Chapter Four — LNG

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A. Introduction and Summary of Analysis of LNG Project Options

To assess whether TC Alaska's proposed pipeline from the North Slope to Alberta will sufficiently maximize the benefits to the people of Alaska and merits issuance of the AGIA License, the commissioners have evaluated several LNG project options. For many years, proponents of Alaskan LNG projects have highlighted specific benefits that may accrue to the people of the State of Alaska from an LNG project. LNG supporters have argued in comments that LNG offers superior benefits when compared to an overland project like the one offered by TC Alaska in its AGIA Application. Alaskans must have confidence that the right path is chosen for working to commercialize North Slope gas. Therefore, a close look at possible LNG options and comparison of those options with the TC Alaska Project is necessary before determining whether awarding a license to TC Alaska will sufficiently maximize the benefits to the people of Alaska.

LNG proponents assert that an LNG project offers superior economics and job opportunities. In particular, they identify an earlier in-service date and access to premium markets in Asia that combine to generate a higher NPV for Alaska. LNG supporters expect additional opportunities for jobs, compared with an overland pipeline into Canada, due to the operation of a liquefaction plant and the development of an in-state petrochemical industry that utilizes natural gas liquids.

This Chapter of the Findings discusses the analysis of possible LNG options and the benefits such options could offer to the state under AGIA—including the estimated NPV to the state and the likelihood of success of the LNG options. It also compares the benefits offered by the LNG options to the benefits offered by the TC Alaska Project.

The analysis of the LNG options shows the following:

- Positive NPV. Several LNG project configurations would likely provide the state with a positive NPV. Putting aside any likelihood of success issues or any comparison with TC Alaska's project, a properly configured and managed LNG project would be economic.
- Likelihood of Success Challenges. Several factors negatively impact the likelihood of success of the LNG project options. For example, an LNG project would be a much larger undertaking, involving not just a pipeline and gas treatment plant (GTP) but also a costly liquefaction plant, tankers to ship the LNG overseas, and the need to secure long-

term gas sales contracts with creditworthy customers. Each of these factors complicates the ability to finance and arrange an LNG project.

Besides the technological difficulties, the commercial complications are substantial.[1] There are simply many more links in the chain including acquisition of a firm, long-term gas supply, securing long-term firm purchase agreements, and negotiating for pipeline as well as tanker capacity (Appendix I, Section 9). In addition, the myriad commercial provisions must come together essentially simultaneously.

LNG options also face an additional hurdle because the Major North Slope Producers appear to continue to view an overland route to Canada as economically preferable. Finally, LNG options face several other significant barriers, including the lack of an obvious route to open access for explorers, and political/regulatory issues which could prevent an LNG project from obtaining the necessary export authorizations.

- After reviewing several LNG alternatives, the Y Line concept is clearly the best LNG option. It provides the most likely way to solve the problems of obtaining export authority by providing substantial deliveries of gas to North American markets in conjunction with the export project. It provides for the maximum market diversification options and allows for substantial sharing of essential pipeline and gas treatment costs, and also results in fewer technical elements (e.g., essential pipeline and treatment facilities) having to be designed/constructed/installed together at the same time as the liquefaction plant.

> The Y Line concept is clearly the best LNG option. It provides the most likely way to solve the problems of obtaining export authority by providing substantial deliveries of gas to North American markets in conjunction with the export project.

[1] As discussed in Appendix F, Section 2.1.4 and Section 2.4 of the Addendum, an LNG liquefaction terminal is more technically complex than just a pipeline project and subject to significant and material additional risks.

B. Background

For almost as long as Alaskans have discussed a natural gas pipeline, they have talked about transporting North Slope gas south along the existing Trans-Alaska Pipeline System corridor to a tidewater facility where it would be chilled into a liquefied natural gas (LNG) form, and then transported by ship to market. As far back as the 1970s, when an Alaskan LNG project sought necessary FERC (then Federal Power Commission) authorizations, to the mid-1980s, when the Yukon Pacific Corporation was first formed with the help of former Governors William Egan and Walter Hickel, the prospect of an LNG project has intrigued resource developers and Alaskans alike. Indeed, in 1975, Senator Ted Stevens sent out a questionnaire which received 45,000 responses. The question posed: "Do you support a trans-Alaska gas pipeline as opposed to a trans-Canadian line?" The results were: Yes—85%; No—8%; and Undecided—9% (TC Alaska Application 2007, page 4). Recent surveys appear to confirm this conclusion, showing that the concept of an "all-Alaskan" LNG line has enjoyed broad support among Alaskans for many years.

By the mid-1990s, two of the major North Slope producers, BP Exploration (Alaska) Inc. and ARCO Alaska Inc., began publicly discussing plans to begin an LNG project with the expectation that gas could be landed in East Asian markets by roughly 2007.

Like other North Slope gas commercialization options, including various sizes of overland pipelines routed through Canada and into North American markets, the economics of an LNG option have historically been stressed. The combination of abundant sources of affordable natural gas supply closer to consuming regions and the costs of steel and labor challenged every project's economic viability. In 1999, the Alaska Gasline Port Authority (Port Authority) was created as a municipal entity. It is comprised of the Fairbanks North Star Borough, the North Slope Borough and the City of Valdez, and was formed "to develop, build or cause to be built, …a project to monetize Alaska's North Slope natural gas which would include a trans-Alaska gas pipeline, liquefaction and gas processing facilities and related infrastructure for the transportation of North Slope natural gas to market…" (AGPA 2007)

In 2002 the Alaska State Legislature re-introduced and extended the Stranded Gas Development Act (SGDA). The Port Authority was among the interested parties that submitted an SGDA application for an LNG project as a prelude to negotiations with the state. Like other independent pipeline project proponents, the proposed Port Authority project was not supported by the administration of the time. Though rejected by then-Governor Murkowski in favor of

exclusive negotiations with the Major North Slope Producer consortium, the Port Authority continued to make the case publicly that it, along with all interested project sponsors, should be allowed a seat at the table. The Port Authority's argument, one embraced by many in the State of Alaska including then-gubernatorial candidate Sarah Palin, was that Alaskans stand to benefit considerably when developers and investors compete for the opportunity to monetize the state's resources.

Alaskans, both inside and outside the Alaska Legislature, recognized that preserving the state's options was essential to striking a fair deal with whomever would ultimately begin the project. The Port Authority and those supportive of its efforts were instrumental in trying to protect the state from becoming highly leveraged in gas pipeline negotiations conducted exclusively with Alaska's three largest producers. After the failure of the SGDA negotiation process, the legislature passed AGIA to create an open and competitive process that secured state needs and thereby ensured that state "gives" were made in exchange for essential state "gets."

The story of resource development in Alaska is one that has been told using words like "partnership" and "cooperation." Equally important, however, are the principles of competition and fairness. Without a comparative analysis between the economics of an integrated pipeline like that proposed by the North Slope Producers and the independent pipeline projects, whether overland to Canada or liquefied at Alaskan tidewater, Alaskans could not be expected to make an informed decision about how to cast their lot for the next several generations. In many ways the tireless efforts of Alaskans like the Port Authority and its supporters laid the groundwork for the competitive process developed through AGIA.

In many ways the tireless efforts of Alaskans like the Port Authority and its supporters laid the groundwork for the competitive process developed through AGIA.

1. Selection of LNG Options for Analysis

Both the Port Authority and Little Susitna Construction Company submitted LNG-based proposals under the AGIA process. Neither the Port Authority's LNG project, nor that submitted by Little Susitna, are eligible for formal consideration under AGIA for the reasons documented in Appendix C. Nevertheless, the commissioners determined that the LNG option was so important to so many Alaskans that it merited consideration as a possible alternative.

Therefore, while not required under the terms of AGIA, a number of conceptual LNG project options were reviewed. The project configurations considered were based upon the only market

signal available: the project configurations for LNG submitted by AGIA applicants, including the Port Authority, Little Susitna, and TC Alaska. In the LNG analysis, the GTP and pipeline cost data developed from the analysis of the TC Alaska application (see Chapter 3 for discussion) were used to ensure an apples-to-apples comparison of costs and cost risk with the TC Alaska Project. Costs and cost risks for the liquefaction plant were developed by LNG project experts contracted by the commissioners. These were compared, for reference purposes only, with the cost figures developed by the Port Authority and Little Susitna. Thus, in their January 30, 2008 letter to the Port Authority, the commissioners stated that they "recognize the importance to the state of undertaking a thorough evaluation of [LNG] project options, and are committed to undertaking such an evaluation before determining whether a pipeline that goes through Canada will sufficiently maximize the benefits to the people of Alaska and merits issuance of a license." (Appendix C) The analysis greatly informed the overall Findings and Determination.

2. Analysis of LNG Options

AGIA requires a determination of whether a project being considered for award of the AGIA License sufficiently maximizes the benefits to the people of the State of Alaska (AS 43.90.180). Accordingly, under the supervision of the commissioners, the Technical, Commercial, Financial and Legal Teams—including London-based Gas Strategies Consulting, an experienced LNG consulting firm—conducted a thorough analysis of LNG project options. The analysis included a comparison between LNG project options and TC Alaska's Project. Two basic factors are critical to understanding that analysis: (1) the integrated nature of an LNG project, and (2) the fact that the primary market for Alaskan LNG supplies would likely be in Asia, not in North America.

LNG comprises a series of elements forming a delivery chain, all of which must be in place in order to have a viable project (Appendix I, Sections 2 and 7.2). These elements include one or more sources of supply (fields), feed pipelines, liquefaction plant, ships and access to regasification plants. The commercial arrangements linking each of these elements are interdependent and must all be agreed to simultaneously before any firm commitments to financing or construction are made. In practice all the agreements must be signed simultaneously. For Alaska that would mean long term North Slope gas supplies, a pipeline across the state to transport that gas supply, a liquefaction terminal located at tidewater and tankers to ship the gas to Asian markets. Unlike an overland pipeline in which shippers can simply sell gas into a very liquid market on a long or short term basis as suits their needs, the

LNG project sponsor(s) must negotiate long-term contracts for the sale of the LNG to customers, typically large utilities. Each of the elements in this chain must be completed successfully for an LNG project to proceed.

The likely market for an Alaskan LNG project is Asia.[2] (Appendix I, Sections 4.1 and 4.6) Japan (the world's leading LNG importer), Korea and Taiwan lack domestic gas supplies and currently import significant quantities of LNG. Because of the lack of domestic gas supplies, future growth in the energy needs of these markets is projected to result in a growing demand for LNG. China, India and other countries in Asia also are emerging as significant potential markets. By contrast, no LNG import terminals exist on the U.S. West Coast due primarily to local opposition; other legal barriers or economic challenges also exist to shipping LNG from Alaska to U.S. West Coast markets.[3] One LNG import terminal exists in Baja California in Mexico, although that is relatively small and has relatively limited uncontracted capacity, and as currently configured, could not fully accommodate the volumes of gas contemplated here. Moreover, the price that can be obtained for LNG in Asian markets, both currently and in the future, is likely to be generally higher than at the Mexican terminal or other North American terminals that might be constructed. (Appendix I, Section 4.3) Thus, the focus of the analysis here is on the Asian market, which provides higher prices and a higher NPV for sales of LNG than potential markets in North America.

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[2] The fact that both LNG applications under AGIA proposed the Asian Pacific as the market of choice further confirms this; see the ANGPA and LSCC Applications under AGIA at: http://www.dog.dnr.state.ak.us/agia/

[3] An additional consideration for any Alaska LNG project is the applicability of the "Jones Act" (coastwise merchandise statute, 46 U.S.C. App. § 883) to any shipments of LNG to an LNG terminal located on the west coast of the United States. The Jones Act may also be a factor in the instance of LNG shipments from Alaska to Canada or Mexico that may re-enter the U.S. market.

The Jones Act requires that any freight being transported between points in the United States, "either directly or via a foreign port," be transported on a ship built in and documented under U.S. laws and owned by persons who are citizens of the United States (Id.). Thus, any transportation of LNG from Alaska to regasification terminals along the United States' west coast would be required to meet these requirements for vessels and their ownership. The only exceptions to the statute are scenarios in which an entity transports its own freight between two terminals that it also owns (which would be unlikely in an LNG scenario), or in the instance of freight being transported to a foreign port, where the cargo is then manufactured or processed into another identifiably new and different product, and then is transported back to the U.S. Natural gas that results from the regasification of LNG would most likely not be considered such a "new and different" product to qualify as an exception to the Jones Act requirements.

Additionally, the statutory language ("no merchandise…shall be transported…between points in the United States…either directly or via a foreign port…") may be interpreted as also requiring any LNG shipped to a terminal in either British Columbia or the coast of Mexico, to comply with the Jones Act if such LNG were to be regasified and transported via pipeline back to the United States.

C. The LNG Project Options

There are an infinite number of potential LNG project configurations that could be considered. To analyze in-state LNG options, the state decided to base its analyses upon the LNG project configurations submitted by AGIA applicants, including the Port Authority, Little Susitna, and TC Alaska. It did so for two reasons. First, the AGIA process provided an important market signal. The resulting LNG applications reflected the judgment of project proponents who had taken the time and expense to submit applications around project configurations that they believed were best. Second, the AGIA process provided a reasonable source of reference data for the state's analysis.

The AGIA-submitted project configurations provided the basis for considering a number of different project sizes and in-service dates (including project expansions). The following LNG project alternatives, which will be referred to in these Findings as the "LNG project options," were analyzed:

- 4.5 Bcf/day Option: This option assumes a 4.5 Bcf/day LNG project using a 48-inch diameter pipeline from the North Slope to Valdez.[4]
- 2.7 Bcf/day Option: This option assumes a 2.7 Bcf/day LNG project using a 48-inch diameter pipeline from the North Slope to Delta Junction, and a 42-inch diameter pipeline from Delta Junction to Valdez.[5]
- 2.7 Bcf/day Expansion Option: One would not build a 42-48 inch diameter pipeline if the total volume of LNG that one contemplated selling was restricted to 2.7 Bcf/d. This base pipeline design makes sense only if one expects future expansions. Accordingly, the state considered a variation of the 2.7 Bcf/day project in which a capacity expansion to 4.5 Bcf/day occurs three years after the initial in-service date. This provides an optimistic ramp-up scenario, but one that is more realistic than the initial 4.5 Bcf/d case. (Appendix I, Section 2)

[4] This scenario is similar to the volume and pipeline facilities proposed in Little Susitna's incomplete application. In addition, the cost and schedule uncertainty associated with a 4.5 Bcf/d project, configured (as was the Port Authority's) with a 48" pipeline to Delta Junction and a 42" pipeline from Delta Junction to Valdez, was also assessed; see "Case 1b" as discussed in Appendix F, Addendum A and Exhibit D, LNG Options Analysis. However, we did not run project economics on this case, as its costs were marginally greater than the other 4.5 Bcf/d, 48" pipeline case that we did model.

[5] This scenario is similar to the volume and pipeline facilities proposed in the Port Authority's incomplete application.

- Y Line Option: The state also analyzed a 4.5 Bcf/day project to Alberta (like the TC Alaska project), expanded to 6.5 Bcf/day capacity through the addition of a 2.0 Bcf/day expansion from the North Slope to Delta Junction and addition of a pipeline to Valdez after the initial in-service date of the project.[6]

Direct comparison of the TC Alaska 4.5 Bcf/day project and an LNG project is in some ways best facilitated by considering the 4.5 Bcf/day LNG project. Volumes are the same, and project timing is similar. This brings the comparative net backs into focus. Accordingly, we consider the 4.5 Bcf/day LNG project configuration as the LNG Base Case. However, the LNG Base Case overstates the NPV that the state might achieve through an LNG project, because such large initial volumes cannot be practicably brought to the Asian Pacific market (Appendix G1, Section 7.12.4).

The LNG Base Case, as modeled, is highly unlikely to occur. It is very unlikely that such large volumes of LNG could be brought to the Asian Pacific market all at once; LNG volumes would very likely have to be phased in over eight to ten years (Appendix I, Sections 2 and 6.2). This is due to the Asian market's inability to absorb an incremental 4.5 Bcf/day as quickly as the very liquid AECO (North American) market.[7] This ramp up was not directly modeled in the NPV analysis, but it is a reality.

Further, the 4.5 Bcf/day scenario is also made unlikely because Asian Pacific buyers typically require certification of twenty years' worth of reserves (Appendix I, Section 4.6). In addition, if Point Thomson gas were not available to be committed to the LNG project, then twenty-year contracts at even 3.5 Bcf/d would still require new gas reserves to be brought on-line, raising questions about the viability of a project this size (Appendix G1, Section 6).

Before discussing the 4.5 Bcf/day LNG Base Case, we will address in the following section the unique issues raised by the Y Line LNG option.

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[6] The cost and schedule uncertainty associated with an initial 6.5 Bcf/d Y Line project was assessed, along with a later Y Line expansion; see "Case 2" and "Case 2a" as discussed in Appendix F, Addendum A and Exhibit D LNG Options Analysis. Such a project configuration is consistent with TC Alaska's Application (see Application at 2.2.3.14). However, economics were run only on the Y Line expansion, rather than an initial 6.5 Bcf/d Y Line project. On balance, proved gas resources do not appear sufficient to support 6.5 Bcf/d at initial operations.

[7] For discussion of AECO Hub market liquidity, see Appendix G2.

D. The Y Line Option

In its application, TC Alaska has stated a willingness to consider constructing, in addition to its mainline to AECO, a lateral to the Valdez area if market demand for a Y Line option is expressed by potential shippers during an open season. Specifically, TC Alaska states that "[w]hile its proposal does not include an LNG option, [it] is willing to consider offering gas treatment and gas transportation services from Prudhoe Bay to an LNG terminal should Shippers commit sufficient volumes to support such services in the initial binding open season."[8]

As discussed by TC Alaska in their application, the Y Line option assumes a 48-inch diameter pipeline through Delta Junction to Alberta where it could be connected to the AECO Hub with an initial capacity of 4.5 Bcf/day, and a 30-inch diameter pipeline from Delta Junction to a liquefaction plant in Valdez with a capacity of 2.0 Bcf/day (TC Alaska Application 2007, Appendix D). TC Alaska offered to construct the 2.0 Bcf/day pipeline to Valdez as part of the initial Project if sufficient volumes were committed in an initial open season (TC Alaska Application 2007, page 13).

A Y Line option could be viable even if volumes for the LNG portion were not committed at the time of an initial open season. TC Alaska would have the commercial motivation to expand their Project facilities if, at some later date, a producer or group of producers wished to market their gas as LNG. But even if TC Alaska did not wish to facilitate an LNG Y Line, TC Alaska would be required to expand the project as far as Delta Junction under AGIA's expansion provisions (AS 43.90.130). From there, given FERC interconnection policy (FERC 2000), a different sponsor could construct the Y Line lateral and necessary liquefaction facilities.

1. Benefits of the Y Line Option

This Y Line alternative would give Alaskans several distinct benefits. A Y Line could piggyback on, and enjoy the superior likelihood of success of, TC Alaska's proposed project to the AECO Hub. It could also, from a portfolio approach, provide superior economics for Alaskans. The optionality created by having a lateral which supplies an LNG project at Valdez could act as a "hedge" against the risk that pricing projections do not turn out as expected. Much in the way

[8] See TC Alaska Application, Executive Summary, p.5 and pp. 16-17. TC Alaska also provided, as part of its Application, a discussion of a study it performed of the Y Line option, and of related tariffs for the GTP and pipeline associated with that option. See TC Alaska Application.

that a diversified portfolio of several stocks is less risky than holding only a single stock, a Y Line would leave the state less exposed to the risk that the price in any one particular market would fall below expectations. A Y Line may also be attractive to gas producers who would prefer access to Asian markets. The factors that go into a producer's identification of a preferred market go beyond NPV. There may be significant strategic advantages to pursuing LNG that a particular producer may decide outweigh NPV considerations.

By working with TC Alaska, LNG proponents would also secure the benefits provided by AGIA for the pipeline and GTP components of the LNG project. These include open access and expansion provisions that would help encourage the maximum development of the state's abundant natural gas reserves on the North Slope. As explained later in this Chapter, absent an overland route to North American markets, an LNG project pursued outside of the AGIA process would probably not provide all the open access and expansion benefits mandated by AGIA.

The Y Line option would have another, related benefit: more jobs. A Y Line would create additional jobs needed to construct and operate the liquefaction plant at Valdez. In addition, the larger 6.5 Bcf/day project would require more exploration and development on the North Slope and would generate significant new employment. A Y Line would need producers and explorers to develop, in addition to the gas resources at Prudhoe Bay, other substantial resources located on the North Slope. The access and expansion provisions mandated by AGIA are essential to ensuring that such development does in fact occur.

A Y Line would also provide the state and its citizens with additional revenue. As discussed in the Commercial Team Report, a 6.5 Bcf/day Y Line would provide the state with a significant additional NPV on top of the NPV provided by TC Alaska's 4.5 Bcf/day project into the AECO Hub. While the NPV of the Y Line would not be as high as the NPV of a 6.5 Bcf/day expanded pipeline to AECO, a Y Line could, as explained above, be a more attractive option for some producers and would provide the state with a more diversified "portfolio" with less exposure to the risks of fluctuations in gas prices (Appendix G1, Section 7).

Ultimately, whether an overland project to AECO is expanded to transport additional gas through the AECO Hub or through a Y Line that supplies an LNG terminal in Alaska will be determined by a variety of economic, technical, regulatory, and political factors. This analysis takes no position regarding which of these two expansion options should be favored by the

State of Alaska. Indeed, the state's essential position is that the decision will likely best be made by the relevant commercial parties.

TC Alaska's statement of its willingness to listen to competitive market forces in determining whether the Y Line option should be pursued provides the state with an intriguing option. Given the additional obstacles facing an LNG project at this time in comparison with an overland route, in the commissioners' view the best way to increase the possibility of a future Alaskan LNG project is to encourage the initial construction of an overland route. Once an overland route is under development, the momentum created by that project may create the environment needed to overcome the additional barriers facing an LNG project. Once an overland pipeline project is under way or in place, the LNG project will be able to share the cost of the gas treatment facilities and pipeline from the North Slope to Delta Junction, and will not bear all of those costs alone. This fact alone also reduces the financing requirements related to the LNG project. Further, once Alaskan gas is flowing (or about to flow) into North American markets, the chances are higher that U.S. agencies will allow export of domestic energy supplies to foreign markets. Putting this as simply as possible, the best way to get an LNG project is to first get the TC Alaska overland project.

> The best way to get an LNG project is to first get the TC Alaska overland project.

E. Analysis of the NPV of the LNG Project Options

The calculation of the estimated NPV of the various LNG projects involves the same basic factors discussed in Chapter 3 with respect to the TC Alaska Project.[9] For ease of comparison with the TC Alaska 4.5 Bcf/day Base Case, and because it produces a higher estimated NPV than the other LNG options, the following discussion summarizes the NPV analysis with specific regard to the 4.5 Bcf/day Base Case LNG Project scenario, described in Section C above. Details concerning the economics of the 2.7 Bcf/day LNG cases (with and without expansion) are provided in Appendix G1.

1. Calculation of LNG Prices

One cannot simply look up "the price" of LNG in the Asia Pacific market. Instead, the vast majority of gas is sold under long-term (e.g., 20-year), take-or-pay, bilateral negotiated contracts. The terms of these contracts are, in the main, confidential (Appendix I, Section 4). This is very different from the natural gas market in North America, where there are public and transparent prices at numerous natural gas trading "hubs." Accordingly, to better understand LNG prices, the state retained Gas Strategies, an international consulting firm, to analyze the question of the potential price that Alaskan LNG could command in Asia.[10] Because it has been and continues to be directly involved in a number of actual LNG deals, Gas Strategies has the market intelligence to gauge not only the terms under which past contracts have been struck, but also to reasonably assess where they are going, and why.[11]

The need for bilateral contracts is driven, in part, by the structure of Asian markets' demand. The North American market is both significantly larger and interconnected; the Asian LNG market is really a collection of segmented markets which in aggregate are about half the size.

[9] Price is the first factor in the NPV calculation: price times volume less cost equals net cash flow, which after adjustments for the project's schedule and discount rates equals NPV.

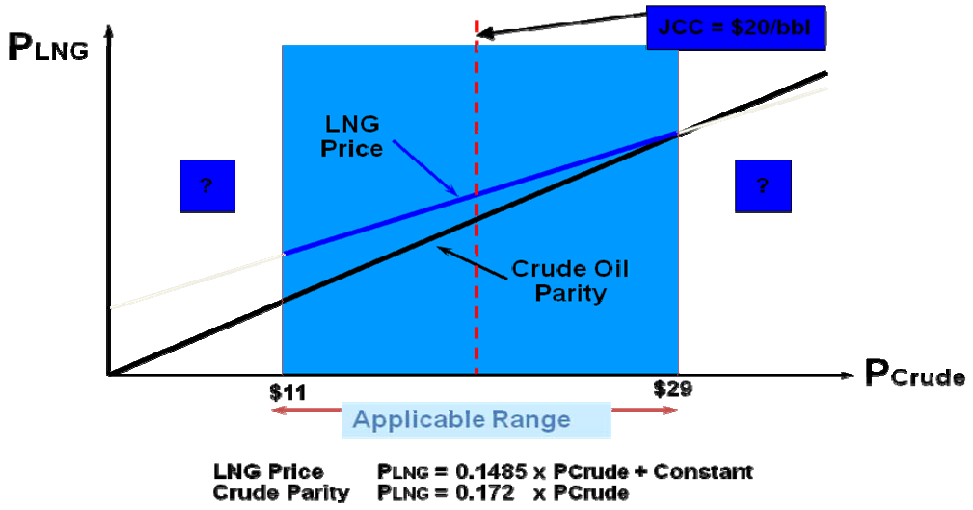
[10] In addition to analyzing LNG prices, Gas Strategies also provided details on other relevant issues, including the structure of LNG markets, particularly in Asia, (see Section 4 and Exhibit A of Appendix I), as well as the structure of LNG business arrangements (see Section 7 of Appendix I) and financing (see Section 8 of Appendix I). In addition, the state relied upon Gas Strategies' market intelligence and industry expertise for estimates of LNG shipping costs between Alaska and Asia (see Appendix I, Section 5.8). The analysis of LNG options also considered input from Goldman Sachs on the structure of LNG arrangements and financing LNG projects. (See Section VI.C of Appendix H).

[11] Gas Strategies' general conclusions about historical contract terms were generally verified by Wood Mackenzie's subscription-accessed database of inferred LNG contract terms.

Total North American demand in 2007 was roughly 30 Tcf; total Asian demand for LNG (which spans disconnected markets in Taiwan, South Korea, Japan, and China) is in the neighborhood of 14 Tcf. (EIA 2008a; NEB 2007; Appendix I, Section 5.3).

The particular pricing terms established in a given contract will be a function of the demand and LNG supply conditions that exist *at the time that the bilateral contract is being negotiated*. Once those terms are struck, the buyer and seller are largely stuck with them, subject to periodic (and potentially limited) reopeners. This places certain risks on both buyers and sellers of LNG. If, as a seller, you are negotiating your contract during a period of tight supply, then you may be able to lock in favorable terms. However, the converse can also occur. For illustration we briefly review the Asian LNG pricing history provided by Gas Strategies (Appendix I, Section 4.5.2). In Asian markets, as a general rule, prices are set by a formula that links gas price to crude oil price (normally Japanese import prices, known as JCC). For many Asian contracts struck from 1986 until 2001, LNG was priced off crude oil in a formula that provided a premium (on an energy basis) to crude oil for oil prices below about $29, and a value decrement for prices over $29.

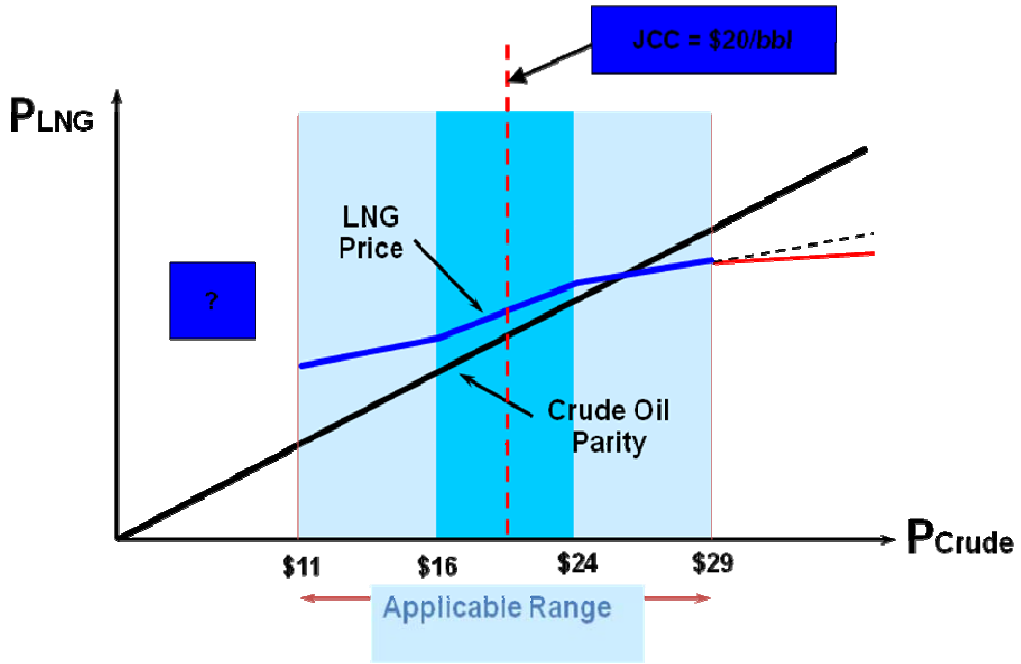
Figure 4-1. Asian LNG Price Formula: The Historical Period



Source: Gas Strategies Consulting; *(Gas Strategies, Section 4.5.2.1)*

Some contracts during this period were priced off crude oil that generated "S-curve" LNG price movements as crude oil prices change. In such contracts the LNG price premium (on an energy basis) was greater at lower oil prices, but was reversed at about $25 oil.

Figure 4-2. Japanese 'S' Curve for LNG Pricing: The Historical Period



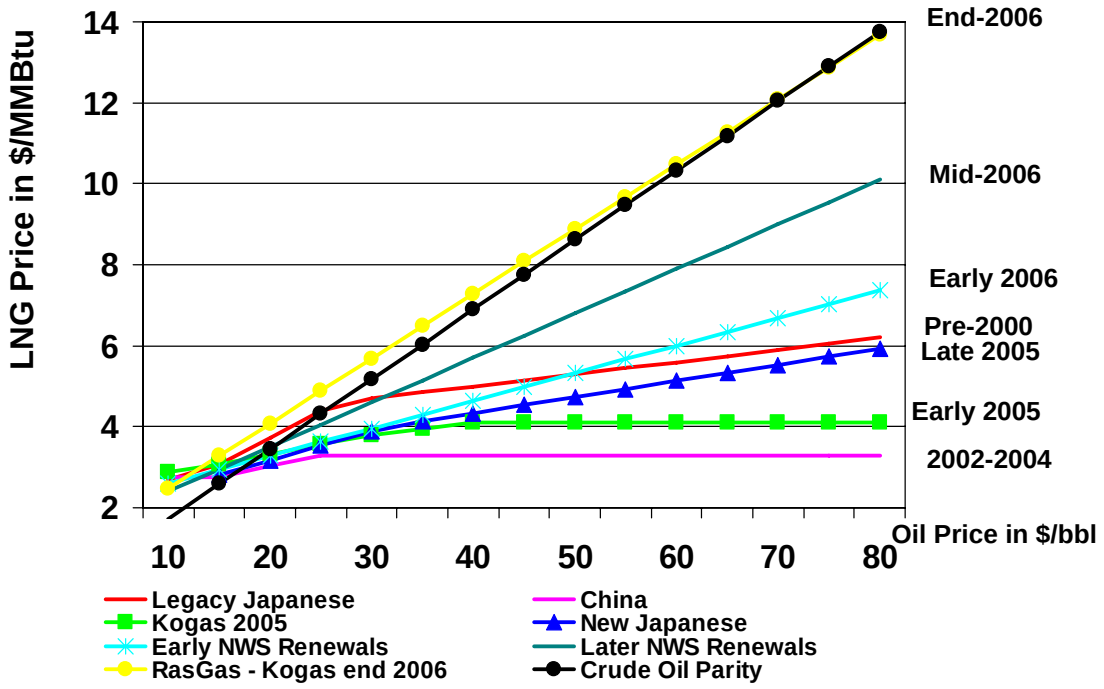
Source: Gas Strategies Consulting; *(Gas Strategies, Section 4.5.2.1)*

However, from 2001 to 2004, there was a shortage of buyers of LNG in the Asian market. LNG buyers were able to negotiate contracts with hard ceilings, such that gas prices (though by formula linked to oil) would top out when oil hit $25. At current oil prices the ceilings mean that these contracts are enormously more favorable to the buyers than the contracts negotiated in the earlier period.

Since 2005, LNG sellers have enjoyed significantly better terms, and are currently obtaining values very close to crude oil parity (on an energy basis).

LNG pricing terms need to be understood as being "sticky." Once the deal has been done, the supply becomes essentially locked into the market for the full duration of the contract; prices can only be readjusted toward the prevailing market level at roughly five-year intervals (Appendix I, Section 4.6). Accordingly, much hinges on market conditions at the time that the contracts are negotiated.

Figure 4-3. More Recent Japanese, Korean, Tawainese, and Chinese LNG Prices Related to Crude Oil Price



Source: Gas Strategies Consulting; *(Gas Strategies, Section 4.5.2.1)*

a. Forecasting LNG Price Scenarios

To develop a projected LNG price for purposes of evaluating the NPV of the LNG project options, Gas Strategies developed three price scenarios—a Base Case, a High Case, and a Low Case. These phrases—"Base," "High," and "Low"—do not refer to the LNG prices that will be realized. Rather, they refer to the general LNG contract terms in relation to crude oil prices. Within a given contract's pricing terms (be it "Base," "High," or "Low"), if crude oil prices are high then, all else equal, LNG prices will also rise. If crude oil prices are low then, all else equal, LNG prices will fall.[12] Accordingly, as a general matter a "High" contract regime will result in a higher LNG price for a given oil price than does a "Low" contract regime.

The Base Case price scenario expects that there will be a balance between LNG supply and demand in Asia, such that sufficient LNG projects will be developed to satisfy the market. This scenario has generally existed for most of the last 40 years (with instances of market

[12] All else is not equal in the Low Price contract scenario. Under such contract LNG prices become tied, not to crude oil, but to Henry Hub prices.

imbalances reflected in the wide disparity of contracts compared to the price of oil). This is a reasonable scenario considering that the structure of the LNG business in Asia is grounded on long-term contracts, meaning that new LNG projects typically cannot proceed until they have secured long-term LNG sales contracts. As a result, it is difficult for supply and demand to be out of balance for a sustained period of time (Appendix I, Section 5.2). Gas Strategies recommended that, for our Base Case evaluation, the contract terms used to derive a delivered price should be: LNG Price = 0.1485 x (Brent price of crude oil) + $0.90 (Appendix I, Section 5.4).[13]

The High Case price scenario projects that the current LNG supply tightness in Asia will continue, even though it represents a divergence from the market conditions that have tended to exist for several decades. This recent tight supply situation is due, in part, to problems with Japanese nuclear reactors, decline of Indonesian supplies, high liquefaction plant costs, environmental opposition to new projects, social and political challenges in producing countries, and strong economic growth driving energy consumption in the market area (Appendix I, Section 5.5). Gas Strategies recommended that for our High Case evaluation, the contract terms used to derive a delivered price should be: LNG Price = 0.162 x (Brent price of crude oil) + $1.00 (Appendix I, Section 5.5).

The Low Case price scenario requires a sustained recession that slows energy and other demand for LNG in Asia with reduced development costs, leading to an oversupply of LNG. This scenario could lead to an extremely low LNG price, and would require a "profound period of stagnation in the US and/or Europe similar at least to the problems of Japan post 1990…" (Appendix I, Section 5.6). Gas Strategies recommended that, for our Low Case evaluation, the contract terms used to derive a delivered price should: LNG Price = 0.9 x (Henry Hub price of gas) - 0.5 (Appendix I, Section 5.6).

To turn Gas Strategies' pricing formuals into a forecast of actual LNG prices, a forecast of Brent crude oil and Henry Hub prices is necessary.[14] For these the state relied on Wood Mackenzie's forecasts. As discussed in Chapter 3, Wood Mackenzie's views of these particular commodity

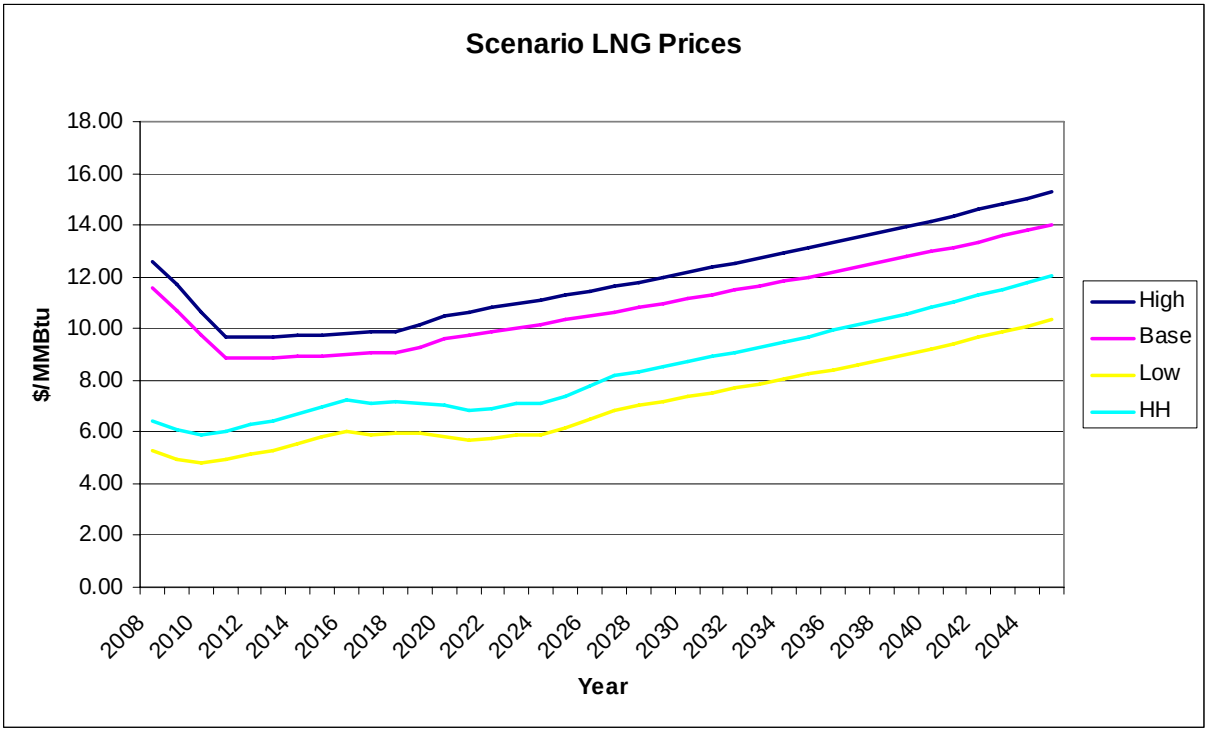
[13] The 'Brent price of crude oil' is an internationally-used benchmark for oil produced in Europe, Asia, and the Middle East. The Brent price is similar to the West Texas Intermediate price, which is the benchmark price often quoted for oil produced in the Americas.

[14] These prices are the variables on the right hand side of the contract-formula equations. If values for these variables are entered, then an LNG price results.

prices is logically and internally consistent with their views of AECO Hub commodity prices. This permits an "apples to apples" comparison of prices between the AECO Hub (for the TC Alaska Project) and Asian Pacific LNG prices (for an LNG option).

Assuming Wood Mackenzie's forecasts of oil and Henry Hub prices are valid, the resulting Base Case price for LNG in the Asian Pacific market in 2020 (in constant 2007 dollars) shows a premium of approximately $3.00 over Henry Hub prices. The High Case price for LNG in 2020 (in constant 2007 dollars) shows a premium that is approximately $4.00 over Henry Hub prices in 2008. The Low Case price for LNG reflects a discount of approximately $2.50 from Henry Hub prices (Appendix I, Section 5.7). This is depicted in the following chart:

Figure 4-4. Asian LNG and Henry Hub Prices in the Different Scenarios (Real 2007)



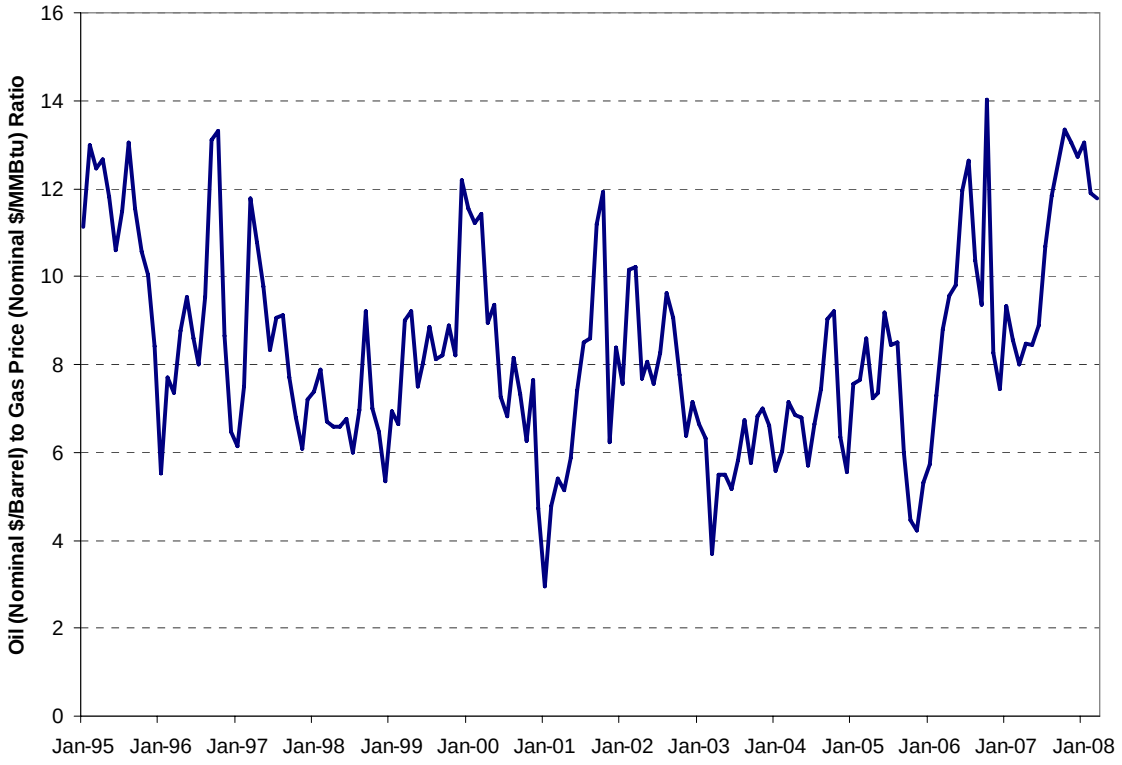
Source: Gas Strategies Consulting/Wood Mackenzie

Recent spot prices and recently negotiated contract prices in the Asian Pacific markets are trading at a greater premium (sometimes as high as $10) than the $3.00 premium generated by our Base Case. At today's oil prices and gas prices, the premium provided by the Base Case is

closer to $7/MMBtu.[15] That is, if an LNG contract for Alaska gas could be struck today at the Base Case contract price, then the premium over Henry Hub prices would be around $7. In trying to think about LNG prices more than ten years into the future, the relevant question becomes two-fold: what contract terms might one receive, and what would be the price premium in the Asian market relative to Henry Hub?

The extent to which Base Case or High Case contract terms yield an Asian LNG price premium depends significantly on the relationship of the price of oil, on an energy equivalent basis, to the price of gas in North America. In historical terms, oil is currently trading at a significant premium to North American natural gas. The oil price to gas price ratio fluctuates over time. For the period of January 1995 to March 2008, the ratio was as high as 14 to 1 and as low as 3 to 1, with an average 8 to 1 (Appendix G1; Section 7.15.4.3).

Figure 4-5. Historical Oil to Gas Price Ratio



Source: Black and Veatch 2008, Appendix G1, Section 7.15.4.3

[15] Based on *Oil Daily's* reported spot prices for Brent ($120.82) and Henry Hub ($11.52) on 5/14/2008. *Oil Daily*; 58 (94):2. May 15, 2008.

There are good reasons to think that the current price relationship—in which oil is priced significantly higher than North American gas—is unlikely to persist over the relevant time frame.

Gas Strategies predicts the current higher premium is not likely to continue, and that during the relevant time frame of any Alaskan LNG project, LNG and North American natural gas prices will likely converge somewhat, trading at prices closer to Henry Hub (and AECO) prices. According to Gas Strategies, "it is unlikely that supply would be as tight as it is at present for a full 20 year period. In practice we would expect the high prices to pull forward enough supply to bring the market back into balance within 5 to 10 years." (Appendix I, Section 5.6)

There is more than enough new LNG supply coming on stream over the next four or five years to eliminate the projected shortfall in Asia. These quantities are targeted to supply the U.S. or U.K. markets, but because these markets are liquid and flexible some or all of the LNG could be diverted to Asia. These diversions would clearly weaken prices in Asia and strengthen them in the U.S. (the rigid Asian contracts would strongly inhibit the reverse happening). In other words, as the United States becomes more dependent on LNG supplies in the next decade, LNG customers in the U.S. will have to pay a (higher) competitive price to attract LNG away from other world markets.[16] (Appendix I, Section 4.7.) Growing global competition for reliable gas supplies, including an increased North American reliance on LNG, will create upward price pressure on LNG. Higher LNG prices will also tend to increase AECO and Henry Hub prices, because sellers will only introduce LNG cargoes to those locations if they can demand a price similar to the price received in competing LNG markets. For example, an LNG supplier is unlikely to dispatch a tanker to North America unless either (a) all of the alternative markets were fully supplied and the only remaining demand was in North America or (b) the market in North America was price competitive with other markets. Accordingly, LNG will act as a force to re-link oil and North American gas prices. (Kelly, 2008)

While Gas Strategies predicts that the current premium is not likely to continue, it believes that the Asian Pacific markets will continue to pay some premium over the Henry Hub price for LNG to ensure the security of its supplies because it does not enjoy the flexibility provided by the diversity of supplies and the significant gas storage facilities that exist in the United States. As a

[16] In actual fact prices will not rise to attract imports on a transactions basis. Rather, the widely-forecasted supply gap in North America will cause prices to rise, which in turn will create incentives for LNG suppliers to sell LNG into the North American market. Still, the effects are the same: it is "as if" North American consumers were paying a higher price to attract LNG cargoes.

result of these factors, Gas Strategies believes its projected Base Case price, which represents a moderate easing of the currently very tight market situation, is appropriate (Appendix I, Section 5.4).

Another driver behind that eventual convergence, independent of the fundamental commodity supply-demand relationship between LNG and natural gas, is the relative price of oil and North American natural gas. As the price of oil diverges from North American natural gas, resources—drilling rigs, geological and engineering expertise—are diverted from North American natural gas exploration and development to pursue more profitable oil opportunities. Given scarce expertise and equipment in the oil and gas sector, divergently high oil prices will tend to reduce resources devoted to developing North American gas. The result of the migration in exploration and development resources will be a reduction in North American natural gas reserves replacement. Depletion without replacement, again considering the relative inelasticity of North American natural gas demand, should begin to tilt the scales such that the value of domestic natural gas rises (Appendix G1, Section 7.15.4).

A detailed discussion of pricing relationships between North American gas and oil prices is contained in Black and Veatch's expert report (Appendix G1, Section 7.15.4). It concludes that, while the price relationship is uncertain, it is more likely that North American natural gas prices will tend to return to their historical average relationship with oil. If Black and Veatch, Gas Strategies, and Wood Mackenzie's views are correct, then the substantial current-day premium received for Asian LNG is likely to narrow significantly.

2. LNG Volumes

The second factor in the NPV calculation is volume. The primary LNG scenario addressed here has the same production volume used to analyze the TC Alaska Project Base Case. Gas volumes for the other LNG project options discussed above are summarized in Appendix G1, Sections 7.4, 7.5 and 7.6.

3. Costs and Schedule Related to LNG Scenarios

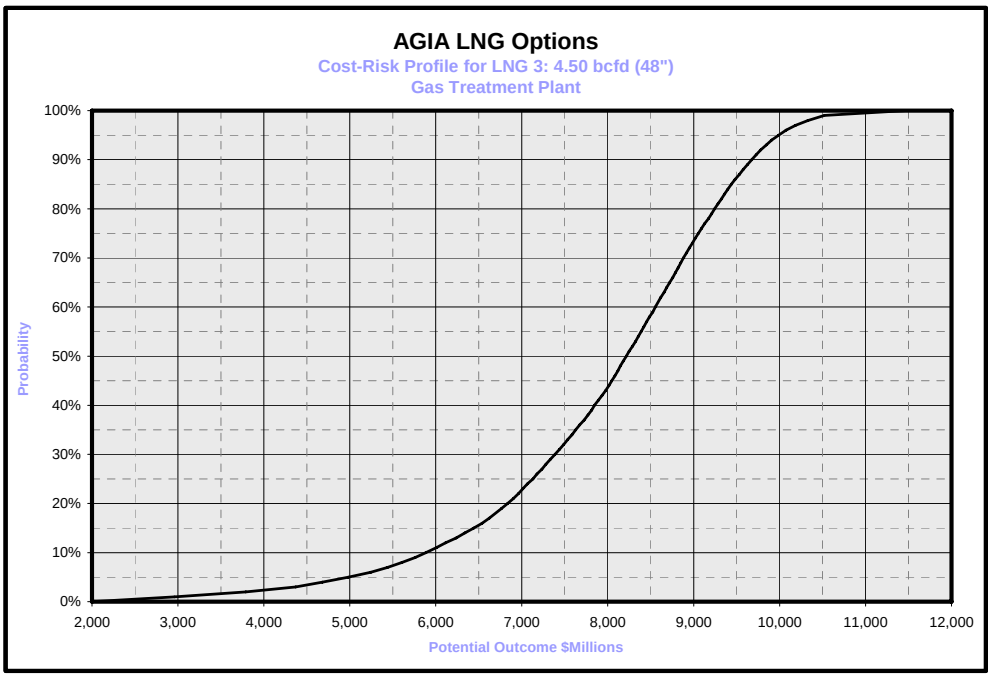
The third factor in the NPV calculation is cost. There are three main cost components for an Alaskan LNG project: (1) the cost of the pipeline and GTP; (2) the cost of the liquefaction plant

in Alaska; and (3) the cost of tankers to transport the LNG to on the market.[17] Those three cost components are summarized below.

Pipeline and GTP Costs. The commissioners' Technical Team estimated a cost and schedule for the GTP and pipeline system (Appendix F, Exhibits B and C). For purposes of estimating the GTP and pipeline costs, the Technical Team used much of the data and analysis that it had already developed while analyzing the TC Alaska Project. This ensured that the GTP and pipeline components of LNG project options were, to the extent possible, based on the same cost assumptions used to analyze the TC Alaska Project (Appendix F, Sections 2.2, 2.3, and Exhibit B). Those data were used in the Technical Team's Monte Carlo simulation; the results of that process were provided to the Commercial Team for its NPV analysis of each scenario.

For the 4.5 LNG Base Case, the current-dollar GTP costs are essentially the same as for the TC Alaska Application (Appendix F, Addendum A Sections 2.2 & 2.3; LNG Options Analysis Exhibit D).

Figure 4-6. Cost-Risk Profile for the LNG Base Case GTP Plant Construction

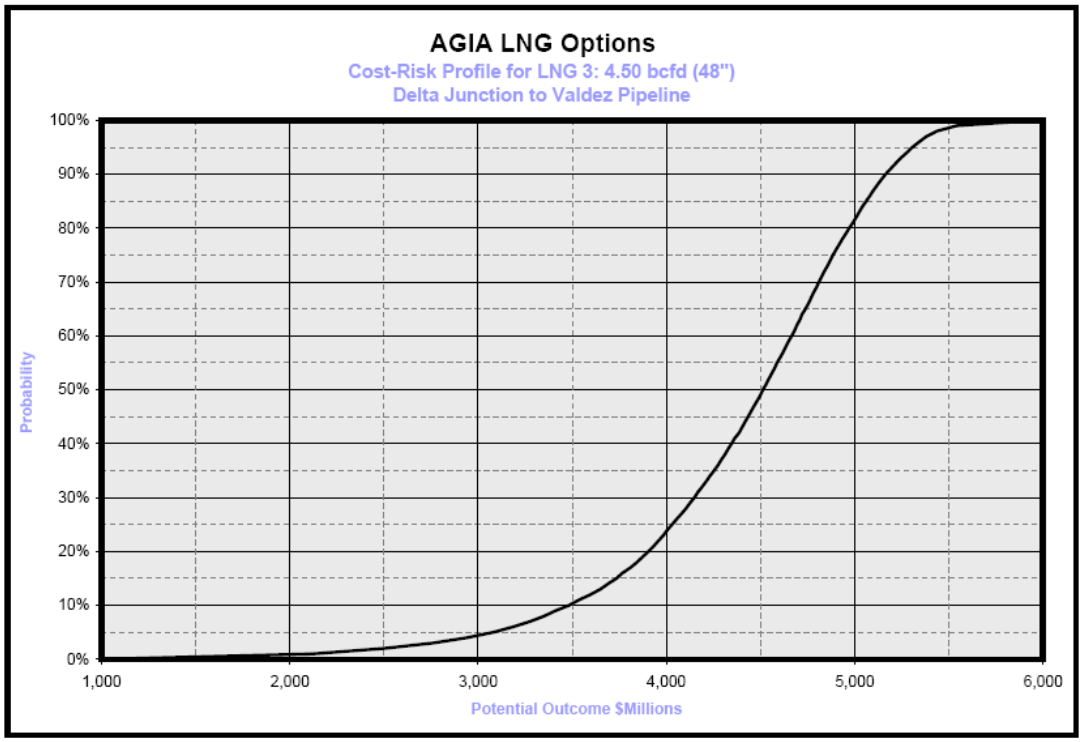


Source: Westney 2008. Appendix F, Addendum A.

[17] The state's NPV analysis of LNG project options modeled LNG prices into the regasification terminal; accordingly, there is no need to consider regasification costs in the "net back" calculation.

For NPV modeling purposes, cost ranges for the pipeline subprojects for the LNG project options are, on a per mile basis, essentially the same as that of the Alaska portion of TC Alaska's pipeline subproject. The Monte Carlo based probability distributions of pipeline costs for the Delta Junction to Valdez pipeline subproject are shown below.

Figure 4-7. Cost-Risk Profile for the LNG Base Case Delta Junction to Valdez Pipeline Construction



LNG3 Cost 4 DJ-V PL 080313.xls Total Chart Printed: 3/24/2008

Source: Westney 2008. Appendix F, Addendum A.

Liquefaction Plant Costs. The process of establishing a probability distribution for the liquefaction plant differed somewhat from that used for the GTP and pipeline subprojects. The Technical Team did not have an AGIA-compliant application to directly evaluate regarding the cost of the liquefaction. Accordingly, they could not follow the process used to generate Monte

Carlo probability distributions for the pipeline and GTP (Appendix F, Addendum A, Section 2.4).[18]

Therefore, rather than trying to generate a probability distribution of costs from the "bottom up," based on subproject cost components, their ranges, and their probability distributions, the Technical Team chose to generate a cost estimate from the "top down." That is, the approach relied on existing data on liquefaction costs from actual projects around the world to generate a representative distribution of liquefaction costs per ton for an Alaskan LNG project.

As a first step, the Technical Team mined data contained in the Westney proprietary data base that shows the costs per ton of LNG output for several recently constructed and operating LNG plants. These liquefaction plants vary in size from about 3.25 million tons per annum (mtpa) to 8.9 mtpa (0.42 Bcf/d to 1.16 Bcf/d), and went into service between 2003 and 2007 (or are currently under construction).[19] The cost per ton of LNG for these plants ranges from a low of less than $350 to over $1,300 for the Snohvit project in Norway (Appendix F, Addendum A, Section 2.4).

Because the projects were constructed at different times, cost components for each LNG plant (*e.g.,* compressors, vessels, pipe, electrical, etc.) were reviewed on a commodity basis and then escalated to 2007 dollars. Because the projects in the data set are generally located in developing countries and in tropical climates, each project cost was adjusted to an Alaska basis for the costs of construction (i.e., using projected labor rates and productivity factors for Alaska). Finally, the highest and lowest costs of liquefaction were excluded from the Westney data set as being unrepresentative. The remaining data were then reviewed and confirmed against the global LNG data base of Merlin Associates (Appendix F, Addendum A, Section 2.4).

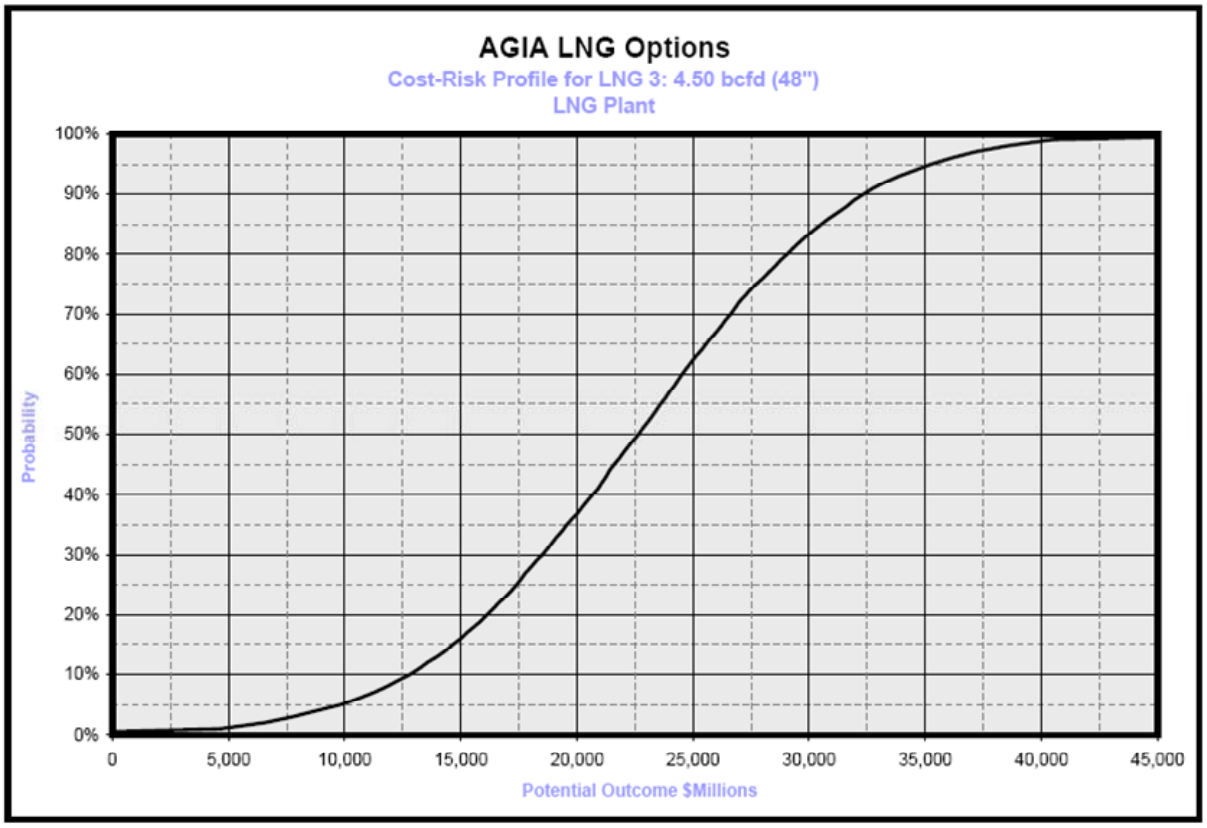
Based on an adjusted data set of liquefaction costs, the best cost case and the worst cost case were used, together with an assumed normal (or "bell shaped") probability distribution, to generate a full probability distribution of Alaskan per ton liquefaction costs. The train sizes for the relevant LNG case under consideration then determined the entire Monte Carlo-based

[18] For the TC Alaska subproject cost estimates, the Technical Team started with "base case" cost estimates of the major components. These were used to establish an overall Monte Carlo based probability distribution based on separate "best" and "worst" case ranges of each of the major cost components and distributions. This process could not be followed for the liquefaction estimate in part because, absent an AGIA-compliant applicant, there was no ability to engage in the necessary clarification process of estimates and assumptions.

[19] One mmtpa of LNG is approximately equivalent to 140 MMcf per day of gas.

probability distribution for the liquefaction plant costs. The result for the 4.5 Bcf/day LNG project is shown below.

Figure 4-8. Cost-Risk Profile for the LNG Base Case LNG Plant Construction



Source: Westney 2008. Appendix F, Addendum A.

Figure 4-8 indicates that the midpoint (or "P50") probability cost of the LNG liquefaction plant is approximately $22.5 billion. The entire range of possible costs is very wide. This is due both to the location and unusual market conditions that have affected liquefaction plant costs for the data set used to assess plant cost risks. But it is also due to the fact that liquefaction plants are quite complex (See discussion in Appendix F, Section 2.4). Because the cost range is wide, the Technical Team recommends that the middle 50% of the probability range—excluding the top 25% and bottom 25% of costs—provides a more useful lens for considering project cost risk. This generates a range of $17.5 billion to $27.5 billion.

Liquefaction cost ranges for other LNG project configurations are summarized in the following table.[20]

Table 4-1. Liquefaction Plant Cost Ranges

Cases	LNG Volume	P25 Value (75% probability of exceeding value)	P75 Value (75% probability of not exceeding value)
2.7 Bcf/day	19 mmtpa	$10.8B	$17.6B
	(2.45 Bcfd)	568 $/T	926 $/T
2.7 Bcf/day Expansion Option	31.5	$17.4B	$27.9B
	(4.06 Bcfd)	552 $/T	885 $/T
Y Line Option	13.9	$8.1B	$13.7B
	(1.79 Bcfd)	582 $/T	985 $/T
4.5 Bcf/day	31.5	$17.4B	$27.9B
	(4.06 Bcfd)	552 $/T	885 $/T

Source: Westney Consulting. Appendix F, Addendum A, Section 2.4.

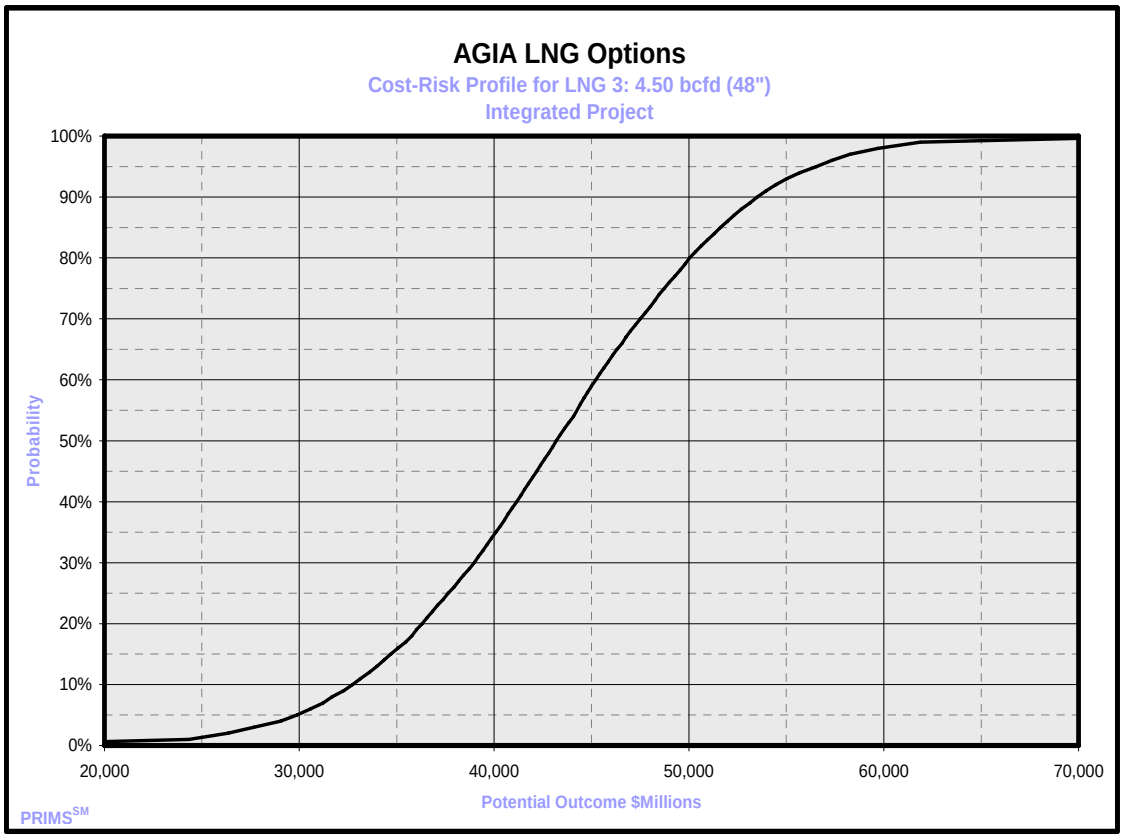
At "P25" there is a 25% likelihood that the actual costs could be lower than stated; at "P75" there is 75% likelihood that the costs would be lower than stated.[21]

Putting all of the pieces together, the risk distribution of the integrated capital costs of a 4.5 Bcf/day project are shown below.

[20] The volumes of each of these cases assume no natural gas liquids ("NGL") extraction, in order to meet the minimum quality requirements of the Asian Pacific markets which is consistent with the market analysis of Gas Strategies (Appendix I, Section 2). However, the Technical Team determined that propane in the quantity required to supply the current and near-term future market in Alaska can be extracted without significant reduction of either the volumes or heating value of LNG. (Appendix F, Addendum A, Section 2.4)

[21] As an additional point of reference, the Port Authority and Little Susitna applications estimated the cost per ton of liquefaction capacity at approximately $550 and $520 respectively, which put them very close to the P25 estimates above. These estimates included a reasonable allocation of their estimated overhead and related costs to facilitate a fair comparison.

Figure 4-9. Execution Cost Probability Distribution for a 4.5 Bcf/d Integrated LNG Project



Source: Westney 2008. Appendix F, Addendum A.

Not including the development schedule, the figure indicates that the mid-point (P50) cost estimate is approximately $43 billion in current dollars. There is less than a 10% probability that costs will be below $32.5 billion.

Schedule

The process for assessing project schedule risk for the pipeline and GTP subproject components was the same as used for the analysis for the TC Alaska project except for the risks associated with the Canadian regulatory process. To assess schedule risk for the liquefaction plant, the Technical Team analyzed the number of LNG trains that would be needed for the entire project at the largest size commercially available (so as to obtain the greatest economic efficiency and minimize the overall installation time and expense).[22] This analysis

[22] An "LNG train" is a complete process unit that turns natural gas into a liquid. The "train" consists of a collection of sub-units and equipment that cleans, compresses and cools natural gas into a liquid. The exact mix of sub-units and

was predicated on the fact that there is a necessary lag between the completion of one train and the time that a follow-up train can be completed. This is because of the necessity to ensure that all of the systems for the first train are fully operational on an integrated basis before adding another train. For purposes of the analysis it was also assumed that three months was the shortest period that could reasonably be expected between completion and a train being fully operational (even though it is likely that a longer period would be necessary; see Appendix F, Addendum A, Section 2.4). The schedule range based on the number of trains was used in the Technical Team's Monte Carlo simulation and the results provided to the Commercial Team for conducting the NPV analysis of the various cases (See Appendix F, Addendum A, Section 1.1).

A comparison of the "P50" schedule for the 4.5 Bcf/d LNG case and the 4.5 Bcf/d TC Alaska Project Base Case shows that the LNG project will require approximately two additional years before the in-service date or before first gas flows. There are two primary factors behind this delay. First, it was assumed that a new state process—including, possibly, a new round of applications under AGIA—would be required for an LNG project, because it was assumed that an LNG project sponsor would require some type of state support to advance the project. This was assumed to push the start date for an LNG project back by one year to provide time for (1) an LNG project sponsor to prepare and submit a new application or proposal to the state and (2) the administration and legislature to review, analyze and approve the granting of an AGIA license. The second factor affecting the timing of an LNG project is the additional time needed to complete and place the multiple LNG trains required for a 4.5 Bcf/d project into service.

Tanker Costs. Tanker costs are a significant component of an LNG project. Gas Strategies estimated that, based upon extrapolations from existing shipping rates, total shipping would come to 99 cents/MMBtu (expressed in real dollars) (See Appendix I, Section 5.8 for discussion).[23] This component is included in the comparison of the estimated cash flow and NPV that would be produced by the TC Alaska Project and the LNG project options (Appendix G1, Sections 1.1 and 7.1).

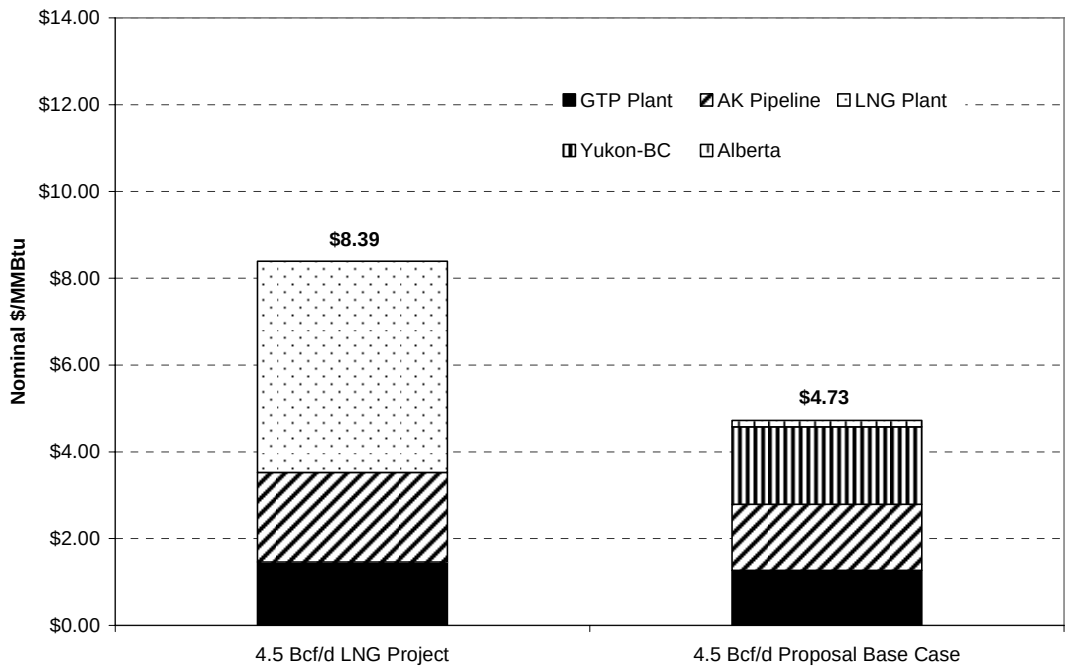
equipment varies depending on which proprietary technology is used. An LNG plant consists of one or more "trains" plus support facilities such as utilities, storage tanks and jetties.

[23] Gas Strategies assumed somewhat larger sized tankers than did the AGIA applicants proposing LNG projects. (See, e.g. LSCC AGIA Application at p. 58). Accordingly, the tanker costs assumed here are on the conservative side.

4. Comparison of LNG and TC Alaska Costs and Tariffs

Based on the Technical Team's cost and schedule projections, a hypothetical levelized rate (or tariff) was constructed for each LNG option.[24] The costs to move gas from the North Slope to Valdez, including the cost of liquefaction at Valdez, would be significantly higher than the costs to transport gas from the North Slope to Alberta, even without considering the costs of shipping the LNG in tankers from Valdez to the Asian market. This is because the LNG options require a capital-intensive liquefaction facility. As shown in the chart below, there is a $3.66 per MMBtu cost difference between the LNG pipeline, GTP and liquefaction costs for a 4.5 Bcf/day LNG scenario and a 4.5 Bcf/day pipeline to Alberta (The TC Alaska Proposal Base Case).

Figure 4-10. Tariff Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case



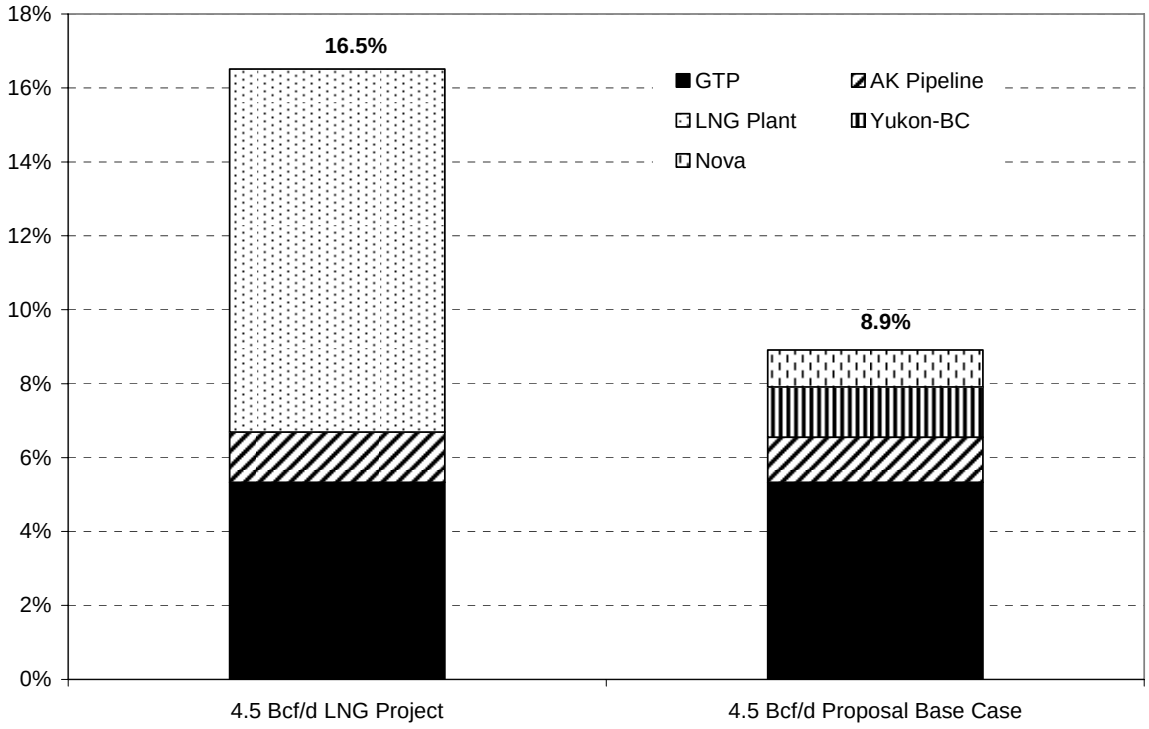
Source: Black and Veatch. Appendix G.1, Figure C-2.

In addition, these costs do not include the substantial amount of shrinkage associated with LNG liquefaction. Making LNG consumes substantial volumes of natural gas, which reduces the amount of gas (or LNG) that is available for sale. As shown in the chart below (Figure 4-11), the

[24] In fact, the costs would be recovered in potentially different charges reflecting the GTP, Alaska pipeline, and liquefaction segments. They are presented here as a single hypothetical cost-based tariff charge to simplify the presentation.

difference in shrinkage between a 4.5 Bcf/day pipeline to Alberta and a 4.5 Bcf/day LNG project is material: 8.9% for the TC Project pipeline to Alberta line versus 16.5% for an LNG project.

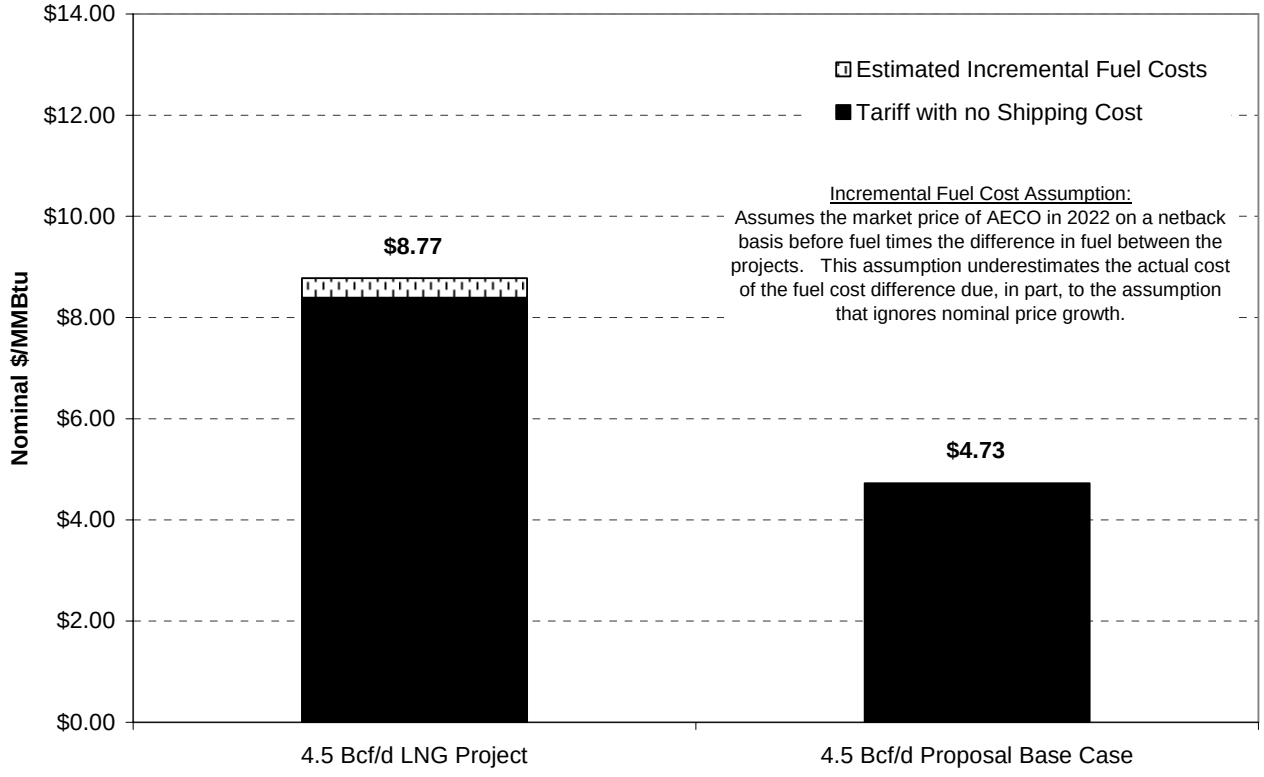
Figure 4-11. Fuel Loss Comparison: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case



Source: Black and Veatch. Appendix G.1, Figure C-3.

In essence, an additional 7.6% of the original gas volume is lost in the transportation and manufacture of LNG versus the TC Alaska pipeline. The value of this incremental 7.6% depends, of course, on how the gas is valued. If it is valued against the AECO price, then the lost gas is calculated as the AECO net back multiplied by 7.6%. Figure 4-12 compares the TC Alaska Project's per unit transportation cost with the LNG project cost to Valdez, including the cost of incremental fuel "lost" to manufacturing the LNG.

Figure 4-12. Tariff Comparison Including Estimated Incremental Fuel Costs: 4.5 Bcf/d LNG vs. TC Alaska Proposal Base Case

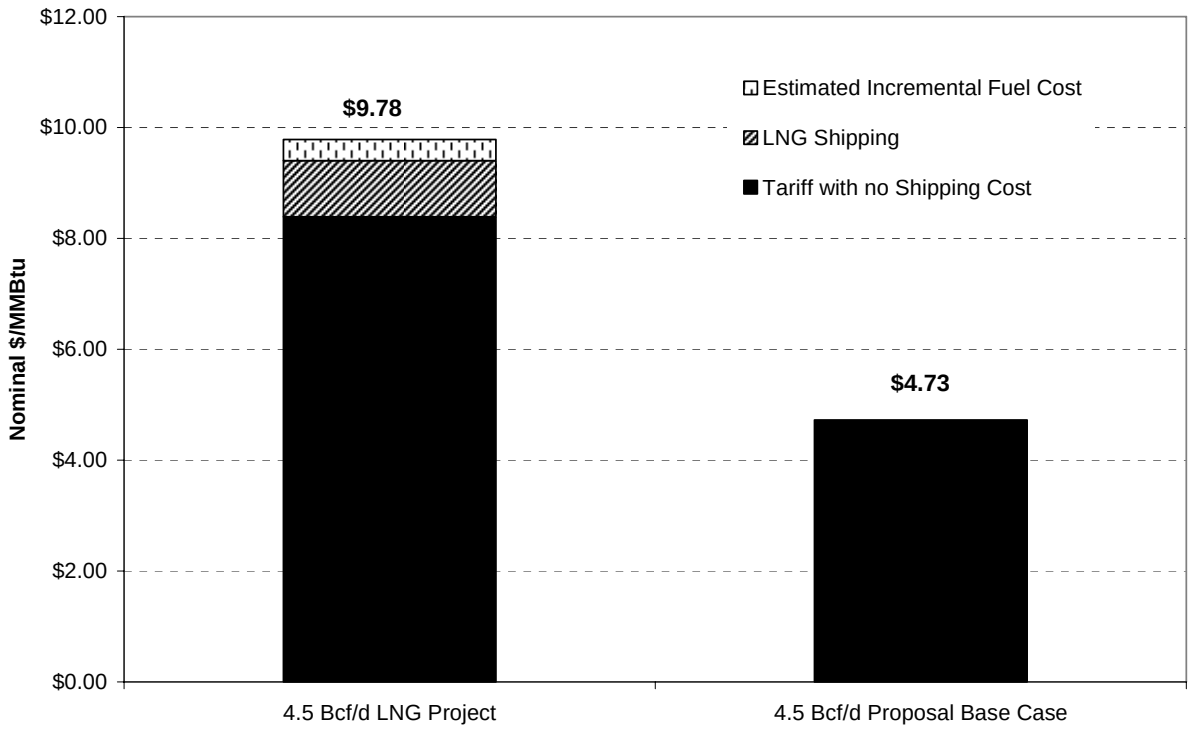


Source: Black and Veatch. Appendix G.1, Figure C-4.

This increases the cost of the LNG project by $.37/MMBtu.

Additional costs associated with shipping LNG to market through LNG tankers must be included. Gas Strategies estimates that LNG tanker and receiving port charges add up to an additional cost of approximately $0.99 per MMBtu (in real, 2008 dollars) of LNG shipped (Appendix I, Section 5.8). As shown on the chart below (Figure 4-13), this increases the cost advantage that the TC Alaska Project has over the LNG project options.

Figure 4-13. Tariff with Incremental Fuel Costs and Shipping Costs



Source: Black and Veatch. Appendix G.1, Figure C-5.

Based on the information presented above, the commissioners conclude that a cost-of-service based tariff for the 4.5 Bcf/d LNG project would be significantly higher than a 4.5 Bcf/d pipeline project to the AECO Hub (Appendix G1, Section 7).[25]

Indeed, under Base Case assumptions, the transportation cost for a 4.5 Bcf/d project into AECO is less than half the cost (48%) that of the LNG project (Appendix G1, Sections 1.1 and 7.3).[26] This is perhaps surprising, given that difference in the integrated project construction cost, in current dollars, between the TC Alaska project and the LNG project is 38%. Factors that lead to a disproportionately higher LNG tariff include the following:

[25] Of course, there may be no tariff for a liquefaction plant. Moreover, open access tolling for liquefaction is not the model, worldwide, for LNG projects (Appendix I, Section 7.8). However, for royalty and tax calculations a liquefaction deduction would be required. The numbers used here reasonably approximate what those deductions might be. If anything, these figures are conservative as they presume a capital structure for tariff calculation purposes.

[26] Critical assumptions, such as cost escalation and inflation, were held constant across the two cases to permit an "apples to apples" comparison.

1) Project capital costs. The capital costs of a 4.5 Bcf/d LNG project are $12.0 billion greater than the costs of constructing a similarly-sized pipeline project to the AECO Hub. Holding everything else between the LNG option and the TC Alaska Project fixed, the greater cost increases the LNG project tariff by $1.97/MMBtu relative to the pipeline project.

2) Volumes delivered to market (fuel losses). The fuel usage/retention of a 4.5 Bcf/d AECO pipeline project is 8.91%, compared with the similarly sized LNG project of 16.5%. Based on the Base Case price assumption from Wood Mackenzie and the Base Case Gas Strategies LNG price, this results in an approximately $0.38/MMBtu increase in the LNG tariff (assuming a 2020 start date).

3) Operations and Maintenance costs. Operations and Maintenance costs for an LNG project will be significantly greater than a pipeline project, owing to the significantly greater complexity of the liquefaction plant. The expected impact to the LNG tariff rates from these higher expenses is $0.36/MMBtu.[27]

4) Property taxes. Property taxes for an LNG project are higher due predominantly to the higher installed capital value of the liquefaction plant.[28] This further raises the LNG tariff by about $0.30/MMBtu.

5) Later in-service date. The Technical Team estimates that an additional two years (for a P50 case) is expected for completion of an LNG project. The rising cost of manufacture coupled with the delay has a negative impact on all sections of the project. The LNG tariff is expected to be $0.11/MMBtu higher due to the GTP delay, $0.16/MMBtu higher due to the pipeline project delay, and $0.36/MMBtu higher due to the liquefaction/terminal facility delay.

6) Interest rate for debt. An LNG project serving Asian markets will probably not qualify for the Federal Loan Guarantee provided under the ANGPA statute.[29] Accordingly, the LNG project will have a higher cost of debt. A higher cost of debt on the project, as assessed

[27] See Appendix F, Addendum A LNG Options Analysis, p. 64 for base line costs, derived from study at pp. 109-113; see Appendix G1 for explanation of how total O&M costs were converted to per unit terms.

[28] In addition, property taxes on the LNG project are greater because a greater percentage of the project is in Alaska and Alaska has a greater tax rate than do Canadian provinces.

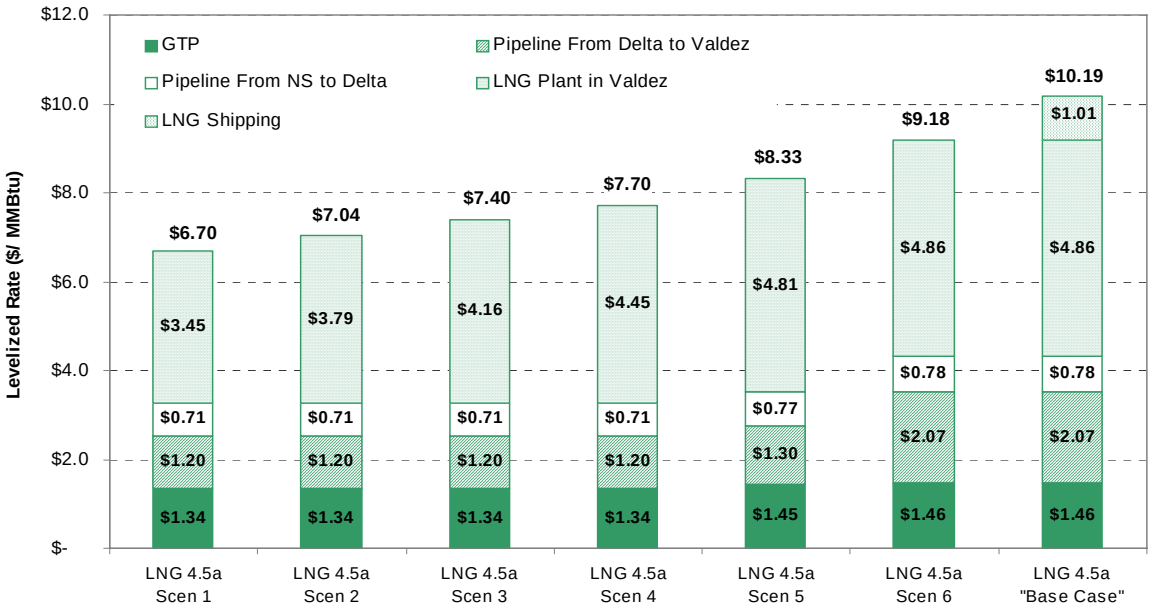
[29] The Port Authority's AGIA application recognized that this would likely be the case: "because the project is an export project the Port Authority has not counted on qualifying for federal loan guarantees under the Alaska Natural Gas Pipeline Act of 2004" (AGPA, 2007)

by Goldman Sachs, is estimated to have an adverse impact on the LNG tariff relative to the TC Alaska Project (Appendix H, Section VI.C). The size of this impact depends on which cases are being compared.

7) Shipping costs. The cost of shipping would be approximately $0.99 per MMbtu (Appendix I, section 5.8).

Figure 4-14 shows how these factors build to ultimately make up the full tariff. The first bar shows the different tariffs for different components of the transportation chain that results from the 4.5 Bcf/d LNG project costs, not accounting for any of the other factors. The second bar adds in the effects of the increased LNG shrinkage at the liquefaction plant. The third through seventh bars progressively add in the effects of higher LNG O&M costs, higher property taxes, delayed in-service date, higher borrowing costs, and the requirement to ship the LNG from Valdez to Asian Pacific markets.

Figure 4-14. Tariff Build Up



Scenario Settings

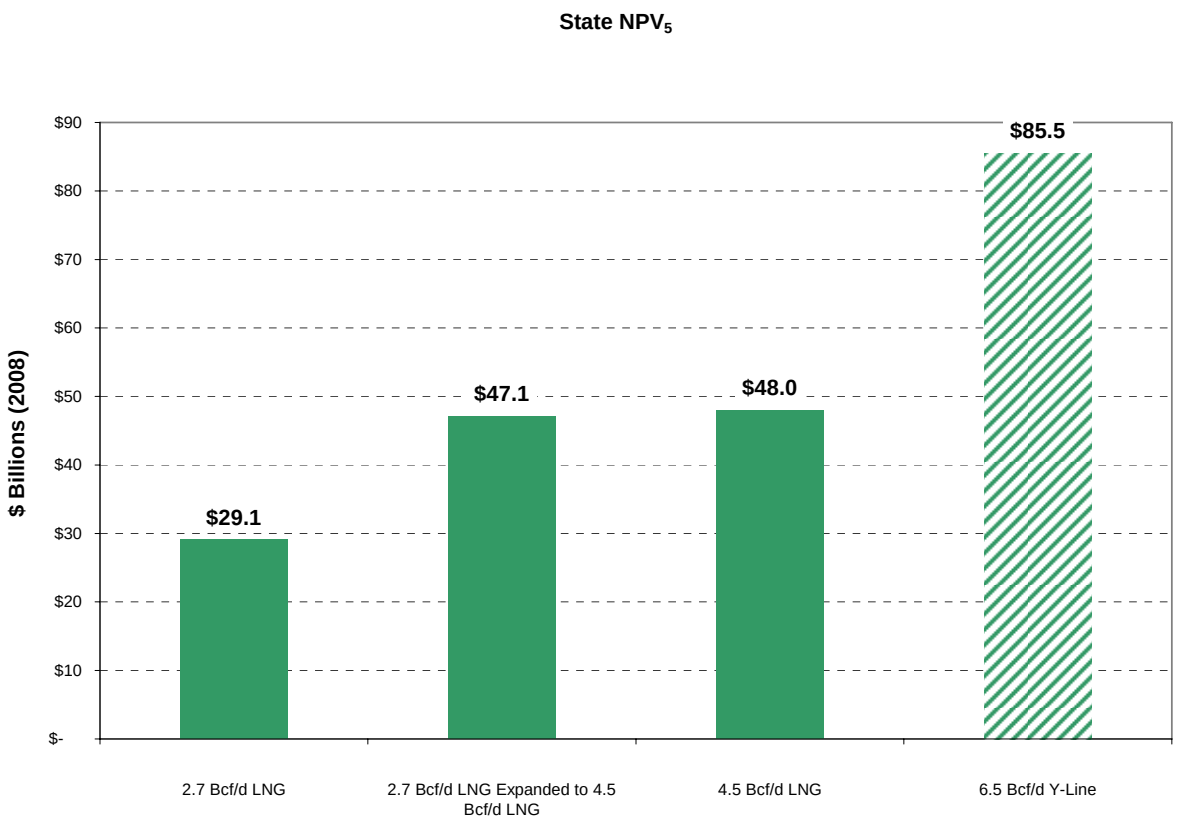
Capital Costs in 08 Dollars	$43,253	$43,253	$43,253	$43,253	$43,253	$43,253	$43,254
Case Volume	Same as AECO	LNG Volumes	LNG Volumes	LNG Volumes	LNG Volumes	LNG Volumes	LNG Volumes
O&M	Same as AECO	Same as AECO	LNG O&M	LNG O&M	LNG O&M	LNG O&M	LNG O&M
Property Tax	Same as AECO	Same as AECO	Same as AECO	LNG Property Tax	LNG Property Tax	LNG Property Tax	LNG Property Tax
In-Service Year	2020	2020	2020	2020	2022	2022	2022
Interest Rate	7.06%	7.06%	7.06%	7.06%	7.06%	7.18%	7.18%
LNG Shipping	N/A	N/A	N/A	N/A	N/A	N/A	$1.01

Source: Black and Veatch. Appendix G1, Section 7.8.3.

5. Estimated State NPV_5

Despite the increased costs associated with transporting, liquefying, and shipping LNG, each of the LNG options reviewed could produce a positive NPV_5 for the state and for the Major North Slope Producers.[30] For example, under the Base Case set of assumptions, a 4.5 Bcf/day, 48-inch diameter pipeline LNG project would produce an NPV to the state of approximately $48 billion, and a NPV to the Major North Slope Producers of approximately $8.6 billion (Appendix G1, Section 7.11). The NPV results to the state for each of the LNG project options, using Base Case assumptions for contract terms, costs, escalation rates, and the like, are summarized in Figure 4-15.

Figure 4-15. State Net Present Value Under Different LNG Project Configurations



Source: Black and Veatch. Appendix G1, Figure C-6.

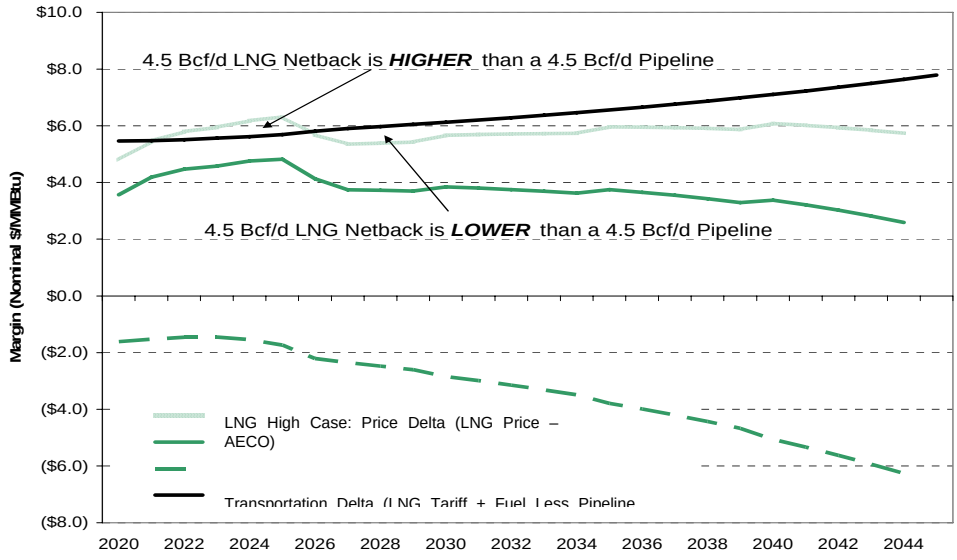
[30] "NPV_5" refers to the NPV calculated using a 5% discount rate.

In sum, although the LNG project options have higher costs than the overland project options, they would still produce a positive NPV under the pricing and cost assumptions discussed above.[31] Because of the likely need to ramp up volumes over an eight to ten year period, rather than the 3 year period assumed in the 2.7 to 4.5 Bcf/d expansion case, the actual configuration of a stand-alone LNG project is likely to provide an NPV_5 of somewhere between the two left-most cases in Figure 4-15.

6. Comparison of Estimated NPVs Produced by the TC Alaska Project and the LNG Options

Under Base Case assumptions for the TC Alaska Project and the LNG options, the TC Alaska Project Base Case has a higher estimated NPV than the LNG options (Appendix G1, Section 7.12.2). In general, this is because the price premium that LNG is likely to enjoy in Asian Pacific markets, relative to prices at the AECO Hub, is generally insufficient to overcome the greater total costs of transporting the LNG to market. This dynamic is graphically shown in Figure 4-16. The black line shows the LNG price level necessary for the LNG project to deliver superior net backs compared to the TC Alaska Proposal Base Case.

Figure 4-16. Margins of LNG Project versus a Pipeline Project



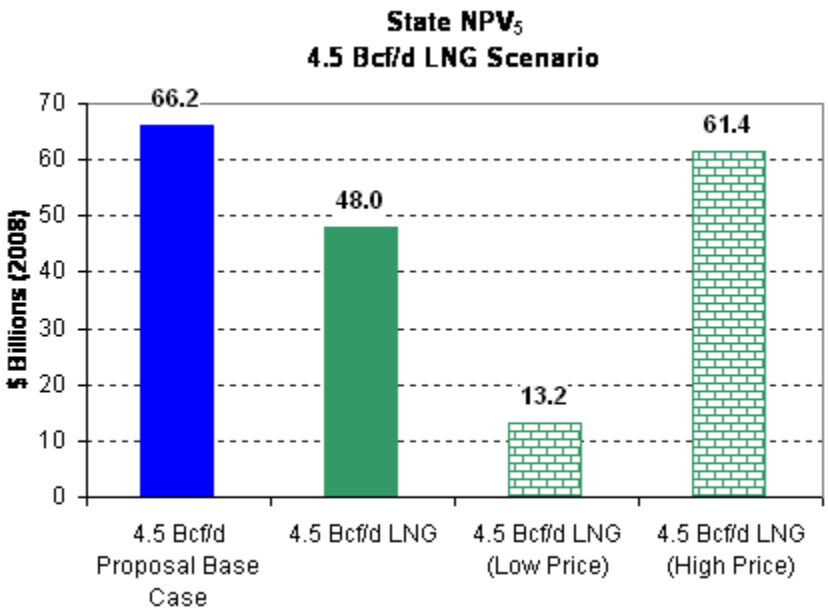
Source: Black and Veatch. Appendix G1, Section 7.12.2.

[31] As with the TC Alaska Project, the estimated NPVs would improve or decline if more optimistic or pessimistic assumptions are used.

Under the high contract price scenario (see Figure 4-16, for the price formula), there are a few years in which the Asian Pacific LNG market is sufficient to overcome the higher transportation costs. However, even in this unlikely High contract price case (Appendix I, Section 5.5), net backs are generally lower than under the TC Alaska Proposal Base Case. Under the Base and Low contract cases net backs never exceed those provided by the TC Alaska Proposal Base Case.

As a result, the TC Alaska Proposal Base Case generates a higher NPV_5 than the comparable Base Case LNG project option under each contract price assumption. This conclusion is depicted in the chart below (Figure 4-17):

Figure 4-17. State NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions



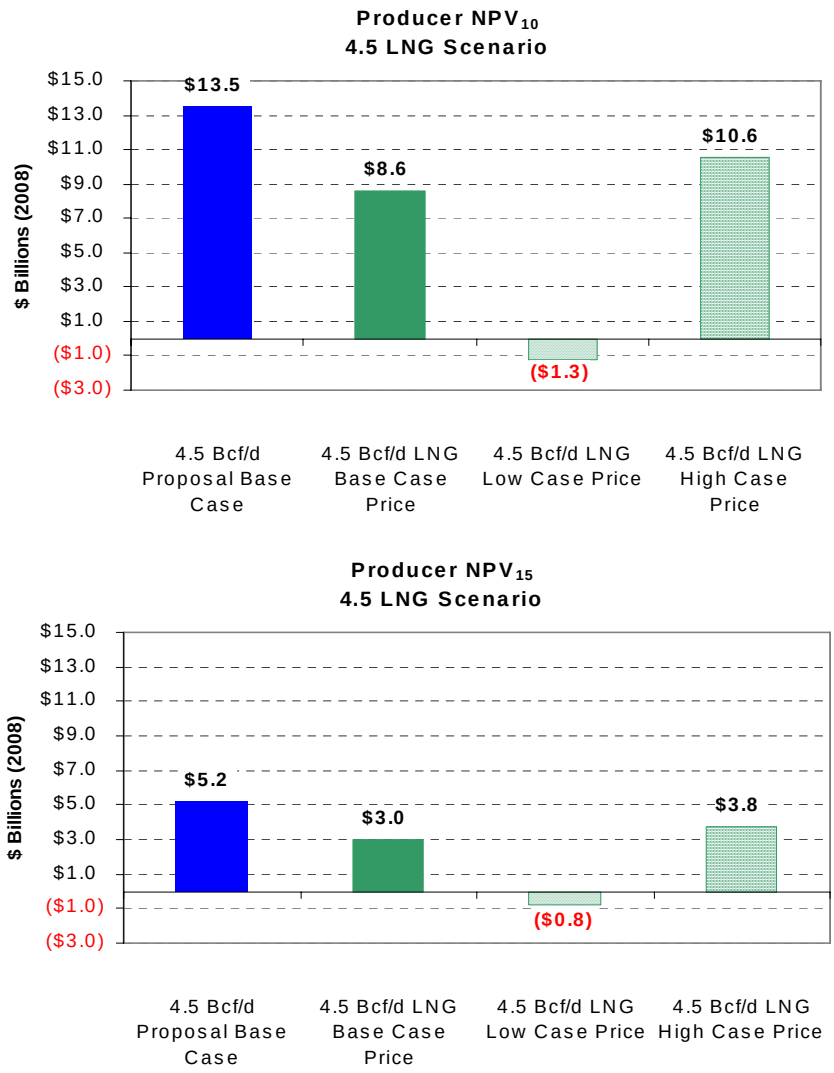
Source: Black and Veatch. Appendix G1, Section 7.12.3.

Figure 4-17 demonstrates that the TC Alaska Project would produce a significantly higher NPV for the State of Alaska than the LNG project across a range of long-term LNG contract arrangements. Under the Base Case set of assumptions, the LNG project would generate for the state an NPV_5 of approximately $48 billion, while the TC Alaska Project would produce a NPV_5 of approximately $66 billion.

The results are directionally similar for the Major North Slope Producers. Under Base Case assumptions, the NPV to the Producers, at both 10 and 15% discount rates, are greater under

the TC Alaska Project than under the 4.5 Bcf/d LNG option. Indeed, for the Low Contract price case, the LNG option fails to deliver positive returns to the producers.[32]

Figure 4-18. Major North Slope Producers' NPV: Comparing TC Alaska Proposal Base Case and 4.5 Bcf/d LNG Scenario Under Different LNG Contract Price Assumptions

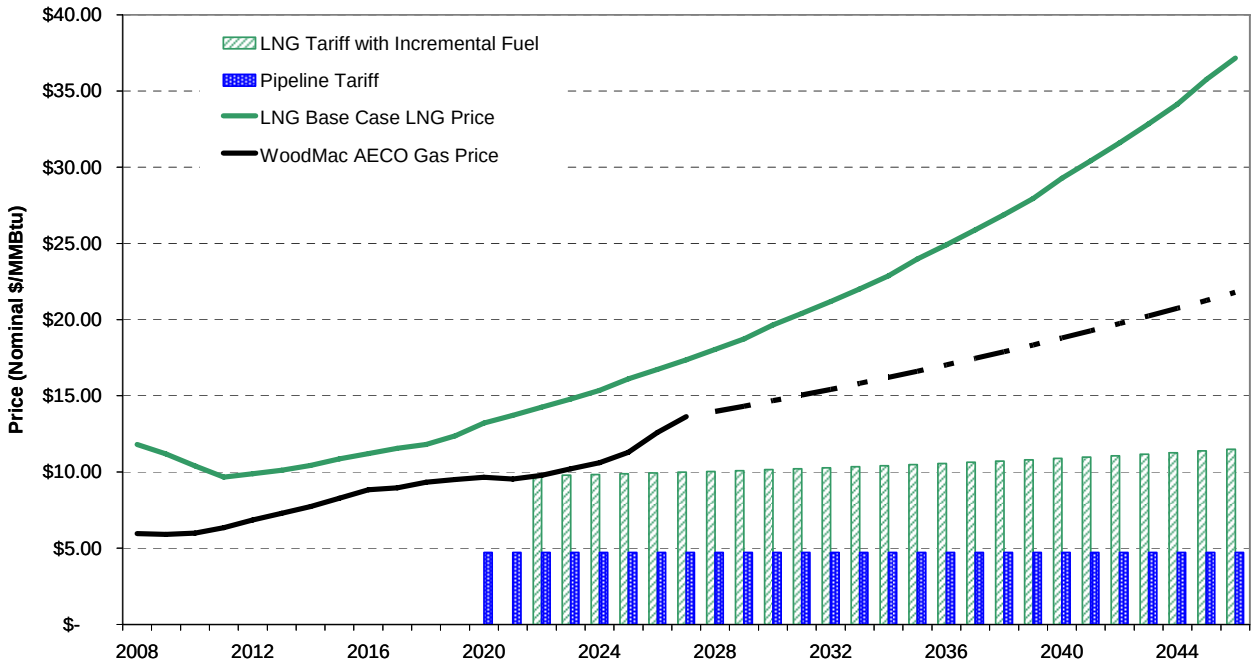


Source: Black and Veatch. Appendix G1, Section 7.12.3.

[32] This result differs directionally from the state's results for several reasons. For one, the state receives property taxes and corporate income taxes from the pipeline and liquefaction projects, while these are net costs for the Producers. In addition, both 4.5 Bcf/d cases significantly rely upon YTF resources. As modeled, under base case assumptions, YTF gas is found, developed and produced to enter the projects to keep them full, regardless of their economics. Because margins under the Low Price contract assumption are poor, the damage to YTF economics serves as a drag on Producer NPVs.

In addition, because LNG transportation costs are higher, the LNG project options considered are more susceptible than TC Alaska's Proposal Base Case to price risk. For a given net back margin, it takes a smaller percentage decrease in Asian Pacific LNG prices to stress an LNG project than it does to stress an overland pipeline project. This result can be visually inferred from Figure 4-19. A 50% drop in the price of LNG prices (the green line) "bites into" the LNG transportation cost (green bars) and thus leads to greater negative net backs than a 50% price drop in AECO Hub prices (the black line) "bites into" overland transportation costs (blue bars).

Figure 4-19. Price vs. Tariff for a 4.5 Bcf/d LNG Project and the 4.5 Bcf/d Proposal Base Case Pipeline Project

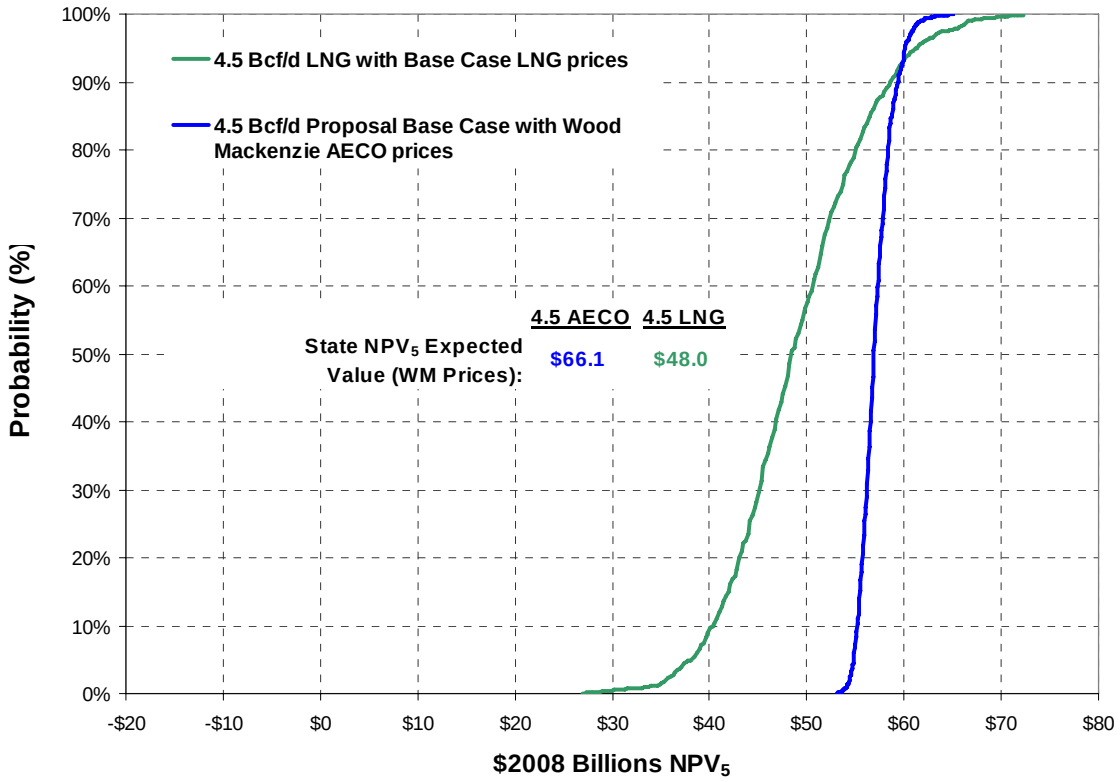


Source: Black and Veatch. Appendix G1, Section 7.12.1.

The analyses presented here are premised on both the TC Alaska and LNG cases coming in at mid-point probability (P50) cost levels. If costs for an LNG project come in lower than expected, then it would be better able to benefit from the expected higher Asian Pacific LNG prices. Figure 4-20 shows the state NPV_5 probability distribution that is generated from Base Case prices (for

both LNG and the TC Alaska Project) and uncertain project costs. It shows the NPV uncertainty that derives from cost uncertainty associated with project scope.[33]

Figure 4-20. Comparative State NPV_5 Distributions Associated with Project Cost Risk



Source: Black and Veatch. Appendix G1, Section 7.12.2.

Figure 4-20 shows that under the Base Case price assumption, there is less than a 10% likelihood that LNG project costs would be low enough for the LNG Base Case NPV_5 to exceed the NPV_5 of a TC Alaska 4.5 Bcf/d project.

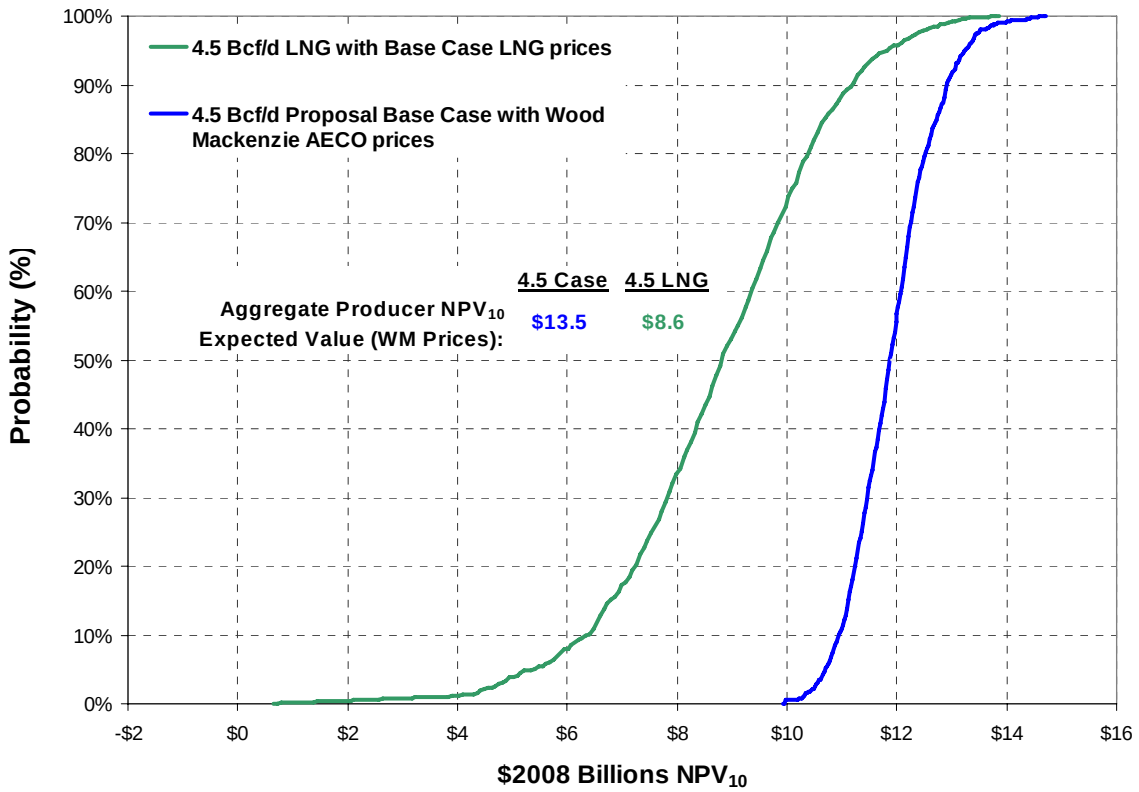
Similar results hold for comparative returns to the Major North Slope Producers from the 4.5 Bcf/d LNG project and a 4.5 Bcf/d pipeline project into Alberta.

There is essentially no chance that construction costs, as measured in current-day dollars and before figuring escalation risk, could be low enough to make an LNG project more profitable for

[33] Uncertainty of the cost escalation in inputs to construction, such as labor, steel, and the like, is addressed subsequently.

the Major North Slope Producers under the Base Case Contract price assumptions. This may help explain why, since at least 2001, the Major North Slope Producers have demonstrated so little interest in pursuing an LNG project for Alaska gas.

Figure 4-21. Comparative Producer NPV_{10} Distributions Associated with Project Cost Risk



Source: Black and Veatch. Appendix G1, Section 7.12.2.

There is another way, besides beating the odds on construction costs, that the 4.5 Bcf/d LNG project could provide better returns to the state than the TC Alaska Project's Base Case. As noted earlier, the extent to which Base Case or High Case contract terms yield an Asian LNG price premium depends significantly on the relationship of the price of oil, on an energy equivalent basis, to the price of gas in North America. As the oil to gas price ratio rises, the price premium generated by the Asian Pacific Base and High Case LNG contracts also rises. Accordingly, a high oil to gas price ratio could improve the relative economics of an LNG project. (See Appendix G1, Section 7.15.4, for a discussion of these points.)

Table 4-2 calculates the NPV difference to the state that would be provided by a 4.5 Bcf/d LNG project compared with the TC Alaska Project Base Case. It shows these differences under

different assumptions about the oil to gas price ratio during the projected period of project operations. It indicates that, if the oil to gas ratio was sustained at ten or above, an LNG project of this magnitude could generate superior returns to the state as compared with an overland project.[34]

Table 4-2. Stakeholder NPV for 4.5 LNG Project Under Alternative Scenarios-Base Case LNG

Scenario 4.5 Bcf/d LNG Project	State NPV_5	U.S. Government NPV_5	Producer NPV_{10}	Producer NPV_{15}
4.5 Bcf/d Base Pipeline Case NPV	$66.1	$30.5	$13.5	$5.2
Base Case LNG Price	($18.1)	($3.7)	($4.9)	($2.2)
8 to 1 Oil to Gas Ratio	($18.4)	($5.1)	($6.1)	($2.7)
9 to 1 Oil to Gas Ratio	($4.4)	($0.5)	($3.4)	($1.7)
10 to 1 Oil to Gas Ratio	$11.4	$3.5	($1.2)	($0.9)
11 to 1 Oil to Gas Ratio	$28.6	$7.0	$0.7	($0.2)

Source: Black and Veatch. Appendix G1, Section 7.15.6.

However, a price ratio of at least 11 would be required to generate a superior NPV for the Producers. Compared with the state, the Major North Slope Producers have a greater sensitivity to the price ratio because an LNG project's costs only detract from their revenues.[35] Here again, these results may help explain why the Major North Slope Producers have shown comparatively little interest in pursuing an LNG project.

Compared with the state, the Producers have a greater sensitivity to the price ratio because an LNG project's costs only detract from their revenues. Here again, these results may help explain why the Major North Slope Producers have shown comparatively little interest in pursuing an LNG project.

It is possible that, going forward, the oil to gas price ratio could be sustained at an average of ten to one. However, as noted earlier, the oil to gas price ratio fluctuates over time (See Figure 4-5, page 4-18). For the period of January 1995 to March 2008, the ratio was as high as 14 to 1 and as low as 3 to 1, with an average 8 to 1 (Appendix G1; Section 7.15.4.3). Recently the oil to gas price ratio has been nearly 12 (Oil Daily 2008b).

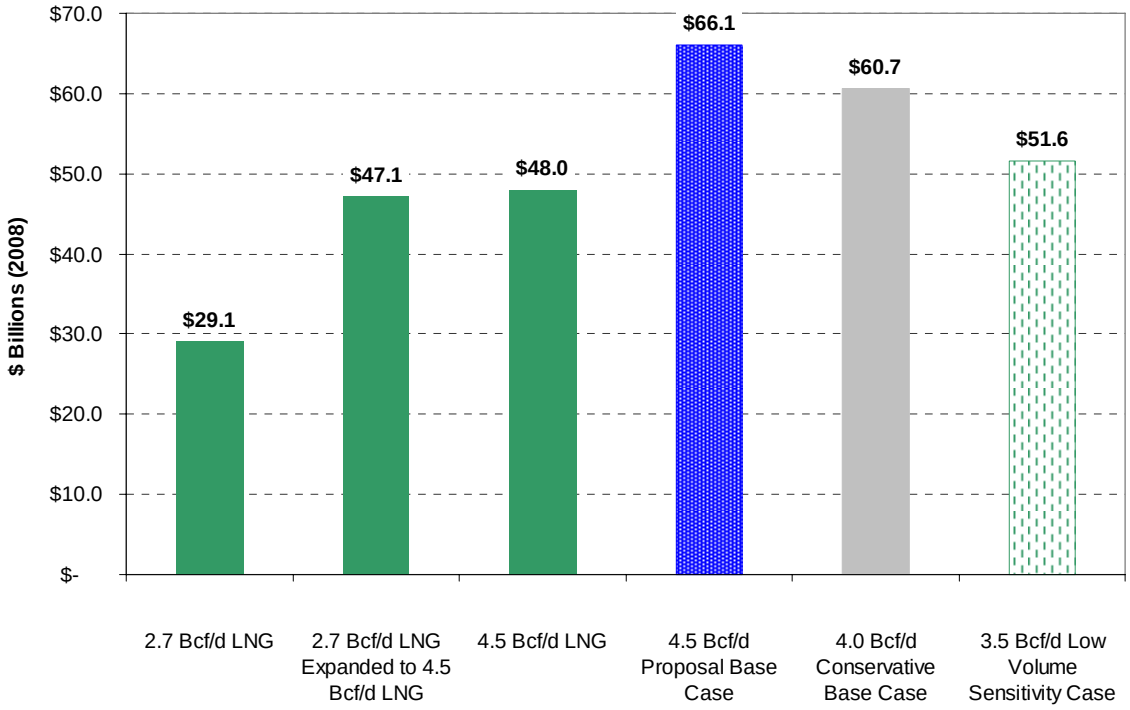
[34] We note again that the 4.5 Bcf/d Base LNG project contemplates initial volumes that are unrealistic. Actual volumes would need to be ramped up over an eight to ten year period. This would significantly decrease the revenue that the state would receive.

[35] The greater sensitivity derives from the fact that, for the producers, higher project costs only reduce their profits. In contrast, increased property tax receipts associated with greater in-state property balances mean that the state enjoys some degree of off-setting benefit from an LNG project's higher costs.

However, the commissioners see no reason to believe that this ratio will continue to depart, on a sustained basis, from historical averages. The current high oil to gas ratio is indicative of the natural volatility experienced for more than a decade. Meanwhile, as discussed previously, there are fundamental market forces that give good reason to believe that, over the relevant time frame, the oil to gas price ratio will more closely approximate its historical norm (Appendix G1, Section 7.15; Appendix I, Section 4.7; Kelly 2008).

Finally, the commissioners note that the volume uncertainty affects the TC Alaska Project just as it does an LNG project into the Asian Pacific. The volume of gas is sensitive to the commitments that gas shippers make. Accordingly, we can also compare returns to the state generated by lower volume TC Alaska projects with a range of LNG projects. The results are shown in Figure 4-22.

Figure 4-22. State NPV Under LNG and TC Alaska Pipeline Cases



Source: Black and Veatch. Appendix G1, Section 7.12.3.

The TC Alaska project generates superior returns compared to any of the LNG projects under Base Case assumptions. Even the 3.5 Bcf/d Low Volume TC Alaska scenario generates a greater state NPV than does the 4.5 Bcf/d LNG project.

F. TC Alaska's Project Has a Greater Likelihood of Success than Any of the LNG Options

In addition to producing a materially higher estimated NPV to the state than the LNG options, the commissioners conclude that the TC Alaska Project has a greater likelihood of success than the LNG options. The stand-alone LNG options face unique, significant challenges to their likelihood of success. Those issues, along with a comparison of the LNG options with the TC Alaska Project, are summarized below.

1. An LNG Project Would Be Significantly More Complex, and Thus More Risky, Than an Overland Route

There are a number of unique challenges that negatively affect the likelihood of success of any LNG project. First and foremost, an LNG project constitutes a significantly more complex undertaking than an overland project such as TC Alaska's, on several levels. As Goldman, Sachs and Co. states in its report, "LNG projects are inherently more complex than gas pipelines. Simply put there are more steps in the 'value chain' which translates into more parties involved, more contractual arrangements, and more technology and construction complexity." (Appendix H, page 43)

For example, to obtain financing, an LNG project, or its shippers, must secure long-term sales contracts for the LNG, in the form of a long-term take-or-pay market contract (Appendix H, Section VI.C). An LNG project cannot go forward without these long-term gas sales contracts. By contrast, the shippers on an overland pipeline project do not need to secure long-term gas sales contracts; instead, they can simply sell their gas into the market at the AECO Hub due to the liquidity of that market. For this reason alone, it would be considerably more difficult for an LNG project sponsor to obtain financing without firm long-term take-or-pay contracts than it would be for an overland pipeline project such as the TC Alaska Project (Appendix I, Sections 8.2 and 9.1).

The long-term sales contracts required for an LNG project will likely require a minimum of 20 years of proven and committed gas reserves dedicated to the project (with the reserves being certified by experts) to support the contracts (Appendix I, Section 4.6). Again, this type of long-term demonstration of sufficient gas reserves would not be required by the parties that are purchasing Alaskan gas at the AECO Hub. To be sure, an overland project, like an LNG project, will have to demonstrate a certain level of available reserves in order to obtain

financing. But, aside from the showing required to obtain financing, an LNG project would have to demonstrate adequate, long-term gas reserves to its customers as a result of the enhanced need of customers in Asia for security of supply, given that they have few if any available alternative supplies. Thus, TC Alaska's Project to the AECO Hub would have a somewhat lower hurdle to clear regarding demonstration of gas reserves than an LNG project.

Several other factors contribute to the enhanced risks and complexity facing an LNG project as compared to the TC Alaska Project. For example, in contrast with the TC Alaska Project to the AECO Hub, the LNG project options will require the design, construction and financing of very costly liquefaction facilities, in addition to establishment of the associated ownership structure and commercial terms and contracts to support the liquefaction facility (Appendix I, Section 7.2). Unlike the TC Alaska Project, an LNG project also requires costly marine transportation arrangements through ownership of or contracting for a significant number of LNG tankers. (Appendix I, Section 5.8). In addition, an LNG project will require that arrangements be made (typically by the buyer) for compatible regasification facilities or services at the market end of the transaction (Appendix I, Section 7.3).

Each of these project elements presents additional complexity and material risks in comparison to the TC Alaska Project, including, as the case may be, cost, technology, completion, currency, country and jurisdictional/choice of law risks. As Goldman Sachs states:

> *"From a comparative standpoint (i.e., [over]land gas line project versus an LNG alterative), injecting this broad range of incremental credit issues and risk factors substantially raises the bar in terms of obtaining investment grade ratings, favorable financing rates and ultimately developing a viable financing plan."* (Appendix H, p. 45)

There are simply more links in the chain that must be completed for an LNG project than for an overland pipeline project. And, even more challenging is that fact that all the links in the chain must be assured simultaneously. Indeed, Gas Strategies states that "[t]he need for proponents of LNG projects, usually the owners of upstream gas reserves, to be assured of all elements in the LNG chain at the time of the investment decision is a key driver in the structuring of LNG projects" (Appendix I).

> There are more 'links' in the project development chain that must be completed for an LNG project than for an overland pipeline project.
>
> Even more challenging is that fact that all the links in the chain must be assured simultaneously.

As a result, an LNG option would inevitably involve a longer schedule than the TC Alaska Project to negotiate all the project arrangements into place prior to the commencement of construction and potentially throughout the project. These challenges are not faced by an overland route. The typical structure of an LNG project involves several different ownership entities that must first agree to the elements of the project and then coordinate their activities to assure the earliest possible start date (Appendix I, Sections 2, 6.1, and 7.2). In many cases, for example, while the consortium of producers often is responsible for construction of the facilities through the liquefaction stage and loading terminal, if the tankers are chartered, another company may be responsible for delivery of the required tankers and still a third entity, the buyer of the LNG, would be responsible for arranging for the receiving terminal and regasification services. Thus, the project manager has a significant challenge to coordinate the various elements of the project and a very heavy negotiating burden.

Moreover, each entity (including each joint venture partner developing the project) would be subject to its own risks and have its own priorities. Such complications, while not guaranteeing that unexpected delays would arise, substantially increase the risks of delays occurring. If they do, the economic basis for the choice of an LNG project would be further eroded (Appendix I, Section 9.1). By contrast, the TC Alaska Project essentially faces none of these risks, but does have right-of-way and regulatory challenges of its own as discussed more fully in Chapter 3.

This is not to suggest that an LNG project could not overcome these barriers. LNG liquefaction projects have been constructed in other challenging areas of the world, and an Alaska project could be successful under the right set of conditions.[36] However, an LNG project involves several, interrelated elements—pipeline/GTP, liquefaction plant, long-term gas sales contracts, demonstration of long-term gas reserves, LNG tanker arrangements—which collectively are more complicated than the challenges facing the TC Alaska Project, and which must be achieved before a project can obtain financing (Appendix H, Section VI. C). The complexity of these multiple factors contributes to the lower likelihood of success for the LNG project options relative to the TC Alaska Project.

[36] That said, unlike most other LNG projects where the gas reserves are located at or near the liquefaction terminal, an Alaskan LNG project would have to construct a lengthy and costly pipeline from the producing area to the LNG liquefaction terminal. This makes the challenges facing an Alaskan LNG project even more complex than for most competing LNG projects located elsewhere in the world.

2. An LNG Project Would Be More Difficult To Finance Than an Overland Route

According to Goldman Sachs' analysis, an LNG project may be able to obtain financing, and could in rare circumstances potentially have a higher NPV than the TC Alaska Project depending on the price of LNG. However, as a result of the complexity and other factors discussed above, it will be quite challenging, and more difficult to finance an LNG project than the TC Alaska Project (Appendix H, Section VI. D). Thus, Goldman Sachs states that "it is difficult to reach a definitive conclusion at this stage about viability of the LNG-based cases," citing the "[a]bsence of key project elements upon which to base analysis." An in-depth analysis of the financeability of an LNG project would require, at a minimum, information about the project's:

- Defined business structure/finance plan.
- Equity sponsor/developer.
- Gas purchaser.
- Ship builder/operator.
- Committed gas volumes to supply the project. (Appendix H)

None of this information is available at this time.

In addition to the relative complexity of an LNG project, the Goldman Sachs report also identifies other issues that we believe would constitute barriers to financing an LNG project.

First, the sheer size of an LNG project makes it more difficult to finance than an overland route. According to the Goldman Sachs report:

> *"Comparing the 4.5 Bcf Proposal Base Case to the 4.5 Bcf LNG case provides a clear cost/per capacity measure. The [TC Alaska] Base Case has an all-in financing requirement of $56 billion, which in and of itself will be a challenge in terms of financing market capacity. The LNG project with comparable capacity requires $85 billion in funding. The second key comparison is between fully loaded transportation costs. In the case of the [TC Alaska] Base Case, the transportation cost is $4.73. For both the 4.5 Bcf and the 2.7 Bcf all LNG projects, the transportation cost is estimated to be between $9.51 and $9.74. In the case of the 4.5 Bcf project, this is driven by larger capital costs; in the case of the 2.7 Bcf project, capital costs are roughly the same as the TC Alaska Base*

> *Case but are spread over fewer units of throughput resulting in a higher transportation cost."* (Appendix H, p. 47)

Second, Goldman Sachs assumes that the Federal Loan Guarantee would not be available to an LNG project (Appendix H, Section VI. D). The TC Alaska Project can take advantage of an $18 billion Federal Loan Guarantee that Congress made available to qualified project through its passage of ANGPA in 2004, and that due to indexing will escalate to approximately $32.9 billion in the year 2020 (Appendix H, p. 50). An LNG project, however, would not have the ability to use the Federal Loan Guarantee if the LNG would be shipped to Asia instead of the U.S. (ANGPA 2004, Section 116). While this does not mean an LNG project could not obtain financing under the right set of circumstances, it makes it more difficult to obtain financing, and again places an LNG project at a disadvantage relative to the TC Alaska Project.[37]

Finally, LNG projects are most typically financed primarily with equity (Appendix I, Section 8.1). This is due largely to the complicated, interrelated nature of the many commercial and financial elements of a project that have to be tied together with contracts in a project financing (Appendix H, Section VI. C). Only the original two trains of the RasGas project in Qatar have raised significant quantities of bond finance (Appendix I, Section 8.3). Given the very high costs of an LNG project, it is unclear from where the equity for the project would come.

3. There Is a Significant Risk LNG Would Not Provide Open Access to Future Explorers, In Contrast With the TC Alaska Project

There is a significant risk LNG would not fulfill the state's interest in achieving a gasline project that can be reasonably expanded on an open access basis for explorers and producers. As explained in detail in Appendix R3, FERC does not require LNG terminals to operate on an open access basis. Thus, FERC does not require LNG terminal owners to allow other parties that may wish to bring additional gas supplies to market to use an LNG terminal. In fact, in the Energy Policy Act of 2005, Congress codified FERC's policy and went a step further by establishing that FERC cannot impose open access requirements on an LNG facility, which the

[37] The lack of loan guarantees would also increase the cost of any LNG project due to the fact that the interest rate on any financing will be higher to reflect the greater project risk that exists because the U.S. government is not guaranteeing the project debt in the event of a project failure (Appendix H, Section VI.D.). This increased cost is reflected in the NPV analysis discussed earlier in this Section.

Act defined to include an LNG export facility.[38] Thus the state could not impose its own open access terms on the LNG facility. Indeed, the only LNG export facility currently operating in the U.S. resides in Alaska (Nikiski) and it is neither FERC jurisdictional nor is it operated on an open access basis (EIA 2008b).

Assuming private ownership of the liquefaction facilities, it is unclear how the state could ensure open access. If the Major North Slope Producers, or any other producer, owned the liquefaction plant (as is typical in many LNG projects), they would be under no obligation as a matter of FERC regulation to provide access to the plant for other explorers and producers, or to expand the plant to allow third-party access.

If the lack of open access prevents an LNG project from being expanded, then any hypothetical jobs advantage for an LNG project would be substantially diminished relative to the TC Alaska project, because of the reduced potential for exploration and production.

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If the lack of open access prevents an LNG project from being expanded, then any hypothetical jobs advantage for an LNG project would be substantially diminished, relative to the TC Alaska project, because of the reduced potential for exploration and production. This problem would be even greater for a smaller LNG project.

4. The Major North Slope Producers Have Indicated Their Preference for An Overland Route Over the LNG Options

Another factor in comparing an overland project to the LNG options is an understanding of which approach the Major North Slope Producers would prefer. In the Major North Slope

[38] See Section 311(c)(2) of the Energy Policy Act of 2005 (codified at 15 U.S.C. § 717b(e)(3)(B)(ii)(I)). Section 311 of The Energy Policy Act of 2005 also gives FERC the exclusive authority over the siting, construction, expansion or operation of an LNG terminal. (Appendix R3, p. 6)

Producers' proposal under the SGDA process, in ConocoPhillip's November 30, 2007 proposal, and most recently in the Producer Project unveiled by BP and ConocoPhillips, the Major North Slope Producers have consistently favored an overland route over an LNG project. It is reasonable to assume that economics play a large role in their decision. Indeed, as shown above, the TC Alaska Project would produce a materially higher estimated NPV for the Major North Slope Producers than would an LNG project, and would engender significantly lower risks (See Appendix G1, Section 7 for further details). Thus, while both TC Alaska and an LNG project face the challenge of convincing the Major North Slope Producers to commit to transport gas on them, any LNG project would face the additional challenge of convincing the Major North Slope Producers to pursue something they have clearly rejected since their major 2001 study of Alaskan gas options.

On top of what appear to be inferior economics for the LNG projects, as discussed previously, securing gas commitments from the Major North Slope Producers for an LNG project may be especially difficult because each has gas reserves in the Pacific and Middle East regions which the companies may also wish to develop as part of their worldwide supply strategy (Appendix I, Section 9.1). Each company will have a different perspective on the priority it puts on developing Alaskan LNG. As a result, there is a risk that at least one of the Major North Slope Producers may not want to push ahead the development of an Alaskan LNG project. As Gas Strategies explains:

> *"In the absence of a strong economic incentive companies will prefer a pipeline project over LNG. This is driven by concerns over project delays and costs arising from their divergent strategic objectives in the Asia Pacific region and the need to secure long term sales contracts. This contrasts with their ability independently to transport gas to the North American market where volume risk is minimal and sales contracts are not required before investing in pipeline capacity."* (Appendix I, p. 4)

In addition, Gas Strategies concludes that the Major North Slope Producers "will be aware of the Federal desire to have Alaskan gas contribute to the energy security of the USA. Protecting their wider US interests may drive a reluctance to be seen to be promoting gas export from Alaska." (Appendix I, p. 54.) These reasons, coupled with the NPV advantage that an overland route would have over the LNG options, help to explain why the Major North Slope Producers have expressed, and likely will express in the future, a preference for an overland route instead of an LNG project.

5. An LNG Project Will Require Proven and Committed Reserves (Certified by Experts) to be Dedicated to the Project

As earlier noted, promoters of an LNG project will have to commit, in advance, to long-term (generally 20-25 year) sales contracts. Buyers will expect these to be backed by sufficient proven and committed reserves to fulfill the contract obligations; they will require a reserves certificate to demonstrate it (Appendix I, p.27). Banks providing funding will, as well, require evidence that sufficient reserves of proven gas are dedicated to the project to fulfill the sales contracts and a gas supply contract that is back-to-back with the LNG sales commitments (Appendix I, p.54-55). This is quite unlike an overland project, where gas shipping commitments from individual parties are sufficient to support financing. As noted earlier, it does not appear that proved reserves are sufficient to support such certificates for a 4.5 Bcf/d project; without Point Thomson gas there would even be challenges for a 3.5 Bcf/d project.

The magnitude of the reserves that will be required to be both proven and dedicated to support any LNG option are significant. More than 5 Tcf of natural gas are required for a 0.65 Bcf/d (5 mtpa) train to operate for 25 years (Appendix I, p. 46). The sponsor will be required to own or have binding contracts to acquire all of the gas to support the project (as well as firm pipeline access to move it to tidewater) at the time the project is structured and financed. This creates a further burden for an LNG project compared to an overland project.

6. Exporting LNG To Asia Presents Regulatory and Political Barriers That the TC Alaska Project Would Not Face

As discussed earlier, the most likely market for an Alaskan LNG project is in Asia. This is due to several factors, including the lack of any LNG receiving terminals on the West Coast of the U.S. or Canada, the fact that there is only one Mexican LNG receiving terminal, and, perhaps most importantly, the fact that LNG prices in Asia are (and are projected to be) higher than natural gas prices in U.S. West Coast markets due to the relative lack of other supply alternatives in Asia. Because Asia would be the primary destination market for Alaskan LNG, it is important to understand the special barriers that an Alaskan LNG project would face in attempting to export LNG to Asia.

The fact that a Federal Loan Guarantee is available for an overland route but is not available for an LNG export project is indicative of the political and regulatory obstacles facing any project which seeks to export LNG outside of North America. There are significant regulatory and

political barriers to exporting LNG to Asian markets, whereas the TC Alaska Project does not face similar barriers.

> The fact that a Federal Loan Guarantee is available for an overland route but is not available for an LNG export project is indicative of the political and regulatory obstacles facing any project which seeks to export LNG outside of North America.

For example, Section 3 of the Natural Gas Act effectively provides that an export to a NAFTA country (Canada or Mexico) shall be approved (Appendix R2). Based on this provision, and past practice by the U.S. Department of Energy (DOE), it would appear to be relatively routine for the shippers on TC Alaska's Project to receive the necessary export authorization.[39] In addition, although TC Alaska will not control any of the sales of natural gas that its shippers make, TC Alaska assumes that a large quantity of the gas initially exported to Canada will eventually be re-imported back into the U.S. after being transported through pipelines that receive gas at the AECO Hub (TC Alaska Application 2007, pp. 2.1-11). Canada is currently a net exporter of natural gas to the United States. As such, the introduction of a substantial incremental volume of natural gas from a pipeline transporting Alaskan gas to Canada would simply reinforce or enhance that exporter status.

By contrast, LNG projects would face several problems in obtaining the necessary authorizations to enable them to export LNG to Asian markets. The authorizations include DOE export authority, which is required to send Alaskan natural gas to a non-NAFTA country such as Japan, Korea, Taiwan or China.[40] As discussed in Appendix R2, although DOE authorized an export of LNG from Prudhoe Bay to Asia approximately 20 years ago that authorization occurred during a period when the supply and demand balance in the U.S. natural gas market was much different than it is today and is projected to be in the future.[41] Supply in the U.S. has struggled to keep pace with demand. Due to these fundamental supply and demand changes, there is a significant risk that DOE would not permit the export of significant quantities of Alaskan LNG to Asia (Appendix R2).

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[39] See *Maritimes & Northeast Pipeline, L.L.C.*, *Order Granting Blanket Authorization to Import and Export Natural Gas from and to Canada,* DOE/FE Order No. 1212 (1996)

[40] See Appendix R2 and 15 U.S.C. 717b (2006)

[41] See *Yukon Pacific Corporation*, DOE Opinion and Order No. 350, 1 FE ¶ 70,259 (1989)

Other export regulations also suggest that any effort to export LNG to Asia could face additional regulatory hurdles.[42] In addition, as a practical matter, any effort to export gas to Asia would face political opposition in both the U.S. and Canada.[43] Because of the political sensitivity of sending domestically-produced energy supplies to markets outside North America, particularly during a period of rising energy prices and declining domestic supplies, a material risk exists that any effort to export LNG to Asian markets would not receive the necessary regulatory approvals (Appendix R2).[44]

Although these export barriers would exist for any project seeking to export North Slope LNG outside of North America, a project seeking to export LNG to China might face additional political and regulatory hurdles. U.S. Congressional opposition to a Chinese company's effort to acquire Unocal was significant. (Lohr 2005). Meanwhile, Sinopec's involvement in the Little Susitna Construction Company's AGIA application caused some in Congress to suggest that an export ban could ensue. (Bolstad 2007) As discussed in Appendix R2, those hurdles create serious doubt that a project could obtain the authority to export North Slope LNG to China.

But in any case, China would probably not be the most attractive buyer for LNG supplies (Appendix I). China is more price sensitive than the other major Asian markets and there are creditworthiness questions around some of the smaller gas buyers. As an emerging gas market, China would need to develop not only the infrastructure to receive and market LNG but also the pipeline and distribution systems to move it from the terminal to the end users (Appendix I). The implications as to the preferred destination market—China or Canada/US—are clear: Canada via an overland pipeline provides sponsors and the state with much more certainty and likelihood of realizing the best value for Alaskan natural gas.

7. An Overland Route Has a Better Opportunity than an LNG Project To Spur a Petrochemical Industry

The specifications for LNG sold to Japan, Korea and Taiwan differ from LNG sold to the U.S. (and European) markets in terms of Gross Heating Value (GHV). The gas distribution systems

[42] Among these are the Naval Reserves Petroleum Act, 10 U.S.C. § 7420; section 28 of the Mineral Leasing Act, 30 U.S.C. § 185; and Foreign Investment and National Security Act of 2007 ("FINSA") at 50 App. USCA 2170.

[43] See Appendix R2, page 8.

[44] See also Appendix I, page 57 (noting that the Major North Slope Producers "will be aware of the Federal desire to have Alaskan gas contribute to the energy security of the USA. Protecting their wider US interests may drive a reluctance to be seen to be promoting gas export from Alaska.").

in these Asian markets require a higher GHV than do U.S. systems (Appendix I, Section 4.4). The Btu per cubic foot of gas required in these three principal Asian markets range from 1050 to 1170[45] (Appendix I, Section 4.4). This is higher than in most U.S. markets where the required GHV ranges from 980 to 1070 Btu. As a consequence, it is unlikely that such a project will spur the development of a major petrochemical industry in Alaska. A petrochemical industry would require that the gas liquids (propane, butane, ethane, and other liquids or liquefiables that increase the heating value of the natural gas stream) be stripped out of the gas stream for separate sales. However, this could not be accomplished while at the same time meeting the Asian market's GHV requirements.[46]

That being said, however, the analysis of LNG liquefaction processes reveals that an LNG project would be compatible with meeting in-state demand for propane. The cost and schedule impact of removing propane from the gas stream, for sale to Alaskans, is minimal. Meanwhile, total Alaskan needs for propane are modest. Accordingly, propane could be stripped from the LNG bound for Asia and diverted to the Alaskan market without falling afoul of Asian Pacific GHV requirements. The impact of propane extraction from both "lean gas" and "rich gas" cases described in the AGIA RFA is shown in Section 2.4 of the LNG analysis.

While an LNG project would not support a major petrochemical industry in the state, an NGL processing plant *could* be installed on TC Alaska's overland project to strip out the gas liquids. (TC Alaska Application 2007, pp. 2.2-2.77). Thus, there is more potential for creation of a petrochemical industry in Alaska via the TC Alaska Project than via an LNG project designed to move gas to Asian markets. Although as currently proposed, the TC Alaska project contemplates processing of NGLs in Alberta, the location of liquids processing will be determined by market forces.

> There is more potential for creation of a petrochemical industry in Alaska via the TC Alaska project than via an LNG project.

[45] Prudhoe Bay gas has a Btu content that generally ranges between 1067 and 1118 Btu.

[46] The difference in GHV also reduces the interchangeability of destination markets for an Alaskan LNG project since gas with the heating value to meet Asian requirements will exceed US requirements.

G. Conclusion

As discussed above, the analysis shows that although LNG project options could produce positive benefits to Alaska, TC Alaska's Project would provide the state and its citizens with greater benefits than the LNG options, including the following:

- Higher NPV. Under the Base Case set of assumptions for each alternative, the NPV to the state would be greater from TC Alaska's Project than from any stand-alone LNG project options. The stand-alone LNG options would only have a higher NPV to the state if future LNG prices significantly exceed the level that are likely to occur in the future on a sustained basis.
- Higher Likelihood of Success. The TC Alaska Project has a greater likelihood of success than a stand-alone LNG project, and accordingly offers a better chance at providing the state with benefits important to Alaskans—including jobs, in-state gas, an open access project, a source of state revenues, and getting a gasline as quickly as possible. For example:
    - The TC Alaska Project is less complex and involves fewer hurdles than an LNG project. In contrast with the TC Alaska Project, which must develop the pipeline/GTP, LNG projects require the development of the entire supply chain—including gas supply, pipeline/GTP, liquefaction plant, and access to LNG tankers and regasification facilities—before a project can obtain financing.
    - Unlike an overland route to Canada, an LNG project must have long-term gas sales contracts with creditworthy customers before it can be financed. By contrast, the shippers on an overland pipeline to Canada can simply make short-term gas sales in the spot market at the AECO Hub.
    - LNG options may also be disadvantaged because the Major North Slope Producers, based on their prior actions and recent indications, view an overland route as economically preferable to an LNG project.
    - While TC Alaska must obtain regulatory authorizations in both the U.S. and Canada, a stand-alone LNG project would have greater difficulty obtaining authorization to export gas from the U.S. to Asian countries, the most likely destination market for Alaskan LNG.

Analysis shows that stand-alone LNG project options are less desirable for the state than the TC Alaska Project. Even if one presumes the simultaneous occurrence of a number of unlikely economic events which could generate a greater NPV for a stand-alone LNG project option, the TC Alaska Project continues to enjoy a significantly higher likelihood of success. Accordingly, TC Alaska has a better chance than the stand-alone LNG options of providing benefits to Alaskans, including jobs, in-state gas deliveries, open access for explorers, and greater revenues for the state and its citizens.

The TC Alaska proposal does improve significantly the prospects of an Alaskan LNG project—the Y Line option. The TC Alaska Project provides Alaska with its best opportunity for a successful LNG project, as a Y Line option. The TC Alaska Project proceeding first will reduce costs and lessen financial and contracting hurdles associated with an LNG project. Coming after gas is already bound for U.S. markets, a Y Line may be able to overcome political opposition to exporting gas. Accordingly, the commissioners believe that the best route to an Alaska LNG project runs through the TC Alaska proposal.

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