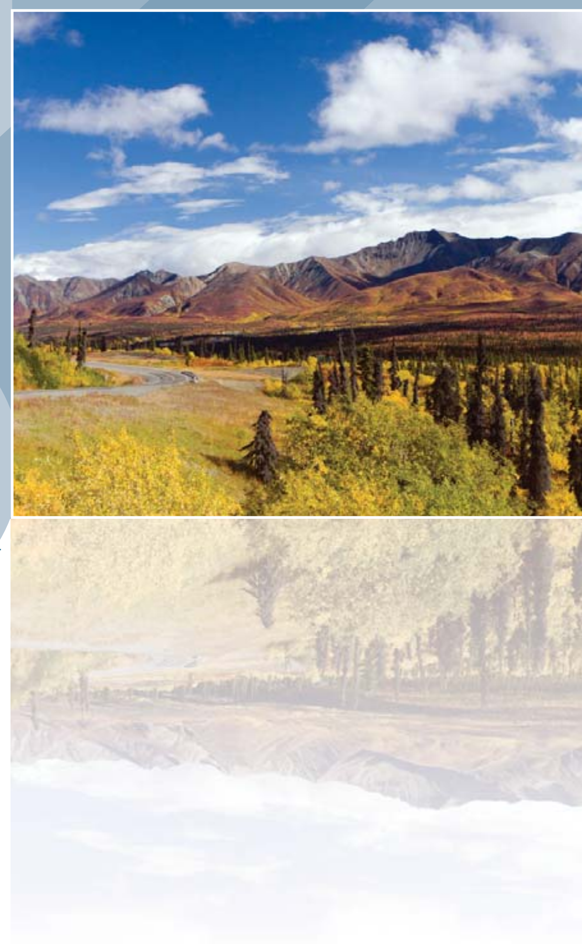

In-State Gas Demand Study
Volume II: Appendices

Prepared for

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Northern Economics
Wisdom • Trust • Relevance • Innovation

In association with

- Institute of Social and Economic Research, University of Alaska
- Science Applications International Corporation

Appendix A: MAP Model Methodology, Assumptions, and Projection Summary

Appendix A: MAP Projection Methodology, Assumptions, and Projection Summary

MAP Projection Methodology

The projections of economic, demographic, and fiscal variables for the state of Alaska and its regions have been generated using the Institute of Social and Economic Research (ISER) MAP Model. The MAP Model, or Man-in-the-Arctic Model, was originally created in 1975 with funding from the National Science Foundation to investigate the impacts of petroleum development on the state. (See Kresge, David and Seiver, Daniel. "Planning for A Resource Rich Region: The Case of Alaska" American Economic Review, 68(20), p 99-104. Kresge, David, Morehouse, Thomas, and Rogers, George. Issues in Alaska Development, University of Washington Press, 1977. Kresge, David et al. Regions and Resources: Strategies for Development, MIT Press, 1984.)

The model has been in continuous use since that time as the most sophisticated and comprehensive tool for projecting the long term future economic, demographic, and fiscal conditions in the state. The model components are constantly revised and updated to reflect the most current economic, demographic, and fiscal conditions.

Sometimes the model is used to analyze the impacts of a particular development or activity, such as the construction of a gas line, or to investigate the implications of a particular assumption about future economic conditions facing the state, such as the future price of oil. (For example, *Economic Analysis of Future Offshore Oil and Gas Development: Beaufort Sea, Chukchi Sea, and the North Aleutian Basin*, prepared for the Shell Oil Company with Northern Economics, March 2009) At other times the model is used to project the most likely future trend in economic and demographic activity to assist in planning efforts like investing in new electrical generating facilities (For example, *Economic Projections for Alaska and the Southern Railbelt: 2005-2030*, prepared for Chugach Electric Association, September 2005). Consequently, interpretation of the projections must be contingent upon the purpose for which the particular study has been designed.

There are 5 components to the MAP model: the ECONOMIC DEVELOPMENT SCENARIO, the ECONOMIC MODULE, the DEMOGRAPHIC MODULE, the FISCAL MODULE, and the REGIONAL MODEL. (They have been completely documented in *ISER MAP Alaska Economic Modeling Documentation*, prepared for the US Department of Interior, June 1986, available from ISER)

The model is driven by an **ECONOMIC DEVELOPMENT SCENARIO** which is a consistent set of assumptions about levels of future basic industry activity within the state, national variables, state fiscal policy variables, and other exogenous factors that are expected to influence the future pattern of economic and demographic trends. The scenario elements are compiled into a document that is an integral part of each projection.

The scenario elements are typically developed by the author in consultation with other Alaskan researchers in the private and public sectors as well as the client for whom the projection is being prepared.

The scenario elements for basic sector economic activity are a collection of both project-specific assumptions and generic industry assumptions. A typical project-specific element is the construction and operation of a gold mine at Fort Knox near Fairbanks while a typical generic element is the assumption of employment growth in the mining industry from projects not currently identified. In recognition of the fact that myopia prevents the identification of all potential projects that may occur over the next 20-50 years, there is a conscious effort in the creation of the scenarios to account for this bias through the inclusion of the generic elements. These generic elements have been developed to be as consistent as possible with historical patterns of industrial activity.

Past experience has shown that there are numerous combinations of scenario elements which, when combined into an ECONOMIC DEVELOPMENT SCENARIO, will yield essentially identical economic and demographic projections. This underscores the robustness of the method of dividing the scenario into a large number of assumptions, each of which individually has a small influence on the outcome.

(An example of this type of analysis is contained in *Economic and Demographic Projections for the Alaska Railbelt: 1988-2010*, for the Alaska Power Authority, August 1988).

At the same time, the projection results are quite sensitive to a small number of scenario assumptions. These include the rate of production and price of oil, the growth in average real wage rates in the US, and the growth of the non wage income of Alaska households.

The **ECONOMIC MODULE** takes the ECONOMIC DEVELOPMENT SCENARIO as input and produces projections of employment, payroll, and gross product by industry based upon econometrically determined relationships. Activity in the basic sectors of the economy, including primarily the natural resource producing sectors, federal spending, and tourism spending, generates payroll and other spending that, with other elements of personal income, results in employment and payroll in the support sectors. The support sectors are composed of portions of the service, trade, construction, utility, transportation, and finance industries.

Total employment is the sum of jobs in the basic and support sectors as well as state and local government and the self employed. Total labor income consists of wages and salaries, the income of the self employed, and supplements to wages (public and private benefits). Total personal income is the sum of labor income reduced by non resident earnings, dividends-interest-rent, and transfer payments. Total personal income ultimately determines the level of household consumption and the total amount of support sector economic activity.

Labor demand drives the **DEMOGRAPHIC MODULE** through changes in migration into the state. The size and age-sex-race composition of the population changes over time as a result of both natural increase (births minus deaths) and net migration. When employment growth increases the demand for labor, the supply of labor grows through an increase in net migration (in migrants minus out migrants) and vice versa. Labor force participation and household formation are both also age-sex-race specific. The demographic output is population and households by 5 year age cohorts by sex by race (Alaska Native and non-Native).

The **FISCAL MODULE** determines the revenues, expenditures, and employment of both state and local government, as well as the status of the Alaska Permanent Fund. The largest sources of revenues, petroleum taxes and royalties and federal grants, are derived from the ECONOMIC DEVELOPMENT SCENARIO. Projections of other revenues are determined within the module.

The level of state expenditures is determined by a set of rules that ensures a balance between revenues and expenditures over time. This is necessary because petroleum revenues will not be sufficient in the future to continue to fund a growing state budget. Consequently the ECONOMIC DEVELOPMENT SCENARIO includes assumptions about the growth rate of expenditures as well as the imposition of new taxes and the allocation of earnings of the Alaska Permanent Fund.

Local government spending is assumed to be equal to local government revenues.

The **REGIONAL MODEL** allocates a limited number of state projection variables—employment by major category, population, households, non labor income, and total personal income—to 27 census areas. This allocation is primarily based on the regional distribution of basic economic activity, included in the ECONOMIC DEVELOPMENT SCENARIO, and the historical pattern of population and income.

MAP Model Long Run Scenario Assumptions

Highlights:

- World oil price averages $100 (2009 $)
- Cumulative North Slope Oil Production = 4.1 Billion Barrels
- Henry Hub natural gas price averages $6.60 (2009 $)
- Gas pipeline operational in 2019 at 4.5 bcf/day
- OCS oil production from Beaufort Sea begins 2021
- Donlin Creek and Pebble Mines developed
- Active duty military force level trends slowly downward
- US recession slows Alaska economy in 2009 and 2010

A. BASIC INDUSTRY ASSUMPTIONS	
A.1. Petroleum	
1. Oil Price	Low sulfur light crude price averages $100 per barrel (2009 $) between 2009 and 2030 (Energy Information Administration, April 2009). This corresponds to an average wellhead price for North Slope crude of $98. (DOR.S08M).
2. North Slope Oil Production on State Lands (Colville to Canning)	Cumulative production of 4.1 billion barrels between 2009 and 2030 (Alaska Department of Natural Resources 2007 Annual Report). (DOR.S08M)
3. Employment (Petroleum and Construction) Associated with Oil Production on State Lands (Colville to Canning)	Constant employment thru 2025, then declining 2% per year (ONS.S08M)
4. Cook Inlet Petroleum Production	Employment constant thru 2020, then declining at 2% per year (OCI.S08M)
5. NPRA	Cumulative production of .5 billion barrels between 2009 and 2030. (NPR.S08M)
6. ANWR	None.
7. OCS	Exploration, development and production occur in the Beaufort and Chukchi Seas as well as the Aleutian Basin. Oil production begins in 2021 in the Beaufort rising to 700 million barrels per day by 2030 from all three areas. Gas production begins in 2024 in the Aleutian Basin and rises to .3 bcf per day by 2030 in all three areas. OCS development stimulates additional production from onshore state lands. (OCS.S08M)
8. Other Oil & Gas	Modest employment centered around Nenana and Copper River Basin. No significant production (OOT.S08M)
9. Trans-Alaska Pipeline	Pipeline continues to operate at current employment level (TAP.S08M)
10. Value Added Oil	Refining employment constant at current level.
11. Natural Gas Price	Henry Hub price averages $6.63 per mmbtu (2009$) between 2009 and 2030 (Energy Information Administration, April 2009) . (ONG.S08M)
12. North Slope Gas Pipeline	Gas pipeline along highway (including spur line) becomes operational in 2019 with initial capacity of 4.5 bcf per day to accommodate production from onshore fields. Subsequent modest capacity expansion allows for marketing of OCS gas (ONG.S08M)
13. LNG in Cook Inlet	Operational at reduced level thru 2018. (OOT.S08M)
14. Agrium Fertilizer	Not operational after 2008. (OMN.S08M)
15. In-state Gas Line (Bullet Line)	Not constructed

A.2. Mining	
1. Greens Creek Mine	Constant employment (MGC.S08)
2. Red Dog Mine	Constant employment (MRD.S08)
3. Pogo	Constant employment (MFG.S08)
4. Kensington Mine	Production begins in 2010 (MKN.S08M)
5. Fort Knox/True North	Production is constant through 2020, then declines 3% annually (MFK.S08)
6. Healy Coal for Export	Production constant (MHC.S08)
7. Livengood Mine	Production begins in 2015 (LIV.08M)
8. Donlin Creek Mine	Production begins in 2014 (MDK.08M)
9. Pebble Mine	Production begins in 2024 on modest scale (MPB.08M)
10. Beluga Coal Production	None
11. Matanuska Valley Coal	None
12. Other Mining Activity	Mining employment net of specifically identified projects increases by 2% annually (MOT.S08)
A.3. Seafood	
1. Commercial Fish Harvesting	Shore-based employment in fish harvesting is constant (SFH.S08M)
2. Commercial Fish Processing	Constant employment (SFP.S08M)
A.4. Tourism	
1. Tourism	Index of tourist visitor expenditures (measuring visitors, days, and real expenditures per visitor day) increases by 5% with visitor and employment growth of 2.5% thru 2025 then 1.5%. Tourism-related infrastructure development grows 2% annually thru 2015 and then 1% (TRN.S08M)
A.5. International Freight Handling	
1. Air Transport Employment	Employment at Anchorage and Fairbanks International airports associated with international freight handling continues to grow 2% annually through 2015 and 1% thereafter. (AIR.S08M)
A.6. Forest Products	
1. Logging and Sawmills	Growth at 1 percent in all regions that currently have logging. (FML.S08M)
2. Timber Manufacture	None. (FMP.S08M)
A.7. Agriculture	
1. Agriculture	Employment in agriculture, primarily for local markets, increases 1% annually. (AGR.S08M)
A.8. Retirees	
1. Retiree Public Income	.2 % real per capita growth rate (GRPITR.R)
2. Migration—Seniors (65+)	In and out migration rates constant based on 2000 census information (PAROLD)
3. Labor Force Participation Rate—Seniors	Constant based on 2000 census information in Labor Force participation rates for Senior population (65+)
A.9. Federal Government	
1. Military Employment	Basic strength level falls 1% annually starting in 2010 (FMI.S08M)
2. Military Expansion	None
3. Civilian Agency Employment	Employment increases at .25% annual rate consistent with long-term trend since 1960 (FCV.S04M)
4. Military and Agency Construction Procurement	Federally funded construction projects administered by federal agencies (including both civilian and military) declines by 5% annually starting in 2009 to a level consistent with the historical trend by 2016. (CON.S08M)
5. Grants to State Government	Grants to state government, for both capital projects and operations, contract until 2013 and then resume growth at the rate of population growth and inflation (FEDEX)
6. Grants to Nonprofits	Drop-in value added in nonprofit sector of $60 million between 2008 and 2013 (FEDNPX)
7. Transfers to Individuals (Medicare and Medicaid)	Growing at rate of population, prices, and income.
8. Cost-of-Living Adjustment	COLA falls from 25% to 15% over the period of 25 years starting in 2006. (FEDCOLA)

B. STATE FISCAL ASSUMPTIONS	
B.1. Petroleum Revenues on Current Production	
1. Severance (ACES) Taxes (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then 14% of wellhead value. (DOR.S08M)
2. Royalties (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then 12% of wellhead value. (DOR.S08M)
3. Petroleum Corporate Income Tax (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then 3% of wellhead value. (DOR.S08M)
4. Property Taxes (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then declining 3% annually in nominal dollars. (DOR.S08M)
5. Bonuses (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenues Sources through 2018 and continuing at constant nominal level. (DOR.S08M)
6. Rents (NS State Land and CI)	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018 and continuing at constant nominal level. (DOR.S08M)
7. Petroleum Settlements from Earlier Year Taxes	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018 and continuing at constant nominal level. (DOR.S08M)
8. Federal-State Petroleum-Related Shared Revenues	None. (DOR.S08M)
B.1. Petroleum Revenues on New Production	
1. NPRA Revenues	Royalties, production taxes, and corporate income taxes based on current state fiscal structure (NPR.S08M)
2. ANWR Revenues	None.
3. OCS Revenues	Royalties, property taxes, and corporate income taxes based on current state fiscal structure. (OCS.S08M)
4. Gas Pipeline Revenues	Royalties, production taxes, property taxes, and corporate income taxes based on current state fiscal structure as reflected in AGIA application (ONG.S08M)
B.3. Other State General Fund Revenues	
1. Personal Income Tax	No tax before 2030 due to high petroleum revenues (EXPIT)
2. Large Project Corporate Income Taxes	Captured in project specific scenario elements
3. Miscellaneous New Revenue Sources	None
4. New Federal-State Shared Revenues	None
5. Agency Transfers to State General Fund (AHFC, AIDEA)	$100 million (increasing with inflation) contributed to general fund annually (RMISX)
B.4. State General Fund Appropriations	
1. General Fund Appropriations	Growth at inflation rate plus population growth rate. (EXEL1, EXEL2)
2. General Fund Capital/Operations Split	90% operations; 10% capital (EXSPLITX)
3. General Obligation Bonds	Bond sales for capital expenditures are fixed percentage of GF capital appropriations (EXCPSGOB)
4. Special Appropriations to Permanent Fund & Other Special Appropriations in Excess of Normal General Fund Spending	None (PFTOGF)
5. Annual appropriation to PERS/TRS retirement accounts	$200 million (PERS)
6. New Matsu Prison	Annual employment of 500 phased in starting in 2011 (PMS.S08M)
7. Medicaid	Combined state and federal expenditures grow 5% annually.
8. Special Capital Expenditures Associated with Gas Line Construction	$500 million prior to gas line construction
9. Chakachamna Hydroelectric Project	Not constructed.
10. Susitna Hydroelectric Project	Not constructed.

B.5. State Non-General Fund Spending	
1. State Loan Programs	AHFC, AIDEA, and other programs function on existing capitalization
2. Grants from Federal Government	See Section A.8.
3. Other Restricted Fund Revenues and Expenditures	Growth at the rate of inflation plus population and per capita real income
B.6. Permanent Fund and Constitutional Budget Reserve, Fiscal Gap	
1. Permanent Fund Principal	Deposits from petroleum revenues continue at 25 % of royalties (EXPF1)
2. Permanent Fund Total Real Rate of Return	4.5 % (RORPPF)
3. Permanent Fund Earnings	After payment of dividend and inflation proofing, remainder accrues in earnings reserve, where it is used to supplement general fund revenues. When earnings reserve depleted, dividend reduced and those funds are used to support general fund (EXPFTOGF)
4. Permanent Fund Dividend	Half of annual earnings of fund paid out as dividend, until such time as Permanent Fund earnings are required to pay for general fund expenditures. Subsequent to that time the dividend payment gradually reduced to 25% of earnings. (EXPFDIV)
5. Constitutional Budget Reserve Real Rate of Return	3 % (ROR+RORPDF)
C. LOCAL GOVERNMENT FISCAL ASSUMPTIONS	
1. State-Local Wage Rates	Growth at rate of inflation and 80% of real increase in the national rate (EXWR)
2. Local Property Tax Rates	Rises from 1.3% to 1.5% by 2024 and then constant (RLPTRATE)
3. Federal – Local Revenue Sharing	None (RSFDNX)
4. Petroleum Property Taxes associated with existing production	Alaska Dept of Revenue (ADOR) Spring 2009 Revenue Sources through 2018, then declining 3% annually in nominal dollars. (DOR.S08M)
5. Petroleum Property Taxes and Federal Transfers associated with new production	See production scenarios. (RPPLOCAL and RLTFPX)
D. NATIONAL VARIABLE ASSUMPTIONS	
1. U.S. Inflation Rate	Approximately 2.5% annually from Energy Information Administration, April 2009. (GRUSCPI)
2. U.S. Real Average Weekly Earnings	.25% real growth (GRRWEUS)
3. U.S. Unemployment Rate	5.5 % (UUS)
4. Base Year for Converting Nominal to Real Dollars	2009
E. ALASKA PERSONAL INCOME	
1. Exxon Valdez Settlement	Alaska residents receive $700 million in settlements in 2009 and 2010. (PITRANX)
2. Dividend-Interest-Rent Income	.5 % real per capita growth (GRDIRPU)
F. POPULATION	
1. Birth Rates & Death Rates	Continuation of historical rates by age, sex and race from 2000 Census.
2. Migration—Work Related	Continuation of historical rates by age, sex, and race from 2000 Census.
3. Labor Force Participation Rate	Continuation of historical rates by age, sex and race from 2000 Census.
4. Households	Continuation of historical rates of household formation by age, sex, and race from 2000 Census.
G. REGIONAL ASSUMPTIONS	
1. Employment	Gradual migration of basic employment from Anchorage to Mat-Su Borough at a rate of 100 employees per year. (BASICSHFT)
2. Commuters	Share of workers filling basic sector jobs in Anchorage who commute from Matsu Borough increases .008 % annually. (RESSHFT1)

NOTES: Codes in parentheses indicate ISER names for MAP Model case files, and codes in brackets indicate MAP variable names.

These are the long-run assumptions. Values for some variable differ in the initial years to reflect the effects of the 2008-2010 recession and other short term conditions.

State Economic Projection Detail

TABLE 1A. PROJECTION SUMMARY
2009 BASE CASE FOR TRANSCANADA INSTATE GAS STUDY

	POPULATION (000)	HOUSEHOLDS (000)	TOTAL EMPLOY-MENT (000)	WAGE AND SALARY EMPLOYMENT (000)	PERSONAL INCOME (MILL 09$)	PER CAPITA PERSONAL INCOME (2009 $)	PETROLEUM REVENUES (FY) (MILL 09$)	OIL PRICE ANS WEST COAST (CY) (NOMINAL $)
2000	627.5	221.6	395.0	280.7	$23,628	$37,653	$2,378	$27
2001	632.0	224.2	401.6	287.9	$24,515	$38,792	$2,632	$22
2002	640.2	228.2	411.3	292.3	$24,903	$38,900	$1,824	$23
2003	647.2	230.6	410.9	296.9	$24,698	$38,162	$2,113	$28
2004	656.6	234.1	421.4	301.4	$25,692	$39,131	$2,405	$37
2005	663.1	238.0	430.9	307.8	$26,743	$40,331	$3,728	$50
2006	669.7	241.8	443.3	314.1	$27,910	$41,674	$4,664	$60
2007	674.5	243.6	441.7	317.2	$28,704	$42,556	$5,497	$67
2008	679.7	246.2	447.3	321.5	$29,967	$44,087	$11,789	$94
2009	680.7	247.8	440.9	316.6	$27,809	$40,852	$5,681	$40
2010	684.1	249.9	438.8	315.3	$27,846	$40,706	$2,889	$52
2011	690.8	253.1	440.4	316.8	$27,945	$40,454	$3,776	$66
2012	691.1	254.0	440.7	317.2	$27,922	$40,402	$4,915	$77
2013	691.3	254.8	441.4	318.0	$27,968	$40,458	$5,315	$88
2014	689.5	254.9	443.2	319.7	$28,237	$40,951	$5,993	$99
2015	693.4	256.9	449.5	324.7	$28,666	$41,344	$6,274	$109
2016	710.9	263.6	461.6	334.2	$29,458	$41,441	$6,214	$118
2017	730.4	271.0	468.2	339.4	$30,054	$41,149	$6,400	$126
2018	741.8	275.5	474.0	344.1	$30,553	$41,187	$6,635	$134
2019	752.9	280.0	477.2	346.7	$30,892	$41,032	$6,625	$140
2020	766.0	285.1	486.6	354.1	$31,542	$41,177	$7,088	$146
2021	783.9	291.9	496.2	361.6	$32,262	$41,157	$7,340	$151
2022	803.1	299.1	508.5	371.1	$33,111	$41,230	$7,016	$157
2023	821.3	305.9	517.0	377.7	$33,855	$41,220	$6,750	$162
2024	834.4	311.0	523.8	383.0	$34,433	$41,267	$6,502	$167
2025	847.1	316.0	530.8	388.4	$35,023	$41,344	$6,172	$172
2026	859.4	320.8	537.3	393.6	$35,578	$41,400	$5,952	$177
2027	870.1	325.0	542.8	397.9	$36,085	$41,471	$5,686	$183
2028	880.4	329.2	548.8	402.6	$36,592	$41,563	$5,565	$190
2029	890.7	333.3	555.1	407.5	$37,129	$41,683	$5,396	$197
2030	899.5	336.8	559.4	410.9	$37,531	$41,725	$5,224	$204

ANNUAL AVERAGE GROWTH RATE

2000-2010	0.87%	1.21%	1.06%	1.17%	1.66%	0.78%	1.97%	6.90%
2010-2020	1.14%	1.33%	1.04%	1.17%	1.25%	0.12%	9.39%	10.83%
2020-2030	1.62%	1.68%	1.41%	1.50%	1.75%	0.13%	-3.00%	3.40%
2000-2030	1.21%	1.41%	1.17%	1.28%	1.55%	0.34%	2.66%	7.00%

MAP MODEL SIMULATION	MODEL FOR ESTIMATING REGIONAL HOUSEHOLDS	
PREPARED FOR	NORTHERN ECONOMICS (TRANSCANADA)	
CREATED	AUGUST 15, 2009	
POPULATION	JULY 1 CENSUS DEFINITION	POP
HOUSEHOLDS	JULY 1 CENSUS DEFINITION	HH
TOTAL EMPLOYMENT	BEA DEFINITION INCLUDES ACTIVE DUTY MILITARY, RESERVISTS, PROPR	EM99.BEA
WAGE & SALARY EMPLOYMENT	ALASKA DEPT OF LABOR DEFINITION	EM97
PERSONAL INCOME	USDC BEA DEFINITION	DF.PIB
PER CAPITA PERSONAL INCOME	USDC BEA DEFINITION	
PETROLEUM REVENUES	INCLUDES PERMANENT FUND CONTRIBUTION BUT NOT CBR REVENUES	DF.RP9S
ANS WEST COAST PRICE	HISTORICAL IS US AVERAGE CRUDE PRICE	

Appendix: Regional Projection Detail

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
WAGE AND SALARY EMPLOYMENT (000)	314.04	315.54	316.00	316.80	318.49	323.48	332.99	338.20	342.83	345.50
North	18.22	18.56	18.61	18.99	19.16	19.82	21.59	22.00	21.73	21.27
Yukon - Koyukuk	2.36	2.37	2.43	2.57	2.61	2.70	3.18	3.26	3.07	2.73
Northern Railbelt	40.61	40.67	40.82	40.96	41.10	41.92	43.72	44.37	44.35	43.79
Denali	2.33	2.35	2.36	2.38	2.40	2.44	2.49	2.53	2.58	2.62
Frbks	38.29	38.32	38.46	38.58	38.70	39.48	41.23	41.84	41.77	41.17
SE Fairbanks	2.60	2.60	2.61	2.61	2.63	2.65	2.68	2.72	2.78	2.84
Yukon - Kuskokwim	9.35	9.54	9.75	9.69	9.52	9.80	9.92	10.08	10.33	10.57
South West	14.65	14.70	14.71	14.75	14.92	15.00	15.26	15.24	15.68	16.00
Southern Railbelt	186.10	186.72	186.52	186.63	187.78	190.21	194.34	197.53	201.19	204.06
Matsu	19.54	20.28	20.42	20.64	20.97	21.52	22.40	22.97	23.49	23.88
Anch	149.62	149.71	149.44	149.32	150.04	151.76	154.80	157.13	159.83	161.96
Kenai	16.94	16.73	16.67	16.67	16.77	16.93	17.14	17.44	17.87	18.22
Valdez-Cordova	4.49	4.51	4.59	4.59	4.61	4.86	5.35	5.45	5.27	4.93
South East	35.67	35.86	35.96	36.01	36.16	36.52	36.95	37.54	38.43	39.31
POPULATION (000)	684.09	690.78	691.11	691.28	689.53	693.36	710.85	730.39	741.80	752.87
North	24.12	24.45	24.55	24.58	24.44	24.44	24.74	25.32	25.76	26.32
Yukon - Koyukuk	5.71	5.76	5.81	5.92	5.91	5.94	6.31	6.47	6.35	6.15
Northern Railbelt	99.39	99.87	99.86	99.77	99.15	99.58	102.37	104.73	105.08	105.07
Denali	1.69	1.71	1.73	1.73	1.74	1.75	1.79	1.85	1.89	1.94
Frbks	97.70	98.15	98.14	98.03	97.42	97.83	100.58	102.88	103.19	103.13
SE Fairbanks	7.01	7.05	7.05	7.04	7.02	7.01	7.05	7.22	7.35	7.52
Yukon - Kuskokwim	25.08	25.49	25.75	25.67	25.32	25.41	25.47	26.02	26.50	27.14
South West	28.43	28.64	28.67	28.64	28.48	28.32	28.44	28.81	29.10	29.50
Southern Railbelt	414.86	419.11	418.73	418.97	418.79	421.89	434.21	447.27	455.43	463.16
Matsu	81.75	84.36	85.28	86.33	86.98	88.91	93.77	96.90	97.88	98.26
Anch	280.71	282.17	280.92	280.07	279.35	280.37	286.77	295.29	301.54	307.99
Kenai	52.40	52.58	52.53	52.57	52.46	52.61	53.67	55.08	56.01	56.91
Valdez-Cordova	9.53	9.63	9.73	9.73	9.68	9.93	10.59	10.88	10.69	10.36
South East	69.96	70.77	70.96	70.96	70.72	70.84	71.67	73.68	75.53	77.66
HOUSEHOLDS (000)	249.87	253.05	253.96	254.76	254.90	256.91	263.58	270.98	275.51	279.96
North	6.88	7.00	7.05	7.08	7.06	7.07	7.16	7.33	7.47	7.64
Yukon - Koyukuk	2.07	2.09	2.12	2.17	2.17	2.19	2.32	2.38	2.34	2.26
Northern Railbelt	37.10	37.39	37.52	37.59	37.47	37.72	38.80	39.71	39.87	39.91
Denali	0.72	0.73	0.74	0.75	0.75	0.76	0.78	0.80	0.82	0.85
Frbks	36.38	36.66	36.77	36.84	36.72	36.96	38.02	38.91	39.05	39.06
SE Fairbanks	2.43	2.46	2.46	2.47	2.47	2.47	2.48	2.54	2.60	2.66
Yukon - Kuskokwim	6.55	6.68	6.77	6.77	6.70	6.74	6.75	6.90	7.03	7.21
South West	8.45	8.55	8.58	8.60	8.57	8.53	8.57	8.70	8.81	8.95
Southern Railbelt	155.33	157.37	157.72	158.26	158.66	160.17	164.86	169.87	173.15	176.34
Matsu	29.30	30.34	30.78	31.25	31.58	32.36	34.15	35.28	35.67	35.84
Anch	106.02	106.89	106.76	106.75	106.79	107.43	109.92	113.23	115.75	118.39
Kenai	20.01	20.14	20.18	20.26	20.28	20.38	20.80	21.36	21.73	22.11
Valdez-Cordova	3.73	3.79	3.84	3.85	3.84	3.95	4.22	4.33	4.26	4.13
South East	27.33	27.73	27.90	27.98	27.97	28.08	28.41	29.21	29.98	30.86
PERSONAL INCOME (09 MILLION $)	$27,846	$27,945	$27,922	$27,968	$28,237	$28,666	$29,458	$30,054	$30,553	$30,892
North	$840	$846	$845	$847	$852	$865	$888	$906	$923	$938
Yukon - Koyukuk	$158	$159	$159	$161	$163	$166	$174	$179	$180	$180
Northern Railbelt	$3,596	$3,598	$3,592	$3,595	$3,620	$3,673	$3,783	$3,850	$3,884	$3,893
SE Fairbanks	$270	$271	$271	$271	$274	$277	$284	$289	$294	$297
Yukon - Kuskokwim	$617	$620	$620	$620	$625	$633	$643	$658	$676	$693
South West	$977	$980	$978	$979	$986	$998	$1,021	$1,037	$1,056	$1,070
Southern Railbelt	$18,024	$18,095	$18,080	$18,118	$18,311	$18,602	$19,140	$19,536	$19,864	$20,081
Valdez-Cordova	$379	$381	$382	$382	$385	$395	$413	$422	$424	$421
South East	$2,985	$2,997	$2,995	$2,996	$3,022	$3,058	$3,112	$3,177	$3,252	$3,319
PER CAPITA PERSONAL INCOME (09 THOU $)	$40.71	$40.45	$40.40	$40.46	$40.95	$41.34	$41.44	$41.15	$41.19	$41.03
North	$34.84	$34.59	$34.44	$34.45	$34.85	$35.37	$35.90	$35.78	$35.84	$35.65
Yukon - Koyukuk	$27.69	$27.54	$27.37	$27.11	$27.55	$27.88	$27.55	$27.64	$28.41	$29.31
Northern Railbelt	$36.19	$36.02	$35.97	$36.03	$36.51	$36.88	$36.95	$36.77	$36.97	$37.05
SE Fairbanks	$38.50	$38.40	$38.42	$38.55	$38.97	$39.60	$40.30	$40.08	$39.98	$39.54
Yukon - Kuskokwim	$24.58	$24.32	$24.09	$24.14	$24.67	$24.90	$25.23	$25.28	$25.50	$25.54
South West	$34.36	$34.21	$34.13	$34.17	$34.62	$35.25	$35.91	$36.00	$36.28	$36.27
Southern Railbelt	$43.45	$43.17	$43.18	$43.24	$43.72	$44.09	$44.08	$43.68	$43.62	$43.36
Valdez-Cordova	$39.80	$39.53	$39.24	$39.29	$39.81	$39.76	$39.01	$38.80	$39.64	$40.67
South East	$42.67	$42.34	$42.20	$42.22	$42.73	$43.17	$43.42	$43.12	$43.05	$42.73

	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
WAGE AND SALARY EMPLOYMENT (000)	352.85	360.34	369.83	376.48	381.78	387.21	392.35	396.64	401.33	406.26	409.67
North	21.03	21.58	22.51	23.08	23.12	23.31	23.51	23.42	23.62	23.91	23.60
Yukon - Koyukuk	2.81	2.89	2.92	2.99	3.05	3.10	3.14	3.19	3.23	3.27	3.30
Northern Railbelt	44.59	45.40	46.12	46.98	47.70	48.34	48.90	49.43	49.94	50.49	50.92
Denali	2.68	2.73	2.80	2.85	2.90	2.95	2.99	3.02	3.06	3.10	3.13
Frbks	41.91	42.66	43.33	44.13	44.80	45.39	45.92	46.40	46.88	47.39	47.78
SE Fairbanks	2.90	2.95	3.01	3.08	3.13	3.18	3.22	3.27	3.31	3.35	3.39
Yukon - Kuskokwim	10.77	10.95	11.18	11.44	11.68	11.88	12.05	12.21	12.37	12.52	12.66
South West	17.48	17.98	19.50	18.37	17.72	17.71	17.86	17.92	18.05	18.19	18.31
Southern Railbelt	208.19	212.74	217.82	222.75	226.66	230.19	233.47	236.36	239.35	242.45	244.81
Matsu	24.57	25.36	26.23	26.90	27.49	28.07	28.62	29.12	29.65	30.20	30.63
Anch	165.04	168.48	172.30	176.11	179.08	181.73	184.17	186.31	188.51	190.81	192.52
Kenai	18.58	18.90	19.30	19.73	20.09	20.40	20.67	20.93	21.19	21.44	21.66
Valdez-Cordova	5.00	5.07	5.12	5.21	5.30	5.37	5.43	5.49	5.54	5.60	5.66
South East	40.08	40.78	41.65	42.58	43.42	44.13	44.75	45.35	45.93	46.50	47.03
POPULATION (000)	766.01	783.87	803.08	821.33	834.39	847.11	859.37	870.12	880.41	890.74	899.47
North	26.55	26.94	27.38	27.95	28.38	28.75	29.08	29.38	29.65	29.91	30.16
Yukon - Koyukuk	6.22	6.32	6.35	6.47	6.56	6.63	6.69	6.76	6.81	6.86	6.92
Northern Railbelt	106.37	108.23	109.86	111.97	113.47	114.84	116.10	117.25	118.27	119.30	120.23
Denali	1.98	2.04	2.09	2.14	2.18	2.22	2.26	2.29	2.32	2.35	2.39
Frbks	104.38	106.20	107.77	109.83	111.29	112.61	113.84	114.96	115.95	116.95	117.85
SE Fairbanks	7.62	7.76	7.90	8.06	8.18	8.29	8.39	8.49	8.58	8.67	8.75
Yukon - Kuskokwim	27.40	27.73	28.07	28.60	29.04	29.40	29.71	30.03	30.28	30.52	30.80
South West	30.16	30.59	31.46	30.96	30.74	30.85	31.02	31.16	31.28	31.38	31.54
Southern Railbelt	472.13	484.92	498.74	511.79	520.64	529.35	537.88	545.13	552.35	559.70	565.40
Matsu	100.42	103.96	107.39	109.56	111.19	113.04	114.95	116.52	118.22	119.98	121.31
Anch	313.94	322.07	331.13	340.76	347.16	353.19	358.98	363.96	368.78	373.69	377.49
Kenai	57.77	58.89	60.22	61.47	62.29	63.12	63.95	64.65	65.34	66.03	66.59
Valdez-Cordova	10.50	10.67	10.82	10.99	11.14	11.28	11.41	11.54	11.65	11.76	11.87
South East	79.07	80.71	82.50	84.54	86.24	87.73	89.08	90.39	91.53	92.64	93.80
HOUSEHOLDS (000)	285.07	291.86	299.06	305.89	311.02	315.96	320.76	325.01	329.19	333.30	336.85
North	7.71	7.82	7.95	8.12	8.25	8.36	8.46	8.55	8.64	8.72	8.80
Yukon - Koyukuk	2.29	2.33	2.34	2.38	2.41	2.44	2.47	2.49	2.51	2.53	2.55
Northern Railbelt	40.43	41.15	41.77	42.56	43.16	43.71	44.21	44.68	45.11	45.54	45.93
Denali	0.87	0.89	0.92	0.94	0.96	0.97	0.99	1.01	1.02	1.04	1.05
Frbks	39.56	40.26	40.85	41.62	42.21	42.73	43.22	43.68	44.09	44.50	44.88
SE Fairbanks	2.70	2.75	2.80	2.85	2.90	2.94	2.98	3.02	3.05	3.09	3.12
Yukon - Kuskokwim	7.28	7.37	7.46	7.60	7.72	7.82	7.90	7.99	8.07	8.13	8.22
South West	9.19	9.33	9.61	9.45	9.38	9.41	9.48	9.53	9.57	9.61	9.67
Southern Railbelt	179.85	184.76	190.02	194.95	198.46	201.88	205.24	208.14	211.08	214.02	216.36
Matsu	36.64	37.94	39.18	39.95	40.56	41.25	41.96	42.56	43.22	43.88	44.40
Anch	120.75	123.92	127.42	131.11	133.67	136.06	138.38	140.39	142.38	144.37	145.96
Kenai	22.46	22.90	23.42	23.90	24.23	24.56	24.90	25.19	25.48	25.77	26.01
Valdez-Cordova	4.18	4.25	4.31	4.38	4.44	4.50	4.55	4.61	4.65	4.70	4.75
South East	31.44	32.10	32.80	33.60	34.30	34.91	35.46	36.00	36.49	36.96	37.45
PERSONAL INCOME (09 MILLION $)	$31,542	$32,262	$33,111	$33,855	$34,433	$35,023	$35,578	$36,085	$36,592	$37,129	$37,531
North	$956	$977	$1,003	$1,029	$1,048	$1,067	$1,084	$1,100	$1,116	$1,133	$1,144
Yukon - Koyukuk	$185	$190	$194	$200	$204	$209	$213	$217	$220	$224	$227
Northern Railbelt	$3,963	$4,042	$4,126	$4,210	$4,277	$4,343	$4,403	$4,461	$4,517	$4,576	$4,621
SE Fairbanks	$303	$310	$317	$324	$329	$334	$339	$343	$348	$353	$356
Yukon - Kuskokwim	$709	$725	$743	$764	$781	$798	$812	$827	$840	$854	$866
South West	$1,104	$1,131	$1,174	$1,177	$1,184	$1,201	$1,217	$1,233	$1,248	$1,264	$1,277
Southern Railbelt	$20,502	$20,985	$21,553	$22,054	$22,429	$22,812	$23,178	$23,504	$23,839	$24,193	$24,449
Valdez-Cordova	$430	$439	$450	$460	$468	$476	$484	$491	$498	$505	$511
South East	$3,390	$3,464	$3,550	$3,638	$3,712	$3,783	$3,846	$3,909	$3,967	$4,027	$4,079
PER CAPITA PERSONAL INCOME (09 THOU $)	$41.18	$41.16	$41.23	$41.22	$41.27	$41.34	$41.40	$41.47	$41.56	$41.68	$41.73
North	$36.00	$36.26	$36.64	$36.81	$36.92	$37.12	$37.28	$37.44	$37.62	$37.86	$37.94
Yukon - Koyukuk	$29.68	$29.99	$30.55	$30.86	$31.17	$31.48	$31.78	$32.06	$32.35	$32.67	$32.88
Northern Railbelt	$37.26	$37.35	$37.56	$37.60	$37.69	$37.82	$37.93	$38.05	$38.19	$38.36	$38.44
SE Fairbanks	$39.79	$39.92	$40.18	$40.17	$40.19	$40.29	$40.38	$40.44	$40.55	$40.72	$40.73
Yukon - Kuskokwim	$25.86	$26.14	$26.48	$26.70	$26.91	$27.13	$27.33	$27.53	$27.73	$27.97	$28.10
South West	$36.61	$36.96	$37.33	$38.01	$38.51	$38.92	$39.25	$39.56	$39.90	$40.29	$40.49
Southern Railbelt	$43.42	$43.28	$43.21	$43.09	$43.08	$43.10	$43.09	$43.12	$43.16	$43.22	$43.24
Valdez-Cordova	$40.99	$41.17	$41.55	$41.83	$42.01	$42.22	$42.40	$42.56	$42.75	$42.99	$43.07
South East	$42.88	$42.92	$43.03	$43.03	$43.05	$43.12	$43.18	$43.24	$43.33	$43.47	$43.48

Appendix B: Summary Tables

Appendix B: Summary Tables

Table B-1 summarizes the components and demand ranges applied in the probability model for each sector during the first five years of pipeline operation. All values are rounded to the ones place. Where demand ranges are applied, the single estimate value is shown in parenthesis below the range[1].

Table B-1. Summary of the Range of Natural Gas Demand Estimates by Sector for Year 1 to 5 of Pipeline Operations (MMcfd), (Single Estimate Values are shown in parenthesis)

Demand Source	Southern Railbelt	Northern Railbelt/ Livengood	Valdez [b]	Total Range [c]	
				Alberta Route	Valdez Route
Residential / Commercial [a]				106 to 142 *(122)*	107 to 143 *(123)*
Residential	68 to 82 *(75)*	1 to 8 *(4)*	<1		
Commercial	36 to 44 *(40)*	1 to 9 *(4)*	<1		
Power [d]	44 to 72 *(71)*	12 to 21 *(21)*	--	56 to 93 *(91)*	56 to 93 *(91)*
Military				*(17)*	*(17)*
Ft. Wainwright	--	8 [e]	--		
Ft. Greeley	--	1 [f]	--		
Eielson	--	8 [f]	--		
Industry				33 to 653 *(263)*	38 to 658 *(268)*
Tesoro Refinery [g]	11	--	--		
Flint Hills Refinery	--	12 [e]	--		
Petro Star Refineries	--	1 [e]	3 [h]		
Other Industrial (Livengood)	--	9			
Alyeska Pipeline/Terminal [i]	--	--	2[i]		
LNG (current) [g]	0 to 230 *(230)*	--	--		
LNG (expansion) [g]	0 to 245 *(0)*	--	--		
Fertilizer [g]	0 to 145 *(0)*	--	--		
Sum of Single Estimates	*(427)*	*(68)*	*(7)*	*(493)*	*(499)*

Note: Values with only single point estimates have a range less than ± 3 MMcfd.
[a] Based on gas utility demand projections and Interior Issues Council (2009)
[b] This demand is only projected to occur under the Valdez Pipeline Scenario
[c] Row sums may not equal the totals due to rounding
[d] Based on Black & Veatch (2008) and updated electric utility information
[e] Interior Issues Council (2009); and Jeff Cook, Flint Hills Refinery. Personal communication with Northern Economics, Inc. January 4, 2010.
[f] ENSTAR Market Study (*Natural Gas Line Load Analysis, Parks and Richardson Highway Routes*. Draft document, January 27, 2009).
[g] National Energy Technology Laboratory, 2006, Alaska Natural Gas Needs and Market Assessment
[h] Based on average projected gas demand per refinery capacity in Interior Issues Council (2009)
[i] Calculated based on information provided by Joe Robertson, Joint Pipeline Office and Department of Transportation Liaison, Alyeska Pipeline Service Company, personal communication with Northern Economics. January 7, 2009.

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[1] Single estimate values for the Residential/Commercial sector demand represent the 50th percentile of continuous distributions. Single estimate values for Power and Industrial sectors demand represent the mode of non-symmetric, discrete distributions.

Table B-2. Maximum Potential Propane Demand in Years 1-5 (Millions of Gallons)

Area	Residential & Commercial	Electric Power	Industrial	Total
Northwest-Arctic	10.4	10.5	24.1	45.0
Yukon - Koyukuk	2.0	3.2	0.0	5.2
Northern Railbelt	17.1	16.8	0.0	33.9
SE Fairbanks	4.1	4.0	1.0	9.1
Yukon - Kuskokwim	10.1	11.0	101.9	123.0
South West	16.9	21.0	117.6	155.5
Southern Railbelt	17.7	0.0	7.7	25.4
Valdez-Cordova	9.9	6.1	12.0	28.0
South East	43.3	11.7	40.0	95.0
Total	**131.5**	**84.3**	**304.3**	**520.1**

Source: Northern Economics, Inc.

Table B-2 shows the maximum potential demand for propane in Alaska without adjusting for possible reductions due to distillate fuels being less expensive when considering the costs of transport and storage of larger volumes of propane.

Appendix C: Power Sector Demand Analysis

Appendix C: Potential Power Sector Natural Gas Demand

1 Introduction and Background

This appendix provides alternative estimates for natural gas consumption in Alaska's electric power sector for four alternative future scenarios. The assessment is limited to the interconnected portion of the electric power grid, called the Railbelt, encompassing Fairbanks, the Metropolitan Anchorage region and the Kenai Peninsula. The Alaska Energy Policy Task Force Report defined the Railbelt as: "the power-sharing area between Interior Alaska, from Fairbanks, and Southcentral, to Homer, connected by roads, generating facilities and transmission lines, which include the Alaska Intertie and the Bradley Lake Hydro Project."[1]

The current scenario assessment of the Railbelt power sector builds upon a previous 2008 study sponsored by the Alaska Energy Authority (AEA). This study by Black and Veatch evaluated the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA). The purpose of the REGA would be to manage and dispatch electric power on the Railbelt grid.[2] In order to evaluate the value of REGA, the study conducted detailed capacity and dispatch modeling of the region's existing electric power system with the model making economic decisions to select the technology and fuel options that minimize long-term costs for customers. This analysis is based upon the following:

- Application of a power cost model to perform a least-cost resource systems optimization to develop optimal portfolios of resources for each of four alternative scenarios.
- The cost and performance characteristics of the region's existing generation and transmission assets, as described below in Section 2.
- Cost and performance characteristics of various resources that could be added to the region's resource portfolio, as briefly described below in Section 3.

For the sake of consistency, this study does not perform independent utility systems modeling, but builds upon the outcomes of the REGA Study's utility capacity and dispatch modeling. Since the economy and energy outlook have changed since the REGA study, the TransCanada project made every effort obtain a current perspective on the future resource mix of the Railbelt utility companies to meet service area electricity demand. This analysis adjusts the REGA outcomes based on this new information.

1.1 Conclusions

Table 1 provides the projection of future natural gas (and propane) demand for year's 2019 and 2030 for the Fairbanks area and the South-Central area of the Railbelt and the total Railbelt power sector. Both daily and annual consumption is provided. The four Evaluation Scenarios provide a significant range of future natural gas consumption, although the most significant changes occur after 2019. By 2030, the Natural gas Scenario yields 20% greater consumption than the Large Hydro / Renewables / DSM / Energy Efficiency Scenario, almost 42% greater than the Mixed Resource Scenario, and 123% greater than the Coal Scenario.

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[1] http://www.akenergyauthority.org/EnergyPolicyTaskForce/FinalNonRailbeltReport.pdf

[2] Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008.

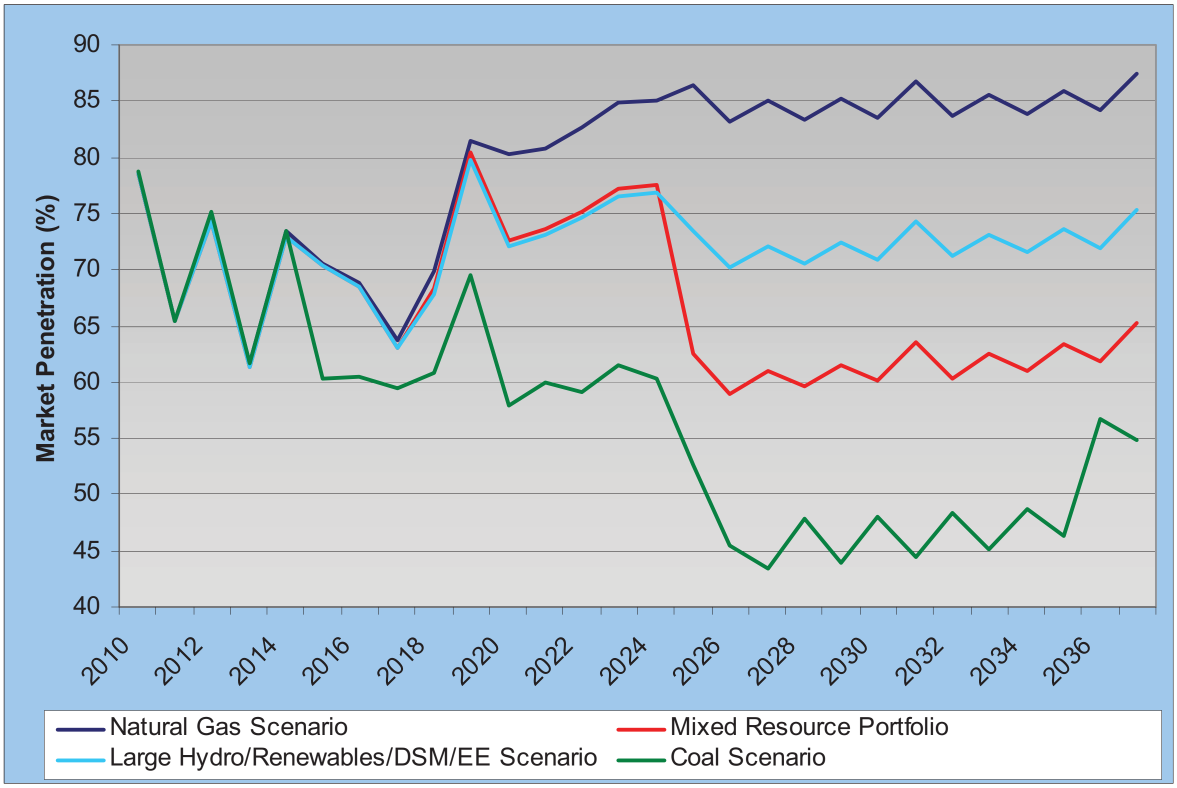
Table 1. Projected Future Natural Gas and Propane Demand for the Railbelt Utilities

Geographic Location	Year 2019			Year 2030		
	Dry Gas Btu/day mmcfd	Propane Btu/day bbld	Total Btu/Yr	Dry Gas Btu/day mmcfd	Propane Btu/day bbld	Total Btu/Yr
Large Hydro / Renewables / DSM / Energy Efficiency Scenario						
Power Sector (FAI)	19.99 / 19.72	N/A	7,298	25.96 / 25.60	N/A	9,475
Power Sector (ANC)	77.80 / 76.73	N/A	28,398	57.95 / 57.15	N/A	21,153
Total Power Sector	**97.80 / 96.45**	**N/A**	**35,696**	**83.91 / 82.75**	**N/A**	**30,628**
Natural Gas Scenario						
Power Sector (FAI)	22.55 / 22.24	N/A	8,231	29.40 / 29.00	N/A	10,733
Power Sector (ANC)	77.36 / 76.29	N/A	28,236	71.25 / 70.27	N/A	26,006
Total Power Sector	**99.91 / 98.53**	**N/A**	**36,467**	**100.65 / 99.27**	**N/A**	**36,739**
Coal Scenario						
Power Sector (FAI)	12.94 / 12.76	N/A	4,724	16.04 / 15.82	N/A	5,856
Power Sector (ANC)	47.85 / 47.19	N/A	17,465	29.20 / 28.80	N/A	10,659
Total Power Sector	**60.79 / 59.95**	**N/A**	**22,189**	**45.25 / 44.62**	**N/A**	**16,515**
Mixed Resource Scenario						
Power Sector (FAI)	19.42 / 19.15	N/A	7,089	14.94 / 14.73	N/A	5,451
Power Sector (ANC)	78.70 / 77.62	N/A	28,727	56.12 / 55.35	N/A	20,484
Total Power Sector	**98.13 / 96.77**	**N/A**	**35,816**	**71.06 / 70.08**	**N/A**	**25,936**

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

Overall natural gas market penetration, as a percentage of total Railbelt electricity generation produced from natural gas-based generators, is shown in Figure 1 below. As expected based on the Table 1 results, penetration is significantly different for the four Evaluation Scenarios. By 2030, the Natural gas Scenario yields 16% greater penetration than the Large Hydro / Renewables / DSM / Energy Efficiency Scenario, almost 34% greater than the Mixed Resource Scenario, and 60% greater market penetration than the Coal Scenario.

Figure 1. Projection of Railbelt Natural Gas Market Penetration as a Percentage of Power Generation Supply (Gas-Based Generation/Total Generation)



Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," September 12, 2008 and SAIC.

2 The Electric Power System in South Central Alaska (Railbelt System)

The interconnected electric system for South Central Alaska (the Railbelt System) consists of six electric utilities in Fairbanks, the Greater Anchorage Area and the Kenai Peninsula. Table 2 lists the main transmission areas and the corresponding electric utilities.

Table 2. Transmission Areas and Utilities in the Railbelt System

Transmission Area	Utilities
Anchorage	Municipal Light & Power
	Chugach Electric Association
	Matanuska Electric Association
Kenai	Seward Electric System
	Homer Electric
Fairbanks-Healy	Golden Valley Electric Association

Source: SAIC

The six utilities that serve the Railbelt region are:

- **Anchorage Municipal Light and Power (ML&P)** – ML&P services an area of 19.9 contiguous miles, including a large portion of the commercial and high-density residential areas of the Anchorage Municipality.[3]

  In 2008, ML&P served an average of 24,108 residential customers and 6,240 commercial customers. ML&P also provides all-requirements power to two military bases. Approximately 81 percent of ML&P's retail revenue comes from commercial accounts and military bases.

  In 2008, ML&P sold 1,118,752 MWh to retail electric customers and retail sales totaled $89,545,097. ML&P's sales to other utilities (Chugach Electric Association and Golden Valley Electric Association) for resale were $16,137,134. ML&P's total electric operating revenue for 2008 was $107,207,803.

- **Chugach Electric Association (CEA)** - CEA serves more than 80,700 retail locations in a service territory which extends from Anchorage to the northern Kenai Peninsula, and from Whittier on Prince William Sound to Tyonek on the west side of Cook Inlet. CEA has 530.10 megawatts of installed capacity at five plants and provides power to Alaskans from Homer to Fairbanks through sales to wholesale and economy energy customers Matanuska Electric Association, Homer Electric Association, the City of Seward, Golden Valley Electric Association, and Anchorage Municipal Light & Power.[4]

  In 2008, CEA sold 1,210,000 MWh to retail electric customers, 1,320,000 MWh wholesale, and 256,100 MWh of economy energy power. Total electric operating revenue for 2008 was $107,207,803. Total electric operating revenue for 2008 was $289,500,000.

- **City of Seward Light and Power (SES)** – SES serves the City of Seward with approximately 2,500 customers. SES purchases power from CEA and provides backup generation.

- **Golden Valley Electric Association (GVEA) -** In 2008, GVEA served an average of 43,304 metered customers. GVEA serves nearly 100,000 interior residents in Fairbanks, Delta Junction, Nenana, Healy and Cantwell.

  In 2008, GVEA's peak load was 217.6 megawatts and total electric operating revenue for 2008 was $214,513,840. GVEA operates and maintains 3,077 miles of transmission and distribution lines and 35 substations. Its system is interconnected with Fort Wainwright, Eielson AFB, Fort Greely, the University of Alaska-Fairbanks in addition to the larger RailBelt grid. **Homer Electric Association (HEA)** – HEA services an area of 3,166 square-mile and 20,214 member-owners with 30,521 meter locations via 2,296 total miles of energized line.

  Homer Electric sold 523,300 MWh of electricity in 2008 with revenue from energy sales at $69.2 million.

- **Matanuska Electric Association (MEA)** - MEA had 52,310 customers as of year-end 2006, and combined revenues of more than $86.3 million. It currently purchases all of its power from Chugach Electric Association; MEA's wholesale power supply contract with CEA expires December 31, 2014 and the association is currently exploring the idea of constructing its own power generation facilities.

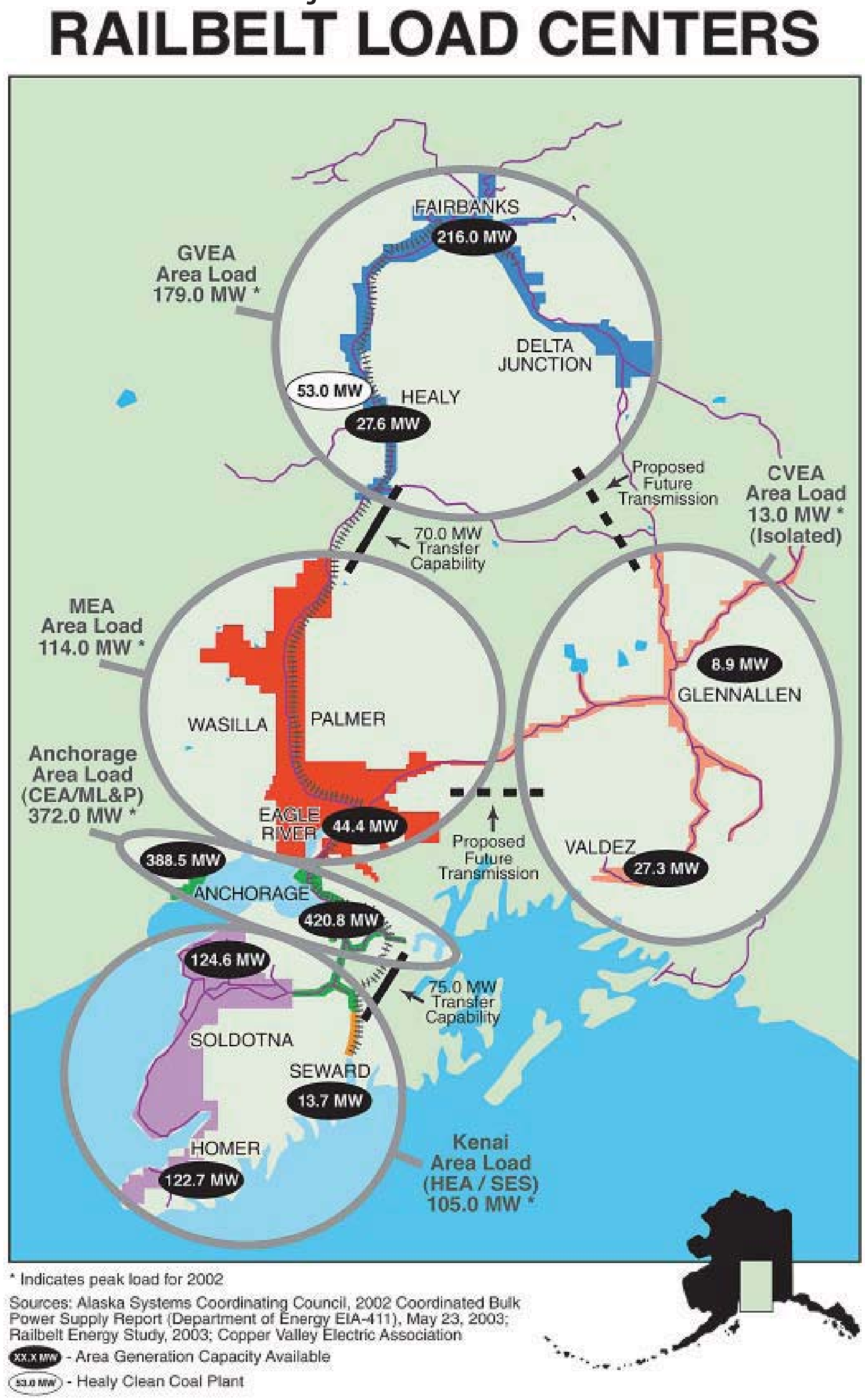
[3] Anchorage MLP website: http://www.mlandp.com/redesign/about_mlp.htm
[4] 2008 Chugach Electric Annual Report, http://www.chugachelectric.com/pdfs/2008_annual_report.pdf

2.1 Characteristics of the Railbelt System

The total peak load of all six utilities is approximately 875 MW. The Railbelt electric transmission grid has been described as a "long straw," as opposed to the integrated, interconnected, and redundant grid that is in place throughout the lower-48 states. This characterization reflects the fact that the Railbelt electric transmission grid is an isolated grid with no external interconnections to other areas and that it is essentially a single transmission line running from Fairbanks to the Kenai Peninsula, with limited total transfer capabilities and redundancies.[2] Figure 1 identifies the major Railbelt load centers (Valdez and Glennallen are not currently connected to the Railbelt grid.)

As a result of the lack of redundancies and interconnections with other regions, each Railbelt utility is required to maintain much higher generation reserve margins than utilities in other locations in order to ensure reliability in the case of a transmission grid outage. Furthermore, the lack of interconnections and redundancies exacerbates a number of the other issues facing the Railbelt region.[2]

Figure 2. Railbelt Load Centers



GVEA's service area makes up the northern load center and is connected with 138 kV lines that flow through Delta Junction, Fairbanks, and Healy. The northern and the central load centers are interconnected via the Alaska Intertie, and the Healy-Fairbanks and Teeland-Douglas transmission lines. The Alaska Intertie is a 345 kV (operated at 138 kV), 170 mile transmission line that is owned by the AEA and runs between the Douglas and Healy substations. The Healy-Fairbanks transmission line is a 230 kV, 90-mile transmission line from the Healy to the Wilson substations which delivers power from the Alaska Intertie directly into the city of Fairbanks. Another 138 kV transmission line also runs from Healy to Nenana to Goldhill and delivers power to Fairbanks. The 138 kV, 20-mile Douglas-Teeland transmission line stretches between the Douglas and Teeland substations and connects the southern portion of the Alaska Intertie to the central load center.

Key B&V modeling assumptions for the Railbelt System are as follows:

- The transfer capability of the Alaska Intertie and Healy-Fairbanks transmission lines are 75 MW and 140 MW, respectively.
- The central load center consists of MEA's, ML&P's, and CEA's service territories.
    - MEA serves customers down the southern half of the intertie and south of the intertie through the towns of Wasilla and Palmer.
    - ML&P serves the load of the residents of Anchorage.
    - CEA serves some residents of Anchorage along with the area south of Anchorage and into the northern portion of the Kenai Peninsula.
- The central and southern load centers are connected via a 135-mile, 115 kV transmission line that connects the Chugach system to the Kenai Peninsula. The transfer capability of the southern intertie is assumed to be 75 MW.
- The southern load center consists of SES and HEA's service territories.
    - SES serves the customers of the city of Seward.
    - The HEA service area includes the cities of Homer and Soldotna.

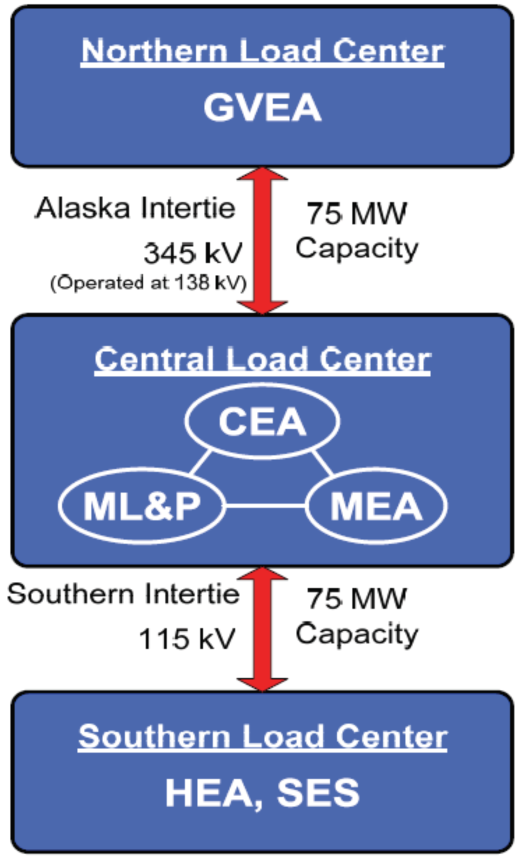
Figure 3 shows the region's three load centers and the existing transfer capability.

The Railbelt System is isolated from all other electric grids in North America. As such, it must be self sufficient in providing electric supply to its customers and this isolation poses special challenges in providing reliable service to customers.

The Railbelt System is characterized by an extremely high percentage of Simple-Cycle Combustion Turbine (SCCT) generating units. This situation exists for a variety of reasons: (1) historically, natural gas from the Cook Inlet has been sold to a captive market, depressing prices; (2) smaller system loads have limited generating technology choice to smaller sized units; and (3) technologies capable of rapid dispatch have been chosen to minimize outage time if a unit should fail.[5]

[5] NETL-RDS, "Alaska Natural Gas Needs and Market Assessment," NETL Strategic Center for Natural Gas and Coal, June 2006.

Figure 3. Existing Load Centers as Modeled by B&V

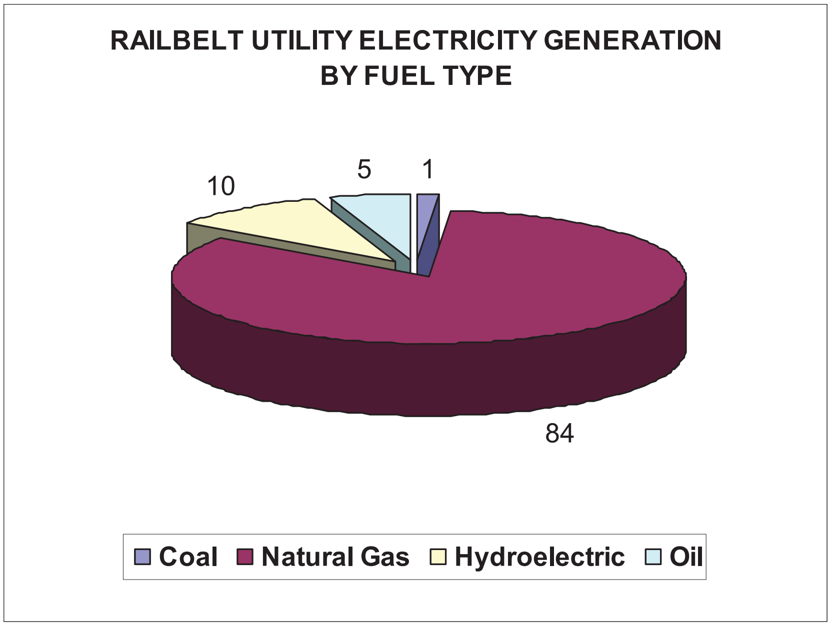


Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

There are a variety of existing generation resources that are owned and operated by the Railbelt utilities, as well as a transmission grid that extends from the Fairbanks area down to the Kenai Peninsula. There are also a broad array of supply-side resource options, both traditional and renewable resources, and demand-side resources (i.e., DSM and energy efficiency programs), available to meet the future electrical needs of the Railbelt region.

Natural gas has been the predominant source of fuel for electric generation used by the customers of ML&P, Chugach, MEA, Homer and Seward. Additionally, customers in Fairbanks have benefited from natural gas-generated economy energy sales in recent years. Figure 4 shows the current level of dependence level of on natural gas in the Railbelt System.

Figure 4. Railbelt Utility Electricity Generation by Fuel Type



Source: SAIC

2.2 Railbelt Utilities: Current and Planned Generation Resources

This section presents available information for the six Railbelt region utilities based on data and information from the B&V REGA Study[2] and updated information obtained by this project from each utility (only 4 of 6 utilities responded) and other sources. This study estimates that the current total Railbelt installed capacity is 1,246 MW based on the B&V study data and updated utility information provided through key informant interviews (see Table 2).

Table 3. Railbelt Installed Capacity (MW)

		Hydroelectric Plants: Existing Capacity			
Utility	Thermal Plants: Existing Capacity	Bradley Lake	Eklutna Lake	Cooper Lake	TOTAL
MEA	0	12.4	6.7	0	19.1
HEA	39	10.8	0	0	49.8
CEA	504	27.4	12	20	563.4
GVEA	275	15.2	0	0	290.2
ML&P	278	23.3	21.3	0	322.6
SES	0	0.9	0	0	0.9
TOTAL	**1,096**	**90**	**40**	**20**	**1246**

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008 and SAIC.

2.2.1 Anchorage Municipal Light and Power (ML&P)

ML&P did not respond to the project's request for current utility information. The REGA Study report identified the following existing thermal power plants:

- ML&P operates seven combustion turbines (Units 1-5, 7, and 8) between two power plants, which operate on natural gas, and one steam turbine (Unit 6), which derives its steam from un-fired heat recovery steam generators (HRSGs).
- Units 1, 2, and 4 are unavailable for commercial operation and are not considered in ML&P's approximate 400 MW of generating capability.
- Combustion turbines 5 and 7 have HRSGs, which allow them to operate in a combined cycle mode with the Unit 6 steam turbine. Unit 5 is frequently cycled when used in combined cycle or simple cycle mode. Unit 5 or Unit 7 may be operated in simple cycle mode when the steam turbine is unavailable.

ML&P's existing thermal units are shown in Table 4. Hydroelectric power is also purchased from Bradley Lake (23.3 MW) and Eklunta Lake (21.3 MW).

Table 4. MLP Existing Thermal and Hydroelectric Units[2]

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Anchorage ML&P - Plant 1	1*	Natural Gas	16.2	n/a
Anchorage ML&P - Plant 1	2*	Natural Gas	16.2	n/a
Anchorage ML&P - Plant 1	3	Natural Gas	32	n/a
Anchorage ML&P - Plant 1	4*	Natural Gas	34.1	n/a
Anchorage ML&P - Plant 2	5	Natural Gas	37.4	n/a
Anchorage ML&P - Plant 2	5/6	Natural Gas	49.2	n/a
Anchorage ML&P - Plant 2	7	Natural Gas	81.8	2030
Anchorage ML&P - Plant 2	7/6	Natural Gas	109.5	2030
Anchorage ML&P - Plant 2	8	Natural Gas	87.6	2030
Anchorage ML&P - Plant 2	6	n/a	n/a	2030

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
ML&P	25.9	90,333	23.3	7.0	53.3	87,412	21.3	0.0	0.0	0.0

* Denotes units not available for commercial operation
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

ML&P, along with CEA, is currently planning to build the so-called Southcentral Power Plant (SPP) to be completed in mid-2013. This will be a 183 MW gas fired combined-cycle plant using three GE LM6000 gas turbines and one steam turbine. Chugach will own 70% and ML&P will own 30%.

2.2.2 Chugach Electric Association (CEA)

The REGA Study report identified the following existing thermal power plants:

- CEA operates 13 combustion turbines between three power plants (Bernice 2-4, Beluga 1-7, and International 1-3) which operate on natural gas
- One steam turbine (Beluga 8) derives its steam from heat recovery steam generators (HRSGs).

In response to the project's request for current utility information, CEA Sent copy of their Tariff Filing Letter dated May 12, 2009.[6] CEA's existing thermal units are shown below in Table 5. As indicated in

[6] Chugach Tariff Letter 305-8, May 12, 2009.

Table 5, CEA also purchases hydroelectric power from Cooper Lake (20 MW), Eklutna Lake (12 MW), and Bradley Lake (27.4 MW).

Chugach depends on natural gas to produce about 90% of the power needed to serve its retail and wholesale member-customers. At present, Chugach uses approximately 27 Bcf of gas per year in its power plants. The gas that Chugach purchases for its fuel requirements all comes from Cook Inlet gas fields. At present, Chugach has no alternative source of gas to fuel its generation facilities.

Table 5. CEA Existing Thermal and Hydroelectric Units[2]

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Bernice	2	Natural Gas	19	2014
Bernice	3	Natural Gas	26	2014
Bernice	4	Natural Gas	22.5	2014
Beluga	1	Natural Gas	19.6	2011
Beluga	2	Natural Gas	19.6	2011
Beluga	3	Natural Gas	64.8	2014
Beluga	5	Natural Gas	68.7	2014
Beluga	6	Natural Gas	82	2020
Beluga	6/8	Natural Gas	108.5	2014
Beluga	7	Natural Gas	82	2021
Beluga	7/8	Natural Gas	108.5	2014
International	1	Natural Gas	14.1	2011
International	2	Natural Gas	14.1	2011
International	3	Natural Gas	18.5	2011

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
CEA	30.4	111,269	27.4	8.2	30.0	87,412	49,200	100.0	50,000	20.0

* Denotes units not available for commercial operation
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

For more than twenty years, Chugach has obtained its gas requirements under a series of long-term gas contracts with the following gas producers: ConocoPhillips (COP), Chevron, Marathon Oil ("MOC"), and Shell (now Anchorage ML&P). The volumes available under these existing long-term contracts will run out in 2010 (in MOC's case) and 2011. For at least the past five years, Chugach has spent a significant amount of time and effort working to obtain replacement gas supplies for the period after the present gas supplies end.

CEA, along with ML&P, is currently planning to build the so-called **Southcentral Power Plant (SPP)** to be completed in mid-2013. This will be a **183 MW** gas fired combined-cycle plant using three GE LM6000 gas turbines and one steam turbine. Chugach will own 70% and ML&P will own 30%.

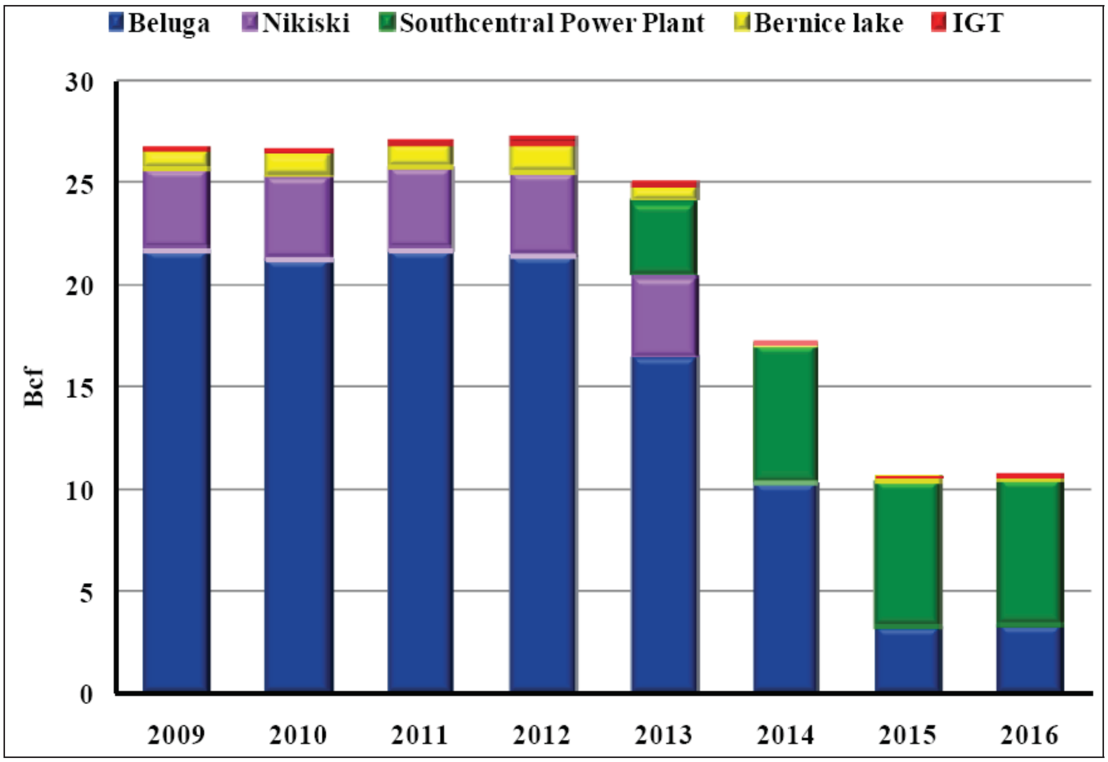
Figure 5 projects a breakdown of Chugach's requirements by generation facility for 2009 through 2016. Note that during the next seven years, the gas usage of various plants is expected to change as more efficient generation is brought on line in mid 2013. Consequently the delivery points and transportation needs will shift accordingly.

Chugach has negotiated a contract with COP (the Chugach-COP Contract) to meet a significant portion of its gas supply needs. The contract enables Chugach to meet 100% of unmet gas requirements through

April 2011, roughly 50% of Chugach's unmet gas requirements from June 2011 through 2015 and about 25% of Chugach's unmet needs in 2016. See Figure 5.

The Contract provides that Chugach will buy from COP a "Firm Gas Supply Tranche" described as "the total volume of Gas equal to 100% of the Gas volumes utilized at the Bernice Lake Power Plant, the Nikiski Power Plant and the International Power Plant, 40% of the Gas volumes utilized at the Beluga Power Plant, and 40% of the Buyer's share of the Southcentral Power Plant excluding any Gas utilized to generate economy energy sales at any or all of those facilities. (Chugach Tariff Letter 305-8, May 12, 2009).

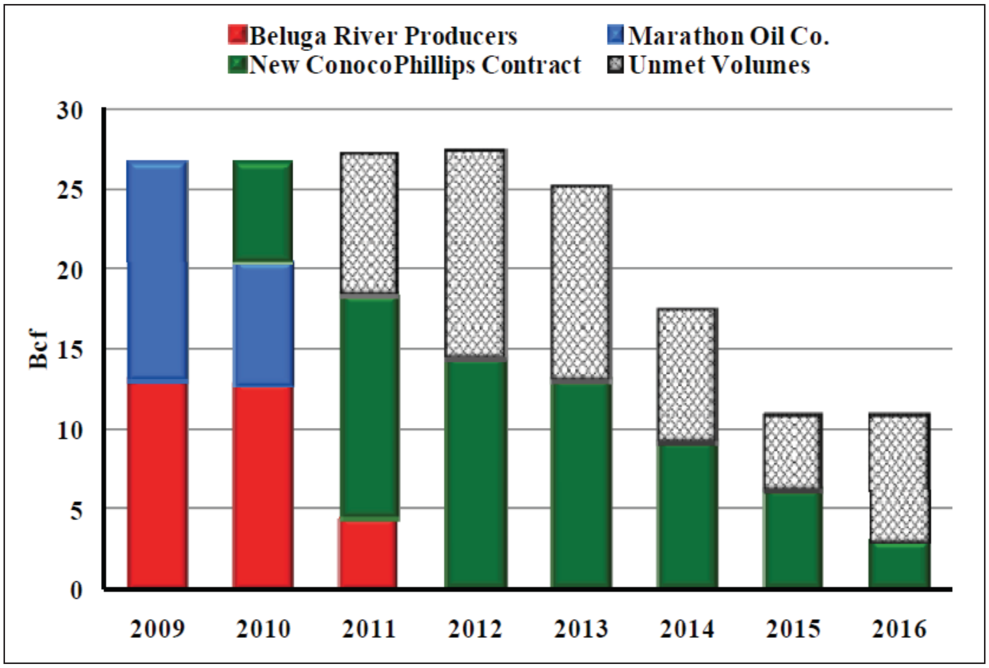
Figure 5. CEA Projection of Natural Gas Required by Plant[6]



Source: Chugach Tariff Letter 305-8, May 12, 2009

Figure 6 presents CEA's projection of natural gas volumes purchased under the Chugach-COP Gas Contract and from other suppliers, including unmet volumes.

Figure 6. CEA Projected Gas Supply by Producer[6]



Source: Chugach Tariff Letter 305-8, May 12, 2009

2.2.3 City of Seward Light and Power (SES)

SES did not respond to the project's request for current utility information. SES has no thermal plant capacity of its own, but does generate power through hydroelectric capacity (see Table 6

Table 6. SES Existing Hydroelectric Units[2]

Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
SES	1.0	3,660	0.9	0.3	0.0	0.0	0.0	0.0	0.0	0.0

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

2.2.4 Golden Valley Electric Association (GVEA)

In response to the project's request for current utility information, SAIC interviewed Henri Dale, Power Systems Manager.[7] Information provided by HEA is included in the following discussion.

The REGA Study report identified the following existing thermal power plants:

GVEA's generating capability of 277 MW is supplied by six generating facilities.

- Healy Power Plant provides 27 MW, is coal-fired and located adjacent to the Usibelli Coal Mine.
- GVEA's 190 MW North Pole Power Plant is oil-fired and built next to the Flint Hills refinery.
- Oil-fired Zehnder Power Plant in Fairbanks can provide 36 MW.
- Delta Power Plant (DPP), formerly the Chena 6 Power Plant can produce 25 MW.

[7] Telephone interview with Henri Dale, GVEA Power Systems Manager, July 1, 2009.

GVEA's existing thermal units are shown below in Table 7. As also indicated in Table 7, hydroelectric power is also purchased from Bradley Lake (15.2 MW).

GVEA comments about their existing capacity utilization are:

- While North Pole GT1 and GT2 could statistically be ready for retirement by 2017 and 2018 respectively, they are both currently in good shape with no known technical issues.
- DPP unit is strictly an emergency-type plant that is a backup unit for the Alaska pipeline pumping station and Fort Greely. It does have black-start capability. It is located at the end of a 100-mile transmission line.
- GVEA is required to keep 30% reserve capacity over peak load.
- Current peak load demand was quoted at 223.1 MW in the REGA report. Therefore, a nameplate capacity of about 290 MWe is technically required.
- Stated that plant retirement dates in the REGA study were calculated statistically and that GVEA expects most of the plants to operate longer than the listed retirement dates. No exact dates given.
- Confirmed that the original Healy coal plant (1967 start, 26.7 MWe) will likely be retired in 2022.

Table 7. GVEA Existing Thermal and Hydroelectric Units[2,7]

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Zehnder	GT1	HAGO	17.7	2030
Zehnder	GT2	HAGO	17.7	2030
North Pole	GT1	HAGO	60[a]	2017
North Pole	GT2	HAGO	64	2018
North Pole	GT3	Naphtha	52	2042
North Pole	ST4	Steam	12	2042
Healy	ST1	Coal	26.7	2022
DPP	1	HAGO	24.9	2030

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
GVEA	16.9	52,894	15.2	4.6	0.0	0.0	0.0	0.0	0.0	0.0

[a] Originally reported as 62 MW in GVEA report. Other minor capacity differences exist; these are possibly due to various capacity numbers given for different bases, i.e. max capacity, nameplate, winter, summer, etc.
Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

GVEA comments about future load requirements are as follows:

- Load growth has historically seen approximately 2%.
- Fort Knox gold mine is expected to shut down permanently sometime between the years 2015 to 2017. This is a 31 MW load that will go away. Originally, a 25 mile, 138 kV transmission line was built to connect the mine to the GVEA grid.
- The recent economic slowdown has resulted in a 6% load decrease that hasn't returned and is not expected to recover.

GVEA comments about future capacity retrofit and additions are:

- The REGA study projected 86 MW of capacity (two 43 MW units) coming online immediately (2008-2009). This projection was due to the model determining that additional new gas plants would be economical in the long run even if the demand was not present at the time due to the more efficient use of low price gas in the new units. *However, GVEA believes that these early units are highly unlikely*.

- The new Healy "Clean Coal" plant will be about 60MW when completed and expects to be operational in 2011, with reliable output achieved in 2012. GVEA expects to retire the unit in 2044. The state of Alaska currently owns the plant, but GVEA has made an offer to purchase the plant and all of the output would be purchased by Homer City Electric. *It was announced on July 22, 2009 that GVEA has worked out a settlement for HCCP. GVEA has agreed to purchase the plant from its owner, the Alaska Industrial Development and Export Authority, for $50 million. AIDEA has agreed to loan GVEA up to an additional $45 million for plant startup and system integration costs. The sale will be completed by August 1, 2009.*[8]
- Healy 1 (current coal-fired plant) would not consider retrofitting to natural gas because it is too old and not economical.
- Combustion turbines fueled with natural gas is most likely option for future generation.
- The original North Pole plant (Units 1 & 2, 120 MWe) could be retrofit with natural gas, but the building that houses the units would be "expensive to retrofit," negating the possibility of a retrofit with gas.
- Expansion of the 60 MWe LM6000 combined cycle unit (GT3) at North Pole would essentially double its capacity, adding 60 MW of generating capacity; the steam headers at the facility were double-sized to prepare for a possible expansion. The project entails installing a 47-MW combustion turbine with a steam turbine that allows us to generate an additional 13 MW (would be designated GT4). GT3 and GT4 could be converted to natural gas for approximately $1 million. GT3 currently fires Naphtha, an extremely clean burning fuel, produced next-door at the Flint Hills refinery. Note that unlike natural gas, oil-firing is not an economical alternative.
- Delta Power (DPP, old Chena 6) is used only about 10 hours per year as backup and emergency generation source to sensitive load points at end of long radial.
- New coal plants will be difficult to pursue given the potential for carbon constraints.
- Nuclear is unlikely option for GVEA.
- Wind and solar are seriously being studied, but GVEA is likely limited to a relatively small amount of wing generation. Intermittent sources present a variability problem that only backup capacity and energy storage can handle. GVEA is studying wind patterns northwest of Healy and on Murphy Dome. Meteorological towers located in interior Alaska continue to collect data. By analyzing this information, GVEA will determine how to best utilize this resource. GVEA is focusing efforts to construct a 24 – 50 MWe wind farm in Eva Creek near Healy – stated as close to shovel-ready with all permitting and internal studies completed. The project would minimally include 16 turbines at 1.5 MW each. This would represent about 20 percent of their peak load.
  - A Delta region group is studying a 50 MW project south of Delta – waiting on financing. A capacity factor of u 31 to 33% is expected based on meteorological studies.
- Note that GVEA currently operates a large battery storage facility (BESS – Battery Energy Storage System) that can provide 27 MWe of output for 15 minutes. Fifteen minutes is long enough for the co-op to start up local generation when there are problems with the Intertie or power plants in Anchorage. This facility was designed strictly to improve system reliability.

[8] GVEA press release, July 22, 2009. http://www.gvea.com/about/hccp/

2.2.5 Homer Electric Association (HEA)

In response to the project's request for current utility information, HEA sent a written answer to questions. Information provided by HEA is included in the following discussion.

HEA's existing thermal and hydroelectric units are shown below in Table 8.

- HEA owns the natural gas Nikiski combustion turbine. During the summer months it can produce a maximum of 35 MW, whereas in the winter it provides 39 MW.
- Hydroelectric power is also purchased from Bradley Lake (10.8 MW).

Table 8. HEA Existing Thermal and Hydroelectric Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Nikiski	1	Natural Gas	39	N/A
Seldovia (Standby only)	1	Diesel	1	?
Seldovia (Standby only)	2	Diesel	1	?
Port Graham (Standby only)	1	Diesel	0.35	?

Hydroelectric Capacity

Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
HEA	12.0	41,139	10.8	3.2	0.0	0.0	0.0	0.0	0.0	0.0

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

HEA comments about their existing capacity utilization included:

- No retirements of existing units is presently planned.

GVEA comments about future load requirements are as follows:

- Summer peak 70 MW expected over the next 5 to 10 year period
- Winter Peak 90 MW expected over the next 5 to 10 year period
- Limited industrial growth (10 MW) expected over the next 5-10 years. Minimal growth expected in non-industrial electric sales over the long term. Due to the small nature of the HEA system, we are sensitive to the activities of any large scale industrial customer that may add to or change its operation on the Kenai Peninsula.

HEA comments about future capacity retrofit and additions are:

- HEA is planning an additional 60 to 90 MW of natural gas fired generation prior to January 1, 2014.
- HEA is no longer a partner in the CEA/MLP Southcentral Power Plant.
- HEA is pursuing renewables to the best of its abilities. The stated goal may only be reached through the construction of extraordinarily expensive (large-scale hydro) or intermittently available (wind or tidal) generating facilities. HEA will continue to pursue this renewable goal and intends to be a leader in accommodating and embracing renewables, but at this time we do not foresee an affordable and reliable method by which this goal can be achieved.

2.2.6 Matanuska Electric Association (MEA)

In response to the project's request for current utility information, MEA sent a written answer to questions. Information provided by MEA is included in the following discussion.

MEA's existing thermal and hydroelectric units are shown below in Table 9.

- MEA owns four backup diesel engine-generators, one of which is retires and two of which are very close to retirement. *All three units will be retired in 2010 and replaced with new diesel fuel generators.*
- Hydroelectric power is purchased from Bradley Lake (12.4 MW) and Eklutna Lake (6.7 MW), operated so as to fully utilize these available water resources.

MEA comments about future load requirements are as follows:

- The MEA, Unalakleet Division 5 and 10 year electric seasonal winter peak demand is projected to be 850 kW (2015) and 850 kW (2020), respectively.
- The MEA, Unalakleet Division 5 and 10 year electric seasonal summer peak demand is projected to be 320 kW and 375 kW, respectively.
- The MEA, Palmer Division 5 and 10 year electric seasonal winter peak demand is projected to be 172 MW (2015) and 186 MW (2020) respectively.
- The MEA, Palmer Division 5 and 10 year electric seasonal summer peak demand is projected to be 84 MW and 90 MW respectively.

Table 9. MEA Existing Thermal and Hydroelectric Units

Name	Unit	Primary Fuel	Winter Rating (MW)	Projected Retirement Date
Unalakleet Division (Backup Only)	1	Diesel	0.5	Only 12,000 hours service
Unalakleet Division (Backup Only)	2	Diesel	0.3	Retired
Unalakleet Division (Backup Only)	3	Diesel	0.53	Soon:120,000 hours service
Unalakleet Division (Backup Only)	4	Diesel	0.53	Soon: 120,000 hours service

Hydroelectric Capacity										
Utility	Bradley Lake				Eklutna Lake			Cooper Lake		
	Percent Allocation	Annual Energy (MWh)	Capacity	Spinning Reserves	Percent Allocation	Annual Energy (MWh)	Capacity	Percent Allocation	Annual Energy (MWh)	Capacity
MEA	13.8	50,508	12.4	3.7	16.7	27,388	6.7	0.0	0.0	0.0

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

MEA comments about future capacity retrofit and additions are:

- MEA Palmer Division's future generation plant is not characterized correctly in the REGA Study. As of September 12, 2009, MEA was planning a 130 to 180 MW natural gas fired power plant beginning commercial operation by January 1, 2015. To this end MEA has purchased approximately 70 acres of land in Eklutna, AK (approximately 10 miles south of MEA's headquarters in Palmer, AK). MEA is engaged in an Engineering, Procurement and Construction/Independent Power Producer procurement process to identify the best power generation fit to serve MEA's members. This process is expected to conclude in 2010. More recent information (http://www.adn.com/money/story/936507.html) suggests that MEA may be unable to build a plant of this size since gas contracts for the plant cannot be obtained.
- Wind turbines will be added into the Unalakleet Division grid in 2009 or 2010. The wind turbines will not be owned by MEA under current plans.
- MEA's Palmer Division is in the final planning and land acquisition process for development of a natural gas fueled generation plant within its service territory by 2014. The prime mover type and capacity for this plant is not currently known.

- MEA's Palmer Division is currently in negotiations with developers to purchase the output of two proposed run-of-the-river hydroelectric projects, and is hoping to develop a landfill gas generation project within its service territory. With these resources, a few household size wind generators interconnected with MEA's distribution system, and MEA Palmer Division's existing hydroelectric generation resources, renewable sources are projected to meet approximately 9% of MEA Palmer Division's 2025 load. MEA is actively participating in discussions related to the development of renewable resource generation capacity within the Railbelt Region, and desires to expand its renewable resource generation portfolio to the extent that such expansion is consistent with prudent utility practice. MEA's Unalakleet Division has been approached by Unalakleet Valley Electric Cooperative (UVEC) about interconnecting wind turbines with MEA's Unalakleet system. Those discussions are ongoing.

2.3 Drivers for Natural Gas Demand in the Railbelt System in Alaska

Natural gas demand for electric power usage in Alaska's Railbelt region is ultimately driven by electricity demand, relative fuel pricing, fuel availability, and the relative efficiency of the electric generators employed. Although natural gas usage for electric power is currently ranging from 35 to 40 Bcf per year, this quantity could change substantially in the future depending on the future generation alternatives. Such a change may not be proportional to the amount of electric power generated for the following reasons.

- Natural gas is available for electric power generation throughout the interconnected electricity grid in Alaska with the exception of Fairbanks. Traditionally, natural gas has been very inexpensive and only competed with existing hydroelectric technologies as a viable fuel choice. However, with the potential introduction of an interconnected natural gas supply with the balance of the continent, local prices will be driven by continental prices. Future increases in natural gas prices may make competing technologies more attractive.
- The existing inventory of electric generating units in the interconnected portion of Alaska is generally older and less efficient. As new more efficient generating units are introduced they will be able to generate the same quantity of electric power using less fuel. For example, the average heat rate of existing natural gas fired plants in Alaska is about 11,000 Btu/kWh; as new efficient plants are built, heat rates could go as low as 7,000 Btu/kWh (a decrease of more than 35%).

3 Electric Power Market Modeling Methodology

As discussed in Section 1, this study does not perform independent utility systems modeling, but builds upon the outcomes of the AEA-sponsored REGA Study, which performed detailed utility capacity and dispatch modeling for four different future energy supply futures. However, since the economy and energy outlook have changed since the REGA study was performed, this study made every effort obtain a current perspective on the future resource mix of the Railbelt utility companies to meet service area electricity demand and adjust the REGA outcomes accordingly.

3.1 Overview of Black and Veatch REGA Study

The Alaska Energy Authority retained B&V to evaluate the feasibility, and economic and non-economic benefits, associated with the formation of a regional generation and transmission (G&T) entity called the Railbelt Electrical Grid Authority (REGA), whose purpose is to manage and dispatch electric power on the Railbelt grid. The study's objectives were to:

- Identify and assess a list of options for the management, operation, access rules, ownership, resource planning, and regulatory structures of the Railbelt generation and transmission system.

- For certain agreed-upon options, further analyze and provide recommendations of possible alternative structures to manage and dispatch electric power throughout the Railbelt region.
- Provide a final work product for stakeholders and decision-makers to consider in planning how to meet the Railbelt region's energy needs over the next 30 years.

The REGA study report is available at:
http://www.aidea.org/aea/REGAFiles/9-12-08_AlaskaRailbeltREGAStudy_MasterFinalReport.pdf

3.2 Methodology Overview

The original B&V REGA report did not contain enough detail to perform the current study. Therefore, SAIC requested supporting data from B&V on May 26, 2009. The information requested included the following:

- Fuel consumption by fuel type, year, utility, scenario
- Electricity generation (kW-hr) by technology type (e.g., gas turbine, coal-fired PC, wind), year, utility, scenario
- Plant retirements by technology type, year, utility, scenario (not sure the plants were retired by the model per the projected retirement dates)
- Busbar electricity prices by technology type, year, utility, scenario
- Average delivered electricity price by utility, year, scenario
- Emissions (e.g., CO_2, SO_2, etc.) by year, utility, scenario

B&V sent data responding to our request on July 23, 2009. The response included data for four scenarios that are further defined in Section 3.3:

- Scenario 1 - Large Hydro/Renewables/DSM/Energy Efficiency
- Scenario 2 - Natural Gas
- Scenario 3 – Coal
- Scenario 4 - Mixed Resource Portfolio

Data provided at the *company level* included: 1) fuel consumption by fuel type (1000MBtu/Year), 2) gaseous emissions by type (Tons), 3) electricity busbar price by fuel ($/MWh), and 4) average delivered electricity price ($/MWh). Data was provided in a spreadsheet format. Data provided at the *unit level* included: 1) electricity generation in million kW-hours for each unit by company and fuel type. Data was provided in a spreadsheet format. All of the B&V data was incorporated into an Excel workbook (project workbook).

In addition to the data provided by B&V, SAIC created two new sets of data in the project workbook for each scenario based on the B&V data: a calculated fuel consumption sheet and a capacity sheet. The study calculates average fuel consumption using the generation and heat rate information provided by B&V while the capacity sheet adds the capacity of each available generating unit to provide overall capacity by utility.

SAIC sent email requests to each utility in mid-June in an effort to schedule phone interviews with appropriate company staff regarding current and projected use of natural gas for electricity generation. Information collected during these interviews along with reports and data received from the utilities and information obtained in the public sector and on utility websites was incorporated into the project workbook.

3.3 Railbelt Power Market Scenarios

B&V developed four "Evaluation Scenarios" that are considered alternative energy futures for the Railbelt region. These are defined as follows:

Natural Gas Scenario: Assumes that all of the future generation resources will be natural gas-fired facilities, continuing the region's dependence upon natural gas.

Mixed Resource Portfolio Scenario: Assumes that a combination of large hydroelectric, renewables, DSM/energy efficiency programs, coal and natural gas resources is added over the next 30 years to meet the future needs of the region.

Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Assumes that the majority of the future regional generation resources that are added to the region include one or more large hydroelectric plants (greater than 200 MW), other renewable resources, and DSM and energy efficiency programs.

Coal Scenario: Assumes the addition of coal plants to meet the future needs of the region.

Discussions were held with Jim Strandberg of AEA and Kevin Harper, the B&V project manager for the RIRP study, to assess the probability of occurrence of these scenarios. The following table presents the consensus from the two of them regarding the probability of each scenario in our two subject years. The probability of the natural gas scenario is higher in 2019 than 2030 because gas is considered a "bridge fuel" until other alternatives can be brought onboard.

Table 10. Assumed Probabilities of Occurrence for Alternative Energy Scenarios

Scenario	Year	
	2019	2030
Natural Gas	45%	20%
Mixed	25%	60%
Large hydro	20%	15%
Coal	10%	5%

Source: Jim Strandberg, AEA

3.4 B&V REGA Modeling Assumptions

The issues and uncertainties that impacted the original B&V REGA analysis include, but are not limited to, the following:[2]

- Future fuel supplies and costs
- Load growth, military base realignment, economic development, and power exports
- Aging generation and transmission assets and planned retirements
- Future desirability and costs of major generation facilities (e.g., coal, nuclear, and hydro facilities)
- Impact of a major power project coming on-line in the Railbelt, such as a large hydropower project
- Potential growth in non-utility generation (e.g., qualifying facilities, QFs, and independent power producers, IPPs)
- Potential transmission system expansions
- DSM/energy efficiency programs, renewables, and distributed generation resources - resource potential, relative economics, and policy-driven targets and growth
- Environmental legislation (including carbon taxes), regulations and constraints.
- Financing – access to capital, costs, and tax implications

- Outcome of proposed Chugach/ML&P merger, coordinated operations, and or joint project development
- Future role of the State, AEA and AIDEA – expand, maintain or sell State-owned energy assets

B&V's conducted their detailed evaluation of power costs over a forward looking 30-year evaluation period between 2008 through 2037. Their evaluation of each Evaluation Scenario utilized nominal dollars with the annual costs discounted to 2009 dollars for comparison using range of discount rates selected to represent reasonable discount rates for the Railbelt utilities. The study used discount rates of 6.0 percent, 8.0 percent, 10.0 percent, and 15.0 percent, with the 6.0 percent set as the base case. For evaluation purposes, the study assumed a general inflation and escalation rate of 3.0 percent

The study developed fixed charge rates for new capital additions based on the cost of capital for each utility for new generating unit additions and used a joint fixed charge rate based for the joint commitment, dispatch, and planning path. The joint fixed charge rate was based on the assumption of being able to obtain taxable and tax-exempt financing, and further assumed 100 percent debt financing. The assumed cost of capital and fixed charge rates presented in Table 11 are based on the following assumptions:

- Financial advisors were consulted and a general consensus developed for purposes of estimating the cost of capital for evaluation purposes.
- MEA, HEA, and CEA were assumed to use National Rural Utilities Cooperative Finance Corporation (CFC) financing with an interest rate of 6.75 percent.
- GVEA was assumed to use RUS financing with an interest rate of 5.0 percent.
- ML&P was assumed to use tax-exempt municipal bond financing with an interest rate of 5.0 percent.
- Fixed charge rates were developed only considering principle and interest for financing terms of 20, 25, and 30 years based on the expected financing lifetimes of the various alternatives.

Table 11. REGA Study Cost of Capital and Fixed Charge Rates[2]

Utility	Cost of Capital (%)	Fixed Charge Rate (%) Financing Terms (Years)		
		20	25	30
MEA	6.75	9.26	8.39	7.86
HEA	6.75	9.26	8.39	7.86
CEA	6.75	9.26	8.39	7.86
GVEA	5.00	8.02	7.10	6.51
ML&P	5.00	8.02	7.10	6.51
Joint Tax-Exempt	5.00	8.02	7.10	6.51
Joint Taxable	6.75	9.26	8.39	7.86

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

B&V developed a load forecast for each utility through the end of the study period based on the load forecasts provided by the utilities. The load forecast includes consideration of existing DSM and conservation programs, but does not include future plans for additional DSM and conservation. Table 12 below presents the load forecast for each utility from 2008 through 2037.

Table 12. REGA Study Railbelt Load Forecast for Evaluation (2008 – 2037)[2]

Year	Utility Peak Demand (MW)					
	ML&P	CEA	GVEA	HEA	MEA	SES
2008	158	477	230	81	141	10
2010	168	489	237	78	149	10
2015	172	272	218	80	172	11
2020	177	285	226	80	186	12
2025	180	296	234	81	201	12
2030	185	307	243	82	216	13
2035	189	319	252	83	231	14
2037	191	324	256	84	237	14

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

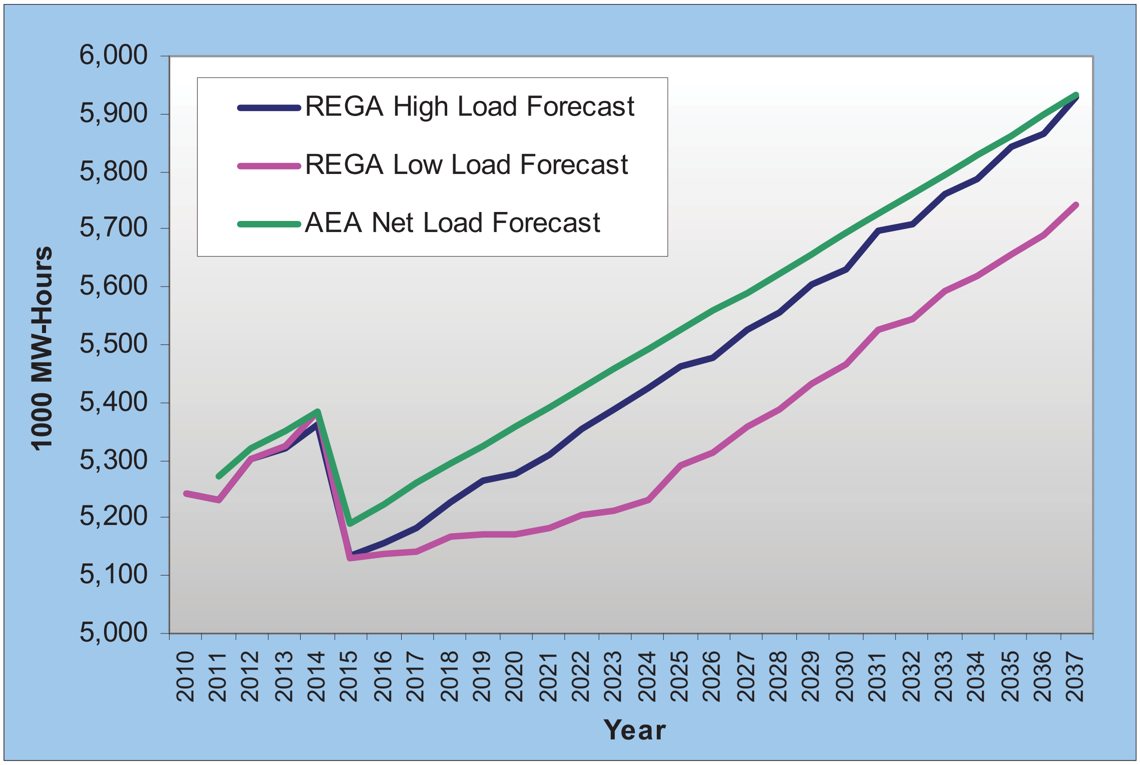
Table 13 lists the total Railbelt load forecast by generation (MW-Hours/Year) for each scenario and compares these values with the Alaska Energy Agency's (AEA) "utility net energy for load forecast"; the latter are generally less than 1% greater than the B&V "High Load Forecast" and up to 4.7% greater than the "Low Load Forecast." Figure 7compares these load forecasts.

Table 13. Electricity Demand Forecasts Used for Modeling

	Railbelt Electricity Demand Forecasts (1000 MW-Hours/Year)				
Year	Large Hydro/ Renewables/DSM/ Energy Efficiency	Natural Gas	Coal	Mixed Resource Portfolio	AEA Net Load Forecast
2010	5,243	5,243	5,243	5,243	--
2011	5,233	5,233	5,233	5,233	5,273
2012	5,304	5,302	5,304	5,304	5,322
2013	5,324	5,322	5,322	5,324	5,353
2014	5,385	5,384	5,383	5,385	5,384
2015	5,130	5,152	5,140	5,130	5,189
2016	5,139	5,182	5,177	5,139	5,225
2017	5,140	5,201	5,210	5,140	5,262
2018	5,170	5,253	5,246	5,168	5,294
2019	5,173	5,269	5,277	5,171	5,326
2020	5,172	5,284	5,296	5,170	5,359
2021	5,184	5,319	5,327	5,183	5,392
2022	5,208	5,359	5,368	5,207	5,425
2023	5,212	5,393	5,398	5,211	5,458
2024	5,232	5,431	5,441	5,231	5,491
2025	5,274	5,466	5,466	5,290	5,525
2026	5,301	5,494	5,493	5,315	5,558
2027	5,341	5,536	5,530	5,356	5,591
2028	5,373	5,569	5,566	5,388	5,625
2029	5,413	5,614	5,605	5,433	5,659
2030	5,446	5,645	5,642	5,467	5,692
2031	5,492	5,700	5,688	5,526	5,726
2032	5,520	5,722	5,719	5,543	5,760
2033	5,562	5,770	5,762	5,593	5,795
2034	5,595	5,801	5,797	5,619	5,829
2035	5,638	5,850	5,842	5,658	5,863
2036	5,672	5,881	5,878	5,689	5,898
2037	5,719	5,930	5,929	5,742	5,933

Source: Black and Veatch, “Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report,” 9-12-2008 and AEA.

Figure 7. Comparison of Natural Gas, Mixed Resource, and AEA Load Forecasts (Excluding SES)



Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008 and AEA.

For consistency purposes, the REGA study used a single reference fuel price forecast for all of the utilities in this analysis. The fuel price forecast reflects a general inflation rate of 3.0 percent and fuel prices are on a $/MMBtu basis.

- **Natural Gas:** Henry Hub spot natural gas prices were taken from the EIA *2008 Annual Energy Outlook* (AEO) projections and used as a starting point to forecast the price of natural gas. Natural gas is assumed to be available from the North Slope in 2020. Natural gas from the North Slope is assumed to be at a $2.00/MMBtu discount to Henry Hub, but transportation costs to the central and southern portions of the Railbelt will offset that discount. ML&P owns gas in the Beluga River Unit (BRU) gas fields. Projected prices and volumes for BRU gas were provided by ML&P.
- **Coal:** Coal price forecasts were developed by escalating the given price per ton annually at two-thirds (66 percent) the general inflation rate (2.0 percent).
- **Fuel Oil:** Average crude wellhead prices for the lower 48 states were taken from the EIA's *2008 Annual Energy Outlook* and used as a starting point for developing heavy atmospheric gas oil (HAGO) and naphtha fuel price forecasts. Distillate fuel oil prices were based on the EIA's 2008 AEO distillate fuel oil price forecast.

The fuel cost projections are shown below in Table 14.

Table 14. REGA Study Fuel Price Reference Forecast ($/MBtu)[2]

Year	Henry Hub Natural Gas	Coal	HAGO	Naphtha	Distillate Fuel Oil
2008	7.67	2.59	17.33	18.75	18.41
2009	8.03	2.67	17.91	19.40	15.57
2010	7.77	2.75	17.65	19.00	15.33
2011	7.61	2.83	17.49	18.73	14.98
2012	7.61	2.92	17.06	18.13	14.56
2013	7.58	3.01	16.60	17.49	14.17
2014	7.58	3.10	16.26	17.00	14.26
2015	7.65	3.19	15.85	16.41	13.93
2016	7.82	3.29	15.46	15.85	13.79
2017	8.16	3.38	15.87	16.25	14.22
2018	8.51	3.49	16.04	16.36	14.85
2019	8.89	3.59	16.60	16.96	15.53
2020	9.00	3.70	17.04	17.40	16.18
2021	9.06	3.81	17.69	18.08	16.83
2022	9.55	3.92	18.38	18.82	17.54
2073	10.05	4.04	19.14	19.63	18.41
2024	10.64	4.16	19.82	20.35	19.38
2025	11.21	4.29	20.72	21.35	20.33
2026	11.84	4.42	21.72	22.44	21.41
2027	12.29	4.55	22.70	23.52	22.40
2028	13.15	4.69	23.83	24.77	23.47
2029	13.93	4.83	24.79	25.81	24.68
2030	14.68	4.97	25.69	26.78	25.83
2031	15.48	5.12	26.80	27.99	27.07
2032	16.34	5.27	27.95	29.25	28.37
2033	17.24	5.43	29.15	30.58	29.73
2034	18.18	5.59	30.41	31.96	31.15
2035	19.18	5.76	31.72	33.40	32.65
2036	20.24	5.94	33.09	34.92	34.21
2037	21.35	6.11	34.52	36.50	35.85

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

Table 15 shows the unit characteristics assumed for the conventional and emerging technologies. Estimates for costs and performance parameters were based on B&V project experience, vendor inquiries, and a literature review; the generic cost estimates for renewable technologies developed by B&V included consideration of specific projects in Alaska, where available, and numerous other projects with costs adjusted for Alaska. Capital costs reflect the total project cost, including direct and indirect costs.

Table 15. Conventional and Emerging Technology Unit Characteristics (All Costs in 2008 Dollars)

Name	Net Output (MW)	Total Cost ($millions)	Primary Fuel	Forced Outage Rate (%)	Full Load Net Heat Rate (Btu/kWh) HHV	Annual Scheduled Maintenance (Days/Yr)	CO2 Emission Rate (lb/MMbtu)
GE 6B Simple Cycle	42.1	52.8	Natural Gas	2.0%	12,270	10	115
GE LMS100 Simple Cycle	98.8	123.4	Natural Gas	2.0%	8,260	10	115
GE LM6000 Simple Cycle	43.0	74.0	Natural Gas	2.0%	9,020	10	115
1x1 GE 6FA Combined Cycle	116.0	253.8	Natural Gas	3.0%	7,300	14	115
2x1 GE 6FA Combined Cycle	235.0	402.5	Natural Gas	4.0%	7,160	17	115
Sub-critical Pulverized Coal	100.0	462.4	Coal	5.0%	10,140	21	211

Source: Black and Veatch, "Alaska Railbelt Electrical Grid Authority (REGA) Study - Final Report," 9-12-2008.

With regard to technology choice, wind and hydroelectric were the only two renewable technologies assumed for future generation resource additions in the REGA study.

Wind generation projects were assumed to be installed in 50 MW blocks. The wind generation was apportioned to each of the Railbelt Utilities in proportion to their 2007 peak demands. The estimated total installed cost for the wind generation was assumed to be $2,500/kW in 2008 dollars. The estimated annual capacity factor was 35 percent. The estimated fixed O&M costs were $18.00/kW-year in 2008 dollars. Ten (10) percent of the net capacity of the wind generation was assumed to contribute to the planning reserve margins. Transmission losses to deliver the wind generation to the transmission system are assumed to be 3.0 percent.

Large hydroelectric generation projects were assumed to be installed in 300 MW blocks. Each hydroelectric project was assumed to have four hydroelectric turbines, each with 75 MW capacity. The hydroelectric generation was apportioned to each of the Railbelt Utilities in proportion to their 2007 peak demands. The estimated total installed cost for the hydroelectric projects was $5,600/kW in 2008 dollars. The estimated fixed O&M and variable O&M costs were $7.50/kW-year and $6.00/MWh, respectively in 2008 dollars. Transmission losses to deliver the hydroelectric generation to the transmission system were also assumed to be 3.0 percent.

3.5 Data Modifications of the B&V REGA Projections

This study incorporated the following data into the B&V data:

- **GVEA:**
  - Based on a phone interview with Henri Dale at GVEA we adjusted the retirement data for the North Pole unit 2. The retirement date was extended 5 years with the unit producing the average of all prior years generation for the first three years and half of that amount for the remaining two years. It was assumed that this unit would scale back generation during the last two years of service.
  - Based on information from an article in Vol. 14, No. 30 of North of 60 Mining News it was confirmed that the Healy Clean Coal Plant (Healy CCP) would be sold to GVEA and that the agreement also provides that Homer Electric will purchase from Golden Valley half of the plant's energy and capacity, starting in 2014.

- Based on information from GVEA's website (http://www.gvea.com/about/_hccp/) it was confirmed that the Healy CCP would be approximately 50MW. However, the interview with GVEA's Henri Dale indicated that the output would be 60 MW, so it was decided to use the higher value.
- According to Black & Veatch, GVEA's two LM6000 units (both 43MW) were assumed to be burn HAGO until 2020 instead of natural gas. However, we modified this to reflect the assumption that the pipeline start year for this study is 2019.
- Updated GVEA North Pole 1x1 CC plant to burn natural gas starting in 2019, listed as burning naphtha.
- Delayed launch of REGA-projected GVEA's two LM6000 units until 2015 based on utility interview response stating that the early launch (2008 – 2009) of these units is highly unlikely.

- **CEA**
  - Mr. Thibert confirmed that the Southcentral natural gas plant will be 183MW with 70% (128MW) going to CEA and 30% (55MW) going to ML&P. The unit will be in service in 2014. Mr. Thibert confirmed that HEA was no longer planning to share power from this plant. Based on this information HEA's share of power from the Southcentral natural gas plant was removed.
- **HEA**
  - It was assumed that the power that HEA would have received from its share of the Southcentral plant would now be purchased from the Healy CCP. This information was incorporated into the data.\
- **MEA**
  - Updated Matanuska LMS100 (2015) units from 98.8 MW to 90 MW based on response from Matanuska to utility interview questions. MEA is still determining the optimum size for this plant, but 90 MW is used in this analysis.

4 Modeling Results

The following sub-sections outline this study's updated natural gas, mixed portfolio, and large hydro renewable results.

4.1 Natural Gas Scenario Results

Table 16, Table 17, and Table 18 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 19 provides total energy consumption for all Railbelt utilities by fuel type.

Table 16. Natural Gas Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	98.8	8,262	New LMS100 (2018)	1	Natural Gas	1/2038
	98.8	8,262	New LMS100 (2022)	1	Natural Gas	1/2042
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	Bradley Lake - 08-13	1	Water	12/2013
	27.4	--	Bradley Lake - 2014	2	Water	12/2014
	27.4	--	Bradley Lake (2015+)	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake (2015+)	2	Water	1/2040
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013
CT Gas	42.1	12,268	New 6B SC (2031)	1	Natural Gas	1/2051
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2019)	1	Natural Gas	1/2039
Combined	52.0	8,269	North Pole 1x1 CC	1	Naphtha	1/2042
	116.0	7,298	New 1X1 6FA CC (2028)	1	Natural Gas	1/2053
CT Oil	62.0	10,100	North Pole	1	HAGO	12/2017
	64.0	9,910	North Pole	2	HAGO	12/2018
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	24.9	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
MLP						
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	43.0	9,023	New LM6000 (2037)	1	Natural Gas	1/2057
	98.8	8,262	New LMS100 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
	21.3	--	Eklutna Lake	1	Water	1/2040
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
MEA						
CT Gas	42.1	12,268	New 6B SC (2021)	1	Natural Gas	1/2041
	42.1	12,268	New 6B SC (2032)	1	Natural Gas	1/2052
	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
	98.8	8,262	New LMS100 (2035)	2	Natural Gas	1/2055
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040

Source: Estimates by SAIC from B&V, 2008.

Table 17. Natural Gas Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,919	2,336	2,751	2,277	2,555	1,054	1,159	931	1,233	1,262	987	1,012	1,328	1,485	1,391	1,545	1,581	1,635	1,579	1,633	1,597	1,601	1,598	1,636	1,618	1,549	1,559	1,527
GVEA	648	1,339	860	1,565	894	999	1,126	1,403	1,097	1,486	1,600	1,730	1,494	1,580	1,488	1,630	1,781	1,724	1,846	1,840	1,861	1,946	1,874	1,896	1,897	1,836	1,901	1,721
MLP	1,675	1,558	1,691	1,480	1,849	1,554	1,966	1,560	1,936	1,346	1,869	1,477	1,805	1,342	1,736	1,171	1,081	1,067	1,074	1,020	1,088	925	1,093	995	1,101	994	1,101	1,109
HEA	0	0	0	0	86	61	87	75	86	47	52	52	51	48	51	46	58	51	58	51	59	46	58	51	58	50	58	46
MEA	0	0	0	0	0	1,484	845	1,232	902	1,129	776	1,049	682	938	766	1,075	993	1,058	1,012	1,069	1,040	1,182	1,097	1,192	1,127	1,420	1,263	1,526
TOTAL	5,243	5,233	5,302	5,322	5,384	5,152	5,182	5,201	5,253	5,269	5,284	5,319	5,359	5,393	5,431	5,466	5,494	5,536	5,569	5,614	5,645	5,700	5,722	5,770	5,801	5,850	5,881	5,930
NG GENERATION BY UTILITY																												
CEA	2,612	2,028	2,444	1,970	2,247	747	892	745	1,046	1,075	800	825	1,141	1,298	1,204	1,358	1,394	1,448	1,392	1,446	1,410	1,414	1,412	1,449	1,431	1,362	1,372	1,341
GVEA	0	0	0	0	0	0	0	0	0	984	1,031	1,185	1,038	1,236	1,145	1,365	1,328	1,365	1,395	1,483	1,408	1,668	1,417	1,538	1,436	1,485	1,442	1,451
MLP	1,508	1,391	1,524	1,313	1,682	1,387	1,799	1,393	1,770	1,179	1,702	1,310	1,638	1,175	1,569	1,004	914	900	907	853	921	759	927	828	934	828	934	942
HEA	0	0	0	0	21	20	27	18	26	3	8	8	6	4	7	1	15	8	15	8	15	2	15	8	15	6	15	1
MEA	0	0	0	0	0	1,484	845	1,156	826	1,053	700	973	606	862	690	999	917	982	935	993	964	1,106	1,021	1,116	1,051	1,344	1,187	1,450
TOTAL	4,120	3,420	3,968	3,283	3,950	3,638	3,564	3,313	3,667	4,293	4,241	4,302	4,429	4,575	4,615	4,727	4,568	4,704	4,644	4,783	4,718	4,949	4,792	4,939	4,867	5,025	4,949	5,185
GENERATION BY FUEL																												
Coal	67	146	147	389	457	395	483	394	470	309	377	351	335	221	292	212	399	306	401	307	403	228	407	307	410	301	409	221
Natural Gas	4,120	3,420	3,968	3,283	3,950	3,638	3,564	3,313	3,667	4,293	4,241	4,302	4,429	4,575	4,615	4,727	4,568	4,704	4,644	4,783	4,718	4,949	4,792	4,939	4,867	5,025	4,949	5,185
Oil	528	1,140	660	1,124	449	592	609	971	592	143	143	143	71	73	0	2	4	2	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	527	527	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	5,243	5,233	5,302	5,322	5,384	5,152	5,182	5,201	5,253	5,269	5,284	5,319	5,359	5,393	5,431	5,466	5,494	5,536	5,569	5,614	5,645	5,700	5,722	5,770	5,801	5,850	5,881	5,930
Generation Percentage																												
Coal	1	3	3	7	8	8	9	8	9	6	7	7	6	4	5	4	7	6	7	5	7	4	7	5	7	5	7	4
Natural Gas	79	65	75	62	73	71	69	64	70	81	80	81	83	85	85	86	83	85	83	85	84	87	84	86	84	86	84	87
Oil	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9	9	9
Hydroelectric	10	22	12	21	8	11	12	19	11	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 18. Natural Gas Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	27.25	20.40	25.11	17.61	19.32	5.42	6.44	5.40	7.53	8.15	5.69	5.96	8.24	9.80	8.75	10.42	10.30	11.02	10.28	11.00	10.44	10.88	10.44	11.03	10.60	10.32	10.12	10.28
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.12	8.50	9.83	8.48	10.23	9.37	11.32	11.03	11.32	10.46	11.19	10.58	12.71	10.65	11.64	10.81	11.20	10.85	10.92
MLP	14.42	13.41	14.59	12.38	16.32	13.24	17.64	13.31	17.31	11.09	16.54	12.41	15.82	11.00	15.03	9.28	7.52	7.58	7.45	7.15	7.17	5.99	7.21	6.51	7.28	6.51	7.28	7.48
HEA	0.00	0.00	0.00	0.00	0.23	0.22	0.31	0.21	0.29	0.03	0.09	0.09	0.07	0.04	0.08	0.02	0.16	0.09	0.17	0.09	0.17	0.02	0.17	0.08	0.17	0.07	0.16	0.02
MEA	0.00	0.00	0.00	0.00	0.00	12.09	6.88	9.42	6.73	8.58	5.70	7.95	4.94	7.03	5.62	8.17	7.49	8.03	7.64	8.11	7.87	9.05	8.35	9.13	8.60	10.95	9.67	11.82
Total Natural Gas	41.67	33.81	39.71	29.98	35.87	30.98	31.27	28.34	31.86	35.96	36.53	36.25	37.56	38.10	38.85	39.20	36.50	38.03	36.00	37.54	36.23	38.65	36.83	38.40	37.46	39.05	38.08	40.52
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	8.12	8.50	9.83	8.48	10.23	9.37	11.32	11.03	11.32	10.46	11.19	10.58	12.71	10.65	11.64	10.81	11.20	10.85	10.92
ANC Nat Gas	41.67	33.81	39.71	29.98	35.87	30.98	31.27	28.34	31.86	27.85	28.03	26.42	29.07	27.87	29.48	27.88	25.47	26.71	25.54	26.36	25.65	25.94	26.18	26.76	26.65	27.85	27.23	29.59

Source: Estimates by SAIC from B&V, 2008.

Table 19. Natural Gas Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,216	5,168	4,440	5,243	4,330	5,107	3,412	4,104	3,827	3,649	2,254	2,977	2,166	4,056	3,112	4,081	3,118	4,098	2,322	4,135	3,124	4,167	3,060	4,152	2,258
Natural Gas	42,255	34,279	40,262	30,402	36,375	31,409	31,710	28,738	32,306	36,467	37,043	36,761	38,083	38,630	39,393	39,745	37,014	38,562	36,505	38,069	36,739	39,192	37,345	38,936	37,985	39,600	38,612	41,083
Naphtha	2,174	2,910	2,187	2,953	1,737	2,285	2,182	2,422	2,175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,641	7,950	3,946	7,864	2,374	2,926	3,290	6,203	3,149	1,421	1,420	1,427	707	725	7	32	49	30	2	4	3	0	0	0	0	0	0	0
Total	48,015	46,886	48,158	45,434	45,654	41,059	42,425	41,692	42,737	41,300	42,567	42,015	42,439	41,609	42,377	41,943	41,119	41,704	40,588	41,192	40,840	41,514	41,479	42,059	42,153	42,659	42,764	43,341

Source: Estimates by SAIC from B&V, 2008.

4.2 Mixed Resource Portfolio Scenario Results

Table 20, Table 21, and Table 22 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 23 provides total energy consumption for all Railbelt utilities by fuel type.

Table 20. Mixed Resource Portfolio Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
New Coal	100.0	10,140	New Coal (2025)	1	Coal	1/2055
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	98.8	9,023	New LM6000 (2018)	1	Natural Gas	1/2038
	98.8	8,262	New LMS100 (2022)	1	Natural Gas	1/2042
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,298	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	BradleyLake - 08-13	1	Water	12/2013
	27.4	--	BradleyLake - 2014	2	Water	12/2014
	27.4	--	BradleyLake - 2015+	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake - 2015+	2	Water	1/2040
	80.1	--	New Hydro (2020)	1	Water	1/2040
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013
	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	42.1	12,268	New 6B SC (2019)	1	Natural Gas	1/2039
	42.1	12,268	New 6B SC (2031)	1	Natural Gas	1/2051
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2028)	1	Natural Gas	1/2048
Combined	52.0	7,298	North Pole 1x1 CC	1	Naphtha	1/2042

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CT Oil	62.0	10,100	North Pole	1	HAGO	12/2017
	62.0	9,910	North Pole	2	HAGO	12/2018
	64.0	8,269	T 1X1 North Pole Retrofit (2031)	1	Natural Gas	1/2056
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	24.9	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
	77.7	--	New Hydro (2020)	1	Water	1/2040
Wind	13.0	--	New Wind (2012)	1	Wind	1/2037
MLP						
New Coal	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	43.0	9,023	New LM6000 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040
	21.3	--	Eklutna Lake	1	Water	1/2040
	64.5	--	New Hydro (2020)	1	Water	1/2040
Wind	10.7	--	New Wind (2012)	1	Wind	1/2037
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
	27.9	--	New Hydro (2020)	1	Water	1/2040
Wind	4.6	--	New Wind (2012)	1	Wind	1/2037
MEA						
New Coal	100.0	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
Combined	116.0	7,298	New 1X1 6FA CC (2035)	1	Natural Gas	1/2060
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040
	49.8	--	New Hydro (2020)	1	Water	1/2040
Wind	8.3	--	New Wind (2012)	1	Wind	1/2037

Source: Estimates by SAIC from B&V, 2008.

Table 21. Mixed Resource Portfolio Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,919	2,336	2,740	2,276	2,503	937	1,068	933	1,055	939	774	900	1,289	1,349	1,303	1,509	1,626	1,628	1,625	1,611	1,674	1,621	1,692	1,662	1,700	1,573	1,611	1,546
GVEA	648	1,339	861	1,558	898	983	1,108	1,388	1,126	1,354	1,440	1,626	1,098	1,394	1,134	1,088	1,167	1,173	1,247	1,319	1,460	1,701	1,506	1,669	1,579	1,308	1,316	1,352
MLP	1,675	1,558	1,694	1,482	1,849	1,558	1,962	1,563	1,975	1,390	1,970	1,593	1,896	1,464	1,838	1,455	1,264	1,272	1,262	1,224	1,062	904	1,058	964	1,049	882	985	789
HEA	0	0	3	3	129	104	86	76	89	50	87	89	83	82	84	162	176	169	175	169	182	163	186	169	187	167	174	163
MEA	0	0	6	5	5	1,548	915	1,181	923	1,438	899	975	841	923	872	1,076	1,082	1,114	1,080	1,111	1,090	1,136	1,101	1,128	1,105	1,728	1,603	1,893
TOTAL	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,168	5,171	5,170	5,183	5,207	5,211	5,231	5,290	5,315	5,356	5,388	5,433	5,467	5,526	5,543	5,593	5,619	5,658	5,689	5,742
NG GENERATION BY UTILITY																												
CEA	2,612	2,028	2,423	1,959	2,228	741	872	737	859	743	496	622	1,012	1,071	1,026	989	1,101	1,106	1,104	1,089	1,152	1,098	1,167	1,140	1,179	1,051	1,090	1,024
GVEA	0	0	0	0	0	0	0	0	0	840	750	990	530	930	682	501	398	490	478	634	688	1,092	726	981	798	637	550	755
MLP	1,508	1,391	1,521	1,308	1,675	1,384	1,788	1,389	1,801	1,216	1,730	1,353	1,656	1,224	1,598	1,020	825	835	825	787	626	466	619	528	613	446	550	353
HEA	0	0	0	0	20	19	25	18	27	3	10	11	7	6	8	2	14	9	14	8	18	2	19	9	20	7	14	2
MEA	0	0	0	0	0	1,467	834	1,099	842	1,357	767	842	709	790	740	793	796	830	795	826	806	851	814	843	821	1,443	1,319	1,609
TOTAL	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,529	4,160	3,753	3,818	3,914	4,022	4,054	3,305	3,136	3,270	3,217	3,345	3,290	3,509	3,345	3,501	3,430	3,585	3,523	3,743
GENERATION BY FUEL																												
Coal	67	146	147	384	455	394	477	393	480	312	412	357	359	255	314	1,121	1,316	1,223	1,308	1,225	1,314	1,154	1,335	1,228	1,326	1,210	1,303	1,136
Natural Gas	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,529	4,160	3,753	3,818	3,914	4,022	4,054	3,305	3,136	3,270	3,217	3,345	3,290	3,509	3,345	3,501	3,430	3,585	3,523	3,743
Oil	528	1,140	653	1,113	447	568	586	947	602	143	142	144	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	524	524	524	524	524	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830	830
Wind	0	0	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33	33
	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,168	5,171	5,170	5,183	5,207	5,211	5,231	5,290	5,315	5,356	5,388	5,433	5,467	5,526	5,543	5,593	5,619	5,658	5,689	5,742
GENERATION PERCENTAGE																												
Coal	1	3	3	7	8	8	9	8	9	6	8	7	7	5	6	21	25	23	24	23	24	21	24	22	24	21	23	20
Natural Gas	79	65	74	61	73	70	68	63	68	80	73	74	75	77	78	62	59	61	60	62	60	64	60	63	61	63	62	65
Oil	10	22	12	21	8	11	11	18	12	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	[illegible]
Hydroelectric	10	10	10	10	10	10	10	10	10	10	16	16	16	16	16	16	16	15	15	15	15	15	15	15	15	15	15	[illegible]
Wind	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	[illegible]
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 22. Mixed Resource Portfolio Scenario: Natural Gas Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	27.25	20.40	24.87	17.58	19.26	5.46	6.40	5.42	6.24	5.78	3.61	4.54	7.33	8.06	7.44	7.51	8.06	8.34	8.08	8.20	8.48	8.39	8.59	8.62	8.69	7.89	7.96	7.79
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.99	6.28	8.33	4.27	7.74	5.61	3.99	3.19	3.90	3.65	4.91	5.38	8.79	5.74	7.83	6.28	4.94	4.24	5.90
MLP	14.42	13.41	14.55	12.33	16.25	13.21	17.52	13.26	17.67	11.47	16.86	12.89	16.03	11.51	15.36	9.44	6.72	7.00	6.72	6.56	4.96	3.80	4.89	4.26	4.84	3.51	4.26	2.76
HEA	0.00	0.00	0.00	0.00	0.23	0.22	0.29	0.20	0.30	0.03	0.12	0.12	0.08	0.07	0.09	0.02	0.16	0.10	0.16	0.10	0.20	0.02	0.21	0.10	0.23	0.08	0.15	0.02
MEA	0.00	0.00	0.00	0.00	0.00	11.95	6.79	8.96	6.86	11.05	6.25	6.86	5.78	6.44	6.03	6.46	6.49	6.76	6.48	6.73	6.57	6.93	6.64	6.87	6.69	10.85	9.85	12.20
Total Natural Gas	41.67	33.81	39.42	29.91	35.73	30.84	31.00	27.84	31.08	35.32	33.12	32.75	33.48	33.82	34.53	27.42	24.62	26.09	25.09	26.50	25.58	27.93	26.07	27.68	26.72	27.27	26.47	28.67
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	6.99	6.28	8.33	4.27	7.74	5.61	3.99	3.19	3.90	3.65	4.91	5.38	8.79	5.74	7.83	6.28	4.94	4.24	5.90
ANC Nat Gas	41.67	33.81	39.42	29.91	35.73	30.84	31.00	27.84	31.08	28.33	26.84	24.42	29.21	26.08	28.92	23.43	21.43	22.20	21.44	21.59	20.20	19.15	20.33	19.85	20.44	22.33	22.23	22.76

Source: Estimates by SAIC from B&V, 2008.

Table 23. Mixed Resource Portfolio Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,167	5,143	4,434	5,181	4,316	5,214	3,443	4,462	3,919	3,913	2,595	3,194	11,383	13,359	12,413	13,275	12,434	13,348	11,710	13,567	12,467	13,483	12,274	13,219	11,532
Natural Gas	42,255	34,279	39,976	30,331	36,233	31,271	31,432	28,227	31,511	35,816	33,582	33,204	33,950	34,296	35,011	27,807	24,967	26,460	25,440	26,875	25,936	28,324	26,432	28,065	27,098	27,651	26,836	29,069
Naphtha	1,919	2,568	1,929	2,586	1,533	2,011	1,925	2,121	1,920	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,641	7,950	3,872	7,769	2,352	2,711	3,089	6,011	3,239	1,420	1,414	1,428	704	709	1	0	0	0	1	0	0	0	0	0	0	0	0	0
Total	47,760	46,544	47,540	44,853	45,261	40,426	41,626	40,675	41,885	40,679	39,457	38,551	38,568	37,600	38,207	39,191	38,326	38,873	38,716	39,309	39,284	40,034	39,999	40,533	40,581	39,925	40,055	40,601

Source: Estimates by SAIC from B&V, 2008.

4.3 Large Hydro/Renewables/DSM/Energy Efficiency Scenario Results

Table 24, Table 25 and Table 26 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 27 provides total energy consumption for all Railbelt utilities by fuel type.

Table 24. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	43.0	8,262	New LM6000 (2018)	1	Natural Gas	1/2038
	98.8	8,262	New LMS100 (2022)	1	Natural Gas	1/2042
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	Bradley Lake - 08-13	1	Water	12/2013
	27.4	--	Bradley Lake - 2014	2	Water	12/2014
	27.4	--	Bradley Lake (2015+)	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake (2015+)	2	Water	1/2040
	80.1	--	New Hydro (2020)	1	Water	1/2040
	80.1	--	New Hydro (2025)	1	Water	1/2040
Wind	13.4	--	New Wind (2013)	1	Wind	1/2038
	13.4	--	New Wind (2018)	1	Wind	1/2043
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CT Gas	42.1	12,268	New 6B SC (2019)	1	Natural Gas	1/2039
	42.1	12,268	New 6B SC (2030)	1	Natural Gas	1/2050
	42.1	12,268	New 6B SC (2031)	1	Natural Gas	1/2051
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2026)	1	Natural Gas	1/2046
Combined	52.0	8,269	North Pole 1x1 CC	1	Naphtha	1/2042
	62.0	10,100	North Pole	1	HAGO	12/2017
	64.0	9,910	North Pole	2	HAGO	12/2018
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	25.68	25,679	Zehnder EMD	5	Distillate Fuel Oil	1/2000
	25.68	25,679	Zehnder EMD	6	Distillate Fuel Oil	1/2000
	13.36	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
	77.7	--	New Hydro (2020)	1	Water	1/2040
	77.7	--	New Hydro (2025)	1	Water	1/2040
Wind	13.0	--	New Wind (2013)	1	Wind	1/2038
	13.0	--	New Wind (2018)	1	Wind	1/2043
MLP						
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	98.8	8,262	New LMS100 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040
	21.3	--	Eklutna Lake	1	Water	1/2040
	64.5	--	New Hydro (2020)	1	Water	1/2040
	64.5	--	New Hydro (2025)	1	Water	1/2040
Wind	10.7	--	New Wind (2013)	1	Wind	1/2038
	10.7	--	New Wind (2018)	1	Wind	1/2043
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
	27.9	--	New Hydro (2020)	1	Water	1/2040
	27.9	--	New Hydro (2025)	1	Water	1/2040
Wind	4.6	--	New Wind (2013)	1	Wind	1/2038
	4.6	--	New Wind (2018)	1	Wind	1/2043

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
MEA						
CT Gas	42.1	12,268	New 6B SC (2026)	1	Natural Gas	1/2046
	42.1	12,268	New 6B SC (2037)	1	Natural Gas	1/2057
	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
	98.8	8,262	New LMS100 (2035)	2	Natural Gas	1/2055
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040
	49.8	--	New Hydro (2020)	1	Water	1/2040
	49.8	--	New Hydro (2025)	1	Water	1/2040
Wind	8.3	--	New Wind (2013)	1	Wind	1/2038
	8.3	--	New Wind (2018)	1	Wind	1/2043

Source: Estimates by SAIC from B&V, 2008.

Table 25. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,919	2,336	2,740	2,276	2,503	937	1,068	933	1,050	942	774	901	1,297	1,341	1,311	1,411	1,412	1,380	1,424	1,394	1,412	1,362	1,428	1,391	1,437	1,358	1,418	1,329
GVEA	648	1,339	861	1,558	898	983	1,108	1,388	1,128	1,352	1,430	1,619	1,091	1,392	1,127	1,383	1,793	1,797	1,834	1,813	1,755	1,765	1,735	1,799	1,783	1,692	1,702	1,621
MLP	1,675	1,558	1,694	1,482	1,849	1,558	1,962	1,563	1,976	1,395	1,974	1,597	1,901	1,467	1,844	1,341	910	897	921	913	1,090	983	1,123	1,041	1,131	1,002	1,087	943
HEA	0	0	3	3	129	104	86	76	92	53	90	92	86	85	87	108	119	113	120	113	120	108	120	113	121	111	120	108
MEA	0	0	6	5	5	1,548	915	1,181	924	1,432	904	974	834	927	864	1,031	1,067	1,154	1,074	1,179	1,069	1,274	1,114	1,217	1,123	1,474	1,345	1,718
TOTAL	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,170	5,173	5,172	5,184	5,208	5,212	5,232	5,274	5,301	5,341	5,373	5,413	5,446	5,492	5,520	5,562	5,595	5,638	5,672	5,719
NG GENERATION BY UTILITY																												
CEA	2,612	2,028	2,423	1,959	2,228	741	872	737	845	737	488	615	1,010	1,054	1,025	1,047	1,048	1,016	1,060	1,030	1,048	998	1,064	1,027	1,073	994	1,054	965
GVEA	0	0	0	0	0	0	0	0	0	830	734	977	517	922	669	946	1,180	1,268	1,219	1,283	1,138	1,316	1,113	1,266	1,158	1,168	1,077	1,178
MLP	1,508	1,391	1,521	1,308	1,675	1,384	1,788	1,389	1,795	1,214	1,728	1,350	1,654	1,220	1,597	1,032	601	588	611	604	780	674	813	732	822	693	778	634
HEA	0	0	0	0	20	19	25	18	27	3	10	10	7	6	8	2	14	8	14	8	14	2	15	8	15	6	14	1
MEA	0	0	0	0	0	1,467	834	1,099	837	1,345	766	836	696	789	726	844	881	968	888	993	883	1,088	927	1,031	937	1,288	1,159	1,532
TOTAL	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,504	4,129	3,725	3,789	3,884	3,993	4,024	3,871	3,724	3,847	3,793	3,918	3,863	4,077	3,932	4,065	4,004	4,150	4,083	4,311
GENERATION BY FUEL																												
Coal	67	146	147	384	455	394	477	393	479	312	408	355	357	252	312	215	390	306	393	308	395	227	400	310	404	301	402	221
Natural Gas	4,120	3,420	3,944	3,267	3,923	3,612	3,519	3,243	3,504	4,129	3,725	3,789	3,884	3,993	4,024	3,871	3,724	3,847	3,793	3,918	3,863	4,077	3,932	4,065	4,004	4,150	4,083	4,311
Oil	528	1,140	653	1,113	447	568	586	947	597	143	142	143	71	71	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	524	524	524	524	524	830	830	830	830	830	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121	1,121
Wind	0	0	33	33	33	33	33	33	66	66	66	66	66	66	66	66	66	66	66	66	66	66	67	66	66	66	66	66
TOTAL	5,243	5,233	5,304	5,324	5,385	5,130	5,139	5,140	5,170	5,173	5,172	5,184	5,208	5,212	5,232	5,274	5,301	5,341	5,373	5,413	5,446	5,492	5,520	5,562	5,595	5,638	5,672	5,719
GENERATION PERCENTAGE																												
Coal	1	3	3	7	8	8	9	8	9	6	8	7	7	5	6	4	7	6	7	6	7	4	7	6	7	5	7	4
Natural Gas	79	65	74	61	73	70	68	63	68	80	72	73	75	77	77	73	70	72	71	72	71	74	71	73	72	74	72	75
Oil	10	22	12	21	8	11	11	18	12	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Hydroelectric	10	10	10	10	10	10	10	10	10	10	16	16	16	16	16	21	21	21	21	21	21	20	20	20	20	20	20	20
Wind	0	0	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 26. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	27.25	20.40	24.87	17.50	19.13	5.37	6.29	5.33	6.02	5.58	3.48	4.40	7.19	7.81	7.30	7.88	7.48	7.49	7.58	7.61	7.48	7.49	7.61	7.59	7.69	7.32	7.53	7.22
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.20	6.39	8.57	4.41	8.00	5.76	8.22	9.75	10.47	10.06	10.60	9.34	10.89	9.14	10.46	9.52	9.58	8.81	9.66
MLP	14.42	13.41	14.55	12.33	16.25	13.21	17.52	13.26	17.61	11.44	16.83	12.85	16.01	11.47	15.34	9.57	4.71	4.77	4.80	4.91	6.01	5.29	6.28	5.72	6.35	5.39	5.99	4.97
HEA	0.00	0.00	0.00	0.00	0.23	0.22	0.29	0.20	0.30	0.03	0.11	0.12	0.08	0.07	0.09	0.02	0.16	0.09	0.16	0.09	0.16	0.02	0.17	0.09	0.17	0.07	0.16	0.02
MEA	0.00	0.00	0.00	0.00	0.00	11.95	6.79	8.96	6.82	10.96	6.24	6.81	5.67	6.43	5.92	6.88	7.19	7.91	7.25	8.12	7.21	8.90	7.57	8.43	7.66	10.50	9.44	12.49
Total Natural Gas	41.67	33.81	39.42	29.83	35.60	30.74	30.88	27.74	30.74	35.20	33.05	32.75	33.35	33.79	34.39	32.57	29.29	30.73	29.86	31.34	30.21	32.60	30.77	32.29	31.38	32.87	31.93	34.35
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	7.20	6.39	8.57	4.41	8.00	5.76	8.22	9.75	10.47	10.06	10.60	9.34	10.89	9.14	10.46	9.52	9.58	8.81	9.66
ANC Nat Gas	41.67	33.81	39.42	29.83	35.60	30.74	30.88	27.74	30.74	28.01	26.66	24.18	28.94	25.78	28.64	24.35	19.54	20.27	19.80	20.74	20.86	21.70	21.63	21.83	21.86	23.28	23.12	24.69

Source: Estimates by SAIC from B&V, 2008.

Table 27. Large Hydro/Renewables/DSM/Energy Efficiency Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,167	5,143	4,434	5,181	4,316	5,196	3,440	4,422	3,895	3,892	2,573	3,181	2,191	3,970	3,117	4,000	3,130	4,021	2,317	4,071	3,153	4,106	3,061	4,089	2,259
Natural Gas	42,255	34,279	39,976	30,249	36,100	31,173	31,315	28,129	31,171	35,696	33,513	33,207	33,813	34,259	34,876	33,025	29,701	31,165	30,276	31,779	30,628	33,054	31,204	32,739	31,817	33,328	32,380	34,829
Naphtha	2,174	2,910	2,186	2,930	1,737	2,278	2,181	2,403	2,175	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,641	7,950	3,872	7,769	2,352	2,711	3,089	6,011	3,195	1,420	1,413	1,426	704	708	1	4	2	1	2	2	0	0	0	0	0	0	0	0
DFO	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Total	48,015	46,886	47,796	45,115	45,332	40,595	41,766	40,859	41,738	40,556	39,348	38,529	38,410	37,540	38,058	35,221	33,673	34,283	34,278	34,911	34,649	35,371	35,274	35,892	35,924	36,389	36,469	37,088

Source: Estimates by SAIC from B&V, 2008.

4.4 Coal Scenario Results

Table 28, Table 29, and Table 30 provide utility-specific results for plant data, power generation, and natural gas consumption. Table 31 provides total energy consumption for all Railbelt utilities by fuel type.

Table 28. Coal Scenario: Existing and New Plants Modeled

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CEA						
New Coal	26.7	10,138	New Coal (2015)	1	Coal	1/2045
	26.7	10,138	New Coal (2020)	1	Coal	1/2050
	26.7	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	19.6	16,500	Beluga	1	Natural Gas	12/2011
	19.6	16,600	Beluga	2	Natural Gas	12/2011
	64.8	12,295	Beluga	3	Natural Gas	12/2012
	68.7	12,446	Beluga	5	Natural Gas	12/2017
	82.0	11,906	Beluga	6	Natural Gas	12/2020
	82.0	11,906	Beluga	7	Natural Gas	12/2021
	19.0	14,655	Bernice	2	Natural Gas	12/2014
	26.0	13,460	Bernice	3	Natural Gas	12/2014
	14.1	16,348	International	1	Natural Gas	12/2012
	14.1	17,435	International	2	Natural Gas	12/2012
	18.5	15,127	International	3	Natural Gas	12/2012
	42.1	12,268	New 6B SC (2021)	1	Natural Gas	1/2041
	42.1	12,268	New 6B SC (2022)	1	Natural Gas	1/2042
	43.0	9,023	New LM6000 (2018)	1	Natural Gas	1/2038
	39.0	11,401	Nikiski	1	Natural Gas	12/2013
	128.0	7,298	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Combined	108.5	9,620	Beluga	6/8	Natural Gas	12/2014
	108.5	9,884	Beluga	7/8	Natural Gas	12/2014
Hydro	27.4	--	Bradley Lake - 08-13	1	Water	12/2013
	27.4	--	Bradley Lake - 2014	2	Water	12/2014
	27.4	--	Bradley Lake (2015+)	3	Water	1/2040
	20.0	--	Cooper Lake	1	Water	1/2040
	20.0	--	Cooper Lake	2	Water	1/2040
	12.0	--	Eklutna Lake - 2008-2014	1	Water	12/2014
	12.0	--	Eklutna Lake (2015+)	2	Water	1/2040
GVEA						
ST Coal	26.7	14,200	Healy	1	Coal	12/2022
	60.0	10,140	Healy CCP	1	Coal	12/2013
	25.9	10,138	New Coal (2015)	1	Coal	1/2045
	25.9	10,138	New Coal (2020)	1	Coal	1/2050
	25.9	10,138	New Coal (2025)	1	Coal	1/2055

Technology Type	Capacity	Heat Rate (Btu/kWh)	Name (unit online year)	Unit	Primary Fuel	Retirement Date
CT Gas	42.1	12,268	New 6B SC (2036)	1	Natural Gas	1/2056
	43.0	9,023	New LM6000 (2008)	1	Natural Gas	1/2028
	43.0	9,023	New LM6000 (2009)	1	Natural Gas	1/2029
	98.8	8,262	New LMS100 (2028)	1	Natural Gas	1/2048
Combined	52.0	7,298	North Pole 1x1 CC	1	Naphtha	1/2042
CT Oil	62.0	10,100	North Pole	1	HAGO	12/2017
	62.0	9,910	North Pole	2	HAGO	12/2018
	64.0	8,269	T 1X1 North Pole Retrofit (2031)	1	Natural Gas	1/2056
	17.7	14,190	Zehnder	1	HAGO	12/2030
	17.7	14,310	Zehnder	2	HAGO	12/2030
	24.9	13,360	DPP	1	HAGO	12/2030
Hydro	15.2	--	Bradley Lake	1	Water	1/2040
MLP						
New Coal	21.5	10,138	New Coal (2015)	1	Coal	1/2045
	21.5	10,138	New Coal (2020)	1	Coal	1/2050
	21.5	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	32.0	9,780	Plant 1	3	Natural Gas	1/2040
	37.4	14,420	Plant 2	5	Natural Gas	1/2040
	49.2	10,740	Plant 2	5/6	Natural Gas	12/2029
	81.8	11,930	Plant 2	7	Natural Gas	1/2041
	109.5	9,030	Plant 2	7/6	Natural Gas	12/2029
	87.6	11,930	Plant 2	8	Natural Gas	12/2029
	43.0	9,023	New LM6000 (2030)	1	Natural Gas	1/2050
	55.0	7,160	CEA/HEA/ML&P Joint 2X1 6FA CC	1	Natural Gas	1/2040
Hydro	23.3	--	Bradley Lake	1	Water	1/2040
	21.3	--	Eklutna Lake	1	Water	1/2040
HEA						
ST Coal	26.7	14,200	Healy (HEA)	1	Coal	1/2040
	9.3	10,138	New Coal (2015)	1	Coal	1/2045
	9.3	10,138	New Coal (2020)	1	Coal	1/2050
	9.3	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	39.0	11,401	Nikiski	1	Natural Gas	1/2040
Hydro	10.8	--	Bradley Lake	1	Water	1/2040
MEA						
New Coal	16.6	10,138	New Coal (2015)	1	Coal	1/2045
	16.6	10,138	New Coal (2020)	1	Coal	1/2050
	16.6	10,138	New Coal (2025)	1	Coal	1/2055
CT Gas	42.1	12,268	New 6B SC (2034)	1	Natural Gas	1/2054
	80.0	8,262	New LMS100 (2015)	1	Natural Gas	1/2035
	80.0	8,262	New LMS100 (2015)	2	Natural Gas	1/2035
	98.8	8,262	New LMS100 (2035)	1	Natural Gas	1/2055
	98.8	8,262	New LMS100 (2035)	2	Natural Gas	1/2055
Hydro	12.4	--	Bradley Lake	1	Water	1/2040
	6.7	--	Eklutna Lake	1	Water	1/2040

Source: Estimates by SAIC from B&V, 2008.

Table 29. Coal Scenario: Projected Power Generation (1000 MW-Hours)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
GENERATION BY UTILITY																												
CEA	2,897	2,336	2,748	2,277	2,486	1,093	1,122	966	1,032	1,060	1,060	1,331	1,391	1,382	1,461	1,451	1,564	1,539	1,519	1,545	1,535	1,534	1,545	1,550	1,554	1,531	1,559	1,465
GVEA	639	1,339	841	1,566	891	1,095	1,168	1,223	1,195	1,314	1,102	1,375	1,210	1,400	1,193	1,480	1,746	1,726	1,829	1,745	1,849	1,794	1,869	1,819	1,884	1,798	1,893	1,791
MLP	1,707	1,558	1,715	1,480	1,918	1,667	2,001	1,677	2,038	1,476	2,209	1,727	2,147	1,659	2,050	1,519	1,088	1,092	1,090	1,103	1,094	1,050	1,106	1,089	1,117	1,082	1,120	1,026
HEA	0	0	0	0	89	115	102	107	84	80	206	59	65	65	72	101	113	153	118	159	123	146	127	165	129	153	127	115
MEA	0	0	0	0	0	1,169	783	1,236	897	1,347	718	835	555	891	664	915	982	1,020	1,011	1,053	1,041	1,165	1,072	1,138	1,113	1,277	1,178	1,532
	5,243	5,233	5,304	5,322	5,383	5,140	5,177	5,210	5,246	5,277	5,296	5,327	5,368	5,398	5,441	5,466	5,493	5,530	5,566	5,605	5,642	5,688	5,719	5,762	5,797	5,842	5,878	5,929
NG GENERATION BY UTILITY																												
CEA	2,589	2,028	2,441	1,970	2,178	578	647	571	638	665	409	682	742	732	810	650	1,002	777	1,002	778	1,001	692	1,005	773	1,003	767	1,006	643
GVEA	0	0	0	0	0	0	0	0	0	579	297	526	293	607	316	526	643	712	720	732	738	838	753	809	771	787	776	835
MLP	1,541	1,391	1,548	1,313	1,751	1,471	1,817	1,480	1,852	1,278	1,997	1,514	1,938	1,449	1,849	1,287	372	396	431	405	429	340	437	387	443	379	444	316
HEA	0	0	0	0	24	12	12	11	13	2	6	2	4	2	5	0	5	3	5	3	5	1	5	3	5	3	5	0
MEA	0	0	0	0	0	1,040	654	1,031	692	1,141	355	473	198	529	303	417	475	513	503	546	535	658	564	631	607	771	1,102	1,456
	4,130	3,420	3,989	3,283	3,953	3,101	3,130	3,094	3,195	3,666	3,064	3,196	3,176	3,319	3,283	2,881	2,497	2,401	2,661	2,465	2,708	2,529	2,764	2,604	2,828	2,706	3,332	3,250
GENERATION BY FUEL																												
Coal	67	146	147	389	465	1,015	1,052	1,016	1,058	945	1,573	1,471	1,601	1,487	1,634	2,062	2,471	2,605	2,381	2,617	2,410	2,636	2,431	2,634	2,446	2,612	2,022	2,155
Natural Gas	4,130	3,420	3,989	3,283	3,953	3,101	3,130	3,094	3,195	3,666	3,064	3,196	3,176	3,319	3,283	2,881	2,497	2,401	2,661	2,465	2,708	2,529	2,764	2,604	2,828	2,706	3,332	3,250
Oil	519	1,140	641	1,124	439	497	468	577	470	142	135	136	68	68	0	0	1	1	0	0	0	0	0	0	0	0	0	0
Hydroelectric	527	527	527	527	527	527	527	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524	524
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	5,243	5,233	5,304	5,322	5,383	5,140	5,177	5,210	5,246	5,277	5,296	5,327	5,368	5,398	5,441	5,466	5,493	5,530	5,566	5,605	5,642	5,688	5,719	5,762	5,797	5,842	5,878	5,929
GENERATION PERCENTAGE																												
Coal	1	3	3	7	9	20	20	19	20	18	30	28	30	28	30	38	45	47	43	47	43	46	43	46	42	45	34	36
Natural Gas	79	65	75	62	73	60	60	59	61	69	58	60	59	61	60	53	45	43	48	44	48	44	48	45	49	46	57	55
Oil	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9	9	9	9
Hydroelectric	10	22	12	21	8	10	9	11	9	3	3	3	1	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0
Wind	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
TOTAL	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100

Source: Estimates by SAIC from B&V, 2008.

Table 30. Coal Scenario: Projected Natural Gas Consumption (Billion CuFt/Year)

Utility	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
CEA	26.98	20.40	25.08	17.69	18.78	4.26	4.77	4.21	4.64	5.04	2.98	5.03	5.45	5.42	5.95	4.81	7.29	5.73	7.28	5.74	7.28	5.20	7.31	5.69	7.29	5.63	7.32	4.74
GVEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.66	2.28	4.21	2.16	4.93	2.36	4.21	5.35	5.86	5.63	5.72	5.78	6.58	5.94	6.34	6.04	6.16	6.08	6.55
MLP	14.78	13.41	14.86	12.38	17.10	14.23	17.90	14.34	18.31	12.16	20.04	14.79	19.38	14.04	18.33	12.32	2.77	3.05	3.19	3.13	3.18	2.64	3.24	2.98	3.30	2.90	3.30	2.42
HEA	0.00	0.00	0.00	0.00	0.27	0.14	0.13	0.13	0.15	0.03	0.06	0.02	0.05	0.03	0.05	0.00	0.05	0.03	0.05	0.03	0.06	0.01	0.06	0.04	0.06	0.03	0.06	0.01
MEA	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total Natural Gas	41.76	33.81	39.94	30.06	36.15	18.62	22.81	18.67	23.10	21.88	25.37	24.05	27.03	24.41	26.70	21.34	15.46	14.67	16.15	14.62	16.29	14.43	16.55	15.05	16.69	14.73	16.76	13.72
FAI Nat Gas	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	4.66	2.28	4.21	2.16	4.93	2.36	4.21	5.35	5.86	5.63	5.72	5.78	6.58	5.94	6.34	6.04	6.16	6.08	6.55
ANC Nat Gas	41.76	33.81	39.94	30.06	36.15	18.62	22.81	18.67	23.10	17.22	23.09	19.84	24.87	19.48	24.34	17.14	10.11	8.81	10.52	8.90	10.51	7.85	10.61	8.71	10.65	8.57	10.68	7.17

Source: Estimates by SAIC from B&V, 2008.

Table 31. Scenario: Projected Total Fuel Consumption by Type (Billion Btu/Year)

Fuel Type	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037
Coal	946	1,748	1,763	4,216	5,244	10,715	10,954	10,600	11,059	9,924	16,222	15,187	16,472	15,082	16,579	20,906	25,067	26,420	24,255	26,747	24,557	26,929	24,785	26,939	24,937	26,696	20,639	21,995
Natural Gas	42,344	34,279	40,497	30,483	36,654	18,883	23,128	18,931	23,426	22,189	25,723	24,389	27,413	24,751	27,074	21,642	15,679	14,873	16,375	14,823	16,515	14,633	16,785	15,262	16,923	14,933	16,992	13,914
Naphtha	1,918	2,569	1,930	2,606	1,533	2,000	1,923	2,009	1,918	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
HAGO	2,548	7,951	3,753	7,864	2,271	2,083	2,001	2,792	2,026	1,437	1,338	1,345	669	680	0	6	15	13	4	3	3	0	0	0	0	0	0	0
Total	47,757	46,545	47,942	45,169	45,701	33,681	38,007	34,332	38,429	33,550	43,283	40,921	44,555	40,513	43,653	42,554	40,760	41,306	40,633	41,574	41,076	41,563	41,570	42,200	41,860	41,629	37,631	35,909

Source: Estimates by SAIC from B&V, 2008.

Appendix D: Alaskan Propane Extraction Facilities Cost Estimates for 0.5, 65, and 300 MMSCFD Plants

Alaskan Propane Extraction Facilities Cost Estimates For 0.5, 65, & 300 MMSCFD Plants

Final Report

Revision Release: October 13, 2009 Rev. 4

Print Format – Double Sided

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Revision Log

Rev.	Description	Revision Date	Completed by
0	Preliminary report	July 10, 2009	IMcK
1	Final Report	August 14, 2009	IMcK
2	Complete Report (for final review)	August 28, 2009	IMcK
3	Final Report	September 8, 2009	IMcK
4	Final Report - confidentiality statement removed	October 13, 2009	IMcK

Notes: 1. Data for Revision 0 was developed during the period from June 24 to July 10, 2009.

Note to Reader

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It is recommended that each new revision or release of this publication be reviewed in its entirety in order to ensure a comprehensive understanding of the contents of this document.

Report Prepared by: Ian McKay

Ian McKay

Signature

October 13, 2009

Date

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1.0 EXECUTIVE SUMMARY

On the Alaskan North Slope, there are 35 trillion cubic feet of recoverable natural gas. Currently this gas either remains in place or is co-produced with oil, separated, and returned to the producing formation. There is no export of this natural gas due to the lack of a pipeline for this purpose.

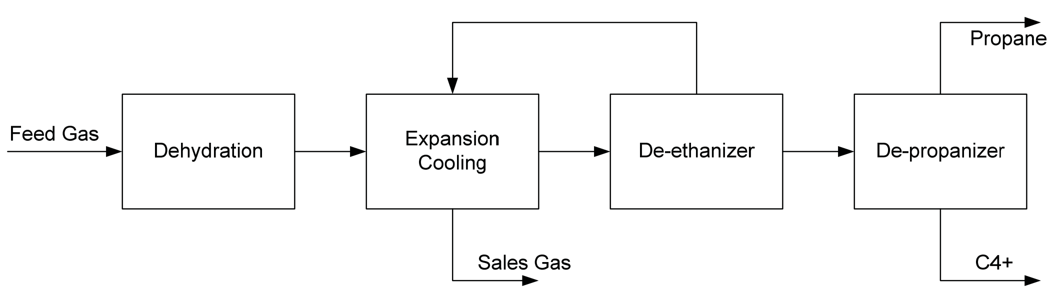
Subsidiaries of TransCanada Corporation have been awarded a license from the State of Alaska (December 5, 2008) for the Alaska Pipeline Project (APP) under the Alaska Gasline Inducement Act (AGIA) and has reached an agreement with ExxonMobil (June 11, 2009) to work together on the project. Following these announcements, "*TransCanada has moved forward with project development, which includes engineering, environmental reviews, Alaska Native and Canadian Aboriginal engagement, and commercial work to conclude an initial binding open season by July 2010*."

Consistent with the requirements as stipulated in the 2005 FERC Open Season Regulations for Alaska Natural Gas Transportation Projects, TransCanada has commissioned Northern Economics to conduct an in-state gas demand study. Included in the study is an assessment of the potential propane demand in-state. This involves analyzing the costs of separating liquid propane, and potentially utility grade sales gas, from the North Slope pipeline gas, for use in local communities as heating/cooking fuel and for potential use in local power generation. This option may provide an improved cost position relative to the fuels that are currently used for these purposes.

Potential scenarios for propane recovery could include so-called "straddle" plants located at communities along the Alaska gas Pipeline route (e.g. Fairbanks, Tok) and/or at the South-central area (e.g. Anchorage) which would require a spur-line to bring raw gas from the Alaska gas pipeline to the community of interest.

TransCanada has retained the services of Gas Liquids Engineering Ltd. (GLE) to validate conceptual design work and provide cost estimation for three propane extraction facilities covering a range of the potential community sizes and locations relevant to Alaska's demographics. The cost estimation data for the propane extraction facilities, provided by GLE, is then used by Northern Economics as inputs in evaluating the overall cost of providing locally produced propane to Alaskan communities.

Gas Liquids Engineering has designed a fractionation facility based on the following block flow arrangement.



Gas Liquids Engineering has found that the design of the expansion cooling section has a major impact on the propane recovery capability of the plant design. GLE has evaluated several designs for the expansion cooling section and has focused on a design which is capable of delivering the 97 weight percent propane recovery to maximize propane recovery from the raw gas.

GLE has also evaluated a range of potential inlet pressures for the feed gas to the facilities and confirmed that the required propane recovery is feasible with the preferred plant design over a range of plant inlet pressures from 1500 to 2400 psia.

Cost estimates for the three facilities have been based on the use of budgetary estimates for major capital and electrical equipment, percentage factors for minor capital and engineering expenses, and factors for installation and owner's costs. In addition a location factor has been determined for each facility to allow for the increased cost of construction in different locations in Alaska relative to western Canada and/or the lower 48 states. Probable costs (P10, P50, P90) were assigned to all capital items, engineering cost, and installation factors. Fixed factors were used for location and owner's cost factors. Monte Carlo simulation was then used in combination with the cost equation, below, to generate probability distribution estimates for the three facilities.

(Plant Capex + Minor Capex + EIC Capex + Engineering) x Installation Factor x Location Factor x Owner's Cost

A summary of the three facilities and estimated costs is provided in the following table.

Facility	Raw Gas Feed Rate (MMSCFD)	Propane Production (BPD)	Sales Gas Production (MMSCFD	Cost Estimates (USD Millions)		
				P10	**P50**	**P90**
Tok	0.5	11.7	0.48	6.44	7.27	8.25
Fairbanks	65	1526	25(1)	79.62	90.45	103.71
Anchorage	300	7046(2)	289.3	165.13	185.80	211.24

(1) The remainder of separated gas is recompressed and returned to the Alaskan gas pipeline.

(2) C4+ production of 1832 bpd is also available from this facility.

The estimates above are at the Class 5 level as defined by the Association for the Advancement of Cost Engineering (AACE International) in Recommended Practice No. 18R-97. Going forward, the accuracy and precision of these estimates can be improved through advancing the extent of engineering activity (basic, FEED, detailed,…) which will support detailed and formal cost estimation.

As more engineering detail is developed, it will also be prudent to scrutinize and refine the values for the estimation factors (installation, location, owner's costs) to reduce the uncertainty associated with estimation, and to improve on the accuracy of the forecast values.

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2.0 INTRODUCTION & BACKGROUND

"*Discovered recoverable natural gas resources on the Alaska North Slope are estimated to be about 35 trillion cubic feet. No natural gas is currently exported off the North Slope because there is no gas pipeline to transport the gas to markets*."[1] This quotation, taken from a 2007 US Department of Energy report, succinctly summarizes the size and current status of the Alaskan North Slope natural gas reserves.

With initial activities beginning in the 1970s and a continued and strong presence today, TransCanada Corporation has sought to design and execute a project to provide a natural gas pipeline for transportation of Alaskan North Slope gas across the State of Alaska, through the Yukon Territory and the Province of British Columbia into Alberta. In Alberta, the new pipeline would connect to existing infrastructure allowing shipment to terminal points in the lower 48 States.

On December 5, 2008 the State of Alaska awarded a license to subsidiaries of TransCanada Corporation for the Alaska Pipeline Project under the Alaska Gasline Inducement Act (AGIA). Following this decision, TransCanada has stated, "*This ratification of our license under AGIA will facilitate TransCanada's continuing commercial negotiations with potential shippers, improving the likelihood of a successful open season and the construction of a natural gas delivery system from Prudhoe Bay to Lower 48 markets*."[2]

On June 11, 2009 TransCanada announced that it had reached an agreement with ExxonMobil to work together on the APP.[3] Following these announcements, "*TransCanada has moved forward with project development, which includes engineering, environmental reviews, Alaska Native and Canadian Aboriginal engagement, and commercial work to conclude an initial binding open season by July 2010*."

Consistent with the requirements as stipulated in the 2005 FERC Open Season Regulations for Alaska Natural Gas Transportation Projects, TransCanada has commissioned Northern Economics to conduct an in-state gas demand study, which includes an evaluation of various options for the provision of propane and natural gas as fuels for local consumption in Alaskan communities (heating, cooking, power generation, etc.).

Assuming construction of the Alaska gas pipeline, the most preferred routes to obtaining propane for communities along the pipeline route would be to use so-called "straddle" plants to recover propane and sales quality natural gas from a slipstream taken from the main pipeline. Unwanted residual gas would be recompressed and returned to the main pipeline. For locations at a distance from the Alaska gas pipeline (e.g. Anchorage), a spur-line would be required to bring raw gas to a suitable fractionation plant.

In preparation for Northern Economics evaluations, TransCanada has retained the services of Gas Liquids Engineering Ltd. (GLE) to provide preliminary cost estimation for three facilities for propane extraction. These facilities differ in their location (proximity to the Alaska gas pipeline) and scale (0.5, 65, or 300 MMSCFD of gas processing). Each, in its own way, would contribute to the recovery of, and potential distribution for, propane and natural gas to Alaskan communities.

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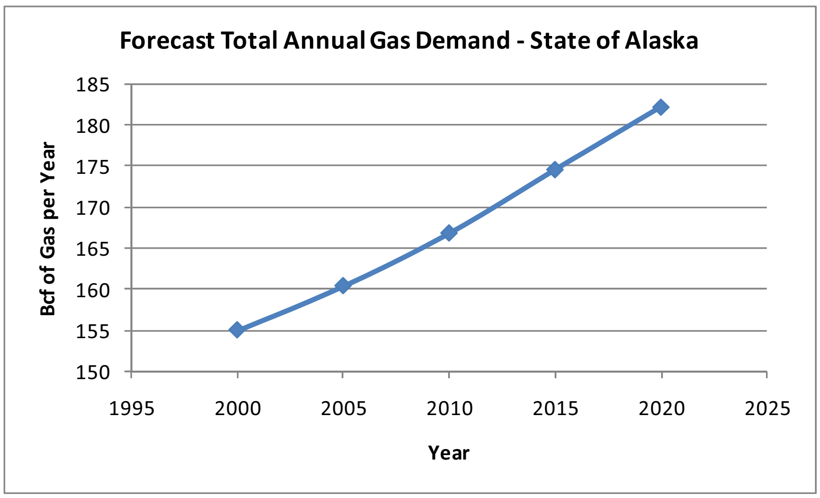
The State of Alaska, working through the Alaska Department of Natural Resources, and Alaska Natural Gas Development Authority (ANGDA), have been developing information on natural gas/propane demand and various supply options over recent years. A brief summary of key studies in this regard follows.

In 2002 the Alaska Department of Natural Resources issued a report, prepared by Econ One Research and the Acadian Consulting Group, addressing the subject of future, in-state demand for natural gas.[4] The study forecast average annual growth rates for natural gas demand in Alaska to be 1.8, 1.0, 0.5 and 0.7 % for the residential, commercial, industrial, and utility sectors, respectively. In aggregate, the average annual growth rate in natural gas demand for the state is expected to be a little less than 1 percent. Total forecast gas demand is shown in Figure 2.1.

Figure 2.1 Forecast Total Annual Natural Gas Demand – Alaska.[1]



Also in 2002, the Alaska Natural Gas Development Authority (ANGDA) was created as a public corporation with the objectives of getting natural gas to communities in Alaska and identifying areas where use of liquefied natural gas (LNG) would be viable.[5]

For natural gas supply, ANGDA has focused its efforts around construction of a natural gas spur-line that connects with the Alaska gas pipeline at around Delta Junction. Routing for the spur-line would follow the Richardson highway to Glennallen and then proceed westwards to Anchorage.[5]

In addition to the development of a natural gas pipeline into the Anchorage area, ANGDA has worked to identify a viable distribution network for propane supply to over 99 % of the state's population.[6] Several studies have served as key building blocks in the development of ANGDA's plan for improved distribution of natural gas and propane in the Alaskan market.[7-11]

In 2004 ANGDA received a report from Michael Baker Jr., Inc. (Baker) who, in turn, worked with Linde BOC Process Plants LLC (Linde BOCPP) to investigate plant configurations for propane and possibly natural gas extraction facilities to be located along a major gas pipeline through Alaska.[7] In the Baker study, Linde BOCPP proposed a plant configuration using turbo-expansion cooling and two fractionation towers to produce three product streams; natural gas, propane, and C4+. For the scenario in which only propane is used locally, the natural gas and C4+ streams are blended, compressed, cooled to 28 F and returned to the pipeline.

The plant was designed to process 10 MMSCFD of pipeline gas. In the full configuration, the plant was estimated to have a capital cost of $10.5 million (USD). Removal of propane refrigeration (for gas returned to the pipeline) would reduce the cost to $7.9 million and removal of both refrigeration and re-compression (natural gas used locally) would reduce the plant cost to $6.1 million.

In 2006, ANGDA received a report titled "ANGDA 06-0414 Spur-line Terminal Conceptual Design July 2006" from the Shaw Group's affiliate, Stone & Webster Management Consultants Inc. (Stone & Webster).[8] This study looked at options to process large amounts of gas (4500, 900, and 500 MMSCFD cases) and included features for gas fractionation, ethylene, and polyethylene production. Of potential interest to the study work described herein is the 500 MMSCFD case for which only gas fractionation was considered. The capital cost associated with this option (propane and natural gas products provided) was $347 million.

In 2007, ANGDA produced a series of three reports dealing with the subjects of propane/NGL recovery. The first of these reports addressed a potential 1000 barrel per day (BPD) propane extraction plant to be located at the junction of the Dalton highway and Yukon River.[9] In a second 2007 report, ANGDA discusses a 100 - 200 MMSCFD NGL extraction facility to be located at Cook Inlet.[10] The third ANGDA staff report from February of 2007 investigates the subject of extracting 20 percent of the natural gas liquids transported via the Alaska North Slope (ANS) pipeline.[11] A key difficulty faced in each of these reports is ANGDA's lack of cost estimation data for suitably sized facilities. A 500 MMSCFD plant is the smallest facility for which ANGDA has reasonable data.[8]

The facilities design and cost evaluation work provided by Gas Liquids Engineering in this report has been produced to support Northern Economics' assessment of the potential demand for propane and natural gas in Alaska as part of the TransCanada's preparation for the 2010 open season for the APP.

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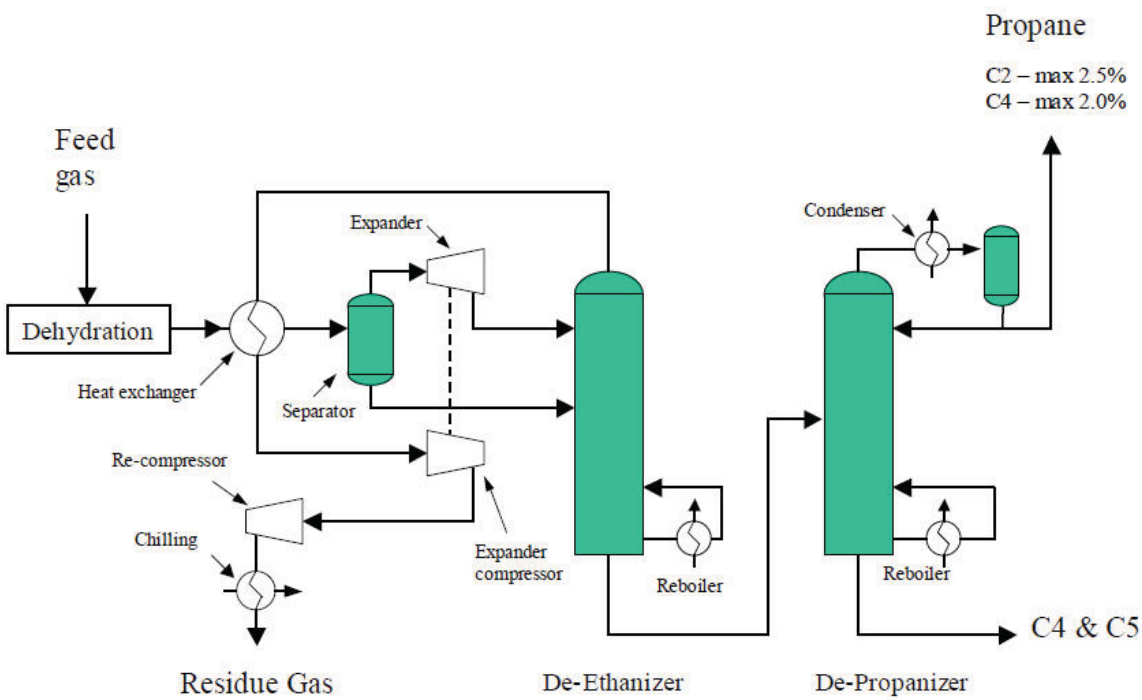
3.0 TECHNOLOGY DEFINITION AND COST ESTIMATION

ANGDA has received process designs for NGL recovery plants from Linde BOCPP and Stone & Webster.[7,8] In subsequent ANGDA staff reports, the analyses have been based on use of the Stone & Webster configuration, shown in Figure 3.1.

Figure 3.1 Configuration of LPG Extraction Plant.[7]



The plant design shown is schematic and does not include all of the associated pipes, valves, and minor equipment that are a part of the fully functional design.

GLE has based its designs for the three facilities (Tok, Fairbanks, Anchorage) on the Stone & Webster configuration. To allow for complete simulation of plant performance, GLE has included additional valves and lines where needed in order to appropriately control pressure and fluid flow in the design. Practical consideration of design/operating pressures for various plant units has contributed to simulation work, which has allowed for optimization of the technical performance of the plant design (need approximately 97 % propane recovery) and provided the basis for cost estimation.

It is important to note that GLE has not been retained to provide multiple potential plant designs, nor a comparative analysis of potential designs in terms of technical performance and estimated cost. However, where appropriate, GLE has provided some commentary on alternative design features/options.

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The three facilities to be estimated are summarized in Table 3.1.

Table 3.1 Description of Propane/Natural Gas Extraction Facilities.

Location in Alaska	Tok	Fairbanks	Anchorage
Scale (MMSCFD)	0.5	65	300
Proximity to ANS pipeline	Adjacent	Adjacent	Remote
Products Recovered	C3, Nat. Gas	C3, some Nat. Gas	Nat. Gas, C3, C4+
Gas Re-injected to ANS Pipeline (1)	No	Partial	No
Facility Inlet Pressure (psia)	1500	1500	1500
Returned Gas Pressure (psia)	n.a.	1500	n.a.

- Re-injection of gas will require gas recompression and possibly refrigeration facilities.

Key assumptions of the simulation and design work presented herein are the facility inlet and returned gas pressures. Values of 1500 psia, for both of these pressures, were assumed in this study, although pipeline system design data indicates inlet pressures in the range from roughly 1900 – 2100 psia if the straddle plants were located at the suction of the nearest main-line compressor stations, or may even be at 2300 - 2400 psia range if the straddle plants were located near the communities of interest (Tok, Fairbanks, and Anchorage).

GLE does not believe that an increased inlet pressure would greatly impact the estimated plant cost due to the configuration of the plant design, in particular the early reduction of pressure to 500 psia in valve V1 (see Figure 3.1.1.),. GLE has provided some "directional" information of the impact(s) of increased facility inlet and return pressures on plant performance and estimated cost in this report.

Each of the three plants is addressed separately in following sub-sections of this report. Plant design and simulation work has been performed using VMGSim software from the Virtual Materials Group. Cost estimations are based on budgetary quotation(s) for capital equipment and factoring of additional cost contributors to enable Monte Carlo simulations for creation of probability distributions for the required plant investments.

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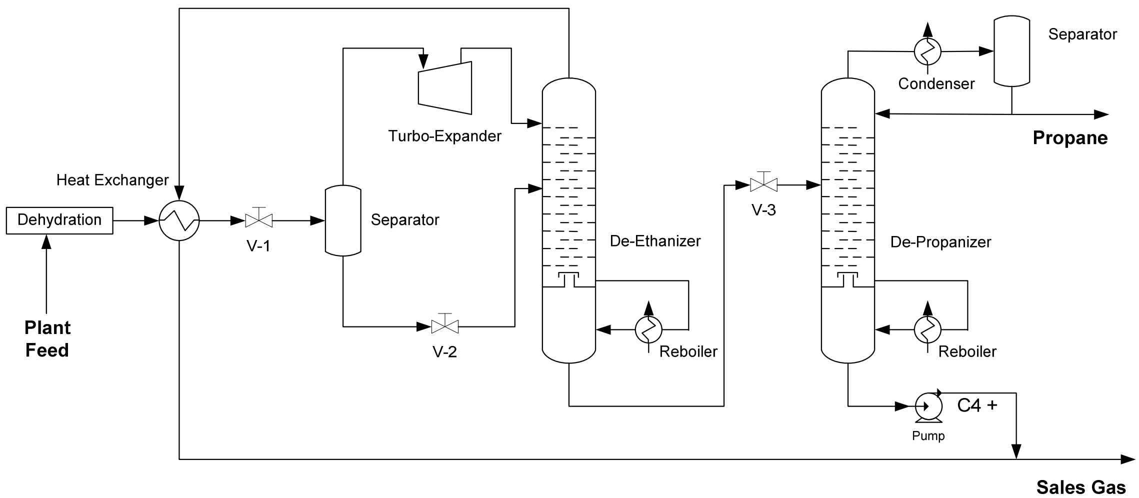
3.1 0.5 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Tok, Alaska

A schematic of the expander + two tower design for the Tok plant is shown in Figure 3.1.1.

Figure 3.1.1. Tok Plant Schematic - 0.5 MMSCFD.



Key features of the design include:

- Molecular sieve dehydration of inlet feed (to prevent hydrate formation)
- Inlet feed heat exchange (to provide initial feed cooling and warm sales gas)
- Initial pressure reduction (V-1; cooling with initial vapour-liquid separation and pressure drop into an acceptable range for turbo-expander casing design)
- Turbo-expander (for coldest feed to top of de-ethanizer tower)
- J-T valve (V-2; for liquid stream pressure drop and cold feed to intermediate stage of de-ethanizer tower)
- De-ethanizer tower (C1 and C2 in overhead vapour and liquid LPG as bottoms product)
- De-propanizer tower (Condensed C3 product from overhead vapour and C4+ as bottoms product)
- C4+ pump (to return C4+ to the sales gas stream for local consumption)

After dehydration and initial feed cooling in the inlet heat exchanger, the pressure is dropped to 500 psia through the Joule-Thomson valve, V-1. As indicated in the bullets above, this initial pressure drop provides sufficient cooling to liquefy a portion of the feed. The gas-liquid separation allows a methane-ethane-rich vapour stream to be routed to the turbo-expander and then the top section of the de-ethanizer tower. The C3+ enriched liquid stream is routed to a second Joule-Thomson valve and thereafter enters the intermediate section of the de-ethanizer. This initial feed fractionation, before the de-ethanizer, improves the overall separation performance of the facilities.

The pressure drop in V-1 also allows for a reduced casing design pressure for the turbo-expander, which reduces the expander cost and opens the field of potential suppliers, many of whom provide units capable of handling inlet pressures in the region of 500 psia.

Turbo-expanders provide isentropic (constant entropy) cooling which allows for greater cooling than the isenthalpic (constant enthalpy a.k.a. adiabatic) cooling achieved with a Joule-Thompson valve. Increased cooling improves the overall performance of the facilities (increased C3 recovery), and when appropriate the work harnessed by the expander can be used for recompression, or power generation, for example.

A simulation flow sheet, with stream table and equipment duty information, is provided in Appendix 1.

For this plant configuration, simulation work has been done assuming the "rich" gas composition from the previous studies and an inlet pressure of 1500 psia[7-11]. Some prior studies appear to have used an inlet pressure of 2000 psia, which was the average value along the Alaska gas pipeline section (assuming 2500 psia exiting compression, dropping to 1500 psia at inlet to next compression station).

GLE believes that there would be logistical and cost synergies associated with locating C3 fractionation facilities near compressor stations for the "straddle" plants. Therefore, taking fractionation plant feed at the lowest pressure (i.e. 1500 psia) is the most likely and cost-effective option. Low plant inlet pressure is the most challenging design case in terms of C3 recovery and is therefore a prudent choice for initial plant design and economic analysis

Based on the considerations above , the Tok plant design, with an inlet feed rate of 0.5 MMSCFD of raw pipeline gas should achieve the following performance levels:

- C1-C2 gas product with gross heating value (GHV) of 1044.5 Btu/scf and dew point of -117.4 F (225 psia) at a rate of 0.478 MMSCFD (925.1 lb/h) (see next 2 bullets).
- C4+ liquid product at a rate of 3.05 bpd (25.8 lb/h) which GLE recommends to be blended with the C1-C2 product stream (see next bullet item).
- Sales gas stream (C1-C2 & C4+) with GHV of 1063.2 Btu/scf and dew point of -47.6 F (220 psia) at a rate of 0.482 MMSCFD (951 lb/h) (**this is a blend of the two intermediate streams, above**)
- C3 liquid product with ≤ 2 wt % ethane and ≤ 2.5 wt % C4+ at a rate of 11.7 bpd (86.1 lb/h)

With this small plant, blending the C4+ stream into the C1-C2 stream increases the gross heating value of sales gas to only marginally above the normal upper limit for utility grade gas (1063 vs. 1050 Btu/scf). Even with the C4+ blended into the sales gas, the dew point at 220 psia is -47.6 F. At atmospheric pressure, sales gas dew point is calculated to be -107 F and for an intermediate pressure of 50 psia, the dew point is -81.1 F. Data for the period from 1971 to 2000, taken from the Alaska Climate Research Center shows the lowest average minimum daily temperature in Fairbanks to be -20 F.[12] Record low temperatures have reached the -65 F region (2008 lowest temperature was -48 F). Under normal conditions, liquid precipitation should not be a significant issue at plant pressure (220 psia). At relatively low pressures (e.g. 50 psia), liquid precipitation should not occur, even at the record low temperatures for Fairbanks. Hence, blending C4+ back into the sales gas is likely the most pragmatic solution for disposition of the C4+ stream. In

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detailed design, it might be prudent to consider including a knock out drum to catch C4+ liquids on the coldest possible days just in case fluctuations in plant feed lead to a coincidence of unusually high C4+ content on record cold days.

For the plant design shown herein, C3 recovery is 96.7 wt % with a C3 content in the propane product of 97.8 wt % (i.e. C2 and C4+ contents are well below spec. limits).

As stated previously, this plant uses a particular configuration of J-T valves with a turbo-expander, and has been initially simulated using a feed inlet pressure of 1500 psia. For comparison, GLE has modeled two additional plant configurations. In the first of these, the turbo-expander is replaced by a J-T valve (3 J-T valve configuration). In the second, alternate configuration, the separator, turbo-expander, and J-T valve (V-2) are removed and only the single J-T valve (V-1) is used for expansion cooling. Further, for each of the three plant configurations (base case plus two alternatives), GLE has evaluated C3 recovery against three inlet pressures, namely 1500, 1900, and 2400 psia. Full details of the alternate plant configurations and simulation runs are not provided with this report. A tabulation of the C3 recovery results is presented below.

Table 3.1.1 C3 Recovery as a Function of Plant Configuration and Feed Inlet Pressure.

Plant Configuration ➔	**Base Configuration**	**3 J-T Valves**	**1 J-T Valve**
Inlet Pressure (psia) 🡻	**C3 Recovery (mass percent)**		
1500	96.70	90.69	85.40
1900	97.46	93.36	87.93
2400	97.74	94.73	89.64

For the range of inlet pressures from 1500 to 2400 psia, the proposed base plant configuration provides superior propane recovery. The single J-T valve plant is not capable of reaching even 90 % propane recovery. Simply replacing the turbo-expander with a J-T valve (3 J-T valve configuration) results in a 6 % decrease in C3 recovery at 1500 psia. This gap decreases to 3 % with an inlet pressure of 2400 psia (base config is 3 % more efficient than 3 J-T valve config. at 2400 psia).

Of the three plant configurations examined above, only the base configuration can provide the required ~97 % propane recovery. Note that at the most likely inlet pressures (1900 - 2400 psia), propane recovery with the base configuration will be above 97 weight percent.

GLE has identified design improvements that can push C3 recovery to ≥99 wt % if needed. This would involve addition of a vapour feed super-cooler. A portion of the vapour currently fed to the turbo-expander would be re-routed to the super-cooler wherein cooling would be provided by the liquid stream exiting valve V-2. The cooled feed stream would then be expanded through a J-T valve, which would reduce temperature further. This super-cooled stream would enter the top of the de-ethanizer, while the turbo-expanded stream and V-2 expanded stream would be fed to lower locations in the tower. With a 1900 psia inlet pressure, the design with super-cooler is estimated to provide 99.3 weight percent C3 recovery.

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For cost estimation purposes herein, GLE has used the plant configuration shown in Figure 3.1.1. This is the simplest plant configuration capable of meeting the 97 wt % propane recovery target.

Cost Estimation

The estimation work described herein targets a Class 5 estimate. The Association for the Advancement of Cost Engineering (AACE International) has published Recommended Practice No. 18R-97, which provides the basis for an estimate classification system for the process industry.[13] The classification matrix from this publication is reproduced in Figure 3.1.2, below.

Figure 3.1.2. Estimate Classification Matrix from AACE Recommended Practice No. 18R-97.[13]

	Primary Characteristic	*Secondary Characteristic*			
ESTIMATE CLASS	**LEVEL OF PROJECT DEFINITION** Expressed as % of complete definition	**END USAGE** Typical purpose of estimate	**METHODOLOGY** Typical estimating method	**EXPECTED ACCURACY RANGE** Typical variation in low and high ranges [a]	**PREPARATION EFFORT** Typical degree of effort relative to least cost index of 1 [b]
Class 5	0% to 2%	Concept Screening	Capacity Factored, Parametric Models, Judgment, or Analogy	L: -20% to -50% H: +30% to +100%	1
Class 4	1% to 15%	Study or Feasibility	Equipment Factored or Parametric Models	L: -15% to -30% H: +20% to +50%	2 to 4
Class 3	10% to 40%	Budget, Authorization, or Control	Semi-Detailed Unit Costs with Assembly Level Line Items	L: -10% to -20% H: +10% to +30%	3 to 10
Class 2	30% to 70%	Control or Bid/ Tender	Detailed Unit Cost with Forced Detailed Take-Off	L: -5% to -15% H: +5% to +20%	4 to 20
Class 1	50% to 100%	Check Estimate or Bid/Tender	Detailed Unit Cost with Detailed Take-Off	L: -3% to -10% H: +3% to +15%	5 to 100

Notes: [a] The state of process technology and availability of applicable reference cost data affect the range markedly. The +/- value represents typical percentage variation of actual costs from the cost estimate after application of contingency (typically at a 50% level of confidence) for given scope.
[b] If the range index value of "1" represents 0.005% of project costs, then an index value of 100 represents 0.5%. Estimate preparation effort is highly dependent upon the size of the project and the quality of estimating data and tools.

A review of the table indicates that a Class 5 estimate is typically performed at the earliest stage of project definition (i.e. little to no definition) and therefore involves a wide range of expected accuracy. GLE typically finds these estimates being performed to an accuracy level of from -20 to +50 % and has used these levels in the preparation of the cost estimates provided herein.

For capital cost estimation, GLE has used the simulation flow sheet information (pressures, temperatures, compositions, flow rates, equipment duties), in combination with some preliminary equipment sizing as the bases of a request to two vendors for budgetary price quotations. The simulation flow sheet for the Tok facility is provided in Appendix 1. The equipment summary is provided in Appendix 2.

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Of the two vendors approached, one provided a response containing reasonably detailed, itemized lists of equipment (with design/specification data) and overall budgetary prices for the three facilities within this study. This estimate (Enerflex Systems Ltd.) is provided in Appendix 3.

The facilities estimate was provided without inclusion of electrical and control equipment and wiring. A separate budgetary estimate for this equipment was received from Kilowatts Design Company, and is provided in Appendix 4. For the Kilowatts estimates items 2 - 4 are treated as EIC Capex (Electrical Instrumentation and Control Capital Expense). The engineering (item 1) and field construction (item 5) costs are rolled up in the engineering and installation factor portions of the cost estimates.

These costs have been taken as the primary input for cost assessment.

Data for input into Monte Carlo simulation is provided in Table 3.1.2.

Table 3.1.2 Input Data for Probabilistic Cost Estimation of 0.5 MMSCFD C3 Fractionation Facility for Tok, Alaska.

Item	P10	P50	P90
Plant CAPEX	$688,000	$860,000	$1,290,000
Minor CAPEX	$137,600	$172,000	$258,000
EIC CAPEX	$520,000	$650,000	$975,000
Engineering (pre-factored) – see note 5	$269,120	$336,400	$504,600
Installation Factor	1.56	1.70	2.05
Location Factor	1.55	1.55	1.55
Owner's Costs	1.2	1.2	1.2

Notes:

1. Monetary values are in US Dollars. Cdn to USD exchange rate taken as 1.16 Cdn = 1.00 USD.
2. Plant capex includes all major process vessels and equipment, skid mounted, piped, valved and fully instrumented. Some equipment (e.g. coolers) will be off-skid and installed on foundations.
3. Minor capex includes storage tanks, utilities (compressed air, heat medium), flare(s), drains, and “straddle” piping. It is assumed that electrical power is taken from the grid, or local power generation. This minor capex value has been set at 20 % of the Plant Capex cost.
4. EIC capex includes wire process skid(s), wire/electrical controls building(s), electrical and control equipment.
5. Engineering costs include all engineering services associated with the EPCM contract for the project. Note that actual engineering cost is the “pre-factored” cost multiplied by the installation, location, and owner’s cost factors (i.e. the total estimated engineering cost, P50, for the Tok facility is $336,400 x 1.7 x 1.55 x 1.2 = $1,063,397).

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6. Installation factor includes the cost of labour and installation equipment required for construction of the project. The values used herein were determined by GLE senior staff taking into consideration the content included in the plant capex and EIC capex estimates, the separation of minor capex as an explicit line item, and GLE project experience.
7. Location factor is based on the Richardson International Construction Factors (2007 data) with consideration of points of manufacture, facilities locations, and the Cdn-USD exchange rate (see note 1).
8. Owners costs are based on the description provided by Stone and Webster, "typically include environmental permitting costs, site preparation costs, offices, warehouse, shops, and laboratory buildings and furnishing, insurance costs, interest cost during construction, financing costs, legal and other consultants' cost, working capital, etc." GLE has used the Stone & Webster estimate of owner's costs being 20 % of the EPC contract cost.

For the first five items in Table 3.1.2, ranges are provided for the estimates with the P10 value being P50 - 20 %, P50 = median estimate, and P90 being P50 + 50 % as per the Class 5 estimate error limits discussed previously. For the final two items in Table 3.1.2, namely location factor and owner's cost, a single value was used for each rather than a distribution.

As indicated in note 7, above, Richardson International Construction Factors for 2007 were used to scale the estimates to reflect the costs of installation in the various Alaskan locations. Available data and relative factors are presented in Table 3.1.3.

Table 3.1.3 Richardson International Location Factor Data and Relative Factors used to Scale Estimates from Calgary to Alaskan Locations.

Location	Rate	Location Factor	Relative Location Factor
Anchorage, Alaska	1.00 USD	1.32	1.40
Fairbanks, Alaska	1.00 USD	1.38	1.47
Houston, Texas	1.00 USD	0.90	0.96
Calgary, Alberta	1.16 USD	0.94	1.00

Note that for the even more remote community of Tok, GLE has arbitrarily assigned a relative location factor of 1.55, which is higher than the values for Achorage and Fairbanks. Stone & Webster used relative location factors of 1.44 and 1.52 for Anchorage and Fairbanks in their 2006 study for ANGDA.[8] These values are only marginally higher than those used in this study.

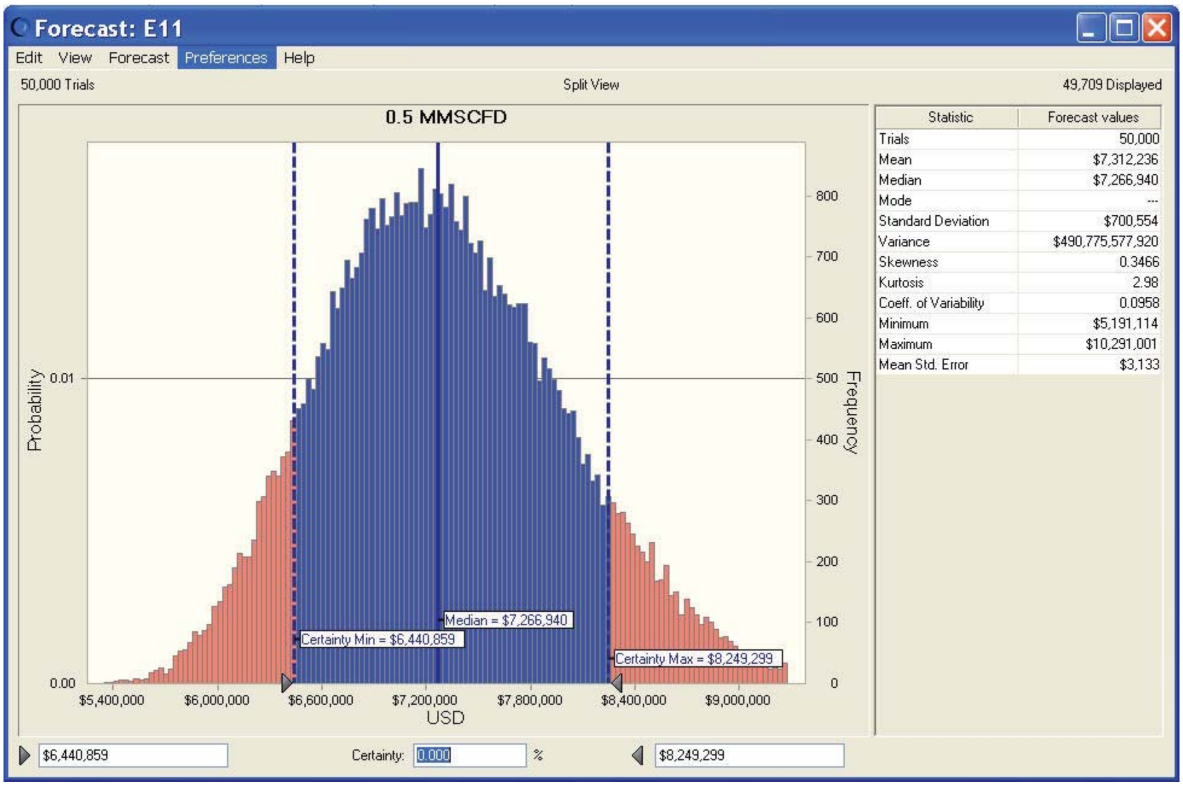
The Owner's Cost estimate was set as described in Note 8, above.

Monte Carlo simulations were performed using Crystal Ball software working as an add-in to Microsoft Excel. For each of the 50,000 iterations performed, probabilistic estimates for the first 5 variables (Table 3.1.1.) were generated and then a single point estimate was calculated using the formula;

(Plant Capex + Minor Capex + EIC Capex + Engineering) x Installation Factor x Location Factor x Owner's Cost

The 50,000 point estimates, taken together, produce a distribution of probable costs for the completed facilities. The probability distribution for the 0.5 MMSCFD plant to be located in Tok, Alaska, is provided in Figure 3.1.3.

Figure 3.1.3. Probable Distribution of Cost Estimate for 0.5 MMSCFD LPG/C3 Extraction Facility (Tok, Alaska).



The median (P50) estimated cost for the completed facility is USD 7.27 million. P10 (Certainty Min) and P90 (Certainty Max) values are USD 6.44 million and USD 8.25 million, respectively.

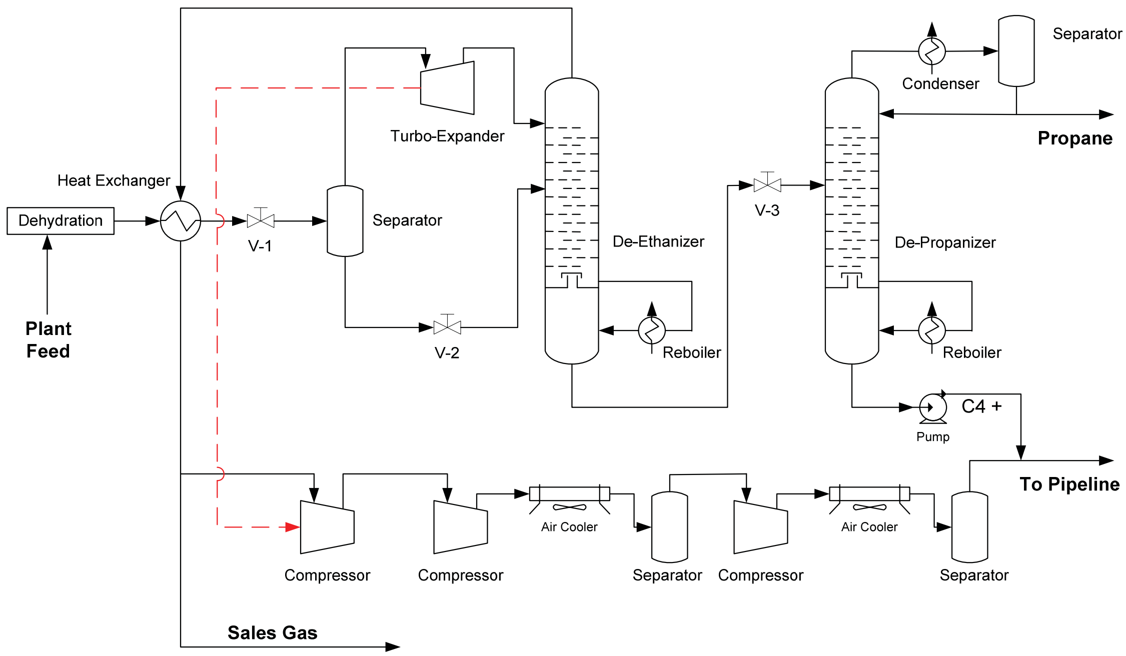
GLE has not added a contingency amount to these estimates. Rather, GLE believes that consideration of contingency is built into the range of values provided with the probabilistic estimation procedure.

Increased inlet pressure would only affect the dehydration section, inlet heat exchanger, and valve V-1. All other down-stream units operate at reduced pressure. Upon qualitative review of the estimate, GLE believes that operating at an increased inlet pressure on the order of 2000 psia would not increase the installed plant cost by more than 5 percent, for the Tok facilities. This is well within the margin of error for the original estimate.

3.2 65 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Fairbanks, Alaska

A schematic of the expander + two tower design for the Fairbanks plant is shown in Figure 3.2.1.

Figure 3.2.1. Fairbanks Plant Schematic - 65 MMSCFD.



The Fairbanks facility is fundamentally the same as the Tok facility in terms of LPG recovery and propane fractionation, albeit at a substantially larger scale. The additional facilities in the Fairbanks plant allow for local use of some of the relatively low pressure, lean sales gas, and for recompression of a sizeable fraction of the lean gas for return to the main pipeline. The entire C4+ stream will be pumped up to pipeline pressure and re-injected with the pressurized lean gas returning to the main pipeline.

The propane product recovered in Fairbanks is estimated to have the same characteristics as that produced in Tok, with the same extent of propane recovery (i.e. 96.7 wt %). Propane production from this facility is estimated at a rate of 1526 bpd (11,196 lb/h). The design rate for lean natural gas off-take for local consumption in Fairbanks is 25 MMSCFD with a gross heating value of 1044.5 Btu/scf and a dew point at 220 psia of -117 F. As local demand in Fairbanks grows, the off-take can be increased substantially provided this is factored into detailed design work for the compression train and associated pipes/valves.

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Cost Estimation

The cost estimate distribution for the Fairbanks facility has been constructed with the same methodology as that for the Tok Plant. The simulation flow sheet for the Fairbanks facility is provided in Appendix 5. The equipment summary is provided in Appendix 6. Budgetary quotations for the fractionation plant and electrical/DCS facilities are provided in Appendices 3, and 4, respectively (see 65 MMSCFD plant sections of these appendices).

Data for input into Monte Carlo simulation is provided in Table 3.2.1.

Table 3.2.1 Input Data for Probabilistic Cost Estimation of 65 MMSCFD C3 Fractionation Facility for Fairbanks, Alaska.

Item	P10	P50	P90
Plant CAPEX	$13,792,000	$17,240,000	$25,860,000
Minor CAPEX	$2,758,400	$3,448,000	$5,172,000
EIC CAPEX	$3,120,000	$3,900,000	$5,850,000
Engineering (pre-factored) – see note 5	$2,950,560	$3,688,200	$5,532,300
Installation Factor	1.48	1.60	1.90
Location Factor	1.47	1.47	1.47
Owner's Costs	1.2	1.2	1.2

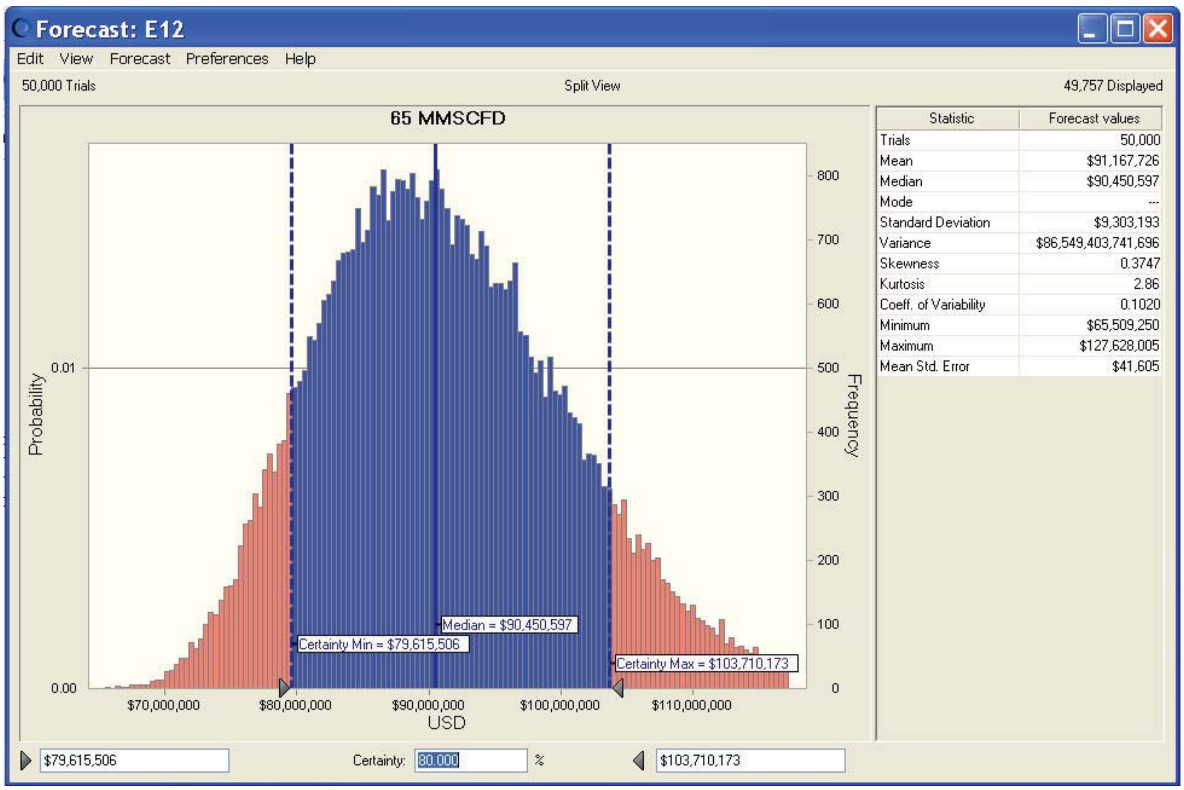
Notes:

1. Monetary values are in US Dollars. Cdn to USD exchange rate taken as 1.16 Cdn = 1.00 USD.
2. Plant capex includes all major process vessels and equipment, skid mounted, piped, valved and fully instrumented. Some equipment (e.g. coolers) will be off-skid and installed on foundations.
3. Minor capex includes storage tanks, utilities (compressed air, heat medium), flare(s), drains, and "straddle" piping. It is assumed that electrical power is taken from the grid, or local power generation. This minor capex value has been set at 20 % of the Plant Capex cost.
4. EIC capex includes wire process skid(s), wire/electrical controls building(s), electrical and control equipment.
5. Engineering costs include all engineering services associated with the EPCM contract for the project. Note that actual engineering cost is the "pre-factored" cost multiplied by the installation, location, and owner's cost factors (i.e. the total estimated engineering cost, P50, for the Fairbanks facility is $3,688,200 x 1.6 x 1.47 x 1.2 = $10,409,576).
6. Installation factor includes the cost of labour and installation equipment required for construction of the project. The values used herein were determined by GLE senior staff taking into consideration the content included in the plant capex and EIC capex estimates, the separation of minor capex as an explicit line item, and GLE project experience.
7. Location factor is based on the Richardson International Construction Factors (2007 data) with consideration of points of manufacture, facilities locations, and the Cdn-USD exchange rate (see note 1).

8. Owners costs are based on the description provided by Stone and Webster, "typically include environmental permitting costs, site preparation costs, offices, warehouse, shops, and laboratory buildings and furnishing, insurance costs, interest cost during construction, financing costs, legal and other consultants' cost, working capital, etc." GLE has used the Stone & Webster estimate of owner's costs being 20 % of the EPC contract cost.

The probability distribution for the 65 MMSCFD plant to be located in Fairbanks, Alaska, is provided in Figure 3.2.2.

Figure 3.2.2. Probable Distribution of Cost Estimate for 65 MMSCFD LPG/C3 Extraction Facility (Fairbanks, Alaska).



The median (P50) estimated cost for the completed facility is USD 90.45 million. P10 and P90 values are USD 79.62 million and USD 103.71 million, respectively.

As for the Tok facility, and increased inlet pressure (on the order of 2000 psia) will affect the design for the dehydration unit and the inlet heat exchanger and valve V1. The remainder of the separation facilities operate at reduced pressure and should not be affected. However, increased compression capacity would be required to return the unused gas to the pipeline.

GLE has investigated the incremental cost to increase the return pressure from 1500 psia to 2400 psia (see Appendix 7). The incremental capital cost for the increased compression is $650,000 CDN ($3,650,000 (2400 psig unit) - $3,000,000 (1500 psia unit) CDN). Taking into account the CDN/USD exchange rate and the installation, location, and owner's cost factors leads to a rough estimate of 1.6 million USD as the incremental cost associated with the increased compression requirement. Note that this assumes a return pressure of 2400 psia, which is the most pessimistic case for cost estimation purposes (1900 - 2100 psia appears to be most probable).

The median cost estimate for the Fairbanks facility operating at 1500 psia inlet pressure is roughly $90 million USD. To operate at higher pressure (~2000 psia) will incur increased costs for the inlet section of the plant (dehydration, heat exchange, valve V1) and residue gas recompression. Based on a mixture of qualitative and quantitative assessment, GLE does not believe that the cost estimate would increase by more than 5 % to accommodate an increased inlet pressure of roughly 2000 psia. This is well within the error limits of the original estimate.

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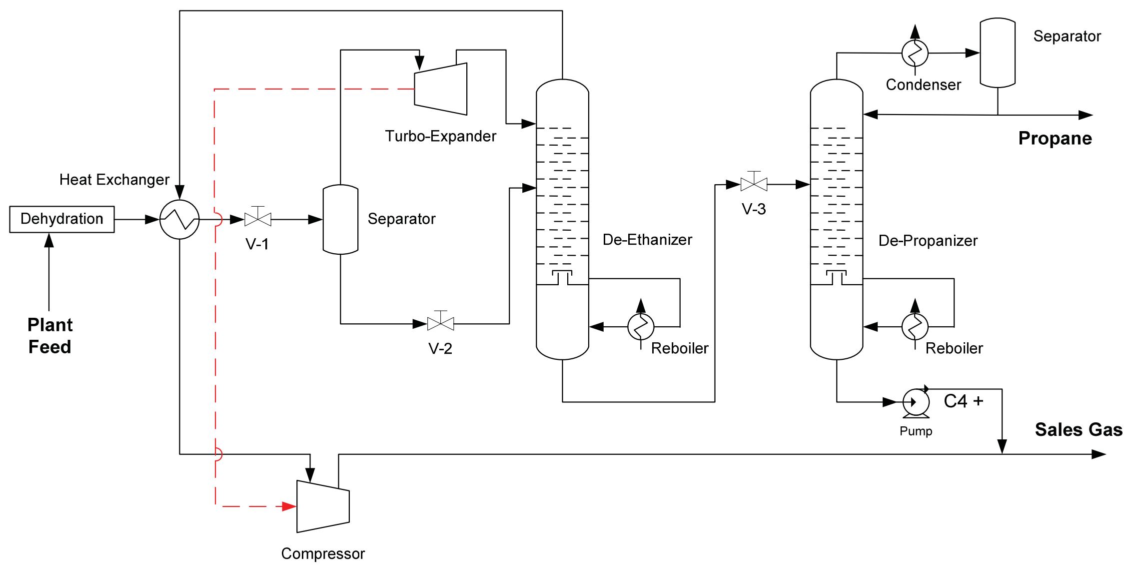
3.3 300 MMSCFD LPG Extraction Plant Process Design & Cost Estimation - Anchorage, Alaska

A schematic of the expander + two tower design for the Anchorage plant is shown in Figure 3.3.1.

Figure 3.3.1. Anchorage Plant Schematic - 300 MMSCFD.



The LPG recovery and propane fractionation portion of the Anchorage plant is of the same design as those for the Tok and Fairbanks plants. In the small, Tok plant, GLE has assumed the work/power generated by the turbo-expander would be braked using a small hydraulic system. For the Fairbanks facility, the expander would be coupled to a first stage boost compressor in the compression train used to raise gas pressure up to pipeline pressure for gas re-injection. In the Anchorage facility, the best option is to use only the boost compression stage to provide a modest increase in sales gas pressure for local distribution and a suitable braking system for the large turbo-expander.

The propane product recovered in Anchorage should have the same characteristics as that produced in Tok and Fairbanks, with the same extent of propane recovery (i.e. 96.7 wt %). Propane production from this facility is estimated at a rate of 7046 bpd (51,680 lb/h).

In the plant configuration shown in Figure 3.3.1, C4+ is blended into the sales gas resulting in the same sales gas GHV and dew point as predicted for Tok. However, if there is a local market for C4+ (possible additional fractionation into butanes, natural gasoline) it could be processed separately. In this case the sales gas would have the characteristics of the lean gas stream simulated for local use in Fairbanks. C4+ production is estimated to be nearly 1832 bpd (15,500 lb/hr) and therefore it might be of interest to study the possibilities for local fractionation and use, or export to other markets.

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Cost Estimation

The cost estimate distribution for the Anchorage facility has been constructed with the same methodology as that for the Tok Plant.

Data for input into Monte Carlo simulation is provided in Table 3.3.1.

Table 3.3.1 Input Data for Probabilistic Cost Estimation of 300 MMSCFD C3 Fractionation Facility for Anchorage, Alaska.

Item	P90	P50	P10
Plant CAPEX	$33,024,000	$41,280,000	$61,920,000
Minor CAPEX	$6,604,800	$8,256,000	$12,384,000
EIC CAPEX	$9,280,000	$11,600,000	$17,400,000
Engineering (pre-factored) – see note 5	$7,336,320	$9,170,400	$13,755,600
Installation Factor	1.32	1.40	1.60
Location Factor	1.4	1.40	1.4
Owner's Costs	1.2	1.2	1.2

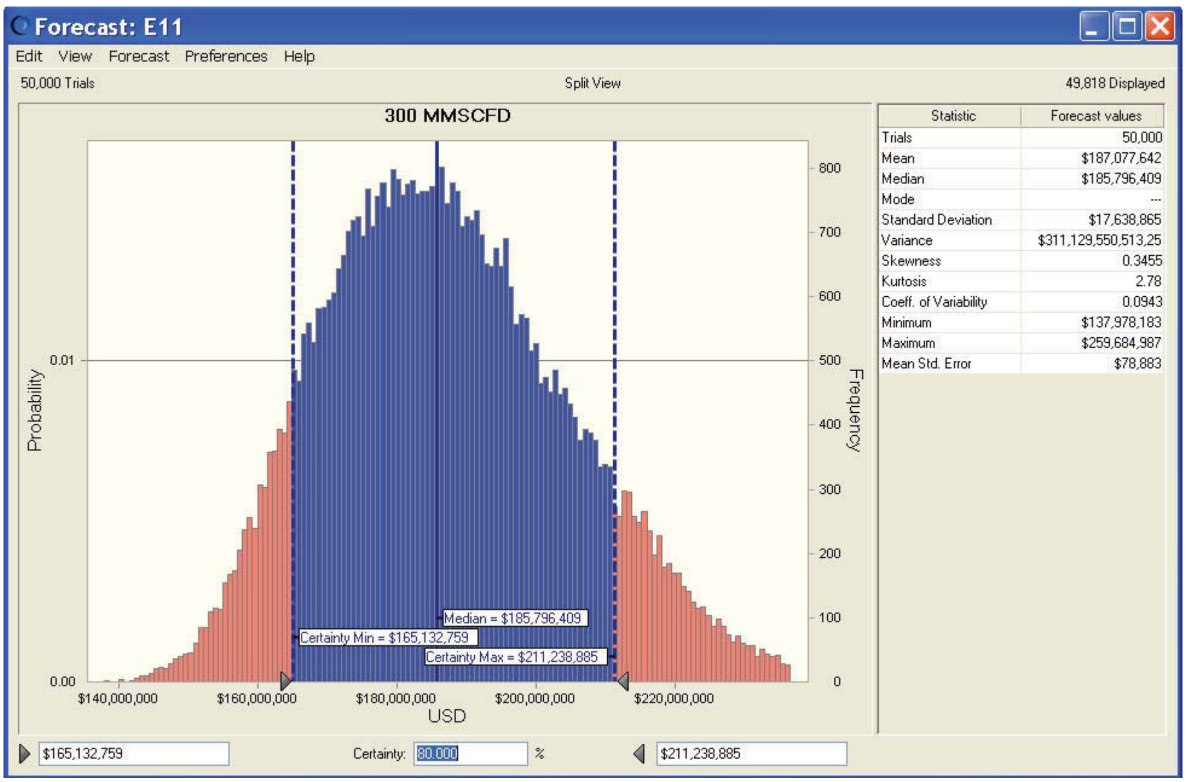
Notes:

1. Monetary values are in US Dollars. Cdn to USD exchange rate taken as 1.16 Cdn = 1.00 USD.
2. Plant capex includes all major process vessels and equipment, skid mounted, piped, valved and fully instrumented. Some equipment (e.g. coolers) will be off-skid and installed on foundations.
3. Minor capex includes storage tanks, utilities (compressed air, heat medium), flare(s), drains, and “straddle” piping. It is assumed that electrical power is taken from the grid, or local power generation. This minor capex value has been set at 20 % of the Plant Capex cost.
4. EIC capex includes wire process skid(s), wire/electrical controls building(s), electrical and control equipment.
5. Engineering costs include all engineering services associated with the EPCM contract for the project. Note that actual engineering cost is the “pre-factored” cost multiplied by the installation, location, and owner’s cost factors (i.e. the total estimated engineering cost, P50, for the Anchorage facility is $9,170,400 x 1.4 x 1.4 x 1.2 = $21,568,780).
6. Installation factor includes the cost of labour and installation equipment required for construction of the project. The values used herein were determined by GLE senior staff taking into consideration the content included in the plant capex and EIC capex estimates, the separation of minor capex as an explicit line item, and GLE project experience.
7. Location factor is based on the Richardson International Construction Factors (2007 data) with consideration of points of manufacture, facilities locations, and the Cdn-USD exchange rate (see note 1).

8. Owners costs are based on the description provided by Stone and Webster, "typically include environmental permitting costs, site preparation costs, offices, warehouse, shops, and laboratory buildings and furnishing, insurance costs, interest cost during construction, financing costs, legal and other consultants' cost, working capital, etc." GLE has used the Stone & Webster estimate of owner's costs being 20 % of the EPC contract cost.

The probability distribution for the 300 MMSCFD plant to be located in Anchorage, Alaska, is provided in Figure 3.3.2.

Figure 3.3.2. Probable Distribution of Cost Estimate for 300 MMSCFD LPG/C3 Extraction Facility (Anchorage, Alaska).



The median (P50) estimated cost for the completed facility is USD 185.8 million. P90 and P10 values are USD 165.1 million and USD 211.2 million, respectively.

Increased inlet pressure (to ~2000 psia) for the Anchorage facility would require design modifications to the inlet section of the plant (dehydration, inlet heat exchange, and valve V-1). After propane and/or C4+ extraction, natural gas is to be used locally and hence there is no residue gas recompression. GLE does not believe that an increased inlet pressure to something on the order of 2000 psia would increased the estimated cost for the Anchorage facility by more than 5 %, which is well within the error range of the original plant cost estimate.

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4.0 CONCLUSIONS AND RECOMMENDATIONS

Using the data and methodology provided herein leads to the Class 5 estimates for the three facilities of interest that are summarized in Table 4.1.

Table 4.1 Class 5 Cost Estimates for Alaskan C3 Recovery Facilities.

Facility	P10 Estimate	P50 Estimate	P90 Estimate
	Estimates in USD thousands		
0.5 MMSCFD Gas - Tok, Alaska	6,441	7,267	8,249
65 MMSCFD Gas – Fairbanks, Alaska	79,616	90,451	103,710
300 MMSCFD Gas – Anchorage, Alaska	165,132	185,796	211,239

GLE has reviewed the methodology for estimation and the results of estimation for this study with several internal experts and has cross-checked the estimates against another internal study. Based on this review, and the quality of input obtained for the estimates provided herein, GLE is quite comfortable with the results obtained.

Going forward, one would improve on the level of engineering detail available through conducting more formal engineering phases (basic, FEED, detailed, etc.) and using the information available to improve the quality of Capex estimates.

The use of factors for installation, location, and owner's cost introduces considerable multipliers into the estimation calculations. As more engineering detail is developed, it will also be prudent to scrutinize and refine the estimates for these factors to reduce the uncertainty associated with estimation, and to improve on the accuracy of the forecast values.

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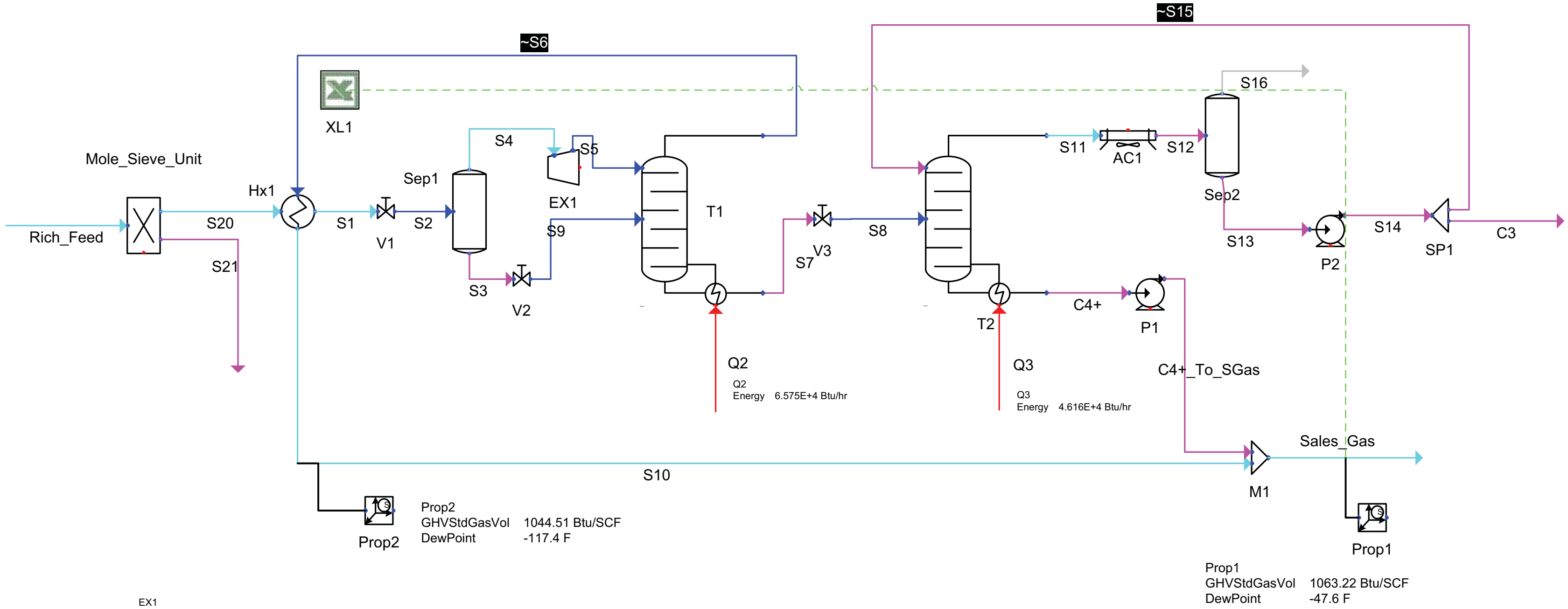
APPENDIX 1

Process Simulation Flowsheet
0.5 MMSCFD Propane Fractionation Facility

Propane Recovery Unit with Recombination of Lean Gas and C4+ for Local Sales Gas
0.5 MMSCFD Feed

Gas Liquids Engineering



Hx1	
DT Tube	-139.74 F
DT Shell	59.35 F
DP Tube	*5.00 psi
DP Shell	*1.00 psi
UA	2440.33 Btu/hr-F
TApproach_Tube_Shell_AppT	*5.00 F

EX1	
Duty	4.976E+0 HorsePower
DP	270.00 psi
Efficiency	81.08 %
In.T	-97.7 F
In.P	500.00 psia
Out.T	-146.8 F
Pout	*230.00 psia

P1	
Duty	1.678E-3 HorsePower
DP	20.00 psi
Efficiency	*75.00 %
Pout	*225.00 psia

Name	Rich_Feed	S1	S2	S3	S4	S5	S6	S7	S8	C3	C4+	Sales_Gas	C4+_To_SGas	S20	S21	S9	S10	S11	S12	S13	S14	S15	S16
VapFrac	1	1	0.76995	0	1	0.94248	0.99999	0	0.05319	0	0	1	0	1	0	0.26163	1	1	0	0	0	0	1
T [F]	28	-31.3	-97.7	-97.7	-97.7	-146.8	-116.7	125.6	116.7	100.9	200.8	21	201.2	28	28	-135.8	23	103.9	100	100	100.9	100.9	100
P [psia]	1500	1499	500	500	500	230	225	230	205	250	205	220	225	1500	1500	230	220	200	200	200	250	250	200
MoleFlow [lbmole/h]	54.9	54.9	54.9	12.63	42.27	42.27	52.51	2.39	2.39	1.96	0.43	52.94	0.43	54.9	0	12.63	52.51	7.84	7.84	7.84	7.84	5.88	0
MassFlow [lb/h]	1037.07	1037.06	1037.06	315.84	721.22	721.22	925.14	111.94	111.94	86.1	25.81	950.95	25.81	1037.06	0	315.84	925.14	344.41	344.41	344.41	344.41	258.28	0
MoleFraction [Fraction]																							
CARBON DIOXIDE	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0	0.0156	0	0.015	0	0.0273	0.0157	0	0	0	0	0	0
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0	0.0062	0	0.006	0	0.0013	0.0063	0	0	0	0	0	0
METHANE	0.864	0.864	0.864	0.6001	0.9429	0.9429	0.9034	0	0	0	0	0.896	0	0.864	0	0.6001	0.9034	0	0	0	0	0	0
ETHANE	0.071	0.071	0.071	0.1973	0.0333	0.0333	0.0735	0.0156	0.0156	0.019	0	0.0729	0	0.071	0	0.1973	0.0735	0.019	0.019	0.019	0.019	0.019	0.0493
PROPANE	0.036	0.036	0.036	0.1402	0.0049	0.0049	0.0011	0.8012	0.8012	0.9748	0.0135	0.0012	0.0135	0.036	0	0.1402	0.0011	0.9748	0.9748	0.9748	0.9748	0.9748	0.9481
ISOBUTANE	0.003	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0039	0.363	0.003	0.363	0.003	0	0.0126	0	0.0039	0.0039	0.0039	0.0039	0.0039	0.0017
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.4966	0.0041	0.4966	0.004	0	0.017	0	0.0023	0.0023	0.0023	0.0023	0.0022	0.0009
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1269	0.001	0.1269	0.001	0	0.0043	0	0	0	0	0	0	0

APPENDIX 2

Major Equipment List
0.5 MMSCFD Propane Fractionation Facility

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

Unit	Water Removal Rate (lb/h)
Molecular Sieve	0.0036

Hx 1	Name		Value		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**2440.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-69132.5**		
	PortName	**InTube**	**InShell**	**OutTube**	**OutShell**
	UnitOperation				
	Is Recycle Port				
	Connected Stream/Unit Op	/S6.Out	/S20.Out	/Sales_Gas.In	/S1.In
	Connected Port				
	VapFrac	1.00	1.00	1.00	1.00
	T [F]	-116.7	28.0	23.0	-31.3
	P [psia]	225.0	1500.0	220.0	1499.0
	MoleFlow [lbmole/h]	52.506	54.899	52.506	54.899
	MassFlow [lb/h]	925.136	1037.063	925.136	1037.063
	VolumeFlow [ft3/s]	0.201	0.034	0.325	0.021
	StdLiqVolumeFlow [ft3/s]	0.013	0.014	0.013	0.014
	StdGasVolumeFlow [MMSCFD]	0.478	0.500	0.478	0.500
	Properties (Alt+R)				
	Energy [Btu/hr]	126199.137	144325.579	195331.626	75193.090
	H [Btu/lbmol]	2403.911	2629.353	3720.785	1369.883
	S [Btu/lbmol-F]	36.083	34.245	39.349	31.481
	MolecularWeight	17.620	18.890	17.620	18.890
	MassDensity [lb/ft3]	1.282	8.409	0.791	14.011
	Cp [Btu/lbmol-F]	9.815	17.297	9.312	24.800
	ThermalConductivity [Btu/hr-ft-F]	0.012	0.029	0.018	0.037
	Viscosity [cp]	0.008	0.016	0.010	0.024
	molarV [ft3/lbmol]	13.748	2.246	22.286	1.348
	ZFactor	0.840	0.648	0.946	0.445
	Fraction [Fraction]				
	CARBON DIOXIDE	0.015684	0.015000	0.015684	0.015000
	NITROGEN	0.006273	0.006000	0.006273	0.006000
	METHANE	0.903379	0.864000	0.903379	0.864000
	ETHANE	0.073527	0.071000	0.073527	0.071000
	PROPANE	0.001126	0.036000	0.001126	0.036000
	ISOBUTANE	0.000007	0.003000	0.000007	0.003000
	n-BUTANE	0.000004	0.004000	0.000004	0.004000
	n-PENTANE	0.000000	0.001000	0.000000	0.001000
	WATER	0.000000	0.000000	0.000000	0.000000

Summary of Plant Unit Design Information			
0.5 MMSCFD Facility			
V1	Name	Value	
	Delta P [psi]	999	
	Cv	0.20844	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S1.Out	/S2.In
	Connected Port		
	VapFrac	1.00	0.77
	T [F]	-31.3	-97.7
	P [psia]	1499.0	500.0
	MoleFlow [lbmole/h]	54.899	54.899
	MassFlow [lb/h]	1037.063	1037.063
	VolumeFlow [ft3/s]	0.021	0.065
	StdLiqVolumeFlow [ft3/s]	0.014	0.014
	StdGasVolumeFlow [MMSCFD]	0.500	0.500
	Properties (Alt+R)		
	Energy [Btu/hr]	75193.090	75193.090
	H [Btu/lbmol]	1369.883	1369.883
	S [Btu/lbmol-F]	31.481	32.476
	MolecularWeight	18.890	18.890
	MassDensity [lb/ft3]	14.011	4.400
	Cp [Btu/lbmol-F]	24.800	14.767
	ThermalConductivity [Btu/hr-ft-F]	0.037	0.032
	Viscosity [cp]	0.024	0.019
	molarV [ft3/lbmol]	1.348	4.294
	ZFactor	0.445	0.553
	Fraction [Fraction]		
	CARBON DIOXIDE	0.015000	0.015000
	NITROGEN	0.006000	0.006000
	METHANE	0.864000	0.864000
	ETHANE	0.071000	0.071000
	PROPANE	0.036000	0.036000
	ISOBUTANE	0.003000	0.003000
	n-BUTANE	0.004000	0.004000
	n-PENTANE	0.001000	0.001000
	WATER	0.000000	0.000000

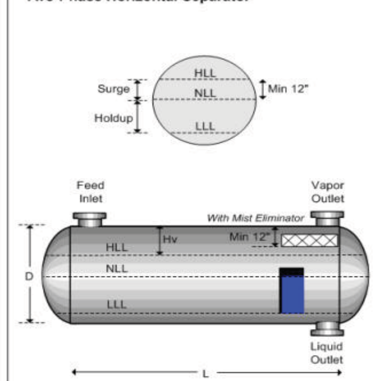
Summary of Plant Unit Design Information

0.5 MMSCFD Facility

Separator 1	PortName	In	Liq0	Vap
	UnitOperation			
	Is Recycle Port			
	Connected Stream/Unit Op	/S2.Out	/S3.In	/S4.In
	Connected Port			
	VapFrac	0.77	0.00	1.00
	T [F]	-97.7	-97.7	-97.7
	P [psia]	500.0	500.0	500.0
	MoleFlow [lbmole/h]	54.899	12.630	42.270
	MassFlow [lb/h]	1037.063	315.841	721.222
	VolumeFlow [ft3/s]	0.065	0.003	0.062
	StdLiqVolumeFlow [ft3/s]	0.014	0.004	0.010
	StdGasVolumeFlow [MMSCFD]	0.500	0.115	0.385
	Properties (Alt+R)			
	Energy [Btu/hr]	75193.090	-17397.379	92590.468
	H [Btu/lbmol]	1369.883	-1377.712	2190.847
	S [Btu/lbmol-F]	32.476	26.662	34.213
	MolecularWeight	18.890	25.007	17.062
	MassDensity [lb/ft3]	4.400	27.925	3.214
	Cp [Btu/lbmol-F]	14.767	18.430	13.672
	ThermalConductivity [Btu/hr-ft-F]	0.032	0.070	0.016
	Viscosity [cp]	0.019	0.101	0.009
	molarV [ft3/lbmol]	4.294	0.896	5.309
	ZFactor	0.553	0.109	0.685
	Fraction [Fraction]			
	CARBON DIOXIDE	0.015000	0.027284	0.011330
	NITROGEN	0.006000	0.001259	0.007417
	METHANE	0.864000	0.600091	0.942855
	ETHANE	0.071000	0.197252	0.033277
	PROPANE	0.036000	0.140246	0.004852
	ISOBUTANE	0.003000	0.012574	0.000139
	n-BUTANE	0.004000	0.016974	0.000123
	n-PENTANE	0.001000	0.004321	0.000008
	WATER	0.000000	0.000000	0.000000

Variables	Value
Design Variables	
VesselDesignType	**Sep2PhaseHorizontal**
MaxIteration	**50**
HoldupTime [day]	**0.0174**
SurgeTime [day]	**0.0035**
VapMassFlow [lb/h]	**721.22**
LiqMassFlow [lb/h]	**315.84**
VapDensity [lb/ft3]	**3.2139**
LiqDensity [lb/ft3]	**27.9253**
P [psia]	**500.00**
WithMistEliminator	**0**
Min_Design_L/D	**1.50**
Max_Design_L/D	**6.00**
Calculated Variables	
VesselLength [in]	137.1272
VesselDiameter [in]	24.000
L/Dratio	5.71
VapDisengagementHeight [in]	12.000
NormalLiqLevel [in]	11.5072
HighLiqLevel [in]	12.000
LowLiqLevel [in]	9.000
VesselWeight [lb]	1652.59
VesselWallThickness [in]	0.5026

Two-Phase Horizontal Separator



Nomenclature

L = Vessel Length
D = Vessel Internal Diameter
Hv = Vapor Disengagement Height
HLL = High Liquid Level
NLL = Normal Liquid Level
LLL = Low Liquid Level

Notes

- Design values are only first estimation. It is not recommended for final dimension
- Stokes' Law constant, K is calculated using York-Demister equation
- For wall thickness calculation;
- Assume carbon-steel for material stress, X-rayed joints for joint efficiency and corrosion allowance = 1/16 inch
- Material = Carbon-steel
- For calculation purposes, mist eliminator thickness/height is assumed to be 4.8 inches

Summary of Plant Unit Design Information			
0.5 MMSCFD Facility			
V2	Name	Value	
	Delta P [psi]	270	
	Cv	0.05742	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S3.Out	/S9.In
	Connected Port		
	VapFrac	0.00	0.26
	T [F]	-97.7	-135.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	12.630	12.630
	MassFlow [lb/h]	315.841	315.841
	VolumeFlow [ft3/s]	0.003	0.014
	StdLiqVolumeFlow [ft3/s]	0.004	0.004
	StdGasVolumeFlow [MMSCFD]	0.115	0.115
	Properties (Alt+R)		
	Energy [Btu/hr]	-17397.379	-17397.379
	H [Btu/lbmol]	-1377.712	-1377.712
	S [Btu/lbmol-F]	26.662	26.945
	MolecularWeight	25.007	25.007
	MassDensity [lb/ft3]	27.925	6.429
	Cp [Btu/lbmol-F]	18.430	15.013
	ThermalConductivity [Btu/hr-ft-F]	0.070	0.066
	Viscosity [cp]	0.101	0.086
	molarV [ft3/lbmol]	0.896	3.890
	ZFactor	0.109	0.254
	Fraction [Fraction]		
	CARBON DIOXIDE	0.027284	0.027284
	NITROGEN	0.001259	0.001259
	METHANE	0.600091	0.600091
	ETHANE	0.197252	0.197252
	PROPANE	0.140246	0.140246
	ISOBUTANE	0.012574	0.012574
	n-BUTANE	0.016974	0.016974
	n-PENTANE	0.004321	0.004321
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information			
0.5 MMSCFD Facility			
Ex 1	Name		Value
	OutQ [HorsePower]		4.98
	Delta P [psi]		270.00
	Pressure Ratio		2.17
	Adiabatic Efficiency [%]		81.08
	Polytropic Efficiency [%]		80.00
	Speed [rpm]		
	Adiabatic Head [ft]		16849.64
	Polytropic Head [ft]		17077.15
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S4.Out	/S5.In
	Connected Port		
	VapFrac	1.00	0.94
	T [F]	-97.7	-146.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	42.270	42.270
	MassFlow [lb/h]	721.222	721.222
	VolumeFlow [ft3/s]	0.062	0.130
	StdLiqVolumeFlow [ft3/s]	0.010	0.010
	StdGasVolumeFlow [MMSCFD]	0.385	0.385
	Properties (Alt+R)		
	Energy [Btu/hr]	92590.468	79928.479
	H [Btu/lbmol]	2190.847	1891.243
	S [Btu/lbmol-F]	34.213	34.438
	MolecularWeight	17.062	17.062
	MassDensity [lb/ft3]	3.214	1.536
	Cp [Btu/lbmol-F]	13.672	10.476
	ThermalConductivity [Btu/hr-ft-F]	0.016	0.017
	Viscosity [cp]	0.009	0.009
	molarV [ft3/lbmol]	5.309	11.110
	ZFactor	0.685	0.761
	Fraction [Fraction]		
	CARBON DIOXIDE	0.011330	0.011330
	NITROGEN	0.007417	0.007417
	METHANE	0.942855	0.942855
	ETHANE	0.033277	0.033277
	PROPANE	0.004852	0.004852
	ISOBUTANE	0.000139	0.000139
	n-BUTANE	0.000123	0.000123
	n-PENTANE	0.000008	0.000008
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

T1	Condenser	No		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED	overheadFeed	Lower_Feed	
	Stage	1	8	
	Connected Obj	/S5.Out	/S9.Out	
	Details			
	VapFrac	0.9425	0.2616	
	T [F]	-146.8	-135.8	
	P [psia]	230.0	230.0	
	MoleFlow [lbmole/h]	42.270	12.630	
	MassFlow [lb/h]	721.222	315.841	
	VolumeFlow [ft3/s]	0.130	0.014	
	StdLiqVolumeFlow [ft3/s]	0.010	0.004	
	StdGasVolumeFlow [MMSCFD]	0.385	0.115	
	Molar Composition			
	CARBON DIOXIDE	0.011330	0.027284	
	NITROGEN	0.007417	0.001259	
	METHANE	0.942855	0.600091	
	ETHANE	0.033277	0.197252	
	PROPANE	0.004852	0.140246	
	ISOBUTANE	0.000139	0.012574	
	n-BUTANE	0.000123	0.016974	
	n-PENTANE	0.000008	0.004321	
	WATER	0.000000	0.000000	
	DRAW	overheadV	reboilerL	
	Stage	1	20	
	Type	VapourDraw	LiquidDraw	
	Connected Obj	/S6.In	/S7.In	
	Details			
	VapFrac	1.0000	0.0000	
	T [F]	-116.8	125.6	
	P [psia]	225.0	230.0	
	MoleFlow [lbmole/h]	52.506	2.393	
	MassFlow [lb/h]	925.128	111.935	
	VolumeFlow [ft3/s]	0.201	0.001	
	StdLiqVolumeFlow [ft3/s]	0.013	0.001	
	StdGasVolumeFlow [MMSCFD]	0.478	0.022	
	reboilerQ (Btu/hr)	**65744.0**		

Section	Section_1
Start	1
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[1in] Pall Rings (M)**
Fp	56.00
PackingAreaperVol [ft2/f3]	68.12
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	0.500
TotalTrayArea [ft2]	0.1963
PackingLengthperSection [ft]	28.500

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information			
0.5 MMSCFD Facility			
V3	Name	Value	
	Delta P [psi]	25	
	Cv	0.06539	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S7.Out	/S8.In
	Connected Port		
	VapFrac	0.00	0.05
	T [F]	125.6	116.7
	P [psia]	230.0	205.0
	MoleFlow [lbmole/h]	2.393	2.393
	MassFlow [lb/h]	111.935	111.935
	VolumeFlow [ft3/s]	0.001	0.002
	StdLiqVolumeFlow [ft3/s]	0.001	0.001
	StdGasVolumeFlow [MMSCFD]	0.022	0.022
	Properties (Alt+R)		
	Energy [Btu/hr]	2077.511	2077.511
	H [Btu/lbmol]	868.193	868.193
	S [Btu/lbmol-F]	34.117	34.134
	MolecularWeight	46.770	46.770
	MassDensity [lb/ft3]	29.209	17.215
	Cp [Btu/lbmol-F]	35.358	33.569
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.080	0.078
	molarV [ft3/lbmol]	1.601	2.717
	ZFactor	0.058	0.089
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.015555	0.015555
	PROPANE	0.801162	0.801162
	ISOBUTANE	0.068671	0.068671
	n-BUTANE	0.091674	0.091674
	n-PENTANE	0.022938	0.022938
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

T2	Condenser	Yes			
	Reboiler	Yes			
	# Ideal Stages	20	Includes Condenser and Reboiler		
	Total stages = 20				
	FEED				
	Stage	2			
	Connected Obj	/S8.Out			
	Details				
	VapFrac	0.0532			
	T [F]	116.7			
	P [psia]	205.0			
	MoleFlow [lbmole/h]	2.393			
	MassFlow [lb/h]	111.935			
	VolumeFlow [ft3/s]	0.002			
	StdLiqVolumeFlow [ft3/s]	0.001			
	StdGasVolumeFlow [MMSCFD]	0.022			
	Molar Composition				
	CARBON DIOXIDE	0.000000			
	NITROGEN	0.000000			
	METHANE	0.000000			
	ETHANE	0.015555			
	PROPANE	0.801162			
	ISOBUTANE	0.068671			
	n-BUTANE	0.091674			
	n-PENTANE	0.022938			
	WATER	0.000000			
	DRAW	condenserL	condenserV	reboilerL	
	Stage	1	1	20	
	Type	LiquidDraw	VapourDraw	LiquidDraw	
	Connected Obj		/C3.In	/C4+.In	
	Details				
	VapFrac	0.0000	1.0000	0.0000	
	T [F]	105.9	105.9	198.1	
	P [psia]	200.0	200.0	202.0	
	MoleFlow [lbmole/h]	0.000	1.981	0.412	
	MassFlow [lb/h]	0.000	87.391	24.545	
	VolumeFlow [ft3/s]	0.000	0.013	0.000	
	StdLiqVolumeFlow [ft3/s]	0.000	0.001	0.000	
	StdGasVolumeFlow [MMSCFD]	0.000	0.018	0.004	
	ENERGY	condenserQ		reboilerQ	
	Stage	1		20	
	Type	EnergyOut		EnergyIn	
	Connected Obj	/Q4.In		/Q3.Out	
	Value [Btu/hr]	32798.1		44285.9	

Section	Section_1
Start	2
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[1in] Pall Rings (M)**
Fp	56.00
PackingAreaperVol [ft2/f3]	68.12
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	0.500
TotalTrayArea [ft2]	0.1963
PackingLengthperSection [ft]	27.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

0.5 MMSCFD Facility

P1	Name	Value	
	InQ [HorsePower]	0.00183	
	Delta P [psi]	23	
	Pressure Ratio	1.114	
	Efficiency [%]	75	
	Speed [rpm]		
	Head [ft]	110.55	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/C4+.Out	/C4+_To_SGas.In
	Connected Port		
	VapFrac	0.00	0.00
	T [F]	198.1	198.6
	P [psia]	202.0	225.0
	MoleFlow [lbmole/h]	0.410	0.410
	MassFlow [lb/h]	24.540	24.540
	VolumeFlow [ft3/s]	0.000	0.000
	StdLiqVolumeFlow [ft3/s]	0.000	0.000
	StdGasVolumeFlow [MMSCFD]	0.004	0.004
	Properties (Alt+R)		
	Energy [Btu/hr]	1334.057	1338.706
	H [Btu/lbmol]	3238.977	3250.266
	S [Btu/lbmol-F]	34.642	34.646
	MolecularWeight	59.582	59.582
	MassDensity [lb/ft3]	29.958	29.996
	Cp [Btu/lbmol-F]	45.094	44.915
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.087	0.088
	molarV [ft3/lbmol]	1.989	1.986
	ZFactor	0.057	0.063
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.000000	0.000000
	PROPANE	0.027024	0.027024
	ISOBUTANE	0.350867	0.350867
	n-BUTANE	0.491006	0.491006
	n-PENTANE	0.131103	0.131103
	WATER	0.000000	0.000000

APPENDIX 3

Budget Pricing - Propane Recovery Unit
Enerflex Systems Ltd.

ENERFLEX

2009 07 03

File: C11166

Gas Liquids Engineering Ltd.
#300, 2749 - 39th Avenue N.E.
Calgary, Alberta
T1Y 4T8

Attention: Richard Piche
Sr. Project Manager

Re: Budget Pricing
Propane Recovery Unit

We wish to take this opportunity to thank you for the above enquiry, and allowing us the opportunity to present our offer for the supply of the referenced materials.

Our budget offer is for the supply of

(A) 300 MMSCFD Propane Recovery Unit
(B) 65 MMSCFD Propane Recovery Unit
(C) 0.5 MMSCFD Propane Recovery Unit

The equipment selection, capacity and operating ranges are based upon interpretation of the information supplied to us within your enquiry documents, or by assumptions we have made in the absence of such information.

Again, thank you for your consideration and we look forward to further discussing our proposal with you at your convenience.

Regards,

Steven C. Graham, P.Eng
General Manager
Production and Processing
Enerflex Systems Ltd.

Cc: Mike Tearoe – BD Manager
Jim Forsyth – Account Manager

A) PROPANE RECOVERY UNIT WITH RESIDUE GAS RECOMPRESSION & C4+RECOMBINATION FOR RE-INJECTION TO PIPELINE 300 MMSCFD FEED

1. Molecular Sieve Dehydration Unit:

1.1. Equipment:

Equipment shall be provided as follows:

1.1.1. Inlet Filter Separator

-Vertical Inlet Coalescing Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.2. Adsorption Vessels

-Vertical vessel, adsorbent material supported on a fixed grid
-Adsorbent: Molecular Sieves on 316 floating screen
-C.A.:1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA516 Gr. 70N

1.1.3. Dust Filter Separator

-Horizontal Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.4. Regeneration Gas Separator Vessel

-Vertical Separator with inlet deflector and demister
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
-Material: SA516 Gr. 70N

1.1.5. Regeneration Gas Heater

-Fired Heater type furnace
-Combustion Section: Lined with fiber block insulation, c/w exhaust stack
-Burner: Forced draft type c/w air blower
-Re-circulation fan: Yes c/w TEFC motor
-Control Panel: NEMA 4x enclosure, Class1 Div.2

1.1.6. Regeneration Gas Cooler/Condenser

-Type: Forced draft aerial cooler
-Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

1.1.7. Regeneration Gas Compressor

-Type: Vertical, single stage centrifugal
-Driver: TEFC motor and vibrations switch

2. Hydrocarbon Dew Point Control Unit:

2.1. Equipment:

Equipment shall be provided as follows:

2.1.1. Gas / Gas Exchanger

- Type: NEN
- TEMA “R” / ASME Section VIII, Division 1 construction
- Duty: 41.479 MMBTU/h
- Tube Material: SA-249-TP-304
- Shell Material: SA-312- TP-304L

2.1.2. Turbo Expander Compressor

- Variable inlet vanes system
- Lubrication system
- Seal gas system
-Power: 2985.80 hp
- Control/annunciator system

2.1.3. Expander Suction Vessel

- Size: 144” O.D. x 33’-0” S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
- Radiography: Full per RT-2
- P.W.H.T.: as required by code
- 2 phase controls
- Stainless Steel construction

2.1.4. De-Methanizer Column

- Size: 108" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA-240-304L

2.1.5. De-Methanizer Reboiler

- Duty: 39.45 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3. Propane Recovery Unit:

3.1. Equipment:

Equipment shall be provided as follows:

3.1.1. De-Propanizer Column

- Size: 90" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA516 Gr. 70

3.1.2. De-Propanizer Reboiler

- Duty: 26.60 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3.1.3. De-Propanizer Condenser

- Duty: 19.69 MMBTU/h
- Type: Forced draft aerial cooler
- Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

3.1.4. C4+ Pump

-Type: Centrifugal, ANSI
- Flow: 61.49 USGPM
- Power: 3.35 hp
-Driver: TEFC motor and vibrations switch

B) PROPANE RECOVERY UNIT WITH RESIDUE GAS RECOMPRESSION & C4+RECOMBINATION FOR RE-INJECTION TO PIPELINE 65 MMSCFD FEED

1. Molecular Sieve Dehydration Unit:

1.1. Equipment:

Equipment shall be provided as follows:

1.1.1. Inlet Filter Separator

-Vertical Inlet Coalescing Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.2. Adsorption Vessels

-Vertical vessel, adsorbent material supported on a fixed grid
-Adsorbent: Molecular Sieves on 316 floating screen
-C.A.:1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA516 Gr. 70N

1.1.3. Dust Filter Separator

-Horizontal Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.4. Regeneration Gas Separator Vessel

-Vertical Separator with inlet deflector and demister
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
-Material: SA516 Gr. 70N

1.1.5. Regeneration Gas Heater

-Fired Heater type furnace
-Combustion Section: Lined with fiber block insulation, c/w exhaust stack
-Burner: Forced draft type c/w air blower
-Re-circulation fan: Yes c/w TEFC motor
-Control Panel: NEMA 4x enclosure, Class1 Div.2

1.1.6. Regeneration Gas Cooler/Condenser

-Type: Forced draft aerial cooler
-Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

1.1.7. Regeneration Gas Compressor

-Type: Vertical, single stage centrifugal
-Driver: TEFC motor and vibrations switch

2. Hydrocarbon Dew Point Control Unit:

2.1. Equipment:

Equipment shall be provided as follows:

2.1.1. Gas / Gas Exchanger

- Type: NEN
- TEMA “R” / ASME Section VIII, Division 1 construction
- Duty: 8.98 MMBTU/h
- Tube Material: SA-249-TP-304
- Shell Material: SA-312- TP-304L

2.1.2. Turbo Expander Compressor

- Variable inlet vanes system
- Lubrication system
- Seal gas system
- Power: 646.92 hp
- Control/annunciator system

2.1.3. Expander Suction Vessel

- Size: 90” O.D. x 20’-0” S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
- Radiography: Full per RT-2
- P.W.H.T.: as required by code
- 2 phase controls
- Stainless Steel construction

2.1.4. De-Methanizer Column

- Size: 48” O.D. x 52’-0” S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA-240-304L

2.1.5. De-Methanizer Reboiler

- Duty: 8.54 MMBTU/h
- TEMA “R” / ASME Section VIII, Division 1 construction
- Type: BKU
- Material: SA516 Gr. 70

2.1.6. Residue Gas Compressor

-Type: Vertical, two stage centrifugal
-Driver: TEFC motor and vibrations switch
-Power: 3814 hp

3. Propane Recovery Unit:

3.1. Equipment:

Equipment shall be provided as follows:

3.1.1. De-Propanizer Column

- Size: 42" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA516 Gr. 70

3.1.2. De-Propanizer Reboiler

- Duty: 5.764 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3.1.3. De-Propanizer Condenser

- Duty: 4.27 MMBTU/h
- Type: Forced draft aerial cooler
- Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

3.1.4. C4+ Pump

-Type: Centrifugal, ANSI
- Flow: 13.46 USGPM
- Power: 13.46 hp
-Driver: TEFC motor and vibrations switch

C) PROPANE RECOVERY UNIT & C4+RECOMBINATION FOR RE-INJECTION TO PIPELINE 0.5 MMSCFD FEED

1. Molecular Sieve Dehydration Unit:

1.1. Equipment:

Equipment shall be provided as follows:

1.1.1. Inlet Filter Separator

-Vertical Inlet Coalescing Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.2. Adsorption Vessels

-Vertical vessel, adsorbent material supported on a fixed grid
-Adsorbent: Molecular Sieves on 316 floating screen
-C.A.:1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA516 Gr. 70N

1.1.3. Dust Filter Separator

-Horizontal Filter Separator
-Internals: Porous Media Filters
- C.A.: 1.5 mm
-Construction: ASME Section VIII, Division 1, Registered, U-stamped
-Material: SA106 Gr. B

1.1.4. Regeneration Gas Separator Vessel

-Vertical Separator with inlet deflector and demister
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
-Material: SA516 Gr. 70N

1.1.5. Regeneration Gas Heater

-Fired Heater type furnace
-Combustion Section: Lined with fiber block insulation, c/w exhaust stack
-Burner: Forced draft type c/w air blower
-Re-circulation fan: Yes c/w TEFC motor
-Control Panel: NEMA 4x enclosure, Class1 Div.2

1.1.6. Regeneration Gas Cooler/Condenser

-Type: Forced draft aerial cooler
-Fan: TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

1.1.7. Regeneration Gas Compressor

-Type: Vertical, single stage centrifugal
-Driver: TEFC motor and vibrations switch

2. Hydrocarbon Dew Point Control Unit:

2.1. Equipment:

Equipment shall be provided as follows:

2.1.1. Gas / Gas Exchanger

- Type: NEN
- TEMA “R” / ASME Section VIII, Division 1 construction
- Duty: 0.06913 MMBTU/h
- Tube Material: SA-249-TP-304
- Shell Material: SA-312- TP-304L

2.1.2. Gas Expander

- Variable inlet vanes system
- Lubrication system
- Seal gas system
-Power: 4.98 hp
- Control/annunciator system

2.1.3. Expander Suction Vessel

- Size: 24” O.D. x 12’-0” S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
- C.A.: 1.5 mm
- Radiography: Full per RT-2
- P.W.H.T.: as required by code
- 2 phase controls
- Stainless Steel construction

2.1.4. De-Methanizer Column

- Size: 6" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA-240-304L

2.1.5. De-Methanizer Reboiler

- Duty: 0.0657 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3. Propane Recovery Unit:

3.2. Equipment:

Equipment shall be provided as follows:

3.1.1. De-Propanizer Column

- Size: 6" O.D. x 52'-0" S/S
- Design: ASME Section VIII Div 1, Registered, U-stamped
-Internals: 20 trays SS, distributor
- C.A.: 1.5 mm
- Material: SA516 Gr. 70

3.1.2. De-Propanizer Reboiler

- Duty: 0.0442 MMBTU/h
-TEMA "R" / ASME Section VIII, Division 1 construction
-Type: BKU
- Material: SA516 Gr. 70

3.1.3. De-Propanizer Condenser

- Duty: 0.03279 MMBTU/h
- Type: Forced draft aerial cooler
- Fan:TEFC motor and vibrations switch
-Tubes: SA179 seemless tubes with aluminum fins
-Accessories: Manual louvers, hail-guards

3.1.4. C4+ Pump

-Type: Centrifugal, ANSI
- Power: 0.0183 hp
-Driver: TEFC motor and vibrations switch

CODES

Minimum requirements are to be in accordance with applicable codes and governmental requirements. Specifically:

- CSA W59 Welded Steel Construction
- The Boiler and Pressure Vessel Act of Alberta (registered in Alberta) and B.C.
- ASME Pressure Vessel Code
- ANSI/ASME B31.3 Refinery Piping
- B.C. / Alberta Building Code
- Canadian Standards Association

PACKAGE

The package shall be skid mounted, piped, valved and fully instrumented. Some of the items like coolers, etc. will be off-skid and installed on foundations.

INSTRUMENTATION

Instrumentation shall include electronic and pneumatic pressure, level and temperature controls. Instruments shall be run on instrument air which shall be supplied to skid. No PLC / DCS is included in the offer.

PIPING

All piping shall be brought to skid edge. Process streams and sweet, dry fuel gas shall be brought to the skid. Pressure relief valves shall be manifolded into a header and brought to skid perimeter. Drains shall be manifolded together into a 2" drain header and brought to skid perimeter. No inter-connecting piping between skids, between field erected equipment and skids has been considered.

INSULATION/PAINTING

The package shall be insulated commercially sandblasted (blast, primer and 2 finish coats of alkyd enamel.

ENERFLEX
Production and Processing
BUDGET OFFER

4. PRICE

Unit	Budget Price (±30%) Ex-Works Nisku, Alberta
300 MMSCFD Plant	$48,000,000.00 CDN
65 MMSCFD Plant	$20,000,000.00 CDN
0.5 MMSCFD Plant	$1,000,000.00 CDN

APPENDIX 4

Cost Estimate for Electrical/DCS for C3 Fractionation Plants
Kilowatts Design Company Inc.

Ian McKay

From: Marc P. Bouchard [MBouchard@kilowatts.com]
Sent: July 9, 2009 11:33 AM
To: Ian McKay
Subject: RE: Ball Park Cost for Electrical/DCS for C3 Fractionation Plants

Ian,
Here is what I've estimated for the costs of the Electrical, Instrumentation and Controls portion for each of these projects.

For the .5mmscfd option:
1. Engineering, PM, Drafting, PLC programming, startup and commissioning - $300K
2. Wire 14' x 40' process skid - $250K
3. Wire 14' x 20' electrical/controls building - $200K
4. Electrical and control equipment - $300K
5. Field construction - $300K

Total: $1.35 million

For the 65mmscfd option:
1. Engineering, PM, Drafting, PLC programming, startup and commissioning - $1,000K
2. Wire process skids - $1,000K
3. Wire electrical/controls buildings - $1,000K
4. Electrical and control equipment - $2,500K
5. Field construction - $2,000K

Total: $7.5 million

For the 300mmscfd option:
1. Engineering, PM, Drafting, PLC programming, startup and commissioning - $3,000K
2. Wire process skids - $3,000K
3. Wire electrical/controls buildings - $3,000K
4. Electrical and control equipment - $7,500K
5. Field construction - $6,000K

Total: $22.5 million

Best regards,

Marc Bouchard
Senior Project Manager

Kilowatts Design Company Inc.
Unit 90 2150 - 29th Street NE, Calgary, AB T1Y 7G4

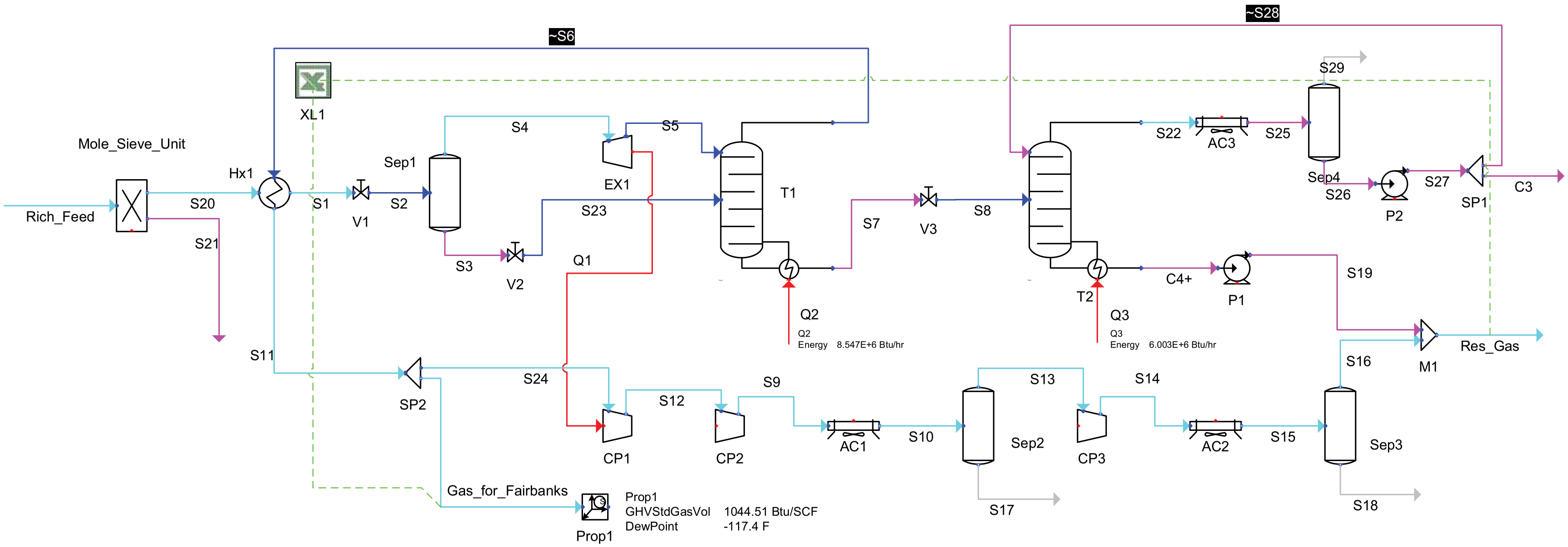
Direct 403.204.6616 Cell 403.807.8515
Main 403.272.9404 Fax 403.272.9433

mbouchard@kilowatts.com

APPENDIX 5

Process Simulation Flowsheet
65 MMSCFD Propane Fractionation Facility

Propane Recovery Unit with Residue Gas Recompression & C4+ Recombination For Re-injection to Pipeline
65 MMSCFD Feed



Hx1	
DT Tube	-139.74 F
DT Shell	59.35 F
DP Tube	*5.00 psi
DP Shell	*1.00 psi
UA	3.17E+05 Btu/hr-F
TApproach_Tube_Shell_AppT	*5.00 F

EX1	
Duty	6.469E+2 HorsePower
DP	270.00 psi
Efficiency	81.08 %
In.T	-97.7 F
In.P	500.00 psia
Out.T	-146.8 F
Pout	*230.00 psia

CP1	
Duty	6.469E+2 HorsePower
DP	83.50186 psi
Efficiency	*75.00 %
In.T	23.0 F
In.P	220.00 psia
Out.T	71.7 F
Pout	303.50 psia

CP2	
Duty	1.896E+3 HorsePower
DP	379.37733 psi
Efficiency	*75.00 %
In.T	71.7 F
In.P	303.50 psia
Out.T	207.1 F
Pout	682.88 psia

CP3	
Duty	1.918E+3 HorsePower
DP	832.12081 psi
Efficiency	*75.00 %
In.T	104.0 F
In.P	677.88 psia
Out.T	243.6 F
Pout	*1510.00 psia

P1	
Duty	1.419E+1 HorsePower
DP	1300.00 psi
Efficiency	*75.00 %
Pout	*1505.00 psia

Name	Rich_Feed	S1	S2	S3	S4	S5	S6	S7	S8	C3	C4+
VapFrac	1	1	0.76995	0	1	0.94248	0.99999	0	0.05319	0	0
T [F]	28	-31.3	-97.7	-97.7	-97.7	-146.8	-116.7	125.6	116.7	100.9	200.8
P [psia]	1500	1499	500	500	500	230	225	230	205	250	205
MoleFlow [lbmole/h]	7136.94	7136.92	7136.92	1641.88	5495.04	5495.04	6825.81	311.13	311.13	254.94	56.22
MassFlow [lb/h]	134818.67	134818.21	134818.21	41059.34	93758.87	93758.87	120267.71	14551.65	14551.65	11196.18	3356.62
StdGasVolumeFlow [MMSCFD]	6.50E+01	6.50E+01	6.50E+01	1.50E+01	5.00E+01	5.00E+01	6.22E+01	2.83E+00	2.83E+00	2.32E+00	5.12E-01
MoleFraction [Fraction]											
CARBON DIOXIDE	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0
METHANE	0.864	0.864	0.864	0.6001	0.9429	0.9429	0.9034	0	0	0	0
ETHANE	0.071	0.071	0.071	0.1973	0.0333	0.0333	0.0735	0.0156	0.0156	0.019	0
PROPANE	0.036	0.036	0.036	0.1402	0.0049	0.0049	0.0011	0.8012	0.8012	0.9748	0.0135
ISOBUTANE	0.003	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0039	0.3633
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.4965
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1267

Name	S11	S12	S9	S10	S13	S14	S15	S16	S17	S18	S19	Res_Gas
VapFrac	1	1	1	1	1	1	1	1	0	0	0	1
T [F]	23	71.7	207.1	104	104	243.6	104	104	104	104	221.5	104.4
P [psia]	220	303.50186	682.87919	677.87919	677.87919	1510	1505	1505	677.87919	1505	1505	1505
MoleFlow [lbmole/h]	6825.81	4080.83	4080.83	4080.83	4080.83	4080.83	4080.83	4080.83	0	0	56.22	4137.05
MassFlow [lb/h]	120267.71	71902.44	71902.44	71902.44	71902.44	71902.44	71902.44	71902.44	0	0	3356.62	75259.06
StdGasVolumeFlow [MMSCFD]	6.22E+01	3.72E+01	3.72E+01	3.72E+01	3.72E+01	3.72E+01	3.72E+01	3.72E+01	2.01E-42	2.01E-42	5.12E-01	3.77E+01
MoleFraction [Fraction]												
CARBON DIOXIDE	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0.0157	0	0.0155
NITROGEN	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0.0063	0	0.0062
METHANE	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0.9034	0	0.8911
ETHANE	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0.0735	0	0.0725
PROPANE	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0011	0.0135	0.0013
ISOBUTANE	0	0	0	0	0	0	0	0	0	0	0.3633	0.0049
n-BUTANE	0	0	0	0	0	0	0	0	0	0	0.4965	0.0067
n-PENTANE	0	0	0	0	0	0	0	0	0	0	0.1267	0.0017

Name	S20	S21	S23	S24	Gas_for_Fairbanks	S22	S25	S26	S27	S28	S29
VapFrac	1	0	0.26163	1	1	1	0	0	0	0	[illegible]
T [F]	28	28	-135.8	23	23	103.9	100	100	100.9	100.9	100
P [psia]	1500	1500	230	220	220	200	200	200	250	250	200
MoleFlow [lbmole/h]	7136.92	0.03	1641.88	4080.83	2744.98	1019.77	1019.77	1019.77	1019.77	764.85	0
MassFlow [lb/h]	134818.21	0.46	41059.34	71902.44	48365.27	44784.72	44784.72	44784.72	44784.72	33589.69	0
StdGasVolumeFlow [MMSCFD]	6.50E+01	2.35E-04	1.50E+01	3.72E+01	2.50E+01	9.29E+00	9.29E+00	9.29E+00	9.29E+00	6.97E+00	2.01E-4[illegible]
MoleFraction [Fraction]											
CARBON DIOXIDE	0.015	0	0.0273	0.0157	0.0157	0	0	0	0	0	0
NITROGEN	0.006	0	0.0013	0.0063	0.0063	0	0	0	0	0	0
METHANE	0.864	0	0.6001	0.9034	0.9034	0	0	0	0	0	0
ETHANE	0.071	0	0.1973	0.0735	0.0735	0.019	0.019	0.019	0.019	0.019	0.049[illegible]
PROPANE	0.036	0	0.1402	0.0011	0.0011	0.9748	0.9748	0.9748	0.9748	0.9748	0.948[illegible]
ISOBUTANE	0.003	0	0.0126	0	0	0.0039	0.0039	0.0039	0.0039	0.004	0.001[illegible]
n-BUTANE	0.004	0	0.017	0	0	0.0023	0.0023	0.0023	0.0023	0.0022	[illegible]
n-PENTANE	0.001	0	0.0043	0	0	0	0	0	0	0	0

APPENDIX 6

Major Equipment List
65 MMSCFD Propane Fractionation Facility

Summary of Plant Unit Design Information

65 MMSCFD Facility

Unit	Water Removal Rate (lb/h)
Molecular Sieve	0.4645

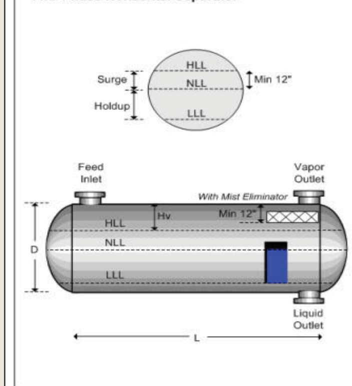
Hx 1	Name		**Value**		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**317242.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-8987220.9**		
	PortName	**InTube**	**InShell**	**OutTube**	**OutShell**
	UnitOperation				
	Is Recycle Port				
	Connected Stream/Unit Op	/S6.Out	/S20.Out	/S11.In	/S1.In
	Connected Port				
	VapFrac	1.00	1.00	1.00	1.00
	T [F]	-116.7	28.0	23.0	-31.3
	P [psia]	225.0	1500.0	220.0	1499.0
	MoleFlow [lbmole/h]	6825.810	7136.920	6825.810	7136.920
	MassFlow [lb/h]	120267.710	134818.210	120267.710	134818.210
	VolumeFlow [ft3/s]	26.067	4.453	42.255	2.673
	StdLiqVolumeFlow [ft3/s]	1.703	1.828	1.703	1.828
	StdGasVolumeFlow [MMSCFD]	62.166	65.000	62.166	65.000
	Properties (Alt+R)				
	Energy [Btu/hr]	16405890.304	18762325.277	25393111.206	9775104.375
	H [Btu/lbmol]	2403.912	2629.353	3720.785	1369.884
	S [Btu/lbmol-F]	36.083	34.245	39.349	31.481
	MolecularWeight	17.620	18.890	17.620	18.890
	MassDensity [lb/ft3]	1.282	8.409	0.791	14.011
	Cp [Btu/lbmol-F]	9.815	17.297	9.312	24.800
	ThermalConductivity [Btu/hr-ft-F]	0.012	0.029	0.018	0.037
	Viscosity [cp]	0.008	0.016	0.010	0.024
	molarV [ft3/lbmol]	13.748	2.246	22.286	1.348
	ZFactor	0.840	0.648	0.946	0.445
	Fraction [Fraction]				
	CARBON DIOXIDE	0.015684	0.015000	0.015684	0.015000
	NITROGEN	0.006273	0.006000	0.006273	0.006000
	METHANE	0.903379	0.864000	0.903379	0.864000
	ETHANE	0.073527	0.071000	0.073527	0.071000
	PROPANE	0.001126	0.036000	0.001126	0.036000
	ISOBUTANE	0.000007	0.003000	0.000007	0.003000
	n-BUTANE	0.000004	0.004000	0.000004	0.004000
	n-PENTANE	0.000000	0.001000	0.000000	0.001000
	WATER	0.000000	0.000000	0.000000	0.000000

Summary of Plant Unit Design Information			
65 MMSCFD Facility			
V1	Name	Value	
	Delta P [psi]	999	
	Cv	27.09706	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S1.Out	/S2.In
	Connected Port		
	VapFrac	1.00	0.77
	T [F]	-31.3	-97.7
	P [psia]	1499.0	500.0
	MoleFlow [lbmole/h]	7136.920	7136.920
	MassFlow [lb/h]	134818.210	134818.210
	VolumeFlow [ft3/s]	2.673	8.512
	StdLiqVolumeFlow [ft3/s]	1.828	1.828
	StdGasVolumeFlow [MMSCFD]	65.000	65.000
	Properties (Alt+R)		
	Energy [Btu/hr]	9775000.000	9775000.000
	H [Btu/lbmol]	1369.900	1369.900
	S [Btu/lbmol-F]	31.481	32.476
	MolecularWeight	18.890	18.890
	MassDensity [lb/ft3]	14.011	4.400
	Cp [Btu/lbmol-F]	24.800	14.767
	ThermalConductivity [Btu/hr-ft-F]	0.037	0.032
	Viscosity [cp]	0.024	0.019
	molarV [ft3/lbmol]	1.348	4.294
	ZFactor	0.445	0.553
	Fraction [Fraction]		
	CARBON DIOXIDE	0.015000	0.015000
	NITROGEN	0.006000	0.006000
	METHANE	0.864000	0.864000
	ETHANE	0.071000	0.071000
	PROPANE	0.036000	0.036000
	ISOBUTANE	0.003000	0.003000
	n-BUTANE	0.004000	0.004000
	n-PENTANE	0.001000	0.001000
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information				
65 MMSCFD Facility				
Separator 1	PortName	**In**	**Liq0**	**Vap**
	UnitOperation			
	Is Recycle Port			
	Connected Stream/Unit Op	/S2.Out	/S3.In	/S4.In
	Connected Port			
	VapFrac	0.77	0.00	1.00
	T [F]	-97.7	-97.7	-97.7
	P [psia]	500.0	500.0	500.0
	MoleFlow [lbmole/h]	7136.920	1641.880	5495.040
	MassFlow [lb/h]	134818.210	41059.340	93758.870
	VolumeFlow [ft3/s]	8.512	0.408	8.104
	StdLiqVolumeFlow [ft3/s]	1.828	0.483	1.344
	StdGasVolumeFlow [MMSCFD]	65.000	14.953	50.046
	Properties (Alt+R)			
	Energy [Btu/hr]	9775104.375	-2261658.876	12036763.057
	H [Btu/lbmol]	1369.884	-1377.712	2190.847
	S [Btu/lbmol-F]	32.476	26.662	34.213
	MolecularWeight	18.890	25.007	17.062
	MassDensity [lb/ft3]	4.400	27.925	3.214
	Cp [Btu/lbmol-F]	14.767	18.430	13.672
	ThermalConductivity [Btu/hr-ft-F]	0.032	0.070	0.016
	Viscosity [cp]	0.019	0.101	0.009
	molarV [ft3/lbmol]	4.294	0.896	5.309
	ZFactor	0.553	0.109	0.685
	Fraction [Fraction]			
	CARBON DIOXIDE	0.015000	0.027280	0.011330
	NITROGEN	0.006000	0.001260	0.007420
	METHANE	0.864000	0.600090	0.942850
	ETHANE	0.071000	0.197250	0.033280
	PROPANE	0.036000	0.140250	0.004850
	ISOBUTANE	0.003000	0.012570	0.000140
	n-BUTANE	0.004000	0.016970	0.000120
	n-PENTANE	0.001000	0.004320	0.000010
	WATER	0.000000	0.000000	0.000000

Variables	Value
Design Variables	
VesselDesignType	**Sep2PhaseHorizontal**
MaxIteration	**50**
HoldupTime [day]	**0.0174**
SurgeTime [day]	**0.0035**
VapMassFlow [lb/h]	**93758.87**
LiqMassFlow [lb/h]	**41059.34**
VapDensity [lb/ft3]	**3.2139**
LiqDensity [lb/ft3]	**27.9253**
P [psia]	**500.00**
WithMistEliminator	**0**
Min_Design_L/D	**1.50**
Max_Design_L/D	**6.00**
Calculated Variables	
VesselLength [in]	234.6176
VesselDiameter [in]	90.000
L/Dratio	2.61
VapDisengagementHeight [in]	12.000
NormalLiqLevel [in]	65.4569
HighLiqLevel [in]	78.000
LowLiqLevel [in]	11.000
VesselWeight [lb]	40799.76
VesselWallThickness [in]	1.713

Two-Phase Horizontal Separator



Nomenclature

L = Vessel Length
D = Vessel Internal Diameter
Hv = Vapor Disengagement Height
HLL = High Liquid Level
NLL = Normal Liquid Level
LLL = Low Liquid Level

Notes

- Design values are only first estimation. It is not recommended for final dimension
- Stokes' Law constant, K is calculated using York-Demister equation
- For wall thickness calculation;
- Assume carbon-steel for material stress, X-rayed joints for joint efficiency and corrosion allowance = 1/16 inch
- Material = Carbon-steel
- For calculation purposes, mist eliminator thickness/height is assumed to be 4.8 inches

Summary of Plant Unit Design Information			
65 MMSCFD Facility			
V2	Name	Value	
	Delta P [psi]	270	
	Cv	7.46485	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S3.Out	/S9.In
	Connected Port		
	VapFrac	0.00	0.26
	T [F]	-97.7	-135.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	1641.881	1641.881
	MassFlow [lb/h]	41059.336	41059.336
	VolumeFlow [ft3/s]	0.408	1.774
	StdLiqVolumeFlow [ft3/s]	0.483	0.483
	StdGasVolumeFlow [MMSCFD]	14.953	14.953
	Properties (Alt+R)		
	Energy [Btu/hr]	-2261658.876	-2261658.876
	H [Btu/lbmol]	-1377.712	-1377.712
	S [Btu/lbmol-F]	26.662	26.945
	MolecularWeight	25.007	25.007
	MassDensity [lb/ft3]	27.925	6.429
	Cp [Btu/lbmol-F]	18.430	15.013
	ThermalConductivity [Btu/hr-ft-F]	0.070	0.066
	Viscosity [cp]	0.101	0.086
	molarV [ft3/lbmol]	0.896	3.890
	ZFactor	0.109	0.254
	Fraction [Fraction]		
	CARBON DIOXIDE	0.027284	0.027284
	NITROGEN	0.001259	0.001259
	METHANE	0.600091	0.600091
	ETHANE	0.197252	0.197252
	PROPANE	0.140246	0.140246
	ISOBUTANE	0.012574	0.012574
	n-BUTANE	0.016974	0.016974
	n-PENTANE	0.004321	0.004321
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information							
65 MMSCFD Facility							
Ex 1	Name		Value	CP1	Name		Value
	OutQ [HorsePower]		646.92		InQ [HorsePower]		646.92
	Delta P [psi]		270.00		Delta P [psi]		83.50
	Pressure Ratio		2.17		Pressure Ratio		1.38
	Adiabatic Efficiency [%]		81.08		Adiabatic Efficiency [%]		75.00
	Polytropic Efficiency [%]		80.00		Polytropic Efficiency [%]		75.91
	Speed [rpm]				Speed [rpm]		
	Adiabatic Head [ft]		16849.64		Adiabatic Head [ft]		13360.89
	Polytropic Head [ft]		17077.15		Polytropic Head [ft]		13523.77
	PortName	In	Out		PortName	In	Out
	UnitOperation				UnitOperation		
	Is Recycle Port				Is Recycle Port		
	Connected Stream/Unit Op	/S4.Out	/S5.In		Connected Stream/Unit Op	/S24.Out	/S12.In
	Connected Port				Connected Port		
	VapFrac	1.00	0.94		VapFrac	1.00	1.00
	T [F]	-97.7	-146.8		T [F]	23.0	71.7
	P [psia]	500.0	230.0		P [psia]	220.0	303.5
	MoleFlow [lbmole/h]	5495.040	5495.040		MoleFlow [lbmole/h]	4080.830	4080.830
	MassFlow [lb/h]	93758.870	93758.870		MassFlow [lb/h]	71902.440	71902.440
	VolumeFlow [ft3/s]	8.104	16.958		VolumeFlow [ft3/s]	25.262	20.159
	StdLiqVolumeFlow [ft3/s]	1.344	1.344		StdLiqVolumeFlow [ft3/s]	1.018	1.018
	StdGasVolumeFlow [MMSCFD]	50.046	50.046		StdGasVolumeFlow [MMSCFD]	37.166	37.166
	Properties (Alt+R)				Properties (Alt+R)		
	Energy [Btu/hr]	12040000	10390000		Energy [Btu/hr]	15180000	16830000
	H [Btu/lbmol]	2190.800	1891.200		H [Btu/lbmol]	3720.800	4124.200
	S [Btu/lbmol-F]	34.213	34.438		S [Btu/lbmol-F]	39.349	39.540
	MolecularWeight	17.060	17.060		MolecularWeight	17.620	17.620
	MassDensity [lb/ft3]	3.214	1.536		MassDensity [lb/ft3]	0.791	0.991
	Cp [Btu/lbmol-F]	13.672	10.476		Cp [Btu/lbmol-F]	9.312	9.627
	ThermalConductivity [Btu/hr-ft-F]	0.016	0.017		ThermalConductivity [Btu/hr-ft-F]	0.018	0.021
	Viscosity [cp]	0.009	0.009		Viscosity [cp]	0.010	0.011
	molarV [ft3/lbmol]	5.309	11.110		molarV [ft3/lbmol]	22.286	17.784
	ZFactor	0.685	0.761		ZFactor	0.946	0.946
	Fraction [Fraction]				Fraction [Fraction]		
	CARBON DIOXIDE	0.011330	0.011330		CARBON DIOXIDE	0.015684	0.015684
	NITROGEN	0.007417	0.007417		NITROGEN	0.006273	0.006273
	METHANE	0.942855	0.942855		METHANE	0.903379	0.903379
	ETHANE	0.033277	0.033277		ETHANE	0.073527	0.073527
	PROPANE	0.004852	0.004852		PROPANE	0.001126	0.001126
	ISOBUTANE	0.000139	0.000139		ISOBUTANE	0.000007	0.000007
	n-BUTANE	0.000123	0.000123		n-BUTANE	0.000004	0.000004
	n-PENTANE	0.000008	0.000008		n-PENTANE	0.000000	0.000000
	WATER	0.000000	0.000000		WATER	0.000000	0.000000

Summary of Plant Unit Design Information

65 MMSCFD Facility

T1	Condenser	No		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED	overheadFeed	Lower_Feed	
	Stage	1	8	
	Connected Obj	/S5.Out	/S23.Out	
	Details			
	VapFrac	0.9425	0.2616	
	T [F]	-146.8	-135.8	
	P [psia]	230.0	230.0	
	MoleFlow [lbmole/h]	5495.037	1641.881	
	MassFlow [lb/h]	93758.870	41059.336	
	VolumeFlow [ft3/s]	16.958	1.774	
	StdLiqVolumeFlow [ft3/s]	1.344	0.483	
	StdGasVolumeFlow [MMSCFD]	50.046	14.953	
	Molar Composition			
	CARBON DIOXIDE	0.011330	0.027284	
	NITROGEN	0.007417	0.001259	
	METHANE	0.942855	0.600091	
	ETHANE	0.033277	0.197252	
	PROPANE	0.004852	0.140246	
	ISOBUTANE	0.000139	0.012574	
	n-BUTANE	0.000123	0.016974	
	n-PENTANE	0.000008	0.004321	
	WATER	0.000000	0.000000	
	DRAW	overheadV	reboilerL	
	Stage	1	20	
	Type	VapourDraw	LiquidDraw	
	Connected Obj	/S6.In	/S7.In	
	Details			
	VapFrac	1.0000	0.0000	
	T [F]	-116.8	125.6	
	P [psia]	225.0	230.0	
	MoleFlow [lbmole/h]	6825.787	311.131	
	MassFlow [lb/h]	120266.593	14551.612	
	VolumeFlow [ft3/s]	26.066	0.138	
	StdLiqVolumeFlow [ft3/s]	1.703	0.125	
	StdGasVolumeFlow [MMSCFD]	62.166	2.834	
	reboilerQ (Btu/hr)	**8546730.8**		

Section	Section_1	Section_2	Section_3	Section_4
Start	1	2	8	10
End	1	7	9	19
internalType	Packed	Packed	Packed	Packed
Design Variables				
PackedDesignBasis	**FLOODFACTOR**	**FLOODFACTOR**	**FLOODFACTOR**	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000	0.8000	0.8000	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**	**0.5000**	**0.5000**	**0.5000**
PackingHoldupMethod	**ESG**	**ESG**	**ESG**	**ESG**
SystemFactor [Fraction]	1.00	1.00	1.00	1.00
PackingName	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**
Fp	27.00	27.00	27.00	27.00
PackingAreaperVol [ft2/f3]	34.32	34.32	34.32	34.32
PackingType	RP	RP	RP	RP
PackingLengthperStage [ft]	**1.500**	**1.500**	**1.500**	**1.500**
SectionAreaFactor [Fraction]	0.8000	0.8000	0.8000	0.8000
Calculated Variables				
TrayDiameter [ft]	5.000	3.000	3.500	4.000
TotalTrayArea [ft2]	19.63	7.07	9.62	12.57
PackingLengthperSection [ft]	1.500	9.000	3.000	15.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

65 MMSCFD Facility

V3	Name	Value	
	Delta P [psi]	25	
	Cv	8.50107	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S7.Out	/S8.In
	Connected Port		
	VapFrac	0.00	0.05
	T [F]	125.6	116.7
	P [psia]	230.0	205.0
	MoleFlow [lbmole/h]	311.130	311.130
	MassFlow [lb/h]	14551.610	14551.610
	VolumeFlow [ft3/s]	0.138	0.235
	StdLiqVolumeFlow [ft3/s]	0.125	0.125
	StdGasVolumeFlow [MMSCFD]	2.834	2.834
	Properties (Alt+R)		
	Energy [Btu/hr]	270100.000	270100.000
	H [Btu/lbmol]	868.200	868.200
	S [Btu/lbmol-F]	34.117	34.134
	MolecularWeight	46.770	46.770
	MassDensity [lb/ft3]	29.209	17.215
	Cp [Btu/lbmol-F]	35.358	33.569
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.080	0.078
	molarV [ft3/lbmol]	1.601	2.717
	ZFactor	0.058	0.089
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.015555	0.015555
	PROPANE	0.801162	0.801162
	ISOBUTANE	0.068671	0.068671
	n-BUTANE	0.091674	0.091674
	n-PENTANE	0.022938	0.022938
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

65 MMSCFD Facility

T2	Condenser	Yes			
	Reboiler	Yes			
	# Ideal Stages	20	Includes Condenser and Reboiler		
	Total stages = 20				
	FEED				
	Stage	2			
	Connected Obj	/S8.Out			
	Details				
	VapFrac	0.0532			
	T [F]	116.7			
	P [psia]	205.0			
	MoleFlow [lbmole/h]	311.131			
	MassFlow [lb/h]	14551.612			
	VolumeFlow [ft3/s]	0.235			
	StdLiqVolumeFlow [ft3/s]	0.125			
	StdGasVolumeFlow [MMSCFD]	2.834			
	Molar Composition				
	CARBON DIOXIDE	0.000000			
	NITROGEN	0.000000			
	METHANE	0.000000			
	ETHANE	0.015555			
	PROPANE	0.801162			
	ISOBUTANE	0.068671			
	n-BUTANE	0.091674			
	n-PENTANE	0.022938			
	WATER	0.000000			
	DRAW	condenserL	condenserV	reboilerL	
	Stage	1	1	20	
	Type	LiquidDraw	VapourDraw	LiquidDraw	
	Connected Obj		/C3.In	/C4+.In	
	Details				
	VapFrac	0.0000	1.0000	0.0000	
	T [F]	105.9	105.9	199.5	
	P [psia]	200.0	200.0	205.0	
	MoleFlow [lbmole/h]	0.000	257.578	53.553	
	MassFlow [lb/h]	0.000	11360.799	3190.813	
	VolumeFlow [ft3/s]	0.000	1.660	0.030	
	StdLiqVolumeFlow [ft3/s]	0.000	0.100	0.025	
	StdGasVolumeFlow [MMSCFD]	0.000	2.346	0.488	
	ENERGY	condenserQ		reboilerQ	
	Stage	1		20	
	Type	EnergyOut		EnergyIn	
	Connected Obj	/Q4.In		/Q3.Out	
	Value [Btu/hr]	4267536.4		5764214.9	

Section	Section_1
Start	2
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[2in] Pall Rings (M)**
Fp	27.00
PackingAreaperVol [ft2/f3]	34.32
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	3.500
TotalTrayArea [ft2]	9.62
PackingLengthperSection [ft]	27.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

65 MMSCFD Facility

P1	Name	Value	
	InQ [HorsePower]	13.46514	
	Delta P [psi]	1300	
	Pressure Ratio	7.341	
	Efficiency [%]	75	
	Speed [rpm]		
	Head [ft]	6266.67	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/C4+.Out	/C4+_To_SGas.In
	Connected Port		
	VapFrac	0.00	0.00
	T [F]	199.5	220.2
	P [psia]	205.0	1505.0
	MoleFlow [lbmole/h]	53.550	53.550
	MassFlow [lb/h]	3190.810	3190.810
	VolumeFlow [ft3/s]	0.030	0.028
	StdLiqVolumeFlow [ft3/s]	0.025	0.025
	StdGasVolumeFlow [MMSCFD]	0.488	0.488
	Properties (Alt+R)		
	Energy [Btu/hr]	176600.000	210900.000
	H [Btu/lbmol]	3299.100	3939.000
	S [Btu/lbmol-F]	34.731	34.999
	MolecularWeight	59.580	59.580
	MassDensity [lb/ft3]	29.872	31.648
	Cp [Btu/lbmol-F]	45.297	40.348
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.055
	Viscosity [cp]	0.087	0.110
	molarV [ft3/lbmol]	1.995	1.883
	ZFactor	0.058	0.380
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.000000	0.000000
	PROPANE	0.027025	0.027025
	ISOBUTANE	0.350865	0.350865
	n-BUTANE	0.491008	0.491008
	n-PENTANE	0.131102	0.131102
	WATER	0.000000	0.000000

APPENDIX 7

Cost Estimates for Residue Gas Compression - Fairbanks Facility

Ian McKay

From: Dan.Fixter@enerflex.com
Sent: July 29, 2009 1:44 PM
To: Mike Richardson
Cc: Ian McKay; Jim.Forsyth@enerflex.com; Barclay.Sexsmith@enerflex.com
Subject: Re: FW: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location
Attachments: 5500 hp Ariel JGZ6 3 stage pd 2400 psi.pdf; Report.pdf

Mike, as per you request enclosed is our budget:

See attached compressor performance run.

5200 HP @ 885 rpm electric motor / Ariel JGZ/6, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,650,000 +/- 20%, approx. delivery 30-36 weeks

Daniel Fixter
Business Development Manager
Optimization Services

ENERFLEX

Enerflex Systems Ltd.
Phone: 403.236-6656
Fax: 403.279-0367
Cell: 403.620-6278
Email: daniel.fixter@enerflex.com
Website: www.enerflex.com

From: Mike Richardson <MRichardson@gasliquids.com>
To: "Jim.Forsyth@enerflex.com" <Jim.Forsyth@enerflex.com>, "daniel.fixter@enerflex.com" <daniel.fixter@enerflex.com>
Cc: Ian McKay <IMcKay@gasliquids.com>
Date: 07/29/2009 11:50 AM
Subject: FW: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

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Jim:

One more time with Dan’s e-mail correct. I guess the “r” finger was broken.

Regards,

Mike Richardson

From: Mike Richardson

Sent: July 29, 2009 11:48 AM
To: 'Jim.Forsyth@enerflex.com'; 'daniel.fixter@eneflex.com'
Cc: Ian McKay
Subject: RE: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Jim:

We have another application for the same client, same location, for the same flow at much higher pressure. Please find the run attached. At this time, we are looking at electric drive only. Could you provide us with another cost estimate ASAP, and send it to myself and Ian MacKay?

Regards,

Mike Richardson

From: Jim.Forsyth@enerflex.com [mailto:Jim.Forsyth@enerflex.com]
Sent: June 29, 2009 11:23 AM
To: Mike Richardson
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Mike,

Please see the attached requested budget. Note Barclay's comment on engine IC design
ambient.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/29/2009 11:16AM -----
To: Jim Forsyth/EMFG/Enerflex@EFX
From: Barclay Sexsmith/EMFG/Enerflex
Date: 06/29/2009 11:04AM
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Note: Cooling of the G3612LE IC to the requested 90 degF would have to be discussed to insure that the customer can provide the required cooling medium.

----- Forwarded by Barclay Sexsmith/EMFG/Enerflex on 06/29/2009 11:03 AM -----

From: Barclay Sexsmith/EMFG/Enerflex

To: Jim Forsyth/EMFG/Enerflex@EFX

Date: 06/29/2009 11:03 AM

Subject: Re: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Caterpillar G3612LE / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,700,000 +/- 20%, delivery, approx. 20 weeks

4000 HP @ 900 rpm electric motor / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,000,000 +/- 20%, approx. delivery 30-36 weeks

Jim Forsyth---06/26/2009 10:02:47 AM---Barclay,

From: Jim Forsyth/EMFG/Enerflex

To: Barclay.Sexsmith@enerflex.com

Date: 06/26/2009 10:02 AM

Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Barclay,

Pls. see this additional budget request from Mike.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/26/2009 10:00AM -----

To: "jim.forsyth@enerflex.com" <jim.forsyth@enerflex.com>
From: Mike Richardson <MRichardson@gasliquids.com>
Date: 06/25/2009 07:13PM
cc: Ian McKay <IMcKay@gasliquids.com>
Subject: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Jim:

Please find attached two performance runs for Ariel JGZ/4 for a gas and an electric driver. As we discussed, the hp required is slightly over a standard Cat 3612 130 IC, so I have used the hp for a Cat 3612 90 IC. The units should be packaged and housed, 3 piece shippable, low temp piping/cooler, sweet trim, EFX (Guardian) AB PLC. The electric motor list would include Westinghouse, Siemens, GE, Reliance, and ABB. I have assumed that the cooler is electric motor driven. Only one unit, either electric or gas drive, will be purchased. If possible, the AFE estimate price and delivery is needed by Monday PM or early Tuesday AM.

Regards,

Mike Richardson, P. Eng.

Senior Specialized Mechanical Engineer

Gas Liquids Engineering Ltd.

#300, 2749 - 39th Avenue NE

Calgary, AB T1Y 4T8

Ph: 403.250.2950

Fax: 403.291.9730

E-mail: mrichardson@gasliquids.com

[attachment "Residue Compressor 1000 RPM 3612 LE 90 IC.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex] [attachment "Residue Compressor 885 RPM electric drive.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex]

Ariel Performance

Company:	Enerflex	Customer:	Gas Liquids Engineering
Quote:		Inquiry:	
7.6.0.1 Case 1:		Project:	Residue Gas

Compressor Data:						**Driver Data:**	
Elevation,ft:	1095.00	Barmtr,psia:	14.116	Ambient,°F:	95.00	Type:	Electric
Frame:	JGZ/6	Stroke, in:	6.75	Rod Dia, in:	2.875	Mfg:	TBA
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000	Model:	TBA
Rated RPM:	1000	Rated BHP:	7800.0	Rated PS FPM:	1125.0	BHP:	5200 (4727)
Calc RPM:	885.0	BHP:	4643	Calc PS FPM:	995.6	Avail:	4727 (0)

Services	**Service 1**					
Stage Data:	**1**	---	---	**2**	---	**3**
Flow Req'd, MMSCFD	37.200	---	---	37.200	---	37.200
Flow Calc, MMSCFD	37.200	---	---	37.200	---	37.200
Cyl BHP per Stage	1857.1	---	---	1648.1	---	1076.7
Specific Gravity	0.61	---	---	0.61	---	0.61
Ratio of Sp Ht (N)	1.2874	---	---	1.2888	---	1.2937
Comp Suct (Zs)	0.9435	---	---	0.9067	---	0.8424
Comp Disch (Zd)	0.9392	---	---	0.9221	---	0.8849
Pres Suct Line, psig	303.00	---	---	N/A	---	N/A
Pres Suct Flg, psig	299.83	---	---	742.17	---	1551.39
Pres Disch Flg, psig	752.17	---	---	1563.79	---	2438.28
Pres Disch Line, psig	N/A	---	---	N/A	---	2414.00
Pres Ratio F/F	2.441	---	---	2.086	---	1.567
Temp Suct, °F	71.70	---	---	120.00	---	120.00
Temp Clr Disch, °F	120.00	---	---	120.00	---	120.00
Cylinder Data:	**Throw 2**	**Throw 4**	**Throw 6**	**Throw 3**	**Throw 5**	**Throw 1**
Cyl Model	11Z	11Z	11Z	8-3/8Z	8-3/8Z	7-1/4Z-VS
Cyl Bore, in	10.500	10.500	10.500	7.875	7.875	7.250
Cyl RDP (API), psig	1154.5	1154.5	1154.5	2181.8	2181.8	3181.8
Cyl MAWP, psig	1270.0	1270.0	1270.0	2400.0	2400.0	3500.0
Cyl Action	DBL	DBL	DBL	DBL	DBL	DBL
Cyl Disp, CFM	576.2	576.2	576.2	314.3	314.3	263.0
Pres Suct Intl, psig	285.58	285.58	285.58	706.82	706.82	1431.78
Temp Suct Intl, °F	77	77	77	124	124	123
Suct Zsph	0.9455	0.9455	0.9455	0.9094	0.9094	0.8456
Pres Disch Intl, psig	783.14	783.14	783.14	1644.41	1644.41	2598.31
Temp Disch Intl, °F	208	208	208	245	245	207
HE Suct Gas Vel, FPM	7164	7164	7164	7651	7651	9529
HE Disch Gas Vel, FPM	6270	6270	6270	7382	7382	8049
HE Spcrs Used/Max	0/4	0/4	0/4	0/4	0/4	0/0
HE Vol Pkt Avail, %	0.67+38.83	0.67+38.83	0.67+38.83	0.66+37.33	0.66+37.33	0.44+34.96
Vol Pkt Used, %	36.26 (V)	36.26 (V)	36.26 (V)	0.00 (V)	0.00 (V)	0.00 (V)
HE Min Clr, %	17.80	17.80	17.80	14.82	14.82	18.19
HE Total Clr, %	32.55	32.55	32.55	15.48	15.48	18.64
CE Suct Gas Vel, FPM	6627	6627	6627	6631	6631	8031
CE Disch Gas Vel, FPM	5800	5800	5800	6398	6398	6783
CE Spcrs Used/Max	0/4	0/4	0/4	0/4	0/4	0/0
CE Min Clr, %	18.06	18.06	18.06	18.81	18.81	23.07
CE Total Clr, %	18.06	18.06	18.06	18.81	18.81	23.07
Suct Vol Eff HE/CE, %	61.5/75.8	61.5/75.8	61.5/75.8	82.8/80.4	82.8/80.4	88.1/86.6
Disch Event HE/CE, ms	11.9/15.3	11.9/15.3	11.9/15.3	15.3/16.9	15.3/16.9	18.6/20.3
Suct Pseudo-Q HE/CE	4.6/4.0	4.6/4.0	4.6/4.0	5.8/4.3	5.8/4.3	5.9/4.2
Gas Rod Ld Comp, %	56.3 C	56.3 C	56.3 C	63.2 C	63.2 C	72.3 C
Gas Rod Ld Tens, %	50.5 T	50.5 T	50.5 T	46.4 T	46.4 T	41.6 T
Gas Rod Ld Total, %	55.3	55.3	55.3	56.9	56.9	59.4
Xhd Pin Deg/%Rvrsl lbf	154/86.4	154/86.4	154/86.4	176/57.6	176/57.6	133/58.6
Flow Calc, MMSCFD	12.400	12.400	12.400	18.600	18.600	37.200
Cyl BHP	619.0	619.0	619.0	824.0	824.0	1076.7

Ian McKay

From: Mike Richardson
Sent: June 29, 2009 5:59 PM
To: Ian McKay
Subject: FW: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Ian:

Please find the cost estimate for the gas and electric drives for your application. The Caterpillar engine is shy on hp with the standard 130 F intercooler. I ran the performance with a 90 F intercooler, which will work fine for most of the year. There will be a possibility of about two weeks that the hp will not be available on the 90F intercooler (daylight heating hours which can be long at this location). We can either accept the derate, or provide a cooling medium besides air.

Regards,

Mike R

From: Jim.Forsyth@enerflex.com [mailto:Jim.Forsyth@enerflex.com]
Sent: June 29, 2009 11:23 AM
To: Mike Richardson
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Mike,

Please see the attached requested budget. Note Barclay's comment on engine IC design ambient.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/29/2009 11:16AM -----

To: Jim Forsyth/EMFG/Enerflex@EFX
From: Barclay Sexsmith/EMFG/Enerflex
Date: 06/29/2009 11:04AM
Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Note: Cooling of the G3612LE IC to the requested 90 degF would have to be discussed to insure that the customer can provide the required cooling medium.

----- Forwarded by Barclay Sexsmith/EMFG/Enerflex on 06/29/2009 11:03 AM -----

From: Barclay Sexsmith/EMFG/Enerflex

To: Jim Forsyth/EMFG/Enerflex@EFX

Date: 06/29/2009 11:03 AM

Subject: Re: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Caterpillar G3612LE / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,700,000 +/- 20%, delivery, approx. 20 weeks

4000 HP @ 900 rpm electric motor / Ariel JGZ/4, 3 stage, sweet, horizontal aerial cooler (electric motor driven), skid mounted (multi-piece, site assembly required by others), self-framing building (site erection by others), Guardian panel, interconnecting piping, etc., BUDGET price $ 3,000,000 +/- 20%, approx. delivery 30-36 weeks

Jim Forsyth---06/26/2009 10:02:47 AM---Barclay,

From: Jim Forsyth/EMFG/Enerflex

To: Barclay.Sexsmith@enerflex.com

Date: 06/26/2009 10:02 AM

Subject: Fw: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

---

Barclay,

Pls. see this additional budget request from Mike.
Best Regards,

Jim Forsyth
Account Manager
Enerflex Systems Ltd.
Phone: (403) 720-4310
Cell: (403) 862-7400
e-mail: jim.forsyth@enerflex.com

-----Forwarded by Jim Forsyth/EMFG/Enerflex on 06/26/2009 10:00AM -----

To: "jim.forsyth@enerflex.com" <jim.forsyth@enerflex.com>
From: Mike Richardson <MRichardson@gasliquids.com>
Date: 06/25/2009 07:13PM
cc: Ian McKay <IMcKay@gasliquids.com>
Subject: AFE Cost Estimate - Gas/Electric drive for Ariel JGZ/4 - Multinational client confidential - Northern Canada location

Jim:

Please find attached two performance runs for Ariel JGZ/4 for a gas and an electric driver. As we discussed, the hp required is slightly over a standard Cat 3612 130 IC, so I have used the hp for a Cat 3612 90 IC. The units should be packaged and housed, 3 piece shippable, low temp piping/cooler, sweet trim, EFX (Guardian) AB PLC. The electric motor list would include Westinghouse, Siemens, GE, Reliance, and ABB. I have assumed that the cooler is electric motor driven. Only one unit, either electric or gas drive, will be purchased. If possible, the AFE estimate price and delivery is needed by Monday PM or early Tuesday AM.

Regards,

Mike Richardson, P. Eng.

Senior Specialized Mechanical Engineer

Gas Liquids Engineering Ltd.

#300, 2749 - 39th Avenue NE

Calgary, AB T1Y 4T8

Ph: 403.250.2950

Fax: 403.291.9730

E-mail: mrichardson@gasliquids.com

[attachment "Residue Compressor 1000 RPM 3612 LE 90 IC.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex] [attachment "Residue Compressor 885 RPM electric drive.pdf" deleted by Barclay Sexsmith/EMFG/Enerflex]

Ariel Performance

Company:	Gas Liquids Engineering Ltd.	Customer:	TBA
Quote:	Size Residue Gas Comp	Inquiry:	
7.6.0.1	Case 1:		Project:	09107

Compressor Data: / **Driver Data:**

Elevation,ft:	*2500.00*	Barmtr,psia:	13.400	Ambient,°F:	95.00	Type:	Nat. Gas
Frame:	JGZ/4	Stroke, in:	6.75	Rod Dia, in:	2.875	Mfg:	Caterpillar
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000	Model:	G3612LE L 90
Rated RPM:	1000	Rated BHP:	5200.0	Rated PS FPM:	1125.0	BHP:	3785
Calc RPM:	1000.0	BHP:	3630	Calc PS FPM:	1125.0	Avail:	3785 (0)

Services	**Service 1**			
Stage Data:	**1**	---	**2**	**3**
Flow Req'd, MMSCFD	37.200	---	37.200	37.200
Flow Calc, MMSCFD	37.200	---	37.200	37.200
Cyl BHP per Stage	1379.3	---	933.2	1271.0
Specific Gravity	0.6083	---	0.6083	0.6083
Ratio of Sp Ht (N)	1.2955	---	1.2986	1.3039
Comp Suct (Zs)	0.9459	---	0.9209	0.8869
Comp Disch (Zd)	0.9415	---	0.9220	0.9012
Pres Suct Line, psia	303.50	---	N/A	N/A
Pres Suct Flg, psia	303.50	---	587.14	886.36
Pres Disch Flg, psia	607.14	---	916.36	1535.00
Pres Disch Line, psia	N/A	---	N/A	1505.00
Pres Ratio F/F	2.000	---	1.561	1.732
Temp Suct, °F	71.70	---	110.00	110.00
Temp Clr Disch, °F	110.00	---	110.00	110.00
Cylinder Data:	**Throw 1**	**Throw 3**	**Throw 4**	**Throw 2**
Cyl Model	13-5/8ZM	13-5/8ZM	12-1/2ZL	9-5/8Z
Cyl Bore, in	13.125	13.125	12.000	9.125
Cyl RDP (API), psig	986.4	986.4	1227.3	1727.3
Cyl MAWP, psig	1085.0	1085.0	1350.0	1900.0
Cyl Action	DBL	DBL	DBL	DBL
Cyl Disp, CFM	1031.7	1031.7	858.2	485.6
Pres Suct Intl, psia	296.21	296.21	573.50	830.64
Temp Suct Intl, °F	77	77	113	114
Suct Zsph	0.9475	0.9475	0.9225	0.8898
Pres Disch Intl, psia	623.67	623.67	942.35	1638.02
Temp Disch Intl, °F	176	176	182	212
HE Suct Gas Vel, FPM	5145	5145	5183	8551
HE Disch Gas Vel, FPM	4959	4959	5058	8036
HE Spcrs Used/Max	0/4	0/4	0/4	0/4
HE Vol Pkt Avail, %	0.32+101.87	0.32+101.87	No Pkt	No Pkt
Vol Pkt Used, %	19.85 (V)	19.85 (V)	No Pkt	No Pkt
HE Min Clr, %	37.80	37.80	43.16	14.31
HE Total Clr, %	58.33	58.33	43.16	14.31
CE Suct Gas Vel, FPM	4898	4898	4886	7702
CE Disch Gas Vel, FPM	4721	4721	4768	7238
CE Spcrs Used/Max	0/4	0/4	0/4	0/4
CE Min Clr, %	40.53	40.53	46.53	17.22
CE Total Clr, %	40.53	40.53	46.53	17.22
Suct Vol Eff HE/CE, %	53.2/65.7	53.2/65.7	77.3/75.9	87.3/85.9
Disch Event HE/CE, ms	10.5/13.7	10.5/13.7	15.0/16.7	15.5/17.0
Suct Pseudo-Q HE/CE	3.1/2.8	3.1/2.8	3.3/3.0	7.3/5.9
Gas Rod Ld Comp, lbf	46203 C	46203 C	45437 C	58444 C
Gas Rod Ld Tens, lbf	40288 T	40288 T	35614 T	42019 T
Gas Rod Ld Total, lbf	86491	86491	81051	100463
Xhd Pin Deg/%Rvrsl lbf	177/61.6	177/61.6	167/74.1	167/65.1
Flow Calc, MMSCFD	18.600	18.600	37.200	37.200
Cyl BHP	689.6	689.6	933.2	1271.0

Ariel Performance

Company:	Gas Liquids Engineering Ltd.	Customer:	TBA
Quote:	Size Residue Gas Comp	Inquiry:	
7.6.0.1 Case 1:		Project:	09107

Compressor Data:

Elevation,ft:	2500.00	Barmtr,psia:	13.400	Ambient,°F:	95.00	Type:	Unselected
Frame:	JGZ/4	Stroke, in:	6.75	Rod Dia, in:	2.875	Mfg:	
Max RL Tot, lbf:	150000	Max RL Tens, lbf:	75000	Max RL Comp, lbf:	80000	Model:	
Rated RPM:	1000	Rated BHP:	5200.0	Rated PS FPM:	1125.0	BHP:	0
Calc RPM:	885.0	BHP:	3603	Calc PS FPM:	995.6	Avail:	0 (0)

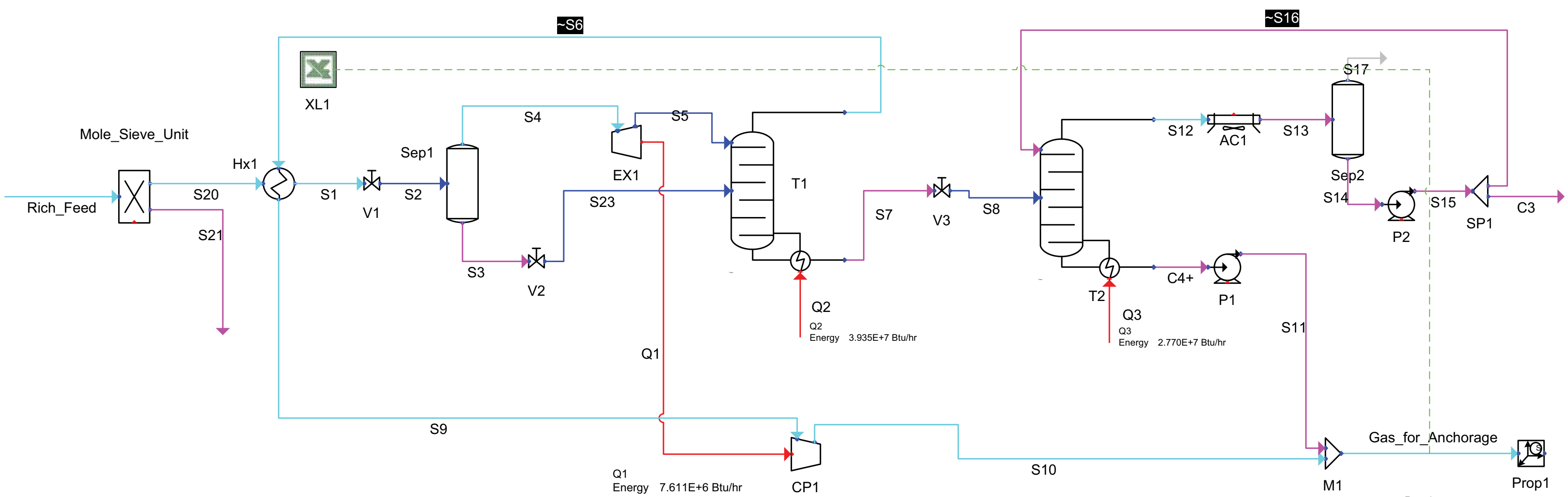
Driver Data: (last two columns above)

Services	**Service 1**			
Stage Data:	**1**	---	**2**	**3**
Flow Req'd, MMSCFD	37.200	---	37.200	37.200
Flow Calc, MMSCFD	37.200	---	37.200	37.200
Cyl BHP per Stage	1382.9	---	906.2	1273.1
Specific Gravity	0.6083	---	0.6083	0.6083
Ratio of Sp Ht (N)	1.2955	---	1.2988	1.3038
Comp Suct (Zs)	0.9459	---	0.9205	0.8872
Comp Disch (Zd)	0.9415	---	0.9215	0.9016
Pres Suct Line, psia	303.50	---	N/A	N/A
Pres Suct Flg, psia	303.50	---	590.80	883.17
Pres Disch Flg, psia	610.80	---	913.17	1535.00
Pres Disch Line, psia	N/A	---	N/A	1505.00
Pres Ratio F/F	2.013	---	1.546	1.738
Temp Suct, °F	71.70	---	110.00	110.00
Temp Clr Disch, °F	110.00	---	110.00	110.00
Cylinder Data:	**Throw 1**	**Throw 3**	**Throw 4**	**Throw 2**
Cyl Model	13-5/8ZM	13-5/8ZM	12-1/2ZL	9-5/8Z
Cyl Bore, in	13.625	13.625	12.500	9.625
Cyl RDP (API), psig	986.4	986.4	1227.3	1727.3
Cyl MAWP, psig	1085.0	1085.0	1350.0	1900.0
Cyl Action	DBL	DBL	DBL	DBL
Cyl Disp, CFM	985.6	985.6	826.0	480.6
Pres Suct Intl, psia	296.85	296.85	578.08	828.84
Temp Suct Intl, °F	77	77	113	114
Suct Zsph	0.9475	0.9475	0.9221	0.8902
Pres Disch Intl, psia	625.97	625.97	937.25	1635.82
Temp Disch Intl, °F	176	176	181	213
HE Suct Gas Vel, FPM	4906	4906	4977	8419
HE Disch Gas Vel, FPM	4729	4729	4857	7913
HE Spcrs Used/Max	0/4	0/4	0/4	0/4
HE Vol Pkt Avail, %	0.30+94.53	0.30+94.53	No Pkt	No Pkt
Vol Pkt Used, %	15.33 (V)	15.33 (V)	No Pkt	No Pkt
HE Min Clr, %	36.82	36.82	38.34	11.87
HE Total Clr, %	51.62	51.62	38.34	11.87
CE Suct Gas Vel, FPM	4688	4688	4714	7668
CE Disch Gas Vel, FPM	4519	4519	4600	7207
CE Spcrs Used/Max	0/4	0/4	0/4	0/4
CE Min Clr, %	38.39	38.39	41.16	14.22
CE Total Clr, %	38.39	38.39	41.16	14.22
Suct Vol Eff HE/CE, %	57.5/66.9	57.5/66.9	79.6/78.5	88.5/87.3
Disch Event HE/CE, ms	12.4/15.6	12.4/15.6	17.5/19.2	17.7/19.4
Suct Pseudo-Q HE/CE	2.8/2.6	2.8/2.6	3.1/2.8	7.1/5.9
Gas Rod Ld Comp, lbf	49884 C	49884 C	47821 C	64337 C
Gas Rod Ld Tens, lbf	43959 T	43959 T	38013 T	47947 T
Gas Rod Ld Total, lbf	93843	93843	85834	112284
Xhd Pin Deg/%Rvrsl lbf	143/85.1	143/85.1	177/70.0	179/70.3
Flow Calc, MMSCFD	18.600	18.600	37.200	37.200
Cyl BHP	691.5	691.5	906.2	1273.1

APPENDIX 8

Process Simulation Flowsheet
300 MMSCFD Propane Fractionation Facility

Propane Recovery Unit with Recombination of Lean Gas and C4+ for Local Sales Gas
300 MMSCFD Feed



Prop1
GHVStdGasVol 1063.23 Btu/SCF
DewPoint -43.2 F

Hx1	
DT Tube	-139.74 F
DT Shell	59.17 F
DP Tube	*0.07856 psi
DP Shell	*0.06871 psi
UA	1.54E+06 Btu/hr-F
TApproach_Tube_Shell_AppT	*4.99 F

EX1	
Duty	2.991E+3 HorsePower
DP	270.00 psi
Efficiency	81.08 %
In.T	-97.6 F
In.P	500.00 psia
Out.T	-146.7 F
Pout	*230.00 psia

Name	Rich_Feed	S1	S2	S3	S4	S5	S6	S7	S8	C3	C4+
VapFrac	1	1	0.77084	0	1	0.94258	0.99999	0	0.05319	0	0
T [F]	28	-31.2	-97.6	-97.6	-97.6	-146.7	-116.7	125.6	116.7	100.9	200.8
P [psia]	1500	1499.93129	500	500	500	230	225	230	205	250	205
MoleFlow [lbmole/h]	32939.74	32939.62	32939.62	7548.36	25391.26	25391.26	31503.85	1435.78	1435.78	1176.55	259.44
MassFlow [lb/h]	622240.01	622237.87	622237.87	188939.06	433298.81	433298.81	555086.33	67151.94	67151.94	51668.99	15491.35
StdGasVolumeFlow [MMSCFD]	3.00E+02	3.00E+02	3.00E+02	6.87E+01	2.31E+02	2.31E+02	2.87E+02	1.31E+01	1.31E+01	1.07E+01	2.36E+00
MoleFraction [Fraction]											
CARBON DIOXIDE	0.015	0.015	0.015	0.0273	0.0113	0.0113	0.0157	0	0	0	0
NITROGEN	0.006	0.006	0.006	0.0013	0.0074	0.0074	0.0063	0	0	0	0
METHANE	0.864	0.864	0.864	0.5992	0.9427	0.9427	0.9034	0	0	0	0
ETHANE	0.071	0.071	0.071	0.1976	0.0334	0.0334	0.0735	0.0156	0.0156	0.019	0
PROPANE	0.036	0.036	0.036	0.1407	0.0049	0.0049	0.0011	0.8011	0.8011	0.9748	0.0135
ISOBUTANE	0.003	0.003	0.003	0.0126	0.0001	0.0001	0	0.0687	0.0687	0.0038	0.3627
n-BUTANE	0.004	0.004	0.004	0.017	0.0001	0.0001	0	0.0917	0.0917	0.0023	0.497
n-PENTANE	0.001	0.001	0.001	0.0043	0	0	0	0.0229	0.0229	0	0.1268

Name	S20	S21	S23	Gas_for_Anchorage	S9	S10	S11	S12	S13	S14	S15	S16	S17
VapFrac	1	0	0.26155	1	1	1	0	1	0	0	0	0	1
T [F]	28	28	-135.7	50	23	52.3	202.1	103.9	100	100	100.9	100.9	100
P [psia]	1500	1500	230	273.5475	224.92144	273.5475	275	200	200	200	250	250	200
MoleFlow [lbmole/h]	32939.62	0.12	7548.36	31763.29	31503.85	31503.85	259.44	4706.18	4706.18	4706.18	4706.18	3529.84	0
MassFlow [lb/h]	622237.87	2.14	188939.06	570577.67	555086.33	555086.33	15491.35	206675.97	206675.97	206675.97	206675.97	155015.38	0
StdGasVolumeFlow [MMSCFD]	3.00E+02	1.08E-03	6.87E+01	2.89E+02	2.87E+02	2.87E+02	2.36E+00	4.29E+01	4.29E+01	4.29E+01	4.29E+01	3.21E+01	2.01E-42
MoleFraction [Fraction]													
CARBON DIOXIDE	0.015	0	0.0273	0.0156	0.0157	0.0157	0	0	0	0	0	0	0
NITROGEN	0.006	0	0.0013	0.0062	0.0063	0.0063	0	0	0	0	0	0	0
METHANE	0.864	0	0.5992	0.896	0.9034	0.9034	0	0	0	0	0	0	0
ETHANE	0.071	0	0.1976	0.0729	0.0735	0.0735	0	0.019	0.019	0.019	0.019	0.019	0.0493
PROPANE	0.036	0	0.1407	0.0012	0.0011	0.0011	0.0135	0.9748	0.9748	0.9748	0.9748	0.9748	0.9481
ISOBUTANE	0.003	0	0.0126	0.003	0	0	0.3627	0.0038	0.0038	0.0038	0.0038	0.0038	0.0017
n-BUTANE	0.004	0	0.017	0.0041	0	0	0.497	0.0023	0.0023	0.0023	0.0023	0.0023	0.0009
n-PENTANE	0.001	0	0.0043	0.001	0	0	0.1268	0	0	0	0	0	0

APPENDIX 9

Major Equipment List
300 MMSCFD Propane Fractionation Facility

Summary of Plant Unit Design Information					
300 MMSCFD Facility					
Unit	**Water Removal Rate (lb/h)**				
Molecular Sieve	2.14				
Hx 1	Name		**Value**		
	Tube DP [psi]		**5**		
	Shell DP [psi]		**1**		
	UA [Btu/hr-F]		**1464195.3**		
	Approach T [F]		**5**		
	Energy Lost Tube [Btu/hr]		**-41479481.4**		
	PortName	**InTube**	**InShell**	**OutTube**	**OutShell**
	UnitOperation				
	Is Recycle Port				
	Connected Stream/Unit Op	/S6.Out	/S20.Out	/S11.In	/S1.In
	Connected Port				
	VapFrac	1.00	1.00	1.00	1.00
	T [F]	-116.7	28.0	23.0	-31.3
	P [psia]	225.0	1500.0	220.0	1499.0
	MoleFlow [lbmole/h]	31503.750	32939.620	31503.750	32939.620
	MassFlow [lb/h]	555081.780	622237.870	555081.780	622237.870
	VolumeFlow [ft3/s]	120.309	20.554	195.023	12.336
	StdLiqVolumeFlow [ft3/s]	7.858	8.435	7.858	8.435
	StdGasVolumeFlow [MMSCFD]	286.920	300.000	286.920	300.000
	Properties (Alt+R)				
	Energy [Btu/hr]	75720000.000	86600000.000	117200000.000	45120000.000
	H [Btu/lbmol]	2403.900	2629.400	3720.800	1369.900
	S [Btu/lbmol-F]	36.083	34.245	39.349	31.481
	MolecularWeight	17.620	18.890	17.620	18.890
	MassDensity [lb/ft3]	1.282	8.409	0.791	14.011
	Cp [Btu/lbmol-F]	9.815	17.297	9.312	24.800
	ThermalConductivity [Btu/hr-ft-F]	0.012	0.029	0.018	0.037
	Viscosity [cp]	0.008	0.016	0.010	0.024
	molarV [ft3/lbmol]	13.748	2.246	22.286	1.348
	ZFactor	0.840	0.648	0.946	0.445
	Fraction [Fraction]				
	CARBON DIOXIDE	0.015684	0.015000	0.015684	0.015000
	NITROGEN	0.006273	0.006000	0.006273	0.006000
	METHANE	0.903379	0.864000	0.903379	0.864000
	ETHANE	0.073527	0.071000	0.073527	0.071000
	PROPANE	0.001126	0.036000	0.001126	0.036000
	ISOBUTANE	0.000007	0.003000	0.000007	0.003000
	n-BUTANE	0.000004	0.004000	0.000004	0.004000
	n-PENTANE	0.000000	0.001000	0.000000	0.001000
	WATER	0.000000	0.000000	0.000000	0.000000

Summary of Plant Unit Design Information			
300 MMSCFD Facility			
V1	Name	Value	
	Delta P [psi]	999	
	Cv	125.06335	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S1.Out	/S2.In
	Connected Port		
	VapFrac	1.00	0.77
	T [F]	-31.3	-97.7
	P [psia]	1499.0	500.0
	MoleFlow [lbmole/h]	32939.623	32939.623
	MassFlow [lb/h]	622237.871	622237.871
	VolumeFlow [ft3/s]	12.336	39.286
	StdLiqVolumeFlow [ft3/s]	8.435	8.435
	StdGasVolumeFlow [MMSCFD]	299.999	299.999
	Properties (Alt+R)		
	Energy [Btu/hr]	45120000	45120000
	H [Btu/lbmol]	1369.900	1369.900
	S [Btu/lbmol-F]	31.481	32.476
	MolecularWeight	18.890	18.890
	MassDensity [lb/ft3]	14.011	4.400
	Cp [Btu/lbmol-F]	24.800	14.767
	ThermalConductivity [Btu/hr-ft-F]	0.037	0.032
	Viscosity [cp]	0.024	0.019
	molarV [ft3/lbmol]	1.348	4.294
	ZFactor	0.445	0.553
	Fraction [Fraction]		
	CARBON DIOXIDE	0.015000	0.015000
	NITROGEN	0.006000	0.006000
	METHANE	0.864000	0.864000
	ETHANE	0.071000	0.071000
	PROPANE	0.036000	0.036000
	ISOBUTANE	0.003000	0.003000
	n-BUTANE	0.004000	0.004000
	n-PENTANE	0.001000	0.001000
	WATER	0.000000	0.000000

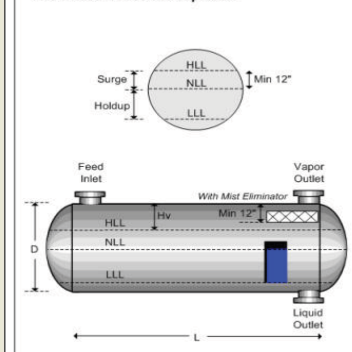
Summary of Plant Unit Design Information

300 MMSCFD Facility

Separator 1	PortName	In	Liq0	Vap
	UnitOperation			
	Is Recycle Port			
	Connected Stream/Unit Op	/S2.Out	/S3.In	/S4.In
	Connected Port			
	VapFrac	0.77	0.00	1.00
	T [F]	-97.7	-97.7	-97.7
	P [psia]	500.0	500.0	500.0
	MoleFlow [lbmole/h]	32939.620	7577.910	25361.710
	MassFlow [lb/h]	622237.870	189504.630	432733.240
	VolumeFlow [ft3/s]	39.286	1.885	37.401
	StdLiqVolumeFlow [ft3/s]	8.435	2.230	6.205
	StdGasVolumeFlow [MMSCFD]	300.000	69.016	230.980
	Properties (Alt+R)			
	Energy [Btu/hr]	45120000.000	-10440000.000	55550000.000
	H [Btu/lbmol]	1369.900	-1377.700	2190.800
	S [Btu/lbmol-F]	32.476	26.662	34.213
	MolecularWeight	18.890	25.010	17.060
	MassDensity [lb/ft3]	4.400	27.925	3.214
	Cp [Btu/lbmol-F]	14.767	18.430	13.672
	ThermalConductivity [Btu/hr-ft-F]	0.032	0.070	0.016
	Viscosity [cp]	0.019	0.101	0.009
	molarV [ft3/lbmol]	4.294	0.896	5.309
	ZFactor	0.553	0.109	0.685
	Fraction [Fraction]			
	CARBON DIOXIDE	0.015000	0.027284	0.011330
	NITROGEN	0.006000	0.001259	0.007417
	METHANE	0.864000	0.600091	0.942855
	ETHANE	0.071000	0.197252	0.033277
	PROPANE	0.036000	0.140246	0.004852
	ISOBUTANE	0.003000	0.012574	0.000139
	n-BUTANE	0.004000	0.016974	0.000123
	n-PENTANE	0.001000	0.004321	0.000008
	WATER	0.000000	0.000000	0.000000

Variables	Value
Design Variables	
VesselDesignType	**Sep2PhaseHorizontal**
MaxIteration	**50**
HoldupTime [day]	**0.0174**
SurgeTime [day]	**0.0035**
VapMassFlow [lb/h]	**432733.24**
LiqMassFlow [lb/h]	**189504.63**
VapDensity [lb/ft3]	**3.2139**
LiqDensity [lb/ft3]	**27.9253**
P [psia]	**500.00**
WithMistEliminator	**0**
Min_Design_L/D	**1.50**
Max_Design_L/D	**6.00**
Calculated Variables	
VesselLength [in]	393.1992
VesselDiameter [in]	144.000
L/Dratio	2.73
VapDisengagementHeight [in]	12.000
NormalLiqLevel [in]	108.442
HighLiqLevel [in]	132.000
LowLiqLevel [in]	13.000
VesselWeight [lb]	1.71E+05
VesselWallThickness [in]	2.7033

Two-Phase Horizontal Separator



Nomenclature

L = Vessel Length
D = Vessel Internal Diameter
Hv = Vapor Disengagement Height
HLL = High Liquid Level
NLL = Normal Liquid Level
LLL = Low Liquid Level

Notes

- Design values are only first estimation. It is not recommended for final dimension
- Stokes' Law constant, K is calculated using York-Demister equation
- For wall thickness calculation;
- Assume carbon-steel for material stress, X-rayed joints for joint efficiency and corrosion allowance = 1/16 inch
- Material = Carbon-steel
- For calculation purposes, mist eliminator thickness/height is assumed to be 4.8 inches

Summary of Plant Unit Design Information			
300 MMSCFD Facility			
V2	Name	Value	
	Delta P [psi]	270	
	Cv	34.45313	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S3.Out	/S9.In
	Connected Port		
	VapFrac	0.00	0.26
	T [F]	-97.7	-135.8
	P [psia]	500.0	230.0
	MoleFlow [lbmole/h]	7577.910	7577.910
	MassFlow [lb/h]	189504.630	189504.630
	VolumeFlow [ft3/s]	1.885	8.188
	StdLiqVolumeFlow [ft3/s]	2.230	2.230
	StdGasVolumeFlow [MMSCFD]	69.016	69.016
	Properties (Alt+R)		
	Energy [Btu/hr]	-10440000	-10440000
	H [Btu/lbmol]	-1377.700	-1377.700
	S [Btu/lbmol-F]	26.662	26.945
	MolecularWeight	25.010	25.010
	MassDensity [lb/ft3]	27.925	6.429
	Cp [Btu/lbmol-F]	18.430	15.013
	ThermalConductivity [Btu/hr-ft-F]	0.070	0.066
	Viscosity [cp]	0.101	0.086
	molarV [ft3/lbmol]	0.896	3.890
	ZFactor	0.109	0.254
	Fraction [Fraction]		
	CARBON DIOXIDE	0.027284	0.027284
	NITROGEN	0.001259	0.001259
	METHANE	0.600091	0.600091
	ETHANE	0.197252	0.197252
	PROPANE	0.140246	0.140246
	ISOBUTANE	0.012574	0.012574
	n-BUTANE	0.016974	0.016974
	n-PENTANE	0.004321	0.004321
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

300 MMSCFD Facility

Ex 1	Name		Value	**CP1**	Name		Value
	OutQ [HorsePower]		2985.80		InQ [HorsePower]		2985.80
	Delta P [psi]		270.00		Delta P [psi]		47.41
	Pressure Ratio		2.17		Pressure Ratio		1.22
	Adiabatic Efficiency [%]		81.08		Adiabatic Efficiency [%]		75.00
	Polytropic Efficiency [%]		80.00		Polytropic Efficiency [%]		75.57
	Speed [rpm]				Speed [rpm]		
	Adiabatic Head [ft]		16849.64		Adiabatic Head [ft]		7987.85
	Polytropic Head [ft]		17077.15		Polytropic Head [ft]		8048.03
	PortName	In	Out		PortName	In	Out
	UnitOperation				UnitOperation		
	Is Recycle Port				Is Recycle Port		
	Connected Stream/Unit Op	/S4.Out	/S5.In		Connected Stream/Unit Op	/S24.Out	/S12.In
	Connected Port				Connected Port		
	VapFrac	1.00	0.94		VapFrac	1.00	1.00
	T [F]	-97.7	-146.8		T [F]	23.0	52.2
	P [psia]	500.0	230.0		P [psia]	220.0	267.4
	MoleFlow [lbmole/h]	25361.710	25361.710		MoleFlow [lbmole/h]	31503.750	31503.750
	MassFlow [lb/h]	432733.240	432733.240		MassFlow [lb/h]	555081.780	555081.780
	VolumeFlow [ft3/s]	37.401	78.269		VolumeFlow [ft3/s]	195.023	170.156
	StdLiqVolumeFlow [ft3/s]	6.205	6.205		StdLiqVolumeFlow [ft3/s]	7.858	7.858
	StdGasVolumeFlow [MMSCFD]	230.980	230.980		StdGasVolumeFlow [MMSCFD]	286.920	286.920
	Properties (Alt+R)				Properties (Alt+R)		
	Energy [Btu/hr]	55550000	47960000		Energy [Btu/hr]	117200000	124800000
	H [Btu/lbmol]	2190.800	1891.200		H [Btu/lbmol]	3720.800	3962.000
	S [Btu/lbmol-F]	34.213	34.438		S [Btu/lbmol-F]	39.349	39.467
	MolecularWeight	17.060	17.060		MolecularWeight	17.620	17.620
	MassDensity [lb/ft3]	3.214	1.536		MassDensity [lb/ft3]	0.791	0.906
	Cp [Btu/lbmol-F]	13.672	10.476		Cp [Btu/lbmol-F]	9.312	9.498
	ThermalConductivity [Btu/hr-ft-F]	0.016	0.017		ThermalConductivity [Btu/hr-ft-F]	0.018	0.020
	Viscosity [cp]	0.009	0.009		Viscosity [cp]	0.010	0.011
	molarV [ft3/lbmol]	5.309	11.110		molarV [ft3/lbmol]	22.286	19.444
	ZFactor	0.685	0.761		ZFactor	0.946	0.946
	Fraction [Fraction]				Fraction [Fraction]		
	CARBON DIOXIDE	0.011330	0.011330		CARBON DIOXIDE	0.015684	0.015684
	NITROGEN	0.007417	0.007417		NITROGEN	0.006273	0.006273
	METHANE	0.942855	0.942855		METHANE	0.903379	0.903379
	ETHANE	0.033277	0.033277		ETHANE	0.073527	0.073527
	PROPANE	0.004852	0.004852		PROPANE	0.001126	0.001126
	ISOBUTANE	0.000139	0.000139		ISOBUTANE	0.000007	0.000007
	n-BUTANE	0.000123	0.000123		n-BUTANE	0.000004	0.000004
	n-PENTANE	0.000008	0.000008		n-PENTANE	0.000000	0.000000
	WATER	0.000000	0.000000		WATER	0.000000	0.000000

Summary of Plant Unit Design Information

300 MMSCFD Facility

T1	Condenser	No		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED	overheadFeed	Lower_Feed	
	Stage	1	8	
	Connected Obj	/S5.Out	/S23.Out	
	Details			
	VapFrac	0.9425	0.2616	
	T [F]	-146.8	-135.8	
	P [psia]	230.0	230.0	
	MoleFlow [lbmole/h]	25361.710	7577.913	
	MassFlow [lb/h]	432733.242	189504.629	
	VolumeFlow [ft3/s]	78.269	8.188	
	StdLiqVolumeFlow [ft3/s]	6.205	2.230	
	StdGasVolumeFlow [MMSCFD]	230.983	69.016	
	Molar Composition			
	CARBON DIOXIDE	0.011330	0.027284	
	NITROGEN	0.007417	0.001259	
	METHANE	0.942855	0.600091	
	ETHANE	0.033277	0.197252	
	PROPANE	0.004852	0.140246	
	ISOBUTANE	0.000139	0.012574	
	n-BUTANE	0.000123	0.016974	
	n-PENTANE	0.000008	0.004321	
	WATER	0.000000	0.000000	
	DRAW	overheadV	reboilerL	
	Stage	1	20	
	Type	VapourDraw	LiquidDraw	
	Connected Obj	/S6.In	/S7.In	
	Details			
	VapFrac	1.0000	0.0000	
	T [F]	-116.8	125.6	
	P [psia]	225.0	230.0	
	MoleFlow [lbmole/h]	31503.633	1435.990	
	MassFlow [lb/h]	555076.601	67161.270	
	VolumeFlow [ft3/s]	120.305	0.639	
	StdLiqVolumeFlow [ft3/s]	7.858	0.577	
	StdGasVolumeFlow [MMSCFD]	286.921	13.078	
	reboilerQ (Btu/hr)	**39446236.2**		

Section	Section_1	Section_2	Section_3
Start	1	2	8
End	1	7	19
internalType	Packed	Packed	Packed
Design Variables			
PackedDesignBasis	**FLOODFACTOR**	**FLOODFACTOR**	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000	0.8000	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**	**0.5000**	**0.5000**
PackingHoldupMethod	**ESG**	**ESG**	**ESG**
SystemFactor [Fraction]	1.00	1.00	1.00
PackingName	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**	**[2in] Pall Rings (M)**
Fp	27.00	27.00	27.00
PackingAreaperVol [ft2/f3]	34.32	34.32	34.32
PackingType	RP	RP	RP
PackingLengthperStage [ft]	**1.500**	**1.500**	**1.500**
SectionAreaFactor [Fraction]	0.8000	0.8000	0.8000
Calculated Variables			
TrayDiameter [ft]	10.000	6.500	8.500
TotalTrayArea [ft2]	78.54	33.18	56.75
PackingLengthperSection [ft]	1.500	9.000	18.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information

300 MMSCFD Facility

V3	Name	Value	
	Delta P [psi]	25	
	Cv	39.23569	
	Characteristic	Linear	
	% Opening [%]	100	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/S7.Out	/S8.In
	Connected Port		
	VapFrac	0.00	0.05
	T [F]	125.6	116.7
	P [psia]	230.0	205.0
	MoleFlow [lbmole/h]	1435.990	1435.990
	MassFlow [lb/h]	67161.270	67161.270
	VolumeFlow [ft3/s]	0.639	1.084
	StdLiqVolumeFlow [ft3/s]	0.577	0.577
	StdGasVolumeFlow [MMSCFD]	13.078	13.078
	Properties (Alt+R)		
	Energy [Btu/hr]	1247000.000	1247000.000
	H [Btu/lbmol]	868.200	868.200
	S [Btu/lbmol-F]	34.117	34.134
	MolecularWeight	46.770	46.770
	MassDensity [lb/ft3]	29.209	17.215
	Cp [Btu/lbmol-F]	35.358	33.569
	ThermalConductivity [Btu/hr-ft-F]	0.047	0.047
	Viscosity [cp]	0.080	0.078
	molarV [ft3/lbmol]	1.601	2.717
	ZFactor	0.058	0.089
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.015555	0.015555
	PROPANE	0.801162	0.801162
	ISOBUTANE	0.068671	0.068671
	n-BUTANE	0.091674	0.091674
	n-PENTANE	0.022938	0.022938
	WATER	0.000000	0.000000

Summary of Plant Unit Design Information

300 MMSCFD Facility

T2	Condenser	Yes		
	Reboiler	Yes		
	# Ideal Stages	20	Includes Condenser and Reboiler	
	Total stages = 20			
	FEED			
	Stage	2		
	Connected Obj	/S8.Out		
	Details			
	VapFrac	0.0532		
	T [F]	116.7		
	P [psia]	205.0		
	MoleFlow [lbmole/h]	1435.990		
	MassFlow [lb/h]	67161.270		
	VolumeFlow [ft3/s]	1.084		
	StdLiqVolumeFlow [ft3/s]	0.577		
	StdGasVolumeFlow [MMSCFD]	13.078		
	Molar Composition			
	CARBON DIOXIDE	0.000000		
	NITROGEN	0.000000		
	METHANE	0.000000		
	ETHANE	0.015555		
	PROPANE	0.801162		
	ISOBUTANE	0.068671		
	n-BUTANE	0.091674		
	n-PENTANE	0.022938		
	WATER	0.000000		
	DRAW	condenserL	condenserV	reboilerL
	Stage	1	1	20
	Type	LiquidDraw	VapourDraw	LiquidDraw
	Connected Obj		/C3.In	/C4+.In
	Details			
	VapFrac	0.0000	1.0000	0.0000
	T [F]	105.9	105.9	199.5
	P [psia]	200.0	200.0	205.0
	MoleFlow [lbmole/h]	0.000	1188.823	247.167
	MassFlow [lb/h]	0.000	52434.528	14726.742
	VolumeFlow [ft3/s]	0.000	7.664	0.137
	StdLiqVolumeFlow [ft3/s]	0.000	0.464	0.113
	StdGasVolumeFlow [MMSCFD]	0.000	10.827	2.251
	ENERGY	condenserQ		reboilerQ
	Stage	1		20
	Type	EnergyOut		EnergyIn
	Connected Obj	/Q4.In		/Q3.Out
	Value [Btu/hr]	19696133.4		26603971.9

Section	Section_1
Start	2
End	19
internalType	Packed
Design Variables	
PackedDesignBasis	**FLOODFACTOR**
DesignFloodFactor [Fraction]	0.8000
DesignDPperLength [inH2O/ft]	**0.5000**
PackingHoldupMethod	**ESG**
SystemFactor [Fraction]	1.00
PackingName	**[2in] Pall Rings (M)**
Fp	27.00
PackingAreaperVol [ft2/f3]	34.32
PackingType	RP
PackingLengthperStage [ft]	**1.500**
SectionAreaFactor [Fraction]	0.8000
Calculated Variables	
TrayDiameter [ft]	7.500
TotalTrayArea [ft2]	44.18
PackingLengthperSection [ft]	27.000

Note: Need to allow suitable tower height for vapour disengagement at top of tower and reboiler returns at base of tower.

Summary of Plant Unit Design Information			
300 MMSCFD Facility			
P1	Name	Value	
	InQ [HorsePower]	3.34635	
	Delta P [psi]	70	
	Pressure Ratio	1.341	
	Efficiency [%]	75	
	Speed [rpm]		
	Head [ft]	337.44	
	PortName	In	Out
	UnitOperation		
	Is Recycle Port		
	Connected Stream/Unit Op	/C4+.Out	/C4+_To_SGas.In
	Connected Port		
	VapFrac	0.00	0.00
	T [F]	199.5	200.8
	P [psia]	205.0	275.0
	MoleFlow [lbmole/h]	247.170	247.170
	MassFlow [lb/h]	14726.740	14726.740
	VolumeFlow [ft3/s]	0.137	0.136
	StdLiqVolumeFlow [ft3/s]	0.113	0.113
	StdGasVolumeFlow [MMSCFD]	2.251	2.251
	Properties (Alt+R)		
	Energy [Btu/hr]	815298.060	823812.654
	H [Btu/lbmol]	3299.125	3333.580
	S [Btu/lbmol-F]	34.731	34.744
	MolecularWeight	59.582	59.582
	MassDensity [lb/ft3]	29.872	29.989
	Cp [Btu/lbmol-F]	45.297	44.757
	ThermalConductivity [Btu/hr-ft-F]	0.046	0.047
	Viscosity [cp]	0.087	0.088
	molarV [ft3/lbmol]	1.995	1.987
	ZFactor	0.058	0.077
	Fraction [Fraction]		
	CARBON DIOXIDE	0.000000	0.000000
	NITROGEN	0.000000	0.000000
	METHANE	0.000000	0.000000
	ETHANE	0.000000	0.000000
	PROPANE	0.027020	0.027020
	ISOBUTANE	0.350870	0.350870
	n-BUTANE	0.491010	0.491010
	n-PENTANE	0.131100	0.131100
	WATER	0.000000	0.000000

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Appendix E: Fuel Price Forecasts

Appendix E: Fuel Price Forecasts

In this report, it is assumed that fuel prices in Alaska during the study period (i.e., the first 15 years of pipeline operation) will be related to fuel prices in the Lower 48. Natural gas prices in Alaska are derived from the Lower 48 natural gas price forecast for Henry Hub (Erath, LA), adjusted by tariff differences in the delivery of North Slope gas to Alaska versus to Henry Hub. The subsequent sections describe the development of the Lower 48 fuel price forecasts, natural gas pipeline tariff assumptions, and resulting fuel prices in Alaska under both the Alberta and Valdez pipeline scenarios.

1 Lower 48 Fuel Prices

Fuel price forecasts used in this report were developed with the National Energy Modeling System (NEMS) and subsequent adjustments as needed to reflect commencement of Alaska pipeline operation at the beginning of 2019. NEMS is a computer-based, energy-economy model developed by the Energy Information Administration (EIA) of the U.S. Department of Energy (DOE). It is designed to represent the important interactions of supply and demand in U.S. energy markets. Primary assumptions include the estimated size of economically recoverable fossil fuel reserves, and changes in world energy supply and demand. The projections reflect known technological and demographic trends under business-as-usual circumstances.

NEMS is used by EIA to develop their annual energy projections as published in the *Annual Energy Outlook (AEO)*. The AEO forecasts incorporate laws and regulations in effect at the time of the NEMS runs, and do not incorporate pending or proposed legislation, regulations, and standards. As such, the March 2009 publication of *AEO2009* does not reflect effects of the stimulus package (i.e., American Recovery and Reinvestment Act, ARRA), which was enacted less than a month prior to publication of the *AEO2009*. However, in April 2009, the EIA released an update of the *AEO2009* “reference case” to reflect the enactment of the ARRA. This revision does not include other scenarios published in *AEO2009*—in particular, the cases for high and low fuel prices, and the “no Alaska” case under which there is no future natural gas pipeline between the North Slope and the Lower 48.

1.1 Natural Gas Prices

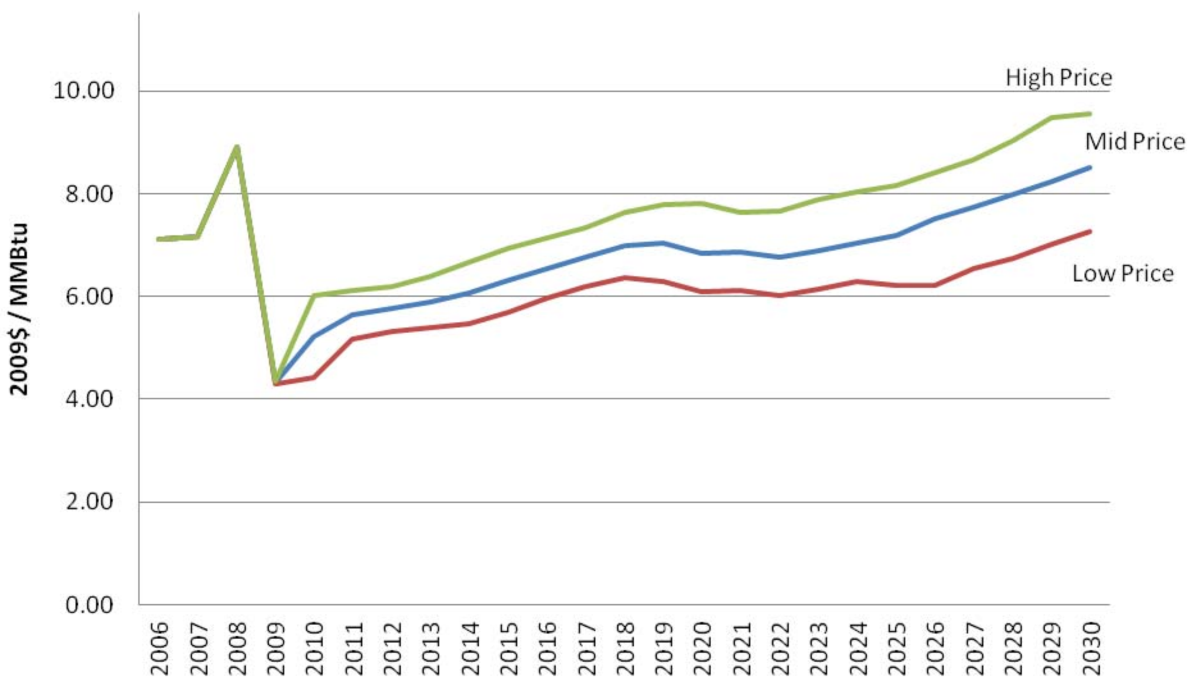
For fuel price forecasts under the Alberta pipeline scenario, SAIC conducted a NEMS run with the same inputs as applied for the revised *AEO2009* “reference case” with incorporation of ARRA. Using these assumptions, the economic analyses within NEMS calculate commencement of Alaskan pipeline operation in 2022, and a subsequent dip in natural gas prices to reflect market response to an increased supply. Over the following years, prices increase to previous levels as demand and supply re-establish the balance that was in place prior to Alaskan pipeline operation.

For the purposes of this report, the NEMS “reference case” forecast of natural gas prices in 2019 and subsequent years were adjusted to reflect a similar dip representing pipeline commencement in late-2018/ early-2019 rather than mid 2022. This adjusted NEMS “reference case” with ARRA is the “mid-price” natural gas forecast under the Alberta pipeline scenario in this report.

A high fuel price scenario was developed based on another NEMS run with the similar inputs as applied for the EIA “high price” scenario, but with incorporation of ARRA. Under this scenario, the NEMS calculates that the Alaska pipeline will be operational in 2020. To roughly reflect commencement of pipeline operation in 2019, modeled natural gas prices in 2019 were reduced by one percent, which effectively makes the 2019 price the same as in 2020, and prices in subsequent years were retained unaltered.

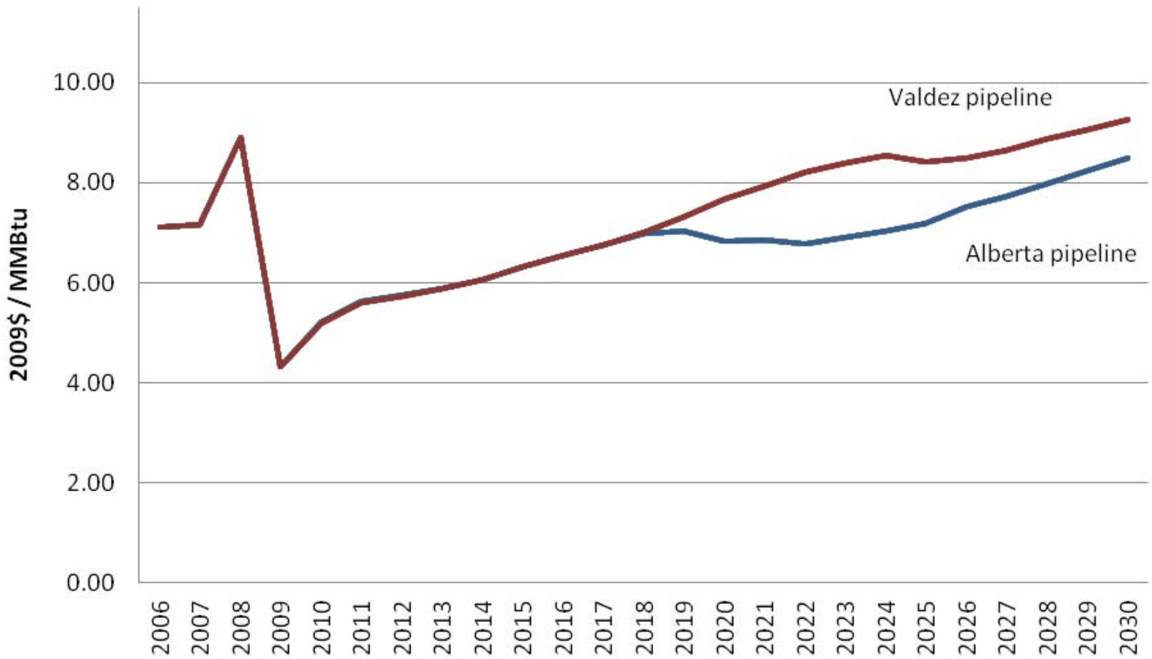
The NEMS input parameters for simulation of the EIA low price scenario were not known, thus the low natural gas forecast is based on reducing the mid-price forecast by the difference between the high price and mid-price forecasts. Figure 1 shows the low, mid, and high natural gas price forecasts for Henry Hub that were used in this report to project natural gas prices in Alaska under the Alberta pipeline scenario.

Figure 1. Forecast natural gas prices at Henry Hub under the Alberta pipeline scenario



For fuel price forecasts under the Valdez pipeline scenario, a NEMS run was conducted with the same inputs as for the AEO2009 "reference case" with ARRA, except with a single change to disallow commencement of Alaska pipeline operations. This run was used as the mid-price forecast under the Valdez pipeline scenario. High price and low natural gas price forecasts were developed by manually applying the relationship between the AEO2009 "reference case" and "low price" scenarios, and the "reference case" and "high price" scenarios (as published in March 2009, without ARRA) to the mid-price forecast (with ARRA and with adjustment to reflect pipeline operation in 2019). The natural gas mid-price forecasts for Henry Hub under both the Valdez and Alberta pipeline scenarios are shown in Figure 2.

Figure 2. Henry Hub natural gas mid-price forecasts under the Alberta and Valdez pipeline scenarios



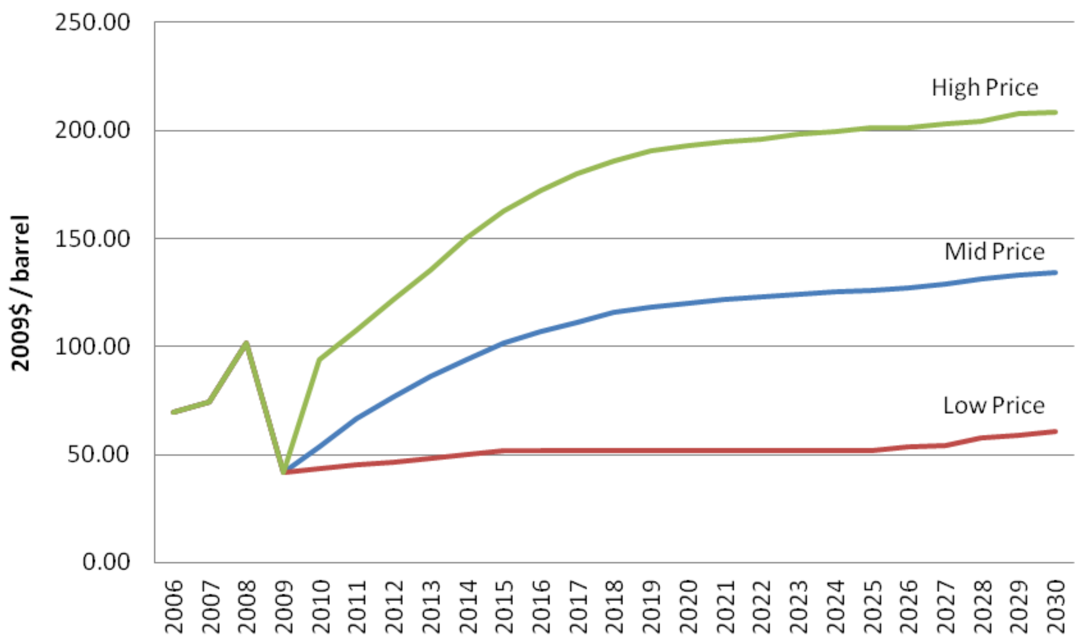
1.2 Petroleum Liquid Fuel Prices

In the NEMS model, natural gas prices are based on the average price of crude oil after taking into account many additional economic and supply considerations. While the NEMS model indicates that the Alaska natural gas pipeline will cause a temporary dip in natural gas prices, no such effect is seen on the price of crude oil and other petroleum products, including jet fuel and diesel. Thus, no adjustments were made to NEMS "reference case" forecasts for liquid fuels, and these are the same as the mid-price forecasts for liquid fuels in this report.

For liquid fuel prices, the AEO2009 (without ARRA) "low price" forecast appears to set price floors of approximately $46.45/bbl for imported crude, and $50.28/bbl for low sulfur light crude (i.e., the average prices from 2024 to 2030, each with a standard deviation of 0.04). The low price crude forecast in this study was developed based on reducing the mid-price forecast by the difference between the high price and mid-price forecast until similar floors were reached. For the high price forecast of crude oil and other petroleum products, the high price NEMS run was retained unaltered.

Liquid fuels price forecasts under the AEO2009 "reference case" and "no Alaska pipeline" case were not significantly different; hence, the same liquid fuel price forecasts were used for the Valdez pipeline scenario as for the Alberta pipeline scenario. Figure 3 shows low, mid, and high forecasts for Lower 48 low sulfur crude oil prices.

Figure 3. Forecast average Lower 48 low sulfur crude oil prices



2 Alaska Natural Gas Prices

Alaskan natural gas prices at primary delivery points were calculated based on the forecasts of Lower 48 natural gas prices at Henry Hub (described above), and estimates of the difference in transportation costs for pipeline natural gas in Alaska versus Henry Hub. Primary Alaskan delivery points are defined as at the main pipeline take-off points, and at the end of a spur line to Southcentral Alaska. The tariff estimates, and average natural gas prices during the periods analyzed in this report (i.e., Years 1 to 5 and Years 10 to 15 of Alaska pipeline operation) are described below.

2.1 Tariff Estimates

TransCanada provided regional average tariff estimates for the Alaska pipeline as nominal, levelized values for 2018 to 2030. Under the Alberta pipeline scenario, a single weighted average estimate was provided for all Alaska destinations. Under the Valdez pipeline scenario, two tariff estimates were provided, one for delivery to the pipeline terminal in Valdez, and the other for the single weighted average of all other in-state take-off points. The TransCanada tariff estimates were given a ± 25% range to represent high and low tariff estimates. The tariff between Alberta and the Lower 48 was based on the historical difference in prices between the Alberta trading hub, AECO, and the US trading, Henry Hub—no range was applied to this tariff.

The route of a spur line to Southcentral and its take-off point from the main Alaska pipeline has not yet been determined. However, for the purposes of developing spur line tariff estimates for this report, it is assumed that under the Alberta pipeline scenario, the spur could extend from Fairbanks or Delta Junction to Beluga. Under the Valdez pipeline scenario, the spur is assumed to extend from Glennallen to Beluga. A range for the spur line tariff was set to encompass the range reflected in a review of estimates developed by several different sources including: Black & Veatch, Paragon Engineering Services, Inc., Michael Baker Jr., Inc., and ANGDA. This range represents the cost of service for varying sizes of pipeline and various throughputs. The mid-price estimate for the spur line tariff is based on spur line throughput that approximates future Southcentral natural gas demand, rather than the mid-point of the range.

Table 1 displays low, mid, and high estimates of tariff prices in mid-2009$ for various segments of the main pipeline to Henry Hub, and for the spur line to Southcentral. Note that these preliminary estimates will change with filing of the open season plan.

Table 1. Low, Mid, and High Pipeline Tariff Estimates, 2009$, MMBtu

	Low	Mid	High
Alberta Route			
North Slope to Canadian border	$1.13	$1.50	$1.88
Canadian Border to AECO	$0.84	$1.12	$1.40
AECO to Henry Hub	$0.75	$0.75	$0.75
In-State Delivery Toll	$0.93	$1.25	$1.56
Spur Line to Southcentral	$1.00	$2.25	$4.00
Valdez Route			
In-State Delivery Toll	$0.93	$1.25	$1.56
LNG Export in Valdez	$1.40	$1.87	$2.34
AECO to Henry Hub	$0.75	$0.75	$0.75
Spur Line to Southcentral	$0.60	$1.40	$2.50

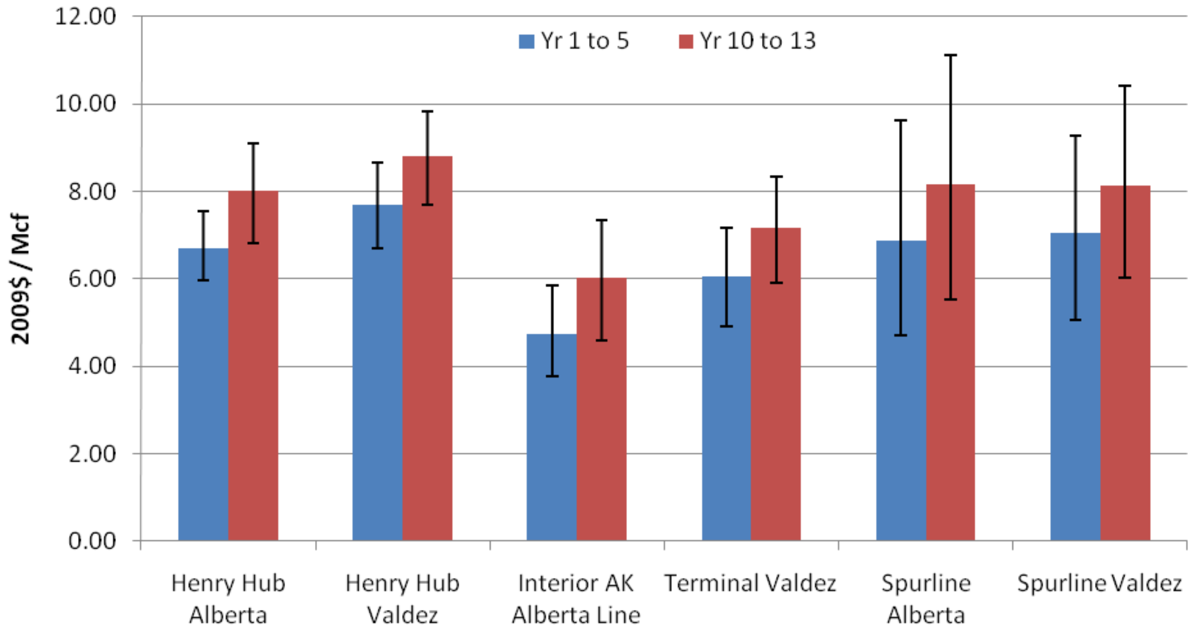
2.2 Average Study-Period Prices

The periods of interest for this study are the first 5 years of pipeline operations (i.e., 2019 to 2023), and years 10 to 15 of pipeline operation (i.e., 2028 to 2032). Average prices during these periods were calculated from the forecast of natural gas prices in the Lower 48, as described above. Note that this forecast extends to 2030; hence, the average price estimate for Years 10 to 15 of pipeline operation is based only on the first three years of this period.

For natural gas prices in Alaska, the total tariff from North Slope to Henry Hub was subtracted from the forecast Henry Hub price to determine the wellhead value of North Slope gas. The addition of tariffs from North Slope to Alaskan locations (Table 1) was then added to the wellhead price to develop an Alaskan price forecast.

Figure 4 displays the average natural gas prices applied in this study at various locations during the two periods of interest. The error bars in this graph represent uncertainty in gas prices, as indicated by the low and high price forecasts, and uncertainty in transportation costs (i.e., tariffs) as indicated by low and high tariff price estimates.

Figure 4. Average forecast natural gas prices under Alberta and Valdez pipeline scenarios, during Years 1 to 5 and Years 10 to 13 of pipeline operation



Appendix F: Industrial Product Price Forecasts

Appendix F: Industrial Product Price Forecasts

Product markets for the modeled industries were assessed to determine preferred markets based on both market prices and shipping distances. Candidate LNG markets include the North American West Coast (e.g., British Columbia, Baja Mexico), Japan, and Korea. In recent years, LNG has sold at a significant premium in Japan and Korea, making these markets preferred for this product. LNG shipping costs from Alaska to Japan are roughly equivalent to, or less than other suppliers competing for the Japanese market.

For Alaskan fertilizer, the US west coast and Asia, are good candidates for future markets, sales to Korea were modeled in the NPV analysis. For GTL products, the US west coast and Alaska are good candidates for future markets. GTL jet fuel sales within Alaska were modeled in the NPV analysis recognizing that the lower shipping costs associated with an in-state market would be preferable. However, ultimately, for all industrial products, the market of choice will be contingent on the balance of local supply and demand.

Forecast prices for LNG, ammonia/fertilizer, and GTL jet fuel are described below.

1 LNG Price Forecast

Global LNG trade has traditionally been dominated by East Asian importers, particularly Japan and South Korea. East Asian importers, including China and Taiwan, accounted for 45% of the world's contracted LNG or about 124.3 million tonnes per annum (MTA) in 2009 (6.1 trillion cubic feet). Japan and South Korea are mature markets for LNG. According to EIA's International Energy Outlook 2009, Japanese natural gas consumption is projected to grow modestly from 3.3 trillion cubic feet (Tcf) in 2010 to 3.7 Tcf in 2030. Korea's consumption is projected to grow from 1.3 Tcf in 2010 to 1.7 Tcf in 2030.

Japanese and Korean LNG prices are typically higher than those in the United States and Europe. The differentials are due to the formulae for calculating the LNG price: in the U.S. and Europe, the LNG price is typically linked to the pre-burner price of alternative fuels (heating oil, heavy fuel oil, coal, etc.) while in Japan and Korea, LNG prices are typically linked to the price of crude oil. East Asian buyers also pay higher rates due to an "Asian Premium," which is attributed to the lack of indigenous sources of natural gas supply and the security-conscious, long-term nature of most East Asian energy contracts. In energy equivalent terms, the Asian Premium on LNG has been found to be greater than the Asian Premium on crude oil.

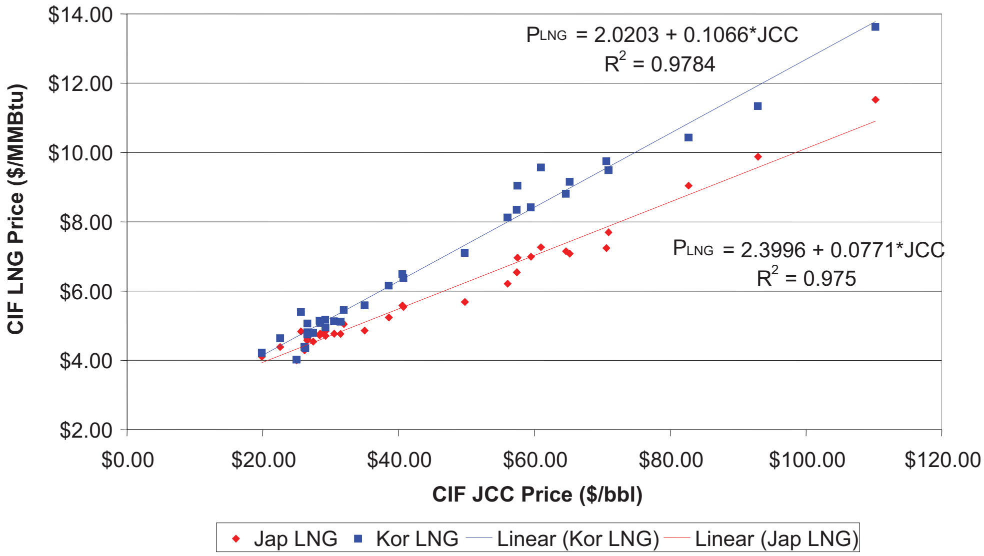
Different LNG contracts employ different pricing formulae, which are rarely disclosed, but it is widely known that Japanese and Korean contracts are linked to the "Japanese Crude Cocktail" (JCC) price, which is a weighted-average of all crude import prices reported by the Japanese Customs office. East Asian LNG contracts also typically include "S-curves," which act as shock absorbers to dampen the effect of large upward or downward swings in the price of crude oil. A simple example of an East Asian LNG pricing formula is shown below:

$P_{LNG} = a + b*JCC - S$

Here, P_{LNG} is the LNG price represented in $/MMBtu and JCC is the Japanese Crude Cocktail CIF price represented in $/bbl. The constant "a" is a price floor that prevents the LNG price from falling below a certain level, so LNG exporters can guarantee recovery of capital costs. The coefficient "b" is greater than 0 and less than 1 and provides the link to crude oil prices. The "S" factor is a constant that reduces the LNG price but is only active when crude oil prices move outside of a preset range. Typically, this preset range covers all upside oil price eventualities that seem likely to occur when the contract is negotiated. The precise values of a, b, and S are negotiated between buyers and sellers and can change depending on the price environment and whether the market favors producers or consumers.

East Asian LNG pricing formulae can be surmised from observing the relationship between LNG prices and the JCC price. Figure 1 plots Japanese and Korean LNG prices against the Japanese Crude Cocktail price from the first quarter of 2000 to the second quarter of 2008. Linear trend-lines are fitted and the inferred pricing formula is shown for each data set. The high R-squared values show that these relationships are highly significant.

Figure 1. Japanese and Korean CIF LNG Prices versus CIF Japanese Crude Cocktail (JCC) Price, 2000 - 2008



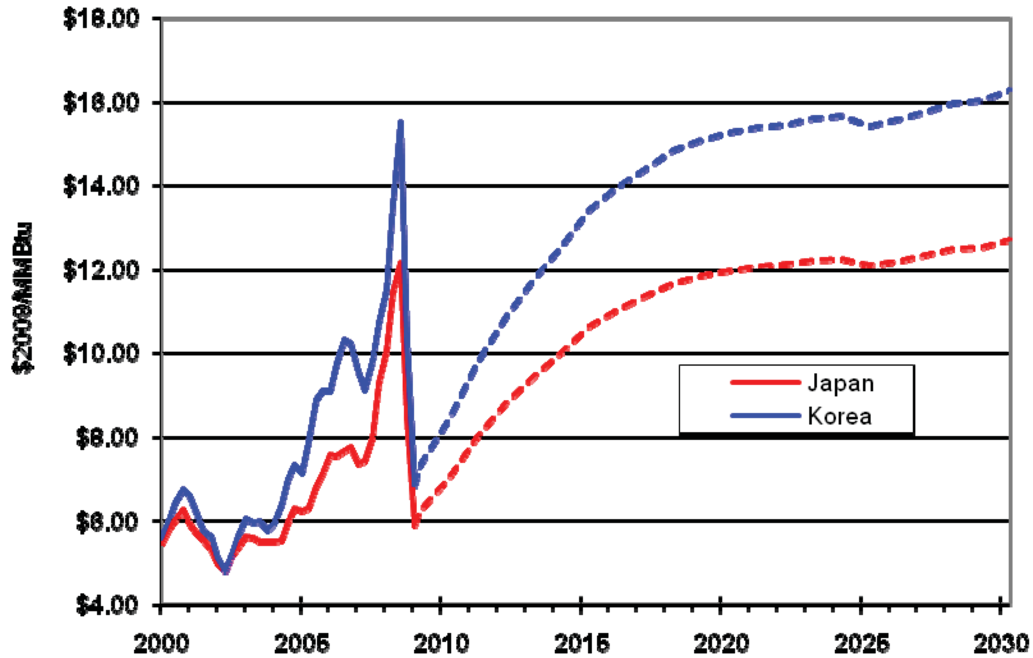
Source: SAIC, derived from Japanese Customs office and Korean Customs office data

The above figure shows that Korean LNG prices are typically higher than Japanese LNG prices at every crude price level and that that the differential increases as the price of crude increases. This implies that the differential is likely not due to different shipping and insurance costs to Korea vs. Japan. The differential is more likely due to Korean pricing formulas that are tied more strongly to crude oil or, potentially, to a greater portion of LNG purchases on the spot market.

Future LNG prices in East Asia can be extrapolated using the inferred pricing formulae from the above figure and forecasts for crude oil prices from Energy Information Administration's Annual Energy Outlook. This forecast method assumes that the LNG pricing formulae that have prevailed in East Asia from 2000 to 2008 will continue to determine future LNG prices. This assumes that LNG contracts will not be significantly renegotiated and that the Japanese-Korean differential continues to be a factor.

Figure 2 shows actual Japanese and Korean CIF LNG prices from the first quarter of 2000 through the second quarter of 2008 and estimated LNG prices based on actual crude prices from the third quarter of 2008 through the first quarter of 2009. Beyond the first quarter of 2009 and through 2030, LNG prices are forecast based on the EIA's projections of future crude prices. All prices are shown in real dollars as of June 2009.

Figure 2. Historical and Forecast LNG Prices in Japan and Korea



Source: SAIC, derived from Japanese Customs office, Korean Customs office, and EIA data

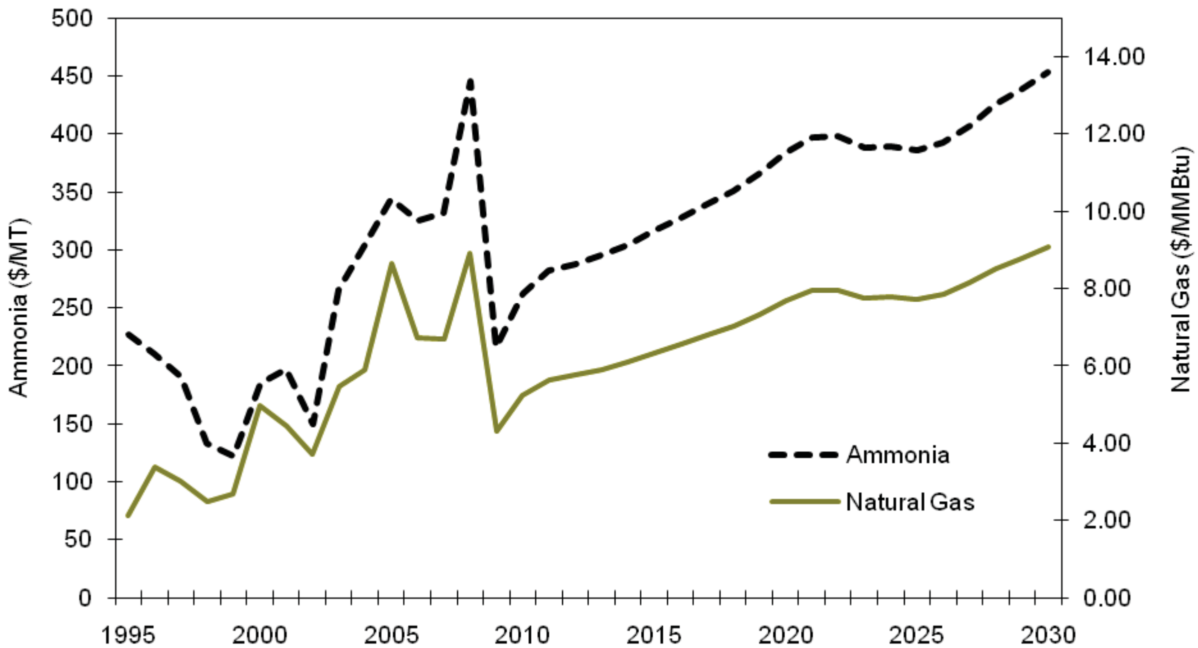
The figure above shows that East Asian LNG prices peaked in the third quarter of 2008 at more than $12 per MMBtu in Japan and more than $15 per MMBtu in Korea. Estimated average LNG prices fell sharply along with crude prices in the fourth quarter of 2008, reaching lows in the first quarter of 2009 of below $6 per MMBtu in Japan and below $7 per MMBtu in Korea. Based on EIA's reference case forecast for crude oil prices, Japanese LNG price are projected to grow by 3.43% per year from 2009 to 2030 and Korean LNG prices are expected to grow by 3.85% per year over the same period. For the purposes of the NPV analysis of LNG facilities conducted in this report, average forecast prices between 2019 and 2030 were applied.

These forecasts assume that the Korean LNG prices continue to be higher than Japanese LNG prices and that the Asian Premium persists over the forecast period. In reality, contract renegotiations may narrow the gap between Korean and Japanese LNG prices and the emergence of an LNG spot market may narrow the gap between East Asian LNG prices and those in the United States and Europe. The forecasted prices in this analysis should serve as one potential scenario for how East Asian LNG prices will evolve. Other price scenarios, such as a convergence of LNG prices across the Atlantic and Pacific basins, should also be considered.

2 Ammonia/ Urea Price Forecast

Forecast product prices for the fertilizer industry was modeled based on the historical relationship with natural gas. The low. mid, and high forecast prices for natural gas were used to project low, mid, and high ammonia prices based on the rough relationship of the price of one metric ton (MT) equal to 50 times the price of natural gas per MMBtu. Historical and projected natural gas and ammonia prices are shown in Figure 3.

Figure 3. Historical and Forecast Ammonia and Natural Gas Prices



Source: SAIC, derived from Japanese Customs office, Korean Customs office, and EIA data

For the purposes of the NPV analysis of an Alaskan fertilizer industry, average projected feedstock and product prices between 2019 and 2030 were applied.

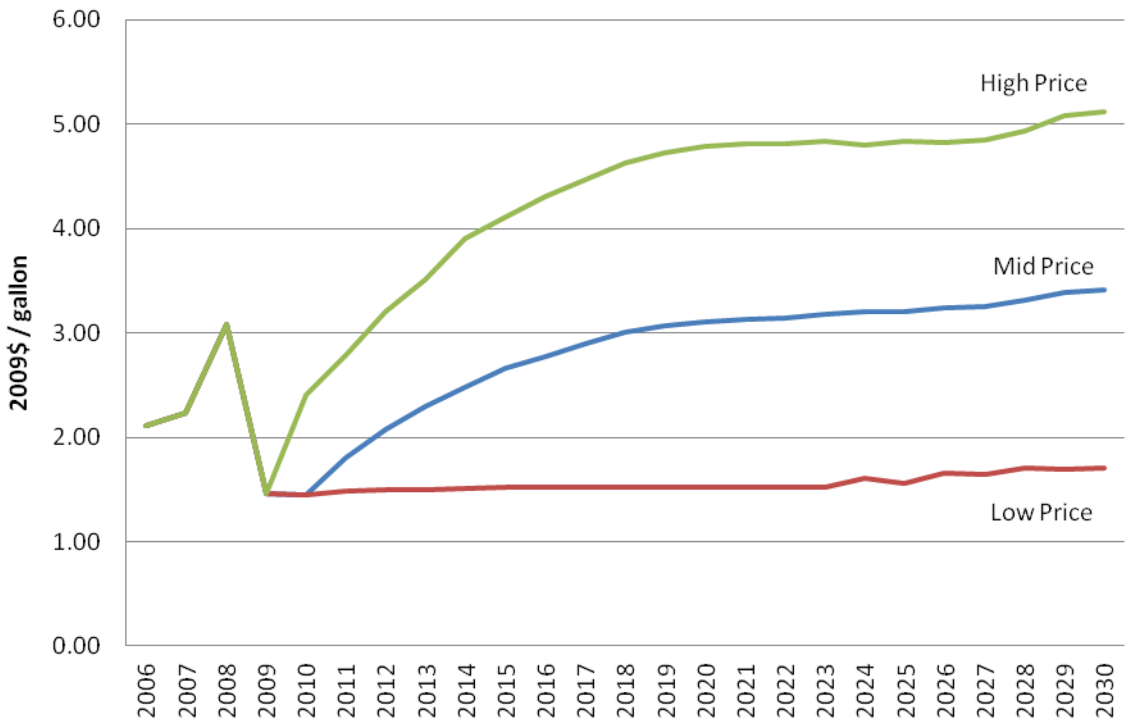
3 Jet Fuel Price Forecast

The modeled product for the GTL complex assessed in this study is jet fuel. The primary market for the GTL product is assumed to be Alaska. It is further assumed that the price of liquid petroleum products in Alaska is linked to the Lower 48. The jet fuel forecast applied in this study was developed using the National Energy Modeling System (NEMS), which forecasts a variety of petroleum-based fuels. The scenarios conducted were the same as those described in Appendix E, Fuel Price Forescasts.

As stated in Appendix E, for liquid fuel prices, the AEO2009 (without ARRA) “low price” forecast appears to set price floors of approximately $46.45/bbl for imported crude, and $50.28/bbl for low sulfur light crude (i.e., the average prices from 2024 to 2030, each with a standard deviation of 0.04). The low price crude forecast in this study was developed based on reducing the mid price forecast by the difference between the high price and mid price forecast until similar floors were reached. For the high price forecast of crude oil and other petroleum products, the high price NEMS run was retained unaltered.

Liquid fuels price forecasts under the AEO2009 “reference case” and “no Alaska pipeline” case were not significantly different, hence the same liquid fuel price forecasts were used for the Valdez pipeline scenario as for the Alberta pipeline scenario. Figure 4 shows low, mid, and high forecasts for Lower 48 jet fuel prices.

Figure 4. Projected Price of Jet Fuel in the Lower 48



Source: SAIC

Jet fuel price differentials between the Lower 48 and Alaska are assumed to be entirely due to transportation costs, allowing direct use of the average projected Lower 48 price between 2019 and 2030 for the purposes of the NPV analyses of a GTL complex conducted in this report.