ALASKA STATE LEGISLATURE
HOUSE RESOURCES STANDING COMMITTEE
February 27, 2016
10:00 a.m.

MEMBERS PRESENT

Representative Benjamin Nageak, Co-Chair
Representative David Talerico, Co-Chair
Representative Mike Hawker, Vice Chair
Representative Bob Herron
Representative Craig Johnson
Representative Kurt Olson
Representative Paul Seaton
Representative Andy Josephson (via teleconference)
Representative Geran Tarr (via teleconference)

MEMBERS ABSENT

All members present

COMMITTEE CALENDAR

HOUSE BILL NO. 247
"An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing

oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

- HEARD & HELD

PREVIOUS COMMITTEE ACTION

BILL: HB 247
SHORT TITLE: TAX;CREDITS;INTEREST;REFUNDS;O & G
SPONSOR(s): RULES BY REQUEST OF THE GOVERNOR

01/19/16	(H)	READ THE FIRST TIME - REFERRALS
01/19/16	(H)	RES, FIN
02/03/16	(H)	RES AT 1:00 PM BARNES 124
02/03/16	(H)	Heard & Held
02/03/16	(H)	MINUTE(RES)
02/05/16	(H)	RES AT 1:00 PM BARNES 124
02/05/16	(H)	-- MEETING CANCELED --
02/10/16	(H)	RES AT 1:00 PM BARNES 124
02/10/16	(H)	Heard & Held
02/10/16	(H)	MINUTE(RES)
02/12/16	(H)	RES AT 1:00 PM BARNES 124
02/12/16	(H)	Heard & Held
02/12/16	(H)	MINUTE(RES)
02/13/16	(H)	RES AT 1:00 PM BARNES 124
02/13/16	(H)	-- MEETING CANCELED --
02/22/16	(H)	RES AT 1:00 PM BARNES 124
02/22/16	(H)	Heard & Held
02/22/16	(H)	MINUTE(RES)
02/24/16	(H)	RES AT 1:00 PM BARNES 124
02/24/16	(H)	Heard & Held
02/24/16	(H)	MINUTE(RES)
02/25/16	(H)	RES AT 8:30 AM BARNES 124
02/25/16	(H)	Heard & Held
02/25/16	(H)	MINUTE(RES)
02/25/16	(H)	RES AT 1:00 PM BARNES 124
02/25/16	(H)	Heard & Held
02/25/16	(H)	MINUTE(RES)
02/26/16	(H)	RES AT 1:00 PM BARNES 124

02/26/16	(H)	Heard & Held
02/26/16	(H)	MINUTE(RES)
02/27/16	(H)	RES AT 10:00 AM BARNES 124

WITNESS REGISTER

JANAK MAYER, Chairman & Chief Technologist
enalytica
Consultant to the Legislative Budget and Audit Committee
Washington, DC
POSITION STATEMENT: As consultant to the Legislative Budget and Audit Committee, continued his PowerPoint presentation (begun on 2/26/16) on enalytica's analysis of the projected impacts that HB 247 would have on the oil and gas industry in Alaska.

NIKOS TSAFOS, President & Chief Analyst
enalytica
Consultant to the Legislative Budget and Audit Committee
Washington, DC
POSITION STATEMENT: As consultant to the Legislative Budget and Audit Committee, answered questions related to the projected impacts that HB 247 would have on the oil and gas industry in Alaska.

ACTION NARRATIVE

10:00:00 AM

CO-CHAIR BENJAMIN NAGEAK called the House Resources Standing Committee meeting to order at 10:00 a.m. Representatives Olson, Seaton, Johnson, Hawker, Herron, Tarr (via teleconference), Josephson (via teleconference), Talerico, and Nageak were present at the call to order.

HB 247-TAX;CREDITS;INTEREST;REFUNDS;O & G

10:00:57 AM

CO-CHAIR NAGEAK announced that the only order of business is HOUSE BILL NO. 247, "An Act relating to confidential information status and public record status of information in the possession of the Department of Revenue; relating to interest applicable to delinquent tax; relating to disclosure of oil and gas production tax credit information; relating to refunds for the gas storage facility tax credit, the liquefied natural gas storage facility tax credit, and the qualified in-state oil refinery

infrastructure expenditures tax credit; relating to the minimum tax for certain oil and gas production; relating to the minimum tax calculation for monthly installment payments of estimated tax; relating to interest on monthly installment payments of estimated tax; relating to limitations for the application of tax credits; relating to oil and gas production tax credits for certain losses and expenditures; relating to limitations for nontransferable oil and gas production tax credits based on oil production and the alternative tax credit for oil and gas exploration; relating to purchase of tax credit certificates from the oil and gas tax credit fund; relating to a minimum for gross value at the point of production; relating to lease expenditures and tax credits for municipal entities; adding a definition for "qualified capital expenditure"; adding a definition for "outstanding liability to the state"; repealing oil and gas exploration incentive credits; repealing the limitation on the application of credits against tax liability for lease expenditures incurred before January 1, 2011; repealing provisions related to the monthly installment payments for estimated tax for oil and gas produced before January 1, 2014; repealing the oil and gas production tax credit for qualified capital expenditures and certain well expenditures; repealing the calculation for certain lease expenditures applicable before January 1, 2011; making conforming amendments; and providing for an effective date."

10:01:33 AM

JANAK MAYER, Chairman & Chief Technologist, enalytica, Consultant to the Legislative Budget and Audit Committee, continued his analysis (begun on 2/26/16) of the projected impacts that HB 247 would have on the oil and gas industry in Alaska. He resumed his PowerPoint presentation entitled, "IMPACT OF HB 247: COOK INLET ASSESSMENT," by turning to slide 6, "COOK INLET OIL AND GAS PRODUCTION: BASIC FACTS." Reviewing the history of Cook Inlet oil and gas production and the evolution of the basin over time, he reminded members that oil peaked in 1970 and then steadily declined to a trough of 7.5 thousand barrels a day (mb/d) in 2009. Since that time oil has had a substantial uptick and is now at 18 mb/d, more than double what the inlet produced less than a decade ago. Gas production, however, has not seen that resurgence in production in particular because gas is limited by local demand conditions. But, there has been a flattening of the gas decline and a plateau. An initial decline in gross production occurred in the 1990s, but then plateaued into the 2000s. The plateau was due to production of gas that had previously been reinjected at

Swanson River Oil Field. A decline then began after 2005, and in the last half decade there has been stable production as a result of new drilling in mature fields.

10:04:07 AM

MR. MAYER moved to slide 7, "OIL UP FROM WORKOVERS, NEW WELLS IN EXISTING FIELDS," to discuss the cause of the oil turnaround post-2010. Drawing attention to the chart on the left, "COOK INLET: GROSS OIL PRODUCTION BY WELL VINTAGE," he explained the chart depicts which decade a well come on line as well as the total production of all the wells. He noted that production from wells drilled between 1991 and 2000 (green line) came down to a trough of about 2 mb/d in 2009, then production began a substantial uptick. That uptick was not new wells, but rather increased production from mature wells that had had substantial capital spent on workovers, the result being more production now than a decade ago. This same increase from workovers also happened with wells drilled pre-1970 (red line). Substantial new drilling began in 2011 (purple line), he pointed out. So, new oil production is coming from a mixture of workover work and the new drilling that began in 2011.

MR. MAYER then brought attention to the chart on the right side of slide 7, "COOK INLET: GROSS OIL PRODUCTION BY FIELD." He pointed out that each of the major oil fields has a substantial uptick in the latter years, the biggest uptick being in the McArthur River Oil Field. However, he noted, almost all of the fields come from a fairly low base and have substantial increases in the last half decade.

10:06:52 AM

MR. MAYER displayed slide 8, "GAS FLATTENING FROM NEW WELLS IN EXISTING FIELDS," and stated that gas production is a slightly different picture than oil. Drawing attention to the left-hand chart, "COOK INLET: GROSS GAS PRODUCTION BY WELL VINTAGE," he explained that the increased production, or at least flattening of decline, is more a question of new wells drilled rather than well workovers. The previous vintages by and large continue a constant decline curve relatively speaking; there is no discontinuity of a moment in time where suddenly a lot of new capital was being spent on old wells. Rather, a number of new wells were drilled in the post-2011 period that have come on line and boosted production and that has helped flatten out that decline. Mr. Mayer turned to the chart on the right side of slide 8, "COOK INLET: GROSS GAS PRODUCTION BY FIELD," and noted

that an increase can be seen in only a handful of fields. In particular, some growth occurred in the Kenai and Beaver Creek fields; a new field, Kenai Loop, came on line in 2012; and some incremental production occurred in Swanson River. Not shown on this chart is the initial production from the first well at the Kitchen Lights Unit that began in December 2015.

10:08:20 AM

REPRESENTATIVE SEATON said the reason HB 247 is before the legislature is tax credits and the value on the tax credits. He inquired as to how much per barrel of oil and how much per thousand cubic feet (Mcf) of gas the $400 million in Cook Inlet credits translate into. He explained he would like to know what the state's cost-to-benefit ratio is for this production.

MR. MAYER replied he does not have these figures due to the limits on publicly available data. The Department of Revenue (DOR) is restricted on what it can release in terms of naming specific taxpayers and what specific activities the credits go to. Teasing out is a big part of the problem - a substantial amount is spent on credits in Cook Inlet and undoubtedly a lot of that is spent on oil production and exploration. A large part of the concern when it comes to credits is insuring adequacy of gas supply for Cook Inlet. However, it is very difficult from the publicly available data to tease out what is being spent on developing new gas resources versus what he suspects is a lot of the spending, which is either on incentivizing new oil production, exploration, or a range of activities that do not necessarily translate into increased gas security for Southcentral Alaska.

REPRESENTATIVE SEATON remarked that there should, at the least, be the ability to get the gross amount paid by the state and the gross amount of per barrel oil equivalent (BOE) or Mcf and, if there is increased production, how much that increased production cost the state in refundable tax credits.

10:11:06 AM

CO-CHAIR TALERICO surmised that the chart on slide 4, "BIG DIFFERENCE BETWEEN NORTH SLOPE AND COOK INLET," depicts the credits in their entirety for the North Slope and for Cook Inlet and does not distinguish between gas and oil.

MR. MAYER responded correct, and said a lot of that undoubtedly goes towards incentivizing new drilling for oil exploration or

other activities that are not necessarily directly related to the question of gas supply for Southcentral Alaska. The focus of his presentation is on the question of maintaining credits, he explained, but in regard to policy concerns there is no question that the current regime and carriage of spending is on a lot of things that are not necessarily tied directly to gas supply for Southcentral Alaska.

10:12:15 AM

MR. MAYER returned to his presentation and reviewed slide 9, "COOK INLET GAS HAS GONE THROUGH MAJOR TRANSITION." He outlined the major transition that has taken place in the Cook Inlet gas market over the last several decades. He described the old Cook Inlet gas market as one with a substantial degree of gas surplus that could be exported via liquefied natural gas (LNG) or the (now closed) nitrogen facilities owned by Agrium U.S., Inc. ("Agrium"). There was period of low wellhead prices where the Regulatory Commission of Alaska (RCA) looked at contracts that proposed pricing based on the Henry Hub. The RCA said the Henry Hub was much too high and could not be done, which is very different than today's world. The overall market view was that gas was long and plentiful and it was an era where gas was produced by large international players. The old market was also one where Southcentral utilities looking to ensure stability and security of supply could get very long-term stable contracts that gave the utilities exactly what they needed. In addition to long-term contracts the producers were willing to offer the utilities a high degree of seasonal flexibility. That seasonal flex largely came from supplies, the fields themselves could flex up and down to quite a substantial degree in a way that they no longer can. But, Mr. Mayer continued, the new Cook Inlet gas market is the opposite of the old. There is now very limited surplus. In off-peak periods there is still some degree of export, but by and large gas is all absorbed into the local market. Today has high wellhead prices, a general market view that gas is short. It is now a gas market where the producers are mostly smaller more focused players. Sales contracts between producers and utilities are for much shorter terms.

10:14:45 AM

REPRESENTATIVE OLSON said another variable at that point in time was the long-term gas contracts with the Japanese. During the four to six weeks of cold snaps, he recalled, the British thermal unit (Btu) content going to Japan could be shorted and then made up for on the next load; this was basically done over

the phone. There was enough supply in Japan to be able to absorb that readily and it worked out for years.

MR. MAYER answered that in terms of where supply flexibility occurred in the past versus where it occurs now, there was enormous supply flexibility solely on the upstream side. Looking across the years between the summer and winter months and what was exported by the Kenai LNG Plant [owned by ConocoPhillips Alaska, Inc. and located in Nikiski], the difference between those two was pretty muted until just the last three years. In the last three years the Kenai facility has suddenly become a big seasonal component of how the seasonal nature of demand can be managed in a way that it was not necessarily in the past.

10:15:59 AM

REPRESENTATIVE HERRON asked whether the old should be wished for or whether the new is just as good.

MR. MAYER replied the old would always be very nice to have back, but unfortunately it is not always possible. Someone responsible for planning, contracting, and purchasing gas at a utility would be very nostalgic for the old. The new is not impossible to live with, it is just harder to figure out what needs to be done to get the security of supply that is needed.

REPRESENTATIVE SEATON requested that as Mr. Mayer continues his presentation he point out if it makes a difference on what the state's policy goal is. For example, if the policy is securing long-term gas for in-state usage and whether that creates definitely different policy options, or if policies are being enacted to allow people to export more gas or to privately market other than within the local supply.

MR. MAYER responded he is aware of those as critical questions and will delve into those as much as he can in later slides.

10:17:47 AM

MR. MAYER returned to slide 9 and continued his review of the transition from the old to the new Cook Inlet gas market. Fundamentally, the mature fields have much less seasonal flexibility than they used to have and that flex in what can be delivered largely instead now comes from the storage side now that there is the Cook Inlet Natural Gas Storage Alaska (CINGSA)

facility and then other demand factors including for instance seasonal cargoes from Kenai LNG Plant.

MR. MAYER displayed slide 10, "MATURE BASIN HAS LIMITED SEASONAL PRODUCTION FLEX," to elaborate on the much more limited seasonal production flex seen today as compared to the past. Bringing attention to the left-hand chart, "COOK INLET: GAS PRODUCTION," he specified it depicts gross production [red line], reinjected gas [green line], and net production [orange line]. It is the same chart as that on the right-hand side of slide 6, he noted, but instead of looking at the production in a smoothed annual data series it looks at a monthly data series so that the intra-year volatility in production can be seen. [Between 1970 and about 2006] there was a really wide degree of variation versus a much tighter band of what can be produced at the wellhead in the last decade or so. Turning to the right-hand chart, "COOK INLET: SEASONAL SWING (MAX MONTH - MIN MONTH)," he explained that the red line represents subtracting the minimum month of the year from the maximum month of the year to see the annual degree of swing of flexibility of what could be delivered from the upstream fields themselves. Between the early 1990s and the latter part of the last decade, a huge amount of ability was had to deliver seasonal flexibility. The gap between the minimum and the maximum could be as high as 200 or 250 million cubic feet per day (Mmcf/d), so a lot of seasonal variability in the structure of demand could be accommodated. Directing attention to the end of the most recent years depicted on the chart, he stated that the large peak seen is probably an artificial one that has more to do with an outage than a long-term pattern. In terms of a long-term pattern, the swing capacity at the upstream end is now down to about 50 Mmcf/d as opposed to the almost 250 Mmcf/d that was had a decade ago.

10:20:13 AM

MR. MAYER moved to slide 11, "DEMAND HAS, MEANWHILE, BECOME MORE SEASONAL," to review the reasons for why demand has become more seasonal than ever before. He explained that the left-hand chart, "ALASKA: GAS DEMAND BY SECTOR," breaks down the demand between residential, commercial, industry, and power generation, while the right-hand chart, "ALASKA: GAS DEMAND," depicts the sum total of those four sectors. As would be expected, the big sources of seasonality in demand are residential and commercial. Power has its own degree of seasonality but is much more muted compared to residential and commercial consumption of gas. The industry sector was of major importance prior to 2006/2007; the shutting of Agrium's nitrogen facility being the big difference

since then. There are two big impacts from that. In the early 2000s there was very little seasonality to the nature of the industrial demand and, because that demand was such a big piece of the total and was fairly stable, in general the total was more stable. A period of short gas supply began in those middle years of the previous decade and industrial usage then became effectively counter-seasonal, it was being used primarily in the off-peak months of the residential and commercial sectors, thereby essentially balancing out the seasonality of the residential and commercial demand. But now that industrial is no longer a major piece of the pie, the overall picture is dominated by the residential and commercial sectors which is where the overwhelming seasonal nature of the demand is. As seen on the right-hand chart, the seasonality of overall demand has gone from a much tighter to a much broader swing - going from less than 150 Mmcf/d to more than 250 Mmcf/d of total demand. So, there is now much less seasonal deliverability on the upstream side, but yet much more seasonal consumption patterns on the demand side. Getting these things to match is obviously a key difficulty for utilities to meet that seasonal demand profile. That is why the Cook Inlet Natural Gas Storage Alaska facility (CINGSA) and the ability to use the Kenai LNG Plant in off months have become critical in trying to manage some of these things.

10:23:15 AM

MR. MAYER reviewed slide 12, "RECENTLY, EXPORTS HAVE OFFERED A SEASONAL OUTLET," reporting that in recent years exports have started to offer a seasonal outlet. He said the chart on the left, "US LNG EXPORTS FROM KENAI," depicts [the volume] of exports from the Kenai LNG Plant during the timeframes of October to March (red line) and April to September (green line) [for the years 1975-2015]. When the two lines are identical, he explained, it is a non-seasonal export profile - export in the winter months is largely the same as in summer months. When the two lines diverge is when the seasonality is seen in the use of that export facility. By and large those two lines track each other pretty well until about 2013. It is in 2014/2015 that that the export facility becomes a substantial component in the seasonality of demand and being counter-cyclical in terms of providing demand during the otherwise off-peak periods for the residential and commercial sectors. In 2014 and 2015 the Kenai LNG Plant exported 13 and 16 Bcf, respectively, which helped support the seasonal flexibility that is required.

MR. MAYER then directed attention to the right-hand chart on slide 12, "KENAI LNG: PRICE OF EXPORTED CARGOES," and noted that until the end of 2014 the Kenai LNG Plant received $14-$16 per million British thermal units (MMBtu). It is easy to see how that was profitable business even if the plant was buying gas in the Cook Inlet rather than producing the gas itself. However, [beginning in 2015] prices dropped into the range of $6-$8/MMBtu and in more recent months have been much closer to $6 than $8. Thought must be given about the combination of two things: 1) ConocoPhillips' divestiture from its Cook Inlet assets that produced the gas historically used for export through the Kenai LNG Plant, and 2) the question of how the future commercial structure works - whether that gas is being tolled or whether ConocoPhillips is buying it at the wellhead. He said he does not know enough about those structures to comment, but warned that if the low prices for exported cargoes continue for a substantial period of time there is a real question as to how viable that is as a route to manage seasonality.

10:26:13 AM

MR. MAYER addressed slide 13, "GAS PRICES HAVE RISEN CONSIDERABLY POST 2004," stating that pricing has clearly been a major factor in enabling additional flattening of decline in gas production. Referring to the left-hand chart, "COOK INLET GAS PRICE VS HENRY HUB," he related that, historically, prices in the Cook Inlet (red line) have usually been substantially below the Henry Hub (green line), or sometimes equal to the Henry Hub. He recalled the "famous" Regulatory Commission of Alaska (RCA) price-making case where the RCA looked at the idea of Henry Hub-based pricing and thought it was outrageously expensive. It is now ironic to see that in recent years the Henry Hub price has been about $2 per thousand cubic feet (Mcf) lower than the Cook Inlet prices, which have stabilized during these recent years. This price stabilization, he explained, is in part the result of the "consent decree" [between Hilcorp Alaska, LLC, and the State of Alaska, approved by the Alaska Superior Court on 1/17/13] and the set prices put in place under a number of gas contracts. Price stabilization is also related to the RCA having to take into account in making pricing decisions the changes that were made by the Cook Inlet Recovery Act [House Bill 280, passed in 2010 by the Twenty-Sixth Alaska State Legislature]. The average Cook Inlet prevailing price is around $6/Mcf.

MR. MAYER then brought attention to the right-hand chart on slide 13, "ENSTAR: ANNUAL GAS SUPPLY CONTRACTS," and explained the data source is from publically available information about

ENSTAR Natural Gas Company's ("ENSTAR") gas contracts from its RCA cost of gas adjustment determination. The chart shows the supply stack by volume and it can be seen that the $6 figure conceals a big variation. A substantial amount of gas is being bought at prices as low or lower than $4/Mcf, an even bigger amount is in the range of $7-$8/Mcf, and there are some smaller contracts with the price as high as $14/Mcf. At this point the consent decree prices are mostly at $7 plus/Mcf. Other jurisdictions have tried to put in place higher gas pricing to incentivize some of the most expensive production around. For example, Argentina trying to incentivize expensive shale and Egypt trying to incentivize expensive offshore deepwater gas. Prices of $5, $6, and $7/Mcf have in most of those cases been sufficient to produce some of that most expensive gas. There is no question that the increase in gas pricing in Cook Inlet has played a major, major role in the flattening of the decline that has been seen and incentivizing the discovery and development of some of the new resources that is being seen at the moment.

10:29:48 AM

MR. MAYER discussed slide 14, "GAS SUPPLY AND DEMAND DYNAMICS IN COOK INLET." On the supply side, he said, gas production in 2015 was [103] Bcf. Recent studies by DNR estimate the proven and probable reserves ("2P reserves") from the legacy fields at about 1.2 trillion cubic feet (Tcf). Additionally, the department estimates about 400 Bcf at the Kitchen Lights and Cosmopolitan fields. Presumably, the department's estimate is intentionally conservative, because it is very different from the statements that have been made by some of the operators of those fields. However, if DNR's figure is used for the moment, the estimate of 2P gas reserves adds up to about 1.6 Tcf.

MR. MAYER qualified that when it comes to the amount of gas at Kitchen Lights and Cosmopolitan, he has no more data than anyone else. He advised that since DNR is clearly authoritative and intentionally conservative, the department's number should be looked at more than any other. He recounted that at the September [2015] hearings on the state's overall credit system, a representative of Furie Operating Alaska, LLC, ("Furie") testified that Furie currently has one well with peak production at about 18 Mmcf/d, but that in principle Furie could be drilling many, many more wells and be producing 200 Mmcf/d for 15 years. Doing the math for the gas resource that would be required to produce 200 Mmcf/d for 15 years, he estimated the size of the resource to be about 1.5 Tcf. So, he counseled,

there are substantial questions yet to be answered in any authoritative way as to the nature of that resource.

10:32:26 AM

MR. MAYER then addressed the demand side for Cook Inlet gas, saying he will use DNR's figure of 1.6 Tcf to think about what that means in terms of the overall supply security situation. He noted that the 2015 consumption of 100 Bcf pretty much matched the supply [of 103 Bcf]. Of that, 80-85 Bcf was in-state demand and another 13-16 Bcf in 2014-2015 was exported through the Kenai LNG Plant. According to the Alaska Gasline Development Corporation's (AGDC) forecasts out to 2030, demand could rise to 115-130 Bcf/year, he related. He offered his understanding that that is mostly not a growing demand in the current areas, but rather additional penetration/new uses of gas. If the nitrogen facility were to restart, AGDC estimates that that would add another 28 Bcf/year per train, or almost 60 Bcf/year given the facility has two trains.

MR. MAYER explained that one set of math could be to take either 1.2 or 1.6 Tcf of gas in 2P reserves and divide that by current or forecast future demand. However, he continued, enalytica hesitates to do that because gas is not produced at a nice constant plateau, but rather on a decline rate. Just because there are reserves that could be produced at that rate at the moment does not necessarily mean it can be done into the future. But, if both Kitchen Lights and Cosmopolitan are able to be developed, it seems there is enough currently known resource to meet current levels of demand at least for the next decade and beyond.

10:34:42 AM

MR. MAYER pointed out, however, that the market side continues to hold its long-time perception and deep concern of gas supply shortage. On the other hand, the public testimony of developers of new resource, such as Furie and BlueCrest Energy, Inc., is that the challenge is lack of demand and the impact of lack of demand in developing their resources. At first blush this seems hard to reconcile and hard to understand. He said this was the question that most perplexed him and Mr. Tsafos when they first began this analysis. He explained that the modeling on the next several slides spell out that picture and why both of these things can be true at the same time. The analysis starts with some hypotheses. For example, is market timing the issue? Is the market currently covered by existing contracts so there

isn't an opening for new producers now, but there will be a window in the future that might enable larger scale development? Is this a natural negotiation process between buyers and sellers who are still trying to figure out the right pricing point to enable development of this resource? How much of it is about fundamentally different views on resource certainty? What is actually at some of these new fields and how reliably deliverable is that gas? All these questions are part of what play into the uncertainty on both sides of this picture. The next several slides are the results of some high level economic modeling done by enalytica to understand what this picture looks like, particularly for someone currently trying to develop new gas resource in the Cook Inlet.

10:36:49 AM

MR. MAYER showed slide 15, "PROJECT #1: MARKET CONSTRAINED (ASSUMPTIONS)," and stated that the modeling does not represent any particular project and is not based on any particular data other than some publically made statements by some of the companies around spending on such things as facilities and wells. Referring to the left-hand chart, "PRODUCTION AND DRILLING," he outlined a hypothetical scenario in which the company has spent $400 million on a facility because it does not have any existing mature fields with production. As an entirely new development, a platform, pipeline, and other facilities had to be built. The company must size the development to eventually produce a substantial quantity of gas. The development could produce, say, 150 Mmcf/day for 10 years. However, the constrained gas market will only allow for the contracting and selling of 15-20 Mmcf/d, so the company only drills one well. (For example, last year Furie testified it drilled one well that could produce on about 18 Mmcf/d.) So, because of the constrained demand in this hypothetical scenario, the company only drills that one well for the first several years. Several years later the company attains the ability to sell 25-30 Mmcf/d and it takes several more years to hit the mark of 30 Mmcf/d. The company therefore spends a whole decade during which it only drills four wells.

MR. MAYER, continuing his discussion of Project #1, turned to the right-hand chart on slide 15, "CASHFLOW AND COMPONENTS: $6/MCF," to review the economics of the hypothetical project. He explained the economics look really, really difficult because the company had the upfront capital expenditure ("capex") of $400 million (blue bars) for building the platform and other facilities. However, the after tax cash flow ("ATCF") (black

dashed line) is nowhere near as negative as capex; this is due to the impact of the substantial credits that are available. Stacking the 25 percent Net Operating Loss (NOL) Credit with the 20 percent Capital Credit results in 45 percent of that cost being borne after the fact by the State of Alaska. The remaining 65 percent is borne by the company. That ratio changes for drilling expenditures ("drillex") where it is as high as 65 percent effective support for spending. Even with the impacts of those credits, he continued, it is still difficult economics to make work, because the company must struggle with the big upfront capital expenditure that had to happen and cannot produce at anything like an optimal rate to justify that capital expenditure due to the constrained demand.

10:40:11 AM

MR. MAYER brought attention to slide 16, "PROJECT #1: MARKET CONSTRAINED (RESULTS)," to look at the six charts summarizing the economic results for this hypothetical project. He noted that the top three charts depict the split of net present value (NPV) across a range of price cases discounted at a 10 percent rate between the company, the federal government, and the state [one chart representing the status quo under Senate Bill 21, passed in 2013, Twenty-Eighth Alaska State Legislature; one chart representing HB 247 for NOL only, and one chart representing Senate Bill 21 with the Gross Value Reduction (GVR)]. He further noted that the bottom three charts depict [the investment metrics] of government take and investor internal rate of return (IRR) [under the status quo, HB 247 for NOL only, and Senate Bill 21 GVR]. He explained that under the status quo there is: no tax on oil, although this hypothetical scenario is looking at a dry gas development; 45 percent in stacked credits for facilities capital spending; and 65 percent in stacked credits for drilling expenditures. As seen by the investment metrics chart for the status quo, Alaska's fiscal regime is one of the most generous in the world with 40 percent or less in government take, but the project's rate of return is still quite challenged. At [lower] prices the rate of return is below 10 percent and at higher price levels the return goes into the high teens. Some of those price levels are enough for a larger, more established player that can get cheap financing to sanction a project. However, smaller players without substantial assets must look for mezzanine financing, which is possibly 20 percent or more. It would therefore be really difficult for smaller players to make this project happen even with the existing substantial credits. It would be possible, but would require further tweaking and optimization and a whole

range of other things to make it happen. Drawing attention to the chart for the split of net present value under the status quo, Mr. Mayer pointed out that [at wellhead gas prices between about $5 and $7/Mcf] this project over its lifespan would be net present value negative, value destroying; and at prices [over $7/Mcf] such a project would be net present value positive, value creating for the company. The federal government would always be well protected. The State of Alaska, across all the depicted prices for this project, would be in a pure subsidy zone, the state in-net would be handing over cash. The credits are always greater than the combination of the royalty and the mineral production tax, the state would in-net be handing over cash on a net present value basis in order to incentivize gas development, essentially it would be a subsidy.

10:43:01 AM

MR. MAYER, continuing on slide 16, reviewed the two charts depicting the economic summary of what HB 247 would do in the Project #1 scenario of a constrained market. Rather than the 45-65 percent in credits, there would only be the 25 percent Net Operating Loss Credit. In those years before production occurs and assuming the company does not already have production and is able to claim a Net Operating Loss Credit, the impact would be to further reduce internal rates of return. The return would go down into the low single digits at the lowest prices and would only get above a 10 percent rate at the highest prices. At most of the depicted prices, government take would be in the zone of 50 percent rather than 40 percent, and would get up towards 60 percent at the [highest prices]. The state would be value negative at some prices and value positive at others, and the company would only look value positive in the highest prices and would be loss making in all the rest.

MR. MAYER turned to the two charts for Senate Bill 21 with the GVR, explaining that the charts are included here not as a recommendation, but simply as an interesting point of comparison for how things would look if the North Slope regime for new oil was extended to the Cook Inlet. In this case there would be high government take of around 60 percent across all prices, which is pretty much what that regime was designed to do. Compared to the internal rates of return under the existing tax structure but with only 25 percent net operating loss, the rates of return don't look all that different. They are a little bit lower, but relative to the difference in government take they are not much lower and the reason is that this is a regime with a 35 percent net operating loss rather than the 25 percent. On

the other hand it is a regime with an actual tax liability at the end when a company is producing cash. The basic idea is that if a company is a smaller producer that cares in particular about internal rate of return rather than the value that is created over the life of the project, a higher credit at the outset has a bigger impact than the cash in the tail. That is a different set of priorities than would apply to a larger and better capitalized company. The basic story here is that when a company is facing market constrained demand and has to spend hundreds of millions of dollars on a new facility, the economics look really, really tough even with credits at this level. The basic impact of the credits is to make what isn't a very marginal investment maybe just possible.

10:45:36 AM

MR. MAYER moved to slide 17, "PROJECT #2: MARKET UN-CONSTRAINED (ASSUMPTIONS)," and posed a second hypothetical scenario with the same resource base as Project #1. For hypothetical purposes he stated the assumptions of 600 Bcf of gas, that there would be a plateau rate, and that the resource would be developed in an optimal manner of about 130 Mmcf/d of gas. Rather than drilling one well every couple of years, three wells a year would be drilled for the first three years to reach that plateau rate. To maintain the plateau rate of production, another one well a year would be drilled for the next many years. Referring to the right-hand chart, "CASHFLOW AND COMPONENTS: $6/MCF," he pointed out that this change in drilling profile looks much healthier for cash flow and is more recognizable as the cash flow profile of an oil and gas investment.

10:46:37 AM

MR. MAYER turned to slide 18, "PROJECT #2: MARKET UN-CONSTRAINED (RESULTS)," to look at the six charts summarizing the economic results for this second hypothetical project. These numbers all look much healthier, he said. The internal rate of return under the status quo would range from 20 percent [at a wellhead gas price of $5/Mcf] to 40 percent [at $9/Mcf], making this a very attractive investment, and the split of net present value would be positive for everyone. Under the status quo, the company would be highly positive relative to the state, a function of a fiscal regime with only 50 percent government take at those prices along with the substantial credits. Those credits, he continued, are clearly essential to get a project that is constrained by market demand to happen; if the market constraint was solved the credits are much less necessary.

MR. MAYER next looked at the summary charts for Project #2 under a scenario of HB 247 with only a Net Operating Loss Credit. He noted the rates of return would be substantially reduced, going from 15 percent [at $5/Mcf] to 30 percent [at $9/Mcf]. If a company could make a development look like that, had certainty when it started the initial investment, and was capitalized to do so, "it's hard to see that that wouldn't be an economic investment sort of under that sort of structure," he continued, he said. Regarding what Project #2 would look like under a scenario of Senate Bill 21 with the GVR, he advised that the same sort of lesson would apply. The upfront credits would be slightly higher, but there would also be higher take in the tail years. Again, lower total value for the company and higher total value for the state, but not fundamentally dissimilar internal rates of return.

10:48:27 AM

REPRESENTATIVE HAWKER observed hypothetical Project #1 assumes a very constrained marketing ability, limiting the frequency and number of wells that can be pursued. Hypothetical Project #2 assumes an unconstrained gas market where wells are drilled every single year and keeping growing production, clearly the economic differential. When Cook Inlet had the consumption by Agrium and the operating/production buffer of exports, it was essentially a completely unrestrained market, he said. As much gas could be moved out of the inlet as could be produced. Today there is not the luxury of that regular export. He asked whether Mr. Mayer has any suggestions for how today's market could be unconstrained or whether export or a new anchor client are the only choices.

MR. MAYER replied that to truly unconstrain the market he thinks export or a new anchor client generally are the only choices. He added that there is possibly some degree of a chicken and egg problem in that an export anchor client would need a substantial degree of certainty of supply before it would be willing to invest substantial money in reopening a facility and the developer of new gas would need to know that that demand is going to be there to make the investments required to prove that the gas can be delivered. There is a role in that world for government to bridge that gap, he advised, whether it is with credits or loan guarantees or other things that can come together and make that happen. But at the moment, he continued, there is substantial spending on a very targeted and tailored set of things in Cook Inlet through the credit program.

10:50:13 AM

REPRESENTATIVE HAWKER said another element that might be at play here is prospectivity. Until a few years ago, producers were operating off the five major gas domes, essentially all it took to get gas was to punch down another straw in those major domes. However, those major domes are now approaching or are depleted. While the argument is made that there are trillions of cubic feet of gas in the inlet, it is an entirely different effort to go find it. He asked whether the committee should consider the prospectivity factor.

MR. MAYER responded that that is absolutely an excellent point. For the next decade or decade and a half of gas security for Southcentral Alaska, he said, it seems that overwhelmingly the biggest challenge is simply development of the known but undeveloped resource base. But, looking out beyond that [time period], it is always important to keep that in mind as well.

10:51:21 AM

REPRESENTATIVE OLSON related that the value-added plant, Agrium, was shut down six or seven years ago, but in the summers of 2013 and 2014 the company looked at the plant to see what it would take to bring it back online. The plant was found to be quite deteriorated and without state assistance in one form or another, he said, he doesn't think the plant will be re-opened.

MR. MAYER answered that he understood and pointed out that part of what makes the next level of analysis really tricky is to understand the cost-benefit analyses. If targeted measures of government support are wanted to enable and ensure development of these resources to provide gas supply to Southcentral Alaska, what is the most effective and efficient means of providing that? Is that effectively subsidizing one or two developments to ensure that even though they would otherwise be uneconomical they can happen without a gas anchor tenant for additional gas demand? Is it providing instead a different measure of subsidy to enable an anchor client? What are the costs and benefits of some of those things? Those are very difficult and tricky questions that are major programs for analysis.

10:52:53 AM

REPRESENTATIVE SEATON stated that the unconstrained assumptions would be a situation in which supply was available so there

would be competition for contracts. When the Agrium plant was operating it relied on low-cost gas, he recounted. In looking at the export costs previously given by Mr. Mayer, if the export market after liquefaction and transportation is the same price or less than the domestic supply market, then that means the only way a company could do that is to have its own gas or else it would lose money. He inquired as to how much of what is being talked about with adding somewhat massive credits into a system, is intentionally disrupting the supply and demand market to get cheap gas to enable a project to go forward that cannot stand on its own economic feet.

MR. MAYER replied those are excellent points and good questions. Regarding role of pricing versus role of credits, he said there clearly is some interchangeability between these two things. The lower prices are, the more things require credits to be viable; the less there are credits in this scheme, the more that higher prices are needed instead. Looking at the curve of internal rate of return in the world of full credits versus the world of only a Net Operating Loss Credit, he advised there would not be many investors willing to do projects this risky for a 10 or 15 percent rate of return. However, he continued, imagining that as possible, there is ultimately a gas price - a higher gas price - that is capable of delivering the equivalent return as in the world of full credits. Therefore, the credits allow a project to go forward at a gas price at which the project otherwise would not have happened.

10:55:53 AM

REPRESENTATIVE SEATON said he is trying to ascertain whether the high amounts of credits to get an unconstrained market actually distort and lower the price so that the effectiveness of lower price goes away unless legislation or regulation are used to fix a higher price in order not to diminish that incentive for all of the other players.

MR. MAYER responded that that depends on a lot of factors. The gas price in Cook Inlet is currently one of the few commodities in the world that hasn't fallen dramatically over the last several years, a nice environment to be in. Suddenly, some initial contracts have been signed between utilities and new sources of supply at slightly lower prices than the consent decree pricing that has governed the majority of those contracts. That said, when it comes to the question of exports and export availability, all of those prices remain on the high side as compared to the export pricing for LNG to Japan that is

seen on slide 12. So, at least until LNG into Asia or other export uses of gas have a much higher value, it is hard to see that prices in the Cook Inlet are artificially low. Relative to the rest of the world, they remain artificially high.

10:58:07 AM

REPRESENTATIVE SEATON clarified he is trying to get to the interaction between the credits which have the goal to stimulate production that isn't sold locally and so is exported or used industrially. That excess supply is going to change the price throughout the market, because more players having more gas will lower [the price]. "I would think that you would have that market condition," he said, "but it seems like we're changing the market condition solely with by applying the credits."

MR. MAYER answered that if it were possible to develop some of these resources at substantial scale and there were nowhere else for that gas to go, that would clearly have an impact on market pricing. The bigger question is whether it is possible to develop these resources without a substantial external source of demand in the first place. He deferred to his colleague, Nikos Tsafos, to further answer the question.

10:59:22 AM

NIKOS TSAFOS, President & Chief Analyst, enalytica, Consultant to the Legislative Budget and Audit Committee, explained how he looks at the supply and demand picture by turning to slide 14. Recalling the constrained and unconstrained market scenarios previously discussed, he said it is clear that an unconstrained market would be great and all these things would be economic. Alaska is sort of stuck in this world of having a lot of credits but also pretty high prices relative to the rest of the world. On the one hand it is being said that Alaska has to get this market going. The challenge with that proposition, he said, and to which he does not yet have an answer, is that if AGDC thinks there is market demand in the state that could go up to 115-130 Bcf/year once some of the potential demand in the Interior is added, plus another 50-60 Bcf/year of nitrogen demand, it is hard to reconcile that demand picture with the supply picture of 1,600 Bcf. It is almost like saying if the demand was there this resource could be developed now, but if this resource is developed now it would probably run out much sooner and maybe not have the supply security for someone like Agrium. Agrium is not going to reopen the plant on the basis of five years of supply, Agrium would probably need longer-term supply. The

question goes back to what Mr. Mayer asked about whether the right number is this 1,600 Bcf or 1,800 or 1,200 or 2,000. Drawing attention to the bottom half of slide 14 about timing, Mr. Tsafos discussed how this market would ultimately develop under the assumption that both the supply and demand picture are correct. The base market would be pretty well covered by the resource and the existing fields with new wells would be able to meet demand. At some point that will run out and will create a wedge for new fields to be able to come in and capture that demand. It is similar to discussions about the Alaska LNG (AK LNG) Project, which is that the project couldn't be brought on line now, but looking out to 2024-2025, some of the existing supply will have fallen, some of the new demand will have come in, and there will be a window.

MR. TSAFOS said if the aforementioned numbers are correct, that would be the market way to resolve this. Essentially there is stranded gas, gas that doesn't have a clear market right now to come in but is not big enough to create that market. It is more than just a chicken and egg thing, there is also a time component which makes it a little more complicated. Going to Representative Seaton's question, there is clearly some market inconsistency and inefficiency here - there is only a handful of buyers and there is only a handful of sellers and there is a price discovered process and there is a time process and that can get messy. If this is the resource base, it is difficult to see how it would be said to bring in all this demand, unless it was thought that by virtue of bringing this demand it would incentivize exploration that gets into the undiscovered resource. Folks looking at this market right now would say that there is nowhere to sell the gas that they might find because they would be fourth in line, whereas if a new market for the gas is created then maybe those folks would think differently. So, that is the only dynamic aspect to that.

11:04:05 AM

MR. MAYER added that a big part of the aforementioned is what the nature is of the known but undeveloped resource base. If it is the size of DNR's current estimate, then it is really talking about mechanisms to aid the economics of developing the resource in a constrained gas market because it is not really sufficient to provide long-term supply at the level of demand that would be had, for instance, with the reopening of the nitrogen facility. If it is substantially bigger than that, and the operators of those places have made some claims that are much higher than DNR's numbers, then higher levels of production and export

demand start to make sense. What is the optimal solution to that problem depends a lot on what is the nature of the known but undeveloped resource base.

11:05:04 AM

REPRESENTATIVE SEATON stated he is trying to get to the crux of the question, which can be seen in the top left chart for the status quo on slide 16. In every price scenario shown, $5-$10/Mcf wellhead gas price, the State of Alaska has a net present value loss, meaning the state's credits are so large that the state will never recover its investment. It may be that some additional production could be stimulated by subsidizing all of that production. In other words, the state is paying an unknown amount per Mcf for production that will go somewhere other than to the local supply base. It is switching profitability from the state to an exporter, whether exported through industrial use or through LNG. Those credits are giving the state a net present value loss for the entire value of the project even at the highest prices, and that is what committee members are here considering - are the credits needed in addition to the price being the highest price in the world? If a price of $5-$6 is sufficient to develop the highest priced gas fields in the world, as stated by Mr. Mayer, should the state double up when the entire double up on the credit system in the status quo is a total net loss to the state and not necessary to achieve the goals of even higher priced gas development? These slides get to the crux of that question, he opined, and he sees that as the only question that the committee is here is to answer: Have the credits done their job and are they necessary though for future production unless the state is just trying to help some private export project? It is fine if [legislators] want to do that, he said, but the credits are not showing up as necessary for domestic production.

11:08:13 AM

REPRESENTATIVE OLSON commented that when Cook Inlet was operating most efficiently it wasn't really relying on the tax incentives or anything else. It was a situation where one of the major producers in the inlet owned the urea plant for 20 or 25 years, the producer always had enough gas one way or another, and the producer always made money on both sides. It worked out really well until the producer started shutting assets and Agrium picked up the property for five years and was unable to do the same thing. There was also additional demand coming from the Anchorage utilities at that point in time. It was extremely

profitable without a whole lot of assistance because it was basically a monopoly on the stranded gas with the exception of the export. He said he thinks Agrium, then the export, and then the Anchorage utilities was the way the pie was divided. It worked extremely efficiently, he opined, but it probably won't be seen again and it probably wouldn't be allowed by the state.

11:09:22 AM

REPRESENTATIVE HAWKER inquired whether enalytica's modeling is of exact circumstances and specific cases that actually exist in the Cook Inlet or is of hypothetical cases.

MR. MAYER replied they are very much hypothetical models. He quoted statistician George Box who said, "All models are wrong, some models are useful." Continuing, Mr. Mayer said these models are definitely wrong, but he hopes they are useful. The models are not based on any confidential detail of any actual existing project. They are a set of educated assumptions as to what various scenarios might look like and are intended to give a directional idea as to the nature of certain circumstances and the basic directional conclusion that says market constrained development is very, very difficult. Market constrained development may well be NPV negative for the state, but it is effectively a subsidy to make a development possible that is still only barely possible with that subsidy. Unconstrained development certainly looks a lot more viable, and potentially viable, without the degree of support. Pure drilling within mature fields is generally quite economic in most circumstances. That, he said, is the high level nature of the conclusion that should be drawn from these.

11:11:07 AM

REPRESENTATIVE HAWKER compared slide 15, "PROJECT #1: MARKET CONSTRAINED (ASSUMPTIONS)," to slide 19, "PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)," and surmised that the same data set for production and drilling is used for both slides.

MR. MAYER responded that he used a lower assumption on initial production from a well. The key differences, he explained, are no upfront capital spend and lower initial production from wells from mature fields versus wells in completely new reservoirs.

MR. MAYER then addressed slide 19, "PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)," stating the final idea here was to make exactly those two changes. What does it look like if

there is no upfront capital spend of $400 million and if the well productivity is reduced somewhat because they are mature reservoirs with less reservoir pressure? He reiterated that the modeling is not anyone's actual infill drilling program; rather, it is a series of very level assumptions. It ignores entry or acquisition costs and treats those as sunk. People actually owning these assets entered at some point, paid a substantial amount of money for those assets, and made those investment decisions based on a tax regime and a tax regime extending into the future, he said, and those are all important provisos.

11:12:57 AM

MR. MAYER moved to slide 20, "PROJECT #3: DRILLING IN EXISTING FIELD (ASSUMPTIONS)," to look at the six charts summarizing the economic results for this third hypothetical project. Addressing the bottom left chart, "INVESTMENT METRICS," for the status quo, he pointed out that the internal rates of return would be enormously high. Once a 50 percent rate of return is exceeded, he explained, those numbers are no longer particularly meaningful because it is really just about the nature of a small initial upfront capital investment and the cash flow that comes afterwards. No one should quote these as knowing what the rates of return are for additional drilling in Cook Inlet; that is not the purpose of this. Enalytica's conclusion from testing these assumptions over a wide range of drilling costs, well productivities, and the other key variables, and treating the past as sunk and looking solely towards the future, is that it is hard to see circumstances under which drilling additional wells in mature fields in Cook Inlet isn't profitable even without credit support.

11:14:08 AM

MR. MAYER showed slide 21, "THE COOK INLET OIL AND GAS MARKET: A SCORECARD," to summarize his presentation. Oil production has turned around dramatically and gas production has stabilized but not turned around, he said, and part of that is due to constrained demand. There has been a major change in the basic structure of supply, demand, prices, competition, and expectations in the Cook Inlet market. Looking at the future, in most circumstances and particularly circumstances under which the known but undeveloped resource could be developed, there is a degree of security of supply for the next decade and beyond. But, understanding how to ensure that resource is developed and best developed requires a better sense of how substantial is the resource base and whether it is best incentivized by credits, or

by other means of subsidizing the development, or trying to provide access to a substantial external source of demand. Lots of these variables depend on better understanding the nature of that resource base in terms of how it can be best incentivized for development. Enalytica's final conclusion is that based on the amount of revenue currently generated from Cook Inlet and the amount spent on credits, it's hard for anyone to look at that and think it is a long-term sustainable picture. Plus, additional uncertainty was injected into the picture last year through the line-item veto and all the rest. Currently, there is enormous uncertainty over the future of what this regime looks like, how bankable these credits are, and what actual economics to apply even to something like additional drilling in existing fields, because it is unknown what the tax regime will be next year or the year after. That more than anything else is possibly the biggest inhibitor to ongoing investment and ongoing development. Finding a way to set a stable and sustainable system that investors know will stay as the regime for the next decade plus is crucial and absolutely paramount.

11:16:33 AM

REPRESENTATIVE HERRON, regarding the statement on slide 21, "Gas production has stabilized after years of steadier decline," interpreted "steadier" to mean no fluctuation decline. Regarding the analysis of HB 247 related to Cook Inlet, he inquired what is good about this proposed legislation, what is bad that should be discarded, and what is ugly that needs work.

MR. MAYER answered that on the good side he would say it is time to be having a serious conversation about Cook Inlet credits - what the state's policy aims are through those credits, what the most efficient way to achieve those aims are, and whether the current credits fulfill that aim. He said it is hard for him to see that there aren't potentially more efficient ways of doing that than the existing system. On the bad side, he continued, he would say removing the Capital Credits that exist at the moment, and particularly making that effective July 1, 2016, seems like a rash decision given there are a number of producers at the moment that have committed to drilling programs for this year and those drilling programs rely on the credit system as it currently exists being in place. A number of those cases are developments that one would really like to see go ahead and he thinks July 1 is probably inadequate lead time to enable that adjustment. Regarding the ugly side, Mr. Mayer noted that the proposal in HB 247 is to leave everything as it currently is, which includes sunsetting of the regime in 2022, taking away the

Capital Credit, and leaving in place the Net Operating Loss Credit. He said the fundamental question here is, What is the optimal fiscal regime for the Cook Inlet in the long term and what is the optimal means? If subsidies are necessary to enable certain activities to occur, what is the optimal means of delivering that? Being worried about the outflow of credits and simply saying to get rid of the Capital Credit because that mostly goes towards some of the ongoing development of mature fields rather than to new development is a crude answer to that question. More analysis and a more refined approach is possibly required to say not just what can be cut now so the state will be okay, but to say what is actually necessary to provide by way of subsidy and how to target those as intelligently as possible. How to craft, not a regime that sunsets in 2022, but an ongoing stable and sustainable regime for the inlet that achieves all of these measures?

11:19:56 AM

REPRESENTATIVE SEATON said he is trying to get to an understanding that an unconstrained market is not going to be created in the immediate term. He continued:

> And if we don't and if we spend a lot of state cash on credits to allow greater production, are we actually turning around and saying, "Okay, we are going to make a surplus that has no market in Cook Inlet to drive down prices which are actually going to be counterproductive in incentivizing other well drilling programs or other supply programs that have been effective around the world of having higher prices actually meaning the market conditions drive the exploration instead of us artificially trying to come in and basically pick winners and losers, whether it's going to be old fields or new fields, ... and giving cash to it.... Can the effect of supplying huge amount of credits be that we distort the market into an effect so that we don't get additional market-driven drilling and exploration?

MR. MAYER deferred to Mr. Tsafos for an answer.

11:21:45 AM

MR. TSAFOS responded that he and Mr. Mayer have spent the last month pouring over data and he still has no clear answer to some of these questions. What happened in Cook Inlet is something

that happens in a lot of places: big basin, big export, then a decline starts, and then it transitions to mostly local supply of market from big companies to small companies. That is pretty typical around the world. Having said that, it is also pretty clear that some of the more natural market forces that come in to help make that transition didn't quite work here. Whether talking about having a contract between a buyer and seller that is not approved by the regulator and therefore creating uncertainty for both sides about what the price structure is, for some reason getting new players to come in and take over assets from bigger companies, something that happened in the United Kingdom (UK) and Norway, happened a little bit later here. There is a pretty clear need to think about how to get this market to work better as a market. Regarding price signals, Cook Inlet has very high pricing but it is not clear that there is enough liquidity of competition that these prices are as dynamic or send as much of a signal as would be liked.

MR. TSAFOS said enalytica has been thinking about, but does not yet have an answer to, the question of, How can a better market be made? This is followed by the question of, How can policy interventions be made along the way to correct distortions in the market? The distortions over time seem to have been more important than the core market mechanisms, he continued, and that makes it difficult to figure out exactly what that market would look like. The market answer would be that [the inlet] has stranded gas that doesn't get developed and that is not a really good answer. It may be the answer, but it is not a very pleasant or satisfactory answer to come to because people have been incentivized to come in and spend money and then it is said that nothing can be done with this gas.

MR. TSAFOS stated that figuring out the answer, which he is still trying to do, goes back to the core principles of how to build a real market here, how to reinforce the market approach of this. As was stated by Mr. Mayer, the taking away of some credits would raise the equilibrium price at which things make sense. The current price is fairly good for some investments and not particularly good for others. The question is whether there is enough of the luxury on the resource base to see how it could play out for a few years, to which he does not know the answer because there is an enormous amount of uncertainty over the resource base. He said it seems there is enough of a cushion for a few years to see how those market forces could play out and whether there is a pricing system that could bring both the buyers and the sellers together to find a nice compromise and enable some of these investments. He offered his

general agreement with Representative Seaton that rather than trying to just artificially prop up a market that isn't quite working, to try to think more generally about how to make this market work better.

11:26:18 AM

REPRESENTATIVE HAWKER pointed out that in looking at the real market today, Cook Inlet has one really significant player and a few smaller players around the edge. The one significant player has been operating under essentially government price controls that came about through the consent decree in order to enter this market. Regarding creating distortions in a market, he said he is wondering whether it is really known how the inlet would work today or if it is being distorted by those government imposed price controls in the consent decree. He inquired whether the market would be different without those price controls and, if so, how different would it be.

MR. TSAFOS replied that Representative Hawker's question is what he was saying before: there are enough factors getting in the way of what would normally be thought of as a well-functioning market, there just aren't have enough buyers and sellers. In the Cook Inlet's case, an overwhelming majority supplier in the market is not going to lead to a very well-functioning market. But, going back to basic economics, if a higher price is ultimately being charged then other folks would come in and undercut that major supplier. As has been seen, some of the recent contracts are below the consent decree, so in some ways that response is happening although not very speedy. The biggest challenge is that the market signals and the market forces are there but they are just not operating very quickly. The evolution must be seen before some of these distortions or restrictions can be corrected. Representative Hawker is right that in the current structure it is not clear that there would be a much different system based on the reality of who the buyers and the sellers are and how the market is structured in Cook Inlet. The question is how to go beyond the current structure and think about what could be a different structure that doesn't require the same level of state support but still has a goal of a well-functioning gas market in the inlet.

MR. MAYER added that clearly one of the biggest impacts of the consent decree has been to substantially raise the gas price that has been paid over that period. Activity levels were low before that. The higher prices of the consent decree and the changes included in the Cook Inlet Recovery Act for how the RCA

assesses pricing decisions, have all been key and as important, if not more so, as the credits in the level of activity that has been seen since then. Because it is one large supplier and because it is an essentially immovable and regulated price decision, it is not one that necessarily responds well to market forces and it is hard to see, other than through some of the new contracts that have been signed, what sort of underlying market signaling that might be.

11:30:28 AM

REPRESENTATIVE HAWKER noted that this discussion is about distorted markets, market inefficiency created with the limited buyers and limited sellers, and the unknown impacts of the consent decree. He recalled that Mr. Tsafos spoke about a need to relook at the tax structure and system in the Cook Inlet. He posited that the Cook Inlet not currently operating in truly a free market would argue that [legislators] ought to be careful about making systemic changes now and to look at what needs to be done sometime, say, after 2018 when things actually are working in a free market environment. Care must be taken not to throw a disruption into a market that will be changing by the expiration of that agreement and how that might affect buyers and sellers.

MR. MAYER answered that Representative Hawker raises an excellent point and enalytica would say that any changes need to be crafted with a view of not just looking at the tax system but the overall functioning of the market and how the overall functioning of the market can be improved and that that particular point in time is clearly key. In a range of price environments and price mechanism scenarios, there are probably better and more efficient ways of targeting state support to achieve the aim of security of gas supply than the existing system. But it is important to take time to think through what that optimal system is, he continued, and set that for the future rather than make immediate tweaks today simply because one can and because one is concerned about the cash outflow which is substantial. This needs to be thought about as a holistic package of reforms rather than a one-time change.

11:32:44 AM

REPRESENTATIVE HERRON, following Representative Hawker's train of thought, noted that HB 247 proposes to make some of these adjustments. So, following Representative Hawker's comment, he

requested examples of pitfalls in HB 247 about those proposed adjustments.

MR. MAYER answered the biggest pitfall comes from the July 1, 2016, effective date. He presumed there will be testimony over the coming weeks of investment programs that are currently committed to by companies on the basis of the existing credits and are programs that one would like to see carried forward. Because in principle it is thought that this can be withdrawn, and therefore it should happen on July 1, poses some substantial risks in his opinion.

REPRESENTATIVE HERRON thanked Mr. Mayer for that reinforcement.

11:34:00 AM

REPRESENTATIVE JOHNSON stated he is troubled by this whole plan. However, something that he keeps thinking about and that has not been discussed, is that to pay these credits [the state] is actually borrowing the money. No one has talked about that opportunity loss, the cost of borrowing that money whether it is from the permanent fund, earnings reserve, or the Constitutional Budget Reserve (CBR). If the state had the money on hand that would be one thing, but this is going into savings to pay these, and so he is troubled by changing it and he is troubled by having to borrow to continue with it. It is very perplexing and not an easy decision to be looking at. He said consistency is probably the most important thing the state could offer, but he hates to borrow the money to be consistent, because it is leveraging the state's future, which is what is being done with the tax credits anyway. It is therefore concerning.

MR. MAYER agreed those are very difficult choices to make, not only in and of themselves, but also in terms of the way the broader market sees what is going on and responds. It is difficult to see that set of choices and think that the current system is stable or sustainable for any significant period into the future. All of those things are reasons to be thinking now about all of the detailed analysis that needs to occur to set a sustainable regime for the future and to try to make that happen sooner rather than later. That may not necessarily be the same thing as making an immediate cut to a credit this year.

11:36:02 AM

REPRESENTATIVE SEATON posited that there are two forces intended to disrupt the market - the consent decree and the credits. The

question is whether they conflict with each other. Based on enalytica's examples of the net present values and what works in the three [hypothetical] examples, it seems it is being said that under almost no scenario are the credits needed for infield drilling; that those can be supported and are economic entirely on their own without those credits. He inquired whether the following is what Mr. Mayer is suggesting would make more sense:

> ... if we are looking at ... changing that credit, we do a timing so that such as infield credits which ... can be supported on their own, are economic, aren't relying on the credits to make the project economic. That those could be July 1 and then at a later set date we could be looking at certain other projects that are already sanctioned and going forward and the credits through that to a certain date, not ... too long in the future, but through the projects that are already sanctioned.

MR. MAYER replied he would place a nuance around that. While enalytica's analysis suggests it is hard to see circumstances under which ongoing drilling in mature fields is not economic even without credit support, a number of other things need to be taken into account in thinking about that. One of those is the sheer degree of uncertainty that exists around the future of the entire tax regime and what that means for anyone making investment decisions even in terms of drilling in the mature fields. What are the other impacts of credits on that activity? If more than 60 percent of a company's drilling cost is effectively borne by the state, the timeframe the company is looking at in terms of measuring those economics is probably short enough that it doesn't really care if in a year or two the entire fiscal system changes because relatively speaking there is so little upfront cash that the company is worried about. If that is not the case, the company probably cares a lot more about what happens in year two, three, four, five, and beyond of this system. If he had a concern about withdrawing credits from those activities, it would be that to ensure those activities continue one would want to know that a stable, competitive, sustainable fiscal regime was in place that applied to those activities that when companies made investment decisions about what they were doing, they were doing it based on that regime, not on a wildly risked set of assumptions because they are simply not sure about what the future looks like.

11:39:54 AM

REPRESENTATIVE SEATON argued that if the consent decree is in place through 2018, then there is certainty among the price support. If the price support was sufficient around the world to get that, especially if some of these are being offered lower but some much higher price contracts for gas, why would there be an expectation that that price support which is being sustained throughout the domestic market would go away, he asked.

MR. MAYER responded that his problem is less about pricing as it is about the rest of the fiscal structure. Is a producer running its economics assuming the ongoing system of no production tax on oil and $.17 on gas? Or is a producer saying it has no idea what next year or the year beyond this fiscal system looks like? Is the producer having to make a series of assumptions as to what it could be and a series of worst case assumptions as to what it could be as opposed to knowing what it actually looks like and the economics of that activity look very different in those two scenarios?

11:41:07 AM

MR. TSAFOS added that high prices and strong state support provide a double support for this system. So, intuitively, one would say that less of either of those two things could be done. But, regarding the economics that enalytica ran on the last few slides, there is a big disclaimer on slide 19 that it is all point-forward. For a company to be drilling at a field it has to be in the field - it has to have platforms, the assets, and the people to do that to begin with - and the major producers in Cook Inlet came in recently based on a fiscal system that they were modeling and they were expecting. While enalytica's modeling is ignoring those costs that are sunk, they are not sunk from the perspective of the company and what it is that brought them here. Going back to Representative Johnson's comment, it is really tough because if nothing is done it is clear it is unsustainable and it is clear everyone agrees it is unsustainable. No one can make an investment decision based on this system because no one believes this system is going to last. Not doing anything creates an enormous uncertainty and just pushes it down the line. At the same time it is not really clear what kind of interventions or changes would be best. But it is clear that [the state] must come to something that is going to be seen as durable and sustainable. Cook Inlet is much more difficult than the North Slope to begin with, especially from the gas side. So, it is not hard to see how the enthusiasm of folks in the Cook Inlet disappears very quickly if some substantial changes are made to the system.

MR. TSAFOS reiterated that the transition from big international players to smaller players probably took a little bit longer than it took other places. That could have been based on the market's perception of Alaska, the risk profile, the opportunity set. These things matter. Investors are looking closely around the world about who is raising taxes and who is cutting taxes. The UK has come out with a tax break. Russia was thinking about raising taxes and chose to raise some and not to raise others. Rio de Janeiro came out recently with a tax hike. In today's global environment investors are super sensitive to thinking about what kind of changes Alaska is making. It is going to be a very tough balance. Something has to be done to make it sustainable, otherwise no one believes it. At the same time, whatever is done must be grounded in enough analysis and reason to do as little harm as possible. It is going to be a tough balance. Even with all the time spent analyzing these things, enalytica is not quite there yet.

11:45:20 AM

REPRESENTATIVE SEATON said he hopes [the state] gets there sometime because it is spending $400 million a year that it doesn't have and a decision must be made someplace as to where that goes. Whether the high gas price is the consent decree or what people are willing to pay, he continued, he has not heard from his constituents any objection to the price they are paying, which is $1 more per Mcf than elsewhere in the Cook Inlet basin in order to support the building of a transmission line down to Homer and Anchor Point. He said he challenges the idea of needing to stimulate to get a lower price on gas for domestic use. Maybe people in Anchorage are telling folks different things, but he has not heard any complaints or concerns on the gas heating bills being received within Southcentral. He said he does not know where the pressure, other than oversupply, would be to drastically lower prices unless oversupply is driven. If these credits are used to drive oversupply and drive down prices, that would cause all those smaller players to not participate in the inlet and further concentrate the supply in one person. He noted the committee has requested more analysis from enalytica regarding more of the policy decision and exactly how those intermingle. He offered his appreciation for all of the testimony.

11:47:40 AM

REPRESENTATIVE JOHNSON stated he hasn't disagreed with anything that has been said. However, he said, he would like for the focus from the administration or future presentations to be on the consequences of now, the consequences of later, the realities of now, and long term versus short term. Right now he is not convinced that the legislation before the committee will accomplish the things that the committee has heard need to be done. He would therefore like to concentrate on what some of those solutions are and concentrate on the doable as opposed to the presented that is in front of the committee. He urged that the committee focus on ways to touch this that do the least damage and that solve the problems so this does not have to be revisited by future legislatures.

11:49:12 AM

CO-CHAIR TALERICO spoke in regard to Mr. Mayer's point about making a change when the state has made a promise and people are locked into a system. He posed a scenario in which a person with a home mortgage is told by the lender that the lender's fiscal situation has changed and so now the lender is raising the interest rate despite the starting agreement. He said he sees that as being a horrible image for the State of Alaska and it will make the state look unstable. He recounted that he has looked into the criteria the state has structured in order to bring investors into the region. Although he wasn't in the legislature then, it appears from the history that consideration was given to ensuring everyone was treated fairly. There have been some failures in Cook Inlet that have cost the state money as well as the private sector. He asked how important Mr. Mayer thinks it is for the state to establish particular criteria to get a stable and sustainable system that goes out in future years. He further asked whether tightening that up is something that Mr. Mayer definitely recommends.

MR. MAYER answered enalytica would certainly say that no one can look at the amount of cash outflow and think it is a sustainable program. It is very difficult to look at the sheer amount of cash outflow also compared to what probably is, in most cases, a relatively limited cash need to assist development of resources. If the overwhelming public policy purpose of this program is to stabilize and provide security of supply to Southcentral gas, it is a much smaller subset of needs than the cash currently goes to. Precisely because of the uncertainty that exists around the future regime and precisely because of the difficult cash position that the state finds itself in, it is worth trying to do as much analysis sooner rather than later to try to figure

out what that regime is. It is also better to take the time to do that analysis and set a sustainable regime for the future, rather than to make changes as soon as possible because one is concerned about the cash and everything else is secondary.

11:52:45 AM

CO-CHAIR NAGEAK said the aforementioned discussion needs to be taken into consideration. He requested Mr. Mayer to follow up in this regard and thanked Mr. Mayer and Mr. Tsafos for their presentation.

CO-CHAIR NAGEAK apologized to the Department of Revenue for running out of time for the department's presentation and announced another time will be scheduled in the near future.

[HB 247 was held over.]

11:54:01 AM

ADJOURNMENT

There being no further business before the committee, the House Resources Standing Committee meeting was adjourned at 11:54 a.m.