Oil & Natural Gas Technology

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Final Report

Beluga Coal Gasification – ISER

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Office of Fossil Energy

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Disclaimer

Abstract

ISER was requested to conduct an economic analysis of a possible "Cook Inlet Syngas Pipeline." The economic analysis was incorporated as section 7.4 of the larger report titled: "Beluga Coal Gasification Feasibility Study, DOE/NETL-2006/1248, Phase 2 Final Report, October 2006, for Subtask 41817.333.01.01". The pipeline would carry CO_2 and N_2-H_2 from a synthetic gas plant on the western side of Cook Inlet to Agrium's facility. The economic analysis determined that the net present value of the total capital and operating lifecycle costs for the pipeline ranges from $318 to $588 million. The greatest contributor to this spread is the cost of electricity, which ranges from $0.05 to $0.10/kWh in this analysis. The financial analysis shows that the delivery cost of gas may range from $0.33 to $0.55/Mcf in the first year depending primarily on the price for electricity.

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Introduction

ISER was asked to prepare an economic analysis of a possible "Cook Inlet Syngas Pipeline" for inclusion in phase 2 of the "Beluga Coal Gasification Feasibility Study, DOE/NETL-2006/1248."

The pipeline chosen for analysis was described in section 7.1 of the *Phase 2 Report* as follows:

> "The concept includes two pipelines to transport CO_2 and N2/H2, which will be fed into the Agrium plant and used as synthesis gas. This study assumes a coal gasification plant location within a one mile radius of the village of Tyonek. The presently planned plant configuration could be modified to take Carbon Dioxide (CO_2) and Hydrogen (H_2) from the stream produced by the Syngas gasifier prior to the introduction of those gases into the F-T reactor. Nitrogen (N_2) would come from the oxygen plant that is planned in conjunction with the F-T plant process and is a byproduct of the oxygen production. The H_2 and N_2 are then combined in a mole ratio of 3:1 into one product stream and the CO_2 is delivered as a second product stream. Each stream is to be transported in a separate pipeline."[1]

Executive Summary

ISER was asked to prepare an economic analysis of a possible "Cook Inlet Syngas Pipeline" for inclusion in Phase 2 of the "Beluga Coal Gasification Feasibility Study, DOE/NETL-2006/1248." The request was made the principal author of the Phase 2 study, Robert Chaney. Dr. Steve Colt of ISER performed the economic analysis using pipeline cost data provided by other project contributors.

The analysis determined that the net present value of the total capital and operating lifecycle costs for the pipeline ranges from $318 to $588 million. The greatest contributor to this spread is the cost of electricity, which ranges from $0.05 to $0.10/kWh in this analysis. The financial analysis shows that the delivery cost of gas may range from $0.33 to $0.55/Mcf in the first year depending primarily on the price paid for electricity to power the pipeline compressors.

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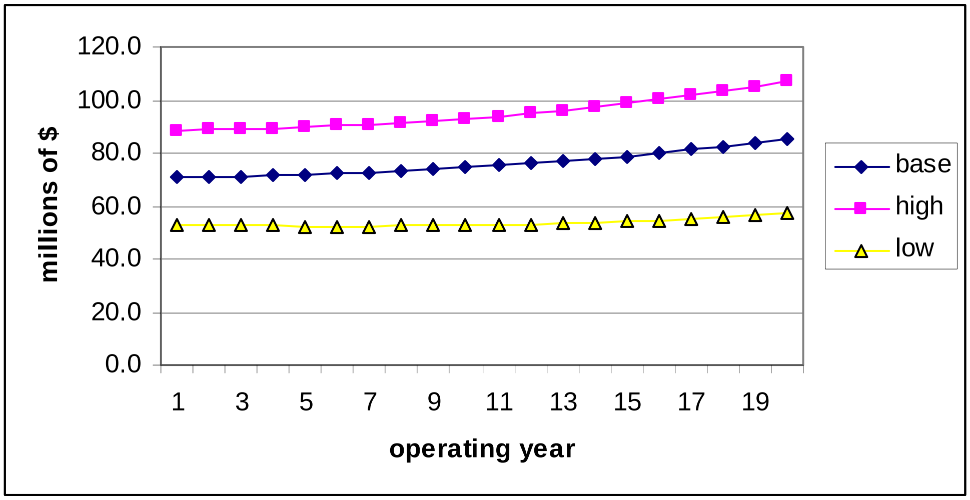
[1] Chaney, et. al. "Beluga Coal Gasification Feasibility Study, DOE/NETL-2006/1248, Phase 2 Final Report, October 2006 for Subtask 41817.333.01.01" Section 7.1.

Table ES-1. Annual SynGas Pipeline Cost of Service

		BASE	HIGH	LOW
COST COMPONENTS, Year 1				
	O&M	35,839,800	44,799,750	23,072,850
	Capital charges	35,100,287	43,875,359	29,835,244
TOTAL COST of SERVICE, YEAR 1		70,940,087	88,675,109	52,908,094
	Total volume of gas from both pipelines (Mcf)	161,030,200	161,030,200	161,030,200
	Cost per Mcf	0.44	0.55	0.33
TOTAL COST of SERVICE, YEAR 20		85,591,816	106,989,770	57,181,363
	Cost per Mcf	0.53	0.66	0.36

The following chart shows the range and trajectories of the total annualized cost of service for the syngas pipeline.

Figure ES-1. Annual Cost of Service for 20 Years



Experimental Methods

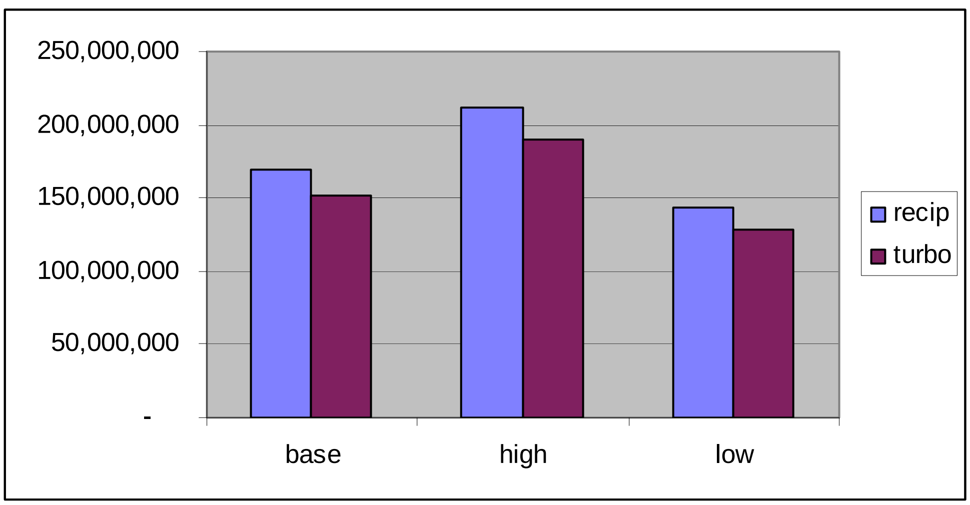
The analysis was conducted using scenario methods combined with net present value discounted cash flows and levelized cost-of-service methods commonly used in utility and regulatory economics. Table 1 shows the scenarios for pipeline capital cost. Turbo compressors were deemed a possible option for reducing capital cost.

Table 1. Capital Cost Assumptions

		Capital Cost Amount		
PROJECT COMPONENT		**BASE**	**HIGH (+25%)**	**LOW (-15%)**
CO2 Land portion				
	Compressors (recip)	15,520,400	19,400,500	13,192,340
	Material	7,007,000	8,758,750	5,955,950
	Construction	3,915,000	4,893,750	3,327,750
	Other	5,560,933	6,951,166	4,726,793
	Total CO2 land	**32,003,333**	**40,004,166**	**27,202,833**
N2H2 Land Portion				
	Compressors (recip)	33,426,000	41,782,500	28,412,100
	Material	13,923,000	17,403,750	11,834,550
	Construction	8,187,976	10,234,970	6,959,780
	Other	10,184,486	12,730,608	8,656,813
	Total N2H2 land	**65,721,462**	**82,151,828**	**55,863,243**
Submarine portion		**71,307,000**	**89,133,750**	**60,610,950**
TOTAL PROJECT COST		**169,031,795**	**211,289,744**	**143,677,026**

Possible Savings from Turbo Compressors				
		BASE	**HIGH (+25%)**	**LOW (-15%)**
	CO2 pipeline savings	(4,700,000)	(5,875,000)	(3,995,000)
	N2H2 pipeline savings	(12,800,000)	(16,000,000)	(10,880,000)
TOTAL PROJECT WITH TURBO COMPRESSORS		**151,531,795**	**189,414,744**	**128,802,026**

Figure 1. Range of Total Project Capital Costs



The timing of capital expenditures is assumed to follow a four-year pattern with annual fractions of 15-30-30-25 percent expenditure. The assumed weighted cost of capital is 12.0 percent (base case), leading to additional capitalized interest of about 12% of the overnight cost. This capitalized interest is incorporated when determining annualized total costs below.

The following table summarizes the O&M cost assumptions used in the economic model.

Table 2. Summary of O&M Costs

	O&M Cost Amount		
COST COMPONENT	**BASE**	**HIGH**	**LOW**
Electricity			
Electricity quantity (million kWh)	410.6	410.6	410.6
Electricity price in 2011 ($/kWh)	0.08	0.10	0.05
Electricity cost in 2011 ($)	32,848,800	41,061,000	20,530,500
Labor	995,000	1,243,750	845,750
Other	1,996,000	2,495,000	1,696,600
TOTAL O&M COST	**35,839,800**	**44,799,750**	**23,072,850**
note: High and Low electricity prices are author judgment. High and Low labor and other are +25% and -15%			

Results and Discussion

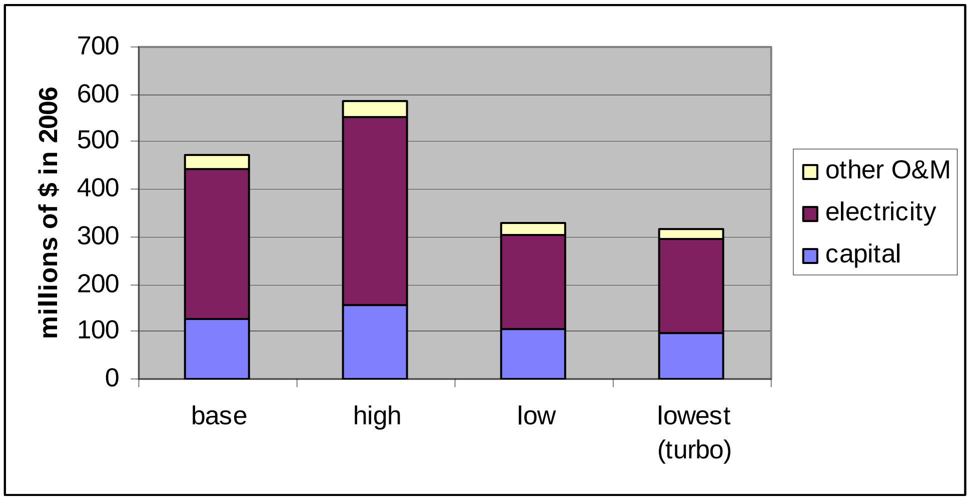
One way to view the overall cost of the syngas pipeline is to combine capital and operating costs into a single net present value (NPV) of future costs. The following table summarizes these NPV cost results assuming a 12% weighted cost of capital as the discount rate and the year 2006 as the decision year or base year for discounting. A 20-year operating life is assumed running from 2011 to 2030.

Table 3. Present Value of Total Project Lifecycle Cost

	Net Present Value of all Costs, as of 2006		
COST COMPONENT	**BASE**	**HIGH**	**LOW**
NPV of Capital Cost (recip compressors)	126,013,259	157,516,573	107,111,270
NPV of O&M Costs, based on:			
annual electricity price escalation	4.0%	4.0%	4.0%
annual escalation all other O&M	3.0%	3.0%	3.0%
NPV of Electricity cost (2011-2030)	317,341,315	396,676,644	198,338,322
NPV of all other O&M costs	27,010,933	33,763,666	22,959,293
NPV of Total O&M	344,352,248	430,440,310	221,297,615
NPV of TOTAL PROJECT COST (2011-2030)	**470,365,507**	**587,956,883**	**328,408,885**
Item: NPV using Low Capital Costs with Turbo Compressors:			**317,319,567**

Two conclusions are noteworthy from the NPV numbers. First, the range from lowest to highest NPV is $271 million, with the highest NPV almost twice the level of the lowest. Second, almost $200 million, or 77%, of this range is due to the range of possible electricity costs that results from a price range of $0.05 to $0.10/kWh. In the base case electricity costs constitute 67% of the NPV of all costs. The following chart summarizes these conclusions by showing the components of total NPV for each case. The “lowest” case is based on the low case but with the additional deduction for turbo compressors.

Figure 2. Components of Lifecycle Cost



A second way to view the cost of this project is to annualize the capital cost and calculate an annualized total cost of service. The following estimates are based on a 20 year straight-line depreciation procedure and a depreciated original cost methodology, as would be used if a separate entity operated the pipeline as a regulated utility.

The total annualized cost of service in year 1 (2011) ranges from $53 million to $89 million. Roughly half of this year 1 cost is O&M and half is capital charges. By year 20 the cost rises somewhat in nominal dollars, but would actually fall in real dollar terms after factoring out general inflation. By year 20 almost all of the annualized cost is for O&M. On a volumetric basis, using a total gas volume of 161,030,200 Mcf, the annualized cost in year 1 ranges from $0.33/Mcf to $0.55/Mcf.

Conclusion

Two major conclusions are apparent from this analysis. First, the range of capital costs for the pipeline depends on the feasibility of turbocharged compressors. Additional technical research might be able to determine whether such technology was feasible and at what incremental capital cost. Second, and most important, although the subsea pipeline is capital-intensive, it would be the ongoing cost of electricity that largely determines the cost of service for the pipeline and hence the project's economic viability.

References

Chaney, Robert, et al. Beluga Coal Gasification Feasibility Study, DOE/NETL-2006/1248, Phase 2 Final Report, October 2006 for Subtask 41817.333.01.01

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