SENATE OIL AND GAS TAX CREDIT WORKING GROUP

SUMMARY REPORT

December 1st, 2015

Background

The subject of oil and gas tax credits (tax credits) was a topic of discussion throughout the 2015 regular session, extended session, and the first and second special sessions. With the State of Alaska (the state) facing a budget shortfall in excess of $3.5 billion, all operating expenses were and continue to be scrutinized.

In recent years, the state's oil and gas basins saw a sizeable increase in investment and activity, both halting an energy shortage that threatened Alaska's largest population centers and revitalizing the North Slope and Cook Inlet with new, independent oil and gas companies. With that significant uptick in activity and private investment however, the amount of public funds allocated to reimbursable tax credits increased commensurately.

On June 17, 2015, the Senate and House Resources Committees convened a joint hearing at the Kenai Chamber of Commerce and Visitors' Center. Members of the House and Senate Finance Committees, as well as the Senate Judiciary Committee Chair, also participated.

The purpose of the hearing was threefold: (1) to understand the fundamental structure of Alaska's oil and gas tax credit system, (2) to hear from participating companies and projects dependent upon that system, and (3) to set the groundwork for a process that would assess the tax credit system in more detail over the summer and fall of 2015.

At the conclusion of that hearing, several members, including the Senate Resources Committee Chair (Chair) Cathy Giessel and the Senate Finance Committee Co-Chair (Co-Chair) Anna MacKinnon, agreed that a methodical process to assess the tax credit system, and any potential changes to that system, would be discussed in a methodical process and implemented over the remainder of the 2015 interim.

On June 29, 2015, Governor Bill Walker deferred payment of approximately $200 million in reimbursable oil and gas tax credits. This deferment was in the form of a gubernatorial veto to a portion of the oil and gas tax credit fund, reducing the allocation from $700 million to $500 million. In the veto message to the Senate President, the Governor stated that the current oil and gas tax credit system was unsustainable. The payment deferral was meant to begin a conversation on the topic.

There were several immediate reactions to the payment deferral. Independent oil and gas companies producing less than 50,000 barrels of oil a day, the only companies legally allowed to received reimbursable credits, came forward and spoke of the adverse effects the deferment had on their firm's finances. Several companies were in the process of obtaining further financing for their projects; the deferment resulted in those financing agreements either being suspended, the loan amount being significantly reduced, or the interest rate being raised. In short, the payment deferral precipitated a liquidity crunch in the state's energy sector for independent companies.

The Commissioner of the Department of Revenue (Commissioner), Randall Hoffbeck, worked assiduously over the course of the summer to reassure the financial institutions and energy companies that the state would continue to honor its obligations. Commissioner Hoffbeck reiterated both publically and to the various stakeholder groups that a payment deferral was not the state rescinding its commitment to reimburse qualified applicants for credits. The initial credit crunch relaxed.

Purpose and Creation of Senate Tax Credit Working Group

The payment deferral, and the reactions from spheres such as the commercial finance sector, prompted Resources Chair Giessel and Finance Co-Chair MacKinnon to expand the scope of the process outlined in the June 17 meeting. A working group, comprised overwhelmingly from the membership of both the Senate Resources and Finance committees was an ideal vehicle to evaluate and assess the subject in greater detail.

Members from the Senate were Senator Cathy Giessel; Senator Anna MacKinnon; Senator Bill Stoltze; Senator Lyman Hoffman; Senator Click Bishop; Senator Peter Micciche; and Senator Bill Wielechowski.

In addition, several private sector stakeholder groups were identified for their relevance on the subject: the trade associations for both the oil and gas companies as well as the support industry, organized labor, and Alaska Native Corporations. Once identified, an invitation was made to some of the representatives of those groups to be part of the working group.

Members from the stakeholder groups were Kara Moriarty, Chief Executive Officer of the Alaska Oil and Gas Association; Rebecca Logan, General Manager of the Alaska Support Industry Alliance; Barbara Huff-Tuckness, President of the General Teamsters Local 959; and Butch Lincoln, Vice President and Chief Operating Officer of the Arctic Slope Regional Corporation.

Members of the Administration participated at almost every meeting, and contributed significantly to the discussion and proceedings. Those members included Commissioner Randall Hoffbeck of the Department of Revenue; Ken Alper, the Director of the Tax Division at the Department of Revenue; Corri Feige, Director of the Oil and Gas Division at the Department of Natural Resources; and Dr. Paul Decker, the Resource Evaluation Manager of the Division of Oil and Gas at the Department of Natural Resources. The group thanks these individuals and their support staff.

The purpose of the working group was: (1) understand the structure and purpose of the state's oil and gas tax credit system, (2) understand the similarities and differences between the state's various oil and gas basins, (3) understand the relationship between the commercial finance sector and the state's oil and gas energy sector (4) produce a report, detailing the findings of the group's meetings, and offering recommendations to both the Administration and the Legislature.

Group Meetings

The group met at the Anchorage Legislative Information Office for all of its meetings. Members attended either in person or telephonically. Meetings were scheduled to analyze individual topics related to oil and gas tax credits:

- September 8: An overview of the Cook Inlet basin from the Administration. The Department of Revenue's Tax Division, and the Department of Natural Resources Oil and Gas Division presented.

- September 22: Presentations from several companies operating in the Cook Inlet. Hilcorp, Apache Corporation, and Blue Crest Energy presented.

- October 1: An overview of the supply surety of Southcentral natural gas from local utilities. Enstar Natural Gas, Chugach Electric Association, Matanuska Electric Association, Municipal Light & Power, and Homer Electric Association presented.

- October 6: An overview of the role commercial lending institutions play in the state's oil and gas sector.

- October 13: An overview of the North Slope basin from the Administration and presentations from several companies operating in the North Slope. The Department of Revenue's Tax Division and the Department of Natural Resources' Oil and Gas Division presented along with Caelus Energy, Great Bear Petroleum, and Brooks Range Petroleum.

- November 20: An overview of the Frontier basins, also known as "Middle Earth" from the Administration and presentations from several companies operating in the Frontier basins. The Department of Revenue's Tax Division and the Department of Natural Resources' Oil and Gas Division presented along with Doyon Limited, The Ahtna Corporation and NANA Regional Corporation.

The presentations, as well as the audio for all meetings can be found at the following web page: https://www.alaskasenate.org/2016/oil-gas-credits/

Purpose of Summary Report

This report contains both the summary of the findings from the group's meetings, as well as recommendations made to the Administration and the Legislature. Several considerations went into the crafting of this report:

- Several statutes related to oil and gas tax credits are set to expire on July 1, 2016.
- The state's fiscal situation is an important element in determining the sustainability of the current tax credit system.
- The global price of oil has an important impact, not just on the state treasury, but the financial capabilities for energy companies of all sizes to invest in oil provinces such as Alaska.
- The state has recently become a 25% owner in the Alaska Liquefied Natural Gas Project (AK LNG), subjecting it to potentially $12-18 billion in cash calls between the present and 2024.

The content of the report is derived from presentation materials from the meetings of the group, as well as some supplemental research. The group extends its sincere thanks to the subject matter experts from the Administration's Departments, as well as the stakeholder groups, for the excellent material that is available for legislators, staff and the public.

FINDINGS

The State of Alaska is an Investor in the Oil and Gas Sector

The development and monetization of Alaskan oil and natural gas is driven to produce several benefits to the state. Firstly, like all other natural resources, oil and gas is directed to be managed by the legislature according to Article 8, Section 2 of the State of Alaska Constitution:

> *"The legislature shall provide for the utilization, development, and conservation of all natural resources belonging to the State, including land and waters, for the maximum benefit of its people."*

The 'maximum benefit' mandate encompasses several types of outcomes that, collectively, constitute the successful management of the state's resources. Oil revenue to state and local governments in the form of production, corporate income and property taxes contribute significantly to funding public services.

Royalties from oil and other natural resources not only augment the public treasury, but also fund the Alaska Permanent Fund, which in turn invests those proceeds, generating returns that produce returns to Alaska, including the annual dividend to all Alaskans.

For the communities of the North Slope Borough and Southcentral Alaska, natural gas serves as a baseload energy source. North Slope natural gas monetization will bring gas to even more Alaskans, and play a larger role in public finances to the State and local governments, as the Alaska Liquefied Natural Gas Project (AK LNG) progresses.

Another benefit is the gainful employment in a traditionally high paying industry and the multiplier effect those jobs have on local economies;

These benefits are in turn contingent on certain behaviors: continued and enhanced investment in exploration, development and production of oil and natural gas. The evolution of the state's main oil and gas basins (the North Slope and Cook Inlet) compelled several policy changes over the past two decades.

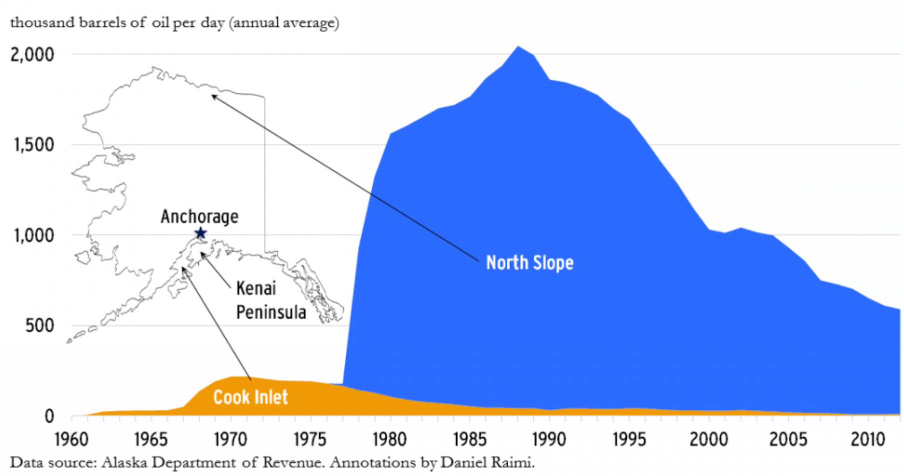
The Cook Inlet basin production of oil peaked in 1970 with a rate of approximately 225,000 barrels per day (bbl/day); for the North Slope, the peak came in 1989 at a rate of 2,000,000 bbl/day. The Cook Inlet's production of natural gas crested in 1996, producing an average of 0.6 billion cubic feet per day (Bcf/d).

When the Cook Inlet and North Slope basins were first being developed in the 1950's and 1970's respectively, they were "green-field" projects. A green-field project is when investment, construction and development for the first time is occurring in a particular area.

This transformation from undeveloped land to one possessing new facilities, roads, pipeline systems, rigs and manpower is extraordinarily capital intensive. Those capital outlays are then recaptured over what is hoped to be many years of successful production and favorable commodity prices.

By the 1990's both basins had transitioned into being brown-field basins. A brown-field basin is when investment is put into an existing area that has infrastructure and facilities, but requires modifications to accommodate the changing dynamics of the resource, as well as the age of the existing infrastructure.

Quite simply, the oil deposits in both areas had changed and diminished. Despite the presence of large remaining reserves, the location and recovery of that oil required a different level and type of investment than had occurred previously. Newer, more modern types of exploration and drilling techniques were in search of more isolated and comparatively shallower plays of oil on the North Slope.



Source: Alaska Department of Revenue, Courtesy of Duke University's Energy Initiative

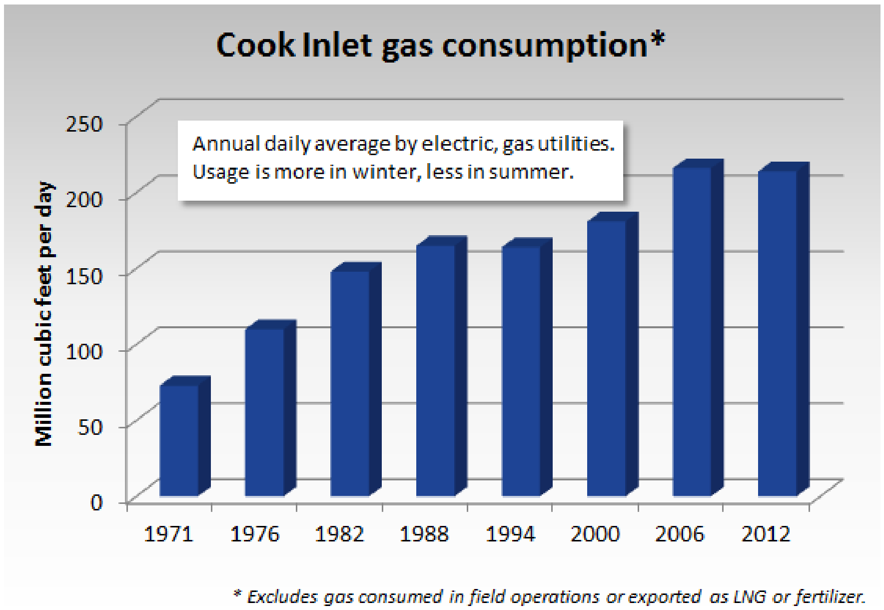
This dynamic created a partial divergence from the interest of the state, which has a strong desire to maximize production and throughput into the Trans-Alaska Pipeline System (TAPS), and that of the three legacy North Slope producers, which sought to maximize recovery on existing projects.

Only a large potential play would justify the capital expenditure from one of the North Slope legacy producers to continue the costly exploration and development process on new prospects.

The continued absence of those investments in new projects would continue the production decline and the eventual obsolescence of the TAPS infrastructure.

Concurrently, Cook Inlet oil and natural gas production continued to decline. While the Cook Inlet oil was not the contributor it once was to the public's finances, the natural gas continued to be valuable, especially with the growth in population in the Matanuska-Susitna Borough and Municipality of Anchorage.

While more residents took up in Southcentral Alaska, the underpinning supply of energy was diminishing.



Source: Alaska Department of Natural Resources, Division of Oil and Gas, U.S. Energy Information Administration, Office of the Alaska Natural Gas Transportation Projects Federal Coordinator

In 2006, the legislature passed a new tax on oil and gas, moving from a gross minimum tax to a net profits model. The new system, called the Petroleum Production Tax (or PPT), also contained several types of credits that could be applied against a tax liability. PPT also created a means by which the credits from smaller producers, those producing less than 50,000 bbb/day, could be repurchased by the State.

The introduction of these credits, the carry-forward annual loss credit (NOL), the qualified capital expenditure credit (QCE), as well as the small producer and new areas credit, were all designed to encourage investment and eventually enhanced production.

The path begun under PPT was continued and enhanced in 2007, when a new tax called Alaska's Clear and Equitable Share (ACES) was passed into law. ACES expanded the NOL from 20% to 25% while removing the annual cap on reimbursements to companies in PPT. The intent of ACES was to use a progressive tax system, tethered to price, while also offering broad incentives to increase capital expenditures in the basins.

While the brunt of the deliberations surrounding PPT and ACES focused on the North Slope, the Cook Inlet basin was also a serious concern because of its role as an energy supplier of gas for local use by over half of the state's population. The PPT bill was modified and capped the Cook Inlet oil from being taxed at the newly passed rate.

When ACES was passed, that cap remained in effect. The effective tax rate for Cook Inlet oil is zero, and currently scheduled to sunset in 2022.

However, the tax systems, and their accompanying credits, did not directly address the underlying concern of decreased production in natural gas for Cook Inlet. A fertilizer plant on the Kenai Peninsula owned by Agrium closed in 2007. The plant, along with the ConocoPhillips LNG export facility in Nikiski, had acted as anchor tenants for natural gas sales.

The two operations also served as de facto storage facilities for local use in the winter time, when demand peaked. The loss of the plant meant a loss of a year round market for Cook Inlet producers that would off-set the wide summer-winter supply swings.

By 2009, insecure energy supply concerns had manifested itself in a series of public service campaigns: the mayors of the Matanuska-Susitna Borough, the Municipality of Anchorage, and the Kenai Peninsula Borough were asking residents to participate in "brown out" drills. Utilities were looking to put gas under contract, and were having difficulty with supplies of more than two years in duration.

In 2010, the legislature passed the Cook Inlet Recovery Act unanimously. The bill focused on increasing gas production through a series of incentives: providing credits for capital costs incurred in the development of storage facilities, reducing the regulatory hurdles, and ramping up the timeline for leasing state lands.

The Cook Inlet Recovery Act led to the construction and operation of the Cook Inlet Natural Gas Storage Alaska (CINGSA) facility, allowing gas produced in the summer months of low demand to be warehoused until called upon in the winter. CINGSA was permitted in January, 2011, and by November, 2012, the first stored gas had been withdrawn.

The 2013 legislative session saw the passage of Senate Bill 21, or the More Alaska Production Act (MAPA), which overhauled the existing ACES system of tax levies and credits on oil, as well as de-couple oil from gas for taxation purposes.

The base tax rate increased from 25% to 35%, while the progressivity element that was tied to price was eliminated. The 20% capital spending credit was extinguished, while barrels of oil received a credit on a sliding scale from $0-8 based on the commodity price. An additional credit for designated new oil was created, called the gross value reduction (GVR).

For oil produced in legacy plays by the legacy producers, a tax floor of 4% was installed, which meant that credits could not be applied to bring a tax liability below that floor.

Each one of the major legislative endeavors into oil and gas taxes in the past decade, (PPT, ACES, MAPA) were designed with the following intended outcomes: increased upfront investment that was offset by credits, followed by an increase in activity and production of oil that could be captured by the state through a higher tax levy.

Though each one of these regimes was the subject of intense deliberation and disparate views on its mechanics, the overarching role of the state in the oil and gas sector was cemented.

Either through allowing for credits against a tax liability, or by purchasing a credit from a smaller producer, the state had become an investor in the oil and gas sector.

Between 2006 and 2014, a cumulative $7.4 billion in credits were issued by the state to legacy producers and independent operators alike. $4.4 billion of those credits were credits against a producers' liability, while $3.0 billion were refundable, or costs rebated by the state.

For companies that did not have a tax liability, but were assessing an exploration and development project in Alaska, there were several hurdles to overcome in order to bring operations into the state's basins:

- Climate. Despite the stereotypes, Alaska is a legitimately harsh place to explore and develop oil and gas projects. The weather is variable, and the isolation of many sites pose health and safety risks that is unusual for other plays in the contiguous United States.

- Legacy field operators. For mid-sized and smaller independents, the North Slope and Cook Inlet had a perception of being the domain of the larger, integrated energy companies. That perception led to an assumption that the major basins were walled off from new entrants.

- Costs. Costs are exponentially higher in Alaska than other oil and gas provinces in North America. For the budgets of an exploration and development project looking for unproven deposits of oil and gas, the costs of Alaskan projects were prohibitive. This was especially true when alternative projects in the contiguous United States cost a fraction of what it was in Alaska.

- Sovereign and regulatory hurdles. Alaska has some of the most stringent environmental regulations in the world. Though this is good for the stewardship of the land and its people, it does present another barrier to entry for new entrants. Combined with a tax system that has changed four times in ten years, the relationship of the sovereign and regulator to operators is perceived as unpredictable.

Taking all these factors into consideration, the state crafted and refined a rebate system to address some of those concerns. As its name implies, a rebate is predicated on initial qualified spending. The spender in turn recoups a portion of those costs as an incentive for spending in that particular manner in that particular location.

Since explorers and developers had no tax liability, there was no incentive for them to embark on those costly projects in the state. By instituting a rebate system, the state was investing in exploration and development projects with the goal of having those projects reach production. Once in production, and after the operator accrued a tax liability, the state would begin to see a return on its investment.

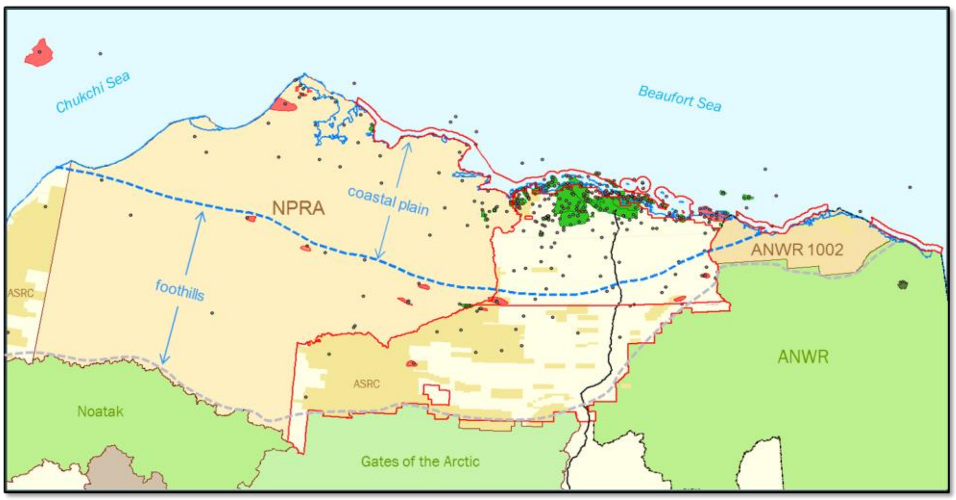
With the transition of the role the state had played, from merely levying a tax and collecting a royalty to now encouraging activities through foregoing a portion of revenue or directly rebating costs, the metrics for measuring success are changing and need to be continually evaluated.

In other words, what is the return on investment (ROI) for these costs, opportunity or monetary, and how is it being achieved? What elements should be incorporated into an effective analysis as to whether or not the state's investment is being realized?

Different Basins, Similar Goals, Various Incentive Structures

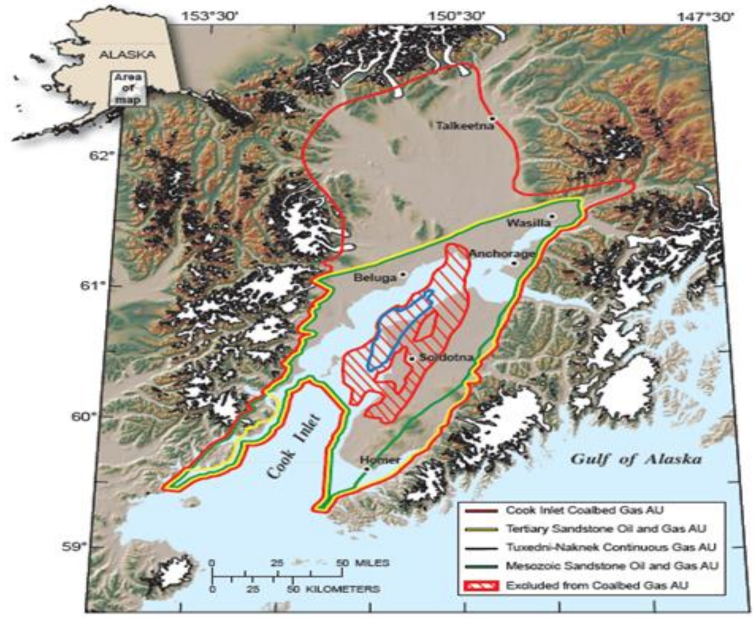
As was noted in the previous finding, the state has two main historical oil basins: the North Slope and Cook Inlet. However, incentives for the basins have some differences:

- For the state, the North Slope, is the main source of revenue, and therefore more production equates to a more vibrant private and public economy. The incentive structure is to maximize the throughput of oil in TAPS and consequently more production taxes, royalties, property taxes and corporate income taxes.



Alaska's North Slope Basin
Source: Alaska Department of Natural Resources, Division of Oil and Gas

- Cook Inlet by contrast, is the energy breadbasket to the state's main population centers through the stores of natural gas. Though valuable to the consumers, natural gas does not command the margins for companies that oil does, even at current prices. Therefore, the state needed to incentivize oil production which would concurrently drive up natural gas delivery.



Alaska's Cook Inlet Basin
Source: Alaska Department of Natural Resources, Division of Oil and Gas

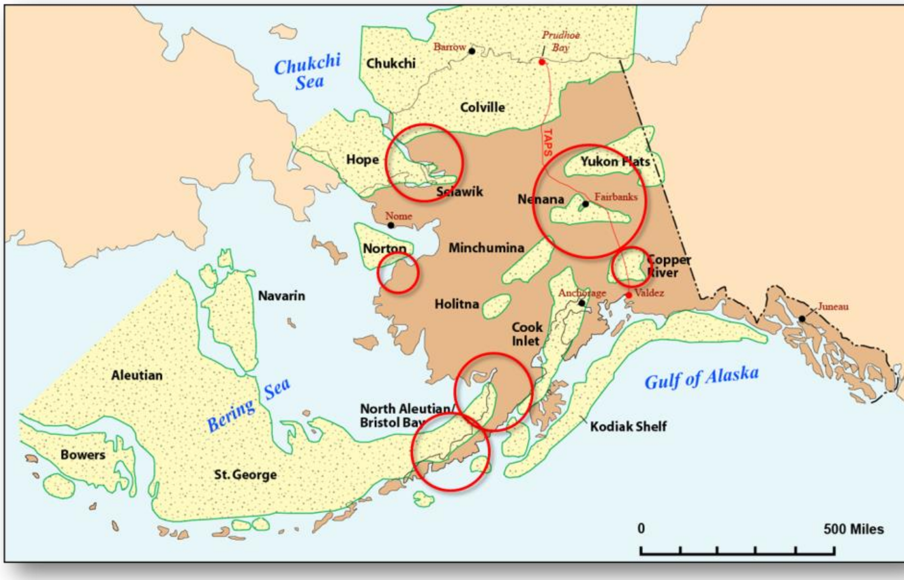
Another featured difference between the basins are the markets. The North Slope has an existing pipeline system that transports its product to world markets. The Cook Inlet is in an isolated market for oil and gas, where the current economies of scale do not justify a ramp up of production beyond a certain point.

The danger of not reaching a certain level of production in the Cook Inlet, as mentioned earlier, is that it would lead to a shortfall in the baseload energy supply for Southcentral communities.

The working group also heard presentations on the subject of the Frontier Basins, also known colloquially as "Middle Earth." Though the terms are used interchangeably, there are a couple of differences:

- Frontier Basins are a specific term for six regions that were listed in Senate Bill 23, which was passed into law in 2012.

- Middle Earth is essentially anywhere in Alaska that is not the North Slope (north of 68 degrees latitude) and the Cook Inlet basin.



Alaska's Frontier Basins (Circled)
Source: Alaska Department of Natural Resources, Division of Oil and Gas

The Frontier Basins, and any investments in Middle Earth specifically, have a narrower geographic focus for its market:

- The Tolsona Project currently being undertaken by Ahtna, Incorporated, is geared for local distribution and consumption in the Copper River Basin and surrounding areas.

- NANA Regional Corporation's efforts in the Kotzebue Basin are likewise to reduce the cost of energy for local communities, which is extraordinarily high.

- Doyon Limited's Nenana Basin project is an attempt to find oil that will feed into TAPS, which is a short distance away. The discovery and production of natural gas could also fuel the local demand in the Interior (Fairbanks North Star Borough and surrounding areas) as well as potentially feed into the proposed Alaska LNG pipeline system, should it come online around 2025.

Despite having a separate set of credits crafted for their unique regions, the majority of Frontier Basin explorers are utilizing the same credits that can be used by Cook Inlet and smaller producers on the North Slope.

The group heard that, though the amounts of cost reimbursements for Frontier Basin credits were higher, the timeframe of being rebated was much quicker under the Cook Inlet credit system. For exploration companies, capital in hand, even a lesser amount, is preferable to a delayed payment of a larger amount.

This was a common theme among all explorers and developers, in all basins, that presented: cash was critical to operations when production had not begun. Until oil or gas production can be brought online, the ability to maintain project capitalization is the critical priority for the venture.

Another distinct difference among the Frontier Basin projects are the companies themselves: almost all are Alaska Native Corporations formed as a result of the Alaska Native Claims Settlement Act of 1971. These corporations were trusted with land as property owners to both maximize the economic health of their respective communities, but to also use returns earned from investments to preserve and strengthen their Native cultures.

Collectively, the three main areas of oil and gas in the state, the North Slope, the Cook Inlet, and the Frontier Basins, are in various field life stages:

- At a general glance, both Cook Inlet and the North Slope are brown-field developments, requiring investment in retrofitting and upgrading existing infrastructure.

- The Frontier Basins by contrast are green-field projects, and most are in the process of exploring for economically provable sources that warrant ramping up infrastructure and further cash expenditures.

A closer analysis shows a more nuanced picture. For example, though the North Slope is often painted with a broad, uniform brush, there are various fields within the basin that have vast undeveloped reserves that do not have infrastructure built out to them yet. It is in these areas that many of the independent exploration and development firms have acquired leases and are running seismic studies, or building pads and stationing centers.

Estimates of technically recoverable oil and gas in both the North Slope and Cook Inlet are high. The following analysis was conducted both in 2009 by the United States Geologic Survey and in 2013 by the State Department of Natural Resources:

- The Cook Inlet is projected to have 599 million barrels of oil (MMBO) that is technically recoverable.

- The Onshore Arctic is projected to have 15.9 Billion barrels of oil (Bbo) that is technically recoverable. This includes oil that can be harvested on federal lands currently not under production.

Though these estimates are high, they are estimates. What is more disconcerting about the Cook Inlet estimates is that most of these are not reserves that are "behind pipe" or readily available for production and distribution. Despite a history that goes back before statehood, there is a deficit of infrastructure in much of the Cook Inlet, requiring enormous up-front cash commitments for companies.

Region	Mean Oil Estimate (Million Barrels)	Mean Gas Estimate (Billion Cubic Feet)
Onshore Arctic	15,908	98,960
Offshore Arctic	23,750	108,180
Interior Basins (only partially assessed) — Includes Yukon Flats and Kandik basins (Nenana, Kotzebue, Copper River, Holitna, & Susitna basins not assessed)	234	5,641
Upper Cook Inlet	599	19,037
Other Southern Alaska — Mainly federal OCS waters, minor AK Peninsula onshore	2,859	23,458
TOTAL	**43 BBO**	**255 TCF**

6

Statewide Resource Assessments of Undiscovered, Technically Recoverable Deposits
Source: Alaska Department of Natural Resources, Division of Oil and Gas

The Cook Inlet basin therefore can be seen as generally a mature area that has large and undeveloped tracts that constitute new development projects. The same can be said of the North Slope basin, albeit, on a much larger scale.

One common denominator between the three areas are the costs. The cost of transporting, drilling, developing and producing are exponentially higher in Alaska than comparable project in the contiguous United States.

At the June 17 joint hearing in Kenai, Blue Crest Energy presented an analysis Citi conducted for the company, comparing costs between the Cook Inlet and similar projects in the continental U.S. Among the cost differences were:

- An offshore well in Cook Inlet at a depth of 7400 vertical feet cost $45 million, while an 8000 vertical feet offshore well in the Gulf Coast cost $8 million.

- An onshore 5000 feet horizontal development well in the Cook Inlet would cost $30 million per well, while a comparable well at 9000 feet in the Permian basin ran between $8-9 million per well.

In addition to the costs, the timing of those costs are of particular consideration:

- Exploration and development projects are capital intensive but are not generating revenues from production. The timing therefore is critical to reach production and start recapturing the investment before a cost overhang is too large to justify continuing.

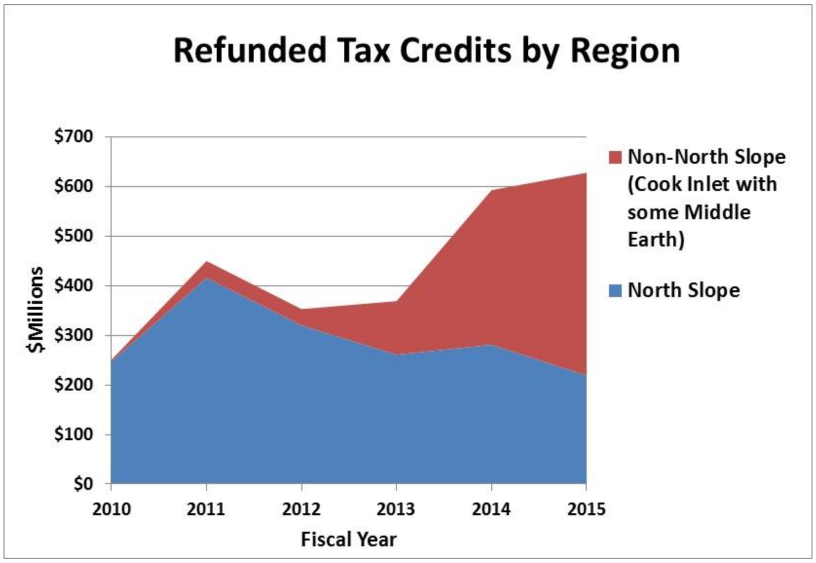
- Production projects are hopefully generating revenues but also are subject to operations and maintenance costs. In addition, in order to enhance the life of a project in production, more capital needs to be spent on exploration, development, and running more efficiently.

Incentives to different companies operating in different basins therefore would have profoundly different effects. For explorers, for example, a change in the production tax rate for oil or gas is of consequence, but not nearly as much as a modification for credits that can keep capital injected into the project when money is dear.

Conversely, a company just entering into production, or that has been in production for a longer period of time, is immediately and very much affected by a change in the production tax rate.

In conclusion, the ability to realize a return on capital already invested is a priority for a producer, while an explorer and developer will generally prioritize an incentive that rebates costs in an expeditious manner.

The Increase in Credit Rebates Correlated With Increased Investment, Activity, New Entrants, Data



Source: Department of Revenue, Tax Division

There are two fundamental components to the State's tax credit system:

- A deduction against a taxpayer's liability.

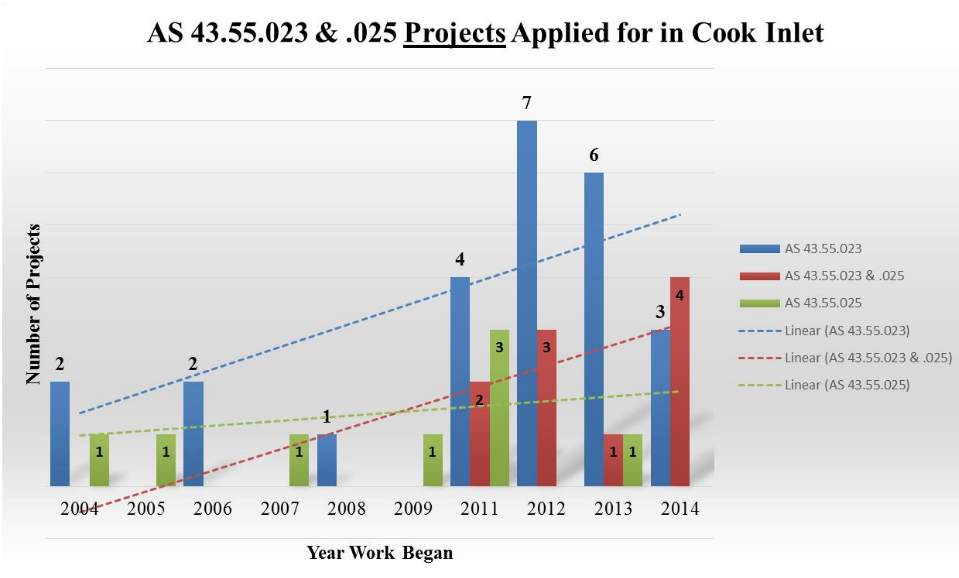
- A rebate for costs incurred from qualified expenditures.

As stated earlier, the purpose of authorizing a rebate structure was to incentivize companies who did not have a tax liability to continue to invest and develop the project(s) it was pursuing. While a company producing more than 50,000 bbl/day in the state can make several deductions against its liability, it cannot receive a rebate once it crosses that production threshold.

The rebate system therefore served two purposes:

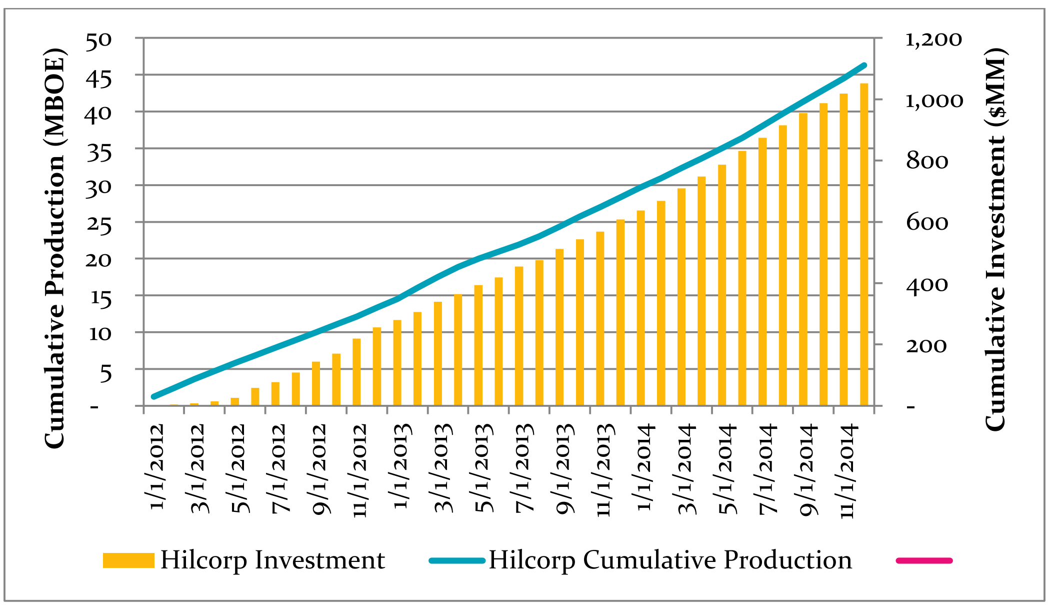
- Levelling the field of play between smaller, independent companies and the larger, integrated energy firms already established in the state, primarily on the North Slope.

- To encourage investment in areas the state had determined production was needed.



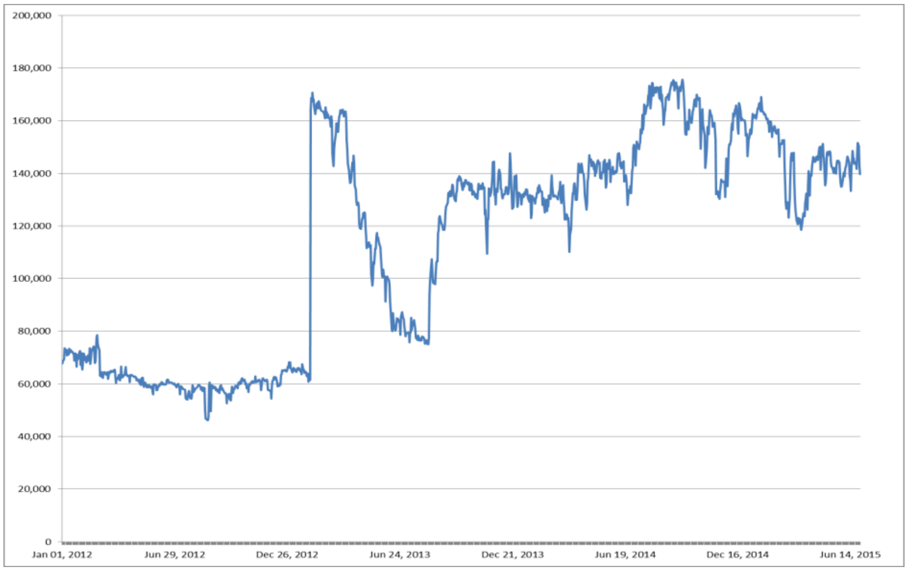
Source: Department of Natural Resources, Division of Oil and Gas

The entrance of companies such as Hilcorp in 2012 brought in new levels of investment that had not been seen in the Cook Inlet basin in several decades. The rate of spend in turn correlated very closely with the increase in production for some companies. While the rebates for the non-North Slope continued to grow between 2011 and 2015, the private investment from the participating companies grew as well.



Hilcorp Alaska Investment from Jan 2012-October 2014
Source: Hilcorp, Presented to Working Group on September 22, 2015.

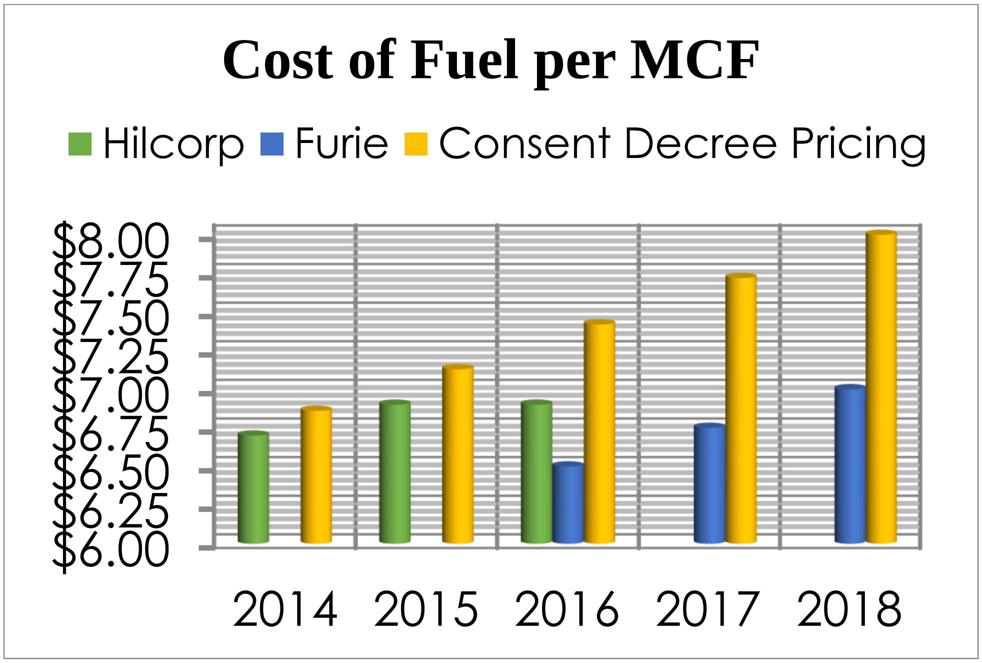
The increase in rebated certificates tended to trend along with increased activity. There was a sharp uptick in the number of project applications with the Department of Natural Resources; there was a significant increase in the amount of seismic activity that was conducted of the 2 dimensional (2D) and 3 dimensional (3D) nature; and for Southcentral, there was a noticeable increase in the production of natural gas from the Cook Inlet.



Cook Inlet Gas Production of Hilcorp Assets from Jan 2012-June 2015
Source: Hilcorp, Presented to Working Group on September 22, 2015

The supply of natural gas for Southcentral utilities appears not only to have increased but to have become diversified.

While firms such as Hilcorp took over and reinvigorated existing assets while also moving towards new projects, companies such as Furie LLC invested in projects such as its Kitchen Lights play that expects to bring on truly new sources of gas to utility companies. This also does not take into account the Cosmopolitan Project from Blue Crest Energy, which could further the diversification and, hopefully, competition which will lower energy costs to Southcentral utilities.



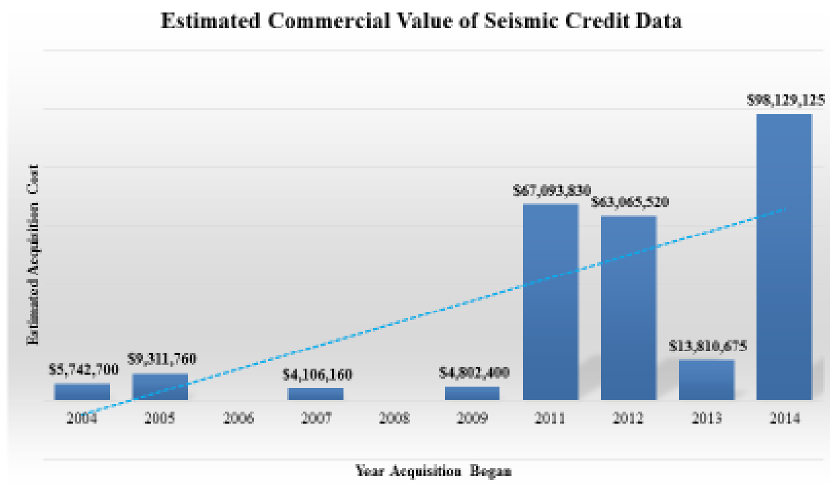
Pricing Agreement Between Furie LLC and Homer Electric Association
Source: Homer Electric Association, Presented to Working Group on October 1, 2015.

An increase in rebate outlays also brought with it an increase in the proprietary data that companies had to turn over to the Department of Natural Resources for eventual disclosure.

Under the current rebate system, in order to be reimbursed for seismic and well work, the applying company will have its well, seismic and geographic data made public:

- For well data, the information becomes public two years after the filing for a rebate.

- Seismic and geophysical data enters the public domain ten years after a rebate filing.



Conservative estimate of Total Acquisition Costs =$266,062,170

Does not include permitting & baseline environmental costs or post-processing

Source: Alaska Department of Natural Resources, Division of Oil and Gas

The required disclosure of data is significant for a number of reasons:

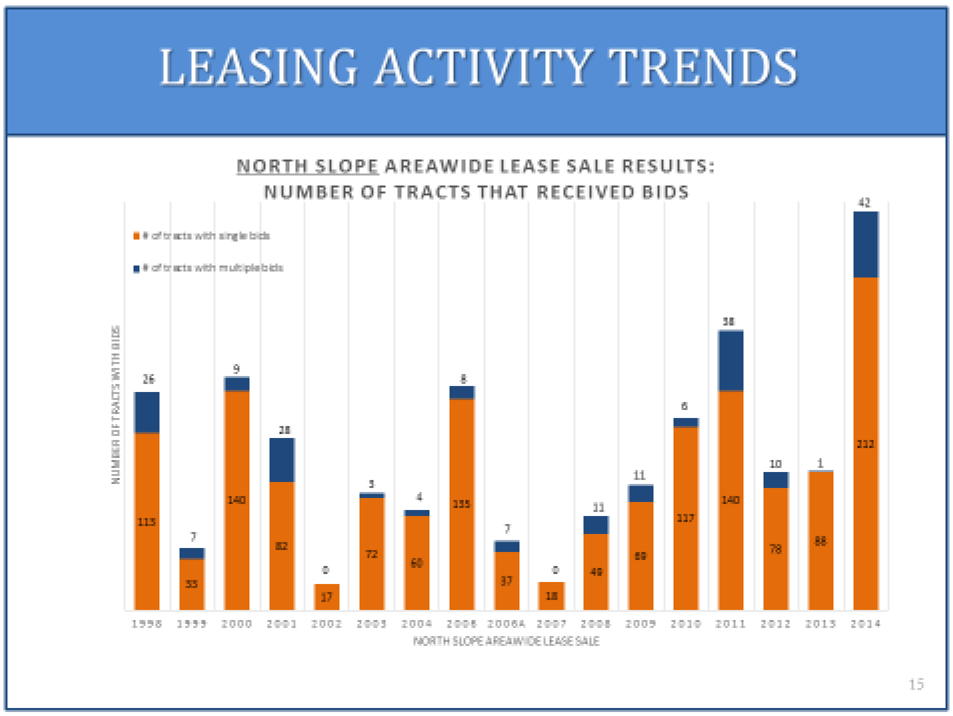
- Firstly, the proprietary value of a company's analysis done on leased projects enhances the overall value of the firm. By keeping information confidential, a company is protecting its competitive advantage and consequently barring access to that data from competitors. By having mandatory releases on this information, the inclination of a company to warehouse the data, and not move the project forward, is greatly reduced.

- Secondly, in the event the rebated firm is not able to bring off the project, the data is available for other entrants to make the investment. One of the greatest obstacles to resource development is the lack of information on a potential project. By reducing the uncertainty by literally having the data public, the likelihood of a project going forward increases.

- Thirdly, the monetary value of the data itself is high. The state, as a possessor of information acquired by private parties, has paid for it by rebating a portion of the cost. The state however did not have to undertake the permitting or direct capital investment entirely on its own.

Despite seeing a drop in rebates between 2011 and 2015, the North Slope still saw an overall increase in leasing activity and other investments.

The timeline also did not wholly capture the arrival of several new entrants with large investment projects on the North Slope, such as Caelus Energy's acquisition of both Pioneer's North Slope assets and its recent purchase of the Smith Bay Exploration Project from Nordaq.



Source: Alaska Department of Natural Resources, Division of Oil and Gas

The arrival of new independents on the North Slope has continued and accelerated, and with it the levelling with the legacy North Slope producers. Hilcorp's acquisition of BP assets in Prudhoe Bay is another example of the diversifying ecosystem.

What is critical to remember is that a significant amount of the activity tied to the rebates portion of the credits, at this juncture, are not tied to production. Though the state receives proprietary data, the benefit to local economies, and the enhanced probability of successful projects, many projects are still in the exploration and development phase.

Until the projects enter into production, neither the state, nor the company, is deriving revenue from them. The timeline from when a project enters production is critical for the moment the state can begin receiving a direct, monetized return on its investments in the rebates.

The State is Importing Private Capital through the Credit Program

When the payment deferral to a portion of the tax credit fund occurred in June of this year, a liquidity crunch ensued. That liquidity crunch in turn brought to bear the relationship between exploration and development companies in Alaska, and professional lending institutions such as commercial banks.

Oil and gas exploration and development are capitally intensive without the promise of production. Because of this risk, historically, commercial lending institutions were averse to conducting business with an operation that did not have bookable reserves as collateral.

When the state modified the oil tax system in 2006, it made the rebate portion of the tax credits transferable and irrevocable. This gave the company that had originally applied for the loan a powerful new tool: proof to commercial lending companies that it had collateral backed by the state.

Being able to monetize the refundable credits have significant implications for a project's economics:

- The objective nature of the credit system means there is a high likelihood that if an expense qualifies, it will be eventually rebated. That in turn allows a company to demonstrate to a bank that its collateral is sound, which in turn gives it access to more unencumbered capital.

- This form of leveraging is critical to a company in the compressed timeframe of exploration and development, when there is no money coming in from production revenues. The quicker a company can replenish and fund more drilling and testing, the higher the likelihood of reaching production.

    - For example, a company can apply for a loan to a lending institution and receive it a month after making a qualified expenditure. The lending institution in turn will wait for the credit to be issued by the state. By having this loan available with the accompanying collateral, a company can access more project funding earlier, accelerating an almost two year process into a little over a month.

- The presence of commercial lending institutions have meant a lower interest rate, which in turn means there are more dollars that can be allocated to the project rather than servicing debt.

The emergence of well-known institutions such as Bank of America and ING did not occur instantaneously once the credit rebate program was instituted. The oil and gas industry has a reputation for the participation of so called "wild-caters" backed by speculative investors.

For exploration and development companies planning a project in the state, the options for funding were:

- Private equity firms, and a very high rate of interest.
- Equity financing by conceding a share of the project itself in exchange for funding.
- Have significant project funds in reserve, normally the funding path for an integrated major or a larger independent company.

Monetizing a credit through accessing private capital transformed the rebate system, rather than rebating against a portion of costs for the applying company, the rebate was now a catalyst for multiplying the number of dollars that can go to the project. Every dollar spent on lower cost capital enhances the probability for success in bringing a project to production.

The use of leveraging the credit system for the purposes of accessing cheaper financing was an avenue exercised by many exploration and development companies in state.

Several companies, including Buccaneer Energy, filed for bankruptcy. In addition, the inability of a company to meet its payment obligation to local vendors and support service contractors harmed local businesses. The nascent field of this form of bankruptcy law vis-à-vis the rebate system allowed a company to take its rebates to payback creditors from outside the state first.

This of course raised an equity issue: if the state is fronting a portion of the costs, should not creditors in the state have some form of preference in bankruptcy?

The case study of a company that was rendered insolvent and unable to meet its obligations to its creditors was indicative of the dynamic in the state's basins: opening up the basins to new entrants meant there would be a higher likelihood of less robust actors participating in a high cost, technically challenging oil and gas province.

This begged the questions, are the lenders lending against the applicant, or the state's credit rating? Frankly, the answer is both.

Without the full faith and credit of the state, and its currently AAA bond rating, issuing a transferable certificate, it would not be possible for an exploration and development company to gain access to the affordable loan rates conventional lending institutions were offering.

On the other hand, lenders do not loan at such a competitive interest rate unless there is a high likelihood the venture will continue. Financial lending institutions, commercial banks in particular, make their livelihoods on long term relationships with customers who utilize their entire menu of financing for their business.

The high risk, high interest rate single plays are more the purview of the private equity sector in the economy, where managers charge a premium on their capital.

Furthermore, there is a murkiness in state law when it comes to bankruptcy and the rights the lender has to repayment. If for example, a lender were to issue a loan based on a credit that would be issued later in the year, and the borrower were to file for bankruptcy before having the credit issued, there is no recourse for the lender to be repaid. This exposes the lender to enhanced risk in a field that is already fairly high in risk.

To mitigate risks, commercial banks assess loans with tremendous due diligence: petroleum engineers, geologists and other subject matter experts are kept on staff to weigh the legitimacy of the project, and the company seeking a loan for the project.

What initially started as an ad hoc system of one bank taking a single loan with one exploration and development company has grown to a program where several hundred million dollars have been leant towards projects in the state just this year alone.

However, what it also has meant is that an interconnected financial system reacts swiftly to the potential loss of collateral. That was why, when the payment deferral occurred in June of this year, the loans in progress were halted, the interest rates raised and the loan amounts either significantly reduced or abandoned altogether.

With the price of oil undercutting the economics of shale projects in the contiguous United States, the lending capital for oil and gas projects is retreating globally with a few exceptions. Alaska is, if not the only, then certainly one of the only oil and gas provinces in North America that is seeing a net import of capital for oil and gas exploration projects.

The injection of private capital has been a buoy to smaller companies attempting to ride out the lower price environment, and to have projects ready to come into the revenue generating production phase.

Recommendations

1. **Look Prospectively to Any Changes:**

If there was one overriding theme from the many presenters through the two months of meetings, it was that any changes need to be done prospectively. There is a great concern that for many projects, with much of the capital already deployed, a massive change in the tax credit system would undermine the fundamental economics.

One of the dangers to making changes to the state's credit system is a lack of purpose: is the purpose of change merely to manage cash flows, or is it to enhance the state's revenues with new projects into the near and mid-term future?

If the overriding concern is the cash outlays being generated by the activity previously encouraged, the state should withdraw entirely from incentivizing behavior, as they represent a massive upfront expenditure with no guarantee of a return. This would of course be disastrous to many other sectors of the state's economy if all incentives were to be abolished, and this report in no way makes that recommendation.

However, the state is facing a massive budget shortfall, and justifiably all indirect expenditures, such as the oil and gas tax credits, deserve scrutiny. At a time when the public sector contraction of spending has the potential to plunge the state's private sector into a recession, the greatest care should be exercised for any changes to the tax credit system.

The state would be well served to put an effective date on changes to the current tax credit system that is graduated, and appreciates the cash flow of the many firms that were encouraged to come and invest in the various basins. A massive change that takes effect even in the next twelve months could be considered retroactive since many projects have gained and expended funds on exploration and development.

2. **Consider the Timeline for Projects**

Many projects are entering the development phase of its life cycle, and several are even close to entering production. To date, the state has spent billions of dollars over the past ten years to incentivize the exploration and development of many projects. This is particularly true in the Cook Inlet basin, where the supply of natural gas can increase tremendously in the next handful of years.

If the state were to dramatically change the credit system, and projects that have advanced to development were to be halted, the state will have lost the investment it made in getting that project to production.

The stakes are very high for both the Cook Inlet and the North Slope. For the Cook Inlet, after 2018, natural gas supply uncertainty begins to grow considerably. As the utility companies presented to the group: though the situation has improved remarkably, Southcentral Alaska is not out of the woods when it comes to a stable supply of energy.

Though there are at least two new projects slated to come online by then, if the economics of those projects falter due to restructuring of the state's credit system, Southcentral communities will be the poorer for it. **Protecting the stability of the Cook Inlet gas supply for the largest population centers in the state is critical.**

For the North Slope, TAPS is over three quarters under capacity. The danger of the state's main infrastructure that moves its most valuable revenue source entering obsolescence is not low. **Encouraging more North Slope production to come online will be critical for the fiscal health of the state.**

If there are to be any changes made to the oil and gas tax credit system, then the state should try to protect the projects already under exploration and development, nearing production. The timeline of a project moving from exploration to production is between five and ten years. The state should keep that timeline in mind, as production is when the revenue, royalties and other elements of government take finally take hold.

3. **Keep the State as a Magnet for Capital Investment**

The state was able to take a rebate program through its refundable credits and have them serve as an importer of capital from around the world. The growth and sophistication of this system by some of the very best lending institutions is worth continuing.

At a time when the state will continue to have serious cash flow issues, bringing in more private sector capital bolsters employment in the local economies, and keep projects moving towards completion.

A significant, unplanned change to the credit system has demonstrated that it can have a reverberation in the commercial lending sector, and would certainly affect the lending abilities of not just oil and gas companies, but other borrowers looking to invest in the state.

One potential change would be to modify the statutes regarding bankruptcy and the Uniform Commercial Code (UCC). This would clear up the murkiness mentioned earlier in the report about bankruptcy and the inability of the lender to recoup its investment from an insolvent borrower.

With a focus on maximizing the use of capital in the state, another recommendation would be to tether rebates to further in-state operations. A company that is headquartered out of the state could be legitimately rebated for its costs, but that rebate is issued on the presumption that the Alaska project is a focus for the company. By tying rebates to the

Alaskan affiliate of a larger company, or making future rebates contingent on spending in the state, Alaskans have an added assurance that state dollars are being spent in the state.

Another recommendation is to ensure Alaskan vendors and support service contractors have a stronger path to repayment in the event a company receiving tax rebates flounders. Alaskan based businesses acutely felt the repercussions when several exploration and development companies declared bankruptcy. **If the state is contributing to a portion of the costs of a project, Alaskan companies that worked with these exploration and development firms need a clear path to be made whole.**

By clarifying the rights of the lender, the banking sector has more surety in its repayment, and can in turn lower interest rates on explorers and developers. This in turn accelerates the project timeframe to reach production, when the state begins to see a return on its investment.

As mentioned in the report, Alaska is one of the few oil and gas outposts in this time of low oil prices that is seeing positive investment of new capital. **At a time when the state's credit rating is being scrutinized more than ever, a deliberate, methodical and graduated approach that still honors commitments currently being made under existing law would be a reasoned strategy.**

4. **Ensure the Production Tax Floor is Protected**

Though much of the attention of the work group meetings, and this report, was dedicated to the refundable tax credits, the subject of deductions against liability did raise an important concern.

Under Senate Bill 21 (aka MAPA), a floor of 4% was instituted against the North Slope legacy producers. This was meant to prevent credits from taking the taxpayer's liability down to effectively zero, which under the older tax system (ACES) was a real possibility.

However, the group learned during its meetings and deliberations that there was potential for an unintended scenario to occur: for a legacy producer to incur a carry-forward annual loss (NOL) that was great enough to drop its tax liability below the floor.

Though there may be disagreement on proposals to increase the floor, at a minimum the floor installed in Senate Bill 21 should be hardened up and protected.

5. **Recognize the Uniqueness of the Frontier Basins**

The overall cash outlays for the state to support the Frontier Basins are relatively small, and the potential benefits to local communities are very large. Despite having credits created specifically for their region, most Frontier Basin operators utilize the credits designed for the Cook Inlet. **It is worth considering to allow the Frontier Basin Credits to expire, and allow for an exemption to the Frontier Basin if any changes were to occur to the credits predominately used by Cook Inlet.**

6. **Enhance Reporting Requirements to Show Investment Levels**

If the state is going to continue a rebated system, or for that matter a deduction system as well, the state is invariably contributing a portion of the treasury to the success of a project. Without compromising the confidentiality and proprietary data of an operator, it would be a service to the public to know what the investment and spend amounts on a project applying for credits are.

This can have a very powerful deterrent effect of companies making very small investments and attempting to recoup a portion of their costs, while competing operations are spending heavily in the state. Though it is not advocated for the names of the operators to be disclosed at this time, the public disclosure of investment amounts can better inform both the public, and policy makers, on any other changes to make to the credit system**. Alaskans deserve to know what the other side of the table is spending on a project if their money is investing in its success.**

APPENDIX

OIL AND GAS TAX CREDIT GRID

Source: Alaska Department of Natural Resources, Division of Oil and Gas

Descriptive Name	Statute	North Slope	Cook Inlet	Notes and Exceptions
Production Tax Ceilings		N/A	Gas:	Sunsets in 2022
	AS43.55.011j	N/A	For leases or properties in production before April 1, 2006: effective tax rate capped at "2006 level" for that property or lease	"2006 level" means 12 month period ending on March 31, 2006
	AS43.55.011j	N/A	For leases or properties in production after April 1, 2006: effective tax rate capped at 17.7c/mcf	
		N/A	Oil:	Sunsets in 2022
	AS43.55.011k		Effective tax rate capped at zero	
	AS43.55.011o	Gas sold for use in-state caped at 17.7 c/mcf	N/A	Sunsets in 2022
Production Tax Gross Value Reduction	AS43.55.160(f)	20% reduction in gross value at the point of production when computing the production tax value for revenue from new units or PA's.	N/A	
	AS43.55.160(g)	10% additional reducton in gross value at the point of production from units where all leaes	N/A	

Descriptive Name	Statute	North Slope	Cook Inlet	Notes and Exceptions
		have a royalty over 12.5%		
Production Tax Per bbl credit	AS43.55.024(i)	$5 credit per taxable barrel of GVR-eligible production	N/A	
	AS43.55.024(j)	A sliding scale credit of up to $8 per taxable barrel credit for non-GVR-eligible production.	N/A	
Exploration Incentive Credits (EICs) under AS38.05.180(i)	AS38.05.180(i)	50% of drilling based on depth and location	50% of drilling based on depth and location	Only availble for leases on state-owned lands when establised as a sale term before acquisition
		50% of drilling based on depth and location	50% of drilling based on depth and location	N/A for unleased, Federal-, or private-owned lands
Exploration Incentive Credits (EICs) under AS41.09.010 (Expired 7/1/2007)	AS41.09.010	N/A	N/A	50% of drilling and seismic costs on unleased state land, 25% on non-state land, expired 7/1/2007
Exploration (.025) Tax Credit (Expires 7/1/2016)	AS 43.55.025	40% of seismic costs outside existing unit	40% of seismic costs outside existing unit	
		1) 30% of drill costs if > 25 miles from existing unit	1) 30% of drill costs if > 10 miles from existing unit	Applies to all lands onshore or in state waters
		2) 30% if pre-approved new target and >3 mi from a well	2) 30% if pre-approved new target	Outside of Cook Inlet
		3) 40% of drilling costs if both 1) & 2)	3) 40% of drilling costs if both 1) & 2)	
Gas Exploration and Development Income Tax Credit: Non-North Slope Gas Development	AS43.20.043	For below 68 degrees latitude, N/A if north of 68 degrees latitude	10% of capital investment made prior to 2010 other than for existing producing unit; credit	All gas south of 68O gas development, same as Cook Inlet***(see note at bottom)

Descriptive Name	Statute	North Slope	Cook Inlet	Notes and Exceptions
Incentive (Prior to 1/1/10)			can be carried forward 5 years	
Gas Exploration and Development Income Tax Credit: Enhanced Gas Development Incentive (Effective 1/1/10, expires 12/31/09)	AS43.20.043(a)(1)	For below 68 degrees latitude, N/A if north of 68 degrees latitude	25% credit for capital expenditure to develop gas reserves for investment 2010 and after including for existing producing unit; credit may be carried forward five years	All gas south of 68O gas development, same as Cook Inlet***(see note at bottom)
Royalty Modification	AS38.05.180(j)	Down to 5%, if new production; down to 3%, if producing or shut-in	Down to 5%, if new production; down to 3%, if producing or shut-in	N/A for unleased, Federal-, or private-owned lands
	AS38.05.180(f)(6)	N/A	As low as 5% for oil production from CI platforms if production falls below specified levels	N/A for unleased, Federal-, or private-owned lands
Discovery Royalty for Pre-1969 leases	[DL-1 Lease Form]	5% royalty for 10 yrs.	5% royalty for 10 yrs.	N/A for unleased, Federal-, or private-owned lands
Discovery Royalty south of T18N, Cook Inlet	AS38.05.180(f)(4)	N/A	5% royalty for 10 yrs.	N/A for unleased, Federal-, or private-owned lands
Cook Inlet Royalty Reduction Field specific, for the following fields only: Falls Creek,Nicolai Cr., Redoubt Shoals, & West Foreland. North Fork & Starichkof not in prod. before 1/1/2004.	AS38.05.180(f)(5)	N/A	5% on 1st 25 MM bbls for 10 yrs, 5% on 1st 35 BCF for 10 yrs, field must be in prod. by 1/1/2004	N/A for unleased, Federal-, or private-owned lands
Production Tax Credits: Qualified CapEx Credits	AS43.55.023(a)	N/A	20% for qualified capex; transferable	All development south of 68 degrees latitude same as Cook Inlet. Shall be taken in lieu of EIC credits (AS43.55.025) and

Descriptive Name	Statute	North Slope	Cook Inlet	Notes and Exceptions
				gas exploration credits (AS43.20.043)
Production Tax Credits: Well Lease Expenditure credit	AS43.55.023(l)	N/A	40% of initangible drilling expense	Transferable
Production Tax Credits: Loss Carry-Forward Credits	AS43.55.023(b)	35% of losses attributable to expenses incurred after 2015; 45% for expenditures in 2014; transferable	25% of loss	Transferable
Production Tax Credits: Frontier Basin Production Credit, non-transferrable credit, for production south of 68 lat. & outside CI basin, eligibility ends 9 years after 1st production	AS43.55.024(a)	N/A	N/A	Available only on non-CI and non-NS lands up to $6MM
		Credits for any one year shall not exceed $6 million	[same as column 1]	To receive the credit first production must occur before May 1, 2016
Production Tax Credits: Small Producer Credit, non-transferrable credit, eligibility ends 9 years after 1st tax pmt.	AS43.55.024(c)	$12 MM for production <50,000 BOE/day, declining on a sliding scale to $0 for production >100,000 BOE/day	[same as column 1]	
Gas Storage: Applies only to storage commencing operations between 12/31/2010 and 1/1/2016	AS43.20.046	$1.50 per MMCF of "working gas" storage capacity, up to lesser of $15MM or 25% of costs incurred to establish gas storage facility; does not apply to gas storage related to gas sales pipeline on the North Slope	[same as column 1]	Shall operate as a public utility regulated by Alaska RCA with open access for 3rd parties; storage capacity determined by AOGCC
	AS38.05.180(u)	No royalty for gas storage lease for 10 years following startup of	[same as column 1]	Credits and exemption from royalty payments shall be passed through to rate payers

Descriptive Name	Statute	North Slope	Cook Inlet	Notes and Exceptions
		commercial operation; non-native gas in storage reservoir presumed to be first-out		
Cook Inlet Jack-Up	AS43.55.025(a)(5) & (m)	N/A	Tax credits for exploration expenses of 80, 90 and 100% prescribed as follows: 100% of 1st well up to $25MM, 90% of 2nd well up to $22.5MM, and 80% of 3rd well up to $20MM; only the first jack-up rig in Cook Inlet receives this credit	Expenses only for drilling of wells from a jack-up rig for wells that test pre-Tertiary; all three wells must be drilled by unaffiliated parties; if well results in production, operator shall repay 50% of credit over ten years after production start-up; shall be taken in lieu of other credits under AS43.55.023 and .025
Incentives as Part of a Program: Exploration Licensing	AS38.05.132	N/A	N/A	Available only on state-owned lands not in sale areas, up to 500,000 acres per license, one-time $1/acre license fee, no bonus bid or annual rental, sole right to covert to O & G leases
Incentives as Part of a Program: Nonconventional Gas Incentive	AS38.05.180(n)(2)	Reduced rental, 6.25% royalty if no competition with 12.5% lease	[same as column 1]	Can apply to license areas after conversion to lease, then same as column 1

*** If requesting this credit, not eligible for any other tax credits or royalty modifications