Alaska's Oil and Gas Fiscal Regime

– A Closer Look from a Global Perspective

ALASKA DEPARTMENT OF REVENUE

Alaska Department of Revenue – Commissioner's Office

January 2012

STATE OF ALASKA

Governor Sean Parnell

ALASKA DEPARTMENT OF REVENUE

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Cover Photo: Alaska Stock; the Central Gas Facility (CGF), Prudhoe Bay Oilfield

This report can be downloaded at:

www.dor.alaska.gov/acloserlook.pdf

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Introduction \\\

For decades, Alaska has been a North American leader in petroleum production. But the state's oil and gas economy does not exist in a vacuum. New technologies and new discoveries mean oil and gas companies have more options than ever when deciding where to invest capital and resources. Fiscal structure is one of the most significant factors producers have to consider when making those decisions. In order to stay competitive in the global market, it is critical that the state look outward to see how it compares with other jurisdictions around the world.

In most jurisdictions, the sovereign right to explore for and produce hydrocarbons and other minerals belongs to the national or local government. This is true on federal and state lands in the United States, although outside of Alaska, there are areas of significant size where individuals own the mineral interest. Whether lands are publicly or privately owned, oil and gas companies have historically shared a variety of attributes that make it worthwhile for mineral owners to offer them significant rights and a share of the profits from exploration and production. These include:

1. A willingness to take large risks and expose significant capital searching for hydrocarbons.
2. Technical expertise in exploration and production including technology not available to the country.
3. Massive capital required to develop large fields and a willingness to invest those funds years in advance of revenues.
4. Highly trained and experienced people capable of managing such major projects.
5. Access to refineries and distribution systems to refine, upgrade and market oil and gas produced.

Simply turning over rights to an international oil company (IOC) in return for cash (and in many cases, a minor share of the revenue being generated) is not an arrangement that is beneficial to the economic health of the resource region. Under early agreements between IOCs and regional jurisdictions, local workers did not receive training or meaningful experience leading to advancement, and the immediate export of oil and gas meant there was no benefit to local industry. Beginning in the 1950s, governments began working to develop fiscal schemes that offered more long-term benefit, with issues of control, involvement of citizens beyond low-level roles and development of local industry and infrastructure beginning to change significantly in the 1960s and continuing to evolve through the present day.

In this report, we will consider how Alaska's fiscal regime compares to comparable jurisdictions around the world. In order to be a good steward of the state's resources, Alaska must define policies that encourage responsible exploration and development and manage the impacts of those policies on stakeholders and constituents. It is the constitutionally-mandated responsibility of the State of Alaska to manage the state's resources in the interest of all Alaskans.

At the same time, fiscal systems are not the only criteria oil and gas producers use to make investment decisions. Factors such as operating costs, economic and political stability and availability of lands for exploration play a role as well. Alaska's position in the global marketplace is unlikely to stay static with time; rather, it will evolve with changes in oil and gas prices, geologic potential, cost structure and outside competition. This publication presents a clearer view of some of these other important criteria used by potential investors when comparing Alaska with the rest of the world.

Peer group selection

One goal of this report is to select a reasonable peer group of jurisdictions that will allow a representative comparison of Alaska's position in the world with respect to oil and gas exploration and development. The Alaska peer group is as follows.

1. California
2. North Dakota
3. Oklahoma
4. Texas
5. U.S. – Gulf of Mexico OCS
6. U.S. – Alaska OCS
7. Canada – Alberta
8. Canada – Northwest Territories
9. Canada – Beaufort Sea
10. Australia
11. Norway
12. United Kingdom

We believe the criteria discussed in this report can provide a logical framework to show the value of using this group of peers. We narrowed the list in part by focusing primarily on concession-type fiscal arrangements, generally similar to Alaska. We preferred a geographic affinity, location in the Arctic, in North America or Europe, or in the Pacific region (Figure 1-1). We looked for jurisdictions with similar size resource potential. We favored jurisdictions with some history of hydrocarbon production. Throughout this report we will compare Alaska to all or portions of this peer group and present data to show the logic of using this comparison group.

Figure 1-1 Peer group jurisdiction and fiscal regime type and geographic affinities

Jurisdiction	Jurisdiction Type	Type of Fiscal Regime	North America	Europe	Arctic	Pacific
Alaska	State	Royalty & Tax	X		X	X
California	State	Royalty & Tax	X			X
North Dakota	State	Royalty & Tax	X			
Oklahoma	State	Royalty & Tax	X			
Texas	State	Royalty & Tax	X			
U.S. GOM OCS	Federal	Royalty & Tax	X			
U.S. Alaska OCS	Federal	Royalty & Tax	X			
Alberta	Province	Royalty & Tax	X			
Canada-Northwest Territories	Federal	Royalty & Tax	X		X	
Canada-Beaufort Sea	Federal	Royalty & Tax	X		X	
Australia	Federal	Royalty & Tax				X
Norway	Federal	Royalty & Tax		X	X	
U.K.	Federal	Royalty & Tax		X		

Hydrocarbon endowment \\\

A region's production history and future production potential are important elements to consider when establishing or reviewing a petroleum fiscal system. It seems logical that Alaska's fiscal system peer group should include jurisdictions that have a similar resource base and production volumes, referred to in this report as the hydrocarbon endowment.

This section of the report focuses on the comparison of Alaska's hydrocarbon endowment for conventional oil and does not address other resource types, such as natural gas and viscous or "heavy" oil. While these resource types will possibly be important contributors if Alaska's overall production is to increase, there is no available source of worldwide unconventional resource comparisons. Note that in addition to statistics for natural gas resources, reserves and production are provided here because they are important components of the resource base in jurisdictions outside Alaska. Estimates are for the conventional natural gas resource and should not be completely dismissed as irrelevant.

Production volumes

The Energy Information Agency (EIA), an agency of the U.S. Department of Energy, is used throughout this report as our primary source for petroleum production and proved reserves for both North America and the rest of the world (Figure 2-1). In the case of Canadian provinces, data were gathered from Canada's National Energy Board (NEB). The EIA provides annual estimates of the United States' proved reserves of crude oil and natural gas based on filed responses to Form EIA-23, Annual Survey of Domestic Oil and Gas Reserves, which includes data from about 1,200 domestic operators.

Figure 2-1 Historic production in Alaska and its peer group jurisdictions

Jurisdiction	Annual Oil Production			Annual Natural Gas Production		
Units	2008	2009	2010	2008	2009	2010
	[MMbbl/d]	[MMbbl/d]	[MMbbl/d]	[MMcf/d]	[MMcf/d]	[MMcf/d]
United States[1]						
Alaska (onshore & state submerged)	910	710	659	1,025	1,025	NA
California	649	664	686	774	720	NA
North Dakota	172	218	310	122	135	NA
Oklahoma	175	184	190	4,882	4,781	NA
Texas	1,089	1,108	1,172	17,970	17,520	NA
U.S. Alaska OCS[2]	0.00	0.00	0.00	0.00	0.00	NA
U.S. GOM OCS	1,551	1,559	1,152	NA	NA	NA
Canada[3]						
Canada-Alberta	1,704	1,802	1,929	5,265	4,866	4,644
Canada-total (includes Alberta)	3,350	3,294	3,457	6,921	6,443	6,247
Rest-of-the-World[4]						
Australia	586	588	549	4,329	4,570	4,364
Norway	2,463	2,350	2,133	9,597	10,011	10,290
U.K.	1,584	1,502	1,393	6,764	5,718	5,447

[1] Data source for United States production reserves is the Department of Energy, Energy Information Agency (EIA) at http://www.eia.gov/oil_gas/natural_gas/data_publications/crude_oil_natural_gas_reserves/cr.html.
[2] The only oil production allocated to the Alaska Outer Continental Shelf (OCS) is a small fraction of the production from Northstar field. This production is insignificant when compared to the rest of Alaska and its peer group and is not broken out in EIA reports. Because of the units used in this table, Alaska OCS production appears as zeros, but the actual production was approximately 1,000 bopd in 2010, 1,500 bopd in 2009, and 3,200 bopd in 2008.
[3] Data source for Canada production is Canadian Association of Petroleum Producers (CAPP) at http://www.capp.ca/library/Pages/default.aspx#blqtLXUqbFz5. Includes light, medium, and heavy oil and mined and in-situ oil sands production.
[4] Data source for Rest-of-the-World production is the Department of Energy, Energy Information Agency (EIA) at http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_a.htm

The purpose of this report is not to explain or offer the definitive cause for these production trends. There are a number of possible explanations for changes in production. Primarily, we provide these numbers as a basis for discussion.

First, let's compare Alaska production with other North American peers (Figure 2-2). This group of North American producers includes all the largest-volume oil-producing jurisdictions in North America. In the past three years, Alaska's production has declined steadily. Production in the states of California and Oklahoma held relatively constant. Oil production in Texas is up slightly and up significantly in Alberta and North Dakota over the same time period. Production from the Gulf of Mexico was down steeply in 2010, likely related to the shut-in of production mandated by the federal government in the wake of the Macondo blowout and oil spill.

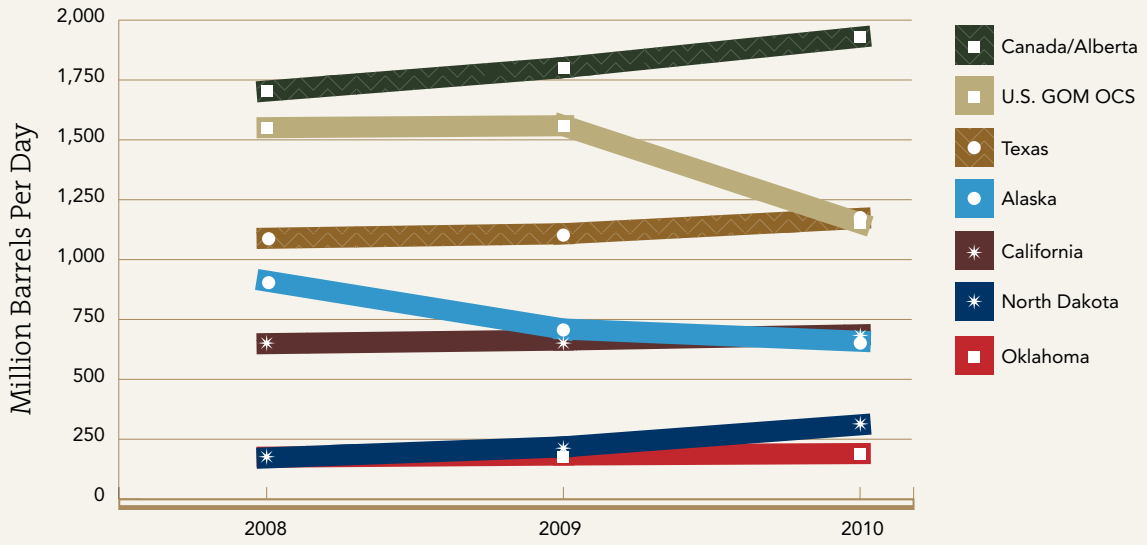
Australia, Norway and the U.K. have all experienced production declines over the last three years, possibly reflecting the maturity of the basins where production occurs.

Proved reserves

EIA defines "proved reserves" as "those volumes of oil and natural gas that geologic and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions." Reserves estimates change from year to year as new discoveries are made, existing reserves are produced and prices and technologies change. Discoveries include new fields, identification of new reservoirs in old fields, and extensions. Extensions are reserve additions that result from additional drilling and exploration in previously discovered reservoirs. Extensions typically account for a large percentage of "discoveries" within a given year. While actual discoveries of new fields and reservoirs are important indicators of new resources, they usually account for a small percentage of reserve additions in a given year. Revisions occur primarily when operators change their estimates of what they will be able to produce from the properties they operate using existing technology and prices.

While several factors influence proved reserves, crude oil and natural gas prices are particularly important. Higher prices typically increase estimates (positive revisions) as operators consider a broader portion of the resource base economically producible, or proved. Lower prices generally reduce estimates (negative revisions) as the economically producible base contracts.

Figure 2-2 Three-year oil production history for Alaska and its North American peers



Source: Department of Energy, Energy Information Agency (EIA).

Figure 2-3 Estimates of proved reserves and undiscovered resources in Alaska and its peer group jurisdictions

Jurisdiction [Units]	Oil Reserves Proved [MMbbl]	Gas Reserves Proved [BCF]	Oil Resource Mean Estimate Undiscovered [MMbbl]	Gas Resource Mean Estimate Undiscovered [BCF]
United States[1,2]				
Alaska (onshore & state submerged)	3,566	9,183	19,600[3]	147,096[3]
California	2,835	2,926	3,688	7,349
North Dakota	1,058	1,213	768	1,464
Oklahoma	802	24,207	637	10,244
Texas	5,496	85,034	5,622	55,468
U.S. Alaska Arctic OCS	NA	NA	23,750[3]	108,180[3]
U.S. GOM OCS	4,007	12		
Canada[4,5,6]				
Canada-Alberta (conventionl)	1,491	35,300	NA	NA
Canada-Alberta (unconventional)	26,000	NA	NA	NA
Canada-Total (includes Alberta)	175,000	61,950		
Rest-of-the-World[5,6]				
Australia	3,318	110,000	46,746	114,000
Norway	5,670	72,000	12,881	183,000
U.K.	2,860	9,040	6,329	23,377

[1] Data source for United States production reserves is the Department of Energy, Energy Information Agency (EIA).
[2] The only oil production allocated to the Alaska Outer Continental Shelf (OCS) is a small fraction of the production from Northstar field. This production is insignificant when compared to the rest of Alaska and its peer group and is not broken out in EIA reports. Because of the units used in this table, Alaska OCS production appears as zeros, but the actual production was approximately 1,000 bopd in 2010, 1,500 bopd in 2009, and 3,200 bopd in 2008.
[3] Data source for Canada production is Canadian Association of Petroleum Producers (CAPP) at http://www.capp.ca/library/Pages/default.aspx#blqtLXUqbFz5. Includes light, medium, and heavy oil and mined and in-situ oil sands production.
[4] Data source for Rest-of-the-World production is the Department of Energy, Energy Information Agency (EIA).
[5] Data source for Canada (total) and Rest-of-the-World reserves is the Department of Energy, Energy Information Agency (EIA) at http://www.eia.gov/emeu/iea/res.html.
[6] Data source for Canada (total) and Rest-of-the-World undiscovered resource estimates is the U.S. Geological Survey (USGS) at http://pubs.usgs.gov/dds/dds-030/

Alaska's proved reserves and peers

Alaska's proved oil reserves exceed all of the other U.S. states except Texas (Figure 2-3). Continuing improvements in technology and changing economics of producing unconventional oil from the Williston Basin could possibly increase North Dakota's reserves to Alaska's level in the future. Similarly, if unconventional oil development occurs on the North Slope, Alaska reserves could also increase dramatically. Proved oil reserves in Norway are much greater than Alaska's but are still within a range that does not preclude them from consideration for an Alaska peer group. Australia's oil reserves are similar in size, and the U.K.'s oil reserves are only somewhat lower.

Proved reserves in both Norway and the United Kingdom have declined in recent years. However, significant new discoveries in Norwegian waters of the North Sea that were announced in the past year may reflect a change in fortune for the basin. At the time of this writing, it remains unclear if they are large enough to reverse the declining trend of oil reserves in the North Sea.

Undiscovered oil resource estimates

The U.S. Geological Survey (USGS) is used throughout this report as our source for undiscovered resource estimates for both North America and the rest of the world.[1,2] The USGS assesses the recoverability of undiscovered conventional oil and gas resources, seen in Figure 2-3.[3] Their analysis estimates how much undiscovered conventional oil and gas is technically recoverable. For the onshore United States, the "assessment units" defined in the USGS analysis do not conform to any state or political jurisdictional boundary. Instead, the "assessment units" are based more on geologic divisions. In this way the USGS avoids dividing otherwise single coherent continuous plays between two or more assessment units. The international undiscovered resource assessment more closely adheres to national boundaries to define the "assessment units" or the geographic limits of the area analyzed. Understanding how much undiscovered technically recoverable resource might be present serves as a basis for calculating how much might be ultimately economically developed.

Technically recoverable resources are those that could be potentially produced using current technology and industry practices. Economically recoverable resources are those that can be sold at a price that covers the costs of discovery, development, production and transportation to the market.

USGS assessments are meant to provide a means to estimate quantities of undiscovered conventional oil, gas and natural gas liquids that have the potential to be added to reserves (proved and otherwise) in some specified future time span. These estimated petroleum volumes reside in fields whose sizes exceed a minimum cutoff value that the USGS establishes for each assessment unit. The term "undiscovered conventional resource" as used in this report is understood to mean short approximations of this objective. Note that the USGS assessment of undiscovered resource has no stated or implied estimate of timing of development or volumes produced.

The USGS defines both heavy oil and shale oil as unconventional and considers those resources separately from its conventional resource estimates. While the USGS provides undiscovered resource estimates for nations in a relatively straightforward manner, its use of assessment units that do not adhere to state boundaries presented a barrier to clear comparisons for this study. To circumvent this barrier, we approximated undiscovered resources by state by visually estimating the areas of the assessment units contained within the state boundaries and prorating the total based on the estimated area allocations.

The USGS assessment effort ranks Alaska's undiscovered resource potential in a relatively high position compared to other parts of the world. Alaska's onshore undiscovered conventional petroleum resource is estimated to be approximately 17 billion barrels of oil. When the estimate for offshore undiscovered petroleum resource is added in, Alaska has over 43 billion barrels of oil. The USGS characterizes these estimates as representing a "significant potential for energy and mineral resource that is unmatched by any other onshore region of the U.S."

Natural gas, viscous oil and other unconventional resources

As stated earlier, we chose to focus the attention of this publication on Alaska's conventional oil and the fiscal systems the state has put in place to capture revenue from it. But it is important to keep in mind that Alaska also has other significant hydrocarbon resources. The state has large quantities of other classes of hydrocarbon resources including natural gas, viscous oil, shale oil, shale gas, coalbed methane, and gas hydrates.

Natural gas

Alaska has a huge resource base of discovered and undiscovered gas (217.91 trillion cubic feet). Expensive and time-consuming exploration programs will be required to extend the natural gas reserves and identify new commercial gas fields. Much of northern Alaska's conventional natural gas remains unexploited awaiting construction of an export pipeline or development of some other export option. Any capital spending to identify new natural gas reserves will only be made by companies expecting long periods of time bef ore payback on investment. All of the options to construct infrastructure to exploit northern Alaska gas will likely be expensive and technically challenging. Two possible scenarios for export of northern Alaska gas are a gas pipeline down existing highways from Prudhoe Bay to Alberta, Canada or shipping liquefied natural gas (LNG) from tidewater. No clear decision has yet been announced on any option.

[1] http://energy.usgs.gov/OilGas/AssessmentsData/NationalOilGasAssessment.aspx

[2] http://energy.usgs.gov/OilGas/AssessmentsData/WorldPetroleumAssessment.aspx

[3] The USGS also does unconventional resource assessments for resource types not included in this report, including coalbed methane, source rock oil and gas (shale oil and gas), continuous tight sands, and gas hydrates.

Viscous oil

Alaska has a large discovered and delineated potential for the production of viscous oil, sometimes referred to as "heavy oil." Viscous oil delineation and test production has been occurring for decades. Schrader Bluff (including West Sak) and Ugnu reservoirs in the Kuparuk River, Milne Point, and Prudhoe Bay units have recently been estimated to contain a total of 23 to 36 billion barrels of viscous oil in place.[4] This compares to a previous estimate of 18 to 40 billion barrels in place in the loosely described "Kuparuk River area."[5] Additional in-place volumes in the Schrader Bluff reservoir at Eni's Nikaitchuq Unit are estimated at 800 to 930 million barrels (AOGCC Conservation Order 639).[6]

Current production of viscous oil flows from six Participating Area (PA) developments in four North Slope units: Kuparuk River, Milne Point, Nikaitchuq and Prudhoe Bay. The combined in-place resources under active development total 5.5 to 7.4 billion barrels. These developments are expected to recover 1.0 to 1.2 billion barrels, with overall recovery factors of 15 to 20 percent.[7]

Other unconventional resources

Alaska has significant potential in the form of several other types of unconventional resources. Notable among these are coalbed methane, methane hydrates, and shale oil.

Coalbed methane

Coalbed methane is a form of natural gas extracted from coal beds. In recent decades it has become an important source of energy in the United States, Canada, and other countries. Coalbed methane is distinct from natural gas produced from a typical sandstone or other conventional gas reservoir because the methane is stored within the coal by a process called adsorption. The methane is in a near-liquid state, lining the inside of pores within the coal (called the matrix). The open fractures in the coal (called "cleats") can also contain free gas or be saturated with water. The adsorbed gas is extracted along with fluid from a well completed in the coal seam (300 to 5,000 feet below ground). Adsorbed gas is released when sustained fluid production reduces the pressure within the coal seam. As formation water is produced from the coalbed, both gas and "produced water" come to the surface through tubing.

Methane hydrates

Another unconventional resource, methane hydrates, is a huge potential hydrocarbon resource in Alaska, as well as in many locations throughout the world. In 2008, the USGS completed the first assessment of the undiscovered technically recoverable gas hydrate resources on the North Slope of Alaska. Using a geology-based assessment methodology, the USGS estimates that there are about 85 TCF of undiscovered, technically recoverable natural gas resources within gas hydrates in northern Alaska.[8] This untapped resource is a significant addition to Alaska's resource base and will possibly prove to be an important component to gas production in the future.

Shale oil

Lately, the focus of unconventional resource discussion in Alaska has shifted to shale oil. Lease acquisitions and discussion of plans to drill test wells in northern Alaska by more than one company has brought considerable attention to the possibility of producing oil and gas from shale in Alaska. The technology necessary to produce oil and gas from shale in the Lower 48 has evolved in the past few years and is now accepted as relatively mainstream. Many oil and gas exploration and production companies of all sizes are participating in the rush to exploit this newly emergent resource. Alaska is now receiving attention as a possible new frontier in this resource play. It remains unclear whether Alaska's shale resource plays can prove productive or if the technology applications and methods used to produce shale oil in the Lower 48 will translate reasonably well to an Arctic environment. No assessments have been done to estimate the resource potential for shale oil in Alaska.

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[4] Hartz, J., Decker, P., Houle, J., and Swenson, R., 2007, The historical resource and recovery growth in developed fields on the Arctic Slope of Alaska (abs), American Association of Petroleum Geologists Annual Convention and Exhibition Hedberg Conference Proceedings, April 1-7, Long Beach, California, 4 p.

[5] Werner, M.R., 1987, West Sak and Ugnu sands; Low-gravity oil zones of the Kuparuk River area, Alaskan North Slope, in Tailleur, I., and Weimer, P., eds., Alaskan North Slope Geology, v. 1: Bakersfield, California, Pacific Section, Society of Economic Paleontologists and Mineralogists and Alaska Geological Society, p. 109-118.

[6] Alaska Oil and Gas Conservation Commission, Conservation Order 639 and production records.

[7] Hartz, J., Decker, P., Houle, J., and Swenson, R., 2007, The historical resource and recovery growth in developed fields on the Arctic Slope of Alaska (abs), American Association of Petroleum Geologists Annual Convention and Exhibition Hedberg Conference Proceedings, April 1-7, Long Beach, California, 4 p.

[8] USGS, 2008, Assessment of Gas Hydrate Resources on the North Slope, Alaska, 2008, USGS FS08-3073, 2 pp.

Lease sales \\\

The State of Alaska offers its oil and gas mineral estate for exploration and development primarily under two programs: conventional oil and gas leases (AS 38.05.180) and exploration licenses (AS 38.05.131 – 134). The Alaska Department of Natural Resources (DNR) is charged with preparing and scheduling a five-year proposed oil and gas leasing program. A detailed description of the state's leasing programs and schedule, including location information for lease sales that will be held in the next five years, is updated annually and is available to view or download from the DNR Division of Oil and Gas website.[9]

Conventional oil and gas leases

In 1998, DNR changed the way it offered state lands for competitive bid oil and gas leasing for the North Slope, North Slope Foothills, Beaufort Sea and Cook Inlet areas. These are the areas designated by the state as having moderate to high potential for oil and gas development. So-called "areawide leasing" became the standard for lease sales so that the state could provide stability and predictability in the lease sale program. In 2004, the Alaska Peninsula was added to the list of areas offered by the state under the areawide leasing program. Under areawide leasing, the state offers all available state-owned land within these five areas for lease by competitive bidding at annually scheduled lease sales. Before areawide lease sales, DNR used a nomination process and wrote best interest findings for each sale.

Conducting annual areawide sales is more cost-effective because it allows companies to plan for and develop their exploration strategies and budgets years in advance and to bid on any available acreage within an entire region. A regular schedule of areawide lease sales allows for quick turnaround of expired or terminated leases, or leases contracted out of units, for reoffer in the next annual sale. The result is more efficient exploration leading to earlier development. It also allows smaller companies and individuals the opportunity to acquire leases in areas of less interest to the major oil companies.

Leasing methods

Alaska has several leasing method options designed to encourage oil and gas exploration and maximize state revenue, as described in AS 38.05.180(f). These methods include combinations of fixed and variable bonus bids, royalty shares, and net profit shares. Minimum bids for state leases are generally $5 or $10 per acre. Fixed royalty rates are generally 12.5 percent or 16 and two-thirds percent, although some have been as high as 20 percent. A sliding scale royalty has also been used on occasion. Lease terms are set at 5, 7, or 10 years, depending on geographical location.

Several months before a scheduled sale, a geologic and economic evaluation of the sale area is prepared to determine the bidding method, leasing method and the lease terms for the sale. Public notice of the sale is sent out to an extensive mailing list maintained by the Division of Oil and Gas. Leases in areawide sale areas must be offered by competitive bidding. Leases will be issued to the highest responsible qualified bidder.

Historical lease sale data

The state has conducted annual areawide sales each year since 1998, totaling 51 sales.[10] Reviews of sale results, summed by year, indicate the levels of participation and interest from bidders for leasing in Alaska over the past decade. Figure 3-1 includes data for leases sold, acres sold, bonus bids received, and participation by bidder class for the period 2000 through 2010. During that time, over 2,200 tracts totaling 8.1 million acres of state land have sold, resulting $152.8 million in bonus bids received.

Figure 3-2 shows participation levels by bidder class as percent of total tracts sold in State of Alaska competitive oil and gas lease sales, 2000 through 2011. For example, in 2000 the major oil companies bidding alone acquired 13 percent of all tracts sold by the State of Alaska in all of the competitive oil and gas lease sales summed for the year, major and/or active independent companies bidding together as a consortium acquired 44 percent, active independent oil companies bidding alone acquired 26 percent, and very small companies and/or individuals bidding alone or together as bidder consortiums acquired 17 percent of tracts sold, totaling 100 percent. Until 2011, the data series reveals a trend toward lower participation levels by major oil companies in Alaska's lease sales during this period. In the period from 2008 through 2010, only three tracts were acquired by major oil companies bidding alone or in a consortium with an active independent.

[9] "Five-Year Program of Proposed Oil and Gas Lease Sales," January 2011: http://dog.dnr.alaska.gov/

[10] 1998 to 2010 areawide sales: 13 were in the North Slope, 13 in Cook Inlet (added in 1999), 11 in Beaufort Sea (added in 2000), 10 in North Slope Foothills (added in 2001), and five in Alaska Peninsula (added in 2005).

Exploration licenses

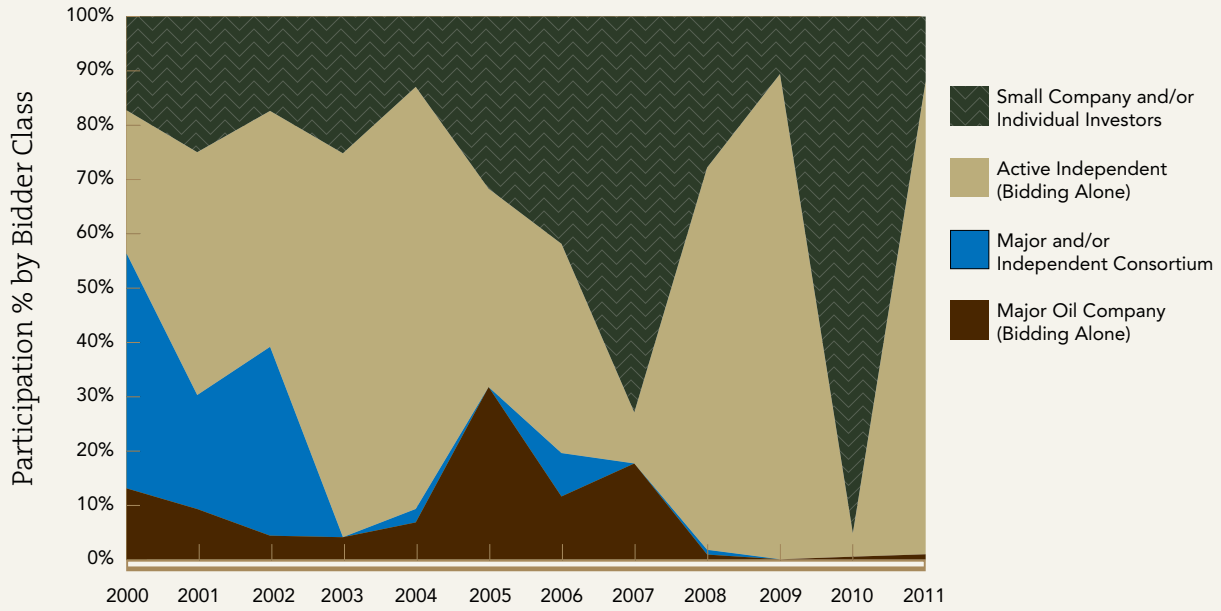
Exploration licensing supplements the state's oil and gas leasing program and encourages oil and gas exploration outside of the known oil and gas provinces in the Alaska Peninsula, Cook Inlet, Beaufort Sea, North Slope, and North Slope Foothills sale areas. The holder of an oil and gas exploration license has the exclusive right to explore an area between 10,000 acres and 500,000 acres in size for a term of up to 10 years. Rather than an up-front bonus payment to the state, as is done in competitive leasing, a licensee must commit direct expenditures for exploration. Because a license has no annual rental payments, the only money guaranteed the state is a one-time $1 per acre licensing fee, which is paid upon acceptance. However, the state is provided all of the geological and geophysical information acquired by the licensee, and so it can gain a better understanding of an area's resource potential.

Each application for an exploration license must go through a public notice and written finding process to determine whether issuance of a license is in the state's best interest. DNR first issues a notice of intent to evaluate the exploration license proposal and solicits any competing proposals for the area. The department then requests public comment on the proposal(s) and goes through a best interest finding process similar to that for oil and gas leasing to determine whether issuing a license for the area is in the best interest of the state. If competing proposals are submitted for an area, the applicants must submit sealed bids. The successful bidder is determined by the highest bid in terms of the minimum work commitment dollar amount.

Figure 3-1 Alaska competitive oil and gas lease sale results summary with all lease sales summed together by year. Source: Alaska Department of Natural Resources, Division of Oil and Gas

Year	Total Tracts Sold	Total Acres Sold	Total High Bonus Bids Received [$ MM]	Number of Lease Sales Held	Major Oil Company Tracts Acquired	Major &/or Independent Consortium Tracts Acquired	Active Independent Tracts Acquired	Small Co. & Individual Investor Tracts Acquired
Annual Totals, All Sales					Annual Total, Tracts Acquired by Bidder Classification			
2000	183	753,252	$11.066	3	24	80	47	32
2001	322	1,432,604	$21.087	4	30	68	145	79
2002	92	329,737	$4.398	4	4	32	40	16
2003	123	326,630	$5.671	4	5	-	87	31
2004	162	558,757	$13.564	4	11	4	126	21
2005	104	420,660	$2.514	3	33	-	38	33
2006	363	1,319,855	$30.158	6	42	29	140	152
2007	85	247,256	$3.748	5	15	-	8	62
2008	115	348,135	$8.383	5	1	1	81	32
2009	85	314,838	$8.150	4	-	-	76	9
2010	203	818,849	$11.954	6	1	-	9	193
2011	366	1,191,586	$32.095	5	84	-	123	159
Totals	**2,203**	**8,062,158**	**$152.786**	**53**	**250**	**214**	**920**	**819**

Figure 3-2 Participation levels by bidder class as percent of total tracts sold in State of Alaska competitive oil and gas lease sales, 2000 through 2011



Exploration and development activity \\\

The worldwide oil and gas industry, like many resource extraction industries, is known for its "boom and bust" cycles. There are a variety of different impetuses for booms and busts. A boom can be brought on by sudden demand for a resource, high sales prices, technology breakthroughs that make the resource extraction economic, or an easing of regulations on the resource to be extracted. Busts are often caused by the exact opposite of what created the boom in the first place, or they could signal a depletion of the resource in a particular locality.

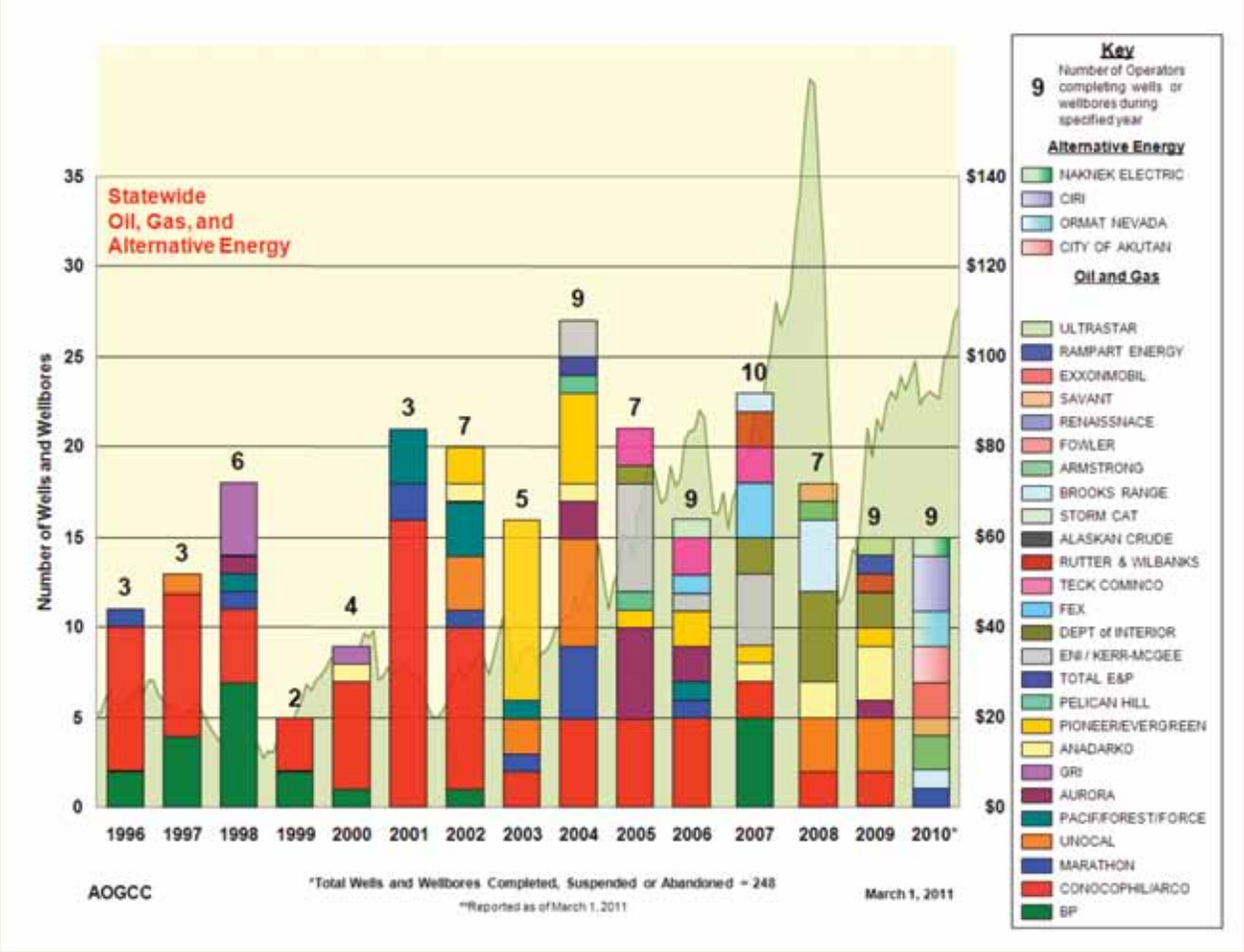
It is not difficult to identify a booming industry. In the case of oil and gas production, common indicators include increases in the number of active drilling rigs, the number of persons employed, and the number of wells drilled. A booming oil or gas development will attract other companies; there will likely be competition for leases, and housing and/or office space may be in short supply.

We provide a review of each of these indicators of petroleum exploration and development activity below.

Drilling activity in Alaska

Drilling activity, including the number and type of wells drilled, is an indicator of oil and gas industry activity. The Alaska Oil and Gas Conservation Commission (AOGCC) issues and monitors permits to drill for oil and natural

Figure 4-1 Exploratory wells and wellbores in Alaska (statewide). Includes all exploration wells that were completed, suspended or abandoned between 1996 and 2010. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel)



gas in the state of Alaska. In a 2011 presentation to the Alaska State Legislature, the AOGCC provided detail on the number and types of oil and gas wells drilled in Alaska from 1996 to 2010. Below, we have reproduced several of the charts that the AOGCC included in its presentation.

Exploratory wells

Figure 4-1 shows the number of exploratory wells and wellbores that were completed, suspended or abandoned in the years 1996 through 2010. The numbers on each column indicate the number of companies that had contributed to the number of wells shown. Figure 4-1 shows a significant amount of exploration well activity in 2001 through 2004 and a substantial drop in activity that began in 2008.

Development and service wells

Figure 4-2 shows the number of development and service wells and wellbores that were completed, suspended or abandoned in the years 1996 through 2010. Like the previous figure, the period from 2000 through 2004 shows a steady, relatively high rate of well development, with a drop in activity beginning in 2005 and continuing through 2010.

Drilling rig counts

The number of drilling rigs in an oil and gas jurisdiction is also an indicator of petroleum-related activity. The AOGCC tracks drilling and workover rig activity within Alaska. Figures from the 2011 presentation, shown as Figure 4-3 and Figure 4-4, indicate that well workover activity has been healthy throughout the years shown in the graphs.

Baker Hughes, an oilfield service company that operates in 80 countries, has been providing counts of rotary rigs for the petroleum industry for over 65 years. Although not as detailed as the information provided by the AOGCC, the rig counts provided by Baker Hughes can be viewed relative to other oil and gas provinces over a given time period. Figure 4-5 shows a comparison of annual average rotary rig counts in Alaska and four other oil and gas-producing states from 2000 through 2010. We note that the data show a dip in rig counts in all states except Alaska in 2009, followed by an

Figure 4-2 Development and service-class wells and wellbores in Alaska (statewide). Includes all development and service wells that were completed, suspended or abandoned between 1996 and 2010. Background graphic shows West Coast spot price for Alaska North Slope crude oil (dollars per barrel)

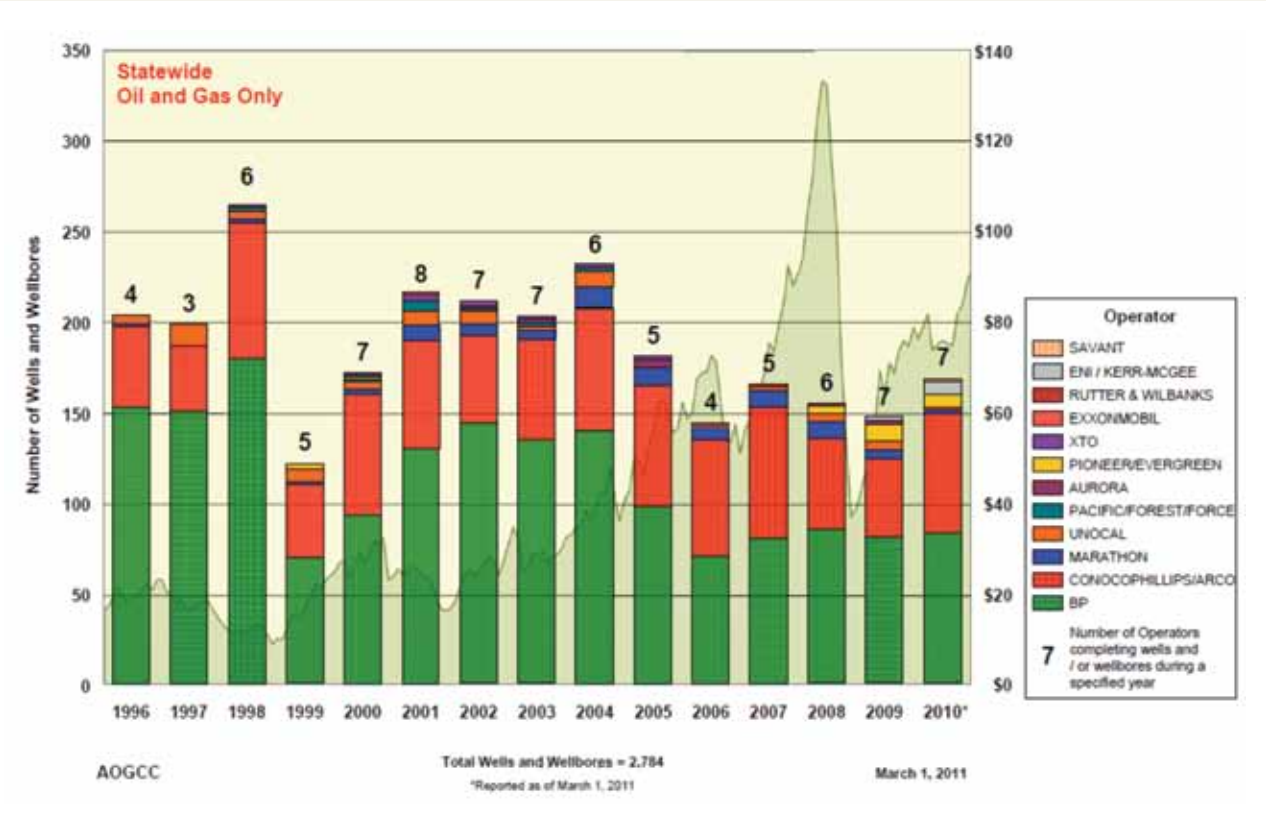


Figure 4-3 Alaska's active workover rigs for each quarter from 2005 through 2010. Solid line represents West Coast spot price for Alaska North Slope crude oil (dollars per barrel)

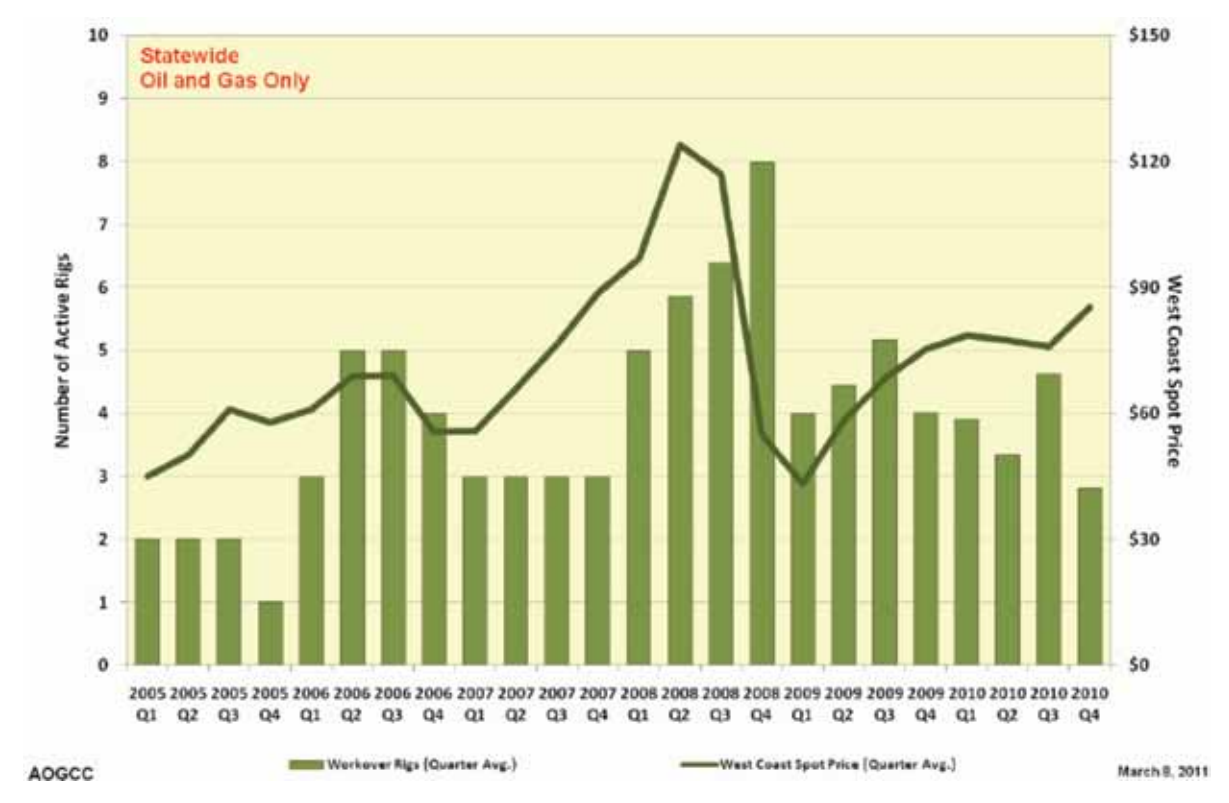
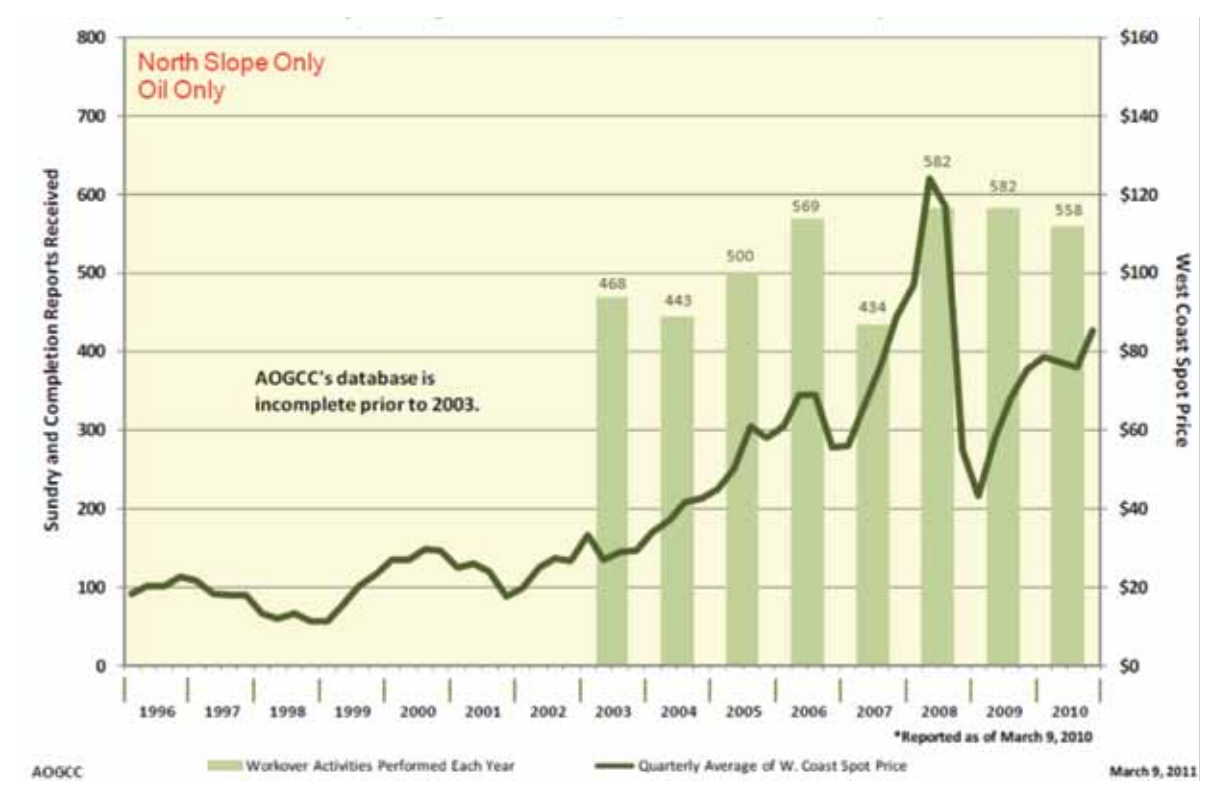


Figure 4-4 Number of Alaska's well workover activities by calendar year, North Slope only, from 2003 through 2010.* Solid line represents West Coast spot price for Alaska North Slope crude oil (dollars per barrel)



increase in rig counts in all states except Alaska in 2010. According to Baker Hughes, the annual average rig count for Alaska has remained flat since 2006. In the other four states, rig counts increased at least 28 percent between 2009 and 2010, and in North Dakota, the number of rotary rigs more than doubled.

Oil and gas employment

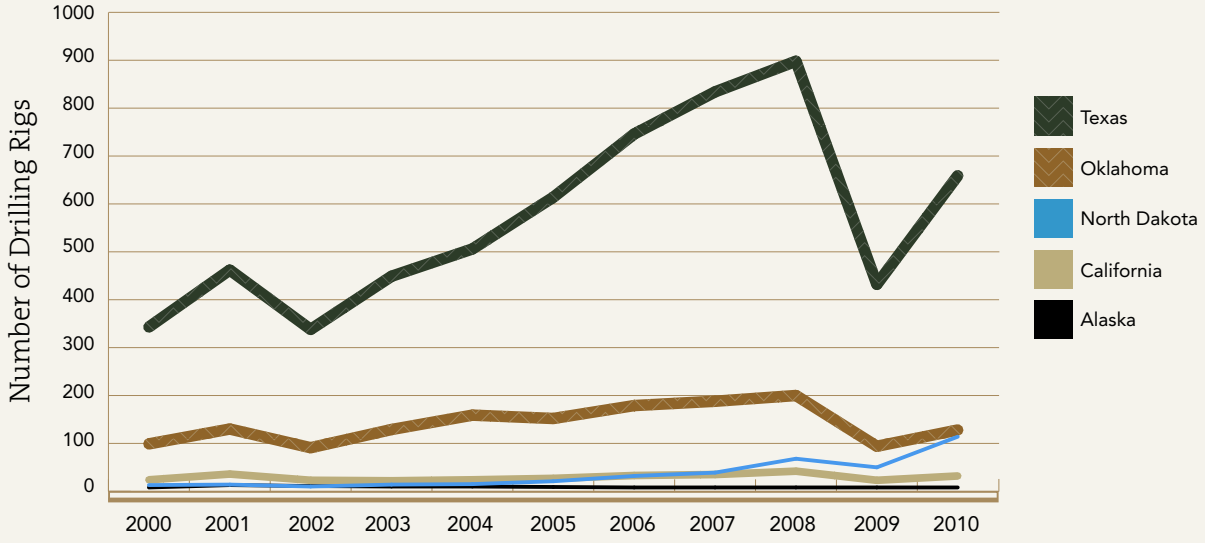
Employment in oil and gas operations has often been used as an indicator of health of the petroleum industry. Due to standard reporting requirements regarding employment in the U.S., companies that explore for and produce oil and gas must report the number of persons employed within their organizations. These reporting requirements would therefore, theoretically, provide useful information about employment in the oil and gas industry. Unfortunately, this information while helpful, has known deficiencies.

Alaska Department of Labor economists explain that the standardized coding for oil and gas jobs changed in 2001 from the Standard Industrial Classification System (SIC) to the North American Industry Classification System (NAICS). This change impacted the classification of some employees. This makes historical comparisons beyond 10 years difficult.

Another known deficiency is the fact that jobs that exist because of or are directly related to the petroleum industry, either through service companies or as an extension of the industry, are not included in the employment totals. For example, employees of the Alyeska Pipeline Service Company, an organization that operates and maintains the pipeline used to transport oil from the North Slope to the port of Valdez, are not included in the oil and gas employment totals in Alaska. These types of anomalies are ubiquitous in Alaska and in other states. While this deficiency typically results in an overall understatement of oil and gas employment, it also affects the ability to do trend analysis.

There are other reasons to view employment data with caution, which extend beyond the scope of this publication. Increases in oil and gas employment in a particular region may be indicative of increased drilling or of facility or site renovation. In the case of Alaska, following a 2006 oil spill there was substantial activity focused on restoring and replacing flowlines and transit lines that carry oil before it enters the trans-Alaska pipeline. It is likely that this activity created the need for additional labor hours. It is difficult to know if there were significant events in other jurisdictions to trigger fluctuations in oil and gas employment in those jurisdictions. Therefore, we do not attempt to draw comparisons between employment in the oil and gas industry in one state to oil and gas employment in another state. A time series of oil and gas employment within Alaska may, however, have validity when compared with a time series of oil and gas employment

Figure 4-5 Number of drilling rigs by state



Source: 2000-2010 taken from Baker Hughes rig count data

in other states, based on national numbers compiled by the Bureau of Labor Statistics.

Presented below are two graphs plotting oil production over the period of 2001 through 2010 against oil and gas employment over the same period. Figure 4-6a shows that Alaska oil production has declined while employment has increased. In contrast, Figure 4-6b shows oil production in Texas during the same period decreasing initially and then increasing while employment increases and then flattens. Figure 4-7 plots Alaska production and oil prices on the same chart along with two events that also occurred during the time period – the March 2006 oil transit line spill and the implementation of the ACES tax structure in 2008.

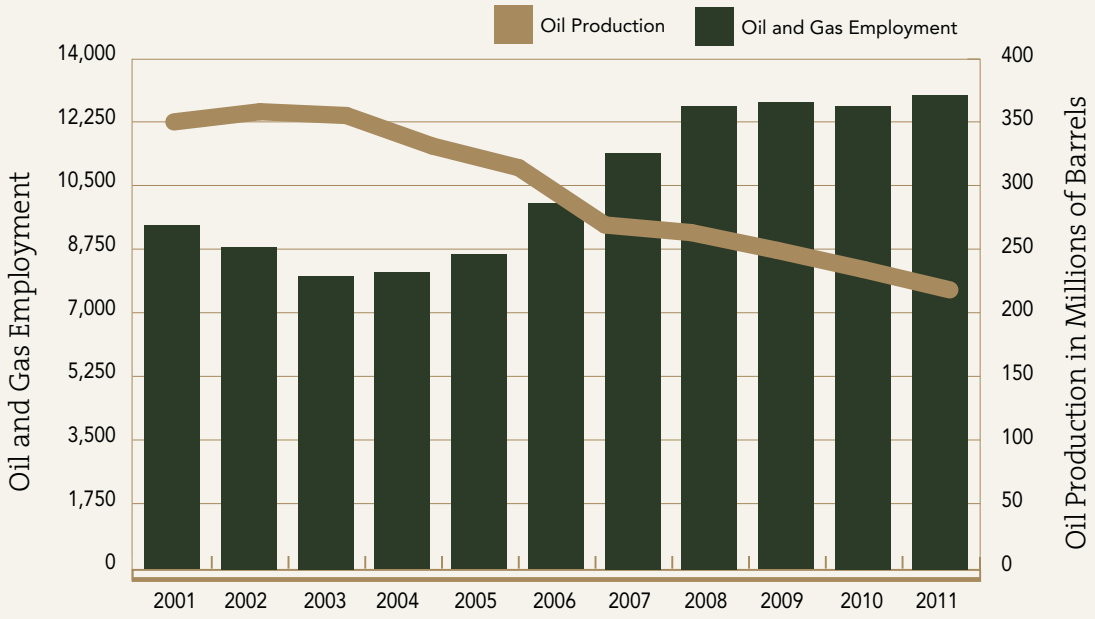
Figure 4-8 compiles production and labor data for six oil and gas producing states. Instead of showing oil and gas production separately from oil and gas employment, the two are combined and presented as barrels of oil per employee. This graph ignores gas production, which may be a significant factor in the employment figures in states other than Alaska. This graph also does not attempt to make comparisons of productivity among oil and gas employees across the states shown. By plotting a time series of these data, however, what is evident is that the barrels per employee decreased significantly in Alaska over the time period shown, but they stayed relatively flat in the other states. Although it is difficult to know how to interpret this result, it is interesting that oil and gas employment would be rising in Alaska even as the barrels produced are decreasing.

Investment in North Slope oil and gas

Investment in the oil and gas industry since exploration began in Alaska has been substantial. The North Slope of Alaska is remote, and prior to oil and gas development had no roads or facilities close to where the development would be. To date, the area has only one road connecting it with the rest of the state, which is itself remote from the other states in the U.S. The amount of investment that had to occur in order to explore for and develop the North Slope's oil and gas, and to transport oil to markets, was an order of magnitude higher than the amount of investment required to produce and transport oil in, for example, Texas. Although the state does not have any official records, estimates for the initial development of the major North Slope fields are in the tens of billions of dollars.

Since that time, billions of barrels of oil have been produced and sent through facilities that were constructed in the 1960s and 1970s. In recent years, the aging infrastructure has begun to show signs of the

Figure 4-6a Alaska Oil Production and Oil and Gas Employment, 2001-2010



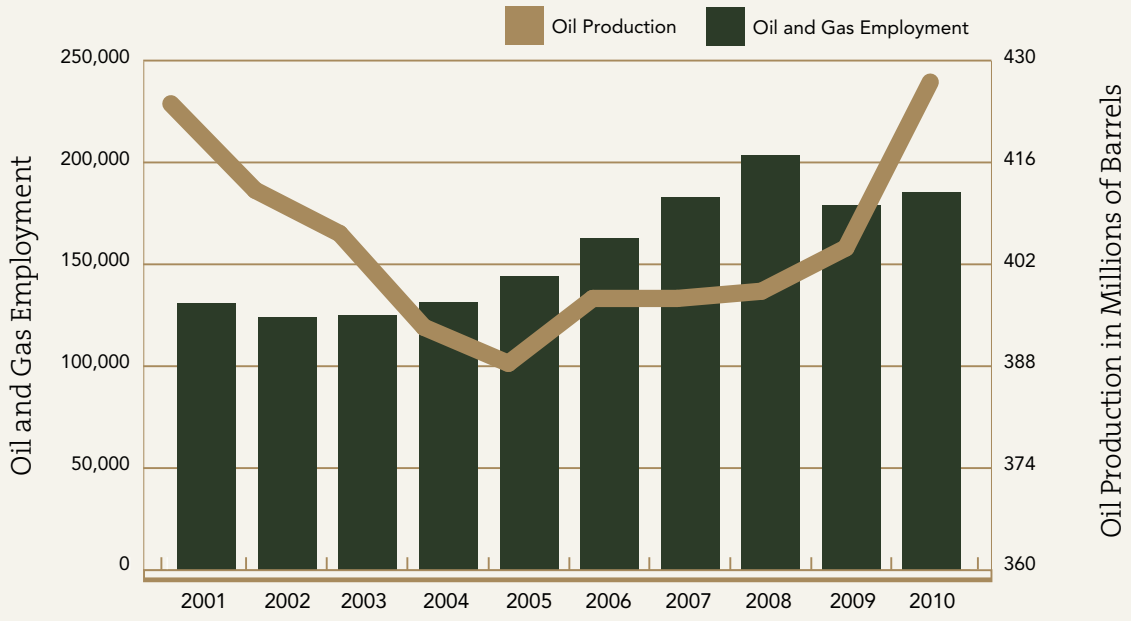
years of wear. Shortly after the pipeline leaks in 2006, BP Exploration (Alaska) Inc. undertook a major project to improve the integrity of the pipelines, flowlines, and associated facilities. The project cost hundreds of millions of dollars and required a significant increase in the labor force.

Investment can be broken down into capital expenditures and operating expenditures, both of which are deductible under the ACES production tax. Capital expenditures are the type of expenditures most often associated with property development and improvements. With the passage of a production tax on net profits, the State of Alaska began to receive information about the amount of investment in North Slope oil and gas operations. Although much of this information has yet to be audited, it provides some estimates with which to assess investment in oil and gas in Alaska.

A four-year time series of company-reported qualified capital expenditures in Figure 4-9 shows that although capital expenditures have increased slightly over the four-year time period, the majority of the increase has been occurring not on currently producing properties, but on developing properties. Developing properties include those that are underdevelopment and are either not yet producing oil or are in the beginning stages of oil production.

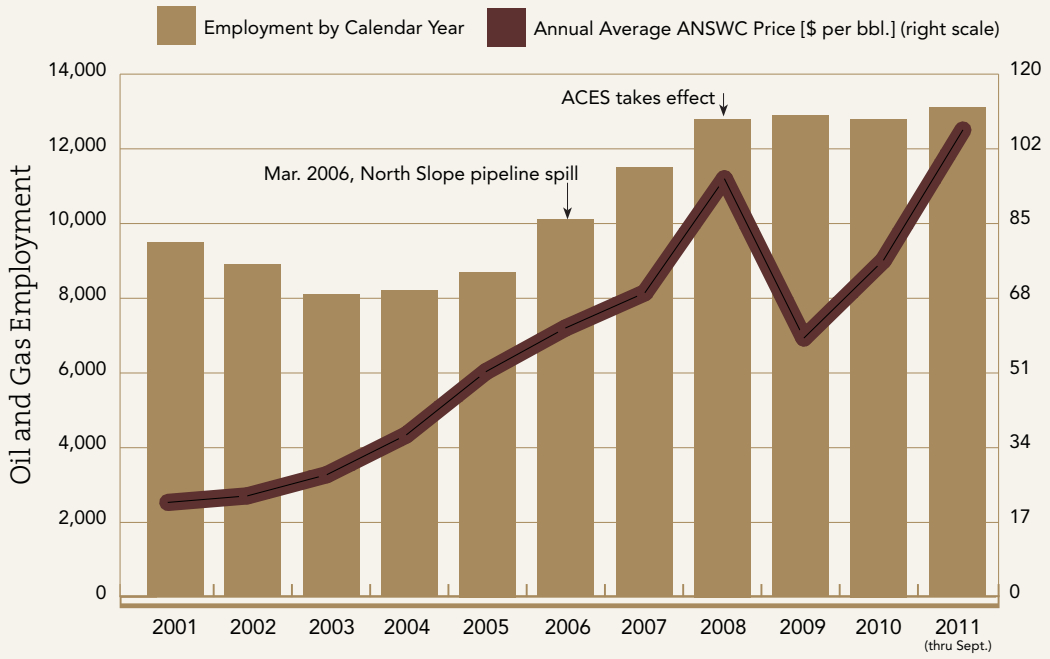
Forecasted expenditures for FY 2013 and beyond are contingent on several factors, including oil prices and availability of capital. Recent news reports regarding new exploration and development on the North Slope hold promise, but all are contingent on these factors and others that are specific to each project.

Figure 4-6b Texas Oil Production and Oil and Gas Employment, 2001-2010



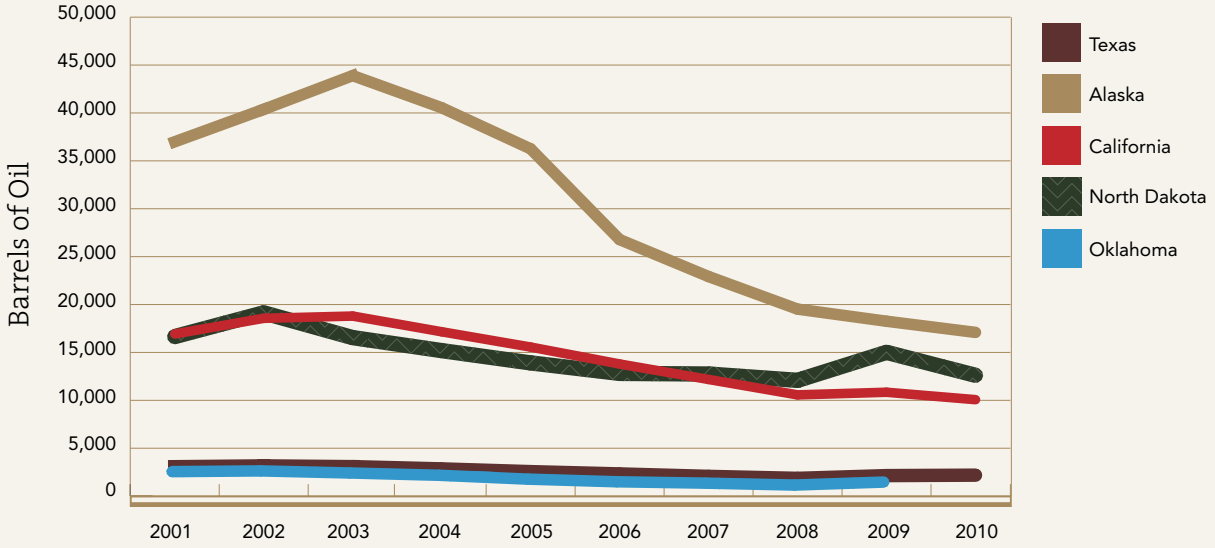
Source: Bureau of Labor Statistics, EIA.

Figure 4-7 Annual employment in Alaska's oil and gas industry with oil price



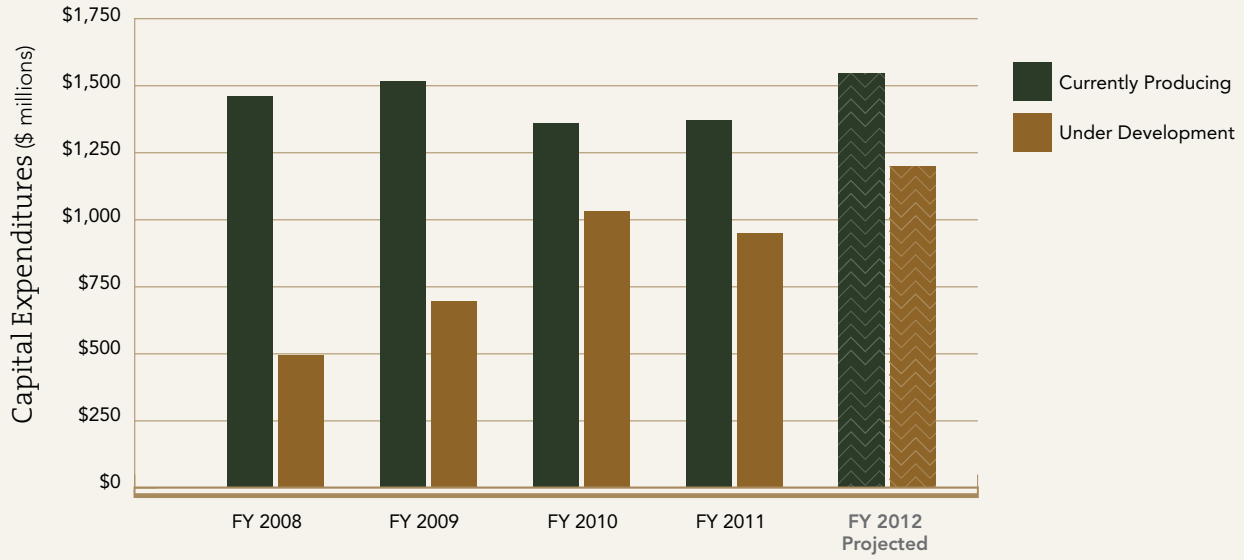
Source: Alaska Department of Labor.

Figure 4-8 Barrels of Oil Production per Employee, 2001-2010



Source: Bureau of Labor Statistics, EIA.

Figure 4-9 North Slope Capital Expenditures by Type of Property, FY 2008-2012



Under Development includes field development at Oooguruk, Nikaitchuq, Pt Thomson, NPRA, and Other North Slope leases.

Alaska's oil and gas fiscal system \\\

Alaska's fiscal system for oil and gas has four major components that raise revenue for the state:

1. Royalty
2. Property tax
3. State corporate income tax
4. Production tax

Each of the components has been part of the oil and gas fiscal system since the 1970s, when oil began flowing from the North Slope, although there have been changes made to the various components over the years. In this section, we provide a brief summary and overview of the four major components of the fiscal systems.

Alaska's fiscal system for oil and gas also has special incentives, generally in the form of tax credits. The number of incentives has grown considerably over the past 10 years as the tax systems have changed. Due to the number of incentives and the credits applied in recent years, we follow our discussion of the components of the fiscal system with a special section describing the incentives in oil and gas royalty and taxation.

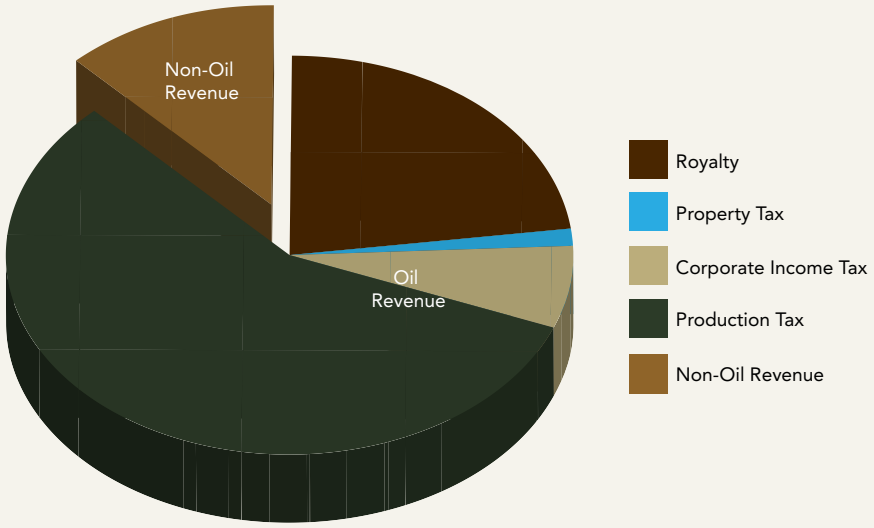
In addition to the four components mentioned above, over which the state has control, there is an additional element controlled only by the federal government: federal corporate income tax. The federal corporate income tax rate component of all U.S. state and federal fiscal regimes is assumed to be 35 percent. The interaction between the elements that the state controls, royalty, taxes and credits, and federal income tax complicates any effort to materially modify the overall fiscal system in favor of those taxpayers that pay federal taxes on Alaska income.

Elements

State's revenue raising components

Oil and gas that is produced onshore in the state of Alaska or offshore within state boundaries is subject to the four components of the Alaska's fiscal system, listed above, that are revenue-raising in nature. Together the four components typically provide between 80 and 90 percent of the state's general fund budget, as shown in Figure 5-1. Provided below is a summary of each of the individual components. We also provide some background and a brief history of the changes to what is currently the largest revenue raising component, the state's production tax.

Figure 5-1 Alaska General Fund Revenue Sources, FY 2011



- Royalty

In natural resource extraction, royalties generally represent the portion of minerals apportioned to the lessor by a lessee who has leased the property to produce the minerals. Currently in Alaska, the majority of leases for oil and gas extraction are on land where the state has title to the mineral estate. Therefore, in Alaska, most of the royalties for oil and gas extraction are apportioned — or paid — to the state. Although leases have varying royalty rates, most of the state leases in Alaska have royalty rates of 12.5 percent. This means that the State of Alaska receives approximately 12.5 percent of all oil and gas produced on state leases. The state royalty may be paid in kind or in value at the state's discretion. When royalties are paid "in kind," the state receives its royalty in barrels (or cubic feet for natural gas); when royalties are paid "in value," the state receives its royalty in dollars.

The federal government also leases land in Alaska for oil and gas extraction, and the state receives a portion of the royalties collected on these leases. In the National Petroleum Reserve-Alaska (NPR-A), the state receives 50 percent of the royalties collected by the federal government. In federal offshore leases that are greater than three miles from shore and less than six miles from shore, the federal government pays the state 27 percent of the royalties it collects from these properties.

Royalties are a significant component of Alaska's fiscal system, often accounting for 30 percent or more of the unrestricted oil and gas revenue paid to the state. Because royalties are paid without regard to oil and gas prices or whether there is any profit associated with oil and gas production, it is considered a regressive element of Alaska's fiscal system.

- Property tax

The State of Alaska levies a property tax on the full and true value of all oil and gas property in the state. The property tax is assessed annually and the tax rate is 20 mills. Oil and gas property that is within local boundaries may also be taxed at the local level, and that amount is deducted from the property tax paid to the state.

The property tax is a relatively small component in Alaska's fiscal system, generating revenues of about $100 million in recent years. The tax is an important component of local governments that have oil and gas property, however, as up to $400 million per year is split among fewer than 10 local governments.

Like royalties, property tax is a regressive element in Alaska's fiscal system, as it is collected without regard to prices or profit.

- Corporate income tax

Alaska's corporate income tax for oil and gas uses a modified apportionment method, whereby a corporation's tax liability is based on the size of its Alaska operations relative to its worldwide net income. The apportionment factors used to determine a corporation's Alaska tax liability are the Alaska operation's (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property. The corporate income tax rate is graduated with the top tax rate of 9.4 percent levied when net incomes exceed $90,000 for the year.

Oil and gas corporate income tax revenues have comprised about 10 percent of the state's unrestricted petroleum revenues in recent years. In addition to mirroring the federal tax code with regard to tax credits, there are several state tax credits applicable to the corporate income tax. These will be discussed in the "Tax Credits" section of this chapter.

- Production tax

The largest revenue raising component of Alaska's fiscal system for oil and gas is the production tax. The current production tax, called Alaska's Clear and Equitable Share (ACES), was signed into law in 2007. ACES taxes the net profits of production after all operating and capital expenses have been deducted. The ACES production tax also offers credits for exploration and capital expenditures and for companies that produce less than 100,000 barrels of oil per day. Prior to the implementation of a net profits-based production tax, Alaska taxed production based on the gross value of oil and gas as adjusted by an economic limit factor.

The ACES production tax is a complex system with two primary tax rates: a base tax rate of 25 percent and a progressive tax rate of 0.4 percent for every dollar the per-barrel profit exceeds $30 up to a per-barrel profit of $92.50, at which point the progressive rate changes to 0.1 percent for every additional dollar in profit. The maximum combined base and progressive tax rate is 75 percent. A company's tax liability may be reduced by credits that are included in the ACES production tax system, the most common being the 20 percent capital expenditure credit. The basic tax calculation under ACES is as follows:

ACES Tax Liability = [(Value – Costs) * Tax Rate] – Credits

Value = Volume of Non-Royalty Oil & Gas Produced * Wellhead Value

Costs = Operating and Capital Expenditures

Tax Rate = 25 percent + 0.4 percent for every $1 per barrel that "net profit" exceeds $30 up to $92.50, then 0.1 percent up to a maximum of 75 percent

Credits = 20 percent * Capital Expenditures (spread over two years) and other credits

At high prices, the ACES production tax generates tax rates that are high relative to the prior tax system on gross value, and higher revenues. For example, the average tax rate on the North Slope under the prior production tax system in the year before the production tax change was approximately 9 percent of the gross value at the point of production (average tax rate of 15 percent times average ELF rate of 0.6). Under that system, the tax on a $100 barrel of taxable (non-royalty) oil would be approximately $8.50 after the transportation costs of $7 per barrel are deducted. ([$100-$7 transport costs]*9 percent). Under ACES, assuming the same transportation costs, and $10 in capital and $10 in operating expenditures, the tax on a $100 barrel of taxable oil would be approximately $29. ([$100-$7 transport costs - $20 expenditures]*42.2 percent)-$2 credit. This example illustrates how the tax under ACES more than tripled the tax liability for much of the oil already under production on the North Slope. At low oil prices, the tax under ACES could be lower than the tax under the prior system. The trend in oil prices since 2007, however, has been for oil to be valued at $60 per barrel or higher, with recent Alaska North Slope crude oil prices exceeding $100 per barrel.

Additional fiscal elements

Lease bonuses and rentals are two additional components that contribute minor amounts of revenue to the state. However, in some jurisdictions these two fiscal components can contribute materially to government take, so they are worth discussing here.

Bonuses are cash payments received by the state, usually at a lease sale, to win the execution of an oil and gas lease. Normally the state's sale terms establish the bonus payment as the bid variable so that the bidder offering the highest bonus bid wins the lease being offered. Since 2000, annual revenues from lease bonus payments have ranged from as low as about $250,000 in 2007 to as high as $1.4 million in 2001.

Lease rentals are annual cash payments received by the state to maintain an oil and gas lease and the rights granted under it. Alaska's statutorily established rates per acre for oil and gas leases are as follows (AS 38.05.180):

1. First year: $1
2. Second year: $1.50
3. Third year: $2
4. Fourth year: $2.50
5. Fifth year and greater: $3 annually

Most State of Alaska lease contracts state that rental paid for a lease in advance, at the beginning of the year, can be claimed as a credit against royalty payments due under the lease for that year. Thus, on Alaska state land, even relatively small production volumes result in refunding of most rental payments through credits against royalty.

Tax credits and Royalty Incentives

Tax credits have also played a large role in Alaska's oil and gas fiscal system. Most of the tax credits in current law were implemented with the change to a production tax on net profits. The tax credits were intended to incentivize certain activities, such as oil and gas exploration. Since ACES was enacted, the tax credits program has expanded. In 2010, tax credits were introduced for natural gas storage and for the first wells drilled in Cook Inlet using a jack-up rig. The credits appear to have been successful in incentivizing the activity sought – as of the printing of this publication, at least one company is undertaking a gas storage project, and a jack-up rig is drilling in Cook Inlet for the first time in over a decade.

There are currently three major categories of tax credits that are commonly applied to the Alaska production tax. AS 43.55.023 offers credits for capital expenditures, certain exploration expenditures, well lease expenditures, and expenditures leading to net operating losses. AS 43.55.024 offers credits to oil and gas producers that produce fewer than 50,000 btu equivalent barrels of oil and/or gas per day. AS 43.55.025 offers credits for exploration expenditures that meet certain criteria related to distance from existing units or wells and for the first persons to drill wells in Cook Inlet using a jack-up rig. These three categories of tax credits make up the majority of the tax credits used against or in connection with the oil and gas production tax.

There are two commonly used credit programs targeted specifically at oil and gas corporate income tax in Alaska. Both of the credits under this program pertain to natural gas. AS 43.20.043 provides a credit of 25 percent of qualified expenditures for exploration and development of non-North Slope natural gas reserves. This credit was extended and expanded in the 2010 legislative session. A second oil and gas

Figure 5-2

Tax Credits applicable to Oil and Gas Production Tax and Corporate Income Tax ($ millions)				
Description of Credit	Credit Rate and Maximum Credit	Amount of Credit Claimed		
		CY 2008	CY 2009	CY 2010
Credits Applicable to the Oil and Gas Production Tax				
Exploration Incentive Credit, AS 38.05.180(i) A non-transferrable credit for the cost of drilling or seismic work performed under a limited time period established by the Commissioner of the Department of Natural Resources.	Up to 50% of the cost of drilling or seismic work, not to exceed 50% of the tax liability to which it is being applied. This credit may also be applied against the state royalty.	$0	$0	$0
Qualified Capital Expenditure Credit, AS 43.55.023(a) and (l) A transferable tax credit for qualified oil and gas capital expenditures in the state. Taken in lieu of exploration incentive credits under AS 43.55.025 and gas exploration credits under AS 43.20.043.	Credit is 20% of eligible expenditures, or 40% for well related expenses outside the North Slope. For credits earned for North Slope capital expenditures under AS 43.55.023 (a), no more than half the credit may be applied in a single calendar year.	"Includes Carried-Forward Loss Credits"		
		$391	$585	$640
Carried-Forward Annual Loss Credit, AS 43.55.023(b) A transferable credit for a carried-forward annual loss, as defined as a producer or explorer's adjusted lease expenditures that are not deductible in calculating production tax values for the calendar year.	Credit is 25% of the carried-forward annual loss. If a transferable credit certificate is applied for North Slope losses, not more than half may be taken in one year.	Totals included in Qualified Capital Expenditure Credits above		
Small Producer / New Area Development Credit, AS 43.55.024(a) and (c) A non-transferable credit for oil and gas produced by small producers, defined as having average taxable oil and gas production of less than 100,000 BTU equivalent barrels per day, or for oil or gas produced on leases outside Cook Inlet and below 68 degrees North latitude, providing the producer has a positive tax liability on that production before the application of other credits. Credit is available until the later of 2016 or 9 years after first commercial production of oil and gas on the properties for which the credit applies.	Credit is 100% of tax liability for eligible oil and gas production. The credit is capped at $12,000,000 annually under the small producer credit for producers with no more than 50,000 BTU equivalent barrels per day. The credit then phases out, reaching zero for producers with 100,000 or more BTU equivalent barrels per day. Under the new area development credit, credit is available up to $6,000,000 per company annually.	$21	$34	$38
Transitional Investment Expenditure Credit, AS 43.55.023(i) A non-transferable credit for qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006. Only available to companies that did not have production in commercial quantities prior to January 1, 2008. Credit may not be used after December 31, 2013.	Credit is 20% of qualified oil and gas capital expenditures incurred between March 31, 2001 and April 1, 2006, not to exceed 10% of the capital expenditures incurred between March 31, 2006 and January 1, 2008.	Cannot be reported due to taxpayer confidentiality		
Alternative Credit for Exploration, AS 43.55.025 A transferable credit for expenditures for certain oil and gas exploration activities. Expires 7/1/2016.	Outside of Cook inlet, credit is 40% for seismic costs outside an existing unit, 30% for drilling costs greater than 25 miles from an existing unit, 30% for pre-approved new targets greater than 3 miles from an existing well, and 40% for pre-approved new targets greater than 3 miles from a well and greater than 25 miles from an existing unit. For Cook Inlet, credit is 40% for seismic costs outside an existing unit, 30% for drilling costs greater than 10 miles from an existing unit, 30% for pre-approved new targets, and 40% for drilling costs that are greater than 10 miles from an existing unit and pre-approved new targets.	$18	$41	$13

Tax Credits applicable to Oil and Gas Production Tax and Corporate Income Tax ($ millions)				
Description of Credit	Credit Rate and Maximum Credit	Amount of Credit Claimed		
		CY 2008	CY 2009	CY 2010
Credits Applicable to the Oil and Gas Production Tax				
Cook Inlet Jack-Up Rig Credit, AS 43.55.025(a)(5) and (l) A credit for exploration expenses for the first three wells drilled by the first jack-up rig brought in to Cook Inlet. 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.	Credit is 100% of costs for the first well up to $25 million, 90% of costs for the second well up to $22.5 million, and 80% of costs for the third well up to $20 million. If exploration well is brought into production, operator shall repay 50% of the credit over ten years following production start-up.	Credit program began in 2011		
Credits Applicable to the Corporate Income Tax				
Internal Revenue Code Credits Adopted by Reference, AS 43.20.021 Under Alaska's blanket adoption of the IRC, taxpayers can claim all federal incentive credits. Federal credits that refund other federal taxes are not allowed. Multistate taxpayers apportion their total federal incentive credits.	For most credits, credit is limited to 18% of the amount of the credit determined for federal income tax purposes which is attributable to Alaska.	Not tracked		
Gas Exploration and Development Credit, AS 43.20.043 A non-transferable credit for qualified expenditures for exploration and development of non-North Slope natural gas reserves.	Credit is 25% of qualified expenditures for investment after January 1, 2010; investments in existing units qualify. Credit is capped at 75% of tax liability as calculated before applying other credits.	Cannot be reported due to taxpayer confidentiality		
Gas Storage Facility Credit, AS 43.20.046 A credit for the costs incurred to establish a gas storage facility. Does not apply to gas storage related to a gas sales pipeline on the North Slope. Facility shall operate as a public utility regulated by the Alaska RCA with open access for 3rd parties. Effective for facilities placed into service between January 1, 2011 and December 31, 2015.	Credit is $1.50 per thousand cubic feet of "working gas" storage capacity as determined by AOGCC. Maximum credit is the lesser of $15 million or 25% of costs incurred to establish the facility.	Credit program began in 2011		
Film Production Credit, AS 43.98.030 A transferable credit for expenditures on eligible film production activities in Alaska. Producer must spend at least $100,000 in a consecutive 24-month period to qualify. Expires the earlier of 7/1/2013 or once $100 million of credits have been approved.	Credit is 30% of eligible film production expenditures, plus an additional 10% credit for wages paid to Alaska residents, plus an additional 2% credit for filming in a rural area, plus an additional 2% credit for filming between October 1 and March 30. Program is capped at $100 million for all projects.	$0	<$1	<$1
Credits Applicable to Multiple Tax Types including Production Tax and Corp Income Tax				
Education Credit, AS 43.20.014 and AS 43.55.019 A non-transferable credit for contributions to vocational educational programs, accredited Alaska universities or colleges for educational purposes or facilities, annual intercollegiate sports tournaments, AK Native educational programs, facilities that qualify under the Coastal American Partnership; under AS 21.89.075 contributions to the Alaska Fire Standards Council also qualify.	Credit is 50% of annual contributions up to $100,000, 100% of the next $200,000 and 50% of annual contributions beyond $300,000. The credit cannot exceed $5,000,000 annually across all eligible tax types. The credit at these rates is effective from January 1, 2011 until December 31, 2020, at which point the maximum credit for any taxpayer is $150,000 per year.	$2	$2	$3
	Total All Credits	**$432**	**$663**	**$695**

corporate income tax credit provides a credit for the costs incurred to establish a natural gas storage facility. The credit amount is $1.50 per thousand cubic feet of working gas storage up to a maximum of $15 million or 25 percent of the costs of the facility. A similar provision is available through the state royalty program, whereby a portion of fees, rentals, and royalties are exempted when requirements for natural gas storage are met.

Figure 5-2 summarizes the tax credits in current law that are specific to the oil and gas production tax and oil and gas corporate income tax and the amount of credits used in each of the past three years. We note that there has been an increasing use of tax credits authorized at AS 43.55.023 over the three-year period.

There are several royalty incentives in current law. Many of them are tailored to a specific project, economic criteria, or lease type. For example, there is a licensing program that allows for more favorable lease terms for explorers to gain access to large tracts of state land. For economically-challenged projects, the DNR commissioner can modify royalty terms to incentivize production. There have been two royalty modifications approved in recent years; these terms are specific to the projects for which they were granted.

Changes to the production tax

Prior to the implementation of ACES, the state had undertaken extensive analysis of the economics of applying different tax rates and credits to various types and sizes of petroleum projects. The first result of this analysis was the introduction of the Petroleum Profits Tax (PPT), which was adopted by the legislature in 2006. The PPT as introduced would have taxed net profits of production at 20 percent and given 20 percent credit for capital expenditures. There was no progressive tax provision in the PPT as proposed. The progressive tax provision was added in legislative committees, along with a number of other changes.

One year later, then-Governor Sarah Palin announced that the Legislature would revisit the changes made to the production tax due to corruption associated with the passage of the PPT legislation. Extensive economic analysis was again conducted on the impact of various production tax rates and credits on different petroleum projects. As a result of that analysis, the governor offered ACES, which was different than the current ACES law, in a special session of the Legislature in the fall of 2007. ACES as proposed and economically tested included a 25 percent tax rate and a progressive rate of 0.2 percent for every dollar that the per-barrel net profit exceeded $30. At the forecast price of $65 per barrel in 2009, it was anticipated that ACES as proposed would provide a 40 percent increase in production tax over the PPT. ACES as passed by the Legislature, however, had a progressive tax rate that was double the progressive tax rate originally proposed. Credits were also expanded with the ACES legislation.

The change from the old Economic Limit Factor (ELF) tax system to the PPT tax system greatly increased the complexity of the tax system, requiring additional auditors to administer and audit the tax returns. The change also significantly increased the government's share of the value of the production at today's oil prices. The change to ACES further increased the government share of the value of the production above that of the PPT tax system. Figure 5-3 shows the increase in production tax at an oil price of $100 per barrel under the ACES tax compared to the previous ELF system. As the figure shows, at $100 per barrel, the ACES tax on the average barrel of North Slope oil is more than triple the amount that would have been paid under the ELF tax system.

Recent studies of fiscal systems suggest that Alaska's government take, especially at oil prices of $100 and above, is substantially higher than other oil and gas jurisdictions.[11] The ACES maximum production tax rate is 75 percent, which is reached when the per-barrel profit is $342.50; the production tax rate at current prices of $100 to $120 per barrel is close to 50 percent. Under current conditions, for the average barrel produced on the North Slope, the federal and state governments will collect taxes and royalties of approximately 90 percent of each dollar that the oil price increases. This measure of a fiscal system is called the marginal tax rate, and it is the rate at which the government taxes each additional dollar of profit earned – in this case, on a barrel of oil.

Since the passage of ACES, credits applicable against the production tax have been added, expanded, and changed, adding to the complexity of the tax system and requiring larger state reimbursements. The tax credit rates are the highest for exploration (30 to 40 percent) and for net operating losses (25 percent), although all qualified capital expenditures are eligible for a 20 percent credit. The structure of the tax credits is such that exploration and new developments receive significant credits (up to 65 percent) and ongoing capital spending in existing fields receives fewer credits (20 percent). The tax credit structure also provides incentives to companies that produce less than 50,000 barrels per day, through its $12 million small producer credit. This system of relatively high tax and high credit rates has led to a divergence of views about ACES. While there are oil and gas companies that praise ACES for its tax credits, there are critics of ACES that say the tax rates are too high.

[11] PFC Energy, vanMeurs Corporation, and Rodgers Oil and Gas Consulting, *World Rating of Oil and Gas Terms: Volume 3 Rating of Arctic Oil and Gas Terms* (Canada 2011).

ACES' impact on current producers and explorers

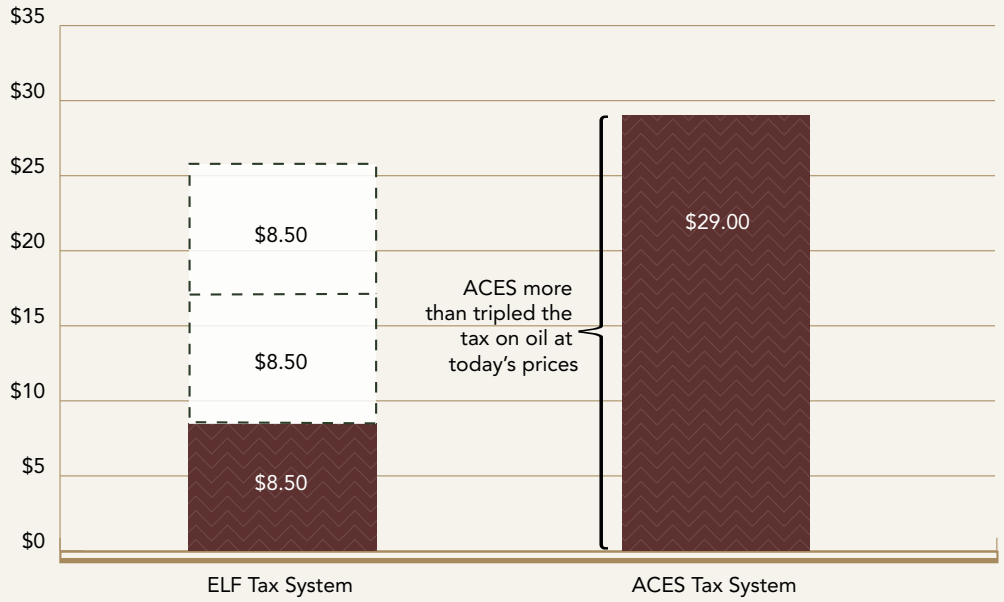
The changes made to the Alaska production tax system over the past five years have been significant in several ways. Perhaps the most significant change in the production tax was the change from a tax on the gross value to a tax on the net value of oil and gas production. A tax on the net value of oil and gas production recognizes the costs of exploring for, developing, and producing oil. Alaska has long had the reputation of being a high-cost area in which to produce oil, and the current tax structure takes that into account in the calculation of the tax. Another significant change is that the production tax is no longer property-specific as the ELF tax system was; under ACES, the tax is company-specific. Each company has a different tax rate every month, depending on its mix of Alaska properties held, the value of its oil and gas, and the amount of expenditures made to produce that oil and gas. Although information presented to the Legislature and the Alaska public shows high-level aggregated figures, a detailed look would show that the tax rates for each individual oil and gas producing company are, in fact, quite unique. When credits are introduced, the divergence between effective tax rates of different companies further increases.

The complexities of the ACES tax system from a state perspective make it difficult to both analyze and administer. A high level of analysis would show the average tax rate on the average barrel of oil produced on the North Slope. To properly address the complexities of the tax system, however, the analysis would show that the tax rate on a portion of Prudhoe Bay oil is slightly different from the tax rate on another portion of Prudhoe Bay oil, which is slightly different from the tax rate on a portion of Kuparuk oil. The complexities of the ACES tax system are also difficult to analyze from a producer or explorer perspective. A modest increase in production costs or oil prices can change the economics of a project significantly. A producer/explorer has to consider this complexity in addition to the other factors oil and gas companies typically weigh, such as the amount of debt to incur on a project or whether to include other investors and, if so, the extent to which the other investors will be allowed to participate in the venture.

Small companies: Incentives work

Oil and gas companies in Alaska are divided on their perspective of ACES. Explorers and smaller companies developing small prospects in Alaska point to the credits in ACES as one of the reasons they are able to afford exploration in the state. Buccaneer Energy, an Australian-based independent, claims it was Alaska's tax credits and local natural gas prices that contributed to its decision to invest in the state. The company has told the press that the exploration credits in ACES are "a significant incentive and substantially reduce the commercial discovery threshold" for its operations in

Figure 5-3 Average Tax on Oil at $100 per Barrel



*Assumes one taxable barrel of oil with an average ELF of 0.6, transport costs of $7, and capital and operating expenditures each of $10 per barrel.

Alaska.[12] Greg Vigil, Executive Vice President, Alaska of Savant, another smaller producer, has said publicly that the credits in ACES for capital expenditures and net operating losses are "paramount" to his company's exploration effort in Alaska.[13]

Exploration credits have also encouraged partnerships between small and large producers. Armstrong Oil and Gas, a Denver-based company, purchased a large amount of acreage on the North Slope with major Repsol YPF. In a March 7, 2011 press release, Repsol Chairman Antonio Brufau called the partnership "a perfect fit in our efforts to balance our exploration portfolio with lower risk, onshore oil opportunities in a stable environment. We are confident that our worldwide experience combined with a partner with an extensive local knowledge is going to deliver value in the near future."[14]

Large producers: ACES takes away upside

Other companies are less positive about the impact of ACES on their Alaska oil and gas operations. Representatives from larger international oil companies such as ConocoPhillips and BP have stated that investment in Alaska from companies such as theirs has stagnated and that Alaska needs to improve its investment climate to attract the capital necessary to produce more oil. In a speech to the Resource Development Council for Alaska, ConocoPhillips CEO Jim Mulva said that because of ACES high production tax rates, "Alaska is not attracting as much investment as it should during periods of high oil prices … and that's downright sad." Mulva pledged on behalf of ConocoPhillips to commit to several new North Slope projects if the state's "business environment is changed for the better."[15]

It appears that competition for capital is driving the investment decisions of many of these oil and gas companies. International oil companies, with operations worldwide, have many oil and/or gas projects to choose from, but a limited supply of capital to invest. If oil is priced at $100 per barrel, and the marginal tax rate of each additional dollar the price increases is 90 percent, then there are likely other places that are more favorable to invest.

[12] Kristen Nelson, "Buccaneer Energy acquires more Cook Inlet acreage," Petroleum News, Vol. 15, No. 22, May 30, 2010.

[13] Kay Cashman, "Savant ahead of schedule," Petroleum News, Vol. 14, No. 51, December 20, 2009.

[14] "Repsol Acquires Exploration Blocks in Alaska's Prolific North Slope, " Press Release dated March 7, 2011.

[15] "Mulva warns of low Taps flow," UpstreamOnline, April 2011.

Fiscal system comparisons \\\

We began this report by presenting information comparing Alaska with a group of peers based on non-fiscal criteria that oil and gas companies may consider. In the previous section we presented Alaska's fiscal regime. In this section we will compare Alaska's fiscal regime with a peer group. Before we begin our comparison, it may be helpful to discuss the basic styles of worldwide fiscal regimes. This publication is not intended to provide an exhaustive treatment of petroleum fiscal regimes, but it will provide a brief introduction to the basic types of fiscal arrangements.

Fiscal regime styles

There are nearly as many types of contractual arrangements between governments and oil and gas companies as there are jurisdictions with mineral resources to recover. Among the many general types of agreements, the basic differences tend to be in various approaches to the four following areas:

1. Ownership. Are the hydrocarbons owned by the oil company in the ground or at the wellhead or elsewhere, or are they owned by the state throughout?

2. Payment. Is payment made by companies receiving hydrocarbons/by lifting hydrocarbons they own, or in lieu of payment for cost and profit recovery?

3. Profit drivers. Is the contract structured such that the oil companies are fully exposed to price risk, or are their returns fundamentally driven by payments based on the amount of money invested?

4. Operational freedom. How do contractual and administrative terms affect the degree of freedom with which companies can operate and vary their investment decisions within the country?

It should be noted that there is no one best approach. None of the specific approaches discussed is necessarily more or less generous than the others, as the specific levels of payments and handling of risk can and do vary greatly from country to country and contract to contract.

Typically there are taken to be three "headline" styles of petroleum regimes: concessions, production sharing contracts (PSCs) and service contracts (Figure 6-1). Typically, under a concession arrangement, the fiscal components are handled separately from the award of rights to explore and produce, while under PSCs and service contracts the fiscal structure tends to be tightly interwoven with the underlying contracts specifying each party's rights.

However, as with any generalization, care must be taken as it is possible to construct any of the headline regime styles to look and act very much like another. In particular, the financial returns from each may be very similar, notwithstanding more obvious differences. Indeed, when countries look to update or modify their petroleum contractual or fiscal regime, they are always "benchmarking" it against those of other countries, and aspects are "borrowed" from one to another regardless of the headline contract style involved.

Concession contracts

The current tax and royalty schemes grew out of concession systems commonly seen in the early part of the 20th century. The concept of tax and royalty fiscal regimes is easy to describe in that the government owners of the minerals leases tracts for exploration and development directly to an oil and gas company contractor group either through negotiations or through some sort of competitive bidding. An initial cost typically includes acreage rental payments plus fixed or variable royalties. The government authorities tax the contractor group members based on their profitability from the block.

The U.S. Outer Continental Shelf (OCS) mineral leases represent a tax/royalty scheme. While most OCS leases contain a competitive bid and fixed royalty payments, tax/royalty schemes can include work commitments, variable royalties, net profit interests, etc.

A number of countries with tax/royalty regimes include, in addition to corporation tax, various forms of "rent" or taxes to capture a greater share of the economic benefit arising from operations, whether these result simply from highly profitable fields or from windfalls such as high petroleum prices. Examples include the U.K.'s Petroleum Revenue Tax (PRT), Norway's Supplemental Petroleum Tax (SPT), Brazil's Special Participation (SP), Australia's Petroleum Resource Rent Tax (PRRT) and Alaska's ACES production tax. In the case of the U.K., Norway and much of offshore Australia, no royalty at all is now levied and the countries rely on "rent" and income taxes for virtually their entire share of profits.

Leases granted under a tax/royalty-style arrangement are quite different from the old-style concession agreements, even though the term "concession" may

still be used (as well as "permit" or "license"). While details vary from one jurisdiction to another, they all contain significant term provisions, usually involving relinquishment of some part of the acreage at various stages such that only the immediate producing area remains held for a long time (typically the life of production). In some jurisdictions, minimum work obligations will also apply to different holding periods. Operators are generally able to book their "net" reserves, which are 100 percent of the gross reserves less royalty.

- Joint ventures

Typical joint ventures (JVs) for development share the risks and benefits from oil and gas development and are associated with concession regimes. The national oil company (NOC) partner may receive a relatively large initial payment for the execution of the JV and the contractor group partners may carry 100 percent of exploration costs and potentially all costs "to the tanks" for first oil. Subsequent capital and operating costs are shared in the proportions of the JV ownership. Management decisions for the field and staffing of the JV are also shared with the host government, typically via the NOC as the JV partner. There is nonetheless a clear separation between the government as a taxing and licensing authority and the government-owned IOC JV partner. Some portion of the exploration and development "carried costs" are typically reimbursed by the NOC partner to the contractor group either in cash or oil. Ownership of the crude government share of the oil is independent of the contractor group ownership. The contractor group is typically entitled only to book reserves for their share of the JV's gross reserves less any government royalty and potentially the reimbursable costs if they are repaid from crude oil.

Production sharing contracts

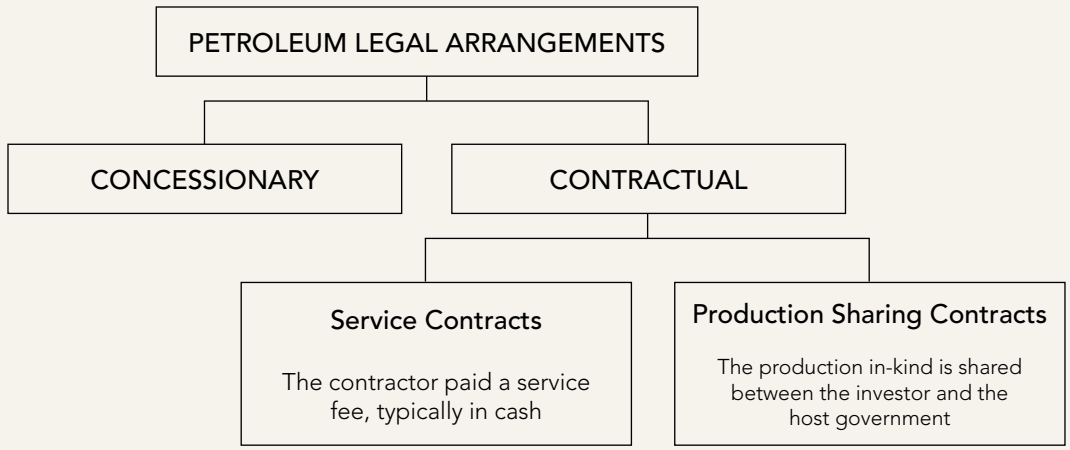
The first production sharing contracts (PSCs) were signed in 1967 with Indonesia. These contracts are also known as production sharing agreements (PSAs) in some locations. The two parties to the PSC are the owner-country usually in the form of an NOC and an international oil and gas company (IOC). Unlike tax and royalty systems, PSCs generally transfer title to the produced hydrocarbons at the export point (as opposed to at the wellhead in tax/royalty systems, under which the resource in the ground is owned by the state). PSCs typically differ from service contracts in that reimbursement to the IOC is in-kind and the parties to the PSC own the rights to their share of the oil.

In general, PSCs divide gross production into what is frequently referred to as cost oil (oil or gas applied to reimburse costs) and profit oil (that in excess of cost oil) with the contractor receiving its compensation from cost oil and a share of the remaining profit oil.

Service Contracts

A service contract is a type of agreement whereby an IOC performs exploration and/or production services for the host government within a specified area for a fee. The host government maintains ownership at all times of the hydrocarbons produced, and usually the IOC (contractor) does not acquire any rights or title to the oil and or gas, except where a contractor is paid its fee in kind (oil and or gas) or is given a preferential right

Figure 6-1. Petroleum legal arrangement classification.



to purchase production from the host government. Pure service agreements between a host government and an IOC are rare. These forms of arrangement are used in Iran, Saudi Arabia, the Philippines and Kuwait, but are not used by governments in North America or Europe.

Complexity

Hovering in the background with all types of fiscal systems is the issue of complexity. Fiscal regimes need to be complex enough to properly compensate the mineral owner, the state or sovereign tax authority, and the investor or developer over the entire life of a project, as well as across the spectrum of different projects that may fall under the same system. On the other hand, fiscal systems that are overly complex can discourage investment when investors can't reasonably forecast their possible profits, costs and risks in a particular jurisdiction. The system that attracts investment most successfully is likely to be the least complex system that still properly allocates costs and benefits at the lowest risk possible.

Peer group jurisdictions

Figure 6-2 includes the highlights of the fiscal regime Alaska offers oil and gas companies interested in

Figure 6-2 Petroleum fiscal regime peer group highlights

Jurisdiction	Royalty (% of Gross Production)	Rental Fees ($ per Acre)	Property /Ad Val. Tax Rate	Federal Corp. Income Tax Rate	State/ Province Corp. Income Tax Rate	Gross Tax Reource Tax	Net Tax,	VAT or Sales Tax Rate	Participation
U.S./States									
Alaska (on shore and state submerged)	State: 12 ½% - 16⅔% Federal: 12 ½%	State: $1 - $3 Federal: $1.50 - $2	Yes	35%	9.4%	-	25% and up (net of costs)	-	-
California	Federal: 12½% Private: 16⅔% - 25%	Federal: $1.50 - $2 Private: $5 - $30	Yes	35%	8.84%	$0.1063/ bbl. $0.1063/ MCF	-	7.25%	-
North Dakota	State: 16⅔% Private: 12 ½% - 25%	State: $0 - $1 Private: $1	None	35%	6.4%	0% - 11.5%	-	5%	-
Oklahoma	Private: 12 ½% - 20%	Private: $1	Yes	35%	6%	7.2%	-	4.5%	-
Texas	Private: 12 ½% - 30%	Private: $3.50	Yes	35%	1% of Net Taxable	4.6%	-	6.25%	-
U.S. GOM OCS	Federal: 18 ¾%	Federal: $7 - $16	None	35%	-	-	-	-	-
U.S. Alaska OCS	Federal: 12 ½%	Federal: $2.50 - $20	None	35%	-	-	-	-	-
Canada/Provinces									
Alberta	Province: 0% - 40%	Province: $1.35	None	16.5%	10%	-	-	-	-
Northwest Territories	Province: 1% - 5%	work commitment, no rental	None	16.5%	11.5%	-	-	-	-
Canada - Beaufort Sea	Federal: 1% - 5%	work commitment, no rental	None	26.5%	-	-	-	-	-
International									
Australia - Deepwater	No Royalty	Federal: $0 - $1	None	30%	-	-	40%	-	-
Norway	No Royalty	Federal: $20 - $80	None	28%	-	-	50%	-	20%
U.K.	No Royalty	Federal: $0.1 - $30	-	30%	-	-	20%	0% - 20%	-

doing business in Alaska compared to a group of peer jurisdictions. We will use the elements presented in Figure 6-3 and in Chapter 5 of this report in our discussion of several other jurisdictions with which we believe the state competes for corporate investment.

In this report we compare Alaska to other concession-based fiscal regimes largely because of the difficulty of making clear comparisons with the fundamentally very different contract-based fiscal regimes.

Alaska's peer comparisons should also include a representative group of states and provinces in the U.S. and Canada. Companies doing business in the U.S. and Canada can relatively easily shift the location of their operations and corporate focus to any fiscal regime they see as more beneficial in either of these two countries.

California

California (Figure 6-4) is a state with resource potential and historic production similar to Alaska's. Issues regarding regulations and environmental concerns make California a reasonable addition to the peer group for Alaska. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

North Dakota

North Dakota (Figure 6-5) has historically experienced lower production volumes than Alaska; however, its production is on the rise. Capital and operating costs are generally assumed to be lower than Alaska. Infrastructure is well established and much more extensive than in Alaska.

Oklahoma

Oklahoma (Figure 6-6) has experienced lower production volumes than Alaska for more than 25 years, and its production is stable to slightly increasing in recent years. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

Texas

Texas (Figure 6-7) is the perennial powerhouse of oil production and potential in the U.S. Production volumes are higher than in Alaska, and its production has been steadily increasing in recent years. As in all of the onshore Lower 48, capital and operating costs are generally assumed to be lower than in Alaska. Infrastructure is well established and much more extensive than in Alaska.

U.S. Gulf of Mexico Outer Continental Shelf

The Gulf of Mexico OCS (Figure 6-8) is another material oil and gas supply source for the U.S. Oil production volumes in the Gulf of Mexico are higher than in Alaska, but were down in 2010, likely due to the Macondo well blowout and spill that occurred that year. Offshore infrastructure is well-established and extensive. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska. There is no state or local corporate tax, property tax, severance tax, production tax or sales tax.

U.S. Beaufort and Chukchi Sea Outer Continental Shelf

The Beaufort Sea and Chukchi Sea OCS (Figure 6-9) has only seen very minimal historic production (from the Northstar field), but has several discovered accumulations and significant potential. There is no infrastructure in the Alaska OCS. Our assumption is that costs will be high and environmental restrictions and permitting hurdles will be greater than onshore Alaska. The U.S. OCS fiscal system has significantly lower overall government take because there is no state or local corporate tax, property tax, severance tax, production tax or sales tax. Producers under the U.S. OCS fiscal system experience significantly lower overall government take than in Alaska.

Alberta

Alberta, Canada (Figure 6-10) has greater production volumes, reserves, and resources than Alaska, a large portion of which is heavy oil and oil sands. However, anecdotal evidence indicates that costs are lower there than in Alaska.

In Alberta, as in the rest of Canada, fiscal terms differ significantly from Alaska. Generally, royalties in Canada are not fixed. Usually the provincial lease contracts allow the government to modify royalty rates at its discretion. In Canada, oil and gas corporations are taxed at the same rate as other corporations. Corporations are taxed by the Canadian federal government and by one or more provinces or territories. The basic rate of federal corporate tax is 26.5 percent, but this rate may be reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. Canada's federal corporate income tax rates are is 16.5 percent, lower than the 35 percent U.S. corporate income tax. The Alberta provincial corporate income tax rate is 10 percent.

Northwest Territories

Northwest Territories, Canada (Figure 6-11), unlike Alberta, has no production history; however, potential is significant. Currently, the Canadian federal government manages oil and gas resources in the Northwest Territories; therefore, the fiscal system is very similar to the Canadian federal offshore Beaufort Sea, described below. Costs here are assumed to be similar to Alaska and infrastructure is limited. The Northwest Territories' fiscal terms differ significantly from Alaska. Generally, royalties in Canada are not fixed. Usually the provincial lease contracts allow the government to modify royalty rates at its discretion. The Alberta provincial corporate income tax rate is 11.5 percent.

Canada Federal Offshore Beaufort Sea

Canada federal offshore Beaufort Sea (Figure 6-12) like the Northwest Territories, has no production history; however, its potential is significant. Costs here are assumed to be similar to offshore Alaska, and infrastructure is limited.

Australia

Australia (Figure 6-13) is included in Alaska's peer group because it has a concession-based fiscal regime and easy access to Pacific Rim markets. In recent years, some Australian oil and gas companies have become interested in Alaska and are now actively pursuing projects here.

Norway

Norway (Figure 6-14) is included in Alaska's peer group because the country applies a concession-based fiscal regime, has a resource base similar to Alaska, and is often the subject of comparison in debates about Alaska's fiscal regime.

United Kingdom

The United Kingdom (Figure 6-15) is included in Alaska's peer group because the country applies a concession-based fiscal regime, has a resource base similar to Alaska, and is often the subject of comparison in debates about Alaska's fiscal regime.

Excluded jurisdictions

The list of peers for Alaska's oil and gas fiscal regimes is short. This is to facilitate, to the extent possible, more direct, logical comparisons. Of the hundreds of jurisdictions and fiscal regimes in the world, we sought out those with the most reasonable parallels to Alaska. This meant excluding the vast majority of jurisdictions. The logic for excluding jurisdictions from the peer group is the same as the logic used to determine which jurisdictions to include.

Excluded states and provinces

We considered including a number of states located in the western U.S. However, most of the states we excluded from the peer group have significantly smaller oil and gas endowment and smaller production volumes than Alaska and the other states included in the list. States that were considered but excluded are Colorado, Kansas, Montana, New Mexico, South Dakota, Utah and Wyoming. Despite their exclusion from the peer group, their fiscal systems are similar to the states that were included, so they are not totally unrepresented in the chosen peer group.

Similarly, we considered including several provinces of Canada in Alaska's fiscal system peer group. But with the exception of Alberta, the resource endowment and historical production was too small to warrant comparison.

Fiscal system exclusions

Internationally, many jurisdictions are excluded from the Alaska peer group because their fiscal regime is not a pure concession-type fiscal system. It is unlikely that Alaska would ever consider moving to a production sharing contract or a service contract fiscal regime and therefore it is logical that these countries are excluded from Alaska's peer group. This exclusion group based on fiscal system type is comprised of countries such as Indonesia, New Guinea, Myanmar, Angola, Nigeria, Egypt, Iraq, Brazil, Columbia, Mexico, and Venezuela.

Geographic location exclusions

A second criterion for excluding some foreign countries is their geographic location. We excluded many countries based on their location away from the Arctic region or the Pacific basin. The logic for this is that the refineries that Alaska's oil supplies are all located on the west coast of the U.S. and the economic barrier is high for them to shift their supply source to other countries outside the Pacific basin. The exclusion group based on geographic location is comprised of countries such as South Africa, Angola, Nigeria, Egypt, Iraq, Brazil, Columbia, Mexico, Venezuela, and Argentina.

Production history exclusions

A third criterion for excluding certain countries is the resource base and production history. Filtering fiscal systems in this way will exclude jurisdictions with a resource base or production history that is longer than Alaska's, such as Russia and many Middle Eastern countries, or where production history, reserves and

undiscovered resource are much less, as in most U.S. states, most Canadian provinces, Thailand, Vietnam, Greenland and Iceland.

Iraq

To offer an example of how this exclusion logic might be applied, we will look at the country of Iraq in detail.

Iraq was excluded based in part on the significant differences between its fiscal regime and Alaska's. Iraq's current fiscal regime is based on a technical service contract. Since 2008, Iraq has offered IOCs the opportunity to bid competitively on service contracts for large legacy fields, each producing between 200,000 and 1 million barrels of oil per day. Contracts are awarded through a competitive bidding process whereby IOCs bid a combination of the production plateaus they believed they could achieve and the per-barrel fees they would accept. The contracting IOC is paid a remuneration fee bid per barrel from a schedule based on a factor equal to the ratio of the cumulative revenue divided by total expenditures. The contractor must then pay a 35 percent corporate income tax and allow for a 25 percent carried interest for the Iraq NOC.

Iraq is also eliminated based on its geographic location. Very little of the production from the Middle East makes it to the west coast of the U.S. due to high transportation costs.

The EIA reports Iraq's reserves at 115 billion barrels of oil and 46 TCF of natural gas. Alaska's reserve base is tiny in comparison: 3.5 billion barrels of oil and 9 TCF of natural gas. IOCs are interested in Iraq despite low service contract payments because the huge production volumes and reasonably certain cash flow from projects in Iraq benefit many companies' overall portfolio mix. Holding existing contracts also places a contractor in a position to win future contracts over the mid- to long term. Alaska simply could not guarantee the same volume assurances over a similar time period.

Figure 6-3 Alaska fiscal system highlights

Royalty:	Generally 12 ½ or 16 ⅔ percent, most production pays at 12 ½ percent. Higher royalty rates on some private lands do exist, but generally private rates are not lower than state rates. Natural gas royalty rate is the same as oil on state and federal lands. Most production in Alaska is on state-owned lands.
Rental:	Alaska state lands: 1st year - $1, 2nd year - $1.50, 3rd year - $2, 4th year - $2.50, and 5th and subsequent years - $3 per acre. Rental is creditable against royalties.
Federal lands:	$1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property Tax:	The State of Alaska levies a property tax on the full and true value of all oil and gas property in the state. The property tax is assessed annually and the tax rate is 20 mills. Oil and gas property that is also within local boundaries may be taxed on the local level and that amount is deducted from the property tax paid to the state.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. The Alaska state corporate income tax rate is graduated with the top tax rate of 9.4 percent levied when net incomes exceed $90,000 for the year. The corporate income tax for oil and gas uses a modified apportionment method, whereby a corporation's tax liability is based on the size of its Alaska operations relative to its worldwide net income. The apportionment factors used to determine a corporation's Alaska tax liability are the Alaska operation's (1) tariffs and sales; (2) oil and gas production; and (3) oil and gas property.
Production Tax (Profit Share):	The Alaska state production tax is fundamentally different than all other federal and state jurisdictions in the U.S., in that it is a "net" tax, after most costs and expenses are subtracted from revenue. The production tax formula consists of two primary pieces: a base tax rate of 25 percent and a progressive tax rate of 0.4 percent for every dollar the per-barrel profit exceeds $30, at which point the progressive rate changes to 0.1 percent for every additional dollar in profit. The maximum combined base and progressive tax rate is 75 percent. A company's tax liability may be reduced by credits that are included in the ACES production tax system, the most common being the 20 percent capital expenditure credit. The basic tax calculation under ACES is as follows: **ACES Tax Liability = [(Value – Costs) * Tax Rate] – Credits** **Value =** Volume of Non-Royalty Oil & Gas Produced * Wellhead Value **Costs =** Operating and Capital Expenditures **Tax Rate =** 25 percent + 0.4 percent for every $1 per barrel that "net profit" exceeds $30 up to $92.50, then 0.1 percent up to a maximum of 75 percent **Credits =** 20 percent * Capital Expenditures (spread over 2 years) and other credits
Resource/ Severance Tax:	None.
Indirect Taxes:	None.
Incentives and Credits:	Alaska offers, by most accounts, generous incentives targeted in several ways. See Figure 5-2 for details on many of Alaska's credit incentives. In addition to tax credits listed in Figure 5-2, Alaska offers special incentives for Cook Inlet and other "non-North-Slope" oil and natural gas production, royalty modification, natural gas storage. Royalty modification, or reduction, may be considered if an operator shows that a development project is uneconomic if developed without royalty modification, but would become economic if the royalty rate agreed to in the lease was reduced or modified in some way. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 6-4 California fiscal system highlights

Royalty:	Federal lands: Most production pays at 12 ½ percent. Natural gas rate is same as oil.
Private lands:	Generally 16 ⅔ or 25 percent, most production pays at 16 ⅔ percent. The majority of production in California is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental:	Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Private lands:	$5 to $30 per acre, assumed to be $20 per acre.
Property Tax:	Property tax is based on the lesser of the market value of the property and the Proposition 13 tax cap value. The rate is assumed to be 1 percent. This rate reflects a statewide average for counties and school districts.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. The California state corporate income tax rate for oil and gas is 8.84 percent.
Production Tax (Profit Share):	None.
Resource/ Severance Tax:	An Assessment Tax applies at $0.1063 per barrel oil or per 10 thousand cubic feet natural gas.
Indirect Taxes:	California assesses sales tax of 7 ¼ percent.
Incentives and Credits:	In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 6-5 North Dakota fiscal system highlights

Royalty:	North Dakota state lands: Most production pays at 16 ⅔ percent. Natural gas rate is same as oil. Federal lands: Most production pays at 12 ½ percent. Natural gas rate is same as oil. Private lands: Most production pays at 18 ¾ percent. The majority of production in North Dakota is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental:	North Dakota state lands: $1 per acre (during exploration period only). Federal lands: $1.50 per acre delay rental for years 1 – 5 and $2 per acre thereafter.
Property Tax:	None.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. The North Dakota state corporate income tax rate for oil and gas is 6.4 percent.
Production Tax (Profit Share):	None.
Resource/Severance Tax:	11.5 percent total, broken down in two pieces as follows: Severance Tax of 5.0 percent plus Oil Extraction Tax of 6.5 percent.
Indirect Taxes:	North Dakota assesses sales tax of 5 percent on all capital goods brought into the state.
Incentives and Credits:	North Dakota offers incentives for certain types of activities and ventures. These programs include lower Oil Extraction Tax (OET) for very-low-production volume (stripper) wells and when WTI oil prices minus $2.50 fall below a "Trigger" price, $46.78. To encourage horizontal oil wells the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, 18 months, or $4.5 million in gross production revenue. To encourage production in the Bakken Formation, the OET is reduced to 2 percent for the earlier of 75,000 barrels produced, or 18 months. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 6-6 Oklahoma fiscal system highlights

Royalty:	Private lands: Rate range between 12 ½ and 20 percent, average assumed to be 18 ¾ percent. Virtually all production in Oklahoma is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental:	Private lands: assumed to be $1 per acre delay rental.
Property Tax:	Oklahoma assesses a Franchise Tax at $1.25 per $1,000 invested, to an annual maximum of $20,000 per corporate entity.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. The Oklahoma state corporate income tax rate for oil and gas is 6 percent.
Production Tax (Profit Share):	None.
Resource/Severance Tax:	7.2 percent total, broken down in four pieces as follows: Severance Tax at 7.0 percent plus Petroleum Excise Tax at 0.095 percent plus Energy Resources Board Fee at 0.1 percent plus marginal Well Fee at $0.0035 per barrel oil and $0.00015 per thousand cubic feet natural gas.
Indirect Taxes:	Oklahoma assesses a sales tax of 4.5 percent on goods and services.
Incentives and Credits:	Oklahoma offers incentives for certain types of activities and ventures. These programs include lower Severance Tax for low oil or natural gas prices. Additionally Severance Tax reductions may apply for deep wells. To encourage exploitation of very deep reservoirs, Severance Tax is reduced for wells drilled below12,500 feet in depth for a period that varies based on depth. To encourage horizontal wells, additional reductions in the Severance Tax may apply. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 6-7 Texas fiscal system highlights

Royalty:	Private lands: Rate range between 12 ½ and 30 percent, average assumed to be 25 percent. Virtually all production in Texas is from private lands. Natural gas generally pays the same royalty rate as oil.
Rental:	Private lands: assumed to be $3.50 per acre delay rental, exploration period only. University lands: $25 per acre at the time of the bid, then $5 per acre annually thereafter. Rental is creditable against royalties.
Property Tax:	Property taxes assessed at 2.5 percent, levied on the fair market value of reserves as determined by discounted present value. This rate reflects a percent average for counties and school districts.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. Texas has no state corporate income tax, however it does levy a Corporate Franchise Tax at 1 percent of "net taxable earned surplus."
Production Tax (Profit Share):	None.
Resource/Severance Tax:	Oil Production Tax is 4.6 percent plus Regulatory Tax at $0.001875 per barrel plus Oil Field Clean-Up Fee at $0.00625 per barrel oil. Gas Production Tax is 7.5 percent plus Oil Field Clean-Up Fee at $0.000667 per thousand cubic feet natural gas.
Indirect Taxes:	Oklahoma assesses a sales tax of 6.25 percent on goods and services.
Incentives and Credits:	Texas offers an incentive, in the form of lower severance tax when oil prices are low. In addition to state incentives, the U.S. federal government offers incentives for certain activities and ventures, including research and development credits, IDC deductions and the carry-forward of tax losses.

Figure 6-8 U.S. Gulf of Mexico Outer Continental Shelf (OCS) fiscal system highlights

Royalty:	18 ¾ percent (2008 terms). Natural gas pays the same royalty rate as oil.
Rental:	If water depth <200 meters: $7 per acre for years 1 – 5 and $16 per acre for years 6 – 10. If water depth >200 meters: $11 per acre for years 1 – 5 and $16 per acre for years 6 – 10.
Property Tax:	None.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. Capital investments in developing oil and gas production sites typically fall into two broad categories, Tangible and Intangible, with tangible being further categorized into two categories. Company classification, Independent or Integrated, is also important. A firm is Independent if its refining capacity is less than 75,000 barrels per day or its retail sales are less than $5 million for the year. Intangible exploration costs are those incurred to identify promising sites and bonus bids paid to acquire lease rights and are subject to Depletion, either cost depletion (UoP) or percent depletion (15 percent). Percent depletion is limited to independent producers and to the value of 1,000 barrels of oil equivalent per day and cannot exceed 100 percent of property taxable income, and 65 percent of the income from all sources before depletion. If daily production exceeds the 1,000 barrel per day threshold, the allowance is multiplied by 1,000 divided by the actual average daily production. The other intangible category is Site Development. Site development costs have no salvage value and are referred to as Intangible Drilling Costs (IDCs). Dry hole costs also fall into this category. Tangible costs, drilling equipment and improvements to property, are recovered under the Modified Accelerated Cost Recovery System (MACRS). MACRS recovery is typically over seven years, but five years is used for drilling equipment. Special rules exist for geological and geophysical expenses. Loss carried forward term is 20 years.
Production Tax (Profit Share):	None.
Resource/Severance Tax:	None
Indirect Taxes:	None.
Incentives and Credits:	The U.S. federal government offers incentives for certain activities and ventures, including royalty reduction, research and development credits, IDC deductions (mentioned above) and the carry-forward of tax losses (mentioned above). Royalty reduction on certain leases, referred to as Royalty Suspension Volume (RSV). Qualification for RSV depends on the particular lease and is triggered at a particular low-price threshold. The threshold price is initially fixed, but increases based on an inflation adjustment.

Figure 6-9 U.S. Beaufort Sea and Chukchi Outer Continental Shelf (OCS) fiscal system highlights

Royalty:	12 ½ percent (recent lease sales). Natural gas pays the same royalty rate as oil.
Rental:	1st year - $2.50, 2nd year - $3.75, 3rd year - $5, 4th year - $6.25, 5th year - $7.50, 6th year - $10, 7th year - $12, 8th year - $15, 9th year - $17, and 10th year - $20 per acre.
Property Tax:	None.
Corporate Income Tax:	The U.S. federal corporate income tax rate is 35 percent. Capital investments in developing oil and gas production sites typically fall into two broad categories, Tangible and Intangible, with tangible being further categorized into two categories. Company classification, Independent or Integrated, is also important. A firm is Independent if its refining capacity is less than 75,000 barrels per day or its retail sales are less than $5 million for the year. Intangible exploration costs are those incurred to identify promising sites and bonus bids paid to acquire lease rights and are subject to Depletion, either cost depletion (UoP) or percent depletion (15 percent). Percent depletion is limited to independent producers and to the value of 1,000 barrels of oil equivalent per day and cannot exceed 100 percent of property taxable income, and 65 percent of the income from all sources before depletion. If daily production exceeds the 1,000 barrel per day threshold, the allowance is multiplied by 1,000 divided by the actual average daily production. The other intangible category is Site Development. Site development costs have no salvage value and are referred to as Intangible Drilling Costs (IDCs). Dry hole costs also fall into this category. Tangible costs, drilling equipment and improvements to property, are recovered under the Modified Accelerated Cost Recovery System (MACRS). MACRS recovery is typically over seven years, but five years is used for drilling equipment. Special rules exist for geological and geophysical expenses. Loss carried forward term is 20 years.
Production Tax (Profit Share):	None.
Resource/Severance Tax:	None
Indirect Taxes:	None.
Incentives and Credits:	The U.S. federal government offers incentives for certain activities and ventures, including royalty reduction, research and development credits, IDC deductions (mentioned above) and the carry-forward of tax losses (mentioned above). Royalty reduction on certain leases, referred to as Royalty Suspension Volume (RSV). Qualification for RSV depends on the particular lease and is triggered at a particular low-price threshold. The threshold price is initially fixed, but increases based on an inflation adjustment.

Figure 6-10 Alberta (Canada) fiscal system highlights

Royalty:	0 to 40 percent. Royalties in Alberta are the primary vehicle by which the province assesses its portion of economic rent. Unlike in the Alaska and other U.S. states, royalty rates in Alberta and other jurisdictions in Canada are not set in the lease contract, leases in Alberta simply state that the royalty is established by the provincial government. This leaves the royalty subject to change as government deems appropriate.
Rental:	C$3.50 per hectare (approx. $1.35 per acre) per year.
Property Tax:	None.
Corporate Income Tax:	In Alberta, the Canadian federal corporate income tax rate is 16.5 percent. The basic rate of Canadian federal corporate tax is 26.5 percent, but it is further reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. The Alberta provincial corporate income tax for oil and gas is 10 percent. Exploration costs are expensed. Land purchase costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10 percent declining balance from the date incurred. Development well intangibles are depreciated at 30 percent declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25 percent declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss Carry Forward term is 20 years.
Production Tax (Profit Share):	None.
Resource/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	Alberta has established programs whereby royalty rates are lowered to incentivize several different types of activities and ventures. These programs include special terms for low production volume wells, low price conditions, horizontal wells, deep gas wells, oil sands projects and coalbed methane, shale gas, solution gas, condensate, and natural gas liquids (NGL) production. The corporate tax rate is 3.0 percent for firms that qualify as "small businesses." In addition to provincial incentives, the Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 6-11 Northwest Territories (Canada) Onshore fiscal system highlights

Royalty:	1 to 5 percent sliding scale. Royalty sliding scale escalates on 18-month intervals. Natural gas pays the same royalty rate as oil.
Rental:	None. Work expenditure commitments may apply.
Property Tax:	None.
Corporate Income Tax:	In Northwest Territories the Canadian federal corporate income tax rate is 16.5 percent. The basic rate of Canadian federal corporate tax is 26.5 percent, but it is further reduced to 16.5 percent by an abatement of 10 percent on a corporation's taxable income earned in a province or territory. The Northwest Territory provincial corporate income tax for oil and gas is 11.5 percent. Exploration costs are expensed. Land purchase costs are depreciated as Canadian Oil and Gas Property Expense (COGPE) at 10 percent declining balance from the date incurred. Development well intangibles are depreciated at 30 percent declining balance. Facilities and well tangibles are subject to the half-year convention and depreciated at 25 percent declining balance from the start of production/Available for Use (AFU) date. AFU rules are relaxed through the Long Term Project (LTP) rules, including the 24-month Rolling Start (RS) rule. Loss Carry Forward term is 20 years.
Production Tax (Profit Share):	Profit share is levied after "payout" at the rate of 30 percent. Payout is determined based on recovery of previous royalty payments, uplifted capital, operating and exploration expenses, plus a rate-of-return allowance of the long term government bond rate plus 10 percent. In determining payout, capital and operating expenses can be uplifted by 1 and 10 percent respectively. The gross royalty is always payable and is creditable against the profit share.
Resource/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	The Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 6-12 Canada Federal Offshore Beaufort Sea fiscal system highlights

Royalty:	1 to 5 percent sliding scale. Royalty sliding scale escalates on 18-month intervals. Natural gas pays the same royalty rate as oil.
Rental:	None. Work expenditure commitments may apply.
Property Tax:	None.
Corporate Income Tax:	In Canada the basic rate of federal corporate tax is 26.5 percent. Offshore areas are not subject to any federal corporate tax abatement and pay taxes at the full federal rate. For Canadian income tax purposes, a corporation's worldwide taxable income is computed in accordance with the common principles of business (or accounting) practice, modified by certain statutory provisions in the Canadian Income Tax Act. In general, no special tax regime applies to oil and gas producers. Depreciation, depletion or amortization recorded for financial statement purposes is not deductible; rather, tax-deductible capital allowances specified in the Income Tax Act are allowed.
Production Tax (Profit Share):	Profit share is levied after "payout" at the rate of 30 percent. Payout is determined based on recovery of previous royalty payments, uplifted capital, operating and exploration expenses, plus a rate-of-return allowance of the long term government bond rate plus 10 percent. In determining payout, capital and operating expenses can be uplifted by 1 and 10 percent respectively. The gross royalty is always payable and is creditable against the profit share.
Resource/Severance Tax:	None.
Indirect Taxes:	Exempt. Canada's goods and services tax (GST) or harmonized sales tax (HST) generally does not apply to oil and gas operations.
Incentives and Credits:	The Canada federal government offers incentives for research and development in the form of scientific research and experimental development credits (SR&ED).

Figure 6-13 Australia Federal Offshore fiscal system highlights

Royalty:	See Production Tax.
Rental:	Various application, permit and annual fees apply, up to about $1 per acre. Work expenditure commitments may apply.
Property Tax:	None.
Corporate Income Tax:	The Australian federal corporate income tax rate is 30 percent. Facilities depreciation is based on prescribed "effective life."
Production Tax (Profit Share):	The Petroleum Resource Rent Tax (PRRT) applies seaward of the territorial sea boundary, with the some exceptions. The PRRT is levied at 40 percent of taxable profit (income) after payout. Taxable profit is determined by deducting from assessable receipts, the total of deductible expenditures, plus certain expenditures. Payout occurs when a project has earned a return allowance equal to Australia's long-term bond rate plus an allowance of 5 percent or 15 percent depending on the specific project. PRRT is deductible in calculating corporate income taxes.
Resource/Severance Tax:	None.
Indirect Taxes:	All sales within Australia are subject to goods and services tax (GST) at the rate of 10 percent. Both Australian-resident and non-resident entities engaged in the oil and gas industry may be subject to GST on services and products supplied. All commercial transactions have a GST impact. Certain exported products and services and other transactions may qualify for exemptions.
Incentives and Credits:	None.

Figure 6-14 Norway Federal Offshore fiscal system highlights

Royalty:	None.
Rental:	Various rentals and annual fees apply, from about $20 to $80 per acre depending on the status of the lease block.
Property Tax:	None.
Corporate Income Tax:	The Norwegian federal corporate income tax rate is 28 percent. Expensing of certain costs is allowed. Depreciation of certain asset classes is based on a straight-line depreciation schedule. Additional tax elements apply.
Production Tax (Profit Share):	Special Tax, sometimes referred to as the "Hydrocarbon Tax," is assessed at a 50 percent rate. Uplift of all capital expenses is at a rate of 7 ½ percent for a period of four years, 30 percent total. Hydrocarbon tax is not deductible against corporate income taxes.
Resource/Severance Tax:	None
Indirect Taxes:	Exempt. Norway's value added tax (VAT) generally does not apply to goods and services used in offshore oil and gas operations.
Incentives and Credits:	See "uplift" of capital expenses above under Production Tax.
State Participation:	Unlike all other jurisdictions discussed in detail in this report, Norway retains the right to exercise a participation interest in offshore oil and gas blocks. Various interest shares have been exercised, in recent bidding rounds about 20 percent participation. These participation interests are managed by a state-run company, Petoro.

Figure 6-15 United Kingdom Federal Offshore fiscal system highlights

Royalty:	None.
Rental:	1st and 2nd years - $0.10 per acre, 3rd through 6th years - $0.60 per acre, then escalating to a maximum of about $30 per acre in the 15th year. There is a mandatory 75 percent relinquishment at the end of Year 3 and a further 50 percent at the end of the primary term in Year 6.
Property Tax:	None.
Corporate Income Tax:	The United Kingdom federal corporate income tax rate is 30 percent. Taxable income is ring-fenced for upstream oil and gas activities. Additional tax elements apply.
Production Tax (Profit Share):	None.
Resource/Severance Tax:	Supplemental Charge levied at rate of 32 percent (20 percent when oil price is below $75) on profits from U.K. oil and gas production.
Indirect Taxes:	The standard rate of value added tax (VAT) in the United Kingdom is 20 percent, with reduced rates of 5 percent and 0 percent. The VAT is potentially chargeable on all supplies of goods and services made in the United Kingdom and its territorial waters.
Incentives and Credits:	The United Kingdom offers incentives for certain activities and ventures, including a Ring Fence Expenditure Supplement (RFES) and certain research and development allowances.

Summary \\\

Alaska is fortunate to be endowed with abundant natural resources, especially oil and gas. Additionally, the state is well-positioned geographically to market those resources to a large area of the world. It is the responsibility of Alaska's government to continuously review its fiscal regime as it applies to its natural resources in light of changes to fiscal regimes of similarly positioned jurisdictions.

By establishing a logical peer group for a comparison, we can start the discussion and improve the outcome of any review of the Alaska's fiscal system. Elements of Alaska's peer group include similarities in fiscal system type, resource base, and geographic location. Certainly there can be criteria that others may wish to add to this list, but we believe that any list of criteria for choosing a peer group should at least include these three.

While it is important to look at Alaska's fiscal regime from the state's perspective, focused on state revenue, in order to help understand potential risks to Alaska's revenue stream, it is equally important that Alaskans consider the perspective of investors in Alaska. Most oil companies look at more than one jurisdiction when making decisions on where to invest, and they will only invest in a place where they believe there are resources to find and where there is reasonable certainty those resources eventually can be produced and sold for a reasonable profit. If we look at this problem from the perspective of the oil company as investor, we will improve the long-term benefit to the state from our natural resources.

We thank the various state agencies for their cooperation in compiling this document.

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This publication was produced by the Department of Revenue.
It was printed in Anchorage, Alaska at a cost of about $9 per copy.