ALASKA STATE LEGISLATURE
LEGISLATIVE BUDGET AND AUDIT COMMITTEE
Anchorage, Alaska
August 31, 2005
9:15 a.m.

MEMBERS PRESENT

Senator Gene Therriault, Chair
Representative Ralph Samuels, Vice Chair
Senator Ben Stevens
Senator Bert Stedman
Senator Lyda Green
Senator Lyman Hoffman
Representative Mike Chenault
Representative Mike Hawker
Representative Beth Kerttula
Representative Reggie Joule, alternate

MEMBERS ABSENT

Senator Gary Wilken, alternate
Representative Pete Kott
Representative Kevin Meyer, alternate

OTHER LEGISLATORS PRESENT

Senator Fred Dyson
Senator Tom Wagoner
Senator Hollis French
Representative John Harris
Representative Les Gara
Representative John Coghill
Representative Ethan Berkowitz

COMMITTEE CALENDAR

REVISED PROGRAM - LEGISLATIVE (RPLs)
OVERVIEW: Econ One: ECONOMICS OF ALASKA NATURAL GAS PIPELINE PROJECT
EXECUTIVE SESSION
RELEASE AUDITS
OTHER COMMITTEE BUSINESS

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

SHEILA KING, Finance Officer
Alaska Commission on Postsecondary Education (ACPE)
Department of Education and Early Development (DEED)
Juneau, Alaska
POSITION STATEMENT: Explained RPL 05-06-6011.

DAVID TEAL, Legislative Fiscal Analyst
Legislative Finance Division
Alaska State Legislature
Juneau, Alaska
POSITION STATEMENT: Provided comments and responded to questions during discussion of the RPLs.

GUY BELL, Assistant Commissioner
Office of the Commissioner
Department of Labor & Workforce Development (DLWD)
Juneau, Alaska
POSITION STATEMENT: Explained RPL 07-06-1052.

MARC ANTRIM, Commissioner
Department of Corrections (DOC)
Juneau, Alaska
POSITION STATEMENT: Explained RPL 20-06-0027.

SHARLEEN GRIFFIN, Director
Central Office
Division of Administrative Services
Department of Corrections (DOC)
Juneau, Alaska
POSITION STATEMENT: Assisted with the explanation of RPL 20-06-0027.

ROBYN A. JOHNSON, Therapeutic Courts Program Coordinator
Alaska Court System (ACS)
Anchorage, Alaska
POSITION STATEMENT: Explained RPL 41-06-9008.

JEFFERY LEITZINGER, Ph.D., President
Econ One Research, Inc.
Los Angeles, California
POSITION STATEMENT: Assisted with the presentation by Econ One Research, Inc.

BARRY PULLIAM, Senior Economist

Econ One Research, Inc.
Los Angeles, California
POSITION STATEMENT: Assisted with the presentation by Econ One Research, Inc.

RICK HARPER, Consultant
Econ One Research, Inc.
(No address provided)
POSITION STATEMENT: Assisted with the presentation by Econ One Research, Inc.

ANTHONY FINIZZA, Ph. D., Consultant
Econ One Research, Inc.
(No address provided)
POSITION STATEMENT: Assisted with the presentation by Econ One Research, Inc.

ACTION NARRATIVE

CHAIR GENE THERRIAULT called the Legislative Budget and Audit Committee meeting to order at 9:15:45 AM. Present at the call to order were Senators Stedman, Green, and Therriault and Representatives Hawker, Kerttula, Joule, and Samuels. Senators B. Stevens, Hoffman, and Representative Chenault arrived as the meeting was in progress.

REVISED PROGRAM - LEGISLATURE (RPLs)

REPRESENTATIVE SAMUELS made a motion to approve the following RPLs: 05-06-6011 - AlaskAdvantage Education Grant Program; 07-06-1052 - Alaska's High Growth Job Training Initiative for Energy; 20-06-0027 - Cooperative Agreement Program (CAP); 41-06-9008 - Family Care Court.

CHAIR THERRIAULT objected for the purpose of discussion. He requested that agency personnel come forward to discuss RPL 05-06-6011.

SHEILA KING, Finance Officer, Alaska Commission on Postsecondary Education (ACPE), Department of Education and Early Development (DEED), explained that the RPL asks for additional authorization to receive and expend federal funds for the AlaskAdvantage Education Grant Program, for which the ACPE is providing matching funds. The ACPE was originally granted the authorization to receive and expend $120,000 in federal receipts. The ACPE has since learned that it has been allocated an additional $7,000 and that it can expect to possibly receive an additional award. This determination is based on other states' usage - some states can't use all of the federal funds that have been allocated to them and so those funds are reallocated to states that can. Therefore, the ACPE is requesting the authority to receive and expend an additional $20,000. In response to a question, she acknowledged that the request contains an over-authorization of $13,000 in anticipation of being awarded that amount later.

9:19:18 AM

DAVID TEAL, Legislative Fiscal Analyst, Legislative Finance Division, Alaska State Legislature, characterized this over-authorization as a wise approach because the ACPE won't have to come back before the committee if those additional funds are awarded.

CHAIR THERRIAULT noted that the committee could either grant the ACPE the over-authorization or only authorize the $7,000 and have the ACPE return if it is indeed awarded additional funds.

9:20:30 AM

CHAIR THERRIAULT asked that agency personnel come forward to discuss RPL 07-06-1052.

GUY BELL, Assistant Commissioner, Office of the Commissioner, Department of Labor & Workforce Development (DLWD), relayed that the DLWD is asking to increase its federal authorization by $3 million to fully receive and expend $7 million in federal funds for a grant the DLWD just received notice of regarding Alaska's High Growth Job Training Initiative for Energy project. He elaborated:

> The actual grant award was $7 million, we expect to expend $6 million this fiscal year [FY], we have $3 million of authorization currently in our budget available for this, and we're asking for the additional $3 million to expend the full $6 million that we had planned to spend under the grant this fiscal year. The grant term expires on November 30, 2006, so the last component ... of the $7 million grant will be spent in fiscal year '07. So basically, we're asking for $3 million in additional authorization to fully expend this grant ... for workforce development.

CHAIR THERRIAULT surmised, then, that the DLWD has $3 million and is asking for an additional $3 million in order to be able to utilize the money that it is certain will be forthcoming.

MR. BELL concurred.

9:22:59 AM

MR. BELL, in response to questions, relayed that there was no component of general fund match on the original $3 million, nor is there a state match requirement.

MR. TEAL added that this particular training initiative was not built into the budget at all. He also remarked: "It's a $7 million grant; $1 million of it will be spent in [FY 07], so they need $6 million in [FY 06]. They have $3 million of unused federal authorization from other sources that they're going to just move within the appropriation for this, so they're asking for [$3 million]."

CHAIR THERRIAULT surmised that the final $1 million will be presented to the Finance committees in the FY 07 budget.

MR. BELL concurred.

9:24:50 AM

CHAIR THERRIAULT asked that agency personnel come forward to discuss RPL 20-06-0027.

MARC ANTRIM, Commissioner, Department of Corrections (DOC), relayed that the DOC is requesting authority to receive and expend $300,000 in federal funding through the Cooperative Agreement Program (CAP) with the United States Marshals Service. The existing agreement provides 50 beds throughout the DOC's system for federal prisoners, and the additional authority would provide another 10 beds, for a total of 60 beds, which would be guaranteed for 15 years. There is no state match requirement, he remarked, adding that the $300,000 in federal funding would be given to the DOC for something that it is already doing - providing beds for federal prisoners. In FY 04 the DOC housed 73 federal prisoners per month on average, and to date in FY 05 the DOC has been housing an average of 70 federal prisoners per month. In conclusion, he said that the money would be used to fund a variety of capital projects and renovation projects in correctional facilities around the state, including security and control programs and projects.

CHAIR THERRIAULT surmised that by making the additional 10 beds available for federal prisoners, the DOC would receive funds for the aforementioned upgrades.

COMMISSIONER ANTRIM concurred, adding both that the money would go into the DOC's pool of capital dollars and that the DOC already provides more beds for federal prisoners than the CAP calls for even with the additional authorization.

SHARLEEN GRIFFIN, Director, Central Office, Division of Administrative Services, Department of Corrections (DOC), in response to a question, relayed that within the DOC's operating budget, the DOC has federal authorization to bill the federal government for its mandate. The federal government will continue to pay the DOC for each mandate in addition to giving the DOC the aforementioned $300,000 - which will not be applied to the mandates served.

COMMISSIONER ANTRIM concurred.

9:27:42 AM

MR. TEAL surmised, then, that there won't be any additional operating money coming in as federal receipts.

COMMISSIONER ANTRIM concurred.

9:29:03 AM

CHAIR THERRIAULT asked that agency personnel come forward to discuss RPL 41-06-9008.

ROBYN A. JOHNSON, Therapeutic Courts Program Coordinator, Alaska Court System (ACS), explained that the request totals $148,700 and would be pass-through funding from Partners for Progress, a nonprofit organization affiliated with the therapeutic courts, and would specifically be for the Family Care Court.

9:30:27 AM

SENATOR GREEN noted that the RPL report specifically says that it is the court's plan to seek continuation funding for the Family Care Court from non-general fund grants or other sources in FY 07.

CHAIR THERRIAULT pointed out that the Legislative Fiscal Analyst's comment attached to that report says in part: "A new position will be created and will be fully funded with these funds. While there is no guarantee that this funding will be available in FY 07, courts stated that it is working very hard to obtain a non-state funding source for FY 07." He suggested, therefore, that [if/when] this item appears in the FY 07 budget, the legislature needs to look at what the funding source is.

CHAIR THERRIAULT removed his objection to the motion to approve the RPLs, and asked whether there were any further objections to the motion. There being none, the RPLs were approved.

The committee took an at-ease from 9:32 a.m. to 9:38 a.m.

OVERVIEW: Econ One: ECONOMICS OF ALASKA NATURAL GAS PIPELINE PROJECT

9:38:43 AM

CHAIR THERRIAULT announced that the next order of business would be the presentation by Econ One Research, Inc. ("Econ One"), regarding the economics of a natural gas pipeline project. He remarked that the Legislative Budget and Audit Committee - in order to prepare for and run, per the Alaska Stranded Gas Development Act, a public comment period of a minimum of 30 days on any gas pipeline proposal that came from the administration - has hired independent counsel. In addition to the committee having the aforementioned specific statutory directive, the legislature itself has a role in approving any proposed contract, and it was felt that as an independent branch of government, the legislature, specifically via the Legislative Budget and Audit Committee, should hire the expertise needed to advise the committee and the full legislature on this issue. The following presentation by Econ One will not pertain to any specific proposal, he added, but will instead provide Econ One with the opportunity to explain to the committee its views regarding Alaska's gas coming to market.

9:40:31 AM

JEFFERY LEITZINGER, Ph.D., President, Econ One Research, Inc., relayed that Econ One is an economic research and consulting firm with offices in California and Texas that provide consulting services - centered on economics - to a variety of industries, including those involving petroleum and natural gas, regulated utilities, electricity, telecommunications, and computers. Econ One has worked for a number of state governments on energy-related matters - Alaska, California, Hawaii, Louisiana, New Mexico, New York, and Texas; for a number of federal government agencies - the U.S. Department of Justice (DOJ), the Federal Trade Commission (FTC), the U.S. Department of the Interior (DOI), and the President's Council of Economic Advisors; for a number of foreign countries and international agencies - the World Bank, Mexico, Nigeria, Turkey, and Tanzania - on matters related to the privatization of utilities and the development of new industries; and for a number of energy and petroleum companies including large, integrated companies such as British Petroleum (BP), pipeline companies such as ANR Pipeline and Koch Gateway Pipeline, and producing companies and distribution companies. He offered his belief that Econ One brings to [its clients] a balanced set of experiences as well as the thoroughness and objectivity that is required for good, economic analysis.

9:43:00 AM

DR. LEITZINGER then relayed that in addition to being the president of Econ One, he has a Ph.D. in Economics from the University of California; has over 25 years of experience in economic consulting including being an economic consultant to the State of Alaska regarding Charter Oil's purchase of the state's royalty in-kind oil, royalty matters involving crude oil in the North Slope and natural gas, and the "BP-ARCO" merger; has served as an expert economist for a number of natural gas pipelines and gas producers, both in regulatory matters and in litigation; has testified before the Federal Energy Regulatory Commission (FERC) and various state-public utility commissions; and that much of his work has involved project analysis, measurement of risk, and rate of return [issues]. He relayed that he has also published articles in a number of widely reviewed public trade publications and academic articles.

9:44:40 AM

DR. LEITZINGER introduced Barry Pulliam, saying Mr. Pulliam is the Senior Economist at Econ One Research, Inc. with almost 20 years of experience consulting in the petroleum and natural gas industries. He informed the committee that Mr. Pulliam has served as an economic expert for the state on severance tax matters, the operation of the Trans-Alaska Pipeline System (TAPS) Quality Bank, state and antitrust investigations, mergers, and the recent arbitration between the state and ExxonMobil regarding crude oil royalties. Furthermore, Mr.

Pulliam has consulted with the states of California, New Mexico, Texas, and Louisiana; worked with federal government agencies; and co-authored two recent studies prepared for Alaska's Department of Natural Resources (DNR) regarding natural gas markets and royalty valuation issues.

DR. LEITZINGER introduced Anthony Finizza, Ph.D., saying Dr. Finizza has special expertise in energy forecasting and in the analysis of investment decisions and has a Ph.D. in economics and finance from the University of Chicago. Furthermore, Dr. Finizza was chief economist for ARCO from 1975 through 1998 where he was in charge of petroleum price forecasting, and, along with management, evaluated and assessed investment decisions. He has consulted with the California Energy Commission, the State of Hawaii, and the International Hydrogen Infrastructure Group on energy-related matters and currently teaches forecasting and modeling at the University of California. Furthermore, Dr. Finizza has published articles in a number of well-respected journals and general-interest publications; is a Senior Fellow with the U.S. Association for Energy Economics; and was the former president of the International Association for Energy Economics.

DR. LEITZINGER then introduced Rick Harper, saying Mr. Harper brings day-to-day, hands-on experience in the industry, particularly with regard to natural gas because he has over 30 years of experience working for natural gas producers and pipelines and has held a number of senior management positions, including 15 years with ARCO - serving as president of ARCO Gas; 10 years with Northwest Natural Gas Company - serving as Senior Vice President with responsibility for marketing, supply, transportation, trading, and storage; and [6 years] with CanorEnergy, Ltd. - serving as President and Chief Executive Officer of that Canadian oil and gas exploration and production company. Mr. Harper has an understanding of and experience with Canadian markets, pipelines, and energy industry; and has testified on matters related to gas markets and pipelines before the FERC, the National Energy Board (NEB) of Canada, and regulatory commissions in Texas, California, and Oregon.

DR. LEITZINGER relayed that Mr. Pulliam has been the central force in terms of organization and management of "the project" and keeping the team all pulling in the right direction.

9:48:39 AM

BARRY PULLIAM, Senior Economist, Econ One Research, Inc., relayed that Econ One's role is to review and analyze the economic models constructed by the administration for purposes of evaluating various gas pipeline proposals. Econ One has also been retained to consult with the Legislative Budget and Audit Committee regarding the economic aspects of any contract brought forth. Econ One began work in the spring of 2005 and met with certain members of the committee and committee counsel, and then met with the employees and consultants of the Department of Revenue (DOR) and the Department of Natural Resources (DNR) who had been involved in the negotiation process and in developing the models that the administration was using and who included Roger Marks, Michael Williams, Randy Hoffbeck, Antony Scott, William Nebesky, Greg Bidwell, Dr. A. Pedro H. van Meurs, Lukens Energy, Muse Stancil, and Goldman Sachs. Additionally, Econ One has met with Dan Dickenson, Commissioner Corbus, and Commissioner Irwin.

9:52:11 AM

MR. PULLIAM said that Econ One has participated in a number of discussions and presentations by the administration regarding the modeling efforts and the negotiations process. In the course of Econ One's work, it has reviewed and analyzed the models prepared by the DOR, the DNR, and their consultants; specifically analyzing how those models were constructed, what their underlying assumptions were, what their inputs were, and the results that were generated. The assumptions that were reviewed included but were not limited to: future gas, natural gas liquid (NGL), and oil prices; likely delivery locations for Alaska gas; pipeline tariffs; capital costs; operating costs; production volumes over time; and the operation of Alaska's fiscal system, both as it is currently and as it might be under the various proposals being discussed. He relayed that in [reviewing the models], Econ One considered the following questions: Do the models do what they are intended to do? Are they operationally sound? Are there conceptual errors? Are there mathematical errors?

9:56:01 AM

MR. PULLIAM relayed that Econ One also interviewed a number of individuals and firms active in the U.S. gas industry regarding Alaska gas - how it will enter North American gas markets and what roll it will have; has analyzed published data, reports, and information regarding U.S. gas markets; and has reviewed confidential data prepared by the producers, TransCanada

PipeLines Limited ("TransCanada"), and the port authority. That data was then used in the administration's economic models, but Econ One is not free at this time to discuss or share that information publicly. Econ One has also reviewed the various confidential proposals that have been put forth by the different parties that the state is negotiating with, and has developed a model of a gas pipeline project using publicly available and non-confidential data.

9:57:57 AM

MR. PULLIAM offered his understanding that should a stranded gas contract be put forward to the legislature, much of the data that is now deemed confidential will become public and can then be discussed. In developing a model using public information, Econ One has looked at the development of the gas reserves and the construction of a gas pipeline under various alternatives, assuming that that construction and development were to occur under the existing fiscal system.

9:59:04 AM

RICK HARPER, Consultant, Econ One Research, Inc., said he would be providing the committee with background information regarding how natural gas functions in the North American marketplace and how Alaskan gas is going to fit against that backdrop. He relayed that the natural gas industry is distinctly different from the crude oil products business - it functions differently, the infrastructure is different, the nature of the product is different - and as the state becomes a major force in the production and delivery of natural gas in North America, [the legislature] will come to understand those distinctions, which he characterized as important particularly from an analytical perspective. He offered his belief that the legislature is aware that a lot has been going on in the energy marketplace in general and in the natural gas marketplace specifically. Prices have been rising to unprecedented levels, resulting in unexpected market responses, but in the past, for a long period of time, the natural gas industry was price regulated at the point of production.

MR. HARPER said that after the price of natural gas stopped being regulated and natural gas prices took off, there was a tremendous boom in drilling. But when those supplies came on, prices collapsed and the upstream industry in North America suffered tremendously. Currently, the situation is much different in that there has been a terrific price run-up, though that could simply be a technical adjustment to the unrealistically low prices seen in the 1990s. There has been a modest increase in drilling, but there hasn't been the same kind of demand moderation that was seen in the 1980s. In the 1980s immediate fuel switching occurred on the part of industrials, but today, the industrial segment of the business doesn't occupy as big a part of the market share in total, fuel switching capability is not in place, and crude oil prices and product prices are also high. Therefore, to some extent, demand has been trending upward.

10:03:57 AM

MR. HARPER relayed that crude oil is a very fungible product, capable of being transported in a number of ways or simply stored. The pricing structures, the regulatory structures, and the commercial structures are reflective of those fundamental physical characteristics. Natural gas, however, is very different. Natural gas can only be moved through a pipeline, and although the means of dealing with natural gas is changing due in part to advances in technology, natural gas is still very distinct from oil in that regard. Referring to a map illustrating the natural gas pipelines in North America, he remarked that it shows a "highway system," and that the natural gas market in the United States is made up of a collection of physically regional markets. Characterizing what has been occurring in the natural gas pipeline industry in recent years as nothing too different from what has been occurring in the "producing side of the business internationally," he said there has been a lot of consolidation of ownership, particularly of interstate pipelines in the U.S.

MR. HARPER reminded members that in the U.S., there are two categories of natural gas pipeline - intrastate pipelines and interstate pipelines - and, again referring to the aforementioned map, pointed out that there are concentrations of pipelines and producing areas and that there are orientations to specific markets - for example, Gulf of Mexico and Gulf Coast production serves Eastern and Midwestern markets, and Western Canada [production] predominately serves the West Coast and to some extent the Midwest. Ownership of natural gas pipelines has traditionally been much different than ownership of crude oil pipelines, he relayed, adding that although he is not aware of any U.S.-based producer owning an interstate pipeline, they routinely "subscribe" to pipeline capacity as a part of their marketing and trading operations. One of the reasons for avoiding ownership of interstate natural gas pipelines, he surmised, could be because of the perception that the Federal Power Commission and its successor, the Federal Energy Regulatory Commission (FERC), might seek to encumber [a producer's] upstream activities with regulated rates of return.

MR. HARPER suggested that another reason could be because of the perception that regulated rates of return are not desirable, particularly given what [a producer] perceives as its other investment alternatives. He went on to relay that in the last 10 years or so, there has been a lot of pipeline construction in North America, and surmised that this is both a consequence of rising demand and a byproduct of the deregulation that occurred in the 1980s and early 1990s. Basically, a lot of the investment made in the 1990s was intended to better intertie markets, to improve supply access, because the basis for buying and selling gas had changed dramatically. Construction has abated a bit in the last three or four years, he noted, adding that most new construction is aimed at connecting new supplies in new basins, particularly in "Deepwater Gulf of Mexico," in Wyoming, and in the Barnett Shale in north Texas. A lot of the "de-bottlenecking" that needed to be done in the marketplace has been done, basically.

10:09:00 AM

MR. HARPER remarked that although natural gas is a less fungible product, one must remember that crude oil has to be converted into other energy forms before it's usable, whereas natural gas can be used from the time it is produced and conditioned, and it can be delivered directly to homes and factories, which is not true of crude oil. Because natural gas has traditionally had a very big role in heating and heating-related utilizations, it's a very seasonal business in terms of its utilizations, physically, and, as it has become increasingly traded as a commodity, those utilization characteristics are reflected in the commodity and financial markets. The business, he explained, operates in two or three different dimensions. There is the physical market in which the product is purchased [for use by] electric utilities, industrials, and local distribution companies, for example. There is also a "paper" or financial market; natural gas is traded on the New York Mercantile Exchange (NYMEX), and, over the last decade, has been the most volatile commodity traded.

MR. HARPER said that natural gas prices are now pushing $13/mmBtu (million British thermal unit), $1 of which is a reflection of what has occurred because of Hurricane Katrina.

He opined that the current price levels are not sustainable, but acknowledged that there has been major structural realignment in North American energy pricing, particularly with regard to natural gas. He characterized this as a huge shift upwards in the "range of uncertainty." Although what occurred in the 1990s created a lot of fear about producing natural gas, this fear is slowly abating and "a steady march upward" [in pricing] can be perceived. Looking forward, however, he said that one can see a different profile, and pointed out that although the NYMEX is primarily a financial market with over 95 percent of its trades never going to physical delivery, it does act as a price discovery mechanism in terms of setting cash prices for the physical market. So there is an expectation that prices will be substantially above what they have been in recent times. Additionally, prices are higher in winter than they are in summer because, unlike crude oil, natural gas is not produced "flat out year around." Instead, natural gas "cycles" with production in the summer being less than half of what it is in the winter.

10:13:28 AM

MR. HARPER relayed that nontraditional supplies are going to play an increasing role in the North American natural gas industry. Historically, the vast majority of U.S.-consumed [natural] gas was produced in the U.S., but Canadian imports have taken on an increasing role, currently representing approximately 14 percent of U.S. consumption. The liquefied natural gas (LNG) business has been around a long time; there are approximately 100 LNG facilities in the U.S., most of which are associated with local distribution companies that use "it" as a means of storing natural gas for "winter-peaking" needs. Currently, there are four active LNG terminals in the U.S. and over 35 proposed projects. So there are a lot of shifts, he remarked, adding his belief that the time is right for the consideration of Alaskan natural gas and [Canadian] "frontier" natural gas.

10:14:36 AM

MR. HARPER explained that natural gas's physical markets trade regionally and tend to operate around physical hubs, which are financially connected and include the Henry Hub in Louisiana - the point of physical delivery for any NYMEX contracts or trades that actually go to delivery; the Chicago Hub - which is important in terms of both its consumption position and its intertie position; and the AECO Hub in Alberta, Canada - which has become very important from a "basis" standpoint. With regard to the term, "basis," he explained that because natural gas is not fungible, and therefore cannot be moved easily to points where prices are higher, a phenomenon called "basis trading" has occurred. So not only does natural gas trade on the physical market and on the financial market, the difference in location also trades. He elaborated:

> In other words, if natural gas at the Canadian Border in British Columbia - a place called Sumas - could be $1 lower than [the] NYMEX one month, it could be $.50 lower the next month. That's called a "basis" or a "basis differential." And "basis" actually trades and trades very actively, and basis is even more volatile than the financial products - the commodity markets. ...

MR. HARPER then referred to a chart, which he said illustrates the basis differentials on August 22, 2005.

10:17:13 AM

CHAIR THERRIAULT asked whether basis is a differential for delivery.

MR. HARPER said no, adding that basis is just what the market believes the relative value of natural gas is at different locations. He mentioned that the AECO Hub is not a specific location; rather gas at the AECO Hub is simply gas that is "moving" - or being traded - on the [Nova Inventory Transfer (NIT)] pipeline system in Alberta. Again, basis is another word for location; because one can't physically bounce gas between locations, a basis differential has become a product that is traded. He then mentioned the term "load factor," describing it as how much capacity is utilized on an average basis over some period. Econ One's expectation, he remarked, is that Alaskan [natural] gas will be "base loaded" into the market, which he said means [the gas] will "move" everyday, adding that the decision regarding whether a supply of gas is base loaded or not has to do with "what happens if you don't produce [a thousand cubic feet (Mcf)] a day - when is that Mcf produced."

MR. HARPER said that in typical Gulf Coast, Gulf of Mexico, reservoirs, an Mcf that's not produced today might be produced 3 or 4 years from now. However in "coal seam" production or tight sand production - like the Barnett Shale in north Texas - an Mcf that's not produced today may not be produced for 30 years, and such may be the case in Alaska. This type of information can help determine, from an economic standpoint, what makes sense to sell now, and what makes sense to have stay off the market during non-peak periods. He went on to say:

> Traditionally, LNG has been base loaded, but I think increasingly LNG is going to ... come to be recognized in a much different way in U.S. markets, particularly foreign LNG, because it is the one fungible aspect of the natural gas business. ... You can take a cargo that's en route from "Trinidad Tobago," which is our largest supplier of LNG today, and you can divert it en route, and you can't do that in the pipeline business. So it gives you physical ... [options], it gives you financial ... [options], and so increasingly I think we will see LNG operate in a very flexible fashion.

10:21:21 AM

MR. HARPER said that basis shifts will always occur when there are pipeline and supply additions because the relative value between locations changes; for example, if Alaskan North Slope gas is delivered to Chicago, the difference in the price between the Chicago Hub and the Henry Hub will change. Changes in basis will also occur over time as additional adjustments in the marketplace occur. He then pointed out that particularly in the western sedimentary basin in Canada, as time has gone on, drilling in the region has moved westward and northward, and as a result, "increasingly lean" natural gas has been discovered. Natural gas in its native state often has other usable products in it - ethane, butane, propane, and other components. Such products exist in Alaskan [natural] gas. To the extent that Alaskan natural gas moves into Alberta, that will be a very positive thing because of the investments that have been made in that location, investments both in processing and in the utilization of feedstock, particularly ethane and propane.

10:23:09 AM

SENATOR FRED DYSON, Alaska State Legislature, offered his understanding that Econ One, by speaking about moving gas through Canada, is then operating under the assumption that Alaskan [natural] gas will enter into the mid-continental market rather than into other available markets.

MR. HARPER disagreed, and clarified that he is merely discussing possible outcomes under various scenarios, and noted that Alaska is not on the "pipeline" map he's been referring to because currently Alaska doesn't have an interstate pipeline for natural gas. He pointed out that on that map, Canada and the U.S. are not differentiated in any significant way, and surmised that this is due to the fact that [the pipeline systems of the two countries] function as a completely integrated infrastructure and are integrated commercially. The regulations promulgated by the NEB and by the "Alberta commission" remarkably mirror those in the U.S., and therefore "things" function on an interchangeable basis. Those that trade the business know no borders and simply consider there to be a North American market, he remarked, although that has not always been the case.

10:25:48 AM

MR. HARPER, on the issue of foreign LNG, said that currently, approximately 800 billion cubic feet (Bcf) of natural gas is imported through four terminals, and [this amount] is expected to double over the next five years. He assured the committee that from a market perspective, foreign LNG and Alaskan [natural] gas - whether delivered via a pipeline as LNG - are not competing because they fill different niches in the market. He noted that the largest of the four foreign LNG terminals is in Lake Charles, Louisiana, and that about 100 percent of the LNG supplies at that terminal are "spot" rather than "long-term contracts."

10:27:47 AM

MR. HARPER, in response to a question, offered his belief that the market has room and the need for both Alaskan natural gas - in any form - and foreign LNG. However, should Alaskan natural gas be converted into LNG, then it's points of entry [into the market] would come into play as a determining factor in certain decisions. With regard to the question of who will buy Alaskan [natural] gas, he noted that the market currently [requires] around 23 trillion cubic feet (Tcf) and is expected to [require] more. Those that would be interested in Alaskan [natural] gas include those that generate electricity - either for utility purposes or otherwise - and local distribution companies. With the collapse of Enron [Corporation] and other events, the "mid-stream part of the business" has eroded substantially, though this should reverse, he opined, thereby opening the door for existing trading houses and emerging "mid-stream" [entities] to play a very active role in purchasing Alaskan [natural] gas.

10:30:28 AM

MR. HARPER mentioned that foreign LNG projects and North Slope production-related projects have similar pricing concerns because of the long lead time required for large capital investments; the two types of projects also engender similar thoughts among those that view them from a market perspective, a financial perspective. Those that give consideration to the financial derivative products of one are also giving consideration to the financial derivative products of the other. There are a whole host of financial products in the natural gas business that allow one to manage price risks separate and apart from the commodity itself; for example, one can buy "puts" and "calls" for natural gas similar to what can be bought for stocks, and those products can in turn be used to create "collars." He went on to describe a "costless collar" as [a product] in which the price for selling and the price for buying are limited to an agreed-upon amount.

MR. HARPER said that of issue in the natural gas business is "forward liquidity," since the market doesn't trade actively on the NYMEX on the "out years," although [the market] is extremely active "two or three years out." He added, "People lock in positions, but they don't tend to lock in long-term positions; that's typically done in the over-the-counter market." He offered his understanding that there are costless collars currently being traded, for the period of 2010 to 2015, on the order of $5.75 on the downside and $8.50 on the upside. He pointed out that in noting that those kinds of deals are being made, he is not saying that the state should do something similar, rather he is merely making members aware that such things are occurring.

10:34:05 AM

MR. HARPER opined that the timing for having [Alaskan natural gas] enter the market is excellent, and that such a product would be a logical addition to the marketplace as it would not be competing on a mutually exclusive basis with any other supply project of which he is aware. There has been a pricing structural uplift and there is adequate pricing support, he concluded.

10:35:12 AM

REPRESENTATIVE SAMUELS asked whether the aforementioned seasonality would affect an Alaskan pipeline project.

MR. HARPER said no, adding his belief that it only makes sense for [Alaskan natural gas] to be physically base loaded into the market.

MR. HARPER, in response to a question, offered his belief that traditionally producers have not been eager to own interstate gas pipelines primarily because of concerns regarding the FERC and the possible regulations it might institute, particularly since natural gas, due to its lack of fungibility, is hauled on a contract basis through pipelines for the most part and thus is generally much more heavily regulated by the FERC than crude oil.

CHAIR THERRIAULT asked whether users of [natural gas] would want to lock into a long-term price, or whether they are moving "to more of a short-term contract pricing."

MR. HARPER indicated that although such users and local distribution companies are interested in and concerned about secure, long-term supplies, they are also concerned about the means by which natural gas is priced. He added:

> You can protect yourself pricing-wise through the physical contract by basically having market-responsive pricing, which you often see - so you've got firm supplies, but you've got pricing that moves with the market - [or] you can fix your price - you can fix it for part of the time or you can fix the price in the contract and then you can unlock that pricing by using these financial derivative products. It's a very complicated thing, but I think what's important for you to know is that there are people that want to contract long-term for these supplies - there is a place in the market for it - and there will be a variety of pricing mechanisms, I think, employed across that backdrop.

10:39:17 AM

SENATOR TOM WAGONER, Alaska State Legislature, referring to a comment made earlier by Mr. Harper, asked why Alaska should even consider letting its NGL be processed in Alberta.

MR. HARPER said he was simply pointing out that the Canadians view NGL as attractive and that the infrastructure to process it already exists in Alberta. He added that traditionally producers have performed the role of extracting liquids from natural gas, and that the gathering and processing assets for doing such are predominantly owned by producers in the U.S.

SENATOR WAGONER asked how many "barrels, equivalent, of liquids," for example, could be obtained from sending 5 Bcf per day through a pipeline system.

MR. HARPER said the calculation is about six to one.

SENATOR DYSON asked whether processing NGL in Alaska might be "a deal breaker for a TransCanada pipeline."

MR. HARPER said he doesn't have an opinion on that issue at this time, though he can appreciate TransCanada's interest in it.

SENATOR DYSON asked what the price of [foreign] LNG would be on the West Coast.

MR. HARPER indicated that [foreign LNG] would come in at the highest price that can be obtained, adding, "It will price itself so that it can move at the market prices that are present."

10:42:46 AM

ANTHONY FINIZZA, Ph.D., Consultant, Econ One Research, Inc., said that the view is that LNG could be, cost-wise, delivered at something like $3.50/mmBtu, though it will be selling at the market price - or higher - of the location where it arrives. He pointed out that LNG would not be setting that price. In response to another question, he relayed that the view is that a cost of $3.50[/mmBtu] would allow a competitive return to the producer, and so any price above that would be even better.

SENATOR DYSON asked whether it would be the case that [foreign] LNG landed at "Long Beach" could not be transported via pipeline to the Midwest market and "beat our gas for price" if the best long-term market for natural gas does indeed prove to be the Midwest market.

MR. HARPER concurred; adding that the basis differential would be affected, but pointed out that such would not result in competition for the product because "those are two different regional markets." In response to another question, he said that a product which lands on the West Coast would not naturally seek to move to the Midwest, so prices would only be affected through the basis interaction. He pointed out that "there's just no highway that exists in that fashion," and therefore he doubted that even a substantial basis differential would stimulate pipeline production between the West Coast and the Midwest.

10:45:28 AM

REPRESENTATIVE LES GARA, Alaska State Legislature, said:

> I just want to follow up on a question that Senator Therriault asked you in the address ... and this addresses the question of whether or not a gas leaseholder would have to fear the return of $2.00 gas. So, one of the things we've always been told is the gas pipeline is potentially not feasible because what if gas prices went down to $2.00 again and then you addressed well you can enter into possibly long-term price contracts mitigating that risk. ... Should we be certain that if ... a leaseholder wanted to sell us gas at a 10-year-locked in price, they could or ... is that a maybe. Is it a definite that ... we could sell the amount of North Slope gas at a locked in price over the next 10 years something similar to the futures price that you had listed on one of your charts, or is that a big maybe.

MR. HARPER replied:

> I think ... it's worthy of consideration, it's certainly not a part of what we've done here as this point. But, yeah, I think ... you would want to look at your options.

REPRESENTATIVE GARA asked:

> But ... would there actually be a market if the leaseholders said, "We do want to lock-in a price for 10 years." Would there be a market for 10 years worth of Alaska gas at a locked-in price?

MR. HARPER answered:

> Yes, yes you can hedge forward. Let's say that we fast-forward now, it's 2012, and you want to lock in your price to 2022. Yes, you could do that through the physical and/or the financial markets. You can absolutely do that at that point.

10:47:01 AM

SENATOR WAGONER asked at what price would gas become vulnerable to other energy sources.

MR. HARPER said at between $4 and $5.

10:47:35 AM

MR. PULLIAM relayed that Dr. Finizza, the next speaker, will address current and future natural gas prices and what the tariffs for moving gas from Alaska will likely be.

DR. FINIZZA said that the background information he will be presenting is derived entirely from studies that are now available to the public, and that he would also be illustrating some of the key uncertainties that should be considered by long-term players in the gas market. Referring to a portion of his PowerPoint presentation, he said that it is expected that the demand for natural gas in North America will grow to roughly 30 trillion cubic feet (Tcf) by the year 2025. A common feature [of forecasts] is that existing supplies are not going to increase, that one must reach out for other sources of natural gas. Directing members' attention to what he called "the wedge to the right," he said, "The studies envision them to come from Canadian sources - Mackenzie Delta, LNG, and Alaska gas." By way of comparison, most forecasts envision Alaska gas as representing approximately 5 percent of the supply source in 2025. Regardless of the study one considers, he remarked, all paint a similar picture.

DR. FINIZZA offered his belief that [prospective] long-term players [in the gas industry] should consider three main issues: the strength of the natural gas market over time, the extent of LNG penetration one could logically expect in a given time period, and the role of competition between gas and alternative energy. He relayed that [the common view for the future is that] the natural gas supply would be "flat," that there would be increases in Canadian supply, that LNG would be somewhat limited from foreign sources, and that Alaska natural gas [could be expected]. Natural gas is going to play a major role in forecasts, particularly with regard to the generation of electricity, he remarked. However, he warned that "this gas doesn't have a free ride here" because there are other competitive sources for base load electricity, notably coal and nuclear sources. With regard to the industrial sector and the household and commercial sector, he suggested that growth will be in line with "income" growth.

10:52:45 AM

DR. FINIZZA, with regard to the transportation sector, said that [most forecasters think that] there won't be much "penetration," though there are those who are envisioning a hydrogen-fueled automobile sector in the future, but that hydrogen would initially be created by reforming natural gas. He relayed that most people think that natural gas prices are currently at a cyclical high, and therefore he reminded members that they should not expect such prices to continue. He then referred to a table on page 3-5 of his PowerPoint presentation, and indicated that it was compiled from the last forecast made by the U.S. Department of Energy's (DOE's) Energy Information Administration (EIA). This chart indicates that natural gas consumption in the U.S. will grow from 22.3 Tcf this year to 30.6 Tcf in the year 2025 - an increase of 8.3 Tcf - and half of that increase will be due to an increase in consumption by electric utilities.

DR. FINIZZA mentioned that studies indicate that 75 percent of all new electric generation capacity will be from natural gas. With regard to the strength of the natural gas position, he remarked, one would have to question whether it could actually penetrate the electric utilities [sector] as depicted in this chart. Dr. Finizza went on to say that studies envision that LNG will be coming into the supply mix at approximately 3 to 4 Tcf per year by the time Alaska is at 1.5 Tcf per year. He reiterated that the view is that LNG, from a cost-basis, could be delivered into the U.S. market for between [$3.00] and $3.50/mmBtu, but, again, will be sold at prevailing gas prices. There are limited "regasification" facilities now, and a lot of people are arguing against establishing any such facilities in their area.

DR. FINIZZA offered his belief that LNG is not going to be of concern since it is not going to be "the marginal supply" and thus it will not be setting prices. Rather, gas prices will be set by the "higher-cost, Lower 48 supplies." The big threat to natural gas, he explained, comes from alternative energy sources, particularly with regard to electricity generation. For example, combined-cycle gas turbine technology is in place now and has a break-even point of around $4.00/mmBtu.

10:56:48 AM

REPRESENTATIVE HAWKER asked for clarification regarding the recent comment that LNG is not a marginal supply and so will not set future gas prices, and an earlier comment that LNG will be a marginal source of supply.

DR. FINIZZA said he was simply using the term "marginal" to emphasize that LNG will not be setting the "marginal price."

MR. HARPER said he was simply using the term "marginal" from a physical standpoint with regard to seasonal changes and base loading.

10:57:37 AM

DR. FINIZZA, returning to his presentation, said that "the coal people" have also noticed the high price of natural gas and so are working on a "clean coal technology" that "gasifies" coal and utilizes a combined-cycle process. The thinking, he remarked, is that such technology might be competitive in the $4.00-$5.00/mmBtu range. He opined that any sustained natural gas price above $5 could accelerate the development of the aforementioned alternative technologies. He indicated that his PowerPoint presentation contains natural gas price forecasts from the EIA, the National Committee on Energy Policy (NCEP), the NYMEX futures market, and a number of Canadian gas consultants.

11:00:43 AM

DR. FINIZZA, referring to page 3-9, said it illustrates the EIA's Annual Energy Outlook (AEO), and that it forecasts prices out to the year 2025 but doesn't reference inflation. This forecast uses "a number of sensitivities" such as low oil price, high oil price, and low economic growth. He relayed that the EIA will go to a probabilistic model for the year 2006 because it has realized that the spread of forecast in the 2005 AEO was not very great and so has "not stated the full sensitivity of future gas prices." He referred to a bar chart on page 3-10 and said it reflects various forecast averages for the years between 2012 and 2025. These forecasts are based on the Henry Hub price, are all in "real" terms, and all pertain to dollars per mmBtu. The left-most bar and the right-most bar, he remarked, represent probabilistic forecasts, while the other six represent average forecasts of various studies done for this 14-year period. The average of those six forecasts amounts to approximately $4.71/mmBtu.

DR. FINIZZA said that the aforementioned left-most bar indicates that there is only a 10 percent chance that prices would fall below the listed amount of $2.76. The aforementioned right-most bar indicates that there is only a 10 percent chance that prices will be above the listed amount of $6.39. Dr. Finizza said that the NYMEX futures prices do reflect the market's expectation of future gas prices, although it isn't that accurate. However, the NYMEX does outperform many forecasters, including the DOE, and therefore should be considered a forecast element.

11:04:14 AM

DR. FINIZZA turned attention to page 3-12 of the presentation, which is a graph of the average view of the NYMEX futures market over the 12-month period of July 2005-June 2005. In viewing this over that one-year period, the market view in 2010 would be about $5.25 in real terms, declining from today's level. Dr. Finizza turned to what this means when gleaning the possible prices when evaluating this major project. He informed the committee that it's considered best practices to review a range of prices. Therefore, one should review a low/stress price case as well as an expected price. With regard to determining possible expected prices, NYMEX offers a market forecast that's about $5.00 [/mmBtu] and the average of publicly available forecasts is about $4.75 [/mmBtu].

DR. FINIZZA said that in order to determine the stress price, one could review what rating agencies use. The rating agencies view a stress price as one that would allow the project to have a fair return [at the stress price] and thus [the project] would remain operative. [Moody's and the S&P] seem to be using a stress price of $3.75 [/mmBtu]. One could also use the mean less two standard deviations from NYMEX, which is about $4.00 [/mmBtu]. Although some have used $3.50 [/mmBtu] as a stress price case, that seems a bit low, he opined. He then reviewed a high price case in which [the price is] the mean plus two standard deviations from the NYMEX market, which is about $6.00 [/mmBtu]. Dr. Finizza noted that this range of prices from the publicly available studies are consistent with competitive prices from the alternative energy and electric utility sectors.

Therefore, he opined that it would be an adequate set of prices to view projects of this type.

11:09:21 AM

CHAIR THERRIAULT highlighted that the long-term price is integral and critical to evaluating the project and its cost and return to the various parties involved.

11:11:07 AM

DR. FINIZZA moved on to the matter of pipeline costs, as provided in the public domain. The pipeline costs can be used to derive an implied tariff, which can be placed against the earlier outlined prices in order to derive likely netbacks under [various] scenarios. He then reviewed page 3-15 of the presentation, which is a spreadsheet showing projected public pipeline costs. He related that the producers have reported that the pipeline costs would be plus or minus 20 percent, and the Tristone Capital estimate is within that estimate. He then highlighted that the producers project the total pipeline cost from the North Slope to Chicago to be $21 billion, in 2005 dollars.

11:13:33 AM

SENATOR DYSON assumed that the cost projections on page 3-15 are referring to a simple "bullet line" rather than tying into the existing excess Canadian capacity.

DR. FINIZZA agreed, and added that the estimate of pipeline costs from Gordondale to Vereville was made by Econ One on the basis of mileage and differential cost of pipe. He specified that if the $7.8 million was broken down into two pieces, it would be roughly a two-third:one-third split. He mentioned that there could be a proposal to only bring the pipeline to Gordondale.

11:15:12 AM

SENATOR DYSON asked if Econ One assumed that present permits in place for the route will prevail.

DR. FINIZZA clarified that his assumptions are those that the producers made. He explained that Econ One tried to take the presented pattern of capital costs and, using Econ One's model and some assumptions, tried to calculate the pipeline tariffs for each segment. The chart on page 3-16 assumes that the project ended at Gordondale and it also assumes publicly available capital, 4.2 Bcf/d sales, an 80:20 debt/equity ratio, 14 percent allowed rate of return for the U.S. and 12 percent for Canada, and debt of 5 percent. With those volumes, the total tariff from the North Slope to the Gordondale market is estimated to be $1.14. If the gas treatment plant at the North Slope is included the estimated tariff is $1.43.

11:17:03 AM

DR. FINIZZA continued with page 3-17, which related the implied netbacks under alternative gas prices. The chart on page 3-17 uses initial values and start with the Chicago price in 2004 dollars, which will increase with inflation whereas tariffs won't. The differential between Chicago and the AECO Hub would be about $.90 [/mmBtu]. Ultimately, the implied netback at the Inlet to pipeline will range from $1.68 [/mmBtu] for the stress price to $3.68 [/mmBtu] for the high price case. In order to determine the implied netback to producers, the operating costs and fuel loss ranging from $.07 to $.11 would have to be deducted as well as the royalty and tax value. Ultimately, the netback to the producers would range from $1.27-$2.83 [/mmBtu]. In response to Chair Therriault, Dr. Finizza clarified that the [projections] were done under the current fiscal structure.

11:20:03 AM

CHAIR THERRIAULT informed the committee that should there be a proposal, the committee would have to run a 30-day public comment period, at a minimum. Although the price and costs are important for evaluation purposes, the committee doesn't assume the role of saying yes or no. The committee only runs the public comment period, after which the contract goes through the legislative committee process and comes before the legislature for review. Therefore, the committee's [responsibility] is to ask questions on behalf of the public regarding whether a good and fair proposal has been brought forth.

11:20:59 AM

SENATOR WAGONER inquired as to why the operating costs and fuel use vary across the four cases. He related his understanding that those are fixed prices.

DR. FINIZZA indicated agreement that the operating costs [are fixed]. However, he pointed out that there is fuel loss and thus the applied value increases as the value of gas increases. In response to Chair Therriault, Dr. Finizza specified that the numbers in the operating costs and fuel use reflect the fuel lost in the line and the operating costs in the upstream.

11:22:10 AM

SENATOR BEN STEVENS returned attention to page 3-2 of the presentation and recalled that Dr. Finizza mentioned that the Alaska portion would be 5 percent of the total. He asked if that would be 5 percent of the total gas consumption in 2025.

DR. FINIZZA replied yes. In further response to Senator Ben Stevens, Dr. Finizza clarified that the LNG is foreign LNG.

SENATOR BEN STEVENS inquired as to the volume Dr. Finizza is projecting from Alaska. He further inquired as to whether it was LNG volume or gas volume.

DR. FINIZZA said, "The Alaska number here that they have, although it's presumed to be pipeline, would be the same if they thought it was LNG." In further response, Dr. Finizza said that volume would be 1.5 Tcf a year and the foreign LNG is roughly double that.

11:23:45 AM

SENATOR BEN STEVENS then turned the committee's attention to page 3-6, specifically the last bullet, which read: "LNG is not marginal supply and will NOT set future gas prices. Set by needed higher cost L-48 supplies". He asked if Alaska is being compared with the Gulf of Mexico production.

DR. FINIZZA answered that it's a combination of Lower 48 fields, including the Gulf of Mexico. He noted that almost all the analysis done for these studies review the supply curves for each region. The alternative sources of supply are studied by basin. Therefore, Alaska is compared to all the supply basins in North America. In further response to Senator Ben Stevens, Dr. Finizza confirmed that Alaska would be a gas price taker.

11:25:07 AM

DR. FINIZZA, in response to Senator Dyson, clarified that [on page 3-2] the consumption to which he was referring was Tcf per year.

11:26:06 AM

REPRESENTATIVE GARA directed attention to page 3-17 of the presentation and opined that one assessment that will be desired is the profit margin this forecast would leave the leaseholders. He then asked whether the netback is the profit.

DR. FINIZZA replied no, and added that the profit margin will be addressed in the afternoon. In further response to Representative Gara, Dr. Finizza confirmed that under the stress price case on page 3-17, there would be some profit.

11:27:55 AM

MR. PULLIAM continued the presentation with packet four, which discusses the return on capital and cost of capital as those relate in the petroleum and natural gas pipeline industries. He began by explaining that measures of profitability that are used, particularly in the petroleum industry are return on capital employed (ROCE) and return on shareholder equity (ROE). Although both look at measures of profit over an investment base, they do so in different ways. The ROCE is one of the most widely used measures of profitability. He explained that capital employed is the sum of capital a firm has either through the issuance of equity or debt. In this context capital companies are measuring the book value of that capital. However, the book value of that capital may not reflect today's market value. He then explained that ROCE is measured by after-tax profits without the cost of debt financing and then that profit is looked at over the total amount of debt and equity. The aforementioned is referred to as the operating profit before financing costs over capital employed.

MR. PULLIAM said that ROE is how the firm's profits look relative to what shareholders have invested and thus it's merely income over the value of the stock from a book value basis. This takes into account any potential benefit the company receives by issuing debt. Therefore, after all the debt and costs are paid there will be a profit, net income, which is reviewed relative to the amount of equity in the company.

MR. PULLIAM then turned attention to how these measures have looked over the years [as illustrated on page 4-5] in relation to the three major producers. On average [the producers] have enjoyed ROCE just under 15 percent. Page 4-6 is the same chart with an average ROCE for the three major producers. Page 4-7 includes TransCanada's ROCE, which he said would be similar to what one would see for many gas pipeline companies. Obviously, the [ROCE] for TransCanada is quite a bit lower, about 7 percent, than that of the petroleum companies, which is attributed to the fact that the gas industry is a very different business. TransCanada operates a gas pipeline that's in a regulated environment with regulated returns. The ROCE is consistent with the risk involved in the business. Page 4-9 is a chart that illustrates that crude oil prices have been generally rising, particularly since 2000. He highlighted that the rises and falls are in rough approximation with commodity prices because the majority of the assets in the petroleum industry are in the upstream. Page 4-10 provides averages over the last 5-10 years for the various petroleum companies as well as TransCanada.

MR. PULLIAM moved on to page 4-11, which reviews return on shareholder equity. These numbers are a little higher than ROCE numbers because they reflect the advantage of employing debt in the business. He noted that typically the petroleum industry doesn't employ a lot of debt, while the pipeline industry does. The chart on page 4-12 shows the average ROE over 10 years, which is about 17 percent. The chart on page 4-13 illustrates what a gas pipeline company would look like in that picture. The chart shows that the returns are higher relative to ROCE because gas pipelines employ more debt and thus the ROE is going to be proportionally higher for those companies. However, the ROE is going to be lower than it is for the petroleum industry because of the different, regulated, operating environment. The chart on page 4-14 shows the average of the producers and TransCanada. The chart on page 4-15 illustrates the returns relative to commodity, energy, and prices. Again, the petroleum price moves with the change in commodity prices over time. However, that's not the case with the gas pipeline industry. Page 4-16 shows the average ROE over the past 5 years and 10 years.

11:41:48 AM

MR. PULLIAM then directed attention to page 4-17 and the weighted average cost of capital (WACC), which is the cost of attracting capital to a project. The WACC is equal to the average cost of the firm's debt and equity, and it depends upon the proportion of debt and equity in the firm's capital structure. Furthermore, the WACC is based on the market value of the firm's debt and equity. As specified on page 4-18, the WACC is measured after-tax costs. He related that the after-tax debt is generally lower than for equity because debt is tax deductible. Furthermore, the after-tax cost of debt is equal to the borrowing cost. Mr. Pulliam moved on to page 4-19, which specifies that the cost of equity is commonly measured using the capital assent-pricing model (CAPM). The CAPM is based on the returns of a company's stock relative to a risk-free return and the overall market returns. Page 4-20 illustrates how CAPM calculates the cost of equity. The first example is the risk-free rate in which the firm is viewed as having an equal risk as the market. He then reviewed the two examples of cost of equity, which take into account the risk-free rate, the market risk premium, and the company specific beta. The beta is the relationship between a company's risk and the market overall. Therefore, a company with a risk level equal to the market would have a beta of 1.0 and thus its cost of equity would be the risk-free rate plus the market risk premium times a factor of one. The second example on page 4-20 is one with risk equal to half the market-wide average, which is about where the petroleum industry has been over the last few years.

11:47:56 AM

REPRESENTATIVE SAMUELS inquired as to what the financial markets review when determining a company's beta.

MR. PULLIAM specified that a beta is the variability of a given company's return versus that in the market overall.

11:48:37 AM

MR. PULLIAM, continuing with page 4-21, highlighted that petroleum and natural gas pipeline industries typically have a beta less than 1.0. In fact, the 2004 betas for the companies being discussed ranged from 0.25 to 0.83. Page 4-22 shows a WACC calculation for the four companies being discussed. He reminded the committee that petroleum companies typically don't employ much debt but rather are highly weighted toward equity. However, gas pipeline companies issue a lot of debt. For example, TransCanada's debt equity ratio is about 50:50. The chart on page 4-23 illustrates the WACC for the specified petroleum companies during 1995-2004. The WACC for the specified petroleum companies has decreased a bit since the mid 1990s and went fairly flat in the late 1990s because of lower interest rates and lower betas. The chart on page 4-24 illustrates the average of the three specified petroleum companies, which reflects the aforementioned pattern. On page 4-25, the aforementioned chart includes TransCanada's WACC, which has a lower cost of capital. The chart on page 4-26 illustrates the average of the two industries. Mr. Pulliam then turned to the chart on page 4-27, which contrasts the capital costs with the commodity prices. The chart illustrates that capital costs have decreased as energy prices have increased. The final chart on page 4-28 of packet four shows the average WACC over 5-10 years. He emphasized that the WACC numbers will become important [as the process continues] because they impact the view of project financing and the viability of a project. Mr. Pulliam noted that the WACC is company-wide and doesn't reflect any specific project but rather are starting points.

11:55:20 AM

SENATOR HOLLIS FRENCH, Alaska State Legislature, asked if one could assume that TransCanada enjoys a significant advantage over petroleum companies when it comes to financing this project because its cost of capital is so much lower than that of the oil companies.

MR. PULLIAM replied no. However, he pointed out that a gas pipeline project would be consistent with TransCanada's business. He reiterated his last point regarding the fact that the WACC is for a firm and doesn't reflect a project specific capital cost.

11:56:29 AM

[DR. FINIZZA] indicated that the kinds of capital costs that accompany a pipeline project are lower than the types of capital costs that accompany upstream investments and such projects.

11:56:59 AM

CHAIR THERRIAULT inquired as to what is included in upstream investments.

[DR. FINIZZA] answered investment in development, exploration, and marketing of the commodity itself as opposed to the transportation.

11:57:21 AM

REPRESENTATIVE SAMUELS asked if one can assume that the numbers presented don't include any implications regarding the possibility of federal loan guarantees, although [the federal loan guarantee] will be a factor in the capital market.

MR. PULLIAM said that [taking into account the federal loan guarantee] typically would provide a lower cost of debt than what's reflected in the numbers presented.

11:58:13 AM

SENATOR HOFFMAN asked if the federal loan guarantee would give one company more of an advantage than another.

MR. PULLIAM replied yes, to the extent the company is a higher [risk] rated company to begin with. The difference between a federal loan guarantee rate and the rate at which it can borrow may be less than a company that's not as highly rated.

11:58:57 AM

SENATOR STEDMAN referred to page 4-22, and surmised that a company with a lower cost of capital, everything else being equal, would probably be more profitable for shareholders and thus that company would be more interested in the project.

MR. PULLIAM said that he didn't know whether he would agree with that because [the interest a company has in a project] would be driven by the risk of the project itself. In fact, a company with a higher cost of capital might still do the project. He suggested that companies should view the project not just based on the cost of capital, but should be making adjustments to reflect the specific project.

SENATOR STEDMAN posed an example in which a project returns 10 percent, and opined that a project with a 7.6 percent cost of capital would be more beneficial than a 9.3 percent cost of capital.

MR. PULLIAM said in the end it should be equally beneficial to them "because it's going to reflect, again, it's going to be what the market is going to require like the economics of the project itself."

12:02:40 PM

DR. LEITZINGER opined that two things are going on with the numbers. He indicated that the numbers reflect the differences in companies' operating abilities as well as different historical choices regarding the types of risks taken. However, when reviewing the possibility of all the companies potentially participating in the same project, one doesn't know whether there would be cost advantages or capital cost savings across companies.

12:05:07 PM

SENATOR STEDMAN suggested reviewing this from a shareholder's perspective because the goal of a company is to increase shareholder wealth. He suggested that if a project had a return of 8.6 percent, the company with return on capital [WACC] of 7.6 percent would increase shareholder wealth while the company with a 9.3 percent [WACC] would decrease shareholder wealth. Therefore, it would seem that the company with increased shareholder wealth would be interested in doing the project, he surmised. He asked if the aforementioned is a use of the numbers [on page 4-22] on a macro level, a sort of "30,000 foot" overview.

MR. PULLIAM indicated that Senator Stedman's points were fair to draw at the "30,000 foot" overview level.

12:07:08 PM

CHAIR THERRIAULT pointed out that [Senator Stedman's case assumes] that all things are equal [between the companies and possible contracts], which isn't the case.

12:07:46 PM

DR. FINIZZA interjected that if the four companies [mentioned on 4-22] were doing the same project and assessed its risk the same, then they shouldn't be using different discount rates. In such a situation, the companies should also compare the expected cash flow to the cost of capital adjusted for the risk, which he predicted wouldn't be 6 percent but probably more in the range of 10-12 percent.

12:08:30 PM

REPRESENTATIVE GARA returned the committee's attention to page 4-7. He asked if he would be correct in his assumption that if a company builds a pipeline, then it should only assume a rate of return of other pipeline companies and not the rate of return of production since it is just building a pipeline.

UNIDENTIFIED SPEAKERS replied yes.

REPRESENTATIVE GARA surmised then that a production company could take its money and make 20 percent elsewhere, and therefore decide not to build a pipeline for a 10 percent rate of return.

12:10:43 PM

CHAIR THERRIAULT announced that the committee would break for lunch and members should return at 1:30 p.m.

1:36:07 PM

CHAIR THERRIAULT called the committee back to order at 1:36 p.m.

1:36:30 PM

MR. PULLIAM recapped the morning's presentation and said that now the presentation will turn to decision-making and possible results of [Econ One's] modeling efforts. He then turned the presentation over to Dr. Finizza.

1:38:06 PM

DR. FINIZZA said he would be discussing decision making, which he suggested is more complicated than he can portray. He highlighted, on page 5-2, questions that oil and gas companies ask when looking at projects. Dr. Finizza opined that the key approach will be discounted cash flow in the evaluations. An estimate of cash flows, he explained, is taken to the firm and discounted at the expected rate of return that they will realize on similar investments of the same risk type. He highlighted the need to recognize the risk-return relationship and the importance of evaluating projects on a risk-adjusted cost of capital basis. He then clarified that this is for an incremental project, and a project with a positive net present value (NPV) is a candidate for acceptance. Dr. Finizza then turned to page 5-6, which presents a stylized cash flow table. In year one of the proposed project, the [expected project cash flow is negative $16 billion capital investment, but from that point forward there are positive cash flows to 2042. That stream of cash flows can be analyzed and can be used to equate the NPV at a specific discount rate [as specified on page 5-6]. He then pointed out that there are variations on NPV in that someone may measure NPV per barrels of oil equivalent (BOE) found or used in the project [as mentioned on page 5-7]. However, since NPV is sensitive to price forecast, the measure would be the division of NPV by the total gas brought to market in the project. He highlighted that although [BOE] isn't a criterion that stands on its own because NPV has to be calculated to get [BOE], some people will look at the measure. Dr. Finizza relayed that $1.00 per BOE is typical of high infrastructure, capital-intensive gas projects such as LNG. Therefore, one would probably look to see something greater than $1.00 per BOE to be in the upper half of the range of projects.

DR. FINIZZA continued with page 5-8, which reviews the Internal Rate of Return (IRR) measure. He explained that the IRR is the discount rate at which the NPV of the cash flows is equal to zero. He informed the committee that a project with an IRR greater than the risk-adjusted cost of capital would be a viable project when there are no capital constraints. However, the year in which such a project is accepted may not be the year in which it's started. Without significant risk factors, IRRs in the 12-15 percent range are viewed as the threshold rate of return. He related his belief that energy companies are developing alternative projects in the 15-20 percent range.

DR. FINIZZA turned to page 5-9 regarding the Profitability Index (PI), which is helpful in examining the case when there are capital constraints. The PI is simply a ratio of the present value of cash inflows divided by the present value of cash outflows, which is referred to as the "biggest bang for the buck" by those who aren't economists. Therefore, any project with a positive NPV would have a PI greater than one. He highlighted that the main use of PI is to allocate capital when there are capital constraints, which can be accomplished by calculating the PI for all the projects in the portfolio, rate them from high to low, and choose the projects in sequence to the point of capital constraint. He cautioned the committee to be wary of different PI definitions as noted at the bottom of page 5-9. He then reviewed the chart on page 5-10, which illustrates one stylized way in which the profitability index could be done. The chart on page 5-11 discusses undiscounted cash flow criteria, which is the sum of all the cash flows in a project without discounting. The undiscounted cash flow isn't used for key investment decisions, although it's often used to present the magnitude of the project. He stressed that [the undiscounted cash flow] violates everything about discounted cash flow analysis and suffers from the failure to reward cash early. The graph illustrates that the NPV is 50 percent higher with the cash early at a 10 percent discount rate. Dr. Finizza stated that in decision-making, one would always want to take [the project] with the highest NPV. He then reviewed [as related on page 5-12] how one might use the financial metrics he has discussed.

1:53:27 PM

DR. FINIZZA pointed out that one could also compare a gasline proposal with another gasline proposal or with the status quo. Using NPV for the following comparison would be useful with the caveat that risk may differ between proposals, and therefore one should be cautious with that. The earlier discussed financial metrics could also be used to evaluate a delay in the gasline, which he indicated would use NPV rather than IRR. Dr. Finizza turned to risk and [incorporating it in the discount rate as reviewed on page 5-13]. He related that as a practical matter, people tend to review adjusting the discount rate. He then provided the committee with an idea of various alternative costs of capital, which are based upon market data and country credit ratings. As noted on page 5-13, the U.S. and other countries in the Organization for Economic Cooperation and Development (OECD) have similar [costs of capital]. However, lesser-developed countries such as Qatar and Venezuela produce [costs of capital] in the range of 21-25 percent. Therefore, using the same discount rate when comparing Qatar and the U.S. wouldn't be valuable. Dr. Finizza stressed the importance of comparing apples to apples, although he acknowledged the difficulty in doing so. He then related that riskier projects should provide greater return while less risk should be mirrored in a lower discount rate.

DR. FINIZZA acknowledged that companies making decisions of this magnitude won't rely on metrics alone [as specified on page 5-14]. Additional issues will be raised such as: does the company have the personnel and skill set to do the project at this time; does the project distract management from other things; does the project size offer economies of scale; is the project discretionary; what is the effect of a delay on project economics; are there contractual obligations that impact timing; does the project offer improved diversification; and does the company have a competitive advantage in the project?

1:59:39 PM

DR. FINIZZA noted that Econ One has presented what it believes to be reasonable prices, but the question becomes what one would logically expect an oil and gas company to use for their economic evaluation. The price is key and is the most important part of the calculation. He noted that producers have been burned by high gas price projections, [and therefore] it's likely that producers will test projects at a price path below their most likely view. He explained, "In a sense, [producers] are high-grading their projects by picking a price that would be actually below what they really, really believe." Having watched oil and gas companies, Dr. Finizza opined that the price view of the oil and gas companies [are below] the market price view by several years on the way up, but correct quickly coming down. He further opined that the current view of most oil companies in evaluating projects would be $24-$26 oil that would translate to $4.00-$4.25 gas. Producers will also stress test the project against what is viewed as a low price, which may be $3.50 [/mmBtu] that corresponds to about $22 in oil prices. He attributed this, in part, to [the fact that] the consequences of error aren't symmetric. If a producer underestimates the future path of prices, it will not undertake high-risk projects. However, returns will skyrocket when the future prices come to bear. If a producer overestimates future prices, such as in the 1990s, the producer will miss opportunities but the misses won't be fully penalized by the market. The aforementioned lack of symmetry is illustrated in the chart on page 5-16.

2:04:34 PM

REPRESENTATIVE KERTTULA returned attention to the graph on page 3-17, and asked if the graph includes federal and Canadian taxes.

DR. FINIZZA clarified that it's before income tax.

REPRESENTATIVE KERTTULA surmised then that it's before the federal taxes and thus would be the same on the Canadian side.

2:06:01 PM

DR. LEITZINGER informed the committee that he would be discussing the analysis of project viability with vertical components, which begins on page 6-1. He explained that projects can be thought of as having two distinct components: an upstream component that involves the development and marketing of the resource and a midstream component that is the construction of a delivery system to take the resource to market. The fundamental question that Econ One has reviewed is in regard to what is required, as an economic matter, to make the development of a gasline project viable and economic. The aforementioned really starts as an upstream matter, but in light of the need for a pipeline the question becomes where to look.

The question of where to look, as addressed on page 6-3, becomes a question of what owners/producers must do to bring the gas to market and commercialize it. If the only way for the project to happen is for the producers to build the pipeline, then the pipeline itself becomes part of the cost to the owners of the reserve. The aforementioned is one in which the economics should be considered as an integrated project. However, Dr. Leitzinger said he didn't believe that's the situation with this project because today a regulated pipeline is viable as a stand-alone investment. Still, he acknowledged that the producers might want to pursue an integrated project, but that would only be the case if the project's economics are improved by the producers owning the pipeline as well. However, the aforementioned shouldn't drag the project down.

2:13:18 PM

CHAIR THERRIAULT asked if the upstream economics are the sale price minus the transportation cost and whether any value is left to bring the resource to market.

DR. LEITZINGER indicated that Chair Therriault was correct. He clarified that when he discusses economics, he thinks of it as an investment project in which the value of the gas is the market [value] less the cost of getting it there. The question then becomes whether that return over time makes sense given the upstream investment necessary to bring that about. The aforementioned differs when one decides that the only way for this project to move forward is for the producers to build the pipeline, in which case part of the producers' investment and part of the evaluation of the economics would include the capital costs associated with having to build that line. Dr. Leitzinger said that with the clear indication that the pipeline is viable on a stand-alone basis it seems correct to think about whether it's viable to proceed based on the upstream economics. If the upstream economics are attractive, the project overall should be viable, he opined.

2:15:07 PM

DR. LEITZINGER posed a situation in which the focus is on the upstream economics, which leads into the question of how one should consider the interface between the upstream costs and the transportation costs. He opined, pointing to history, that it's reasonable to suppose that regulated pipelines traditionally don't make for good gas merchants. Therefore, he didn't expect a circumstance in which the producers in the upstream would sell gas at the entry point to the pipeline. Instead, he expected that the owners of the upstream resource would pay for transportation and move that gas downstream to trading hubs such as Chicago. Given the current regulations, pipelines would typically follow a cost-of-service model, an allowed rate of return, and a lifetime pipeline tariff. He then opined, in relation to transfer prices, that upstream capacity commitments to pay for the fixed costs of the capacity will be necessary. In a situation in which the producers pay as they go for the use of the pipeline, the incremental costs of using the capacity may discourage continued gas marketing and interfere with the overall economics of the project. One of the risks the pipeline owners face when investing in a pipeline is whether the upstream producers will continue to bring gas to market. He reiterated the need to have capacity commitments.

DR. LEITZINGER turned to the meaning of capacity commitments in terms of the economics of the project [as discussed on page 6-5]. He clarified that a capacity commitment doesn't mean it becomes an integrated projected. "To say that I make a capacity commitment to buy service from you as a pipeline over time is not the same thing as saying I own the pipeline," he further clarified. Capacity commitments are used frequently down South between owners and shippers of gas and regulated pipelines. Still, those remain separate companies and separate commercial transactions. Furthermore, a capacity commitment isn't the same as debt nor is it a consumer of the company's debt capacity. Moreover, capacity commitments aren't advances of capital. Capacity commitments, he explained, are contractual agreements over time to continue to pay to use the facility. Also, a capacity commitment doesn't mean that the borrowing capacity of upstream producers would be limited or reduced. Dr. Leitzinger specified that a capacity commitment does change expected cash flow and risk. If one agrees to a capacity commitment as a shipper, then that individual is committed to continue paying the cost, even in a world with very low prices. Therefore, a capacity commitment creates an effect on expected cash flow and increases the risk of the owner of the resource. However, both effects are small in the present context, he opined.

2:25:38 PM

DR. LEITZINGER then turned attention to the graph on page 6-6, which illustrates that with a nominal Alberta price of $8.00/mmBtu produces a netback of about 6.25. He explained that the prices on the graph include inflation. Therefore, a price in Alberta just over $8.00 [/mmBtu] with a 2.5 percent inflation assumption is the same as the real price of $5.00 [/mmBtu]. The graph on page 6-6 illustrates the economics without a capacity commitment. As long as the price in Alberta is more than $1.75 [/mmBtu], there is margin to be made by moving the gas to Alberta. In a situation in which there are no capacity commitments, the project would shut down. The graph on page 6-7 illustrates that gas prices and netback with a capacity commitment stay the same for all the prices for $1.75 [/mmBtu] and above. However, when prices are less that $1.75 [/mmBtu] at Alberta, the netbacks are negative and the company would lose money. He highlighted that the graph shows that for the vast majority of the price cases, it's a positive netback and the presence of a shipping commitment has no effect. Even when one assumes that all of the prices on the graph are equally likely and there is a shipping commitment, the total expected value is only reduced by about 1 percent. However, not all the prices are equally possible. He then turned attention to the graph on page 6-8, which includes the earlier mentioned low price scenario and the expected price scenario. He opined that there is a very low probability of being in an environment in which the prices in Alberta are less than $1.75 [/mmBtu] or that the shipping contract would have an adverse impact on economics. Therefore, the shipping commitment shouldn't be considered an adverse piece.

2:35:13 PM

DR. LEITZINGER closed by relating some of the potential pitfalls, as specified on page 6-9. By any of the performance metrics, the performance associated with a gasline project will be lower if the upstream and pipeline are integrated than if just looking at the upstream. The aforementioned is also the risk when the project is put together on an integrated basis. Dr. Leitzinger then informed the committee that "size does matter" because a lower return on a large project can be more attractive than a high return on a small project. Therefore, one needs to be sensitive to whether the projects are mixing businesses of different types as well as the size of the project. Alaska's project is big, even by world standards, he stressed. Therefore, he cautioned the committee to make rate-of-return comparisons for projects of like size and risk.

2:38:34 PM

CHAIR THERRIAULT returned the committee's attention to the graph on page 6-8 and said:

> Based on the price for transportation, which was developed this morning, at a $1.75 [/mmBtu] and the likely price scenarios that were developed this morning and talking about blending the two projects or having the pipeline lower the expected rate of return, net present value, all of those things because you've got the component that is a regulated utility ... and a regulated rate of return on it. So, it pulls down the economic return, but it pulls down the risk too. You've also got the dynamic of if you got a company that's committed to capacity and you're down below a $1.75 ... however, losing money on every ... quantity that they're shipping. They're offsetting that somewhat by the fact that they're at least getting the regulated rate of return or providing the shipping for moving the good. ... by blending the two you help with that potential downside.

DR. LEITZINGER agreed, and offered that if the upstream and the pipeline are put together, most of the investment dollars will be largely insensitive to price fluctuations. Therefore, it will generate a consistent rate of return consistent with the low risk. Furthermore, in an integrated sense the ownership of the capacity, the obligation to pay, would create an area on the graph that would relate the return generated on the pipeline assets.

2:42:23 PM

MR. PULLIAM moved on to page 7-1 regarding Econ One's efforts in modeling a gas pipeline project. He noted that this modeling uses public information that's reasonable. He began on page 7-3 with the development of the model of a project that runs along the Alaska Highway to Alberta, Canada. The model was developed under the assumption that development would occur under the existing fiscal system and rules. Furthermore, different price, cost, and ownership scenarios have been modeled. He then reviewed pages 7-5 and 7-6, which relate the major assumptions of the model as follows:

> Gas pipeline developed and gas sold under current fiscal terms
>
> 30-year project, with sale beginning by year-end 2012

Gas production of 4.5 BCF per day; approximately 50% from Prudhoe Bay, 16% from Point Thomson, and the balance from other fields

Gas sales of 4.2 BCF per day in Alberta (AECO Hub)

Gas prices in Alberta average $0.90/MMBtu below Henry Hub/Chicago levels

Average heat content of 1.1 MMBtu per MCF

Gas treatment plant, pipeline, and Point Thomson facilities financed with a combination of 80% debt (with federal guarantees) and 20% equity

Borrowing costs on federally guaranteed debt of 5% per year

FERC allows a 14% rate of return on equity for U.S. portion of pipeline; NEB allows a 12% return for Canadian portion

Costs and prices inflated by 2.5% per year from 2004

Capital costs consistent with producer presentation to legislature in August 2001 and June 2004

Capital cost include gas treatment plant, pipeline, and Point Thomson field development costs

We have added additional capital for construction of a "feeder" pipeline from Point Thomson to the gas treatment plant and for development of gas reserves outside of Prudhoe Bay and Point Thomson

We assume gas sold on a "BTU" basis (i.e., no uplift for potential NGL extraction) --likely a conservative assumption

Consistent with this assumption, we have not included capital for a NGL extraction facility

We have not attempted to model any related impact on liquids production at this time

2:49:17 PM

CHAIR THERRIAULT highlighted the assumption that the average heat content would be 1.1 mmBtu per mcf, and then related his understanding that the model used a blended stream.

MR. PULLIAM replied yes, and clarified that the assumption is that the gas would flow down to Alberta before any liquid extractions would occur.

CHAIR THERRIAULT then turned attention to the assumptions regarding the rates of return for FERC and NEB, and inquired as to whether the differentiation is based on what occurs now when a line that is located in the U.S. enters Canada. He asked if in such a situation the [rates of return] come close to normalizing.

MR. PULLIAM opined that such a scenario hasn't occurred yet, although he acknowledged that there are some lines from Canada that come into the U.S. Typically, the Canadian lines have a lower rate of return. He explained that once a project is running, FERC will want to hear from all the parties and discuss whether the initial rate of return should be adjusted. Oftentimes the [initial return] is adjusted down because what was initially perceived as risk is no longer perceived as such. He informed the committee that the model includes the ability to adjust the numbers and review different results.

2:52:03 PM

MR. PULLIAM continued discussing the major assumptions, and emphasized the importance of capital costs of this project. Capital costs include the gas treatment plant, the pipeline, and Point Thomson field development costs. He related his understanding that the gas treatment plant and Point Thomson will be eligible for federal loan guarantees and thus have been treated as such in the assumptions. The assumption is that incremental costs would be required for the development of Point Thomson. Mr. Pulliam highlighted the inclusion of a "feeder" pipeline from Point Thomson as well as additional costs for additional development. It's likely that liquids extraction will be viable with this project. Under Econ One's assumptions gas would be sold on a BTU basis and thus the uplift or capital costs for a NGL facility haven't been included. Furthermore, there has been no attempt to model the potential related impacts on liquids because he opined that they wouldn't be likely to change the fundamental results.

2:57:06 PM

MR. PULLIAM reviewed the scenarios with regard to pipeline ownership as presented on page 7-7. Scenarios with different gas price assumptions and different cost assumptions were reviewed as well. The range of plus or minus 20 percent is used in Econ One's modeling. He then turned attention to page 7-9, which discusses gas prices. The numbers were run using a base line average price of $4.90 from EIA's Annual Energy Outlook. The prices from EIA fall in the $4.05 to $5.10 range. The aforementioned is consistent with other public forecasts of gas prices. High and low price scenarios have been reviewed as well. He then moved on to the cost sensitivities as related on page 7-10.

3:02:16 PM

MR. PULLIAM continued with the results of these models and directed attention to pages 7-11 and 7-12, which details the scenario in which the producers own 100 percent of the pipeline. The chart on page 7-13 details the different investment metrics that result from the assumptions specified on pages 7-11 and 7-12. He explained that the column headings with the 10 designation refer to a 10 percent discount rate. He noted that the IRR figures were calculated over the entire capital base, and thus don't incorporate the advantages of leveraging. He drew attention to the low price scenario, which relates that the IRR drops down to 17.2 percent. He then reviewed the charts on page 7-14 that detail the base case and a case with a 20 percent increase in costs. The charts on page 7-15 compare the base case to a case in which the costs decrease by 20 percent.

3:07:43 PM

MR. PULLIAM moved on to page 7-16, which is the scenario in which the producers own 50 percent of the pipeline. Page 7-17 provides the specifics of this scenario. The chart on page 7-18 shows that in a situation in which ownership in the pipeline drops, the NPV at the 10 percent [discount] rises as does the IRR because the pipeline will have a regulated WACC and will earn about 6.5 percent. For purposes of project evaluation the 10 percent discount wouldn't be appropriate to use for regulated assets. However, in this exercise of different scenarios, keeping a constant discount rate allows one to see how the numbers change. The charts on page 7-19 provide a base case scenario versus a scenario when the costs increase by 20 percent while the charts on page 7-20 provide a base case scenario versus a scenario when the costs decrease by 20 percent.

3:11:12 PM

MR. PULLIAM turned attention to pages 7-21 and 7-22, which review a scenario in which the producers own 0 percent of the pipeline and ship over a third-party owned pipeline. The results of the aforementioned scenario are related in the chart on page 7-23. The aforementioned chart illustrates that the NPV will increase because of the lack of the capital burden of the midstream investment, and the IRR will increase as well.

3:12:47 PM

MR. PULLIAM, in response to Senator Stedman, confirmed that these [scenarios] are all unleveraged.

SENATOR STEDMAN inquired as to how sensitive the numbers would be if some leverage was employed.

MR. PULLIAM said that [the producers] typically don't have much debt in their capital structure. However, Econ One believes that they will incur some debt because of the availability of the federal loan guarantee. The assumption is that a large part of the investment will be debt financed, but the returns and NPV are over the entire capital base, unleveraged. In further response to Senator Stedman, Mr. Pulliam agreed that leverages and returns on the equity piece will be more than presented.

3:14:41 PM

MR. PULLIAM then pointed out that the chart on page 7-24 compares the base case to a case in which the costs are increased by 20 percent. The chart on page 7-25 compares the base case with the costs decreased by 20 percent. He then moved on to the impact of leverage on project economics as related on page 7-26. He reminded the committee that thus far the analysis of the return reflect unleveraged economics, but it's true that FERC and NEB won't assume unleveraged economics. However, the [models] assume that the tariffs will be set based on the capital structure that's going to be used. Leverage, he stated, has a significant benefit in a project such as this because [it offers] the ability to significantly increase returns to shareholders. Still, companies remain mindful that increasing leverage comes at the cost of increasing risk, which is one of the reasons why shareholder returns increase as a company's leverage increases. Alaska's project is a different kind of project in which the leverage won't be viewed as very risky. The chart on page 7-27 returns to the integrated scenario in which the producers own 100 percent of the pipeline. The top chart is the base case, including the debt and the equity, while the lower chart is a leveraged case with equity capital only. The charts on page 7-28 show the same effect but in the scenario in which the producers only own 50 percent of the pipeline. Again, the effect of leverage is considerable on the returns. The charts on page 7-29 reflect the impact of leverage on project economics when the producers own none of the pipeline. He noted that in this case, the assumption is that the producers would use debt for the conditioning plant and the Point Thomson development costs but not for future development costs, which would be all equity.

3:19:25 PM

SENATOR STEDMAN inquired as to how sensitive this analysis would be if the life of the line is 10-20 years longer.

MR. PULLIAM answered that this analysis, at a 10 percent discount rate, isn't very sensitive. The out years don't have a large impact on NPV and IRR, although the undiscounted cash numbers get large. If there was a pipeline that ran over the course of 30 years, the assumptions used here are that FERC would set a levelized tariff that would recover the capital in 30 years. However, if the project continued after that the capital couldn't be recovered again and thus the tariff would decrease considerably. In response to Chair Therriault, Mr. Pulliam confirmed that the leverage assumes an 80:20 ratio, with the exception of the incremental investment that would be required upstream. Although Econ One has modeled it with equity, [the producers] may use some debt.

3:22:01 PM

SENATOR STEDMAN inquired as to how the three scenarios presented today compare with the international marketplace.

MR. PULLIAM answered that the scenarios, based on generally, publicly available information Econ One has reviewed, appear to compare favorably.

3:22:48 PM

CHAIR THERRIAULT noted his initial surprise that the IRR increased with the lower producer participation in the pipeline.

MR. PULLIAM mentioned that there is also a perversity with regard to the borrowing costs. He then turned attention to page 7-13, which discusses the scenario in which the project is integrated. Intuitively one would think that if borrowing costs decrease, then the project should look better. However, in view of the NPV 10 it looks worse and drives down the IRR because it's the pipeline portion that's held to a regulated return. On the upstream [lower borrowing costs] drive the IRR up because there would be higher netbacks while driving down the return on the midstream portion. By making the midstream cheaper, it helps the upstream by lowering the tariff.

3:25:59 PM

REPRESENTATIVE HAWKER turned to the base case scenario presented by Econ One, and asked if it had factored into the cash flows a provision for dismantlement, removal, and restoration (DR&R) for the pipeline.

MR. PULLIAM replied no. He echoed his earlier testimony that those costs would be so far in the future they would have a negligible effect. He said [DR&R] should be in the cost basis from the beginning.

3:27:00 PM

REPRESENTATIVE GARA questioned whether there are other factors that need to be considered. He related his understanding that this [model] assumes the pipeline will deliver Prudhoe Bay and Point Thomson gas. However, how does this [model] address allowing additional gas into the pipeline, he asked. He also asked if the myriad of provisions a producer could impose for letting gas on and off the pipeline could impact this analysis and the state's revenue.

MR. PULLIAM acknowledged that those are important to consider, certainly to the extent that someone can create a bottleneck to the necessary infrastructure. However, to the extent that the facilities are regulated, there should be guarantees that access will be considered. With regard to the ability to increase the cost of transportation from a spur line, he expected those to be regulated assets. Therefore, he didn't believe there would be the ability to increase the price of a pipeline higher than what a regulatory agency would allow. Still, an access issue further upstream could be problematic.

3:29:58 PM

REPRESENTATIVE HAWKER asked if this modeling is a triple net or is this a modeling of the netback before corporate income taxes.

MR. PULLIAM clarified that [the model] includes all taxes, after-tax cash flows.

The committee took an at-ease from 3:30 p.m. to 3:52 p.m.

3:52:37 PM

SENATOR WAGONER asked why the oil companies seem hesitant to build a gas pipeline at this time if the documents presented today are even close to reality.

MR. PULLIAM said that he is mindful that the oil companies are in the midst of negotiating with the state over fiscal terms. Setting that aside, the oil companies may want to do other projects that they are at risk of losing to competition. Furthermore, the oil companies may take the view that gas prices are going to remain healthy and thus it becomes a matter of when to sell the gas.

3:55:02 PM

DR. FINIZZA continued Econ One's presentation by addressing the impact on state and municipal revenue from a delay in the gas pipeline's in-service date. He highlighted that the chart on page 8-3 merely reviews the revenues to the state in undiscounted terms for the four price scenarios. If the pipeline didn't start until the end of 2018, the state would've lost $9.8 billion of revenue over that time. However, he noted that loss could be recouped later in life. He then turned to the chart on page 8-4, which illustrates that a delay in the project to 2018 would cause a reduction in the NPV at the 10 percent discount rate in the amount of $2.7 billion. In response to Chair Therriault, Dr. Finizza confirmed that the aforementioned would bring the [project] to today's NPV. He then suggested that it may be appropriate to think of the state impact in terms of a smaller discount rate, and therefore the same calculation is illustrated with a NPV at a 5 percent discount rate as illustrated in the chart on page 8-6. He clarified that [these charts] are related only to the state's take.

4:00:38 PM

REPRESENTATIVE GARA directed attention to the charts on page 8-5 and posed a scenario in which it's a 30-year project with $35 billion in gas revenue. Therefore, he questioned how $.7 billion out of $35 billion a loss of 26 percent.

DR. FINIZZA clarified that the NPV for the state's revenue isn't $30 billion, rather it's $2.7 billion divided by $26.6 billion and thus is about [$10 billion].

CHAIR THERRIAULT reiterated that it's just the state's take.

DR. FINIZZA interjected that the undiscounted cash revenue to the state is more than $30 billion.

4:04:10 PM

MR. PULLIAM concluded the presentation by addressing the impact on the investment metrics from an increase in the gas production severance tax. He reminded the committee that the current gas severance tax rate is 10 percent and there's an ELF applied to it. Page 9-4 relates the results of a 10 percent increase in gas production taxes on project returns, assuming EIA AEO pricing of $4.90. The chart shows this information in five-year intervals. He mentioned that the chart is based on the producers' standpoint. The next couple of pages relate the same information at different price scenarios. The chart on page 9-8 illustrates the results of a 25 percent increase to the severance tax, which takes the severance tax rate from 10 percent to 12.5 percent. As expected, the NPV decreases. Furthermore, the earlier the change occurs, the higher the result. He then turned attention to page 9-12, which details the results of a 50 percent increase to the severance tax such that it's increased to 15 percent. In either of these cases, the further out in time there is a change in the severance tax, the smaller the impact of the change would be on the investment matrix. Mr. Pulliam clarified that the timeframes in five-year increments refer to that much time after the project has started.

4:11:32 PM

REPRESENTATIVE GARA pointed out that Alaska has a corporate tax, which used to be a 9 percent corporate tax on true profits. However, now the state taxes 9 percent on "fake" profits because of the worldwide apportion accounting, which allows deductions for those profits made in other locations. He inquired as to the impact of returning to the old model in which there was a 9 percent tax on the true profits without the ability to take a deduction for investments outside the state.

CHAIR THERRIAULT said that could be considered for future discussion.

4:13:41 PM

CHAIR THERRIAULT recalled earlier testimony regarding foreign LNG not competing with Alaska gas, and inquired as to why that would be the case.

MR. PULLIAM related that the view of the public studies, with which Econ One would share, is that the price setting mechanism would be Lower 48 higher cost supplies. Therefore, "their" price would be the marginal price of gas going into the U.S. market until other sources of gas with a marginal case less than that would include LNG and Alaska. Therefore, both [foreign LNG and Alaska gas] would be price takers.

CHAIR THERRIAULT informed the committee that Econ One may be asked to review the economics of the most recent proposal from the Alaska Gasline Port Authority (AGPA). Chair Therriault opined that if the legislature was given a proposal by the administration, the model used by the administration may have differences in regard to the value of certain pieces. However, today's presentation provides the committee with modeling that will likely be used in evaluating a project.

4:17:43 PM

REPRESENTATIVE ETHAN BERKOWITZ, Alaska State Legislature, related his desire for the committee, which is the lead agency on this project, to inquire as to whether the Commissioner of Revenue has done an economic analysis. If so, he asked that it be made available to all legislators.

CHAIR THERRIAULT agreed to make such an inquiry.

REPRESENTATIVE BERKOWITZ requested that the committee consider doing its own investigation as to whether the prevailing cost, price positions, et cetera preclude the gas from the market at this time. (Indisc.)

CHAIR THERRIAULT commented that the information provided today is good information from which one could draw his/her own conclusions.

4:19:05 PM

SENATOR GREEN highlighted the current situation in Louisiana and Mississippi after Hurricane Katrina, and asked whether other areas would rally due to the loss of offshore facilities.

UNIDENTIFIED SPEAKER pointed out that there has been a sharp reaction from the gas market such that the prices over the next few months will be pushing $13/mmBtu. At this point there isn't knowledge as to whether it's a speculative response. However, there have been reports that gas compressor stations were destroyed, and thus there may not be any economic mitigation in the near future. With regard to this presentation, he said that he didn't see any impacts that would change the pricing or other operating assumptions of this study. However, the oil side is a different question.

The committee took an at-ease from 4:21 p.m. to 4:28 p.m.

EXECUTIVE SESSION

4:28:12 PM

REPRESENTATIVE SAMUELS made a motion to move to executive session for the purpose of discussing confidential audit reports under AS 24.20.301. There being no objection, the committee went into executive session at 4:30 p.m.

6:05:19 PM

CHAIR THERRIAULT brought the committee back to order at 6:10 p.m. Present at the call back to order were Senators Stedman, Hoffman, and Therriault and Representatives Chenault, Hawker, Kerttula, Joule, and Samuels.

RELEASE AUDITS

6:06:51 PM

REPRESENTATIVE SAMUELS made a motion for the preliminary audit, 45-30033A-05 - University of Alaska, Unit Cost Analysis Phase I - to be released to the appropriate agencies for response. There being no objection, the preliminary audit was released.

REPRESENTATIVE SAMUELS made a motion for the final audit, 25-30034-05 - Department of Transportation & Public Facilities, AMHS Vessel Maintenance and Repair Procurement - to be released to the public. There being no objection, the final audit was released.

ADJOURNMENT

There being no further business before the committee, the Legislative Budget and Audit Committee meeting was adjourned at 6:07 p.m.