HOUSE FINANCE COMMITTEE
May 3, 2023
1:34 p.m.

1:34:08 PM

CALL TO ORDER

Co-Chair Foster called the House Finance Committee meeting to order at 1:34 p.m.

MEMBERS PRESENT

Representative Bryce Edgmon, Co-Chair
Representative Neal Foster, Co-Chair
Representative DeLena Johnson, Co-Chair
Representative Julie Coulombe
Representative Mike Cronk
Representative Alyse Galvin
Representative Sara Hannan
Representative Andy Josephson
Representative Dan Ortiz
Representative Will Stapp
Representative Frank Tomaszewski

MEMBERS ABSENT

None

ALSO PRESENT

Nicholas Fulford, Senior Director, Gas and Energy Transition, GaffneyCline; John Crowther, Deputy Commissioner, Department of Natural Resources; Rena Miller, Special Assistant, Office of the Commissioner, Department of Natural Resources; Eric Demoulin, Director of Administrative Services, Department of Revenue; Frank Richards, President, Alaska Gasline Development Corporation; Nick Szymoniak, Manager, New Business Ventures, Alaska Gasline Development Corporation; Representative Justin Ruffridge.

PRESENT VIA TELECONFERENCE

Ashlee Adoko, Director of Office of Project Management and Permitting, Department of Natural Resources; Helge Eng,

Director, Division of Forestry and Fire Protection, Department of Natural Resources; Kris Hess, Deputy Director, Division of Mining, Land and Water, Department of Natural Resources.

SUMMARY

HB 50 CARBON STORAGE

HB 50 was HEARD and HELD in committee for further consideration.

HB 49 CARBON OFFSET PROGRAM ON STATE LAND

HB 49 was HEARD and HELD in committee for further consideration.

PRESENTATION: ALASKA LIQUEFIED NATURAL GAS PROJECT UPDATE

Co-Chair Foster reviewed the meeting agenda.

#hb50
HOUSE BILL NO. 50

"An Act relating to the geologic storage of carbon dioxide; and providing for an effective date."

1:35:10 PM
AT EASE

1:35:57 PM
RECONVENED

Co-Chair Foster continued to review the agenda.

1:36:41 PM

NICHOLAS FULFORD, SENIOR DIRECTOR, GAS AND ENERGY TRANSITION, GAFFNEYCLINE, introduced himself and the PowerPoint presentation "CCUS Value Chain and Business Case" dated May 3, 2023 (copy on file). He shared that he had worked on around a dozen CCS [carbon capture storage] projects worldwide, but predominately in Texas and Louisiana. He began on slide 2 and provided the agenda for the presentation. He stated that the industry was unfolding at a rapid rate. He relayed there were quite a few useful lessons that could be drawn from activities around the

world. One of the features of the journey was that the different sequestration agreements had reached an advanced stage in their discussions so that cost stack and pore space leasing costs were starting to come to the surface. As the contracts became more sophisticated there were a number of commercial considerations emerging. He reported that the environment for CCS in Alaska was very different from Texas, Louisiana, and many other parts of the world.

Mr. Fulford moved to slide 3 titled "Significance of State Related Charges in Development." He shared that in the context of the CCS industry, Alaska was in a fairly early stage. He elaborated that many of the projects in Texas and Louisiana had reached fully termed sequestration agreements typically between an emitter (e.g., a petrochemical plant or power station) and transportation storage companies (T&S). He detailed that T&S entities had to address where the carbon dioxide (CO2) was sequestered, and part of their contractual framework pertained to pore space leasing agreements. He expected the journey in Alaska to move through the same kind of phase. He relayed that the focus had been on the geology and rock properties in the past few months and the outcome of the work was to demonstrate that the state had considerable potential.

Mr. Fulford continued reviewing stages on slide 3. The second stage was techno-economic project feasibility, which included a high level dialogue with potential emitters and people interested in storing CO2 and a more advanced perspective on pore space leasing. He noted it would include the kind of regulatory and legislative framework HB 50 was designed to address.

Mr. Fulford moved to the third phase, which would be termed a pre-financial investment decision (FID) phase. He detailed that the emitters and the sequestering T&S companies were finding it useful to adopt a heads of agreement framework, which entailed an eight to ten-page agreement (that was not typically legally binding) to provide some assurance for lenders and the industries looking to sequester their carbon. He expounded that part of the agreement would likely include a reasonably detailed explanation of the pore space arrangements and location. At that point, much more detailed financial modeling would occur, including levelized cost storage and taxes. The fourth phase – FID – would include an array of contracts, which would be carefully scrutinized by lenders,

particularly if any project finance was involved. There would also be an EPC or development contract to look at construction.

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Representative Hannan asked what the last term [EPC] used by Mr. Fulford stood for.

Mr. Fulford replied that EPC stood for engineering, procurement, and construction (EPC) contract.

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Representative Galvin referenced the technical feasibility stage shown on slide 3. She recalled discussion in committee the previous week about transportation of a product thousands of miles to another location. She found it to be a significant barrier to the project concept. She remarked that the committee had not yet seen the size or type of container needed. She thought it was an important part of the plan. Alternatively, she considered that perhaps there was only thought about oil and gas on the North Slope, which was an entirely different vision. She asked for Mr. Fulford's comments.

Mr. Fulford responded that the distance between the emitting source and the sequestration site was a critical part of the picture. He stated that the distance was relatively short for most of the existing projects or projects in development. He highlighted an ammonia plant where an injection well was being drilled within the plant boundary, which created substantial savings. He estimated that for the Gulf Coast, the distance the economics were sustainable was about 50 miles. He elaborated that at that point the compression in the pipeline tariffs started to encroach. He noted it was within the current envelope of the 45Q tax credits of about $85 per ton and the capture, transport, and sequestration came out of that. The marine transport of CO2 was being done between Denmark and Norway and was a relatively groundbreaking and developing technology. Although there had not been any largescale CO2 marine transportation vessels built yet, they were on the drawing board. He relayed that to move CO2 from Southeast Asia to Alaska in a large oceangoing CO2 vessel would cost about $50 per ton. He stated it would be comparable to a complex CO2 capture facility.

Representative Galvin surmised that if the ship were to be built and the [transportation] cost was $50 per ton, it sounded like the market was much higher than in other places. She remarked that she could be wrong and perhaps Japan and Asia had other market choices. She asked if Alaska was really a good choice for them.

Mr. Fulford responded that there were a number of energy intensive Asian economies without any readily available CO2 sequestration facilities; therefore, a number of them were looking actively at cross border CO2 export projects, in which case the distance and complexity was a factor. The regulatory ability to monitor and measure and be confident in secure storage was also particularly important. He stated that one interesting synergy with respect to Alaska was the potential export of LNG [liquid natural gas] and the import of CO2. There were a number of Japanese companies looking at the concept. Although the economics and technology were yet to be determined, it was one of the factors that made CO2 imports more relevant than other ones.

Representative Galvin asked Mr. Fulford to speak to the economics of a future situation where the technology existed for Asia or another country to ship its carbon to Alaska for sequestration and Alaska shipped out its LNG or another gas product. She asked what the revenue would look like for Alaska.

Mr. Fulford responded that the strategic scale of CCUS [carbon capture, utilization, and storage] in Alaska was significant on a global level. He stated it was useful to keep in mind that the numbers and volumes were material when turning them into revenue numbers. He relayed that moving LNG from Alaska to Asia cost about $1.00 per million Btu [British thermal unit], which corresponded to about $50 per ton. He elaborated that when exporting LNG, the exporter bore the return cost of the empty ship. He stated that equally with CO2 "you'd be doing the same." He relayed that in theory, if the activities could be combined into one business model, it would mean the potential for halving the costs, which would create much more economic opportunity. He believed the concept was a number of years away, but it was worthy of exploration for Alaska's oil and gas future. He noted there were other strategies available

including processing gas into ammonia or another organic compound, which was more transportable than hydrogen and could be used to export instead of gas. He stated that CCUS was a facilitating technology that would aid in the process.

1:51:09 PM

Representative Josephson referenced the terms price discovery and levelized cost storage used by Mr. Fulford. He asked for an explanation of the terms.

Mr. Fulford responded that there were dozens of emitters in the U.S. Gulf Coast energy corridor who were all looking for cost effective storage of their CO2. There were perhaps half a dozen viable storage candidates. He elaborated that currently the dialogue was going back and forth between emitters and storage entities and price discovery was the negotiation process of what was almost a commodity price. Levelized cost was a term associated with carbon projects and was a way of turning the capital and operating costs into a tariff. He elaborated that the levelized cost of CO2 storage may be $20 per ton, which meant that financing the capital and operating expenditures would require a $20 per ton tariff over a 20-year period in order to pay it off.

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Co-Chair Johnson referred to the CO2 backhaul. She asked whether natural gas was a liquid that compressed at relatively the same rate [as CO2] making it possible to use the same ships [for transportation].

Mr. Fulford explained that the concept of LNG out and CO2 back had economic advantage, but the technology did not yet exist. The factors mentioned by Co-Chair Johnson were key and would have to be addressed. He believed it would be many years before the option was available.

Co-Chair Johnson referenced the number of different entities from which the CO2 might be received. She asked if CO2 gas was pure or included other chemical compounds. She asked if it varied by company.

Mr. Fulford replied that for a point to point CCS scheme, the quality of the CO2 was much less important as long as it was in a form that could be easily injected and would

remain in the reservoir. He relayed that CO2 quality was key for emerging industrial hubs in the same way that gas transmission system had a certain spec, which had to be adhered to. He stated in that case, some emitters may place additional costs in pretreating CO2 to get it to the right quality.

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Mr. Fulford advanced to slide 4 and the unit technical cost of some examples of real life sequestration projects. He detailed that the technical cost amounted to the upfront capital expenditures and 20 years of operating expenditures. He noted the information was useful as a comparison between different concepts, but it did not translate into a tariff. For the most part, the capture of CO2 was a significantly higher proportion of capital than lease storage. He relayed that the transport and to some extent the compression were variable. The example on the left of the slide was an industrial hub concept and showed relatively small transport and storage cost, reflecting economies of scale in the unit technical cost. The other two examples on the slide showed a gas processing project and an LNG acid gas pre-treatment project. He explained that the predominance of capital and operating expense required for the two projects was for the capture. He noted he would go into additional detail on the numbers in the next couple of slides.

Mr. Fulford moved to slide 5 titled "Example Costs for a 200 to 250MMscfd Project (3.9 to 4.8 MTPA)." The slide corresponded to the gas processing and LNG acid gas pre-treatment projects [shown on slide 4]. He noted the two projects were very similar. He pointed out that a certain amount of compression was required to bring the CO2 up to the required critical pressures. The slide showed $77.3 million in compression capital expenditure and $40 million for injection wells. The other costs were less in descending order of magnitude. The example project was 4 to 5 million tons per annum (MTPA) of CO2 with approximately $125 million in upfront capital expenditures. The right side of the chart listed operating expenditures with the two key components being fuel for the compression and monitoring cost of injection wells and monitoring equipment, which was very expensive. The total operating expenditure was about $8 million.

Mr. Fulford continued to slide 6 and went through a potential hypothetical scenario in terms of what the cost may be for leasing the pore space. The scenario applied a $1 per ton additional cost for the pore space lease, which changed the numbers accordingly. The change added about $4.5 million per annum of operating expenditures (a 35 percent increase compared to the example without pore space leasing).

Mr. Fulford moved to slide 7 and highlighted a scenario where the pore space lease was capitalized and moved upfront as a capacity charge or something similar. He detailed that at a 10 percent discount rate the pore space lease (capital) came to about $38 million, which added about 30 percent (the capital expenditure would go from $125 million up to $163 million). The purpose of the slides was to provide real life examples to give a sense of how much projects cost and the impact of pore space.

2:00:12 PM

Representative Hannan looked at the row in the capital expenditures column of the examples showing the owner's cost. She asked if that reflected the contractor or developer cost for Alaska. She noted that Alaska would be the owner of the pore space. She asked if the pore space lease cost was borne solely by the developer. She noted that in some of the examples discussed, Alaska was the owner of the space and perhaps a developer in some regard.

Mr. Fulford replied that the owner's costs predominately related to the surface facilities and were typically paid by the developer. He noted that the legal and regulatory arrangement surrounding the ownership of pore space in Alaska was well defined in its constitution. He stated that generally the costs would be sustained by the developing company and not the state.

Representative Hannan stated her understanding there was not currently an example of an LNG/CO2 exchange because it was not happening anywhere yet. She noted that under the concept of the LNG project in Alaska, the state would own the project and would invest in its development. She asked for verification that Alaska expected to be the owner of the sequestration pore space and the owner of the accompanying facilities.

Mr. Fulford replied that the concept of the export of LNG and import of CO2 was in the distant future and may not be feasible given it was so far away; however, in the context of the LNG project, he envisioned that a project of that scale and complexity would require a series of legislative steps to go forward (which was the case in most countries GaffneyCline worked with in terms of LNG development). The default assumption would be that the LNG project would pay a tariff to a T&S company to deal with its CO2. He remarked that it could be done in a different way, which had more synergies for the state and the way its revenues were determined.

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Representative Stapp observed that the examples used a 12-year operating capacity time in the formula used. He asked if it was standard in the industry to amortize costs over 12 years. He highlighted that the pieces of legislation under discussion had a much longer timeframe.

Mr. Fulford responded that the 12 years was a throwback to the previous 45Q [tax] structure. He relayed that 20 years would be more typical injection framework and possibly longer.

Representative Stapp asked if a 20-year calculation would reduce the cost because there would be 20 years of capital expenditures versus 12.

Mr. Fulford responded in the affirmative. He stated that with discount rates, the later years started to have less effect. He relayed that for most companies looking at developments, being able to secure the longest possible secured cashflow was advantages for everyone and resulted in lower tariffs.

Representative Stapp asked if the increase of the per tonnage fees to the allowable federal 45Q tax credits was incorporated into the cost assessments. He believed it was $85 per ton for standard capture and he understood it was considerably higher for direct-year capture at $180 [per ton].

Mr. Fulford replied that he was frequently asked how to factor in 45Q and was it considered a credit or revenue. He explained that GaffneyCline considered the 45Q tax cashflow

and the associated direct pay to be revenue. For example, if the levelized cost was $50 per ton (which may be typical for a gas processing plant) and a tax credit could be secured at $85 (for a limited time), it would be considered as a profitable project with an IRR [internal rate of return] of potentially greater than 10 percent.

Representative Stapp remarked that the cost per ton for carbon storage was less than the available 45Q tax credit. He remarked on the seven-year period. He asked if the difference in the capital expenditure cost of the project was factored in. He stated a project would not be paying any taxes at a federal level even if it was a subsidy. Alternatively, he asked whether the effective credit made a project economical or not was used as a baseline.

Mr. Fulford responded that the capital investment and operating expenditures involved in a CCUS project was purely a cost and unless there was a revenue mechanism to compensate, no investment would happen. He noted it was the reason nothing was happening despite the interest in CCUS from a lot of countries. There was an emissions trading system in Europe, which was about $100 per ton. There was the LCFS [low carbon fuel standard] in California, which was similar depending on how much could be captured. Additionally, there was the federal 45Q. He explained it was providing a very significant financial incentive. He highlighted an LNG pre-treatment plant already producing CO2 as an example. He stated it was roughly adequate for something like an ammonia or hydrogen plant, and inadequate for a gas-fired power station. He explained there was a merit order of projects, some were economic and others were not and the cutoff was somewhere between a large hydrogen plant and a gas-fired power station.

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Co-Chair Johnson thought Mr. Fulford had stated that some of the carbon capture technology was not yet available. She asked what kind of carbon emissions load existed that may be transported to Alaska.

Mr. Fulford replied that the largest projects being discussed in Texas were 100 MPTA (the Exxon Houston ship channel project). There was also an existing pipeline that would take 16 MTPA. He noted that in the context of

industrial emissions across the country it was minimal. The limitation was the economics of capture.

Co-Chair Johnson referred to the monitoring equipment (capital and operating) costs. She assumed that the standards from the registry would drive what the monitoring equipment would be.

Mr. Fulford responded affirmatively. He relayed that all of the projects had to obtain a license from the EPA [Environmental Protection Agency] or from the state authority depending on the jurisdiction. He stated it would determine the extensive array of surface and surface monitoring to examine what was happening to the plume and check for any leakage.

Co-Chair Johnson surmised it applied to carbon and the Alaska Gasline Development Corporation (AGDC) depending on whether there was a line or other types of equipment installed. She asked how 404 primacy would impact the capital costs. She asked if Mr. Fulford anticipated any difference in the capital cost if the state assumed it.

Mr. Fulford replied that the capital investment would probably not change, but the operating expenditure may be reduced. He elaborated that based on some of the projects GaffneyCline was working on, the cost of an EPA class VI permit application was relatively high but expected to drop. He remarked that for states with primacy, the class VI process was perceived to be much less complex.

Co-Chair Johnson wondered how familiar Mr. Fulford was with companies' financing based on zero carbon emissions. For example, project financing where zero carbon emissions was a requirement or provided a given number of points towards obtaining a loan.

Mr. Fulford summarized that he was very familiar with the topic, which likely warranted a separate discussion. He explained there were clear examples of low carbon projects attracting low cost finance from different sources. There were an increasing number of financial organizations that would deprioritize or not lend to projects they perceived to be incompatible with their carbon goals. Additionally, some of the tech companies with a particularly aggressive net zero target would pay several hundred dollars per ton for a CO2 removal credit.

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Co-Chair Edgmon stated his understanding that three states had 404 primacy including Florida, New Jersey, and Michigan. He asked if all three states were doing carbon capture.

JOHN CROWTHER, DEPUTY COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, responded that the 404 primacy was distinct from the class VI primacy. He did not know the status of carbon projects in the three states mentioned by Co-Chair Edgmon, but it was not dependent or associated with 404 primacy. He clarified that the class VI primacy through the EPA was for sequestration wells.

Co-Chair Edgmon stated that was his understanding. He thought the exchange between Co-Chair Johnson and Mr. Fulford could have been inferred differently.

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Mr. Fulford advanced to slide 8 titled "Supply, Demand and Levelized Cost." He highlighted a scenario turning the cost breakdown on slide 7 into a tariff excluding the pore lease cost spaces and the other significant commercial risks, the levelized cost or tariff would likely be about $10 to $12 per ton. He stated there seemed to be a price of about $20 per ton that would support some of the larger T&S projects serving the Gulf Coast. The slide highlighted there was a substantial amount of sequestration potential available in the U.S. and to be competitive it was necessary to be at the lefthand side of the curve shown on slide 8. He used the ExxonMobil Houston ship channel project (the largest envisaged project) as an example with 100 MTPA for 20 years, which was about 2 gigatonnes and on the left side of the chart. He relayed that Alaska was perceived to have about 50 gigatonnes available in the Cook Inlet, which was also still very much on the lefthand side of the chart.

Mr. Fulford briefly turned to slide 9 showing a summary of some of the leasing fees other states had been securing. He turned to slide 10 titled "Alaska Considerations." He relayed that on a technical level, most of the Gulf Coast projects were aimed exclusively at saline aquifers (water carrying geological formations), which had an extensive but less well defined CO2 storage capacity. The focus in Alaska

was currently on depleted gas reservoirs, which were well documented and with very clear traps. The largest difference conceptually between Alaska and other parts of the U.S. was that Alaska had very low state emissions. He discussed the three benefits of Alaska pursuing a CCUS strategy. The first was that the foundation of the Alaska economy continued to be the oil and gas industry. He stated that as all of the recent developments had served to underline, to enable the industry to continue to make the future tax revenues more resilient, an assertive and clearly established carbon management strategy would be needed to help go forward. He elaborated that not only would it protect existing revenues and cashflow, it would potentially secure new investments and future tax royalty that may otherwise be at risk in a world without carbon management.

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Mr. Fulford relayed that the second benefit was the LNG project (the monetization of North Slope natural gas). He stated that having a robust carbon management strategy to accompany the project would be an essential part of the project going forward from a "social license" perspective. He shared that based on his experience speaking with Japanese banks and others who could conceivably be interested, it was clear that lending to such a project would be dependent on it being presented in a low carbon fashion. He explained that natural gas and carbon capture were two foundation stones of the ammonia and hydrogen industry, which would be an important feature going forward. The third benefit the potential for Alaska to participate in the large scale imports of CO2.

Representative Josephson noted that he was a big supporter of the large diameter gasline proposed in past legislation, SB 138 [legislation proposed by former Governor Sean Parnell in 2014] and could see how "this" could be helpful to that endeavor. He considered the subject of social license [in regard to CCUS projects being a catalyst for LNG/gas monetization (shown on slide 10)]. He asked if it could potentially less helpful if the goal post on the international scene moved, which was likely to happen. For example, if the Paris Accord became the Barcelona Accord and had more aggressive goals to achieve. He asked if the consideration could become outdated because the world was in crisis.

Mr. Fulford responded that it was a very topical question. He stated that part of his role at GaffneyCline was to take a view on gas and LNG demand and how it was unfolding. Currently there was likely a bigger gap in LNG forecasts, particularly in the post 2030 era. He considered the investment required to move the world's energy systems to a renewable or net zero system and the ability of global economies to sustain the expenditure. He explained it was difficult to create the circumstance where rapid decarbonization would occur. He believed taking a more balanced view of the role that unmitigated natural gas or low carbon fuels like ammonia or hydrogen would take and looking at the timeframe for the Alaska LNG project, it should be a viable proposition with the right buyer and contract structure. He noted that much would depend on the willingness of buyers to invest.

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Mr. Fulford provided conclusions on slide 11. He relayed that the commercial framework for CCUS was rapidly evolving; however, the tariffs and price point based on the hardware and required capital expenditure were beginning to come together. The capture economics continued to be the biggest part of the equation and getting those addressed was perhaps the key to large scale CCUS. The commercial terms varied significantly depending on the risk allocation. In particular, currently the biggest stumbling block was the ability of an emitter to guarantee off taker. He explained that an emitter would always want its CO2 to be taken, but a storage project may not always be able to take it. There was currently a very active negotiating dialogue in the U.S., from which there were many lessons to be learned in Alaska. Much of the same dialogue was being held outside the U.S. at the government level, with a bit slower pace and a different set of cost drivers.

Representative Ortiz looked at slide 11 and asked for an explanation of the bullet point: "commercial terms depend heavily on project structure and risk allocation."

Mr. Fulford responded with an example. He explained that once a large industrial emitter secured sequestration, it was able to collect the 45Q [tax credit] and perhaps a premium for low carbon fuel. However, if the emitter was unable to secure the emissions, it may face liabilities of

$100 to $300 per ton for having to vent the CO2, or not. On the other hand, the storage entity may be paid $20 per ton to take the CO2. He clarified that the emitter was ideally not about to take a $300 liability for not doing so. He explained that the back and forth on short and long-term liabilities could create some large, stranded costs, which had to be somehow allocated in the contract framework.

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Co-Chair Edgmon asked how Mr. Fulford would respond to the viewpoint that the idea of carbon capture could be considered a Ponzi scheme. He reasoned that by the time much of the factors were worked out, particularly on the sequestration side, the planet may have pivoted to more carbon friendly in terms of emissions. He considered that idea seemed promising in the current environment but may not bear out in the future. He referenced the continued use of the word "emerging" [used to describe carbon capture technology]. He asked what Mr. Fulford would say to a person who thought the idea sounded like crypto currency or something similar. He stated that the end goal was to not just provide environmental social government (ESG) licenses to an emitter, but to actually reduce carbon. He asked what would happen if it did not pan out and the multibillion dollar emerging industry began to sputter and disappear.

Mr. Fulford replied that real money was currently being deployed into CCS from credible and respectable institutions including pension funds and New York based infrastructure funds. Secondly, the International Panel on Climate Change (IPCC) was pushing hard for a rapid decarbonization of the world's economy. He elaborated that the IPCC had stated that CCUS was an essential part of the transition from present to net zero. He considered some of the transformational energy systems like fusion and imagined that in 50 or so years carbon capture would be an older technology; however, there was a very clear role for the next 50 years and investment was taking place currently.

Co-Chair Edgmon thanked Mr. Fulford for the presentation.

Co-Chair Foster thanked Mr. Fulford and set an amendment deadline for May 10, 2023, at 5:00 p.m.

HB 50 was HEARD and HELD in committee for further consideration.

2:30:49 PM
AT EASE

2:32:34 PM
RECONVENED

#hb49
HOUSE BILL NO. 49

> "An Act authorizing the Department of Natural Resources to lease land for carbon management purposes; establishing a carbon offset program for state land; authorizing the sale of carbon offset credits; and providing for an effective date."

Co-Chair Foster began with a review of the fiscal notes.

2:34:14 PM

ASHLEE ADOKO, DIRECTOR OF OFFICE OF PROJECT MANAGEMENT AND PERMITTING, DEPARTMENT OF NATURAL RESOURCES (via teleconference), reviewed the fiscal impact note OMB Component Number 2733, control code RFFnp, dated 5/2/23. For FY 24, the total operating cost was $194.4 and consisted of $156.1 in personal services, $10.0 in travel, $16.3 in services, and $12.0 in commodities for one full-time permanent large project coordinator position beginning in FY 24 to stand up and administer the state projects program (path 2 in the upcoming presentation). The fund source was undesignated general funds (UGF) to be replaced with revenue.

Representative Josephson asked about Ms. Odoko's statement that general funds would be replaced by revenue. He did not see that going out to FY 29.

Ms. Adoko responded that the Department of Natural Resources (DNR) did not know exactly when revenues would be online and the department would provide additional detail on the topic during its presentation. She had additional notes regarding FY 25 and beyond if the committee was interested.

Co-Chair Foster asked Ms. Adoko to repeat her last statement.

Ms. Adoko explained that she had covered FY 24 in her fiscal note explanation but offered to provide additional information on FY 25 and beyond.

Co-Chair Foster asked for clarification. He asked Ms. Adoko to proceed.

Ms. Adoko relayed that for FY 25, the total operating costs were $369.8, made up of $264.5 in personal services, $10.0 in travel, $81.3 in services, and $14.3 in commodities. The cost covered a full-time administrative officer I permanent position to perform budget, reporting, accounting, and other functions to support the state projects program (path 2 in the upcoming presentation. There was a cost associated with one survey needed to support the state projects program. The numbers carried forward for FY 26 and beyond to support the large project coordinator and administrative officer.

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RENA MILLER, SPECIAL ASSISTANT, OFFICE OF THE COMMISSIONER, DEPARTMENT OF NATURAL RESOURCES, remarked that there was also a capital request on the fiscal note.

Ms. Adoko added that there was a capital appropriations request of $425.0 for contracting the subject matter expert and consult for developing program regulations and contracts and implementing the state projects program.

Co-Chair Foster thanked Ms. Adoko. He moved to the next fiscal note.

2:39:56 PM

HELGE ENG, DIRECTOR, DIVISION OF FORESTRY AND FIRE PROTECTION, DEPARTMENT OF NATURAL RESOURCES, (via teleconference), went through the fiscal note control code ZmXiS, OMB component number 435. The note showed FY 24 costs of $147.3 including $107.9 for a forester, $10.0 for travel, $17.4 for services, and $12.0 for commodities. The note showed a startup cost of $10.0 and supply costs of $2.0 annually. The out years beginning in FY 25 would revert to $2.0 annually, for a total of $137.3. Revenues

were not specifically estimated due to timeline uncertainty and potential project variation. He relayed that credit sales may occur in FY 28 at the earliest. Revenue generated from carbon offset projects would be deposited into the carbon offset fund established by the bill.

Mr. Eng continued to review the fiscal note. Expenditures for Division of Forestry and Fire Protection (DOF) and Office of Project Management and Permitting (OPMP) staff would be funded by unrestricted general funds (UGF), but the intent was to utilize the carbon offset funds in place of general fund dollars once revenues began materializing. The one permanent forester position would primarily be involved in updating state forest management plans as required by the legislation as well as inventory and ensuring management practices adhered to the commitments in the carbon offset project and meet the requirements of the projects. Regulations would be developed and adopted by the commissioner.

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Representative Josephson had not heard that the earliest credit sale would occur in FY 28. He observed that project development would occur in the coming two fiscal years followed by the intervening carbon offset project development timeline, which sounded familiar to project development. He asked why so much time was needed. He did not sense that the tribes needed as much time to get going.

Mr. Eng responded that the fiscal note was an estimate and was developed with experts in the field. He stated that carbon offset projects were an undertaking. Based on his experience, the timeline shown in the fiscal note was fairly typical for a carbon offset project.

Ms. Miller added that Anew had presented on general project timelines and had indicated that 18 months was a reasonable time from start to finish for a project, but due to the variability of conditions in Alaska depending on the specific project, a second field season may be necessary. She explained that project timing worked well and could encompass two field seasons within 18 months, the timeframe would be more condensed; however, depending on start dates and field season timing it may take 24 months. She stated the department hoped to get things off the ground as soon as possible. There would likely be private landowners and

the department would have to write regulations. She elaborated there would be a period of time after regulations were written where the department would field interest and consider which projects to advance.

Representative Josephson asked if the bill would apply to private landowners.

Ms. Miller responded in the negative. She relayed there was language in the state projects area that made it abundantly clear. She referenced Representative Josephson's mention that Alaska Native Corporations may have the ability to get projects going faster. She clarified that had been her previous reference to the private landowner difference.

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Representative Hannan stated that the bill had been talked about as a forestry bill; however, she observed that out of the four positions in the three fiscal notes, the forester position was the cheapest. She remarked that according to the fiscal notes, the bulk of the money required to operate the bill would be in OPMP, operated by a consultant to do website development and monitoring. She stated there had been discussion about the need to increase the state's forest management practices and regularly measure and monitor. She asked if her understanding was accurate.

Ms. Miller responded that there was an important differentiation between project costs for any particular project and the cost of the state having the carbon offset program that would undertake multiple projects that may or may not all be related to forestry. The things required by the project including inventory required by the registry, the computer modeling, the papering of the project design, and ongoing verification and auditing were all project costs and were not reflected in the fiscal notes. She added that looking to the likelihood that some of the greatest carbon attributes were in the forests, it made forestry projects a very likely endeavor for the new carbon offset program. The situation would entail a lot of ongoing work with DOF as the project continued. She clarified that DOF would not be doing the project, but it would need to be doing a number of things to support the project. The division would also need to manage timber harvests, which was not technically part of the project.

Representative Hannan referenced the capital budget item in the OPMP fiscal note. She referenced the contractor that would develop the website and conduct registry work. She surmised the contractor was not likely to be an Alaskan entity. She thought it would be someone dealing with carbon offset across the country versus someone in Alaska helping the state manage its forest.

Ms. Miller responded that working specifically with the registry would be a project cost. She referenced the OPMP contract cost of $75,000 for website and systems development and explained that the bill required project details to be reported by the state regularly. There were additional funds for expertise on setting up the project framework and regulations. She noted it was a new field and the department wanted to ensure regulations were established with expertise in the field. There was also $250,000 in capital related to contractual subject matter expertise (largely legal and commercial) that would help the state in evaluating contractual and commercial terms with entities it would be working with on projects.

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Representative Josephson referenced Ms. Miller's statement that the project costs would not be shown in the fiscal notes. He asked if it was because they were taken from the state's share of the profit. He asked where the project costs resided if they were not in the fiscal notes.

Ms. Miller responded that the upcoming presentation would go into more detail on the topic. She explained that absent upfront capitalization, the state would be working with a turnkey type of developer/contractor that would cover the upfront project costs including inventory, papering, and computer modeling of carbon storage. The contractor would receive a portion of the credit revenue in exchange for frontloading the costs and taking the initial project risk. In the future there would be incoming revenue from the project into the fund created under the bill, which would provide a source of capitalization for future projects where the state could look at other contractual agreements and service contracts that would potentially enable the state to undertake more of the work directly.

Representative Josephson referenced the department's statements about the need to monitor timber harvest by the

program. He asked if it was fair to say that the bill had the effect theoretically of slowing timber harvest.

Ms. Miller responded that the department did not expect carbon offset projects to slow timber sales. Timber sales would continue to be managed by the division. She explained that if there was a carbon offset project on lands where timber sales occurred, the forests would need to be managed in part under the carbon offset project.

Representative Josephson surmised that it could necessitate a reduction in harvest.

Ms. Miller responded that DNR did not anticipate a reduction in harvest under the improved forest management protocols the state would be doing on those forests. The department expected to be making a commitment with the registry to not increase harvest levels to the full annual allowable cut on land enrolled in a project.

2:54:01 PM

Representative Galvin recalled from a prior presentation to the committee the idea about a turnkey project where the state would be able to work with an organization that was responsible for the detailed work. She remarked that when she had asked about the costs the organization would charge it was her impression the answer depended on many different variables. She considered that it may have something to do with what was negotiated. She had heard the cost was up to 20 percent of the project. She asked if other states that may be working on similar legislation ever included "not to exceed" clauses [on the costs]. She asked if the department had a process on other projects where it had guardrails in place.

Ms. Miller responded that Michigan was the only other state with carbon offset projects on public land. She would follow up with information on details on the arrangement in that context. She elaborated that there were some unusual terms in the RFP [request for proposal], such as the exclusive right to all future projects on those state forests. She stated it was always a balance and she confirmed that details were negotiated. She noted there may be other things a party may want to negotiate in a contract. For example, perhaps a developer would train in-house employees so they would be more able to do projects

in the future without relying on a project developer. She relayed there was no limit on the topic in the bill. She believed the protection was somewhat inherent in the responsibilities of the department in looking out for the state's best interests and being able to regularly justify what it was doing as they came before the legislature annually and other times as requested. She thought the department had a strong track record of being responsible in that context.

Representative Galvin remarked that the concept in the bill was potentially a big ticket item of around $300 million. She referenced an "amazing project" that someone had presented in recent months. She reasoned that 20 percent of that total was a substantial chunk of change to be the moderator of the work. She understood it was a lot of work, but also appreciated it was an opportunity for business as well as for legislators. She thanked the department.

Co-Chair Foster requested a review of the fiscal note from the DNR Division of Mining, Land and Water.

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KRIS HESS, DEPUTY DIRECTOR, DIVISION OF MINING, LAND AND WATER, DEPARTMENT OF NATURAL RESOURCES (via teleconference), went through OMB Component Number 3002, control code OEyBr. She clarified that the fiscal note pertained to the leasing program only and not for the state project program previously discussed by OPMP and DOF. For FY 24 the note included $117.5 for a full-time natural resource specialist III position, $5.0 for travel, $17.4 for services, and $12.0 for commodities for a total of $151.9. For FY 25 through FY 29, the total operating costs dropped by $10,000 because it was a one-time cost in commodities and supplies to set up the office. The funding source was UGF and there would be a transition over to program receipts once revenue started coming in. She relayed that the division would come back to the committee if the program required additional positions in the future. She detailed that the new position was a range 18 and would initially be used to set up regulations. The position would travel to help develop the regulations and would subsequently transition to adjudicating applications for leases on state land.

Co-Chair Foster requested a review of the fiscal note from the Department of Revenue (DOR).

3:02:30 PM

ERIC DEMOULIN, DIRECTOR OF ADMINISTRATIVE SERVICES, DEPARTMENT OF REVENUE, relayed that the DOR fiscal note, OMB Component Number 123, had been reduced down to zero. The fiscal note discussed the need for collaboration with DNR when it came to fiscal management of the program and generating new revenues for the state. He relayed it was anticipated there would be substantial collaboration between the executive leadership of both departments to be able to bring the credits to market, which would include conversations with stakeholders as things started to evolve. The department had decided to come back to the committee for personal services needs in future budget cycles as the programs were developed and started to gain traction. He asked if there were any questions from the committee.

Co-Chair Foster noted there were currently no questions. He thanked Mr. DeMoulin.

3:03:39 PM

Co-Chair Foster relayed that the committee would hear two additional presentations during the meeting. He began with a presentation from DNR.

Ms. Miller introduced the PowerPoint presentation titled "House Bill 49: Fiscal Picture," dated May 3, 2023 (copy on file). She relayed that the bill would allow the state to stand up two programs for leasing and state projects to enable the state to monetize natural resources through carbon. The department was not asking for approval of any specific project in the legislation. She highlighted that there was a strong and growing interest in carbon offsets and capital to be deployed. The department wanted to ensure Alaska was positioned well to participate in the carbon business, to make good use of its resources and provide revenue to the state. The bill included two distinct paths to monetizing carbon. The first path was state leases to third parties, referred to as "carbon leases" (bill Sections 3 through 5). The second path was for the state itself to undertake carbon offset projects, referred to as "state projects" (bill Sections 1 through 2 and 6 through

13). The two paths had different costs and different revenues, which would be reviewed in the presentation.

Ms. Miller moved to slide 4 titled "Path 1: Carbon leases." As reviewed in the fiscal note from the Division of Mining, Land and Water, the department would need people to promulgate regulations and receive and process lease applications. Once leases were awarded, they would need ongoing monitoring to ensure conditions were met and that everything was in line. The department was seeking one permanent full-time position. There was program receipt authority for the Division of Mining, Land and Water in the legislation and ideally, once there was incoming revenue from carbon leases, the revenue would supplant general fund and the additional would go to the general fund. The revenue for the carbon leases was indeterminate in amount and timing and was driven entirely by demand of people who have interest in carbon use on state land. She noted it would vary depending on the area of land lease, the particular concept, the value of what they were able to store, and who they were able to generate returns with.

Ms. Miller continued to review path 1 pertaining to carbon leases on slide 5. She highlighted that timber harvest rights were not included with a land lease. She provided a hypothetical example of a carbon lease where a company wanted to lease 10,000 acres and invested capital of its own to regenerate a forest. She elaborated that it may be 20 or more years before the trees were large enough to sequester the amount of carbon needed to meet protocols, but at that point the company could generate offsets through the new trees and make revenue. Under the scenario, while the bill gave options, it was likely the state would want some kind of annual fee for the land lease and potentially a percentage of the carbon revenues once there was revenue coming to the lessee for their work and invested capital. Under the example, the land and forest would revert to the state at the end of 55 years.

Ms. Miller reviewed a second hypothetical carbon lease example on slide 5. The scenario involved a kelp farm (potentially grown for food production) that overlaid a carbon offset project to help with kelp production economics or because they were interested generally. Under the scenario, the state may get an annual fee for the land lease and some percentage of the carbon revenue.

3:08:25 PM

Representative Galvin asked why the state would choose to lease acres to another company that could find its own turnkey organization to assume risks of a project. She thought it seemed the state was hiring another middle manager. She was trying to understand the reasons.

Ms. Miller responded that although the bill required the division to structure compensation to maximize return to the state, a lessee's primary motivation may or may not be profit off the carbon. She used the kelp farm scenario [on slide 5] as an example. Potentially there would be enough of a carbon purpose associated to offset some of the marginal economics. In that instance the state would be realizing some percentage of revenue related to the carbon purpose and the ability to advance another program the legislature had authorized that went to local economic development. The other example [on slide 5] involved substantial risk and upfront capital. She noted it may or may not be something the state was prepared to engage in. She stated that if a third party wanted to take it on, there was the potential to let them take the risk that the trees grow the way they were supposed to on schedule and that they were able to generate the credits, put upfront capital in, and still generate some revenue from allowing someone else to take on the activities.

Ms. Miller believed that in other instances, a lessee's primary interest may be trying out some newer carbon purpose things that were not quite as established. Under the scenario, the lessee would be looking to achieve an environmental benefit and the revenue was important too in order to justify and fund the work and the state would get its share of the revenue. She believed there were a number of permutations. She reminded committee members that the state forests were not eligible for lease and would be reserved for state projects.

Representative Galvin asked if Native organizations had done anything similar involving leasing of acres and a middle person. Alternatively, she wondered whether Native organizations had directly contacted companies looking to take on a project.

Ms. Miller responded that to her knowledge the landowner did not lease the land to a developer. She stated her

understanding that the landowner was able to work directly with a developer as a partner/contractor to develop projects.

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Ms. Miller advanced to slide 7 titled "Path 2: State Projects - Review." She detailed that the bill stood up the carbon offset program for the state to undertake its own projects that would be housed under OPMP. She explained it was an existing model within DNR that was proven at being able to manage things spanning different divisions and needs. The state would be the project proponent and owner and may work with a partner such as a project developer. There would be costs to start and manage a project over its term. The project would generate credits for carbon stored and the state would sell credits to buyers and generate revenue.

Ms. Miller continued to discuss path 2 pertaining to state projects on slide 8. She noted that the committee had seen similar information from Kurt Krapfl with the American Carbon Registry and potentially from Josh Strauss with Anew. The idea was to show how the steps worked within a project.

Ms. Miller advanced to slide 9 and discussed costs associated with state projects. There were fixed program costs regardless of the number of projects the state undertook. She highlighted that the costs shown on the slide were reflected in the fiscal notes. The slide also noted the initial capital to OPMP to establish the framework and retain expertise. Project dependent costs included feasibility analysis, implementation (including the initial forest inventory, computer modeling of the growth to set a baseline and accountability), papering a project in order to submit it to the registry, and ongoing project maintenance (inventories were required periodically as well as onsite and desktop verifications).

Ms. Miller continued to review project dependent costs on slide 10. There were a variety of ways for the state to approach projects including use of state staff and funds or contracting with a project developer. She elaborated that the state could hire a project developer on a fee for service basis or work with the Department of Revenue to hire separate marketing companies to assist with marketing.

The state could also look to an ala carte concept and contract directly on a fee-for-services basis with companies engaged in one particular aspect of the project development such as counting and measuring trees in the forest inventory or computer modeling for the growth.

Ms. Miller advanced to state project scenarios on slide 11. The scenarios featured potential pilot projects identified by Anew. She clarified that the slide did not indicate the projects would be undertaken or in the exact form described by Anew; however, they provided a way to show how the costs and returns played out over the life of a project. The scenarios included modest returns, and much would depend on timing and number of projects, the project sizes, the verified carbon stored by the projects, the price of credits, and the marketing success. Ultimately, the money from the credit sales would flow into the fund created under the bill. The department saw carbon as an additional layer of land and resource use that complimented the existing uses, which did not consume or sever a state resource, and was additive (e.g., in state forests with ongoing harvests).

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Ms. Miller continued to slide 12 titled "Path 2: State Projects – 1-project scenario." The slide used and expanded on Anew's crediting tables. The column on the left showed the project year, the second column showed the total credits generated in a project, the third column reduced the credits by 30 percent to account for any leakage, and the fourth column showed buffer credits at 18 percent on average (the insurance pool in the event of natural disasters required by the registry). The fifth and sixth columns showed conservation and removal credits, respectively. She believed Mr. Strauss with Anew had thoroughly described the difference between the two items. The seventh column showed gross project revenue and the eighth column reflected the project expense, which was specific to the project. The next columns showed the net project revenue and developer share, respectively. She noted the developer share was 20 percent, if any, because projects that were not turnkey operations would not be a flat 20 percent. She elaborated that a fee-for-services model would be covered in the project expenses. The second to last column on the right reflected fiscal note/DNR program costs, which were not part of the project but were

important to show when looking at potential revenue from a project. The final column was net state revenue that reflected everything pulled together.

Ms. Miller moved to a scenario on slide 13 where three projects were done concurrently. She relayed that the big difference was in the fixed DNR program costs, which had not changed from the one project slide [12] to the three project slide [13]. She highlighted a larger scope of potential revenue [shown in the net state revenue column on the right].

Ms. Miller continued to slide 14 titled "Path 2: Carbon Offset Revenue Fund." She explained that revenue from credit sales would flow to the fund. She referenced Section 6, page 6, lines 13 through 20 of the legislation where the fund details were laid out. She reviewed the slide:

HB 49 version \U:

- Fund is outside general fund (GF)
- Revenue automatically flows into fund – "shall" be deposited
- Legislative appropriation required for DNR fund use
- Used for purposes of Carbon Offset Program
- Unobligated amount over $10M returns to GF annually

Ms. Miller addressed potential uses [of the fund]. The fund would go towards paying project bills and required project maintenance (ongoing costs of recurring inventories and audits in order to keep generating additional credits from the project). She elaborated that there may be projects at some point with other activities involved (e.g., thinning) that would generate additional credits. The fund would also be used towards initiating additional carbon offset projects and feasibility, start-up, and implementation to continue generating additional revenue to the fund and general fund.

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Representative Josephson asked for verification that state forests were eligible and a prime target for the program.

Ms. Miller responded that "we've been able to affirm the potential of that" and trees had a tremendous ability to store carbon. She stated that trees would be the first place to start looking at the different projects.

Representative Tomaszewski stated his understanding that once the fund reached $10 million, anything above that would start rolling into the general fund. He looked at the one project scenario for state projects on slide 12 that showed $11 million in 2032. He asked for verification that there would be no revenue to the general fund for ten years.

Ms. Miller responded it was true assuming there was only one project. She clarified that DNR found it highly unlikely there would only be one project. The department thought there was tremendous potential and anticipated multiple projects.

Representative Tomaszewski observed the costs were $4.5 million during the same time period and $11 million in revenue.

3:23:09 PM

Co-Chair Edgmon thought that the numbers built into the ten-year forecast for the state were wildly above what the committee was hearing presently. He cited $300 million in the current year, $500 million for the next year, and $900 million coming up. He stated it was perhaps attainable down the road if every cylinder collected at full speed. However, the assessment he was hearing was much smaller and more modest. He stated it was still promising and worth exploring but did not reflect hundreds of millions of dollars. He asked for comment.

Ms. Miller responded that the department was discussing and presenting modest revenues with the affirmed potential. The department wanted to build on and explore what it believed to be greater potential. She stated it would depend on what kind of protocols the state was able to tap into under the parameters of the bill on what kind of land.

Co-Chair Edgmon asked if it was possible to have several hundred million in revenue in a handful of years.

Ms. Miller responded it was not possible in a handful of years due to the initial time constraints. She estimated there were around four years to do regulations, receive and evaluate projects, decide what projects to move forward with, and 18 to 24 months of project development.

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Representative Coulombe observed that the expenses in the fiscal notes and the $447,100 [shown in the DNR program cost columns on slides 12 and 13] were all coming out of UGF, but the revenues went into a different fund.

Ms. Miller responded that the positions would be funded by UGF until there was sufficient revenue coming in from carbon offset projects to supplant the UGF. She stated it would be immediately. She relayed that the column showing DNR program costs did not indicate a fund source. She explained that if there was revenue in the carbon offset fund, it would cover the cost and UGF would no longer be necessary.

Representative Coulombe remarked it did not appear there would be any revenue in the years indicated by Ms. Miller. She thought it looked like the state was paying and paying and then it would magically be flipped.

Ms. Miller confirmed that the state would rely on UGF in the initial years before credit revenue was flowing.

Co-Chair Foster thanked Ms. Miller for her presentation.

HB 49 was HEARD and HELD in committee for further consideration.

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^PRESENTATION: ALASKA LIQUEFIED NATURAL GAS PROJECT UPDATE

3:30:39 PM

FRANK RICHARDS, PRESIDENT, ALASKA GASLINE DEVELOPMENT CORPORATION, introduced himself and his colleague. He relayed he would provide an update on Alaska Gasline Development Corporation's (AGDC) commercial structure and on activities the corporation had undertaken to move the [Alaska Liquified Natural Gas (LNG)] project forward. He provided a PowerPoint presentation titled "Alaska LNG Project Update," dated May 3, 2023 (copy on file). He reviewed that AGDC was a state corporation created by the legislature in 2013 with a mission to maximizing the North Slope natural gas assets to be able to ring them through and develop infrastructure for Alaska's needs to help lower the cost for Alaskans and commercialize resources and provide them to international markets to bring in revenue to the state.

Mr. Richards moved to slide 3 and stated that the Alaska LNG project was not the project legislators had heard or read about over the last 20 years. He explained that some modifications had been made over the past several years, primarily around the commercial aspects of the project in terms of lowering the cost of supply. Additionally, the concept was to increase revenues to the state and would transition development back to the private sector for funding and construction.

Mr. Richards turned to slide 4 titled "Alaska LNG: Gas for Alaskans and Export." He relayed that LNG stood for liquified natural gas. The project would utilize resources in the Prudhoe Bay and Point Thomson Units for a total of 40 trillion cubic feet (Tcf) of proven, conventional produced gas available for export. The gas in Prudhoe Bay alone amounted to 8.5 billion feet, which was compressed and put back down. The project included the development of an Arctic carbon capture plant on the North Slope where carbon dioxide (CO2) would be removed, captured, and sequestered in a reservoir. He explained it would enable the project to take advantage of the [federal] 45Q tax credits that would equate to $600 million in additional annual revenue. The pipeline would run from Prudhoe Bay paralleling the Trans-Alaska Pipeline System (TAPS) towards Fairbanks and continuing along the Parks Highway and Alaska Railroad to Nikiski where an LNG plant would be built adjacent to the existing Agrium and Kenai LNG facilities.

The LNG would be produced at the plant in Nikiski and shipped overseas on tankers.

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Mr. Richards moved to slide 4 and highlighted that Senator Dan Sullivan had recently shared with the legislature that the Congressional delegation had been very supportive of the project. He shared that Senator Sullivan had traveled to Asia with AGDC to interface with countries and offtakers. He noted the senator's enthusiasm and support was very helpful.

Representative Josephson referenced Mr. Richards' statement about the $600 million more to the project with 45Q tax credits. He asked if the amount was net to the state.

Mr. Richards responded that the 45Q tax credits were extended in a bipartisan effort by Congress. He clarified that the owners of a carbon plant like the Arctic carbon capture plant would receive the tax credits. The first five years would equate to approximately $600 million in cash available to the operator and the remaining seven years of the project's life would be in tax credits available for the producer to sell. He elaborated that the credits would be $85 per ton and the plant would capture about 7 million tons per year.

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Representative Stapp asked if the plant would qualify for the direct capture credit of up to $180. He asked for verification that the amount was on top of the existing credits available for enhanced oil recovery.

Mr. Richards responded that there were two provisions in the 45Q tax credits. One was for carbon sequestration priced at $85 per ton. The other was for enhanced oil recovery at $55 per ton. He clarified that the credits were not cumulative.

Representative Tomaszewski asked if the 807 miles of pipe [shown on slide 4] was large diameter.

Mr. Richards responded that the pipe was 42 inches in diameter and would be buried for the vast majority of the line except for fault crossings.

Representative Tomaszewski observed that the proposed route was well outside the Fairbanks boundary. He asked what kind of tap was included for the Fairbanks area.

Mr. Richards responded that there was an offtake point for Fairbanks located off the Chatanika River. The alignment would run south to Livengood and cross the area around Minto Flats. He noted it was the first major offtake point on the line.

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Representative Hannan presumed that the monetary descriptions and benefits Mr. Richards described were critical through the numbers in the rest of the presentation. She recalled from one of the committee's meetings on carbon sequestration that there was 10 years in the tax code before Congress would have to renew the credit or it would go away. She wondered if AGDC used the same timeframe for the development of the project given that the Arctic carbon capture plant was critical to the economics. Alternatively, she wondered if the project would extend to 15 to 20 years. She noted she may have the tax code expiration date wrong.

Mr. Richards responded that AGDC and Goldman Sachs calculated the tax credit timeframe to be 12 years, which equated to approximately $7.2 billion available to the project. He pointed to a chart on slide 6 showing the cost of supply. He deferred to his colleague for additional detail in the 45Q tax credit provision.

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NICK SZYMONIAK, MANAGER, NEW BUSINESS VENTURES, ALASKA GASLINE DEVELOPMENT CORPORATION, responded that Alaska LNG was very competitive with strong economics. The challenge of moving the project forward was due to its size and complexity, not the economics. The state's cost of supply was $6.55 to deliver to Asia including the purchase of the gas on the North Slope, paying for profits to the investors of the AK LNG system, and transportation. He highlighted that the cost was well below LNG market prices in Asia and was cheaper than Cook Inlet gas. He stated that as any business owner, the state and investors would not be selling the LNG at the cost of supply, it would be sold at

market prices. He noted that prices may be linked to crude oil, Henry Hubb (Lower 48 gas price), or a combination of the two and fixed costs. The cost of supply included $1.45 for raw gas and fuel, of that $1.25 was the purchase price of the raw gas from producers. He relayed that the discussions were currently under negotiations. There was the possibility that if the gas could be sold above $6.55 that the extra revenue could be shared between the producers, the state, and investors.

Representative Hannan restated her previous question. She provided a scenario where the tax code expired in 12 years and the line was not yet operating. She asked AGDC was saying that it was immaterial to the economics of the project. She asked for verification that the project could move forward without the carbon capture element and the element was merely an ancillary benefit that made the project more profitable.

Mr. Richards responded in the affirmative. He shared that in talks with individuals in Washington D.C. around the bipartisan reestablishment of the provision, they had seen the benefit and had recreated it and increased the cost. He noted that hopefully the bipartisan support would continue when it needed to be renewed in the future. However, AGDC was not relying on it, but it was a solid benefit to the project.

Mr. Szymoniak added that there was a deadline for when construction needed to start, which he believed was eight to ten years out. The corporation expected construction to start within that period followed by the 12-year period. He stated they did not run a material risk of running out of time to benefit from the 45Q tax credits.

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Representative Cronk remarked that he had the same concern as Representative Tomaszewski. He highlighted that the coldest area in Alaska was the Interior and he hoped that it was not excluded from benefitting from a cheap source of heat. He asked if all of the land needed to build the line was secured.

Mr. Richards responded that 93 percent of the land had been leased to the project by the state or the federal government. There was 7 percent remaining and AGDC would be

in discussions with the municipalities and private landowners. He stated that the remaining lands would be leased prior to the final investment decision.

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Mr. Richards moved to slide 7 titled "Lower Cost Energy for Alaskans." The mission provided by the legislature was the ability to provide and realize North Slope assets to bring low cost energy to Alaskans. He detailed that the cost of supply on the international market was $6.55, which meant Alaskans would be able to receive the gas at a range between $4 and $5 per million btu because it would not require liquification or shipping. The price charts shown on slide 7 provided an indicator of what the price would be compared to historic Cook Inlet gas prices. The slide also showed a price comparison between natural gas, heating oil, and electricity. The outcome was a significant savings to households using natural gas or had electricity produced by natural gas.

Mr. Szymoniak continued to slide 8 titled "Alaska LNG: New State Revenue." He relayed that the analysis on net state revenue that would be generated by the AK LNG project had been produced by the Department of Revenue (DOR). He noted that AGDC had worked closely with DOR on the inputs. He detailed that the chart included property taxes at the full statutory 20 mills, but it only showed the state's share and excluded the municipal share. The chart also included the corporate income tax for the upstream and midstream. He highlighted a significant jump in corporate income tax revenue around year 10, which was associated with depreciation of the investment in AK LNG pipeline and plant. The chart also reflected production tax and royalties, which accrued from the sale of natural gas and increased production from Point Thomson that would be unlocked by a major gas sale to the AK LNG project.

Mr. Richards advanced to slide 9 titled "Positive Climate Impact." He relayed that the positive impact of the project would be the replacement of coal in Asia with natural gas. He pointed to a bar chart reflecting the lifecycle of greenhouse gas emissions from natural gas versus coal power. He emphasized that 77 million tons of carbon dioxide would not be emitted from coal power production by replacing it with natural gas from Alaska.

Mr. Richards moved to slide 10 titled "Major Permits and Authorizations." He relayed that the AK LNG project had gone through the regulatory process led by the Federal Energy Regulatory Commission (FERC). He elaborated that AGDC had obtained the federal permits and the two major state permits pertaining to air quality. The corporation had the rights-of-way and it would continue to keep the projects current and ready to go to construction.

3:46:02 PM

Representative Cronk asked for details about the Alaska Rural Energy Fund.

Mr. Richards responded that that the Alaska Rural Energy Fund was created in either HB 9 or SB 138 where legislators saw there were communities that would not be benefiting from energy off the project. The legislation created an affordable energy fund that would allow revenues to come into the state that the legislature could appropriate to communities without direct access to the project. He relayed that 20 percent of the royalty payments would be paid into the fund that could be appropriated by the legislature.

Representative Josephson wanted to ensure that another bill sponsored by Senator James Kaufman would not eliminate the fund.

Co-Chair Foster suggested that Mr. Richards may want to check with Senator Kaufman to make sure his legislation would not eliminate something AGDC may need in the future.

Mr. Richards noted that Senator Hoffman had been "pretty gleeful" about the recognition that the fund was there. He would follow up with the senator's staff.

Co-Chair Edgmon did not know whether Representative Josephson was referring to a bill that the committee had heard on rural electrification. He noted it was completely different [than the topic at hand].

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Mr. Szymoniak relayed that the next several slides would describe how AGDC was going about getting AK LNG built and developed with private investors. He stated that over the

years there had been substantial effort and capital spent on AK LNG by the state and producers. He elaborated that the effort had gone to a fully permitted project with significant engineering, design, and field work behind it. He explained that the permitting and work to date was very valuable. There were many investors looking to invest in LNG projects. The asset was fully owned by AGDC and the corporation had hired Goldman Sachs to raise investment capital for AK LNG. He reported it would take an additional ~$150 million to get the project to a final investment decision (FID) when construction would start and the full $44 billion was committed. Much of the additional funding would be for front end engineering and design (FEED) and the overhead and legal and commercial work to get all of the LNG sales contracts, financing agreements, and other agreements to advance the project.

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Co-Chair Johnson noted there were currently differences between the funding included in the House and Senate operating budgets. She explained that one of the reasons for the difference was the inclusion of a federal appropriation of $4 million secured by [U.S.] Senator Lisa Murkowski. She stated that some of the difference was the House's inclusion of some operating funds for AGDC. She believed that the Senate had possibly included some capital funding outside of the $4 million. She asked for details on the funding AGDC needed.

Mr. Richards responded that the FY 24 operating request in the governor's budget was approximately $3.1 million for personal services, travel, services, and commodities to keep the AGDC operating team moving forward. The funding provided for a small number of employees, computer services, rent, heat, electricity, and small commodities. The $4 million that came in from Senator Murkowski had not been included in the capital budget request because it had been working its way through Congress at the time. Congress had passed the bill and the president had signed it; the bill included $4 million in federal funds specifically for AGDC to use in FEED. He elaborated that the FEED effort was approximately $150 million. The corporation was looking to the private sector to fund the amount in addition to the amount provided by Congress. He noted that unbeknownst to AGDC the federal funding had a match requirement, which was the reason for a $2.5 million request for state funds. The

funds would go towards moving the project through commercial and legal aspects and FEED to bring the project ultimately to FID. He summarized that AGDC's operating budget request was included in the House's budget. The second funding request was around receipt authority and match requirements.

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Representative Hannan asked whether AGDC was requesting that the two additional requests be in the FY 24 or FY 25 budget. She asked if the general fund match was to match a federal capital receipt.

Mr. Richards clarified that it was a FY 24 request and the federal fund receipt authority of $4 million was the Senator Murkowski appropriation for FEED. In order to utilize the federal funding, there was a state match requirement of $2.5 million UGF.

Representative Hannan asked if it was the first time the committee had been notified of the request for inclusion in the FY 24 operating budget.

Co-Chair Johnson responded that the request was not brand new. She explained it was the reason AGDC had been invited to present to the committee. She had learned of the request recently; it had not been part of the original operating budget because the federal funding came in mid-session. The idea was to hear from AGDC to get an update and to be appreciative of the funding and learn what the legislature needed to do in terms of matching funds.

Mr. Richards added that Senator Murkowski's request was in the U.S. operating budget ahead of time; however, AGDC had not known what the [U.S.] Department of Energy's (DOE) match requirement would be, if any. He stated it had taken AGDC almost three months to work through the DOE hierarchy to get to a program manager and understand there was a match requirement. He explained it was the reason for the late news provided to the governor and Office of Management and Budget. He apologized for the timing of the request and explained it had been extremely difficult to get a response from DOE.

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Representative Josephson stated his understanding that the $3.1 million in the House version of the operating budget was not included in the Senate's version. He asked how AGDC would move forward without the money if the Senate prevailed on the issue.

Mr. Richards responded that AGDC would not move forward. He explained that it would not have the legislative authority or the funding to be able to continue operations. He stated that if the budget did not include the funding, he supposed AGDC would move out of its offices, layoff its people, and put its project in boxes.

Co-Chair Edgmon stated his understanding that Goldman Sachs was under agreement to raise investment capital to get the project to FID, which eventually would lead to the $44 billion construction portion of the project. He asked if the funding to pay Goldman Sachs was under the service line item totaling $1,197,000 [shown on slide 20].

Mr. Richards responded that Goldman Sachs was working with AGDC on a contingency basis and would not get paid until funds were raised from private sector entities. He clarified that Goldman Sachs would be paid by the private sector entities, not AGDC.

3:57:04 PM

Representative Galvin looked at the $1.8 million for personal services [on slide 20] and considered the additional $4 million in federal receipts. She asked how many employees currently worked at AGDC.

Mr. Richards responded there were currently four filled positions, but there were eight or nine PCNs available.

Representative Galvin asked for verification that the services request was for other contracting work, not for Goldman Sachs. She asked what the request represented. She noted it was not a typical budget for the committee to look at and she was striving for more clarity on the request.

Mr. Richards responded that the services line represented paying rent, utilities, IT services, and some small contracts for personal services. The majority of the work

AGDC had done over the years to advance the project on the commercial side had been part of the corporation's capital expenditures. He explained that when the legislature capitalized the AK LNG fund, AGDC had been utilizing those funds with the authorization of its board of directors to advance the project. He stated it was where most of AGDC's contractual expenses resided.

Co-Chair Foster asked if Mr. Richards was only in town for the rest of the day.

Mr. Richards agreed.

Co-Chair Foster stated there was time for one additional question. He offered to bring AGDC back before the committee at a later date to answer any additional questions.

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Representative Stapp referenced AGDC's testimony that the project had the best economics of any project in North America. He asked if ADGC had high confidence that Goldman Sachs would be able to raise the required $150 million in private equity needed for FID.

Mr. Richards responded in the affirmative. He relayed that Goldman Sachs was not doing the work for free; the financial entity saw the value in the project. He explained that Goldman Sachs was bringing high value equity developers and international companies to the table to advance the project.

Co-Chair Foster asked if Mr. Richards had any closing comments.

Mr. Richards thanked the committee for its time. He stated that AGDC was advancing the project and there was keen interest. Part of the keen interest was working with investors who were doing their due diligence on the project and on the state. The corporation was engaged with investors on a daily basis and its goal was to present hopefully positive results in the near-term.

Co-Chair Foster thanked the presenters. He noted there may be an additional meeting scheduled to answer any additional questions the committee may have.

Co-Chair Foster acknowledged Representative Justin Ruffridge in the room.

Co-Chair Foster reviewed the agenda for the following day's meeting.

#
ADJOURNMENT

4:03:03 PM

The meeting was adjourned at 4:02 p.m.