ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
Anchorage, Alaska
November 22, 2013
10:07 a.m.

MEMBERS PRESENT

Representative Eric Feige, Co-Chair
Representative Dan Saddler, Co-Chair
Representative Peggy Wilson, Vice Chair
Representative Mike Hawker
Representative Craig Johnson
Representative Geran Tarr
Representative Chris Tuck

MEMBERS ABSENT

Representative Kurt Olson
Representative Paul Seaton

OTHER LEGISLATORS PRESENT

Representative Scott Kawasaki (via teleconference)
Representative David Guttenberg (via teleconference)
Representative Tammy Wilson

COMMITTEE CALENDAR

GASLINE ISSUES

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

JANAK MAYER, Director
Upstream & Gas
PFC Energy
Washington, D.C.
POSITION STATEMENT: Introduced a PowerPoint presentation entitled "Summary from North Slope Gas & LNG Symposium" dated 11/22/13.

NIKOS TSAFOS, Natural Gas Team
PFC Energy
Washington D.C.
POSITION STATEMENT: Provided a PowerPoint presentation entitled "Summary from North Slope Gas & LNG Symposium" dated 11/22/13.

JOE BALASH, Acting Commissioner
Office of the Commissioner
Department of Natural Resources (DNR)
Anchorage, Alaska
POSITION STATEMENT: Provided a PowerPoint presentation on the key findings of the Alaska North Slope Royalty Study (ANSRS).

PETER ABT, Managing Director
Management and Consulting Division
Black & Veatch
Overland, Kansas
POSITION STATEMENT: Provided a PowerPoint presentation entitled, "Alaska North Slope Royalty Study Highlights" dated November 2013.

DEEPA PODUVAL
Principal Consultant& Management Consulting Division
Black & Veatch
Overland, Kansas
POSITION STATEMENT: Provided a PowerPoint presentation entitled, "Alaska North Slope Royalty Study Highlights" dated November 2013.

ACTION NARRATIVE

10:07:50 AM

CO-CHAIR ERIC FEIGE called the House Resources Standing Committee meeting to order at 10:07 a.m. Representatives P. Wilson, Tarr, Tuck, Hawker, Johnson, Saddler, and Feige were present at the call to order. Also present were Representatives T. Wilson, Kawasaki (via teleconference) and Guttenberg (via teleconference).

GASLINE ISSUES

10:08:31 AM

CO-CHAIR FEIGE announced that the only order of business would be discussion of gasline issues.

10:08:34 AM

JANAK MAYER, Director, Upstream & Gas, PFC Energy, informed the committee he has served as a consultant to the legislature for the previous two years on tax reform issues, and in August delivered a gas symposium on the core concepts needed to consider the issues around gas commercialization.

10:09:33 AM

CO-CHAIR FEIGE stated that PFC Energy was recently purchased by IHS, a consulting firm of which ExxonMobil Corporation is a client, and asked how the firm endeavors to "keep clients separate."

10:10:01 AM

MR. MAYER confirmed that in June, 2013, PFC Energy was acquired by IHS, a large international provider of data analysis and information, and which has a substantial energy practice. Like PFC Energy, IHS has many oil company clients, and specifically works under contract for ExxonMobil Corporation on Alaska natural gas commercialization issues. This presents a potential for a conflict of interest; however, prior to the acquisition, PFC Energy had agreed to present the gas symposium and thus determined that from the time of acquisition, to the end of 2013, PFC Energy "is its own separate legal vehicle; [Nikos Tsafos] and myself are employees of PFC Energy, not of IHS directly." Mr. Mayer further explained that although PFC Energy is owned by IHS, he and Mr. Tsafos work in a separate office in Washington, D.C., have no day-to-day contact with IHS, and maintain a strict separation on the question of Alaska gas commercialization and the materials presented at the gas symposium in August, 2013. In fact, the materials presented at the gas symposium were almost entirely prepared before the acquisition, and the scope of the work has been limited to the general nature and fundamental concepts of natural gas and natural gas commercialization rather than recommendations related to fiscal terms or project structure.

10:12:22 AM

NIKOS TSAFOS, Natural Gas Team, PFC Energy, began his presentation of what he described as the summary version of the four-day symposium held in August. He noted that the topics covered would be condensed and more focused versions of the following: the executive summary; core concepts for gas

developments that include the fundamental differences between oil and gas; supply/demand fundamentals that explain the global market; indicative project economics comparing the cost of LNG projects in Alaska and worldwide; commercial structures that cover the important question of which developers are responsible for aspects of the project; the conclusion; and a glossary with units. Mr. Tsafos directed attention to slide 3, entitled "Executive Summary" and pointed out the first conclusion was that natural gas, and particularly liquefied natural gas, is a growing market, especially in Asia. Due to its proximity and its history in providing natural gas to Japan, Alaska is ideally positioned to capture the demand for LNG in Asia. Second, direct competitors for this market are the Lower 48 states and Western Canada. As an aside, Mr. Tsafos advised that the recent surge in natural gas from shale in North America has become a source of competition for Alaska. Third, a benefit Alaska holds is that the three large upstream producers interested in an LNG project have a great deal of proven experience around the world, yet the question is not whether they can develop an LNG project, but whether it is good business to do so. Fourth, PFC Energy analysis has shown that LNG from Alaska can be competitive provided that the fiscal terms are such that costs can be kept down; for instance, a cost of $45 billion is competitive and a cost of $65 billion is "more marginal." Lastly, because very large projects take a long time to complete and Alaska is not unique in this challenge, he stressed the importance of structuring the parameters of the project properly. For example, the allocation of risk and reward makes a difference, particularly with partner alignment due to the fragmented nature of the gas market. He explained, "... the final price that a consumer pays in Tokyo, that price is allocated among a very large number of suppliers and they're not equally benefitting from that final price."

10:20:12 AM

MR. TSAFOS continued to slide 4 entitled, "The New Geography of Global LNG: Many Options..." and slide 5 entitled, "... But Also Risks" reminding the committee that prior to 2007, consumers in Japan had only two sources for LNG - Qatar and Australia - which kept the price of gas high. However, today consumers in Asia and Europe have many sources for LNG throughout the world, so the fact that a project in Alaska is "economic" or "makes sense in isolation" may not be sufficient to project developers or to buyers if there are other choices. On the other hand, each area of supply carries a set of political, commercial, technical, and/or financial risks thus the economics of a project in

Alaska, together with its offering of risk and reward, will be compared to that of the rest of world.

MR. TSAFOS directed attention to slide 7, entitled "Think Micro, Not Macro; Gas is Not a Global Market." On the slide, two graphs indicated the prices of oil and gas earned by the largest oil and gas companies. The graphs illustrated that the six largest international oil companies earn almost the same price for oil - even as the price rises and falls - but there is a large variation between companies in the price realized by the sale of gas. Mr. Tsafos explained that the price of oil is determined by a global market, but there is no global market for gas and instead specifics really matter. The graphs also illustrate the cost of oil and gas in thermal equivalency and for the same amount of energy a lot more money is made from oil than gas, thus the value of oil is much greater relative to that of gas.

MR. TSAFOS turned to slide 8 entitled, "Gas is Very Different Than Oil" and reviewed the differences between oil and gas in several areas. In terms of global production, oil production is 86.1 million barrels per day [MMB/D] and gas production is 54 million barrels of oil equivalency per day [MMBOE/D]. In terms of geography, oil production is centered in the Middle East and gas production is based mostly in Europe, Eurasia, and North America. However, both the highest oil and gas reserves are found in the Middle East, with additional oil reserves in Central and South America, and additional gas reserves in Europe and Eurasia. Gas pricing is set by Henry Hub in the U.S., NBP in the United Kingdom (UK), and by Germany and Japan in their respective countries. Mr. Tsafos reiterated that there is not a global market for gas pricing, "because one part of the world is paying [$2.86 million British thermal units] and another part of the world is paying [$16 million British thermal units]". He stressed that to whom gas is sold and how gas is sold really matters. In terms of different end-users, oil consumption is driven by transportation, and gas consumption is driven by power and industry. In terms of trade, two-thirds of oil produced crosses a border to market, but 69 percent of gas is consumed in the country in which it was produced; this results in less trade and fewer price conversions. In terms of marketing, oil is produced and then put on the market whereas gas requires a market before production.

10:27:21 AM

MR. TSAFOS continued to slide 9 entitled, "What Does an LNG Plant Look Like?" He observed that oil and gas companies are attracted to the production of LNG - despite the major upfront investment required - because after the project is developed it can be put on "auto-pilot" without much additional investment. In fact, an LNG project is a long-life asset that generates significant cash flow and predictability. The graph on slide 9 illustrated a typical scenario, except for years seven through ten, when the model assumes the cost of bringing a new source of gas online. A different picture for oil production was shown on slide 10, entitled "Oil and Gas Have Different Production/Economic Profiles..." which illustrated two graphs comparing an LNG project with a deep-water oil project. In order to generate $2 billion of net present value [NPV] from oil or gas, a "lot more" gas is needed. This was also illustrated by the graph on the right side of slide 10, which indicated that the after tax cash flow [ATCF] from the oil project repays the investment cost within eight to ten years. The aforementioned different economics of oil and gas create very different challenges for fiscal terms, state participation, and state revenues. This comparison was continued on slide 11, entitled "... and Different Economic Outcomes." Again, in order to generate $2 billion NPV, gas requires significant additional reserves [gas reserves shown in red, oil reserves shown in green], more capital expenditure [CAPEX], and a much longer production life. He also pointed out that an LNG project has a lower rate of return in exchange for its stable, long-term cash flow; therefore, understanding the motivation for a stable, long-term cash flow is essential for the design of the fiscal terms for an LNG project. For example, Mr. Tsafos cautioned that a fiscal term structure that makes sense for one year of investment and three-year payback is not appropriate for seven years of investment and thirty-year payback. He then continued to slide 12 entitled, "LNG is Big, Complex, Risky and Multi-Stakeholder." The major point of slide 12 was that the greatest amount of money is spent after most of the risks have been accounted for. He summarized five steps to the completion of an LNG project: 1. Ensure that the gas reserves exist, which is not a concern in Alaska; 2. Sign sales and purchase agreements [SPAs] with buyers in order to demonstrate the existence of a market for the gas; 3. Secure project financing by using signed contracts as collateral; 4. Award engineering, procurement, and construction contracts to a company or companies to build the plant; 5. Finalize all federal, state, and local approvals. He stressed that there are no commitments made until the boards of all of the participating companies make a Final Investment

Decision [FID], which is not done until all of the aforementioned matters are resolved or nearly so.

10:33:18 AM

MR. TSAFOS displayed slide 13 entitled, "The LNG Value Chain." He described the LNG value chain as slightly different as that of oil in terms of the capital that is required at different points of the value chain, and where a company is located on the chain. One company may develop the field, another liquefies the gas to LNG, another ships to the buyer. In the case of oil development, the majority of capital distribution comes at the upstream location on the chain to find and develop the oil; in addition, Alaska has a significant transportation component. In the case of gas, the cost of liquefaction and the pipeline required in Alaska are significantly more costly than the upstream development. Again, this emphasizes the differences between gas and oil development.

MR. TSAFOS continued to slide 15 entitled, "The World is Turning More and More To Gas" and slide 16 entitled, "Growth at 2.3% per Year Driven by Asia." He returned attention to the status of the market for gas and stressed that overall, the world is turning more and more to natural gas. Although there has been an increase in the supply of coal related to China's entry into the World Trade Organization, the use of gas is growing and since the mid-'90s is now the second most important fuel for the production of electricity. Industry outlook projections put gas into first or second place for fuel sometime between 2030 2040. Mr. Tsafos advised the increase in the use of gas is expected because of "the cleanness of the gas and its more attractive carbon intensity relative to coal and oil and other fuels." Slide 16 depicted one graph that illustrated gas demand by region projected to 2030 and that world demand will grow by about 2.4 percent. In fact, world consumption between 2010 and 2030 will grow by 175 billion cubic feet per day [bcf/d] which is equal to three times the 2010 U.S. demand. Furthermore, a disproportionate share of the increased demand is Asia, which again places Alaska in a good position to capitalize on that market. Slide 17 entitled, "Asia Drives LNG Demand As Well" was a graph illustrating LNG demand by region. Noting that the LNG market is less than one-tenth of the global gas market and only one-third crosses a national border after production and prior to consumption, he reminded the committee to focus specifically on LNG, and LNG transported by pipelines, when discussing gas in general. The growth of LNG demand - and the "prize" for LNG

suppliers - is Asia, as that region accounted for two-thirds of growth since 1990 and will make up two-thirds of the new demand.

10:39:18 AM

MR. TSAFOS continued to slide 18 entitled, "Industry Has Responded with Many and Big Proposals" and observed that when gas prices increased an excessive number of projects were planned around the world. The graph on slide 18 illustrated the "unrisked capacity" that would be reached if every announced project was completed as planned; it is not plausible that all of the projects will be built, but they were announced because "talk is cheap." Completion of all of these projects would produce 771 million tons per annum [MMTPA], which is an enormous supply of LNG that would "crash the market." Slide 19 entitled, "North America is Largest Prospective Supplier," indicated that 40 percent of the world's proposed capacity would come from the U.S.; furthermore, adding Canada to the U.S. results in 57 percent from North America, and adding Australia concentrates 71 percent of the proposed capacity in these three countries. This concentration of supply is important because prospective buyers endeavor to avoid risk by purchasing from more than one source. Slide 20 entitled, "Growth Clustered: N. America, Africa, Australia," was a map that illustrated the anticipated growth from 2012 through 2030 in most regions, except for the Middle East and North Africa [MENA]; this lack of growth will turn future LNG buyers from MENA to the growth areas of North America, East Africa, and perhaps Australia. Mr. Tsafos commented that the aforementioned map is fluid and as such, buyers and sellers can adjust; in fact, each buyer will consider more gas contracts than necessary to plan for any contingencies, and "just because someone is not looking at you today, doesn't mean they're not going to be thinking of you much more highly in six months, or just because someone is banging on your door today, doesn't mean they won't disappear six months from now." He pointed out that sources for gas in Iran and North Africa have not proven to be as reliable as expected. He concluded that a decision to build an LNG project must consider the following: that a buyer can withdraw; how to keep buyers interested; and what is happening throughout the world. Mr. Tsafos warned, "This is really the game that you are confronted with because the buyers are shopping around, [and] the companies are shopping around because, again, the companies have more opportunity that they can pursue in any given year."

10:47:23 AM

MR. TSAFOS presented additional data regarding demand on slide 21 entitled, "Widespread Growth in Asian LNG Demand." Two graphs illustrated demand growth in Asia, broken down by country, to inform members on the importance of the demand for gas from Asian countries other than China, such as India, Korea, and Taiwan. Slide 22 entitled, "Window into Asia: Small by 2020, Grows Post 2020" illustrated the windows of opportunity for Alaska and other suppliers of LNG. In 2020 there is a "gap" or window of 27 million tons [MMT] of demand for LNG that is not covered by preliminary or finalized purchase contracts. By 2025, the total demand is estimated to be 290 MMT, with 29 MMT covered by preliminary contracts, and 146 MMT covered by finalized contracts, leaving the questions of whether and how a contract can be obtained for a portion of the 115 MMT not yet under contract. Finally, Mr. Tsafos turned to slide 23 entitled, "What Price Can Alaska Expect?" and noted that the manner of pricing gas is not only immensely complex, but is undergoing a period of change. He presented six economic factors in gas pricing:

- When buyers have choice, the price of a product tends to fall close to the cost of supplying the goods; when sellers have choice, prices tend to rise, and over time the two prices adjust and converge due to competition. However, due to the lapse in time needed to increase the supply of gas, "the price at which the supply makes sense, and the price at which the consumer no longer wants to consume - there is a huge gap."
- PFC Energy estimates the breakeven price of most of the new LNG projects worldwide is between $8-$11 per million British thermal units [/MMBtu], but gas in some regions, such as Japan, is priced higher at $16/MMBtu to compete with the price of oil.
- Gas is not a global market, thus consumers are charged local market prices; for example, approximately $2/MMBtu in the U.S., where the cost is going down to the cost of supply, and $16/MMBtu in Japan, where the price is increasing to the maximum that consumers will pay.
- Because of the difference in price and the known price of LNG production, consumers are bringing pressure to bring the price down by creating competition, and at this time there is more gas available for contracts, turning the market today to a buyer's market.
- In this situation, the pace at which Alaska develops its new supply of gas is critical, and actual development is needed to convince competitors to lower prices.

- Project partners can be protected from a variation in prices by the use of an "S curve" which links the price of gas to the price of oil. This structure ensures partners don't lose a lot of money because the partners also agree not to increase the price above a certain point - there is a "floor" and a "ceiling" on the price. The S curve structure is attractive for state-owned companies or shareholders because sufficient revenue is guaranteed to cover their financial needs. Mr. Tsafos concluded by saying, "There's the attraction of giving up some 'upside' in order to provide a basis for security - financial security - for the state and for the project partners."

10:56:34 AM

REPRESENTATIVE TARR returned attention to slide 8 and said in the development of Alaska's resources, the type of oil is a consideration as some oil is harder to develop. She asked what type of oil is included in the estimate of global reserves and whether the quality affects the cost of development.

MR. TSAFOS agreed quality does matter. Oil development has two factors: the cost to develop oil into something usable, and the quality issue. Quality is affected by gravity - designated by heavy, medium, and light - and the sulfur content. Price differentials are fairly well established between heavier and lighter oil; generally, the previous worldwide trend toward heavier oil has been interrupted by the development of shale oil in the Lower 48. Regarding the cost of development and the world supply of oil, PFC Energy believes that most sources can be economic from $70-$90 per barrel [bbl], thus production costs that are significantly lower than that mean higher profits. Usually it is more expensive to develop unconventional and heavier oils.

10:59:09 AM

CO-CHAIR SADDLER inquired as to where the negotiations to reach the final investment decision on large LNG projects tend to fail.

MR. TSAFOS, in response, returned attention to slide 12, noting that the first bullet point - certifying reserves - is not a matter of contention. Also, the fourth bullet point - choosing a construction company - is a competitive bid process and is not subject to negotiation. Bullet point five - securing approvals - can be a bottleneck and can stop a project in some countries,

but is also not subject to commercial negotiation. Bullet point three - financing - generally depends upon the sales and purchase agreements, and whether all the parties are creditworthy. Most of the problems arise with bullet point two - the price of the gas and under what terms the gas is sold. Unless there is an environmental or technical challenge, analysts believe the strongest indicator that a project will proceed is whether preliminary or near-final contracts have been signed with major companies. Additional questions arise if there are negotiations about the shareholding structure, exploration licenses, or sovereignty.

11:04:04 AM

CO-CHAIR SADDLER asked whether Alaska is negotiating fiscal terms at a point just before the second bullet point: sign sales and purchase agreements.

MR. TSAFOS cautioned that the topics listed on slide 12 do not happen in sequence, but must happen "in parallel." For example, SPAs and construction quotes will not be signed unless gas reserves have been certified, and without construction quotes financing cannot be secured. He said, "this is the challenge of LNG, that it is ... not sequential, and the difficulty of these projects is that you have to be moving all these things together. And the challenge is that if one thing is so patently lagging, you can't move any of the other pieces." He agreed that Alaska lacks the preconditions to move ahead in any of the bullet points shown on slide 12, because of "another element of fiscal term participation." Without momentum, partners are reluctant to move ahead when a Federal Energy Regulatory Commission [FERC] approval can cost over $100-$200 million in the Lower 48.

11:07:27 AM

MR. MAYER restated the changes in the worldwide gas market since 2007. He advised that today the decision-making process around potential LNG projects involves many more options and these new opportunities must be applied to an Alaska LNG project. Mr. Mayer directed attention to slide 25 entitled, "Oil-Indexed Pricing to Asian Markets" noting that all of the analysis on pricing is in terms of breakeven prices in dollars/MMBtu of LNG. There are many mechanisms around the world to price gas, with the lowest from Henry Hub in the U.S. and the highest in Japan. Key reasons for the low U.S. prices are that the U.S. has the only deep liquid, gas-on-gas competition, and has gas markets

where gas is priced "on its own" as a commodity. Conversely, in Asia, the market is based on LNG that was first imported to Japan as a substitute for fuel oil to generate electricity, and thus was priced against oil. For instance, if LNG is priced at 0.l6x the price of crude oil imported to Japan, the gas price would result in thermal equivalency, which means the cost is equal for the heat content of both gas and oil. Recently, contracts have been signed with a slight discount in thermal equivalency when compared to crude oil. Breakeven prices for an LNG facility would include the cost of all of the construction capital, all of the upstream development, investment in a pipeline, and investment in a liquefaction project. Calculating gas price, using all of these factors, results in an appropriate rate of return in the range of $8-$15/MMBtu to break even, and pay back all of the capital needed to build the project. In terms of thermal equivalency, a breakeven rate of return on a contract with Japan at $12/MMBtu - 0.15x oil price - equals a price of $80 per barrel [/bbl] Brent or Alaska North Slope (ANS) oil. A return of $15/MMBtu is the same as $100/bbl Brent or ANS oil. He cautioned that in an oil-linked market, information on the price of oil is needed in order to determine whether a gas project makes sense.

11:13:58 AM

MR. MAYER continued to slide 26 entitled, "New LNG Projects are Expensive" and pointed out the extraordinary increase in project costs and breakeven pricing for new projects in the Asia Pacific basin, compared to past decades. In fact, the graph on slide 26 showed the Pluto LNG project, which came online two years ago, has a much higher breakeven price than seen before. Breakeven prices for proposed and under construction projects ranged from $9-$15/MMBtu and above.

11:15:13 AM

CO-CHAIR SADDLER asked Mr. Mayer to explain the negative upstream values indicated for the existing Darwin LNG T1, North West Shelf T4, and North West Shelf T1-3 projects shown on slide 26.

MR. MAYER explained that the Darwin and West Shelf projects have substantial oil reserves; therefore, if oil prices are constant at $90/bbl, they will break even. In fact, these projects have sufficient liquids so they can pay back capital expenses without a profit from gas. He then turned to the range of projects shown on slide 26, stating that they are overwhelmingly located

in Australia, where there have been substantial rises in costs due to the competition with coal and copper mines for skilled labor and material resources. Companies who made FIDs on projects five or more years ago may have failed to anticipate these cost escalations; for example, the Pluto LNG project requires a breakeven price in excess of $15/MMBtu and only makes sense "in an above $100 barrel [of oil] world." At the time the operator of Pluto LNG made its FID on the project, the cost estimate was 50 percent lower; this is an example of one of the fundamental risks to the equity participants of such a project. In addition, slide 26 illustrated the new supply of gas that will be coming online and feeding Asia Pacific customers at a cost range of between $9-$14/MMBtu. He said, "Above that sort of $13, $14, $15 range you really start to get well out of the level of competiveness with what is currently proposed for the Asia Pacific market."

11:19:34 AM

CO-CHAIR SADDLER asked how the sponsors of the Pluto project protected themselves against higher labor and materials costs.

MR. MAYER added that the Pluto operator also faced another high risk which was due to further appreciation of the Australian dollar, because Australian LNG projects express revenues in U.S. dollars, but most of their costs are paid for in Australian dollars.

MR. TSAFOS, in response to Co-Chair Saddler, suggested that to protect themselves operators can try to sign multi-year contracts, hedge, and reallocate a portion of the risk, although is it challenging to find a partner who will take all of the commodity risk of building materials. Project developers can also attempt to lock down the cost of construction materials with pre-purchase bids; however, it not clear whether developers can be fully protected. The most protection comes with good project management, which can keep cost escalation as low as 10 percent.

11:22:16 AM

CO-CHAIR FEIGE asked what affect a rise in inflation could have on the costs of the proposed Alaska project after the FID is made.

MR. MAYER explained that if the rise in inflation was a "broader phenomenon" related to the U.S. dollar, that type of overall

inflation would also affect the price Alaska receives for its marketed LNG. However, specific inflation related to construction costs in Alaska, or construction in general, would lead to unanticipated cost overruns that could harm a project. He returned attention to slide 26, noting that the aforementioned projects are largely Australian and Asian, but when looking at worldwide proposed projects, more than half are in North America, primarily on the U.S. Gulf Coast or in Western Canada. These are projects that - unlike those in Australia - do not require deep-water offshore gas development, but that can buy gas from pipelines without upstream development. In fact, many of these projects are close to existing brownfield facilities such as those that were built for an expected, but unrealized U.S. gas shortage. The gas shortage was averted with the sudden development of shale gas, and with relatively little further investment developers can look to converting the import terminals to export terminals. Furthermore, since these facilities do not have to start from scratch, they have economics that are closer to brownfield development and can be more cost competitive.

11:26:00 AM

REPRESENTATIVE JOHNSON observed that when the import facilities were built the cost of transporting the gas was incorporated, and asked whether that cost is included or is "[written] off as an accounting procedure ...."

MR. MAYER said from an economic perspective that is a sub cost. At this point the facility is there and can be used as an export facility for relatively little additional cost. In further response to Representative Johnson, he clarified that for investment decision-making, in this case an economist ignores sub cost and asks, "From this point forward what should I do?"

MR. TSAFOS gave the example of the Cheniere Energy, Inc. facility at Sabine Pass, which generates cash flow from a long-term contract with Chevron/Qatar that allows access to the facility along with the right to import gas.

11:28:22 AM

REPRESENTATIVE TUCK referred to slide 27 entitled, "Lower 48 is An Alternative-But Not Necessarily Cheap: & It is Volatile," and asked what makes the price of Lower 48 gas more volatile than gas from other areas.

MR. MAYER deferred the question until later in the presentation. He directed attention to the two graphs on slide 27 that relate to the LNG plant at Sabine Pass, and explained that PFC Energy looked at this project because it started as an import terminal, and was turned into a liquefaction export project. It is also one of the first facilities to sell LNG to Japan and Korea at a price not indexed to oil, but based instead on the Henry Hub price. Utilities in the Asian markets are very interested in purchasing gas at the Henry Hub price even after adding on the cost of liquefaction and shipping. Slide 27 illustrated the KOGAS contract at the Henry Hub price of $6/MMBtu with a gas surcharge of $0.9, a liquefaction fee of $3, and a shipping cost of $2.8, resulting in a delivered cost of $12.7/MMBtu. Hypothetically, this contract would have been competitive in 2012 when compared to crude oil-linked LNG. However, the contract would have been "a pretty bad deal" in the years 2000-2009, because Henry Hub has a degree of volatility unknown in the world oil market.

11:31:53 AM

REPRESENTATIVE JOHNSON asked for the delivery cost of LNG beginning at today's Henry Hub price of $3.66/MMBtu.

MR. MAYER estimated the delivered price to be $8-$9/MMBtu under that scenario. He explained that the Henry Hub price of $6 was chosen after study of the available shale gas resource in the Lower 48. Shale gas wells have a steep decline rate which means developers have to be constantly drilling to maintain production. In addition, there are extreme variations in productivity and breakeven prices. He said, "There certainly is a substantial amount of resource out there that is economic at $2, at $3 per MMBtu, but it's limited and if we look at what's going to need to be drilled to maintain and continue to grow production, you can't meet it just through wells that are economic at $2 and $3 per MMBtu. You can meet an enormous amount of future production from resources that would be economic in the $4, $5, $6 range." Therefore, PFC Energy anticipates an upward trend closer to the $6 range than to the $3 range. He acknowledged that Lower 48 Henry Hub price LNG is a formidable competitor to Alaska LNG for Japan and Korea markets at this time, but may not be "in the longer run."

MR. TSAFOS reminded the committee that the final investment decision is made while "making a 25-year bet" on what gas prices will be during four to five years of construction and a 20-year contract. He restated that in 2006-2007 it was widely believed

there would be a gas shortage in the U.S., but now it is known that the U.S. is awash in gas.

11:35:19 AM

REPRESENTATIVE JOHNSON informed the committee Australia has decided not to impose carbon taxes, a decision which bodes well for coal. He asked whether PFC Energy is confident about the $6/MMBtu gas price in light of this trend away from carbon taxes.

MR. MAYER advised that carbon taxes also impact LNG projects to a lesser degree than coal. PFC Energy analysis agrees that a tax of $20-$25 per ton of carbon emissions hurts the cash flow of producers, but when compared to the fluctuations on a yearly basis of oil and gas prices and project costs, the tax makes very little difference to the breakeven price. In fact, the biggest change to the coal industry has been the flood of unconventional natural gas in the Lower 48, which has led to the closing of aging coal-fired power capacity in the U.S. and to the increased export of U.S. coal.

11:37:27 AM

REPRESENTATIVE TUCK asked whether Japan would still choose to link gas prices to oil prices in today's market.

MR. TSAFOS noted that the contracts are only one to two years old thus there has not been enough time for Japan to reconsider its position, but the impact will be known in 2019. His experience is that the oil and gas industry is engaged in "heated discussions" over the idea of whether or not to depend on the volatile U.S. market for the pricing of gas.

11:39:31 AM

CO-CHAIR FEIGE observed those selling gas are exerting pressure to keep the price linked to oil, because that generally results in keeping the price high.

MR. TSAFOS agreed that non-U.S. suppliers are happy with $16/MMBtu gas, and they won't change until forced to do so when buyers have more options available.

CO-CHAIR FEIGE suggested asking for the highest price possible.

MR. TSAFOS cautioned that there is a risk to setting a high price if buyers have a negative reaction. He assured the committee that sustainable deals happen when buyers and sellers understand there will be fluctuations over the life of a 20-year to 25-year contract.

11:42:21 AM

CO-CHAIR FEIGE returned attention to slide 27 and the chart depicting a contract with KOGAS. He asked if taxes and royalties were included in the Henry Hub price.

MR. MAYER said yes; the price to purchase gas out of the pipeline includes royalties, severance tax, and tariff.

11:42:57 AM

REPRESENTATIVE TARR observed the gas market is a dynamic market, with many recent changes. She asked if companies will consider offering operating contracts with shorter terms.

MR. TSAFOS agreed there are more short-term contracts at this time, not because of uncertainty, but because companies need gas immediately. Companies cope with uncertainty by writing contracts that allow a change in the destination of the gas, instead of writing point-to-point contracts. Long-term contracts are essential to obtain financing because their duration establishes the required cash flow.

MR. MAYER further explained that these projects are financed with "project finance or non-recourse debt." A group of producers set up a legal vehicle which is the entity that develops the project, thus the bank has no recourse to the parent companies; the only asset is the capital for the project and the value of the contract signed with Triple "A" rated utilities. The contract is of value because the commitment from the utilities is to buy the gas on a "take or pay basis," whether they need the gas at that point or not. This is what the project takes to the bank, and without a 20-year contract in place the project is not creditworthy.

11:45:43 AM

MR. MAYER concluded that slides 26 and 27 point out that the new projects in Australia are expensive, and potentially Alaska can be competitive with them. Today gas from the Lower 48 into Japan is priced at $8-$9/MMBtu - which is difficult competition

- although those prices may be climbing to the $12/MMBtu range in the long run. He noted that one obvious advantage for Alaska is shipping, and continued to slide 28 entitled, "Does Alaska Have a Shipping Advantage?" The biggest component in the delivered cost to Japan is feedstock, but there is also a substantial cost to shipping. The table on slide 28 illustrated that the full shipping cost from southern Alaska to Japan is $0.67/MMBtu. This estimate includes an assumed amount for the Panama Canal tariff for shipping from the U.S. Gulf of Mexico, and shows a clear advantage for Alaska when shipping to Japan and Korea.

11:48:45 AM

MR. MAYER, in response to Representative Johnson, said the size of the ships is assumed to be 170,000 cubic meters, which is above the 140,000 cubic meter average. There are also enormous ships that can only dock at a few gas terminals.

11:49:26 AM

REPRESENTATIVE TUCK asked how Australia is able to maintain the low shipping cost to Japan, South Korea, and China shown on slide 28.

MR. MAYER explained Australia is positioned at an even distance to all three markets.

11:49:55 AM

CO-CHAIR FEIGE asked how the size of vessels affects the cost.

MR. MAYER responded that if more ships are needed the overhead is higher, although the costs are also affected by charter rates.

MR. TSAFOS added that it is now possible to build bigger ships for the same cost, for example, a 170,000-175,000 cubic meter ship can be purchased for $200-$220 million. A bigger ship uses more fuel.

11:51:05 AM

MR. MAYER turned attention to slide 29 entitled, "AK South Central LNG Concept." The slide illustrated an upstream component consisting of additional developments at Point Thomson including 14 additional wells, construction of a gas treatment

plant at Prudhoe Bay, a pipeline to tidewater, and construction of an LNG facility with the approximate capacity of 17-18 million tons per annum [MMTPA]. The costs are estimated at $14 billion for upstream and gas including the new wells, $12 billion for the pipeline, and $20 billion for liquefaction, making a total of $46 billion, hypothetically.

11:52:34 AM

REPRESENTATIVE P. WILSON pointed out the estimate is in 2011 real dollars.

MR. MAYER said "real dollars" is simply a way of saying there will be inflation in the future, but to understand future costs one must start with a fixed timeframe. In further response to Representative P. Wilson, he said the U.S. has low inflation at the moment; however, inflation is expected to return to 2-2.5 percent over time.

MR. TSAFOS explained the benefit of using an estimate is mostly for comparative purposes to understand how the cost compares with the rest of the world; for example, some projects that were built in 2000 are inflated to 2011 dollars to make them comparable. If this project is begun in 2015 and takes five years to build, "none of these things are going to look like that because of inflation."

MR. MAYER further explained the purpose is also to compare the estimated breakeven price, because breakeven prices are compared to other projects "in the same year's dollars."

11:54:19 AM

MR. MAYER continued to slide 31 entitled, "How Would $20bn for an 18 mmta Liquefaction Facility Compare With Other Recent Projects?" He said paying $20 billion for 18MMTA of liquefaction capacity would equal approximately $1,111 per ton and places the proposed Alaska South Central LNG [Alaska SCLNG] project at the lower end compared to the cost of recent projects. The graph on slide 31 placed projects built over the last decade to the left of Alaska SCLNG, and projects built recently were placed to the right. The graph shows that $1,111 per ton is "overall, optimistic or competitive when it, when it comes to LNG pricing [and] certainly very achievable, but just looking at the range of other projects that have built [there is] substantial scope for things not turning out quite, quite that ideally." Mr. Mayer noted the blue bars on the chart were

for projects that were compared to Alaska SCLNG at the gas symposium. He began to further compare projects beginning with a scenario at the $20 billion dollar range.

11:56:04 AM

CO-CHAIR SADDLER asked Mr. Tsafos to translate 18MMTA to billion cubic feet [bcf].

MR. TSAFOS answered that would equal a little over two billion cubic feet [bcf] per day.

11:56:27 AM

MR. MAYER continued to slide 32 entitled, "Breakeven Economics for Hypothetical $46bn Project," and said a project in the $20 billion liquefaction cost range, when taking the initial cost assumptions and applying 12.5 percent royalties, seems to be very competitive at a $10.44/MMBtu free on board [FOB] cost. But if the liquefaction cost is as high as the Wheatstone LNG project - close to $2,000 per ton - there is a very different picture; for instance, the FOB cost, at the jetty, becomes $13.65/MMBtu to break even. Thus the price goes from quite competitive to "only barely" competitive. This highlights the impact of project cost escalation on basic breakeven economics. Slide 34 entitled, "What if Upstream Production Also Faced a 16.7% Royalty and a 35% production Tax?" illustrated the impact of the aforementioned factors in addition to an increase in liquefaction cost; these factors place FOB cost at $14/MMBtu and close to $15/MMBtu delivered into Asian markets. The addition of higher pipeline costs also puts FOB costs "well into a $15/MMBtu world" [slide 35]. Mr. Mayer concluded that the previous examples demonstrate the core of project economics and the essential importance of keeping costs under control, both in terms of the circumstances at FID and understanding the upside risks - particularly if the state were to be an equity participant - and the role fiscal terms play in assuring competitiveness.

11:59:08 AM

REPRESENTATIVE TARR asked whether the legislature should evaluate the opportunity of an equity share in the "whole, entire project or are there opportunities for state ownership at different pieces?"

MR. TSAFOS said this is the most important question that legislators can ask due to the importance of the commercial structures of projects. He first turned attention to slide 39 entitled, "Project Structure Really Matters" which was an example of a project bringing gas from Equatorial Guinea to Japan and involving three transactions. The first transaction illustrated was gas produced at the Alba Field in Equatorial Guinea and sold for $0.27 per thousand cubic feet [mcf] to the liquefaction facility. The liquefaction plant sold the liquefied gas for FOB $2.30/MMBtu - a price linked to Henry Hub - at the jetty at Bioko Island. The buyer shipped the gas to Japan and sold it for an average price of $17.14/MMBtu. In retrospect, it seems like the gas should not have been sold for $0.27/mcf, or for $2.30/MMBtu, but at the time of the deal, when the "25-year bet" was made, the first company did not want to invest millions of dollars and be an equity partner in the liquefaction facilities. Furthermore, the company selling the gas for $2.30/MMBtu did not want to ship the gas or negotiate long-term contracts. Thus this is a lesson of risk and reward in the value chain and where in the value chain an entity places itself. And another party upset with the circumstances in this case was the government of Equatorial Guinea, because the gas was taxed at its value when it left the border, although additional compensation was paid later to restore balance.

12:03:27 PM

MR. TSAFOS encouraged the committee to think about Alaska's participation as it pertains to the revenues from the royalty on gas when it is sold at the wellhead, and the challenge of setting the price high. He cautioned, "But it's hard to do that if you're not participating in any other costs, because you want all of the upside but none of the risk ... and that's difficult, it's difficult to cut a deal where you get all of the upside and you don't put down any, any of the risk." If structured well, an entity makes a certain profit, and if structured poorly, it makes one-fourth, one-third, or one-half of that profit. However, the distribution of risk and reward in the project must be negotiated with all of the parties in order to ensure their participation. The key is how to create alignment in the project for Alaska as a state, and to also consider the risk and reward for the other parties. Fully integrated equity participation entails fiscal responsibilities, durability, and alignment, because all of the parties "rise and fall together." Usually, this type of structure also leads to less intro-project acrimony, unsustainability, and tension, therefore equity participation is not just a financial decision, but a decision

about how to create a structure that allocates risk and reward so that everyone is happy.

12:07:19 PM

MR. MAYER referred to slide 41, entitled "Options for Alaska to Participate," and opined that the two options of receiving revenues through royalty gas, or participating as an equity partner, are but the two extremes of many choices. In the first option, the state takes royalty and any production tax at the wellhead, after determining the value at the wellhead and the transfer price. The other option is for the state to take the value of royalty gas in-kind, and participate "all the way through the value chain; the state will have gas itself to put through the pipeline, to put through the LNG facility and at the other end, ship it somewhere and have to establish a marketing operation ... there are states that do that, they tend to be states with large, well-established national oil companies that have the capability to do that ..." In the aforementioned instance, they take all of the risks along the way, such as cost overruns, price fluctuations, marketing, and contractual production obligations. In between these two extremes, there are different options such as taking in-kind gas through the pipeline and selling it at the liquefaction point. However, each option involves many transactions, the difficulty of allocating value along the chain, and assigning risk and reward.

12:10:14 PM

CO-CHAIR SADDLER raised the question of companies that have a 20-year commitment and "make a bad bet." He asked whether there is a willingness of parties to renegotiate terms.

MR. TSAFOS advised that for long-term deals there are two remedies available. The first is to include in the contract the ability to review the terms every few years. This is a price review clause called the renegotiation provision, of which there are limitations to the amount of the adjustment in price. Failing that, there is a reconciliation mechanism that utilizes the standard process of arbitration. This is seen in Europe but not as much in Asia, where generally there are attempts to resolve the conflict within the contract, and where contracts occasionally have provisions for back payments. He said, "There is definitely an understanding in these deals that they do have to be resilient to change. For the most part it is a price renegotiation clause, which is generally fairly restrictive." In addition, there may be one time in the life of a contract

when renegotiation is allowed outside of the aforementioned review cycle. In further response to Co-Chair Saddler, he acknowledged that there are lots of arbitration cases where companies or countries are dissatisfied; for example, in Brunei a renegotiation occurred over S curve pricing.

12:14:28 PM

CO-CHAIR SADDLER asked whether there are cases where renegotiation or arbitration failed.

MR. TSAFOS said in the '80s a contract between Algeria and the U.S. was never fulfilled. Indonesia has also failed to deliver gas from some of its older plants and penalties were paid to the buyers. In the case of "take or pay" contracts there may be recourse in the governing laws of the country. Typically, a failure does not happen much because the business of LNG takes place in a "pretty small world" and it is important to uphold one's reputation and to resolve things amicably.

12:16:58 PM

CO-CHAIR FEIGE recessed the meeting until 1:30 p.m.

CO-CHAIR FEIGE called the House Resources Standing Committee back to order at 1:39 p.m.

1:39:55 PM

JOE BALASH, Acting Commissioner, Office of the Commissioner, Department of Natural Resources (DNR), relayed that Black & Veatch conducted a study to address royalty findings commissioned for the purpose of protecting the state's royalty interest for its natural gas [slide 5]. The aforementioned study focused on royalty value and cash flows to the treasury as a consequence of exporting gas to the Asian liquefied natural gas (LNG) markets. Many Alaskans, including Governor Parnell, have expressed interest in obtaining North Slope natural gas to serve their local communities. The department has focused on royalties since royalties are the primary way in which Alaskans benefit from the ownership of the resource. Keep in mind that the terms of the state's royalty agreements with producers are civil in nature and can only be changed if both parties agree. Thus the state doesn't have the luxury of unilaterally changing the terms. In fact, it is rare when both parties find it in their interest to mutually agree upon changes. Therefore, questions surrounding commercialization of Alaska North Slope

(ANS) gas will arise and the state needs to be prepared to answer them.

ACTING COMMISSIONER BALASH touched on background information related to specific key terms in agreements, including the right to switch from "in value" to "in kind" royalty methodology on relatively short notice, 90 days to 180 days, and the manner in which the resource is valued at the lease boundary. More than ten years ago the state undertook a serious effort with respect to developing a natural gas pipeline into the North American hub. At that time, the department developed a solid understanding of how the terms affect the shippers, transporters, and the state, including considering solutions for potential hurdles for project sponsors and firm shippers and how to maximize its opportunities. It also became clear that certain accommodations were needed in order to facilitate a project.

ACTING COMMISSIONER BALASH noted that two key differences emerged between a North American project and an LNG project: the market itself and the transportation infrastructure, including the AKLNG's regulatory structure. With respect to the market differences, when moving gas in a pipeline from the North Slope to the deep, liquid Alberta trading hub the value of the commodity in the market is known, so there is very little to argue about in terms of commodity prices since the starting point for gas valuation is straightforward. However, with respect to LNG, the legislature's consultants have already attested that the basis of exchange is very specific and detailed commercial terms are embodied in the sales and purchase agreement (SPAs). Although the SPAs do contain common features, each is unique in terms of the agreement, which makes for an opaque market and manner in which the commodity is valued. This creates challenges for the state when it seeks to determine the value of the state's royalty on LNG. The second key difference for the AKLNG project lies with the transportation infrastructure itself, he said.

ACTING COMMISSIONER BALASH explained that with the North American model - in which the commodity starts in the producing fields - the royalty happens at the lease unit boundary and the natural gas moves from that point to the market through a regulated transportation system. Specifically, the system is regulated for access by third parties and for rates. Therefore, the state would rely on regulation to determine any cost deducted from market value for purposes of transporting the commodity, which raises and represents the fundamental issue:

in an LNG project - with a Gas-to-Power (GTP) and a pipeline - the state can likely rely on the Federal Energy Regulatory Commission (FERC) to regulate those pieces; however, that isn't the case with liquefaction. The terminal itself is subject to the exclusive jurisdictions of FERC, whose authority is embodied in [Section 3 of the Natural Gas Act (15 U.S.C. §717b)]. Because the FERC regulates for environmental and health safety issues but not currently for access or rates, there isn't a regulatory backstop to assess the appropriate charge for the liquefaction service. Thus the department has taken to referring to the process as "a little bit of a black box." Under the terms of an LNG lease, the lessee is entitled to certain deductions when transporting hydrocarbons to market. This represents a reasonable transportation charge; however, with an unregulated facility - which has yet to be constructed - the question then becomes what is reasonable. To answer that, the department researched and reviewed types of models used for LNG construction and determined three major categories: integrated [upstream], merchant, and tolling structures - each with a different risk profile and a different, reasonable expectation for return. Aside from the risk profile, the method of financing the facility and the amount of the finance charges will determine the reasonable transportation deduction. Consequently, the question becomes what will happen in the specific case of the AKLNG project.

ACTING COMMISSIONER BALASH relayed that from discussions with project sponsors the department understands the AKLNG project will likely be developed as an integrated system, which he agreed makes sense. In fact, the producers have the North Slope commodity as well as an interest in ensuring a reliable transportation system in order to enter into a long-term sales agreement with interested buyers. However, the state faces challenges with an integrated system since the producer can move costs and structure financing throughout the value chain that makes the most sense for decision-makers. In terms of producers, this will entail decisions based on what is necessary or beneficial to ensure that the project succeeds. On the other hand, this won't necessarily comport with the state's interest in acquiring relatively lower tariffs for the charges. Of course the state will be interested in the lowest charge possible so the royalty value - the netback value - will be as high as possible. This encapsulates the root misalignment with lessees in Prudhoe Bay and the North Slope fields which have led to vicious fighting, at times, over royalty interests [slide 13].

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ACTING COMMISSIONER BALASH suggested that misalignment has come at the cost of a more robust investment climate and activity in Alaska's oil industry. Any solution, he ventured, must involve key threshold questions, including whether this [LNG] project is even feasible from a commercial perspective. Also, the fundamentals in the marketplace and the demand will dictate whether the market can handle sufficient volumes of LNG from Alaska to allow efficiencies of scale. In evaluating both cases, the results were good, but were also sobering, he remarked. He cautioned that the [LNG] project isn't a given and while the economics appear to be robust, the AKLNG project may not attract the kind of capital from the project sponsors necessary for a viable LNG project.

ACTING COMMISSIONER BALASH again advised that the government's take in the cash flow is set a little high. He suggested returns for the companies are close, but not to the point of creating confidence that the project will command sponsors to invest capital. The department has considered several options the state could take to address these issues. While there is little the state can do about federal corporate income tax rates, the department has examined other aspects, including reductions to gas royalty, production tax, and state property tax, or simply eliminating them. These points were considered during consideration of HB 4, as well as any necessary benefits to the state to construct and carry the costs of the proposed gas pipeline. He acknowledged that while the state can provide some benefits to project sponsors, it will come at some cost to the state. Consequently, the state has sought alternatives and believes an equity investment in the project is one option to consider.

ACTING COMMISSIONER BALASH emphasized if the AKLNG project is set up appropriately, with the right participants, that the state could be in a position of being able to improve the economics for the project sponsors while doing as well or better in terms of long-term cash flow to the state [slide 14]. The department's focus has been on the present value in terms of the state's cash flow. Finally, the state will need to make a large upfront capital commitment that the state must be vigilant about as it considers the time value of money to ensure future returns, he said.

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REPRESENTATIVE HAWKER offered his recollection that with an integrated project concerns focused on cost shifting so the state and producer would not be aligned. He asked for the vehicle or means that would be used to shift costs in order to consider whether sufficient volumes exist to affect the outcome of a project economically.

ACTING COMMISSIONER BALASH answered that this would depend more on the concentration of debt and equity relative to the individual component. Certainly, it's conceivable to set up a very favorable debt-to-equity structure for the pipeline and establish very reasonable tariffs in-state, yet still have a different capital structure for the liquefaction plant that could affect the AKLNG project. The capital structure in turn will play a big role in the ultimate charge and is deducted against the state's market value. In this way the liquefaction facilities create the most concern with regard to what would be considered reasonable in terms of an agreement because the risks associated with the project from the producer's perspective will drive them to a higher number. Conversely, the state's interest in a lower charge will push it to a lower number. He emphasized that closing such a gap isn't going to be easy. It's really the financing structure he's referring to when he talks about cost shifting, he stated.

REPRESENTATIVE HAWKER emphasized the importance of recognizing that the costs aren't "hard-dollar" costs. He offered his belief that the testimony in front of the legislature has left an impression that the [oil and gas] industry can just run rampant and move costs up or downstream at will, but that's not really the case. Instead, the movement relates to investors being able to make business decisions that result in the minimization of their tax obligation to the government. He characterized this as being a legitimate function of business. However, it sets up the dynamic with the state such that the state will try to constrain industry's ability to maximize their benefit and instead maximize the benefit to the state. He reiterated that this provides important reasons to establish the department as part of the process. He ventured that numerous ways exist to regulate the proposed AKLNG, but the key point to remember is that this refers to debt and financing costs and not hard-dollar costs to the project.

ACTING COMMISSIONER BALASH agreed in very broad terms Representative Hawker is correct, since some costs can be allocated differently within an integrated project structure, although those are relatively minor when compared with the

effect financing the capital structure has on this. He related a scenario in which in which a company and its board of directors has an expectation on returns of 15 percent, with 15 percent as the hurdle. It could use that as a means to recover capital at the liquefaction terminal, which could be one way to achieve what it needs in order to get corporate approval to move the project forward. Certainly, this wouldn't in and of itself make it an appropriate or reasonable charge, but the company might take that type of action to gain approval to allow the project to go forward. Ultimately, the state will pay for the infrastructure one way or another because of the terms of the agreement and lease so the only question that remains is the financing terms for the state's portion of the project.

ACTING COMMISSIONER BALASH directed attention to slide 12 entitled, "Executive Summary - Key Findings." He said the department has come to understand the advantage of taking an equity position since the department can determine the best interests of the state while it also frees up the other parties to do as they see fit. Historically, these three companies [ExxonMobil Corporation, ConocoPhillips Alaska, Inc., and BP Exploration (Alaska) Inc.] haven't always had the same perspective. Thus the opportunity for the companies to set their own finances within the project according to their individual needs is actually another tremendously beneficial step the state could take. Otherwise, if all the costs are rolled in together, with all of the competing credit demands and return demands, the state may have to wait a very long time for that type of resolution to occur.

2:03:13 PM

PETER ABT, Managing Director, Management and Consulting Division, Black & Veatch, referred to slide 16 entitled "Alaska North Slope Royalty Study." He relayed that Black & Veatch was engaged to carry out four primary tasks: 1 to undertake a review of the LNG markets; 2) to provide a brief overview of the supply chain elements; 3) to review the fiscal framework; and 4) to evaluate risk allocation and fiscal structures. With regard to LNG markets, the study sought to provide an overview of how LNG is currently traded and the various markets that may be available to a project in Alaska. Additionally, Black & Veatch wanted to review historical and future global LNG pricing trends, discuss supply and demand projections in the LNG market, and identify any implications on the project in Alaska. Unlike the crude oil markets, the LNG market is highly concentrated, he said. As previously mentioned, the LNG market is illiquid and

very opaque. In fact, seven countries account for about 70 percent of the global demand and Asia Pacific accounts for 70 percent of all global trade. He reviewed slide 18 entitled, "Recent Market Dynamics: Summary." The market has been growing rapidly and is anticipated to grow at a rate of 14-15 percent in Asia over the next five to seven years.

MR. ABT stated that LNG supply is also highly concentrated with eight countries controlling over 80 percent of the global exports in 2012. Additionally, liquefaction capacity is rarely developed on a speculative basis and LNG projects are expensive, typically costing $5 billion to $20 billion per project, although at times costing in excess of $20 billion. Typically, projects are project financed, which requires firm revenue commitments in the form of long-term SPAs from LNG suppliers. One key provision of supply unique to LNG market that differs from natural gas is the specifications and gas quality varies from project-to-project and buyers have various needs, as well. With respect to pricing and contracting, the market has been dominated by long-term SPA contracts ranging from 20-25 years. Further, a small spot market has been exacerbated in the past five years. Many contracts originally developed to deliver LNG, are no longer necessary, which has allowed the contractors an opportunity to trade on a spot basis in the global market.

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MR. ABT said that unlike crude oil, there is no liquid price marker for LNG since the market is set at a local trading point or market. Price structures are developed to allow reasonable price certainty over the term of the contract for buyers and sellers. Oil linkage has been the price driver in LNG market, specifically in Asia, since the 1970s. He pointed to the light blue line on the slide and noted Black & Veatch developed a reference case to identify anticipated demand growth going forward through 2030 as depicted on slide 19 entitled, "Outlook for LNG Demand Growth Varies across Forecasting Agencies." The slide also plots other forecasts developed by other firms, including Ernst & Young, GDF Suez, and BP. In essence, Black & Veatch's estimates present a relatively conservative case compared to others. Perhaps others have used more aggressive demand growth assumptions in Asia in new emerging markets; however, Black & Veatch believes the assumptions might be a little overaggressive in terms of LNG potential in Europe, as well as in terms of new market growth, specifically marine transportation fuels.

MR. APT, in response to Co-Chair Feige, clarified that the metric used is compound annual growth rate (CAGR). For example, the reference case for the forecast horizon from 2010-20 is 5.1 percent, but after 2020 the CAGR is 2.6 percent.

MR. ABT, in response to Co-Chair Saddler, advised that the reference case Black & Veatch is referring to is the base case for the purpose of the entire study. In short, once the financial analysis is reached, this will be the market demand assumptions that were used to drive the financial analysis, he said.

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MR. ABT pointed to the importance of understanding how the Alaska LNG project stands relative to other LNG projects since the project will compete to reach the demand in the next 20-30 years. Thus Black & Veatch has developed a break-even price for the AKLNG price, which is used to measure the relative competitiveness of one project versus another [slide 20]. Based upon the current estimate for the capital cost for the AKLNG project, Black & Veatch has developed a tariff for the LNG plant and for the GTP, assuming the shipping cost at $1 to move to markets in Asia. As depicted in the graph, Black & Veatch has also estimated the "state take" and the "federal take," with the assumption such that the break-even price for the AKLNG project is about $12.30 per [million British thermal units (MMBtu]. This is a conservative estimate, which is subject to a number of factors over time, he said. Additionally, the state has one advantage since it has a lower ambient temperature; therefore, more LNG product can be produced in Alaska than in other global locations due to the cold temperatures. Further, the break-even price is heavily influenced by capital projects (Capex) and labor costs incurred in the project construction phase, although these factors could also have a positive impact to the extent that Capex and labor costs are less than anticipated.

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REPRESENTATIVE HAWKER, referring slide 20, asked for the metric used to calculate the state's take.

2:12:50 PM

DEEPA PODUVAL, Principal Consultant, Management Consulting Division, Black & Veatch, in response to Representative Hawker, explained that Black & Veatch assumed the tax structure

established by SB 21 as the baseline fiscal structure to determine the state's take.

REPRESENTATIVE HAWKER pointed out the footnote indicates the discount rate used to calculate present value is 8.5 percent for mid-stream and 10 percent for upstream. He questioned whether the assumption modeling used represents the same metrics used by potential investors in the LNG project - the producing groups.

MS. PODUVAL responded that modeling requires assumptions; however, she stated that their assumptions were very generic assumptions. She suggested that as Mr. Abt continues with his slides, the committee will see what drove Black & Veatch to use certain assumptions, but essentially, the assumption used is based on a 70/30 debt-to-equity capital mix for the mid-stream. Certainly, a range of reasonableness exists in terms of what those figures might be; however, after reviewing comparable projects, the consultants believed it would be a good marker to use. She reiterated the assumptions would essentially deflect an average cost of capital, assuming a 70/30 percent debt-to-equity ratio with a 12 percent return on the debt equity.

MS. PODUVAL, in further response to a question, repeated the assumption for return on debt equity at 12 percent, with an estimated 7 percent for cost of debt, she believed.

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REPRESENTATIVE P. WILSON recalled the assumption was based on 2011 "real" dollars, as compared to the conservative numbers used. She questioned the reason such conservative numbers were used for break-even figures.

MS. PODUVAL suggested the assumption refers to an earlier presentation by PFC Energy, Inc.; specifically, using real dollars or figures based on today's dollars may account for one of the differences Representative Wilson had observed. She said the committee will also find - during the presentation portion that covers the supply chain elements - a significant uncertainly exists in terms of the capital costs. The study considered LNG projects that have achieved final investment decisions and are currently under construction. She emphasized that several drivers within the LNG market drive costs upward, such as competition for resources and inflationary measures. Thus this study attempted to identify markers between the capital cost estimates illustrated by the producers on the proposed $45-65 billion project, and select a number that is

reasonable within the range to use for its baseline analysis. In further response, she confirmed that Black & Veatch's analysis uses 2013 figures.

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REPRESENTATIVE HAWKER recalled prior testimony on this subject. He offered his belief that the return on equity figures seemed low compared to what was relayed by those making the investment decisions. He further recalled the aforementioned testimony had a return on equity ranging from 15 percent to 18 percent.

MR. ABT relayed that he would answer Representative Hawker's point soon and would also discuss the expected returns on equity that the producers are expecting to realize or typically receive for midstream investments. In further response to a question, Mr. Abt responded that it's correct that the figures used relate to midstream and liquefaction.

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MR. ABT returned to his PowerPoint to slide 21 entitled, "On the Global Supply Curve, AKLNG Appears to currently be out of the money, Modifications Required for Competitiveness [slide 21]. He emphasized that it appears that the current AKLNG project is marginally "out of the money." He pointed out the break-even price is plotted on the vertical axis and each LNG project currently under development expected to come into service after 2013 is depicted along the horizontal axis. The relative width of each bar indicates the capacity of the project. The chart demonstrates that the AKLNG project is a relatively large project. The shaded box reflects the range of supply expected to meet the demand in 2025. In other words, the area represents incremental supply that will be developed in the next three to seven years to meet demand in 2025 - or the demand growth. He explained that demand growth is determined by calculating what is currently available to serve the market and recognizes the decline in production and considers new projects under construction or anticipated to be in-service. Based on the market he estimated there would be relatively large amount of market still unserved in 2025, which explains why the box has such a wide range, he said.

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MR. ABT, in response to Co-Chair Saddler, concurred that the chart includes the 20-25 year contracts available to meet the

demand in 2025 and the projects are calculated to serve for 20-25 years.

MR. ABT explained that the negotiations for the LNG projects typically commence before final investment decisions are made since one of the key drivers in making the final investment decision happens once the contract is negotiated. In fact, 90-95 percent of the offtake will be fully contracted prior to construction commencement, he said. Since a project typically takes 5 to 6 years to construct, the final investment decisions need to be made in 2018 to meet a 2025 in-service date, which means that contracts must be negotiated in 2014 to 2016 in order to meet that timeframe.

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REPRESENTATIVE HAWKER, noting that the chart is labeled an illustrative chart, questioned whether the chart data is vague. He further asked whether the projects included are ones in which final investment decisions have been reached or if the study also includes a matrix of LNG projects that may not come to fruition.

MR. ABT clarified that the graph represent those LNG projects that are either under construction, under development at some level, or are nearing final investment decisions, but are ones contemplating being in service throughout that timeframe. In other words, the graph represents the total number of LNG projects Black & Veatch is aware of that could complete for the market in 2025. In further response, he answered that the graph includes all LNG projects. He acknowledged that part of the uncertainty may stem from the fact that some of the projects are probably not viable. For example, the graph also includes LNG projects located in some regions of the world with the likelihood of geopolitical instability or other factors. For example, all of the projects in the Lower 48 are included, yet it is possible not all of the aforementioned projects will be constructed.

REPRESENTATIVE HAWKER asked whether it was probable that some of the LNG projects would not be included.

MR. ABT answered perhaps, but on a break-even basis, he stressed that these projects would fall below the level of the AKLNG project. He acknowledged this tends to add uncertainty in the marketplace since it is unknown which of these projects will be available to meet the demand in 2025. In further response, he

clarified that the word "illustrative" doesn't have any special connotation.

2:25:24 PM

MR. ABT emphasized that Black & Veatch has all of the data used to develop the curve. He indicated that Black & Veatch also performed further economic analysis similar to the previous slide for the state; however, he emphasized that the data used is proprietary information so the data cannot be published. The graph is identified as "illustrative" since the specifics are not included that would allow committee members to draw conclusions. Suffice to say that the state is "out of the money" at the current projected demand and price levels in 2025, he said. In further response, he agreed the assumptions made are based on the current economic fiscal framework.

2:26:53 PM

REPRESENTATIVE P. WILSON, referring to whether the existing law is retained under SB 21, surmised that the Lower 48 market has been substantially fluid since considerable opposition to fracking exists. She asked whether [the fluid market] would affect pricing and limit available gas.

MR. ABT agreed it would. He said the presumption is that the development of natural gas in the Lower 48 will continue without any reduction to the availability of supply due to regulatory changes that might affect hydraulic fracking. While some factors may affect the outcome of some projects, such that the projects would not occur, the factors go beyond the hydraulic fracking and have more to do with project location. For example, the U.S. Department of Energy [DOE] has yet to permit all of the projects requesting export authorization to non-free trade countries. Although only four countries have currently received that authorization, approximately 20 additional projects are in the queue awaiting authorization. Once the projects receive DOE authorization, the parties will next need to obtain a Federal Energy Regulatory Commission (FERC) permit to construct the facilities. Finally, the parties will have needed to sign long-term contracts with creditworthy counterparties. Therefore, several hurdles stand in the way of these projects being developed, he said.

2:29:28 PM

REPRESENTATIVE JOHNSON, referring to slide 21, asked where the red line would fall under the previous tax - under AGIA - and whether that analysis has been performed.

MS. PODUVAL answered that Black & Veatch has performed preliminary analysis [under AGIA] but the final figures are not available.

ACTING COMMISSIONER BALASH advised members that the department will present several follow-on modules for this study to the committee as early as [December]. He anticipated the follow-up will consider the questions raised, but will also provide a final level of detail on the impacts a project like this would have on in state energy deliveries and value of expansions.

REPRESENTATIVE JOHNSON said he hoped this will happen sooner rather than later.

REPRESENTATIVE TARR acknowledged the number of factors present, and noted the graph estimates the competitiveness of the LNG project today based on the break-even level. She asked how frequently the analysis should be undertaken since other projects could also shift.

MR. ABT responded that this analysis is ongoing and new information is available each day. He agreed the [market] is extremely fluid so the department does anticipate some shifting will happen. He reiterated a significant amount of information is extremely proprietary so most of the LNG project proponents will not aggressively discuss cost increases until forced to do so. Therefore, the analysis is based on the information available and the firm continually "mines" for more and better information. Certainly, the curves will be updated to reflect new information.

MS. PODUVAL advised that at the same time other countries are performing similar analysis on their projects and making changes to their fiscal terms, which creates an ongoing dynamic and causes LNG projects to move.

MR. ABT explained that cost pressures found in Alaska are also being experienced throughout the world, including labor shortages and material cost escalation. For example, serious run-up in costs has occurred during the last five years just in the liquefaction section alone. He predicted that some of those pressures will continue, which will affect all projects, not just the AKLNG project.

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MR. ABT turned to discuss slide 22 entitled, "Growing Lower 48 & Canada Approvals Mean that the Opportunity for New Projects could Narrow Going Forward." In summary, a tremendous amount of pressure exists throughout the world for the [LNG] market. Currently, a number of projects are under construction and most of the LGN projects located in Australia will fill the demand prior to 2020. Further, a number of projects in Canada and the Lower 48 currently seek approval to meet the LNG demand. An estimated unmet opportunity of about 50 million tons in 2025 and an additional 30 million tons in 2030 exists. Therefore, a tremendous opportunity exists for the AKLNG project to meet this demand, he concluded.

MR. ABT discussed slide 23, entitled, "Prospective Future U.S. LNG Exports Have Created an Alternative to Traditional Crude Linked LNG Contracting." As previously mentioned, the majority of long-term SPAs in the LNG market are linked to crude oil, he stated. The typical Japan Crude Cocktail (JCC) linked contract applies to LNG produced throughout the world, which is sold predominantly to the Asia-Pacific market. Further, since LNG is indexed to crude a slope or percent is applied to the dollar per barrel price of crude oil. Typically, this ranges from 14.5 percent to 15 percent of the crude price - plus a fixed "adder" that generally represents the cost of shipping from the supply source to the market. A recent development due to the abundance of shale gas in Lower 48 is that projects have been selling at Henry Hub linked prices. In turn, this has created a new pricing dynamic in the marketplace and has provided an alternative to crude oil linked pricing. He elaborated on the way LNG is sold - such that it is sold free on board (FOB) in the Lower 48 - where the buyer pays the cost of shipping, plus the price is linked to the Henry Hub prices. He turned back to the example on slide 23, which shows the contract structure under the Cheniere Energy, Inc. [Cheniere], Sabine Pass Liquefaction facility. He explained that Cheniere basically has been selling LNG to buyers at the tailgate of the liquefaction plant for 115 percent of Henry Hub prices plus a fixed price ranging from $3-$3.50 per million British thermal units (MMBtu). Referring back to the second chart on slide 23, he advised that the effect of the landed price in Korea is about $12 when Henry Hub is at $6, as opposed to a landed price of $15 to $20 - depending on the price of crude. Although buyers in Asia are particularly attracted to the Henry Hub linked prices, the good news is there isn't an unlimited amount of supply. While some

pressure has been placed on Japanese buyers by the traditional LNG sellers to accept Henry Hub linkage, thus far the sellers have not been willing to acquiesce to those structures, he said.

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MR. ABT turned to slide 24 entitled, "In the Long Run Through 2030, LNG Market Can Evolve within a Broad Range." In addition to the reference case, Black & Veatch reviewed the impact on the market price as well as the ultimate price for LNG. On the high case - or high-priced case - LNG exports would be permitted at a relatively slow pace. He predicted the permitting pace to remain the same in the Lower 48 so non-North America conventional supplies, such as the supplies from Mozambique or additional supplies from Australia and Alaska will be able to compete to serve the remaining demand. Under the high-priced scenario, the Asian demand will grow much more rapidly than has been expected in the aforementioned reference case. Further, the very high-cost LNG projects in Australia and Russia will become the marginal sources of supply. However, those projects are to the right of the AKLNG project in the supply curve. Under such a structure, sellers will continue to demand high slope oil-linked contract terms for the LNG projects at 14.5 percent or 15 percent of the JCC. He predicted under the high-case scenario the LNG market price in the Asia-Pacific region will range from $14-$18 per MMBtu.

Mr. ABT, turning to the low-priced case, explained what might drive this will be unconstrained supply from the Lower 48 since all projects that have applied for export authorization will have been approved and those projects can subsequently secure customers, financing, undertake construction, and go into service. Under the aforementioned situation, all of the remaining LNG supply - including the supply in Alaska - needs to compete with Henry Hub (HH) linked prices since HH becomes the price setter for Asian LNG. He further predicted that the underlying HH price will increase due to the high-growth demand in the Lower 48. Thus the landed price for LNG in Asia would fall in the $10-$14 range. Although it is still be possible to have a break-even price at $12-$12.50 - which would allow Alaska perhaps to compete in that market - there is certainly more risk in that market, he said. In response to a question, he elaborated that what is meant by North America is the HH linked price shown in this slide [slide 24]. Alaska would be part of conventional supplies that could compete on oil-linked pricing, he indicated.

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REPRESENTATIVE HAWKER asked whether he could estimate the probability of the outcome for the high or low case since the assessment of risk involves the assignment of risk probabilities of the outcomes. He offered his belief those factors will be critical to the outcome and to this conversation.

MR. ABT responded that based upon the level of approval activity in Washington - with respect to Lower 48 projects - he expected that the permitting process will continue at a slow pace. He offered his belief that there is a better likelihood of a higher price forecast rather than a lower price forecast event occurring. However, Black & Veatch is comfortable with the reference case as the base case, he said. Certainly, deeper delving into the specific economics of the ultimate price will happen, but for now he expressed comfort with what Black & Veatch projected, which is $14-$15/MMBtu. In response to Representative Hawker's question on whether that would be the $6 Henry Hub range, he answered that it would be in the $6-$6.5 Henry Hub range.

2:42:21 PM

REPRESENTATIVE TARR asked why Black & Veatch has confidence in a slow permitting process and what factors have overwhelmed that process.

MR. ABT answered that the permitting process is multi-faceted and the U.S. Department of Energy (DOE) has been progressing at slow pace, although he thought the DOE will continue to process the permit applications. While the DOE would not officially stop processing applications, the agency will likely control the processing timeframe, he said. Once project sponsors receive authorization from the DOE, subsequent reviews will be performed using the FERC process, which he characterized as a very deliberative process. In fact, the FERC process includes other factors not considered by DOE, such as hydraulic fracturing and associated potential air quality issues impacts on the environment, all of which could serve to delay the timing on the project approvals. Thus, uncertainty surrounding the approval process forces buyers to look at alternatives in their portfolio to meet demand timeframe and window. He pointed out that the buyers know the demand in the market and must find secure supply to meet that demand in the timeframe under discussion.

2:44:38 PM

MR. ABT turned to slide 25 entitled, "The Movement of LNG Prices Within these Ranges is expected to depend on Three Key Factors." This slide highlighted factors that could influence the range of pricing [including supply-demand balance, seller market power, and buyer market economics]. Certainly, the global supply demand balance does impact the material effect on the LNG price for several reasons. First, although many good LNG projects exist, some are very speculative or projects are located in regions that are not necessarily conducive to LNG projects due to lack of infrastructure or local support. Second, sellers in the market exhibit a great deal of market power so LNG producers have maintained pricing discipline over time, which is why the JCC index has stayed as the predominate price marker. Third, producers have the ability to undercut competing producers on price, which has sometimes occurred, but it is often driven by factors that may or may not currently be considered. For example, in Australia a price floor was preferable so decision-makers settled for a much higher "adder" with a lower slope. This decision allowed the LNG project to move forward with necessary financing. Finally, LNG projects must be competitive with other alternative fuels available to the buyer, including nuclear, oil, or locally-produced shale gas.

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MR. ABT highlighted four main points on slide 26 entitled, "Summary: LNG Markets." First, the LNG market is characterized by highly capital intensive projects supported by long-term contracts across the entire supply chain. Second, the LNG market is illiquid and opaque, with few players, in contrast with the liquid and transparent oil market. Third, the LNG demand is estimated to grow over time, but it's important to note that multiple supply sources are competing to meet this additional demand. Fourth, the AKLNG project appears to be "out of the money" within the current status quo; however, the cost or fiscal modifications could address that and enhance competitiveness of the AKLNG.

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CO-CHAIR SADDLER asked whether any fiscal changes could be made that would not have any impact yet could inadvertently create false trails.

MS. PODUVAL answered that the committee will see some measures that are more effective than others further on during the

presentation. She offered her belief that any financial or other changes made would likely improve the LNG project, but it's a matter of whether it will be enough to move the AKLNG project to be competitive in the market. However, there may be other ways to structure things differently. For example, it might be possible to give more [profit] to producers instead of to the U.S. government [in taxes].

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MR. ABT brought up slide 27, entitled "Supply Chain Elements - Scope." Turning to the supply side of LNG projects, he offered to provide a brief overview of the current capital cost estimate for the Alaska LNG project, then discuss the capital structures that likely applicable to the AKLNG project, and finally, touch on the various commercial structures for the AKLNG project.

MR. ABT referred to the slide 28, entitled "Project Capital Costs Update Increases Baseline AKLNG Project Cost to $45 Billion (2013$) [slide 28]". He said Black & Veatch's current estimate of the AKLNG Project is $45 billion, which varies from the range of $45 billion to $65 billion previously discussed. Granted, this estimate does not include costs the producers typically consider such as a number of the costs upstream from the GTP, but it includes the GTP, the pipeline, and the LNG terminal. However, these figures do not include the costs upstream of the GTP, or from the field to the GTP. Mr. Abt provided a brief history. In 2008, a preliminary assessment was done during the Alaska Gasline Inducement Act (AGIA) process. At that time the AKLNG project cost estimate was $27 billion. In consultation with several of the state's consultants - Pingo International and Westney Consulting - Black & Veatch has revised its cost estimate to the 2013 cost estimate. He pointed out the cost estimates for each phase is reflected in the state's estimates, as follows: the GTP at $10 billion, the pipeline at $12 billion, and the LNG terminal at $23 billion, with the AKLNG total estimate totaling $45 billion. He pointed out that these cost estimates fall within the producers' estimate [$37 billion to $54 billion] - which the producers have already announced.

MR. ABT focused on the capital structures in slide 29, entitled, "Capital Structures Vary from Project to Project Depending on Risk Profile and Partner Preferences." He said that all of Black & Veatch's economic analysis assumes a capital structure of 70 percent debt and 30 percent equity. He briefly listed a representative sample of other projects that are currently under

construction or in operation, which illustrate that many project sponsors have accepted the aforementioned 70 to 30 debt-to-equity structure, despite their desire to have an all-equity financed project. He highlighted Exxon-Mobil Corporation's [Exxon-Mobil] Papua-New Guinea project (PNGLNG), in which ExxonMobil is partnering with the National Petroleum Company of Papua New Guinea. This project consists of a partnership of three local companies, and a Japanese company. He reported this project as an approximately 7 million ton [MTPA] project under construction estimated to begin operation next year.

MR. ABT provided an overview of the Australia Pacific project - APLNG, which he described as a ConocoPhillips and Origin partnership, with Sinopec owning about one-fourth interest. He said ConocoPhillips has been the primary driver behind the LNG portion - the liquefaction terminal, while Origin is responsible for the upstream and the pipeline portions. This project represents a two-train design with a capacity at 9.0 MTPA. Sinopec is responsible for the primary off-take, consisting of about 75 percent of the LNG produced for its markets in China. Obviously, having a credit-worthy counter party such as Sinopec is what helps to underwrite the project financing, he said.

MR. ABT said the Gorgon LNG is the project closest in structure - in terms of challenges and size - to the AKLNG project. He also identified Gorgon LNG as the world's largest capital investment, estimated to cost $53 billion. While Chevron Corporation is the leader of the project, Shell Western E&P Inc. and ExxonMobil Corporation are the primary stakeholders, along with three Japanese utilities with a minority interest in the project, [Chubu, Osaka Gas, and Tokyo Gas]. The Japanese market is the primary targeted market, but each project sponsor will lift their own gas in the form of LNG and each one is responsible for its own marketing. He contrasted this to the Papua-New Guinea and Australian LNG projects with a joint-venture marketing arrangement. He emphasized the importance of understanding this aspect, since he will discuss commercial structures momentarily. Under the proposed structure for the AKLNG project, each party would be responsible for selling their own equity volumes rather than having a joint marketing company; however, joint marketing is not off the table at this time, he said.

MR. ABT explained that the Qatar project was highlighted since in 2008 or 2009, it represented the largest project-financed project in the world, underwritten by Qatar and ExxonMobil's balance sheet. He highlighted it as one project that did not

have primary off-take volumes due to the current market conditions at the time it was built. Therefore, ExxonMobil guaranteed the market for delivery to Europe, he said.

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MR. ABT turned to slide 30 entitled, "Producer Expectations of ROE for Infrastructure Projects Exceed FERC-approved ROE for New Builds." This slide provides a high-level overview of some equity-returned benchmarks in the marketplace. Typically, producers don't invest in midstream assets, although they will do so if it will enhance their returns for their upstream positions. For example, producers will not typically build a pipeline, but will do so to get their product to market or to enhance the value of their product. For internal purposes, producer expectations on return for midstream assets that support an upstream position fall typically in the 12-15 percent range - based on Black & Veatch's analysis and surveys conducted over time. Typically, a straight utility return falls in the 12 percent range. He explained that a utility return is typically an annuity, such that a long-term contract is signed with a credit-worthy counterparty that guarantees its performance over the life of the contract. This basically gives a risk-free rate of return of on equity of 12 percent, he offered. He related his understanding this is what TransCanada PipeLines Limited (TransCanada) asked for during the AGIA process. In fact, FERC has shown recognition that many returns are driven by the cost of money - which has gotten much cheaper in the past five years - so FERC-authorizations have decreased as well. Previously, FERC allowed returns of 14 percent for new-build pipelines, but recently its approval has been under 12 percent, with a few projects coming in at 11.7 percent. The return rates have dropped under ten percent for FERC litigated cases on existing pipelines. He pointed out the difference in FERC rates for existing and new pipeline projects such that FERC recognizes the additional risk associated with construction of a new pipeline as opposed to continuing to provide service under a previously certificated long-serving asset. He concluded that this provides the range that Black & Veatch has observed with FERC's recent decisions.

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MR. ABT, in response to Co-Chair Feige's question regarding whether this relates to minimum returns on equity before FERC will approve the project, clarified that it pertains to default rates the FERC will authorize. He elaborated that a process

exists for negotiated rate settlements with customers which essentially creates a "black box." In those instances it is possible that the earned returns under those rate structures could exceed this level; however, the level represented in Black & Veatch's benchmark study used are ones approved by FERC for the certificated rates for the services provided.

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REPRESENTATIVE HAWKER remarked that the rates of return are critical to the calculations involved in Black & Veatch's modeling. He asked whether the consultant has spoken with the three producers regarding rates projected for the AKLNG project.

ACTING COMMISSIONER BALASH answered that the department has conducted conversations with producers on some of these key issues; however, he would not characterize the conversations as setting a specific cost of capital for the AKLNG project; instead the department discussed a range of scenarios. He offered his belief that the slide is representative of the weighted average cost of capital because the capital structure employed by any one company might be different than another.

3:02:08 PM

REPRESENTATIVE HAWKER followed up. He observed this discussion relates specifically to the cost of capital. He asked whether the department differentiates between cost of capital and the overall hurdle rate for "go" or "no go" decisions on projects.

ACTING COMMISSIONER BALASH answered yes; but for only purposes of evaluating the economics. He clarified that the department is not trying to set individual company hurdle rates across the board so some assumptions were made to wrap everything together in a status quo case.

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REPRESENTATIVE HAWKER remarked his key point is that the study is based on many assumptions, but it not may be reflective of the decision-making process being undertaken at the producer level.

ACTING COMMISSIONER BALASH agreed. He acknowledged the study doesn't represent the final outcome or the specific requirements that any one of the project sponsors will have for this project.

3:03:35 PM

MR. ABT moved to slide 31 entitled, "Commercial Structure of Project Influences Risk and Control." He described three types of structures commonly applied to an LNG project: integrated, merchant, and tolling structure. First, under an integrated structure the interests among all participants are clearly aligned with cost and risk sharing among the partners, with concentrated control of the project within the project sponsor group. Second, under the merchant structure there can be less capital requirement for individual sponsors. Typically, a separation of control exists between the upstream element and the midstream or LNG project itself. Additionally, joint venture marketing agreements are commonly used in which the LNG project is a responsible party for marketing the LNG to the buyers. Third, under a tolling structure, long-term contracts are entered into that establish set rates and guaranteed returns established for the party who provides a service for a fee. He characterized this structure as being similar to the manner used in pipeline companies in Lower 48. Granted, the tolling arrangement does not provide any market upside to the terminal itself in an LNG project since the party paying for the service enjoys the benefit of any rise in the commodity price once the natural gas is converted to LNG and sold into the marketplace.

MR. ABT noted the structure will impact facility operation, financing, and determining deductions when calculating the state's take. In response to a question, he identified a toll as a service provided by a third party for a fee. He continued, noting three elements of the proposed project exist: the GTP, the pipeline, and the LNG facility. Under tolling, the state would own the GTP and any gas that would flow to the GTP and the pipeline. The state would pay a fee to the pipeline owner for the gas to flow through the pipeline. In this structure, the producers and the state would not invest in the construction of the pipeline; instead, the pipeline owner would invest and collect a fee or toll for providing that service over time.

3:07:03 PM

MR. ABT referred to slide 32, entitled "LNG Project Commercial Structures" pointed out this slide depicts all three structures on one slide. First, the integrated LNG project structure is one in which the LNG project company has the same project sponsors or partner for each segment of the project. Interests are aligned from the upstream through the liquefaction - at which point the LNG is sold - at the tailgate of the

liquefaction or sold on an ex-ship basis since the partners may decide to also include the risk of shipping to the buyers. Even under an integrated structure it can be set up as a joint venture marketing agreement - in which the entire output can be sold by a single entity - or each partner could sell their own equity volumes separately. On the surface the integrated LNG project structure seems ideal for Alaska except that the state doesn't participate in upstream, which creates a potential for misalignment of interests.

MR. ABT said with the merchant or non-integrated LNG project structure, the upstream is separate from the downstream and an LNG project is created that is generally responsive of the LNG plant. Under the merchant system, the LNG project buys natural gas from the upstream, liquefies it, and sells it to the market at the tailgate of the liquefaction plant; or it takes the shipping risk and the LNG is delivered ex-ship (DES). The advantage or upside in the merchant system is typically enjoyed by the LNG project company rather than the upstream participants. "Why would an upstream party want to do this," he asked. Maybe the parties receive a fixed price for the natural gas at the inlet of the LNG plant, which is sufficient enough to generate the terms to invest in the upstream. Further, the parties may choose not to allocate any capital to an LNG project or participate in marketing LNG, such as in the Equatorial Guinea LNG project, in which the producers sold to BG Group, who took all of the upside and downside risk of the LNG.

MR. ABT turned attention to the third structure, the tolling structure, in which the LNG liquefaction plant performs services for a fee from upstream. Under tolling, the upstream would pay a fee to third party to build the infrastructure and convert the natural gas to LNG and deliver it back to the upstream participants at the tailgate of the liquefaction plant. Under this structure, the producer would have the ability to market the LNG either at the tailgate of the LNG facility to a buyer or take the shipping risk and move it to the market and sell it on ex-ship basis.

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MR. ABT stated that slide 33 entitled, "Key Characteristics of LNG Project Structures," outlines the advantages and disadvantages of the three aforementioned structures. First, under the integrated structure, equity owners can sell LNG either individually or under a joint venture arrangement. He indicated the primary advantage for an integrated structure is

it provides participants control over the entire value chain since interests are aligned, transparency of costs exists throughout value chain, and cost sharing occurs. Thus, everyone knows the percentage of risk costs involved and share any tax benefits that may accrue. He stressed the primary disadvantage of an integrated structure is that capital costs are extremely high for an LNG project and span the supply chain. From the state's perspective, another major drawback would be control is concentrated within project sponsor group, so expansions and entry of new participants can be difficult. For example, one party may want to expand, but the others may not wish to do so. Therefore, it is imperative to address expansion rights in the joint venture agreements, he said.

MR. ABT highlighted the advantages and disadvantages of the second structure, the merchant structure. He said the primary advantage of the merchant structure is that it lowers capital costs of sponsors if different ownership exists between upstream and the LNG project. He reiterated that the LNG plant construction is extremely expensive and many producers don't care to invest in the midstream. Still, sometimes it becomes necessary to develop such a structure to comply with local government regulatory requirements. Often times, while local governments don't have an interest in the upstream, they may wish to participate in the LNG marketing. Thus they demand a merchant structure so profits flow directly to the government treasury. One disadvantage from the producer's perspective of the merchant structure would be that it provides much less flexibility to sell the LNG since the LNG project company is responsible for marketing the LNG, not the individual producers. All things considered, most producers would not choose the merchant structure.

MR. ABT briefly highlighted the third structure, tolling. He said distinct advantage relates to contractually assured fees and returns. Certainly, from an alignment perspective of the state, the state would know clearly the deductions, with little ambiguity. Also, the tolling structure would allow multiple sources of supply access to the asset and assures long-term third-party access since the tolling entity would be receptive to expansion. Equally important, the tolling structure also facilitates project financing for an LNG project since contractual terms exist throughout the life of the project - which bankers tend to view favorably. The real downside to the tolling structure would be that the LNG would not receive any upside in the market and the LNG plant would only receive a straight fee as a return. For example, if LNG prices increase

significantly from expected levels, the profits would flow back to the producers and the LNG plant would not receive any of the upside.

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CO-CHAIR SADDLER, referring to slide 33, asked for further clarification on the bullet point in the tolling structure, which read: Potential tax benefits if title transfers are taxed.

MR. ABT explained that under a tolling structure, the FERC regulation requires the shipper must have title so when a point of sale occurs it could become a taxable event.

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REPRESENTATIVE HAWKER asked for further clarification on the matrix. He asked whether Mr. Abt is aware of any consistencies in terms of profit-sharing versus concessionary tax regimes on projects worldwide.

MR. ABT answered that would depend upon the project participants, the level of government involvement in the project, and how the "government's take" is earned.

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REPRESENTATIVE HAWKER followed up by asking whether any type of consistency in the outcome and choice in the project structure exists or if it is determined by project.

MR. ABT answered yes; that each project is unique and structured on unique aspects dependent on a multitude of factors that will be considered when the project is financed.

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REPRESENTATIVE TARR commented under the tolling option the producers are not involved in the midstream process as the pipeline owners. She inquired as to how the state would proceed to locate an owner.

ACTING COMMISSIONER BALASH understood the question to be "the willing seller - willing buyer" dynamic of any deal and the relative positions of strength a given party has in terms of a viable deal. He answered that the department's perspective, the

state has easily identifiable interests and identifying a partner would differ fundamentally from a specific producer's interests. As previously mentioned, the state could run into misalignment, such that the state might be happy with tolling arrangements with various pieces of infrastructure for the AKLNG project, yet other participants may not desire any interest in tolling whatsoever. In short, the key will be to find a path and common ground that works for everyone.

3:20:29 PM

REPRESENTATIVE P. WILSON referred to slide 33 to the disadvantages of the integrated structure. The specific bullet point read, "Concentrated control makes expansions and entry of new participants difficult." She posed a scenario in which a company who is not initially involved may later wish to put gas in the pipeline and become a part-owner in the pipeline. She asked whether that would be possible with the integrated structure.

ACTING COMMISSIONER BALASH answered that ultimately parties will want to know how the project structure will work for them, especially if they make a big commitment upfront. Certainly, it is important to understand how others will come in and out of the project. In the final analysis, initial sponsors will want stability in terms. In other words, initial sponsors will want to know what they signed up for won't change. In fact, that may ultimately be important to the state, as well, he said.

3:22:17 PM

MR. ABT turned to slide 34, entitled "Commercial Structure of AKLNG Project Could Drive Misalignment between the State and Producers." He noted [Acting] Commissioner Balash has mentioned several times the importance of developing the commercial structure of the AKLNG project to avoid misalignment between the state and the producers. Obviously, it's important to understand a producer-owned project will create risk for the state and its revenues due to potential misalignment of these issues, in particular, once the discussion around deductions to determine the state's take arises. Specifically, Black & Veatch has been most concerned with the impact at the LNG plant since the LNG plant will not fall under FERC jurisdiction for rate-making purposes since the FERC jurisdiction is limited to authorization to construct. Thus, the tolls across the LNG plant may be subject to a number of factors that will also need to be considered.

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REPRESENTATIVE HAWKER commented that FERC is not concerned with the economic underpinning for the rate-making structure. He asked for clarification on whether the FERC not exerting authority means that regulatory authority can't exist or if the state could also establish primacy and ratemaking structure for the LNG plant.

ACTING COMMISSIONER BALASH responded that he specifically asked this of counsel and his understanding is that the Congress reserved to the FERC exclusive jurisdiction on this matter. Therefore, he was not inclined to take that approach.

REPRESENTATIVE HAWKER said it seemed odd that the federal government would leave such a gaping hole in regulatory authority and that it seemed incongruous.

ACTING COMMISSIONER BALASH responded that the FERC authority was established in Section 3 of the Natural Gas Act [(15 USC §717b)] for LNG projects. That authority was fundamentally constrained by codification of Hackberry policy [adopted by the FERC in the December 2002 Hackberry LNG decision]. He explained that FERC under current law is prohibited from imposing its authority on the sponsors of the liquefaction plant. He further understood that the codification expires in early 2015 and he was unsure of whether the Congress will extend that codification - which he supported.

REPRESENTATIVE HAWKER remarked that he considered it as being another risk factor.

MS. PODUVAL offered her belief that the original intent behind the lack of FERC authority was because LNG was never intended to serve U.S. consumers. Thus there wasn't a need to protect international consumers of LNG for ratemaking purposes.

3:27:23 PM

MR. ABT turned attention to slide 35, entitled "It is Critical to Create Alignment between State and Producer Interests to enable State Receiving its Full Share of Value from the AKLNG Project."

3:27:30 PM

REPRESENTATIVE P. WILSON asked whether Black & Veatch's entire analysis is based on a relatively high return on equity, such that the state would have a high participation in the pipeline.

MS. PODUVAL responded that this premise was created to demonstrate how misalignment could play out. Of course, Black & Veatch is not suggesting that is how it would play out, but rather how misalignment could affect this project if the state did choose an equity-rich structure and an aggressive equity policy.

3:28:21 PM

MS. PODUVAL returned to the presentation. Slide 35 provides an example of how the financial structure related to the LNG plant could impact the economics of this project for the state. She turned attention to the left bars representing the status quo, using a 70 percent debt to 30 percent equity ratio. The chart considers the tariff on the different components. This case allows producers to choose to finance the LNG plant with 100 percent equity with a 14 percent return on equity (ROE). She pointed out the gray bar - which represents the LNG tariff, jumps from $6.73 to $10.78 with 100 percent equity. However, the net effect would be a reduction on royalty payable to the state along with production taxes since those costs would be considered as netbacks. The bar on the right shows an example of a less drastic financial structure, with the far right bar using a 30 percent debt and 70 percent equity with a 14 percent ROE for the LNG plant. Accordingly, this shows the state could lose billions of dollars of value through misalignment.

MR. ABT remarked that this chart really exemplifies the importance for the state to be involved in the project to ensure transparency and to be fully aware of all costs for each link in the supply chain.

3:30:39 PM

MR. ABT related Slide 36 entitled, "Summary: Supply Chain Elements" summarizes the supply chain elements. First, the capital costs for the AKLNG project are likely to remain uncertain throughout the development, primarily related to labor uncertainty going forward. Second, the current total midstream project cost estimates for the GTP, the pipeline, and the LNG plant are estimated by the producers to range from $39 billion to $54 billion. Third, complex LNG projects typically have an integrated commercial structure that gives the sponsors maximum

control, although that is subject to multiple factors - often driven by government influences. In fact, he predicted that ultimately the AKLNG project will be integrated structure to ensure the interests of the state and the producers remain aligned throughout the development of the project. However, it is important to know that it will be challenging for the producers and partners to ensure transparency and the total alignment of interests with producers as the project moves forward. He emphasized the process will be challenging, even if the state uses an integrated structure. Again, much of this is driven by the fact that the state doesn't participate in the upstream. Hence the upstream remains a bit of a "black box."

3:32:27 PM

REPRESENTATIVE TARR referred back to slide 35. She asked for the timeframe used that would show the state could lose billions of dollars of value through misalignment.

MS. PODUVAL answered the study used a 30-year analysis period for this report.

3:32:59 PM

REPRESENTATIVE HAWKER said he was aware of the conundrum and number of problems being identified that link to the inability to regulate LNG entity itself, the debt-to-equity structure, and points upstream related to the project. He recalled earlier testimony that FERC authority precludes state jurisdiction over regulating an LNG facility. He asked whether the state has the ability to regulate upstream of the [LNG plant] and benchmark the state's regulatory decisions by statutory authority in relation to the returns generated in LNG plant the state can't control. In other words, the state would like control against some shifting and state regulation might be a way for the administration to pursue that security.

ACTING COMMISSIONER BALASH answered that from the department's perspective, perhaps, it could be pursued through the production tax mechanism; however, he offered his belief that the process would likely break down in the resolution of royalty payments and royalty valuation. In any event, the department is constrained by the terms of the existing contracts. For example, the normal process for the AKLNG project would consist of project construction, companies would make payment on their royalty obligations based on their estimates, and the state would then conduct an audit. In the event the state determined

the companies shortchanged the state due to overcharges for liquefaction, it would have to go to court for ultimate resolution. In essence, that is how the ANS litigation began. In that instance, the ultimate resolution consisted of settlements on methodologies to apply and use going forward. Of course, with respect to the AKLNG, an opportunity exists to reach a settlement upfront before moving forward. Further, he offered his belief that companies would probably be motivated to reach that settlement going forward and estimate the royalty obligations; however, that would still require the state to come to a mutually agreed upon understanding of the rates that would be applied in terms of ROE rates. Hence, the state keeps coming back to this juncture: will the state be able to come to agreement on what the cost of capital should be for deducting the transportation charges. He predicted the state will be inclined to push for low rates and the producers will be inclined to have certain requirements they can't go below. He offered his belief those are likely two different numbers.

3:37:14 PM

REPRESENTATIVE HAWKER said he wasn't thinking in those terms, but rather in terms of the FERC. He asked if FERC doesn't exert its ability to regulate up and down pipeline, whether the state could. For example, could the state roll out the integrated project, indicated the numbers it wants, yet the returns will be regulated on other side beginning with that number as a constant, not a variable.

ACTING COMMISSIONER BALASH acknowledged that is one way to solve the problem mechanically, but whether it would suffice and result in a project moving forward is the question.

REPRESENTATIVE HAWKER appreciated that concluding point. He wondered at what point that government steps too far in the way of achieving its objectives and stops a project from moving forward - one more time.

ACTING COMMISSIONER BALASH agreed. He offered his belief that identifies the state's ultimate challenge and the reason the department has identified the aforementioned equity alternative a potential "game changer" - one that could for the state and for the producers.

3:39:14 PM

CO-CHAIR FEIGE The committee took an at-ease from 3:39 to 3:53 p.m.

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 3:53 p.m.