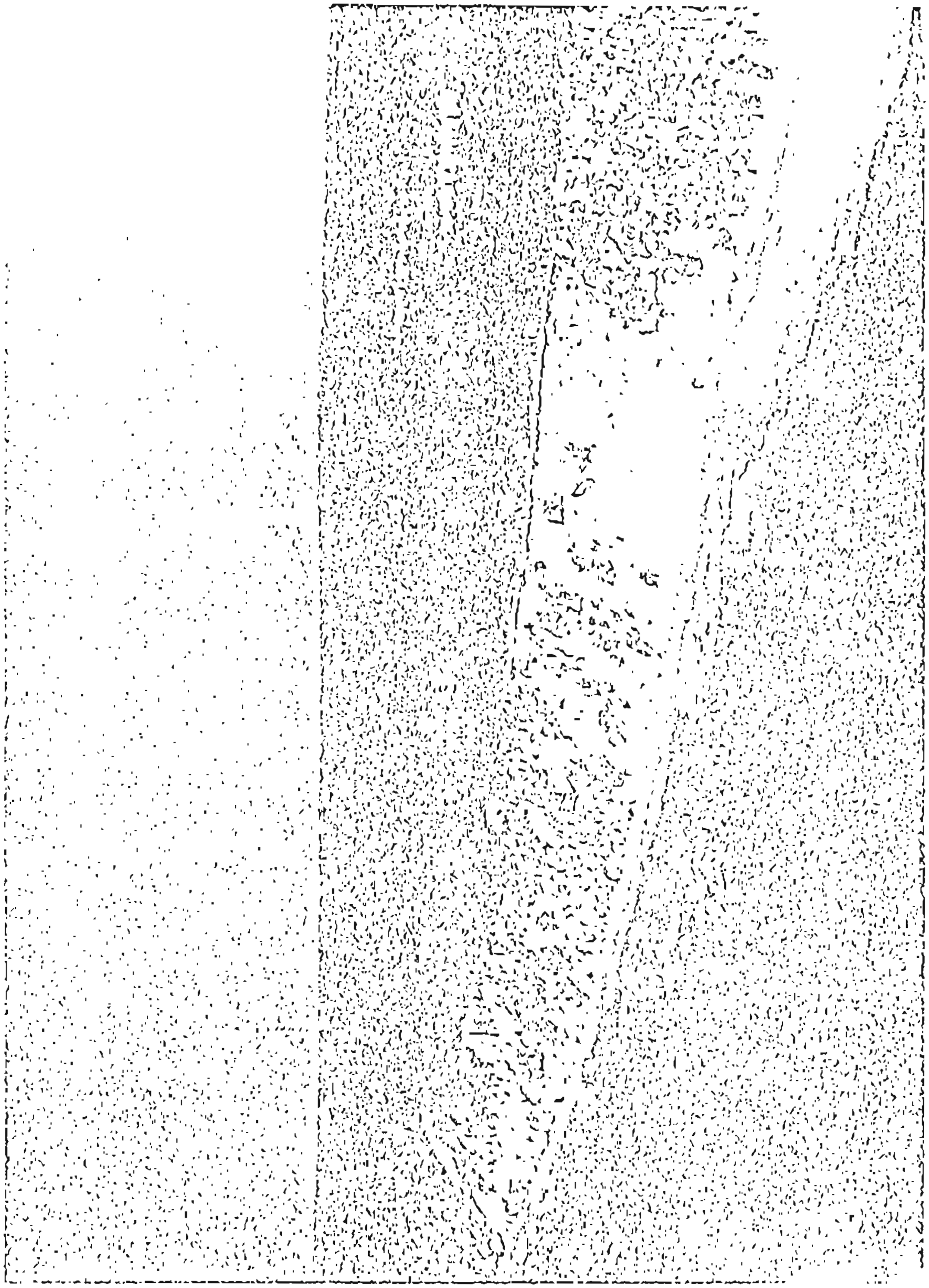

FIGURE 3 AERIAL VIEW OF NORTH FORELAND AREA

about $2 per long ton. A fleet, composed of ships of 100,000 DWT class, was designed to carry solvent refined coal product to both Japan and the United States (Long Beach, California). For the Japanese trade, ships were of Japanese manufacture and crew. For the U.S. trade, ships were of U.S. manufacture and crew. Table 6 shows the estimated costs for transporting both coal and solvent refined coal product to Japan and California. In these preliminary studies, liquid solvent refined coal appears to have slightly lower transportation costs than solid solvent refined coal because of lower investment cost of handling of a liquid cargo than of a solid cargo.

Table 6

MARINE TRANSPORTATION COSTS
PER LONG TON[a]

	Kawasaki, Japan	Long Beach, California
Coal	$5.85	$4.90
Dry SRC	6.00	4.90
Liquid SRC	5.45	4.70

* FIO (free in and out costs)--excludes cargo handling costs.

Markets for Solvent Refined Coal

In order for the development of the Beluga coal deposits to be practical, an adequate market must exist for the refined product. Within this market, the coal product must be cost competitive with similar fuels. For these reasons, a preliminary study was made of energy market trends in Japan and on the West Coast of the United States and Canada.

The growth in demand for fossil fuels in the thermal electric and industrial sectors in California and Japan could potentially support several

100,000 barrel-per-day SRC plants. Table 7 shows that the growth in energy demand in these two markets is very substantial. In the California market, most demand will be in the southern region. Other Pacific rim areas, including British Columbia, Washington, Oregon, South Korea, and the Philippines will provide less significant markets for solvent refined coal because of small energy demand, indigenous fuel production, and/or reliance on hydroelectric resources.

Table 7

MARKET STUDY CONCLUSIONS

	Thousand B/Day Fuel Oil Equivalent Demand To 1980	1980 to 1990
Japan	2,100	3,000
California	390	450
Other Pacific rim countries	170	230

An estimate of costs of competitive fuels in constant 1974 U.S. dollars is given in Table 8 (California) and Table 9 (Japan). The estimated total cost of solvent refined coal products delivered to each of these markets is shown in Table 10. These values, which vary between $1.60 and $1.80 per million Btu depending upon the financial structure of the producer, upon the product type, and upon the destination, are the sum of mining, conversion, and transportation costs. They include a credit of 28 cents per gallon for the light hydrocarbon liquids produced in the SRC process. These results indicate that solvent refined coal delivered to California or Japan (Figure 4) would be competitive with petroleum fuel oils at the current price of $11 per barrel ($1.75 per million Btu). Although petroleum prices may decline as North Slope and outer continental shelf reserves are developed, the potential minimum cost of solvent refined coal products is sufficiently low to remain competitive. Thus, it appears that the development of this coal conversion complex is potentially economically feasible.

Table 8

PRICES OF COMPETITIVE FUELS
U.S. WEST COAST TERMINALS
(Constant 1974 U.S. Dollars)

	Current	1980-85
Naphtha, ¢/gallon	31-34¢	22-27¢
Heavy fuel oil, $/barrel	$7.50-11.00	$9-10
Heavy fuel oil, $/MM Btu	$1.19-1.75	$1.43-1.59
Crude oil, $/barrel	$8.00	$6.00-8.00

Table 9

PRICES OF COMPETITIVE FUELS, JAPAN
(Constant 1974 U.S. Dollars)

	June Imports	Government Wholesale Maximum	1980-85
Naphtha, ¢/gallon	37.06¢	27.30¢	20-25¢
Heavy fuel oil, $/barrel	$14.28	$11.00	$8.00-9.00
Heavy fuel oil, $/MM Btu	$ 2.27	$ 1.75	$1.27-1.43
Crude oil, $/barrel	$11.42		$6.50

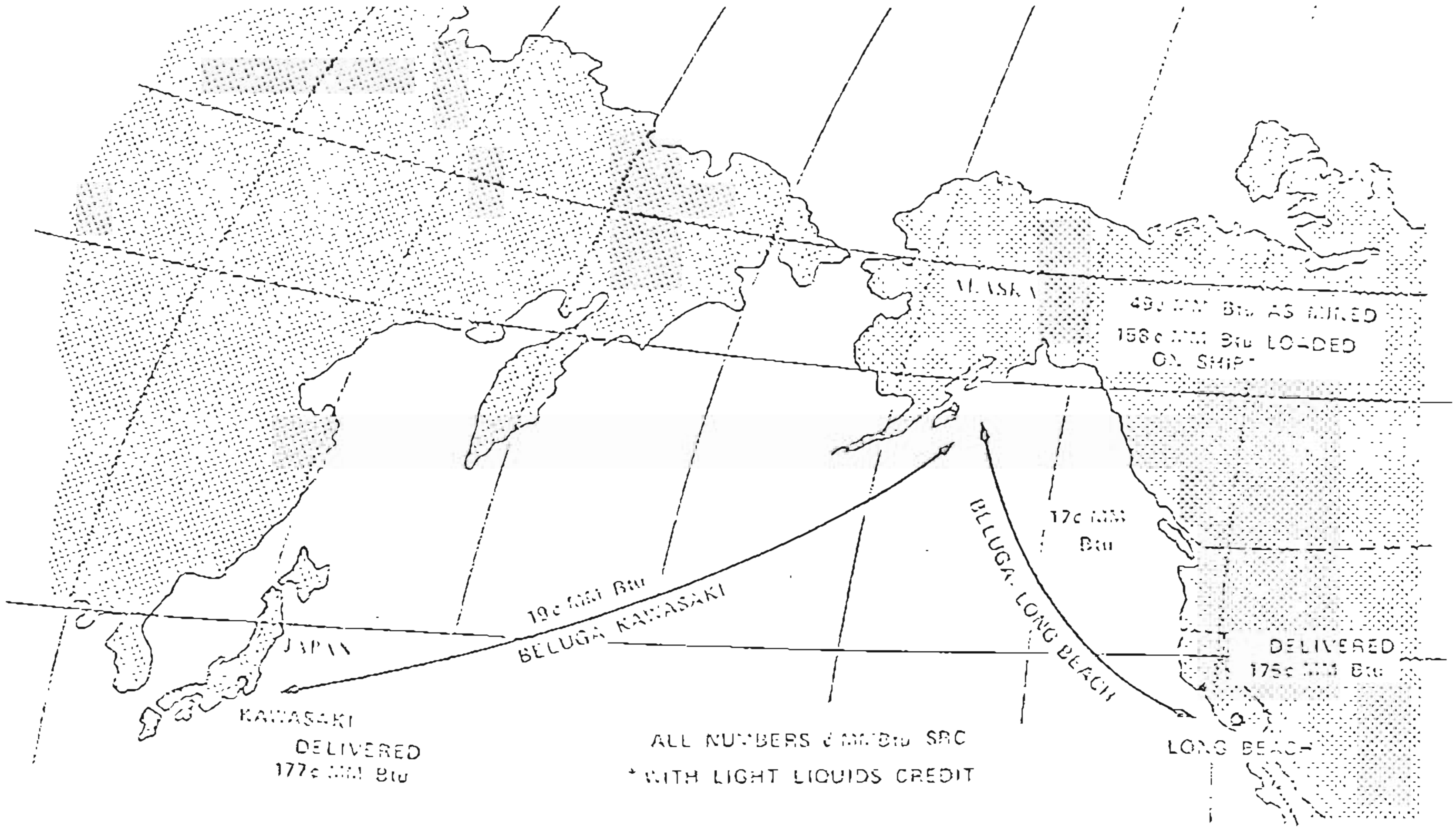

FIGURE 4 COST COMPONENTS OF DELIVERED LIQUID SOLVENT REFINED COAL*

Table 10

SUMMARY OF DELIVERED COSTS
(Constant 1974 U.S. Dollars)

	U.S. West Coast ($/MM Btu)	Japan ($/MM Btu)
Beluga coal	$0.85	$0.91
Liquid SRC		
Utility financing	1.00	1.02
15% DCF ROI	1.75	1.77
Solid SRC		
Utility financing	1.04	1.07
15% DCF ROI	1.81	1.84
Petroleum fuel	1.19-1.75	1.75

The development of these coal reserves may spur the emergence of a large, coal-based synthetic fuels industry. Such development would ensure a steady, reliable source of clean energy to the potentially large future markets in California and Japan. Based on this preliminary analysis, these synthetic fuels may compete favorably with other clean fuels at current prices. Further developments in coal conversion technology may improve the market position of these fuels.

CHANGING ECONOMICS OF ALASKAN COALS [1]

by

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The increase in energy prices in the United States has generated a renewed interest in Alaska's coal. Indeed, our purpose in meeting here this week is to take an updated look at Alaskan coals, their distribution, geology, characteristics, and economics. My approach to appraising the changing economics of Alaskan coals is to estimate the cost of producing one million tons of coal annually in four different areas of Alaska, project these costs to 1978, and compare them with the estimated cost of producing oil and gas.

The timeframe for making these cost estimates was fairly short. But this seems to be the way the world is going now; more people want more answers to more complicated questions more quickly, preferably yesterday. The proper evaluation of a coal deposit is a costly endeavor. Time, money and Bureau policy preclude our making a proper evaluation of each deposit for which cost data is requested. Such an evaluation requires an exploration and drilling program followed by bulk sampling and coal preparation testing to determine the characteristics of a specific deposit. Such a program of exploration, drilling, sampling, and testing requires a minimum of one year. A more realistic estimate is two or three years. The estimated cost of producing coal from one specific deposit based on such an evaluation is probably within 5 to 10 percent the actual cost.

An alternative to a proper evaluation is one in which the engineer assumes he knows the vital information gleaned from exploration, drilling, sampling and testing. Here, the geology is assumed to be similar to an adjacent area for which a description exists, and the nature of the overburden is assumed to be competent for underground mining or strippable for surface mining. We feel an evaluation of this type, where the important parameters are assumed, the capital costs for the mining and cleaning equipment are determined, and the manpower and other operating costs are derived, requires approximately three man-months per property. The estimated cost resulting from this type of evaluation is probably accurate to within plus or minus 20 percent.

More recently, the time allowed for estimating the cost of producing from deposits or areas has shortened from three months to as little as three days. Requests for cost estimates come from both industry and government. Companies that have never operated in Alaska are asking what level

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[1] A paper presented at the Alaskan Conference on Coals, University of Alaska, Fairbanks, October 15-17, 1975.

of costs they can expect to see should they attempt to develop certain properties. They want to know what factors drive up the cost of Alaskan development. But often the one thing they are really seeking is a number they can relate to other properties being considered elsewhere in Alaska, the Lower 48, or abroad. Government agencies are more concerned about general areas rather than specific properties; however, their requests bear one resemblence to industry requests--a short time for making the determination.

What should be done about these requests? Should we try to convince those seeking information their requests are unreasonable in the timeframe available? Should we suggest their questions be made into beautiful research projects of almost any time or money duration, preferably ones lasting one or two years? Or, should we shrug our shoulders and ignore the requests? This last ploy works well until one's own agency initiates a program which demands the generation of cost data for every known resource.

One quick and dirty solution we have devised for answering these "quicky requests" is the updating of past studies to the present, and then Alaskanizing the data. The ingredients required are a study paralleling the property at hand, the capital and operating costs including depreciation, a profitability factor and finally, indexes, specifically a construction index, an operating index, and an Alaskanizing index. A proper massaging of the various ingredients will produce a dry data powder which my wife insists engineers thrive upon. As word of your dry data spreads, you will find yourself immersed in water heated by the friction you've created with your numbers. This concoction of dry data powder and hot water may be recognized at a distance as "hot index soup," a substance which nourishes those asking for a quick handout and allows the engineer to beat a hasty retreat back to his present one-year project in hopes that all will be forgotten soon.

Let's see how to apply "soup indexes" to the present question: what are the economics of producing coal in Alaska today and how do the costs compare with other fuels? With only one operating coal mine in the State there is precious little data to draw upon, thus another reason why "soup indexes" are used. Even if a full working knowledge of that one coal mine were available, we would still be guessing at the costs entailed in producing coal elsewhere in the State. Since this would not solve the problem, let's look at the data available to derive costs for mining in the Beluga, Jonesville, Healy, and Attigun areas. Fortunately two detailed coal studies published by the Bureau of Mines for the Lower 48 provide a basis to begin our study. The first is IC 8535 entitled "Cost Analyses of Model Mines for Strip Mining of Coal in the United States," and the second is IC 8632 entitled "Basic Estimated Capital Investment and Operating Costs for Underground Bituminous Coal Mines." Since capital and operating costs were derived in 1969 and 1973, they have to be updated to 1975. The Chemical Engineer Plant Cost Index is used for updating capital costs and the Nelson Refinery Process Index published in the Oil and Gas Journal is used for updating operating costs. Estimating current costs using these indexes is enough to put us in hot water. Moving the mines to Alaska presents the most questionable part of the study, and this puts us in the soup. Moving is done via an index map currently under development at the Alaska Field Operation Center in Juneau. Soup indexes for the State were derived by the author based upon previous mining economic studies, the U.S. Army's Military Pricing Guide, and a file on construction costs of buildings completed around the State. Probably cost estimates using soup indexes may be no closer than plus or minus 33 percent.

For the Attigun area on the North Slope of the Brooks Range, we used as our model an underground bituminous coal mine producing 1.06 million tons of coal annually from a 6-foot coal seam (fig. 1). Using soup indexes of 2.10 for capital costs and 2.04 for operating costs over those in the Lower 48, we obtained capital costs of $40.4 million, $19.7 million for operating costs, and $2.5 million for depreciation. These costs include high wages and the assumptions that 243 underground miners will come to the mine to work. For 12, 15 and 20 percent DCF rates of return on investment, selling prices of $22.27, $23.59 and $25.90 per ton, respectively, were required, or $1.48, $1.57 or $1.73 per million Btu's based on coal having 7,500 Btu's per pound.

For estimating the cost of mining one million tons of soft coal annually in the Healy area, we used as our model a subbituminous strip mine in Montana (fig. 2). A 25-foot seam of coal was overlain by an average of 75 feet of overburden. We reduced the scale of the model from five million tons per year to one million using the six-tenths factor. Using soup indexes of 1.43 for plant construction and 1.62 for plant operation, we derived total capital costs of $11.4 million, operating costs of $7.2 million, and depreciation costs of $0.8 million. For 12, 15 and 20 percent DCF rates of return on investment, we derived selling prices of $8.21, $8.60, and $9.30 per ton, respectively, or 48, 51 and 55 cents per million Btu's based on coal having 8,500 Btu's per pound. Again, these are average prices for coal on an as received basis for on-site power generation.

For the Jonesville area, we used as our model an underground mine producing 1.06 million tons of bituminous coal annually from a 6-foot seam (fig. 3). Using soup indexes of 1.26 for plant construction and 1.54 for plant operation over the Lower 48 costs, plant investment came to $24.2 million; plant operation, $14.9 million; and depreciation $1.5 million. For a 12 percent DCF rate of return on investment, the price required was $16.25 per ton or 65 cents per million Btu's. For 15 and 20 percent DCF rates of return on investment, the required selling prices were $17.03 and $18.42 per ton or 68 and 74 cents per million Btu's based on coal having 12,500 Btu's per pound. These may be optimistic estimates for mining Jonesville coal owing to the steep dip of the beds.

For the Beluga area, the analogy of a strip mine in Montana producing 5 million tons of coal annually from a 25-foot seam of subbituminous coal was used (fig. 4). Overburden averaged 75 feet. This mine scale was reduced to one million tons annually using the six-tenths factor. Using indexes of 1.68 for construction and 1.74 for operation, the final capital costs became $13.4 million, operating costs were $7.7 million, and depreciation $0.9 million. The final required selling prices at 12, 15 and 20 percent DCF rates of return on investment were $8.92, $9.39, and $10.20 per ton, respectively. This works out to 59, 63, and 68 cents per million Btu's based upon 7,500 Btu's per pound.

Up to this point we have estimated the prices required to produce about one million tons of coal annually for on-site power generation. As the Beluga area is a likely spot for development in the near future, let's look at the cost to produce 1, 3, and 5 million tons of coal annually, and bring it to the coast for export from Alaska (fig. 5). As our model, we again used a five million ton-per-year mine in Montana producing from a 25-foot seam and having an average overburden of 75 feet. Using our soup indexes for the Beluga area we obtained total capital costs of $35.2 million for the five million ton-per-year mine, $25.9 million for the three million ton-per-year mine, and $13.4 million for the one million ton-per-year mine. To install a 35 mile railroad with sufficient locomotives, cars, unloading facilities, and docking facilities for the largest mine required $38.4 million; for the middle-size mine, $32.9 million; and the smallest mine, $28.6 million. The addition of the export facilities raised the price for coal produced by the five million ton-per-year mine from $5.36 to $8.47 per ton, or from 37 to 56 cents per million Btu's. The price required for the product from the three million ton-per-year mine went from $6.57 to $11.01 per ton, or from 44 to 73 cents per million Btu's. The price for coal produced from the smallest mine went from $10.20 to $22.12 per ton, or from 68 cents to $1.47 per million Btu's.

Now that we have looked at the estimated costs to produce coal in four areas of the State, let's project those costs to 1978 and compare them to the cost of producing oil and gas. Our very rough estimates of coal prices indicate that with a 20 percent DCF rate of return on investment, one million tons of coal can be mined for power generation in the Attigun area for $1.73 per million Btu's, at Healy for 55 cents, at Jonesville for 74 cents, and at Beluga for 68 cents. Assuming a 10 percent inflationary rate during the next three years, coal could be available in the Attigun area for $2.30 per million Btu's, at Healy for 73 cents, at Jonesville for 98 cents, and at Beluga for 90 cents.

An article in the September 15 issue of the Oil and Gas Journal estimated the cost of finding and developing natural gas in 1975 at $1.19 per million Btu's, and estimated the price would increase to $1.51 per million Btu's in 1978. The average weighted cost of all crude oil received in U.S. refinery inventories for July was $10.47 per barrel or about $1.75 per million Btu's. By 1978, average oil prices in the U.S. may be much higher.

From our use of soup indexes, it would appear that Alaska's low sulfur coals having a price of less than $1.50 per million Btu's may become attractive sources of energy by 1978. In the case of the Beluga coals, any mine producing one million tons of coal per year, or more, may be an attractive source for on-site power. However, only very large mines will be economical if the coal is to be exported from Alaska.

FIGURE 1.- Coal mining costs in the Attigun area for power generation

Example: Underground mine producing 1.06 million tons of bituminous coal annually (IC 8632)

Assumptions: Six feet of coal, 57% recovery, continuous miners, 20-year life

1973 costs to February, 1975:	plant construction	= 179.5/144.1 = 1.25
	plant operation	= ([(257.5/168.0)-1].45) + 1 = 1.24
Lower 48 to Attigun:	plant construction	= 1.89 ÷ 9 = 2.10
	plant operation	= 1.84 ÷ 9 = 2.04

Plant investment:	\$15,376,700 x 1.25 = \$19,221,000 x 2.10 =	\$40,364,000
Plant operation :	\$ 7,793,900 x 1.24 = \$ 9,664,000 x 2.04 =	\$19,715,000
Depreciation :	\$ 945,400/\$15,376,700 = 0.0615 x \$40,364,000 =	\$ 2,482,000

For 12% DCF rate of return:	
R=plant investment ÷ 7.469	\$ 5,404,000
Less depreciation	2,482,000
Depletion + net profit	2,922,000
Depletion + net profit = 3/4 gross profit	
Gross profit = 1.333 x (depletion + net profit)	3,895,000
Plus plant operation	19,715,000
Sales	\$23,610,000
Selling price/ton	22.27
Price per MMBtu @7,500 Btu/lb	1.48

For 15% DCF rate of return:	
R=plant investment ÷ 6.259	\$ 6,449,000
Sales	\$25,003,000
Selling price/ton	23.59
Price per MMBtu @7,500 Btu/lb	1.57

For 20% DCF rate of return:	
R=plant investment ÷ 4.870	\$ 8,288,000
Sales	\$27,454,000
Selling price/ton	25.90
Price per MMBtu @7,500 Btu/lb	1.73

FIGURE 2.- Coal mining costs in the Healy area for power generation

Example: Strip mine producing 5 million tons of subbituminous coal annually, Wyoming (IC 8535)

Assumptions: Plus 500 million tons of coal, 25-foot seam, up to 120 feet of overburden, 75-foot average, 20-year life

1969 costs to February, 1975: plant construction = 179.5/119.0 = 1.51
plant operation = ([257.5/102.5)-1].45) + 1 = 1.68

Lower 48 costs to Beluga area: plant construction = 1.43
plant operation = 1.62

Plant investment: \$13,879,100 ÷ 2.63 = \$5,277,000 x 1.51; \$7,968,000 x 1.43 = \$11,394,000
Plant operation : \$ 6,943,400 ÷ 2.63 = \$2,640,000 x 1.68; \$4,435,000 x 1.62 = \$ 7,185,000
Depreciation : \$ 920,600/\$13,879,100 = 0.0663 x \$11,394,000 = \$ 755,000

For 12% DCF rate of return:	
R=plant investment ÷ 7.469	\$ 1,526,000
Less depreciation	755,000
Depletion + net profit	771,000
Depletion + net profit = 3/4 gross profit	
Gross profit = 1.333 x (depletion + net profit)	1,028,000
Plus plant operation	7,185,000
Sales	\$ 8,213,000
Selling price/ton	8.21
Price per MMBtu @8,500 Btu/lb	0.48

For 15% DCF rate of return:	
R=plant investment ÷ 6.259	\$ 1,820,000
Sales	\$ 8,605,000
Selling price/ton	8.6
Price per MMBtu @8,500 Btu/lb	0.51

For 20% DCF rate of return:	
R=plant investment ÷ 4.870	\$ 2,340,000
Sales	\$ 9,298,000
Selling price/ton	9.3
Price per MMBtu @8,500 Btu/lb	0.5

FIGURE 3.- Coal mining costs in the Jonesville area for power generation

Example: Underground mine producing 1.06 million tons of bituminous coal annually (IC 8632)

Assumptions: Six feet of coal, 57% recovery, continuous miners, 20-year life

1973 costs to February, 1975:	plant construction	= 179.5/144.1 = 1.25
	plant operation	= ([(257.5/168.0)-1].45) + 1 = 1.24
Lower 48 costs to Jonesville:	plant construction	= 1.26
	plant operation	= 1.54

Plant investment:	$15,376,700 x 1.25 = $19,221,000 x 1.26 =	$24,218,000
Plant operation :	$ 7,793,900 x 1.24 = $ 9,664,000 x 1.54 =	$14,883,000
Depreciation :	$ 945,400/$15,376,700 = 0.0615 x $24,218,000 =	$ 1,489,000

For 12% DCF rate of return:	
R=plant investment ÷ 7.469	$ 3,242,000
Less depreciation	1,489,000
Depletion + net profit	1,753,000
Depletion + net profit = 3/4 gross profit	
Gross profit = 1.333 x (depletion + net profit)	2,337,000
Plus plant operation	14,883,000
Sales	$17,220,000
Selling price/ton	16.25
Price per MMBtu @12,500 Btu/lb	0.65

For 15% DCF rate of return:	
R=plant investment ÷ 6.259	$ 3,869,000
Sales	$18,056,000
Selling price/ton	17.03
Price per MMBtu @12,500 Btu/lb	0.68

For 20% DCF rate of return:	
R=plant investment ÷ 4.870	$ 4,973,000
Sales	$19,527,000
Selling price/ton	18.42
Price per MMBtu @12,500 Btu/lb	0.74

FIGURE 4.- Coal mining costs in the Beluga area for power generation

Example: Strip mine producing 1 million tons of subbituminous coal annually, (Wyoming (IC 8535)

Assumptions: Plus 500 million tons of coal, 25-foot seam, up to 120 feet of overburden, 75-foot average, 20-year life

1969 costs to February, 1975: plant construction = 179.5/119.0 = 1.51
plant operation = ([(257.5/102.5)-1].45) + 1 = 1.68

Lower 48 costs to Beluga area: plant construction = 1.68
plant operation = 1.74

Plant investment: $13,879,100 ÷ 2.63 = $5,277,000 x 1.51 = $7,968,000 x 1.68 = $13,386,000
Plant operation : $ 6,943,400 ÷ 2.63 = $2,640,000 x 1.68 = $4,435,000 x 1.74 = $ 7,717,000
Depreciation : $ 920,100/$13,879,100 = 0.063 x $13,386,000 = $ 887,000

For 12% DCF rate of return:	
R=plant investment ÷ 7.469	$ 1,792,000
Less depreciation	887,000
Depletion + net profit	905,000
Depletion + net profit = 3/4 gross profit	
Gross profit = 1.333 x (depletion + net profit)	1,206,000
Plus plant operation	
Sales	$ 8,923,000
Selling price/ton	8.9
Price per MMBtu @7,500 Btu/lb	0.5

For 15% DCF rate of return:	
R=plant investment ÷ 6.259	$ 2,139,000
Sales	$ 9,386,000
Selling price/ton	9.3
Price per MMBtu @7,500 Btu/lb	0.6

For 20% DCF rate of return:	
R=plant investment ÷ 4.870	$ 2,749,000
Sales	$10,199,000
Selling price/ton	10.2
Price per MMBtu @7,500 Btu/lb	0.6

FIGURE 5.- Comparison of power facilities versus export facilities at Beluga

Annual production (tons)	Mine cost for power generation	Cost of transportation facilities	Total cost
5,000,000	$35.2 million	$38.4 million	$73.6 million
3,000,000	$25.9 million	$32.9 million	$58.8 million
1,000,000	$13.4 million	$28.6 million	$42.0 million

Price required for coal at 20% DCF

Annual production (tons)	Power generation	f.o.b. tidewater, Cook Inlet
5,000,000	$5.36 per ton (37¢MMBtu's)	$8.47/ton (56¢/MMBtu's)
3,000,000	$6.57 per ton (44¢/MMBtu's)	$11.01/ton (73¢/MMBtu's)
1,000,000	$10.20 per ton (68¢/MMBtu's)	$22.12/ton (147¢/MMBtu's)