SCOMM

129:9

ATTACHMENT "A'
INITIAL QUESTIONS

GENERAL BACKGROUND

The Committee conducted a number of public hearings on the construction of a pipeline to deliver natural gas to the lower 48 or to a liquefaction plant in Southcentral Alaska for delivery of liquefied natural gas to Asia, Mexico or California. Before several of these meeting the Committee, the Committee had sent various questions regarding the respective jurisdiction of the FERC and Regulatory Commission of Alaska (RCA) over a natural gas pipeline, upstream access to the pipeline, and downstream access to a pipeline to the FERC, the RCA and the law firm of Morrison & Foerster (Mofo), which represents the governor. The Committee received a lot of good information from the agencies, Mofo, and others about these issues. However, some of the information seemed conflicting or incomplete. Additionally, more questions, which I will break down by subject area, were raised. These questions are of vital importance to Alaskans and this body in making informed decisions regarding Alaska's ability to benefit from a natural gas pipeline. It is important that the Legislature get its own expert legal advice regarding these issues.

UPSTREAM ACCESS

Background

One group that desires to build a natural gas pipeline to the lower 48 and become its owner is composed of three largest owners of gas reserves on the North Slope, BP, Phillips, and Exxon (Owner Producers). The Owner Producers are among the largest companies in the world. Originally, under ANGTA, the Owner Producers were prohibited from owning any portion of the Alcan pipeline because of anti-trust concerns. ANGTA was later modified to allow the Owner Producers to own some portion of the pipeline. Since the time of that amendment, however, the FERC has unbundled pipeline services on the downstream end to allow for more competition. If the Owner Producers own the pipeline, many competitive concerns may arise, particularly with access to the pipeline by other potential shippers. Those potential shippers include the State of Alaska, which owns about 12.5% of the known reserves, and other oil and gas producers, like Anadarko and Alberta Energy (Non-Owner Producers), that have leased state or federal acreage with gas potential.

If the gas pipeline is a "contract carrier" as discussed above, the Committee understands that the Owner Producers will have a so-called "open season." During this period, potential shippers of gas are given the opportunity to enter long-term contracts with the pipeline owner, presumably on a fair and equitable basis. We were told that the reasons for an open season included demonstrating the need for a pipeline and providing information for sizing of the pipeline. If the Owner Producers own the pipeline, there is little need for an early open season since they have enough gas reserves themselves to justify construction of a pipeline and size it, assuming an adequate market exists. We were also told that the open season must be conducted before an application is filed and that the FERC does not control the open season.

The Owner Producers have informed the state that they intend to conduct an open season as early as first quarter of this year, although production will not flow through the pipeline for about seven years. (More recently, in response to request for comments to the royalty-in-kind gas sale proposed by the Department of Natural Resources, the Owner Producers have suggested that an open season may be delayed.) Further, the Committee has told that the application process alone would likely take eighteen to twenty-four months to complete.

Allowing the Owner Producers to control the date for an open season and to require a binding commitment to ship gas so early in the process creates several problems for the state. First, the state will not be in a position to decide whether it wants to ship its gas by first quarter of this year. It will not even know whether it will be allowed to have midpoint deliveries to Alaska markets. Second, the Non-Owner Producers say that they will not be in a position to enter firm contracts so early in the process (without taking inordinate risk). If the Owner Producers sign twenty-year contracts for the full capacity of the line with themselves, then the state and the Non-Owner Producers would be effectively shut out.

It is in the Owner Producers' interest to shut their Non-Owner Producers out of the pipeline rendering the latter's leases valueless and forcing them to relinquish the leases to the state and the federal government. Ultimately, the Owner Producers could use their monopoly power to buy the leases cheaply from the state and federal government. Usually a pipeline company, which does not own the gas resource, conducts the open season. It has no motive to take advantage of other owners of the gas resource. That will not be the case here. Moreover, the Owner Producers, unlike a non-affiliated pipeline company, will have an incentive to create high tariffs. High tariffs reduce royalties and taxes, and create another formidable barrier to entry.

During the course of the Committee's hearings, we were also told that the FERC lacks the ability to control expansion of a pipeline. In other words, even assuming that expansion would be economic and would yield a reasonable return to the owners, the FERC cannot require it.

Initial Open Season

Here are some of the questions upon which we believe expert advice is needed. Is it true that the initial open season must be conducted before filing an application? Has the FERC ever considered an application before an open season? Is it true that the FERC has no control over the open season? Given the situation here, can the FERC delay the open season until later in the process? Would the state have the ability to block an early open season either before FERC or in court and on what basis would a challenge be most successful?

If the open season cannot be delayed, can the FERC stipulate that the original open season only requires an expression of interest rather than a binding commitment? Has the FERC ever issued such an order? If there are over-subscriptions, will space be pro-rated? What will be the method for pro-rationing, proven reserves, high bid, or some other method? Who will determine the duration of firm capacity obligations, the Owner Producers or the FERC? Will the length be 10, 15, or 20 years?

Expansion Open Season

Assuming that the Owner Producers effectively shut out the state or Non-Owner Producers from the initial open season, we have several questions regarding expansion of the pipeline. Does the FERC have the authority to mandate expansion for the benefit of the state or Non-Owner Producers over the Owner Producers' objection? If so, how would that be determined? Has FERC ever ordered expansion of a pipeline? Assuming that the pipeline were expanded, how would the tariff be determined? Would the parties seeking expansion only bear the incremental costs of the expansion? Would they have to bear part of the original costs? (ANGTA, unlike what we understand the FERC's general practice to be, allows the costs of a conditioning plant at Prudhoe Bay to be recovered from shippers. If Non-Owner Producers had to be build their own conditioning plant at their field, it would seem unfair to allow recovery of the Prudhoe Bay conditioning plant costs from them.) Assuming that the pipeline were expanded, how would access to the new capacity be allocated? Would the Owner Producers have the right of first refusal to the new capacity or would another open season be conducted?

JURISDICTION

Background

The Trans Alaska Pipeline System (TAPS) carries oil from the North Slope to Valdez. Along the route, some oil is delivered into intrastate commerce in the Fairbanks area for the Williams and Petro Star refineries and in Valdez upstream of the marine terminal for another Petro Star refinery. The oil delivered to the marine terminal is transferred to tankers for shipment primarily to lower 48 markets with an occasionally shipment to the Far East market.

The TAPS is operated as a "common carrier" pipeline, which must accept all oil tendered to it on an equal basis to all shippers. If there is insufficient capacity for the volumes tendered, the pipeline company apportions its available capacity to accommodate all shippers requesting capacity. The RCA and the FERC jointly regulate the TAPS. The RCA regulates the intrastate shipments, while the FERC regulates the interstate shipments.

Naturally, Alaskans want the North Slope gas, virtually all of which has been discovered to date is owned by the state, to be available for in-state demand just as North Slope oil is available for in-state demand. We were told during the hearings, however, that the pipeline would not be a common carrier pipeline and that Alaska (and its regulatory agency, the RCA,) may have little say about the availability of gas for in-state demand.

In contrast to the TAPS situation, we were told at the hearing that, if "one molecule of gas" were shipped on a gas pipeline for interstate use, the pipeline would be exclusively regulated by the FERC. Even though the FERC would have exclusive jurisdiction, we were also told that the RCA would have general jurisdiction over "lateral lines" and that the RCA was "looking into these issues further."

The FERC representatives repeatedly answered their questions with reference to the Natural Gas Act (NGA), while barely mentioning the Alaska Natural Gas Transportation Act (ANGTA). Although the NGA does not talk about Alaska in-state use of North Slope gas, Section 13 of ANGTA clearly contemplates that North Slope gas transported along the Alaska Highway (Alcan) route to the lower 48 would be available for in-state use by Alaskans. With this background in mind, we have many questions regarding the respective agencies' jurisdiction and state access to North Slope gas for in-state demand.

State Access for In-State Demand and Tariffs

Assuming that the gas were to follow the Alcan route, where does the RCA's jurisdiction over lateral lines begin under the Natural Gas Act (NGA) and the Alaska Natural Gas Transportation Act (ANGTA)? Would the FERC or RCA decide whether mid-route delivery points could be established to serve Alaska markets such as Fairbanks, a spur line to Southcentral, and a spur line to Valdez? Under section 13 of the ANGTA, is an Alaskan mid-route delivery point required? Under either the NGA or ANGTA, could the FERC decide that the Alaska market would not be served, only the lower 48 market? If the pipeline owners opposed an Alaska mid-route delivery point, could the FERC mandate such a point? On what basis would FERC decide to allow a mid-route delivery point in Alaska at the time of the original construction of a pipeline? At a later date?

Can FERC guarantee now that Alaska will have access to **its own royalty gas**? If FERC cannot guarantee access to gas for Alaska under current law, what tweaking of federal law would you recommend to guarantee such access?

What would be the basis for in-state tariffs? Would there be a "postage stamp" tariff charging gas delivered to Fairbanks the same tariff as gas delivered to Chicago? Or would the tariff be determined on a mileage basis? According to Mofo, there was litigation regarding this issue in the late 1970's and the state's theory of a mileage-based tariff prevailed. Would that theory prevail under the NGA?

Regulation of In-State Tariffs and Prices

We were told that even if there were mid-route delivery points in Fairbanks, Delta Junction, and Tok, the RCA would not set tariff rates between the North Slope and those points in Alaska, rather the FERC would. Is this true under the Natural Gas Act (NGA)? Is it true under the ANGTA? What would be the basis for determining in-state tariffs on a pipeline with a Midwest final destination given that most of the costs would be incurred to serve the Midwest market?

Assuming that the tariff for shipment to Fairbanks is lower than the tariff for shipment to the Midwest, would the FERC set the price in Alaska for the gas? Would the state have the authority to set the price? How would the price in Fairbanks be determined?

Regulation over Hubs

We understand that the FERC does not regulate certain lengthy pipelines in the Gulf of Mexico that bring gas from the deep water to onshore pipelines. There the gas enters a "hub," a place where various pipelines meet. These lengthy pipelines may be thought of as gathering lines as opposed to transmission lines. In some respects an Alaska pipeline is akin to such gathering lines until it gets to a hub such as Fairbanks, where the gas could go to different markets. When the Committee asked questions about moving the jurisdiction of FERC to downstream of a Fairbanks hub, we got less than clear answers. Is it possible to move the FERC's jurisdiction downstream to a Fairbanks hub? In essence, is it possible to move the wellhead from Prudhoe Bay to Fairbanks? If it were not possible under existing law, what changes would you recommend so that the wellhead could be moved?

Regulation as a Common Carrier

As discussed above, the TAPS is a common carrier. We were told at the hearing that gas pipelines, unlike oil pipelines, are contract carriers. This means that a gas pipeline is not obligated to accept all gas tendered to it for transportation. In some respects, a gas pipeline through Alaska along the Alcan route would be more like the TAPS in that there is unlikely to be any competitor pipeline. Has the FERC ever regulated a gas pipeline as a common carrier pipeline? If so, what was the basis for the decision?

Regulation under the NGA or ANGTA

Under the ANGTA, a route for delivery of North Slope gas to the lower 48 has already been selected. That route is the Alcan route and it was selected ahead of an "Over the Top" route and a LNG route. Moreover, the Alcan route is the subject of a treaty and has already been approved by the Congress, the President and the Canadian government.

Given the ANGTA, what authority does the FERC have to consider a competing application for delivery of North Slope gas along an Alcan route under either the ANGTA or the NGA? Given the ANGTA, what authority does the FERC have to consider a competing application for delivery of North Slope gas along an Over the Top route under either the ANGTA or the NGA?

Under the NGA or the ANGTA, what authority will the state have with respect to environmental and right of way issues, including state-owned rights of way.

During the hearings the FERC staff stated that it couldn't even speculate about how long an application under the ANGTA would take to process. They could only say that it would not take any longer than a conventional NGA application. Since the whole purpose of the ANGTA is to expedite the certification and approval process, why can't FERC commit to a faster than conventional track for an ANGTA application?

Response To Request For Proposal
Answers to Questions on Attachment A

I. Upstream Access

A. General Discussion

The Legislature is correct in being concerned about the reality of "open access" on a pipeline owned either all, or in part, by the three largest owners of gas reserves on the North Slope – BP, Phillips, and Exxon. However, those same concerns exist whether or not BP, Phillips, and Exxon have an ownership interest in the pipeline. That is because BP, Phillips, and Exxon will be the anchor shippers. As such, whether or not they hold an ownership interest in the pipeline, they have an enormous amount of power and, therefore, control over (a) the structure and timing of an "open-season"; (b) the structure of the pipeline's tariff; and (c) the terms and conditions under which service will be provided to both the anchor shippers and others. They may also have a certain amount of control over the pipeline's potential expansion if not directly, indirectly through precedent agreements or undisclosed letter agreements.

1. Contract Carriers and the "Open Season": Natural gas pipelines are today somewhat of a hybrid between common carriers and contract carriers. Prior to the open access requirements imposed on virtually all federally-regulated interstate pipelines, interstate pipelines were true "contract carriers." They provided service to those with whom they chose to contract – service being provided pursuant to the rates and terms and conditions generally applicable to all similarly-situated shippers. These were usually set out in generally-available Rate Schedules. However, pipelines were also free to provide unique services tailored to a particular customer's needs -- so long as the pipeline obtained FERC approval prior to commencing service. These contracts were filed as separate "Rate Schedules." They were a part of the pipeline's filed tariff and, therefore, were public. They could become the basis for an undue discrimination claim down the road if the pipeline refused to provide similar rates or terms and conditions of service to a similarly-situated person requesting service. But, because pipelines were usually fully-contracted for on a firm basis, and because pro-rationing of service cannot be ordered under the Natural Gas Act, access was usually denied because of a lack of available firm capacity.

Some, but not all of this changed when FERC began to require interstate pipelines to provide "open access" transportation. Now, pipelines are still allowed to contract with whom they choose but there are new rules governing how "excess" or "turned-back" capacity is to be made available. Rules have also been established to govern the means through which contracted-for but unneeded capacity can be temporarily released or permanently resold by the existing capacity holder. But, for pipeline expansions or new pipelines, until FERC developed its "open season" requirement there was no obligation to afford all potential shippers access to capacity on a non-discriminatory basis.

As the RFP observes, FERC has stated that the reasons for an open season include demonstrating a "need" for the pipeline and providing information regarding the "sizing" of the pipeline. These regulatory objectives are of little significance when dealing with an Alaskan natural gas pipeline. However, there is a more general objective also articulated by FERC -- to provide all potential shippers an equal opportunity to enter into long-term contracts with the pipeline. This latter objective, also, can be frustrated through advance negotiations, timing of the open season, or both.

Generally speaking, a new pipeline will hold an "open season" for all or some portion of its capacity. But, there are no specific rules or regulations governing the procedures for allocating generally-available pipeline capacity for new projects. Rather, there are only general guidelines and these guidelines – which have as their basis the NGA's nondiscrimination requirement – tend to reflect the complexities and risks associated with planning, financing, and developing new pipeline projects. Therefore, without rules governing how an open season should be conducted, an aggrieved shipper must wait until after the capacity has been awarded and the certificate has been filed before it can raise an objection.

The "need" for the Alaskan pipeline, it would seem, should be measured by reference to the projected need for additional natural gas in both Alaska and the Lower-48 – not by the willingness of BP, Phillips, and Exxon to contract with the pipeline. Similarly, the proper sizing of the pipeline should be determined by reference to the delivery potential of reserves along the route of the pipeline or accessible to the pipeline (as is done in the OCS) not by reference to the reserves that BP, Phillips, and Exxon are willing to commit to the pipeline. Of course, the viability of the pipeline is in large part, dependent upon the receipt of long-term contractual commitments from BP, Phillips, or ExxonMobil. The ultimate question then, is whether these producers either need to, or can be required to, produce these gas reserves. Alternatively, can they be enticed into producing their reserves? But, if one allows the "need" for this pipeline or its sizing to be controlled exclusively by the outcome of the open season, FERC would be abdicating its regulatory responsibility to BP, ExxonMobil, and Phillips. Therefore, in this case, it would not be beyond the pale for FERC to indicate that it will move forward and process an application for an Alaska pipeline on the basis of overall national need – not on the basis of executed binding precedent agreements. This could be done as a matter of policy to eliminate or mitigate the significant power that these producers currently hold over the terms and conditions of service on an Alaskan pipeline. FERC could at the same time, indicate when the pipeline should hold its open season and the terms and conditions under which that open season will be conducted. This would have to be done by a new rulemaking.

B. Initial Open Season – Response to Specific Questions

1. Although FERC prefers that an open season be held prior to the filing of a certificate application it is not required. Open seasons have been held before and after the filing of certificate applications. And, in some cases, the open season has been held after the certificate has issued. In situations where the open season is held either after the application is filed or after the certificate has issued, it is usually because pre-subscriptions of capacity are already sufficient to justify the pipeline. On new projects, FERC has allowed a significant amount of capacity to be pre-subscribed – and not even made subject to the outcome of the open season – generally where owner-shippers have significant reserves to ship and have committed a significant amount of capital to the project. For example, in Green Canyon Pipe Line Co., 47 FERC ¶ 61,310 (1989), 78% of the pipeline's capacity was pre-subscribed with only 22% made available through an open season. FERC has not been sympathetic to protests raised by potential shippers which were not prepared to commit to capacity at the time of the open season. Shell Gas Pipeline Co., 74 FERC ¶ 61,219 (1997).

2. It is not true that FERC has no control over the open season. It is true that FERC has yet to exercise control over the open season except on an after-the-fact basis when faced with complaints of undue discrimination or preference. We believe that it is well within FERC's authority to promulgate rules of a general or specific nature governing open seasons.

3. We do not believe that the state could block the project sponsors from conducting an early open season either by filing a complaint before FERC or by seeking relief in the courts. Given the existing statutory and regulatory scheme under which FERC operates, any such challenge would be deemed premature and dismissed by FERC; and any attempt to seek judicial review of a FERC decision declining to entertain such a complaint would fail the ripeness standard. Further, because exclusive jurisdiction over appeals from FERC action resides in the Courts of Appeals, there is no jurisdiction in the United States District Courts. As such,

under the existing regulatory scheme, a challenge at FERC would have to await the filing of a certificate application reflecting the allocation of capacity from the open season, and any challenge to FERC's ruling would have to await a final decision on the merits before an appeal could be brought in a United States Court of Appeals.

If the Legislature were to conclude that it is essential to have this issue addressed before an application is filed, the best option is to seek a rulemaking at FERC governing the timing of and rules for conducting an open season for the Alaska pipeline. Although FERC has no obligation to respond affirmatively to such a request, we believe that if the filing is preceded by meetings with FERC Staff and the FERC Commissioners to explain the basis for concern, the Legislature will have a receptive audience. At the same time, the state could consider a federal legislative directive to FERC to promulgate rules regarding the timing and content of any open season for an Alaskan pipeline, including guidelines on how capacity is to be allocated.

4. If an open season is held and an application is filed based on the results of that open season, FERC could rule, in response to a complaint, that given the long lead time between the filing of the application and the proposed in-service date of the pipeline that a second open season should be held to confirm or reallocate capacity. That second open season would have to take place within some specified time prior to the commencement of construction because, as a practical matter, financing must be in place prior to the commencement of construction and financing will be dependent upon the pipeline's contracts. FERC could also make this determination as a part of a rulemaking regarding the Alaskan pipeline project were a petition for a rulemaking filed. The arguments would have to be persuasively made – as we believe they could – because FERC has never recharacterized as an "expression of interest" an open season that the pipeline considered "binding" and based upon which it entered into "binding" precedent agreements. Keeping in mind that under the Natural Gas Act a pipeline is free to enter into binding contractual commitments, FERC will have to make the finding that those commitments are contrary to the public interest and require modification.

5. In a properly-conducted open season, an over-subscription means that there are qualifying bids for more capacity than has been <u>offered</u> in the open season, keeping in mind that certain capacity may be pre-subscribed and, therefore, not offered. Capacity is generally allocated based upon the highest net present value ("npv") to the pipeline (typically, the discounted cash flow of incremental revenue per dekatherm based on factors such as rate, term, quantity, reserve commitment, and date on which service is to commence). <u>E.g.</u>, <u>Nautilus</u>

Pipeline Co., LLC, 78 FERC ¶ 61,325 (1997); Southern Natural Gas Co., 96 FERC ¶ 61,008 (2001); Tennessee Gas Pipeline Company, 76 FERC ¶ 61,101 (1996); Texas Eastern Transmission Corp., 79 FERC ¶ 61,258, order on reh'g, 80 FERC ¶ 61,270 (1997). Only capacity for which there is a tie tends to be pro-rated, although using pro-rationing as the method for breaking the tie is not required. E.g., Kern River Gas Transmission Co., 95 FERC ¶ 61,022 (2001); Transcontinental Gas Pipe Line Corp., 66 FERC ¶ 61,273 (1994); Green Canyon Pipe Line Co., 47 FERC ¶ 61,310 (1989); Shell Gas Pipeline Co., 76 FERC ¶ 61,260 (1986). The only real rule is that the criteria used to allocate capacity must be applied without undue discrimination. Id.

6. The pipeline may establish a minimum term for contracts for newly constructed facilities National Fuel Gas Supply Corporation, 77 FERC ¶ 61,005 (1996), as well as a maximum term. Southern Natural Gas Company, 96 FERC ¶ 61,008 (2001). There is no FERC policy on the duration of contracts – they may be for the life of the reserves.

C. Expansion Open Season – Response to Questions

1. FERC has absolutely no authority to mandate an expansion of the pipeline under existing law and any attempt by FERC to condition a certificate on a requirement that expansion capacity be constructed would be challenged as ultra vires. Panhandle Eastern Pipe Line Co. v. FERC, 204 F.2d 675 (3d Cir. 1953). To the best of our knowledge, FERC has never successfully ordered the expansion of a pipeline under the Natural Gas Act. (FERC does possess that power, in certain circumstances, under the Outer Continental Shelf Lands Act although, to the best of our knowledge, it has not used that authority).

2. Pipeline expansions are treated in much the same way by FERC as are new pipelines. Rates are usually designed on an incremental basis to ensure that customers bear only those costs associated with the facilities that they use. Of course, an expansion customer may benefit from the original capacity, depending on the operational characteristics of the pipeline. In a case where a pipeline expansion is to be used by the original shippers and where the expansion shippers also utilize the original capacity the costs of the expansion may be rolled into the original cost and allocated among all shippers.

3. Access to new capacity would be handled consistently with the tariff of the existing pipeline or in accordance with the same rules discussed above for new pipelines. Some pipelines have included in their tariffs specific procedures

to be followed for purposes of allocating expansion capacity. When this is done, and the tariff is approved by FERC, the pipeline need only follow its tariff rules when allocating capacity.

4. The Commission strongly encourages, and, in fact, expects that an open season will be held for all new capacity, including expansion capacity. Again, in the absence of a tariff provision stating otherwise, pre-subscriptions are permitted if the facts and circumstances so require. The Legislature should be aware that bids can be submitted in the initial open season for both initial capacity and expansion capacity if the open season is so structured. Rights-of-first-refusal ("ROFR") relate to the right of an existing shipper to continue its existing service upon contract expiration by matching the highest competitive bid for service up to the maximum rate. Under FERC's Order No. 637 certain restrictions apply to the ROFR but, to respond to the state's question, these rights do not extend to new capacity.

II. Jurisdiction

A. General Discussion

A primary distinction between natural gas pipelines subject to FERC's jurisdiction under the NGA and oil pipelines subject to FERC's jurisdiction under the ICA is that oil pipelines are common carriers while gas pipelines are not. In addition, the commingling of interstate gas with intrastate gas in a common stream causes the entire gas stream to fall within the exclusive jurisdiction of FERC under the NGA as being "in interstate commerce." However, the sale of natural gas to communities or distribution companies in Alaska is not within FERC's jurisdiction even though the gas travels in a commingled stream through an interstate pipeline. As such, the availability of the Alaskan gas for in-state use is not affected, other than in instances of pipeline operational problems or capacity restraints. The terms and conditions of the transportation service, however, will be within the province of FERC (including those relating to capacity curtailments). State agencies can regulate wholly intrastate facilities or facilities which form part of an intrastate natural gas company even if natural gas is received from an interstate pipeline. This can be done by having the natural gas transported through the interstate pipeline under NGPA section 311(a)(1) to the point of interconnect with the intrastate facilities or by transporting the gas through the interstate pipeline under NGA § 7, thereby transforming the intrastate system into a Hinshaw pipeline which is exempt from FERC's jurisdiction under NGA section 1(c). In the latter case it would be essential that the RCA exercise regulatory control over the intrastate facilities and that the gas be consumed within Alaska. With that as background I will respond to the specific questions asked, to the extent possible.

B. State Access for In-State Demand and Tariffs – Response to Specific Questions

1. The RCA's jurisdiction over lateral lines exists wherever there are intrastate facilities owned and operated by an Alaskan company which are used to sell or deliver gas, whether bundled or unbundled, to customers in Alaska (whether wholesale or retail). Under the Natural Gas Act, federal jurisdiction ends at the local distribution of gas (NGA § 1(b)) or at the point of interconnect between an interstate transmission system and an intrastate transmission system where all of the gas received by the intrastate system is consumed within the state and the rates and services of the intrastate system are subject to regulation by a state commission. NGA § 1(c), 15 U.S.C. § 717(c).

2. Assuming that the pipeline which is ultimately constructed is the pipeline which was authorized under ANGTA, FERC would have the authority to order mid-route delivery points in Alaska were the pipeline to refuse to provide the requested delivery points. Under Section 13 of ANGTA, in the exercise of that authority, FERC is required to ensure that the State of Alaska may ship its royalty gas for use within Alaska "and is to issue whatever authorizations are necessary to withdraw such gas from the interstate market for use within Alaska." (Note: The language of ANGTA pre-dates the Wellhead Decontrol Act and, therefore, speaks in terms of withdrawing gas from the interstate market. Before the decontrol of wellhead sales of natural gas, once the sale of gas in interstate commerce commenced or the transportation of natural gas in interstate commerce commenced, the entire gas stream became dedicated to the interstate market and could not be withdrawn from that market for intrastate purposes. That is no longer the law. Natural gas from a single wellhead may now be sold in both the interstate and intrastate markets. There is no longer a concern about "withdrawing" gas from the interstate market because gas is no longer "dedicated" to the interstate market. Rather, contracts will control the destination of gas.) However, if the pipeline is not constructed under the authority of ANGTA, but only under the NGA, then the State of Alaska would have to file a complaint against the pipeline were it to refuse to allow the required intrastate delivery points and/or the required interconnection with intrastate facilities. The Complaint would have to be based on the prohibition in NGA § § 4 and 5 against undue discrimination and undue preference.

3. Given the language of Section 13 of ANGTA, the State of Alaska is "authorized" to ship its royalty gas on the approved Alaskan pipeline system but the statute does not specify under what "terms and conditions" or whether access is guaranteed for the State's royalty gas. While the clear inference is that Congress intended all shippers to have "access" the statutory language does not go that far. On this point as well as the issue in II E., infra, additional research is required. However, if an Alaskan pipeline is constructed solely under the authority of the Natural Gas Act – without reference to ANGTA – then the State of Alaska, clearly, would have to participate in the open season in the same way as a private party.

4. If one were to conclude that under ANGTA FERC can guaranty access to the state's royalty gas, then the Legislature's primary concern should be whether a pipeline can be approved outside of ANGTA. There are those (including DOE and FERC) who believe that current law does not require that a pipeline constructed to bring North Slope Alaskan gas to the Lower 48 must be the pipeline authorized under ANGTA. Rather, they believe that such a pipeline could be authorized solely under the NGA. As explained in response to E. below, we are unable, without additional research, to opine as to the correctness of that position. Regardless of the answer to that question, and given the view of the DOE and FERC, it would be best to ensure transportation capacity rights for the state's royalty gas in any new legislation directed at the Alaska natural gas pipeline.

5. In-state tariffs would related only to intrastate facilities and, therefore, would be governed exclusively by Alaskan law.

6. FERC-approved rates – which would apply to deliveries made within the State of Alaska or in interstate commerce – would be governed by federal law. Under current FERC policy rates are to reflect distance absent other overriding factors. 18 C.F.R. § 284.10(a)(3) (2001). The Commission has concluded that on most pipeline systems, the costs of providing service are materially affected by the distance the gas is transported. E.g., Northwest Pipeline Corp., 82 FERC ¶ 61,158 (1998); Kern River Gas Transmission Co., (ALJ: 94 FERC ¶ 63,008 (2001)). However, the Commission does not mandate mileage-based rates. For example, on some systems distance may not materially affect the cost of doing business – the most common factor in determining whether the permit postage-stamp rates is whether the pipeline received gas at both ends of its system so that the gas may flow in either direction, rather than in a single upstream to downstream direction. Northwest Pipeline Corp., 82 FERC ¶ 61,158 (1998); East Tennessee Natural Gas Co., 64 FERC ¶ 61,159 (1993); Williams Natural Gas Co., 41 FERC ¶ 61,037 (1987), Southern Natural Gas Co., 10 FERC ¶ 61,287 (1980).

In addition, the Legislature should be aware that FERC allows negotiated rates which may differ significantly from tariff rates.

C. <u>Regulation of In-State Tariffs and Prices</u>

1. It is true, as noted above, that even if there were mid-route delivery points in Alaska, FERC would set the rates for that transportation service. This is because, due to the commingling rule, all of the gas in question is treated as gas being transported interstate commerce placing <u>exclusive</u> jurisdiction over the rates for such transportation service in FERC. NGA § 1(b). ANGTA does not alter this regulatory scheme. In fact, ANGTA Section 13 preserves FERC's jurisdiction over rates stating that "the . . . [FERC] shall issue all authorizations necessary to effectuate such shipment and withdrawal subject to review by the Commission only of the justness and reasonableness of the rates charges for such transportation."

2. If distance-based rates were structured for the Alaskan pipeline, more costs would be allocated to shippers designating delivery points in the Midwest over shippers designating Fairbanks.

3. FERC has no jurisdiction over the price at which natural gas can be sold in Alaska. The state would have the authority to set the price for such sales. And, presumably, the price in Fairbanks would be a delivered price inclusive of the cost of the gas, the interstate transportation costs, and any intrastate transportation costs.

4. It is unlikely that FERC would disclaim jurisdiction over the transportation of natural gas from the North Slope to Fairbanks. While the unusual length of pipeline bringing natural gas from the wellhead to the "hub" is similar to the long, deepwater gathering lines in the Gulf of Mexico, both in concept and in purpose – bringing natural gas from a wellhead located a significant distance from a possible point of interconnection on the interstate pipeline grid –here there is only one continuous pipeline which will extend from the North Slope to natural gas markets. This configuration is indicative of an interstate pipeline, not a gathering system. In fact, we would conclude that were a pipeline comparable to that proposed for Alaska to be constructed in the Gulf of Mexico, the entire pipeline would be classified by FERC as an interstate pipeline subject to the Commission's NGA jurisdiction.

5. While I do not believe that FERC would be inclined to disclaim jurisdiction over the portion of the Alaska pipeline extending from the North Slope

to Fairbanks if there is only one pipeline under common ownership which will take the North Slope gas to market, such a determination might be obtained if there were two separate entities (potentially even with the same ownership) and a bifurcated line – that is, Company A owning the line (and, ideally it will pick up more than just North Slope gas) from the North Slope to Fairbanks, and Company B owning the line from Fairbanks south. It may also be possible – albeit somewhat difficult – to obtain authorization from FERC for a "dual-use" facility. Under this scenario, the state would lease an undivided interest in the pipeline facilities to Fairbanks for the state's royalty gas and obtain a ruling from FERC that the leased capacity is subject only to state regulation. While FERC has in some instance, allowed the converse, policy considerations here could play a significant role in attempting to expand that authorization. Any of these approaches would require the full cooperation of the pipeline owners and appropriate rulings from FERC.

6. As noted above, capacity reservations for the state's royalty gas and state control over that capacity is potentially achievable under existing law through the arrangements discussed above. However, an amendment to ANGTA to ensure state control over the capacity used to transport the state's royalty gas would be the best solution, as would, of course, explicit language in any new federal legislation.

D. **Regulation as a Common Carrier – Response to Specific Questions**

1. There appears to be no question that there will be only one major gas pipeline transporting North Slope gas to the Lower 48. However, that does not alter the fact that under existing law, including both ANGTA and the NGA, such a pipeline is not a common carrier. Legislation would be required to alter that status and it is my understanding that the United States Congress would not support such legislation. Legislation addressing competition issues related to access, however, may well to receive such support.

2. Neither FERC nor its predecessor has ever regulated a natural gas pipeline as a common carrier. To do so would be outside the scope of the agency's authority under its enabling acts.

E. Regulation Under the NGA or ANGTA – Response to Specific Questions

1. The issue of FERC's authority to approve an application for delivery of North Slope gas along a route different from that authorized under ANGTA is subsumed into the question whether ANGTA precludes FERC from considering an application filed exclusively under the NGA for an Alaskan natural gas pipeline intending to deliver natural gas from the North Slope of Alaska to the Lower 48. I am aware that competent counsel (both public and private) have differing views on this critical issue. I am also aware that DOE and FERC are of the view that FERC may consider and approve under its Natural Gas Act authority a competing application which proposes a route other than the Alcan route.

As I mentioned above, I do not know the answer to these questions at this time. Additional research and analysis is required. Of course, Congress could render that issue moot through legislation such as S. 1766.

2. The state's authority regarding environmental issues and rights-of-way, including rights-of-way through state-owned lands, continues, intact, with the caveat that the state cannot refuse to grant the necessary rights-of-way nor can it interfere in the construction of a federally-approved project along a federally-approved route. However, FERC has historically listened to legitimate state concerns and can be expected to continue to do so, conditioning certificates accordingly. But, in the end, FERC's decision will control.

3. FERC cannot now commit to a faster track for approval of a project because it has not seen the application and does not know how extensive an environmental review it will be required to conduct. FERC has stated publicly that the existing environmental data for ANGTS is stale and that updated studies and analysis must be filed and reviewed, even for the existing route. The time that will be required to conduct that review will depend, on large part, on how complete the data are and how much opposition the project receives. Absent a statutory mandate to complete the review within a specified time, FERC simply will not commit to any particular timeframe within which it will grant a certificate.

ALASKA STATE LEGISLATURE

JOINT COMMITTEE ON NATURAL GAS PIPELINES

Official Business

Senator John Torgerson, Chair
Senator Rick Halford
Senator Pete Kelly
Senator Johnny Ellis

Representative Joe Green, Vice-Chair
Representative Brian Porter
Representative Scott Ogan
Representative John Davies

To: Joint Committee on Natural Gas Pipelines

From: Senator Torgerson, Chair
Joint Committee on Natural Gas Pipelines

Date: February 15, 2002

Subject: Attachment to Committee Meeting Folders for 2/15/02

The United States Senate is no longer considering SB 1766, the Energy Policy Act of 2002, and is now considering S. 1948. Enclosed please find the pages pertinent to the Alaska Natural Gas Pipeline that we received on February 14, 2002.

Session: January – May
State Capitol, #427
Juneau, AK 99801
Phone: 907-465-2828
Fax: 907-465-4779

Interim: May – December
35477 Kenai Spur Hwy., Suite 101A
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New Federal legislation 2/14/02

TITLE VII – NATURAL GAS PIPELINES

Subtitle A – Alaska Natural Gas Pipeline

SEC. 701. SHORT TITLE.

This subtitle may be cited as the "Alaska Natural Gas Pipeline Act of 2002".

SEC. 702. FINDINGS.

The Congress finds that:

(1) Construction of a natural gas pipeline system from the Alaskan North Slope to United States markets is in the national interest and will enhance national energy security by providing access to the significant gas reserves in Alaska needed to meet the anticipated demand for natural gas.

(2) The Commission issued a certificate of public convenience and necessity for the Alaska Natural Gas Transportation System, which remains in effect.

SEC. 703. PURPOSES.

The purposes of this subtitle are–

(1) to expedite the approval, construction, and initial operation of one or more transportation systems for the delivery of Alaska natural gas to the contiguous United States;

(2) to ensure access to such transportation systems on an equal and nondiscriminatory basis and to promote competition in the exploration, development and

production of Alaska natural gas; and

(3) to provide federal financial assistance to any transportation system for the transport of Alaska natural gas to the contiguous United States, for which an application for a certificate of public convenience and necessity is filed with the Commission not later than 6 months after the date of enactment of this subtitle.

SEC. 704. ISSUANCE OF CERTIFICATE OF PUBLIC CONVENIENCE AND NECESSITY.

(a) AUTHORITY OF THE COMMISSION.– Notwithstanding the provisions of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719-719*o*), the Commission may, pursuant to section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)), consider and act on an application for the issuance of a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project other than the Alaska Natural Gas Transportation System.

(b) ISSUANCE OF CERTIFICATE.–

(1) The Commission shall issue a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project under this section if the applicant has–

(A) entered into a contract to transport Alaska natural gas through the proposed Alaska natural gas transportation project for use in the contiguous United States; and

(B) satisfied the requirements of section 7(e) of the Natural Gas Act (15

U.S.C. 717f(e)).

(2) In considering an application under this section, the Commission shall presume that–

(A) a public need exists to construct and operate the proposed Alaska natural gas transportation project; and

(B) sufficient downstream capacity will exist to transport the Alaska natural gas moving through such project to markets in the contiguous United tates.

(c) EXPEDITED APPROVAL PROCESS.– The Commission shall issue a final order granting or denying any application for a certificate of public and convenience and necessity under section 7(c) of the Natural Gas Act (15 U.S.C. 717f(c)) and this section not more than 60 days after the issuance of the final environmental impact statement for that project pursuant to section 704.

(d) REVIEWS AND ACTIONS OF OTHER FEDERAL AGENCIES.– All reviews conducted and actions taken by any federal officer or agency relating to an Alaska natural gas transportation project authorized under this section shall be expedited, in a manner consistent with completion of the necessary reviews and approvals by the deadlines set forth in this subtitle.

(e) REGULATIONS.– The Commission may issue regulations to carry out the provisions of this section.

SEC. 705. ENVIRONMENTAL REVIEWS.

(a) COMPLIANCE WITH NEPA.– The issuance of a certificate of public convenience and necessity authorizing the construction and operation of any Alaska natural gas transportation project under section 704 shall be treated as a major federal action significantly affecting the quality of the human environment within the meaning of section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)).

(b) DESIGNATION OF LEAD AGENCY.– The Commission shall be the lead agency for purposes of complying with the National Environmental Policy Act of 1969, and shall be responsible for preparing the statement required by section 102(2)(c) of that Act (42 U.S.C. 4332(2)(c)) with respect to an Alaska natural gas transportation project under section 704. The Commission shall prepare a single environmental statement under this section, which shall consolidate the environmental reviews of all Federal agencies considering any aspect of the project.

(c) OTHER AGENCIES.– All Federal agencies considering aspects of the construction and operation of an Alaska natural gas transportation project section 704 shall cooperate with the Commission, and shall comply with deadlines established by the Commission in the preparation of the statement under this section. The statement prepared under this section shall be used by all such agencies to satisfy their responsibilities under section 102(2)(C) of the National Environmental Policy Act of 1969 (42 U.S.C. 4332(2)(C)) with respect to such project.

(d) EXPEDITED PROCESS.– The Commission shall issue a draft statement under this section not later than 12 months after the Commission determines the application to be complete and shall issue the final statement not later than 6 months after the Commission issues the draft statement, unless the Commission for good cause finds that additional time is needed.

(e) UPDATED ENVIRONMENTAL REVIEWS UNDER ANGTA.– The Secretary of

Energy shall require the sponsor of the Alaska Natural Gas Transportation System to submit such updated environmental data, reports, permits, and impact analyses as the Secretary determines are necessary to develop detailed terms, conditions, and compliance plans required by section 5 of the President's Decision.

SEC. 706. FEDERAL COORDINATOR.

(a) ESTABLISHMENT.– There is established as an independent establishment in the executive branch, the Office of the Federal Coordinator for Alaska Natural Gas Transportation Projects.

(b) THE FEDERAL COORDINATOR.– The Office shall be headed by a Federal Coordinator for Alaska Natural Gas Transportation Projects, who shall–

(1) be appointed by the President, by and with the advice of the Senate,

(2) hold office at the pleasure of the President, and

(3) be compensated at the rate prescribed for level III of the Executive Schedule (5 U.S.C. 5314).

(c) DUTIES.– The Federal Coordinator shall be responsible for–

(1) coordinating the expeditious discharge of all activities by federal agencies with respect to an Alaska natural gas transportation project; and

(2) ensuring the compliance of Federal agencies with the provisions of this subtitle.

SEC. 707. JUDICIAL REVIEW.

(a) EXCLUSIVE JURISDICTION.– The United States Court of Appeals for the District of

Columbia Circuit shall have exclusive jurisdiction to determine–

(1) the validity of any final order or action (including a failure to act) of the Commission under this subtitle;

(2) the constitutionality of any provision of this subtitle, or any decision made or action taken thereunder; or

(3) the adequacy of any environmental impact statement prepared under the National Environmental Policy Act of 1969 with respect to any action under this subtitle.

(b) DEADLINE FOR FILING CLAIM.– Claims arising under this subtitle may be brought not later than 60 days after the date of the decision or action giving rise to the claim.

SEC. 708. LOAN GUARANTEE.

(a) AUTHORITY.– The Secretary of Energy may guarantee not more than 80 percent of the principal of any loan made to the holder of a certificate of public convenience and necessity issued under section 704(b) of this Act or section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) for the purpose of constructing an Alaska natural gas transportation project.

(b) CONDITIONS.–

(1) The Secretary of Energy may not guarantee a loan under this section unless the guarantee has filed an application for a certificate of public convenience and necessity under section 704(b) of this Act or for an amended certificate under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) with the Commission not later than 6 months after the date of enactment of this subtitle.

(2) A loan guaranteed under this section shall be made by a financial institution subject to the examination of the Secretary.

(3) Loan requirements, including term, maximum size, collateral requirements and other features shall be determined by the Secretary.

(c) LIMITATION ON AMOUNT.– Commitments to guarantee loans may be made by the Secretary of Energy only to the extent that the total loan principal, any part of which is guaranteed, will not exceed $10,000,000,000.

(d) REGULATIONS.– The Secretary of Energy may issue regulations to carry out the provisions of this section.

(e) AUTHORIZATION OF APPROPRIATIONS.– There are authorized to be appropriated to the Secretary such sums as may be necessary to cover the cost of loan guarantees, as defined by section 502(5) of the Federal Credit Reform Act of 1990 (2 U.S.C. 661a(5)).

SEC. 709. STUDY OF ALTERNATIVE MEANS OF CONSTRUCTION.

(a) REQUIREMENT OF STUDY.– If no application for the issuance of a certificate of public convenience and necessity authorizing the construction and operation of an Alaska natural gas transportation project has been filed with the Commission within 6 months after the date of enactment of this title, the Secretary of Energy shall conduct a study of alternative approaches to the construction and operation of the project.

(b) SCOPE OF STUDY.– The study shall consider the feasibility of establishing a government corporation to construct an Alaska natural gas transportation project, and alternative means of providing federal financing and ownership (including alternative combinations of government and private corporate ownership) of the project.

(c) CONSULTATION.– In conducting the study, the Secretary of Energy shall consult with the Secretary of the Treasury and the Secretary of the Army (acting through the Commanding General of the Corps of Engineers).

(d) REPORT.– If the Secretary of Energy is required to conduct a study under subsection (a), he shall submit a report containing the results of the study, his recommendations, and any proposals for legislation to implement his recommendations to the Congress within 6 months after the expiration of the Secretary of Energy's authority to guarantee a loan under section 708.

SEC. 710. SAVINGS CLAUSE.

Nothing in this subtitle affects any decision, certificate, permit, right-of-way, lease, or other authorization issued under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g).

SEC. 711. CLARIFICATION OF AUTHORITY TO AMEND TERMS AND CONDITIONS TO MEET CURRENT PROJECT REQUIREMENTS.

Any Federal officer or agency responsible for granting or issuing any certificate, permit, right-of-way, lease, or other authorization under section 9 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719g) may add to, amend, or abrogate any term or condition included in such certificate, permit, right-of-way, lease, or other authorization to meet current project requirements (including the physical design, facilities, and tariff specifications), so long as such action does not compel a change in the basic nature and general route of the Alaska Natural Gas Transportation System as designated and described in section 2 of the President's

Decision, or would otherwise prevent or impair in any significant respect the expeditious construction and initial operation of such transportation system.

SEC. 712. DEFINITIONS.

For purposes of this subtitle:

(1) The term "Alaska natural gas" has the meaning given such term by section 4(1) of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719b(1)).

(2) The term "Alaska natural gas transportation project" means any other natural gas pipeline system that carries Alaska natural gas from the North Slope of Alaska to the border between Alaska and Canada (including related facilities subject to the jurisdiction of the Commission) that is authorized under either–

(A) the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719-719*o*); or

(B) section 704 of this subtitle.

(3) The term "Alaska Natural Gas Transportation System" means the Alaska natural gas transportation project authorized under the Alaska Natural Gas Transportation Act of 1976 and designated and described in section 2 of the President's Decision.

(4) The term "Commission" means the Federal Energy Regulatory Commission.

(5) The term "natural gas company" means a person engaged in the transportation of natural gas in interstate commerce or the sale in interstate commerce of such gas for resale; and

(6) The term "President's Decision" means the Decision and Report to Congress on the Alaska Natural Gas Transportation system issued by the President on September 22, 1977

pursuant to section 7 of the Alaska Natural Gas Transportation Act of 1976 (15 U.S.C. 719c) and approved by Public Law 95-158.

SEC. 713. SENSE OF THE SENATE.

It is the sense of the Senate that an Alaska natural gas transportation project will provide significant economic benefits to the United States and Canada. In order to maximize those benefits, the Senate urges the sponsors of the pipeline project to make every effort to use steel that is manufactured or produced in North America and to negotiate a project labor agreement to expedite construction of the pipeline.

(b) A waiver, reduction, or deferral of tax made by the commissioner under (a) of this section is not effective until approved by the legislature. The legislature may approve a waiver, reduction, or deferral of tax under this section only by enacting legislation.

*** Sec. 11.** AS 46.40.094 is amended by adding a new subsection to read:

(d) Notwithstanding any other provision of this section, for a natural gas pipeline project from the Alaska North Slope following a route that parallels the Trans Alaska Pipeline System and the Alaska Highway to the Canadian border or a route that runs south to Alaska tidewater for which the project applicant has complied with AS 38.35.240 and obtained all certificates described in that section, any agency responsible for the consistency determination with respect to proposed uses or activities involved in the project may, in its discretion, conduct the review and make the consistency determination in separate phases in a manner that promotes review of proposed uses and activities based upon the project's design, construction sequence, and schedule.

*** Sec. 12.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LIMITATION OF CERTAIN ACTIONS. A legal proceeding may not be initiated to challenge the constitutionality of sec. 2 of this Act or the constitutionality of AS 38.35.235 - 38.35.259, added by sec. 5 of this Act, more than 60 days after the effective date of this Act.

*** Sec. 13.** The uncodified law of the State of Alaska is amended by adding a new section to read:

LEGISLATIVE AUTHORIZATION AND APPROVAL. AS 42.40.695, added by sec. 9 of this Act, and this section constitute the approval required by AS 42.40.285 for the issuance of the bonds described in AS 42.40.695.

*** Sec. 14.** This Act takes effect immediately under AS 01.10.070(c).

State Financial Participation in an Alaska Natural Gas Pipeline

- ➢ **The History**
- ➢ **The Project**
- ➢ **The Options**
- ➢ **The Costs**
- ➢ **The Risks of State Participation**

Prepared by the Alaska Department of Revenue
January 31, 2002

PETRIE PARKMAN & CO.

CH2M HILL

STATE OF ALASKA

Department of Revenue

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January 31, 2002

The Honorable Tony Knowles
Governor of Alaska

The Honorable Rick Halford
Senate President
Alaska State Legislature

The Honorable Brian Porter
Speaker of the House
Alaska State Legislature

The Honorable John Torgerson
Chairman, Joint Natural Gas Pipelines Committee
Alaska State Legislature

Dear Governor Knowles, President Halford, Speaker Porter and Senator Torgerson:

It has been six months since Senate Bill 158 was signed into law, calling on the Department of Revenue to prepare a report on the merits of state ownership or financing of an Alaska Gas Pipeline project. In those six months my staff, our consultants and I have spent considerable hours looking for the light at the end of the pipeline. We had hoped that light would lead us to clear and convincing answers to the questions: Should the state invest in a natural gas pipeline? If so, where would the state get the money? Are the rewards worth the risks? Would state financial participation in the project help bring about the start of construction?

Although we have reached the end of our assignment, we did not find answers to every question. It was like finding the light at the end of the line, only to discover that you don't have the authority to turn the switch on and off. Although we believe the financial risks to the state are substantial, it is possible that some would decide—as a matter of public policy—that the state should take such sizable risks in an attempt to exercise greater control over its own destiny.

As for finding the money for state participation in a project, Alaska is a little short on cash these days—unless you go into the Permanent Fund, which presents several legal and political constraints. Clearly, one answer is that state participation perhaps could be a plus if the state could issue tax-exempt bonds to help finance the multibillion-dollar project. But that switch is in federal hands.

We believe our report sheds new light on old discussions, and serves as a reference book on the project. Our work includes:

- A comprehensive review of the history of Alaska gasline proposals.
- A summary of current gasline proposals and potential sponsors.
- An analysis of the issues of state financial participation—how much money would be needed, and where could it come from.
- An explanation of what could or could not work for state financing—and why not.
- And what are the risks of putting up state money.

I believe our report provides you—and the Alaska public—with the information needed to make informed decisions.

In closing, I would like to thank our two consultants on this report: Dave Gray of CH2M Hill and Bill Garner of Petrie Parkman & Co. Mr. Gray is director of energy economics for CH2M HILL's Bellevue, Washington, office, and Mr. Garner is in the Houston office of Petrie Parkman, an investment banking firm that specializes in oil and gas issues. Their technical assistance was key to the success of this report.

As you read through this report, please call on the department for any additional information you need. I look forward to working with you on this project, which is so important to Alaska's future.

Sincerely,

Wilson L. Condon
Commissioner

Executive Summary

The purpose of this report is to examine whether the State of Alaska should financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets.

The legal and fiscal issues today are not much different than the gas pipeline concerns Alaskans have grappled with over the past 30 years. During that time, the state and private groups commissioned several reports both favoring and dissuading state financial participation. Although the issues have not changed much, certainly the legal, regulatory, market and fiscal situation today is much different than that of decades ago.

Today, proponents of state involvement cite three main reasons for the state to participate in ownership or financing of an Alaska Gas Pipeline project:

- It would be a good investment with a healthy rate of return and minimal risk.
- Alaska should control its own financial destiny and development of its resources.
- State involvement would enhance the project's feasibility—that is, the pipeline would stand a better chance of getting built sooner if the state was a financial partner.

The answers, however, are much less clear than the questions.

A Good Investment

The state is in a precarious financial position as it starts 2002. Its ability to provide essential services will be tested as the Constitutional Budget Reserve Fund runs out of money. The Department of Revenue projects that the reserve fund, which has helped cover state spending for all but two years since 1991, will hit empty by Labor Day 2004. Alaska may be resource rich but we are cash poor—unless you count the Permanent Fund. Other than taking money out of the Permanent Fund to invest in a gasline, the state is in no position to write a check for any significant investment in a gas pipeline project, regardless how good the investment.

The Alaska Permanent Fund

There are several options for using the Permanent Fund for state investment in the project:

- Spend money from the Earnings Reserve Account to buy in as a gasline partner. This means going into the business of owning and operating a natural gas pipeline. This could be done by a legislative appropriation to another state agency or new state corporation to make an equity investment in the pipeline. However, withdrawing too much from the Earnings Reserve Account could jeopardize its future ability to pay for inflation proofing of the fund's principal and dividends.
- The legislature could change state law to authorize a direct investment by the Permanent Fund in the gasline business. A statute change would be required because the Permanent Fund's investment authority does not cover going into the gasline business.
- Or the Permanent Fund, as part of its regular asset allocation and investment mix, could decide to buy shares in a public traded corporation or buy bonds issued by the corporation or corporations that own the pipeline. These investments, however, would give the state no more control over the project than any other minority shareholder, and any return would depend on the corporation's performance and stock or bond value. Any such investment would—by constraint of the Prudent Expert Rule for Permanent Fund investments—be limited to a small percentage of a pipeline corporation's stock or debt.

Taking on State Debt

The state and its municipalities are looking at how to pay for several billion dollars of school construction and repairs, and deferred maintenance to public facilities. The state, which has not issued any general obligation bonds in nearly 20 years, will go to market in the next year if legislators agree with the governor's proposal for school bonds. Taking on new debt for schools and other needs most likely will consume all of the state's available debt capacity, unless Permanent Fund earnings are diverted from the dividend program to pay debt service.

Any over-ambitious reliance on debt to finance a state investment in the gasline could jeopardize Alaska's credit rating, which could have a domino effect as it raises the cost of borrowing for the state and municipalities.

Rate of Return

The Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada would regulate the rate of return on any interstate pipeline, and we expect that return would not differ significantly from what the state—or the Permanent Fund—could earn in other investments with similar risks.

Risks to the State

State investment as a partner in the project could put the state at financial risk if there are construction overruns, delays in completion of the project, unbudgeted calls for additional capital, or volatile natural gas market conditions. Unlike large corporations, the state does not maintain reserves for such risks, and it would be a difficult policy call to tell the public that key government services might be cut back to make money available for gasline expenses.

State Control

Proponents who advocate state financial participation in the project for reasons of control raise two points: (1) Alaska should take a stronger hand in managing its resource development, and (2) a belief that North Slope oil producers took advantage of the state by inflating tariffs on the Trans-Alaska Pipeline System, thereby reducing their oil tax and royalty payments to the state.

Both are emotional issues, and both require an unemotional review.

First, whether the state should take an active role in managing the development and marketing of its oil and gas resources is a public policy call. If people believe that is the overriding issue in this project, then it might justify the financial risks to the state. However, advocates of this position should carefully weigh the risks against the potential benefits. Could state participation in the gasline make it happen any sooner? Would state participation dissuade corporations from putting up their own billions—private money that Alaska needs. And is it the role of government to build and operate for-profit ventures? We believe the state could best control the development of its resources by regulating their extraction and use, and project. The lower cost of tax-exempt debt could help tip the project toward economic feasibility, and that could be a proper role for the state to take in assisting in the development of its natural resources. Even with the lower interest rate on tax-exempt debt, however, it is still possible that the companies might choose to issue their own taxable debt in order to take advantage of the federal tax benefits of owning and depreciating the line.

As it says in the cover letter to this report, there are no easy answers.

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SECTION 1

Introduction

This report analyzes opportunities for the State of Alaska to financially participate in a pipeline to transport natural gas from Alaska's North Slope to domestic or foreign markets. The project is generally referred to in this report as the Alaska Gas Pipeline. The Alaska State Legislature, by passage of Senate Bill 158 in May 2001, directed the Commissioner of the Department of Revenue to prepare this report.

The analysis looks at a number of options for financial participation, ranging from outright state ownership to financing a project owned by others. It discusses the possible financial risks and rewards for each option and, where enough information is available, presents conclusions.

This report is not specific to any one proposal for commercialization of Alaska gas. Proposals include transporting North Slope gas to either Alberta, Canada, to feed into the existing North American pipeline grid for shipment to U.S. markets, or to tidewater for liquefaction and shipment of liquefied natural gas (LNG) to domestic or overseas markets.

A North Slope gas pipeline has been seriously considered since the 1970s, but to date questionable economics have always blocked its construction. The project is further complicated—or aided, depending on your perspective—by the significant amount of study, legislation, development and permitting that have already occurred or may yet need to occur in the United States and Canada.

This report uses the existing body of work on state participation in a pipeline as the starting point for its analysis. The team that produced this report included the Alaska Department of Revenue, its economic and financial consultants, and attorneys specializing in public finance and law. In addition to its own analysis, the team interviewed Alaska policymakers, oil and gas company officials, pipeline company representatives and other interested parties to obtain ideas and opinions on state participation in the project.

Key criteria used to analyze the options include the effects on the economic and financial health of the state of such a large investment, the potential for risks to the state, and whether state participation could actually help the project. Estimates of project costs, financing parameters and financial risks were used to analyze the consequences of state investment in the project and to determine the effect on the state's financial position. State funding sources were assessed in terms of legal and financial possibilities.

This report is organized into the following key sections:

2) Background, provides information on Alaska oil and gas development. It also discusses the state's economic and financial profile.

3) Alaska Gas Pipeline Overview, discusses pipeline route proposals and sponsors, and opinions expressed for and against the pipeline during interviews conducted for this report.

4) Ownership and Financial Participation Options and Evaluation Criteria, identifies the ownership and financing options to be considered as specified in SB 158. It also presents the evaluation criteria specified in SB 158 and identifies additional evaluation criteria considered in this report.

5) Evaluation of Financial Participation and Ownership Options, lists and evaluates each of the sources of state funds for a potential equity investment, financing options, and ownership alternatives.

6) Investment Setting, discusses the key factors affecting potential risks and returns for an investment in the Alaska Gas Pipeline, including future gas market conditions, governmental regulation, permit requirements and project costs.

7) Potential Returns from Pipeline Investment, evaluates the risks associated with the project and reviews potential returns associated with each of two investment options: pipeline ownership and ownership of capacity rights purchased from the pipeline owner. This section also discusses potential effects of an investment on the state's cash flow.

8) Effect on State of Alaska from Pipeline Investment, evaluates the effects of state ownership options on Alaska's financial position. This section looks at the state's

financial integrity and creditworthiness, and its credit rating. It also discusses balancing the benefits to the state vs. the costs of a pipeline investment.

9) Effect of State Participation on Project Success, discusses the value of access to information that might be gained from state participation and assesses possible conflicts of interest in the state's potential dual roles as an owner and regulator. This section also looks at how state participation might help or hinder project completion and operation, and identifies how other parties participating with the state might benefit or suffer from state participation.

10) Conclusions and Recommendations, presents conclusions regarding state participation.

11) References and Acknowledgements, provides a list of the resources used in preparing this report.

confirmation hearings, promised he would not lift the land freeze without consulting the Senate Committee on Interior and Insular Affairs.

After several exchanges with the Senate Committee, Secretary Hickel in January 1970 modified the land freeze to open federal land for the pipeline right of way. Almost immediately, two court injunctions were issued prohibiting the proposed right-of-way grant. The Alaska Native residents of Stevens Village successfully obtained an injunction as a consequence of their claim to lands the pipeline would need to cross. The Wilderness Society obtained a separate injunction on the basis of the newly enacted National Environmental Policy Act and a claim that the proposed pipeline right of way was wider than permitted under applicable federal law.

After these two injunctions were issued in early 1970, the oil companies—along with the state, Alaska Natives and the environmental community—all turned to Congress to resolve the Alaska Native land claims and to squabble over establishing a substantial list of proposed parks, wildlife refugees and wilderness areas in Alaska.

Before the injunctions were granted—and believing that North Slope oil would soon be moving to market—the Alaska Department of Natural Resources auctioned the state's unleased North Slope acreage and received $900 million in bonus payments from the winning bidders. By the summer of 1970, however, state officials had become frustrated with the delay. Apparently, the governor and other state policymakers believed state construction and ownership of the proposed oil pipeline could provide a way around the roadblocks created by the unresolved Alaska Native land claims and the objections of the environmental community. To that end, Governor Keith Miller appointed a 15-member citizens group comprised of prominent citizens from Alaska's business and labor communities to examine the benefits of state ownership. To accomplish this mission, the Governor's Pipeline Commission, as it was called, hired the international consulting group Harbridge House Inc. to report on the feasibility of state ownership and operation of TAPS.

Harbridge House issued its report in December 1970. In its report, Harbridge concluded that state ownership would neither avoid nor resolve the Alaska Native land claims issues. Harbridge reached similar conclusions regarding the environmental community objections. In the consultant's view, state ownership would not accelerate the resolution of the problems causing the delay and private enterprise could construct the pipeline more expeditiously than state government.

Although Harbridge acknowledged that state ownership (1) could lead to lower tariffs because the state would not be subject to either state or federal income tax or municipal property taxes, and (2) could provide the state with access to information about pipeline costs and tariffs that would otherwise be unavailable, the consultants nevertheless concluded state ownership simply was not feasible. To reach this conclusion, Harbridge observed that the state lacked the experienced staff needed to manage such an enterprise and that the state would jeopardize its ability to provide necessary public services if it took on the financial and operating risks of the oil pipeline.

Finally, Harbridge expressed the view that it was unlikely the state had the financial strength needed to borrow the amount of money required to construct the project.

The Harbridge report was released just as Bill Egan succeeded Keith Miller as governor in December 1970. Possible state ownership of TAPS was reconsidered in the early months of his term and, on October 31, 1971, Governor Egan announced he had decided to proceed on a course of action leading to state ownership of the proposed pipeline. He based his decision on the potential financial benefits of state ownership outlined in the Harbridge report.

Governor Egan presented his proposal to TAPS owners, believing that state ownership would be feasible only if the oil companies supported it. The immediate response from the joint venture was negative. Nevertheless, in late 1971, the state again retained several consultants to examine the feasibility of state ownership.

The administration concluded—based upon the consultants' advice—that a state-owned pipeline was desirable and could be financed and constructed on the same schedule as a privately owned pipeline under the following conditions:

- That Alyeska Pipeline Service Company, the management company established by the TAPS owners to construct and operate the pipeline, would agree to act as the state's contractor for construction and operation of the line.

- That the major North Slope oil-producing companies would guarantee shipment of sufficient quantities of oil to generate enough tariff revenue to pay for the pipeline.
- That the major North Slope producers would guarantee completion of the pipeline.

In 1972, the Egan administration proposed legislation to implement the plan for a pipeline constructed and owned by the state. The oil companies opposed the proposed legislation, and it was not enacted.

Congress eliminated the land claims issue as a barrier to constructing an Alaska oil pipeline when it passed the Alaska Native Claims Settlement Act in December 1971. The Wilderness Society lawsuit, however, remained an obstacle. In February 1973, the U.S. Court of Appeals for the D.C. Circuit held that the Secretary of Interior lacked the authority to issue the permit for the proposed TAPS right-of-way. The state and the companies then turned to Congress for relief. Congress obliged and provided the Secretary with the necessary authority by passing the Trans-Alaska Pipeline Authorization Act in October 1973. Pipeline construction began in early 1974.

The TAPS owners then turned to the state for assistance in obtaining tax-exempt financing for the project's marine terminal at Valdez. If it could be established that the marine terminal was a public port, then financing by a public entity could be tax exempt. The oil companies requested the Alaska Industrial Development Authority to sponsor the proposed financing, but Governor Egan opposed the plan and instructed the authority not to approve it. Tax-exempt financing for the marine terminal in an amount totaling $1.265 billion ultimately was arranged through the City of Valdez. The bonds were secured solely by the security of the companies and did not involve the credit of the City of Valdez. The city obtained a 1 percent impact fee from the financing, which it placed in a permanent fund.

When oil started flowing through the pipeline in June 1977, the state initiated litigation over the tariffs for shipping oil on TAPS. Much of the state's revenue was calculated after tariffs were deducted from the value of the oil, and the pipeline tariffs had become a major point of contention between the state and the TAPS owners.

In July 1977, a representative of BP Pipelines Inc., owner of 16.6 percent of TAPS, approached the state and proposed selling its share of the pipeline to the state. BP's representative suggested that the proposal would align the state's interest with those of the other pipeline owners. BP contended that state pipeline ownership in an amount almost equivalent to its economic interest in the oil production stream (at the time a royalty interest of 12.5 percent and a production tax interest of almost 11 percent) would eliminate the need for the state to battle the companies over pipeline tariffs. The state declined to pursue the proposal, in part, because state officials believed state ownership would unacceptably increase the conflict between the state's regulatory responsibilities with respect to pipeline operation and the state's interest in maximizing public revenue.

BP's proposal to sell the state its share of the pipeline was renewed in February and March 1978 and again rejected by state policymakers.

State Participation in Gas Pipeline Development

At the same time that state officials were considering BP's proposal to sell the state its share of the oil line, they also were considering possible state investment in a proposed pipeline to carry North Slope gas to market. Northwest Pipeline Company (now the Williams Companies) was the leader of the group of companies that in 1978 had obtained federal approval in 1978 for its proposal to build the Alaska Natural Gas Transportation System (ANGTS), a gas pipeline from the North Slope to Fairbanks and then down the Alcan Highway to mid-North America. Northwest Pipeline said it needed help from the state to finance the proposed project. The company, headquartered in Salt Lake City, operated pipelines from gas fields in the Rocky Mountains to markets in the mountain states and Pacific Northwest.

But it was almost a decade earlier, just one year after the Prudhoe Bay discovery in 1968, that Arctic Gas, a consortium of major North Slope producers with other producing and gas pipeline companies, began a series of studies on how best to move Prudhoe Bay gas to market. These studies, which started in 1969, culminated in a March 1974 application to the Federal Power Commission (FPC) for a certificate to construct a pipeline across Northern Alaska and Canada to the Mackenzie Delta and then up the Mackenzie River to Alberta and mid-North America.

harvests in 1998.[5] Although the fishing industry experienced its ups and downs during the 1990s, it averaged 4 percent of the gross state product and was responsible for 7 percent of statewide employment.[6] Unfortunately for Alaska, the strong growth in the worldwide farmed salmon industry has caused major problems for the state's natural fisheries. Low prices and oversupplies in the market are creating troubles for Alaska fishers, processors and communities.

Mining

Between 1999 and 2000, production of minerals increased by 5 percent to $1.1 billion, in part due to the increased value of zinc. Development expenditures in 2000 increased to $137 million from $34 million the previous year. This is mostly due to expenditures at Red Dog, Greens Creek, Fort Knox and Pogo mines.

State and Local Government

During the 1990s, state and local government accounted for 12 percent of the gross state product and 18.5 percent of Alaska's employment.[7] The Alaska Permanent Fund dividend pumps around $1.1 billion into the economy each year. The state's unrestricted general fund budget is at $2.4 billion for the fiscal year ending June 30, 2002.

Transportation

Because of Alaska's size, isolation and dependence on natural resource exports, the transportation sector is particularly important. The percentage of private employees in the transportation sector in Alaska is twice as large as in the nation as a whole. Employment in the air transportation sector grew by 37 percent between 1990 and 1998 and accounts for more than 10,000 jobs.[8] Alaska's location—equidistant between Europe and Asia—has made it an important international hub for airfreight. Anchorage International Airport is the No. 1 airport in the United States in the amount of freight landed, with approximately 650 million

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[5] U.S. Department of Commerce, National Marine Fisheries Service, Office of Science and Technology, Fisheries Statistics and Economics Division, "Fisheries of the United States 1999." October 2000.

[6] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[7] Institute of Social and Economic Research, *Trends in Alaska's People and Economy* (October 2001).

[8] Alaska Department of Labor and Workforce Development. Alaska Economic Trends, "Transportation." November 1999.

pounds of freight in Fiscal 2001. The airport is responsible for about one of every 10 jobs in Anchorage.[9]

Tourism

Tourism has grown rapidly in the past 10 years. For example, from 1990 to 1998, summer visitors increased from 690,000 to 1,135,000. From October 1997 to September 1998, tourists spent approximately $949 million in Alaska. The tourism industry generated an annual average of slightly less than 16,000 jobs in 1998.[10]

Outlook

Alaska Department of Labor statistics show that moderate growth of the Alaska economy has continued even in the face of the nationwide recession. Yet, as discussed below, state government has been a significant source of "new" money in the economy during the past two decades because it has pumped money derived from the oil industry and Permanent Fund dividends into the economy. As the state begins to use "recycled" money—money from taxes on residents or money from reduced dividends—the economy will necessarily contract unless a new source of new money is found. Although new money is possible through new projects, such as the Alaska Gas Pipeline, economists would not consider the economy stable because the projects on the drawing board are, at this time, too uncertain. Thus, the facts presented below indicate that during the next few years the Alaska economy may not be as robust as it has been in past 25 years.

State Government Fiscal Profile

In examining the state's fiscal profile, three facts command overwhelming attention:

1. The state's tax base is extremely concentrated—in fact, three tax and royalty payers were responsible for more than 75 percent of the money spent from the general fund in Fiscal Year 2001.

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[9] Scott Goldsmith, University of Alaska; "Anchorage International Airport: 1998 Economic Significance." September 1998.

[10] McDowell Group Inc. "Economic Impacts of Alaska's Visitor Industry 1999: Update, May 1999."

2. The state is spending more money each year than it takes in as revenue, and will soon reach the point where its readily available fiscal reserve (the Constitutional Budget Reserve Fund) will no longer be available to balance the state budget.

3. The state has $25 billion in a large savings account, the Permanent Fund, the principal of which cannot be spent but which has a very large earning capacity.

The narrowness of the state's tax base is a result of the state's reliance on its oil and gas industry to supply almost all of state income since the beginning of Prudhoe Bay production. Oil started flowing from Prudhoe in 1977, and three years later the legislature repealed Alaska's personal income tax and gross receipts business tax. Although municipalities have sales and property taxes, the state has no state sales tax or property tax, except for a property tax on oil and gas property.

Reliance on oil industry taxes and royalty payments worked very well for the state for many years, producing unprecedented budgets and even surpluses during the early '80s. In 1988, however, Prudhoe Bay production peaked, and state revenue has been in the decline ever since.

In addition to overall declining revenue, the state also experiences volatile revenue. Given the narrow tax base, the state's fiscal system is very dependent on the health of the oil industry. During the early years of North Slope production, the state enjoyed the ride of high oil prices during the late '70s and early '80s. It then felt the full brunt of the crash in 1986, when the price of Alaska North Slope crude fell from $22.25 in January 1986 to $9.72 per barrel in July 1986. State revenue fell by 42 percent due to the fall in oil prices. In response, the state reduced its workforce by 10 percent. There were almost 2,000 fewer state workers in 1987 than in 1985. The state's capital budget was reduced from $2 billion in 1985 to $343 million in 1987.

In the face of declining state revenue and the dependence on volatile oil prices, Alaska voters amended the constitution to create another reserve account in addition to the Permanent Fund—the Constitutional Budget Reserve Fund (CBRF). The state funded the CBRF with money from settlement of tax and royalty disputes with the oil companies—revenue largely owed from the boom decade of the '80s.

Although oil prices—and state revenues—recovered from the crash of 1986, the state's annual spending in the 1990s began to exceed the amount received each year as "unrestricted revenue." The decline in state revenue is not due solely to declining oil production. It's also the consequence of a provision in the state's oil and gas production tax, called the Economic Limit Factor (ELF), which lowers the tax rate on less productive fields. The idea behind the ELF is that less productive fields are more costly to operate, so a lower tax rate will keep old fields in production longer and encourage development of marginal fields. With more production, the state benefits in the long run. As the state's highly productive large fields age, however, and the ELF formula kicks in, the state is experiencing a significant reduction in oil tax revenue.

During the 1990s, the state managed to avoid deficit spending by reducing its budgets and drawing down the CBRF. The balance of the CBRF, as of January 1, 2002, was $2.65 billion. The projected budget deficit for Fiscal Year 2002—the budget gap—is $865 million; for FY 2003, it's $1.078 billion. Assuming no changes in budget or taxes, the Department of Revenue predicts the CBRF will be depleted by late summer 2004, under any reasonable oil price scenario.

A bright spot on the state's financial profile is its Permanent Fund. The 1976 constitutional amendment requires that at least 25 percent of the state's oil, gas and mining lease bonuses, rentals, royalties and federal mineral revenue sharing payments are deposited into the fund.

The fund has grown significantly over the years through its investment earnings, and as of January 1, 2002, had a market value of about $25 billion. The fund expects to earn, on average, about 5 percent per year after inflation.

According to the constitutional amendment, the legislature may spend the earnings of the fund for any public purpose, but the amendment offers no guidance on what that might be. Early in the fund's existence, the legislature established a dividend program to distribute some of the fund's earnings to the residents of the state. The annual dividend is calculated under a statutory formula that distributes approximately one-half of the actual realized earnings, and then deposits into the principal of the fund the amount necessary to "inflation proof" the principal. The 2001 dividend was $1,850 per person. Not surprisingly, the dividend program is extremely popular with Alaska residents. Any earnings left over after dividends and inflation proofing are deposited into the fund's Earnings Reserve Account, where the money is invested just as the fund's principal and its earnings are included in calculating the annual dividend. The legislature has in the past transferred significant portions of the Earnings Reserve Account into principal, but in recent years the practice has been to allow the reserve to accumulate. Although there are different ways of calculating the value of the reserve, the balance at the end of Fiscal 2002 is expected to be about $3 billion. To date, the Earnings Reserve Account has never been spent on state services.

Another bright spot is the state's low level of debt. Although Alaska did some bonding for capital projects during the early years of the pipeline, those bonds were timed to mature with the "Prudhoe Bay curve" such that as oil revenue declined, debt service payments also declined. Currently, the state has no outstanding general obligation bonds, although, as of June 30, 2001, it owed more than $70 million in certificates of participation, a type of debt used for lease/purchase of state assets.

One consequence of the low level of capital spending, however, is that the state is behind in building and maintaining many of the facilities needed by a growing state. In January 1998, the Deferred Maintenance Task Force, a group commissioned by the legislature, issued a report recommending spending $1.4 billion on schools (both major maintenance and construction), the university, highways and airports, the state ferries, harbors, buildings, American Disabilities Act requirements, and water and sewer upgrades. Although approximately $200 million of these projects have been completed, additional projects, including up to $641 million in school projects, have been identified to add to the total.

In summary, although Alaska has a reasonably strong economy, the state's fiscal profile is in flux. This is not to suggest that the state government is facing an insurmountable economic crisis—solutions to the problem do exist, and will be found. The state's fiscal situation, however, does suggest two important considerations.

First, it should be clear that state policymakers are going to have to wrestle with changes to the state's fiscal regime. They must determine whether this is the appropriate time to consider an investment in a project as large as the proposed gas pipeline. Policymakers must be aware of the time and resources that such an investment would require, and the financial risk such an investment would entail. Alaska currently does not have a long-range fiscal plan, and the state will soon need to identify new revenue sources and/or immediate budget reductions. This all must be done before the gasline would generate any revenues. The timing, therefore, is not favorable.

Second, it should also be clear that the CBRF is not a potential source of revenue for investment in the project. The state currently relies on the dwindling CBRF to help pay for needed public services each year. Due to the volatile nature of Alaska's oil and gas tax and royalty revenues, the state must retain enough money in the CBRF—unless Alaskans are willing to use the Permanent Fund for that purpose—to provide the equivalent of "overdraft protection" for years of low oil prices. Without the CBRF to protect the state during the inevitable years of low oil prices, Alaskans could face the prospect of losing essential state services, seeing their dividends cut, or taking money out of the Permanent Fund to balance state spending. Accordingly, this report does not recommend that the state invest CBRF money in the project.

SECTION 3

Alaska Gas Pipeline Overview

Just as there were multiple proposed projects and potential developers in the 1970s, there is a similar list of possible participants and pipeline plans for the start of the 21st century. This section describes the major proposals and proponents. It is expected, however, that because of the huge scale of the project, proposals and sponsors may shift and realign over time. This section also presents information summarizing citizen and industry opinions about the advisability of state ownership.

Currently, pipelines—or pipelines in combination with liquefied natural gas (LNG) plants—are the only options being studied by the major producers and pipeline companies for bringing North Slope gas to market. An alternative that has been discussed from time to time is a process known as gas-to-liquids (GTL) conversion technology. This process converts natural gas to refined liquid petroleum products, which could be shipped to market via the TAPS oil pipeline to Valdez. However, GTL—which consumes large amounts of gas in the conversion process—is not expected to be economical for marketing North Slope natural gas in the reasonably foreseeable future.

Proposed Pipeline Routes

There are three general pipeline routes under active consideration in 2002 by parties proposing to move North Slope gas to market. They are all shown in Figure 3-1.

1) **Alcan Highway Route.** The route follows the TAPS oil pipeline from Prudhoe Bay past Fairbanks to Delta Junction. From Delta Junction, it generally follows the Alcan Highway across eastern Alaska, the Yukon Territory and northeastern British Columbia to central Alberta. There, Alaska gas would connect with the existing North American gas pipeline system. The governor of Alaska currently favors this route, and Alaska state government is devoting significant time and money to promote it.

2) **Over-the-Top Route.** The route follows the shoreline in the shallow offshore waters of the Beaufort Sea from Prudhoe Bay 370 miles to the Mackenzie Delta in Canada's Northwest Territories. From the Mackenzie Delta, this route continues 850 miles up the Mackenzie River Valley and into northern Alberta. A pipeline following this route would move gas to the mid-North America market from both the Alaska North Slope and the Mackenzie Delta. Alaska's governor and legislature strenuously oppose this route. The legislature in 2001 passed a bill—Senate Bill 164—prohibiting rights of way for any pipeline following this route. Environmental groups and Alaska Natives living on the North Slope also strenuously oppose using this route for fear of disturbing the sensitive North Slope marine environment.

3) **All-Alaska Route.** This route parallels the oil pipeline from the North Slope to Valdez. Once at tidewater in Prince William Sound, the gas would flow into an LNG plant that would liquefy the gas so that it could be transported in specially constructed tankers to markets in East Asia or the U.S. West Coast and Mexico. Advocates of the route have submitted petition signatures to the lieutenant governor for a November 2002 statewide vote to create a government-owned corporation called the Alaska Natural Gas Development Authority to develop the state's North Slope gas resources. The initiative, if approved by voters, would direct the corporation to promote, build and operate a project using the All-Alaska Route.

Some potential project sponsors have also proposed a so-called "Y" Line that combines elements from the Alcan Highway Route and the All-Alaska Route in order to access multiple markets. Under these proposals, the sponsors would construct pipelines both down the Alcan Highway to mid-North America and to an LNG plant near Valdez. This proposed routing could provide North Slope gas to mid-North America, East Asia and the West Coast of the United States and Mexico.

Some project sponsors have also suggested the possibility of constructing spur lines to transport gas to the Southcentral Alaska distribution grid. Both the Alcan Route and the All-Alaska Route could accommodate projects that include a spur line from Fairbanks to connect with the Southcentral distribution grid in the southern Susitna Valley. The All-Alaska Route

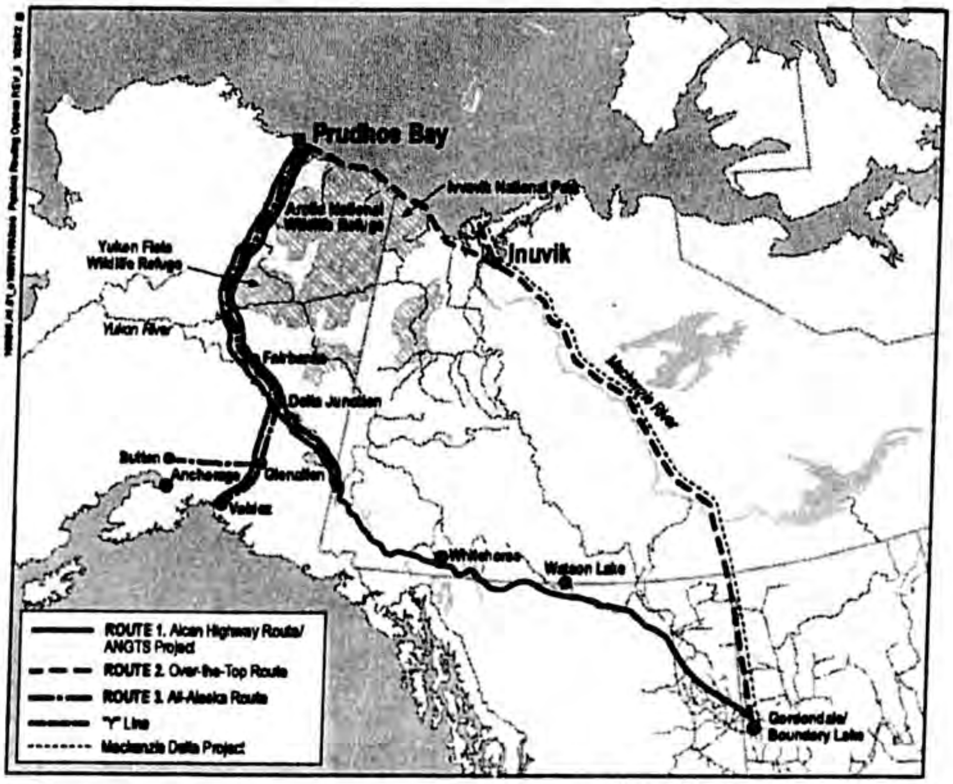

Figure 3-1
Proposed Pipeline Routes

would also accommodate a spur line from Glennallen to the end of the distribution grid at Sutton.

Potential Projects

1) Alaska Gas Producers Pipeline Team Projects

Three major producers—ExxonMobil, BP and Phillips—hold the working interest in most of the discovered natural gas reserves on the North Slope. The discovered reserves in two units—the Prudhoe Bay and Point Thomson units—make up a large proportion of these reserves.

On several occasions since the Prudhoe Bay discovery in late 1967, these three producers, or their predecessors in interest, have considered options to commercialize North Slope natural gas. Most recently, they formed the Alaska Gas Producers Pipeline Team to study the feasibility of constructing a pipeline from the North Slope to mid-North America. They

Port Authority's Combined Alcan Highway and All-Alaska Project

- Volume: 3.0 bcf per day of North Slope gas down the Alcan and 3.0 bcf per day of North Slope gas to an LNG plant at Valdez.
- Project cost: $18 billion for the pipelines only in Alaska (the Port Authority proposal includes no pipe beyond the Canadian border); a gas conditioning plant on the North Slope; and the liquefaction plant and LNG terminal at Valdez. The necessary pipe from the Canadian border into Alberta and beyond could add several billion dollars more to the total cost of serving the market.

4) Arctic Resources Company (ARC)

Arctic Resources Company is a Houston-based corporation formed in 1999 that, together with its Canadian affiliate ArctiGas Resources Ltd. Partnership, proposes to construct a pipeline using the Over-the-Top Route to transport North Slope and Mackenzie Delta gas to market. The company has announced it plans to place ownership of the project in the hands of Alaska municipalities and Canadian First Nation groups. ARC believes this ownership structure would make the project exempt from corporate income taxes in both countries. ARC favors the Over-the-Top Route for economic reasons—the company believes a pipeline using this route could bring gas to market at a lower cost. However, in a bow to Alaska politics, the company proposes using project revenue to finance development of a gas supply to Fairbanks through extraction and distribution of propane from the TAPS crude oil stream.

ARC's Over-the-Top Project

- Volume: 4.0 bcf per day of North Slope gas and 1.2 bcf per day of Mackenzie Delta gas.
- Project cost: $7.8 billion, not including the cost of a North Slope gas conditioning plant or the cost of building new take-away capacity from the project's Alberta terminal.

5) Alaska Natural Gas Development Authority

If the All-Alaska Gasline Initiative that would establish the authority passes in November, the authority will have the responsibility to promote a project using the All-Alaska Route together with a spur line from Glennallen to Sutton. The project would include a gas conditioning plant on the North Slope and an LNG plant on Prince William Sound. The authority would be responsible for arranging to finance and build the project, and for buying, transporting and marketing the gas.

Collateral Infrastructure

With the substantial volume of new gas supply flowing to Alberta through the Alcan Route, new take-away pipeline capacity would be needed to transport gas out of Alberta and into U.S. and Canadian markets. This would be necessary because the existing pipeline capacity from Alberta is expected to be fully utilized by the time an Alaska line is completed. It is uncertain exactly how this new capacity would be added, although it likely would include capacity upgrades on existing pipelines as well as construction of new pipelines. For planning purposes, one sponsor has estimated the cost of a single new so-called "bullet" pipeline from Alberta to Chicago at $5.3 billion.

All projects would require construction of a gas conditioning plant to prepare North Slope gas for transport by pipeline. The North Slope oil producers have estimated the cost of a 4 bcf per day plant at about $2.6 billion. The Alaska Gasline Port Authority has estimated the cost of a 6 bcf per day plant at $4.2 billion.

In addition, natural gas liquids extraction facilities would be needed for each route. The North Slope oil producers estimate the cost of these facilities to be about $300 million for either the Over-the-Top or the Alcan Highway Route. The Alaska Gasline Port Authority estimates the cost at about $400 million for a plant at Valdez.

The All-Alaska Route would require investment in LNG facilities in Valdez, as well as expansion of marine shipping facilities. The Alaska Gasline Port Authority has estimated the construction cost of the LNG facility at about $4.1 billion, including a liquids extraction plant.

2) **The state should invest to protect its financial interests and control its own destiny. This category can perhaps best be described as taking steps to ensure that Alaska benefits as much as possible from the project, and to ensure that the state treasury receives all of the money it should from the sale of North Slope natural gas.**

Many of the opinions centered on the value of a "seat at the table." Most people believe the state needs to have a seat at whatever table pipeline owners sit at as they discuss costs, management decisions, flows, operations, maintenance needs and whatever else partners talk about. Most of those interviewed cited years of contentious disputes between the state and the Trans-Alaska Pipeline System owners over transportation tariffs for moving crude oil from the North Slope to Valdez as something they would prefer to avoid in an Alaska Gas Pipeline. Many believe the state has not received as much tax and royalty revenue as it might have from North Slope oil because of excessive pipeline tariffs, and they are convinced a seat at the table of gasline owners would prevent a repeat of those problems. The tariffs are important because the state's royalty and production tax revenues are calculated after transportation costs are deducted from the sales price for the oil or gas.

In addition to knowing what the pipeline owners are spending and how it might affect the tariffs, many interviewees said signing on as a project partner could put the state in a better position to influence several key decisions: pipeline route, Alaska-hire provisions for construction and operation of the line, and provisions for in-state use of some of the gas. Of those who want to push for in-state spur lines and off-take provisions for local use of the gas, most acknowledged that even as a partner the state could not require any business to build or operate an unprofitable venture. They said any in-state project would have to stand on its own financial feet.

Interestingly, although there has been much interest in stripping the gas liquids to develop a petrochemical industry in Alaska, the interviewees were split on whether that made economic sense. Several were strong in their words that they did not want to see a "Petrochemical Gulch," as they called the Houston, Texas, area, developed in Alaska.

And while most everyone said they favor the Alaska Highway Route for a gasline, those same people said the major players probably would have made that decision long before the state signed on as an investor.

Regarding state involvement in control and oversight of project decisions, the group was about evenly split on whether acting as a business partner would be a conflict of interest for the state in its main role as a taxing authority, environmental and job safety regulator.

3) Many said state participation could help make the project more viable—simply put, moving it along so that it gets built sooner rather than later. Everyone interviewed said they would like to see an Alaska Gas Pipeline built for the money it would bring to the state treasury, for the construction jobs it would create, and for the economic boost a new industry and potentially cheaper energy would bring to Alaska. The dilemma for many was how state participation could move along the start date for construction. Certainly, state financial participation could help if the State of Alaska could find a way to lower the cost of the project, but all but a few acknowledged that would be difficult to manage.

Some thought the sheer political will of Alaska and a strong voice at partner meetings, perhaps even some delicate pushing, could get the project off the planning boards and into the groundbreaking stage. One referred to state participation as the "jump start" to the project by sending a positive signal to gas producers, pipeline companies and potential investors. However, others admitted they are skeptical that state participation as a project partner could have any immediate effect on whether the project gets built.

Some, however, cautiously warned that state involvement in the project, coupled with Alaskans' perception that natural gas would create new industries in the state, could lead state officials to push for uneconomical restrictions or side projects to the pipeline—"skew the decision making," as one person said. Or, as another said, emotions of the day can stampede government into making bad decisions. The other side said having the state participate as a partner could be a good learning experience, in that Alaskans could see from others that some dreams are unprofitable—in effect saving us from our own mistakes.

Industry Consensus

The list of interviewees from industry included representatives of:

- ExxonMobil
- Phillips
- BP
- Anadarko
- Alberta Energy
- Duke Energy
- Williams Companies
- TransCanada
- Westcoast Energy
- El Paso Energy

The natural gas industry representatives were very aware of the economic benefits the project represented. However, they viewed the gasline as a private-industry project and not one that required or was logical for state participation. Their rationale is as follows:

- The companies believe the state does not need a "seat at the table" to ensure that it has access to the all the information it requires. The state can gather most of the information it needs regarding pre-construction activities by active participation in the Federal Energy Regulatory Commission (FERC) and Canada's National Energy Board (NEB) process. The state also would be actively involved through its own regulatory oversight process. After construction, the state would continue to have access to the information it needs through state and federal public filings and private discussions with the gasline owners.

- Several companies believe the state is not necessarily adept at making rational business judgments. The open marketplace will dictate where gas development projects can and will be developed within the state. The state, however, may want its joint-venture partners to pursue gas development projects that are politically popular, but uneconomic.

- Industry believes that if the state were a member of the joint-venture governing board, the joint-venture might not be able to move quickly enough when key decisions are needed.

And, again, the state's decisions might not be made on the basis of economics, but for political reasons. Management of any major joint venture is difficult, and industry believes that government participation at the table would only magnify these management difficulties. Given the size of the project, the financial consequences of any delay can be significant.

- Although several companies acknowledge that state participation might ease or expedite the issuance of state permits, it is not believed that the state would be useful in the federal or Canadian permit process. The companies have significant, relevant experience in handling these issues.

- Many companies thought the state might be in a natural conflict-of-interest position as both an equity holder and as a regulator. This might create tension on the joint-venture management committee because the private company members might question the motives of controversial state decisions. Some companies questioned how the state could properly balance its legal and moral obligations to its citizens with its fiduciary obligations to its joint-venture partners.

- Industry believes that if the Alaska Gas Pipeline is economically viable, the sponsors would have access to more than adequate capital from existing financial markets, likely at better terms than the state could offer. In fact, state participation might make financing more problematic due to the nature of the sources of the state's equity or debt funding and requirements the state might impose to safeguard its investment.

- Some companies believe that proponents of state ownership are motivated by the prospect of a high direct rate of return on the pipeline investment, and that this motivation would be much less if they understood that the returns would be regulated.

- Industry is of the opinion that the amount of money the state probably would be able to invest—and the amount of equity participation percentage the sponsors likely would wish to sell—would allow the state to obtain only a small, minority position restricted in terms of management participation and access to day-to-day information.

- In at least some proposed organizational structures, the same joint venture would own and operate the entire pipeline from Alaska to Canada. In that situation, it might be inappropriate or politically unfeasible for the state to own an interest in foreign assets.

More importantly, industry does not believe that state equity participation would materially advance the construction of the gasline, assist its operation or enhance its profitability. Several companies believe state participation would actually *hinder* the project. Today's situation is not at all like the early 1970s, when state participation was actively sought by many of these same proposed developers. Industry now believes it has adequate resources to ensure the success of the project without state involvement. As many companies stated, this is a private project, not a public one.

Although industry has acknowledged the state could force its way into the joint venture, it appears unlikely any of the competing sponsor groups would welcome the state's attempt to become a partner.

SECTION 4

Ownership and Financial Participation Options and Evaluation Criteria

As noted in the Introduction, this study was mandated by passage of Senate Bill 158 in the spring of 2001. The bill is provided in Appendix A.

The legislative purpose was to obtain analysis and recommendations regarding State of Alaska options "to participate in commercial development of the state's natural gas resources through ownership of or provision of financing for a gas pipeline project." Further, the bill directs the Commissioner of Revenue to consider specific ownership and financing options and to evaluate these options according to specific criteria.

Ownership and Financing Options

SB 158 gives five directives for this report. Three relate to ownership and financing options, and two relate to evaluation criteria. The state ownership and financing options are:

- Participate by taking an equity position in a gas pipeline project by owning all or a portion of the project, or establishing a state-owned public corporation or authority to construct and operate the project.
- Participate in financing the project, which could include issuing general obligation bonds or revenue bonds of a state-owned public corporation or authority, or in another appropriate form such as guaranteeing debt. The review should include what terms the state, or its public corporation or authority, should require as conditions for providing financial support for the project.
- Participate by establishing a private corporation that would be comprised of Alaska residents who wish to become shareholders of a new corporation that would own a portion of the project or assist in the construction and operation of the project.

In addition to these directives, the Commissioner of Revenue has given consideration to whether the state should participate in commercial development of the Alaska Gas Pipeline by purchasing capacity rights from pipeline owners.

Evaluation Criteria

The two evaluation directives require use of the following criteria in considering the state's ownership and financing options for participation in the Alaska Gas Pipeline:

What is the effect of participation on the state's cash flow, its continuing ability to pay for essential public services, and financial integrity and creditworthiness.

Would state participation create additional risks for the completion and operation of the project; cause the project to be completed and to operate successfully; and help or hinder other parties participating with the state or its public corporation or authority in the completion and operation of the project.

Based on ideas offered by during interviews for this report, the Commissioner of Revenue added the following additional evaluation criteria:

- Whether ownership in the pipeline would provide additional information that would be helpful to the state in maximizing its royalty share of gas production or other state revenue.
- Whether there would be a conflict between (1) state ownership in the Alaska Gas Pipeline and the associated motive to maximize returns, and (2) the state's role and responsibility to regulate pipeline construction and operations

Each of the identified ownership and financing options is evaluated against these criteria in Sections 5 through 8. Conclusions are summarized in Section 10.

SECTION 5

Evaluation of Financing and Ownership Options

The state has numerous options for financial participation in the project, including:

- Contributing capital as an equity investment for all or part of the project cost.
- Making capital available through or as a debt investment for all or a portion of the project cost.
- Guaranteeing debt.
- Making in-kind contributions.
- Combining one or more of the above options.

This section reviews and analyzes each of these options in detail and discusses the financial benefits and drawbacks to each.

Financial Participation Options and Analysis

The source of funding is a key factor in determining whether the state should participate by taking an equity position in the Alaska Gas Pipeline. The funds must be available when needed and, of equal importance, must be legally authorized for use as such an equity investment. Use of any of the state's pools of money will have opportunity costs to the state.

The state has a variety of sources for providing capital, including using money on hand or borrowing it. Potential sources of cash include the state general fund, Constitutional Budget Reserve Fund, Permanent Fund and Earnings Reserve Account of the Permanent Fund. Sources of debt include the proceeds of general obligation or revenue bonds or certificates of participation. At a minimum, legislative authorization would be required to tap any of these funding sources and, as discussed below, some of these sources are more plausible than others.

Timing of Capital Calls

Evaluating whether to invest a particular fund in a gasline project involves practical considerations such as the anticipated timing of the project and volatility of the cash stream from a natural gas pipeline of a project size never before constructed in this country. Regulatory approvals for the project would require a minimum of two to three years, with construction expected to take an additional two to three years. Thus, the earliest the project could be moving gas to market would be late this decade, perhaps seven years after the decision is made to go ahead with the project. The analysis in Section 7 is based on the assumption that the Alaska Gas Pipeline would be operational in 2009.

The state's cash requirements for the project would commence almost immediately and increase in size and frequency as work progresses. Initially, any investment would likely require that the state make an immediate, initial contribution to the existing partners to "buy in" to the project (we assume not on a "promoted" basis, where the state would be required to pay a premium over a pro-rata share of the actual investment). It is difficult to predict the size of this initial investment. However, assuming the project sponsors have spent $200 million before the state joins the venture, and the state were able to take a 12.5 percent equity position in the partnership, the initial equity contribution would be $25 million.

For the first few years, the joint venture's capital calls likely would be relatively small, considering the size of the project as a whole. However, once construction begins, the number and size of capital contributions would increase dramatically (ranging up to an annual contribution of nearly $300 million (2001 dollars) for a 12.5 percent stake). Further, depending upon the skill of the project's budget forecasters and the ability to minimize cost overruns, the size of ongoing funding requirements would be difficult to plan for.[11] Another concern would be whether the line started flowing on schedule—particularly if the state needed the revenue to cover the debt it had issued for its investment in the project.

The point is that in order to participate in this project, the state would be required to make significant calls upon its available funding sources and credit for a number of years before the gasline would turn a positive cash flow. Even the first year or so of the of pipeline's

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[11] Another complicating factor will be whether and how the project is financed.

commercial life, which may or may not begin as forecasted, likely would not show strong or even positive cash flow due to the typical start-up issues all new pipelines face.

Thus, the source of the state's project funding would need to fit the following profile:

1) It must be immediately available.

2) It must be capable of making large capital contributions without delay and without any expectation of repayment for at least seven years, assuming the project is completed on schedule.

3) It must have the flexibility to timely meet significant and sometimes unpredictable capital calls.

It is also important for the state to keep its risk exposure to a minimum because a state government does not maintain a net worth to absorb serious losses. In this respect, it is unlike the corporate participants in the project. Losses sustained by the state would eventually have to be paid for through reduced services or higher taxes upon the citizens. Losses also could lower the state's bond rating, which would drive up the cost of borrowing for all kinds of public projects, including local schools.

Sources of Equity Funding

As discussed below, the legislature could consider a number of existing state funds as sources of funding for an Alaska Gas Pipeline.

The General Fund

In theory, the state could decide to appropriate unrestricted funds directly from its general fund to pay for its investment in the Alaska Gas Pipeline. Although it is ultimately a political question, there are practical problems with this approach. The general fund currently operates at a deficit and this status is not expected to change within the next few years. The state already has numerous calls on the limited money available within the general fund and it would be difficult, therefore, for the state to impose new taxes or cut public services to the extent necessary to make money available for an equity contribution to the project.

Permanent Fund Direct Investment

There are several ways the Permanent Fund might be able to invest in the gasline project. As a passive investor it might, under the proper conditions: (1) invest in the stock of a company or companies owning the gasline; (2) invest in the bonds used to finance the project; or (3) participate in a private equity limited partnership that finances some portion of the project. However, if the proposed investment were structured so that the Permanent Fund became actively involved in the gasline business, it lacks the legal authority to make such an investment.

The Permanent Fund, the state's major savings account, was created in 1976 by constitutional amendment. A specified portion (at least 25 percent) of the state's mineral lease rentals, royalties, bonuses and federal mineral revenue-sharing payments are dedicated to the principal of the fund.

The constitutional amendment establishing the fund placed one restriction on how the fund was to be invested: It must be invested in income-producing assets specifically designated by law as eligible for Permanent Fund investments. The legislature passed comprehensive legislation in 1980 specifying a list of permitted investments and establishing the Alaska Permanent Fund Corporation as an independent state agency to manage the fund's assets. This legislation declared the Permanent Fund to be an inviolate trust to be managed by the Board of Trustees according to a version of the Prudent Investor Rule often referred to as the Prudent Expert Rule.[12]

The legal list governing permitted investments has been amended several times, and allowable investments include mortgages, real estate investments, certificates of deposit, term deposits or bankers' acceptances, and interests in domestic and non-domestic companies.[13] There are other limitations, too. This statutory list also places a 5 percent limit

12 The Prudent Investor Rule as applied to investments of the fund means that in making investments the board of trustees shall "exercise the judgement and care under the circumstances then prevailing that an institutional investor of ordinary prudence, discretion, and intelligence exercises in the management of large investments entrusted to it not in regard to speculation but in regard to he permanent disposition of funds, considering probable safety of capital as well as probable income." AS 37.13 120 (a).

13 AS 37.13.120

on the amount of voting stock the fund may own of a single corporation. And, domestic stocks owned by the fund, with some exceptions, must be listed at the date of purchase on an exchange registered with the federal Securities and Exchange Commission.[14]

Another requirement in statute is that the board must favor in-state investments if the risk and return are equal to the alternative investment opportunities.[15]

The legislature also adopted a 5 percent "basket clause," which allows the trustees to invest up to 5 percent of the fund's total assets in "other types of investments not specifically listed," so long as the Prudent Expert Rule is satisfied.[16]

Considering all of the above limitations in statute, could the state use the investment authority of the Permanent Fund to go into the gas pipeline business as a partial or 100 percent owner of the project? Without a change in the laws governing the investment authority of the Permanent Fund, the answer is "no." Although the Permanent Fund currently lacks the authority to invest as an active participant in a North Slope gasline business, the legislature could amend the statute and specifically direct the Permanent Fund to make such an investment.

It would be different, however, if the Permanent Fund were simply buying stock or investing in bonds issued by a corporation or corporations that own the gasline. The Prudent Expert Rule requires the trustees to weigh risk and reward and consider investments within the context of the fund's overall asset allocation, while avoiding the concentration of investments in single entities. To comply with the rule, the trustees follow a detailed decision-making process that includes adopting an annual asset-allocation policy and selecting specialized managers to achieve a balanced, diversified portfolio. Under the available investment authority and the constraints of the Prudent Expert Rule, the trustees might well be able to make limited investments in either the equity or the debt of a North Slope gasline enterprise.

Finally, legal question exists as to whether a gas pipeline project that would not produce income for a period of years would qualify as an income-producing investment under the law

[14] AS 37.13.120(l)

[15] AS 37.13.120(l)

[16] AS 37.13.120 (k) (1).

and whether the constitutional limitation would permit such an investment. We understand that the trustees believe this specific limitation would not preclude this kind of equity investment in a gasline project, but there is no specific legal ruling on the income-producing issue.

Earnings Reserve Account of the Permanent Fund

If the legislature decided it would be in the Alaska's best interests for the state or an independent state corporation to enter the North Slope gasline business, it could appropriate money from the Permanent Fund's Earnings Reserve Account (ERA) to a state agency for that purpose.

Income earned on Permanent Fund investments is credited to the ERA and, on June 30 each year, appropriations are made from the ERA first for dividends to residents of the state and then for inflation proofing of the Permanent Fund's principal. Any undistributed income remaining in the ERA is available to cover future dividend or inflation-proofing needs. The legislature also may appropriate money from the Earnings Reserve Account at any time for any purpose. To date, however, it has never appropriated the money for anything other than dividends, inflation proofing or to increase the principal of the fund.

The Department of Revenue anticipates that the amount of surplus earnings available from the Permanent Fund each year over the next decade will average about $250 million. However, the actual amount available in any one year will vary enormously—ranging from $0 to more than $500 million, depending on the performance of the financial markets and the mechanics of how the surplus is determined.

However, one must remember that the only vehicle the Permanent Fund has to absorb volatility in its investment income is the ERA. Committing the Earnings Reserve to the gas project might jeopardize the Permanent Fund's ability to pay dividends and inflation proofing. And, considering Alaska's general fund deficits, bond rating agencies might view such a commitment unfavorably.

In summary, appropriations from the ERA could be a source of funding for the project. This course of action, however, presents a number of obvious economic and political risks.

Actual and projected Permanent Fund principal and Earnings Reserve Account balances are shown in Figures 5-1 to 5-3, as are the month-to-month fluctuations in the ERA balance.

Figure 5-1

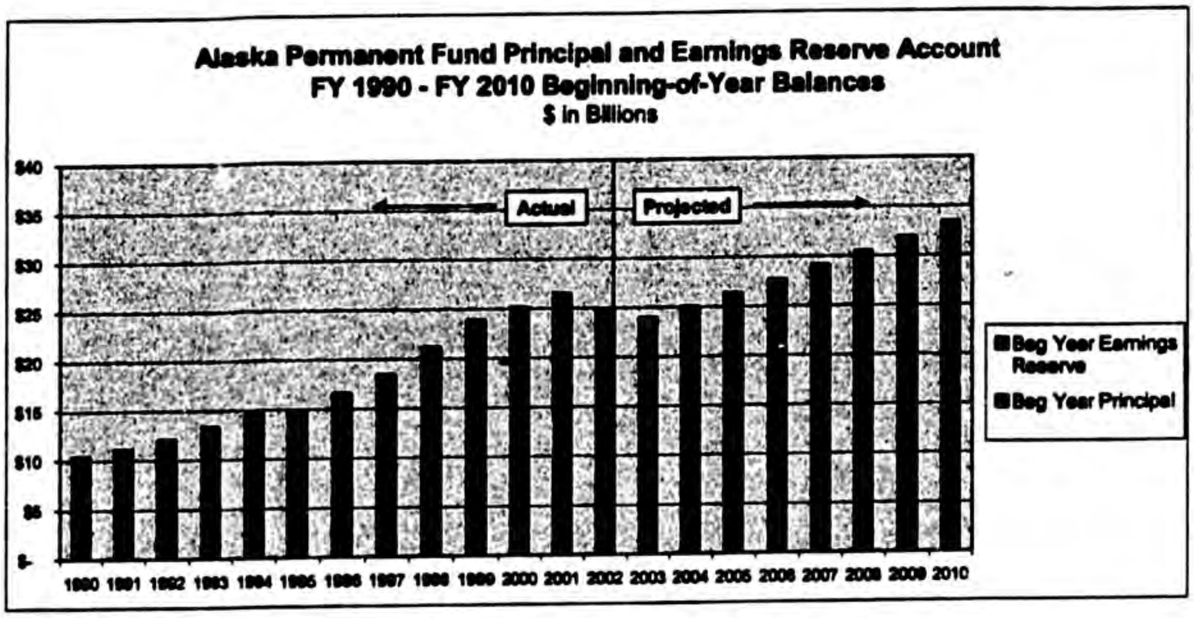


Figure 5-2

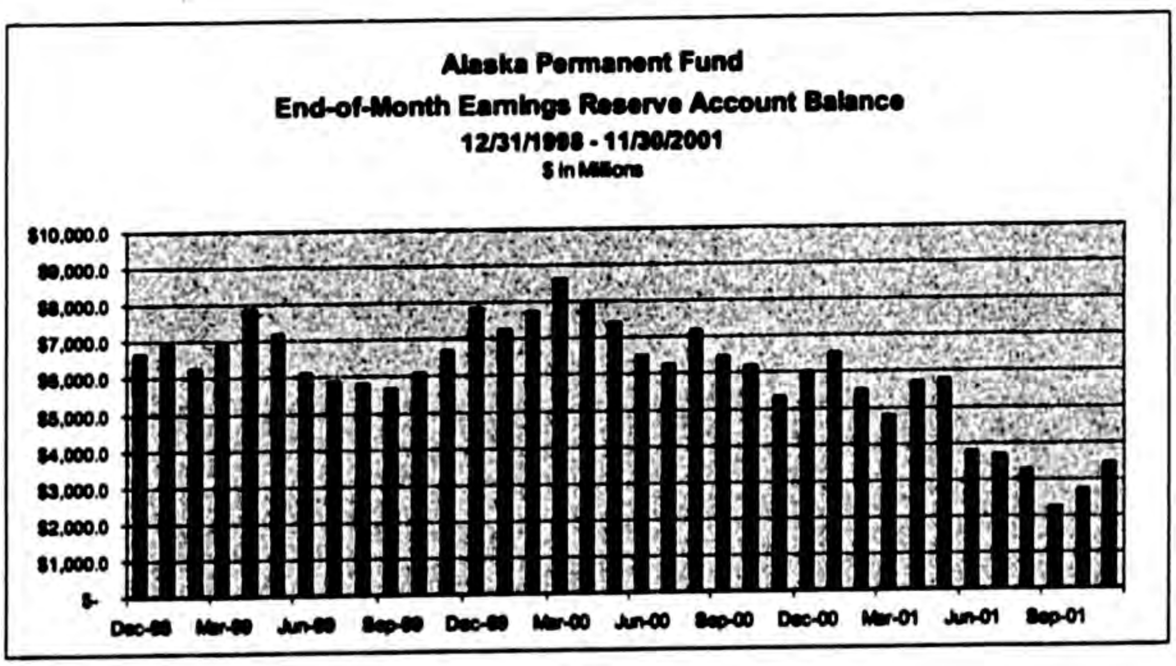
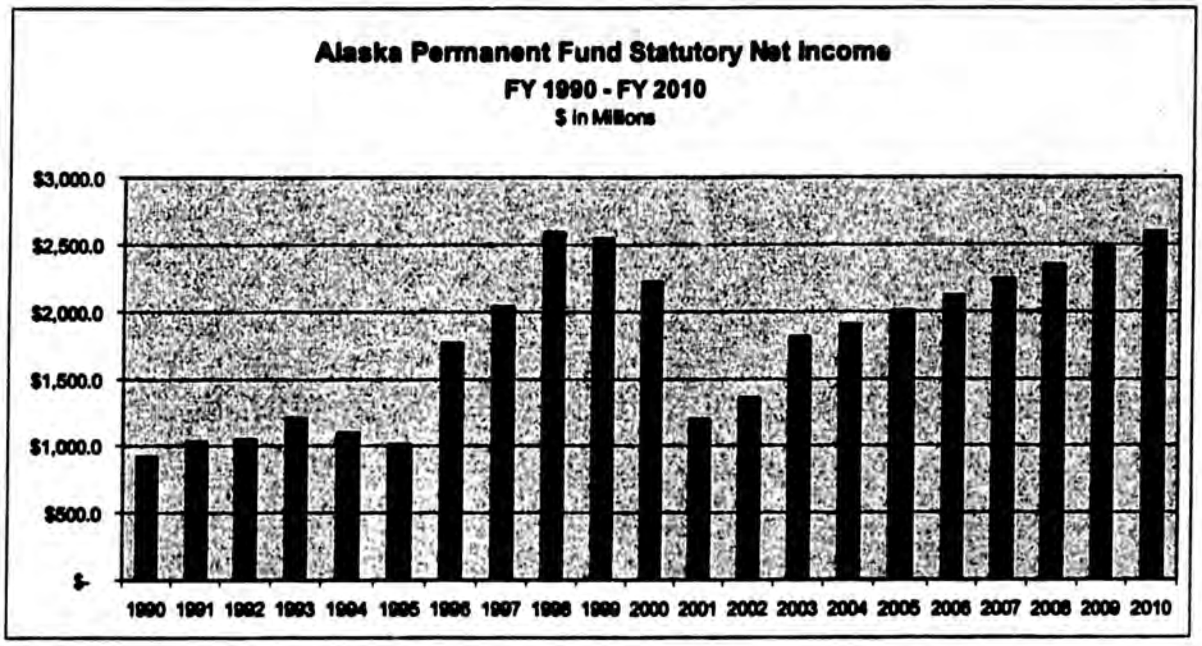


Figure 5-3

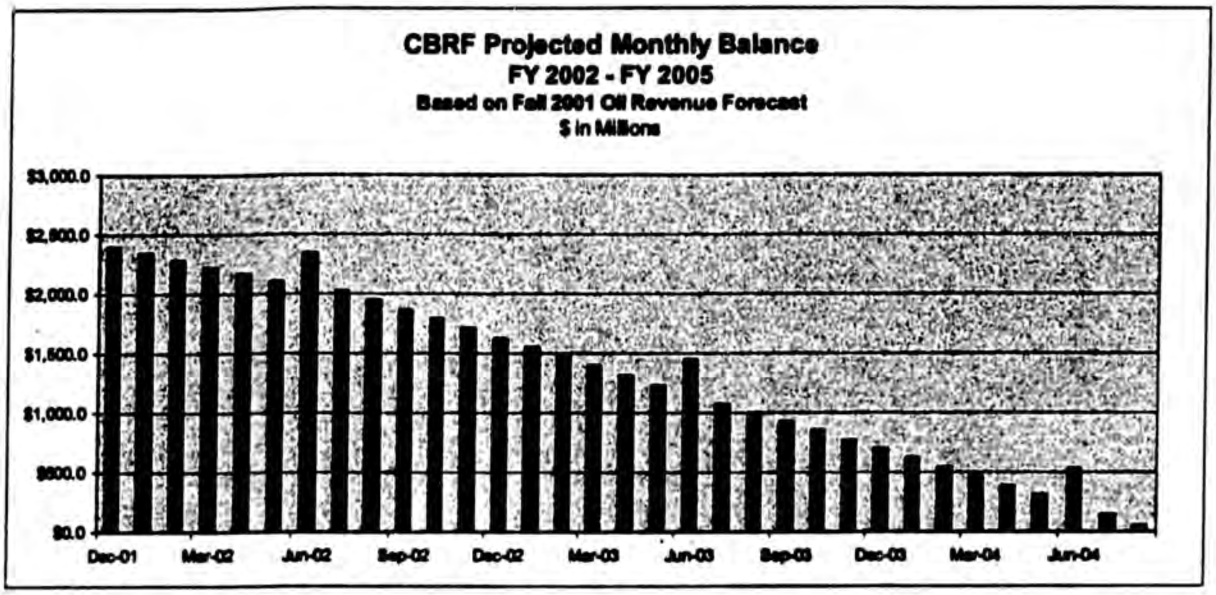


Constitutional Budget Reserve Fund

Created by the voters in 1990, the Constitutional Budget Reserve Fund (CBRF) holds the proceeds from settlements of oil and gas tax and royalty disputes since July 1, 1990. It generally requires a three-quarters majority vote of each chamber of the legislature to withdraw money from the account. For all but two years since 1991, the state has relied on the CBRF to fill the difference between unrestricted general purpose revenue and the annual state budget. Over the past 10 years the state has deposited about $5.5 billion into the CBRF, earned about $1.5 billion from investments, and withdrawn more than $4.3 billion to pay for public services—leaving a balance of $2.65 billion on January 1, 2002.

The projected declining balance of the CBRF is illustrated in Figure 5-4.

Figure 5-4



Note: The $300 million peaks in June are caused by repayment of the beginning year draw.

A fundamental problem with using the CBRF as a potential source for equity investment in the project is that the Department of Revenue forecasts the CBRF is likely to be depleted by late summer 2004 due to declines in unrestricted general fund revenue.

Given the uncertainty of any remaining balance in the CBRF after Fiscal 2004, and the potential negative reaction by bond rating agencies to using this fund for purposes other than covering annual general fund deficits, the CBRF is not a viable source of equity funding for the project.

In-Kind Contributions

Some have suggested that another source of equity for state investment in the Alaska Gas Pipeline could be in-kind contributions from income-generating items like right-of-way lease payments or advance sales of state royalty income. Even if the state was willing to forego the steady revenue benefit of such income, there is a significant problem with the in-kind concept. Using these funds this way likely would violate the dedicated-funds prohibition in

Alaska's Constitution.[17] As a result of this constitutional limitation, the proceeds of state taxes and licenses generally are prohibited from being deposited anywhere but the general fund and the Permanent Fund.[18] If the legislature wished to pursue this alternative further, review by the Attorney General's office would be appropriate.

In any event, with respect to right-of-way lease payments only, it is not expected that the payments would produce enough income to support a "trade" for equity. Although approximately 700 miles of the Alaska Highway Route would be in Alaska and the majority of the route would cross state lands, the state's earnings from right-of-way lease payments would be modest. In Fiscal 2001, for example, the state received only $730,000 from lease rental payments for the 800-mile Trans-Alaska Pipeline System. Annual lease payments from the gasline likely would be similar.

Sources of State Debt Funding

Although an outright appropriation from one of the above sources of state funds does not appear practicable, it is possible the state could structure some type of bond issuance to obtain funds for an investment in the project. The different bonding alternatives are discussed below. The intricacies of coordinating private debt obtained by project sponsors and public debt of the state would be complex and would require further analysis after the gasline funding plan is known. It should be noted, however, that the state would face formidable legal and practical hurdles to financing a significant portion of the project with tax-exempt debt.

There are several types of debt that could be issued, depending on the state's level of commitment. Debt instruments include general obligation bonds, lease-purchase obligations and revenue bonds (with or without state "moral obligation" guarantee). State-guaranteed

[17] "DEDICATED FUNDS. The proceeds of any state tax or license shall not be dedicated to any special purpose, except as provided in section 15 of this article [establishing the Permanent Fund] or when required by the federal government for state participation in federal programs. This provision shall not prohibit the continuance of any dedication for special purposes existing upon the date of ratification of this section by the people of Alaska." Alaska Const. art. IX, Sec 7.

[18] Lengthy discussions of the dedicated funds prohibition in the context of natural resources revenues, including royalties and bonuses, are found at 1982 Alaska Op. Atty. Gen 13 (November 30, 1982) and 1975 Alaska Op. Atty. Gen (May 2, 1975). Presently, right-of-way revenue is deposited to the general fund. Of royalty and bonus income, 25 percent is allocated to the Permanent Fund, 0.5 percent to the state school fund, and the remainder to the general fund.

bonds are not considered feasible because they would require an amendment to the Alaska Constitution.[19]

The combination of state debt (e.g., general obligation bonds and revenue anticipation notes) and state-supported debt (a portion of University of Alaska debt, lease-purchase financings, and a share of municipal general obligation bonds for school construction) are the measure of Alaska's debt burden used by Moody's, Standard & Poor's and Fitch in assigning a credit rating to state debt obligations. As discussed below, the state's current bonding ability is limited unless the state is willing to accept lower credit ratings.

Today the state maintains favorable credit ratings for its various debt instruments. Its most recent credit ratings were Aa2 by Moody's, AA by Standard & Poor's and AA by Fitch, which are in the high end of debt rating scheduled. However, all general obligation bonds of the state have since been retired (the last in Fiscal 1999). The state's debt rating history is set forth in Table 5-1.

TABLE 5-1
State of Alaska Credit Rating History
(ratings as of date shown)

Moody's Investor Services		Standard and Poor's		Fitch Investor Services	
July 13, 1961	Baa	June 4, 1971	A	May 3, 1994	AA
September 12, 1969	Baa1	January 23, 1975	A+		
August 29, 1974	A1	June 14, 1980	AA-		
June 13, 1980	Aa	August 5, 1992 forward*	AA		
November 26, 1998 forward	Aa2				

* Standard and Poor's has withdrawn its rating of the State of Alaska, as all general obligation debt of the state has been repaid. The state expects to obtain ratings from the three rating agencies in 2002.

[19] Alaska Const. art. IX, sec. 8. The voters did, however, amend the constitution in 1982 to permit the state guarantee of housing loans for veterans issued by the Alaska Housing and Finance Corporation.

General Obligation Bonds

The legislature could authorize the issuance of general obligation bonds to fund a state contribution to the Alaska Gas Pipeline. General obligation bonds, as debts of the state, are backed by the state's full faith and credit. General obligation bonds are the most secure of debt instruments and, therefore, bear the lowest rate of interest. However, general obligation bonds must be ratified by the voters and approved by the State Bond Committee.[20] The state has no general obligation bonds outstanding today (the last were paid off in 1999).

The state has issued general obligation bonds 49 times since statehood, raising almost $1.4 billion. Although there is no statutory limit on the amount of such bonds, the size of a general obligation bond issuance to support this project could be the largest in state history. The largest to date was $200 million issued in 1982. We estimate that a 12.5 percent share of the Alaska Gas Pipeline could require an investment in the range of $1.5 billion, unless project financing is available.

There are legal issues and at least one practical issue associated with the issuance of such bonds in support of an investment in the project. First, the state is precluded constitutionally from lending its credit directly to benefit a private entity.[21] The proceeds of general obligation bonds, thus, could be available to purchase a state equity investment in a pipeline (assuming appropriate statutory declaration of public purpose). The proceeds of such bonds, however, could not be used to make a loan to private investors.

Second, the issuance of general obligation debt to make an equity investment in a joint venture appears to be unconstitutional. The Alaska Constitution states that such bonds may only issued for capital improvements.[22] Issuance of debt to support an investment in a joint venture that would own a natural gas pipeline would not be a permitted use of general obligation bond proceeds because it would not be a capital improvement for public use, but rather an investment in an ownership entity. The proceeds of any general obligation bond issue, therefore, would need to be used solely to acquire an undivided interest in an asset, the

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20 Alaska Const. art. IX, sec. 8; A.S. 37.15.

21 Alaska Const. art. IX, sec. 9.

22 Alaska Const. art. IX, sec 9.

pipeline. This may not be a practical method of structuring the relationship of the other parties participating in the project.

Third, the state's borrowing capacity may be too insignificant to be of any practical assistance to support the investment. The state's borrowing capacity can be measured using generally accepted ratios (as discussed in Section 8 of this report). These ratios represent acceptable norms for issuing debt. It has been state policy to stay within the range of committing 8 percent of unrestricted general fund revenue to debt service, in order to maintain the state's historical AA credit rating.[23] At a limit of 8 percent of the general fund's unrestricted revenue, the state's available maximum general obligation bond capacity ranges from about $210 million of 10-year bonds to approximately $300 million in 15-year bonds.

However, investors have recognized the shift over time from when most state revenues were unrestricted to today, when a significant portion of revenues are restricted by the state's direction. That is, the state has segregated money into various funds that create restricted revenues rather than unrestricted—the largest of which is the Permanent Fund. If we add Permanent Fund earnings (after inflation proofing) to the state's unrestricted revenue and take 8 percent of that, the state's available debt capacity would jump dramatically—about $1.2 billion of 10-year bonds to $1.7 billion in 15-year bonds.

Nevertheless, any new issuance of state debt (especially if it relies on restricted revenues for debt capacity purposes) would be carefully reviewed by the rating agencies due to the state's uncertain fiscal situation. A proposal by the state to exceed its current debt service thresholds would need to be carefully reviewed for presentation to the rating agencies in order to avoid a downgrade.

State-Supported Debt

State-supported debt is debt for which the ultimate source of payment is, or may include, appropriations from the state general fund. The state's full faith and credit is not pledged

[23] Debt service, for determining debt capacity, includes debt service on general obligation bonds, University of Alaska bonds that are state supported, state reimbursement of municipal school debt, and lease payments on lease purchase financing.

[24] Since 1996, the largest taxable general obligation bond issuance was by the City of New York for general purposes and public improvements in the principal amount of $434.1 million. Source: Thomson Financial.

against the debt, and state-supported debt is not considered state-guaranteed debt for purposes of the Alaska Constitution because the state's payments on the debt, even if the subject of a contractual commitment, are contingent on annual legislative appropriation. As a result, citizen approval of such debt is not required—although legislative approval is required in almost all instances.

The form of state-supported debt that might be useful in this project is lease-purchase financing obligations consisting of certificates of participation (COPs) issued by lessors of facilities used by the state. In such situations, generally the debt is secured by the lease payments on the leased facilities.

The limitations inherent in this type of financing are similar to those associated with general obligation bonds, except that no public vote is necessary. This debt also would not be tax-exempt, and the state has limited capacity without jeopardizing its credit rating. Further, the complexity inherent in structuring a financing of this magnitude as a lease is substantial. The state probably would lack sufficient debt capacity to lease the entirety of the pipeline to the project sponsors.

Revenue Bonds

Probably the more likely source of debt financing would be through the issuance of some form of revenue bonds. These most probably would take the form of bonds issued by a state agency and secured by revenues generated from the use of the pipeline, such as ship-or-pay contracts for moving gas through the line. In the most customary form of revenue bonds, the project and its revenues constitute the sole source of repayment of the revenue bonds. Private corporate guarantees and letters of credit also could provide additional security.

In a separate type of revenue bond, additional security would be obtained from a reserve fund that includes a discretionary capital reserve provision. A typical capital reserve fund is approximately equal in size to the maximum amount of debt service required in any year. If the reserve fund falls below its required level and if a moral obligation concept were applied, the legislature may, but is not legally required to, appropriate funds sufficient to restore the capital reserve fund (in other words, the state has a "moral obligation"). The authority to issue moral obligation revenue bonds is contained in the enabling legislation of several state agencies such as the Alaska Energy Authority and the Alaska Industrial Development and Export Authority.

The revenue bond concept is not new to this project. Authority for revenue bonds was approved for the Alaska Pipeline Financing Authority in 1978. In its enabling legislation, the Financing Authority was authorized as a conduit to issue revenue bonds up to the principal amount of $1 billion, inclusive of amounts required for capital reserves, for the purpose of purchasing or otherwise acquiring any obligation issued with respect to the ANGTS project—provided that the payment on that obligation was fixed and certain as to terms of repayment. Debt service on the bonds was to be paid from the income and receipts derived from the project. The bonds were expressly not debt of the state or any political subdivision, and were to be paid exclusively from the project income. The state pledged that it would not limit or alter the rights and powers vested in the Financing Authority to fulfill the terms of any contract made with the bondholders or in any way impair the rights and remedies of those holders unless the bonds were fully paid and discharged.[25]

Revenue bonds are not a general obligation of the state, nor does the state provide security for the debt in any other manner except in the case of "moral obligation" pledges. Depending upon the other available security, a "moral obligation" could provide additional credit enhancement and lower interest rates to traditional revenue bonds.

Alaska Gasline Port Authority Financing Proposal

As described in Section 3, the Alaska Gasline Port Authority has proposed an innovative plan to finance a pipeline from the North Slope and an LNG facility at Valdez, along with an additional line branching away at Delta Junction to carry natural gas to the Canadian border to connect with the Lower 48 grid. The Port Authority proposes to finance 100 percent of the costs with a combination of tax-exempt and taxable revenue bonds. Based upon legal and financial analysis and an IRS letter, the authority believes its *income* would be tax-exempt.[26] Since the letter application to the Internal Revenue Service is not available, it is not clear whether the ruling is based upon all of the relevant facts.

[25] AS 44.82.150, repealed 1994.

[26] Private Ruling 200017018 (January 27, 2000).

First, according to the IRS response, the Port Authority represented that the authority's revenues would be derived primarily from the sale of natural gas to municipalities within the state and to other purchasers expected to include governmental and private enterprises. But the vast majority of the authority's revenues would, in fact, be derived from sales of natural gas outside the state.

If the underlying facts have not been fully or accurately described in the letter to the IRS, the IRS is not bound by the ruling and it may not be relied upon.

Second, there may be an issue regarding the fact that the Alaska Constitution does not specifically authorize port authorities to exist as political subdivisions of the state, and only the state or a political subdivision may issue tax-exempt bonds.

It is generally more expensive to borrow money without any equity commitment because 100 percent debt financing—the absence of any owner contribution whatsoever, such as buying a house with no down payment or other collateral—increases the risk to creditors of not recovering the entire debt. Thus, 100 percent debt financing for the project, if it is available at all, could come at a relatively high cost. This high financing cost could negate all or a portion of the relatively limited benefits attributable to the port authority structure.

The Port Authority claims that it would be exempt from federal income taxes for the amount of income it retained for itself (estimated by the Port Authority at $37 million per year) and the amount it remitted to the state and other municipalities (estimated at $333 million per year). This income would come from the "profit" earned by the Port Authority on the difference between what it paid the producers for the gas and what it was able to earn by selling the gas and LNG on the world market. This income tax savings could be seen as a benefit to the project. The foregone tax would be about $130 million per year, according to Department of Revenue estimates.

A few comments on the practical considerations of the Port Authority plan also should be made. The Department of Revenue and its consultants are unaware of any LNG terminal facility, gasification facility or natural gas pipeline in the world that has obtained 100 percent debt financing. LNG facilities with up to 75 percent debt have been constructed, but they are the exception—something in the range of 60 percent to 70 percent is more common. The hurdles to obtain even this level of financing is high, with lenders generally requiring the following to be in place just for a "conventional" project financing of a LNG terminal:

- A long-term LNG sales agreement with creditworthy purchasers for a minimum base load.
- Long-term natural gas supply agreements with creditworthy suppliers for a minimum volume.
- Acceptable quality and quantity of proven gas reserves.
- Liquefaction capacity sufficient to meet the project's sales obligations.
- Fixed-price or minimal determinable price contracts.
- Long-term transportation agreements with sufficient capacity to meet delivery schedules.
- Capped marine freight price.
- An experienced shipbuilder if transportation is via a new tanker.
- Experienced vessel owners and operators.
- Proven technology.
- Fixed-price, date-certain engineering, procurement and construction contracts with experienced, creditworthy contractors.
- An appropriate framework among creditors to harmonize force majeure provisions and other potential contractual issues.
- A cash-flow allocation to allow each project access to appropriate payment stream.
- Adequate payment security mechanisms such as escrow accounts and letters of credit.

The prerequisites for financing a natural gas pipeline are similar. Some of the requirements listed above for an LNG facility can be met by the Port Authority, but it still faces formidable challenges to satisfy others. For example, obtaining gas supply commitments from North Slope producers and suitable off-take agreements from purchasers seems unlikely for a variety of reasons, including:

- Their lack of interest in LNG exports from Alaska.
- Their involvement with gasline proposals they believe are more commercially viable than LNG.
- The question of what happens when the Port Authority gasline gets to the Canadian border.
- Their concerns about doing business with an entity controlled by municipalities.

Other Financial Participation by the State

State Loans to Project Sponsors

If funds are available, loaning money to the project may be a more desirable alternative for Alaska than equity participation due to a stronger claim on revenues, lower construction and operation risks, and fewer conflicts of policy interests. There are practical limitations on the state's participation, however.

- First, Alaska would need to have funds available to lend to the project. The source of such funds may affect the ability of the state to meet other governmental needs.
- Second, any financial return to the state would be delayed at least until after 2010.
- Third, the debt structure easily could put the state in a minority or subordinate position with little control over the project or its operation.
- Finally, and most importantly, the state's debt likely is not needed by the project developers.

During the interviews, the potential project developers generally indicated they only would have an interest in state financial participation if the state could somehow issue tax-exempt securities. As discussed above, this alternative would probably require an exception to federal tax law. Most of the potential project developers have credit ratings and overall financial resources equal to or more substantial than that of the state (Table 5-2). They likely would be able to obtain attractive interest rates and terms and, accordingly, state taxable debt is not particularly attractive as an alternative. As shown in the following chart describing common credit measurement factors as of January 15, 2002, the creditworthiness of the potential gasline project sponsors is good to excellent. Further, even though this project is of enormous magnitude, there appears to be adequate debt capacity in world capital markets today to fund it.

TABLE 5-2

Corporate Debt Rating of Potential Project Developers

Company	Senior Debt (SP/Moody)	Debt + Pfd / Bk Cap	Fixed Charge Coverage	Debt + Pfd / EBITDX	Debt + Pfd / DsCF
ExxonMobil	AAA/Aaa	15%	92.6	0.3	0.4
BP	AA+/Aa1	24%	N/A	1.5	2.4
Phillips	BBB+/A3	47%	14.1	0.9	1.4
Duke	A+/A1	49%	7.3	2.9	5.2
TransCanada	A-/A2	72%	2.3	5.1	9.2
WestCoast	A-/ n/a	72%	2.6	7.0	11.3
El Paso	BBB+/Baa2	58%	3.9	3.5	3.9
Williams	BBB+/Baa2	55%	2.3	3.5	9.3

EBITDX = Earnings before Interest, Taxes, DD&A, and Exploration Exp.

DsCF = Discretionary Cash Flow = Net Income + DD&A + Def. Taxes + Exploration Exp. + Other Non-Cash Items

Debt + Pfd / Bk Cap = (Total Debt + Preferred Stock) / Total Book Capitalization

Fixed Charge Coverage = EBITDX / (Interest Expense + Pre-Tax Preferred Dividend)

Direct Guarantees

Even though the creditworthiness of the known project sponsors is high, if there is a shortfall in that respect perhaps the companies might have an interest in the state lending credit support through forms of state guarantees. Generally, the use of a guarantee would be of significant benefit only if the guarantor has a credit rating higher than the rating on any debt issued by the pipeline investors—which does not appear to be the case with the state.

In contrast to direct funding through an equity investment or debt, debt support would not require the outlay of state funds. The guarantee could be provided by either (a) the state directly guaranteeing debt issued by the sponsors, (b) a state authority guaranteeing debt issued by the sponsors, or (c) the state guaranteeing debt issued by the authority, the proceeds of which would then be lent to the sponsors. The state's obligation, in all cases, would be limited and contingent upon various events as the state could negotiate, such as expiration date, subordination rights, amount, guarantee payment terms, equity conversion rights, etc.

The structures referred to in (a) and (b), however, may require voter action. Further, the Alaska Constitution prohibits the state from directly guaranteeing private debt.[27,28]

Assuming the two hurdles mentioned above could be overcome, there are various forms that an appropriate state guarantee could take. A direct, full-faith and credit guarantee by the state obviously would constitute the strongest credit support the state could make, but this also would be the riskiest for the state. There is the possibility that a guarantee could be structured in a form that is constitutionally permissible. The legislature may be able to set aside a specific category of reserve funds within the general fund or Earnings Reserve Account of the Permanent Fund, for example, upon which to base a limited guarantee. However, this would require further analysis of the Attorney General and, even if legally permissible, would be removing flexibility to meet future fiscal requirements of the state.

Moral Obligation Guarantees

The state may also be able to lend its credit support through pledging its moral obligation in some form of financing structure. Such a moral obligation would not constitute the legal indebtedness of the state and would not, therefore, require action by the voters. Such a structure has won credibility with investors in other contexts where it has been employed because of the perception of rating agencies and investors that the state undertaking such a moral obligation would, if necessary, honor its moral obligation by appropriating funds to meet debt service shortfalls. The failure to do so would be regarded as a derogation of the state's credit and hurt the state's ability to sell its securities.

The moral obligation commitment could be strengthened by earmarking a single revenue source as security for the moral undertaking. Such a structure would involve the legislature appropriating existing revenue to a state authority and then enacting legislation to appropriate

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27 Alaska Const. art. IX, sec. 8.

28 In 1982 the voters approved a constitutional amendment that permits the state to guarantee unconditionally as a general obligation of the state the payment of principal and interest on revenue bonds issued by the Alaska Housing Finance

a revenue stream to the authority in future years, subject to the right of future legislatures to reverse such appropriation. Because the legislature is not legally required to appropriate such revenues in any year, such action should not constitute a legal dedication of revenues in contravention of the constitutional prohibition previously discussed. The authority would, in turn, issue debt secured by a pledge by the authority of such revenues and then lend the debt proceeds to the project sponsors. The revenue stream so pledged would not be utilized to pay debt service unless the sponsors defaulted on the loan agreement and, to the extent not utilized for debt payments, the revenue stream would be available in any year for any other purpose designated by the legislature.

Compensation to Alaska for Loan Guarantees

In the event that Alaska decides to extend a limited and contingent guarantee, the state would be entitled to compensation for its undertaking. There are a number of ways such ways such values could be determined in an arms-length negotiation with the sponsors. However, these alternatives are beyond the scope of this report.

Tax Issues

Under existing federal tax law, states may issue tax-exempt municipal bonds for public projects, such as schools. Without an exception to the existing Internal Revenue Code, however, bonds—whether general obligation, revenue or other type—issued to finance a project such as the Alaska Gas Pipeline are likely to be almost all taxable. This debt would be considered "private-activity bonds," and the interest on private-activity bonds, except for those that finance certain exempt facilities and nonprofit enterprises, is taxable.

Debt is classified as a private-activity if it meets certain tests, established under the regulations promulgated under Section 141 of the Internal Revenue Code. The debt must meet both the private-use and private-payments tests. In addition, if the debt proceeds are deemed to have been used to make "private loans," the debt is considered to be private-activity bonds.

Corporation for the purpose of purchasing mortgage loans made for residences of qualifying veterans. This is the only purpose for which state-guaranteed bonds may be issued.

Certain categories of facilities, however, may be eligible for tax-exempt financing. It is possible, though not certain, that certain aspects of this project could qualify for tax-exempt financing as "dock and wharf" facilities, such as a marine LNG terminal.[29] The eligible portion would likely only be a fraction of the entire cost and, therefore, use of this exception would still mean that all or substantially all of the project could be financed only on a taxable basis.

Another exception under federal law is the private-activities cap. Under this cap, each state is allowed to issue tax-exempt bonds for private activities up to certain limits. In the case of Alaska, the limit is currently $187.5 million per year. However, this amount already is fully subscribed each year for debt issuances of the Alaska Industrial Development and Export Authority, Alaska Housing Finance Corporation, Alaska Student Loan Corporation, municipalities and other purposes. The State Bond Committee allocates the annual allowance.

The tax treatment of the debt does not change depending upon the identity of the issuer. Thus, debt issued by a conduit or other state agency is not any more likely to be exempt. In addition, the type of debt also does not necessarily affect its tax status. Tax status depends upon the use of the proceeds and the sources of repayment of the debt.

There is a market for taxable bonds. However, the market for this debt is untested since there have been no comparable issues by other states in the past.[30]

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[29] There has been at least one successful tax-exempt funding of a marine terminal in Alaska. When the state refused in 1974 to support state tax-exempt financing for TAPS, the City of Valdez was considered as a potential issuer for at least the marine terminal facilities. In that year, the voters of Valdez authorized a bond issue of up to $2 billion for financing the marine terminal facility. In 1977, after receipt of an IRS ruling recognizing the tax-exempt treatment of the bonds, the City of Valdez, on behalf of ARCO and with utilization of ARCO's credit capacity, issued $265 million in Terminal Revenue Bonds. These bonds, as all successor terminal bond issuances, were secured solely by the project revenues and the company's credit. The credit of Valdez was not required. The city received a 1 percent impact fee from the financing and began to accumulate the funds in a permanent fund. Subsequently, in 1977, SOHIO undertook the same financing, and by the end of 1978 a total of $1.265 billion of Terminal Revenue Bonds had been issued for each of the various owners of the marine terminal. Since the initial issuance of the bonds, there have been numerous refundings with extensions of bond maturities up to 2037 in some cases. Almost all of the original debt amount still is outstanding.

[30] For example, since 1996 the largest taxable municipal general obligation bond issuance appears to have been by the City of New York for general purposes and public improvements in the principal amount of $434.1 million. Source: Thompson Financial.

Because the state's private-activity cap already is fully utilized—and insufficient to finance much of a state investment in the gasline—and because only a fraction of the project could qualify as a dock or wharf facility, the analysis in this report is based on the reasonable assumption that almost all debt issued by the state for this project would be taxable. Under this assumption, debt participation by the state does not appear economically attractive, because the state probably could not obtain substantially better interest rates than private parties. The state could obtain better interest rates only if it could issue tax-exempt municipal bonds for the project under a special exception to federal law. This option is discussed below.

Tax-Exempt Financing

As discussed above, the state would need a special exception to federal law in order to issue tax-exempt bonds to finance the Alaska Gas Pipeline.[31] Although rare, such special exceptions do occur. Here, a special exception would be predicated on the fact that the pipeline is a unique transportation project that could provide a stable domestic source of energy. Given that the project would serve the important national interest of making the country less dependent on foreign energy, the possibility of tax-exempt financing is worth considering.

If tax-exempt financing were available, what would it look like?

First, we assume the state would issue some form of revenue bond, not a general obligation bond, because a general obligation bond would put an intolerable amount of financial risk on the state.

Second, as required under federal law, the state would be the owner of at least as much of the project as it financed through tax-exempt bonds.

Third, most likely a gasline revenue bond would be in the form of an industrial development bond issued through a state authority such as AIDEA or other special-purpose entity that the legislature might create. The bond would be issued by the authority to finance facilities that are then leased to the private-entity user at a rent equal to debt service on the bonds and for a

[31] The advantage of the gasline qualifying as a permitted private activity is that the private-activity monetary cap does not apply.

term equal to the maturity of the securities. Alternatively, the issuer might be able to loan the proceeds of the industrial development bond directly to the private-entity user on repayment terms equal to the terms on the bonds. In either form, the responsibility for construction and operation of the project would remain with the private developers.

Fourth, security for payment of the debt would be revenues from the project itself, likely supported by ship-or-pay contracts with the producer/shippers.

Fifth, the financial markets likely would finance no more than 70 percent of the project with this kind of debt. The remaining 30 percent would have to be an equity contribution. Options for the equity financing would be direct state contribution (which could be $3.5 billion to $4 billion on a $12 billion to $14 billion project cost), or a similar contribution from some other party—for example, the producers could be asked to contribute the 30 percent equity share under contract as a prepaid tariff.

If the state were able to provide tax-exempt financing, would it make the Alaska Gas Pipeline more attractive to the private parties whose participation is necessary to get this project off the ground? This question is difficult to answer. Even though there almost certainly would be an economic benefit from tax-exempt financing, whether the resulting structure is attractive to the producers or pipeline companies is an open question.

A financial analysis of the benefits of tax-exempt financing would have to consider many variables. One of the most important of these is the spread between tax-exempt interest rates and taxable rates. Usually this spread will be around 25 percent (such as 8 percent for taxable bonds and 6 percent for tax-exempt), but it can vary with market conditions and may be different for a project like this.

A second consideration is the value that a private owner gives up when the state takes over ownership of the project. Primary among these foregone benefits is the right to depreciate the asset. The value of this benefit over time to a company will depend on the company's tax rate and its discount rate—i.e., the value it places on having money today rather than in the future. If the producers owned the pipeline, the tax law would allow them to claim accelerated depreciation, under which they would be able to deduct the cost of the pipeline from their taxable income over 16 years, with larger deductions occurring in the first six years.[32] In addition, they could deduct their interest payments. If the state owned the pipeline, the producers could only deduct the cost of their lease payments to the state. Over time, they would deduct roughly the same total that they would have deducted had they owned the project, but it would take much longer to realize the economic benefit of the deduction without the use of accelerated depreciation.

Because of the time value of money, the accelerated depreciation payments allowed under a private-ownership scenario would reduce the economic benefit of tax-exempt financing. In the early years of the project, a private owner would be better off with taxable financing. One attempt to model the cost advantage of tax-exempt financing for a typical producer shows that, under one set of reasonable assumptions, tax-exempt financing is economically advantageous, but it would take 13 years for an owner to realize a cost advantage from tax-exempt financing.

In sum, unlike the other options discussed in this report, tax-exempt financing might make feasible a project that otherwise would be uneconomic. Alternatively, the state might be able to extract an additional state benefit if it were to provide tax-exempt financing to lower the costs for an already profitable project. Since tax-exempt financing does offer financial benefits, the state may consider supporting a federal effort to obtain a tax-exemption for state debt for the project.

Even if tax-exempt financing were an option, however, it is not certain that the sponsors of the Alaska Gas Pipeline would prefer that option. That would depend on the resulting ownership structure and actual savings to the sponsors over their own costs of capital and foregone benefits such as depreciation.[33]

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32 26 U.S.C. § 168.

33 If any portion of the state's equity funds originated from proceeds of a tax-exempt bond, this structure could jeopardize the use of accelerated depreciation by the private entities for the entire project. Under a worst-case scenario, the entire project would be required to use 125 percent of useful-life and straight-line depreciation.

Ownership Alternatives

SB 158 requires the Department of Revenue to consider specific forms of equity investment in the project. There are two major alternatives: direct state ownership or establishment of a public authority such as the Alaska Industrial and Export Development Authority (AIDEA). The bill also requires the department to consider the merits of a private corporation comprised of Alaska residents who wish to invest in the project. This corporation would own a portion of the project and/or assist in its construction and operation. These alternatives are discussed below.

Direct State Ownership

The state owns and has financed a variety of public facilities. Although there is no direct constitutional impediment in Alaska to a public/private joint venture, the use of public/private partnerships historically has not been an ownership mechanism for state facilities. However, it is an option for non-public facilities, as occurred in December 2000 when AIDEA took an initial equity stake in Alaska Seafoods International, an Anchorage seafood processing company. AIDEA obtained a larger equity stake in the corporation the next year after the state authority helped restructure the business, which faced a severe cash shortage. Although we are not aware of any situations where the state itself—rather than AIDEA or another agency—directly owns a part interest in a private venture, we also are unaware of any specific legal prohibitions to such a structure.

However, as mentioned in the discussion above, it is important to note that the state is precluded, by the Alaska Constitution, from "lending its credit directly to benefit a private entity." We do not believe that would necessarily prevent the state from taking a stake in a private partnership, as long as the state could show it was not lending its credit to the private entity.

Public Authority

Funneling the state's investment through a public authority would avoid some of the problems of direct state ownership. A public authority would provide a one-step removal from direct involvement of state government with a private company. With an independent board of directors and executive director (albeit possibly appointed by the governor and even confirmed by the legislature), and statutory provisions that provided the authority with a degree of management independence, an independent authority could act and react more like a private business entity.

The creating legislative enactment could provide an authority with independent corporate powers, bond issuance and credit guarantee capacities, and the ability to engage independently in federal programs. A separate legal authority also could maintain a degree of separation from the customary political process associated with state government and establish a clearly dividing line for liability. The assets delivered and pledged to the authority could be the only public assets available to satisfy claims against the project, possibly shielding the state from any potential damages.

Private Corporation of Alaska Citizens

Alaska could participate in the ownership, construction or operation of a gas project by creating a private corporation expressly for that purpose. It may be possible, moreover, to devise strategies that leave most of the shares of the corporation in the hands of state government and its citizens. The approach nevertheless raises a number of questions that should be addressed before it is seriously considered.

This concept was proposed in a report prepared for the state in 1978 by Dillon, Read & Co. It was modeled upon the structure of the Alberta Energy Corporation (AEC), which at that time was owned in part by the government of the Canadian Province of Alberta. AEC was capitalized initially by the provincial government with an investment of $75 million. Subsequently, in 1975, Alberta offered shares worth an additional $75 million publicly. Provincial residents, however, were given a priority during the first three weeks of the offering. All of the shares were sold during the priority period, so afterward AEC had a total capitalization of $150 million, with 50 percent of the corporation owned by Alberta residents and the other 50 percent owned by the province.

The Dillon, Read report suggested this model as a possible approach for Alaska, based on the assumption that funds used for the state's initial equity investment in the corporation could be obtained by issuing tax-exempt general obligation or revenue bonds. Under existing law, a private (non-governmental) corporation may not issue tax-exempt bonds, except in compliance with certain Internal Revenue procedures for non-profit corporations.

Several things have changed since the Dillon, Read report was issued. Over the years, the Alberta government has extricated itself from its ownership of AEC. The province divested the last of its shares in 1993. And, more noteworthy, U.S. tax laws changed dramatically in 1986. As a consequence, bonds used to raise funds to capitalize a private corporation would, almost certainly, not qualify as tax-exempt.

This approach of a private corporation raises a number of issues. For example, attempting to limit shareholders exclusively to Alaska citizens may present practical problems and perhaps even legal ones. As a practical matter, a residency requirement for shareholders may be difficult to monitor and enforce. It almost certainly would diminish the market value of the corporation's shares. And, as far as the U.S. legal system is concerned, this concept may be unprecedented. We are not aware of any state forming a private corporation, whose shareholders are limited to state residents, in order to advance a development project in the state. Legal challenges to this approach are therefore possible. Among other things, the validity of the residents-only shareholder's rule might be challenged as lacking a legitimate public purpose. The restriction also might be challenged under the Privileges and Immunities Clause of the U.S. Constitution[34]—which essentially guarantees equal treatment among citizens by state governments—notwithstanding the "private" nature of the corporation. Before following this approach, a thorough analysis of questions like these would be advisable.

More significantly, this approach fails to offer any tax or financial advantage over the development of a project by existing private corporations. As previously mentioned, the tax code underwent significant revision in 1986, and Dillon, Read's assumption in 1978—that the state could issue tax-exempt bonds to raise funds for the initial capitalization of the corporation—is no longer valid.

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[34] ..."No state shall make or enforce any law which shall abridge the privileges or immunities of citizens of the United States"... U.S. Const., Amend. XIV, sec. 1.

It is also difficult to see what advantages this approach provides over other, more readily available, alternatives. Providing Alaskans the opportunity to hold shares in the project, by itself, would appear to be an insufficient justification, because Alaska and its citizens already can hold shares in the corporations with an interest in developing North Slope gas. A new, state-sponsored corporation is highly unlikely to offer a "smarter" option for development, because existing corporations with experience building and operating large gas pipeline projects are likely to build and operate the North Slope project better, for less.

The potential upside from participating in this project is not extraordinary, because the earnings on the corporation's gas pipeline investment would be regulated by FERC.

And participating in order to influence the pipeline route is unnecessary, since Alaska law already forecloses the Over-the-Top Route.

Due to the size and scope of this idea, if the legislature wishes to pursue it further we recommend that special tax, securities and investment banking advisers be retained.

The preceding concerns, of course, are not exhaustive. Using state revenues to form a gas pipeline corporation would further concentrate the state's—and, therefore, its citizens'—investments toward oil- and gas-related activities, while diversification away from such activities may be a more prudent investment strategy for a state already so dependent on oil and gas.

In addition, the new corporation presumably would borrow most of the funds necessary to build the project or its share of the project. But lenders would require long-term, ship-or-pay commitments from the major North Slope gas owners before they would be willing to risk their funds. These gas owners, however, would not enter long-term, ship-or-pay commitments in support of a project (other than one they themselves sponsor) unless (1) they conclude that the project as a whole is economic, and (2) they believe the project sponsor can build the project and operate it reliably at a lower cost.

make it certain that the sponsor would need to revise the ANGTS option from the approved proposal. In addition, FERC "is likely to be required to conduct additional environmental analysis." ANGTA gives FERC "broad authority to amend" the certificate if it does not result in change in "the basic nature and general route of the approved transportation system." Although FERC is unlikely to adhere strictly to conditions that are no longer practical or technologically optimal, it is not clear how much latitude either the project sponsor or FERC has to revise the ANGTS without further congressional action.

- There appears to be nothing in ANGTA that prevents FERC from considering, under the Natural Gas Act, other proposals filed by other sponsors or routes different from the ANGTS route. However, limitations placed by the ANGTA on such FERC considerations are unclear and might also require clarification from Congress.

Major Regulatory Issues for Transporting Alaska Gas—2002 and Beyond

Open Access

U.S. pipelines are built when their sponsors obtain and accept a Certificate of Public Convenience and Necessity from FERC under Section 7 of the Natural Gas Act. Canadian pipelines need similar certificate authority, usually from the National Energy Board (NEB). To move gas from Alaska, multiple jurisdictions would exercise regulatory authority, however, the primary regulatory authorities would probably be FERC jurisdiction within Alaska, NEB jurisdiction within Canada, and FERC jurisdiction again downstream to ultimate markets in the United States.

To construct a multi-jurisdictional pipeline and get it financed in a timely manner requires regulatory approvals, a known and agreed-upon tariff structure, an approved pipeline route and set of initial rates, and transportation agreements that have a term and volume to allow financing and that mirror each other by jurisdiction and in receipt and delivery point. Each section of an integrated, multi-jurisdictional pipeline needs to have understood contract terms that match adjoining upstream and downstream facilities. This includes transportation volumes (size of pipe), gas quality standards (type of gas), known tariff structure (the cost to move the gas from Point A to Point B), and simultaneous service. Each piece of the pipe must be operational concurrently, must physically be capable of moving the volumes nominated by its shippers or upstream pipeline, and be able to deliver like volumes into downstream pipelines or to downstream customers. The contract volumes, terms, and titles need to match. As noted above, under ANGTA, these issues were largely negotiated as part of the supply arrangements assumed by the pipelines. In today's world, this might not work.

Open Season Processes

In a world after FERC Order 636, pipelines need to use a nondiscriminatory process to solicit contracts for transportation service. This is true both for a new pipeline and for expansion of an existing pipeline. Typically this is done through a so-called "open season" solicitation. The open season announces the intention of a pipeline company to build new facilities based upon an expression of interest by parties willing to contract for service on those new facilities.

The open season can be done in a variety of ways, but generally it leads to a process yielding binding transportation agreements of a term and volume adequate for regulatory approval of a certificate to construct and for ultimate financing approval. This means that all parties are given simultaneous equal opportunity to "bid" for pipeline space under a clearly defined set of time frames and rules. Ordinarily bidders must meet minimum standards (including demonstration of credit support) to be awarded transportation space.

For a multi-jurisdictional pipeline such as an Alaska pipeline project , the combined project would need to "perfect" contract support for each leg of the pipeline (i.e. Alaska, Canada, Lower 48 states) to allow a complete, coincident contract path for the cumulative volumes. ANGTA did not contemplate an open season process or a Section 7 NGA filing, because the filing authority was ANGTA itself. It is not evident how these issues would be resolved. The manner by which firm capacity would be obtained for the Alaska pipeline and its alignment with existing downstream pipeline firm capacity is unclear. This might be the most significant issue surrounding the economic and commercial viability of building these pipeline facilities.

Tariff

ANGTA contemplated a cost-of-service tariff, common in the period leading up to the ANGTA negotiations. Under this type of tariff, the cost of gas and the cost of owning and operating a pipeline is computed monthly and billed to customers of the pipeline. All costs including return are periodically reviewed for reasonableness, and cost of capital and capital structure are reviewed in periodic rate proceedings, as prescribed in Section 4 of the Natural Gas Act. Within ANGTA, an incentive rate-of-return feature was included to recognize the risk and cost of the formidable undertaking involved in a project to move large quantities of Alaska natural gas such a great distance to market. The concept involved a 50-basis-point risk premium on the equity return.

This type of cost-of-service tariff is now used less and less frequently both in the United States and Canada. Within the United States, tariff design has moved toward a straight fixed variable (SFV) rate design. This tariff approach does not have monthly cost adjustments. There is no longer a requirement for periodic rate filings under Section 4, and rate proceedings are generally the prerogative of pipeline owners or can be initiated by other parties under Section 5 of the NGA. Because most costs are fixed, the primary basis for cost recovery is a fixed-demand charge rather than in a commodity charge.[36]

A similar tariff approach has evolved within Canada for NEB-regulated pipelines. An SFV rate design is matched with a periodic review of rate levels and an incentive type of rate design that allows pipeline companies to share expense and capital cost savings with shippers between periodic rate reviews.

Another change is that ANGTA provided full cost-of-service rate recovery for all costs. This would have included the actual costs of construction if those costs exceeded the estimated costs filed with the certificate application. Today's pipeline rate regulation has moved toward putting the pipeline owners at risk for cost overruns or increases. Initial operating rates are established based upon estimated costs to complete a project. Pipeline owners today have a tremendous incentive to control project costs because initial rates usually are based upon

[36] FERC has expressed a willingness to consider alternative forms of rate design, and this has occurred when a pipeline and its customers can structure a rate design with sufficient support to be filed as a settlement offer with FERC.

estimated costs to completion. Should actual costs exceed these costs, they have the opportunity to try to recover them in a rate proceeding (and indeed, the burden of proof to demonstrate prudence of costs falls on parties making those arguments). However, rate proceedings are costly and inherently uncertain as to outcome. Hence, they are not the recourse pipeline owners are prone to seek. Pipeline owners have a real incentive to contain construction costs to certificated levels.

A major tariff issue in today's regulatory environment is the issue of rolled-in vs. incremental rates for service. This is particularly of concern for major new pipeline investments that integrate with downstream existing pipelines. New facilities under ANGTA were, of necessity, incrementally priced. There were no existing facilities to roll the costs into. Although the Canadian ANTGS prebuild in 1983 was incrementally tolled, incremental vs. rolled-in tolling has continued to be an issue for every major expansion of the prebuild portions of the ANGTS system since that time. The NEB has continued to support a rolled-in standard for Canadian mainline pipelines, primarily on TransCanada.

A pipeline from the North Slope to Alberta would constitute a new transportation route, so service on the pipeline would be incrementally priced. However, capacity on pipelines and routes out of Alberta would necessarily be expanded and therefore be subject to the incremental vs. rolled-in pricing controversy.

Other major issues in the current integrated North America gas market are common tariffs and electronic access to information. Today's market is an open market. Gas is a true commodity and is interchanged both financially and physically through a variety of contract forms and terms. These terms necessitate common or like language in tariffs defining everything from gas quality to nomination standards and uniform multisystem transportation agreements. None of these issues were contemplated within ANGTA. A variety of modern issues ranging from gas quality to contract terminology were not contemplated or built into ANGTA.

The Alliance Pipeline Project from Northern British Columbia to Chicago is an example of a new major pipeline project where all these issues had to be anticipated and built into the project design, and ultimately into the project approvals and financing. This is a bullet high-pressure system that takes gas from the start of the project in the north and moves it

SECTION 7

Potential Returns from Pipeline Investment

As described in Section 6, the state could choose to pursue either or both of two ownership options associated with the Alaska Gas Pipeline. These two options are ownership in the pipeline and ownership of capacity rights purchased from the pipeline owner through the open-season process. This section evaluates risks and reviews potential returns associated with each of these two options. Additionally, potential effects on the state's cash flow are discussed.

Pipeline Ownership

State ownership in the pipeline could conceivably range from partial to full ownership. Given the planning and development investment that private sponsors have already made in the pipeline, the substantial further investment still required, and the fact that the state does not have adequate expertise to lead pipeline development, we do not believe full ownership is a practical option. Accordingly, state ownership would very likely be limited to partial ownership. The state's partial ownership share is usually discussed as being the same ratio as the state's royalty rights to gas produced on the North Slope, or 12.5 percent. However, the state could take ownership at levels above or below this share.

Ownership Risks

As discussed in Section 6, project ownership would allow the state, as part of the ownership structure, to participate in selling pipeline capacity. But in order to use capacity for its own gas, the state would need to purchase capacity rights under the same open-season rules as any other customer—ownership does not bestow any capacity rights or privileges.

The Alaska Gas Pipeline would be regulated by FERC in the United States and the NEB in Canada. Construction of the project would not begin until long-term contracts are in place to reserve all or most of the system capacity. Tariffs and the return on the investment in the pipeline would be established based on negotiations between pipeline owners and customers that buy capacity rights on the system. Returns on equity investment in the system would be in the range of 12 percent to 13 percent if negotiations and regulatory approval were to follow those that occurred with the Alliance Pipeline Project. There might be incentives that could increase returns above this level.

Although the investment would earn a regulated return, there would be risks of earning a lower return than that established in the negotiation and regulatory approval process. These risks include risk of construction cost overruns, project abandonment or mothballing, inadequate capacity subscription or customer default, operating problems, regulatory setbacks, insurance inadequacies and easement conflicts. Each of these risks is discussed below.

Construction Cost Overruns

As described in Section 6, construction of the Alaska Gas Pipeline alone could cost upward of $10 billion in 2001 dollars—a gas conditioning plant on the North Slope and expanded pipeline capacity out of Alberta would be billions more. Although contingencies are included in the sponsor's cost estimates, actual costs could well grow above those estimates. There are a number of developments that could cause cost overruns. These include the following:

- Problems with new technology or approaches associated with the project
- Construction productivity problems in the arctic conditions
- Inadequate skilled labor and other resources to construct the project efficiently
- Construction delays. These could occur from more adverse weather conditions than planned, interruption in delivery of pipeline or other materials, labor disputes, accidents and safety problems, technology difficulties, unplanned environmental occurrences (including archeological finds) and political developments
- Demand for pipe to meet project needs pushing pipe prices above budgeted levels
- Enhanced security in response to terrorist threats
- Mismanagement, particularly of developments that could cause cost overruns

Typically in a regulated environment, however, construction cost overruns are largely recoverable as long as they can be defended as being prudent. For example, cost increases due to project delays because of abnormal weather would be viewed as unavoidable and therefore likely would be added to the owner's rate base. Although other parties, such as pipeline customers or FERC or NEB staff, might resist such adjustments, they would typically have to prove imprudence in order to exclude cost overruns from a revised tariff. If the owner were not able to find ways to contain unavoidable costs through cost reductions elsewhere, FERC or NEB might award it a lower than anticipated rate of return, but this would not likely be a substantial adjustment. So, the pipeline owner's risks from cost overruns are practically limited to imprudent costs, regulatory delays before rate relief is granted for unavoidable cost increases, and a potential for FERC and NEB to allow a lower than planned rate of return due to lower than expected performance in cost management.

Project Abandonment or Mothballing

Although contracts signed for pipeline capacity should reduce much of the risk that the Alaska gas pipeline would be abandoned or mothballed (indefinitely delayed), such a risk does exist. It is not unusual for a major energy project to be delayed or abandoned. In fact, ANGTS has already been delayed once. Many investments made in its planning process during the late 1970s and early 1980s are likely to be lost. There have been numerous other smaller energy projects in Alaska that have not been constructed. On a larger scale, during the 1980s, numerous nuclear power projects in the United States were abandoned or mothballed before construction was completed.

Unless the pipeline is not completed at the request of pipeline capacity owners, funds invested in an abandoned project could not be recovered and would be lost to project investors. Similarly, mothballing could result in lost investment or substantially reduced returns on investment made prior to mothballing.

Inadequate Capacity Subscription or Customer Default

The pipeline is planned to be full in a few years time and operate at a 95 percent capacity factor. There is some risk that the pipeline would not carry this load level or be subscribed under ship-or-pay contracts through its entire project life. Also, it is possible for a party that has contracted for pipeline capacity to default on payments. Further, if gas prices are down at the time a contract for pipeline capacity expires, it is possible that the capacity would not be resubscribed and could remain idle for some time. As a result, some costs could go unrecovered.

Operating Outages

The pipeline owner would be responsible for providing usable pipeline capacity with limited outages for maintenance and limited system failures. Outages due to "force majeure" (acts of God) would likely require customers to continue to pay for their capacity reservation despite the temporary interruption. Nonetheless, to the extent that the pipeline operation outages exceed the negotiated terms for allowable outages, revenues could be lost and returns negatively affected. System outages can occur from a variety of causes. These include equipment failure or lower than expected performance; management, information or process failure; labor or contract disputes; and catastrophic events. Extended outages could significantly lower revenues and returns for the pipeline owner.

Regulatory Setbacks

The pipeline would be operated under the regulatory oversight and approval of FERC, NEB and numerous other national, state, provincial and local regulators. Through the associated regulatory process, decisions could be made that negatively affect the owner's ability to earn its authorized return. Risks of lower returns could result from decisions made within the existing regulatory framework, changes in regulatory requirements, and tariff and procedural interventions by third parties.

Insurance Inadequacies

Because the Alaska Gas Pipeline would be so capital intensive, it is vital that it carry customary levels of property and liability insurance. However, there is no assurance that this insurance would be available, at least at affordable rates in the future. Inadequate insurance coverage could result in significant losses for the pipeline owner.

Easement Conflicts

The pipeline would require that easement rights be acquired from thousands of landowners. In addition, it might have to acquire rights from First Nations groups in Canada. Even if easements and rights of way are obtained through standard legal processes, the risk would exist for legal conflicts and claims arising out of construction or operation of the pipeline.

Projected Returns from State Investment in Pipeline

Financing of the Alaska Gas Pipeline is assumed to include a debt/equity ratio of about 70/30. The two sponsor groups evaluating pipelines from the North Slope to Alberta are projecting this capital structure, and the Alliance pipeline had this structure. With the 70/30 debt/equity ratio for the Alaska Gas Pipeline, debt cost is assumed to be 8 percent and the regulated return on equity is assumed to be 12 percent.

However, actual returns on equity could vary from planned levels. There is risk of lower return due to the risks outlined above. There is also a prospect of a higher return if the pipeline owner performs in a way necessary to achieve incentives that would likely be built into the tariff.

Financial Model

To understand the range of possible returns from state ownership, a financial model was developed by the Department of Revenue's consultants. The primary focus of the model was to estimate the range of possible returns that could be earned from investment in the North Slope-to-Alberta pipeline given the various investment risks outlined above. The model also provides for analysis of variances in the tariff from different assumptions relating to taxes paid on returns to equity and debt components to invested capital.

However, the model was not developed to estimate the absolute tariff level. So, resulting tariff calculations should be considered as only general approximations. Further, no estimates were made of the cost to expand capacity out of Alberta to complete the transport of North Slope gas to final markets.

The model calculates annual revenue requirements and levelized tariffs necessary to meet those requirements over an assumed 25-year life of the pipeline. It then calculates the 25-year internal rate of return (IRR) based on application of the tariff and a range of projected actual operating results. The model also includes a tax component that calculates potential income tax benefits from state ownership.

The model estimates both rate base and a replacement cost new less depreciation (RCNLD) value of the pipeline for each year of the projected 25-year operating period. The rate base estimate is used to calculate annual return requirements based on the debt/equity ratio, debt costs and regulated equity returns discussed above. The RCNLD estimate is used to calculate annual property tax associated with the pipeline.

The model calculates revenue requirements in each year as the sum of operation and maintenance costs (including administration), depreciation, property tax, income tax and return on rate base (in terms of interest expense and return on equity). Capital, operation and maintenance costs were directly input based on estimates made by the sponsors evaluating the Alaska Highway Route. Depreciation was calculated based on straight-line, 25-year depreciation rate. Property taxes were calculated by applying an assumed tax rate of 2 percent (20 mills) to the RCNLD value of the pipeline in each year. Income taxes are discussed separately below.

In the model, the annual revenue requirement calculations are in turn used to calculate a levelized tariff per MMBtu. This tariff, when applied to the projected gas volumes, produces a cash flow that yields the same IRR as the projected 25-year revenue requirement. The tariff is calculated both in terms of nominal prices (including projected inflation) and in terms of real prices (2001 dollars). In the base case, it is assumed that federal income tax would be paid on all returns to invested capital. That is, it is assumed that interest paid on bonds issued to finance the project would be taxable and that the state's share of net income to the project would also be taxable. However, the model provides analysis of the degree to which the pipeline tariff would be lower with tax exemptions to these returns (see Income Tax Approach and Assumptions, below).

The model projects actual operating results under a number of different possible scenarios. These scenarios reflect both risks of achieving lower than regulated target returns and possibilities of higher than target returns from capitalizing on incentives assumed to be included in the tariff. Probabilities are assigned to a range of risk and incentive possibilities, and a set of Monte Carlo simulations of operating results are run. The results are compiled into an expected value and a risk profile (probabilistic range) of IRRs from ownership investment in the pipeline. The structure of the risk analysis is shown graphically in Appendix B.

Income Tax Approach and Assumptions

If pipeline ownership is in the form of a single corporation with specific shares held by the individual owners, income taxes would be assessed before returns flow back to the owners. This would mean that return on the state's equity share would be taxed in the same way as that of the private owners. However, if ownership in the pipeline is in the form of a partnership or limited liability company, the possibility exists that the return to the state would not be taxed.

Income tax was calculated assuming that 50 percent of the pipeline investment and income generated from the investment would be within the United States (Alaska) and 50 percent would be within Canada. For the U.S. portion of the pipeline, a 9.4 percent state and a 35 percent federal income tax rate were assumed. Federal tax was calculated assuming a 1.5 times accelerated depreciation schedule over 15 years, with benefits of this tax treatment flowing through to the tariff. For returns generated in Canada, provincial tax rates were estimated to average 14 percent and the federal income tax rate was assumed to be 22 percent, based on official projections by the Canadian government. Canadian tax law recognizes depreciation costs as capital cost allowance (CCA). A 4 percent annual CCA is allowed on the declining value of pipelines. The CCA is 20 percent on general equipment and 30 percent on transportation and computer equipment. The weighted average for investment in the Alaska Gas Pipeline was estimated to be 5 percent for input to the financial model.

Risk and Incentive Inputs

As outlined above, pipeline owners face risks and incentives that can affect returns on the owner's investment in the Alaska Gas Pipeline. Many of the risks were reflected in the financial model through the following inputs.

The risk of construction cost overruns was evaluated by assuming that there was a 40 percent chance of cost overruns. The size of overruns evaluated ranged from 15 to 30 percent. It is recognized that some of the cost overruns would be recoverable through a tariff adjustment; a range of 0 to 100 percent recovery was evaluated.

The chance of project abandonment or mothballing was assumed to be 3 percent.

Inadequate capacity subscription or customer default was addressed with three separate inputs. First, a 1 percent probability was input for the risk of a customer with reserved capacity being unable or unwilling to pay for his take-or-pay obligation because of contract disagreements or financial difficulty. The percent of pipeline capacity affected was evaluated at 5 to 30 percent. The number of years affected was evaluated at 1 to 6 years.

Second, the prospect of the pipeline not being fully subscribed by the time it begins operation was given a 5 percent chance. The percent of the pipeline capacity unsubscribed was assigned a 5 to 10 percent probability, and the number of years affected was evaluated at 1 to 5 years.

Third, insufficient demand for pipeline capacity when individual capacity reservation contracts expire was evaluated at a 5 percent probability. The expiration of contracts was evaluated at years 10 to 25, and the percent of capacity left unused as a result was evaluated at 10 to 25 percent.

Operating outages were evaluated for both chronic above-plan outage levels and for a one-time catastrophic event. Chronic outages were assumed to have a 10 percent chance, with uncompensated downtime running from 2.5 to 5 percent. The chance of a one-time catastrophic failure was evaluated at a 2 percent chance. The one-time event was given an equal chance of occurring in any of the 25 years in the analysis period.

It was assumed that the owner would have an incentive to share in the benefit of cost savings during construction. The owner realizing shared-savings was evaluated assuming there was at a 10 percent chance of a 10 percent cost underrun, and that the owner would share 25 percent of the savings.

Estimated Returns

Applying the above assumption, the model shows that the expected IRR value for ownership investment in the Alaska Gas Pipeline is 8.1 percent to total capitalization and 10.1 to equity. For equity, this is 1.9 percentage points lower than the assumed regulated rate of return. The range of returns to total capitalization is from 7.1 percent at the 10th percentile to 8.8 percent at the 90th percentile, while the range of returns to equity is from 5.8 percent at the 10th percentile to 12.0 at the 90th percentile.

These ranges are shown in risk profiles presented in Figures 7-1 and 7-2, respectively. The risk profile shown in these figures is a graph of the probability that returns would be at or lower than the levels listed on the X-axis of the chart. Not reflected in these profiles is the chance that the state could actually lose money through the pipeline investment. This would happen if the state invested capital only to have the pipeline not be completed. The chances of such an occurrence are unknown. However, as noted above, this possibility was assigned a probability of 3 percent for the purposes of this analysis.

Figure 7-1
Probabilistic Range of Returns to Total Capital Invested in the Alaska Gas Pipeline

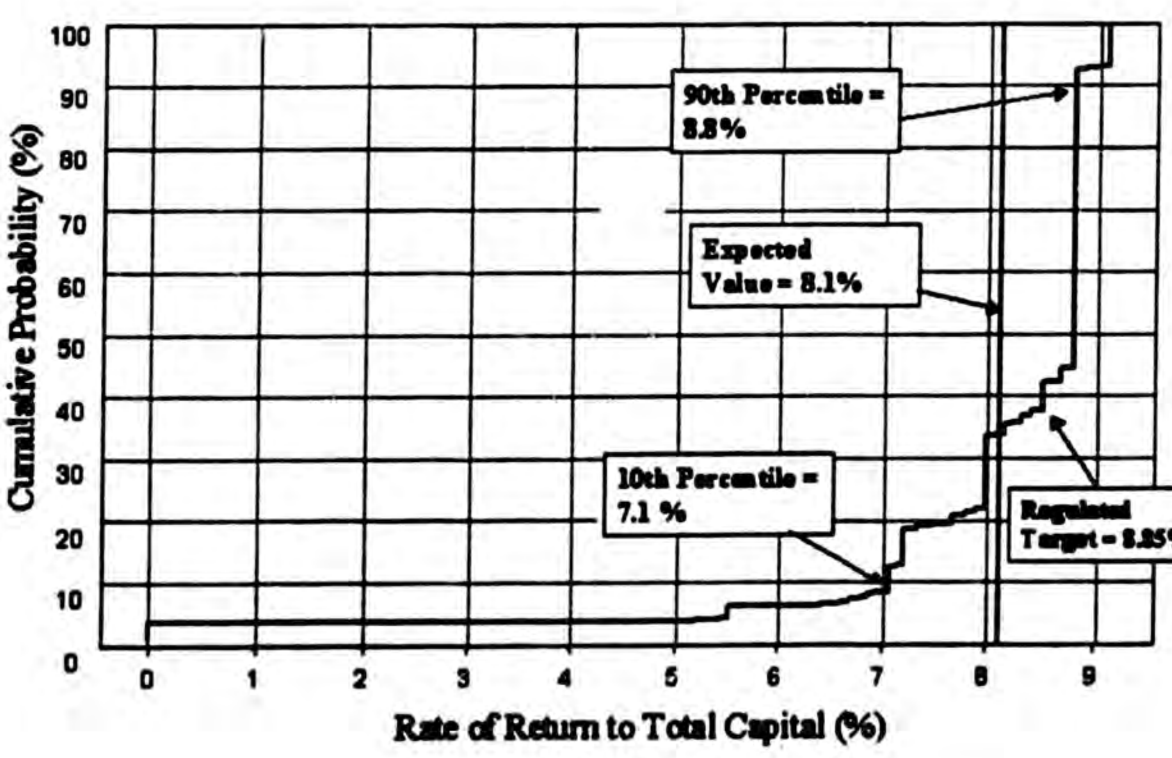
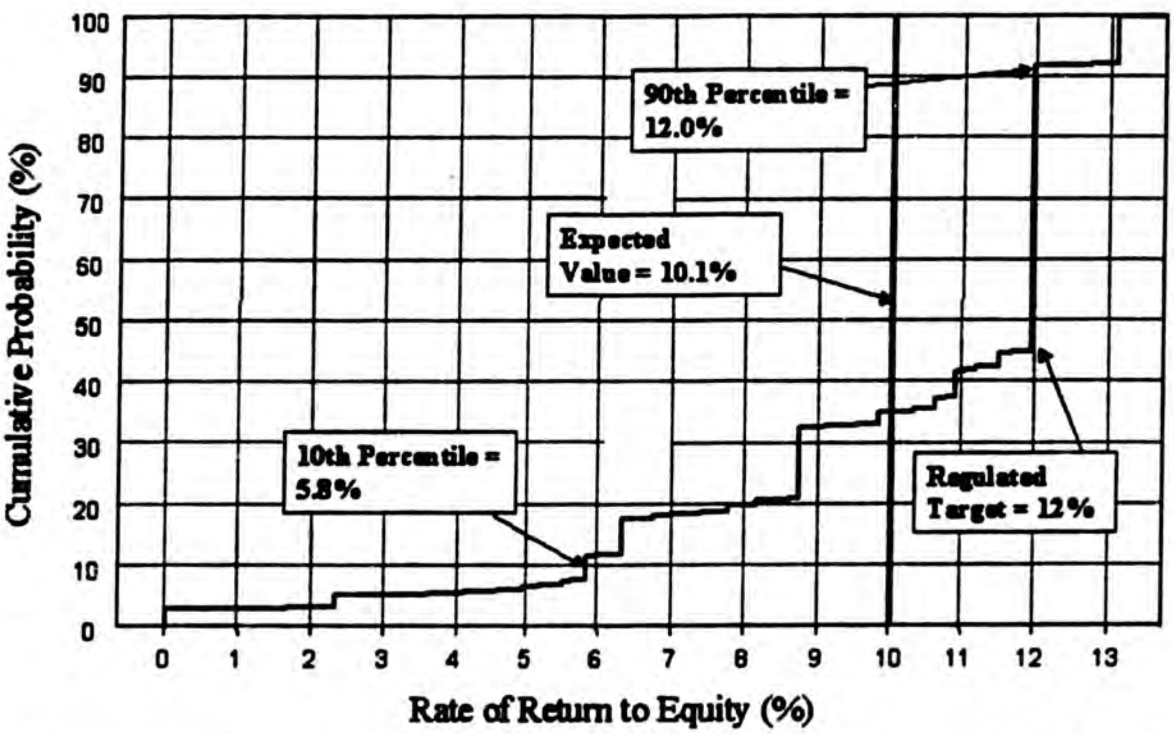


Figure 7-2
Probabilistic Range of Returns to Equity Invested in the Alaska Gas Pipeline



Possible returns on equity are presented for various levels of ownership participation and probabilities in Table 7-1. These estimates are based on a projected debt equity ratio of 70/30.

TABLE 7-1
Alaska Gas Pipeline
Probable Returns to Equity Investment

				Return to Equity					
				Percent Return			Avg. Annual Return (Millions of 2001$)		
Ownership Level	Capital Structure (Millions of 2001$) Debt	Equity	Total	Expected Value	10th Percentile	90th Percentile	Expected Value	10th Percentile	90th Percentile
12.5%	1,085	465	1,550	10.1%	5.8%	12.0%	52	36	59
25.0%	2,170	930	3,100	10.1%	5.8%	12.0%	103	71	119
50.0%	4,340	1,860	6,199	10.1%	5.8%	12.0%	206	143	237
100.0%	8,679	3,720	12,399	10.1%	5.8%	12.0%	413	285	474

Base inputs to the model were developed on the assumption that all returns to invested capital would be subject to federal corporate income tax. However, in separate computer runs, the financial model was also used to calculate tariff reductions that could be achieved if project owners were 100 percent exempt from federal income tax. This included separate analyses for federal income tax on returns to equity (profit) and on interest associated with debt used to finance the pipeline. For that analysis, a 70/30 debt-equity ratio was assumed.

The analysis showed that tariffs would be about 8 percent lower if the project owner or owners were exempt from federal income taxes on 100 percent of the return to equity. If bonds issued to finance the debt portion also were tax exempt, it was assumed that the interest rate on the bonds would be 5.6 percent rather than the 7.5 percent in the base analysis for taxable debt. This analysis showed that tax-exempt bond financing would lower the pipeline tariff by an additional 10 percent. So, if the project were able to avoid federal income tax on its profits and was financed with tax-exempt debt, the pipeline tariff would be a combined 18 percent lower than under fully taxable ownership.

If the tax exemptions applied only to a 12.5 percent state ownership share of the pipeline, the overall effect on reducing the tariff would be just 2.2 percent.

Given the speculative nature of such cost savings and ownership arrangements, the method for allocating these cost saving (in a separate tariff for the state or as a reduction in the common tariff for all customers) was not considered in this report.

Sample printouts of model input and output are provided in Appendix C.

Ownership of Pipeline Capacity Rights

In lieu of an equity investment in the Alaska Gas Pipeline, or in conjunction with an investment in the project, some proponents have asked whether the state should acquire pipeline capacity rights. The state could acquire capacity rights by making a contractual commitment for firm capacity. This commitment would likely consist of a long term (15 or 25 years) binding obligation to ship or pay for the capacity. The ship-or-pay obligation would probably be in the form of a fixed-demand charge for the obligated capacity. Because almost all of the owner's costs would be fixed, almost all of the revenues generated from the tariff would be through the fixed-demand charge. There would also likely be a nominal commodity charge per thousand cubic feet (mcf) of transported gas to cover the owner's variable costs (costs that vary according to volumes transported through the pipeline).

Although the process for allocating pipeline capacity rights under ANGTA is uncertain, it is assumed they would ultimately be sold through an open-season process. Because pipeline owners need early commitments to demonstrate project need to regulators and to manage their own risks and obtain any necessary project financing, the open season, and hence the state's commitment to pay for its capacity share, would occur before final planning and permitting activities and pipeline construction.

Once the pipeline is constructed and operating, the state could use its capacity in either or both of two ways. First, the state could use its capacity to move its own gas taken as in-kind royalty. It could sell the gas in Alberta or pay for other pipelines to further transport the gas to market in the Lower 48 or Canada. Second, the state could resell pipeline capacity rights to others that have gas to transport. The price for this service could vary above or below the tariff the state pays for the capacity rights.

Risks of Capacity Ownership

Risks associated with state purchase of capacity rights on the Alaska Gas Pipeline are described below for each of the two potential uses of the capacity: transport of the state's gas if the state takes its royalty share on an in-kind basis, and resale of capacity rights for gas transportation by others.

Transport of State Gas

The state has the option to take its royalty share on either a value[37] or in-kind basis; the state can shift between these two bases on six months' notice. If the state takes its royalty share on an in-kind basis, it may do so with the intent of realizing higher value than it would by simply taking its royalty share on a value basis. Purchasing capacity rights on the pipeline would be a logical first step to achieve this objective.[38] As noted above, obtaining such

[37] Based on state law (AS 38.05.180) and lease agreements, the royalty gas value is based on the value of pipeline-quality gas ready for transport from the North Slope under the terms of some of the leases.

[38] Taking the state's royalty share in kind without proportionate reserved capacity on the pipeline might create undue risks that the state could either not get its gas to market or be forced to do so at a relatively high cost and resulting relatively low return. This is because there will be substantial gas production and treatment capability on the North Slope that will likely keep the pipeline filled; those without pipeline capacity rights would be shut out or forced to pay high rates to gain access. This risk is eliminated, of course, if the royalty-in-kind purchaser has its own reserved capacity.

capacity rights would require a long-term commitment (15 years or more) to take or pay for the reserved pipeline capacity. Taking royalty in-kind does not require the state to nominate capacity if the buyer nominates its own capacity or uses the gas on the North Slope.

While the intent would be to earn higher returns, taking its royalty share in-kind—together with purchase of pipeline capacity rights—creates additional costs and risks for the state relative to taking its royalty share in-value. These costs and risks include the following:

1. Costs incurred to market the gas.
2. The risk of absorbing losses from high costs or poor market conditions.
3. The risk of paying for capacity even during extended outages caused by force majeure.
4. The risk of not realizing as high market prices as the gas producers and therefore earning less than if the state were to take its royalty share on a value basis.

Each of these costs and risks is discussed in more detail below.

The primary benefit of taking the state's royalty share on an in-kind basis with purchase of pipeline capacity rights is that it could ensure that the state's proceeds are based on the true market value of the gas. That is, it avoids the risk that the royalty share, when taken on a value basis, could be calculated at an artificially low value.[39] Losses to the state from royalties calculated on an artificially low market price can easily exceed the extra costs and risks associated with taking the state's royalty share on an in-kind basis.

The following subsections discuss each of these four extra costs and the risks associated with taking the state's royalty share on an in-kind basis with purchase of pipeline capacity rights.

Gas Marketing Costs

The state's costs to market the gas in a downstream market is an extra cost the state would bear with its royalty share taken in-kind. It would likely include the cost of establishing a

39 The general basis for the calculation of value when royalties are taken on a value basis will be the higher of value delivered to market or the proceeds received less transportation costs. Market value will likely be determined from sales prices at market hubs. This might be in Alberta (e.g., AECO) or closer to its actual end use, with prices at a number of hubs in the Lower 48 states and in Canada used to calculate market value. The transportation costs will, at a minimum, be the cost of delivering North Slope gas across the Alaska gas pipeline to Alberta. If market value is established closer to market, transportation in other pipelines will also be included in the calculation.

state agency or paying a third party to market the gas and include some administrative costs to oversee the operation.

Management of the marketing process from the wellhead to the burner-tip is a sophisticated process requiring quick decisions implementing a well-conceived marketing strategy. It requires, among other things, the use of short- and long-term positions, various derivative products, and strict adherence to marketing and trading policies. Although the state could contract for a marketing service or develop the expertise in-house, the learning curve is steep and seemingly trivial decisions can have substantial financial and legal consequences.

Risk of Absorbing Losses from High Costs or Poor Market Conditions

Owning pipeline capacity rights and taking royalty share in-kind creates a risk that the state could realize a negative net value for its gas—which could happen if the Alaska Gas Pipeline tariff were higher than the value of gas delivered to Alberta. This could occur due to high pipeline costs or poor gas market conditions. Higher-than-expected tariffs could result from pipeline cost overruns. As described above, such overruns would likely be rolled into the tariff as long as they were not shown to result from imprudent management decisions. Lower-than-expected gas prices could result from poor market conditions. If adequate pipeline capacity to ship gas out of Alberta does not develop, the resulting oversupply in Alberta and the limited access to downstream markets would drive prices for Alberta gas prices to abnormally low levels. Low prices could also occur if new gas supplies and/or low demand in North America at least temporarily drive prices to levels that are lower than the transportation costs to deliver gas to market.

This risk does not apply to the option of taking the state's royalty share on a value basis. If the same poor market conditions were to occur under this option, the netback value to the producers would be negative. However, the state would likely simply receive no royalties rather than a loss. It is our understanding that the state would not be liable for a negative royalty payment from the producers' losses. Rather, it is assumed that the royalty would be waived or set at zero.

Force Majeure Risk

As discussed above in the subsection on Pipeline Ownership Risks, owners of pipeline capacity rights may be required to continue to pay for their capacity reservation during periods of pipeline service interruption caused by acts of God. These could include interruptions due to events that are beyond the control of the pipeline owner (e.g., natural disasters, fires, explosions, terrorist acts, other sabotage and other catastrophes). If the state purchases capacity rights on the pipeline to market royalty gas, it runs the risk of continuing to pay during force majeure events. Such risks are avoided when royalty is taken on a value basis. (In any case, state royalty revenues would be interrupted if North Slope gas deliveries were interrupted—regardless whether gas were taken on a value or an in-kind basis.)

Realized Market Price Risk

Because gas producers have substantial expertise in marketing their products, they are likely to receive maximum value for their sales of North Slope gas. If the state were to take its gas on an in-kind basis and market it in downstream markets, it would probably have to establish a gas marketing agency and staff it with industry experts. Nonetheless, because marketing of wholesale petroleum products is not a core business of the state, there is some risk that it would not realize as high of a value in its sales as would the producers. All other things being equal, this would result in lower royalty value accruing to the state than if it were to take its royalty share on a value basis. On the other hand, there is a potentially significant opposite risk, that the calculated royalty share, when taken on a value basis, could be artificially low, possibly lower than the value achieved by taking the state's royalty on an in-kind basis.

Resale of Pipeline Capacity Rights

The state could take the risk of marketing its reserved capacity on the pipeline to others that have a need to transport gas to market. This could include existing oil and gas producers, as well as entities that might discover and produce gas in the future. To the extent that the state could sell, or release, its capacity rights for a higher price than the fixed charge it would be obligated to pay, plus its administrative costs, it would profit. In the opposite direction, the state would lose money if it could not cover these costs in its resale of capacity rights.

It has been suggested that the state might purchase capacity on the pipeline specifically to make capacity available so that future new production would have access to markets through the pipeline. The logic is that this would increase production and, with it, state royalty and tax revenues. However, to the extent that the pipeline would be full with production from existing wells, the state would already be benefiting from full production to fill the pipeline.

Once pipeline capacity opened up after production declines from existing wells, it would become available for new production. Therefore, the state does not have much to gain from risks associated with purchasing pipeline capacity rights for resale if it is indifferent to whose gas fills up the pipeline. This is not necessarily the case, however. There will be little exploration for gas for decades if those that would explore cannot get the gas they find into the pipeline. A diversified group of gas producers is desirable to the state, as is exploration and development in new areas in the state.

Returns from Capacity Ownership

Purchase of capacity rights have higher risks and potential returns than investment in a share of the pipeline itself. Returns are much less certain than the regulated return from pipeline ownership. The North Slope gas producers recognize this higher risk in establishing a "hurdle rate" of return for their projected cost for treating and transporting their gas. In their feasibility studies, the producers will probably require a relatively high rate of return on all investments they make in treating and transporting gas through the Alaska gas pipeline. Most of this risk consists of the fixed commitment to pipeline capacity.

As noted above, returns from capacity purchases made to market state royalty gas need to be assessed in terms of the state's ability to realize higher value than that calculated under a royalty value formula. Any extra value obtained from use of the pipeline to market royalty gas must be sufficient to cover the cost to market the gas, the risks of absorbing losses during poor market conditions, improper management decisions and force majeure events, and the risk that the state cannot market gas as well as the producers.

The potential for added or reduced overall returns to the state from purchase of pipeline capacity rights cannot be estimated until:

1. The precise method is determined for calculating the value of the state's royalty share. It is entitled to the higher of market value or sales proceeds.
2. The cost to market gas taken on an in-kind basis is estimated.

3. The estimated Alaska Gas Pipeline tariff is known and assessed against the prospects for poor market conditions, particularly as they relate to North America market access from Alberta.

4. The state's ability to market gas supplies relative to the producers' ability is assessed. State officials acknowledge that the state should never expect to be as skilled in marketing gas as those in the business.

Once these uncertainties are clarified, the state would be better able to assess the potential return from investing in capacity rights and taking its royalty payment on an in-kind basis.

Purchase of pipeline capacity for resale would be a speculative venture. Returns from pipeline capacity purchase for resale would depend on the state's ability to resell the capacity at a higher price than its tariff cost, plus the cost of administering the resale program. As noted above, it is not likely that purchase of pipeline capacity to hold for others would increase gas production and thereby increase state royalties. Therefore, the direct return from a pipeline capacity purchase for resale would simply be a function of the state's ability to resell the capacity at a higher level than its costs.

Effect on State Cash Flow

If the state were to purchase an ownership share in the pipeline equal to its royalty share of 12.5 percent, and assuming a debt/equity ratio of 70/30 and a $12.5 billion total project cost, the state's equity investment would be $465 million (2001 dollars). Equity contributions at higher ownership levels are shown in Table 7-1.

As noted above, with the risk assumptions made for this analysis, the expected rate of return on equity invested in the pipeline is projected to be 10.1 percent, with a 10 to 90 percentile range of 5.8 to 12.0 percent.

Investment of this capital in the pipeline would require a delay in realized returns. The state's obligation to advance cash for its equity investment would begin as soon as its purchase of an ownership share was complete. These payments would begin at relatively low levels as planning and engineering are completed, then increase to higher levels during actual pipeline construction. The pipeline would not start generating revenues until operations begin. We have assumed that the earliest pipeline operations could start is 2009. The state's return on the equity it invested during planning and construction would be capitalized and rolled into the overall project capital base as part of "allowance for funds used during construction" (AFUDC). AFUDC would become part of the investment upon which the state and other pipeline investors would earn their return. Accordingly, between 2002 and 2008, the Permanent Fund, Earnings Reserve Account or other state funding source would be drawn down by the state's investment in the pipeline. This would total an estimated $465 million (under the assumptions stated above), of which $338 million would be direct investment from a state funding source, and $127 million would be in the form of AFUDC.

If the Permanent Fund (including the Earnings Reserve Account) was the source of funds, the investment would reduce Permanent Fund dividends by an estimated cumulative total of perhaps $60 or so by 2010. This reduction would be repaid in future years through earnings on the AFUDC component of the state's investment.

Ownership of capacity rights on the pipeline would have little effect on state cash flow under normal operating conditions. This is because costs incurred from monthly take-or-pay payments would be directly offset from sales revenues. Assuming that the capacity rights were being used to transport Alaska royalty gas to market for sale, revenues produced from gas sales would cover the cost of capacity rights. The risks to this normal cash flow are discussed above. Under the worst of the risk scenarios a force majeure event could occur, interrupting pipeline operations while the state is required to continue making its capacity payments. Under those circumstances, 12.5 percent ownership of the pipeline would reduce the state's overall cash flow by an estimated $21 million per month.

SECTION 8

Effect on State of Alaska from Pipeline Investment

This section evaluates the effects that financial participation in the Alaska Gas Pipeline would have on the state's financial integrity, creditworthiness and ability to pay for essential public services. Any damage to the state's financial integrity and creditworthiness would lessen its ability to finance projects for public services. This section also evaluates several non-financial issues, such as state involvement in pipeline management.

Effect on the State's Financial Integrity and Creditworthiness

A factor the state should consider in determining the manner in which it may participate in the project is the effect its participation would have on its financial integrity and creditworthiness. The state's overall financial integrity and creditworthiness is best measured by the credit rating assigned to its general obligation debt by agencies that rate debt as part of the lending process for public bond offerings. Three prominent rating agencies are Moody's, Standard & Poor's and Fitch.

Having a solid credit rating is a valuable benefit to the state, especially in times of fiscal uncertainty. Further, the state's credit rating indirectly inures to the benefit of or detracts from the rates that Alaska municipalities have to pay on their own debt.

The state itself has no outstanding general obligation debt, so the credit rating agencies have not re-evaluated Alaska's full rating recently. However, Alaska's most recent general obligation bond sale was rated at the high end of the ratings scale.

If the state were to participate financially in the gasline project, the rating agencies—in setting new rates for State of Alaska debt—would take into account several factors, including: (1) the form of the state's participation; (2) the feasibility and economic viability of the project and the likelihood of its completion; (3) the estimated increase in state revenues generated by the project; (4) the effect of the project on the state's overall economy; and (5) the timing of the benefits and costs to the state.

As discussed in Section 4, a small amount of equity or debt currently could be made available to the gasline project without damage to the state's current credit ratings. However, a multibillion-dollar capital investment funded by state debt that would be sufficient to gain majority control or a major influence in the project would likely have an uncertain, if not immediately negative, effect on the state's credit ratings. This would be the case for several reasons, including the fact that the project is not a typical governmental investment (in public infrastructure, *e.g.*, highways, prisons, etc.).

In addition, the debt would represent a governmental investment of unprecedented concentration in resource extraction, an industry with a history of substantial price volatility. Unless major adjustments were made in the state's operations and anticipated capital expenditures, it is probable that such investment would have to be funded by a very substantial amount of new general obligation debt, revenue bonds or creative use of sources of equity. The result would be increasing the state's indebtedness with respect to standard yardsticks such as population, resources and economic indicators.

Finally, the returns to the state would be over the long term. And, particularly in the near term when the project is just starting operations, these returns would not be assured.

Importance of the State's Credit Rating

The state has good reason to maintain a solid credit rating. A downgrade of the state's rating would have direct and indirect financial consequences and, although harder to quantify, would create political problems between the state and its municipalities.

A reduction in the state's credit rating would result directly in higher borrowing costs each time the state entered the credit markets. This is true both for certificates of participation and general obligation debt. Higher debt costs would reduce the amount of money the state could borrow for public service projects. That is, the more money that is paid out in higher interest rates, the less money the state could borrow for the actual projects. This potential effect is discussed below.

The various state corporate entities (Alaska Housing Finance Corporation, AIDEA, Alaska Municipal Bond Bank Authority, Alaska Student Loan Corporation) that enter the debt market would also likely face higher borrowing costs. For those entities that contract with banks for additional credit support, the costs of bank lines and letters of credit would be more expensive. Furthermore, the state's strong credit position, as well as its substantial cash reserves, indirectly enhance the credit of municipalities throughout the state.

The higher borrowing costs would be evident not only in higher interest rates but also higher costs of bond insurance, further reducing the state's ability to raise as much money as it may want for public service projects.

And although of lesser direct effect to the state, the holders of state debt would see the value of their investments in the state diminish in value because a lower debt rating would reduce the value of state debt in the hands of existing bondholders.

The cost of a full step downgrade of the state's credit from the strong AA level to a strong single A level—while difficult to estimate—would be significant. A downgrade of the state's rating would ripple through all of the governmental units of the state, likely resulting in across-the-board downgrades. Ultimately, this would affect all of the state's $6.5 billion in outstanding bond debt, particularly as bonds matured and new bonds were issued.

Over the past 10 years the difference or spread between AA and A rates have averaged 16 basis points. While this is a good starting point to determine how much the cost of capital would rise after a downgrade, there is a larger story to tell. Until the early '90s, the state historically paid an "Alaskan penalty" on its bonds that ranged from 15 to 50 basis points. The market assessed this excess cost because of the distance of the state from the financial markets, lack of information and the isolation of the state's economy. The current high ratings of the state are the result of consistent performance of the state and its economy, and the prevalent perception that Alaska has significant resources available. A downgrade, however, would be a major event that could very well bring back the penalty for Alaska issuers.

Finally, Alaska is a "non-specialty state," meaning there is a small population and no tax benefit to in-state investors of tax-exempt bonds because there is no state personal income tax. Therefore, the state relies very heavily on investors outside the state to purchase bonds, and a downgrade could hurt Alaska more heavily than it would a state with a larger population and state income tax.

In sum, the cumulative effect of these considerations if the state were downgraded from AA to A would likely be in the 25 to 40 basis points range. This increased cost of capital would result in an additional $250,000 to $400,000 in interest expense per year for every additional $100 million borrowed. Assuming a rolling level of debt at $6.5 billion, a downgrade could eventually cost between $16.25 million and $26 million annually.

Balancing State Benefits and Costs

The financial analysis above leads the Department of Revenue to conclude that a monetary equity investment in the Alaska Gas Pipeline would likely provide the state with a positive return on investment over the long term. The sources of state funds are limited, however, and likely would need to be raised through the issuance of some form of debt—which would present its own set of financial problems as discussed in detail above.

However, just because the state *can* invest on some modest level does not mean that the state *should* invest. In addition to the strictly financial issues, there are numerous practical aspects to the investment discussed below.

- Of some importance to the state in contemplating an equity or debt investment is the substantial risk it would entail if the state invests in the project as a business partner. Unlike a major oil company or integrated natural gas pipeline, the state has little capability to monitor or control those risks and does not have the financial strength to absorb large capital or operating losses. It would be different, however, if the state were simply a shareholder in a corporation that owned the Alaska Gas Pipeline. As a shareholder, the state would be shielded from any liability. The only risk would then be the stock price.
- If Alaska were to become an active participant in the enterprise as an equity investor, it would be required to advance funds almost immediately to buy into a sponsor partnership to gain the same rights as other equity investors. Thereafter, the state

would be required to meet continuing capital calls. Therefore, Alaska would need to have readily available funds for this purpose or make borrowing arrangements to make money available now and continuing for the next several years of construction. Both of these options would substantially infringe upon the state's flexibility to meet public service needs. Given the magnitude of the state's anticipated needs for public services, the policy and constitutional limits on the state's available funds, and the ongoing revenue shrinkage due to declining North Slope oil production, there would appear to be little room for such a financial commitment.

- Superficially, one might conclude that any equity ownership would give the state a degree of control over management of the Alaska Gas Pipeline system, including a control over major policy decisions—such as retention of gas or gas liquids for in-state use—which could not be obtained in other ways. However, it is highly unlikely that the existing ANGTS sponsors or producers group would be willing to make a significant amount of equity available to the state. We understand that various parties in one consortia already are seeking higher ownership percentages; other third parties are interested in joining the consortia; and many companies do not want the state as a business partner. Accordingly, there is a "sellers market." In this circumstance the sponsors would be dictating the terms of the state's investment, and the state would likely have very little negotiating leverage. Thus, as a partner, the state probably would become just a minority participant with limited, if any, management rights. The amount of information shared with the state probably also would be restricted. The state's interests are likely to differ in important respects from the sponsors, so that it frequently would be outvoted in the event of a dispute.

- As a participant in the Alaska Gas Pipeline, Alaska might magnify the conflict between its interest as a regulator of the project in its sovereign capacity and its already existing economic interest in the project as both a royalty holder and a taxing authority. There also would be a conflict between the state's duties to its citizens as a regulatory and taxing agency and the fiduciary obligations of the state as an equity partner to the other project partners. It has been suggested that the use of a separate state-established corporation or authority as an investment vehicle would mitigate this conflict. While the interposition of a separate governing board certainly would help to mitigate the conflict, ultimate authority and control over the participation of the state in the enterprise would remain with the legislature and the governor.

- There is precedent in times of national emergency and wartime conditions for governments to become involved in the development, construction and ownership of pipelines.[40] Absent such extraordinary circumstances, public sector investment in pipeline projects is not customary in the United States. The Department of Revenue and its consultants were unable to find a single material natural gas pipeline project in North America today where a state or federal government entity was a participant. There still remain a few examples associated with Canadian provinces, however the trend is for privatization of those investments. There is precedent internationally for such governmental investments, but usually those circumstances are dictated by tradition, national security issues, World Bank financing requirements, or the inability to get the project developed any other way. None of those situations are applicable to this project.

[40] The classic example is the federal government's involvement in the construction of the "Big Inch" oil pipeline from the Gulf Coast to the East Coast in World War II.

SECTION 9

Effect of State Participation on Project Success

This section discusses examines whether state participation as an equity or debt holder might help or hinder completion and operation of the project. This obviously is an important consideration for the state. Anything done to improve or hinder gas royalty income would have a measurable effect on the state's cash flow.

Interest of the Pipeline Sponsors

Among the issues discussed with the companies interviewed was how they viewed having the state as a partner and whether they saw the state as adding value to the project design, development, construction and operation process. As mentioned previously, for a variety of reasons the companies were not in favor of the state as a partner. At best, several of them thought the state would not materially aid implementation or operation of the project and, at worst, some thought the state's involvement would be a negative factor .

Those that believe the state's participation would impede progress of the pipeline said they were concerned about the state politicizing and slowing the multitude of decisions that must be expeditiously made—especially in route selection, marketing, procurement and selection of contractors. Although not critical of the quality of the state's personnel, the companies were concerned that the state simply lacked expertise in commercial enterprise activities and was not accustomed to making business decisions at the pace required by the project. Further, they were concerned that the state's presence in the project would needlessly interfere with or add layers of confusion to the complex financing program that would be required by some of the project sponsors. The requirements of the state and the requirements of the lenders vis-à-vis the state in the financing process might be incompatible and mutually burdensome.

Critical Success Factors

Industry's concern is borne out by an examination of the important factors that would be critical to the success of the initial phase of the project. These include the requirements for:

- Shipper contracts
- Pipeline design
- Federal, state and provincial approvals
- Construction permits
- Right-of-way and land use permits
- Off-take agreements
- Engineering, procurement and construction contracts
- Financing

The state would have little effect on the successful outcome of these requirements, except in expediting state right-of-way approvals, obtaining state and local permits and, if it so chose, to contract for the shipment of its royalty gas. The execution of most of these critical success issues are solely within the province of the Alaska Gas Pipeline. Most of the potential sponsors have had substantial experience with addressing these issues in the development and construction of natural gas pipelines throughout the world.

The state would not have any effect on the two most critical factors to the success of the project over the long term: the market for the natural gas and construction costs. The size of the natural gas market in Alaska is very limited. The marketplace will be the Lower 48, an intricate energy market with which Alaska has no commercial experience. Further, there is little the state could do to assist in the gas pipeline engineering and construction decision and implementation process. This simply is not a core competency of the state.

Supplying $300 million to $500 million of state funding really would not significantly assist the potential project sponsors, given their sizes and capabilities. In fact, the size of probable state funding likely would not be much different that the size of the project contingency factors built into the potential sponsors' economic modeling. So, from a financial point of view, the state's participation would be immaterial.

As discussed in Section 6, the North American natural gas landscape has been significantly changed over the 25 years a North Slope natural gas pipeline has been under consideration. Although the pipeline companies involved in the late 1970s and early 1980s were large, they still needed to seek outside capital sources, such as the state, to help fund the project. Today, with the wave of mergers and consolidations sweeping the oil and gas producer and pipeline industries, the major players interested in developing the gasline are much larger and much more sophisticated. Of the 10 companies interviewed for this report, the smallest, Alberta Energy, had an enterprise value of $8.4 billion; the largest, ExxonMobil, about $266 billion. (And the mergers continue: Alberta Energy on January 25, 2002, confirmed reports it will merge with rival PanCanadian Energy Corporation to create what could be Canada's largest oil and natural gas company with a market capitalization of approximately $19 billion.)

Several of the companies interviewed are so large—as shown in Table 9-1—that they said they did not intend to borrow to finance their share of the $10 billion to $18 billion project cost, but merely intended to "write a check" off their balance sheet.

TABLE 9-1

Enterprise Value of Oil and Gas and Pipeline Companies

Company	Enterprise Value ($MM)
ExxonMobil	265,706
BP	184,556
Duke	44,964
El Paso	40,808
Williams	23,523
TransCanada	22,505
Phillips	20,937
Anadarko	18,116
WestCoast	10,463
Alberta Energy	8,433

Enterprise Value = Market Value + Debt + Preferred Stock Value + Minority Interest - Net Working Capital

The size and sophistication of the industry and the size and complexity of the project give rise to several important realities Alaskans should consider in making the judgment whether to make an equity or other financial investment in a North Slope pipeline project.

If the state could provide a means for tax-exempt debt financing of the project, it might improve the economic feasibility of the project and therefore increase the chances the project is actually constructed.

SECTION 10

Conclusions

Based on information developed in this report, the Department of Revenue's consultants offer the following conclusions about state financial participation in the Alaska Gas Pipeline:

1) Even if state ownership were restricted to just pipeline facilities, full ownership of the Alaska Highway Route pipeline would require $9 billion to $10 billion (2001 dollars) for construction. Deferred returns to capital invested during the estimated seven years before the project is likely to be completed would bring the total estimated pipeline investment to $13 billion to $14 billion. (These deferred returns are referred to as Allowance for Funds Used During Construction, discussed in Section 7 of this report.)

2) Without legislative action, the state does not have a ready source of cash for such a large investment. This is true even if the state were to limit its investment to 12.5 percent, an ownership equal to its royalty share of North Slope natural gas. Even at that reduced ownership level, the state's share of the total project investment could be as much as $1.75 billion (12.5 percent of $13 billion to $14 billion).

3) The state could make a significant investment if the legislature changed state law to direct the Permanent Fund to write a check. A 12.5 percent investment in the pipeline, assuming it was all equity and no debt, would take about 7 percent of the Permanent Fund. Even if the investment were 30 percent equity and 70 percent debt, the equity investment would still take more than 2 percent of the Permanent Fund's market value — making it the single largest holding of the fund. This large of an investment in a single entity, with the risks discussed in this report, might well violate the Prudent Expert Rule in state law governing Permanent Fund investment decisions. Additionally, about 80 percent of the state's unrestricted general purpose revenue currently is derived from oil and gas taxes and royalties. Permanent Fund investment in the pipeline would exacerbate the state's heavy reliance on one industry.

4) The legislature could appropriate money from the Earnings Reserve Account of the Permanent Fund to a state agency or other corporation to make the actual pipeline investment, thereby avoiding the issue of what is a permissible Permanent Fund investment. However, the Earnings Reserve Account is the Permanent Fund's sole method of absorbing market volatility, and any significant withdrawal from the account would jeopardize Permanent Fund dividends and inflation proofing.

5) The Alaska Constitution does not allow general obligation bonds to finance state participation in a joint business venture. This would limit the state to financing and owning 100 percent of the project. Further, such a major issuance of general obligation bonds or other state-supported debt would compromise the state's creditworthiness and, as a result, reduce its credit rating. At the state's current level of indebtedness, a downgrade from an AA to an A rating could increase the state's overall borrowing costs by an estimated $16 million or more per year. The state's ability to finance other public services also would be compromised. In addition, a reduction in the state's creditworthiness would likely have a negative, cascading effect on municipalities and other public agencies in Alaska.

6) The most plausible source of state participation through debt funding would be the issuance of taxable revenue bonds, secured for example by ship-or-pay contracts with the North Slope gas producers. However, the feasible size of such an issuance is uncertain. State issuance of bonds large enough to finance 70 percent of a 12.5 percent share of the pipeline (approximately $1.2 billion) would place the state in uncharted waters. Although ship-or-pay contracts with the producers should provide good security for the bonds, the large size of the debt relative to any previous State of Alaska revenue bond issuance, the manner and nature of the use of the bond proceeds, financial market pricing and repayment security requirements raise novel issues in the context of an Alaska gasline.

7) It theoretically would be possible for the state to sponsor a private corporation of Alaska investors to participate in the project. However, there are myriad practical, legal and public policy issues that need further review, including the source of investment funds, the qualifications for investors, tax implications, management of the entity,

constitutional matters and administration of the program. More importantly, it is difficult to understand how this proposal would provide any material improvement over any other available source of gasline investment capital. It appears to introduce yet another layer of complexity to an already difficult situation.

8) The largest risk associated with investment in the pipeline is that it would not be completed. In that case, the state's investment would be lost. Assuming the project would be completed, return on the state's investment would be regulated by the Federal Energy Regulatory Commission in the United States and the National Energy Board in Canada, and would likely result in a return consistent with or higher than state investment guidelines. Assuming a FERC/NEB-approved target return to equity of 12 percent, the state could expect to earn an average return to equity of about 10 percent. Probability analysis shows that average returns to equity over the life of the pipeline could range from 5.8 percent at the 10^{th} percentile to 12 percent at the 90^{th} percentile. Returns on the debt portion of the state's investment, however, would be limited only to the associated interest rate on that debt.

9) Pipeline ownership does not automatically provide the owner with capacity to ship gas on the pipeline. Capacity to transport gas would need to be separately purchased though an open-season process.

10) The state's need to purchase pipeline capacity rights to transport gas is dependent upon whether the state decides to take its 12.5 percent royalty share of North Slope gas on an in-value or in-kind basis. Pipeline capacity purchase might be prudent if the state decides to take its royalty share on an in-kind basis, in that it would assure the state of capacity to transport its gas to market. Otherwise, purchase of pipeline capacity would be speculative. Since the pipeline is likely to be full from its outset, purchase of capacity to provide a pathway for future discoveries would not increase total North Slope gas production or royalties paid to the state.

11) The primary benefits of establishing a state-owned public corporation or authority to construct and operate the pipeline are in the legal ability to assist state ownership and financing of the project. Such establishment could also reduce the conflicts of interest that might otherwise exist from direct state ownership. Separating the ownership into a

semi-autonomous function could at least attempt to build a barrier between the state's responsibility to regulate the pipeline and its interest in maximizing return to its investment. However, it is unlikely that a state-owned corporation or authority would reduce pipeline costs. Without a specific exemption from the private-activity restrictions in federal tax laws, neither the state nor a state-owned corporation or authority would be able to issue tax-exempt debt to finance the pipeline.

12) It is unlikely that the state could provide any loan guarantees to other investors in the pipeline. The Alaska Constitution prohibits the state from "lending its credit directly to benefit a private entity." Regardless of the state's ability to do so, it appears there is little to no interest among prospective private pipeline sponsors for the state's participation in the project's financing, unless it could be tax-exempt. Therefore it appears that providing state loan guarantees or taxable debt would not aid project feasibility.

13) State ownership would not likely improve the feasibility of the project or be valued by private-sector project sponsors. There was a general consensus among industry representatives interviewed that a public/private ownership relationship with the state either would not help or would be a hindrance to the project. Reasons given include the following: State politics could impede and otherwise compromise the decision-making process; pipeline ownership and operation is not within the core mission or competencies of the state; state decisions would be complicated by its dual role as owner and regulator (even if mitigated by a state-owned, semi-autonomous entity); and general differences between public and private goals and cultures would detract from the decision-making process. These factors would create additional risk for pipeline investors and cause them to not favor the state as a partner in the project.

14) If the private sponsor groups welcomed the state as a partner, the state would receive some form of management participation based upon the level of its financial contribution. The state, however, would have a fiduciary responsibility to its partners to keep non-public data in confidence. The state may find itself, therefore, in an untenable legal and ethical position trying to balance the informational needs of the state government with its partnership responsibilities. In truth, since the gasline project will

be subject to extensive regulation by various U.S. and Canadian governmental entities, much of the information pertinent to the partnership will be available through the regulatory process.

SECTION 11

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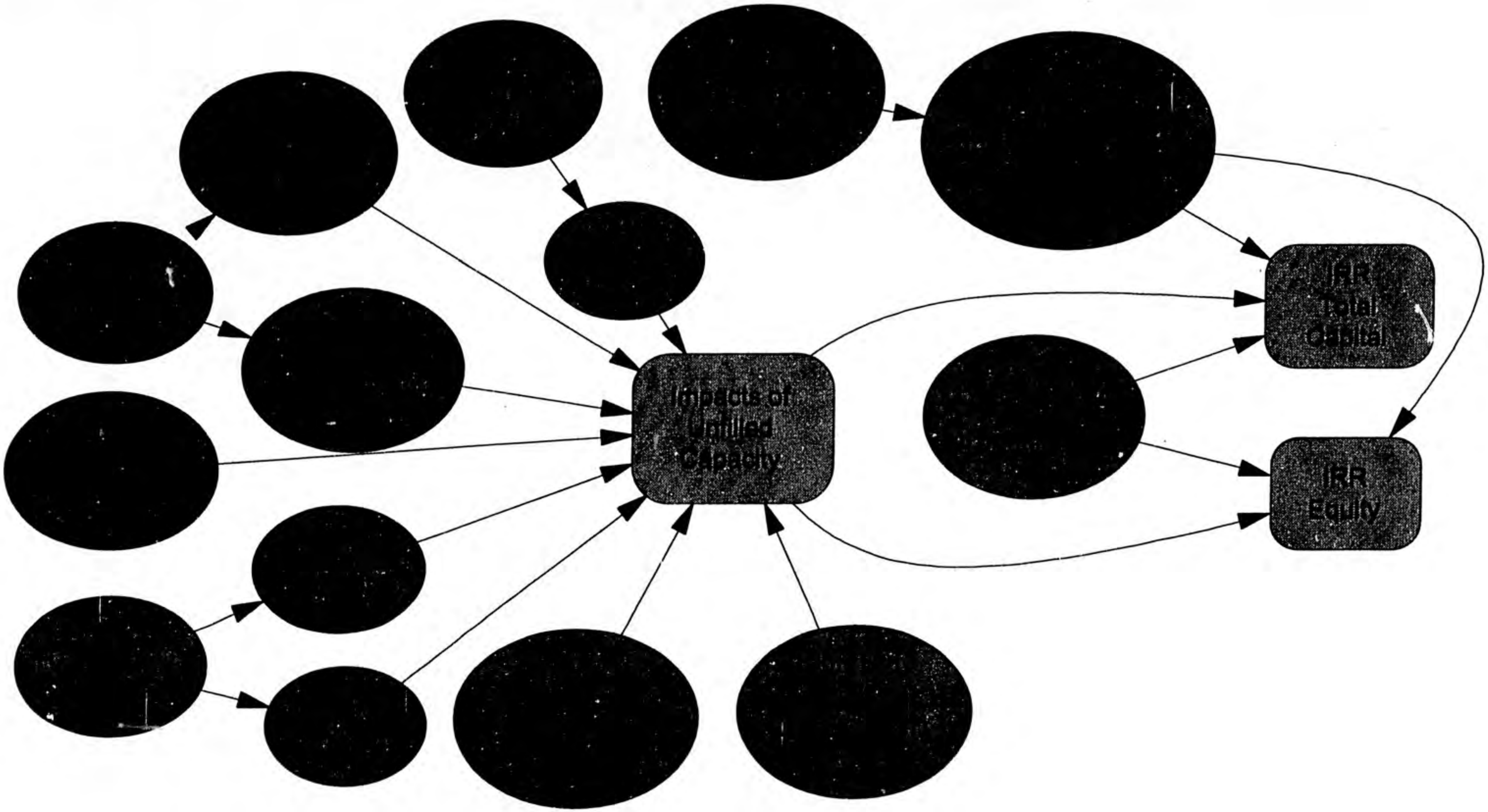
Appendix B
Risk Analysis Structure

Cost Drivers and Uncertainties Effecting Returns on the Alaska Gas Pipeline

Influence Diagrams illustrate conditional relationships between decisions, uncertainties, & outcomes



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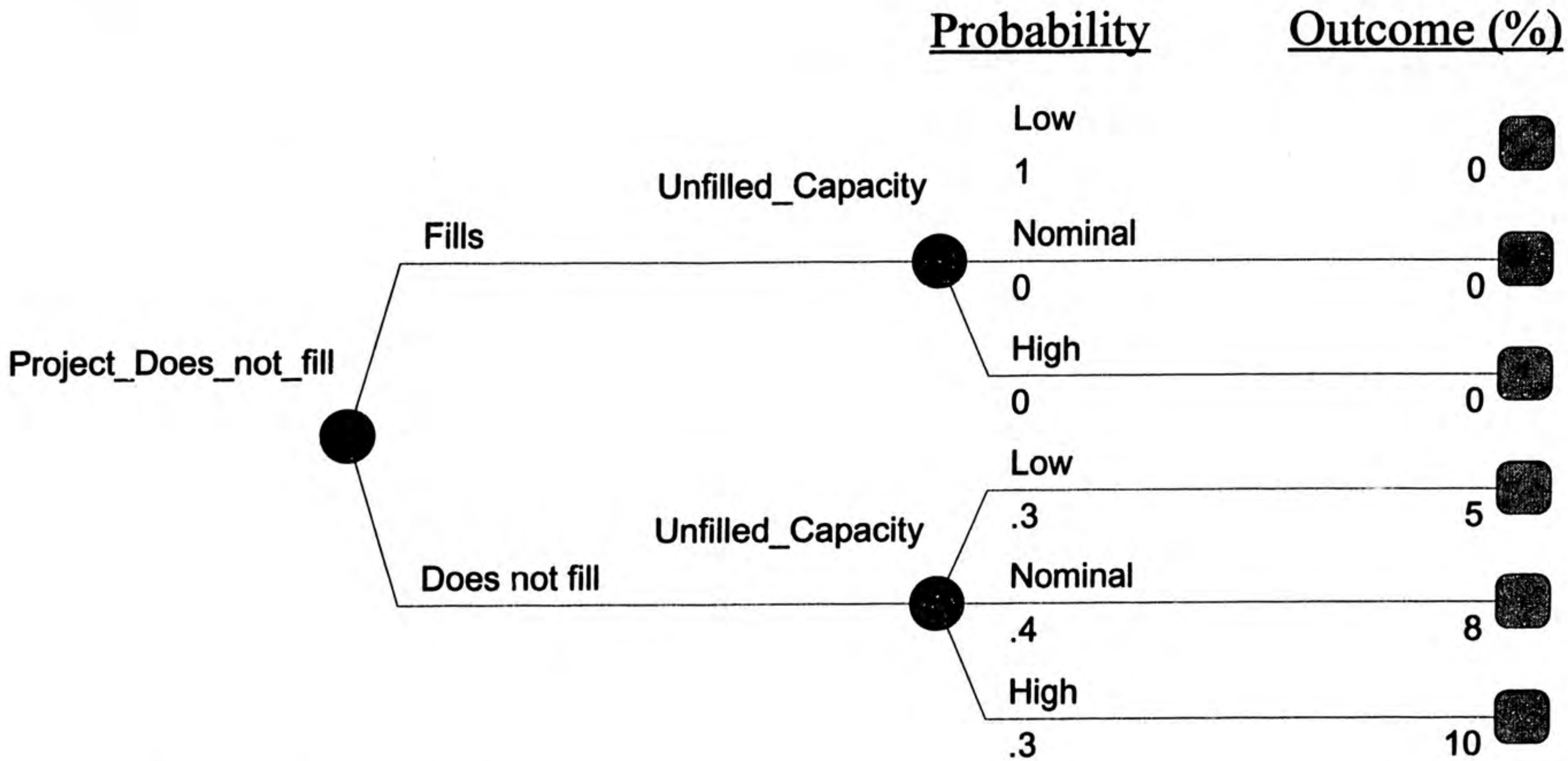
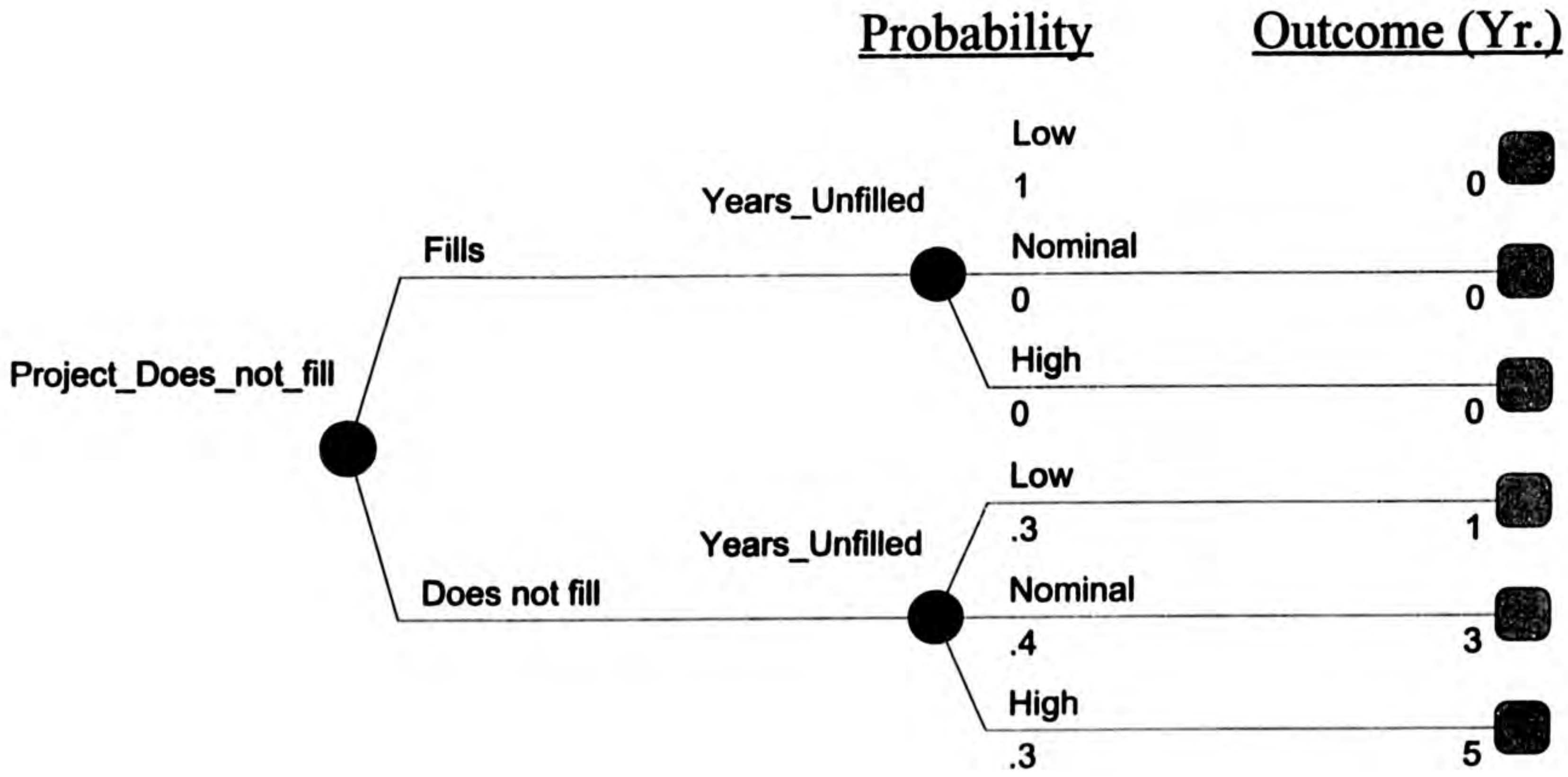


Note: Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

Uncertainty Branch



Note: Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

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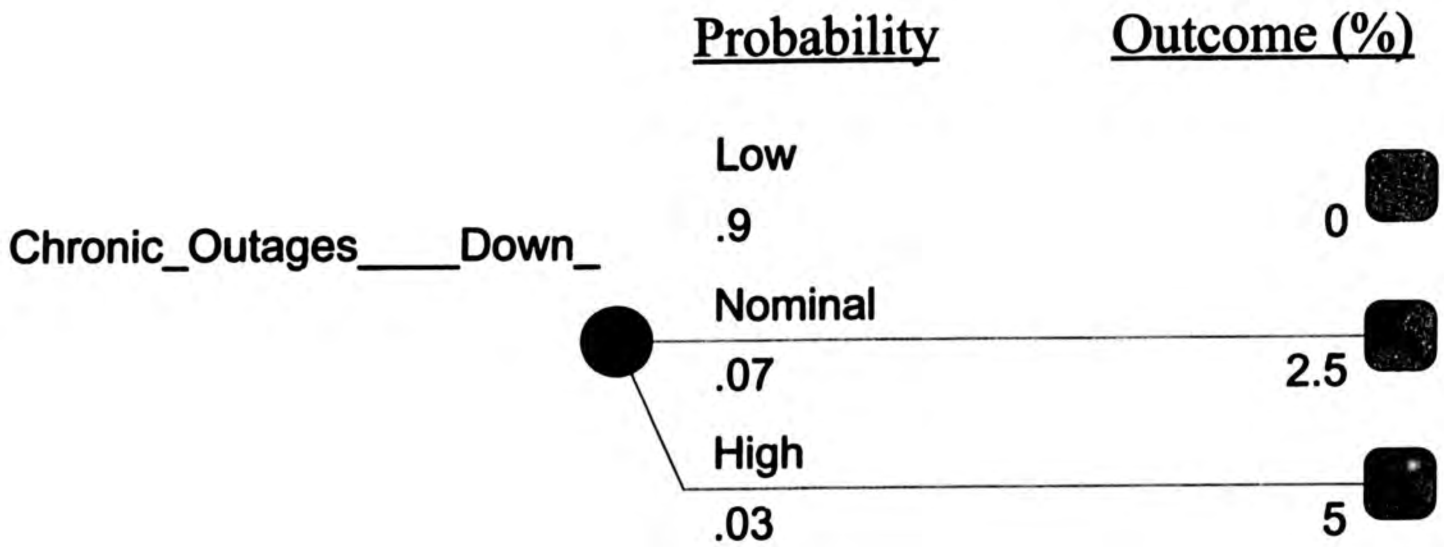

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Numbers on right represent value (years, $, %, etc…)

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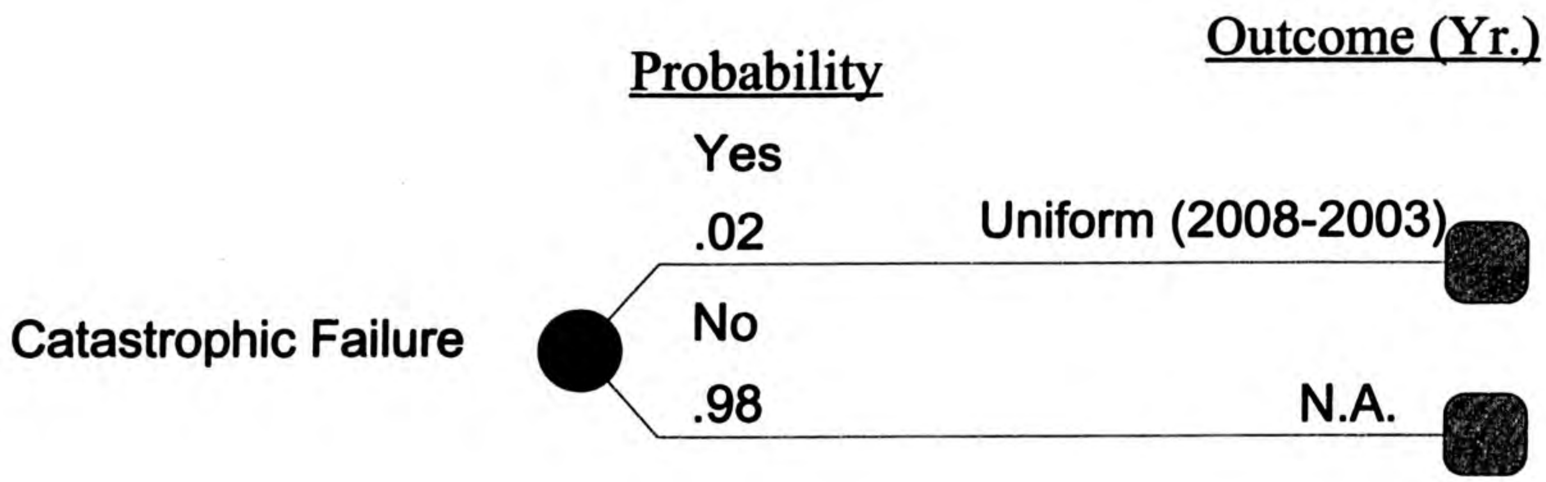

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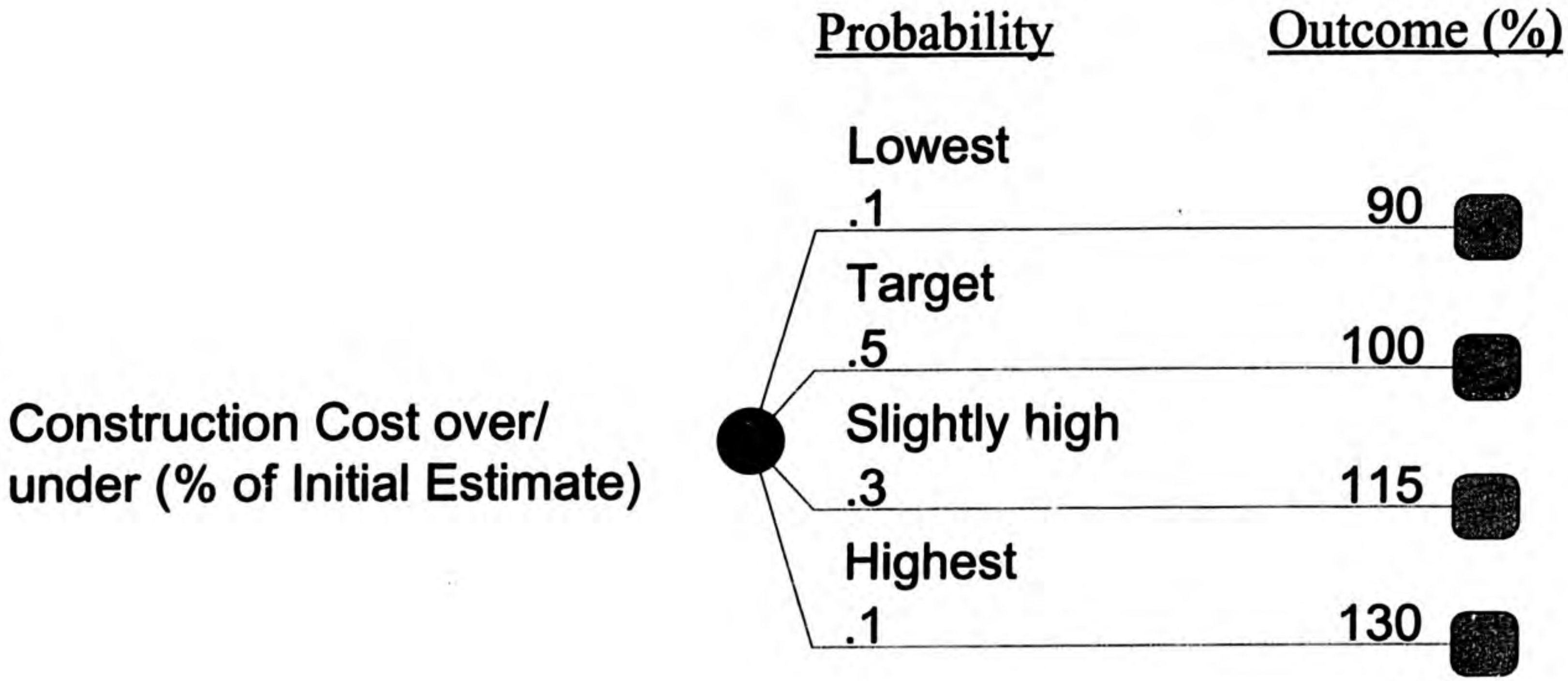

Note: Numbers on left represent branch probability.
Numbers on right represent value (years, $, %, etc…)

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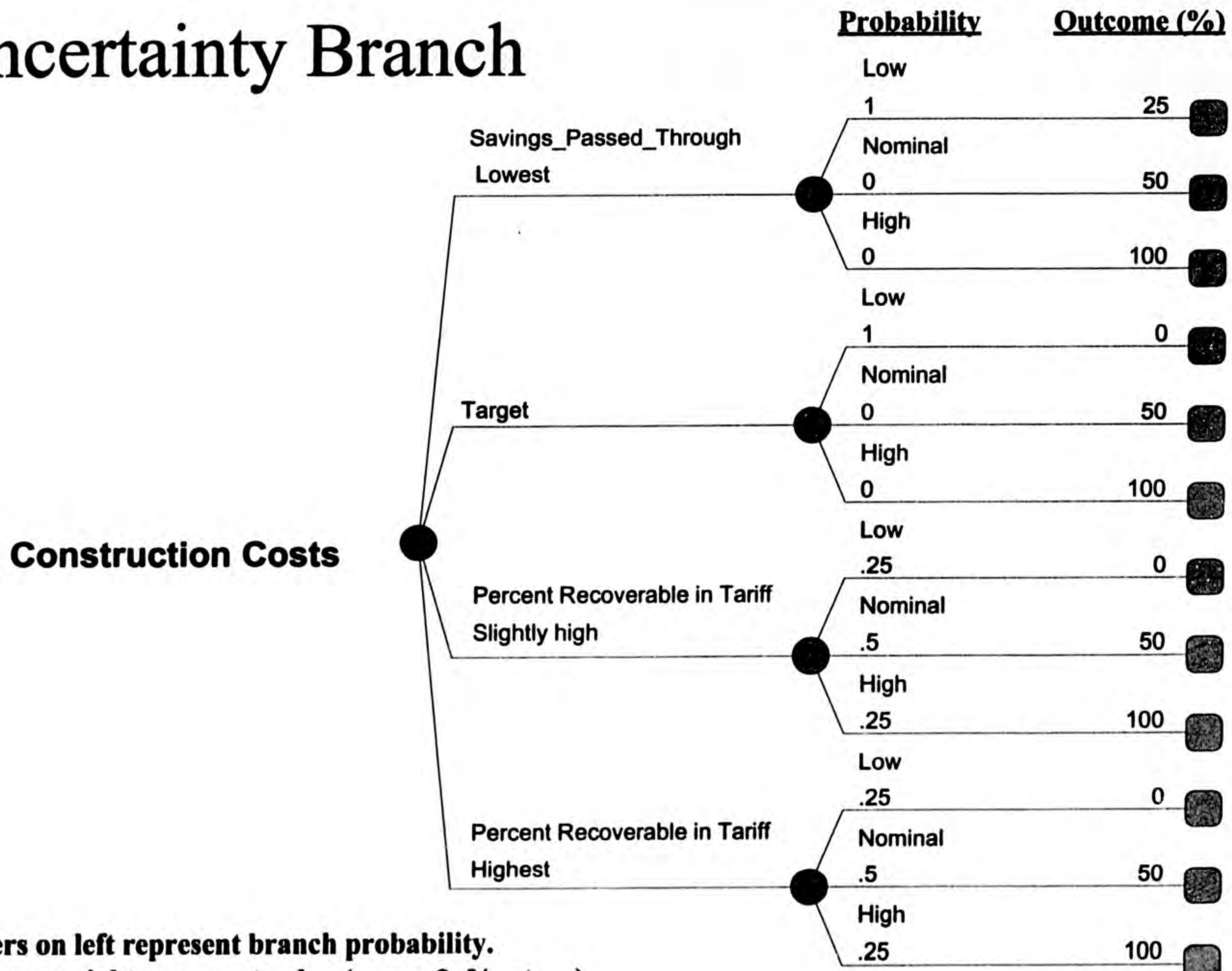
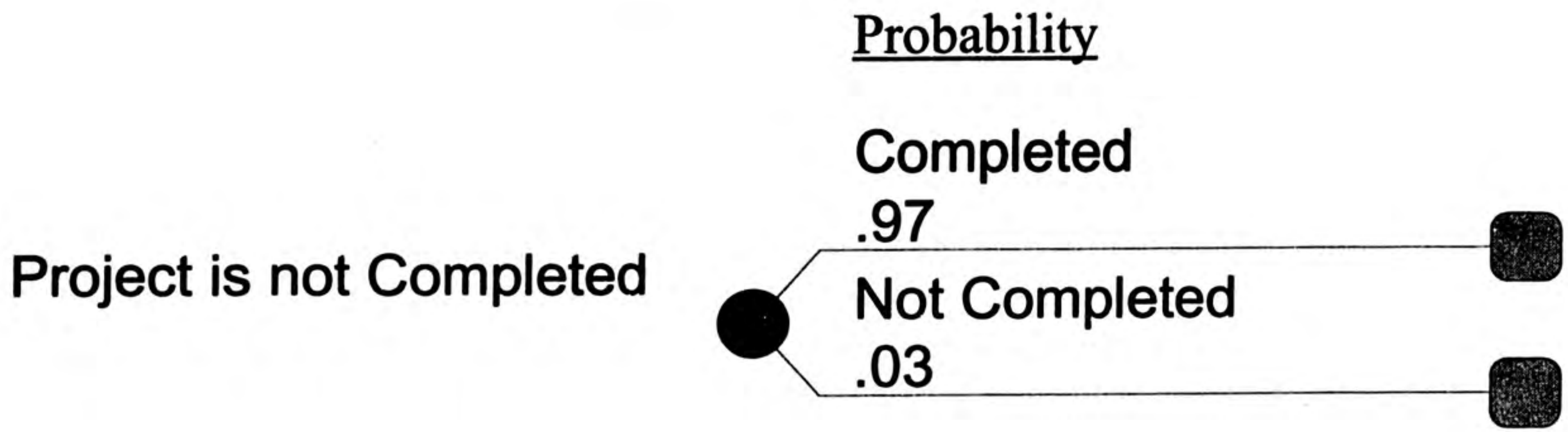


Note: **Numbers on left represent branch probability.**
Numbers on right represent value (years, $, %, etc…)

Uncertainty Branch



Note: Numbers on left represent branch probability.

Appendix C
Sample Model Input and Output

TABLE 2

Alaska Gas Pipeline

Financial Analysis of Ownership Participation by the State of Alaska

Investment Costs

(Billions of Dollars)

01/25/02

Year	Cumulative Through 2001	2002	2003	2004	2005	2006	2007	2008	Total
Planning and Construction									
Expenditure profile	2%	2%	10%	16%	22%	23%	18%	7%	100%
Billions of 2001 Dollars	0.21	0.22	0.91	1.40	1.98	2.06	1.61	0.62	9.00
Billions of Nominal $	0.21	0.23	0.96	1.51	2.18	2.33	1.87	0.73	10.01
AFUDC	0.20	0.18	0.63	0.80	0.88	0.68	0.35	0.06	3.78
Total Cost	0.41	0.41	1.59	2.30	3.06	3.01	2.21	0.80	13.79
									13.79

Allocation from Producers	2%	2%	10%	15%	21%	22%	17%	7%	95%
Adjusted	2.3%	2.5%	10.1%	15.5%	22.0%	22.9%	17.9%	6.9%	100.0%

TABLE 3
Alaska Gas Pipeline
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Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Tariff Calculation (North Slope to Alberta)													
Rate Base													
Beginning of Year		1,724	1,655	1,586	1,517	1,448	1,379	1,310	1,241	1,172	1,103	1,034	965
less: Depreciation		69	69	69	69	69	69	69	69	69	69	69	69
End of Year	1,724	1,655	1,586	1,517	1,448	1,379	1,310	1,241	1,172	1,103	1,034	965	896
Property Tax Value													
Replacement Cost New Less Depreciation		1,724	1,696	1,666	1,633	1,598	1,560	1,519	1,475	1,428	1,378	1,324	1,266
US Revenue Requirements													
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation		34	34	34	34	34	34	34	34	34	34	34	34
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
US Income Taxes		16	(12)	(7)	(3)	1	4	5	4	3	2	2	1
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Return to Equity		31	30	29	27	26	25	24	22	21	20	19	17
Total		159	128	130	131	132	132	130	126	122	118	114	110
Canadian Revenue Requirements													
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation		34	34	34	34	34	34	34	34	34	34	34	34
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
Canadian Income Taxes		25	13	13	13	14	14	14	15	15	15	15	15
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Return to Equity		31	30	29	27	26	25	24	22	21	20	19	17
Total		168	153	150	148	145	142	140	137	134	131	128	125
Total Revenue Requirements													
Operation and Maintenance		30	31	32	32	33	34	35	36	37	38	39	40
Depreciation		69	69	69	69	69	69	69	69	69	69	69	69
Property Tax		34	34	33	33	32	31	30	30	29	28	26	25
Income Taxes		40	0	6	10	14	18	19	19	18	17	17	16
Interest Expense		90	87	83	80	76	72	69	65	62	58	54	51
Return to Equity		62	60	57	55	52	50	47	45	42	40	37	35
Total Revenue Requirements		327	280	280	279	277	274	270	263	256	249	242	235

TABLE 3
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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Tariff Calculation (North Slope to Alberta)													
Rate Base													
Beginning of Year	896	827	758	689	620	552	483	414	345	276	207	138	69
less: Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
End of Year	827	758	689	620	552	483	414	345	276	207	138	69	(0)
Property Tax Value													
Replacement Cost New Less Depreciation	1,205	1,140	1,072	998	921	839	753	661	565	463	356	243	125
US Revenue Requirements													
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation	34	34	34	34	34	34	34	34	34	34	34	34	34
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
US Income Taxes	(0)	(1)	(2)	15	32	31	30	29	28	28	27	26	25
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Return to Equity	16	15	14	12	11	10	9	7	6	5	4	2	1
Total	106	102	98	112	125	121	117	113	108	104	100	95	91
Canadian Revenue Requirements													
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation	34	34	34	34	34	34	34	34	34	34	34	34	34
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
Canadian Income Taxes	15	15	15	15	15	15	14	14	14	14	14	13	13
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Return to Equity	16	15	14	12	11	10	9	7	6	5	4	2	1
Total	122	118	115	112	108	105	101	98	94	90	87	83	79
Total Revenue Requirements													
Operation and Maintenance	41	42	43	44	45	46	47	48	49	51	52	53	55
Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
Property Tax	24	23	21	20	18	17	15	13	11	9	7	5	2
Income Taxes	15	14	13	30	47	46	45	44	42	41	40	39	38
Interest Expense	47	43	40	36	33	29	25	22	18	14	11	7	4
Return to Equity	32	30	27	25	22	20	17	15	12	10	7	5	2
Total Revenue Requirements	228	221	213	224	234	226	218	211	203	195	186	178	170

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Financial Analysis of Ownership
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Tariff and Base Internal Rate of Return Projections
Dollar Amounts in Millions unless Otherwise Indicated

		2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Revenue Requirement per MMBtu														
US			0.85	0.68	0.69	0.70	0.70	0.71	0.70	0.67	0.65	0.63	0.61	0.59
Canadian			0.90	0.82	0.80	0.79	0.77	0.76	0.75	0.73	0.71	0.70	0.68	0.67
Total			1.74	1.50	1.49	1.49	1.48	1.47	1.44	1.40	1.37	1.33	1.29	1.26
Levelized Tariff Estimates														
<u>Nominal Tariffs (Current $/MMBtu)</u>														
Total Tariff	1.38													
Included Income Taxes	0.11													
Tariff w/o Inc Taxes	1.27													
Added Cost of Inc Taxes														
Total	8.7%													
Federal only	6.7%													
Monthly Cost	21.23													
<u>Levelized Tariff (Constant 2001$)</u>														
Total Tariff			1.43	1.20	1.17	1.13	1.10	1.06	1.02	0.97	0.92	0.87	0.83	0.79
Levelized	0.92													
Projected Income, Cash Flow, and Internal Rate of Return														
Income Statement														
Revenues														
Tariff[1] ($/MMBtu)			1.74	1.50	1.49	1.49	1.48	1.47	1.44	1.40	1.37	1.33	1.29	1.26
Annual Sales (BCF)			[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Btu per cubic foot			1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Total Revenues			327	280	280	279	277	274	270	263	256	249	242	235
Operating Expenses														
Operation and Maintenance			30	31	32	32	33	34	35	36	37	38	39	40
Depreciation			69	69	69	69	69	69	69	69	69	69	69	69
Property Tax			34	34	33	33	32	31	30	30	29	28	26	25
Total Operating Expenses			134	134	134	134	134	134	134	134	134	134	134	134
Operating Income before Income Tax			193	147	146	145	143	140	135	129	122	115	108	101
US Income Taxes			15.64	(12.30)	(7.45)	(3 20)	0.57	3.91	5.03	4.16	3.24	2.43	1.50	0.70
Canadian Income Taxes			24.85	12.58	13.06	13.49	13.86	14.18	14.44	14.66	14.83	14.96	15.04	15.09
Operating Income after Income Taxes			153	146	140	134	128	122	116	110	104	98	92	85
Interest Expense			90	87	83	80	76	72	69	65	62	58	54	51
Net Income			62	60	57	55	52	50	47	45	42	40	37	35

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	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Revenue Requirement per MMBtu													
US	0.57	0.55	0.52	0.60	0.67	0.65	0.62	0.60	0.58	0.56	0.53	0.51	0.49
Canadian	0.65	0.63	0.61	0.60	0.58	0.56	0.54	0.52	0.50	0.48	0.46	0.44	0.42
Total	1.22	1.18	1.14	1.19	1.25	1.21	1.17	1.12	1.08	1.04	1.00	0.95	0.91

Levelized Tariff Estimates

Nominal Tariffs (Current $/MMBtu)	
Total Tariff	1.38
Included Income Taxes	0.11
Tariff w/o Inc Taxes	1.27
Added Cost of Inc Taxes	
Total	8.7%
Federal only	6.7%
Monthly Cost	21.23

		2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Levelized Tariff (Constant 2001$)														
Total Tariff		0.74	0.70	0.66	0.68	0.69	0.65	0.61	0.58	0.54	0.51	0.47	0.44	0.41
Levelized	0.92													

Projected Income, Cash Flow, and Internal Rate of Return

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
Income Statement													
Revenues													
Tariff[1] ($/MMBtu)	1.22	1.18	1.14	1.19	1.25	1.21	1.17	1.12	1.08	1.04	1.00	0.95	0.91
Annual Sales (BCF)	[redacted]												
Btu per cubic foot	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080	1,080
Total Revenues	228	221	213	224	234	226	218	211	203	195	186	178	170
Operating Expenses													
Operation and Maintenance	41	42	43	44	45	46	47	48	49	51	52	53	55
Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
Property Tax	24	23	21	20	18	17	15	13	11	9	7	5	2
Total Operating Expenses	134	133	133	133	132	132	131	130	130	129	128	127	126
Operating Income before Income Tax	94	87	80	91	102	94	87	80	73	66	58	51	44
US Income Taxes	(0.23)	(1.03)	(1.96)	14.98	31.86	30.99	30.13	29.26	28.39	27.53	26.66	25.80	24.93
Canadian Income Taxes	15.10	15.07	15.02	14.92	14.80	14.65	14.47	14.27	14.04	13.78	13.51	13.21	12.89
Operating Income after Income Taxes	79	73	67	61	55	49	43	37	31	24	18	12	6
Interest Expense	47	43	40	36	33	29	25	22	18	14	11	7	4
Net Income	32	30	27	25	22	20	17	15	12	10	7	5	2

TABLE 3

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Financial Analysis of Ownership

Participation by the State of Alaska

Tariff and Base Internal Rate of Return Projections

Dollar Amounts in Millions unless Otherwise Indicated

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
US Income Taxes													
Revenues		159	128	130	131	132	132	130	126	122	116	114	110
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation (for Taxes)		43	82	74	66	60	54	51	51	51	51	51	51
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Taxable Income		38	(30)	(18)	(8)	1	10	12	10	8	6	4	2
State of Alaska Tax		4	(3)	(2)	(1)	0	1	1	1	1	1	0	0
Federal Tax		12	(9)	(6)	(2)	0	3	4	3	2	2	1	1
Total US Income Tax		16	(12)	(7)	(3)	1	4	5	4	3	2	2	1
Canadian Income Taxes													
Revenues		168	153	150	148	145	142	140	137	134	131	128	125
Operation and Maintenance		15	15	16	16	17	17	17	18	18	19	19	20
Depreciation (for Taxes)		22	42	40	38	36	34	33	31	29	28	26	25
Property Tax		17	17	17	16	16	16	15	15	14	14	13	13
Interest Expense		45	43	42	40	38	36	34	33	31	29	27	25
Taxable Income		69	35	36	37	38	39	40	41	41	41	42	42
Total Canadian Income Tax		25	13	13	13	14	14	14	15	15	15	15	15
Cash Flow													
Capital Investment	(1,724)												
Operating Income		153	146	140	134	128	122	116	110	104	98	92	85
plus Depreciation		69	69	69	69	69	69	69	69	69	69	69	69
Net Cash Flow	(1,724)	221	215	209	203	197	191	185	179	173	167	160	154
Interest expense		90	87	83	80	76	72	69	65	62	58	54	51
Principal payment		48	48	48	48	48	48	48	48	48	48	48	48
Principal and interest payment	(1,206)	139	135	132	128	124	121	117	113	110	106	103	99
Net Cash Flow after Interest Payment	(517)	83	80	78	75	73	70	68	65	63	60	58	55
IRR–Total Capital	8.85%												
IRR–Debt	7.50%												
IRR–Equity	12.00%												

[1] The tariff shown is based on the simplifying assumption that the tariff will be equal to the annual revenue requirements. In fact the tariff will be negotiated to be fixed for many years base on a levelizing formu

TABLE 3
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Dollar Amounts in Millions unless Otherwise Indicated

	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033
US Income Taxes													
Revenues	106	102	98	112	125	121	117	113	108	104	100	95	91
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation (for Taxes)	51	51	51	25	-	-	-	-	-	-	-	-	-
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Taxable Income	(1)	(3)	(5)	36	77	75	73	71	69	67	65	63	61
State of Alaska Tax	(0)	(0)	(0)	3	7	7	7	7	6	6	6	6	6
Federal Tax	(0)	(1)	(2)	12	25	24	23	23	22	21	21	20	19
Total US Income Tax	(0)	(1)	(2)	15	32	31	30	29	28	28	27	26	25
Canadian Income Taxes													
Revenues	122	118	115	112	108	105	101	98	94	90	87	83	79
Operation and Maintenance	20	21	21	22	22	23	24	24	25	25	26	27	27
Depreciation (for Taxes)	24	23	22	20	19	18	18	17	16	15	14	14	13
Property Tax	12	11	11	10	9	8	8	7	6	5	4	2	1
Interest Expense	24	22	20	18	16	14	13	11	9	7	5	4	2
Taxable Income	42	42	42	41	41	41	40	39	39	38	37	37	36
Total Canadian Income Tax	15	15	15	15	15	15	14	14	14	14	14	13	13
Cash Flow													
Capital Investment													
Operating Income	79	73	67	61	55	49	43	37	31	24	18	12	6
plus Depreciation	69	69	69	69	69	69	69	69	69	69	69	69	69
Net Cash Flow	148	142	136	130	124	118	112	106	99	93	87	81	75
Interest expense	47	43	40	36	33	29	25	22	18	14	11	7	4
Principal payment	48	48	48	48	48	48	48	48	48	48	48	48	48
Principal and interest payment	95	92	88	84	81	77	74	70	66	63	59	55	52
Net Cash Flow after Interest Payment	53	50	48	46	43	41	38	36	33	31	28	26	23
IRR--Total Capital													
IRR--Debt													
IRR--Equity													

[1] The tariff shown is based on the simplifying assumption that the tariff will be equal to the annual revenue requirements. In fact the tariff will be negotiated to be fixed for many years base on a levelizing fo

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