

**ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE**

February 23, 2015

1:32 p.m.

MEMBERS PRESENT

Representative Benjamin Nageak, Co-Chair
Representative David Talerico, Co-Chair
Representative Bob Herron
Representative Craig Johnson
Representative Kurt Olson
Representative Paul Seaton
Representative Andy Josephson
Representative Geran Tarr

MEMBERS ABSENT

Representative Mike Hawker, Vice Chair

COMMITTEE CALENDAR

OVERVIEW(S): ARCTIC NATIONAL WILDLIFE REFUGE BY THE DEPARTMENT
OF NATURAL RESOURCES AND THE DEPARTMENT OF REVENUE

- HEARD

PREVIOUS COMMITTEE ACTION

No previous action to record

WITNESS REGISTER

SUSAN MAGEE, Statewide ANILCA Program Coordinator
Office of Project Management & Permitting
Department of Natural Resources (DNR)
Anchorage, Alaska

POSITION STATEMENT: Provided an overview of the provisions of ANILCA that are relevant to the recently released Arctic National Wildlife Refuge Revised Management Plan.

PAUL DECKER, Acting Director, Petroleum Geologist
Division of Oil & Gas
Department of Natural Resources (DNR)
Anchorage, Alaska

POSITION STATEMENT: Provided a PowerPoint overview of potential oil and gas development in the Arctic National Wildlife Refuge.

KEN ALPER, Director
Tax Division
Department of Revenue (DOR)
Juneau, Alaska

POSITION STATEMENT: Provided a PowerPoint presentation about revenue potential to the State of Alaska from oil and gas development in the Arctic National Wildlife Refuge.

DAN STICKEL, Assistant Chief Economist
Tax Division
Department of Revenue (DOR)
Juneau, Alaska

POSITION STATEMENT: Answered questions regarding the revenue potential from oil and gas development in the Arctic National Wildlife Refuge.

ACTION NARRATIVE

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CO-CHAIR BENJAMIN NAGEAK called the House Resources Standing Committee meeting to order at 1:32 p.m. Representatives Herron, Tarr, Johnson, Josephson, Olson, Seaton, Talerico, and Nageak were present at the call to order.

OVERVIEW(S):

Arctic National Wildlife Refuge by the Department of Natural Resources and the Department of Revenue

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CO-CHAIR NAGEAK announced that the only order of business is an overview of potential oil and gas development in the Arctic National Wildlife Refuge by the Department of Natural Resources and the Department of Revenue.

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SUSAN MAGEE, Statewide ANILCA Program Coordinator, Office of Project Management & Permitting, Department of Natural Resources (DNR), said she represents a small group of state employees from various departments who work diligently to review federal plans, policies, and regulations to ensure the provisions of the Alaska National Interest Lands Conservation Act (ANILCA) appropriately recognize and protect state interests. She said she will be

providing an overview of the provisions of ANILCA that are relevant to the recently released Arctic National Wildlife Refuge Revised Management Plan, which is the vehicle for the Wilderness and Wild and Scenic River recommendations that were recently announced by the President of the United States.

MS. MAGEE related that ANILCA was passed by Congress in 1980 after extensive debates and a series of compromises. It designated or expanded over 100 million acres of conservation system units (CSUs) and other conservation designations across the state. It more than doubled the National Wilderness Preservation System (NWPS), it designated 26 Wild and Scenic Rivers, it identified 12 additional study rivers, and it gave the U.S. Department of Interior a three-year time limit to follow up with recommendations on those. It also allowed for a one-time follow up Wilderness review of areas not already designated for potential recommendation. This applied to the National Park Service (NPS) and the U.S. Fish and Wildlife Service (USFWS) and had a seven-year time limit. Also, ANILCA prohibited further studies for the single purpose of establishing new conservation system units, commonly referred to as the "no more clauses." Wilderness and Wild and Scenic Rivers are both defined under ANICLA as conservation system units. Because the conservation areas were of such unprecedented size, and to accommodate the state's developing economy, limited infrastructure and distinct rural lifestyles, ANILCA included a number of unprecedented exceptions that are unique to Alaska.

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MS. MAGEE explained the Arctic National Wildlife Refuge (ANWR) was initially established in 1960 through a public land order (PLO) as the Arctic National Wildlife Range, and included the Coastal Plain. Under ANILCA the range was expanded and re-designated as the Arctic National Wildlife Refuge, and new purposes were identified similar to the majority of other refuges in Alaska. Additionally, ANILCA designated the Mollie Beattie Wilderness, an area included in the original range; it designated three Wild and Scenic Rivers; it directed the study of the Porcupine River for potential recommendation as a Wild and Scenic River; and it provided specific direction for the Coastal Plain in Section 1002, which is why the plain is often referred to as the 1002 Area. Under this section Congress directed the Department of Interior to conduct an inventory and assessment of the fish and wildlife resources of the Coastal Plain and an analysis of the impacts of oil and gas exploration, development, and production. It also authorized oil and gas

exploration activities. The end result of all of that work was a legislative environmental impact statement (EIS) and the Section 1002(h) report, issued in 1987. It recommended Congress authorize full leasing of the entire area for oil and gas production. To date, however, Congress has not acted on that recommendation.

MS. MAGEE said the Arctic National Wildlife Refuge Comprehensive Conservation Plan (CCP) is the vehicle for the Wilderness and Wild and Scenic River recommendations that were recently announced. The final CCP recommends Congress designate as Wilderness nearly the entire refuge, including the 1002 Area, which in total is approximately 19 million acres. The CCP also recommends four new Wild and Scenic Rivers. One of those rivers, the Hulahula, is in the 1002 Area. The Atigun River is on the western border of the refuge near the Dalton Highway and the Trans-Alaska Pipeline System (TAPS). These recommendations can be forwarded to Congress for action after the record of decision (ROD) is signed for the final plan. There is a 30-day hold period which ends 2/26/15. Then Congress can act to either reject or designate these areas or it can take no action on the recommendations. The no action leaves everyone in a limbo status and USFWS policy will then be relied upon to protect the recommended areas and rivers until Congress does act.

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MS. MAGEE pointed out a number of issues with the CCP. Even though the recommendations do not change the prohibition in ANILCA on oil and gas production in the refuge, and Congress would need to act on the Wilderness and Wild and Scenic River recommendations to put them into effect, pursuant to agency policy the areas and rivers now have a special recommended status that can affect a variety of uses and activities on lands within and adjacent to the refuge. For example, that recommended status sends a clear message to Congress making it more difficult to authorize oil and gas development in the Coastal Plain. Also within the refuge, permits for commercial recreation guiding activities may be more limited or have permit stipulations to protect wilderness character or values. Outside the refuge the USFWS provides input through the 1969 National Environmental Policy Act (NEPA) process on the impacts of development projects occurring on adjacent lands to refuge resources and values. For example, the Point Thomson oil and gas development EIS addressed impacts to the Arctic National Wildlife Refuge and mitigation was initially based on a misconception that the 1002 Area was part of a congressionally

mandated Wilderness Study Area. [The state] corrected that and the mitigation was modified, but [the state] is concerned that the current recommended status could affect the Alaska Liquefied Natural Gas (LNG) Project (AK LNG), which will run adjacent to the Arctic National Wildlife Refuge.

MS. MAGEE said the state's position on the Wilderness and Wild and Scenic River reviews is that the USFWS is following agency policy, not ANILCA. The "no more clause" says no more studies for the single purpose of establishing a new CSU unless authorized under ANILCA or another act of Congress. The reviews authorized under ANILCA had time limits and Congress has not provided any new directions. The U.S. Fish and Wildlife Service says the studies do not violate the "no more clause" in ANILCA if they are housed within a larger management plan because that gives them more than one purpose. But, she argued, the reviews themselves clearly state that their purpose is to consider recommendations to establish new CSUs. The USFWS also says it is complying with ANILCA's planning requirements in conducting the study, but ANILCA only says the USFWS should identify and describe the special values of the refuge, not study them for potential recommendation.

MS. MAGEE pointed out that policy is not law, but policy is supposed to be based on law and the U.S. Fish and Wildlife Service's Alaska policy on conducting Wilderness reviews was reversed in the beginning of the Arctic planning process, without consultation with the state or Native interests and also no public review even though its policy on directives indicates there should have been. She noted that USFWS policy now says Wilderness reviews will be conducted in all future CCP revisions, so it will apply to the Yukon Flats, Yukon Delta, Alaska Maritime, and Izembek refuges. The revised plans will also include Wild and Scenic River reviews.

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MS. MAGEE stated another issue is that the CCP did not look at oil and gas development alternatives because the USFWS said it did not have authority to authorize oil and gas activities, even though the same can be said for the Wilderness and Wild and Scenic River reviews and the USFWS doesn't think ANILCA limits the agency in that regard. Additionally, while the revised CCP references the Section 1002(h) report, it does not acknowledge the actual recommendations. The U.S. Fish and Wildlife Service also indicates it intends to manage recommended areas and rivers under the minimal management category. [The state] still feels

this is problematic because the Arctic National Wildlife Refuge revised CCP provides a more restrictive overarching management framework that promotes a wilderness-like experience regardless of whether or not the Wilderness and Wild and Scenic River recommendations are acted upon. Also, minimal management, which is already the most restrictive category other than the Wilderness and Wild and Scenic River categories is more restrictive in the revised CCP. For example, public use cabins, which are allowed by ANILCA in designated Wilderness for health and safety purposes, will not be allowed or even given consideration anywhere in the Arctic National Wildlife Refuge under minimal management.

MS. MAGEE related another issue is that the Alaska Department of Fish & Game (ADF&G) is concerned the more restrictive, hands off management approach in the CCP, in combination with some other regulatory wildlife related changes currently under consideration by the USFWS, will impact ADF&G's ability to effectively manage fish and wildlife resources in accordance with the state constitution and, by extension, the availability of meaningful harvest opportunities, including for subsistence. Lastly, future stepdown management plans are likely to impose additional restrictions on uses and access in the Arctic National Wildlife Refuge. The CCP calls for a visitor use and management plan, a wilderness stewardship plan, to begin right after the ROD is signed. The CCP also requires Wild and Scenic River management plans for the three existing Wild and Scenic Rivers and four more if Congress designates the recommended rivers. It also calls for an ecological inventory and monitoring plan, as well as some other things.

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PAUL DECKER, Acting Director, Petroleum Geologist, Division of Oil & Gas, Department of Natural Resources (DNR), began with slide 2 of his PowerPoint overview of the Arctic National Wildlife Refuge (ANWR) entitled, "ANWR 1002 Area." He pointed out the refuge is just about the same size as the state of South Carolina, about 19.8 million acres. Within the refuge, the Coastal Plain, or 1002 Area, is about the same size as Delaware.

MR. DECKER noted the committee's request was for him to provide before and after comparisons. He said slide 3 depicts refuge management under the previous plan or, in essence, the no action alternative. Under the previous plan the 1002 Area, outlined by the box at the top of the map, was managed in minimum management mode in contrast to the Wilderness area shown in green. The

southern and southwestern parts of the refuge were in minimal management status rather than Wilderness status. The blue indicates the Wild and Scenic Rivers that traverse the refuge.

MR. DECKER turned to slide 4 to show what the refuge will look like if the new/current management plan is adopted. The Coastal Plain becomes proposed Wilderness or minimal management with Wilderness recommendation, as does the southern and southwestern part of the refuge. So, the entire refuge will be managed as defacto Wilderness until, and unless, Congress makes some other decision. Also seen are the additional Wild and Scenic River designations, one is the Hulahula River which flows through the 1002 Area. It is not only the 1002 Area that is of concern. The southwestern part of the refuge is also very important to geologists with the state and U.S. Geological Survey (USGS) for gaining access to important outcrops that can be used for studying, evaluating, and extrapolating information for beneath the state lands that are located just to the north of that southwest portion of the refuge. This area of state land is the mountain front on the east side of the Haul Road. So, this is a secondary consideration compared to the potential loss of access to the oil and gas lands of the Coastal Plain.

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MR. DECKER drew attention to slide 5 to outline key moments in the 1002 Area's history. He said this list is a subset of the history provided by Ms. Magee that is pertinent to the oil and gas activities and potential of the area. He pointed out that Section 1002(a) of ANILCA did three things: directed the Secretary of Interior to assess the area for fish and wildlife; required an analysis of the impacts of oil and gas exploration, development, and production; and authorized certain low-impact oil and gas exploration activities. Between 1983 and 1985, low-impact exploration activities were conducted, and nearly 1,200 line miles of two dimensional (2-D) seismic data was collected. He said he has seen that data and it is absolutely imperative for understanding anything about the sub-surface in the Coastal Plain. However, it is challenging data to work with and it is strongly believed that modern seismic techniques using three dimensional (3-D) seismic would greatly enhance understanding of the 1002 Area sub-surface. The 2-D seismic activity and the one well drilled on Kaktovik Inupiat Corporation (KIC) lands by Tenneco in 1984 and 1985 represent the sum total of the sub-surface knowledge.

MR. DECKER addressed the USGS map of the 1002 Area on slide 6 depicting the discovered oil and gas accumulations around the edges of the Arctic National Wildlife Refuge. He pointed out that the football-shaped area is a schematic depiction of Point Thomson which has oil, gas, and condensate. The green boxes indicate wells that have discovered, including several in the offshore and along the shoreline, as well as just south of Point Thomson at Sourdough. The red boxes indicate gas accumulations, Kavik and Kemick, both discovered in the late 1960s and located a little bit farther into the foothills where the area tends to be more gas prone. He called attention to the undeformed and deformed areas of the 1002 Area, explaining that deformed is a geologic term for rocks that have literally been deformed, meaning the layers of rocks have been bent, broken, folded, and faulted. It is associated with the tectonic compression of the area, with tectonic forces squeezing Northern Alaska to create the Brooks Range. An analogy would be to imagine a snowplow advancing from south to north, the blade pushing the snow in front of it. The undeformed area would represent the part of the parking lot that the snowplow hasn't gotten to yet. The deformed area would be the portion in front of the plow where the snow is munged up and compartmentalized into little bits and pieces instead of the nice original layers. This geological complexity of building the Brooks Range also has temperature implications in addition to the structural implications.

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REPRESENTATIVE SEATON inquired whether those are the same kind of differential structure found between Kuparuk and Prudhoe Bay.

MR. DECKER replied it is a very different style of deformation along the Barrow Arch between Prudhoe Bay and Kuparuk, which has not at all felt the snowplow, so to speak. The undeformed area would be more akin to Prudhoe Bay with caveats. Prudhoe Bay, Kuparuk, and most of the major fields have not felt the impact of the snowplow. That is part of the reason why the undeformed area is believed to be considerably more valuable in terms of oil habitat - it is much more likely to have more oil in the undeformed area than in the deformed area.

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MR. DECKER addressed slide 7 entitled, "USGS 1998 Resource Assessment Undiscovered, Technically Recoverable Resource." He noted the map on the right side of the slide highlights in yellow the undeformed area of the 1002 Area. The numbers in the

blue box on the left are estimates of undiscovered, technically recoverable resource. It is not looking at reserves yet - just undiscovered resource that is judged to be technically, not necessarily commercially, recoverable. It is only talking about the volumes of oil that could be recovered by the technology available at this time; so, obviously, very speculative numbers. The only way to arrive at a meaningful answer on that kind of a question is to create a range of outcomes, a probability distribution, and that is what is depicted by the three columns of numbers in the blue box. The low-side estimate is the "F95" column, meaning a 95 percent confidence that the actual volume of undiscovered, technically recoverable oil would be larger than that number. The "F05" column is the number at the upper end of the scale, meaning a 5 percent confidence that there is more resource than that. The "Mean" column is not necessarily the center or the "P50," it is the average of the entire probabilistic distribution. In this assessment the USGS looked at the federal 1002 lands, the Native lands around Kaktovik, and the state waters going out to three miles from the shoreline. The average, or mean, estimate for the entire assessment is about 10.4 billion barrels of recoverable oil. Within just the federal lands, the mean estimate is about 7.7 billion barrels; and, of that, the mean estimate for the undeformed part is about 6.4 billion barrels and about 1.2 billion barrels for the deformed part. So, according to this prediction, the undeformed area only represents about one-third of the 1002 Area, yet it has about five times as much oil as the other two-thirds that is deformed area. That makes the undeformed area about 10 times more valuable on a barrel-per-acre basis, and key is that it's adjacent to state lands, including Point Thomson and Sourdough.

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REPRESENTATIVE TARR asked whether the 1998 USGS resource assessment is based on the 2-D technology of the 1980s and the one well that was drilled.

MR. DECKER responded the one well very likely is not included in that assessment because that well has been held confidential to the parties involved; a couple of oil companies that are left still have access to that data. Because the well was drilled on Native lands it has been legitimately held confidential for all these years.

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MR. DECKER defined some exploration terminology (slide 8), but qualified the definitions are informal. A "play" in exploration terms is a set of known or hypothetical accumulations of hydrocarbons that are closely related to each other because of some shared geologic characteristic. Typically the shared characteristic is the reservoir rock unit, so the oil and gas is predicted or known to occur within a certain age reservoir formation. A "prospect" is one of the postulated hydrocarbon accumulations that can be identified from geological and geophysical information; it is a discreet potential accumulation and typically hasn't yet been confirmed by drilling a discovery well. This same word is also used to describe discoveries that have not yet been commercially sanctioned, that still need some delineation. An "accumulation" is oil or gas that is known to be trapped in a viable reservoir rock with enough saturation of the hydrocarbons that it can be recovered by drilling wells, drawing down the pressure, and sucking it out. "Reserves" are not the same as resources; rather, reserves are the class of resources that have been discovered and are commercially producible. Reserves does not apply to undrilled prospects or undiscovered resources; therefore, a key point is that there are no reserves in the Arctic National Wildlife Refuge at this time.

MR. DECKER noted the graphic on the left of slide 9 represents a stratigraphic column from the 1998 USGS assessment of the Arctic National Wildlife Refuge. It summarizes the rock layers: where the source rocks are, where oil and gas may be present, and how the different plays are broken out for the assessment. The column represents the oldest and deepest rock layers at the bottom and the youngest and shallowest rock layers at the top. The ages of the rocks span hundreds of millions of years. The greatest resource potential lies in some of the younger Cenozoic rocks, which are the sand-bearing formations depicted in yellow and specifically the Sagavanirktok Formation. He said the two charts on the right side of slide 9 represent histograms of size class, what the USGS calls field size classes. Each column in the charts represents a size class that is double of the next smaller size class to the left. The upper graph shows the number of accumulations, with the deformed area depicted by green bars and the undeformed area depicted in yellow bars. Most of the predicted accumulations, outlined by the red box, are going to be in the three size classes between 32 million barrels and 256 million barrels, which are smaller fields than Prudhoe Bay. Thirty-two million barrels would probably be really pushing it to be economically recoverable, but 250 million barrels would very likely be commercially viable. The lower graph shows the volume of undiscovered oil resources and

how it is predicted to fall out in the various size classes. Most of the oil is predicted to occur in accumulations that are between about 128 million and a billion barrels in size, as outlined by the red box. The oil in those size classes would very likely be economic to recover it accessible to oil and gas leasing and development. He pointed out that the graphs represent the average, or mean, case.

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REPRESENTATIVE SEATON requested Mr. Decker to further explain the graphs on the right side of slide 9.

MR. DECKER explained the top right graph is the number of accumulations - the number of discreet prospects envisioned by the USGS in each size class. The tallest bar on the graph represents the field size class of 64-128 million barrels and the USGS expects there to be about 8 accumulations of that size in the undeformed area and just under 1 accumulation in the deformed area. Because it is a statistical way of doing this, the numbers are not round.

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MR. DECKER resumed his presentation, turning to slide 10 to discuss the major exploration plays in the assessment area. He explained that when all of the oil assessed in the mean case is allocated to the various plays, or suites in which it is predicted to be present, it is almost ranked by age as well as by size class. As was seen in the stratigraphy column, it's the youngest suite of rocks that has the largest resource potential. In particular are the Brookian Topset and Brookian Turbidite plays. These are nearly age equivalent of each other, but the Topset is sandstones, conglomerates, and reservoir rocks deposited in shallow water, whereas the Turbidite is sandstones and mudstones deposited in much, much deeper water. The Brookian Topset play is the most prospective at 6.2 billion barrels. Actual accumulations representative of the Topset play include the Hammerhead discovery and the Kuvlum accumulation offshore in the outer continental shelf (OCS). Representative of the Turbidite play are places like Badami, the Flaxman discovery at Point Thomson, Sourdough just south of Point Thomson, Yukon Gold, and the Stinson accumulation. The other plays listed on slide 10 are, for the most part, also-ran contenders. Brookian Topsets, Brookian Turbidites, Brookian Wedge, and the Thomson and Kemik Sandstones are likely to be present in the undeformed area because they can all form

stratigraphic traps, so there is no sole reliance on structural traps to actually find compartments to trap the oil.

MR. DECKER drew attention to the block diagram of the Brookian sequence depositional model on slide 11. He said the mountains in the diagram represent the Brooks Range, with the rivers spilling out of the mountains carrying sediment. The sediment deposited onshore and near shoreline - the fluvial and deltaic systems - is the Topset play. The sediment carried across the continental shelf and down the continental slope onto the basin floor of the ocean - creating fans or aprons - represents the Turbidites or deepwater plays.

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MR. DECKER displayed a well log [slide 12] for the Brookian Topset play as manifested in the Hammerhead discovery located not very far offshore in eastern Beaufort OCS waters. He explained the non-marine, fluvial-deltaic, and shallow marine sandstones and conglomerates are separated from each other by intervening siltstones and mudstones that create seals that contain the oil and gas. The hallmark is high reservoir quality - great porosity, great permeability - but only a fraction of the interval is actually pay zones. The red arrows show the gas pays and the green shows oil pay. Both oil and gas occur in this accumulation and occur in stacked, relatively thin zones that are 10-50 feet thick. This is a very different style of reservoir than the Prudhoe Bay reservoir where there may be 400 feet of continuous light oil and gas.

MR. DECKER turned to slide 13 to show two well logs for the Brookian Turbidite play, one a Badami well and one from the Flaxman discovery at Point Thomson. He said Badami has never really performed as hoped due to compartmentalization and a variety of other geologic complications. The Flaxman discovery, however, looks like a much better reservoir, on the order of 100 million barrels, plus or minus. The relatively thin test interval in the Flaxman well flowed at rates of 2.5 thousand barrels of oil per day, as well as a couple of million cubic feet of gas. With Point Thomson going to development, it is anticipated that some of these Brookian discoveries in the unit, and maybe nearby, could also come on line and it is hoped they will perform better than Badami.

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MR. DECKER called attention to the map on slide 14 depicting existing wells with red dots and the 2-D seismic data with red lines that was used in the 1998-1999 USGS assessments. The KIC 1 well is the only well located within the 1002 Area, he said, and it is still confidential. The other wells are located in state waters, on state lands, and in the OCS and were drilled over the last several decades. The geology of the Arctic National Wildlife Refuge was worked out by interpolating inwards. The 2-D seismic, acquired in 1983, 1984, and 1985, was very challenging acquisition and very difficult geology to image properly. The seismic spacing is on the order of three to eight miles between lines and a lot can fall through a sieve that coarse. So, about a year and a half ago the state proposed acquiring its own three-dimensional (3-D) seismic surveys across the entire Coastal Plain [slide 15]. This would not be cheap, but the value would be new data - state-of-the-art technology that could be acquired in prioritized areas, starting with the undeformed area, then moving next to the Marsh Creek Anticline Area, and then progressing east and then south across these five areas over a period of about three years. It would be a very ambitious program. While not all of the data may get done, it could begin with the prioritized area. This proposal made it all the way to a formal application to the Department of Interior for a seismic permit to do the work.

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MR. DECKER moved to slide 16, explaining the rationale for the State of Alaska's proposal for 3-D seismic in the 1002 Area. Section 1002(a) of ANILCA, he reiterated, set aside the 1002 Area specifically to assess the area for a variety of resource values and assess whether it would be a good place to explore for oil and gas in the national interest. [In the division's] view, the data from the mid-1980s is wholly unsatisfactory for making a high resolution final management decision especially one that would make it all off-limits forever. [The division] believes the newer technology would give a much better resolution and a better understanding of the probability distribution. The state took the point of view that the authority to conduct exploration of this sort had never really expired. Since it is winter-only seismic exploration, it is low impact and would have very minimal permanent impacts. However, the Department of Interior's response to the state's proposal was that it has expired and would take an act of Congress to open it back up.

MR. DECKER turned to slide 17, pointing out the aforementioned is not the first time the State of Alaska has taken an interest in trying to maintain the Arctic National Wildlife Refuge as an area that could be opened to exploration. In 2003 the Division of Oil & Gas put together a report entitled, "Oil and Gas in the ANWR? It's Time to Find out!" Available on the division's web site, this report is an in-depth explanation of how the USGS conducted its analysis in its 1998-1999 assessment. The report stressed the differential importance and value of the undeformed area and also stressed the importance of modern 3-D seismic to making a good assessment. Also stressed in the report is the decrease in footprint in terms of winter-only ice pad drilling, as well as today's smaller development footprint with gravel and year around access. More wells than ever can be drilled from a smaller pad with a larger sub-surface drainage area through deviated and horizontal well technologies. The Alaska State Legislature has also taken a number of actions since 1993, including a number of endorsements and appropriations to promote public education on the issue, proposing exploration and leasing, and opposing Wilderness designation.

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REPRESENTATIVE HERRON noted the President of the United States recently said the federal government will consult with State of Alaska officials and indigenous people when there are any decisions to make in an Arctic matter. He inquired what the division's counterparts in the federal government say when asked that question. He surmised the division's federal colleagues choose to consult with the state when they choose to.

MR. DECKER replied the division has, for the most part, an exceptional working relationship with its federal colleagues. The division keeps it mostly at a professional level rather than straying into questions of politics. However, he continued, the division has called out its good friends and colleagues in the USGS for instances where the division felt the communication could have been better, one example being the 2010 USGS reassessment of the National Petroleum Reserve in Alaska. The USGS took it upon itself to update the previous resource assessment in the petroleum reserve and the division felt that a better outcome would have been yielded had the division been consulted throughout the process. In this case, the division sent a letter directly to the Secretary of Interior and the USGS director. He said Representative Herron's point is well taken that more communication is always beneficial.

REPRESENTATIVE HERRON surmised that the division's written and verbal communications are still asking the question, "How come you don't want to have a complete conversation?" He asked what the federal response to that is.

MR. DECKER confessed that since the announcement came out about the new CCP he has not reached out to his federal colleagues to have this conversation; therefore it would be speculative of him to try to predict how his professional colleagues would react to that. The decisions being made, he added, are being made at a much higher level than the geologists he is dealing with. The geologists he is aware of all share the view that the 1998-1999 resource assessment is still the best estimate of the resource potential in the area and it could be improved upon.

REPRESENTATIVE HERRON opined that many people in the Capitol and around Alaska are frustrated. For example, an environmental impact statement (EIS) for the [proposed] safety corridor through the Izembek [National Wildlife Refuge] was done by indigenous people, the State of Alaska, and the U.S. Fish and Wildlife Service (USFWS). However, USFWS officials in Alaska were taken by surprise when others higher up in the federal government made the decision to say no. He expressed his fear that this could happen to the state elsewhere, and maintained that it has happened.

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MR. DECKER resumed his presentation, addressing slide 18. He said [the division's] 2013 application to conduct seismic surveys in the 1002 Area was about making informed decisions. The Alaska State Constitution says the state's objective is to manage its resources by making them available for the maximum use consistent with the public interest. Decisions need to be made that are based on current information and not 30-year technology, he argued. [The division] believes that whether the resources are on state or federal lands, consideration must be given to both the state and the federal interest. [The division] is not at all convinced that setting this land aside is in the national interest, much less in the state interest. Further, the National Environmental Policy Act (NEPA) process cautions against making decisions based on incomplete or unavailable information.

MR. DECKER turned to slide 19, saying [the division] believes the plan it put forth was in compliance with ANILCA and was consistent with federal regulations governing exploration plans.

The Department of Interior turned down the plan in support of the USFWS conclusion that any new exploratory activity is prohibited by ANILCA, rather than authorized by ANILCA, and that it would require an act of Congress to reauthorize.

MR. DECKER drew attention to slide 20, relating [the division's] belief that significant questions remain unanswered. He said describing something so uncertain must be done by a probability distribution. The right answer is unknown to the question of where on the probability distribution the resource potential is for oil in the 1002 Area. Another question is whether the undeformed area adjacent to state lands is significantly richer and more cost effective than the deformed area. These questions translate to the question of, What is the best decision for the United States and the State of Alaska? He said [the division's] pitch is to know before walking away forever (slide 21).

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REPRESENTATIVE TARR asked whether the state's position is that all areas should be available for oil and gas exploration and leasing activities. The state's position on the 1002 Area has been clearly outlined today, she said, but she is asking whether there are any areas within the state that have been suggested as not being suitable for oil and gas.

MR. DECKER answered the Department of Natural Resources (DNR), and the technical staff at the Division of Oil & Gas, can identify significant areas of the state that have very low oil and gas resource potential. When it comes to land selections and processing the over-selections, some parcels may be evaluated as having no resource potential for oil and gas. For example, volcanic or igneous rocks may be very prospective for hard mineral deposits but have essentially zero potential for oil and gas. Additionally, [DNR] recognizes conservation units, state parks, and national parks and would never advocate for oil and gas extraction [in those areas].

REPRESENTATIVE TARR asked whether areas that [DNR] might recommend for conservation would only be recommended after [DNR] could say they weren't available or didn't suggest them for oil and gas exploration or leasing.

MR. DECKER replied he sees it as a question of timing. Drawing attention to the Alaska land status map displayed on the wall in the committee room, he noted the state lands are shown in blue and said those lands identified as having oil and gas potential

were recognized two or more decades ago. Very prospective for oil and gas, as seen by the division's area-wide lease sale areas, are the central North Slope, state waters just offshore of the North Slope, onshore down into the foothills, the rest of the onshore North Slope, the National Petroleum Reserve-Alaska, and the Coastal Plain of the Arctic National Wildlife Refuge. Cook Inlet represents another highly productive hydrocarbon basin. Also identified are the southern shores of Bristol Bay, the Alaska Peninsula area-wide sale where over a million acres are available on annual area-wide lease sale terms, just like Cook Inlet and the North Slope lease sales. The aforementioned represent the lion's share of the oil and gas resource potential in the state. Other basins are still in an early phase of exploration for oil and gas, such as the Nenana, Copper River, Yukon Flats, and Susitna basins. Most of the lands that are truly prospective for oil and gas were recognized as such some time ago, and the set-asides for other conservation reasons are largely independent of those lands.

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REPRESENTATIVE SEATON pointed out that state selections occurred before the time of shale oil and gas. He asked whether there are additional areas that are now prospective oil and gas with the addition of tight shale.

MR. DECKER responded that, for the most part, the best place to explore for shale is the North Slope and, in his view, even that is currently very challenged given today's price environment. Once shale is commercially viable, the North Slope would be the place to start looking given its world-class oil and gas source rocks and that they are at the right thermal maturity. The other parts of the state don't tend to see that same richness of source rock at the right thermal maturity to be highly prospective for source rock reservoir or shale oil.

REPRESENTATIVE SEATON referenced slides 10 and 20 and the concept of a Brookian Topset play that is 6.2 billion barrels of technically recoverable. He inquired whether there could be economically recoverable oil there.

MR. DECKER answered the aforementioned is a common question when talking about resource assessments that specifically refer to undiscovered, technically recoverable resource numbers. It is tempting to ask how much of this will actually be gotten. He said he tries to avoid falling into this trap because it varies from assessment area to assessment area. A certain fraction of

the oil is going to occur in accumulations that are too small to warrant economic development. A certain size accumulation is needed to make it viable commercially and that size is going to vary depending on how close it is to other infrastructure, the flow rates that can be established, and a variety of other parameters. There is both the size class issue and the price issue. The Department of Revenue will speak next about a USGS follow-up assessment that attempts to look at how much of that is commercially viable and how that varies with price and costs of services.

REPRESENTATIVE SEATON recalled Dan Seamount of the Alaska Oil and Gas Conservation Commission (AOGCC) telling the committee on 2/20/15 that if Prudhoe Bay was re-pressurized to its original 4,500 pounds per square inch (PSI), an addition one billion barrels of oil would be recovered. He asked whether this means that re-pressurization would be one-tenth the size of the entire 1002 Area or equal to the 1002 Area. Saying he is trying to determine comparative values, he further asked whether it would be expected to be able to recover a billion barrels out of the plays listed on slide 10.

MR. DECKER replied it would be valuable to hear the Department of Revenue speak in regard to this direction.

The committee took an at-ease from 2:35 p.m. to 2:41 p.m.

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KEN ALPER, Director, Tax Division, Department of Revenue (DOR), began with slide 2 of his PowerPoint presentation, stating that the 1002 Area of the Arctic National Wildlife Refuge is the most promising unexplored area in Alaska. A large amount of resource is believed to be in that relatively compact area. At 1.5 million acres, or 2,300 square miles, the 1002 Area is about the size of the City and Borough of Juneau or the state of Delaware. Development of Point Thomson suddenly brings the Arctic National Wildlife Refuge much closer to existing infrastructure, allowing the refuge to be built up without a lot of new work in virgin territory.

MR. ALPER turned to slide 3 and cautioned that talking about revenue from the Arctic National Wildlife Refuge is highly speculative. He said the Department of Revenue (DOR) worked with the Department of Natural Resources (DNR) to identify consensus estimates from the previous federal reports. This is an undiscovered, technically recoverable resource, so DOR can do

its best to say what would happen if it is developed, but cannot say that it will be able to raise this money. At this point, the refuge's proven reserves remain at zero. Before putting any numbers before the committee, he said he wants members to first understand DOR's assumptions.

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MR. ALPER called attention to the source documents highlighted on slide 4: the 2005 "Economics of 1998 U.S. Geological Survey's 1002 Area Regional Assessment: An Economic Update," and the 2008 "Analysis of Crude Oil Production in the Arctic National Wildlife Refuge." He explained that the 2008 report [by the U.S. Energy Information Administration (EIA)] was in response to a question from U.S. Senator Ted Stevens to look at some economic potential and was focused more on a replacement for imports and an effect on the U.S. oil market. The USGS report included a statement that said assuming the price of oil is over about \$55 a barrel, 90 percent of the oil is going to be recoverable economically. The gap between technical and economical becomes relatively narrow at \$55. Since that was in 1998, the number now would be somewhat higher.

MR. ALPER spoke to slide 5, "Assumptions: Total Volume," saying DOR is working under the assumption that because the largest fields would be brought on first and because those largest fields are the ones that will be inherently the most economical, the great bulk of what is considered technically recoverable will be economically recoverable in DOR's modeling. He said the chart on this slide is directly from DNR's presentation and uses the USGS numbers. The mean number of 7.69 billion barrels is for the federal 1002 Area, and the mean number of 10.36 billion barrels is for the entire study area, which also includes state land, near offshore, and the Native corporation land near Kaktovik. Thus, roughly 75 percent of the oil is going to be from federal land and developed under federal rules, and the other 25 percent will be different.

MR. ALPER addressed slide 6, "Assumptions: Distribution of Volume," explaining that for purposes of modeling DOR presumed [most of the resource is in] the undeformed part [of the 1002 Area] and DOR estimated that 15 percent would be state oil and 10 percent would be oil on Native corporation land.

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MR. ALPER reviewed slide 7, "Assumptions: Production Timeline," stating the EIA report laid out a production timeline that would take about 10 years from the moment permission is given to explore for oil. Assuming permission is given in January 2016, it would take [until 2019] to get the plans together and the leases and permits issued, so exploration would begin in about 2019. Assuming the first field is found three years later in 2022, and development takes four years, the first production would be in 2026, consistent with the EIA report timeline of 10 years after authorization. From there DOR used its own speculation of how to do this, which would be starting with the largest fields, bringing one new field on line every two years, totaling 25 new fields being brought on line over a period of 50 years, and adding up production and consequent revenue through 2075. He said this is very much outside of the standard workload done by DOR, given the department typically projects production and revenue about 10 years into the future. Beyond that it ceases to be material for budget purposes for projecting the state's revenues, but DOR was happy to do this projection when asked by the committee co-chairs to provide this analysis.

MR. ALPER noted the graph on slide 8, "Assumptions: Field Size Distribution," comes from the USGS. He said the white, black, and grey bars on the graph represent the low probability, the mean, and the best case or high probability for the number of accumulations. The Y axis is the number of distinct oil fields of these different sizes. Turning to slide 9, "Assumptions: Field Size Development," he said DOR ran a model in three different cases. In the high case, two of the twenty-five fields are at more than a billion barrels and the smallest of the twenty-five fields are at 128-256 million barrels. In the low case, there are no billion barrel fields, two 512-1024 million barrel fields, and [three] fields of [32-64 million barrels]. The total number of barrels that would be produced through [2075] would be 4.5 billion, 7 billion, and 9.7 billion barrels in the low, base, and high cases, respectively. In response to Representative Seaton, Mr. Alper clarified that the total number of barrels would be the aggregate production over the 50 years of oil production starting in 2026, with the fiftieth year of production of oil being in 2075.

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MR. ALPER drew attention to slide 10, "Assumptions: Production Profile," pointing out the graph depicts a fairly standard algebra rhythm for how a new oil field is ramped up, peaked, and then declined. The graph includes curves for the seven different

sizes of fields. It takes two to three years for production to go up, a few years at the top of production, and then a decline at about 6 percent [per year] as per DOR's standard curve.

MR. ALPER discussed slide 11, "Assumptions: Price of Oil." He said these assumptions are getting a bit more speculative, but most important is that throughout the study [all prices and costs assume] 2015 constant numbers. This was done because the numbers sound highly distorting when inflation is built into them going 50-60 years into the future. For example, \$110 with 2.25 percent interest 60 years from now is about \$400 a barrel for oil. Putting \$400 barrels on the screen would just confuse the issue, he said. The number of \$110 is not particularly magical: the DOR Revenue Sources Book projects a 2024 price of \$134.39 a barrel; backing that price to current dollars at 2.25 percent gets to within a few cents of \$110 a barrel. So, DOR used that number for the modeling purposes. Scenarios were also run at a higher and a lower price, which he will review later.

MR. ALPER turned to slide 12, "Assumptions: Gas," noting DOR chose not to bring gas into the modeling at this point primarily because it would have complicated the work beyond what DOR was capable of doing in the three days that were had to generate this. Also, the gas resource information is far less defined; there is no geology or reports that tell roughly in volumes how much gas there is. Further, DOR didn't worry about the cost of handling the injecting and so forth of associated gas. The reality is, should the Alaska LNG Project (AK LNG) move forward on the anticipated timeline, the known reserves that are essentially part of the initial production will have tapered out and there will be room in the AK LNG line around 2045 or 2050, which works out nicely with the development of the Arctic National Wildlife Refuge that is being envisioned in this model.

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MR. ALPER moved to slide 13, "Assumptions: Costs," saying that companies are spending money to do this. He explained that an annual exploration cost of \$500 million is assumed beginning in 2019 because it is roughly twice what is being spent on exploration right now on the North Slope. After 10 years when a good exploration regime will have been undertaken, annual cost assumptions are cut in half to \$250 million and continued onward after the 10 years. If/when accumulations are found, the development capital expenditures are assumed to be \$10 per barrel based on the size of the field, with that concentrated over an eight-year timeline at the beginning of the development

of each field. Once oil is being produced, another \$5 per barrel in capital expense is assumed to be maintenance spending. Once oil is being produced, an operating cost of \$20 per barrel is assumed for running the fields. The aforementioned costs are important for calculating the profits-based tax because these are lease expenditures. The netback, or tariff, cost is \$12.25 per barrel; that takes DOR's estimates of 2024 and brings them back to 2015 dollars and adds a little bit for the new feeder line bringing the new oil from the refuge over to pump station 1 of the [Trans-Alaska Pipeline System (TAPS)].

MR. ALPER reviewed slide 14, "Assumptions: Fiscal (Royalty)." A royalty rate of 12.5 percent was assumed for the sake of simplicity, he explained, but a wide range of different royalty rates is possible given three different land owners and that there will be a number of different lease offerings. The 12.5 percent correlates with the major state-owned fields in the North Slope. For federal royalties, DOR assumed current law, which is the state gets 90 percent. This assumption could be controversial, he allowed, because it is reasonable to think that before the federal government would allow something tremendous like this to go forward, it would insist on a different split arrangement. He also pointed out that under Alaska's production tax law, private royalties are subject to a 5 percent gross production tax. Thus, the KIC royalties would be subject to a 5 percent gross production tax, which was recognized in DOR's royalty calculation.

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MR. ALPER called attention to slide 15, "Assumptions: Fiscal (Production Tax)." Under the current tax regime established by Senate Bill 21, he noted, these new fields will be eligible for the 20 percent gross value reduction (GVR). Also included in Senate Bill 21 for new fields was a per-barrel production credit of \$5. Because DOR is keeping the price of oil at 2015 levels going forward, the \$5 subtraction factor is reduced at the same inflation rate - so that \$5 is decreased to a smaller number going further and further into the future for the purpose of calculating production tax. It is also assumed that this will be a single stand-alone company, thereby avoiding issues of blended taxes. As well, DOR is not considering any impact on the current producers within the North Slope and how it might impact their taxes. It is a simplifying mechanism, but the net effect is roughly the same no matter how it is done. Additionally, if companies are operating in the red during the early years - spending money and not yet producing - Alaska's

tax system considers that to be net operating loss and the state currently reimburses those as a 35 percent credit under the carry forward annual loss credit. That is seen as a negative cash flow to the state during some of the early years of this project.

MR. ALPER discussed slide 16, "Assumptions: Fiscal (Other Taxes)." He said the corporate income tax is an apportionment formula that works out to be about 6.5 percent of after-production tax profits, and DOR used that 6.5 percent number in this analysis. Corporate income tax cannot be negative or zero, so there is no carry forward. For property tax, current collections are about \$1.25 per produced barrel, but that is an aggregate. These numbers are shared with local jurisdiction because nearly all the associated infrastructure is within the North Slope Borough. The current apportionment is about 92.5 percent to the borough for comparable assets, so only 7.5 percent of that \$1.25 goes to the state.

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MR. ALPER then turned to slide 17 to review the total projected volume of oil produced and the total projected net revenue to the state for the study period of 2016-2075, based upon the aforementioned assumptions and caveats. Regarding projected total volume, he reported that 7.1 billion barrels of oil would be produced under this model at the base case; at the high case, which is considered 5 percent likely, it would be 9.7 billion barrels; and at the low case, which is considered 95 percent likely, it would be 4.5 billion barrels. Regarding projected total net revenue in constant 2015 dollars, he reported [\$94.8] billion at low case, \$210 billion at high case, [and \$150.9 billion at base case] over the 50 years of production.

MR. ALPER displayed slide 18 to show how the aforementioned [hypothetical] production volume would look in graph form for the low, base, and high cases. He pointed out that in the base case (blue line), production peaks at 550,000 barrels a day in the early 2040s, which is roughly the size of current North Slope production, and then production declines in the years after that. In the high case [green line], production peaks at over 700,000 barrels a day and in the low case [red line] the production peak is about 350,000 barrels a day. He moved to slide 19 to present a production graph for the base case that shows the volumes of the 25 fields layered on top of each other.

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REPRESENTATIVE JOSEPHSON referenced slide 18 and concluded that DOR's projections for the refuge are that it will be larger than Kuparuk but smaller than Prudhoe Bay.

MR. ALPER replied the Arctic National Wildlife Refuge is many small fields, so in aggregate it would produce oil that is larger at its peak than Kuparuk and smaller than Prudhoe Bay. He would be cautious, he advised, to say it is larger because there is no single accumulation within the refuge presumed to be at that type of field. In the high case the largest single field is in the level of one to two billion barrels in place.

REPRESENTATIVE JOSEPHSON inquired why it is projected that it would take 10 years from discovery to production given there is already a pipeline in place, unlike during Prudhoe Bay's development from 1967-1977.

MR. ALPER responded DOR used certain estimates from the EIA. He said he is not an engineer and will not speculate too far as to how that might go. Permitting is different than it was in the late 1960s and early 1970s. The 1969 discovery was at the tail end of an exploration period where people had been up there looking for oil for several years. Built-in within that 10 years is the initial offering of leases and the initial exploration that might lead to a discovery. Between the discovery and first production is only about four years, basically the construction time of getting the field itself developed and the feeder pipeline. The Point Thomson feeder line that is in place can handle about 70,000 barrels per day. So, if the volumes started increasing to the substantial numbers DOR is talking about, it would take a new and larger pipeline going all the way back to Prudhoe Bay.

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MR. ALPER provided the projected lease expenditures in graph form [slide 20], with the spending broken into the categories of startup capital, ongoing capital, operating costs, and exploration capital. He said these very large spending numbers will have massive economic impact within Alaska, with corporate spending being between \$4 and \$7 billion a year for many years.

MR. ALPER displayed what state revenue would look like in graph form for the base case scenario [slide 21]. He explained exploration spending would begin in 2019 according to the assumptions, but without any production these early expenditures

would be eligible for the net carry forward annual loss credit. Once oil production starts, royalty revenue and property tax would begin, and several years' later revenues would begin from production tax and state corporate income tax. In constant 2015 dollars, revenues would reach a maximum of about \$4.5 billion per year, tapering down slowly to about \$3.5 billion per year in the far out years of the study period.

MR. ALPER turned to slides 22 and 23 to break out the key components of revenue in the base case scenario. He noted the red curve for royalties on slide 22 is the same as the red band within the mixed curve on slide 21. He pointed out that 75 percent of this oil is federal oil; of that federal oil, the state is getting 90 percent of the royalty. Should the royalty split be different, then this red curve would be somewhat smaller, although it would not in any way change any of the other economics. Also, whatever the number is within this red area, 25 percent of that number goes directly to the permanent fund; in other words, the red curve is all royalty, including royalty that will go to the permanent fund. Moving to slide 23, he discussed the component of production tax revenue in the base case scenario. He drew attention to the credits [that would be paid out by the state] in the early years, but noted large tax revenues would be realized once there is substantial levels of production. Production tax [net of all credits] would be \$1.5-\$2 billion per year [from about 2038-2075].

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MR. ALPER displayed slide 24, explaining it is a graph of all the components of state revenue for the high case scenario. He noted that in the high case the amounts of oil are larger, but all the other assumptions, such as the cost per barrel and price of oil, are the same. Therefore, the revenues are another couple hundred billion dollars higher. Drawing attention to the graph on slide 25, he said it is the same components of state revenue but for the low case scenario. The lower amount of oil results in less revenue, but the revenue amounts are still substantial for many years into the future.

MR. ALPER moved to slide 26, stating DOR also did an analysis of state revenue at a higher oil price of \$140 per barrel instead of \$110. He pointed out that the costs upfront - the credits - are the same, but revenue in the out years is much higher, peaking at about \$7 billion per year in the base case scenario. However, he continued while turning to slide 27, if the oil price is low [\$80 per barrel in the base case scenario], it

becomes a constrained project where the state may not see sufficient revenues to warrant the investment undertaken by the state. He qualified that an oil price of \$80 going forward to 60 years from now seems a very unlikely scenario to him personally, but DOR wanted to provide both high and low numbers to provide a sense of what the state's potential options.

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MR. ALPER addressed slide 28, saying other benefits would accrue to the state besides money once the Arctic National Wildlife Refuge property is developed. The first benefit would be gas. In addition to the billions of dollars in revenue from producing and developing that gas, the life of the Alaska LNG Project would be extended by decades. Because a lot of the AK LNG core infrastructure would have already been paid for, this second generation of gas would be even more profitable than the first. The benefit to the Alaska economy of the base case investment spending of almost \$7 billion per year would be almost incalculable. The state's economy would be tremendously increased, as would the number of jobs for many, many years. Another benefit would be extending the life of the Trans-Alaska Pipeline System (TAPS). These hundreds of thousands of additional barrels of oil would set aside for another generation the issue of when TAPS is not going to have enough oil to operate economically. Lastly are the local benefits; for example, the North Slope Borough would be looking at a couple hundred million dollars just within the borough every year in property tax revenue.

MR. ALPER, speaking to slide 29, urged committee members to keep in mind that this is just one possible view. It is by no means a projection, and not a forecast. It is a model based on parameters that DOR came up with that were reasonable based upon the best available information. What could be produced over a 60-year period is entirely dependent on someone finding oil, that oil being producible, and being able to bring the oil to market under the terms and conditions that DOR imagined here. Actual development could happen faster or slower. He made it clear that DOR does not currently include any Arctic National Wildlife Refuge production or revenue inside DOR's official forecasts.

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REPRESENTATIVE TARR said she appreciates seeing the analyses for high and low oil prices, but noted today's oil price is \$55. She inquired whether DOR has run the numbers for a price of \$55.

MR. ALPER replied DOR has not specifically run the numbers at \$55. He offered his expectation that given the cost of bringing this oil to market, including the remote location, it might not pencil out very well if it was found that \$55 was going to be the price of oil for decades. The DOR Revenue Sources Book anticipates this price will hold for a year or so and then there will be a recovery by 2017 to something more like what was seen in recent years before the \$55.

REPRESENTATIVE TARR posed a scenario in which one of the three major North Slope producers becomes involved in producing on the Arctic National Wildlife Refuge. She asked whether during development the producer would be able to apply the net operating loss credits against its other production tax for other oil revenue. She further asked whether that would cause a shift in the state's other oil revenue receipts if this is done.

MR. ALPER responded that if development was done by the current suite of producers in the North Slope, rather than by a new company, the expenditure would result in a spending offset to their profits for their other production within Alaska, not a carry forward annual loss credit. It would be a savings at the same rate - a 35 cent on the dollar reduction in their tax liability, which the state would see on the revenue side rather than on the expenditure side. Should the spending drive the companies to a place where they are no longer profitable, the companies would have to carry the loss on their books and hold it against a future year's tax liability because a large company in Alaska is not eligible to get a carry forward annual loss credit reimbursed in cash. So it would shift some of the cash flow to the right a little bit, but the net effect in dollars would be roughly the same.

DAN STICKEL, Assistant Chief Economist, Tax Division, Department of Revenue (DOR), added that, for this analysis, DOR did not make any distinction between existing producer and new producer. It was just the question, What is the net fiscal impact to the state? It is a 35 percent credit and that is what is shown.

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REPRESENTATIVE SEATON, regarding the slides depicting components of revenue, inquired whether [the net operating loss credit]

would be a cumulative outflow from state revenue of about \$9-\$10 billion.

MR. ALPER answered "more or less." Looking at the graph, he said it would be a large cost to the state because of the large capital spending and, under current law, the state would be reimbursing 35 cents on the dollar. For example, for a company coming to Alaska and spending \$5 billion, the state's 35 percent reimbursement to that company would be \$1.75 billion.

REPRESENTATIVE SEATON, presuming a mix of developers, calculated the state could be looking at reducing those taxes payable from other oil and gas production to near zero, as well as looking at reimbursement in the credits for the net operating loss carry forward in the following year. He asked whether a mix of new and existing players could result in diminishing then-current revenue from oil taxes, as well as the state being liable to new players for quite large directly reimbursable credits, like what is being played out under the Point Thomson development.

MR. ALPER replied the number on the graph on slide 21, which is roughly consistent in the other scenarios, is a sum total of what Representative Seaton is describing as a mix of companies doing the work. For those companies that are incumbent producers having other ongoing profits in Alaska, the state would see it as a reduction from tax. For the new players, the state would see it as a credit paid out. However, the sum total would be the number seen on the chart.

REPRESENTATIVE SEATON calculated that, depending upon the mix of developers, the state could possibly not have any income from production tax and only a small amount from royalty. He asked whether, depending upon the mix, the state could get in a situation where it didn't have any income or had very little income, and would still have the expenses of the other portion.

MR. ALPER responded Representative Seaton is looking at the early years of a massive project where there would be potentially large cash outflows to the state. That would be something the state would have to find a mechanism to finance, or absorb, with the understanding and expectation that there would be quite larger revenues coming to the state several years afterwards when these oil fields are under production. It is not terribly different from what is currently being discussed on the gas pipeline where the state is going to have a major investment component in the early years and a major tax impact because of some of the work that's going to need to happen to

enable the gas pipeline to get built, yet the expectation is that the billion dollars of annual revenue that comes in once over that hump. There will, he said, most definitely be hump.

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REPRESENTATIVE JOSEPHSON pointed out that in today's scenario the state is bringing in apparently about \$2.5 billion of revenue in the current fiscal year and will have a \$3.5 billion deficit. He recalled that this year the legislature's experts have talked about revenue of \$3.5 billion from a gasline. He posited that if the state had a gasline and production from the Arctic National Wildlife Refuge at the same time, the state would be able to sock away billions of dollars every year. He inquired whether that is possible.

MR. ALPER answered the expense side of the state's ledger is beyond what was done in this analysis. But, yes, he allowed, it does seem like a tremendous amount of money that will be coming into the state at that point in the future.

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REPRESENTATIVE SEATON observed on slide 13 that the assumption for development capital expenditures is \$10 per barrel over an 8-year development timeline, the assumption for maintenance capital expenditures is \$5 per produced barrel each year, and the assumption for operating cost is \$20 per produced barrel each year. He asked whether these figures are within the ballpark of where the state is now at a \$25 net operating cost, the \$20 operating cost plus the \$5 maintenance. He further asked whether that is the cost scenario range that the state has in the current production tax or profit-based tax.

MR. ALPER replied the \$20, \$5, and \$10 add up to a total of \$35 per barrel in lease expenditure, which is in the ballpark and is actually a little low for what is being seen right now. It must be realized that what is happening right now is not just the operation of current fields but the development of some new large fields that aren't producing anything yet and those costs get absorbed into the totals. The \$10 per barrel development capital expense on slide 13 represents working on next year's oil field while building this year's oil field. These things are all happening at the same time so it ends up being an aggregate number that roughly lines up with what is the current spending in the North Slope. The North Slope is pretty much used as the model by DOR.

REPRESENTATIVE SEATON drew attention to the 35 percent credit depicted on slide 21, saying he doesn't see any costs related to production tax as those new fields come on. He inquired whether he is misinterpreting that or whether it is a subtraction from the aggregate of production tax received by the state.

MR. ALPER displayed slide 20 to respond, explaining it shows the industry investment totals. A big bump in capital spending is seen in the early years, primarily because the largest fields are developed first and the largest fields have the highest capital investment component to them. In those early years production is small or nonexistent. The outflow of cash [from the state] represents that large capital expenditure before there are substantial amounts of revenue and production, and that is cashed out to the developer at 35 cents on the dollar.

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REPRESENTATIVE TARR recalled that oil prices peaked at almost \$150 around 2008, but was around \$60 just before that, and today the price is \$55. She asked how DOR accounts for that much price fluctuation when modeling for a 60-year time period.

MR. ALPER answered that, without running a very different and more complex modeling, DOR cannot. What was considered a reasonable, average number was chosen and taken forward. He recalled that Mr. Barry Pulliam of Econ One Research was before the committee several years ago to talk about his expectation of long-term oil prices. Mr. Pulliam made a compelling case for \$80 and \$130 being a long-term low and high, \$80 being the point at which much of the more marginal current production might fall off for being uneconomical and \$130 at which a bunch of really new production might come on line. Mr. Pulliam anticipated a relatively stable time bouncing within that range going forward, and \$110 conveniently falls within that and also conveniently lines up with DOR's own long-term projections. There is no magic to this, he added, and the one thing he can guarantee about this presentation is that DOR is wrong - it will not be exactly what has been put before the committee.

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REPRESENTATIVE SEATON recalled some consultants were expressing concern that under existing scenarios the state could be looking at not making any money from some of the fields over time. He surmised that while slide 21 doesn't include net present value

of the money expended and the money received, DOR's analysis looks at this as being a profitable deal for the state over the operating length of the fields.

MR. ALPER replied yes, explaining DOR also assumed roughly the same economic profile for each of the 25 different fields, meaning the same cost per barrel for the smaller versus the larger fields. In real life, however, variation is expected due to geological differences, some fields being more constrained, and some that are more capital intense. So, it is possible that some of the conditions being talked about by Representative Seaton might come into play. Some of the inherently less profitable fields might not pencil out for the state and they might not get developed because they don't pencil out for the producer either.

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ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 3:22 p.m.