ALASKA STATE LEGISLATURE
LEGISLATIVE BUDGET AND AUDIT COMMITTEE
Anchorage, Alaska
June 14, 2006
10:07 a.m.

MEMBERS PRESENT

Senator Gene Therriault, Chair
Senator Lyman Hoffman
Senator Gary Wilken (alternate)

Representative Ralph Samuels, Vice Chair
Representative Reggie Joule (alternate)
Representative Kevin Meyer (alternate)
Representative Beth Kerttula (via teleconference)

MEMBERS ABSENT

Senator Ben Stevens
Senator Ralph Stedman
Senator Lyda Green

Representative Mike Chenault
Representative Mike Hawker
Representative Pete Kott

OTHER LEGISLATORS PRESENT

Senator Gary Stevens
Senator Hollis French
Senator Thomas Wagoner

Representative Norman Rokeberg
Representative Les Gara
Representative Berta Gardner
Representative Paul Seaton
Representative Jay Ramras

COMMITTEE CALENDAR

PRESENTATION BY ECON ONE ON THE ADMINISTRATION'S PROPOSED NATURAL GAS PIPELINE CONTRACT

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

BARRY PULLIAM, Senior Economist
Econ One Research. Inc.
Los Angeles, CA
POSITION STATEMENT: Presented information on the fiscal interest findings.

ANTHONY FINIZZA, Ph.D., Consultant
Econ One Research, Inc.
Los Angeles, CA
POSITION STATEMENT: Presented information on the fiscal interest findings.

JEFFREY LEITZINGER, Ph.D., Senior Economist & President
Econ One Inc.
Los Angeles, CA
POSITION STATEMENT: Presented information on the fiscal interest findings.

ACTION NARRATIVE

CHAIR GENE THERRIAULT called the Legislative Budget and Audit Committee meeting to order at 10:07:06 AM. Senators Hoffman, Wilken (alternate), and Therriault, and Representatives Kerttula (via teleconference), Joule (alternate), Meyer (alternate), and Samuels, were present at the call to order. Also present were Senators Gary Stevens, French, Guess, and Wagoner, and Representatives Rokeberg, Gardner, Seaton, Ramras, and Gara.

Introduction

CHAIR THERRIAULT announced that the purpose of the meeting was to hear a presentation of information from legislative consultants who have been hired through the Legislative Budget and Audit Committee.

10:08:03 AM

BARRY PULLIAM, Senior Economist, Econ One Research Inc., introduced and offered background information related to himself and each co-presenter.

10:11:22 AM

CHAIR THERRIAULT noted that he had received a number of e-mails from legislators requesting that as part of the presentation to occur over three days, there be some opportunity for roundtable discussion. He indicated that he hopes to accommodate that request at the end of the presentation, perhaps by Friday.

10:13:26 AM

MR. PULLIAM outlined that he would be covering the following issues during the morning's portion of the presentation: the modeling of the gasline, the contract and how such compares with the status quo. Dr. Finizza, he said, will cover gas pricing, investment analysis, and how the project fits into the "opportunity set" of projects. Later in the day, he noted, Dr. Leitzinger will talk about the economics of transportation. He said tomorrow morning he would readdress the issue of numbers, offering further detail. Following that, the presentation will conclude with a discussion of fiscal interest finding in general and ways to think about the various tradeoffs that are involved from an economic standpoint.

MR. PULLIAM directed attention to page 6 of the introduction handout, which lists the following three topic areas: Economics of the Gasline and Comparison to Other Projects Worldwide; Analysis of the Fiscal Terms in the Contract and How They Compare to the Current Fiscal System; and Analysis of Key Conclusions Contained in the Fiscal Interest Findings. Referring to page 7 of the handout, with the heading of, "ANS Gas is stranded," he highlighted the following key points on the page: Projects Compete Worldwide for Limited Development Resources; ANS Gas Project Involves Relatively High Transportation Costs; High Cost makes Economics Relatively Unattractive; and Other Worldwide Project Opportunities Will Take Priority. Mr. Pulliam, referring to page 8 of the handout, said state pipeline participation is needed to allow the project to hit worldwide target economics. Furthermore, fiscal certainty for gas and oil is needed to preserve the upside economics and balance potential downside outcomes. As shown on page 9, "Contract Protects the State's Fiscal Interest," he said the project will generate substantial benefits for the state, and the contract is "revenue neutral" relative to the fiscal status quo.

Returns to State and Producers

10:18:06 AM

MR. PULLIAM directed attention to the next handout, entitled, "Returns to State and Producers." He addressed the "Key Model Assumptions" shown on pages 2-5. He said his model tries to use similar assumptions as that compiled by the administration, and he said he would highlight where his model is different than the administrations. He continued:

> First off, on volumes, we used the same assumptions that the administration has: about 4.3 [billion cubic feet (Bcf)] delivered into pipeline, resulting in about 4.2 [Bcf] delivered to Alberta, [Canada]. If you went further to Chicago, that number would be about 4.1 Bcf as a result of losses.

10:22:29 AM

MR. PULLIAM said Econ One has used the same construction cost calculation as that of the administration, which, as shown on page 2 of the key model assumptions, would be $13,600 to Alberta Energy Company (AECO) and $21,000 to Chicago. The former site he characterized as the "most likely case," while Chicago is considered "unlikely." He stated that Econ One has calculated a higher capital costs than the administration has related to "finding gas further out." He said Econ One and the administration have the same pipeline commission date of 2015, with a full capacity date of 2016. He outlined the minimum Btu for low, base, and high scenarios regarding Chicago Citygate Gas, which are $4.00, $6.00, and $8.00, respectively. He said the assumption is that the pricing at AECO is approximately $0.90 below that of Chicago, which is a similar to the administration's slightly lower differential in that regard. He continued:

> As the administration has, we've assumed that gas and oil trade at a 6:1 ratio. So, for our base case assumption of $6.00 gas, that would translate into an oil price of about $36 dollars a barrel, which ..., in fact, may be a little bit low. We've assumed that [natural gas liquids (NGLs)] will be extracted from the gas - about 2 gallons per Mcf. We have also calculated the value of ... extracting those NGLs ...; under our base case assumptions we place that at about $0.12 at Mcf. This is something different than what the administration does; they do not assume ... an additional value for liquid extractions ....

MR. PULLIAM, referring to page 4 of the key model assumptions, said Econ One has assumed an inflation rate of 2.5 percent, while he offered his understanding that the administration assumes 2 percent. He relayed that ultimately the numbers will be presented in real, 2005 dollars - inflation adjusted - thus that difference will not be a "driver." As shown on page 4, he highlighted that following assumptions: borrowing costs for the purpose of building the pipeline at 5.5 percent, equity returns for the pipeline at 14 percent in the U.S. and 12 percent in Canada, a debt ration at 80 percent, tariffs in nominal terms are assumed at $1.62 to AECO and [$2.17] to Chicago, and in real, inflation-adjusted terms at approximately $0.90 to AECO and $1.21 to Chicago. He indicated that these numbers are similar to the assumptions put forth by the administration.

10:26:03 AM

REPRESENTATIVE SAMUELS asked if Econ One has figures relating to "existing pipe capacity to Chicago."

MR. PULLIAM responded, "We have assumed that in terms of when we look at the pricing in AECO; we've taken Chicago minus $0.90 as AECO value, which would then assume use of existing pipeline ...." He continued with his presentation, noting that, as shown on page 5 of the handout, the state's gas marketing costs are listed at $0.055, which matches the number the administration has used. The potential royalty-in-value (RIV) versus royalty-in-kind (RIK) difference is listed at 2 percent. Also built in is a 15 percent federal investment tax credit and a 35 percent contribution credit on the gas treatment plant (GTP) and feeder lines, and he said Econ One has assumed that "those credits would not pass through into lower tariff, thus they would accrue to benefit the owners of those facilities - the people who put the capital in place.

10:28:19 AM

MR. PULLIAM said Econ One includes the impact of incremental oil production in its model, which is one place where the company differs from the model that the administration has used. He stated:

> We have taken into account here the fact that you'll get some different oil production over time at Prudhoe [Bay], and at Point Thompson, of course, you'll get ... some oil production along with the gas development there. We've also taken into account in the out

years, as you start to explore and find gas, that there'll be some incremental oil that'll come along with that.

MR. PULLIAM, in response to a question from Representative Samuels, confirmed that the Econ One's model is consistent with the administration’s model in regard to the GTP credit not being passed through [to shippers in tariff]. He said tomorrow he would speak further regarding what would happen to the tariff and the economic if "that had to be passed through." In response to a follow-up question from Vice Chair Samuels, he stated that it is his understanding that the determination would be made by the Federal Energy Regulatory Commission (FERC), although he added that legislation passed could have an effect.

10:29:47 AM

MR. PULLIAM turned to page 6 of the handout, which shows the revenues and investment metrics analyzed under three different fiscal systems. He mentioned the SGDA proposed contract, and he said Econ One has looked at how that compares to the ELF-based system, which is currently in place. The third system listed is the PPT. He said there has been legislation in play to amend the terms of the ELF system.

MR. PULLIAM reviewed the summary of severance tax treatment under alternative fiscal systems, as shown on page 7 of the handout. The chart on the page displays the following: a nominal rate of 10 percent for ELF, 20 percent for PPT and 7.25 percent for [the Stranded Gas Development Act (SGDA)]; and an expected average ELF of minus .725 for ELF, not applicable for PPT or SGDA; a gross revenue exclusion not applicable for ELF, 0.67 for PPT, and not applicable for SGDA; a tax rate at wellhead of 7 percent for ELF, 13.33 percent for PPT, and 7.25 percent for SGDA; deduction of costs not applicable for ELF, 20 percent for PPT, and 20 percent for SGDA; and capital credits not applicable for ELF, 20 percent for both PPT and SGDA.

10:35:15 AM

MR. PULLIAM directed attention to page 8 of the handout, which he said illustrates what would happen under the various systems in the case of "new gas production." The effective tax rate for the ELF-based system would be 7.25 percent of the wellhead value. For the PPT system, he highlighted, the effective tax rate increases as prices increase; the illustrated wellhead values of $2.00, $4.00, and $6.00 result in the effective tax rates of 4.63, 6.38, and 8.70 percent, respectively. The reason for that, he explained, is related to deduction of costs. The costs are not changing as the prices are moving, thus the amount of deduction is smaller, in relative terms, as prices move up, he said. Furthermore, using the PPT system includes getting capital credit, which means not only deducting costs, but also deducting 20 percent of capital.

MR. PULLIAM, continuing with page 8, said that under the proposed contract, the effective tax rates corresponding with the wellhead values of $2.00, $4.00, and $6.00 would be minus 1.45 percent, 2.90 percent, and 4.35 percent, respectively. A lower wellhead rate can result in a negative tax rate. He explained, "What's going on here is you're fixing your ... tax at the wellhead that you're taking 7.25 percent, but you're allowed to deduct for your production costs at the PPT rate [of] 20 percent, and then you're allowed to get your capital costs. So, that drops your effective tax rate down."

10:37:40 AM

MR. PULLIAM noted that in the case of Prudhoe Bay, that kind of drop would not be seen, because there are not really any new costs there associated with production; therefore, the effective rate in Prudhoe Bay would be more like the rates under the current ELF system. He concluded, "But under a new field, where you're going to have to be ... spending money to develop a new gas field, you would get an effective lower rate than the 7.25 percent rate."

CHAIR THERRIAULT recalled that Mr. Pulliam had previously made some comparisons similar to those being shown today. One was based on the Point Thompson Field, because there was some information available regarding the expected expense of building there. He noted that Mr. Pulliam had also shown comparisons related to an "NPRA-type field," the numbers for which were estimated, because "we don't know exactly what we found out there." He asked if Mr. Pulliam blended together that information to come up with "the new gas production."

MR. PULLIAM answered yes, saying the information in the handout currently before the committee is hypothetical and uses the same numbers that have been used "for a new gas field coming on line." He said that means about .35 cents per NCF capital costs and .15 cents in operating costs.

10:39:05 AM

REPRESENTATIVE SAMUELS asked Mr. Pulliam to confirm that if the gross revenue exclusion (GRE) were to disappear, the effective tax rates would increase.

MR. PULLIAM answered that's correct.

REPRESENTATIVE SAMUELS observed, "On your proposed cases ... you're using, in your model, four, six, and eight Chicago, and then at wellhead you're going two, four, and six." He indicated that the Chicago example [from the key model assumptions shown on page 4] shows an amount of $2.17. He asked, "What happens to the .17 cents then in your model ...?"

MR. PULLIAM clarified:

> This is simply for illustration here. ... The [$2.00, $4.00, and $6.00] here do not correspond necessarily to the numbers used in ... the modeling. In the modeling, we'll get a wellhead net back that is equal to the price at the sales point, minus the tariff cost, and whatever that is, that's the one we'll value.

CHAIR THERRIAULT asked Mr. Pulliam if he would be able to plug in some of the parameters related to the last two versions of the bill - one by the Senate and one by the House - and "run the numbers" fairly quickly.

MR. PULLIAM answered yes.

10:41:09 AM

MR. PULLIAM, returning to his presentation, directed attention to page 9 of the handout, which shows estimated project revenues to state and municipalities using a base $6.00 gas case. He said that in this model, the assumption has been made that the project would be constructed to Alberta, Canada, and there would be "gas blowing through existing or extended lines from there." The top section of the page shows the dollars to the state in various categories in "2005 dollars." The bottom section of the page, he noted, shows the numbers in net present value (NPV), using an 8 percent discount rate for the state. He said the administration's modeling used 8 percent for state and 6 percent for municipalities; however, Econ One used 8 percent for both "as a simplifying assumption for the entire revenue stream."

REPRESENTATIVE SAMUELS asked if the assumption on the $6.00 Chicago gas is also the assumption used in the administration's model.

MR. PULLIAM replied that the administration has used several different numbers. He offered his understanding that the administration’s "base case" was [$5.50], and he stated, "When I get through here, I'm going to have a [$5.50] ... case here as well, for purposes of comparing." Mr. Pulliam explained the terms on the page 9. He said gas revenues, including royalties and severance taxes, equal all the cost that the state is going to have to bear. Regarding the negative amount shown for the GTP and feeder credits, he said that reflects a 35 percent allowance on the capital for those facilities. The fourth row - "Revenue Before Oil Effects" - includes pipeline investments. Oil effects, he explained, relate to the amount that's due the incremental oil production.

10:45:09 AM

MR. PULLIAM said the sixth row - "Revenues Before P/L Investment Income" - totals all the "upstream" income, as well as property and income tax, before getting to the category of pipeline investment income, which is shown in the seventh row.

MR. PULLIAM turned to page 10, which shows the estimated project revenues to the state and municipalities, using a base $6.00 gas case. He explained that the two columns on the page show a comparison between the proposed contract and the PPT-based system. The numbers go up in the PPT system, he noted, which is a result of the fact that there are generally higher tax rates as well as cost deductions such as the upstream cost allowance. In row 3, he highlighted, there are no "GTP/Feeder Credits" for the PPT. The oil effects are about the same. As shown on row 7, there would not be any pipeline investment income for the PPT, unless the state was to become an investor in a pipeline. As on the previous page, he relayed, the bottom of page 10 shows the NPV associated with the same items.

10:48:05 AM

MR. PULLIAM directed attention to page 11 of the handout, which again shows the estimated project revenues to state and municipalities, with a base $6.00 gas case, but this time adds the ELF-based system to the comparison. He observed that the numbers shown in the ELF-based system column are "a little bit lower and a little bit closer to the proposed contract." There are no feeder credits or GTP credits or some of the cost allowances in the ELF-based system. Furthermore, the oil effects are smaller, because there are no PPT rates on oil under the ELF-based system.

MR. PULLIAM pointed out that page 12 of the handout - a continuation of the estimated project revenues to state and municipalities - shows a line-item comparison of the proposed contract and the PPT-based system, both in 2005 and NPV terms.

10:49:24 AM

MR. PULLIAM said page 13 of the handout continues the comparisons, adding in the difference between the proposed contract and the ELF-based system. Consistent with previous discussion, he noted, the tax rates are lower under the ELF-based system, thus the difference would be smaller. Mr. Pulliam said that on page 14 of the handout, he "turned those differences into percentages" to make it "easier to grasp." On page 14, he noted, columns four and five show the percentage difference for each line item for the PPT-based system and ELF-based system, respectively. He offered further details.

10:51:24 AM

CHAIR THERRIAULT asked, "On column one, ... that pipeline investment income, ... what calculation is behind that $1.2 billion?"

MR. PULLIAM answered, "$1.2 billion in investment income that the state would earn as a result of owning part of the pipeline." In response to a follow-up question from Chair Therriault, he explained, "This is in 2005 dollars, over ... the first 30 years of pipeline operations." He continued:

> I've broken that out as a separate piece so you could look at these effects, both before a pipeline investment and after. ... I think before a pipeline investment gives you a little more apples [to] apples comparison, because the pipeline investing ... is ... a return on something ... you're putting your money into, as opposed to just return on the gas and hydrocarbon resources.

10:52:33 AM

MR. PULLIAM returned to his presentation, directing attention to pages 15 and 16 of the handout, which show the differences and percentage differences, respectively, for the estimated project revenues to state and municipalities, using a low $4.00 gas case. He continued:

> What you find is that at lower prices, the percentage differences are a little bit higher than they are at higher prices, and that's because you've got some fixed costs that you're going to bear under the contract, like upstream cost allowances [and] GTP credits that are not going to vary with prices. So, at lower prices, the difference between a the [proposed] contract and ... either of the other two systems will higher ... on a percentage basis,.[while] at higher prices it'll be lower.

MR. PULLIAM said pages 17 and 18 of the handout show the differences and percentages, respectively, using a high price scenario of an $8.00 gas case. In that scenario, he relayed, the percentage differences drop relative to the lower prices. Mr. Pulliam turned to page 19, which shows the aforementioned comparisons, using a gas case price of $5.50, which is the price the administration has used for its base case. He stated:

> We find a little bit higher difference than what the administration has in its results. This is due to a couple of reasons. One, we have included oil impact in our model. In addition, there is a difference in the treatment of costs for new gas development. In the administration’s work, they have not included those gas costs as a deduction against the gas revenue. Instead, they have assumed those are just costs that are going to be deducted ... - oil tax under the PPT. So, there's a difference in the treatment between what the administration does (indisc. -- street noise) with what we have, as far as new gas ... development. The administration essentially puts the gas cost on against the oil, and what we've done, for purposes of new gas coming on, is we have allocated a portion of the cost based on the ... oil and gas production coming out of the field. So, for instance, Point Thompson is going to be producing somewhere between 80 and 85 percent of that as a gap. New ... gas fields that are coming on ... are also expected to be about 80-85 percent gas. So, in looking at gas development costs ... of those

> fields, we have put that same percentage ... as cost against the gas revenues, and then the balance against the oil.

10:56:50 AM

CHAIR THERRIAULT said there had been discussion in the Senate questioning if the "build-out" cost gets subtracted against the oil stream, resulting in the gas being cost-free and "you just split them according to the ratio that you think the production off the field is going to bear."

MR. PULLIAM said that's right. He stated that Prudhoe Bay is not going to incur many, if any, incremental costs, but Point Thompson will require significant costs to develop. Furthermore, the new gas will have to come from a new field. He continued:

> The work that the administration has done has assumed that those are largely gas fields, with mostly gas production coming out of them, with some associated oil. So, we have put the cost proportionate to the barrel of oil equivalent of gas versus oil. We've also included here, in the analysis, ... the oil effects ..., so, if you include those oil effects in there, it counted for all the costs regardless of whether it's oil or gas.

REPRESENTATIVE SAMUELS directed attention to page 19, and noted that in the row showing "Oil Effects," [on line 5 of the section pertaining to 2005 dollars], the amount shown under the column for the ELF-based system is lower than the amounts in the columns for the proposed contract or the PPT-based system. Compared to that, he noted, the "Oil Effects" amount shown [on line 5 of the section pertaining to the NPV] is greater in the column for the ELF-based system than for the proposed contract or the PPT-based system. He asked if that has to do with upfront costs.

MR. PULLIAM responded, "It's because of the deduction that you allow." He continued:

> Typically, ... [when] you're thinking about a development of a field, the costs are going to come up front. So, on a net present value basis, you're going ... to be paying more early, which is one of ... the attractions, of course, of the PPT system, for

> encouraging develop[ing] and investment, is to allow those deductions up front and help the economics.

REPRESENTATIVE SAMUELS, in response to Chair Therriault, clarified his previous question. He said he had assumed that the higher amount under "Oil Effects" in the ELF-based column for the NPV was due to the upfront costs at Point Thompson for development of the credit system.

MR. PULLIAM reconfirmed that's correct. He offered further details.

11:00:11 AM

REPRESENTATIVE SAMUELS spoke about choosing to raise the tax rate but not invest in the pipeline company, thus getting money from the gas, not the pipeline company, and he indicated that this would increase the risk factor. He stated, " I understand the risk of the cost overruns and all that kind of stuff, but generally you're going to make your 12 or 14 percent, or whatever (indisc.) until you've got a steady cash flow, as opposed to taking all the market risk on the gas itself."

> If you took that pipeline investment income, and instead of choosing to invest in the pipe, you ... chose to take your money -- if you say, "I want 'x' amount of money total," and instead you chose to raise the tax rate but not invest in the pipeline company, and get your money - you want your money from the gas and not from the pipe co. - you would also, though, increase your risk, and in my view, the pipe co. money is just going to be instead of the pipeline company makes their money -- you know, I understand the risk of the cost overruns and all that kind of stuff. But generally you're going to make your 12 or 14 percent, or whatever (indisc.) until you've got a steady cash flow, as opposed to taking all the market risk on the gas itself.

MR. PULLIAM said he does agree that the revenue stream from the pipeline is less risky than from (indisc. -- overlapping voices).

REPRESENTATIVE SAMUELS asked, "Just on the financial side of things, if you want to take some of your money and mitigate your risk by buying 'pipeco,' is that incorporated into these numbers at all, to where that risk factor -- because now you've mitigated some of the state's risk - the market risk - with gas?"

MR. PULLIAM responded that he does not know that "mitigation of the risk" is the correct point of view to have. He said he thinks there is merit in the state's having investment in the pipeline. However, he said the state needs to think about the return being consistent with the risk of the investment, and that consideration has to be made against the alternatives.

REPRESENTATIVE SAMUELS asked if Econ One's model takes into account how much risk the state is willing to take.

MR. PULLIAM replied that there is no separate component in the model reflecting a risk differential, other than to recognize the investment revenue. He said the administration has done that, as well in its fiscal interest findings, where it is possible to find where the investment income on the pipe is and discern how that is separate from the revenues on the gas. He said, "I have not seen anywhere in there where ... they've tried to quantify or suggest that they would rather take ... the pipeline return as opposed to return on more risky upstream ..."

11:04:36 AM

MR. PULLIAM returned to his presentation, noting that page 20 of the handout shows "those numbers in percentages." Page 21 shows the estimated revenues and investment metrics for producers, using a base $6.00 gas case for the proposed contract. He related that he has broken down that category into "Upstream," "Midstream," and "Combined Upstream and Midstream" investments. He said the chart on the page follows the format of previous pages, but adds a few more components. The categories displayed for each of the three aforementioned investments are: revenues in 2005 dollars; NPV with a 10 percent discount rate; NPV divided by the barrel of oil equivalent (BOE) at production; profitability ratio; and the internal rate of return (IRR), shown in percentages. Mr. Pulliam reviewed the numbers on page 21, noting that the numbers for the midstream investment are considerably lower. He explained, "That's because it's just a regulated ... pipeline. It's going to earn a tariff consistent with the cost of capital for a regulated pipeline, and that cost of capital is going to be pretty low if you have a high debt ratio and a fairly low debt cost." The combined upstream and midstream investments mirror the results the administration chose in its work, he said, and that combination would have higher revenues and a little bit lower NPV.

11:09:28 AM

MR. PULLIAM, in response to a request for clarification from Chair Therriault, stated that the investment in the pipeline that is contemplated and set out in the fiscal interest findings will be funded at 80 percent debt. In fact, he added, it is contemplated that the pipeline company will seek a federal loan guarantee on that debt, which will afford it "pretty attractive financing." He said, "We've assumed 5.5 percent, which is about 3 percentage points over expected inflation." He said he thinks that is realistic, given the backing of the federal guarantees. He noted that the interest payments on the pipeline debt are deductible, which has an additional favorable impact on costs. He stated, "It's contemplated that 20 percent of the pipe will be financed with equity - ... nondebt sources. In the U.S., Burke, Inc. would allow something like a 14 percent return, and then Canada, a little less - the NEB something like a 12 percent return. Combine all that and you get a weighted average in the low 6 percent range."

CHAIR THERRIAULT said he wanted it clarified that the 12 to 14 percent that will probably be allowed by the FERC will just apply to the equity portion - the portion related to debt.

MR. PULLIAM relayed that the notion behind FERC regulations is that they will allow a return consistent with the weighted average cost capital, thus it will incorporate the debt financing, which is low-cost, and the equity financing, which is high-cost.

11:12:04 AM

MR. PULLIAM turned back to his presentation, directing attention to page 22 of the handout, which adds to the estimated revenues and investment metrics for producers, at a base $6.00 gas case, the PPT-based system. That system, he reviewed, has higher tax rates and does not have some of the cost reductions that the proposed contract has. Furthermore, there is no provision in the system whereby the state would own a piece of the pipe; it is 100 percent producer-owned. As a result, in the midstream section of the page, higher revenues are shown. The combined upstream and midstream investment, which is reported in the fiscal interest findings, shows a little bit lower total revenue, lower NPVs and lower IRR. The chart on page 23 of the handout adds in the ELF-based system for comparison. Under the combined upstream and midstream investment, he pointed out, there is a little bit higher NPV and IRR under the ELF-based system. The chart on page 24 of the handout adds to the previous charts' information the proposed differences between the PPT-based system and the proposed contract, while page 25 highlights the differences between the ELF-based system and the proposed contract. He offered further details.

11:14:27 AM

MR. PULLIAM said the chart on page 26 turns the previously compared differences into percentages. Under the combined upstream and midstream section, the ELF-based system has an NPV about 10 percent lower than the that of the proposed contract, while the PPT-based system has an NPV about 16 percent lower than the proposed contract. Moving on to the chart on page 27, Mr. Pulliam explained that it shows [estimated revenues and investment metrics for producers], using the low $4.00 gas case. Page 18, he noted, shows the percentages for the $4.00 gas case. He explained that with the low price case, the percentage differences are higher due to some of the features of the proposed contract, which allow credit and cost deductions that are not variable to price. He explained, "So, at lower prices, you're going to provide a higher change on the [market potential value (MPV)] under the ... proposed contract." The chart on page 29 shows a high $8.00 gas case, and the chart on page 30 "turns that into a percentage difference." He said, "At the higher prices, the percentages are lower."

11:17:15 AM

MR. PULLIAM directed attention to the charts on pages 31 and 32, both of which show the estimated revenues and investment metrics for producers, using the $5.50 gas case included in the fiscal interest findings.

11:18:09 AM

MR. PULLIAM turned to the issue of cost overruns, which he said are also called cost sensitivities [shown on pages 33-38 of the handout as estimated total returns to the State of Alaska and Municipalities]. Page 33 assumes an asymmetrical distribution, showing figures ranging from a 10 percent cost decrease up to a 50 percent cost increase. He stated, "It doesn't mean you couldn't have less of a ... decrease, but this is the kind of pattern that's included in the fiscal interest finding." Revenues to the state are shown under the proposed contract in columns 1 and 2, under the PPT-based system in columns 3 and 4, and under the ELF-based system in columns 5 and 6. He stated, "While the numbers are higher in the PPT system and the ELF system, relative to the proposed contract, it changes relative to ... cost increases. You don't have that big of a percent of change to the state revenues as costs move around." He pointed to the figures in the lower half of page 33, under the heading, "NPV (8)," and said, "Those differences get larger relative to the other two systems, and that is because ... in large part you are providing capital credit to the GTP and the Point Thompson feeder, so those ... costs go up if you provide a higher ... amount of credit up front."

11:20:24 AM

MR. PULLIAM directed attention to the chart on page 34, which shows the same pattern of figures, but with a $4.00 gas case scenario, which results in higher percentage differences due to cost increases. He explained, "That's because you've got less of the revenue coming in from gas; less of it is priced sensitive with gas, so you'll have ... [a] bigger percentage decrease with cost overruns under a low-price scenario." Referring to the chart on page 35, he said, "You would have a smaller decrease ... with higher prices. So, you get more of your revenue coming in that's price sensitive; as costs go up, the impact is less at higher prices."

CHAIR THERRIAULT asked what is being tracked in column 2.

MR. PULLIAM answered, "Column 2 is the percentage difference in state revenue relative to the cost as projected." He offered further details.

11:22:37 AM

MR. PULLIAM turned to the chart on page 36, which shows cost sensitivities related to estimated producer economics, [using a $6.00 gas case]. There are three columns: the proposed contract, the PPT-based system, and the ELF-based system. Each column is divided into: revenues and the percentage of change from that projected. He stated, "As you're putting out more cost up front, the impact on your NPV is higher ...."

11:24:30 AM

[The following discussion is inaudible, but essentially was repeated for the benefit of those who could not hear it initially.]

SENATOR HOLLIS FRENCH, Alaska State Legislature, regarding the chart on page 33, observed that under the heading of 2005 dollars, with a 50 percent increase in costs, the decrease for the state is 6.7 percent. He compared that to page 36, where he observed that under 2005 dollars, the same value of a 50 percent increase in costs comes to minus 3.9 percent, which is almost half the amount. He asked if he is reading that correctly.

MR. PULLIAM responded yes. He continued:

> There's two things going on: One is, ... under contract you're providing credit for some of the capital that's being put in, like ... the GTP and at the feeder line - the 34 percent contribution credit. And so, as costs go up, ... the state's going to be putting out a bigger share of that. ... The other thing is, when I'm looking at the state revenues, I'm looking at those all after financing, and so on all of these I'm looking at what's the net factor to the state after financing. When I'm looking at the producer numbers, these are all consistent with the way that ... present in the fiscal interest findings and the way you look at these investment metrics; they're all prefinancing revenue streams.

SENATOR FRENCH said he thinks it is important for people to keep in mind that a cost overrun affects the state worse than it affects the producers.

11:27:51 AM

MR. PULLIAM returned to his review of the chart on page 36 to note that each of the different investment metrics are laid out to show how they change with a change in costs.

MR. PULLIAM, in response to a query from Representative Samuels related to Senator French's prior question, explained, "The discount rates that are used for the state are 8 percent; the discount rates that are used for industry are 10 percent. So, ... if you have higher cost up front, you're going to have (indisc. -- street noise)."

11:29:46 AM

MR. PULLIAM, in response to further comment by Representative Samuels, said, "If you include the capital of the pipeline, and look at it on an integrated basis, given the higher discount rate that's used, you'd get a bigger decrease."

11:30:31 AM

REPRESENTATIVE NORMAN ROKEBERG, Alaska State Legislature, stated his understanding that the state and the FIF were using the state 5 percent discount rate, not an 8 percent.

MR. PULLIAM responded:

> Actually, ... the state ..., in different sections of the fiscal interest finding, ... use 8 percent where they ... look at the state impacts of the front section, and then later on, they switch and use a 5 percent rate. And in both ... cases they say it's an appropriate rate, so there's a bit of an inconsistency there. We have used the 8 percent rate, which is, in our understanding, is consistent with the opportunity costs - the funds for the state. We think [it is] a more appropriate rate than the lower 5 percent rate.

REPRESENTATIVE ROKEBERG said:

> I come down on the side of the state's expectations of returns on the lower ranges, in terms of the cash flow. ... It's very hard to equate the state as an entity to a private sector entity in terms of their return investments and their capitalization rates when you build a band of investment-type theories, or whatever you're going to use to establish a cap rate, it's different animal. I just would hope that the statistics are consistent, is all; and there seems to be some inconsistency.

11:32:24 AM

REPRESENTATIVE SAMUELS asked if using the 10 percent rate, as shown on page 36, is a typical industry standard.

MR. PULLIAM answered yes, certainly for looking at upstream investment opportunities. Midstream opportunities, he said, would be a different matter, because as a regulated asset there typically is a lower return set.

11:33:07 AM

MR. PULLIAM directed attention to the slide on page 37, which shows the same metrics, but at a lower, $4.00 gas case. He stated, "Of course, at lower prices, the impacts are going to be greater, because you don't have as much gap income to support the investment." Slide 38, he noted, looks at the same metrics, but uses a higher, $8.00 gas case, and there, the differences are smaller, he said. More of the revenue is being driven by higher gas prices, he added. Mr. Pulliam turned the chart on page 39, which shows "Government Take." He said, "We have looked at government take here for the State of Alaska, and for all governments, and we've done it using 2005 dollars." Under the "All Governments" section of the page, he noted that under the proposed contract there would be a slightly progressive government take. The government takes would be higher under the PPT-based system, with a little bit of progressivity. The ELF-based system, he said, would be a slightly regressive system. He noted that the numbers shown on page 39 are a slightly different that but not far off from the numbers found in the fiscal interest findings.

11:36:49 AM

The committee took an at-ease from 11:35 a.m. to 11:41 a.m.

What Natural Gas Prices Should Be Used?

11:41:14 AM

ANTHONY FINIZZA, Ph.D., Consultant, Econ One Research, Inc., said this portion of his presentation will attempt to back up the gas price numbers used in Mr. Pulliam's analysis, speak to gas markets, and establish price distributions that will be used in follow-up analyses of the FIF. He stated that gas prices are the most important variability in the metrics being discussed, as well as the most difficult to forecast.

DR. FINIZZA directed attention to the handout entitled, "What Natural Gas Prices Should Be Used?" He noted that the chart on page 2 of the handout shows that Alaska gas, along with LNG, will be a feature of U.S. gas supply over the next several decades. Alaska, he related, is projected by the EIA to make up 6.5 percent of the total gas supply to the U.S. [between 2016-2030]. As shown on the chart on page 3 of the handout, he said it is known that the Alaska [North Slope] Resource Potential is high compared to the rest of the country. He highlighted that the known reserves are 35 trillion cubic feet (Tcf). Furthermore, the USGS estimates 120 Tcf of undiscovered reserves, much of which will be economic. Regarding the chart on page 4, Dr. Finizza said USGS reports that Alaska contains approximately 40 percent of estimated undiscovered U.S. reserves from conventional [gas] resources. As shown on the chart on page 5, even after adding unconventional gas from the Lower 48 to the totals, Alaska still holds approximately 20 percent of the U.S. reserves.

DR. FINIZZA said there are critical uncertainties related to Alaska gas in the following categories: the strength of natural gas market, the extent of the LNG penetration, and the competition of gas with alternative energy. He highlighted the key points on the chart on page 7, regarding future natural gas markets, including that: the natural gas supply in North America will be tight; the Lower 48 will be in sharp decline, in particular from conventional reserves. Furthermore, LNG will be somewhat limited by existing and planned facilities. Electric utilities growth of gas will be limited by high gas prices, he noted. There will, he said, be stiff competition from coal-based, electric generation, which was at one point considered to be a favored market for new gas supply. There is unlikely to be growth in the household/commercial industrial level beyond the traditional growth in population or GNP, he relayed, and no one expects that major impact in the transportation market. He added, "A lot of it is going to hinge on the power ... market."

DR. FINIZZA directed attention to a table on page 8, showing a U.S. natural gas demand outlook. He said he presented a table just like it last August, which offered a look at incremental natural gas demand by sector, as reported by the Department of Energy's annual energy outlook. He continued:

> At that time, they thought the incremental increase in natural gas [from] 2005-2025 - now that's five years less than this chart - would be three, four, and now they've scaled it back to one, because they recognized, as we all should recognize, that higher natural gas prices reap competition, particularly from using less electricity in one sense, and also from competing supply sources such as coal and alternatives.

DR. FINIZZA, regarding page 9, said it looks like 3-4 Tcf a year will be needed in the supply mix for LNG, and it that amount will probably rise. He said it looks like LNG could be delivered to market at costs in the $3.00-$3.5 million Btu range, but it will be sold at the prevailing domestic gas price, which Dr. Finizza said Econ One believes will be set by higher cost domestic supply, not by LNG prices. He highlighted that LNG costs from Qatar to the U.S. are $2.50/million Btu. He indicated that that breaks down into the state of the raw gas through liquefaction, shipping, regasification, and pipeline access. In summary of page 9, he stated that LNG will not be setting future gas prices. The prices will be set by higher cost, Lower 48 supplies.

11:47:54 AM

DR. FINIZZA directed attention to a chart on page 10 of the handout, which shows sample LNG costs of transportation of the gas pipeline versus other gas projects in the world. He said he obtained the figures from the Cambridge Energy Research Associates. He offered an example from the chart, highlighting figures for shipping costs, gas liquefaction, "regasification," and a pipeline access fee, and compared that to comparable figures related to tariff, previously shown by Mr. Pulliam, and he stated, "You'd get $3.25 to $3.50, getting gas from the well in Qatar to the gulf coast of the U.S. into a pipeline hub that would be comparable to, say, Chicago or ending up something of that sort."

DR. FINIZZA, regarding the issue of alternative energy sources, shown on page 11, confirmed that natural gas will faces threat from alternative power technologies when prices are high. He said there are two technologies having claims of being "economic" at prices of $4.00-$5.00 an higher; thus, he said it should be expected that natural gas will face competition from other energies over time. He added, "That should deflate anyone's idea of having extremely high gas prices in the future."

DR. FINIZZA turned to page 12, showing public natural gas price forecasts. He pointed to the first bulleted point on the page, which is EIA's annual energy forecast, produced January 2006, and he noted that Econ One has taken those numbers and developed some probability distributions. He highlighted the next bulleted point on the page, which is the NYMEX futures market, but he said those numbers "don't go far enough," and there's some debate as to their forecasting content. Pertaining to the chart on page 13, related to natural gas price outlook, he emphasized the importance of thinking about the "chances of prices being a certain level." He explained that to produce the chart, he used the methodology he was advised to use by Henry Hub in conjunction with a Department of Energy survey related to probabilities of prices, which is yet unrecorded. He offered further details.

DR. FINIZZA discussed page 14, which addresses the forecasting content of NYMEX futures, and he said that this forecast, although reflecting the market's expectation of future gas prices, has been proved inaccurate. Notwithstanding that, he said, the forecast does seem to outperform the "EIA's AEO"; but "there is not enough evidence of its long-term viability as a forecasting tool." Page 15, he noted, shows Henry Hub historical prices with "the NYMEX strip" at selected points in time. He explained that an erratic pattern on the page is explained by "the seasonality component for the heavy use of gas in the winter heating season ...." He said, "If you take that picture and statistically try to determine what that is telling us, it gives us a view something like ... $5.5-$6.5 dollars in real terms over that period. Of course, that's stock before the pipeline startup."

11:53:04 AM

REPRESENTATIVE LES GARA, Alaska State Legislature, said he would like Dr. Finizza and Mr. Pulliam to get back to the committee regarding at what price point the state would start losing money on gas, and to describe what revenue ramifications would affect the state, should prices continue to be low for one year, for example. He explained, "I just want to understand those downside risks of the royalty and production tax in kind issue."

11:54:14 AM

MR. PULLIAM responded that he would be willing to supply that information, but would not do it without also proffering what the likelihood of such a scenario would be.

DR. FINIZZA continued with his presentation, directing attention to page 16 in the handout, which is entitled, "National Oil company Price Views." He said the top three bullet points on page 16 are inferences about what companies must have been thinking about oil prices in recent asset acquisitions. He offered further details. At the bottom of the page, he noted, is a quote attributed to Jim Mulva, the Chairman of ConocoPhillips, which was reported in the Petroleum News and read in part: "What we really look at is prices of $7 to $8 ... and if they're north of that, that's all the better for the transaction. We tested also at about $5 per mcf." Dr. Finizza stated, "Those would be higher than we would think would be a reasonable planning case and higher than the ones we used as our 'most likely.'"

11:55:59 AM

DR. FINIZZA, in reference to the graph on page 17, said he attempted to put together a way of comparing natural gas price forecasts. He continued:

> It took two things to do that: One was we had to put them on the same year's dollars - 2005 - to make them comparable. Also, you'll notice or recall that the EIA shows rising gas prices, and that's a feature of EIA from year to year. We also had some analyses done for the state by Lukens, which also showed rising real gas prices. But the fiscal interest findings, PFC, Infor Insights use a flat price, so I've converted these rising real prices into flat equivalents by making sure that the present value of the result would be the same under both cases. So, I've put it, I believe, on an apples to apples basis. I've also, where there was an ability to see if there was a distribution around their ... mean value, I indicated that on this bar chart.
>
> So, in the fiscal interest findings, ... we see them use a $3.50 number and [an] $8.50 number, and also a $5.50 number means. I interpreted that ... as P20, Mean, and P80; I put that on 2005 dollars, since they their analysis in real terms with no inflation, I call that 2005 dollars, as well. PFC used a price case in their evaluation of the LNG option - a piece of work done for the Department of Revenue - and they used the number around $6.50 ... 2005 dollars. Lukens Energy had a price distribution which ... I converted into flat numbers again. They used a mean that's very close to $6.00, $7.50 for their P80 case that is ... [an] 80 percent chance prices will be at that or lower or 20 percent at that price or higher. They use a P20 at about $3.50, $3.60.

11:58:17 AM

DR. FINIZZA continued reviewing page 17 as follows:

> The EIA numbers - the three there - I converted that chart I showed you earlier into ... a flat equivalent.

> They get numbers a little below $5.00, and little below $6.00, and a little above $6.00, in terms of that distribution. You'll note that it's a tighter distribution than any of the other ones who have distribution. In the fiscal findings there was some work on the workforce piece at the end. Information inside used a number in 2005 dollars that would be something a little above $5.00 for their ... mean value - $5.25.
>
> We've concluded from looking at all of these variations that the amenable distribution would be the one that we have here: $4.00 of the P20 case, $6.00 mean expected value, and ... a P80 at $8.00. It fits in fairly nicely, I think, with the other groups, taking from all of them.

DR. FINIZZA, in reference to page 18, continued as follows:

> So, how would we use these prices? I think best practices would require evaluation of projects ... at a range of prices - no one just does one - and particularly looking at a low price, as well as the expected price, recognizing that with the low price case you would expect not to have any negative net present value, obviously, maybe a modest return, [and] not a lot of economic rent available. So, we're saying that expected prices would be something around $6.00 mmBtu, and a low stress-price case would be about $4.00 mmBtu, and a high one at $8.00 [mmBtu].

DR. FINIZZA said producers would possibly be more conservative than Econ One regarding these numbers. In reference to page 19, he first noted that producers have been burned by forecasts of high gas and oil prices in the past. He mentioned the rollercoaster of prices from the high in the 1970s to the low of the 1980s. He continued:

> There is a lot of institutional knowledge about those boom/busts, and I think it does continue to permeate the business. ... I'm thinking that they will test their projects against the tacit to be below this most likely view. So, that might be somewhere around $36.00-worth of oil, and maybe $6.00, if they use the 6:1 ratio, or it could be a slight bit lower.

> Producers will certainly stress-test their projects; my guess would be somewhere around $4.00 mmBtu. [It] might be higher if Jim Muldon's right, but I think [$4.00 mmBtu] might be a reasonable guess from someone who can't see into oil companies. I mean, you could ask them, but this is a trade secret, and it's an important thing to keep secret. And [I'm] just reacting to what I remember when people had best-guess views out there in the past we would try to be more conservative, because the consequences of error are not symmetric. It's much easier to take credit if the price [is] higher than you called; that's because it was your good work. But if they're much lower, you obviously would be punished by your board of directors as well as Wall Street.

DR. FINIZZA concluded by reviewing the upside, mean, and downside prices covered previously.

12:02:23 PM

REPRESENTATIVE SAMUELS, following up on Representative Gara's question as to when the state would go "into the red," stated his assumption that if the gas is shipped to Chicago, the amount at which the state begins losing money would be at a rate below $2.17. He asked if he is oversimplifying the case.

DR. FINIZZA concurred that that calculation is "approximately right."

REPRESENTATIVE SAMUELS noted that that information comes from page 4 of Mr. Pulliam's previous presentation.

REPRESENTATIVE MEYER asked what the current gas price is.

DR. FINIZZA said he does not watch the current gas price and, thus, doesn't know that answer to that question.

REPRESENTATIVE MEYER asked if gas prices tend to follow oil prices.

DR. FINIZZA replied that in general, gas prices are positively correlated with oil prices, although not perfectly, and there have been dramatic differences. He offered examples. He said some people think the "they are converging." Part of the difference is due to the higher cost of transportation for gas than oil.

12:04:24 PM

REPRESENTATIVE ROKEBERG, in response to Representative Gara's "well-placed question," said he thinks one of the biggest concerns Alaskans have related to "guarding the contract" is the shipping capacity issue. He said, "But they all vary -- I think they relate around the price sensitivity, and I appreciate your comments on the low stress prices in looking at your projections here." He stated that it is clear that when Alaska gas is delivered to market it will have an impact on market prices; there will be a "substantial amount of absorption." He said he would like to know how other gas shippers hedge their pricing problems.

DR. FINIZZA responded as follows:

> If you believe that the distribution of huge prices is something like any of these distributions here that have the statistical distribution, the chance of ... market price being at $2.00 is fairly low. [That is] not to say that that can't happen for periods of time, [but] it certainly won't likely average that for 20 [or] 30 years. So, whatever you think that risk is, in terms of dollars, make sure you multiply it by a small number.
>
> A second thing is, if you wanted to hedge that, you have an option of hedging at one place, and that's on the NYMEX, but we have a little problem here: you don't generally see the strip going out far enough; it certainly isn't even at the point of the pipeline build. So, you'd have to figure out some other ... way. Let's say the pipeline started up in 2006. You would have an option, I suppose, of - if you saw a strip like this - to hedge that. The cost of that ... is going to be determined by the markets perception of how probable is ... $2.00 ... [per mcf]. It might be a very inexpensive insurance policy to buy; one you'll never use.

12:07:13 PM

REPRESENTATIVE ROKEBERG said he didn't want to take more of the committee's time, but is curious as to "how you absorb 4.5 billion [Btu] into the market in one fell swoop and how you can hedge that." He questioned where the ultra low stress price would be found and whether it has to be planned for on a cash-flow basis.

DR. FINIZZA, in response to Representative Rokeberg's concern about absorption into the market, said people who put together price views of the future "believe it's going into the market." He added, "So, they ... you can actually see some of the price forecasts that are made, when it enters the market, it actually depresses in."

REPRESENTATIVE ROKEBERG observed that this is an influence to the North American gas market.

DR. FINIZZA concurred. He said, "This is not a small -- 6.5 percent of total supplies. So, its impact on prices, and the fact that it's going to Chicago through [the] Alberta hub is recognized when modelers look at ... the price implications of this. Prices would be different if you had more gas or less. So, it's already taken into account."

12:08:42 PM

SENATOR WILKEN reported that the current gas price is at $6.59.

The committee took an at-ease from 12:08:57 PM to 1:22:31 PM.

Risk Analysis of Alaska Gasline Project

DR. FINIZZA commenced the first afternoon presentation pertaining to the fiscal interest findings related to project risks, and he used the correlating handout to outline the key points. He highlighted page 2, which shows the project risks identified in fiscal interest findings. Economic risks, he reviewed, included market risk, cost overruns, and completion risk. He then brought attention to page 3, which shows testimony by Pedro van Meurs, Ph.D., from May 10, 2006, at which time Dr. van Meurs stated that the combination of cost overrun and price risks - cost overruns being too high and prices too low - result in a 20-30 percent chance that a gasline project will not be built with a stranded gas project.

DR. FINIZZA said he quantified the two risks - cost overrun and price - using some aforementioned scenarios, and he concluded that the probability of having an uneconomic problem on the two risks together would be smaller than stated in the fiscal interest findings. He then addressed the earlier questions of Representatives Gara and Rokeberg regarding the risk of the project economics being poor in any given year, which he said is different than asking about the project as a whole being uneconomic over the entire life of the project. He continued as follows:

> If, ... whatever the tariff lost cost would be in a given year ..., you believe that there's only a ... 1 percent chance that prices would be below that in a given year, over a 30-year period ... the chance of at least one year being under $2.00 ... would be something like 25 percent - a one in four chance that at least one of those years would be below that point, although the project could be, on average, good.
>
> If you thought that as a chance of 5 percent of risk prices in any given year would be below the $2.00 level, it would be something like a 75 percent chance that there would be at least one year in 30 that you would be there. So, ... when asking the question, be clear whether you're talking about an entire 30-year period or just the random occurrence of one price, which won't ruin the project, but it could put you into a bollixed situation for a given one-year period.

REPRESENTATIVE JOULE, [referring to page 15 of Dr. Finizza's prior presentation, which shows the Henry Hub natural gas price distribution], observed a downward turn in the price outlook to about 2015, and he asked if the cost associated with building also comes down.

DR. FINIZZA surmised that costs are highly correlated with demand and activity in the industry, thus, he said he imagines costs would go down [with the price outlook], although he added that "it's not entirely commensurate."

DR. FINIZZA returned to the current presentation and directed attention to page 4, which provides a probability reminder to avoid a "perfect storm" analysis. He explained that he is warning against picking all the things that can go wrong and thinking there is a high probability of that happening. He offered further details as shown on the page and through anecdotes. Regarding page 5, which addresses resource risk, Dr. Finizza said there is a risk related to the inability to have gas available to fill the line for the full length of the contract; however, he said he does not think the risk is high enough to "continue with it in this analysis."

DR. FINIZZA, skipping to page 7, talked about price and cost overrun risk, explaining that he used the Monte Carlo technique, which uses "the probability distributions of these two variables to see if I can ascertain the likelihood that the project would be negative." He said he used the three price distributions: EIA, PVM, and Econ One. The Lukens price scenario was close enough to that of Econ One, which is why he said he chose not to include it. He also noted that he used the cost overrun risk distribution that "seems to be indicated in the fiscal findings."

DR. FINIZZA, in reference to page 8, said he used a "lognormal" distribution in the price cases. The chart on the page reflects the chance that there may be higher prices than lower, generally. He turned to the triangular distribution used for cost overruns, shown on page 9, which provide the minimum and maximum values and likeliest points. The graph, he outlined, shows a distribution where the minimum cost overrun is 90 percent of the one assumed, and the maximum is 150 percent of the most likely. He said, "With an asymmetric risk like this, the expected value actually is higher than 100; so, this analysis is going to give you a cost overrun on average that's higher than the most likely value." On page 10 continued with the cost overrun risk information. He said the two aforementioned risks were modeled jointly. He continued:

> We assumed two things: one was that the two risks were correlated, so that ... when you had higher prices, you generally had higher cost overruns, to ... reflect the idea that higher ... prices are generally a result of greater activity in the industry and costs go up when they're competing for scarce equipment, et cetera. And also, assuming that they weren't correlated. So, you can do it either way, and the conclusion isn't that different. I then calculated the financial metric, using ... that distribution ... of the prices ... for cost overruns, jointly, in that correlation.

DR. FINIZZA said the first set of results are in the chart on page 11, which shows the producer net cash flow (NPV10) under various gas price and overrun distributions. The high axis shown on the page is the net present value, and the "x" axis is the accumulative distribution of occurrences of those values of probability distribution. The point where that distribution crosses the zero NPV10 line, he said, "would give you sort of the indication of the chance, over all those distribution randomly drawn samples, of this project over that time period having an uneconomic feature." He said in the case of the FIF scenario, "you're talking something that's in the 5 percent range." Chart 12, he relayed, shows the NPV10 under two [alternative] sets of fiscal terms: the 2005 ELF term and the proposed contract. The chart shows that the proposed contract is less risky, but significantly so. Page 13, he noted, looks at the IRR under the same aforementioned gas price and overrun distributions. If you were to compare the numbers with an IRR of 10 percent, for example, the bottom two cumulative distributions cross the 10 percent line on the "y" access, roughly at 6-7 percent. He explained that for the chart on page 14, he expanded the graph from page 13. He mentioned a probability regarding the chart on page 14, and he offered an estimated of 5 percent or higher.

1:37:03 PM

DR. FINIZZA turned to the conclusions on page 15. He related that - looking at the price risk inherent in any project of this type and the cost overrun risk as overstated in the fiscal interest finding - the risk of having an uneconomic project would range between 1-5 percent. If the oil effects and the effect of getting value from extracting natural gas liquids from the gas are ignored - as they are by Dr. van Meurs - then the risk [of being uneconomic] rises to approximately 7.5 percent - not the 20-30 percent that has been depicted.

SENATOR WILKEN asked Dr. Finizza to illustrate where on pages 13 and 14 the conclusion on page 15 is supported.

1:40:37 PM

DR. FINIZZA first addressed the second bullet point on page 15, which has to do with the aforementioned 1-5 percent risk. He directed the committee back to the chart on page 14 and explained:

> You can see ... the crossover point; I've drawn a horizontal line on graph 14 at the 10 percent internal rate of return, assuming that would be the hurdle rate used. So, if the ... IRR goes below 10 percent, one would argue that that's not recouping the cost capital, so it would be a negative and uneconomic project. And I'm saying that these are slightly above 10 percent - this ... fiscal interest finding's line. So, ... it's right about at the 5 percent level.

> ... If you want ... to see how I get the less than one percent, I note that there is much smaller than 1 percent if I draw the line on page 14 - the blue line is the EIA - that one would not hit 10 percent until somewhere close to zero. There's no such thing as zero, so I can't report it at zero change.

DR. FINIZZA next addressed the third bullet point on page 15, which is in regard to the risk rising to 7.5 percent. He said he does not have a graph that shows that the 7.5 percent would be a result of taking out the oil effects and the positive uplift effects from NGL; however, returning to the graph on page 14, he showed the committee where the line would be drawn if it were there.

DR. FINIZZA finally addressed the conclusion expressed in the top bullet point on page 15. He stated:

> There's no way we saw you could get this 20-30 percent chance with those two critical assumptions of the price scenario and the cost overrun scenario. You could get it if, one, you believe that the risk of a crossover run is much greater than stated in the fiscal interest finding, or if you thought prices were going to be significantly lower than stated in the fiscal interest findings, or a combination of the two.

1:42:08 PM

REPRESENTATIVE ROKEBERG pointed to the chart on 13 and said it appears that as prices and cost overruns increase, so does the IRR. He asked for clarification.

DR. FINIZZA used the EIA line on page 13 as an example. He said taking the EIA mean value of roughly $6.00 and adding on top of that the chance of an overrun going between 90 and 150 percent of the stated assumption - [as shown on the chart on page 9] - would result in the IRRs shown on page 13. He said the fiftieth percentile would be somewhere around an IRR of 20 [percent], which he clarified means that 50 percent of the time, IRRs will be approximately 20 percent.

REPRESENTATIVE ROKEBERG asked Dr. Finizza if the IRR increases with the increase of prices and cost overruns.

DR. FINIZZA said the chart doesn't specify that, but in general, the higher the prices, the higher the IRR.

REPRESENTATIVE ROKEBERG asked, "What about cost overruns."

DR. FINIZZA responded that, taken out of a statistical distribution analysis, cost overruns do not help the IRR - they lower it. He continued:

> That's not what this chart is meant to say. This is saying if you looked at all the possible futures of the ... existence of the gap pipeline, what is the most likely IRR you would get, given these distributions of prices and overruns? And the answer is 20 percent. And what's the chance that you would get an IRR below 10 percent? ... If you had the price view of the fiscal interest findings, it would be something like 5 percent. That's what this is telling you.

MR. FINIZZA, in response to a follow-up question from Representative Rokeberg, explained that an overrun does not generally increase the IRR - it does the opposite. Turning back to page 8, he said, "This is a distribution of how prices might look ... if you wanted to say for a given year there's a chance it would be at $6.00; there's a smaller chance it would be above [$8.00]; there's a smaller chance it would be below [$4.00]." He continued:

> You also, at the same time, are asking yourself while that's happening - and I'm going to move to page 9 - I have a potential cost overrun for whatever reason. It could be that I ... didn't realize it would be as much money as ... I thought, et cetera. And in fact, we think that generally ... we would agree with the fiscal interest findings that the risks are more asymmetric. There's a higher chance that ... costs will be higher than you believed than lower, although it's not impossible to have lower costs than you expect .... We've merged those two facts together to get your simultaneous look at the future. And one of the ways of depicting the results of that world, rather than just give one number for a given price and a given cost, I'm giving it for everything; I'm giving it for the whole distribution of all possibilities. This is to get away from people picking the ... worst possible price and the worst possible case and getting

panicked. ... It turns out there's a low probability of that, so we want to avoid that in assessing the risk view. You want to say, "What is the real risk here?" If you believe those views, the real risk here is more in the order of 5 percent.

1:47:40 PM

DR. FINIZZA, in response to a question from Chair Therriault regarding the [left-hand] side of [the chart on page 13], said, "Between ... the 0 and the 10 percent are more likely the events that have low prices and high overruns." In response to a follow-up question from Chair Therriault regarding probability, he mentioned a figure of 5 percent on the aforementioned chart.

1:48:04 PM

REPRESENTATIVE MEYER surmised that there is a 90 percent chance that the IRR will be a 25 percent or greater.

DR. FINIZZA said that's correct.

REPRESENTATIVE ROKEBERG asked Dr. Finizza to confirm that he selected his fiscal model for the purpose of demonstrating that the fiscal interest findings "overstate the case" in regard to cost overruns and prices.

DR. FINIZZA answered that's correct. He indicated that the 20-30 percent risk assessed through the fiscal interest finding does not seem consistent with "these independent views of the world of how cost overruns ... or how prices would work." He added, "You'd have to assume ... the chance of cost overruns much higher, which is not stated (indisc.). ... It says there's a good chance of 150 percent of the base case, perhaps [it] would have to be multiples of that."

1:50:18 PM

REPRESENTATIVE ROKEBERG observed that on the charts on pages 13 and 14, "the slopes are relatively consistent, except when they spike." He said, "It seems to me in most case scenarios when they diverge we have lower prices and higher cost overruns, but here you have a statistical, relative slope on the curve ..., and I guess ... I ... find it a little bit troubling." He asked Dr. Finizza to speak to that issue.

DR. FINIZZA said he doesn't think much can be gained from "the real slope," because in a metric such as this "they do have a large, ... flat piece." He suggested, "What could be constructive is to find out what happens at the tail ends of that, and that's what ... I think you're addressing." He directed attention to the bottom graph line on page 13, which shows the FIF price scenario and cost overrun distribution combined, and said that the left-hand portion of the graph shows that it is lower than all the others, thus, one could conclude that it holds a higher risk than all of the other price scenarios.

1:51:58 PM

JEFFREY LEITZINGER, Ph.D., Senior Economist & President, Econ One Inc., offered the following clarification:

> Let me make a suggestion about the shape of that and what might lie behind it; I think I could help answer your question. As [Dr. Finizza] described, the numbers that are being plotted here come about by drawing randomly from a distribution of prices and a distribution of cost overruns. A lot of the time in that process, when you randomly draw a good price case, you'll randomly draw a mediocre or a poor cost overrun case, and the results will tend to wash out. So, you have a lot of this distribution which is flat range in the middle of the page, where much of the time it's not very sensitive, because the results are tending to offset each other. You have a few cases in either tail where you draw a very favorable price scenario and a very favorable cost scenario. That doesn't happen very often that you're going to get out on those tails of ... both distributions at the same time. When that happens, the IRR in the project is going to spike way up, and that's what you see on the very right-hand side of table 13.
>
> And then there are a few situations where you draw a very bad price scenario and a very high cost overrun, and part of the point that [Dr. Finizza] is making is that it doesn't happen very often that both of those things come true at the same time. And so, you have a limited number - and that's the downward turn in the curve at the left-hand side of the page - where you really get very poor internal rates of return. And the lesson from it is ... these distributions are

> independent for much of the time you're going to fall in that flat middle range, and the project results aren't going to be very sensitive.

DR. FINIZZA indicated that one of his considerations in making the graph was to "give it a greater chance that when we have high prices, we have (indisc.)." He added, "But actually made those two of them more likely to happen, because I believe that higher prices and higher cost overruns tend to go together, because they cause the increase in the activity in the industry."

1:54:35 PM

CHAIR THERRIAULT asked Dr. Finizza to clarify that on chart 13, where a line hits the sixtieth percentile at 20 percent IRR, that means that "the chances are 60 percent it will be below that point, and only 40 percent that it will be above that point."

DR. FINIZZA responded that's correct.

1:55:08 PM

SENATOR WILKEN, regarding page 15, asked if the word "overstated" really means "slightly overstated" or "grossly overstated," or whether the word as used is "pretty close for our purposes."

DR. FINIZZA responded by noting that the chart on page 14 is a closer view of a part of the chart on page 13. He said:

> If the statement that there's a 20-30 [risk], so let's round it off to ... an average of the two - 25 percent chance of it being economic, I would say that this distribution would have to intersect with [the] 10 percent IRR line at [the twenty fifty percentile] ..., and it doesn't.

DR. FINIZZA, in response to a follow-up question from Senator Wilken, he explained:

> If I were to conclude from these charts that there was a 25 percent chance of the project being economic, rather than what I say is 5 here, the curve would have to be significantly lower and it would have to intersect this line at 25.

CHAIR THERRIAULT asked whether the curve would come straight down.

DR. FINIZZA answered, "Possibly."

SENATOR WILKEN asked Dr. Finizza again to qualify the word "overstated."

DR. FINIZZA replied that he would use the adverb, "greatly." He added, "And by the way, when I say, 'FIF' here, I mean the fiscal interest finding scenario. They don't have these graphs in there." He said he doesn't know what assumption was made to come up with 20-30 percent.

SENATOR WILKEN asked, "Did they run a Monte Carlo simulation?"

DR. FINIZZA answered, "Not to my knowledge."

SENATOR WILKEN said, "You took the difference [and] looked at it."

1:59:02 PM

DR. FINIZZA, in response to a question from Senator Gretchen Guess, Alaska State Legislature, explained that he chose 10 percent as the number at and above which the idea of the project should be entertained, and said "The targets you talked about were developed in concert with (indisc.) projects that DOC provided the administration, and we'll talk about that later on."

2:00:28 PM

CHAIR THERRIAULT, regarding prior information discussed, clarified that the findings pulled from the FIF were gleaned from the findings of the administration.

2:02:41 PM

Investment Performance Metrics and Decision-Making: How Do Oil and Gas Companies Make Investment Decisions?

2:03:04 PM

DR. FINIZZA began his next presentation regarding how oil and gas companies make investment decisions. He directed attention to page 2 of the handout, which addresses how those companies look at projects, and he said the questions asked are whether the project: offers a strategic fit, offers diversification, and creates wealth. He emphasized the importance of treating investment and financing as separate decisions to ensure that all investments are evaluated on a consistent basis. He said projects are compared using the same ground rules. Turning to page 3, which addresses the choice of the discount rate, he reviewed that currently, 10 percent is being used for the gasline discount rate. He said that seems to be common number used in the fiscal interest findings, and he finds no fault with that. He relayed that there is a risk associated beyond what is assumed "here," which must be taken into account somehow. Page 4, he said, lists financial criteria as: net present value (NPV), NPV per barrels of oil equivalent (BOE), profitability index (PI), IRR, and undiscounted cash flow. He stated his intent to talk about some of those criteria and how they play a role in judging or comparing among projects. Some of the criteria play a stronger role than others, he added.

2:05:20 PM

DR. FINIZZA directed attention to page 5, which offers more in-depth information related to the financial criteria for the NPV. He indicated that included in the present value of future cash flows is the capital invested in the project. He stated, "By my way of thinking, this is the supreme financial metrics, since a project with NPV adds value to the firm." He said future cash flows should be discounted to reflect the uncertainty of those cash flows and "when they are going to be expected." Furthermore, if a project generates cash in excess of "that" to compensate for the risk, the value of the firm increases, he said. He added, "So, when we say, 'NPV10,' it means we have a NPV of the stream of cash flow discounted at the 10 percent discount rate."

DR. FINIZZA discussed page 6, which is related to stylized cash flow and shows a chart of expected project cash flows. He explained that a big investment is made in year one, and then, as time goes on, cash flows from the project. He said, "These are going up, probably, with inflation." He continued:

> We do these in nominal dollars .... If you took this stream of cash flows - one negative and the rest positive - and discounted it at 10 percent, you get $6.5 billion dollars .... That is ... above zero; that would be ... if you had a project like this and

> could get these cash flows in this manner, this would add value to your firm and you would undertake it. If your discount rate was 5 percent, you know some people may think that ... 5 percent ... would be worth more to them.

DR. FINIZZA, in regard to the information relating to financial criteria of the NPV per BOE, found on page 7, said people will try to view the NPV of the cash flows in relation to how much reserves are found. He said this measure is highly sensitive to price forecasts. Directing attention to page 8, and listed the financial criteria for the IRR as follows: the discount rate at which the NPV of a project's cash flow equals zero; all projects with an IRR greater than the risk-adjusted cost of capital should be accepted when there are no capital budget restraints; and an IRR of 10 percent currently indicates a good threshold rate of return.

CHAIR THERRIAULT surmised that the aforementioned issue of [no capital budget restraints] has to do with having to weigh the opportunity costs.

DR. FINIZZA replied yes. He stated, "If you have a constraint ..., you have to do something about picking the right project. Even though they may be good projects, you may want to figure out a way to maximize your portfolio. This would not be a measure to do that, just to give you a heads up."

2:08:49 PM

DR. FINIZZA continued with his presentation. As shown on page 9, he related that the NPV and IRR metrics can be in conflict. If that conflict exists, the NPV dominates, because it is the metric that offers more value. He reviewed when the IRR should not be used: to compare mutually exclusive projects; to compare independent projects that are of different scale or have vastly different cash flows; to compare independent projects with different risks unless the cash flows have been risk adjusted or if the IRRs are compared to different risk-adjusted hurdle rates, and when the IRR is considerably higher than the cost of capital, since it assumes that proceeds are invested at the IRR rate.

DR. FINIZZA directed attention to page 10, which shows a financial criteria profitability index (PI). He defined PI as the present value of cash inflow, divided by the present value of all cash outflows. He said the hope is that the PI is greater than 1 - the higher, the better. Dr. Finizza said, "It's not going to give you any different answer than your NPV number." He explained that the PI measure is helpful in allocating capital if there are capital restraints. He referred to the chart on page 11, which is titled, "Useful To Allocate Available Capital," and which shows information pertaining to a profitability index and cumulative capital. He talked about the [vertical] line called, "Available Capital program," and said the projects that fall on the graph line between the available capital line and the unacceptable project line are good projects, but will not produce a "big bang for the buck."

2:14:17 PM

DR. FINIZZA then turned to the table on page 12, which shows the comparison of the gasline project with other opportunity projects. The two column headings on the table are: projects that are independent, when more than one can be done; and projects that are mutually exclusive, when only one or the other can be done. He said an example of an independent project is the comparison of the gasline with other international projects. In this example, he continued, if there are no capital constraints, then any of the discounting methods would work, such as the NPV and IRR. Furthermore, the project could be undertaken with an NPV greater than zero, but the IRR would not be valid if projects were of different scales. If there is a capital constraint, the NPV method would be preferred for independent projects, and that NPV would be ranked by the PI. Regarding projects that are mutually exclusive, Dr. Finizza relayed that if there is no capital constraint and the projects are of the same scale and risk, the one with the highest NPV should be chosen. When the risk is different, cash flows for risk should be adjusted and the NPV used. Furthermore, in this scenario, the IRR would not be valid for comparing mutually exclusive projects.

DR. FINIZZA turned to page 13, which is a graph illustrating the project net cash flow for two stylized projects: an early project and a late project. He said he made up the projects for the purpose of producing this example. He pointed out that the NPV of the project that starts earlier is higher than the NPV of the one that starts later, whereas the IRR is the same, because it is the same project. On page 14, he noted, is a graph illustrating undiscounted project cash flows. He stated, "Page 14 is a financial criteria that I'm so glad has disappeared from the face of the fiscal interest findings; I actually don't think undiscounted project cash flows [have] any merit. I didn't think so [on] August 30 of last year. Somehow it was thrown around. I think that it is often used for presenting to unsophisticated folks, and that certainly cannot be the case here."

DR. FINIZZA moved on to page 15, which offers a summary of the use of financial metrics. He said if he were to compare the gasline with other projects in the portfolio, he would compare on the NPV and use the PI to allocate if necessary. If comparing the gasline proposal with another gasline proposal or [evaluating the effect of] a delay in the gasline, he said he would use the NPV.

2:18:31 PM

DR. FINIZZA turned to the subject of page 16: incorporating risk in the discount rate. He emphasized the importance of handling risk in analyses, and he said there are two methods of doing it. He said adjustment must be made to cash flows that are risky, for example when the average is known, but not the volatility around it. Adjustment must be made for risky cash flows. He stated:

> I think a lot of people, rather than adjust the cash flows for riskiness, tend to adjust the discount rate they have to ... jump over - making it higher. So, for example, if you were looking at a project, and you wanted to see its viability in a highly risky political situation, you may demand a higher IRR than if you had it in a ... nonthreatening, nonrisky environment, such as maybe a pipeline project or something like that.

DR. FINIZZA addressed page 17, which lists potential constraints that he said are not "captured in metrics." He said there could be reasons people want to put one project ahead of another, even though it may have a worse IRR or NPV. For example, the project might be lost if delayed. Other considerations include whether the producers have the skill set, the time to focus, and a competitive advantage in the project, and whether the project offers improved diversification.

2:21:09 PM

CHAIR THERRIAULT recalled that the aforementioned Dr. van Meurs had once spoken about the size of a project and the cash that would "be spun off of this," and he said the doctor's comments had taken into account that the overall NPV might be lower, but would be overcome by the size of the project. He asked Dr. Finizza to address that topic.

DR. FINIZZA said that if he had to compare two differing projects, the smaller project may have a high IRR, while the larger one may have a larger NPV. In trying to choose one project over the other, he said, "it would seem like a high IRR one might tell me to do that expense of one that adds more value to the firm."

2:23:05 PM

SENATOR WILKEN referred to the language one page 16, which shows that the [Ibbotson Associates] work indicated the following international costs of capital, based on market data and country credit ratings: U.S. - 12 percent; Norway - 13 percent; Qatar - 21 percent; and Venezuela - 25 percent. He said there has been discussion about an 8-10 percent discount rate. He asked, "And so, if we were going to build this project in ... Venezuela, instead of using a 10 [percent discount rate], we'd be using a 25 [percent rate]?"

DR. FINIZZA answered yes. He continued:

> Let's say you had an IRR from a project in ... Norway, and it had an IRR of 15, and you had an IRR in Venezuela of, say, 20. You would probably say, "I'm more happy with the Norwegian one, because of ... [the] risk premium, ... and I would reject, perhaps, the Venezuela one, even though it had a higher IRR at the same discount rate, but it didn't pass the hurdle of 25.

SENATOR WILKEN turned to page 6, regarding the stylized cash flow, and he noted that an inserted box in the lower right-hand portion of the page shows NPVs of 0, 5, and 10 percent. He indicated that he would like to know how that would effect the example of Venezuela at 25 percent.

DR. FINIZZA responded, "Yes, you'd probably end up with a pretty low number - possibly negative - and you'd be saying to your self, 'Would I put that kind of money in Venezuela when I know I won't have 30 years of stable government to get it back?' And the answer is: I wouldn't put that money in Venezuela."

Alaska Project Rank with Other Investment Opportunities

2:26:37 PM

DR. FINIZZA began his next presentation, regarding comparisons of the Alaska project to other investment opportunities in the world. He said the comparisons use PFC's database of modeled projects with the following criteria: capital expenditures of at least $1 billion, production start date of 2006 or later, for the purpose of making level comparison. He explained that any project started prior to 2006 would have been advantaged by the high prices. He said projects can be identified as predominantly oil or gas, and they can be split by country – Organization for Economic Cooperation and Development (OECD) versus non-OECD.

2:27:47 PM

REPRESENTATIVE SAMUELS asked if there is another cutoff other than the capex of $1 billion.

DR. FINIZZA answered that there are two projects over $10 billion, but at a $3.5 billion capex there are 16 projects. He indicated that using the other capex does not change the conclusion. He noted, "It's ... the largest capex in the database; we have reason to believe that there's another project in the database that ... has a higher capex, but they didn't fully capture it." He stated:

> We have [been] led to believe that these are projects that are currently underway, sanctioned. Some of them may fall off, of course, because they're not in productions. Some of them have capital investments already ... made, and ... they've made sure for us that they've captured what we asked them to capture - all of the capital that's relative to the project - so that we can make comparisons with the gasline, saying, "If ... the gasline were to come to fruition now, ... it would be evaluated in the same way that these projects on the board - some of these that are starting up in 2009 - how do holdings stack up?"

DR. FINIZZA directed attention to page 3, entitled, "Composition of PFC Database Used in Analysis," which shows projects over $1 billion in CAPEX with production starting after 2005. The total shown is 55, which he said is rounded up to 60. He said, "It turns out that sponsors are in 32 of those 55." He said the PFC data is confidential and, thus, he has not been privy to viewing cash flows or project details. As shown on the chart on page 3, he reviewed that [18 of the 55] projects are in industrialized OECD countries; 10 of those are oil projects and 8 are gas related. [37 of the 55] projects are non-OECD, with 26 being oil-related and 11 gas-related. He explained that the parenthesis in the chart show how many sponsors there are.

2:31:31 PM

REPRESENTATIVE MEYER surmised that the majority of the projects are in the higher risk countries, which relates to the need for a higher IRR in those areas.

2:32:18 PM

DR. FINIZZA agreed. Regarding page 4, he stated that he has to take some issue with [the PFC analysis]. He noted that the work done in May, using the same database, was done in real terms, but discounted at 10 percent. He said that is equivalent to "NPV 13.5," not "NPV 10." He explained that this biases results against the Alaska gasline project. Econ One's work corrects that. Furthermore, he said, as a rule, transportation and regasification capital is excluded for the gas projects in the PFC database. As a result, he relayed, any IRRs that do not have capital in them will "look higher than it should."

DR. FINIZZA presented a map of all the PFC projects, shown by dots on a map on page 5. Most of the areas are under water. Page 6 shows that there are two projects over $10 billion, , which illustrate that most are in water. Slide 6 shows the PFC projects in relation to their CAPEX by using different size dots on the map. The largest dot represents projects with a CAPEX over 10 billion, the middle-size dot represents projects with a CAPEX over $3.5 billion, and the smallest dot represents those projects with a CAPEX under $3.5 billion.

2:35:40 PM

DR. FINIZZA then turned to page 7, which shows project comparisons where the producer net cash flow is NPV10. Dr. Finizza explained that the chart shows both a $35 and $25 gas level and a 6:1 oil/gas price ratio. He said he purchased the calculations from PFC and added the labels. Superimposed on the chart is Econ One’s model analysis of the Alaska project. He noted where the Alaska gasline to Alberta and Chicago show on the graph line, which he said "should come as no big surprise that the Alaska gasline would be on the top of the list on that

NPV10." In response to a question from Chair Therriault, he confirmed that "2005 fiscal terms" mean ELF terms.

DR. FINIZZA directed attention to page 8, which shows profitability index (PIR10), with the same $35 and $25 oil and 6-1 oil:gas price ratio as the chart on page 7. He said:

> Using the same two prices and using the same array, ... we get different locations here. So, this is a measure of the biggest bang for the buck. The array is such that I can identify percentile, so if you look at, for example, the first large ... dot for the Alaska gasline, it would say that on a profitability index it would rank roughly in the top 25 percent of the project at $35, and it would be in the ... 60-something percentile ... under $25. If I want to see the impact of going to Chicago, which has ... additional capital cost, et cetera, to build that line, the ranking of the Alaska gasline would slide pretty much to the right as you can see. So, the big [square] on the left ... is the Alberta project, and if I were to take it out of the list and put it back in as a Chicago gasline, it would slip one whole quartile, at least.
>
> But on the basis of these first two indexes - these are now, remember, ongoing ... sanctioned projects - those two metrics would, I think, place the Alaska gasline under a 2005 fiscal terms in a very favorable comparative situation.

2:39:44 PM

SENATOR WILKEN, referring to slide 8, asked Dr. Finizza to confirm the following:

> On slide 8, if we're going to build a gasline to Alberta under the 2005 fiscal terms, and ... looking at all 50 of those sanctioned projects - three of which are mega projects - the Alaska gasline, 75 percent of those sanctioned projects have a profitability index less than the Alaska gasline.

DR. FINIZZA answered that's correct. He stated, "I picked these two prices because ... in the PFC work it would be closest to our $6.00 gas and $4.00. So, this is like best-guess in stress price."

2:40:52 PM

SENATOR HOFFMAN asked Dr. Finizza if he would be providing comparisons related to the PPT.

DR. FINIZZA answered, "I will show you the ... difference between ELF and PPT, and I will show you also the proposed contract one by one."

2:41:21 PM

DR. FINIZZA moved on to page 9, which shows a comparison that uses NPV10, divided by the BOE found in the project. He continued:

> It appears at the ... low half of the percentile of sanctioned projects. In the impact of Chicago versus Alberta, it's not as great, in terms of the ranking change.

CHAIR THERRIAULT asked, "So, this is just graphing the NPV10?"

DR. FINIZZA replied, "It's ... per unit of reserve found." He added, "Ideally you'd like to see this larger - in the large end of the range .... For large projects I can imagine it's not easy to do."

2:42:49 PM

DR. FINIZZA moved on to page 10, which shows the project comparison, using the IRR, with the $35 and $25 oil and 6:1 oil/gas ratio. In response to a previous query by Senator Guess regarding the fiscal interest findings' target, he said:

> It seems that the target was done the following way: Take all the projects and find the lowest twentieth ... percentile and say, "To be a good project you have to be ... above the worst 20 percent." And that's how the target was picked for each of these metrics - not being the top 20, being the top 80.

DR. FINIZZA explained that he chose to use quartiles, rather than quintiles in charting the metrics. He continued:

> So, it's only on this measure and this measure alone that puts it in the last quartile of sanctioned

> projects. And so, I think, given the general weaknesses of the IRR in comparing, when you don't have all the things right, makes it problematic that I would call this disadvantaged on this measure - basically this measure alone.

DR. FINIZZA said one concern with the IRR would be not having all the capital for the projects. He directed attention to the chart on page 11, which shows the effect of the proposed contract on the IRR, using $35 oil and a 6:1 oil/gas price ratio. He pointed to the right-hand dot along the graph line, [which shows the Alaska Gasline to Alberta in 2005 fiscal terms], and compared that with [the dot to the left, which marks the point on the graph line for the Alaska gasline to Alberta in the proposed contract]. He said, "You moved this project, in an IRR sense, up three points." He said he does not think that is a significant move, given the uncertainty of measurements.

DR. FINIZZA turned to the graph on page 12, which shows the effect of fiscal terms of the IRR, using $35 oil and a 6:1 oil/gas price ratio. He said:

> Simply moving the Alaska gasline to the Alberta hub from the ELF, which is the left-most of those two larger diamonds [on the graph line] to ... what I call the 2000 fiscal terms - the PPT, without the proposed contract, moves it down, of course. High tax rates, less cash flows. It only moves it two positions.

2:46:52 PM

DR. FINIZZA said another way to look at the ranking is found on the table on page 13, which shows a ranking of the Alaska gasline by size class. He said the chart compares the 2005 ELF fiscal term, the 2006 PPT fiscal term, and proposed contract under the categories of all 56 projects and the 16 projects over $3.5 billion in CAPEX. Under each fiscal term and projects category are numbers under the following headings: NPV10, PIR10, NPV10 per BOE, and IRR.

2:48:46 PM

DR. FINIZZA, in response to Chair Therriault, confirmed that in one example, under the PIR10 and the 2005 ELF fiscal term, the Alaska gasline project to Alberta would rank 14 out of 56 among the sanctioned projects.

2:49:28 PM

DR. FINIZZA directed attention to the table on page 14, which shows a summary of the ranking of existing projects at $35 oil and a 6:1 oil/gas price ratio. He highlighted the use of ranking quartiles shown in numbered boxes on the right-hand side of the table. The IRR category shows as being in the bottom quartile. He stated:

> Now that bottom quartile, as I said, is the main - Achilles' heal I think was the term used in the fiscal finding book - and it's solely on that basis, it seems like, that this has been deemed to be a troubled project in comparison.

DR. FINIZZA turned to table on page 15, which is the same as on page 14, but uses $25 oil. The only difference shown, he pointed out, is that the PIR10 is shown in the first ranking quartile [from the second]. Directing attention to page 16, which includes a table illustrating political risk, he emphasized the importance of comparing IRRs in relation to their risk-adjusted cost of capital.

DR. FINIZZA moved on to the topic of incorrect ranking by the IRR, illustrated on pages 17-19.

> I took the PFC database and eliminated the top six projects, only because I want to get everything on kind of the same scale, so that brings things between $1 and $4 billion, ... and I ran the projects two ways. I said, "I'm going to do a hypothetical capital budget," ... rank them by profitability index - biggest bang for the buck - and then do it by descending IRR ....
>
> It turns out the portfolio ranked by PI provides higher net present value, brings in more reserves, and uses less capital, than you would [have] hoped it would do.

DR. FINIZZA offered examples from page 18. He said he ranked the various projects on the profitability index. He reviewed the totals for the first three projects on the top half of the page. The projects shown on the bottom half of the page are ranked by the IRR, highest to lowest, and the result is lower BOE, lower NPV10, and higher capital. Page 19 repeats the illustration, again the top half of the page is ranked by PIR10 and the bottom half is ranked by IRR. The totals for the former are greater in NPV10, less in BOE, and less in CAPEX. He explained:

> So, if I were trying to optimize the portfolio and I believe these to be the cash flows and IRRs, I would do it the first way and get better results. ... So, that's a demonstration of that one caveat I gave earlier about ranking projects. ... It seems like there's some element of that in the fiscal interest findings, and a lot of the things were done to marginal increases in the IRR that don't even get you into the top quartile. They used, of course, the quintile as their target. ... That boundary is arbitrary, by the way; it's lousy either way.

2:56:39 PM

DR. FINIZZA then reviewed his conclusions as related on page 20, which are that the Alaska gasline: is the largest project; has the best financial performance at NPV10 at best estimate prices, is not falling out of the top quartile at low prices; has the biggest PIR, ranking in the top half; is in the third quartile of NPV10 per BOE; and has a low IRR. That IRR, he said, is not useful for comparison between projects that do not include all the capital, are of different scale, or have different risk. He added, "And I think all three of those conditions could conceivably hold here, and [it's] certainly not something to put your hat on." He said it seems that the project, as defined by current fiscal terms, is not disadvantaged on major financial metrics.

2:57:55 PM

REPRESENTATIVE BERTA GARDNER, Alaska State Legislature, referred to page 3 and asked Dr. Finizza to offer a definition of the word "sponsors" used there.

DR. FINIZZA indicated that the word is used to mean a variety of things. He said that Exxon Mobile, ConocoPhillips Alaska, Inc., and BP are involved in 32 of the projects, either individually or in partnership.

REPRESENTATIVE MEYER asked if there is no other project at this magnitude.

DR. FINIZZA, in terms of the CAPEX, noted that the Kashagan project [in Kazakhstan] is listed in the PFC database at $24 billion. He added, "But in talking with Daniel Johnston and also ... 'Googling' it through the various (indisc. -- coughing), it seems like Kashagan has [an] ... estimated capital of $29 billion; ... that would make it pretty much larger."

REPRESENTATIVE MEYER asked, "Are the sponsors in that one?"

DR. FINIZZA answered yes. To an inaudible question he responded, "That's in oil."

The committee took an at-ease from 3:00 p.m. to 3:13 p.m.

3:13:47 PM

CHAIR THERRIAULT announced that that there would be an official Legislative Budget and Audit Committee meeting during the lunch hour break the following day, Thursday, June 15, as well as a round table discussion at 3:00 p.m.

Economic Relevance of Transportation Costs

3:14:58 PM

DR. LEITZINGER commenced his presentation regarding economic relevance of transportation costs. He directed attention to the chart on page 2, which illustrates a breakdown of net capital expenditures as reflected in the fiscal interest findings and represents, in 2005 dollars, a total of approximately $21 billion. He said the pie chart adds up to $18 billion dollars, all related to transportation costs. He stated, "The findings observe that this amount would make the Alaska natural gas transportation project one of the most expensive projects in the world from a transportation standpoint. The findings then go on to make the point that this unusually high transportation cost hurts the project from a financial and economic standpoint, and on that basis, as I would understand the findings, concludes that the gas has been stranded in Alaska." He said that is the topic on which he would focus.

DR. LEITZINGER said the first observation he would make based on the modeling efforts and having reviewed the information and findings and conferred with his colleagues, is that there is ample revenue from the projects, based on expected prices and production, to support the transportation costs. According the findings there are over $120 billion in 2006 dollars in expected net cash flow to the producers from the project if the gasline is built to Alberta. He said that would be the highest net cash flow project in the world. Furthermore, in light of that revenue, and after fully recognizing all of the associated transportation costs, the project is, by any normal economic metric, very attractive, he said. Dr. Leitzinger continued:

> [Dr. Finizza] spoke earlier in his presentation about the net present value of the project based on a discount rate, 10 percent, which reflects adjustments for risk and cost of capital. That net present value, according to the findings, under the base case prices, is $12.7 billion. That $12.7 billion net present value would make the project among the highest worldwide. ... Under the base case assumption, rates of return on invested capital for the project range between 15 and 20 percent, and that's on all of the total capital. Those 15 to 20 percent rates of return greatly exceed company cost of capital for the sponsors. Clearly there is enough return to warrant and support the investment of capital.
>
> The findings go on, however, to make a slightly different point. It's not that the project won't stand on its own economics or that there isn't enough revenue to support the required transportation costs, but rather, as [Dr. Finizza] was explaining ..., they put the project on the world stage and conclude that because ... resources for energy development on the world stage are limited, and because Alaska has high transportation costs, the Alaska project will be competitively disadvantaged.
>
> Well, let me ask this question: Disadvantaged relative to what? One ... comparison that appears and it would seem to me to be the answer for this question in some significant part in the findings that appears frequently is a comparison between the average transportation cost projected for the Alaska natural gas project just over $2. We talked $2.17, I think, earlier today. The findings report a number of $2.25. That number is compared in turn against an LNG cost of approximately $1.20, and those two numbers - as I would understand the findings - are held out as the demonstration of the disadvantage that the Alaska Natural Gas project suffers on the world stage because of its transportation costs.

DR. LEITZINGER suggested that it is important to closely view that comparison, because he said he thinks there are problems inherent in it related to the way it is measured and in the conceptual framework behind the comparison.

3:21:41 PM

DR. LEITZINGER continued as follows:

> The first thing to note - and this Dr. Finizza touched on in his presentation - is the LNG costs that are quoted in the findings reflect the cost of tanker transportation. Those LNG costs do not reflect the cost of liquefaction; they don't reflect the cost of regasification at the point of delivery; and they don't reflect the cost of then transporting the gas from the regasification facility to the market. Based on the estimates that Dr. Finizza provided, if you include those other costs, the cost to bring LNG from overseas to the Lower 48 is more on the order of $2.50 per mmBtu - if anything somewhat higher than the transportation costs projected for the Alaska Natural Gas project.
>
> The second problem: The $2.17 or $2.25 figure that's discussed for the Alaska Natural Gas project is a ... levelized, nominal dollar figure that applies to the life of the Alaska Natural Gas project. So, we're talking about a project that doesn't come on screen for 10 years or so, under the projected timeline, and then continues into the future for 30-35 years, or more. So, we're talking, then, about a $2.00 cost that ... extends on into the future with the effects of inflation at 2, 2.5 percent a year for 45 years. The fact of the matter is the LNG costs that people also talk about in the comparison today are current market costs for LNG, so you have a serious timing and apples and oranges problem. You're comparing today's dollars against tariff dollars for this project which are going to occur 20-40 years in the future.
>
> If we take the $2.17 levelized tariff and bring it back into 2005 dollars to make it comparable to a current LNG cost number, that figure is about $1.20. So, ... either way, if you correct the timing differences or ... be sure and put all of the LNG

costs into the comparison, I see no demonstration in the comparison of the ANS project against LNG that its transportation costs [place] it at a disadvantage.

The other thing I would note in that regard: The NPV10 per BOE is going to reflect the net value for ... the energy - each unit of the reserve that's produced - including the cost of transportation. ... That measure of performance for the gas project achieves the target level set forth in the fiscal findings at gas prices anywhere above $4.00 for Alberta and anywhere above $4.50 for Chicago. For base case prices for gas in the findings of $5.50, it would seem that the project - just looking at whether or not there's enough money left over after transportation costs on an NPV10 basis - there's plenty of revenue to support those costs.

One final, ... passing observation I would make before I move to another aspect of this: If relatively high transportation costs were a barrier to the development of the project, I suggest to you that there would still be 9 billion barrels of oil on the North Slope.

3:25:57 PM

DR. LEITZINGER talked about the investment implications of transportation costs. He said that many side-by-side comparisons can be done, but ultimately the decisions made are those based upon investment. He stated that the question is whether this project, given its transportation costs, makes sense as an investment matter. He said one must understand where the $18 billion to build the line is going to come from. The FIF indicated that 80 percent of the transportation cost will be supplied by lenders, and those loans are expected to be limited recourse and, thus, the lenders wouldn't be able to reach the sponsors to secure the loans. Furthermore, the loans are expected to be supported by federal loan guarantees, which will reduce the cost of the loans. Finally, the loans will be secured by commitment on the part of the owners of the resource who agree that they are going to pay to use the pipeline over its lifetime. From an investment standpoint, he said, the 20 percent of the $18 billion pipeline that is equity financed would provide a 13 percent rate of return on equity. If that 13 percent is spread over the entire $18 billion, the resulting rate of return would be roughly $2.5 billion. He noted that shippers on the pipeline would need to commit to pay between

$1.2 and $1.8 billion a year in transportation payments, depending upon the route of the pipeline.

3:29:48 PM

DR. LEITZINGER turned to the subject of the investment implications of the aforementioned facts, in terms of how the cost will be paid. He asked the question of whether or not the project would have to support a 2.5 percent rate of return on $18 billion, and he said his answer would be no. He explained, "The project sponsors do not have to spend $18 billion to build this project, and I think any investment metric or comparison, which, in effect, is dragged down by a 2.5 percent rate of return on $18 billion isn't providing the proper picture." He posed the question as to whether a 13 percent rate of return would be enough if 20 percent of the cost is coming through equity, or if the need to invest that equity would be a drag on the economics of the project. He proffered that if the regulators do their job in assigning rates of return so that the facilities they regulate are sufficient to attract capital, the 13 percent figure should not be too low; it should not be a drag on the project. He added that there is evidence to support that. He said other independent pipeline companies have come forward and expressed a willingness to build the pipeline, subject to a regulated return. Furthermore, he said, it is known that the findings conclude that it would be a good investment for the state to own 20 percent of the line, and there has been discussion related to the difference between the 13 percent equity return and the state's cost of capital. He said, "Clearly, it seems that that's enough ... return ... on an independent basis to support that kind of investment." He relayed that in the discussion about having another company potentially build the pipeline there is a recognition in the findings that the producers would not be willing to supply their gas for that kind of project, and that it would take some years for the state, in that case, to legally "wrestle the gas away from the producers." He said based on the years that would take, the findings reach the conclusion that it would be uneconomic to have someone else attempt to build the pipeline. He continued as follows:

> At the same time, as I further understand it, the producers are saying in this case, "Well, if we're going to build the pipeline" - which parenthetically, according the findings, they won't let anyone else build - "if we're going to build it, we're ... an ENP company, and in ENP, ... we're not designed to obtain

pipeline level returns. If we're going to build a pipeline, we need ENP-level returns to make it worthwhile."

And so, part of ... what's driving some of the underlying analysis in the findings is how can one overcome the financial disadvantage posed by only receiving 13 percent rate of return on the equity investment in the pipeline. I would suggest that that's not a problem of the return being inadequate, but a question really of which companies are building and what their business models and expectations are.

3:34:13 PM

DR. LEITZINGER directed attention the chart on page 6, which shows the capital structure of the major three sponsors associated with the pipeline project. Based on current information, he noted, those sponsors have approximately a combined market capitalization of $676 billion, long-term debt of $28.8 billion, which, in terms of their capital structure as a group, positions them as companies with 96 percent equity, roughly, and 4 percent debt. Even if all of the cost associated with the project were assigned to these three companies, it would increase the debt percentage of their capital structure by 2 percent. He stated that he does not see any evidence presented in the findings to suggest that the difference between a capital structure that is 4 percent debt and one that is 6 percent debt would have any significant consequences on the companies' availability of capital or cost of raising capital.

3:36:18 PM

DR. LEITZINGER addressed the risk implications in transportation costs. As previously mentioned, the manner in which transportation costs will be paid is by commitment on the part of the shippers over the life of the project to pay for the use of the pipeline. Commitment, he said, is known to create risks. Dr. Leitzinger drew attention to the chart on page 8, which shows gas prices and netbacks without a capacity commitment. The vertical axis of the chart shows different Alberta gas prices in nominal levels ranging from zero up to $16. The line on the chart shows the netback to the shipper faced with the prospect of a $2 tariff. At an Alberta price that is any amount above $2, the shipper would send the gas down the line, pay the $2, and that shipper would achieve the net result reflected in the [area of the chart labeled "B"]. Dr. Leitzinger noted that the horizontal axis shows the nominal product netback.

DR. LEITZINGER turned to the next chart on page 9, which shows the gas prices and netbacks with capacity commitment. The difference shown in this chart occurs when Alberta gas prices dip below $2. In that case, the shipper would not have the option of simply shutting down production and not paying, but presumably would continue shipping the gas and suffer negative netbacks. He pointed out that the chart shows area "B" - reflecting all circumstances where there is a positive netback - to be a large area relative to area "A" - the area affected by the shipping commitment.

DR. LEITZINGER said, "One could say, 'Well, that's just a question of how you draw your graph.'" In response to that hypothetical remark, he turned to the next chart on page 10, which shows the same chart as on page 9, but with information pertaining to expected prices added. He continued:

> The prices that we have been talking about as expected prices in this case are the $6.00 gas price. On a nominal basis going forward over the life of the project - and remember, since I'm talking about the nominal $2.00 tariff I need to put it on that same basis - that over the life of the project is a $10.35 price. The stress price scenario that we've used in the findings of $3.50 works out in nominal terms over the life of the project to be $5.65. Dr. Finizza's T20 price, from his discussion earlier today, was around $4.00. The point is, the probability, I think, based on all the information people have today about markets - that we're going to be seeing $2 gas prices in Alberta for any sustained period of time, and certainly for enough time to turn the economics of this commitment into ... a substantial risk exposure - seems to me to be remote.
>
> And now I'll add one other piece to thinking about that: The NPV10 analysis that we have been using to talk about the project - the 10 percent discount rate - includes within it adjustment for time value of money and risk. Chart 11 is a chart that I believe Mr. Pulliam used last ... summer ..., and it shows his calculated weighted average cost of capital for the three sponsor companies. And you note they range from a low of 7.6 percent for ExxonMobil [Corporation] to

> 9.3 percent for ConocoPhillips [Alaska, Inc.], and that weighted average cost of capital is going to reflect the normal risk ... associated with their business. The 10 percent discount rate that we're using to evaluate this project has, at the very least, a full 1 percent ... extra premium associated with risks specific to Alaska, and if we ... take the NPV calculations for the gas project, and instead of using a 10 percent discount rate to evaluate those economics, we had used a 9 percent discount rate, that 1 percent difference would increase the project net present value by $5 billion. And the point of that is by using ... a discount rate for this project of 10 percent, which is higher than the companies' weighted average cost of capital by at least a point, the analysis already builds in something like a $5 billion adjustment to account for the risk associated specifically with the project. To me, that kind of adjustment is more than adequate to pick up the small chance - going back to chart 10 - that for some material period in time, the shippers who enter into ft commitments end up in the small box over on the left-hand side. There is risk associated with the FT commitments. The manner in which people have done the economics here, the discount rates that have been used, I think are more than adequate to account for it.

3:44:35 PM

SENATOR WILKEN asked if the additional $5 billion associated with using 9 percent rather than 10 percent is added to the $120 billion mentioned from page 3, or to the $12.7 billion.

DR. LEITZINGER answered $12.7 billion.

SENATOR WILKEN surmised that that means $7-8 billion would be added to the $12.7 billion if the actual cost of capital was used.

DR. LEITZINGER replied yes.

3:45:30 PM

DR. LEITZINGER directed attention to the "Achilles heal" of the project - the IRR calculation. He reviewed some of Dr. Finizza's previously stated information regarding IRR. First, he noted that as an economic matter, the IRR is a poor investment metric, particularly in comparing projects with different time frames, costs, locations, and risks. Second, as a conceptual matter, the IRR is designed to capture the relationship between cash outflow at the early stage of the project and inflow once the project is on and commercialized. The internal rate of return calculations that are used in the findings and compared against projects in the rest of the world to reach the conclusion that Alaska is disadvantaged, he said, treat the entire $21 billion in pipeline costs as a cash outflow at the front end of the project. He stated, "As an investment metric - since those dollars are not outflows, as far as the potential sponsors of this project are concerned - I don't think that's a correct use of IRR for this purpose." Another problem, he noted, is that a number of the other projects - particularly the other LNG projects on the list - do not include the full capital costs. He explained that those projects do not include the cost of tankers or the cost of regasification at the point of delivery. He related, "Unless you put all the right costs in the other projects, you are not going to get a valid comparison to an IRR calculated ... for the Alaska project, which has all of the costs included as a cash outlet." Furthermore, the projects to which Alaska is being compared are oil and gas projects, and the transportation economics are fundamentally different between oil and gas. Expected returns and investment profiles in gas projects are different than they are in oil projects, worldwide. He continued:

> Now, you might think, "Well, if that were the case, wouldn't companies just pursue the highest, pursue the best, and leave the others?" Well, the fact is there are different uses for oil and gas around the globe. There are different markets for oil and gas. I'm not saying their prices move independently, but there are ... separate markets for both of them, and there is reason - even if the returns are different for the two types of investment - to pursue both. So, I don't think that if you're going to be ... doing comparisons of the Alaska Natural Gas project in terms of economics - particularly IRR measures - that you should be comparing it against oil prices.

DR. LEITZINGER stated that even if it were true that by some perspective it made sense to put all the transportation costs into an internal rate of return calculation for the Alaska Natural Gas project and then run the numbers and start comparing it to projects elsewhere around the world, I think one of the fundamental things you would have to recognize is that a regulated gas pipeline business and ... investment involves a fundamentally different risk profile - a fundamentally lower risk than in energy marketing or energy development. And if you have an Alaska project, which in its IRR calculation is heavily weighted to pipeline investments, ... returns, and costs, you simply have to take that into account when you're doing your comparison. You cannot hold that up against another project elsewhere in the world which does not have that kind of component with the same risk profile; it is purely and simply apples and oranges.

3:51:37 PM

DR. LEITZINGER summarized that he failed to see the case that the Alaska Natural Gas transportation project is challenged based on market prices and costs. Rather it's economically viable on its own terms. Furthermore, in today's market there's a growing focus on the part of major oil companies to find more reserves and replace those reserves being used. Alaska is offering one of the largest reserves with the largest net present cash flow of any in the world. He said he finds it hard to believe that a project like that is challenged. He said there is no shortage of capital to build the necessary pipeline and there is no reason to believe that the 13 percent return on equity would pose a drag on the project. He stated, "One of the striking things to me is that all of those other projects have already received project sanction; they are already underway. Well, where's the next project going to come from. What is it that Alaska is standing behind in line, in that regard?" He opined that the 10 percent discount rate that has been used and the values that flow from it are more than enough to offset and compensate for the risks involved in the project; they are substantially more than company costs of capital. He finished, "It's hard to see where the challenge is."

3:54:31 PM

SENATOR WILKEN returned to page 3, for which he noted Dr. Leitzinger had listed 5 points that supported the statement that there is ample revenue to support expected costs. He asked Dr. Leitzinger to confirm that his recollection is correct that those five items are as follows: there would be a $120 billion cash flow to producers if the pipeline is built to Alberta; the project would result in potentially one of the greatest cash flows in world; by any financial metric the project is very attractive; there would be an NPV of 12.7 billion; and 15-20 percent rates of return greatly exceed the cost of capital for the producers.

DR. LEITZINGER confirmed that Senator Wilken had noted the five points correctly. He added that at least four of those five points come directly from the FIF.

3:55:55 PM

DR. LEITZINGER, in response to a question from Chair Therriault regarding LNG costs, said Dr. Finizza had provided the following information [on page 9 of his presentation entitled, "What Natural Gas Prices Should Be Used?"]: [$0.80] liquefaction, $0.40 regasification, and $0.10 transportation from the point of regasification to market.

3:57:18 PM

SENATOR HOFFMAN noted that the presentations highlighted positives, and he asked about negatives, such as high labor and material costs.

DR. LEITZINGER responded that the cost of a project is a significant question. He said he thinks some of the analysis provided by Dr. Finizza showed that even with a fairly wide range of cost overruns, there would not be a substantially negative effect on economics. He said he does not have a view as to whether or not the $21 billion estimate is a good one in today's market conditions. He stated his assumption that people will be looking at the issue more closely "as they move forward."

SENATOR HOFFMAN stated, "The success and failure of projects being completed on time is probably more critical than the cost overruns on getting the project to be successful. This is what we had heard in testimony from [International Profits Associates, Inc. & Integrated Business Analysis, Inc. (IPA-IBA)], and none of that is really taken into consideration here."

DR. LEITZINGER acknowledged that Econ One did not run models with regard to an extended schedule.

CHAIR THERRIAULT recalled Mr. Pulliam's chart regarding a project that was delayed by eight years.

SENATOR HOFFMAN pointed out that the example was of delaying the start of a project, not delaying after it had already been started. He said, "And that, I think, is the big question."

4:00:36 PM

SENATOR GARY STEVENS, Alaska State Legislature, inquired as to the federal loan guarantee and whether it can be expected that additional funds would be available "if and when the cost of the project increases."

DR. LEITZINGER said his answer is based on the review of the FIF. He said there was an expectation that the project would be able to make use of the federal loan guarantee. He stated that he does not remember a discussion regarding when those funds would be made available relative to the expense; however, he noted that he also does not remember an issue being raised on the subject.

4:01:52 PM

CHAIR THERRIAULT reviewed the previously announced schedule for tomorrow.

4:03:05 PM

ADJOURNMENT

There being no further business before the committee, the Legislative Budget and Audit Committee meeting was adjourned at 4:03:16 PM.