Stranded Natural Gas Commercialization

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Contents

Abstract

Natural gas that is trapped in hydrates has the potential to become a large source of energy when there is becoming a large shortage in conventional energy sources. This report addresses the supply of gas hydrates in Kamchatka, Russia. The natural gas that can be produced there can be sold to neighboring markets such as China and Japan. The two major transportation options are to either construct a pipeline to transport the natural gas to mainland Russia for transport to other markets or to use LNG tankers to transport the gas to Japan.

The both options have been shown that they can be profitable if pursued at the correct conditions. The larger facilities tend to yield a higher return, but those options cost more to pursue. At a flow rate of 390 million standard cubic feet per day, the total capital investment for the LNG is $10.6 billion compared to the total capital investment for the pipeline which is $12.3 billion. Both of these options lead to a positive net present worth, but the LNG NPW is $10.9 billion and the pipeline NPW is $545 million. The average return on investment for the LNG facility is 23.86% and for the pipeline it is 18.76%. Therefore, both of the options could be chosen, but if the largest profit is needed, then the LNG facility is the most profitable option to pursue.

Introduction

Since the production of conventional natural gas is on a decline around the world, it is become necessary to start looking at producing unconventional or stranded natural gas. Methane hydrates would fit into this category. A hydrate, or clathrate, is an ice-like crystalline structure with natural gas suspended in it. It is estimated that there are approximately 168 cubic feet of gas per 1 cubic foot of water. Methane hydrates are found in many places around the world, but the hydrates found on land are mostly located in the Arctic and Antarctic regions. They are located in permafrost at shallow depths between 1000 and 5750 feet in these regions. There are an estimated 30,000 to 49,100,000 trillion cubic feet (Tcf) in oceanic natural gas hydrates, and 5,000 to 12,000,000 Tcf in continental natural gas hydrate deposits. For a perspective on the possibilities of this supply, "current worldwide natural gas resources are about 13,000 Tcf and natural gas reserves are about 5,000 Tcf." (Natural Gas 1998)

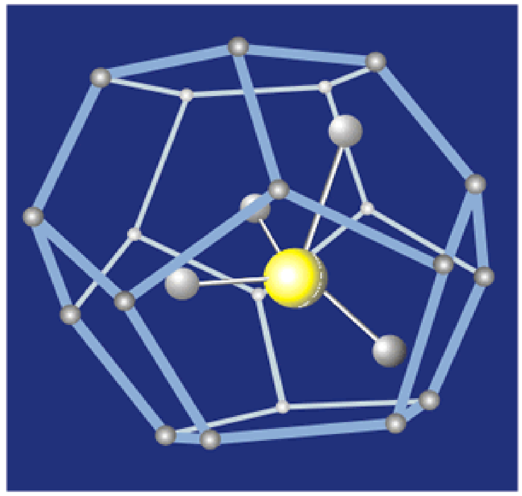

Figure 1 - Basic structure of methane hydrate. (USGS)

The natural gas hydrates hold a great deal of potential for the future of energy, but can the technology be discovered to produce it efficiently since it is found in barren locations of the world, and is there a way to make it economical? The paper attempts to answer this question by not only producing the hydrate, but also looking at the possibility of transporting it to the global market via LNG or pipeline.

Background

Methane hydrates are naturally forming structures of methane gas trapped within a crystal lattice of ice. Typically, hydrates are found in permafrost regions and on the ocean floor, where pressure is high and temperature is low. They are formed when small gas molecules come into contact with water at high pressures and low temperatures (around 3 – 10 MPa and 273 – 283 K for methane hydrates). (Koh)

Hydrates in nature have about twice the amount of energy compared to the total fossil fuel resource. (Koh) The general structure of methane hydrates are $CH_4 \cdot 5.75\ H_2O$.

There are different methods to produce methane hydrates. Since hydrates are in solid form, they cannot be produced normally in a well. One method to produce methane hydrates is to mine the hydrates, like a coal mining operation. This method is dangerous to workers since the threat of asphyxiation is possible due to the dissociation of hydrates during the mining process because the hydrates are unstable at atmospheric pressure.

Another method of producing natural gas from hydrates is through depressurization. This method is the simplest and most economical since it simply requires that the pressure in the well be lowered to allow for dissociation of the hydrates in the reservoir.

The hydrates in question are in the region of Kamchatka, Russia. This area is a mountainous region primarily composed of permafrost due to its cold temperatures. It is close to Japan, as well as mainland Russia, allowing for access to numerous LNG markets. **Figure 2** shows where Kamchatka is in Russia.

Figure 2 - Map showing the location of Kamchatka in Russia.

Current research in the field of natural gas hydrates is minimal. There is only one group in Canada that is doing research in producing natural gas hydrates. The groups is a Japanese and Canadian team, and they were able to sustain flow from a research well located in the Mackenzie Delta for 6 days through depressurization. Although this seems like a small feat, it is significant that they have made such an accomplishment when no other group is working on research to actually produce natural gas hydrates. They were also able to support the idea that other forms of dissociation, such as thermal injection, are not economically feasible (Canadian).

Assumptions for the Project

There are many assumptions that must be made so that an analysis can be done. The first assumption is that no major problem can occur. The major problems or hindrances that may be associated with producing natural gas hydrates are large amounts of water and sediment being produced along with the gas. If a large amount of water is produced, storage will be a problem because of the cold temperatures at which the hydrates will be produced at. Sediment will cause a problem because of possible pipe clogging problems, and it could also cause damage to the separator. Another assumption is that the natural gas hydrate is found at a depth range of 2000 to 4500 feet. Four different flow rates are also going to be assumed, and they are going to correspond to liquefaction facility capacities. The flow rates are 130, 195, 260, and 390 million standard cubic feet (mmscfd). These flow rates correspond to a 1, 1.5, 2, and 3 million tons per annum (mtpa). This assumption was so that a proper economical analysis can be made between the forms of transportation used. It is also assumed the maximum flow rate of the well is equal to 890 thousand standard cubic feet.

Timeline for the Project

The following timeline outlines the project that will be taking place in Kamchatka. This timeline shows all of the necessary steps that must be followed to make this process profitable.

Tasks	1	2	3	4	5	6	7	8	9	10	11-30
Have Logistic for both the LNG/ Pipeline started											
Seismic: 5 person team (6-8 weeks)	$54										
Order Materials for Pipeline/LNG facility											
Find crew and begin measures to house and feed them											
Ship Intial Equipment: Build Pad 1											
Drill 1st Well, perform core analysis, and other analysis											
Cap well until Pipeline/LNGbuilding is completed											
Build Pipeline/LNG: will take 3 - 6 years (Assume 4 years)											
Start building facilities for each location (approx. 2 months per facility)											
Drill all other wells											
Start wells to sells											

Figure 3: Timeline for Project

The first step in the process is to take seismic data. If the seismic data turns out to be negative, then the loss will be $54 million. If the project continues, then the pipeline or LNG facility will be transporting natural gas to sales in 9 years. The initial net present worth for the first 9 years is between -$5 to -$25 billion dollars for flow rates equaling 130, 195, 260, and 390 million standard cubic feet per day (mmscfd).

Overview of Drilling Operations

Basically, there are just a few steps to drilling a well for the production of hydrocarbons. Initially, seismic data must be taken to determine the viability of the location to produce hydrocarbons. This is done with large trucks that have heavy hammers on them that pound the ground, sending seismic waves through the ground. The waves are reflected back to the surface from different layers of rock underground and received by geophones that are then converted into a map showing the reservoir underground.

After the seismic data is obtained, the well placement can be done. Drilling occurs afterwards. Drilling equipment, such as the drilling rig, is brought onto the well site and drilling occurs until the final depth is reached. Horizontal (directional) wells are drilled instead of traditional vertical wells because this allows for more production sites to exist in the well.

After the well is drilled, logging is done in the well to determine the composition of the underground layers. Casing is cemented into the well and perforated to allow for the reservoir to be producible without affecting other subsurface layers, especially the water table underground.

Finally, production equipment is installed on the surface to allow for the gas and water being produced to be processed and prepared for transport. Also, the valves on the surface allow the operators to control the pressure in the well.

Drilling Locations

The actual field that is going to be produced is on the western coast of the peninsula. This location was chosen because it is thought to be the location of permafrost and or conventional reservoirs (Diver). This is significant because it has been proven that most gas hydrates exist above already existing conventional reservoirs. This fact has been found to be true in Northern Russia and in Alaska. The area that is going to be explored for natural gas hydrates measures about 3500 square miles. Current research being performed in the area of natural gas hydrates on the North Slope of Alaska and the Mackenzie Delta of Canada show that hydrates can be located by shooting seismic data. Although it has been found that seismic data can sometimes be inaccurate, if it is shot with the correct frequency, it is the most accurate indirect way of finding their location. For this reason, a seismic analysis will be performed over this entire area. The cost of the seismic, based on a three square mile block costing $30,000, would come out to be $35 million. There will be a 5 man geological team working on the project. It is estimated to take five to seven week and cost $54 million (Mansingh and Melland). There are going to be multiple different drilling locations on the peninsula. Table 1 displays the number of locations that would have to be built and the number of wells that will need to be drilled for each flow rate.

Needed Production (MMscfd)	130	195	260	390	780
Number of wells	147	221	294	442	883
Number of locations	37	55	74	110	221

Table 1: Number of wells and locations needed

The location of the drilling sites starts at the western edge of the entire location. From that location, the locations will be placed in a triangular pattern around the first well, and then the triangle will be filled in to make a rectangular configuration. Then another triangle will be built around the already finished locations, and the process will continue. The following map, **Figure 3**, shows the location of the drilling pads (red dots), the area in which rights to drill have been granted (red boundary), and the first drilling location (white dot).

Figure 4: Map of Drilling Locations and Gathering System

Methane Hydrate Dissociation and Production Modeling

There are numerous ways that methane hydrates can be broken down and produced from a hydrate formation. Halliburton published a patent that describes using thermal injection in conjunction with depressurization. (Chatterji) This involves pumping methanol and ammonia into a well, allowing them to react, and injecting the mixture into the fractured formation. This is then subsequently pumped back out, allowing the heat of reaction to melt some of the hydrate underground. Also, with pumping out the mixture, the pressure begins to lose pressure, allowing for hydrate dissociation.

Depressurization is another method of producing methane hydrates. According to Pooladi-Darvish, the most economical method of producing natural gas from gas hydrates is through depressurization. After the well is perforated and stimulated, the surface valves are opened to allow the pressure to decrease in the well. This lowers the pressure in the reservoir to below the equilibrium pressure, allowing for dissociation.

As the hydrate breaks down, natural gas is evolved. This gas becomes producable. However, with the dissociation of hydrate, the ice is melting into water. This water is also produced from the reservoir as the gas is produced.

The Wiggins and Shah model describes how the pressure inside a hydrate reservoir changes over time for a constant gas flow rate. Other models were considered, but the Wiggins and Shah model considers changes in both distance and time. It is also a function of the distance from the wellbore. The model is given by the following equation with the variables listed below:

$$p_I^2 = p_o^2 + \frac{q_{sc}\mu_I Z T p_{sc}}{2\pi k_I h T_{sc}}\left[EI\left(-\frac{r^2}{4\alpha_I t}\right) - EI\left(-\frac{R^{*2}}{4\alpha_I t}\right)\right] \tag{1}$$

R* is the dissociation front determined by:

$$R^* = 2\sqrt{\alpha_\mathrm{I}\lambda t}$$

Where λ is determined by the solution to the following equation.

$$\frac{q_\mathrm{sc}}{\pi h}\left[\exp(-\lambda)\right] = 4\phi S_\mathrm{H} B_\mathrm{H} \alpha_\mathrm{I} \lambda$$

The Wiggins and Shah model is derived from the continuity equation to determine the pressure profile both within the dissociated and undissociated zones. It utilizes dissociation kinetics to determine at what pressure the hydrate dissociates. The equation for the hydrate dissociation is given by:

$$K_{\mathrm{d}}(p_{\mathrm{eq}} - p_{\mathrm{o}})^{n} = B_{\mathrm{H}} \frac{p_{\mathrm{sc}}}{RT_{\mathrm{sc}}} \frac{\mathrm{d}R^{*}}{\mathrm{d}t} = B_{\mathrm{H}} \frac{p_{\mathrm{sc}}}{RT_{\mathrm{sc}}} \sqrt{\frac{\alpha_{\mathrm{I}}\lambda}{t}} \qquad (2)$$

Where:

- K_d is the dissociation constant
- P_{eq} is the equilibrium pressure
- P_o is the dissociation pressure
- B_H is the gas-to-hydrate ratio
- P_{sc}, T_{sc} are the pressure and temperature at standard conditions, respectively
- R is the universal gas constant
- α_I is the hydraulic diffusivity constant = $k/\varphi\mu c_t$
- λ is the transcendental equation parameter
- t is the amount of time

The assumptions for the Wiggins and Shah model are:

- Radial flow
- Homogenous and isotropic reservoir with constant thickness and porosity
- Negligible gravity effects
- Pressure dependent c_t and μ evaluated at average pressure
- Isothermal hydrate dissociation with no volume change
- Hydrate dissociation at an interface between the dissociated and undissociated zones only
- Gas phase in dissociated region only
- No effect of dissociated water on gas flow

The limitations of the Wiggins and Shah model are:

- The model cannot simulated high flow rates
- Cannot be used with irregularly shaped reservoirs

An empirical formula relating equilibrium pressure and temperature (Nazridoust) is given as:

$$\ln(P_{eq}) = -7657.3\left(\frac{1}{T}\right) + 33.87 \qquad (3)$$

Where:

- $P_{dissociation}$ is the dissociation pressure of the methane hydrate, psi
- T is the temperature in the formation, K

Figure 4 shows how the dissociation pressure changes with temperature.

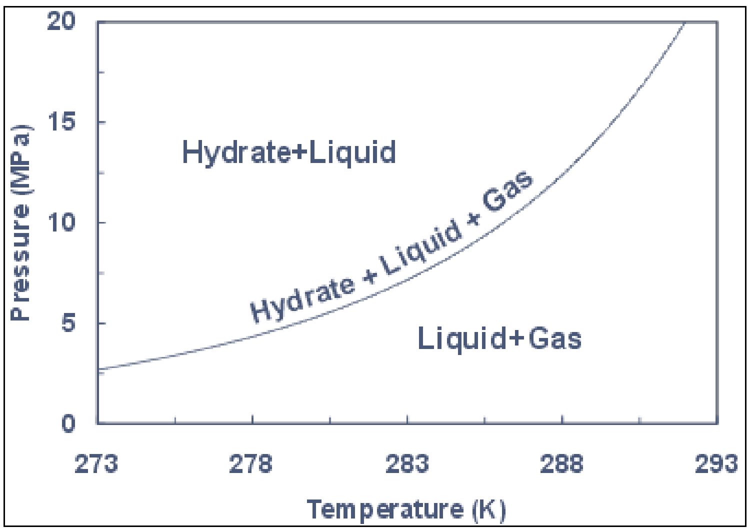

Figure 5 - Trend of dissociation pressure versus temperature.

Figure 4 shows that as the temperature increases, the pressure that hydrates will dissociate increases. Therefore, at higher temperatures, less depressurization is required to dissociate the hydrates. However, at constant temperature, depressurization is required to dissociate the hydrates. Since the temperature of the formation does not change with time in a purely depressurization method of production, the more the pressure can be lowered in the well, the more effectively the hydrates can dissociate.

The following figures show how the reservoir pressure profile changes from 0.1 to 20 years. The dissociation front grows further away from the wellbore over time. The pressure profiles are taken at 0.1, 1, 2, 5, 10, and 20 years.

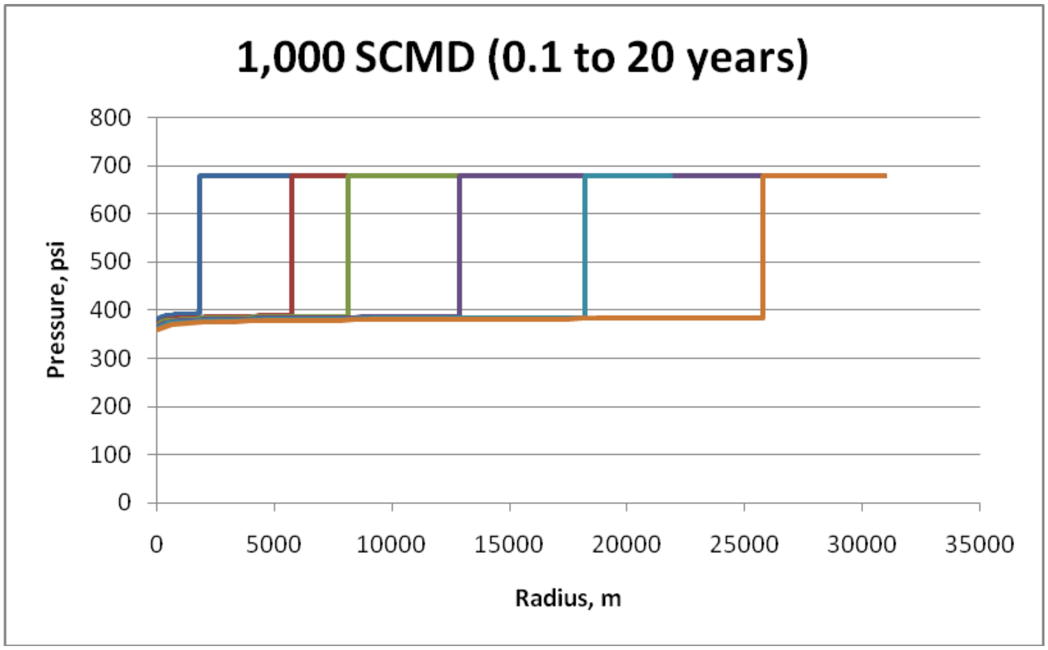

Figure 6 - Reservoir pressure profile for a constant flow rate of 1,000 SCMD.

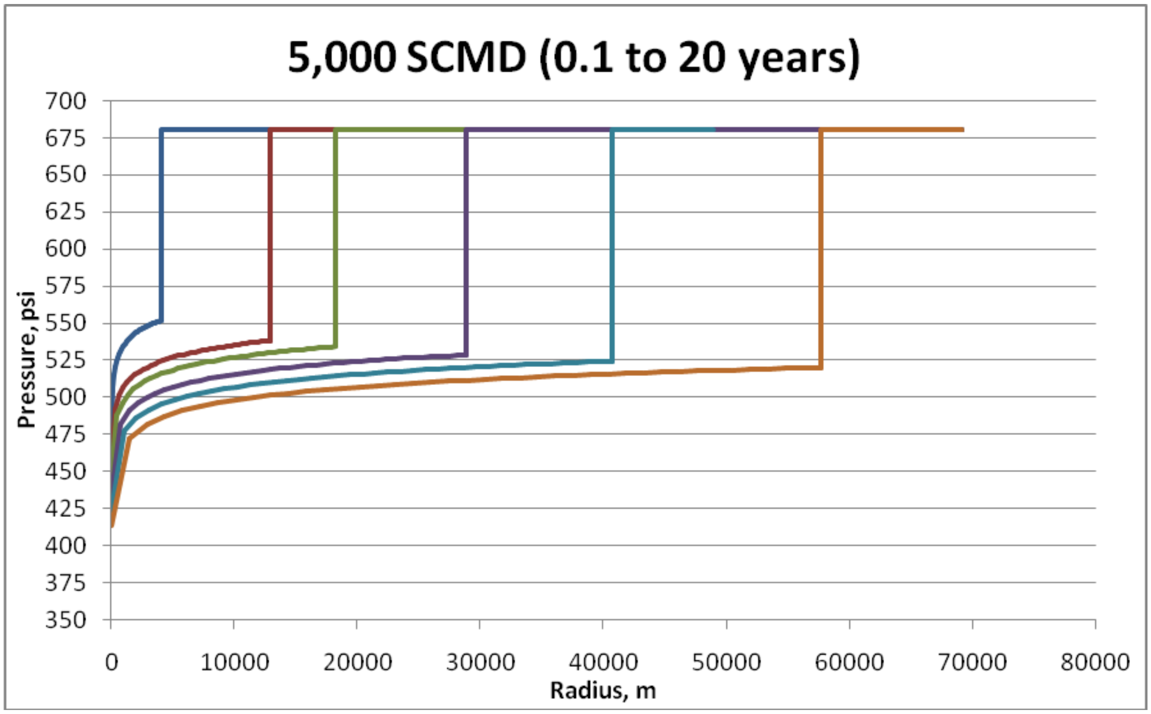

Figure 7 - Reservoir pressure profile for a constant flow rate of 5,000 SCMD.

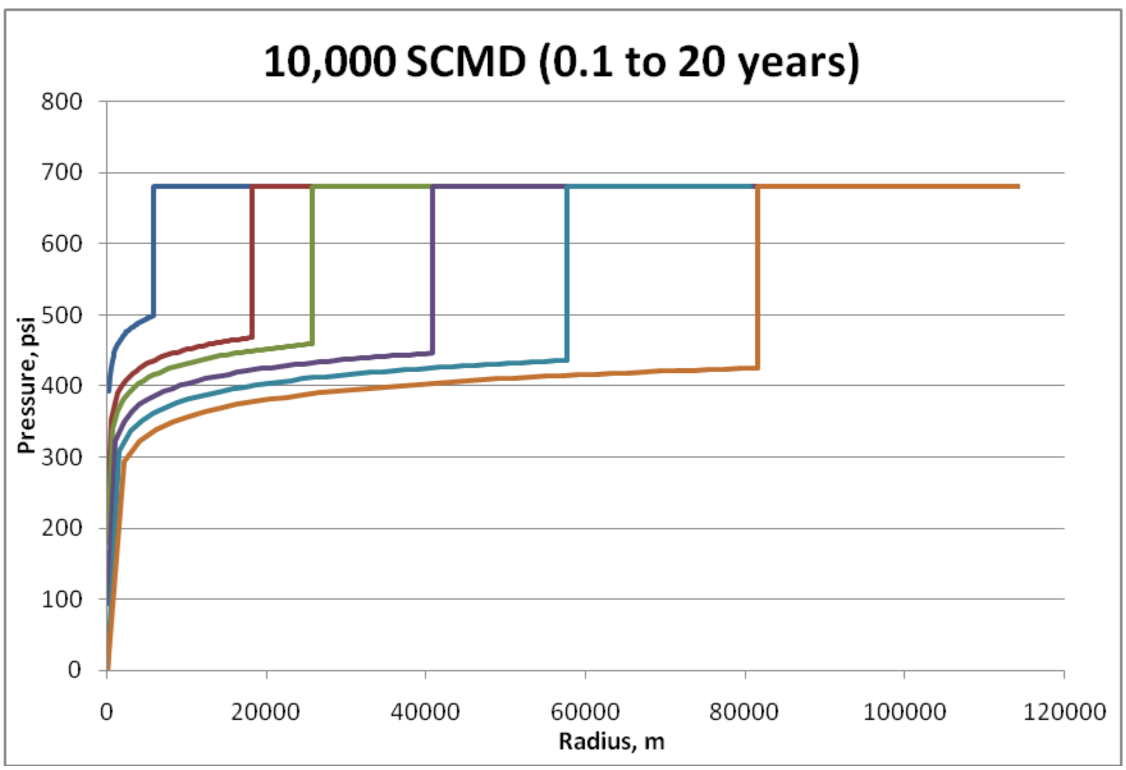

Figure 8 - Reservoir pressure profile for a constant flow rate of 10,000 SCMD.

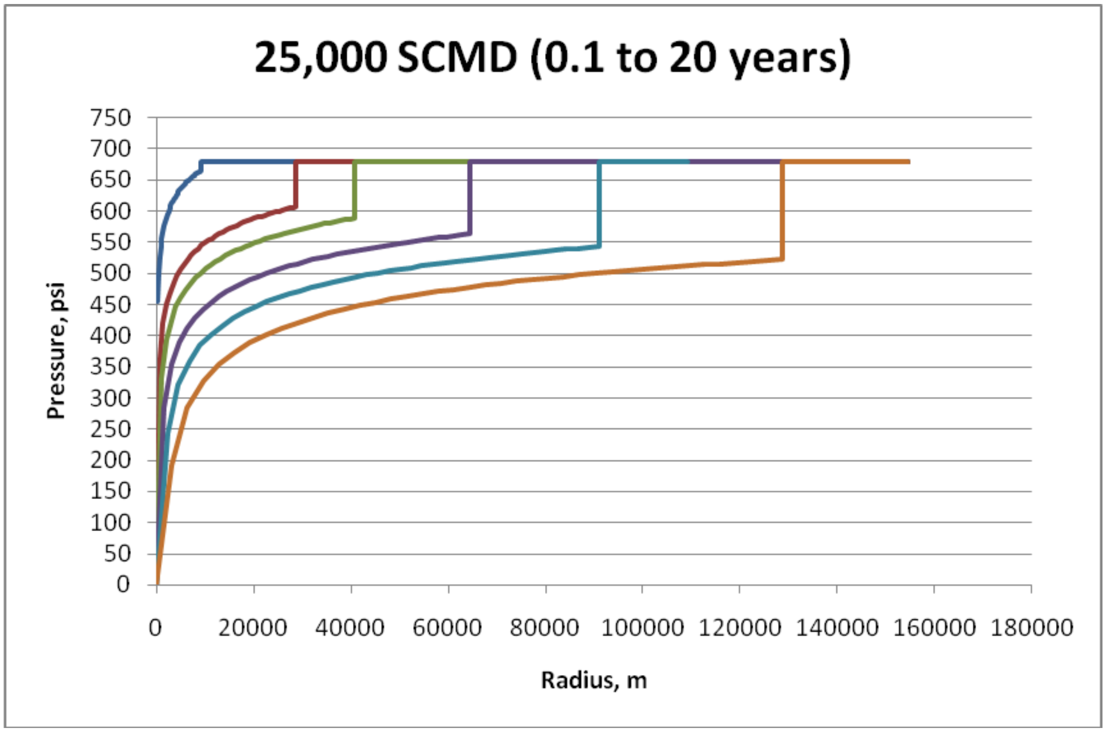

Figure 9 - Reservoir pressure profile for a constant flow rate of 25,000 SCMD.

After 25,000 SCMD flow rate, choke conditions appear in the reservoir and the model is not designed to model choke flow. To determine if the reservoir limits the maximum flow overall, the flow in piping must be determined. It can be seen in **Figure 9** that the maximum flow rate in the piping is far greater than the flow rate in the reservoir as given by the Wiggins and Shah model. Therefore, the reservoir is the flow-limiting factor and choke conditions must be modeled in the future to determine the true maximum flow rate in the reservoir.

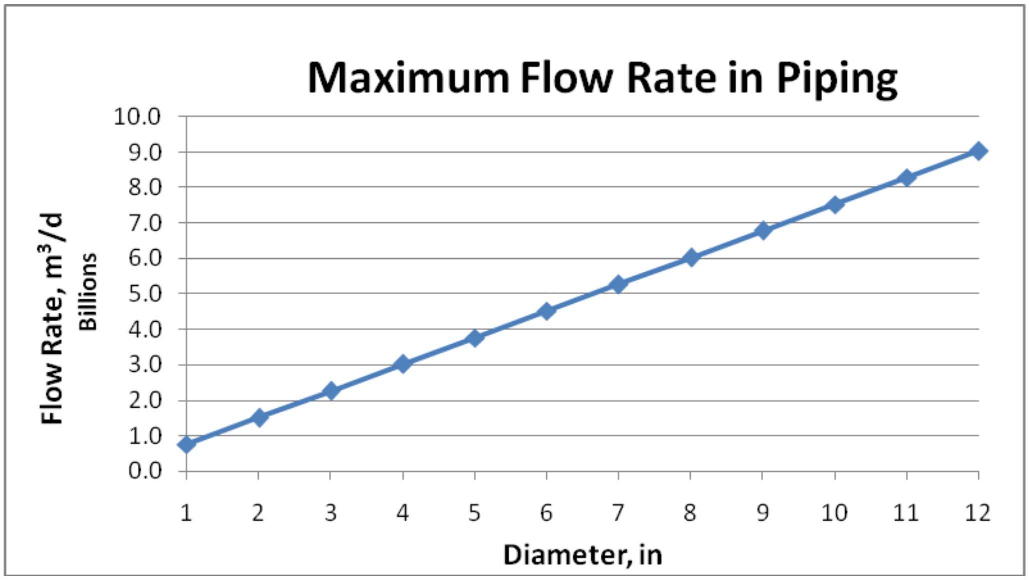

Figure 10 - Maximum flow rate of gas in the pipe leading to the surface.

Wellhead Facilities

Now that the gas is being produced, the proper equipment needs to be put at each facility. The locations will consist of four Christmas tree devices which house the choke and valves that control the flow of the well (Figure 6), two vertical 3-phase separators (Figure 7), and a compressor.

Figure 11: Example of Christmas tree device

Figure 7: Example of vertical 3-phase separator

It is not necessary to have a separate dehydration facility because the gas entering the pipeline is assumed to be the minimum pipeline quality gas, and a dehydration unit was included in the liquefaction facility since all water must be removed before the gas can be liquefied. The separator that will be used was designed using the gravity settling theory, which states that "the liquid drops will settle at a velocity determined by equating the gravity force on the drop with the drag force caused by its motion relative to the gas phase" (Arnold, pg104). The equations that associated with the gravity settling method were as follows:

$$d^2 = 504\left(\frac{TZQ_g}{P}\right)K \qquad K = \left[\left(\frac{\rho_g}{\rho_l - \rho_g}\right)C_D\right]^{1/2} \qquad d^2 h = \frac{t_r Q_l}{0.12}$$

where,

d = diameter of the separator in inches
T = operating temperature in °R
Z = gas compressibility
Q_g = gas flow rate in million standard cubic feet per day
P = operating pressure in pounds per square inch (absolute)
K = constant that depends on the gas and liquid properties
C_D = drag coefficient
d_m = liquid drop to be separated in microns
ρ_g = density of gas in pounds per cubic foot
ρ_l = density of liquid in pounds per cubic foot
h = height of liquid volume in inches
t_r = retention time in minutes
Q_l = water flow rate in barrels per day

The following table summarizes the equipment specifications, the number of each per location, and the price. Note that the equipment was designed to handle that highest possible flow rate, estimated at 3.4 MMscfd, of four wells producing per pad.

Equipment	Specs	Number of Each	UOM	Cost
Christmas Tree	Max P: 10,000 psia	4	MM$	$0.20
Vertical 2-phase separator	Flow rate: 100 MMscfd	2	MM$	$0.15
	Diameter: 5.3 m			
	Height: 8.5 m			
	Volume: 326 m^3			
Compressor				
Pad 1	437.77	1	MM$	$0.88
Pad 2 - ?	6771.51	1	MM$	$13.54

Table 2: Surface Equipment Specifications and Cost

The total cost to build a facility is $2 million for the first pad, and then $14.6 million for the ones after that. The reason the first is cheaper is because the gathering facility is only one mile away from the first production site. The operating cost of the surface equipment is assumed to be 18% of the capital investment.

The gathering system was created so that money could be saved on extra pipeline. Each of the facilities will be tied to the facility that is closest on the way to the main gathering facility. Figure 8 shows how the system will be designed.

Figure 8: Gathering system layout

Transportation Options

Now that it is known that the hydrate in Kamchatka can be produced and a production curve has been established on a per well basis, an analysis can be done to establish if it is more profitable to transport natural gas from Kamchatka to sales. The following method was used to look at the profitability of using LNG or a pipeline. The LNG will be delivered to Japan, and pipeline will deliver gas to Magadan, Russia and then to Blagoveshchensk, Russia. If the pipeline proves to be profitable, then it will be extended into China at a later time.

Liquefied Natural Gas

The first option that is going to be examined is Liquefied Natural Gas, or LNG. It is becoming a world leader in transporting stranded natural gas; therefore, it is logical to consider the use of it in the transportation of the stranded natural gas in Kamchatka. There are many aspects of the LNG process that must be analyzed to develop the economics of an LNG venture. The LNG value chain is as follows:

1) Gas Reserves/ Production
2) Liquefaction
3) LNG Shipping
4) Regasification and Storage
5) Market

The first step in the value chain was addressed earlier in this paper. Now the rest of chain will be analyzed.

Liquefaction Facility

The liquefaction facility is a complex and large facility. It should be built next to a waterway so that the LNG can be loaded and transported over long distances efficiently. Figure 9 shows the actual location, the purple dot, of the liquefaction facility on the Kamchatka Peninsula.

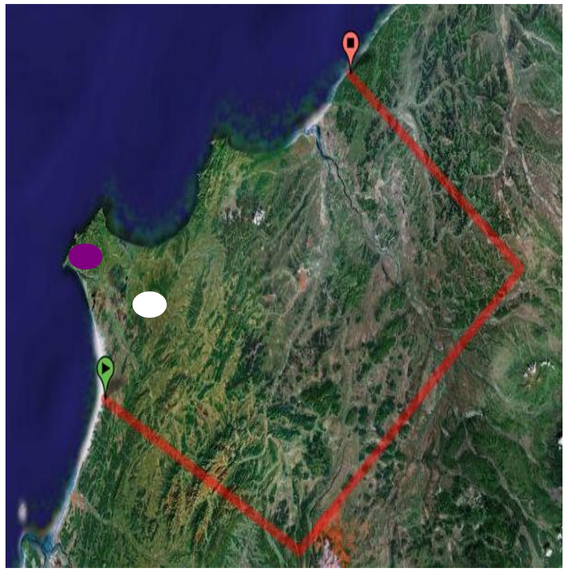

Figure 9: Liquefaction facility location

There are many different types of liquefaction processes currently being employed in the world, but the process that this analysis is based on is the ConocoPhillips Optimized Cascade (**Figure 10**).

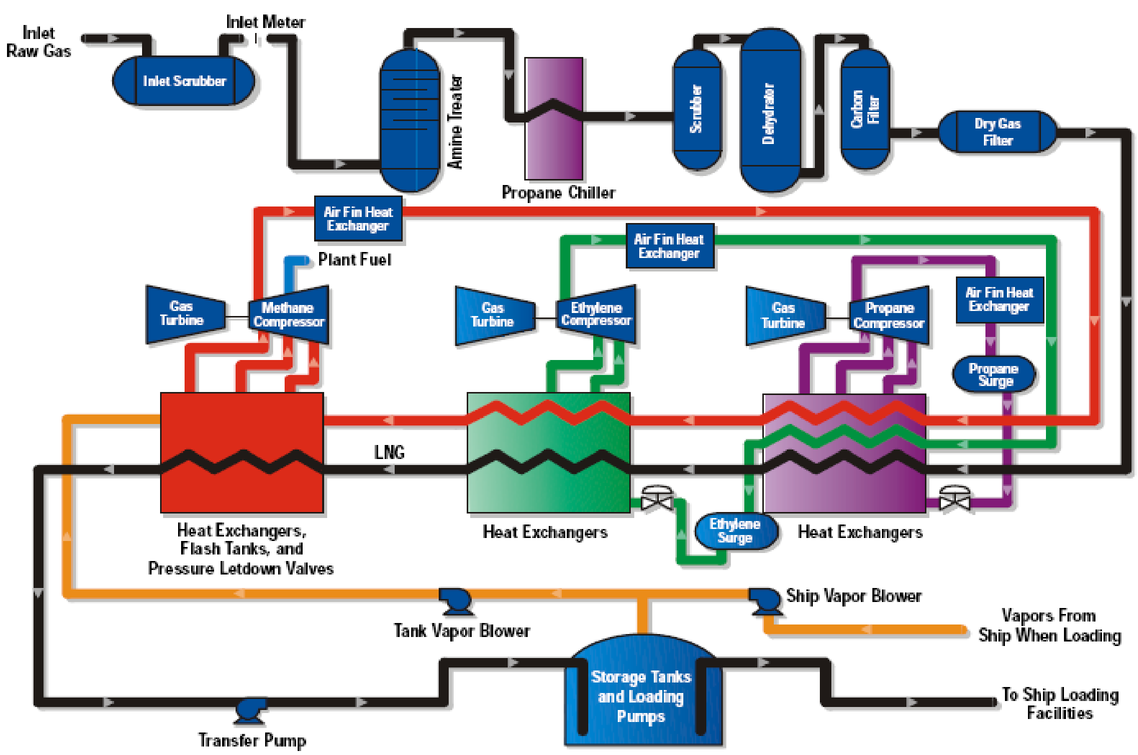

Figure 12: ConocoPhillips Optimized Cascade Process

The first part of the process is to remove contaminants such as water, CO_2, and mercury. Next, the process utilizes three pure refrigerants. The refrigerants used are propane, ethylene, and methane. At each refrigerant stage in the process, there are two to four pressure levels per cycle. The temperature range for each stage is (Chiu, Dr. Chen-Hwa):

Refrigerant	**Temperature Range**
Propane	Ambient to -30°C
Ethylene	-30°C to -90°C
Methane	-90°C to -160°C

All of the cycles are closed loop except for the methane cycle. By leaving this cycle open, the efficiency of the process increases. ConocoPhillips can now build a facility for approximately $225/tpa plus indirect costs (COP Website). The total cost for the four different flow rates are as follows:

Liquefaction Facility Capacity (mtpa)	Natural Gas Supply (MMscfd)	Cost of Facility (MM$)	Operational Costs (MM$/yr)
1	130	$871	$157
1.5	195	$1,306	$235
2	260	$1,742	$314
3	390	$2,613	$509

Table 3: Liquefaction facility costs

The total cost and the operational cost was obtained for an economic analysis on an LNG facility (Seddon).

This process was decided on for a variety of reasons. It was chose to reduce the risk involved with unsure gas flow rates because the plant can be turned down to 10-15% capacity unlike the other processes which can only be turned down to 40% capacity before having to shut down completely. It has also been known to be more environmentally friendly, have minimal space requirements, and the operation tends to be easier since pure refrigerants are used in the process.

Shipping

The delivery of LNG from the liquefaction facility located on the western coast of Kamchatka to the regasification facility in between Aomori and Morioka, Japan is based on the use of LNG tankers that have a capacity of 120 to 149 thousand cubic meters. The capacity of each of the ships for the different flow rates does not account for losses. The boil-off rate of the LNG is 0.13% per day (Hubbard). This will have to be taken into account when the cash flow is calculated. The average cost of a 140 thousand cubic meter LNG ship is $160 million (EIA, The Global). The size of the ships changes with increasing LNG capacity, but stays within the normal range of LNG tankers being built currently (EIA, The Global). The operational costs remain the same for each of the ships though because they are traveling the same distance. **Table 11** shows the operating costs for one ship.

Shipping			
Operation Costs			
Speed (18 knots)	1 knot = .869 mph	15.642	mph
Distance to Japan		1600	miles
Sea voyage time		4.3	days
Delay		3.0	days
Load		2.0	days
Unload		2.0	days
Total Trip	One Way	11.3	days
	Round Trip	22.5	days
Cost of Trip	One Way	$619,411.63	
	Round Trip	$1,238,823.25	
Total Daily Cost		$55,000.00	

Figure 13: Shipping Operational Costs

The sea voyage which is approximately 1,600 miles was calculated to take a little over 4 days, but since weather can be a problem when traveling by sea in this area, 3 days were added for delay time. After adding 2 more days each for loading and unloading, the total travel time of a one way trip is 11 days. The total daily charter cost for a medium LNG tanker is $55,000-65,000. The total capital cost of the ships varies with each situation that was examined. The following table summarizes these costs.

Capital Costs	130	196	260	390
Capacity of Ship (m^3)	120000	120000	120000	140000
Cost of Ship (MM$)	$137	$137	$137	$160
Number of Ships	2	2	3	3
Capital Investment (MM$)	$274	$274	$411	$480

Table 4: Ship costs

Storage and Regasification Facility

The regasification facility that is being used in the economic analysis is a design that uses sea water to heat up the LNG to a vapor at 45°C (**Figure 10**).

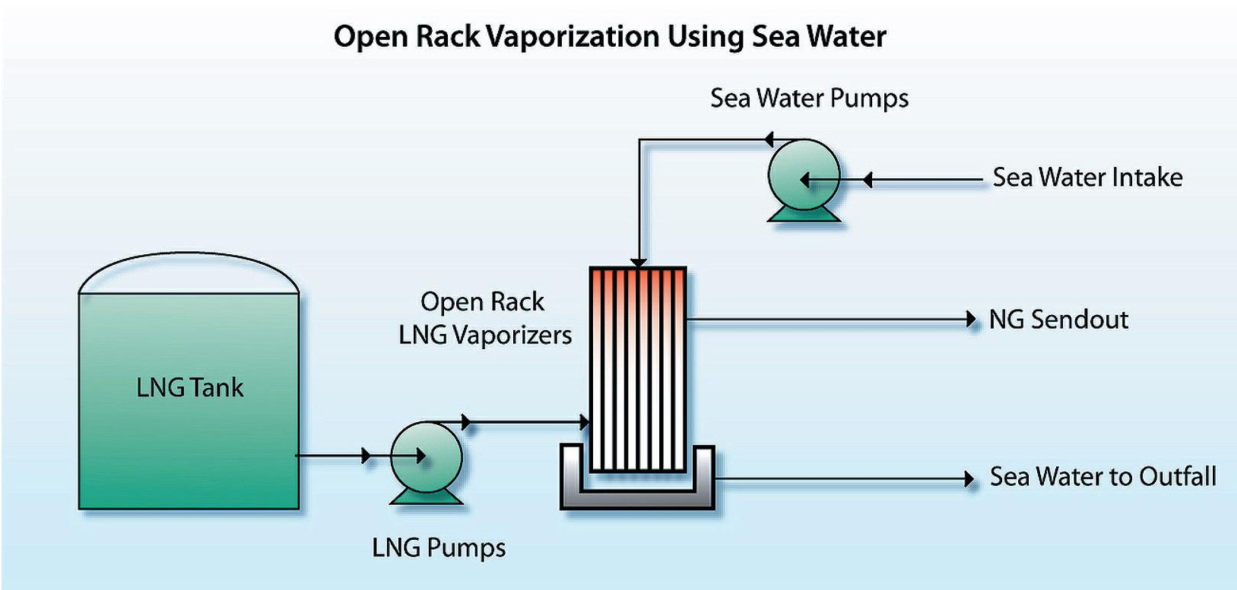

Figure 14: Regasification Facility

The sea water is used as the heating liquid for the open rack vaporizers. “Sea water vaporizers have low operating costs because they require no natural gas fuel consumption and have no emissions. However, they are climate sensitive.” (Eisentrout) As long as the water remains warm enough to heat up the LNG, this facility is the most profitable of older technologies, but recent plants are being built to regain some of the energy that was put into condensing the natural gas. The facility is going to be estimated at the same cost for each one of the cases. This is going to be done so that as more LNG is being shipped into Japan, the company can profit off the capacity. It also leaves room for expansion if Kamchatka production increases. The capital cost of a 3.3 mtpa facility including storage was estimated to be $434 million (Seddon, pg 259).

Pipeline to Magadan, Russia, and Blagoveshchensk, Russia

The pipeline is going to be going to Magadan, Russia on its way through to Blagoveshchensk, Russia so that the gas to be distributed to more of the region. If the pipeline is found to be economical, then it will be expanded to the Chinese sells market.

The pipeline is going to be made of steel on land and duplex stainless steel under water and the diameter of the pipeline will depend on the project. The pipeline will first be designed for the optimum diameter; then that diameter will be scaled up slightly so that the production project can increase over the pipelines lifetime. The pipeline was originally sized using the Panhandle B equation, but after analysis, it was realized that simulation software such as PRO-II could use a more complex analysis and arrive at more accurate answers where elevation and other factors could be taken into account.

The main aspect that is taken care of with this equation is the height change. This is extremely important due to the fact that around 260 miles of the pipeline will be underwater pipeline. The following map, **Figure 13**, shows the path of the underwater pipeline.

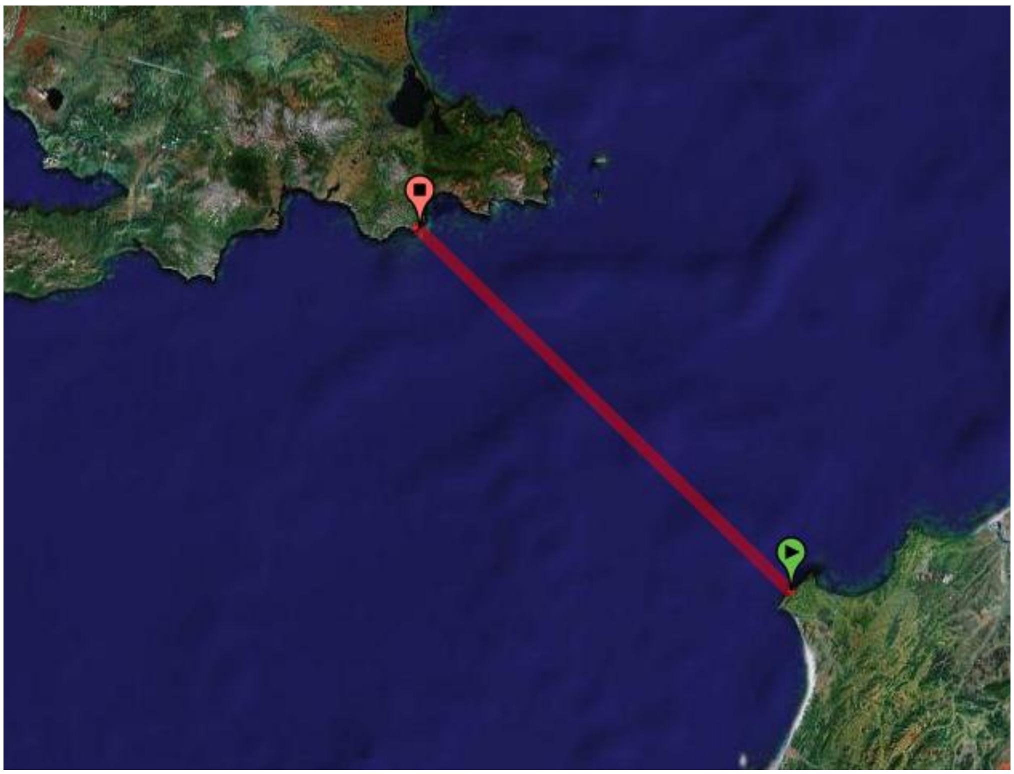

Figure 15: Underwater Pipeline (Google Maps)

The next map, **Figure 14**, shows the exact path that will be followed for the on shore pipeline.

Figure 16: On Shore Pipeline (Google Maps)

It is important to note that neither of these maps shows the elevation changes which are evident along the pipeline's path. They were taken into account when they were designed though. The following chart shows each pipe and the elevation that was taken into account using contour maps of the areas (Contour).

Pipe	Length (miles)	Elevation (in)
PI 26	20	64
PI 3	0.0568	-3600
PI 24	0.0568	-3600
PI 4	62.5	300
PI 22	62.5	300
PI 27	62.5	300
PI 28	62.5	300
PI 5	0.0473	3000
PI 23	0.0473	3000
PI 6	50	150
PI 29	50	150
PI 7	50	200
PI 30	50	-100
PI 8	50	200
PI 31	50	-50
PI 9	50	-50
PI 32	50	0
PI 10	50	100

Pipe	Length (miles)	Elevation (in)
PI 33	50	100
PI 11	50	50
PI 34	50	50
PI 12	50	-50
PI 35	50	-50
PI 13	50	-50
PI 36	50	-50
PI 14	50	50
PI 37	50	-50
PI 15	50	100
PI 38	50	100
PI 16	50	100
PI 39	50	100
PI 17	50	-100
PI 40	50	-200
PI 18	50	-200
PI 41	50	-200
PI 42	50	-200

Table 5: Pipe elevation simulation information

After the PRO/II simulation was ran with each of the flow rates. The pipe information and cost of each piece of pipe can be found in Table 6.

Flow rate	**MMcfd**	**130**	**195**	**260**	**390**
On Land					
Pipeline length	feet	7233599	7233599	7233599	7233599
	miles	1370	1370	1370	1370
Pipeline nominal diameter	in	24	24	24	30
Length	feet	7233599	7233599	3801599	7233599
Cost	$	$472.72	$472.72	$248.43	$626.01
Pipeline nominal diameter	in			30	
Length	feet			3432000	
Cost	$			$297.01	
Total Cost of Pipe Materials	MM$	$472.72	$472.72	$545.45	$626.01
Underwater					
Pipeline Length	ft	1363334	1363334	1363334	1363334
Pipeline nominal diameter	in	6	6	6	8
Length	feet	1100	1100	600	1100
Cost	$	$0.074	$0.074	$0.041	$0.004
Pipeline nominal diameter	in	16	24	8	24
Length	feet	681117	1362234	500	681117
Cost	$	$209.29	$583.21	$0.06	$291.60
Pipeline nominal diameter	in	24		24	30
Length	feet	681117		1362234	681117
Cost	$	$291.60		$583.21	$373.92
Cost of Pipe Materials	MM$	$500.97	$583.28	$583.31	$665.60

Table 6: Pipe information and costs

The pipeline is going to be run as a high pressure pipeline with the discharge pressure out of the compressors being 2000 psia. The pipeline is also going to be placed on supports because burying the pipeline is not possible in most of the region due to the mountainous terrain and the freezing temperatures. Compressor stations will be situated every 100 miles and the compression ratio is set to not exceed 2. This was chosen from previous specifications of a pipeline design assignment (Dr. Mallinson). There are also 100 sections over the length of the pipe and 3 safety valves in between each compressor. The total compressor costs were calculated on the basis of $2000 per horsepower needed (Menon). The total capital investment is as follows (Table 7) for the different cases:

Pipeline from Kamchatka to Blagoveshchensk, Russia					
Flow rate (MMscfd)		**130**	**195**	**260**	**390**
Pipe Materials Cost (MM$)	On Land	$472.72	$472.72	$545.45	$626.01
	Underwater	$500.97	$583.28	$583.31	$665.60
Labor Costs (MM$)	On Land	$175.13	$175.13	$183.11	$191.84
	Underwater	$671.45	$734.40	$734.40	$758.09
Other (MM$)	Compressors	$97.86	$252.05	$484.35	$660.80
Total Capital Investment (MM$)		**$6,124.50**	**$7,758.75**	**$9,363.44**	**$12,297.43**

Table 7: Pipeline Capital Investment (millions)

The labor costs were done in depth with information about how many people are needed to build the pipeline and what the productivity of the crew will be in relation to the surroundings (Page). The other costs that were involved in the calculation of the capital investment include:

- Right-of-Way (10%)
- Tariff ($1 per MMBTU)
- Meter Stations (5 @ $300,000 each)
- Valves (60 @ $100,000 each)
- Pipe fittings (elbows and tees)
- SCADA (3%)
- Environment and Permitting (15%)
- Engineering and Construction (15%)
- Contingency (10%)

Royalties

After all of the costs are calculated, another cost that must be taken into account is royalties paid to Russia for the gas. The royalties effect the two different transportation options in different ways. For the LNG option, the royalties must be made to Russia because the gas is being sold in another nation, but the royalties in the pipeline case will only be paid if the land that is being drilled on belongs to someone other than the government. Therefore, the case to look at closely is the LNG case. Figure 12 shows the effects of changing the percentage given back by royalties.

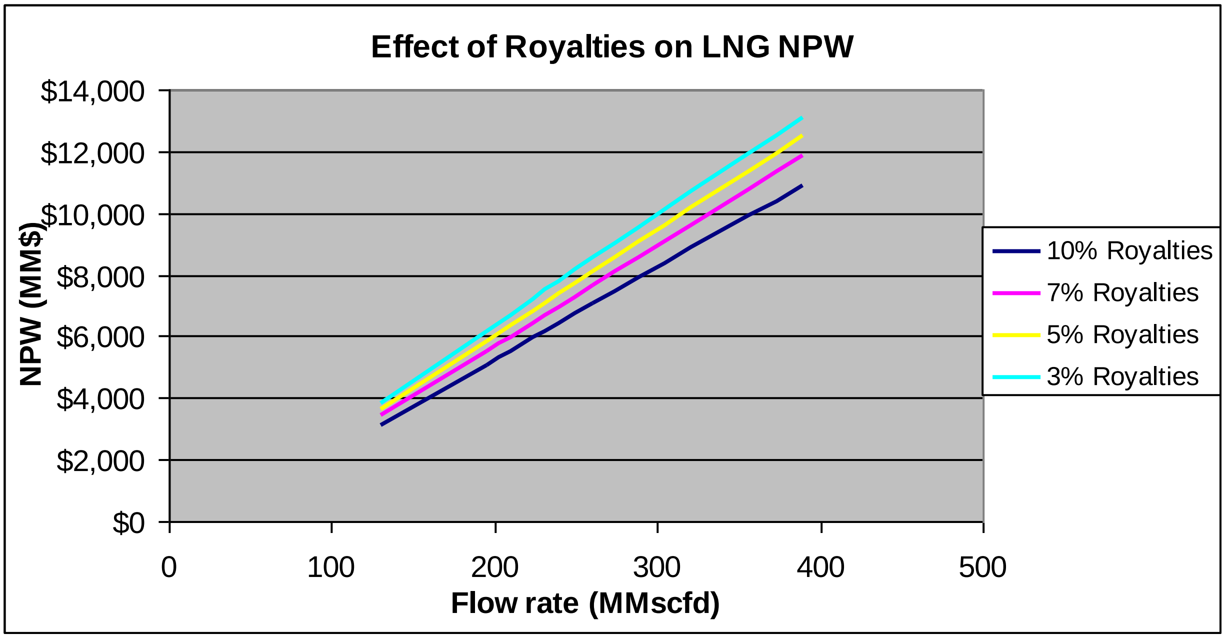

Figure 17: Royalties effect on NPW

The graph displays that royalties can cause a project to be unprofitable. Since the previous conclusion was made, it was decided to assume that 10% royalties was the maximum that Russia would ask for.

Gas Price

The next step in preparing an economic analysis is to calculate the profit gained from the selling of the natural gas. The amount of natural gas is known, but the selling price of natural gas is volital and can not be assumed to be constant over the time period of the project. The price of natural gas was estimated by using the commercial consumer U.S. gas prices from

1980 – Present (EIA: The Commercial). After these prices were analyzed, the percentage change was found along with the probability that the change would be positive. These values were then placed in the random Excel function to obtain the following graph of future gas prices.

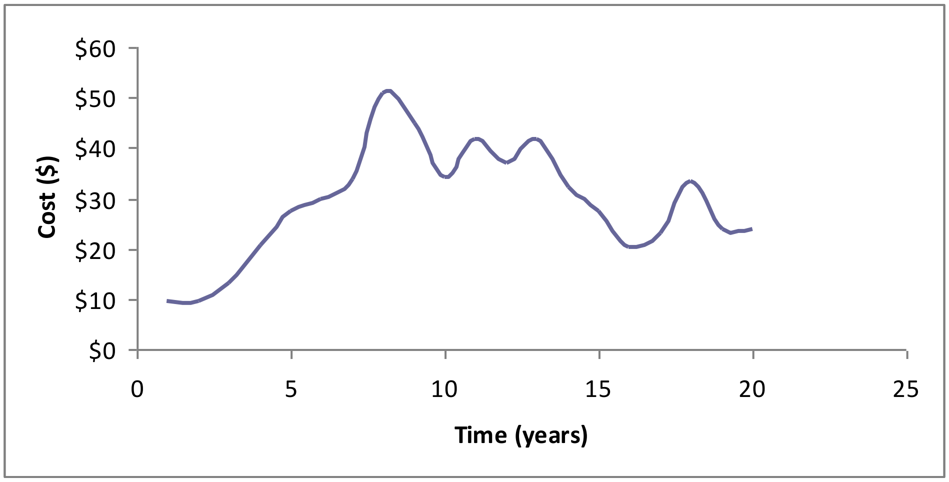

Figure 18: Future natural gas prices

Comparison

After the all of the costs were found for the LNG and pipeline option, they must be compared to each other to see which one is more profitable. First, the figure below shows how the costs to build the LNG facility compare to building the pipeline facility. It is important to remember that the drilling and facilities costs will be the same for each of the cases.

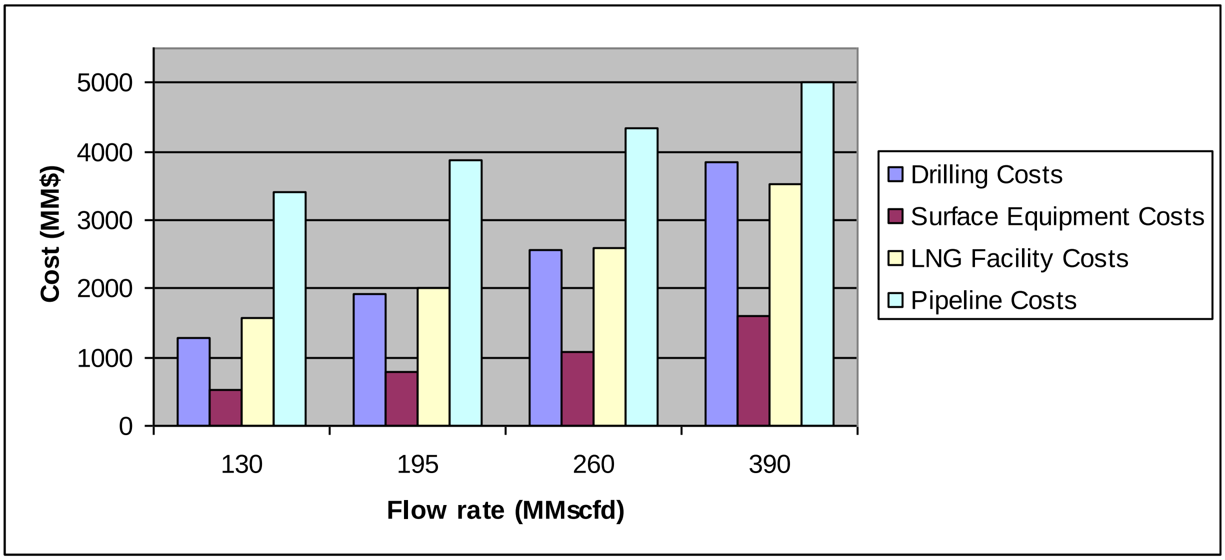

Figure 19: LNG and pipeline cost comparison

Figure 14 shows that the pipeline costs are greater. The only other costs are the operational cost that must be taken into account.

To complete the economic analysis of the two options, the net present worth (NPW) and return on investment (ROI) was then calculated for each of the cases. The life time of the project was assumed to be 29 years and the interest rate was assumed to be 10% for the NPW calculation. For the ROI calculation, an average ROI was taken to find the ROI for over the life time of the project and straight line depreciation was assumed. A summary of the NPW and ROI for all of the cases is below in **Table 8**.

Vertical Wells (883000 ft^3/d)		
Net Present Worth	**LNG**	**Pipeline**
130 MMscfd	$3,119	-$4,427
195 MMscfd	$5,078	-$3,384
260 MMscfd	$7,059	-$2,274
390 MMscfd	$10,927	$575
Return On Investment	**LNG**	**Pipeline**
130 MMscfd	20.58%	1.91%
195 MMscfd	22.31%	5.62%
260 MMscfd	22.98%	9.80%
390 MMscfd	23.91%	18.81%

Table 8: NPW and ROI Comparison

Through this analysis, it was found that the there are many projects that lead to a positive NPW and ROI. This is a good example of how both NPW and ROI need to be looked at because all of the LNG projects have a positive ROI, but when the NPW of the project is calculated, they are not positive. This is due to the fact that the following equations were used.

$$NPW = \sum_{n=k}^{n-1} \frac{CF_k}{(1+i)^k} + \frac{CF_n + WC}{(1+i)^n} - TCI \qquad ROI = \frac{Sells - Costs - Depreciation}{TCI}$$

These equations illustrate that the reason for the different signs of the NPW and the ROI is for the reason that the total capital investment (TCI) is subtracted in the NPW equation unlike the ROI equation were it is only divided by the ROI.

Further Study

After looking at the results of drilling vertical wells, it was decided to look at the possible economics of drilling horizontal wells instead. The assumption was made in the economics that the drilling of horizontal wells will require a 10% increase in price. It was also assumed that the daily production rate of each well will increase by 3 because each well would be producing from

3 zones instead of from one zone in the vertical well case. This means that the total daily natural gas flow rate that will be expected is 2.65 MMscfd for each well. This flow rate decreases the number of wells that have to be drilling and the number of locations with each location still containing 4 wells to the following:

Maximum production per well (MMscfd)	2.65			
Needed Production (MMscfd)	130	195	260	390
Number of wells	49	74	98	147
Number of locations	12	18	25	37

Table 9: Wells and Locations needed

The change in cost is directly related to the drilling costs. The following table shows the difference that is made in the NPW and ROI.

Horizontal Wells (2.6 x 10^6 ft^3/d)		
Net Present Worth	**LNG**	**Pipeline**
130 MMscfd	\$5,130	-\$1,216
195 MMscfd	\$7,956	\$1,315
260 MMscfd	\$10,901	\$3,992
390 MMscfd	\$16,683	\$9,973
Return On Investment	**LNG**	**Pipeline**
130 MMscfd	35.92%	7.93%
195 MMscfd	39.88%	17.03%
260 MMscfd	41.39%	21.85%
390 MMscfd	44.09%	29.82%

Table 10: Horizontal drilling NPW and ROI

If the extra money is put into drilling, then almost all of the cases are seen as profitable. Therefore, if horizontal wells can be drilled and produced by the model that is given earlier in the report.

Another Transportation Option

Another option was looked at to see if it was going to be profitable also. The other form of transportation that was looked at was gas to liquid (GTL) technology. This economic analysis was only completed for the vertical well case, but it was completed for both 30 year life times and 40 years life times with 10 years used for building the facilities and drilling the wells. The cost of the GTL facility is $934.5 million using the Synthol technology (Seddon, pg 231). The ships used to ship the GTL is half the cost of an LNG tanker (EIA). With these assumptions being made, the following economics were made (Table 11).

GTL Economics		
Net Present Worth	**30 years**	**40 years**
130	$3,107	$4,022
195	$4,817	$6,199
260	$6,448	$8,297
390	$9,829	$12,611
Return On Investment	**30 years**	**40 years**
130	22.76%	23.40%
195	23.33%	23.99%
260	23.30%	23.96%
390	23.60%	24.25%

Table 11: GTL economics

By looking at Table 11, it is easy to see that GTL is also a viable option for the transport of the natural resources from the Kamchatka Peninsula.

Conclusions and Further Analysis

One of the aspects that could be researched modeled more extensively is the dissociation of the wells and the design of the drilling and completion plans for the wells. By doing this, a method could possibly be developed to dissociate the hydrate at a quicker rate.

Another interesting aspect of this project is the disposal of the water produced from the well. This is a great idea for another project because there are a variety of different possibilities for disposal. This analysis would have to be completed by assuming that the water was of a specific purity, or by looking at all of the possible compositions of water that could possibly be produced.

The LNG and GTL option could also be further analyzed by designing the facilities in detail so that all prices are known to less uncertainty. Each option also has a variety of technology associated with building all of the pieces of the supply chain making is possible to analyze many options in depth.

Some options to look further into this topic would be to perform a detailed risk analysis of all of the uncertainties in each of the options. More detailed design could also be done so that a concrete plan could be completed.

A more detailed plan could also be put together. There are a variety of aspects that could be further analyzed so that the plan could be considered on a higher level of certainty, but with the analysis done in this report shows that each of these options have a large potential to be a positive economic venture for any company.

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