ALASKA STATE LEGISLATURE
JOINT MEETING
JOINT COMMITTEE ON LEGISLATIVE BUDGET AND AUDIT
SENATE RESOURCES STANDING COMMITTEE
June 16, 2004
8:34 a.m.

MEMBERS PRESENT

LEGISLATIVE BUDGET AND AUDIT

Representative Ralph Samuels, Chair
Representative Mike Chenault (via teleconference)
Representative Mike Hawker
Representative Beth Kerttula
Representative Reggie Joule - alternate

Senator Gene Therriault, Vice Chair
Senator Con Bunde

SENATE RESOURCES

Senator Scott Ogan, Chair
Senator Tom Wagoner, Vice Chair
Senator Fred Dyson
Senator Ralph Seekins (via teleconference)

MEMBERS ABSENT

LEGISLATIVE BUDGET AND AUDIT

Representative Vic Kohring

Senator Gary Wilken
Senator Ben Stevens
Senator Lyman Hoffman

SENATE RESOURCES

Senator Ben Stevens
Senator Kim Elton
Senator Georgiana Lincoln

OTHER LEGISLATORS PRESENT

Representative Les Gara

Senator Gretchen Guess

COMMITTEE CALENDAR

ALASKA NATURAL GAS PIPELINE ISSUES/PIPELINE COSTS & TARIFFS

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

Presentations By:

MARK MYERS, Director
Division of Oil and Gas
Department of Natural Resources

DAN DICKINSON, Director
Tax Division
Department of Revenue

MARK HANLEY, Public Affairs Manager
Anadarko Petroleum Corporation

GARTH SALISBURY, Managing Director
JP Morgan Chase and Co.

NANCY ROHMAN, Vice President
JP Morgan Chase and Co.

WILLIAM BENHAM, Vice President
Regulatory Affairs
BP Energy Company

DAVE McDOWELL, Director, External Affairs - Gas
British Petroleum (BP)

TONY PALMER, Vice President
Alaska Business Development
TransCanada Corporation

WILLIAM WALKER, General Counsel
Alaska Gasline Port Authority;
Attorney at Law, Walker & Levesque, LLC

RIGDON BOYKIN, Special Counsel
Alaska Gasline Port Authority;
Attorney at Law, O'Melveny & Myers LLP

DANIEL IVES, Vice President and Principal
Lukens Energy Group, Inc.
Representing the Alaska Department of Law

ROBERT LOEFFLER, Senior Partner
Morrison & Forrester, LLP

NAN THOMPSON, Commissioner
Regulatory Commission of Alaska (RCA)
Department of Community & Economic Development (DCED)

ACTION NARRATIVE

TAPE 04-6, SIDE A [BUD TAPE]
Number 001

CHAIR RALPH SAMUELS called the joint meeting of the Joint Committee on Legislative Budget and Audit and the Senate Resources Standing Committee to order at 8:34 a.m. Joint Committee on Legislative Budget and Audit members present were Representatives Samuels, Chenault (via teleconference), Hawker, Kerttula, and Joule (Alternate) and Senators Therriault and Bunde. Senate Resources Standing Committee members present were Senators Ogan, Wagoner, Dyson, and Seekins. Also in attendance were Representative Gara and Senator Guess.

CHAIR SAMUELS explained that the purpose of the meeting today and tomorrow is to attempt to educate members of the committee and the legislature in general with regard to the complicated issues of the natural gas pipeline and the legislature's role in approving a contract under the Stranded Gas Act. He noted that the testimony is by invitation only and questions from the members should be forwarded to him or Senator Ogan who will ask the question at the end [of each presentation], if there is time. Otherwise, the responses to the questions will be provided to the committee members in writing.

Number 012

MARK MYERS, Director, Division of Oil and Gas, Department of Natural Resources, specified that he would address the impact of pipeline costs on royalty payments. He provided the committee with a copy of the slides he will present. He began by pointing out that although a producer shipping down a pipeline and a royalty owner have similar interests, in some way the two are different. Furthermore, royalties are different than taxes in that the royalties are based on the lease. Different leases have different provisions with regard to how royalties can be calculated and the allowable deductions. The lease is a contractual relationship that the legislature can't change, which is unlike taxation that the legislature can change. The lease provides some stability for all parties.

MR. MYERS explained that the state has two choices with its royalty share. The state can physically take possession of the royalty in-kind (RIK) and sell it, which the state does with much of its oil. Although the state normally takes its oil upstream and has the purchaser ship the oil, there is nothing restricting the state from selling it downstream in the market. The second choice is taking the royalty in-value (RIV), which means that it would leave [the royalty share] with the producer who would sell it and the state would receive the proceeds from that sale minus the deductions. Therefore, if RIV is chosen, the state receives from the producer the value netted back to the lease, but the state would incur the transportation costs and additional costs depending upon the language of the lease.

MR. MYERS specified that the netback equals the destination value minus the transportation as well as any field/conditioning costs. In Prudhoe Bay, the state in 1980 reached a settlement in which the state agreed to pay a certain amount for those costs. In newer formed leases, the state wouldn't incur either cost, no matter whether the royalties are RIK or RIV. However, for those leases formed prior to 1979, DO1 leases, the state wouldn't incur the costs under RIV but would be required to pay fuel costs under RIK. The aforementioned is the current view of the courts. Mr. Myers highlighted that one powerful protection the state has built into the lease is that the transportation is the actual and reasonable costs of transportation from field to market. On the oil side, the state is, on an ongoing basis, going through the process of determining whether the transportation costs are actual and reasonable through a reopener process.

MR. MYERS highlighted the bullet specifying: "Pipeline tariffs do not necessarily represent the actual and reasonable costs of pipeline transportation." He characterized pipeline tariff methodology as an art that can be done in various ways because there can be a disconnect between the tariff structure and what is actual and reasonable. The tariffs are a direct reduction against the royalty value that is netted back to the lease. The page entitled "Calculation of Royalty Netback Value for ANS Gas" shows the netback the state would hypothetically receive from various fields with a destination value of $4.00. He acknowledged that $4.00 is somewhat arbitrary. The illustration also assumes that the trunk pipeline tariff from Alaska to the Chicago market is $2.00. He pointed out that the document erroneously specifies that the conditioning cost for Prudhoe Bay would be $.20. The conditioning cost for Prudhoe Bay should be $.40 and the field cost should be $.20. Therefore, the netback royalty value would be about $1.65 per thousand cubic feet (mcf) at $4.00. For Point Thompson, the state wouldn't pay fuel costs if it was left RIV and there would be an allowable deduction to move the gas from Point Thompson to Prudhoe Bay, and an adjustment for the quality of the gas. The result is a higher netback. The North Slope Foothills lease is an example of a modern lease in which the gas, a cleaner gas, sells for $4.00 with no BTU [British thermal unit] adjustment and fuel costs. Therefore, the netback royalty value would be less since the development costs wouldn't be incurred. He noted that this is from the royalty perspective.

MR. MYERS clarified that there are two major classes of tariffs. One class is a recourse rate, which is established by Federal Energy Regulatory Commission (FERC). The other is a negotiated rate. Furthermore, the rates can vary depending upon the class of shippers. Although the rates can't unduly discriminate, the rates can discriminate based on certain factors. He also pointed out that firm service versus interruptible service can have different rates. The interruptible service rate is a rate that is purchased in the market if the space is available, although there is no guarantee to ship the gas. Interruptible service can be more expensive or cheaper. Pipelines that are later in life typically have a lot of excess capacity, as is the case in the Alberta system in Canada. In that case, most folks would purchase interruptible service because of its availability. However, projects in the earlier stages may not have much interruptible service, which may mean that much of it may not be available or it might come at a premium cost. Mr. Myers explained that in the rate-setting mechanism there are a number of variations. The allowed rate of return on equity can vary quite a bit depending upon the view of FERC. The cost of the debt is a big factor as is the debt equity ratio. Generally, the rate of return allowed is only allowed on that capital supplied by the pipeline company itself. Therefore, the rate of return calculation is only on the amount borrowed. How the capital is structured will be a major determinant in the rate structure, he said. The rates are also affected by the length and method of depreciation.

MR. MYERS turned to the cost of service (COS), recourse tariff, versus a levelized tariff. The COS tariff, which is a typical type that FERC would approve as a recourse rate, would start higher and decrease over time. The aforementioned occurs because as the asset depreciates there is less and less rate base in the capital, and therefore the tariff is designed to reflect that. In negotiated tariffs, it's not uncommon to negotiate a levelized tariff in which the tariff is the same throughout the entire period. With a levelized tariff, the tariff would be lower at first, but later that tariff would be higher than it would've been under a recourse rate. The different tariff types provide advantages to different parties. The state, which doesn't own the pipeline, would want a higher netback to obtain income early in the project, and therefore a levelized tariff would probably be the preferable mechanism. The gas producers under a third-party pipeline ownership would also prefer a negotiated, levelized, tariff because of the desire to receive a higher netback earlier. However, the gas producers who own the pipeline would prefer a recourse rate, COS tariff, in order to receive the maximum rate of return upfront. He reiterated that the state may prefer a levelized tariff if revenue is a priority for the state. Negotiated tariffs, which are individually negotiated with each customer, have been permitted by FERC since 1996. Negotiated tariffs can be lower or higher than a recourse tariff. In the example presented in Mr. Myers' booklet, the recourse and negotiated tariffs are approximately equal in year nine.

MR. MYERS highlighted that the COS tariff doesn't follow a nice downward trend. The COS tariff is only adjusted at points when someone approaches FERC to request [an adjustment]. In a general scenario, the initial rate would hold for an 18[-year] period and then it would drop. If two years later someone makes a rate case and it takes two years to adjudicate that case, the adjustment would start at the point of adjudication. Therefore, [the COS tariff] ends up being a stair step effect that is dependent upon how often people go before FERC and file. Generally, the shippers will pay more under the recourse rate. Mr. Myers returned to the state's perspective and recommended that in order to receive just and reasonable [transportation] it will probably be necessary to obtain a pipeline tariff settlement or the default will be a COS type tariff.

Number 210

SENATOR OGAN asked if any other states have an ownership position in an oil or gas pipeline. If so, what has been the experience of those states, he asked.

MR. MYERS answered that he didn't know of any other states that have an ownership position in an oil or gas pipeline, although he did know of cases in which states have set up authorities that have helped finance a pipeline. He noted that states have taken capacity on pipelines, have bought transport, and have marketed their royalty shares down stream. He noted that Texas does the aforementioned.

SENATOR OGAN offered his understanding that Wyoming may have some sort of ownership in a pipeline recently.

Number 226

DAN DICKINSON, Director, Tax Division, Department of Revenue, emphasized Mr. Myers' earlier comments that sovereign taxes are very different than the royalty, which is a contract. He turned attention to a packet of information labeled "Alaska Natural Gas Pipeline Issues," and explained that there are four major bites at the apple on the oil side and the gas side. One is royalty because most of the development has been on land that the state owns. Additionally, there is a production tax, which is based on the amount of oil and gas that's produced. There is a special income tax that applies to producers of oil and gas. Finally, there is a special oil and gas property tax. Mr. Dickinson said that he would address the production tax.

MR. DICKINSON pointed out that the legislature set the rules and can unilaterally change those rules. Currently, there is a 10 percent production tax on gas and a 12.5-15 percent production tax on oil. He noted that for the economic limit factor (ELF) for gas he will use an estimate of about 80 percent. He explained that the 10 percent is multiplied by the ELF which is multiplied by the gross value at point of production, which equals the tax. In contrast to royalty, the gross value at the point of production includes no upstream costs that are deductible. Therefore, he likened it to the newly formed leases under royalty. In order to find the gross value at the point of production, one must take the value at the destination less the actual costs of transportation. The aforementioned looks a lot like the royalty situation, although how the actual transportation costs are determined is very different.

MR. DICKINSON turned to a document entitled, "Potential Production Tax Revenue." The document uses a destination value from $2.00 to $10.00 with a tariff of $2.40 and assumes the following: 4 bcf (billion cubic feet) per day; 365.0 days per year; 87.5% non-royalty fraction; 10% tax rate; and 80% estimated ELF. Multiplying all of the assumptions together at a $6.00 destination value would result in production tax revenues of about $367 million. At a $10.00 price, the production tax revenues will be close to three-quarters of a billion a year. However, if the price was $2.00 and the tariff didn't cover the costs, the minimum of $.064 cents per mcf will kick in. Therefore, if the price drops to $2.00, the tariff would no longer be relevant and a tax would be collected based on the $.064 a barrel. The aforementioned situation results in $2.8 million minimum. The tax deduction for the tariff would be about $245.3 billion a year, except for the cases in which the tariff is larger than the destination value.

MR. DICKINSON pointed out that there will be some issues with regard to whether the tariff or some other measure would be used. The law, AS 43.55.150, specifies that [the state] would be allowed to deduct the reasonable cost of transportation of the oil or gas. Furthermore, the law specifies that the reasonable costs of transportation will be the actual costs, except under the following circumstances: when the parties of the oil or gas are affiliated; when the contract for the transportation of oil or gas is not an arm's length transaction or is not representative of the market value of that transportation; when the method of transportation of oil and gas is not reasonable in view of existing alternative methods of transportation. If all three criteria are met, the law specifies: "the department shall determine the reasonable cost of transportation, using the fair market value of like transportation, the fair market value of equally efficient and available alternative modes of transportation, or other reasonable methods." Mr. Dickinson turned to the part of the law that specifies: "Transportation costs fixed by tariff rates properly on file with the Regulatory Commission of Alaska or other regulatory agency shall be considered prima facie reasonable". The aforementioned means that the presumption is that the filed tariff is correct, although that can be challenged by the department.

MR. DICKINSON pointed out that the legislature has the ability to set what tax is levied on the gas. He informed the committee that in 1977 the Supreme Court laid down the rules regarding what one state can do when it wants to tax the business of a corporation that has interstate business. The Supreme Court specified that in order to tax the interstate activities of a corporation, the tax can't be discriminatory; the tax must be fairly apportioned to the state; the local activities in the taxing state must establish a sufficient nexus; the tax must be fairly related to services provided by the state. Mr. Dickinson explained, "As you think about the ... tariffs, which is what this is really about, the irony is you could probably set up a scheme that treated Alaska and looked at the Alaskan tariff as something that you could ignore ... whereas you're going to have to take [into] account the tariffs that are paid further downstream."

MR. DICKINSON informed the committees that Alberta, Canada, has a tax that's 1 percent of the gross receipts or 25 percent of the net receipts. In other words, all the cost deductions of a project are allowed and after all the costs are deducted there is a 25 percent tax. However, if the gross receipts are higher, then that's taxed instead. Therefore, the tariffs, the other deductible costs, become irrelevant to that calculation. Mr. Dickinson highlighted the difference between an allowance and a deduction. In conclusion, Mr. Dickinson turned to the Stranded Gas Act and explained that "we're" trying to create a contract which will be used to effect the sovereign's right to tax. The companies have expressed concern that when they develop a project with a 20-30 year time horizon, the sovereign will come in at a later year and effect the economics of the project. Therefore, the Stranded Gas Act attempts to create a situation in which the sovereign is restraining its right to tax over some time period in the hope that there will be a project to tax.

Number 420

SENATOR OGAN recalled the Amerada Hess Corporation case, which was a very expensive and contentious case that resulted in the constitutional budget reserve. He asked Mr. Dickinson to review what was learned from that case.

MR. DICKINSON explained that the Amerada Hess Corporation case was specifically about royalties, although there were parallel tax cases that investigated many of the same issues. He said that case was fundamentally about value. During the time of the case there was no transparent market for oil as there is now for oil and gas. Therefore, he didn't believe there would be situations in which one huge exporter says the oil is worth $22 while the other says it's worth $35, although there will continue to be conflicts regarding the exact [amount]. The other piece [of the case] was in regard to transportation costs. In the lease that governed the royalty obligation there were no specifics, which resulted in both sides arguing that they had met the general statement of principle. From that, one can learn that it's better to determine [the specifics] beforehand, to the degree possible. One may hesitate being too specific when looking at something 10-15 years down the road because one may not know the factual situation that will be present. Mr. Dickinson opined that there will always be conflicts, although hopefully the conflicts can be $10-$30 million conflicts instead of $100 million conflicts.

Number 477

MARK HANLEY, Public Affairs Manager, Anadarko Petroleum Corporation, said that he would provide the committees with an explorer's perspective. This would be an explorer who hasn't discovered gas already, but does have significant acreage positions in gas prone areas. Mr. Hanley pointed out that what he's heard thus far is that every entity wants to do the best for its shareholders, although there are different motivations. Therefore, the state needs to understand those motivations, how they fit together, and whether they are fair or not. Decisions on the aforementioned will determine whether companies such as Anadarko explore for gas or not. As has been indicated, the rules in this game are fairly flexible. For example, earlier Mr. Myers stated that pipeline tariffs don't necessarily represent the actual and reasonable cost of pipeline transportation, which is of concern for an explorer. An explorer would want the lowest rate possible in order to generate the highest wellhead, which provides the most economic ability to explore and make the most money. In general that would be true for the state as well. However, if the tariffs don't represent the actual and reasonable cost, he doubted they would represent [less than] the actual cost. He assumed that the assumption is that the tariffs would be higher than the actual and reasonable cost. Therefore, the explorer's position would be negatively effected. Furthermore, the rates can't be unduly discriminatory, which he surmised to mean that they can be duly discriminatory. Moreover, there can be the "black box" methodology in which the rates are known, but whether those rates are fair or not isn't known. The aforementioned is a difficult situation.

MR. HANLEY turned to the question of who makes the decisions on how these things are set up and said that it depends. Sometimes the pipeline owners set up things in the tariffs, and other times it can be FERC as part of the regulatory process, or even the state can specify that charges aren't reasonable for royalty purposes. In fact, "they" may be able to obtain a lower transportation rate. Mr. Hanley reiterated that the rules of the game are very fluid and there is much ability to change those rules. Therefore, explorers are going to sit back and watch.

MR. HANLEY stated, "If there's no gas pipeline, there's no exploration." He acknowledged that people say there is a lot of gas out there, and perhaps [Anadarko] could build the pipeline. However, Mr. Hanley pointed out that 35 trillion cubic feet (tcf) of discovered gas that is already being produced and for which there is no exploration risk "and it's challenged getting this pipeline going." The odds of someone being able to find another 30 tcf of gas to justify this pipeline is next to nil. Therefore, it is likely that explorers aren't going to be able to find enough gas nor would they invest the billions of dollars to do so. Mr. Hanley related that Anadarko is very supportive of building a gas pipeline. However, the rate for explorers needs to be as low as possible, which he believes to be true for producers as well. As in the case of oil, the farther away one is from infrastructure, the larger the field needs to be. With a lower tariff, there will be smaller fields that are economic and create the chance of obtaining more revenue. Therefore, generally it's in everyone's interest to have the rate be as low as possible.

MR. HANLEY turned to the issue of reasonable access terms and conditions. He pointed out that the Foothills area tends to be more gas prone and not as liquid prone. Although it's known that it's a gas prone area, it isn't known if it's commercial because that wasn't tested. Mr. Hanley informed the committee that a couple of years ago Northern Economics did a study for Anadarko with regard to commercial gas development in the Foothills area. The study goes through the 30-year life of a gas product in the Foothills area.

TAPE 04-6, SIDE B

MR. HANLEY informed the committees that in Prudhoe Bay alone there is 35 tcf of gas while the estimate for the remainder of the North Slope is somewhere between 70-80 tcf of undiscovered gas potential. In the Arctic National Wildlife Refuge (ANWR) area and Foothills area, there are [gas] estimates of 8.5-9 tcf. There is a lot of potential for gas and exploration. With all that, one might question why a gas line hasn't been built.

However, typically the largest risk in exploration is the geological site, the underground side. The [risk surrounds] whether gas will be found; whether there is enough gas to flow in quantities; and whether the gas will be close enough to infrastructure to make a commercial gas find. However, the largest risk in Alaska is the aboveground risk, the commercial risk, [which includes] the risk of the tariff being too high, construction cost overruns, legal challenges, permitting, and price risk. The aforementioned are fairly significant risks, but the state can come in with fiscal security.

MR. HANLEY addressed the difference between explorers and producers, which he explained through an example of how capacity on a pipeline is acquired. This pipeline will be a contract carrier rather than a common carrier. Mr. Hanley emphasized that pipeline ownership has no bearing on capacity ownership. Capacity is allocated during an open season. Typically, the pipeline owners will set the terms, the tariff, and express interest. Then an entity can sign up for capacity, which is typically a 20-year contract. The entity would be committed to pay for that capacity regardless of whether any gas moves down the pipeline. Although the aforementioned is a risk, the benefit is that the capacity is owned by the purchasing entity and no one can pro-rate that entity out of that capacity. This is important because explorers are unlikely to explore for gas before there is some progress indicating that a pipeline will happen. If the pipeline moved forward tomorrow, the open season would likely happen in a couple of years. However, it takes 3-5 years for explorers to determine whether they have a commercial gas find, which means that all of the existing capacity is likely to be taken by the existing gas holders because they have the gas and once the terms are known, they can nominate capacity. Mr. Hanley specified that the expansion tariff rate and the terms and conditions of the expansion of the pipe are probably most important for explorers. He informed the committee that the design of the pipe and how it's set up can determine the expansion rates. Typically, expansion of a gas line means adding compression rather than the pipe getting larger or adding new pipe. Furthermore, the design of the pipe can determine the terms and conditions as well as the rates of any expansion. Just adding the compression could result in initial expansions that should have a tariff rate that would be lower than the initial tariff. If the gas line is designed [to allow for expansion], explorers will have some idea that the expansion will be no more than the existing tariff and will probably be a little less than the existing tariff. However, he noted that pipelines can be designed so that every expansion is more expensive, which is of concern for the explorers.

MR. HANLEY mentioned that tariff terms are as important as tariff rates. He recalled discussion with regard to a BTU tariff versus a mcf. He explained that if [there was a change to a mcf tariff] without having a quality adjustment, one could find, on a volume basis, that the liquid heavy oils with a higher BTU content actually do better. Therefore, [the explorers] could end up at a competitive disadvantage if the tariff is set a certain way. With regard to expansion, the terms and conditions can be set such that initial pipeline owners maintain a right of first refusal on all expansion capacity. The aforementioned can stymie a competitor who would have to approach a competitor that has the right of first refusal on all the expansion capacity. If such conditions are included in the tariff, it is of concern. Mr. Hanley related [Anadarko's] view that FERC doesn't have the ability to force the expansion of a pipeline, which is concerning in a situation in which the pipeline is owned by the producers who are competitors of the [explorers].

Number 772

MR. HANLEY clarified that [Anadarko/explorers] want the lowest tariff possible and typically would prefer a flat line [a levelized tariff] as presented by Mr. Myers because a number [of explorers] already have exploration acres. A higher tariff in the beginning could mean that [Anadarko and other explorers] couldn't explore for that gas. Furthermore, it's a bit more costly in the Foothills. He related that Anadarko would incur costs as far as development and exploration that don't exist at Prudhoe Bay because the gas has already been discovered. Because of the aforementioned [Anadarko and other explorers] will be as challenged, if not more challenged than others. Mr. Hanley turned to the proposal of 4.5 bcf a day pipe, and pointed out that a penny a day would mean $45,000 a day or $16.5 million a year. Twenty cents, which may be 10 percent of the $2 tariff, can result in as much as $330 million a year. Therefore, pennies on the dollar make big differences on the netbacks.

MR. HANLEY informed the committees that there is a normal incentive to have a low tariff with a high netback. However, if it's a producer-owned pipe and the producers are aligned, there may be some incentive to shift as much profit as possible to the pipeline. There may be a producer interested in obtaining a much higher rate of return on the pipe because the producer would obtain the profit from that while reducing the wellhead value, which results in a double benefit. Reduction in the wellhead value results in the pipeline owner paying less in severance taxes and property taxes. Mr. Hanley noted that explorers have a varied interest. However, generally speaking the explorers want the lowest rate possible and want a pipeline built. In fact, often the explorers are aligned with the state's interest in trying to obtain the most revenue and the highest wellhead value. Many times the explorers are aligned with the producers, and sometimes the explorers are aligned with the pipeline owner. Typically a pipeline owner that isn't a producer isn't necessarily concerned with controlling capacity and in fact, expanding the pipe and lowering the operating cost is beneficial to them as well. Therefore, a pipeline owner that isn't a producer may be more interested in expanding the pipe sooner than a producer-owned company that may want to utilize the pipe to control capacity, which allows control of exploration. Mr. Hanley reiterated that the explorers want a pipeline to be built, the lowest possible rate, and fair and reasonable terms. He concluded by highlighting that [the explorers] believe exploration is good as is competition, and furthermore the more gas that is put in sooner will result in more people involved in the pipeline, which should lower the cost.

Number 827

SENATOR OGAN inquired as to who would be the operating partner in the areas labeled "Anadarko Partial" shown on the map provided to the committees.

MR. HANLEY answered that in some areas Anadarko would be the operating partner and in other areas it would be ConocoPhillips Alaska, Inc. Generally speaking, in Alpine and to the west in the NPR-A [National Petroleum Reserve-Alaska] area, Anadarko has interests with ConocoPhillips, which is the operator. In the Foothills region, Anadarko has state acres and ASRC [Arctic Slope Regional Corporation] acres in which Anadarko is the operator.

SENATOR OGAN highlighted that currently Alaska Oil and Gas Conservation Commission (AOGCC) has the authority to regulate the waste of hydrocarbon. Senator Ogan opined that the state has an interest in which gas is produced first because a company that owns gas in the Prudhoe Bay unit would want to sell that gas. However, it seems to be in the state's advantage to place gas that doesn't interfere with oil production in the line first because it would mitigate the decline of revenues from the oil. He inquired as to Mr. Hanley's thoughts on the aforementioned.

MR. HANLEY suggested that a model would need to be run. He said he would want to support putting in the Foothills gas first because that's where Anadarko has an acreage position. However, the state should review it because Mr. Myers indicated that the state might receive a bit lower netback on [the Prudhoe Bay unit] gas. He noted that even with a model, there would be some policy calls. Mr. Hanley mentioned that the ability to get gas in that pipeline is going to improve oil exploration economics because when one explores for oil on the North Slope one often finds gas.

Number 0872

GARTH SALISBURY, Managing Director, JP Morgan Chase and Co., clarified that he and Ms. Rohman are financial experts, and therefore both would focus on the financial aspects of building a natural gas pipeline. He utilized a booklet entitled "Interim Hearings: Alaska Natural Gas Pipeline Issues" that was provided to the committee. He began by specifying that the final outcome of a gas pipeline will be dictated by a large group of stakeholders, some of which are listed on page 4 of the booklet. Mr. Salisbury opined that current market prices certainly would support building a pipeline.

MR. SALISBURY turned to some of the assumptions he [and Ms. Rohman] used, the largest of which is project cost. The projections for the cost and scope of the pipeline vary widely. For the purposes of this presentation, Mr. Salisbury specified that he is assuming a treatment plant cost of about $2.6 billion and a project cost assumption of about $11.6 billion. He noted that he [and Ms. Rohman] have no opinion with regard to the actual costs of these facilities, the aforementioned are merely assumptions. He emphasized that the focus will be in regard to the relative differences for various financings of any given costs. Therefore, the total cost for this entire project is $14.2 billion with a throughput assumption of 4.5 bcf a day. The project life/term of debt assumption is 30 years, which is a bit conservative from a project life standpoint, although it's a bit aggressive from a debt standpoint. The assumption for the initial term is 15 years. He highlighted that any pipeline owner would want to block in shipping contracts before the contract was completed and have an idea of the tariff in order to obtain financing. The assumed project bond rating for the entire financial package is an "A". He acknowledged that many pipeline projects are in the "B," "AA," or "BBB" category, which [provide] lower rating and higher financing costs. The debt to equity ratio for the base case will be 60 percent debt and 40 percent equity. The return on the equity will be 12 percent on the assumption. Furthermore, the depreciation methodology assumes a straight line for 30 years.

MR. SALISBURY echoed earlier remarks specifying that a number of factors go into a tariff, as specified on page 7 of the booklet. Mr. Salisbury said that he would like to isolate the financing components of the tariff, and therefore he was going to focus on the cost of the project, a tax rate, contract term/asset life, and the annual throughput. For purposes of this presentation he focused on the capital expenditure, the return on the equity, whether there would be a federal guarantee on the debt, and the tax status of that debt. He clarified that he is referring to tax exempt debt rather than the tax status of the pipeline owner; this presentation will strictly refer to the tax treatment for the debt that's issued. The presentation will not focus on the operating and maintenance costs, general administrative costs, or any additional capital expenditures made to improve or expand the pipeline.

MR. SALISBURY turned to debt to equity ratios. Generally speaking, large gas pipeline projects in the U.S. range from 50-67 percent debt. Therefore, common debt to equity ratios for pipeline projects range from 50:50 to 70:30 debt to equity. For this analysis, the range assumed will be 50:50 to 67.67 and 33.33.

MR. SALISBURY went back to page 9 of the booklet regarding financing assumptions. For a base case, the capital structure will have a debt of 60 percent and 40 percent equity and the return on the equity will be 12 percent. It will also be assumed that the debt issued will be standard corporate taxable debt and that there is no federal loan guarantee. The aforementioned will be the base case from which variations will be taken. He noted that the base case incremental financing tariff, an average tariff over a 30-year project life, produced a tariff of about $0.79 MMBtu [one million British thermal units]. He returned to the debt to equity ratios, which is outlined on page 11 of the booklet. From the base case scenario, as the equity component is increased at a 12 percent return on the equity, the tariff will increase because the remaining component of that capitalization is at a much lower cost, somewhere in the 6-7 percent range. Therefore, how this pipeline is financed and its capital components are going to be very important. If the equity is increased to 50 percent, the tariff would be increased to $0.85. The analysis illustrates a couple of different debt structures, one of which is amortizing tranches, which produces a lower overall debt cost. The base case scenario uses the amortizing tranches, and therefore the debt component is about 6.4 percent under an "A" rating. Therefore, as the equity component is varied from a high of 50 percent to a low of 33 percent, the range is about $0.9. The deviation between the equity components is $1.2 billion to $1.5 billion.

MR. SALISBURY moved on to the return on the equity. He highlighted that FERC allows a specific return on the equity component in the tariff. The return normally ranges from 10-14 percent. With the base case, the $0.79 tariff is produced. However, as the equity component is increased to as high as 50 percent and the return on the equity to 14 percent, the difference in total debt and equity costs over the life of the project amounts to about $6 billion. Mr. Salisbury stated that the producers and explorers will be concerned with regard to the debt to equity percentage and the return on the equity allowed in the tariff.

MR. SALISBURY addressed the issue of tax exemption, with the focus being on tax-exempt debt, the debt issued to finance the pipeline, rather than the tax status of a producer or someone using the pipeline. He directed attention to the graph on page 14 of the booklet, which is a comparison of the 30-year Treasury rate to the 30-year Revenue Bond Index. As the graph illustrates, in higher interest rate environments, the relative spread between taxable and tax-exempt rates is higher. Over the last 20 years as rates have steadily declined on average, there has been a compression on the tax-exempt and taxable rates such that the value of tax-exemption today is worth quite a bit less than it was 10-20 years ago. On average, the spread between a 30-year taxable bond and a 30-year tax-exempt revenue bond has been about 50 basis points, one-half of 1 percent. Currently, the spread is around .3 percent. He noted that there have been a number of times when the taxable rate has been lower than the tax-exempt rate. Therefore, there wasn't much benefit to financing the taxes in that market.

Number 190

MR. SALISBURY provided the committees with a basic overview of municipal bonds. He explained that municipal bonds are debt securities that are only issued in the U.S. by a U.S. state, a local government, or a governmental entity. Municipal bonds are typically used to raise capital for building roads, schools, and other public infrastructure projects. He further explained that the exempt notion is that the interest paid to investors is exempt from income taxes. Therefore, as mentioned earlier, tax-exempt rates are generally lower than taxable rates. Since this tax exemption is considered a subsidy by the U.S. Treasury, there are strict regulations governing the use of tax-exempt bonds. Mr. Salisbury highlighted the Alaska Railroad Corporation's ability to issue tax-exempt debt for a project like the gas pipeline, which is important and unique. He specified that municipal bonds are often secured by tax revenues, although in this case the discussion is about a bond that is secured by a stream of enterprise revenues.

MR. SALISBURY turned to the reason why investors are willing to accept a lower interest rate on a tax-exempt bond. He noted that the value of the exemption is based on the tax rate of the holder of the investment, which is why certain investors are part of municipal bonds or not based on their tax rates. For example, the after tax yield of a 35 percent tax rate investor who would purchase a taxable bond at 7.5 percent would be 4.88 percent, and therefore, this particular investor would be better served by buying the municipal bond at 5 percent and paying no taxes because the net yield is 5 percent afterwards. However, the average investor who is in a lower tax bracket is better served by purchasing a taxable bond because his net yield after paying taxes is higher. Therefore, the investors in taxable bonds are generally wealthy individuals who are paying near the maximum tax rates.

Number 234

NANCY ROHMAN, Vice President, JP Morgan Chase and Co., turned to the value of tax exemption [page 18 of the booklet]. Obviously, tax exemption can significantly reduce the interest cost and the debt service on the financing. Historically, tax-exempt debt has been worth more than it is in the current market. As rates rise again, there may be a return to normal spread levels where tax exemption will be worth more. She compared the base case scenario to a tax-exempt deal and estimated that the tariff will be reduced.

TAPE 04-7, SIDE A

MS. ROHMAN said that if one were to return to the normal spread relationship, the value would be $0.04. She then turned to the advantages of tax-exempt debt, which would include lower interest costs. Furthermore, tax-exempt debt provides more structuring opportunities. In municipal finance there is the concept of "serial" bonds for which the debt can be amortized quicker over time. Another advantage is the flexible call options, which is the notion that once the bonds are issued, municipal tax-exempt debt typically provides more flexibility to restructure financing. Tax-exempt debt also provides a favorable "capital charge" and an active "retail sector." She explained that the corporate market is an enormous market that is run by sophisticated institutional investors and corporations. Because of the notion of "Bill Gates versus Average Joe", there is a very active retail sector in the tax-exempt market. A retail buyer base is an advantage because when one prices a deal, one would be dealing with a broader buyer base. Clearly, the disadvantages of tax-exempt debt are the significant tax law constraints that accompany tax-exempt debt. Furthermore, there are fewer "deep pocket" investors with tax-exempt debt because the municipal industry is a lot smaller than the corporate industry.

MS. ROHMAN moved on to the Federal Loan Guarantee, which is discussed on page 21 of the booklet. Section 386 of the Energy Policy Act of 2003 provides for Federal Loan Guarantees. Basically, [the Act] says that the guarantee can't be greater than 80 percent of the total capital costs of the project, including interest. Furthermore, the Federal Loan Guarantee is capped at $18 billion and the term of the loan agreement shall not exceed 30 years. Ms. Rohman pointed out that the Federal Loan Guarantee pledges "the full faith and credit of the United States to pay all of the principal and interest on any loan or other debt obligation entered into by a holder of a certificate of public convenience and necessity." Although she characterized the aforementioned language as a sure thing, she noted that it's not a sure thing. In terms of the amount, the Federal Loan Guarantee has ranged from $10-$18 billion. She highlighted that the Federal Loan Guarantee can have a significant impact on this financing. Since all the pipeline scenarios call for a debt to equity ratio of less than 80 percent, the pipeline may be able to issue all of its bonds with a Federal Loan Guarantee. Furthermore, the U.S. government's strong credit provides the potential for much better financing, which will reduce interest costs. The tariff with the Federal Guarantee is $0.78 [as illustrated in the chart on page 24 of the booklet]. With a $1.00 cost, she estimated $540 million. She emphasized that this is a ballpark estimate that [would change] based on the ultimate structure of the deal. "What you actually achieve in the interest rate savings is going to be highly dependent on the final structure," she pointed out. Furthermore, she informed the committees that the Federal Guarantee should be measured on the effect of the tariff reduction as well as whether the deal can be accomplished.

MR. SALISBURY interjected that the spread presented is very conservative. In the real world the magnitude of financing a $15 billion project the value of that exemption would most likely be multiples of this.

MS. ROHMAN returned to the booklet, page 25, which discusses the value of the Federal Loan Guarantee on tax-exempt debt. If the benefit of the exemption is obtained as is the Federal Loan Guarantee, the base case would stay in the same spot and the tariff would be reduced by $.04; it's the combined value of the two. She estimated a total debt cost savings of $1.8 billion.

Number 072

SENATOR OGAN related a situation in which a state entity is used to issue tax-exempt debt. He asked if it would be commercially reasonable or whether there has been precedence for the state to receive an equity interest in the pipeline in exchange for making the project more reliable.

MR. SALISBURY replied that there is very little precedent for state involvement in a natural gas pipeline. However, there are examples of state entities that have assisted utilities. Most often all of the benefit garnered by having state involvement has been passed on to ratepayers/users, such as in the case of the electric utilities. There isn't a good example in which a state exemption was utilized to garner profits for the state.

SENATOR OGAN turned to Mr. Salisbury's forecast of interest rates, and asked if he believes it's important to get the project financed as soon as practical. He also asked if Mr. Salisbury feared that rising interest rates would make the project uneconomic.

MR. SALISBURY opined that JP Morgan believes that interest rates have been and will continue to increase. However, interest rates are still very, very low. Even as interest rates rise over the next couple of years, they won't have the type of impact on this tariff that many other components do. Components such as the debt to equity ratios and the return on equity are much more important to a project such as this.

Number 111

SENATOR DYSON directed attention to page 9 of the booklet, which he understood to mean that over the projected life of the project it will cost $14.2 billion just to "rent" the money to do the construction.

MR. SALISBURY clarified that the $14.2 billion is the total project cost, which includes the estimates for the treatment plant and the "A to B" components. He further clarified that doesn't include the interest component related to the debt.

SENATOR THERRIAULT turned to the chart on page 25 of the booklet. He asked if the deviation in costs from the base case of $1.84 billion is a reduction in the total project cost or just in the financing.

MR. SALISBURY answered that it's a reduction just in the financing component, the interest costs related to the different scenarios.

Number 135

SENATOR GUESS, in reference to the chart on page 24, asked if the financing charge would increase from the base case scenario to the Federal Loan Guarantee when there is more equal debt to equity ratio.

MR. SALISBURY replied yes. He added that presumably the Federal Loan Guarantee is always going to be helpful, but that's related to the base case scenario of 60 percent debt. If it's 50 percent debt with more equity with a higher return, it will cost more.

SENATOR GUESS asked, "If you go over from that base case ... on a 50:50 Federal Guarantee to none, ... am I reading it correct that the difference between those two is an increase in finance costs of $715 million?"

MR. SALISBURY replied yes.

SENATOR DYSON recalled the [assumption] that the pipeline costs would be [$11.6 billion], and asked where the pipeline would terminate.

MR. SALISBURY answered that the pipeline would terminate at the Alaska-Canadian border, and therefore he assumes that Canada will build the pipeline to the Alberta terminal.

Number 166

WILLIAM BENHAM, Vice President, Regulatory Affairs, BP Energy Company, informed the committees that BP Energy Company is BP's North American gas and power marketing and trading business. He explained that in his role at BP he has periodically provided testimony to the FERC and on occasion before state legislatures on the subject of gas pipeline tariffs. Therefore, he is presenting testimony on behalf of BP, ExxonMobil Corporation, and ConocoPhillips Alaska, Inc., per their request. He specified that he would refer to the aforementioned three companies as the Sponsor Group. He said that he would offer a brief overview of the Sponsor Group's preliminary cost and toll estimates, the process for establishing a toll and the allocation of risks, a discussion of the differences between contract carriage and common carriage, the approval of tariffs, and a closing summary. He informed the committees that his primary background is in interstate pipeline ratemaking procedures, tariffs, and the role of the FERC. However, he noted that he has limited knowledge with regard to "the Alaska gas project specifically, and therefore his comments are designed to provide general insights into accepted tariff methodology and the role of FERC in establishing gas pipeline tariffs, as will be required for the Alaska gas pipeline." He noted that the committees should have a written summary of the key generic points covering the topics of building, owning, operating, and transporting gas on a typical gas pipeline regulated by FERC. The written summary will also review the key risk factors faced by pipelines, shippers, and producers in connection with a typical new pipeline project.

MR. BRENHAM paraphrased from the following written testimony [original punctuation provided]:

> **Preliminary Cost and Toll Estimates**
> As has been previously communicated in other forums by the Sponsor Group, we estimate the total capital cost of the Alaska Gas Pipeline at approximately $20 billion, in 2001 dollars. This figure would be somewhat higher in today's dollars, accounting for inflation since 2001. The figures I'll be sharing with you will be quoted in 2001 dollars because they refer back to the joint $125 million feasibility study

that was completed by the Sponsor Group in the 2001-2002 timeframe. That study evaluated the feasibility of constructing a pipeline from Alaska's North Slope to Lower-48 US markets by way of either a Northern Route or a Southern Route, with the conclusion that the project was technically feasible, but that the commercial risks outweighed the potential rewards. As you and we are very well aware, current State law has prohibited the State from issuing a Right of Way for a Northern Route until a Southern Route is built. My testimony will focus on the Southern Route.

The Southern Route project was estimated to cost approximately $19.4 billion, with an accuracy of +/- 20%. The components of this cost estimate were as follows:

North Slope gas treatment plant	$2.6 billion
Gas pipeline and compressor stations from the North Slope to the Alaska/Canada Border	$4.4 billion
Gas pipeline and compressor stations from the Alaska/Canada border to Alberta, Canada	$7.2 billion
Gas pipeline and compressor stations from Alberta to US market	$4.6 billion
NGL extraction facilities	$0.6 billion
Total capital cost	$19.4 billion

The capital cost estimate resulted in an estimated toll to the market of $2.39/mcf. This toll is merely a preliminary estimate of a toll that might ultimately be approved by FERC and the NEB [National Energy Board of Canada] for an Alaska gas pipeline. The ultimate toll will not be known for some considerable time, and better estimates will require more work as the project is developed.

The Process for Establishing a Toll and the Allocation of Risks

The process of developing and gaining regulatory approval of this toll (tariff rate) and having it approved by the necessary regulatory authorities is well-established in both the US and Canada. Pipeline tariff rates are a direct result of the cost of constructing and operating the pipeline. The actual formulation of the toll, indeed the entire tariff structure, (of which the toll is one component) is subject to well-established regulatory standards, with oversight provided by the FERC in the US, and the NEB in Canada.

The rate that gas pipelines will charge for transporting gas is based on what is referred to as the "cost of service". The cost of service includes components such as operating cost, maintenance, taxes, depreciation and a fair and reasonable return on capital investment that is consistent with the specific risks of the project. The return to pipeline investors, consisting of both return on the equity and the cost of debt, is determined by the risk undertaken by those pipeline investors. For example, if a pipeline investor undertakes a capital cost overrun risk, that investor might reasonably expect to be compensated for taking this risk by receiving a higher return on the equity investment that is made. Conversely, if a pipeline investor takes no such risks, the return on equity might be reasonably expected to be lower.

The specific capitalization structure, which is the measure of the relative amount of equity and debt financing, will vary by project, depending on the project risk and how this risk is allocated between the pipeline company and those that will be shipping gas on the pipeline. The capitalization structure must ultimately be within the guidelines established by the FERC and the NEB and be acceptable to any involved financial institutions. The factors which impact the relative risk of gas pipeline projects would include such items as:

- the economically recoverable reserves and deliverability;
- credit risk of customers, (the pipeline shippers);
- nature of pipeline investment (e.g. arctic, remote, etc.);
- capital cost and schedule risk allocation between shippers and pipeline owners, with the degree of risk depending on how the parties agree to share these risks, a matter which is first negotiated by the parties and ultimately approved by the FERC and the NEB.

For the feasibility study work performed by the Sponsor Group, which I referenced earlier, the Sponsor Group determined a toll using assumptions similar to those that were actually implemented on the Alliance Gas pipeline, the most recent major US-Canadian gas pipeline project. This was simply a placeholder, as it was recognized rates for this line could be different due to its specific risks. However, for the Alaska gas pipeline project, the pipeline company may choose to offer negotiated rates. In this event, shippers and pipeline owners may negotiate rates and choose to allocate risks in a different way for this specific project, with such negotiated rates of course being subject to regulatory oversight.

I would point out here that a "negotiated rate" is a term used by the FERC to describe any toll that is not tied to the maximum toll derived through the cost of service. "Negotiations" between the parties, in the traditional sense of the term, are not always necessary to establish such a rate.

I would further point out that even if the pipeline chooses to offer negotiated rates, shippers would still have the option to pay what are called "recourse" rates, these rates being based on the approved cost of service.

Both FERC and the NEB have well-established regulatory processes that balance and protect the interest of all parties, including consumers. The FERC ensures that "just and reasonable rates" are implemented, based on almost 70 years of Natural Gas Act precedent, policy and case law. However, Natural Gas Act regulation of interstate gas pipelines differs from FERC's regulation of crude oil and liquids transportation established under the Interstate Commerce Act in several important respects.

Contract vs Common Carriage

Let me briefly explain the difference between the systems of carriage on gas pipelines versus crude oil and liquids pipelines, such as the Trans-Alaska Pipeline System. U.S. liquids pipelines that provide interstate service are regulated as "common carriers" pursuant to regulations derived from the Interstate

Commerce Act. Under the common carrier regulations, shippers are not allowed to contract for specific quantities of capacity and, therefore, do not pay related monthly demand/reservation charges - payment is only for capacity utilization based on actual throughput volumes. The advantage for common carrier shippers is that they "pay as they go" on actual delivered volumes. The disadvantage is that no shipper is assured of a specific level of capacity availability. When new oil supplies are tendered for transportation on a full oil pipeline, available capacity may be prorated or curtailed among existing shippers.

In contrast, because much gas usage is closely related to critical end uses such as industrial feedstock, home heating and electricity generation, and thus needs the assurance of defined, stable capacity availability, natural gas pipelines under FERC or NEB authority operate as "contract carriers". Under contract carriage, shippers have the opportunity to contract for a reservation of available capacity on a firm, non-discriminatory, basis for a specified period of time. What we call "open seasons" are often used to ensure capacity is awarded without undo discrimination to all parties that meet the open season requirements.

In the context of gas pipelines, the term "open access" is used to refer to the opportunity to contract pipeline capacity at specific points of time under open season processes. Parties who hold firm, contracted capacity are not subject to proration at the behest of other shippers, thus guaranteeing that their production will flow. As additional capacity is needed to serve new shippers, open seasons are held to determine the interest and economic feasibility of adding new capacity.

Pipeline owners and financial lenders desire these long-term contracts for firm capacity to ensure repayment of the capital cost of building the pipeline. Without these commitments, gas pipeline projects, which by their nature involve a longer payout than oil projects, could not be financed. Shippers need the contract quantity commitment to ensure capacity is available to support their needs.

A shipper's economics are founded on the availability of the contracted capacity. In exchange for the pipeline's commitment to reserve a specified quantity of capacity for a shipper, the shipper agrees to pay a monthly reservation charge which is due regardless of whether gas is actually shipped.

The Approval of Tariffs

The FERC and NEB processes offer an opportunity to all interested and affected parties, such as the State of Alaska, to actively participate in the establishment of just and reasonable rates on pipelines in which they have an interest. FERC staff is charged with representing consumer interests to ensure that these rates are established on a just and reasonable basis. The FERC has outstanding resources and expertise and is permitted to audit the records of regulated pipelines.

Any gas pipeline project, including the Alaska gas pipeline project, can only happen if the expected tariff rate is acceptable to shippers, pipeline owners and regulators. Only reasonable, prudently incurred, pipeline capital and operating costs will be allowed to be included in the tariff. FERC and NEB procedures are designed to ensure this happens. In fact, lower pipeline costs are in the best interest of the State of Alaska, gas producers and the pipeline company, provided risks are properly allocated between the pipeline and the gas producer/shipper. This is because lower pipeline costs translate into lower rates that attract shippers to transport gas on the pipeline, and thus higher wellhead netback prices are realized, which in turn benefits both the producers and the State of Alaska. Both producers of gas, and the pipeline on which that gas is transported, need the lowest possible costs to create a financially viable project and a healthy natural gas business in Alaska, supporting a full pipeline for decades to come.

Let me just make some final comments about tariff rates. The tariff rate will be a function of many factors. Each of these factors has a certain impact on the actual rate. The chief factor, though, in determining the rate is the amount of capital cost. Obviously, the actual capital cost will not be known until the pipeline is constructed. Those capital costs are recovered over time as depreciation. It is too early in the process for the Sponsor Group to determine how the various factors that recover the capital cost and provide a return on investment will be calculated. For example, the debt-equity ratio may be affected by the existence of Federal loan guarantees. The depreciation schedule is affected by its overall impact on the toll over time. The longer the depreciation period, the lower the toll will be over time, all other factors being equal. The allocation of the risk for cost overruns will be the result of negotiations between the potential shippers and the pipeline. However, the FERC, following US Supreme Court precedent, must allow the recovery of prudently incurred costs even if those costs are in excess of the estimated costs.

To put it simply, it is still too early in the process to provide a definitive outline of the method that the Sponsor Group, or the pipeline entity, will use to establish a tariff rate.

Summary

And so to summarize, I'd like to offer these closing comments. First, gas pipeline tolls and tariffs are established as a direct result of the associated costs of constructing and operating the gas pipeline. The Sponsor Group has come up with a preliminary estimate of what these costs might be. However, if the project progresses to detailed engineering and project planning, an effort we estimate would take something like two years, this cost estimate would be refined and a more precise basis for the toll defined.

Second, any gas pipeline project can only happen when the expected tolls are acceptable to all parties: shippers, pipeline owners and the regulators. These tolls will reflect appropriate risk sharing between shippers and pipeline owners. The known resource availability, proven deliverability, and excellent shipper credit rating all serve to reduce the risks for prospective Alaska gas pipeline owners. Project risks such as cost overruns and schedule delays must still be better estimated and appropriately allocated between the parties. How these risks are allocated will be a key factor in determining the ultimate pipeline toll.

And third, both the State of Alaska and pipeline shippers will benefit if the lowest cost pipeline is the one that actually is built. FERC's and NEB's procedures are designed to ensure that only prudently incurred costs are included in a pipeline tariff, thereby protecting consumers. As I mentioned earlier, pipeline tolls and other tariff terms and conditions are established under well established principles that allow recovery of just and reasonable costs, by both the FERC in the US and the NEB in Canada. Whichever group or entity ultimately builds an Alaska natural gas pipeline, they will have to pursue the same regulatory process and be subjected to the same scrutiny.

Number 600

MR. BENHAM turned attention to the document entitled "U.S. Gas Pipelines - Key Points", which he provided to the committees. He specified that the aforementioned document provides generic points that aren't specific to the Alaska pipeline. He suggested that the committees might want to focus on Part E, entitled "**Key Risk Factors for New Pipeline Projects;**". He noted that these factors can vary with the project and may be more or less important depending upon the project. Mr. Benham highlighted the risk for the pipeline, the shippers, and the producers, which is delineated in the above-mentioned document.

TAPE 04-7, SIDE B

CHAIR SAMUELS asked if one could contract half of the volume and the other half would be the common carriage.

MR. BENHAM replied no. He explained that under the U.S. system there will be a series of parties that will have firm capacity in a pipeline. He posed a scenario in which the parties have firm capacity in the pipeline and the entire capacity is contracted out to the firm shippers. In the aforementioned situation, the firm shippers have a right to utilize all the capacity for which it has contracted and no subsequent shipper can enter and take that capacity. However, there may be situations in which not all of the capacity is contracted or all of the contracted capacity isn't being used. In such situations there will be opportunities for other shippers to make firm contracts for unsubscribed capacity or to come in and transport on an interruptible basis. Mr. Benham clarified that in US pipelines there isn't a hybrid design, that is there isn't a situation in which someone can reduce the capacity rights an existing shipper has on a line.

SENATOR BUNDE asked if Mr. Benham has any experience with state or any other governmental equity in pipelines.

MR. BENHAM replied no.

Number 660

REPRESENTATIVE GARA returned to page 2 of Mr. Benham's written testimony, which specifies that the commercial risks outweigh the potential rewards of constructing a pipeline. How would passage of the House's version of the loan guarantee impact [the Sponsor Group's] view of the feasibility of a pipeline. Furthermore, if the state sought a 10 percent equity interest, would the project be viewed as more feasible from [the Sponsor Group].

MR. BENHAM reiterated that he isn't familiar with the specifics of the Alaska arrangement, and therefore he deferred to Mr. McDowell.

Number 679

DAVE McDOWELL, Director, External Affairs - Gas, British Petroleum (BP), responded that federal legislation and fiscal incentives would reduce risk for projects such as this. However, federal guarantee loans alone wouldn't be enough to reduce risk and result in moving forward to the next phase. Mr. McDowell indicated that U.S. federal legislation, a State of Alaska fiscal contract, a clear and efficient green field regulatory process in Canada, and cost reduction are all very important. Mr. McDowell, in response to Representative Gara's second question, said that he is ill equipped to speculate on the matter.

SENATOR BUNDE remarked, "I don't mind being pioneers, but somewhere in this world someone's got a equity in a pipeline that we should learn from."

SENATOR DYSON returned to his earlier question regarding the location of the pipeline and recalled that [earlier testimony] has related that the $11.6 million will build a pipeline from Prudhoe Bay to the Alberta hub rather than to the border.

Number 707

SENATOR OGAN posed a situation in which an explorer doesn't have gas to offer during an open season, and asked if a producer-owned pipeline could open a season that's advantageous while others might not even have gas to nominate to the pipeline.

MR. BENHAM noted that such situations are faced in the U.S. He explained that generally a pipeline owner in a situation in which there may be an opportunity to increase through-put in the line looks favorably on that. If a shipper is a latecomer to the process, that shipper can gain access by approaching an existing shipper to determine whether there is any excess capacity. In fact, he recalled that the FERC and the NEB have programs that allow existing shippers the ability to release capacity to a new shipper. However, Mr. Benham highlighted that the FERC doesn't have any inherent authority to require a pipeline to expand. Historically, the economic incentives to expand have been sufficient to ensure that all shippers who want and need capacity have it available to them. The FERC and the NEB would always review whether there is concern with regard to discrimination. Furthermore, there is the Essential Utilities doctrine that would presumably come into play in such a situation. Mr. Benham opined that there are various legal and commercial avenues that would be present to allow recourse to those markets.

SENATOR OGAN characterized the situation in Alaska as unique because he believes that the capacity could be filled with existing supplies for quite a few years, and therefore potentially shut out explorers and smaller independents from exploration in the Foothills and other areas. However, the state has an interest in those areas being developed. He indicated the need to keep exploring even with the capacity that already exists. Senator Ogan noted that he wasn't completely comfortable that FERC will have the same "alignments" the state would and be as concerned.

MR. BENHAM provided the following analogy with the offshore pipelines when the sizing occurs to accommodate the expected gas production. The sizing typically isn't restricted to the shippers who are ready to produce and ship on the line at the time the line is to go into service. With the offshore pipelines, a pipeline owner will generally review the resource capability in the area to be served by that line. Often, the line will be sized to meet the needs of those ready, willing, and able to contract at the time of the initiation of operation as well as the potential for future throughput. Therefore, he suggested that a good model with regard to how [Alaska's gas pipeline] might evolve would be the pipeline network in the Gulf of Mexico.

MR. McDOWELL reminded the committees that as part of the $125 million joint feasibility study, the large diameter 52 inch line [with capacity of] 4.5 bcf a day is designed to be expandable up to 5.5 bcf a day with the addition of compression. "Certainly the line we're contemplating would be expandable as well, and it really is in everybody's interest; more volumes mean lower unit costs. For expansions it makes sense," he said.

Number 790

SENATOR OGAN inquired as to who pays for expansion.

MR. BENHAM answered that if the expansion is one that's viewed as beneficial to all the customers in the system, the FERC, in the past, has allowed those costs to be rolled into the existing costs of the system. Therefore, the rate increment for the new shipper is actually somewhat dampened because of the spreading of the costs across the existing system. The FERC has indicated that when the incremental cost of the expansion is less than 5 percent, it's automatically rolled into the existing costs of the system. However, if the incremental cost of the expansion is more than 5 percent, a test reviewing whether the expansion is beneficial to all the customers in the system occurs. If the aforementioned test isn't met, the FERC may determine that incremental pricing is appropriate. Under incremental pricing, the new shippers would be responsible for the incremental costs of the expansion or addition to the system. The FERC's policy on [expansion] is somewhat flexible in that parties are allowed to show whether incremental cost [increases] or a rolled in cost [increase] is better. He explained that under the incremental concept, [FERC] doesn't want the existing shippers to bear the cost of service that benefits only the new shippers. To the extent that the expansion of the system includes benefits that go beyond the services provided to the new shippers, there is the potential for those costs to be rolled into [the existing charges]. The impact on the new shipper will be less than it would be if the new facility was priced on an incremental basis.

Number 835

TONY PALMER, Vice President, Alaska Business Development, TransCanada Corporation, utilized a slide presentation entitled "Alaska Gas Pipeline Construction Cost Risks" as he paraphrased from the following written remarks [original punctuation provided]:

> The Alaska gas pipeline project will be a huge undertaking requiring the skills and initiative of two nations to bring to a successful in-service. The sheer magnitude of the project and its risks means that no single group can assume the entire project risk. Like all large pipeline projects, the Alaska project faces a wide variety of development and operating risks, including natural gas commodity prices, gas reserves, customer credit and capital costs. Given its scale, the Alaska project has the potential to strain the world supply of steel pipe, other pipeline materials and construction labour, particularly if the project is constructed all the way to Chicago. So, an assessment of capital costs risk is an appropriate subject for review in this legislative proceeding.
>
> The question posed by the Committee's agenda seems to suggest that capital cost overruns on the Alaska project are inevitable and that the only way to deal with those overruns is to increase the tariff. TransCanada does not agree with these assumptions. First, despite the magnitude of the Alaska project, it is not a foregone conclusion that there will be cost overruns. Second, even if there are cost overruns, such costs do not necessarily have to increase the tariff.

BACKGROUND

> TransCanada is a longstanding developer and operator of large-scale natural gas transmission systems. We undertake a systematic process to address major risks on our pipeline projects. Firstly, in stage 1, we identify the components of each particular risk. In stage 2, we quantify the risks using probability assessment. Finally, in stage 3 we attempt to mitigate the risks and assign them to the parties most capable of managing or bearing that risk. I will focus my comments on construction cost risks today.

In stage 1, although there are a multitude of small risks that will always occur on major construction projects, the principal capital cost risks for the Alaska gas pipeline are project delay and cost overruns. Under the category of project delay, subcomponents include legislative or regulatory delay, environmental delays, competition for resources, and weather. In the cost overrun category, there are two broad subcomponents, labour and materials (including steel, compressors, valves, etc.). I will speak to how TransCanada proposes to address each of these categories later in my testimony.

In stage 2, TransCanada utilizes its 50 years of experience and expertise in the high-pressure natural gas pipeline business to estimate a range of values for each quantifiable variable or capital cost line item. Expert opinions from internal and external sources such as steel companies, contractors, construction companies, etc. are solicited and compared with TransCanada's in-house database on actual results for other major construction projects in North America and internationally. Our engineering teams assess the risk distribution profile for each variable and determine a probability assessment of the outcome. We then use computer model simulations to determine P(10), P(50) and P(90) and expected value of the quantifiable risks. Then using a TransCanada economic model, we include these multiple uncertain variables, each with its own range of values and probability profile, to determine stakeholders' risks for overall capital costs.

In stage 3, we attempt to mitigate and /or assign project risks to the appropriate stakeholders. I will spend the majority of the remainder of my remarks on this section as it is the most complex and important part of the process. There are a number of ways to mitigate the project delay and capital cost overrun risks and to assign the remaining risks to stakeholders. TransCanada believes the Alaska gas pipeline can proceed now, if project stakeholders are ready to restructure the project by limiting the project to the frontier pipeline, using existing facilities and legislation where available, better matching of risks and rewards and engaging credible project proponents to construct the pipeline and manage the risks.

MITIGATION OF PROJECT RISKS

There are a number of factors, applicable to all large scale pipeline projects, that can be used to control capital cost overruns on the Alaska project. TransCanada conducts detailed engineering studies including the use of contingencies in our cost estimations. TransCanada's normal practice is to seek firm price commitments from pipe mills and contractors after completing proper planning and logistic arrangements. Project labour agreements with contractors are sought to ensure construction is not disrupted.

The route selection along the Alaska Highway provides all-weather access to work sites, winter and summer, to facilitate year-around construction, all subject to environmental windows. The availability of an all-weather road will reduce construction time and assist in logistics for the project.

In addition to these factors, there are several specific steps that TransCanada recommends be taken to mitigate the construction cost risks of the Alaska project.

Reducing the Scale of the Project

Limiting the project to the frontier pipeline would be a significant step to controlling construction costs overrun risks by reducing the scale of the project. Constructing a new pipeline from Prudhoe Bay to Alberta for approximately US$12-13 billion [2004 dollars that recognize inflation 2001-2003], connecting to an extension of the Prebuild and using spare capacity on existing infrastructure would diversify pipe and labour requirements, allow for a staged planning process and provide a broader selection of suppliers to the construction project. TransCanada would propose to retain the pipeline economies of scale by constructing a 4.5 bcf/d pipeline designed for cost effective expansion. We would, of course, be prepared to construct a different pipeline design should customer needs change.

Use of Existing Infrastructure
Once the new pipeline reaches Alberta, it should connect to existing Alberta-to-market pipeline infrastructure, supplementing when and if necessary. The existing Alaska Highway Prebuild facilities have a capacity of 3.3 bcf/d to markets east and west of the Rockies. The current total export capacity of pipelines from Alberta is approximately 15 bcf/d. Significant spare capacity is available today and is expected to be available at that level or higher when the Alaska project is in-service. Spare capacity on facilities to remove natural gas liquids is also available within Alberta. Minimizing downstream new construction from Alberta by integrating with existing infrastructure will reduce the competition for resources thereby reducing capital cost overrun risk for the project. In addition, the tariff for Alaska gas on the existing infrastructure will be lower than it would be on a newly constructed pipeline. For these reasons, TransCanada believes that Alaskans and Canadians can achieve a win-win solution by utilizing that spare capacity and constructing only the necessary facilities downstream of Alberta.

Use of Established and Tested Regulatory Framework
TransCanada also firmly believes that with a construction project of this scale and risk level, it is important to act consistently with existing legislation and treaties. The use of existing legislation provides a significant time advantage and assurance of approvals versus new contested proceedings. TransCanada's proposed in-service date of 2012, if a commercial deal is struck by 2005, is evidence of the efficiency of using existing legislation and certificates.

Canada and the United States signed a Treaty some 25 years ago setting out the principles for the transportation of Alaskan gas from Prudhoe Bay through Canada to the Lower 48. This agreement established the rights and benefits for each nation from this project. The Treaty is a fundamental foundation for the project. Subsequent to the signing of this agreement, the United States and Canada each passed legislation to expedite the project, and create a single window regulatory structure on both sides of the border. They also granted certain corporations the right to construct the pipeline in Canada and the U.S. The Canadian legislation is the Northern Pipeline Act (NPA) which granted Foothills Pipe Lines Ltd., a TransCanada subsidiary, the right to construct the Canadian section of the pipeline. Those certificates are valid and are in full effect today. Foothills utilized these certificates to construct the Prebuild sections of the Alaskan project in 1981/82 and has relied upon the NPA to expand the Prebuild five times to transport western Canadian gas in anticipation of the Alaskan project.

The United States Government passed the Alaska Natural Gas Transportation Act (ANGTA) to facilitate the construction of the Alaska Highway Pipeline in the United States. TransCanada and its subsidiaries hold the ANGTA certificates to construct the Alaskan section of the pipeline. In recent years, the ANS Producers have sought enabling legislation in the U.S. Congress as an alternative to the use of ANGTA. TransCanada believes that if enabling legislation is passed in the United States, then either ANGTA or enabling legislation can be utilized for the Alaskan section of the project.

It will also be important to leverage the use of existing rights of way to expedite the project and avoid cost overruns and project delay. TransCanada and its subsidiaries were granted the U.S. Federal right of way in Alaska many years ago and these remain valid today. On June 1, we reactivated our pending application for a right of way on State lands within Alaska. The State has commenced re-processing of our right of way application and we will continue to diligently pursue this right of way to create another valuable asset to advance an Alaska gas pipeline. TransCanada has indicated that it is prepared to convey the State right of way to another party subject to that party successfully commercializing the Alaskan section of the project and that party interconnecting with Foothills at the Alaska/Yukon border. Foothills has held a valid right of way through the Yukon for 20 years. Seeking new rights of way in the U.S. and Canada can be a time-consuming and costly process and can increase the risk of capital cost overruns.

TransCanada has had a longstanding relationship with the First Nations in Canada along the project right of way. The regulatory proceedings that led to Foothills being granted its certificates from the Government of Canada committed Foothills to provide training, employment and business opportunities to First Nations. We have communicated the long-term project benefits to communities along the pipeline and we will continue to conduct community consultations. We have commenced signing protocols with First Nations, including negotiations on participation agreements with the Kaska, one of the First Nations in the Yukon and north B.C. TransCanada will negotiate with other First Nations when they are ready to proceed.

Use of Advanced Technology

For the Alaska gas pipeline project, TransCanada has selected a pipe platform of 48" and 2500 psig to transport an initial volume of 4.5 bcf/d with an inexpensive expansion up to approximately 6 bcf/d. This pipe platform is optimal for these volumes and uses a pipe size that TransCanada has years of experience with and pipe strength of X80. TransCanada first installed X80 pipe on its system in 1994 and has since installed several hundred miles of large-diameter X80 pipe from multiple steel suppliers. TransCanada is the only pipeline company in North America that uses X80 for large natural gas transmission projects.

We have recently installed the world's first X100 line pipe (next generation of high-strength steel) in 2002 with a second installation in 2004. In early 2004, we also installed a section of X120 pipe in collaboration with ExxonMobil. TransCanada has led the development and installation of high-strength steel and is optimistic that X100 pipe may be utilized for the Alaska gas pipeline in order to lower steel and construction costs.

TransCanada has also led the advancement of large compressor installations. We have installed a 33 MW compressor in 2003 on our system in Alberta to test the size compressors needed for the Alaska Highway gas pipeline. This size compressor will lower the overall cost of the project and reduce the number of compressor stations, thereby reducing the environmental impact of the project.

TransCanada firmly believes in testing all the major components to be installed on a project of this scale before commencing construction. We are a world leader in both pipe strength and compressor technology construction and operation. We also have made significant strides with partners in advancing welding and trenching technology as well as testing pipe strength, fracture arrest, etc.

Reliance on an Experienced and Credible Developer

To construct a project of this complexity and scale, it is important that credible project proponents lead the construction and operation of the pipeline. TransCanada believes it has an unparalleled record in constructing and operating high–pressure, large diameter natural gas pipelines in cold climates.

TransCanada is a successful developer of mega-projects, world class in both scale and experience. This is well-illustrated by our massive system expansion projects of the 1990s. Our project teams directly managed large-scale Canadian facility expansion programs with costs totaling approximately C$14 billion. These capital programs included nearly 11,000 km (7,000 miles) of large-diameter pipe (30" to 48"), 2,361 megawatts of compression, and 376 custody transfer meter stations. The work stretched across the continent. The largest single project was the C$1.8 billion Iroquois project, carried out in the early 1990s. It included 1,200 km of pipeline loop and 17 MW of compression power.

We have designed, constructed and operated pipelines in virtually every type of topography of the world. Through almost 50 years of domestic experience and approximately 20 years of international experience, we have succeeded in the discontinuous permafrost of northern Alberta, the jungles of Malaysia, the prairies of southern Saskatchewan, the mountains of Chile, and the muskeg and bedrock of northern Ontario.

We operate one of the world's largest fleets of gas turbine-powered natural gas compressors. Over 90% of the total compression power on TransCanada's system is produced from 222 gas turbine drivers, ranging in power up to 32 MW, with fuel efficiencies up to 40%. In addition, at certain sites, we operate a number of electric and reciprocating compressor drivers.

Aero derivative and light-industrial-type gas turbine units are the current turbo-compressor standard at TransCanada. This type of unit allows for minimal outages for heavy maintenance or unscheduled repairs, due to their modular design and the resultant ability to change out defective modules at site. Availability rates of over 96% are typically achieved on the TransCanada fleet.

The results from a 2001 benchmark study confirm that TransCanada has been, and continues to be, the lowest cost provider of safe and reliable natural gas transmission facilities. Out of more than 1,000 of the top quartile (lowest cost) projects in NEB and FERC databases, TransCanada's total installed capital costs were lower than those of any of the competitors.

In addition to installing these facilities at the absolute lowest cost, TransCanada's overall project development efforts have been consistently on budget and on schedule. During the 1990s, our C$14 billion capital program was delivered within 0.6 per cent of the budgeted amount. Our projects were ready for service generally on or before originally scheduled dates and in no case did we experience substantial schedule setbacks. In a world where major project overruns are not uncommon, we are proud of our track record of tightly controlling schedule, budget and risk on all of our major projects. Our success can be attributed to our extensive project management experience, our ability to develop effective relationships with key stakeholders and our implementation of leading-edge pipeline technologies such as high-strength steels and mechanized welding.

ASSIGNMENT OF CAPITAL RISKS

Once the mitigation initiatives are implemented, there will remain residual capital cost overrun risks despite the best efforts of experienced pipeline companies, construction companies, regulators, shippers and governments. However, these risks do not necessarily result in higher tariffs and lower netbacks to the shippers or gas or royalty owners. The original Alaska Highway gas pipeline contemplated capital cost risk sharing by the pipeline owners. TransCanada is prepared to share that risk with other project stakeholders. We believe it is important that other project stakeholders and beneficiaries including governments share in capital cost and overrun risks to ensure an alignment of interests and to minimize the risks of project delay.

Number 224

SENATOR DYSON, referring to the chart on page 4 of the presentation, asked if the new pipe would have to go all the way to Caroline.

MR. PALMER clarified that TransCanada suggests constructing a new pipeline to Boundary Lake, which is on the border of Alberta and Saskatchewan, and extending the existing prebuild north from Caroline, as necessary, because there is spare capacity on the Alberta system.

SENATOR DYSON surmised then that the green lines on the chart on page 4 represent what must ultimately be expanded. Therefore, he further surmised that the Pacific gas transmission line would have to be expanded in capacity.

MR. PALMER confirmed that if gas is to go to California, it may need expansion. However, at this point it's difficult to determine whether there will be sufficient spare capacity to the market or markets that Alaskan gas will seek.

SENATOR DYSON asked if the same would be true from the portion from Monchy to Chicago. "That's a alternative that may or may not need to be built depending on the varieties of the market," he surmised.

MR. PALMER replied yes, adding that [in Monchy] the Northern Border pipeline was built as part of the prebuild, which has capacity of more than 2 bcf a day. There may or may not be spare capacity at the time Alaskan gas comes to market, and therefore it may need to be expanded. In further response to Senator Dyson, Mr. Palmer clarified that the Foothills agreements go to the border of the Lower 48, which is Monchy and Kingsgate. He specified that [the Northern Border pipeline] runs from Beaver Creek to Monchy, and Kingsgate.

TAPE 04-8, SIDE A

MR. PALMER, in continued response to Senator Dyson, related that the forecast is that there will be significant increases in demand for natural gas in western Canada, particularly in the areas of oil sands, heavy oil, and electric generation. Mr. Palmer informed the committees that a couple of years ago there was projected growth in oil sands gas demand to [more than] 2 bcf a day. As a result of improving technology and high gas process, the aforementioned has been reduced to 1.5 bcf a day. TransCanada believes that the McKenzie Valley gas will be used within Alberta, the market from which it will be distributed. However, he noted that it will increase the pool of gas in Alberta.

SENATOR DYSON recalled that Premier Cline wanted to ensure that any northern gas was available for Alberta's value-added processing. Therefore, he asked if Mr. Palmer anticipated that Canadian gas will meet Alberta's need for gas as a feedstock for its petrochemical industry.

MR. PALMER said that today there is a lower quality liquids stream of gas than there was five years ago, which is the nature of additional pipelines being built out of the basin to market. Furthermore, the liquids content in Alberta gas is declining. Therefore, there is spare capacity at those large plants identified on page 4 of the presentation. Mr. Palmer opined that he expected the owner's of those facilities to compete very vigorously for the removal of Alaskan liquids as the gas passes.

Number 022

SENATOR OGAN related that he has heard from various sources that [TransCanada's] tariffs are a bit on the high side. Therefore, he questioned whether TransCanada could be competitive, tariff-wise, with the proposed bullet line or the other applicants.

MR. PALMER said that he wasn't present today to identify the tolls that have been discussed with potential customers, as those are private at the moment. As the development process proceeds he said he would be pleased to discuss that. "Fundamentally, we ... believe that we will build the most competitive, cost competitive, and toll competitive project from Prudhoe Bay to Alberta.... And we're prepared to do that under different tariff methodologies that will suit the customer and the pipeline company." With regard to the tariffs from Alberta to market, if spare capacity is available it will be the lowest cost alternative and will give Alaskan gas the most market diversity, the highest netback. Mr. Palmer pointed out that from TransCanada's system the gas can either be sold within Alberta or markets from San Francisco to New York could be sought. If additional pipes are built from Alberta to market, those might result in a new single line to a particular market or they may be expansions of individual pipes. Therefore, it's difficult to predict the tolls without knowing where Alaskan gas will go. He noted that after comparing the costs of integration with existing systems versus a new line, TransCanada believes integration is a much lower cost alternative as well as a higher netback alternative for Alaskan gas.

Number 052

SENATOR OGAN commented that it would make some sense that plugging into an existing infrastructure would result in some cost savings. He recalled briefings from the Energy Council during which there has been speculation that Alberta will possibly export less gas to the Lower 48 because it will require most of the gas it produces for domestic use. Furthermore, he recalled reading somewhere that coal bed methane may be 20 percent of the gas that's exported in the near future. Therefore, he inquired as to the amount of gas that TransCanada would have to export.

MR. PALMER agreed that Alberta will consume more gas than it does today. In the [coming] 8-10 year timeframe, he predicted that Alberta gas will peak and then start to decline, in terms of supply. The aforementioned is with conventional and unconventional reserves being produced. He indicated that there [will be] a very significant demand growth in western Canada for natural gas. With increasing demand and flat to declining supply there is less gas to move through the existing pipes. However, he expected the McKenzie Valley pipeline to be in service by the end of this decade, which will [increase the supply]. That gas will be placed in the Alberta pool. Mr. Palmer opined that Canadian gas will decline significantly, in terms of supply, over the course of the next decade. Although the forecast is for unconventional supply to increase, it won't increase enough to offset declines in conventional production. Mr. Palmer emphasized that the aforementioned are forecasts, which can change. Part of the value of integrating into the existing system is that the decision regarding what pipes to build away from Alberta can be deferred by a couple of years. In further response to Senator Ogan, Mr. Palmer said that he wasn't qualified to answer how much of the liquids can be removed in Alberta.

The committee recessed until 1:33 p.m. at which time Senator Ogan reconvened the joint meeting. From this point, Senator Ogan chaired the meeting.

BILL WALKER, General Counsel, Alaska Gasline Port Authority (AGPA); Attorney at Law, Walker & Levesque, LLC, informed the committees that the AGPA was formed in 1999 by the North Slope Borough, the Fairbanks North Star Borough, and the City of Valdez. The purpose of AGPA was to cause a gas line to be built. After formation of AGPA, it applied for and received an IRS ruling stating that only the income to AGPA would be tax exempt. While the application process was occurring, AGPA put together a team to determine the viability of the project. Mr. Walker showed a slide that illustrated that the AGPA project consists of one line and two trunk lines. The main line is a LNG (liquefied natural gas) line to Valdez with a line through Canada on the Canadian Highway route and a line from Glennallen to Palmer to tie into the Southcentral gas grid. The goal is to obtain the maximum distribution of gas throughout Alaska.

MR. WALKER said that AGPA has maintained the premise that a world-class team must be assembled, and therefore AGPA met with the board of directors of Bechtel Corporation in October 1999 to present the concept of AGPA and explained that a cost estimate for the project was necessary. Bechtel Corporation put together a very detailed cost estimate for the project. He noted that Bechtel Corporation was told that with this project, cost overruns couldn't occur. Therefore, Bechtel Corporation built in cost overruns of $1.8 billion and owner contingencies of $900 million. Additionally, the corporation was instructed not to assume any infrastructure benefits on the North Slope. Furthermore, 8-10 percent inflation was included as were all the soft costs, such as interest during construction, line pack, insurance, et cetera. The aforementioned has resulted in very complete numbers. Mr. Walker noted that another member of the team is Taylor-DeJongh, Inc., which, for the third year in a row, was voted the number one investment banking oil and gas firm in the world. The information from Taylor-DeJongh, Inc. is constantly updated to provide the best available information. The other member of the team is O'Melveny & Myers LLP.

MR. WALKER informed the committees that the Alaska Gasline Port Authority filed a stranded gas application. However, subsequent meetings with the state indicated that a protocol agreement would be more appropriate, which lead to entering into a protocol agreement and withdrawal of the stranded gas application. Initially, AGPA looked at only an LNG project. He explained that the concept is project finance, which is 100 percent financed with a high debt service coverage ratio. Initially [in 2000], AGPA was advised that the project would require 1.7 and the first run on the LNG went over that. Since that time the "Y" line concept has been added in order to share the costs of the gas conditioning plant on the North Slope and 550 miles of pipe from Prudhoe Bay to Delta, where the "Y" would take place with roughly three lines to Canada and three lines down to Valdez and also the leg over to Cook Inlet. Mr. Walker noted that AGPA has met with Agrium representatives in order to discuss ways in which Agrium could have access to the gas under AGPA's concept. He said that there are approximately four benefits to AGPA's structure, each of which will impact the tariff. Mr. Walker opined that AGPA's structure will provide the lowest tariff with the maximum return to Alaskans. In closing, Mr. Walker highlighted that AGPA has worked with all parties. He mentioned that the benefit of the IRS ruling of the tax exemption is huge because it places what would normally be paid in federal taxes back into the project. Therefore, AGPA's debt service ratios are phenomenal, as illustrated on page 25 of the booklet he provided. Mr. Walker specified that the base case assumes a $3.75 price in Chicago, a $2.75 price with the LNG in Valdez. Such a base case would return a wellhead price of $1.48, which he believes to be fairly significant.

Number 236

RIGDON BOYKIN, Special Counsel, Alaska Gasline Port Authority; Attorney at Law, O'Melveny & Myers LLP, began by informing the committees that AGPA is not prepared to provide the committee with a tariff today. However, AGPA can inform the committees of the implicit tariff within AGPA's structure. He explained that the assumption is that AGPA would purchase the gas at the wellhead and sell it to the ultimate consumer. The aforementioned was in response to being told that the project cost too much and that there was no market. The only way to prove whether there is a market is to find a buyer for the gas and determine what that buyer is willing to pay for the gas. From a tax perspective, the assumption provides the maximum bang for the buck. If AGPA owns everything down to the conditioning plant, more is saved for the ultimate consumer and more is produced for the producers in terms of netback. Therefore, the focus is on the netback for the producers at various cost levels.

MR. BOYKIN turned to the benefits of AGPA. First, there is the "Y" line, which saves $6 billion in AGPA's particular cost model. The aforementioned produces significant cost advantages. Second, AGPA can sell a percentage of the debt on a tax-exempt basis. He acknowledged that the Alaska Railroad Corporation (ARRC) bonds may be used on a tax-exempt basis, although it would require a difficult IRS ruling. Therefore, it was not assumed that the ARRC bonds could be used. However, as a municipal organization, AGPA can use tax-exempt debt as long as the IRS rules on private use are satisfied. Basically, AGPA believes it could obtain tax-exempt debt for about 30 percent of the debt that would be used on this project. More than that can't be used because most of the gas is being used by private entities rather than municipal uses. The tax-exempt debt is worth between $200-$400 million a year depending upon how much is actually used. He also noted that AGPA's income is tax exempt. Therefore, the mismatch between depreciation, interest rates, and taxes is eliminated. Mr. Boykin said that most important is that AGPA is charging economic rent of $370 million for the use of this structure. He explained that 60 percent of the $370 million goes to the state, 30 percent to all the municipalities on a per capita basis, and 10 percent to equalize energy prices for communities that couldn't take advantage of the pipeline corridor or other pipeline benefits. "The net-net of this is unless our project ends up having a huge cost ... it has to be automatically the lowest cost, implicit tariff because of these advantages," he remarked.

MR. BOYKIN acknowledged that there are issues that need to be addressed; such as how should gas from a pipeline such as this be priced in state. He said there are alternatives on that. For example, the most normal way to price gas for in-state usage is to price at the cost or just under the cost of alternative fuels. Another way, albeit more controversial, would be to take Chicago prices and subtract the transportation costs to Chicago and utilize that as the in-state price. He opined that one of the largest potential benefits is if one can determine a way in which to have relative cost advantage on gas versus the Lower 48, and this is a potential opportunity for that.

MR. BOYKIN turned to the issue of cost overruns. The simple answer that most want is that the state or the producers should handle the cost overruns. However, he didn't believe that to be viable. Indirectly, cost overruns impact the producers much more than the state. Mr. Boykin said he didn't believe it would be typical for the state to undertake backstopping the cost overrun unless the cost overrun was caused by some action at the state level. If the construction is parsed into pieces, the cost of many of the pieces is certain. However, there will be some pieces for which the cost isn't known as well as the weather. Mr. Boykin informed the committees that he has performed some sensitivity studies with regard to what happens with overruns. On port authority's base case of $1.58 netback to the producers, a $4 billion overrun reduces the netback to $1.34. Therefore, he suggested that there's enough in the netback pricing to allow absorption of some very large overruns. The $4 billion overrun was on top of $2.7 [billion] of contingency. Mr. Boykin emphasized, "I think that the contingencies that you have in these things are very significant and we all ought to work our tails off to try and mitigate them. If they do materialize, though, it's not necessarily a project killer." Mr. Boykin concluded by offering to provide the committee with the results of different types of inputs that he has acquired from Taylor-DeJongh, Inc.

MR. WALKER commented that for the first time, Alaska has a distinct advantage from the market side. The stability of supply is becoming more important than it was four to five years ago. A number of companies have suggested that there should be a premium attached to the LNG from Alaska. He noted that in most joint ventures the government owns 70 percent and the private sector owns 30 percent. Therefore, the criticism that a quasigovernmental industry shouldn't be involved in this project because that's the typical way it's done. [The tax exempt status] available from the federal government makes this an extremely profitable project to all of Alaska. As page 25 of the "Alaska Gasline Port Authority February 2004" illustrates, the annual return to the state is $1-$2 billion in revenue.

MR. WALKER mentioned that AGPA participated in a round table discussion with US Secretary of Energy Spencer Abraham in Los Angeles. He informed the committees that California consumes 8.5 bcf a day of gas and Alaska reinjects about 6.5 bcf a day of gas. Secretary Abraham said there has to be a way that this need and market opportunity can be filled from Alaska. Mr. Walker acknowledged that although there are issues that have to be resolved, for once Alaska's proximity and temperature is advantageous. In fact, the last 90-120 days have been extremely active and encouraging. He noted that AGPA has entered into one memorandum of understanding (MOU) on a gas receiving facility in California. Furthermore, AGPA has met with a number of the Governor of California's advisors on a number of occasions and have been advised that the offshore [facilities] "have a leg up" with regard to the permitting process.

MR. BOYKIN explained that although AGPA is a governmental entity, it isn't planning on building an infrastructure to manage construction or operate the facility. The aforementioned would be contracted out to other parties. If [the structure proposed by AGPA] were used, the pipeline construction and operation could be managed by an entity such as Enbridge, TransCanada, or MidAmerica. Mr. Boykin clarified that AGPA is trying to create a structure and a situation that produces significant benefits that can be shared between the producers and the ultimate consumer. Mr. Boykin then emphasized the need to take into consideration the value of the liquids that would be taken down the gas line. In AGPA's model, the liquids are worth $1.75 billion per year. Furthermore, this pipeline has recently been made more viable because on the Lower 48 leg it's now possible to get some contracts on a long-term basis in Chicago, which wasn't possible as recent as a year ago. He noted that public service commissions are now pushing utilities to fix gas prices on a long-term basis and ensure access to gas on a longer-term basis.

Number 565

SENATOR DYSON related that he is quite impressed by the evolution of the process. He opined that a hub or manifold somewhere in the Interior that allows the distribution of gas to wherever the market dictates is wise. Senator Dyson noted that he was also impressed by AGPA seeing the need to bring gas to Southcentral Alaska. However, he expressed surprise that the major portion of AGPA's plan is the sale of LNG on the Pacific Rim, [which flies] in the face of other experts saying that LNG receiving facilities on the West Coast are slim to none and that the chance to compete against the very low cost LNG will make Alaska's LNG noncompetitive.

MR. BOYKIN explained that the revenue split between the two legs of the project is probably 60:40. As for the market, AGPA is pricing it at $2.75 at Valdez as the base case. The aforementioned has created a lot of interest around the world. He related his belief that there will be two to three facilities on the West Coast, regardless of what others are saying. The [O'Melveny & Myers] firm is working on three of them and the clients are spending tens of millions on the permitting process. However, he opined that those facilities in California will be offshore. For example, Crystal Energy would use an old abandoned oil platform brace, he predicted. Many of the objections about LNG would be satisfied by putting those facilities off-shore, although he acknowledged that not all [objections] would be met.

TAPE 04-8, SIDE B

MR. BOYKIN related that those heavily dependent on LNG are increasingly becoming concerned with regard to the stability of LNG from some of the countries with much unrest. Also Alaska's proximity [is advantageous] and could result in LNG swaps. In response to concerns regarding the Jones Act, Mr. Boykin emphasized that the ships cannot be produced in the time required under the Jones Act. Therefore, it is believed that a number of the provisions of the Jones Act would be waived. He noted that there has been much support on this from the maritime unions in Alaska, who have said they would work on this to avoid the Jones Act becoming an impediment to the development of LNG and the West Coast.

Number 670

CHAIR OGAN inquired as to how one gets past the [reality] that the guys with the gas make the rule.

MR. WALKER explained that the first few years of the AGPA was to acquire a relationship and gas from the producers. The focus has been to sell the gas to the market so that the price is known and work all the pieces up to the wellhead, and then make a presentation to the producers. The goal would be to make an offer to the producers that they can't refuse because the economics would be so strong. Mr. Walker opined that with the structure AGPA has, it will return a higher wellhead than the producers could achieve on their own and it eliminates as much risk to the producers as possible. Therefore, "it's basically to present on a commercial basis, an offer to purchase." The aforementioned has been done in the past with one producer, although it was probably premature because AGPA didn't have all the pieces together.

MR. BOYKIN interjected that as far as he knew no one has made a bona fide offer to the producers. Until that occurs, the response [is unknown].

Number 698

DANIEL IVES, Vice President and Principal, Lukens Energy Group, Inc., informed the committees that he is representing the Alaska Department of Law. He said he would address the specific question regarding the agreements that must be reached before FERC weighs in on tariff issues. To answer that question, he provided a brief evolution of the natural gas transportation market and new pipeline capacity planning, specifically focusing on the open season process. [Throughout his presentation he referred to a packet of information from the Lukens Energy Group, which is contained in the committee packet.] He explained that in the mid 1980s FERC issued Order 436, which [required] open-access non-discriminatory transportation for those parties that sought to provide transportation. As Mr. Palmer mentioned earlier, quite a number of market centers have been developed in Alberta. The Alaskan gas would come through the aforementioned area and flow down to Chicago through the Northern Border Pipeline, the Alliance pipeline, and the Great Lakes Gas Transmission pipeline. On the West Coast there is the PGT pipeline, which brings the volumes down to Los Angeles and San Diego. Mr. Ives highlighted that the opening up of the pipeline markets has begun to create vibrant market centers. Market centers typically have interconnections of multiple pipes and there may also be processing plants and access to gas storage facilities. All of this is the result of the unbundling of the sales and transportation of natural gas. Therefore, the market became very robust as market centers were created around the country. He mentioned the Henry Hub, which he referred to as ground zero for natural gas pricing in the Lower 48.

MR. IVES explained that with the issuance of Order 636 the open access order was taken one step further by requiring mandatory unbundling of the sales and transportation of natural gas and related services, such as storage, peaking service, gathering, and processing. As the market centers evolved, much activity has occurred with price risk management. Mr. Ives highlighted that with the implementation of Order 636, all of the pipelines in the country were required to completely redo their tariffs and implement the open-access service. The aforementioned process was managed on a settlement process basis, in which FERC was very active. He said that FERC has been very active in regulating the natural gas markets and helping to facilitate the implementation of its policies. Order 636, he noted, also provided for a capacity release program in which shippers could release their capacity. Therefore, the parties, on an open access fully disclosed basis, could offer up capacity for the highest bidder.

MR. IVES turned to FERC's Order 637 in 2000. Order 637 simply provided a number of enhancements to Order 636. For instance, the scheduling provisions for natural gas were enhanced and thus provided shippers the ability to fine-tune daily nominations. Moreover, the order provided enhanced capacity segmentation rights such that customers could take the contract path from the wellhead to the burner tip, section it off, and release the capacity to those wanting to pay for it. Furthermore, there was increased informational reporting requirements for interstate pipelines, which resulted in enhanced information for firm, interruptible, storage, and capacity release transactions and for the Index of Customers. Therefore, Order 637 provided enhanced transparency to the contracting process.

MR. IVES recalled the Natural Gas Act of 1938 (NGA), which provided for the regulation of natural gas companies. One of the provisions of NGA requires companies to obtain a certificate of public convenience and necessity (CPCN) from FERC prior to the construction, extension, or acquisition and operation of pipeline facilities. Part of the process requires the applicant to demonstrate the need for the new capacity, which is typically demonstrated by the evidence of contracts, market studies, and reserve studies. He noted that the exact process with regard to determining the need isn't mandated by FERC. Therefore, it's incumbent upon the pipeline operator or project sponsor to put together a market study to demonstrate the need for the project and that it's been offered on a nondiscriminatory basis to all.

MR. IVES proceeded to provide a quick overview of the typical FERC application process. Typically, the pipeline would hold an open season to determine a market need, then select a pipeline route and perhaps some alternative routes. The pipeline would identify landowners, start easement negotiations, and hold public meetings with the public and the various agencies involved. The environmental surveys would begin and ultimately file an application with FERC. However, FERC has modified the process such that it has implemented a process to speed up the certification process by FERC being involved earlier in the process and working with the companies on a prefiling basis. The aforementioned, he opined, would be particularly important in the Alaskan project considering the magnitude, the number of agencies involved, and the countries involved. The process is fairly complex, and therefore any help in compressing the timeline will be invaluable.

MR. IVES moved on to the open season process, which is discussed on page 8 of the booklet he provided to the committees. He explained that the open season process provides shippers the opportunity to express their interest in transportation capacity on a pipeline. The process is open to all shippers who want to provide natural gas supplies or take gas deliveries on the pipeline. He noted that many producers hold firm capacity on interstate pipelines in order to move the gas from the production area to the market centers. A number of the "LDC" type customers purchase gas at market centers rather than at the production area. He highlighted that the open season process is held at the discretion of the pipeline. At least one of the agreements filed under the Stranded Gas Pipeline Act has mandated an open season process for its application. He explained that typically the open season projects are posted on the Internet web sites of the pipeline sponsors. He recalled one of the Stranded Gas applications that he reviewed, which required that six months prior to an open season there would be notice such that the entire world would know about an upcoming open season. The aforementioned is encouraging. Pages 10-12 of the Lukens Energy Group booklet specifies what may be contained in an open season announcement, which may include descriptions of alternative projects.

MR. IVES pointed out that an alternative in the open season process would be a nonbinding letter of interest. A pipeline would "pre-float" the open season process and letters of interest are sent out for response. After that process, the full open season process would occur. He noted that new projects are typically conditioned on the pipeline's ability to timely obtain FERC certification without material modifications to the project and upon completion of the construction. The aforementioned indicates the need to have the regulators involved at all levels and very early in the process. He turned attention to page 15, which has an example of rates from an open season document for Kinder Morgan. The example illustrates that the open season was shopped with various alternatives for various levels of interest. He noted that economies of scale could be seen in the chart. He also noted that FL&U rates, the fuel use and unaccounted for gas, can be a significant factor in the era of $6 gas. The aforementioned plays into the construction of the pipe and whether one would put in more pipe or more compression.

MR. IVES moved on to precedent agreements, which is an interim contract that is a legally binding contract with terms, conditions, penalties for nonperformance, and mandates for performance. The ultimate mandate is that when FERC issues the certificate on terms that are generally consistent with the open season, the shipper will ultimately sign a service agreement at the various rates and quantities for the various receipt and delivery points. Typically, the precedent agreement outlines what the shipper wants, the path, the quantities, the agreement to enter into a service agreement, and the pipeline's agreement. Mr. Ives pointed out that there are "conditions precedent" that must be done. The pipeline must obtain rights-of-way for the route on acceptable terms and conditions, FERC's approval with the issuance of a certificate by a date certain upon terms and conditions consistent with the precedent agreement. Furthermore, the pipeline's board of director and the shipper's board of director must approve entering into the project and the service agreement, respectively. The shipper must also satisfy credit requirements, the standards for which have tightened significantly. Moreover, the project must remain economically viable. Precedent agreements also include efforts and timing, termination rights for the shipper and the pipeline, a termination fee, and other provisions. The ultimate goal is to have a project that's approved with the shipper under the service agreement under the pipeline's tariff. He mentioned that a precedent agreement would typically include force majeure, assignment, a most favored nations clause, governing law, and notices.

MR. IVES highlighted that the precedent agreements typically mirror the pipeline service agreement. In reviewing the project and whether to authorize it, FERC reviews the firm commitments by the shippers pre-construction and pre-certification in order to determine the market interest in the project. Furthermore, FERC may also have market studies done in order to review the global market versus what specific shippers are willing to purchase. The FERC may also review the supply end of the market as well in order to determine whether the project is well supported in that area. One of FERC's conditions in the filing process is that the pipeline or sponsor must file the agreements in support of the project as one of its exhibits.

MR. IVES turned to FERC's policy statement. The FERC did have a presumption for the roll-in pricing of expansions of pipelines, assuming they didn't go above a 5 percent limit. In 1999, FERC changed its presumption from roll-in pricing to incremental pricing, which essentially left the pipeline responsible for the cost of new capacity if it weren't fully utilized. With respect to project enhancements, if the incremental rate exceeds the recourse rate, then the incremental rate is charged. However, if the incremental rate is less than the recourse rate, the recourse rate is charged and the project is rolled in. If nothing bars the aforementioned, he expected that policy to be applied to the Alaskan project as well. Mr. Ives pointed out the board's goals and objectives for certificate policy, which are listed on page 23 of the Lukens Energy Group booklet.

MR. IVES moved on to page 25 of the Lukens Energy Group booklet, which discusses the certification process. He informed the committees that 18 CFR [Code of Federal Regulations] provides the basic regulations for FERC and Part 157.6 describes the general content of applications for each project. He explained that essentially one would file a mini rate case. Ultimately one would show who would pay and under what rate schedules, and the contracts that support this. Certain information regarding the applicant and landowners. Mr. Ives related a story that illustrated that FERC is very interested in what [the average citizen] thinks about running pipes. He pointed out that page 27 specifies the exhibits are required to be filed with each application. Exhibit I, market data, would contain the requirement for the contracts and the market studies to be filed as evidence that the project is bona fide. Exhibit P contains the tariff and all the effective rate schedules. Exhibit P will also provide information relating whether the proposal of a new rate is the result of negotiation, a cost-of-service rate, or the involvement of discounting. One must also consider the competitive factors and was the rate made available to all similarly situated customers. Therefore, Exhibit P is fairly comprehensive. In addition to FERC's traditional filing process, FERC has recently adopted the National Environmental Policy Act (NEPA) prefiling process in which FERC and the related agencies will be involved much sooner. He noted that many of the landowner relationships and the environmental scoping studies will be started much earlier in the project; the government will be brought in early to expedite the process, identify the critical issues, and determine how to resolve those.

MR. IVES directed the committees to page 34 of the Lukens Energy Group booklet, which has a timeline. The timeline illustrates that under the expedited process, the order is issued much earlier. In this case, about six to seven months are shaved off the process. Furthermore, the scoping studies are conducted much earlier in the process. Under the expedited process, FERC is involved in a much earlier stage of the process. After going through the entire process, FERC has wide latitude with regard to setting the terms and condition of the certificate. The FERC will review and analyze the application and supporting information. The FERC may require the applicant to make changes to the project such as alternate routing in order to ameliorate environmental and/or landowner concerns. Other changes may be in regard to configuration and sizing, based on variance in routing or design load, or rates to reflect the final costs. Moreover, FERC may require that there be a rate-refresher after a certain period of time, which has typically been three years.

Number 233

SENATOR BUNDE turned to the timeline and surmised that the worst-case scenario would result in a two-year process whereas an expedited process would be a year process. He assumed the aforementioned would relate to a typical pipeline. However, Alaska's project would be a large project that he didn't guess would be typical. Senator Bunde inquired as to the time involved in actually dealing with a project the magnitude of Alaska's project.

MR. IVES agreed that Alaska's project is of a large scale and scope. One of the factors that helps expedite the process is that this project would predominantly deal with the operations within one state versus multiple states. Furthermore, he related his understanding that FERC intends on being involved in this project early.

TAPE 04-9, SIDE A
Number 0001

MR. IVES highlighted that there have been agreements signed by Canada and the United States that will promote cooperation between the two countries in terms of expediting the project. Furthermore, he opined that any enabling legislation may put FERC under considerable pressure, either by law or by inference, to speed their process. "So I think you're going to see a 'all hands on deck' effort by the [FERC]; I do have a certain amount of confidence in them, having worked with them for a number of years," he said.

SENATOR BUNDE remarked: "But in the worst-case scenario, two to three years."

MR. IVES replied: "Yeah, I think you're right."

Number 0015

ROBERT LOEFFLER, Senior Partner, Morrison & Forrester, LLP, offered the following:

> Before I get to the assigned topic, I want to pick up on the Senator's last question. I had the privilege - or "misprivilege" - in 1974 or [1975] of going to the first of 18 months of hearings on the Alaska gas pipeline. To give you an idea of the speed of FERC at the time, it took one day and a half for all the attorneys to enter their appearances - that was just the token. Because of that, Congress intervened before to pass legislation - the Alaska Natural Gas Transportation Act of [1976] - and, indeed, the federal energy bill, and there's consensus on the so-called enabling provisions, provide essentially for a two-year process.
>
> Indeed, FERC is required to grant the certificate within 60 days, the completion of the impact statement. So if that legislation passes, Congress has provided a solution to what otherwise can be a slow process; if the legislation does not pass, [the] FERC has taken steps to improve the process from the late 1970s - much needed steps. ...

Number 0049

MR. LOEFFLER turned to the range of permissible methodologies that the FERC might apply in setting tariff rates for an Alaska gas pipeline. He specified that he is going to speak generally about the methodology and standards the FERC uses to set gas pipeline rates. He pointed out that in the appendix, there is material from a sample rate case at FERC. There is also a hypothetical illustration and a range of results in a large number of recent FERC cases that will provide some parameters. However, with Alaska everything's a little bit different, which is also true [with regard to how] FERC [deals with Alaska]. The magic standard is that of ANGTA and many other regulatory statutes, which is that the rates have to be just and reasonable. However, there's a lot of flexibility in those standards. He recalled when TAPS started operation, there was a huge controversy regarding the proper way to set the rates on TAPS and that controversy continues to this day. The good news is that gas pipeline rates are set on [a] standard utility ratemaking basis, which is "original cost" ratemaking. Still, there are a lot of details, which have some real dollar consequences with regard to what happens in Alaska.

Number 0062

MR. LOEFFLER emphasized that there are different regulatory regimes for oil pipelines and gas pipelines. For oil pipelines, dual jurisdiction exists. Therefore, the Regulatory Commission of Alaska (RCA) sets rates for shipments inside Alaska while FERC sets rates for shipments that go into interstate commerce. However, for gas pipelines FERC sets the rate for the gas that goes from Prudhoe Bay outside Alaska, and the rate for any gas that's taken off in Alaska, as long as that gas travels on the main pipeline. Mr. Loeffler remarked that the committees have probably noticed a relative absence of discussion related to the role of the RCA [because its] role will not correspond to what it was for the oil pipeline. He noted that "there's established [U.S.] Supreme Court law on that: ... once the FERC is in there, it's in there comprehensive on any rate that goes for the main pipeline, whether that gas is taken off inside or outside Alaska. There's a second consequence: for an oil pipeline to go into business or to exit the business, you do not need permission from the FERC, [but] for a gas pipeline you do." When TAPS started out, the FERC didn't have any process that corresponds to what there will be for the gas [pipeline]. For gas pipelines, one applies to FERC, which regulates the size and pressure of a gas line as well as whether it serves the public interest. Furthermore, [FERC] has a huge environmental impact process. "It's a comprehensive form of regulation," he remarked.

Number 0089

MR. LOEFFLER specified that gas pipeline regulation is the "bread and butter" of what the FERC does. "They really don't like to do very much with oil pipelines, which was one of the problems," he commented. Therefore, one must remember this framework when thinking about fighting the last war, which is the TAPS war, and fighting the wars that are to come on the gas [pipeline]. Mr. Loeffler pointed out that the [U.S.] Supreme Court has said that the FERC has very broad discretion in ratemaking; there's no single formula or combination of formulae for determining just and reasonable rates, although the original cost is the overarching thing. However, that's not true for oil pipelines, and therefore, again, there's a difference in the two.

Number 0093

MR. LOEFFLER remarked that the objective is to strike a balance between rates that protect consumers from excessive rates, and those that reward investors for the risks of investing in the pipeline. In the [Hope Natural Gas] case, the [U.S.] Supreme Court teaches that the rates should attract capital to the regulated enterprise and allow it to earn what other projects facing the same risk do. Furthermore, rates are set "in the first instance" by the pipeline rather than FERC. Therefore, the pipeline puts out a set of proposals and will file proposed rates in the open season. The FERC reviews [those], and certainly the pipeline cannot depart wildly from FERC precedent in figuring out what the rates are. Again, one must remember that there's considerable leeway in how a project will design and negotiate its rates with its proposed shippers. Mr. Loeffler returned to a point that Mr. Ives made regarding when the FERC approves the facilities. When FERC grants a certificate of public convenience and necessity, it does a mini rate review. He explained that FERC expects to have a rate case sometime [in the future], and therefore rates are set in line with FERC precedent. However, there's a lot of discretion in that FERC precedent and one doesn't get to litigate rates until later in the process.

Number 0139

MR. LOEFFLER turned to the details in setting rates, and said that it's basically a cost-plus system. The rates are designed to recover the operating costs, depreciation, taxes, and return on capital investment. This process is called, "calculation of a cost of service, or revenue requirement." He mentioned the revenue requirement set forth in appendix A. He explained that the rates are designed to allow a pipeline to recover all the costs as well as an opportunity to earn a return on the invested capital. However, most of the energy in ratemaking is spent on the following three things: determining the return/profit component; the depreciation; and the rate design. He explained that the rate of return calculation is basically one in which the commission is trying to determine the "overall cost of capital" the enterprise should receive. In order to determine the return, the cost of capital is multiplied by the rate base, which is the property devoted to public utility service. The rates are designed to capture all that return, he noted.

Number 0161

MR. LOEFFLER moved on to steps [necessary to achieve a rate]. He turned to [one of the steps] the capital structure of the asset, that is the percentage of the asset that is debt and the percentage that is equity put in by the investors. Once that's determined, the cost of each class of asset must be determined. He remarked that it's fairly easy to determine the amount of debt of a pipeline. Preferred stock goes into debt, he noted. Mr. Loeffler explained that to determine the return on equity, the earnings of other pipelines in the industry are reviewed and used to set up a proxy or standard. After the pipeline entity argues about what [constitutes] the right proxy group, the right year, and the right factors, then a proxy reference point is established. A proxy reference point is really a range of returns. However, then the pipeline entity argues that it's not an average pipeline, but rather more risky and thus deserves more. The shippers, on the other hand argue that the pipeline entity isn't risky at all and thus the pipeline entity should earn less. "That's the nature of the fight," he said. The FERC, since at least 1998, has used this discounted cash flow methodology, which is referenced on page 9 and in appendix B. The proxy idea is to review what investors in pipeline stocks expect to earn. The FERC has gone to a method that is sort of front-weighted, which places more weight on recent earnings than long-term earnings because everyone's more anxious to earn money these days.

Number 0181

MR. LOEFFLER maintained that selection of the proxy group is not a science: there's a lot of argument that goes into how you do it. Appendix [C] is a list of about 60 cases, which highlights that the rate of return on equity has ranged from 12.38 percent to 14 percent. Mr. Loeffler said he expected there could be some point of contention between the state and any pipeline project regarding what is considered the appropriate rate of return on equity. He pointed out that in the early 1980s, when the Alaska gas pipeline last made its way through the FERC, it created an incentive rate of return mechanism to try [to] control costs. The center point of that was a 17.5 percent rate of return on equity. However, that was during a time when all returns were at [a] historic high; long-term U.S. government bonds were at 15 or 16.25 percent. Although that's not today's environment, it's one reference point that he was sure someone will mention. He recalled that in the TAPS rate case, there were many arguments that it was the "first of it's kind, cold and dark, it deserved a particular sort of return." Mr. Loeffler said that when FERC analyzes the risk, it looks at various types of risk such as the risk during the construction period, the operating period, and the financial risk relating to capital structure. The aforementioned is reviewed in order to determine the right number for the risk. Whether the project is [project] financed or financed off the balance sheet is important when determining the correct rate of return or the overall return on capital for a pipeline. Mr. Loeffler explained that project finance means that it's essentially the earnings from the pipeline that will support the debt. Project financing is very common in real estate as well as in pipeline projects.

Number 0216

MR. LOEFFLER explained that typically a project-financed pipeline will borrow 70-80 percent of the cost of a project. The last time the gas pipeline went through, it was a "75 percent debt:25 percent equity" structure, he noted. He related that debt almost always costs less than equity. Therefore, if one has a lot of debt in the capital structure, the amount of the return that is assigned to debt is large and the overall amount of the return is less. On the other hand, if one has a huge amount of equity, it receives a higher rate of return, which "tends to drive up a pipeline." In reviewing pipelines that weren't project financed recently, one finds capital structures in the industry of 50 or 60 percent equity, which isn't atypically. However, in reviewing project finance, one finds much less. Although there's no universal rule as to what's acceptable, it makes a big difference in the return element. Therefore, a critical decision to ask is, how will these projects be financed: project financed with a lot debt; or financed on a recourse basis with a lot of equity?

Number 0243

MR. LOEFFLER addressed the question regarding how FERC decides whether a capital structure is appropriate, that is whether it has too much debt or too much equity. Basically, FERC reviews how the project was actually financed. [If the project was] financed, hypothetically, at the parent company level, as opposed to the pipeline company level, then FERC will say maybe it's the parent company's capital structure that should be used. However, FERC reviews whether the debt was reasonable. He noted that FERC prefers actual as opposed to hypothetical capital structures. With a hypothetical [capital structures], "it would have to construct what it thinks the world should be as [opposed] to what it is." Although FERC does this sometimes, it's rare. Now, when you actually go through the math, which this does, it's sort of interesting because what I did was take a hypothetical pipeline - million-dollar pipeline - and I have three cases.

MR. LOEFFLER directed attention to a comparison chart, which utilizes three cases for a hypothetical pipeline. The project-financed pipeline is three-quarters debt with lots of money borrowed from the bank. For the equity-rich pipeline he proposed that it's a very large, worldwide oil company worth a lot of money and with very little debt. He also proposed hypothetically that two of the three companies on the North Slope are in this position of being an equity-rich pipeline with only 10-20 percent debt. He explained that he assigned the project-financed project slightly different equity numbers because the FERC tends to look at such a project as riskier than [an equity-rich pipeline project] with the equity of a very rich company behind it. He explained that [the chart] uses the same cost of debt. Therefore, the return, which goes into the rate with the costs and depreciation, before accounting for interest on the project-financed pipeline, is $95,000. However, the [return for] the middle of the road pipeline is "about [$]105 and [$]104." Still, one has to deduct, from that return element, all the money necessary to pay for the bonds. Therefore, one finds [that] the equity-rich pipeline brings much more money home to the parent company than the project-financed pipeline. However, one must [remember that] in one case [the pipeline owner/investors] used 80 percent of their own money whereas in the other case [the project-financed pipeline owner/investors] borrowed three-quarters of the money from the bank. "So they're the two polar extremes, and that's the point of my illustration," he said.

MR. LOEFFLER directed attention to a chart that follows his prepared statements; it lists many rate cases. He said that one must not take too much comfort in this long list of cases because Alaska is the largest project to go through FERC, "and it will set it's own rules." The cases are sorted by whether the pipelines were project financed or not project financed. Therefore, one can see, in the last column, that most of the project-financed pipelines have an overall cost of capital around 10 percent. The chart further relates the pipelines that were not project financed but rather financed off the balance sheet of their owners have a higher return "on that." Although one would have to adjust for the time of the case and the particular circumstances of the corporation, it's illustrative of how the process works at FERC [and] the advantages of project financing.

Number 0329

MR. LOEFFLER turned to the question of why wouldn't everyone with the resources put 80 percent of the equity in the project. He explained that in unregulated businesses, many companies don't view 14 percent return on equity, which is about as high as the FERC has awarded in any of these cases, is not as good as they can do with other investment of their money. Therefore, some may prefer a project-finance route and thus tie up as little money as possible in this project.

MR. LOEFFLER said he needed to make a few corrections to his testimony. He provided the following qualification: "pipeline companies are allowed to earn this return after taxes, so there's a step that I omitted." A tax allowance or tax gross-up (ph) is added on top of the amount of the return so that after tax, on a hypothetical stand-alone basis, the amount earned is the identified return. "And there are a lot of dollars involved in that," he remarked. He then commented on open seasons as they apply to this pipeline and the [Congressional] legislation that provides that FERC will adopt open season regulations for this project, although normally there hasn't been anything that resembled detailed, open season regulations. He pointed out that although there are a lot of FERC rulings, they occur after the pipeline arrives when someone complains that the open season was unfair or performed incorrectly. If this legislation is passed, he predicted that FERC would be more proactive. The FERC will be required to adopt the set of regulations within 120 days of the legislation governing open seasons for this pipeline, and therefore there will be regulations in advance of open seasons for this pipeline. He noted that there are other provisions of the enabling legislation that address such issues as expansions, lateral service in Alaska, et cetera.

The committee took an at-ease from 3:25 p.m. to 3:45 p.m.

Number 0380

NAN THOMPSON, Commissioner, Regulatory Commission of Alaska (RCA), Department of Community & Economic Development (DCED), said she would be offering a historical perspective on what rate regulation on pipelines has meant under Alaska law, and her experience regarding regulating pipelines. She began by talking about the AS 42.06, which sets a standard for rates as just and reasonable and based on cost. The aforementioned statute states a clear policy that parallels the policy for rate setting on pipelines, both for utilities and pipelines across the country. That statute created a regulatory agency with authority to set cost-based rates. She related that the reason agencies like the

RCA exist at all is because utilities and, in some cases, pipelines are monopolies. Therefore, regulation is necessary to ensure that prices are fair. Agencies such as the RCA are thought of as a replacement, economically, for the market, which doesn't exist in monopoly services like utilities. "It's the responsibility of the regulatory agency in this context to look at the costs of the pipeline, or the utility, the cost of building the pipeline, and provide them a reasonable opportunity to recover their investment," she explained. The agency must review the ongoing costs and the original cost of construction in order to determine how the entity can recover a return on its investment, all of which is factored into the rates.

MS. THOMPSON said, "There isn't a perfect answer to rates." However, under the law there is a zone of reasonableness for which there is considerable case law across the country. The case law specifies that compensatory rates are those that aren't less than compensatory. In other words, the [pipeline owner/investors] are allowed a reasonable opportunity to recover costs "and they're not excessive." Therefore, RCA's role is to review the detail of the costs and strike the balance. Ms. Thompson added that AS 42.05 addresses affiliate costs, which is applied to pipelines and utilities in Alaska. When some of the costs included in the operations or construction of a pipeline are incurred by an affiliate, this statute ensures that the pipeline rates don't include any costs higher than would've been paid if those same services were performed by a third party.

MS. THOMPSON informed the committees that the RCA uses a formula to determine rates for a utility or pipeline. Basically, the return is determined by reviewing the capital structure, the cost of debt, and a risk adjustment if that's appropriate. That return is multiplied by the rate base, which is what it costs to build the asset minus depreciation. Then, the aforementioned is added to the operating expenses, depreciation, and taxes. Therefore, a rate case before an agency like the RCA is lawyers and experts presenting evidence with regard to what the numbers that get plugged into that equation should be. Therefore, the RCA uses the formula consistently to ensure that the rates are just and reasonable. She said, "It's really the determination of what those different inputs are that's the challenging part of a rate case." She provided an example. On depreciation, utility [owners and pipeline owners] are entitled to recover the costs they put into building the asset. Therefore, questions arise regarding the time period [of recovery] and the schedule [of recovery]. The RCA reviews what is going to be fair to the shippers, now and in the future. If all of the costs are recovered early in the life of the pipeline, then arguably the earlier shippers bear more of the burden than the later shippers. However, if much of the costs are recovered early, then what incentive will the pipeline owners have, in later years, to continue to operate the line, she asked. She highlighted that it's not uncommon for the expected life of a pipeline to change over time.

MS. THOMPSON turned to the litigation history of TAPS, which she suggested would probably be a good case to understand while contemplating the gas [pipeline]. She informed the committees that when the pipeline was constructed, there was a lot of dispute regarding what rates would be charged for shipment on it. The legislature became involved in hearings, and there was much fact-finding before the RCA. Litigation, in several different forums, went on for about 10 years when the parties settled. The aforementioned resulted in what's know as TSM, or the TAPS settlement methodology. Due to the statute that specifies the regulatory commission has a responsibility for just and reasonable rates, it was presented to the agency for approval. The APUC [Alaska Public Utilities Commission], as the RCA was named at the time, accepted the TSM. "They didn't approve it - they accepted it," she emphasized.

Number 0501

MS. THOMPSON added:

> They said ..., "All the parties who are here before us today are telling us this is a good idea, [and] we're not going to take the time" for whatever reason "to do the type of analysis we normally do to ensure that the rates are cost-based; we're going to accept this settlement [because] the parties agree." It was an efficiency decision. But they said, "If there's ever a protest, we're going to have to revisit this ... because we don't know ... a lot about what we're approving, we don't know exactly what some of the numbers are in this settlement, but it's okay because the parties agree."

MS. THOMPSON related that there was a methodology under which filings were made annually, with some cost information, by the TAPS carriers. The rates were adjusted based on those. In 1997 one of the shippers protested and charged that the rates were too high, and therefore the process began for reexamining [the methodology]. Eventually, there was a five or six week long hearing to gather evidence in order to make a decision. She noted that there were a lot of pretrial motions. Ms. Thompson said:

> But the difficulty in that case, which explains why the order concluding it was so long and the proceeding was so complex, was that when the original settlement was approved, they never had clear pegs for some of the numbers. The agency had not made a finding, ... for example, [that] the amount of depreciation [in] the order was just and reasonable. Nobody knew. They were ... numbers that the parties had agreed on, but the agency hadn't done what it was supposed to do ... [per] the statute in making a just and reasonable finding.

Number 0532

MS. THOMPSON explained that in order for the RCA to determine what the rate should have been in 1997 when the protest was filed, it had to determine how much of the asset the pipeline had already recovered through rates. Therefore, much of the testimony in that proceeding was reviewing a lot of detailed, historic records to determine a fair place to start from. The aforementioned necessitated deterring how the rates calculated under this TSM compared to cost-based rates, which was the directive in the statute. Upon reviewing the evidence to compare those two types of costs, it was determined that the [pipeline owners] had a significant opportunity for recovering more than the costs they had incurred to date. Therefore, the rates were set going forward.

Number 0571

MS. THOMPSON stated that the biggest adjustment was in depreciation. The [carriers] argued that what had been characterized as depreciation, the TSM filings for 20 years, wasn't really depreciation after all. [The carriers argued] that they hadn't really recovered as much as they had been identifying as depreciation over the years, and therefore the RCA should allow them to recover more. However, the agency didn't find that argument plausible and decided to use the amount that the [carriers] had already charged shippers for depreciation while using straight-line depreciation going forward. She explained that when the RCA compared cost-based rates to TSM rates, the TSM rates were 57 percent higher over that period of time, which was a rather significant difference between what the settlement methodology produced and what the RCA thought fair, cost-based rates should have been. Therefore, the RCA set the rates going forward as it would in any other rate case. "I think the importance of this case and the lesson for you when you're considering how the gas [pipeline] tariff should be set, and I think probably even the carriers would agree that going through that process is something they would want to avoid the second time, ... [is that] it was enormously expensive," she highlighted. In fact, at one point in the process the carriers were required to file litigation-cost reports because those are arguably recoverable in rates. She recalled that the last litigation-cost report was about $14 million, which is a huge sum of money that might have been more productively spent on something else. "The importance of process ... is something to think about when you're thinking about how you might avoid this circumstance again," she said. She further said:

> What that case told us is that as a result of the commission deciding, "Well, we'll just accept the settlement because everybody agrees," and they were under enormous pressure at the time from folks who had been litigating for 10 years and saying, "Look, we agree, it's all over, don't look at this," it created a problem that has taken ... it's successors many years to live (indisc.) ... [tape changed sides mid-sentence.]

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MS. THOMPSON continued [tape begins mid-sentence]: "... the settlement methodology produced. The cost based rates were significantly lower." She remarked that transparency in the process has been a problem throughout. The RCA makes sure that services provided on a monopoly basis are at a fair price and understandable to the public or anyone who has to pay those rates. However, when things are filed at settlement, often the settlement documents are not always public. Furthermore, the pipeline tariffing process is less transparent than the utility tariffing process. Ms. Thompson related her personal belief that a public process is often fairer. "Sometimes you need to have information in order to be able to file an appropriate protest or in order to be able to certainly put on a good case before us," she explained. Therefore, the rules need to be fair and allow potential shippers the opportunity to become involved in the rate-setting process while providing information about what they think is fair or not. She encouraged the committees to ask questions, explaining that reasonable rates are important because when encouraging development one needs to be think about who the shippers are in the line right now as well as the shippers who may be or want to be in the future. She also encouraged the committees to make sure that the rates are reasonable so that in the long term, development can be encouraged.

MS. THOMPSON opined that if she had been on the commission at the time the settlement was presented, she would've argued that the commission should've reviewed the settlement under the just and reasonable standard rather than accepting the settlement because everyone agreed. "It's always going to be guesswork to some extent when you're setting rates," she remarked. Under a normal utility context rates are adjusted every four or five years or if there's a major change. "You don't have to guess what the rates are going to be for 20 years, you have to guess over a reasonable time horizon, which varies with the utility, depending on what their operations are like," she said. She noted that the decision in this case is on the RCA's web site.

MS. THOMPSON noted that the other argument/discussion one may have in the context of gas line rates, is regarding comparison to FERC and why other RCA's processes are different than FERC. She explained, "There's one important significant difference between what FERC does and what we do as a state regulatory agency and that is most of FERC's pipeline regulatory structure in the Lower 48 is very different but that's because there's competition. There's often down there more than one-way to get the gas to market." However, it's unlikely that there's going to be more than one gas pipeline from the North Slope, at least in the foreseeable future. Therefore, some of the market-based rate-setting mechanisms that FERC uses probably aren't appropriate in this context because there are no competitors to discipline prices. She concluded by relating that continued enforcement of the just and reasonable rate will best ensure long-term stability in the gas market.

CHAIR OGAN said that previous speakers have testified that ratemaking is very transparent so there should be no overriding tariff issues. The FERC would regulate the pipeline while the RCA would have a seat at the table and play more of an advisory role. He asked Ms. Thompson what rate-setting mechanism she would suggest if FERC's process is not appropriate to Alaska's single gas line.

MS. THOMPSON said RCA's only jurisdiction will be over intrastate shipments – gas that comes off the line within the state. The RCA collaborated with FERC on the TAPS case and others, and the two agencies have signed a memorandum of understanding to work cooperatively on pipeline issues. She noted, as an example, the Quality Bank case has been before both agencies for many years; the RCA and FERC held concurrent hearings on the case last year. FERC and the RCA have a history of cooperation that has been somewhat institutionalized. She said the RCA has no interest in regulating interstate rates.

CHAIR OGAN asked Ms. Thompson to elaborate on her comment that FERC's regulatory process is designed for the Lower 48 where competition exists and on how it will consider the Alaska rates.

MS. THOMPSON explained:

> What I was trying to articulate was that the methodologies they use for setting gas pipeline rates in the Lower 48, not necessarily their jurisdiction over this line – I don't know how they're going to regulate this line, whether they will apply a different regulatory review standard than they do in the Lower 48 gas pipeline. But in the Lower 48, gas pipeline rates are set under a very different mechanism and there's a minimal standard of review, at least economically, because there are market forces that operate there to keep those lines reasonable - there's competition. ... The owners of the pipeline have incentives that don't exist when there's only one route to keep the rates low. I don't know what they will use to set rates for this line. That may or may not be true. I wasn't trying to draw a comparison between their regulation of this gas pipeline but more gas pipeline regulation in general.

CHAIR OGAN thanked Ms. Thompson for her presentation and service to the state. He then announced that the committee would recess until 8:45 a.m. the following morning.

[Although the beginning of the June 17th meeting starts on Tape 04-9, Side B, it was placed on a separate tape, Tape 04-9A, for ease.]