

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

February 1, 2010

1:03 p.m.

MEMBERS PRESENT

Representative Craig Johnson, Co-Chair
Representative Mark Neuman, Co-Chair
Representative Kurt Olson
Representative Paul Seaton
Representative Peggy Wilson
Representative David Guttenberg
Representative Scott Kawasaki
Representative Chris Tuck

MEMBERS ABSENT

Representative Bryce Edgmon

COMMITTEE CALENDAR

OVERVIEW BY TONY PALMER, TRANSCANADA ALASKA: AGIA UPDATE/OPEN SEASON

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

A.M. (TONY) PALMER, President
TransCanada Alaska, LLC;
Vice President
Alaska Development
TransCanada
Calgary, Alberta, Canada

POSITION STATEMENT: Provided a PowerPoint presentation and update on TransCanada's Alaska Pipeline Project.

PAT GALVIN, Commissioner
Department of Revenue (DOR)
Anchorage, Alaska

POSITION STATEMENT: During the overview on the Alaska Pipeline Project, answered questions.

ACTION NARRATIVE

[1:03:05 PM](#)

CO-CHAIR MARK NEUMAN called the House Resources Standing Committee meeting to order at 1:03 p.m. Present at the call to order were Representatives Seaton, Guttenberg, Kawasaki, Tuck, Johnson, and Neuman. Representatives P. Wilson and Olson arrived as the meeting was in progress.

OVERVIEW BY TONY PALMER, TRANSCANADA ALASKA: AGIA UPDATE/OPEN SEASON

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CO-CHAIR NEUMAN announced that the only order of business is on overview by Tony Palmer, TransCanada Alaska: AGIA Update/Open Season.

A.M. (TONY) PALMER, President, TransCanada Alaska, LLC; Vice President, Alaska Development, TransCanada, noted that he is chairman of the management committee of the Alaska Pipeline Project. He introduced members of his project team present at the hearing: Paul Pike, Senior Project Manager for the project, ExxonMobil Development Company (ExxonMobil); Patty Baloski (ph), External Affairs for the project; Jim Morris, Project Counsel for the project; Brian Dumfy (ph), Public Affairs for the project; and Tom Roberts who handles the project's work in Washington, DC.

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MR. PALMER began his PowerPoint presentation, explaining that on [1/29/10] the Alaska Pipeline Project (APP) went through a teleconference on the rollout of its Federal Energy Regulatory Commission (FERC) filing for the project's first open season (slide 2). All of the information from that filing is available on both TransCanada's and FERC's websites. In an open season, the pipeline company provides potential customers with design, commercial terms, and an estimate of project costs, tariffs, and timelines. While this is normal in an open season, it is usually done in private and is confidential between the pipeline company and its customers. The Alaska Pipeline Project is unique in that this information has been divulged to the public

and to competitors, which is something that has never occurred before.

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CO-CHAIR NEUMAN said there were several things unique with the 20 "must haves" that were required by Governor Palin during the time the Alaska Gasline Inducement Act (AGIA) was being considered. He surmised the \$500 million provided in AGIA for reimbursements was also unique.

MR. PALMER responded yes. When [TransCanada] made its AGIA application over two years ago, that application and all of its information became public. Certain rights were obtained under the AGIA license and certain obligations to the State of Alaska were encumbered.

CO-CHAIR NEUMAN commented that since those are Alaskans' dollars it is appropriate they be able to see what is going on.

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MR. PALMER resumed his presentation (slide 2). He said the goal of the open season is executed contracts with potential customers. This open season will offer service to potential customers that want service throughout Alaska, as well as service to the Lower 48 via Alberta, British Columbia, or via Valdez, Alaska, for liquefied natural gas (LNG) markets in the U.S. or internationally. A number of parties in Alaska wanted an LNG alternative to be put forward in addition to a pipeline through Alberta, which has been done. During the open season, any customer that wishes to have deliveries within Alaska, or to Valdez, or to Alberta on the way to the Lower 48 will have an equal opportunity as APP has comprehensive proposals for both alternatives in front of the state of Alaska and the FERC.

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MR. PALMER stressed that no individual commercial party can make this project a success (slide 3). Any large pipeline project goes through a lengthy development stage, and if it is successful it then moves forward to construction and ultimately operation. Thus, this project must first succeed in the current development phase. Prior to open season, APP did a tremendous amount of work on the materials included in its FERC filing, and work to advance the material in the filing will continue until April 2010. Assuming FERC's approval is received on a timely

basis, APP will hold the open season from May through July 31, 2010. Post open season will be from August 2010 through 2014. All stakeholders in the project have important initiatives underway to advance the project. In addition to the Alaska Pipeline Project, these stakeholders include producers/shippers, governments, and others. All parties must work together and all must achieve commercial and regulatory breakthroughs for the project to succeed. This is the nature of every major pipeline project, not just this one in Alaska.

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MR. PALMER, in response to Co-Chair Johnson, stated he will address [the commercial and regulatory conditions that are needed to move this project forward] when he gets to slides 14 and 15.

MR. PALMER, in response to Co-Chair Neuman, agreed to provide another update in April 2010.

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MR. PALMER highlighted the achievements to date (slide 4). Over the decades producers and potential shippers have explored and developed gas reserves, he said, and that is an advantage for this project because it is known that there is approximately 36 trillion cubic feet (Tcf) of proven gas. Those parties have also examined alternatives for transportation routes as well as potential markets for the natural gas. The State of Alaska passed AGIA three years ago, establishing the requirements for this major project and that is a critical factor for any large pipeline project. It is local opposition or dissention that often causes large projects to go off track, even if there is governmental and regulatory approval. There was a comprehensive review by Alaska's administration and legislature of APP's license which was granted in fall 2008. He related that the state is finalizing the royalty regulations as set out in AGIA.

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MR. PALMER credited the U.S. government and the FERC for establishing a legislative and regulatory structure that has an expedited, single-window structure with specific timeframes to review the regulatory regime on this project, which is a tremendous advantage relative to other major projects. Additionally, a federal loan guarantee of \$18 billion plus inflation has been established, a huge advantage that was not in

place 30 years ago. With the U.S. government, FERC has also set forward the regulatory process which TransCanada has now initiated. The Canadian government has established a legislative and regulatory structure for this project that is also expedited and single-window. TransCanada has held a certificate from [Canada's] National Energy Board for this project for 30 years and has 25 percent of the project in Canada in the ground and TransCanada has moved gas under that project for 28 years.

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MR. PALMER, in response to Co-Chair Neuman, understood that it is up to the State of Alaska as to whether its royalty share will be taken in-kind or in-value. If the state takes its royalty in-kind, he expects the state would then want to be a shipper on the project and, as such, would be examining the terms that APP has just put forward to determine whether it wishes to be a customer. If the state takes its royalty in-value, he expects the state would rely on the leaseholders to ship the state's gas. In further response to Co-Chair Neuman, Mr. Palmer assured members that APP will be providing the opportunity during the open season for Alaska customers to nominate gas, whether that is the State of Alaska, or utilities, or industrials, or other parties.

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MR. PALMER continued his presentation, noting that TransCanada has held a right-of-way through the Yukon since 1983 (slide 4). He next addressed what the Alaska Pipeline Project itself has done (slide 5). For the past five years, APP has said that the best and most effective way to develop this project is an alignment of five parties: the State of Alaska, the three North Slope producers, and TransCanada. Today there is an alignment of TransCanada and the state via the AGIA license that was granted in 2008. In June 2009, TransCanada and ExxonMobil aligned as well. The Alaska Pipeline Project has offered and continues to offer equity participation to "BP" and "ConocoPhillips." Both TransCanada and ExxonMobil would like to see such an alignment, but to date no concrete negotiations have taken place with the other two parties.

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MR. PALMER, in response to Co-Chair Johnson, explained that APP has dealt with the corporate offices of ConocoPhillips and BP, as opposed to offices at Denali - The Alaska Gas Pipeline.

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MR. PALMER, in response to Co-Chair Neuman regarding export from Valdez, said that at this point for both the Alberta route option and the Valdez route option, APP does not yet know who would specifically be customers. The large producers could decide to put their gas in either direction. They are very sophisticated players in the Lower 48 market as well as the LNG game, and they may decide to put their gas to the LNG option, in which case they are clearly capable of constructing a liquefaction facility [in Valdez] and making arrangements to take their gas to market. If a non-major producer came forward and decided to make a very large commitment to the pipeline, APP would be happy to have discussions with that party as well.

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MR. PALMER resumed his presentation, noting that APP initiated its pre-filing with FERC last year (slide 5). At FERC's request, this pre-filing was earlier than had been anticipated. The project is continuing to move forward with the Northern Pipeline agency (NPA) in Canada. Alaska Pipeline Project has initiated negotiations with the First Nation parties in Canada that have been ready to have discussions, and has commenced interfaces with Alaska Native groups and communities along the project corridor. All of the previous claims on previous projects have been removed at no cost to TransCanada and the original partnership from 30 years ago has been dissolved.

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MR. PALMER, in response to Representative Seaton regarding APP's earlier fear of loss of control in the FERC filing process, stated there were extensive discussions with FERC staff and other representatives of FERC prior to the pre-filing, and an amicable settlement was reached that resolved APP's concerns and met the needs of FERC. In his view, it has been positive for both sides. In further response to Representative Seaton, he said this resulted in a modest incremental cost to the project.

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MR. PALMER returned to his presentation (slide 5). He said APP has developed comprehensive Alberta and LNG alternatives and has complete technical, cost estimates, and schedules for both alternatives in front of the public. Alaska Pipeline Project filed its open season plan with FERC on [1/29/10]. As required by FERC, APP also completed an in-state gas study which was done under contract by Northern Economics, Institute of Social and Economic Research (ISER), and Science Applications International Corporation (SAIC). The study is on the FERC website as well as APP's website. Northern Economics and its colleagues will be conducting a technical conference on the study in Anchorage on February 4, 2010, at 2:00 p.m. The study results will indicate offtake points on the pipeline for deliveries to Alaska as well as appropriate tariffs for in-state deliveries. The final results for these will come out in the open season.

CO-CHAIR NEUMAN interjected that his staff will get copies of that to committee members.

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MR. PALMER reviewed the open season timeline (slide 6). He said the filing begins a 60-day FERC review for the U.S. section. The public comments and FERC's review are primarily procedural and are in regard to whether APP has met the 21 requirements. It is hoped that FERC will approve the plan by the end of March [2010] so the project can move forward in April to prepare the final items. The open season would then commence in May and conclude at the end of July [2010].

MR. PALMER, in response to Co-Chair Johnson, understood that FERC is expected to respond within 60 days and has not indicated a longer response time.

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MR. PALMER resumed his presentation (slide 6), noting that the FERC application is for the U.S. portion of the project and for the Alberta option there will be concurrent Canadian open seasons. He explained that there are three possible outcomes to any open season: no bids, unconditional bids for the full volume, and conditioned bids. It is the norm in major pipeline projects to get conditioned bids and he expects there will be conditioned bids this time. If conditioned bids are received, APP will work with those customers to resolve their conditions, and the target for that is year-end 2010.

MR. PALMER addressed conjecture that not having the final open season results until year-end 2010 is related to the political schedule. He pointed out that in its AGIA application, [TransCanada] stated that it expected to conclude its open season by September 2009 and that conditions would be negotiated with customers over the following 100 business days, which would have been February 2010. This schedule was based on the desire and hope that the license would be received by April 2008. However, the administration's and legislature's reviews took longer than that and the schedule was therefore moved back. The 100 business days is still exactly the same as it was in the AGIA application. It is the norm to take several months to resolve conditions on a major project of this scale.

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MR. PALMER, in response to Representative P. Wilson, explained that Canada has open seasons like in the U.S., except there is currently no filing required with the National Energy Board of Canada to get approval for the open season process. Thus, the FERC stage that was initiated on [1/29/10] is not required in Canada. Assuming the project receives FERC approval on the timing he described, APP will be conducting concurrent open seasons in Canada for the Canadian portion of the project, if parties wish that. TransCanada's own system within Alberta will be conducting an open season, as well, for customers that want to get right to the Alberta Hub.

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CO-CHAIR JOHNSON noted it is currently a 50/50 split on the \$500 million incentive. He asked at what point it will become 90/10.

MR. PALMER explained that APP must expend the monies first. The state then reviews those costs to determine whether they are in compliance and, if so, reimbursement is at 50 percent of the expended costs incurred up to July 31, 2010, the end of open season. Post that stage, the state will reimburse up to 90 percent until the \$500 million is reached, at which point the state's contribution is capped but TransCanada's and ExxonMobil's contributions are not.

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Mr. Palmer, in further response to Co-Chair Johnson, explained that APP has so far received \$1.1 million in reimbursement for expenses incurred in first quarter 2009. Processing of the

reimbursement was slower than was hoped due to the state and APP trying to resolve technical issues in transferring the information on a computer basis. Last week APP submitted for second quarter [2009] and will shortly be submitting for third and fourth quarters [2009]. As of the end of December 2009, APP has spent about \$60 million. Thus, subject to the state's review, reimbursement would be for the state's portion of \$60 million. As APP has worked through the process with the state, it has found some issues that are very challenging from an administrative standpoint. Alaska Pipeline Project is not being charged for items such as him, and therefore the state is not reimbursing any of his costs for this project. This same decision has been made for employee expenses to date because the administrative burden was too great. Thus, the state's reimbursement is actually less than 50 percent of APP's expenditures; however, APP does expect the state will hit the \$500 million cap as the project moves forward.

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CO-CHAIR NEUMAN understood that the state's share of reimbursement to APP is \$30 million to date, after the contract was signed between TransCanada and the State of Alaska, of which APP has received only \$1.1 million.

MR. PALMER replied yes, but he believes the state's reimbursement will ultimately be less than 50 percent of \$30 million because of the aforementioned items.

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CO-CHAIR JOHNSON inquired whether the state is on budget and has enough to cover this cost.

PAT GALVIN, Commissioner, Department of Revenue (DOR), nodded yes. In further response, he said the state is pretty close to right on budget. He related that on [1/29/10], the Department of Revenue distributed a report on the reimbursement fund with a detailed list of the items that are part of the reimbursement. He offered to answer follow-up questions after members have looked at the report.

MR. PALMER added that the Alaska Pipeline Project has been very pleased with its relationship with the administration while trying to resolve how computers can talk to each other.

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MR. PALMER turned to slide 7 of his presentation regarding the open season plan. Alaska Pipeline Project believes its [1/29/10] FERC application offers a comprehensive, highly credible, and competitive open season plan, he said. The project believes TransCanada and ExxonMobil have unparalleled expertise and experience in inter-state and inter-provincial gas pipelines and gas treatment plants. In 2008 TransCanada stated that it did not wish to construct the gas treatment plant because that is not its area of expertise, he related. However, it was a requirement of the AGIA application, and TransCanada indicated it would proceed with the project even if it could not find someone else to do the plant. Therefore, he is pleased to tell members that ExxonMobil, the global leader in gas treatment plants in TransCanada's opinion, is now a partner and the leader in that side of the project. He further offered his belief that TransCanada is the leading pipeline company in North America. TransCanada moves 20 percent of the natural gas across the continent every day and it has \$17 billion-worth of pipelines under construction now in Canada, the U.S., and Mexico. TransCanada knows how to do the engineering and how to get the regulatory approvals to proceed. A critical part of the credibility of what the project is putting forward to members is that customers are needed and regulatory approvals are needed. When ExxonMobil joined the project it shared the producer study from 2001, which is being used for the project. As a team, TransCanada and ExxonMobil have done over one-quarter million hours of engineering, regulatory, technical, environmental, commercial, legal, and project management work to complete the [1/29/10] FERC filing. This joint project work has provided improved understanding of scope, costs, complexities, and risk for this large, complex project.

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CO-CHAIR JOHNSON recalled that the 2001 study was a joint study by all the producers. He asked whether the approximate \$200 million for that study has been, or will be, submitted for reimbursement.

MR. PALMER answered, "No, it will not; and no, it has not." He recalled that the cost of the study was \$125 million. Those costs were incurred by ExxonMobil and other parties prior to the license, he continued, and reimbursement is not being sought. As well, TransCanada is not seeking reimbursement for the costs it incurred under AGIA prior to the license. In further

response, he reiterated there will be no AGIA reimbursement for the aforementioned \$125 million study.

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REPRESENTATIVE SEATON, in regard to conditioned bids, noted that the one condition being talked about is tax rates. He inquired as to what conditions are generally received for large pipelines.

MR. PALMER quipped that some of the project's potential customers are in the room and he does not want to give them new ideas. However, he said he is happy to outline those conditions that are fairly standard during open seasons. First, customers often want assurance that the pipeline company has all the regulatory approvals for conducting business. That condition, however, cannot be satisfied at the time where precedent agreements are concluded because this project will have a FERC filing in 2012 with a hoped-for approval by 2014. A second standard condition is potential customers requesting that the pipeline company improve the offer in some fashion. Sometimes this can be done, and sometimes not; the project has done this already. Another standard condition is that customers want to be ensured their commitment is subject to the pipeline company receiving sufficient volumes in total to make the project economic. Lastly, it is standard for customers to want a commitment that the pipeline will be in service by a particular date or not before a particular date.

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REPRESENTATIVE TUCK recalled that Denali - The Alaska Gas Pipeline provided its FERC pre-filing about a year ago and that it was a new type of filing rather than a full filing. He asked how the Alaska Pipeline Project's [1/29/10] filing compares to Denali's.

MR. PALMER responded that Representative Tuck is right, Denali's filing was very, very brief, just a few pages of documentation, as was the case for APP's pre-filing a few months later. The pre-filings kicked off the process where FERC assigned staff to the project. However, the project's [1/29/10] FERC filing is several hundred pages and comprehensively indicates the project's capital costs, tariffs, commercial terms, terms and conditions, design and engineering work, and so forth. All of this information is also available to the public and it will be used as the project goes forward in the open season. The

precedent agreements - the potential customer contracts - are included in the filing, and that is a unique process that is not normally shared at this stage with the public as it is normally strictly between a pipeline company and its potential customers; generally precedent agreements are not filed with FERC until they are executed.

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REPRESENTATIVE TUCK inquired whether there is anything more that TransCanada needs to do to meet the FERC filing requirements.

MR. PALMER replied that APP thinks it has met all the conditions and therefore it is waiting to hear from FERC in 60 days. Mr. Pike and his team have met with FERC staff a couple of times, and while that does not predispose a final decision, APP believes all the conditions have been satisfied.

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CO-CHAIR JOHNSON, in regard to the two kinds of open season - binding and conditional - asked whether during this first open season, a potential customer is bound to ship its gas if all of its conditions are met.

MR. PALMER answered that this is a binding open season and customers that commit their gas will take on significant obligations to share development costs with the pipeline company, provided the precedent agreement is resolved. However, as is the case in almost every major pipeline project, the customers preserve the right at final investment decision to withdraw from the project, at significant financial cost to the customer for doing so. This is laid out in the precedent agreements that have been filed and this is the norm.

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CO-CHAIR JOHNSON surmised the conditions that will be received will be very specific, so in a few months all the cards will be on the table.

MR. PALMER presumed the co-chair is discussing a potential condition with regard to upstream fiscal taxation.

CO-CHAIR JOHNSON said yes.

MR. PALMER said he cannot presume exactly what language a particular customer will use if that is one of the customer's conditions. The customer might say satisfactory to it as opposed to a specific set of numbers. It is in the customer's hands, not his, as to how the customer drafts its response to the pipeline company. Alaska Pipeline Project, as per the legislature's request, will not be engaged in those issues.

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CO-CHAIR JOHNSON stated that if the conditions are so vague, it cannot be a terribly binding commitment for gas.

MR. PALMER responded that there will be some conditions the pipeline company can resolve and those were described to Representative Seaton. There will also be some the pipeline company cannot resolve and in that circumstance then, yes, the pipeline company will have to examine how it goes forward if there is a request that that issue be resolved. If it is not resolved the company has an obligation under AGIA to continue for FERC application. So, the pipeline company may or may not have binding obligations to customers if there is an outstanding item that the company does not control.

MR. PALMER, in further response to Co-Chair Johnson, said Alaska Pipeline Project is going through a binding open season and the co-chair is describing a particular condition that a customer may indicate in response to that open season. If the customer wants a fiscal structure satisfactory to it, and if that has not been resolved by the end of 2010, then clearly that is something APP cannot resolve; APP will still proceed with the project, but that commercial breakthrough will not have been achieved from APP's standpoint. However, he is not suggesting that that is the only condition that will be received in the initial open season and this is why he is reluctant to say it is not a binding open season; in many cases it will be a binding open season, but in the particular case described, it may not be.

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CO-CHAIR JOHNSON inquired whether Mr. Palmer would consider it a failed or a successful open season should the pipeline company receive a conditioned bid for long-range tax concessions for fiscal certainty so that there is not something the company can take to the bank for financing.

MR. PALMER allowed that if that is the case at the end of the period that is defined to resolve items, then it certainly is not a completely successful open season. Alaska Pipeline Project will have to determine at that time whether it is a failed open season. If the state and producers are within a short period of time of resolving it and have said so, then he will not call it a failed open season. If, however, there has been no progress and there is no hope on the horizon, then perhaps it will be a failed open season.

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CO-CHAIR JOHNSON asked whether this means the legislature would need to hold a special session given the timing of the open season's closure.

MR. PALMER replied that the open season will conclude in July 2010, and if conditioned bids are received APP expects it would take through the end of 2010 to resolve the conditions that are in control of APP. However, the circumstance being described by the co-chair is something APP clearly cannot control. If that is a condition and the other items have been resolved, then APP is in the state's and producers' hands as to when or if that is ever resolved.

CO-CHAIR NEUMAN stated that at a later date the committee will be hearing a presentation reviewing how open seasons work.

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REPRESENTATIVE GUTTENBERG inquired whether the FERC filing is black and white in regard to the project's filing being either approved or disapproved, or can FERC come back with something that is conditional on terms that have yet to be done.

MR. PALMER said he thinks it is relatively black and white because there are 21 conditions, which makes it relatively procedural and straightforward. Perhaps FERC could come back saying there is one condition that needs to be changed, but FERC is not at this point commenting on the quality of APP's commercial terms or capital estimate. Alaska Pipeline Project thinks it will get approval in 60 days or shortly thereafter and the open season conducted on the May-July schedule as described. It will be during the 2012 filing for the certificate that FERC will comprehensively review all items for the in-depth content that is behind all of the materials, he added. During that

process it is not unusual for FERC to come back with conditions that must be resolved to receive the certificate.

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REPRESENTATIVE GUTTENBERG noted that APP's slippage on the projected open season coincides with the legislature's longer period of time to approve the contract.

MR. PALMER answered yes; it was the administration and the legislature. When the filing was made at the end of November 2007 the basis of the schedule was that the license would be issued in April [2008]. The administration's recommendation came in May 2008 and the legislature's review took nearly two months. There were not enough votes in the legislature to expedite that licensing process, so there was an additional lag of 90 days. Thus, the license was received in December [2008]. The 100 business days is exactly the same as what was included in the AGIA application. So, while this now happens to run through the political timeframe, it had nothing to do with [TransCanada's] plan in any fashion.

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REPRESENTATIVE OLSON surmised that on a project of this magnitude and complexity, it is not unheard of to have two or three failed open seasons before the kinks are all worked out.

MR. PALMER responded yes, as major projects are developed a re-wind will occasionally happen. The magnitude of work that has gone into the material that was just filed with FERC is unusual at this stage; however, that does not mean APP will be successful. Alaska Pipeline Project will go through the process with a credible and competitive proposal and will do its best to make it succeed, but it clearly takes two parties to make this succeed - the pipeline company and potential customers.

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REPRESENTATIVE OLSON asked what the timeline would be for a second open season if the first open season is a failure.

MR. PALMER replied that under AGIA the obligation is to go to the market every two years to see if there are requirements for gas service. However, if it is the situation described earlier by Co-Chair Johnson, and all other issues have been resolved but the fiscal issue, and then, for example, that fiscal issue is

resolved by the state and the customers in six months, the pipeline company could act quickly and hold another open season without waiting for two years.

REPRESENTATIVE OLSON presumed the 800-pound gorilla is the fiscal terms.

MR. PALMER said that is clearly an issue that potential customers have indicated publicly that needs resolution.

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REPRESENTATIVE P. WILSON inquired how substantial the penalty is when a customer withdraws its bid from a project.

MR. PALMER explained that if a customer committed in the initial open season, executed a precedent agreement with the pipeline company, and then decided in 2014 to withdraw, the customer would be obliged under the precedent agreement to reimburse the company for the full development costs of the project. However, if it is the pipeline company that decides to withdraw, there is a sharing mechanism. So, the precedent agreement is truly binding, and everyone involved in it, including the state, makes a significant financial commitment.

REPRESENTATIVE SEATON stated that during the presentation on how open seasons work, he would like to hear about the relationship between the benefits of bidding at the initial open season and at what point the advantages of bidding in the initial open season get withdrawn from the parties.

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MR. PALMER continued his presentation (slide 8), stating that the Alaska Pipeline Project is offering better commercial terms and access than those included in the AGIA application. These benefits are available to shippers that commit in the initial open season because APP recognizes that it is facing a highly competitive environment not just to move Alaska gas to market, but also from other sources of gas that are competing both in the Lower 48 and in global markets. He said comprehensive Alberta and Valdez options are being offered that are responsive to shipper discussions. Potential customers at Valdez requested a 48 inch, 3.0 billion cubic feet per day (Bcf/d) pipeline to Valdez, which is provided in APP's FERC application. Potential customers requested access to other pipelines upstream of the Alberta Hub rather than strictly going into TransCanada's system

at the Alberta Hub. Thus, while he believes that customers will want to go into the Albert Hub, they will have the option to not do this and to sell their gas in other markets through existing infrastructure. A 25-year minimum contract term was included in the AGIA application and that has now been reduced to 20 years. Thus, a customer can select terms from 20 years to 35 years. The project is also offering potential customers the enhancement of short-term interruptible, overrun, and park-and-loan services within Alaska or downstream. Additionally, APP is sharing development costs in circumstances where APP terminates.

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MR. PALMER further pointed out that APP is offering better commercial terms by \$500 million per year. He put this into context by explaining that the State of Alaska's total financial commitment under AGIA is \$500 million. These better commercial terms reduce the tolls by \$500 million per year over a 25-year life. This is being done by reducing the return on equity (ROE) to 12 percent. Also, through depreciation, APP will only recover 80 percent of its initial capital through those initial contract terms.

MR. PALMER, in response to Co-Chair Neuman, stated that in its AGIA application, [TransCanada] provided a formulaic approach that would have yielded a 14 percent ROE, and for capital recovery had anticipated recovering 100 percent of the capital over the initial contract term. Thus, the changes shift risk away from the customers to the pipeline sponsors. Lastly, in its AGIA application [TransCanada] had indicated that expansions should be funded with 60 percent debt and 40 percent equity, and 30 percent equity is now being proposed. He explained that equity yields a higher cost and higher income tax for customers than debt, so a reduction in the amount of equity is a benefit to customers and Alaskans and a detriment to the pipeline owners.

CO-CHAIR NEUMAN remarked that competition is a good thing.

[2:16:43 PM](#)

CO-CHAIR JOHNSON asked what the life of the pipeline is anticipated to be.

MR. PALMER answered it depends upon whether it is the physical life or the economic life that is being described.

CO-CHAIR JOHNSON asked what happens after 20 years.

MR. PALMER said it depends. Physically, this pipeline will last many decades. TransCanada has pipelines that have been in service for 50 years and some in the Lower 48 that have been in service for 60 years. In the event there is no more gas after 20 years, the pipeline would be retired and APP would not have earned as much money as it had hoped. If there is lots more gas in Alaska, which is what APP is hoping for, then either new contracts or contract extensions would be obtained, in which case APP will have the opportunity to receive a 12 percent return.

[2:18:03 PM](#)

CO-CHAIR JOHNSON said that if APP is negotiating terms from a pipeline that is already built, APP is holding all the cards. Therefore, he is unsure that APP is mitigating risk as much as it is shifting risk into year 2021. At that point, APP will be the only game in town and in control of the math. He inquired whether there will be an option that says the 12 percent ROE will remain the same in the future.

MR. PALMER responded that the co-chair is doing exactly what he would expect a sophisticated customer to do. Because APP has already contemplated this, the 12 percent ROE and other terms being offered will be available to customers for a renewal period as well.

[2:19:41 PM](#)

CO-CHAIR JOHNSON argued that if there is gas after 20 years, APP is not really mitigating the risk, it is shifting the risk.

MR. PALMER replied that with 10 years before in-service and 20 years later, there is huge risk as to whether the gas will be available, the project economic, and that APP has completed the capital cost with a reasonable amount of credibility. If APP has not, the customers will have to pay the costs for that for 20 years. If APP has very high costs, then it would not likely be competitive and the customers would be unlikely to renew. Therefore, it is exactly opposite of the co-chair's description. Alaska Pipeline Project is taking on that risk and he believes the customers will look at that as a very attractive option being put forward. He said he would be pleased to be on the other side where it is the customers that are taking the risk,

which is what APP's original proposal was. Thirty years in time may be quite different than today, he continued. For example, 35 years ago the price of gas in the Lower 48 was 44 cents per million British Thermal Units (MMBtu). So, yes, he thinks APP is taking on a lot of risk.

[2:22:08 PM](#)

CO-CHAIR JOHNSON asked what an 80 percent capital recovery will do to Mr. Palmer's company if there is no gas in 20 years.

MR. PALMER answered that both companies, as well as any other sponsors, will have repaid the debt to the banks and will have received a much lower return than 12 percent.

CO-CHAIR NEUMAN recalled there are several off-ramps for TransCanada Alaska, LLC. Everyone must work together to make this happen, he said.

MR. PALMER clarified that if the project goes in service as he has described, the sponsor's are taking the risk that in 20 years there will be additional gas and there will be customers that will enable the sponsors to earn this 12 percent return, otherwise that return will not happen.

[2:23:40 PM](#)

MR. PALMER returned to his presentation (slide 9), noting there are two [48-inch] pipeline options [from Alaska's North Slope]. The [Alberta] option would deliver 4.5 Bcf/d of gas through a 1,700-mile-long pipeline to the Alberta Hub and pipeline systems that serve the North American market. The Valdez option would deliver 3.0 Bcf/d of gas through an 800-mile-long pipeline for conversion to liquefied natural gas (LNG) at a plant to be built by others and delivered [by ship] to U.S. or international markets. Both options include: an opportunity for Alaska communities to acquire natural gas from the pipeline via at least five offtakes in Alaska, a huge world-class natural gas treatment plant (GTP) for removing carbon dioxide and other impurities located at Prudhoe Bay adjacent to existing facilities, and an approximately 58-mile-long transmission pipeline connecting the Point Thomson field to the plant.

[2:26:07 PM](#)

MR. PALMER, in response to Co-Chair Neuman, said there is no question the \$500 million cap from the state will be hit long

before APP is finished spending money on the development stage to get to final investment decision. In further response, Mr. Palmer said the project's expenditures will soon be seen in the state's reimbursement document mentioned by Commissioner Galvin.

[2:27:41 PM](#)

MR. PALMER returned to his presentation and reviewed project cost estimates and indicative tolls for the Alberta option (slide 10). He noted that all of the costs he is presenting are in 2009 dollars. The capital cost range is \$32-\$41 billion and the target in-service for the project is 2020. He pointed out that the gas treatment plant is the time-critical component of this project as it is the sealifts that determine the ultimate in-service date for this project, not the pipeline. The tariff range, including fuel, is \$2.80-\$3.50 per MMBtu from the GTP to the Alberta Hub. The Alberta Hub gas price, as forecasted in December 2009 by the U.S. Department of Energy in its Annual Energy Outlook, is \$6.25-\$7.65 MMBtu for the years 2020-2030. Thus, the margin is about \$3.00-\$4.00 per MMBtu in netback, which APP believes makes the project both technically and commercially viable.

[2:29:53 PM](#)

MR. PALMER, in response to Representative Olson, said that 18 months ago the cost was \$26 billion in 2007 dollars. In further response, he explained that from 2007-2009, the cost of oil and gas projects went up due to inflation in the industry. Also, the U.S. dollar has deflated relative to other foreign currencies, including the Canadian dollar. The majority of costs will be in Canadian dollars, and when this is converted to U.S. dollars it results in higher costs. While it was stated in the filing that TransCanada did not plan to build a gas treatment plant, a conceptual cost estimate was supplied that was based on a two sealift season. However, after bringing in an experienced partner in the gas treatment plant, it was learned that three sealifts will be required, which significantly increases the gas treatment plant cost. Additionally, there is a modest other cost increase in the pipeline. In further response, he assured Representative Olson that Alaska will be getting a very high quality system, both in the gas treatment plant as well as the pipeline.

[2:32:32 PM](#)

CO-CHAIR JOHNSON inquired what the tariff would be if all the customers selected a 20-year contract as opposed to a 25-year contract.

MR. PALMER estimated the tariffs for this shorter time period would be approximately 15-20 cents higher for a 20-year contract, but cautioned he is calculating this in his head.

CO-CHAIR JOHNSON asked whether this pipeline can be built without gas from Point Thomson.

MR. PALMER responded that the pipeline company seeks to have available to it all possible gas from existing fields as well as to-be-found fields. However, APP is not in the position of stipulating how much or whether gas will be available from any particular field; that is the responsibility of the state, the producers, and the Alaska Oil and Gas Conservation Commission (AOGCC). He said the numbers seen here are calculated based on 4.5 Bcf/d of initial capacity and 4.5 Bcf/d for 25 years.

[2:34:55 PM](#)

MR. PALMER, in response to further questions from Co-Chair Johnson, said Point Thomson gas would add 15-20 cents per MMBtu to the numbers he has cited, given that gas from Point Thomson adds an extra 58 miles as opposed to the customers coming on at Prudhoe Bay. He said there will be no reimbursement from the state's AGIA fund for the Point Thomson line because it was not included in the AGIA application. It is known that there may be gas available from Point Thomson and APP wants to attract that gas. So, APP is offering service in the open season for that piece of pipe for customers that have gas at Point Thomson. Customers do not have to take it and the state will not be reimbursing any monies for it.

[2:36:34 PM](#)

CO-CHAIR JOHNSON inquired whether there would be a tariff for "ConocoPhillips, British Petroleum, or any of the other producers" for gas that comes in from other fields at Prudhoe Bay to this line.

MR. PALMER replied that other customers having gas outside of Prudhoe Bay and Point Thomson could build a line to Prudhoe Bay and pay for that line themselves. Or, they could ask APP to provide that service and APP would consider that request. If

APP built a line for a customer, that customer would pay a tariff.

MR. PALMER, in response to Co-Chair Johnson, clarified that only customers moving gas from Point Thomson to Prudhoe Bay would pay that 15-20 cents; customers having gas at Prudhoe Bay would not pay that 15-20 cents. Thus, if APP builds a 58-mile pipeline that moves 1.1 Bcf/d, a Point Thomson customer would pay \$2.80-\$3.50, plus 15-20 cents, per MMBtu to move the gas from Point Thomson to Prudhoe Bay.

[2:38:55 PM](#)

MR. PALMER, in further response to Co-Chair Johnson, recalled that the players at Point Thomson include "ExxonMobil, BP, Chevron, Conoco," as well as other players. If they choose to nominate gas from Point Thomson Field and they want to move it over to Prudhoe Bay to enter this major system, they will have to pay the 15-20 cents. If they do not wish, or are unable, to nominate Point Thomson gas, they will not pay the 15-20 cents.

CO-CHAIR JOHNSON asked whether TransCanada is going to build the line between Point Thomson and Pump Station 1.

MR. PALMER answered yes, if customers nominate it, bid for it in the open season, and request it. If they do not, then there would be no customers and APP would not build it.

[2:40:12 PM](#)

CO-CHAIR JOHNSON inquired whether part of the partnership with ExxonMobil is to build the line, given that ExxonMobil is the driver here.

MR. PALMER responded yes, the Alaska Pipeline Project proposal is offering service on that piece of pipe from Point Thomson Field over to Pump Station 1, over to the gas treatment plant. The two sponsor companies have asked APP to offer that service not just to ExxonMobil, but to all parties that have gas in the field.

[2:40:51 PM](#)

REPRESENTATIVE OLSON asked whether there will be a decision from AOGCC by the time the open season is held on what can actually be taken out of Point Thomson.

MR. PALMER replied he does not have that answer and the question should be posed to AOGCC. He has no insider information as to how and when AOGCC will make that decision, given that that is not something a pipeline would normally be involved with. However, it is certainly something APP is interested in.

REPRESENTATIVE OLSON commented he is unsure whether there is a timeline on the AOGCC for that decision.

CO-CHAIR NEUMAN related that Commissioner Galvin is shaking his head no.

[2:41:57 PM](#)

REPRESENTATIVE P. WILSON posed a scenario in which oil is found at Point Thomson and there is gas, but the gas cannot be taken until some years later. She asked whether a customer can apply for open season and specify that the gas would not be available until a certain later date.

MR. PALMER said the answer is generally yes, but it will have an impact on the structure of the tolls unless APP has 4.5 Bcf/d from other locations that can fill the pipe prior to Point Thomson becoming available. The tariffs would have to be recalculated by APP should there be, say, 3.5 Bcf/d for two years and then 4.5 Bcf/d after that.

[2:43:32 PM](#)

MR. PALMER, in response to Co-Chair Neuman, agreed that these tariffs are based on the liquids contents in the gas after having had discussions with the field operators. It is the customers' decision as to where those liquids are removed, and removal of the liquids at a particular location will have an impact on the toll because the tolls shown in this presentation are in a heating content of one million Btu's per day.

[2:46:36 PM](#)

REPRESENTATIVE TUCK inquired whether there is a possibility that a pipeline could be built to Alberta in addition to a pipeline to Valdez, or must it be one or the other.

MR. PALMER responded that APP has defined a proposal for 4.5 Bcf/d to Alberta and 3.0 Bcf/d to Valdez. Alaska Pipeline Project does not believe there is 7.5 Bcf/d of gas to be committed at the end of this open season to allow both pipes to

be constructed immediately; thus, APP thinks it is "either or." If one alternative succeeds and moves forward, there is always potential to expand that option or have a Y-line in the future. At the moment, APP must succeed at getting one of the alternatives over the finish line so there is a volume that works to either Valdez or Alberta. Once a pipeline is in service, it can draw on more exploration and additional gas that might allow both markets to be served in the future, or it might allow expansion of the original pipe to the original destination.

[2:48:45 PM](#)

REPRESENTATIVE TUCK posed a scenario of having a total of 5.5 Bcf/d committed, and asked whether a branch of 1.0 Bcf/d could then go off to Valdez.

MR. PALMER replied that APP is always willing to look at an option, and 5.5 Bcf/d going to market would be a good option and a happy outcome. In this case the tolls would be different than what are currently being described for the two alternatives.

[2:50:40 PM](#)

MR. PALMER returned to his presentation and illustrated how gas price forecasts have changed since the AGIA filing (slide 11). The U.S. Department of Energy produces an Annual Energy Outlook (AEO) every year in December, he explained. When APP made its filing in November 2007, the AEO 2007 was from December 2006, which is depicted by the [black] line on the graph. In real 2009 dollars, the gas price forecast for 2020 by AEO 2007 was about \$5.75 per MMBtu and for 2030 the forecast rose to about \$6.60. The AEO 2008 gas price forecast, depicted in blue, was slightly higher. The AEO 2009 was actually done in April 2009 because the U.S. Department of Energy did not have a lot of credence in its December 2008 numbers because of the volatility at that time and decided to do an update. The AEO 2009, depicted in green, shows a significantly higher forecast of about \$7.20 per MMBtu for 2020 and about \$8.60 for 2030. The AEO 2010, which was completed in December 2009 and is depicted in red, forecasts a gas price of about \$6.25 for 2020 and about \$7.65 for 2030. Thus, the most recent forecast, while down from 2009, is still about 60 cents per MMBtu higher than what was forecast at the time of the AGIA application, which helps with the project's viability.

[2:53:41 PM](#)

MR. PALMER, in response to Co-Chair Neuman, noted that natural gas is one of the most volatile commodities, if not the most, in terms of price, even more so than oil. It is APP's view as the pipeline sponsor that the project is viable. However, it is up to the customers to decide their own views in that initial open season, given that it will be the customers' risk as to the ultimate commodity price of the gas that will be delivered in the marketplace.

2:54:35 PM

CO-CHAIR NEUMAN inquired whether there is any way to look at these graphs with a hedge. He further asked what the general expectation is for return on equity.

MR. PALMER said that since he is not a producer he will not give a forecast as to what expected return producers may need. In regard to the ability to hedge, he understood it is very difficult to hedge beyond five years out for any significant volume. Parties committing to this project this year would be committing to a gas price forecast commencing in 2020 and continuing for 20-30 years thereafter. Thus, he does not think they can realistically hedge that risk this year.

MR. PALMER, in further response to Co-Chair Neuman, said that once the project is near in-service and certainly for the first few years of operation, customers could, if they wished, hedge early years of the project, assuming the markets in 10 years time are just like they are now. However, customers still could not hedge for a time period as long as 20 years.

2:58:09 PM

REPRESENTATIVE P. WILSON commented that another risk is the possibility of an alternative energy source coming into use.

MR. PALMER agreed this is another very significant risk. He noted that the U.S. Department of Energy does try to account for this in its AEO forecasts. All parties committing to this project - producers, the state, APP, and others - are taking on significant risk, but that is the nature of the business. The flip side is the potential for large reward. If gas prices turn out to be as forecast, there would be a \$3-\$4 margin times 25 years, which is about \$120-\$150 billion in value after paying for the transportation costs.

MR. PALMER, in further response to Representative P. Wilson, said the Canadian government also has an energy price forecast, as do many consultants on a proprietary basis for their clients. The AEO 2010 forecast is in the range of a lot of forecasts, although that does not mean there are not differing forecasts and it does not mean that it is necessarily correct.

[3:01:36 PM](#)

REPRESENTATIVE GUTTENBERG requested Mr. Palmer to discuss his perspective on the [Mackenzie Gas Project that is being proposed through the Mackenzie Valley of Canada's Northwest Territories].

MR. PALMER noted this is a topic on which he will be careful with his response. He said it is TransCanada's belief, and probably ExxonMobil's as well, that both projects are not restricted by lack of demand, but the flip side is there is no guaranteed market for either pipeline except local uses. Both projects will have to compete in the marketplace just like other sources of gas and they will compete on price given that natural gas is such a fungible commodity - all gas, regardless of source, looks and burns the same, so it is the price delivered in the marketplace where it must compete. The market throughout North America is highly liquid and once the gas is into major hubs like Alberta or the Lower 48, it must compete effectively on cost. The question is whether the gas can be competitive at the market price that is established since neither project drives that price. In his view, both the Mackenzie and Alaska projects will go forward based on regulatory and commercial breakthroughs for each project. They are on totally independent tracks and are not linked. One or both can succeed, or one or both can fail based on how they do on those regulatory and commercial breakthroughs. The Mackenzie project is at a different stage than this Alaska project. The Alaska project is going through Canada under the Northern Pipeline Act, which is an act specific only to the APP. The Mackenzie project is through an application to the National Energy Board that was made in October 2004. At that time the Mackenzie project had all its customers in hand, but six years later it is still waiting for regulatory approval which is expected this fall. Mr. Palmer disclosed that TransCanada has a 5 percent interest in the Mackenzie project and is also funding the Aboriginal Pipeline Group, a one-third potential owner in that project. Thus, TransCanada is highly interested in, but not driving, the Mackenzie Gas Project.

[3:06:04 PM](#)

MR. PALMER, in response to Representative Olson, stated that the APP has started to have discussions with the British Columbia First Nations. He said he will not go into the Yukon circumstance since he has had that discussion with Representative Olson before. He said British Columbia is what he would call "traditional pipelining territory" with thousands of miles of existing pipeline. Currently, TransCanada has applications to extend its Alberta system into British Columbia to move British Columbia shale gas over the next several years. All items are not yet resolved, but he thinks they are resolvable issues. In further response to Representative Olson, Mr. Palmer said he does not see much difference for this project with the First Nations than 18 months ago, but TransCanada's intention is to construct pipelines into British Columbia in the next two to five years, something it was not doing a couple of years ago. Discussions are ongoing with those parties now.

CO-CHAIR NEUMAN said this is a serious issue because Alaska's future is riding on these folks.

[Mr. Palmer's presentation was continued on 2/3/10.]

[3:08:45 PM](#)

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 3:09 p.m.