BLM 2019 Study

2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems: Onshore Report

U.S. Department of the Interior
Bureau of Ocean Energy Management
Bureau of Safety and Environmental Enforcement
Bureau of Land Management

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DISCLAIMER

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List of Abbreviations and Acronyms

$/bbl	dollars per barrel
$/mcf	dollars per thousand cubic feet
$/MMBtu	dollars per million British thermal unit
ANS	Alaska North Slope
APD	Application for permit to drill
bbl	barrel
Bcf	billion standard cubic feet
Bcf/d	billion standard cubic feet per day
boe	barrels of oil equivalent
boe/d	barrels of oil equivalent per day
BLM	Bureau of Land Management
CAD	Canadian dollar
capex	capital expenditure
CFR	Code of Federal Regulations (U.S.)
CO	Colorado
CO_2	carbon dioxide
CO_2e	carbon dioxide equivalent
DOI	U.S. Department of the Interior
E&P	exploration and production
EIA	Energy Information Administration
EMV	expected monetary value
Fed	Federal
ft	feet
IRR	internal rate of return
LA	Louisiana
Mcf	thousand standard cubic feet
MMbbl	million barrels
MMbbl/d	million barrels per day
MMboe	million barrels of oil equivalent
MT	Montana
n/a	not applicable
ND	North Dakota
NM	New Mexico
NPR-A	National Petroleum Reserve in Alaska
NPV	net present value
OH	Ohio
ONRR	Office of Natural Resources Revenue
opex	operating expense
PA	Pennsylvania
Pri	Private
SEC	U.S. Securities Exchange Commission
St	State

Tcf	Trillion cubic feet
TVD	true vertical depth
TX	Texas
U.S.	United States
USC	U.S. Code
USD	U.S. Dollar
UT	Utah
WTI	West Texas Intermediate
WV	West Virginia
WY	Wyoming
YTF	yet-to-find

Executive Summary

E.1 Introduction

The U.S. Department of the Interior (DOI) has contracted an updated study of the oil and gas fiscal systems of other countries, U.S. states, and private lands to help ensure that oil and gas investments on Federal lands remain competitive with other jurisdictions, and that the public is receiving a fair return for Federal oil and gas resources.

Since the publication of the 2011 Comparative Assessment of the U.S. Federal oil and gas fiscal system[1], significant changes to oil and gas market conditions have globally taken place. With an increase in U.S. onshore supply, world oil and gas prices have fallen. This low price environment has changed the competitive landscape of the oil and gas investments in the United States and globally. Key factors that have contributed to this change in landscape include:

1. The amount and type of the oil and gas resources available and the activities of oil and gas suppliers around the world. The "shale revolution" has transformed the U.S. into a top producer of natural gas and crude oil. Production from tight oil and shale gas plays has currently overtaken conventional oil and gas production in the U.S. and is expected to push U.S. crude oil and condensate production to 14 million barrels per day (MMbbl/d) by 2025, with natural gas exports reaching 5 billion cubic feet per day by 2020 (IHS Markit base case outlook).

2. Dramatic shifts in commodity prices have led to a shift from long-cycle barrels to short-cycle barrels. Although the traditional exploration cycle typically exceeds five years from lease sale to first oil production, the emergence of tight reservoirs and advancements in the technology associated with their development have created the potential for sustainable development opportunities that are both short- and long-cycle.[2] Spending on exploration is decreasing in new conventional ventures and increasing in tight reservoirs in proven "Super Basins" and a select set of emerging basins with multiple stacked targets.[3]

As the third in its series of the 2018 Comparative Analysis of the Federal Oil and Gas Fiscal Systems, this onshore report focuses on three peer groups that reflect the diversity of resources concepts and environment in the Federal mineral estate—Alaska conventional onshore, the Lower-48 conventional, and the Lower-48 unconventional resources. The first report compares other countries' offshore fiscal systems with the shallow water and deepwater of the U.S. Gulf of Mexico. The second report (Offshore Frontiers Report) provides comparisons of other jurisdictions' fiscal systems with the systems used for Federal offshore frontier areas.

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[1] Agalliu, I. 2011. Comparative assessment of the federal oil and gas fiscal systems. U.S. Department of the Interior, Bureau of Ocean Energy Management Herndon. VA. OCS Study, BOEM 2011-xxx. 300 pp.

[2] Short-cycle barrels are projects that can generate profit within one to two years of development, or, in the case of new entrants, projects that progress to FID in less than three years. The typical deepwater project averages seven years to reach FID with exponentially more upfront investment.

[3] "Super Basins" are basins that already have produced five billion barrels of oil and contain the potential to produce an additional five billion barrels.

E.2 Objective

The objective of this study is to inform the DOI about the relative competitive position of the Federal oil and gas fiscal systems with oil and gas fiscal systems of the respective states and private mineral estates competing for investment, to help ensure that oil and gas investment on Federal lands remains competitive, and that the public is receiving a fair return for Federal resources. To achieve this objective, the study compares North American fiscal systems against current Federal lease terms, as well as alternative royalty rates requested by the DOI to be included in this study. It is not within the scope of this study to make recommendations related to DOI policies on Federal mineral estate, but rather serve as a tool for informing decision-making on the appropriate fiscal terms for Federal oil and gas leases.

E.3 Key Findings

The competitiveness of the Federal fiscal systems hinges on more than the components of the government take. The ability of the Federal fiscal system to remain competitive depends among others on the prospectivity and scale of the resource base in each jurisdiction, the exploration and development costs, the fiscal terms, prevailing market prices, and other factors.

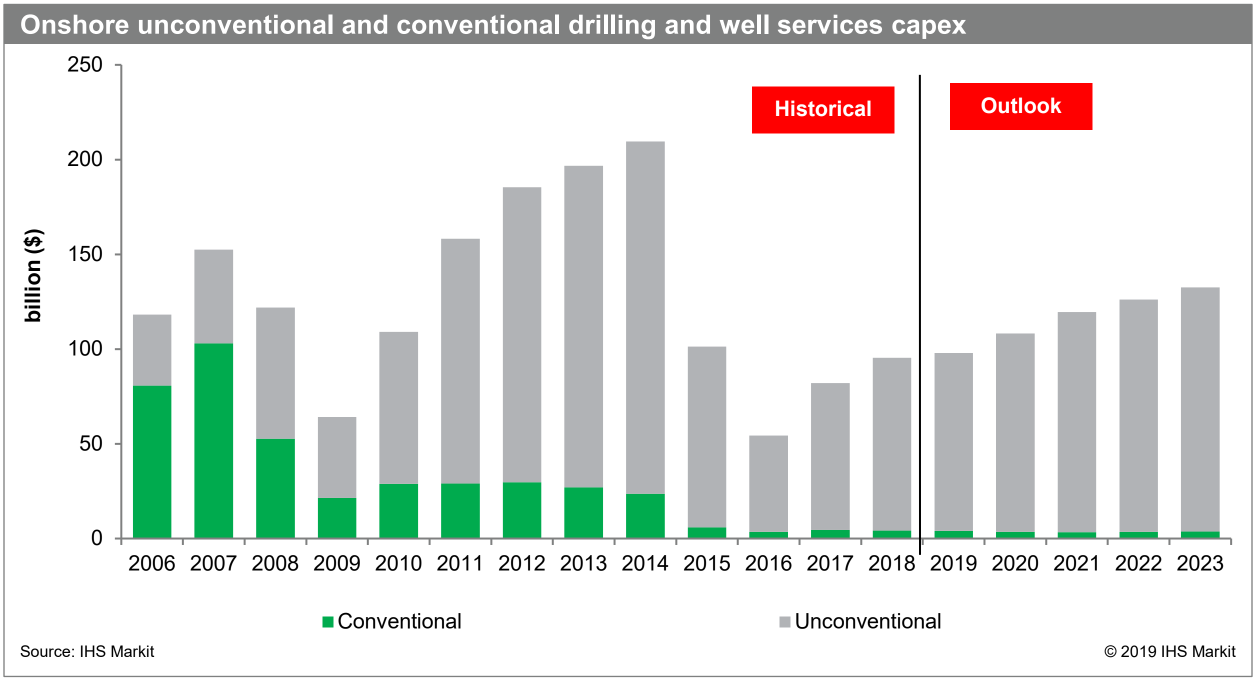
In the U.S. onshore, the scale of the resource base and the exploration and development costs in the particular play tend to drive where capital is spent. Within the same jurisdiction the competitiveness of the Federal fiscal system will depend on the attractiveness of the Federal mineral estate. Changes to the Federal fiscal system will have a greater impact on projects with marginal economics such as conventional oil and gas resources in the Lower 48.

The Federal fiscal system consists of various levies controlled by local governments (or municipalities), state governments, and the federal government. As examples, state governments generally impose severance taxes on production and the federal government, notably, imposes income tax on corporate entities as well as royalties and rentals for the mineral estate. **The DOI, therefore, does not have control over many of the levers that comprise its fiscal system.**

Royalties, bonuses, and rental payments are the primary aspects of the fiscal system that are controlled by the DOI. Changes to levies imposed by state and local governments are not very frequent—some of them have not changed their severance taxes in decades. Few tend to be very reactive to commodity prices—Alaska has a long history of frequent changes to its oil and gas production tax. In such cases, alignment with the state fiscal system could make the Federal fiscal system more sensitive to oil market changes.

Unconventional oil and gas developments—principally in low-permeability tight and shale formations—are attracting most of the capital among the U.S. onshore resources. Oil and gas drilling activity has a strong correlation to market conditions, this is especially notable for the short-cycle barrels from unconventional reservoirs. Such reservoirs provide exposure to a shorter-cycle and price-responsive asset type that generates more immediate cash flow—key attributes amid the volatile commodity price environment. The number of new wells spudded in the selected jurisdictions between 2014 and 2018 is positively correlated to the fluctuations of the oil markets. Unconventional oil and gas developments are the most competitive and are attracting most of the capital expenditure (capex) among U.S. onshore resources. IHS Markit forecasts that tight oil production will account for 81 percent of U.S. crude oil supply by 2040, compared to 62 percent in 2018 and 15 percent in 2010. The major plays included in this study, such as Wolfcamp Delaware, Bakken, and Bone Spring, will account for 44 percent of the U.S. crude oil supply by 2040, compared to 25 percent in 2018 and 6 percent in 2010.

Figure E-1. Onshore unconventional and conventional drilling and well services capex



Modeling approach

IHS Markit ran 9 conventional Alaska, 102 conventional Lower-48 U.S., and 44 unconventional economic models. Three price scenarios are applied to the economic models, reflecting a base, high, and low price. All field and well cost models feed into economic models as inputs through Federal, state, and private fiscal systems relevant to each area. With 155 economic models, a total of 465 cases are analyzed under the three price scenarios.

IHS Markit evaluated the 465 cases using the following economic metrics:

- **Internal rate of return (IRR):** The rate at which the sum of the project's discounted cash outflows equals the sum of the project's discounted inflows.
- **Net present value per barrel of oil equivalent (NPV/boe):** The amount of value in today's terms that each boe of entitlement production will generate for the operator on a full-cycle basis including dry holes, appraisal, development, and abandonment.
- **Expected monetary value (EMV):** The sums of the NPV given success and NPV given failure, weighted by the probability of occurrence. Not applicable for unconventional resources.
- **Government take:** Government take is a general term used to describe the share of revenues that accrues to the government (or governments) over the life of an E&P project. The calculation of government take in this study includes the share of revenues accruing through royalties, taxes, and other fiscal and quasi-fiscal levies such as regulatory fees. Government take in this report is defined as the government or governments' percentage of pretax project net cash flow on an undiscounted basis.

Most unconventional plays offer robust rates of returns to investors across all jurisdictions and fiscal systems, with Bone Spring outperforming the other plays with regard to the median, as well as the range, of the investor IRR. (Figure E-2). The Federal fiscal systems generally offer better IRR than the state and private fiscal systems except in Marcellus and Niobrara—where the Federal mineral estate is in the subplays with higher cost per barrel of oil equivalent (boe). In selected plays, the Federal mineral estate offers greater estimated ultimate recovery (EUR) per well than comparable resource on the state and private mineral estates, allowing operators to amortize their per-well drilling costs across a greater number of boe sold, and realizing a greater return on investment under the prevailing fiscal systems.

The median IRR across all the plays, prices and mineral estates averages 40 percent—with the average for Federal mineral estate at 45 percent. In the majority of the plays, the Federal mineral estate generates healthy rates of return under the high and base price scenarios used for this study. Some of the subplays, such as New Fairway in the Bakken, New Mexico and Texas Deep in Bone Spring, Niobrara Wattenberg, and Parkman yield acceptable rates of return even under the low oil price scenario.

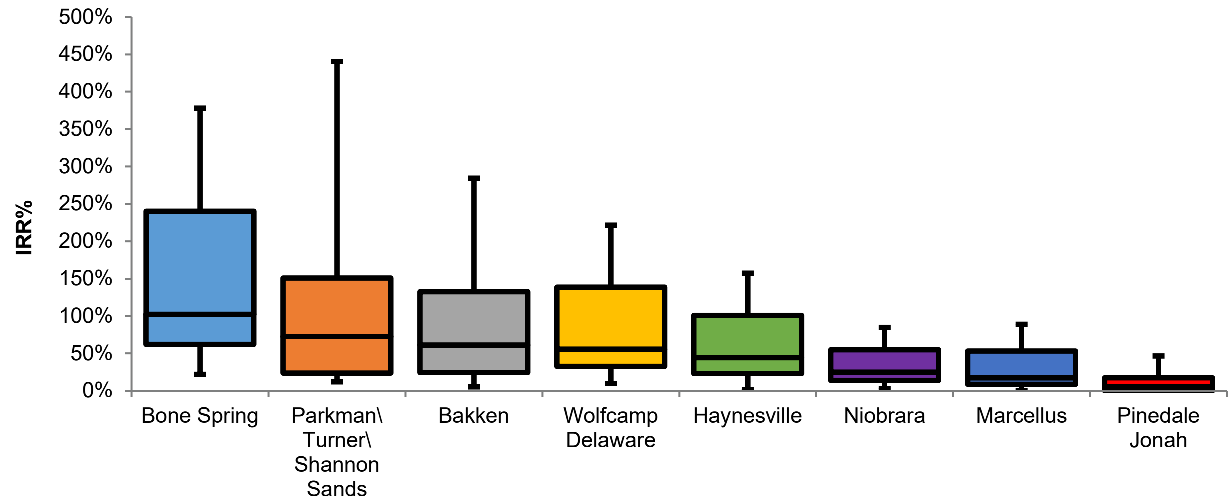
IRR: Box and whisker chart

Each box represents a particular fiscal system's distribution of all cases (low, base and high price scenarios for all three field sizes).

- The ends of the box represent the upper and lower quartiles (the 75th and 25th percentiles, respectively).
- The horizontal line inside the box represents the median (the 50th percentile or middle value or the range).
- The whiskers, the two vertical lines outside the box, show the minimum and maximum values.

Figure E-2. IRR: Ranking of Federal mineral estate unconventional plays—Range across subplays and prices

IRR: Federal mineral estate unconventional plays



Notes: Rank ordered by median IRR. The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median.

Source: IHS Markit

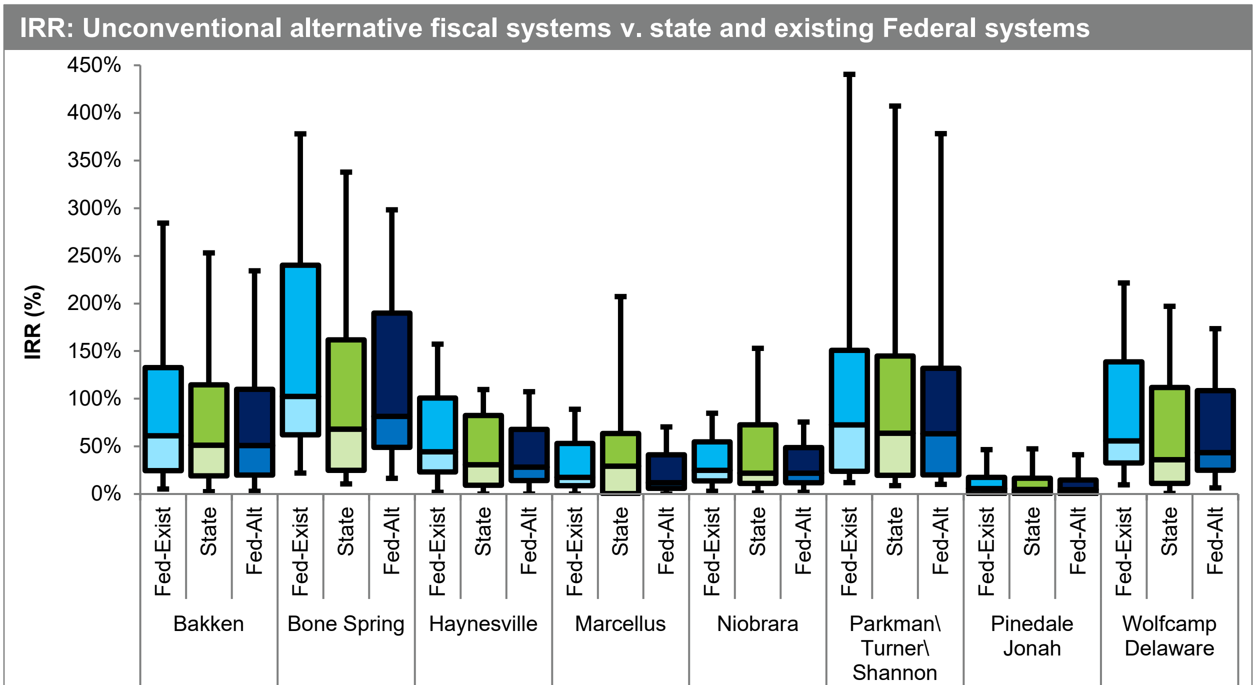
Investors would expect similar returns to the mineral estates of the respective states if the BLM were to raise the Federal royalty rates to match those of the state fiscal systems. While an increase in royalty rates results in lower rates of return and places the Federal fiscal systems at a small comparative disadvantage when compared against the state fiscal systems[4], the higher EUR per well observed on Federal mineral estate in certain tight-oil plays offsets any comparative disadvantage resulting from the increase in royalty rates. Such a measure would not necessarily make the Federal mineral estate less attractive on average by comparison to investment opportunities on state and private mineral estates (Figure E-3).

Alternative Fiscal Systems

The fiscal system alternatives analyzed in this section were requested by BLM. They do not necessarily represent the current or future plans of the BLM. They have been applied to understand the extent to which, if any, such alternatives might impact investment decisions and the competitiveness of the Federal mineral estate.

[4] The longer timeframes for approval of applications for permit to drill on Federal versus state mineral estate result in lower IRR under the Federal fiscal system when uniform EURs per well are assumed across the Federal and state mineral estate.

Figure E-3. IRR: Unconventional alternative fiscal systems vs. state and existing Federal systems



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. Fed-Exist is the existing Federal system and Fed-Alt is the alternative Federal system.

Source: IHS Markit

Price Scenarios

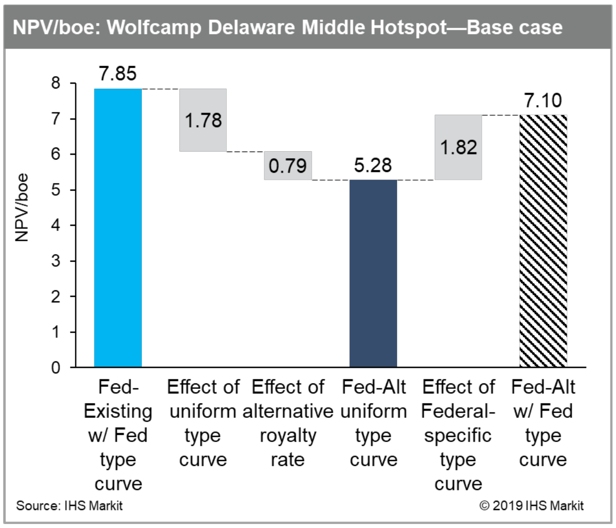
Three oil and gas price scenarios were used for the economic analysis. The IHS Markit base case crude oil and natural gas price outlooks for the third quarter of 2018, which correspond to the time this study was commenced, are applied for this study. The high and low case price scenarios were generated using a variance of minus 40 percent and plus 60 percent from the base case for the low and high case scenarios, respectively. The West Texas Intermediate (WTI) crude oil price scenarios adopted for this study average at about $40, $66, and $105 per barrel (bbl) for the low, base, and high cases, respectively, for the 2019–40 period. The Henry Hub natural gas prices adopted for the economic analysis average at $2.38, $3.96, and $6.34 per million British thermal units (MMBTU) for the low, base, and high case during the same period. The price cases are in 2018 real terms.

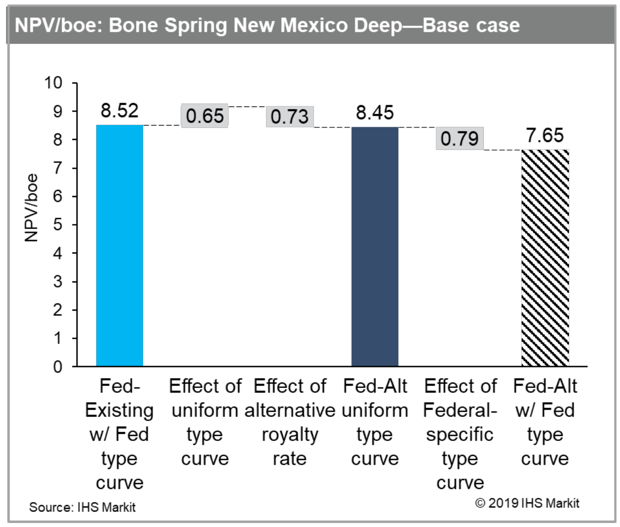
Competitiveness of the Federal fiscal system varies by play—depending on the EUR from wells drilled on the Federal mineral estate. Investment on Federal mineral estate in the Wolfcamp Delaware and the Bakken plays outperform investments on state land.[5] The Federal mineral estate would be more attractive on average than the mineral estate on state and private lands in these plays, even if royalty is

[5] For Wolfcamp Deleware, Bakken, and Bone Spring, IHS Markit developed separate type curves for wells drilled into the state and Federal mineral estates.

increased to match the state rate. In Bone Spring, however, investments on the Federal mineral estate underperform those on state land i.e., a lower EUR per well was observed on the Federal mineral estate. If the alternative Federal fiscal system is applied to the specific type curve for the Federal mineral estate in this instance, the impact on project economics would be twice that of the royalty rate change on the uniform type curve for the subplay.

Figure E-4. NPV/boe: Wolfcamp Delaware and Bone Spring—Base case





The illustration of the impact on NPV/boe of the alternative royalty rates on the Federal mineral estate for two tight oil plays in the Permian Basin presented in Figure E-4 is a clear indication that the attractiveness of the Federal fiscal system depends on more than the components of the government take. For unconventional resources, the characteristics of each play, the location of the Federal mineral estate—i.e., the sweet spot area versus the fringes of the play—and the EUR per well on Federal versus state and private mineral estates contribute to the competitiveness of the Federal mineral estate.

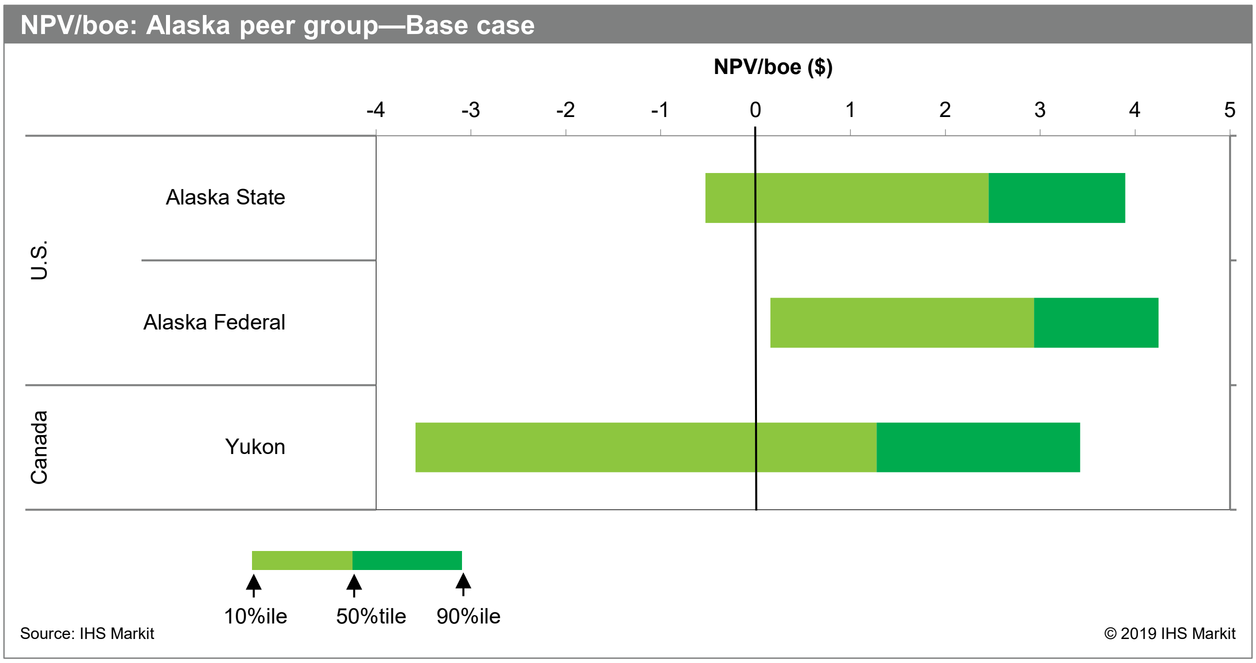
The Alaskan Federal fiscal system for conventional resources is more attractive to investors than the state of Alaska and Yukon fiscal systems. The majority of projects on the Federal mineral estate in Alaska generally yield better value per barrel than their peers when all three prices are taken into account. The Alaskan projects on Federal mineral estate yield positive NPV/boe under the base and high price scenarios except for the 50 MMboe field size. Based on the distribution of recent fields in Alaska, the 50 MMboe and the 100 MMboe oil fields are more probable than the 200 MMboe field, with a P90, P50, and P20 respective probability.[6] Under the base price scenario, the Alaska Federal fiscal system yields better value per boe than its peers (Figure E-5). Alaska state mineral estate and Yukon projects are more sensitive to the low-oil price environment than projects on Federal mineral estate (Table 5-4). They present with values that are 30 percent to 100 percent lower than the ones for Alaska Federal fiscal system. The higher royalty rates applicable in the Alaska state and in Yukon fiscal systems—16.67 percent and 22.4 percent, respectively, versus 12.5 percent in the Federal fiscal system—contribute to the steeper value erosion under the low-price environment for projects in these jurisdictions. The Federal fiscal system, however, is subject to instability caused by frequent changes to the oil and gas production tax made at the state level. Decisions

[6] P20 means that 20 percent of the estimates exceed the P20 estimate of 200MMboe, or that the P20 estimate is greater than 80 percent of the estimates; consequently, the P90 estimate of 50 MMboe is greater than 10 percent of the estimates. P50 estimate of 100 MMboe represents the median.

made by Alaska with regard to its share of revenue from oil and gas investments in the state apply to the state and Federal mineral estates.

Figure E-5 displays the range of NPV/boe for the projects in the Alaska peer group under the base price scenario. The lighter green bar represents the P10 values. The border between the lighter and darker green bars represents the P50 values, whereas the darker green bars represent the P90 values.

Figure E-5. NPV/boe: Alaska peer group—Base case

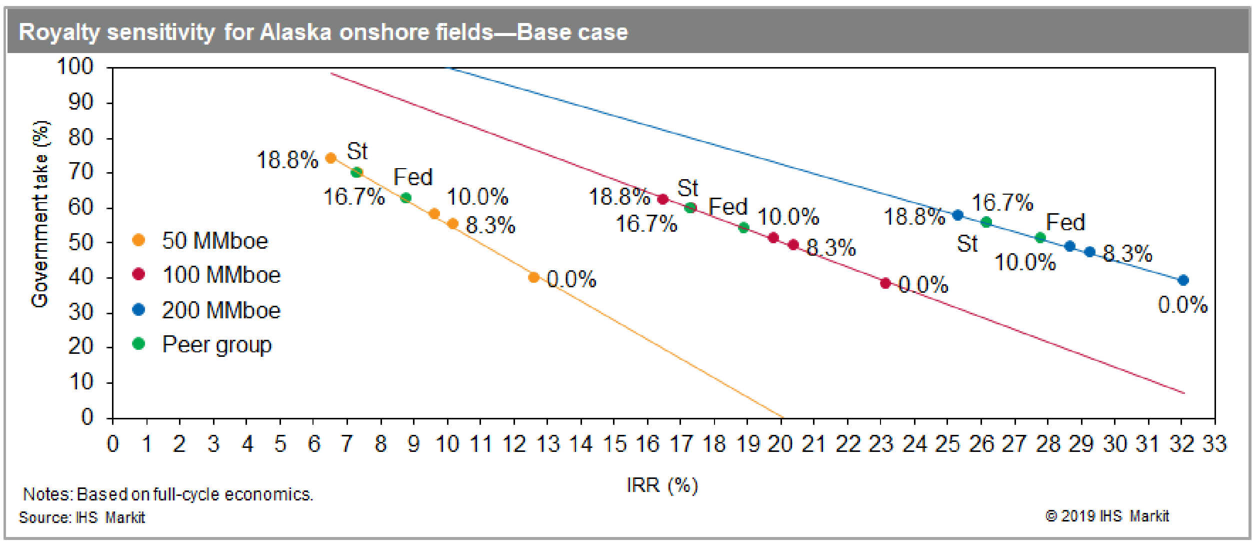


An increase in the Federal royalty rate to match the state rate would bring the NPV/boe expected in the Federal fiscal system in line with the state of Alaska's fiscal system—i.e., similar results as in the state mineral estate would be expected. However, the change would make the Federal fiscal system even more sensitive to commodity price changes and it would likely face similar challenges to the state of Alaska when commodity prices are low. While the Federal fiscal system in Alaska under the state royalty rate would yield robust rates of return for oil fields ranging at 100–200 MMboe, with this alternate royalty rate, the Federal fiscal system would lose the advantage it had against investments in the peer group and would become very sensitive to commodity price changes. After the 2014 drop in commodity prices, most companies use prices well below the base price used in this study to make investment decisions. Therefore, the ability of investments to withstand cycles of low commodity prices is important. Currently, neither the state nor the Federal fiscal system is attractive under the low oil price environment.

Royalty rate sensitivity chart

Sensitivities performed on a wide range of royalty rates on Federal mineral estate in Alaska produce a range of investor rates of return between 8 percent and 19 percent under the base case for all three field sizes. In figure E-6, which displays results of the sensitivity analysis, each trend line represents a field size. The data points illustrate the impact of royalty rates to the investor IRR and government take as the royalty rate changes from 12.50 percent to 18.8 percent and zero percent. The trend lines indicate how sensitive a particular field is to the royalty rate changes; a more horizontal trend line has higher response to the change in royalty rate, while a more vertical line indicates less elasticity. The lines are indicative only and may be inaccurate beyond the data points. The green-colored data points identify the current state and Federal fiscal systems results. The other data points represent results for alternative royalty rates. The state results in this instance overlay the results of the Federal royalty alternative that matches the state royalty rate.

Figure E-6. Royalty sensitivity for Alaska onshore fields—Base case



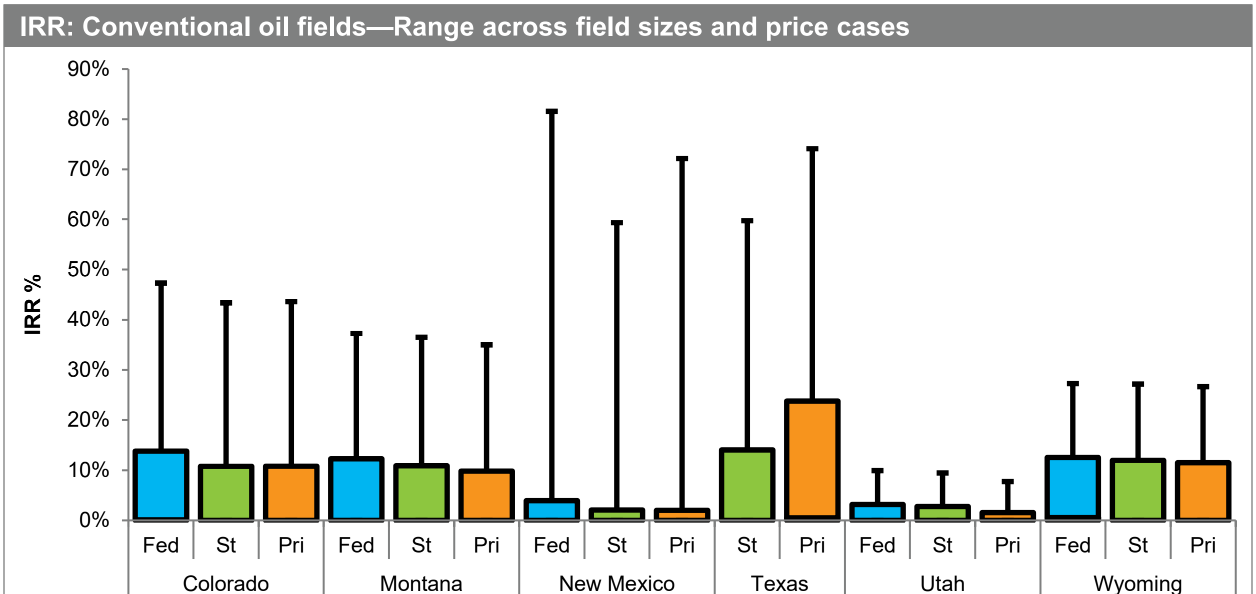
Overall, the returns to investors under royalty alternative of 16.67 percent drop by one or two percentage points across the three price cases for this study. In particular, cases where the IRR was at 9–10 percent are now pushed further into uneconomic territory. Investors expect a minimum 10 percent rate of return for onshore oil and gas projects. While the larger field sizes such as the 200 MMboe field were viable under the low price environment, they are no longer economic under the royalty alternative. Also, the development of small fields, i.e., 50 MMboe oil fields under the base price environment, could be affected by the 16.67 percent alternative.

The conventional oil and gas fields in the Lower 48 are the most economically challenged of the three peer groups, reflecting the maturity of the resource. The conventional field sizes for new discoveries onshore in the U.S. tend to be small. IHS Markit selected 1 MMboe, 2 MMboe, and 5 MMboe field sizes to model, as they are the most representative of the conventional oil and gas field distribution in the jurisdictions selected for this analysis. They represent the P5, P10, and P50 of the oil and gas discoveries made between 1989 and 2018 in the states within this peer group.

The Federal fiscal system for conventional oil resources is competitive with its peers, but it tends to only offer attractive returns for fields of 5 MMboe or larger reserve size in the high and base price scenarios. The 5 MMboe oil field has a lower probability of occurrence. As these resources mature, and the share of new fields with 5 MMboe or more decreases, there will be limited opportunities for investment in conventional resources in the Lower 48. Fields with reserves of 1–2 MMboe, which make up the majority of the potential new discoveries in the Lower 48, are not economic across all jurisdictions under the base and low price scenarios.

The majority of the cases are uneconomic, resulting in a zero percent median IRR for all fiscal systems in this peer group (Figure E-7). For the top quartile of the results, investor IRR on Federal mineral estate is above the 10 percent investment threshold in Colorado, Montana, and Wyoming. While the return to investors in New Mexico is among the highest, in the 5 MMboe oil field high and base cases, the 2 MMboe oil fields are not economic under any of the price scenarios for this study in the state. The oil fields in Utah do not yield optimum rates of return under any price scenario. That is reflective of the lower resource potential compared to other states.[7]

Figure E-7. IRR: Conventional oil fields—Range across field sizes and price cases



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. In this case, the median and lower quartile are at 0 percent IRR. Fed is Federal, St is state, Pri is private.

Source: IHS Markit

Generally, the investor IRR is one to three percentage points higher on Federal mineral estate than the respective state land, except for New Mexico, where the difference is more prominent—thirteen percentage points. The range for bonuses for state lands in New Mexico is much higher than Federal mineral estate, assuming $4,500/acre for state lands, $400/acre for private lands, and $300/acre for Federal mineral estate. This upfront cost results in the gap in IRR between Federal mineral estate and state lands. The IRR analysis further highlights the unattractive economics associated with discovery and development

[7] Johnston D, Wyoming—Legal and Fiscal Frameworks: Best Practices, November 2018.

of the 2 MMboe and 1 MMboe oil fields across all jurisdictions and fiscal systems. **The current market prices, which were below the base price assumption as of July 2019, do not favor the development of smaller-sized conventional fields.**

Conventional natural gas fields in most plays and basins struggle to remain economic at current and forecasted natural gas prices in the United States. Conventional gas resources are highly mature in the Lower 48. New fields tend to be small and with marginal economics, at best. It is extremely challenging for the conventional gas fields to compete with wells in the most prolific unconventional gas plays that have kept commodity prices for natural gas persistently low in North America.

For conventional natural gas fields in the Lower 48, the range in IRR is narrower—the upper, median, and lower quartiles are at zero percent IRR, with 87 percent of the cases generating no return. For the high case 5 MMboe gas fields, the hurdle rates for investment decisions are surpassed in four out of six states reviewed for this study. In the base case scenario, the 10 percent investor IRR threshold is surpassed only in New Mexico on Federal, state and private land (Table E-1). The conventional gas field development in the Lower 48 is challenged by the marginal size of discoveries and the persistently low commodity prices that result from abundance of lower cost supplies from shale gas and tight oil formations.

Table E-1. IRR: Conventional gas fields across field sizes and prices

Jurisdiction		IRR (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	23	2	0	0	0	0	0	0	0
	State	20	0	0	0	0	0	0	0	0
	Private	20	0	0	0	0	0	0	0	0
Montana	Federal	0	0	0	0	0	0	0	0	0
	State	0	0	0	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0	0
New Mexico	Federal	72	0	0	40	0	0	0	0	0
	State	56	0	0	25	0	0	0	0	0
	Private	64	0	0	28	0	0	0	0	0
Texas	State	15	0	0	0	0	0	0	0	0
	Private	19	0	0	2	0	0	0	0	0
Utah	Federal	2	0	0	0	0	0	0	0	0
	State	1	0	0	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0	0
Wyoming	Federal	20	3	0	0	0	0	0	0	0
	State	18	1	0	0	0	0	0	0	0
	Private	17	0	0	0	0	0	0	0	0

Source: IHS Markit

For conventional resources, where economic results are marginal at best, the attractiveness of projects to potential investors is highly sensitive to changes of royalty rates on Federal mineral estates. The application of alternative royalty rates to conventional resources that increases the share accruing to the Federal government could negatively affect the ability of such projects to attract investors. The application of alternative royalty rates on Federal mineral estates would generally align the government take on Federal mineral estate with that on state lands. Although, at a first glance, both the percentage decline in IRR and the dollars per barrel ($/bbl) value loss to investors in relation to the NPV/boe may not appear substantial, the Lower-48 conventional resources with marginal economics are more sensitive to price fluctuations, and thus more vulnerable to any change in the status quo.

The differences in revenue stream and the lower cost per unit observed in unconventional resources give them a competitive edge against all other onshore oil and gas resources in the United States. Despite the nuanced differences in economic results for the three mineral estates, i.e., Federal, state, and private, the range of investor IRR and the NPV/boe for unconventional plays considered for this study is significantly higher compared to conventional resources in Alaska and the Lower 48. Figures E-8 and E-9 display stark differences of NPV/boe and IRR values for tight oil plays and conventional oil fields under the base price scenario.

Figure E-8. NPV/boe: Range across mineral estates and resource types—Base case oil

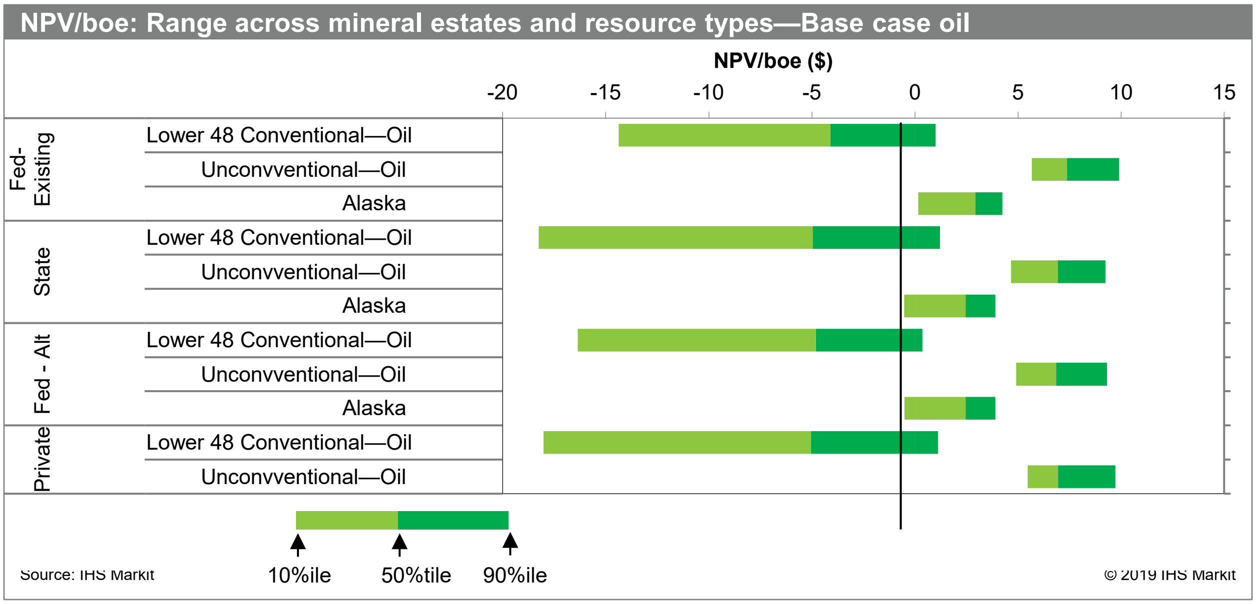
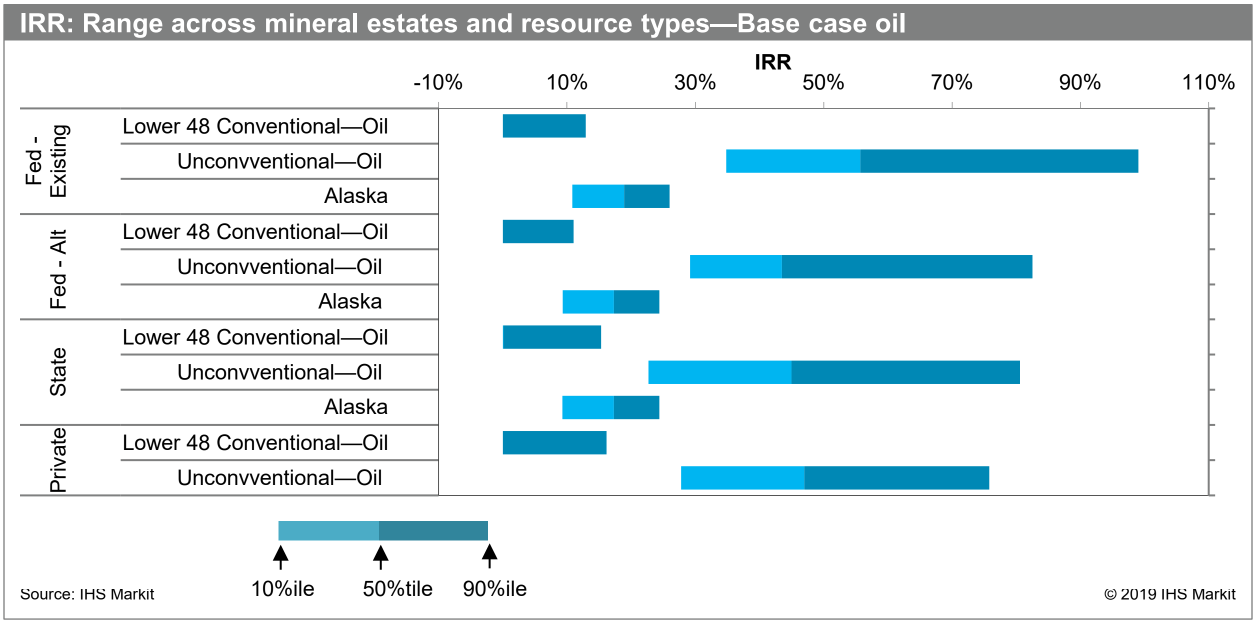


Figure E-9. IRR: Range across mineral estates and resource types—Base case oil



Discretionary royalty relief—End of life

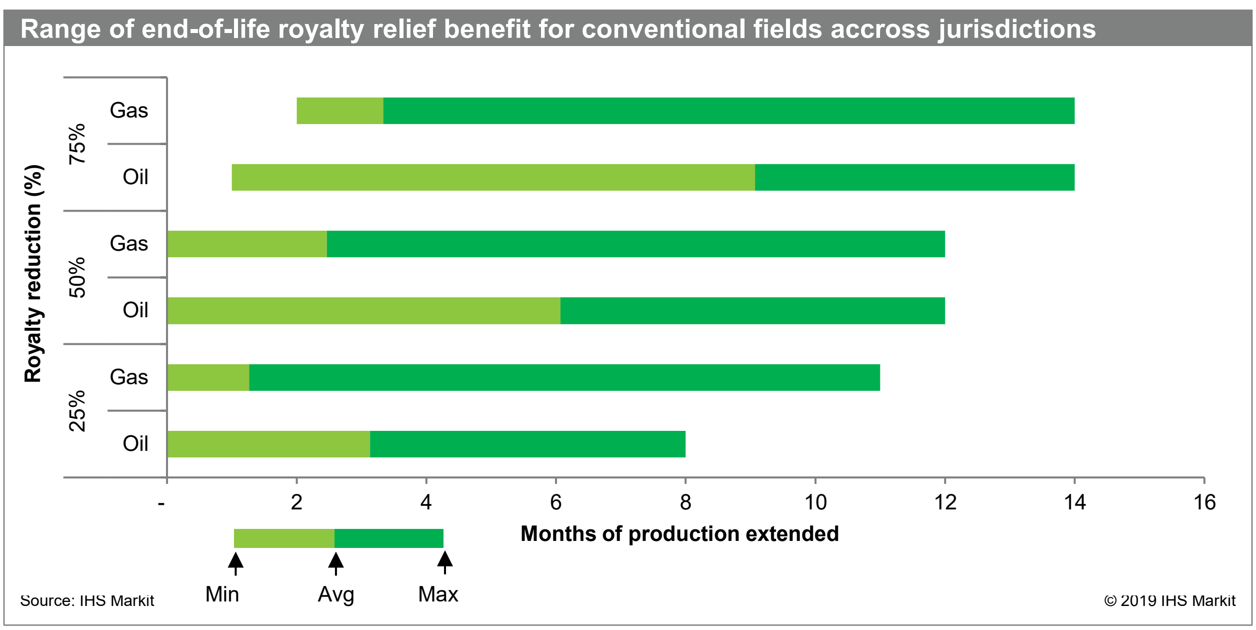
IHS Markit was asked to examine a discretionary royalty relief alternative for producing leases that are approaching the economic limit, i.e., have earnings that cannot sustain production under existing royalty rates and relief would likely result in additional production.

There is no uniform solution with regard to end of life royalty relief. If such a relief was to be offered by BLM, the benefits are unlikely to be substantial in terms of length of extension of the field life. Relatively greater benefit is likely to occur for uneconomic projects that previously reached an economic limit. The resulting benefit, however, is a likely extension of field life in months rather than years. Wells differ with regard to:

- **The extent of royalty relief necessary to extend the field life**—some fields resulted in no life extension until 75 percent royalty reduction was applied.
- **The primary output**—oil wells tend to benefit more from the discretionary relief. Wells with oil as the primary product tend to benefit from a longer extension of the producing life than wells with primary gas production—the extension is still limited to months versus years.

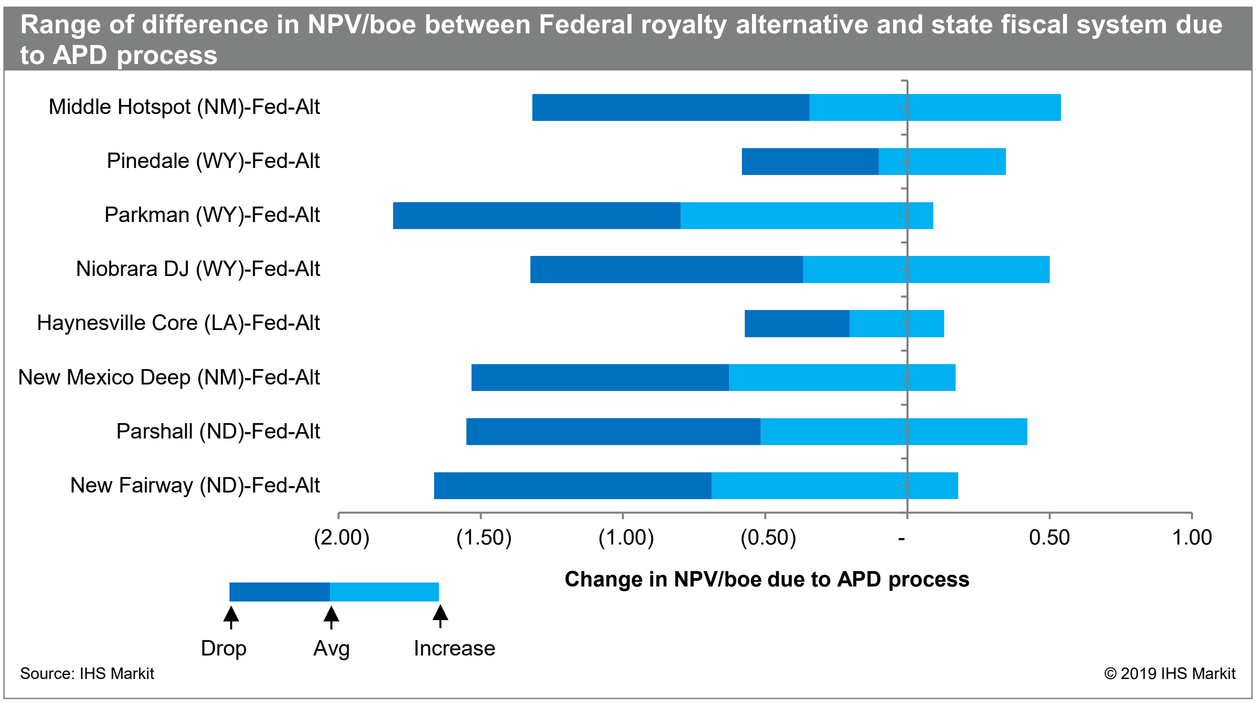
IHS Markit applied a reduced royalty rate whenever daily production from a well fell below the average daily production rate threshold for at least 12 months in a row. To follow the IRS definition of a stripper well, the average daily production rate threshold was set to 15 boe/d. Three tiers of royalty rate reduction of 25 percent, 50 percent, and 75 percent were analyzed. The study measures the incremental months of production resulting from the end-of-life incentive to assess the impact of the incentive. The application of the end-of-life royalty relief resulted in an average increase of the producing life by four months across all oil and gas fields under the base price scenario, with the minimum extension ranging at 0–2 months and the maximum one ranging at 8–14 months (Figure E-9).

Figure E-9. Range of end-of-life royalty relief benefit for conventional fields across jurisdictions



Differences in the application for permit to drill (APD) approval timelines between the BLM and state mineral estate have a relatively minimal impact on project economics. While the BLM has recently taken steps to shorten the APD processing timelines, the study assumes a 10-month delay, the maximum observed over a 10-year period.[8] The 10-month delay assumed for this study is intended to measure the maximum impact the APD approval process could have on project economics in the Lower 48. If the Federal royalty rate is increased to match the respective state royalty rate, the highest impact of the APD process would be observed in the most profitable projects, i.e., unconventional resources in the high and base price scenarios and the 5MMboe oil fields in the high price scenario. As project profitability goes down under the low price scenario, the delay of capital spent tends to have the opposite effect—i.e., result in higher NPV/boe than the state fiscal system. In the high price scenario, the NPv/boe is likely to drop on average by $1.29/boe compared to the state mineral estate under the uniform type curve, which assumes the same EUR per well for the Federal mineral estate and state and private mineral estates in each subplay. In the low price scenario, on average, the NPV/boe would likely increase by $0.30/boe compared to the state fiscal system. Overall, the impact of the APD process on unconventional plays across all three price scenarios is likely to result in $0.47/boe average drop in the NPV/boe (Figure E-10).

Figure E-10. Range of difference in NPV/boe between Federal royalty alternative and state fiscal system due to APD process



BLM has taken steps to reduce APD processing time "by prioritizing permitting, modernizing its databases, and shifting resources across the BLM offices," resulting in the average APD processing time dropping to

[8] In 2011 the APD processing timeline averaged at 10 months, while the 2017 average was 9 months. Efforts are being made to bring the BLM APD permitting timeline closer to the state process. In 2017, permits that used the new version 2 of the Automated Fluid Minerals Support System (AFMSS) only required 122 days (approximately 4 months).

approximately six months, including time to determine an application to be administratively complete.[9] Given the efforts by BLM from 2017–19 to clear the backlog of APDs and shorten the APD approval process, the impact on project economics is likely to be even less significant than the one observed in this study. While the tangible benefits of an expeditious APD approval process are not substantial on NPV/boe basis, the intangible benefit relates to the ability to plan and proceed with drilling programs that involve sufficient contiguous acreage to enable multiple wells per drilling pad with long laterals required for tight and shale formations. Improved APD approval timelines offer companies the necessary clarity and certainty required to develop drilling programs and engage service providers for the executions of such programs. Where the acreage positions include state or private and Federal mineral estates, any potential APD processing delays on Federal mineral estate are likely to impact the timing of the combined drilling program on state and private lands. The shortening of the APD processing timelines, however, does not come without risks. Such timelines need to be sufficient to account for the environmental impact of drilling on Federal lands. Striking the right balance between an expeditious process and environmental protection is key to an optimum APD approval process. A recent federal court ruling that temporarily blocked drilling on roughly 300,000 acres of Federal land in the state of Wyoming for failure to sufficiently consider climate change highlights the challenges associated with striking the right balance between shorter APD processing timelines and review of environmental impact.[10]

[9] Nedd M. 2019 March 12. "Examining the Policies and Priorities of the Bureau of Land Management, the U.S. Forest Service, and the Power Marketing Administrations" U.S. Department of the Interior, Bureau of Land Management, Testimony before House Committee on Natural Resources Subcommittee on Energy and Mineral Resources.

[10] Corbett E. "Federal Judge Blocks Trump Administration from Drilling on Federal Land" Fortune, March 20, 2019.

1 Context and Scope

1.1 Background

This report has been contracted to provide an updated comparative assessment of the U.S. Federal oil and gas fiscal system with the fiscal systems of state governments and private mineral owners in the U.S. and Canada. Similar to the predecessor study, Comparative Assessment of the Federal Oil and Gas Fiscal System (2011 Study), the purpose of this study is to inform the DOI and BLM about the relative competitiveness of Federal oil and gas resources that the BLM manages and to ensure that the public is receiving a fair return for development of these resources.[11] As the third installment in this series of the 2018 Comparative Analysis of the Federal Oil and Gas Fiscal System, this onshore report focuses on three peer groups that reflect the diversity of resources concepts and environment in the Federal mineral estate—Alaska conventional onshore, the Lower-48 conventional, and the Lower-48 unconventional resources. The first report, published in March 2019, covers the U.S. Gulf of Mexico offshore. The second report focused on the offshore frontier for both Alaska and non-Alaska regions.[12]

The 2011 Study compared 29 oil and gas upstream fiscal systems including the Federal fiscal systems for Wyoming and offshore Gulf of Mexico. The focus at the time on the Federal mineral estate was on conventional oil and gas resources. The 2011 Study found that both the onshore and offshore resources on Federal mineral estate were a high cost alternative to shale gas resources being developed in North America. At the time of the 2011 Study, the unconventional revolution was on the rise, although there was still uncertainty about the performance of shale gas resources. The study found that shale gas resources could drive the higher-cost resources developed during the high price environment off the margin, if shale gas continued to perform better than expected.

Since the publication of the 2011 Study, much has changed regarding onshore U.S. production, especially in terms of the growth of unconventional resources.

1. **The U.S. is now the largest global producer of oil and natural gas, and North America is expected to remain the largest region in terms of exploration and production (E&P) capex through at least the early 2020s.** In the 2012–13 timeframe, the U.S. overtook Russia and Saudi Arabia as the leading global combined producer of petroleum and natural gas.[13] The U.S. had already been the world's leading producer of natural gas by 2009 and it became the world's leading crude oil producer in 2018.[14]

Most of the growth in U.S. production is due to shale gas and tight oil, driven by advancements in horizontal drilling and hydraulic fracturing techniques. E&P interest in the U.S. is expected to remain strong. E&P capex in North America is overwhelmingly driven by the U.S., and this capex is expected to significantly

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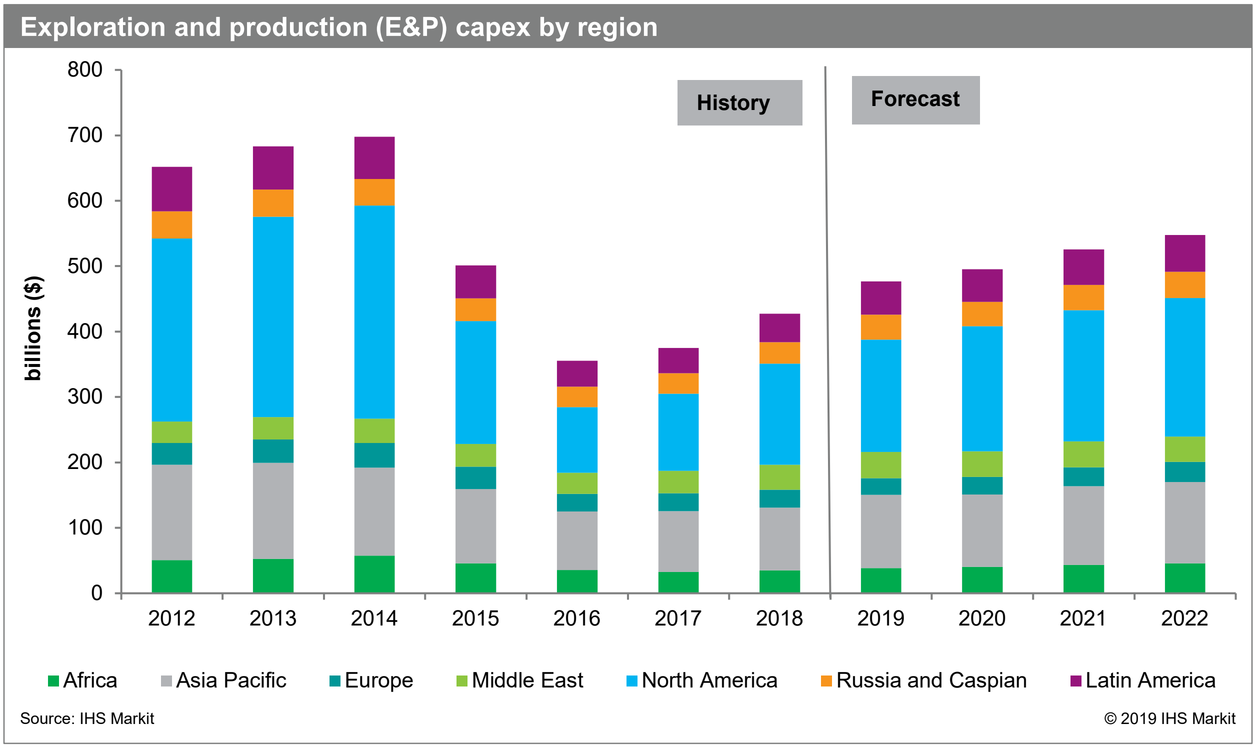
[11] Agalliu I, "Comparative assessment of the federal oil and gas fiscal systems," U.S. Department of the Interior, Bureau of Ocean Energy Management Herndon, VA, Outer Continental Shelf Study, BOEM 2011-xxx, 2011, 300 pp.
[12] Agalliu I, Montero A, Adams S, Gallagher S, "2018 Comparative assessment of the federal oil and gas fiscal systems," Sterling, VA, U.S. Department of the Interior, Bureau of Ocean Energy Management, OCS study, BOEM 2018-xxx, 2018, 293 pp.
[13] Dorman L and Kahan A, "United States remains the world's top producer of petroleum and natural gas hydrocarbons," Energy Information Administration, May 21, 2018.
[14] Dunn C and Hess T, "The United States is now the largest global crude oil producer," Energy Information Administration, September 12, 2018.

outpace spending in all other regions through 2022.[15] Only when oil prices were low in 2016 and 2017 did North American E&P capex fall to roughly match capex in the Asia Pacific region.

Figure 1-1. Exploration and production capex by region



2. Shale gas and tight oil, which have driven the U.S. hydrocarbon resurgence, have benefitted from dramatically increasing efficiencies, especially in the Permian Basin, which is the nation's most productive basin at present. In terms of tight oil production, the most significant unconventional basin in the U.S. has been the Permian. Even during the worst parts of the oil price downturn that began in 2014, Permian oil production continued to rise.[16] Peak well production has increased by 125 percent in the past five years, and PV10 breakeven prices have fallen from about \$75 to less than \$40 in that timeframe. [17] The Permian basin continues to set records, and IHS Markit expects production of nearly 6 million barrels per day (MMbbl/d) from the basin by year-end 2020.

In addition to the increases in production, the Permian Basin benefitted from dramatic improvements in capital efficiency and well productivity. Capital efficiency refers to the average production generated by each dollar spent. Capital efficiency is attributed to lower oil field service costs, improving logistics and streamlining of operations, a focus on the most productive "sweet spots" of acreage, longer lateral lengths, and greater use of proppant, some of it driven by the 2014 drop in commodity prices.[18]As shown in Figure

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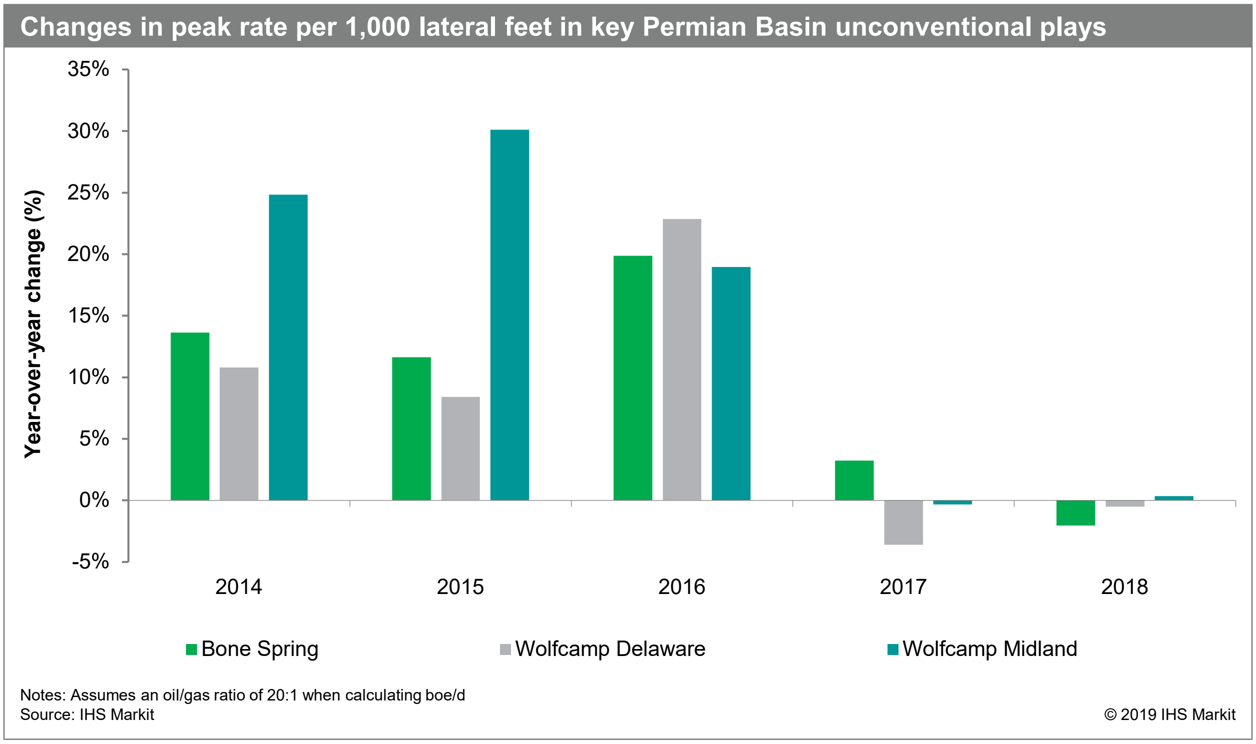
[15] Markwell P, "Upstream oil & gas industry outlook: innovating for performance, but competition for capital remains," IHS Markit Energy & Natural Resources, November 19, 2018.
[16] LeBlanc R, "Will low, volatile prices slow the Permian juggernaut?" IHS Markit Energy & Natural Resources, March 28, 2019.
[17] PV10 is the present value of oil and gas revenues, discounted at a rate of 10 percent per year.
[18] Greater use of proppant means larger amount per proppant per foot of lateral length.

1-2, well productivity increased substantially over 2014–16, but it has largely stabilized since. Well productivity can be measured in terms of peak rate per 1,000 lateral feet (ft).

Figure 1-2. Changes in peak rate per 1,000 lateral feet in key Permian Basin unconventional plays



3. Despite the expected leveling off in efficiency improvements, shale gas and tight oil activities are expected to remain strong over the next five years. The basic metrics of hydraulic fracturing activity—wells and stages hydraulically fractured, and proppant pumped—are all expected to remain stable or increase through the early 2020s in the United States and North America.

Figure 1-3. North American wells drilled and fractured, and frac stages

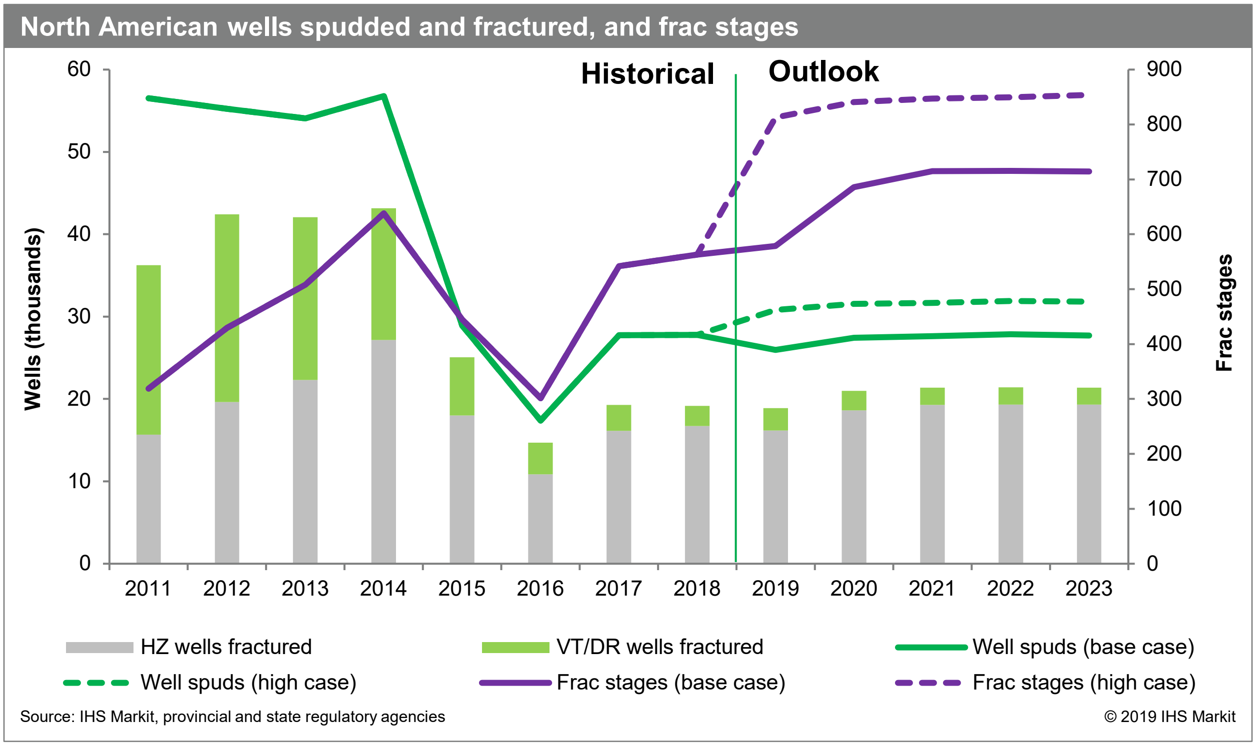
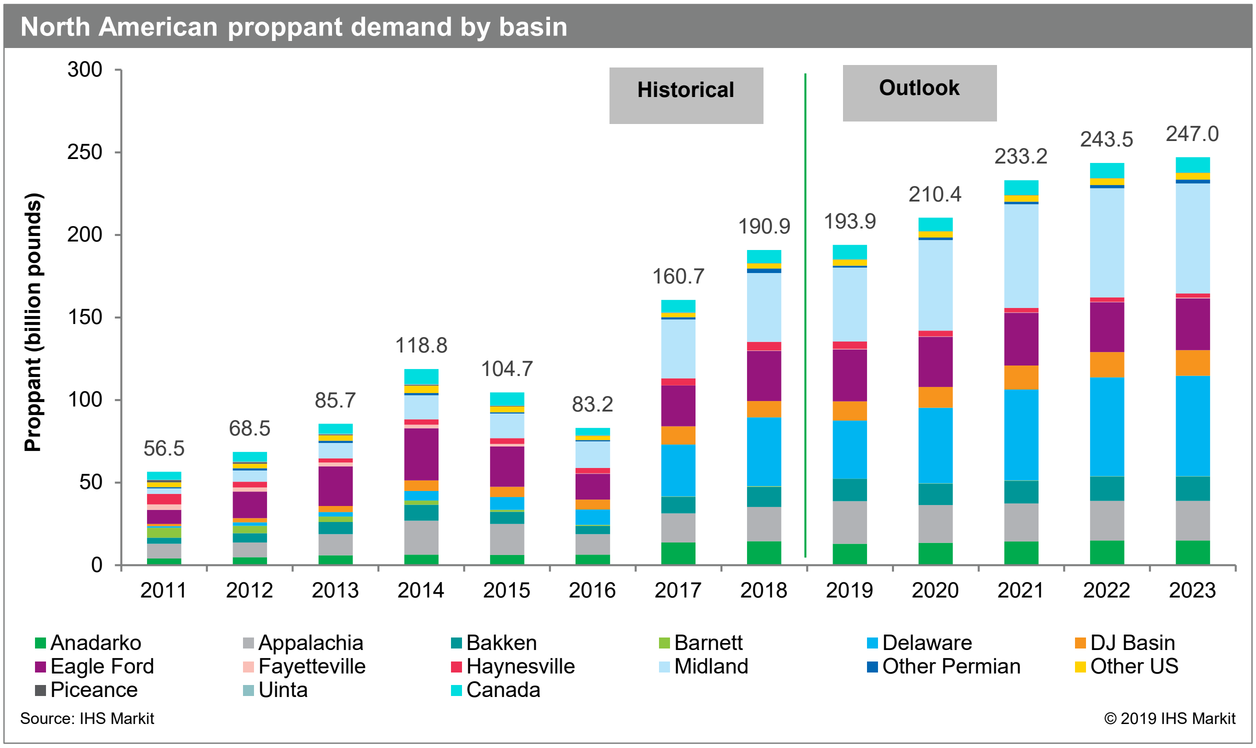


Figure 1-3 shows that horizontal wells fractured in North America are expected to remain stable through 2024.[19] Meanwhile, frac stages are expected to rise through 2021, as average wells have more stages, sometimes because of longer laterals. While proppant consumption is expected to track frac stages fairly well, it is expected to continue to grow slowly even into 2023 (Figure 1-4).[20] Both frac stages and proppant consumption indicates some continued improvement in productivity, but the progress is expected to level off.

[19] Perez Pena P, "Operators cautious spending plans will slow down activity in North America the first quarter of 2019," IHS Markit Energy & Natural Resources, February 14, 2019.
[20] Vaucher D, "Proximity, proximity, proximity – the key to the proppant market," IHS Markit Energy & Natural Resources, January 4, 2019.

Figure 1-4. North American proppant demand



IHS Markit forecasts strong activity for unconventional resources in the United States, even if progress occurs more slowly than in the past. In fact, it is only after 2025 that IHS Markit sees any substantial roadblocks. Thereafter, the inventory of the most-productive acreage in the Permian Basin may begin to exhaust itself, and then the Permian may face structural obstacles to growth, such as midstream and gathering bottlenecks or water and fracking sand availability.

1.2 Approach and Scope of Work

1.2.1 Jurisdictional Selection and Field Sizes

The criteria used to select the different peer groups, field sizes, and development cost models reflect the diversity of resources, concepts, and environments in the Federal mineral estate. Conventional oil and gas E&P environment and investment opportunities in Alaska differ widely from Lower-48 conventional E&P activity, in terms of operating environment, cost of finding and development, prospectivity, and expected oil and gas discoveries. In the Lower 48, the development of conventional and unconventional oil and gas resources differs with regard to the size of the resource, uncertainty surrounding the resource potential, capital and operating costs, production profiles, etc. Therefore, the onshore Federal mineral estate is divided into three main peer groups: Alaska conventional resources, Lower-48 conventional resources, and unconventional resources. Native American tribal fiscal systems are not within the scope of this study and therefore not included in this analysis.

This study differs significantly from the 2011 study with regard to the representation of the onshore resources on the Federal mineral estate, as well as selection of peer groups for comparing the Federal fiscal system. In the 2011 Study, the Federal mineral estate was limited to the conventional and coalbed methane resources in the state of Wyoming. This study, on the other hand, includes conventional oil and gas resources located across five states in the Lower 48, eight major unconventional plays across ten states, and the conventional oil resources in Alaska North Slope. The selection of the peer groups for comparison is also different. The 2011 Study relied on a combination of North American and international onshore jurisdictions. The 2011 Study, however, recognized that a significant portion of companies interested in investing for onshore oil and gas exploration and production in the United States are not likely to compete globally for resources, except for super majors and major oil companies. Therefore, the current study relies entirely on North American jurisdictions for comparative analysis. Another departure from the 2011 Study is the comparison with the terms expected on private mineral estate alongside comparisons with state fiscal systems.

1.2.1.1 Alaska Onshore

The Alaska North Slope Basin (ANS) is an arrested, late-emerging-phase basin holding both conventional and unconventional hydrocarbon resources. This study focuses solely on the Alaska onshore conventional hydrocarbon resources. Recent discoveries have underscored this classification. In 2017, recoverable reserves increased six-fold in previously ignored shallow Cretaceous formations—Nanushuk and Torok—totaling 4 billion barrels. The basin has produced 16.8 billion barrels of oil to date, with 38 billion barrels of oil equivalent (50 Tcf[21] of gas and 28 billion bbl of oil) in remaining recoverable reserves. IHS Markit estimates that there are 9.5 billion boe of yet-to-find (YTF) volumes in the National Petroleum Reserve in Alaska (NPR-A), Area 1002 of the Arctic National Wildlife Refuge (ANWR), and central North Slope combined.[22]

For the purpose of this study, oil is considered as the only primary product since gas is either reinjected or exported to Prudhoe Bay for power generation and injection. Therefore, the analysis of the Alaska conventional peer group consists only of oil fields, i.e., fields where crude oil is the primary output. A review of oil fields discovered since 2010 in Alaska shows fields ranging from 33 MMbbl to 630 MMbbl. The fields selected for this analysis include 50 Mmboe, 100 Mmboe, and 200 Mmboe, representing P90, P50, and P20, respectively.[23] The distribution is skewed by the presence of a few large fields and the limited number of discoveries in this period. The fiscal systems compared are the Alaska Federal mineral estate, Alaska state mineral estate, and Canada Yukon. The Canadian territory of Yukon was selected for the similarities in the operating environment. However, the area is considered to be frontier in terms of level of exploration carried out to date and geological risk involved.

Table 1-1. Onshore Alaska conventional fields and jurisdiction selection

Primary product	Field sizes	Fiscal system
Oil	50 MMboe 100 MMboe 200 MMboe	Alaska Federal Alaska state Yukon

Source: IHS Markit

[21] Trillion cubic feet

[22] Yet-to-find (YTF) volumes: the estimated volumes of undiscovered hydrocarbons to be discovered in a certain time frame for a specific play or basin. YTF can be calculated via multiple statistical methods depending on the resource type.

[23] P90 means that 10 percent of the estimates exceed the P90 estimate (50 MMboe) or that the P90 estimate is greater than 10 percent of the estimates. Consequently, the P50 estimate of 100 MMboe is greater than 50 percent of the estimates and the P20 estimate of 200 MMboe is greater than 80 percent of the estimates.

1.2.1.2 Lower-48 Conventional

The Lower-48 conventional peer group selection includes the top producing states with significant Federal mineral estate. The peer group selection for onshore conventional fields first examined the top-12 producing states, and selected five jurisdictions with significant Federal mineral estate: Colorado, Montana, New Mexico, Utah, and Wyoming.

The other states in the top-12 ranking were eliminated because there is no significant Federal mineral estate in the jurisdiction. Since Texas is the number one producer of oil and gas in the country, it is included as part of this peer group and evaluated only on state and private mineral estate.

Table 1-2. Onshore conventional top producing states

State	Annual oil production (MMbbl)	Annual gas production (Bcf[24])	Annual oil equivalent production (MMboe)	Significant Federal mineral estate	Selected jurisdiction
Texas	1,618	8,814	3,087	N	√
Alaska	175	3,255	717	Y	
Oklahoma	201	2,946	692	N	
North Dakota	459	856	602	N	
Louisiana	46	2,830	518	N	
New Mexico	250	1,524	504	Y	√
Colorado	168	1,831	473	Y	√
Wyoming	87	1,721	374	Y	√
California	169	199	202	N	
Utah	37	297	87	Y	√
Kansas	35	203	68	N	
Montana	21	46	29	Y	√

Source: IHS Markit, EIA data

The conventional field sizes for new discoveries onshore in the United States tend to be small. The following fields sizes for both oil and gas systems are representative of expected field sizes for this peer group: 1 MMboe, 2 MMboe, and 5 MMboe (Table 1-3). IHS Markit selected these field sizes because they are the most representative of the conventional oil and gas field distribution in the jurisdictions selected for this analysis. Figure 1.5 shows the distribution of the fields discovered after January 1, 1989 ranked by size. This distribution is skewed by a few large fields but one can note that the P5[25] is 4.9 MMboe, the P10 is 1.9 MMboe, the P50 is 0.1 MMboe, and the P90 is only 416 barrels.

[24] Billion standard cubic feet

[25] P5 means that 5 percent of the estimates exceed the P5 estimate or that the P5 estimate is greater than 95 percent of the estimates. Consequently, the P10 estimate is greater than 90 percent of the estimates the P90 estimate greater than 10 percent of the estimates.

Figure 1-5. Lower-48 conventional peer group field-size distribution for fields discovered from 1989 to 2018

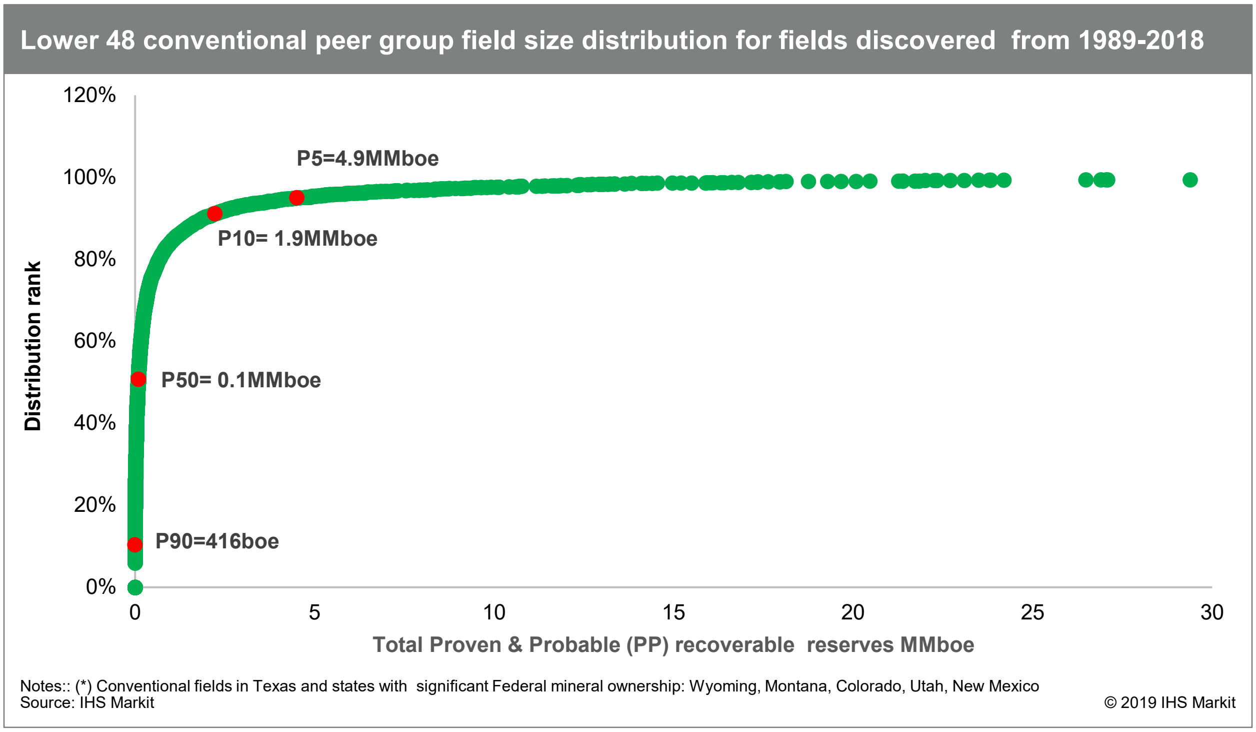


Table 1-3. Onshore Lower-48 conventional fields and jurisdiction selection

Primary product	Field sizes	Federal mineral estate	State and private mineral estates
Oil Gas	1 MMboe 2 MMboe 5 MMboe	Colorado Montana New Mexico Utah Wyoming	Colorado (CO) Montana (MT) New Mexico (NM) Texas (TX) Utah (UT) Wyoming (WY)

Source: IHS Markit

1.2.1.3 Unconventional

The unconventional peer group is divided into subgroups defined around the unconventional plays. Each play consists of its own peer group. The unconventional plays have been selected based on activity levels, the importance in the U.S. onshore production mix, and overlap with significant Federal mineral estate. The activity levels of the eight plays below represent approximately 30 percent of all wells spudded in the United States in 2017 (Table 1-4). If considering only unconventional wells, these plays would represent an even greater share of wells spudded. The Wolfcamp Delaware has the greatest number of wells spudded, followed by the Bakken.

Table 1-4. Number of wells spudded in onshore unconventional plays in 2017

Unconventional play	Unconventional wells spudded in 2017
Wolfcamp Delaware	1,822
Bakken	1,277
Niobrara	1,009
Marcellus	935
Bone Spring	536
Haynesville	418
Pinedale Jonah	344
Parkman\Turner\Shannon Sands	89

Source: IHS Markit © 2019 IHS Markit

IHS Markit and the BLM worked together to establish the selection of the unconventional plays and subplays that matched best the following criteria:

- High activity in 2017, with the highest number of new wells spudded in 2017,
- Good overlap with Federal mineral estate, and
- Materiality in the future energy mix.

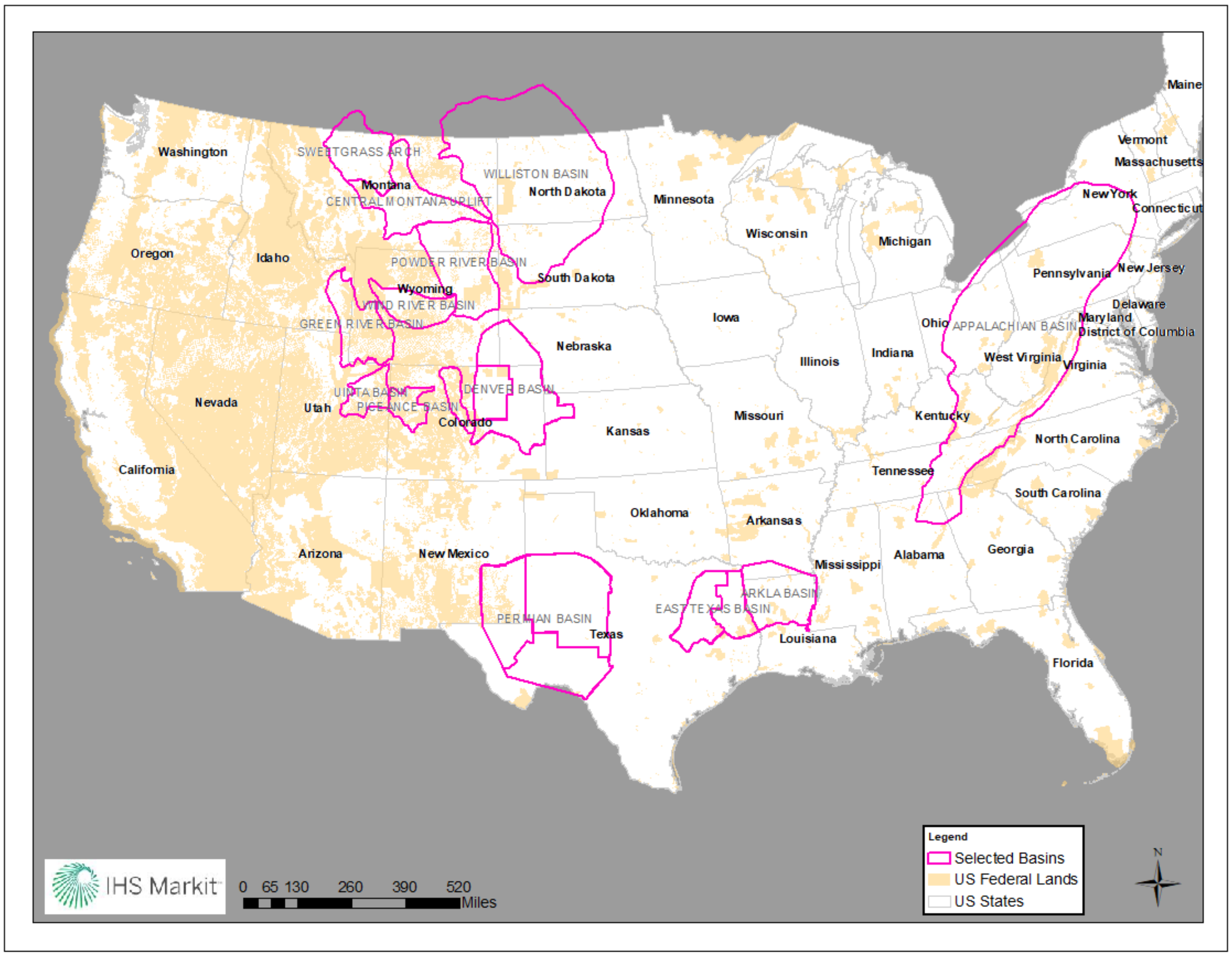
The following paragraphs indicate the drivers behind the selection of key unconventional plays for this study:

- The Bakken play is the third-largest tight oil play in the United States. Its oil production represents 8 percent of the total U.S. oil output for 2018 and is forecasted to average 1.57 MMbbl/d between 2019 and 2038. This play overlaps with the Federal mineral estate in its sweet spots, the New Fairway and Parshall subplays.
- The Bone Spring play is one of the major tight oil plays in the United States, representing 8.4 percent of total U.S. oil output in 2018 and 1.81 MMbbl/d of expected average oil production between 2019 and 2038. The Bone Spring play overlaps with Federal mineral estate in its New Mexico core areas.
- Haynesville is one of the two major shale gas plays in the United States accounting for 7.5 percent of the U.S. natural gas production in 2018. While the Federal mineral estate is not as substantial in this play as in some of the tight oil plays, the importance of Haynesville in the future U.S. natural gas supply outlook was a key factor in including this play in this study.
- The Marcellus is the largest shale gas play in the United States. It accounted for 24 percent of the U.S. natural gas output in 2018. The Marcellus is expected to contribute about 30% of the U.S. natural gas output by 2040. Despite its lack of significant overlap with the Federal mineral estate, the Marcellus is included in this study because it is expected to attract the lion's share of U.S. natural gas investments over the next 20 years and compete with natural gas investments across the Federal mineral estate.
- The Niobrara DJ and the Wattenberg subplays of the Niobrara tight oil play are included in the study due to the important role the Niobrara plays in current U.S. oil production—8.1 percent of U.S. oil output in 2018—as well as the overlap with the Federal mineral estate.
- The Parkman/Turner play has seen an increasing amount of activity, with 88 new wells spudded in 2018. Although it represented only 2% of the U.S. oil output in 2018, it is an emerging play with considerable overlap with the Federal mineral estate.

- The Pinedale Jonah play has the highest levels of overlap with the Federal mineral estate. In 2018, this play accounted for 2% of U.S. natural gas output.
- The Wolfcamp Delaware play was the second-highest producing tight oil play in the United States in 2018, after the Eagle Ford. Its oil output accounted for 16.7 percent of total U.S. production in 2018. This share is projected to increase to 29.2 percent by 2040. This tight oil play also overlaps with the Federal mineral estate in New Mexico, particularly in Lea County, which hosts one of its sweet spots.

Based on the geographical overlap between the Federal mineral estate (Figure 1-6.) and the unconventional plays selected for this study, the following five states were chosen to represent the Federal fiscal system: Louisiana, New Mexico, North Dakota, West Virginia, and Wyoming.

Figure 1-6: Federal mineral estate and geological basins



Federal mineral estate—Jurisdictional justification

<u>Louisiana (LA)</u>

There are scattered, but substantial Federal mineral estates in eastern Texas (TX) and western Louisiana. **Haynesville** is one of the major gas plays spread across these two states.

<u>New Mexico (NM)</u>

While Federal mineral estates are more common in eastern New Mexico than in west Texas, there is some overlap. The high level of drilling activity in the **Bone Spring** and the rest of the Permian Basin necessitates its inclusion. The **Wolfcamp Delaware** is another hotspot and included for the same reasons as the Bone Spring.

<u>North Dakota (ND)</u>

The **Bakken** is in western North Dakota and eastern Montana (MT), where there is substantial overlap with the Federal mineral estate, especially in western North Dakota.

<u>West Virginia (WV)</u>

There is some Federal mineral estate in West Virginia and southeastern Ohio (OH), particularly where **Marcellus is** located.

<u>Wyoming (WY)</u>

The Federal government owns much of the land in Wyoming. The regions more toward the northeast portion of the state contain the **Parkman\Turner\Shannon Sands,** while the western part of the state has **Pinedale Jonah**. To the south, the **Niobrara** runs through Wyoming and into Colorado (CO).

Table 1-5 provides a summary of the plays and subplays analyzed and the Federal, state, and private mineral estates in each play and subplay. The selection of the jurisdiction for the Federal mineral estate was based on the location of the majority of the Federal mineral estate in the particular play or subplay.

Table 1-5. Onshore unconventional plays and subplays selected

Unconventional play	Subplays	Primary product	Federal mineral estate	State lands	Private lands
Bakken	New Fairway	Oil	ND	ND	ND
	Parshall		ND	ND	ND
	Elm Coulee			MT	
Bone Spring	New Mexico Deep	Oil	NM	NM	NM
	Texas Deep			TX	
Haynesville	Haynesville Core	Gas	LA	LA	LA
	Shelby Trough			TX	
Marcellus	Marcellus Super Core	Gas		PA, WV	PA
	Marcellus Southwest Core		WV	PA	PA
	Marcellus Periphery			OH	
Niobrara	Niobrara DJ	Oil	WY	WY, CO	CO
	Niobrara Wattenberg			CO	CO
Parkman\Turner\Shannon Sands	Parkman	Oil	WY	WY	WY
	Turner Sands		WY	WY	WY
Pinedale Jonah	Pinedale	Gas	WY	WY	WY
	Jonah		WY	WY	WY
Wolfcamp Delaware	Middle Hotspot	Oil	NM	NM	
	Southern Liquids			TX	TX

Source: IHS Markit

Each unconventional play is analyzed for all three mineral estates of Federal, state, and private. Since plays span across state lines, some plays do not include all mineral estates. Manitoba has not been included in the Bakken as the presence of the resource in this province is relatively minor. New York has not been included for the Marcellus plays since fracking is banned in the state and there is no unconventional drilling as a result. To ensure that the analysis included comparisons between the most attractive areas for investment, the areas with the most recent concentration of drilling were included in the study.

1.2.2 Exploration and Development Costs

In order to mirror the investment environment in each jurisdiction, the study relies on development cost models that take into account the characteristics of the geological formations in the respective jurisdictions, the respective geological formation, reservoir pressure, distance from infrastructure, regional costs, etc. The approach used for this study is very similar to the that used for the 2011 Study. The following subsections provide detail to development concepts used for each peer group.

IHS Markit models assume a 10% real discount rate, reflecting a high-level consensus on minimum project return expectations for oil and gas operators. This hurdle rate can be dissected into the weighted average cost of capital (WACC) of these operators plus a discretionary premium. The WACC is the sum of the operator's cost of equity and its cost of debt. Both cost of equity and cost of debt depend on inflation, as their calculation implies the use of a risk-free rate that is derived from inflation. An inflation rate of 2 percent is generally assumed.

1.2.2.1 Unconventional Resources—Development Cost Models

IHS Markit built 22 unconventional well models: 18 models containing uniform type curves at the subplay level—i.e., no distinction between Federal, state, or private mineral estate—and 4 models reflective of wells drilled after January 1, 2017 in the Federal mineral estate in the Wolfcamp Delaware and Bone Spring plays in New Mexico and the New Fairway and Parshall subplays of the Bakken in North Dakota. Type curves at the subplay level were developed for wells in the top-three quintiles in terms of expected ultimate recovery (EUR) per well. These well models include average type curves for the areas of interest and typical drilling, completion, and facilities costs.

The unconventional resources of this study focus on single-well economics. Therefore, the study considers the costs of developing resources from the unconventional plays, but it does not consider the costs of exploring for or finding the resources, given that their presence is known. Consequentially, the expected monetary value (EMV) is not used as a performance indicator for unconventional resources. Signature bonuses and lease costs are allocated on a per-well basis.

IHS Markit used in-house proprietary cost models for its design of unconventional wells. The reservoir engineering team relied on the IHS Markit Plays and Basins service for generic play-type curve generation and IHS Markit Harmony software to establish custom production profiles for the wells overlaying the Federal mineral estate.

1.2.2.2 Conventional Resources—Exploration and Development Cost Models

IHS Markit built 36 conventional field models in the Lower-48 onshore conventional peer group and 6 conventional field models for the Alaska onshore peer group. The same field model is used for each mineral estate. For example, Alaska state and Alaska Federal mineral estate assume the same production costs, but with different fiscal systems. The study focuses on typical exploration and development costs in each onshore conventional jurisdiction to account for differences in reservoir depth, elevation, well productivity, regional capital and operating costs, environmental or other regulatory compliance, and transportation costs.

Conventional exploration well-cost estimates are prepared for each reserve case for each jurisdiction. These estimates consider topography and reservoir depth characteristics for each jurisdiction, while also accounting for rig type, local rig rates, and expected drilling times. The economic metrics incorporate exploration success rates for each jurisdiction. The NPV/boe, IRR, and government take metrics in this study consider a full-cycle profile by grossing-up the cost of exploratory wells to include the average number of wells drilled per discovery. The EMV metric considers the risk involved when drilling a single exploration well to evaluate the decision operators make when investing in exploration. Appraisal costs are also included in each model. They are grossed-up on the same basis as the exploration costs in the full-cycle models, assuming an 80 percent chance of success of appraisal. Appraisal costs are included for all metrics.

The development concepts are assessed for each reserve case for each jurisdiction to reflect the respective environment and the types of facilities typically used. The development concepts consider the level of existing infrastructure, existing and potential market locations, and the density of offtake capacity, which influence the amount of capital and operating expenses required to develop and produce a field. When available, the development costs per well reflect the more experienced operators that have drilled the most wells in the past few years to represent a median cost.

IHS Markit's proprietary tools and databases are the basis for this analysis. The cost-modeling software QUE$TOR™ was used to generate the full-cycle development cost models for the Alaska chapter of this study. QUE$TOR™ is the world's leading software solution for new oil and gas project cost analysis, and is the industry standard tool for cost evaluation and concept optimization of new oil and gas field developments. QUE$TOR™ has been benchmarked against actual project costs and is continuously updated to reflect the latest changes in technology. QUE$TOR uses primary input data, including recoverable reserves, gas and liquid ratios, reservoir depth, and water depth. It leverages IHS Markit basin data to generate a production profile that supports the development of concept and design flow rates.

Additionally, IHS Markit leveraged the data from IHS Markit products EDIN and ENERDEQ to determine the expected development parameters for each field model. EDIN is a global database of international E&P activity; it also tracks E&P activity for the U.S. shelf, onshore United States, and onshore Canada. EDIN and ENERDEQ also provide data in the form of a geographical information system allowing for the determination of distances and proximities to pipelines, platforms, markets, and other terminals.

All field- and well-cost models feed into economic models as inputs through Federal, state, and private fiscal systems relevant to each area. IHS Markit ran 9 conventional Alaska, 102 conventional Lower-48 U.S., and 44 unconventional economic models. Three price scenarios are applied to the economic models, reflecting a base, high, and low price. With 155 economic models, a total of 465 cases are analyzed under the three price scenarios.

IHS Markit evaluated the 465 cases using the following economic metrics:

- **Internal rate of return (IRR**): the rate at which the sum of the project's discounted cash outflows equals the sum of the project's discounted inflows.
- **Net present value per barrel of oil equivalent (NPV/boe):** the amount of value in today's terms that each boe of entitlement production will generate for the operator on a full-cycle basis, including dry holes, appraisal, development, and abandonment.
- **Expected monetary value (EMV):** the sum of the NPV given success and NPV given failure, weighted by the probability of occurrence. Not applicable for unconventional resources.
- **Government take:** a general term used to describe the share of revenues that accrues to the government (or governments) over the life of an E&P project. The calculation of government take in this study includes the share of revenues accruing through royalties, taxes, and other fiscal and quasi-fiscal levies such as regulatory fees. Government take in this report is defined as the government's (or governments') percentage of pretax project net cash flow on an undiscounted basis.

The analysis in this study provides comparisons for each economic indicator separately. This marks a departure from the 2011 Study that ranked jurisdictions on the basis of a composite index that consisted of economic indicators, as well as measures of the degree of progressivity or regressivity of the fiscal system, revenue risk, and fiscal stability. More detail about the economic indicators of this study is provided in Chapter 5. While the DOI contracted this study to provide an updated comparative assessment of the U.S. Federal oil and gas fiscal system, the significantly different scope and approaches involved do not allow for a comparison of the results and findings between the two studies.

1.2.3 Price Assumptions

The study uses three oil and gas price scenarios in its economic models, referenced in the results as high case, base case, and low case. A global market price is used for crude oil, while regional market prices using differentials to Henry Hub are used for natural gas. In order to provide a consistent analysis of the Federal mineral estate onshore and offshore, the study uses the IHS Markit base case crude oil and natural gas price outlooks for this study, given that the Energy Information Administration (EIA) does not provide outlooks for natural gas prices in Europe or Asia, which were relevant for the Gulf of Mexico and Offshore Frontiers Reports. See Figure 1-7 for IHS Markit and EIA price crude outlooks to 2040. See Figure 1-8 for the low, base, and high case price assumptions for natural gas. The study applies minus 40 percent and plus 60 percent to the base case for the low and high case scenarios, respectively. The selection of crude oil prices for this analysis is not intended as a forecast, but reflects the relatively wide range between the high and low commodity price ranges witnessed in the past decade. The West Texas Intermediate (WTI) crude oil price scenarios adopted for this study average at about $40, $66, and $105 per barrel for the low, base, and high cases, respectively, for the 2019–40 period. The Henry Hub natural gas prices adopted for the economic analysis average at $2.38, $3.96, and $6.34 per million British thermal units (MMBtu) for the low, base, and high cases during the same period. The price cases are in 2018 real terms.

Figure 1-7. Crude oil price scenarios v. EIA (reference case)

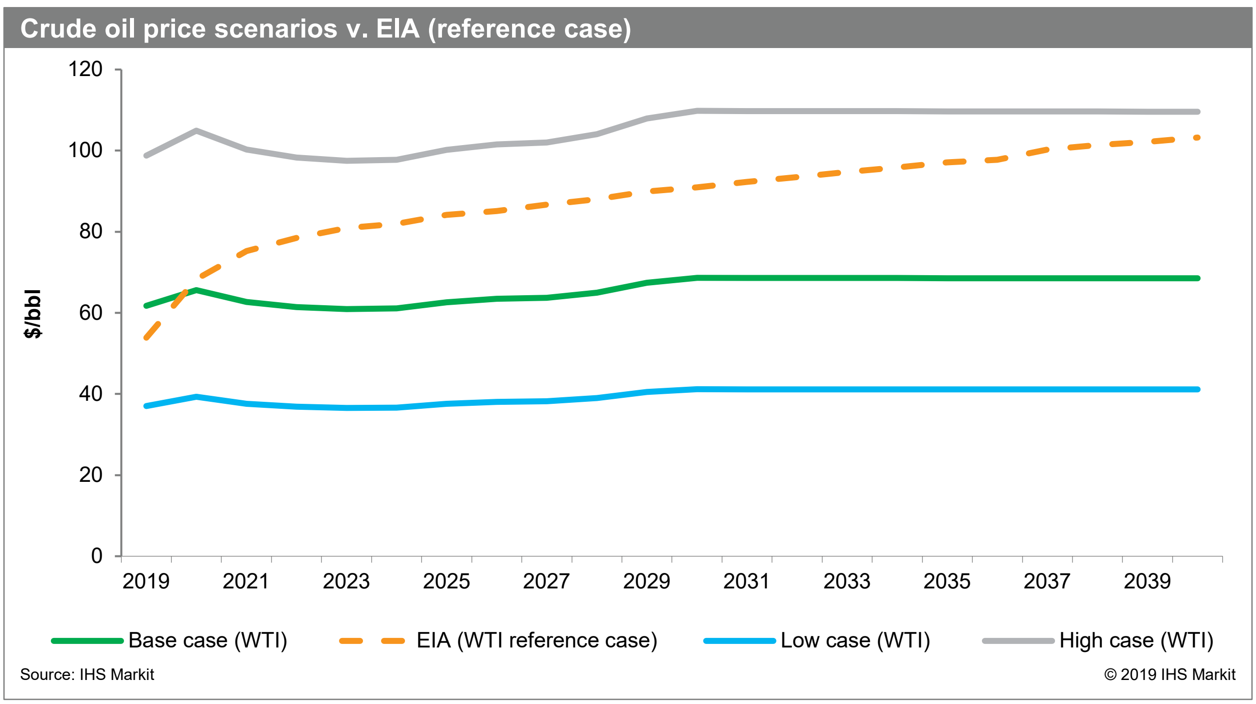
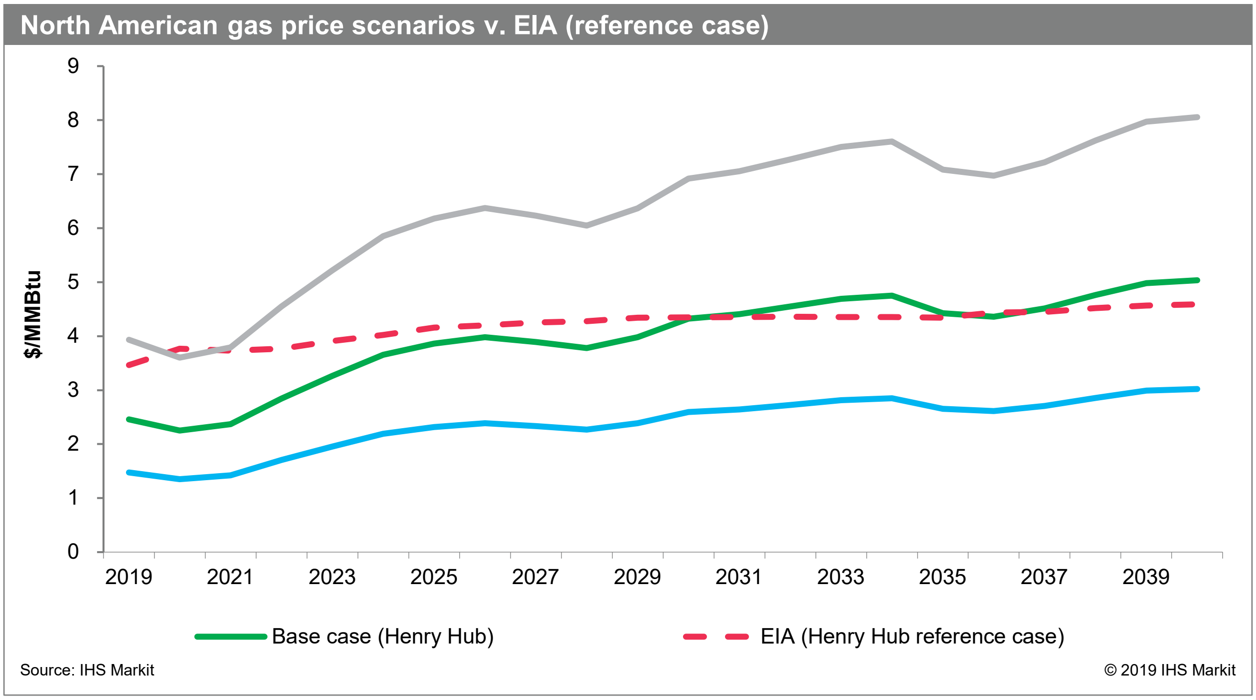


Figure 1-8. North American natural gas price[26] scenarios vs. EIA (reference case)



1.2.4 Organization of the Report

This report is organized in seven chapters.

Chapter 2 provides a qualitative assessment of fiscal, contractual, and lease terms applicable in the respective jurisdictions; acreage award criteria, such as signature bonuses; work commitments and other factors; and E&P terms.

Chapter 3 examines the current E&P landscape, highlighting trends in licensing activity, exploration, YTF resource potential, and exploration and development costs. Furthermore, this chapter provides an explanation and discussion of the policy decisions made by various jurisdictions and insights on the competitive landscape in the future.

Chapter 4 analyzes trends in fiscal terms since the drop of commodity prices in 2014. The chapter focuses on changes in fiscal terms and industry response, as well as the policy initiatives to incentivize exploration, encourage investment in unsanctioned discoveries, late-life-asset strategies, and financial responsibility for decommissioning.

Chapter 5 provides a comparative analysis of fiscal terms, such as government take, NPV/boe, and EMV. Fiscal systems are assessed based on each individual metric.

Chapter 6 provides a detailed analysis of the fiscal systems alternatives for the U.S. Federal fiscal system, including a discretionary relief for fields approaching their economic limit. This chapter examines the

[26] Gas price in dollars per million British thermal unit ($/MMBtu)

impact of each alternative fiscal system on the various indicators developed for this study, as well as any shift in ranking among the respective peer groups.

Chapter 7 finalizes the study's conclusions.

2 Characteristics of Fiscal Systems Reviewed

2.1 Fiscal and Contractual/Lease Terms

For the purpose of this study, IHS Markit defines a jurisdiction as the political boundary (e.g., a state in the U.S.) within which the development of oil and gas resources occurs. The jurisdictions included in the onshore peer groups for this study differ somewhat in terms of the nature and range of fiscal levies. The study analyzes 13 jurisdictions, including 12 states in the United States and Canada's Yukon.

The fiscal systems present in each jurisdiction are comprised of the terms and conditions placed on development by a number of sources. For example, U.S. Federal income tax laws apply across all jurisdictions in the country, while state tax laws apply to only the developments occurring within the respective state. Further individual resource owners specify terms and conditions that apply only to the development of resources from a particular mineral estate, e.g., the BLM can specify terms and conditions specific to the Federal mineral estate.

As an example, when the study refers to the Federal fiscal system in Wyoming, it refers to all of the terms and conditions placed on the development of the Federal mineral estate within the state of Wyoming. Of those terms and conditions, the BLM only has control of a relative few. When the study refers to the state fiscal system in Wyoming, it refers to all of the terms and conditions placed on the development of the Wyoming state-owned mineral estate. For private minerals, the terms and conditions depend on the agreements with each particular owner. For the purpose of this study, IHS Markit makes some general assumptions about the characteristics of the terms and conditions on private leases to create a fiscal system for privately owned minerals for each jurisdiction.

Fiscal systems differ across jurisdictions because of a variety of factors, including historical precedent, preference for size and scope of government, and ability to raise sufficient revenues with or without an income tax. Some jurisdictions produce a combination of conventional and unconventional resources, while others produce either conventional or unconventional, depending on their resource endowment.

The ownership rights determine the fiscal system applicable in each jurisdiction. Unlike international E&P investments and the outer continental shelf lands area where resources in the ground are held by the national/Federal government, ownership of resources in the ground onshore in the U.S. falls into three main categories:

- Federal ownership,
- State ownership, and
- Private ownership.

Table 2-1 identifies the fiscal systems analyzed in this study.

Table 2-1. Onshore fiscal systems analyzed

Jurisdiction	Resource ownership		
	Federal	State	Private
Alaska	X	X	n/a
Canada – Yukon	n/a	X	n/a
Colorado	X	X	X
Louisiana	X	X	X
Montana	X	X	X

Jurisdiction	Resource ownership		
	Federal	State	Private
New Mexico	X	X	X
North Dakota	X	X	X
Ohio	n/a	X	X
Pennsylvania	n/a	X	n/a
Texas	n/a	X	X
Utah	X	X	X
West Virginia	X	X	X
Wyoming	X	X	X

Source: IHS Markit

There are some commonalities in fiscal regimes across the jurisdictions, regardless of the owner of the minerals. All impose lease acquisition levies such as bonuses, royalties, and lease retention levies such as rentals and delay rentals. However, not all jurisdictions use the same mix of taxes. For instance, Texas and Wyoming have no state income tax, while Ohio has a gross receipts tax that functions similarly to a severance tax. Certain jurisdictions have no or limited ad valorem tax or no severance tax. Finally, many jurisdictions have various regulatory fees.

There are some differences that exist between Federal and state mineral estates. For instance, lease sizes tend to be somewhat larger on Federal mineral estate than on state lands. However, licensing terms and lease terms tend to be relatively similar across jurisdictions.

This chapter provides an overview of the contractual and fiscal terms applicable in the jurisdictions selected for the onshore comparison. A more-detailed description of the terms by jurisdiction is provided in Appendix A.

2.1.1 Types of Contractual and Fiscal Systems

The onshore fiscal systems are uniform in the sense that the same type of right is granted across all states and territories included in this study. The E&P rights in the United States and Canada are granted under the royalty/tax system or, as is commonly referred to, under an oil and gas lease. Under this system, the lessor carries all investment risk and is granted contractual and property rights over the resource in the ground. They usually pay bonuses, rentals, and royalties to the owner of the mineral estate and are subject to other taxes at the state and Federal/national level.

2.1.2 Key Components of Government Take

The levies included in each fiscal system reflect the sharing of risk between the government and the investors. The U.S. and Canadian fiscal systems incorporate both front-end loaded levies that place the revenue risk entirely with investors and profit-based levies that allow for the sharing of the revenue risk between the government and investors. The design of the fiscal system reflects the needs for Federal/national, state/territorial, and local governments to generate revenue, while still ensuring their jurisdiction is sufficiently attractive to investors.[27] The components of government take in the United States and Canada generally fall into the following categories:

[27] S. Tordo, D. Johnston, and D. Johnston, "Countries' experience with the allocation of petroleum exploration and production rights, The World Bank, January 2010, 12.

- Production-based levies,
- Income- or profit-based levies, and
- Other fiscal and quasi-fiscal instruments.

This section examines some of the main fiscal instruments adopted by the fiscal systems covered in this study (Table 2-2). Additional levies and allowances apply to many of the jurisdictions reviewed. High-level summaries of the respective fiscal and lease terms are shown in Appendix A.

Table 2-2. Key fiscal instruments

Jurisdiction	Bonus	Royalties	State income tax	Federal Income tax	Ad valorem tax	Severance tax	Profit-based production tax	Regulatory fees
Alaska	X	X	X	X	X	n/a	X	X
Canada – Yukon	X	X	X	X	n/a	n/a	n/a	n/a
Colorado	X	X	X	X	X	X	n/a	X
Louisiana	X	X	X	X	X	X	n/a	X
Montana	X	X	X	X	X	X	n/a	X
New Mexico	X	X	X	X	X	X	n/a	X
North Dakota	X	X	X	X	X	X	n/a	X
Ohio	X	X	n/a	X	X	X	n/a	X
Pennsylvania	X	X	X	X	n/a	n/a	n/a	X
Texas	X	X	n/a	X	X	X	n/a	X
Utah	X	X	X	X	X	X	n/a	X
West Virginia	X	X	X	X	X	X	n/a	X
Wyoming	X	X	n/a	X	X	X	n/a	X

Source: IHS Markit

2.1.2.1 Production-Based Levies

ROYALTIES

Royalty is payable to the mineral owner (i.e., Federal/national government, state/territorial government, or private owner). They are usually levied on gross production or gross proceeds often with allowances for transportation and processing. Usually the transportation allowance or deduction is measured from the well head to the liquid market. In jurisdictions such as Alaska that are remote from liquid markets in the Lower 48, the transportation allowances can be quite significant. Royalties are often tax deductible. The royalties adopted by jurisdictions in this study fall into two categories—flat-rate and sliding scale.

Flat-rate royalties: Adopted by the majority of the jurisdictions in this study, the flat-rate royalties are much more regressive in nature than sliding scale royalties, since they are applied at the same rate regardless of the project profitability. Flat-rate royalties have been adopted by the Federal government, as well as most state/territories and private land owners.

Sliding-scale royalties: These are designed to enable the resource holder to capture the upside when revenues increase and to soften the burden on investors when revenues decline. While there are a variety of potential bases for sliding-scale royalties, only one such royalty rate can be found among the jurisdictions in this study. Yukon has a two-tiered system that is initially based on a cumulative production threshold, and it then fluctuates depending on commodity prices. Initially, royalties are at a low rate until cumulative production reaches a threshold. Then, royalty rates are progressive and bounded, depending on the ratio of the "par price," which is a reference price determined monthly by the regulator, and the "select price" that is set from time to time by the oil and gas regulator.

Table 2-3 contains the range for royalties modeled in each jurisdiction.[28] The most common royalty rates in the U.S. are 12.5 percent, 16.67 percent, 18.75 percent, 20 percent, or 25 percent.

Table 2-3. Onshore royalty rates—States/territories

<table>
<tr><th>Jurisdiction</th><th>Federal mineral estate (%)</th><th>State/territorial land (%)</th><th>Private land (%)</th></tr>
<tr><td>Alaska[29]</td><td>12.5 or 16.67</td><td>12.5 or 16.67</td><td>n/a</td></tr>
<tr><td>Canada – Yukon</td><td></td><td>10–25</td><td>n/a</td></tr>
<tr><td>Colorado</td><td rowspan="13">12.5</td><td>20</td><td>20</td></tr>
<tr><td>Louisiana[30]</td><td>25</td><td>30</td></tr>
<tr><td>Montana</td><td>16.67</td><td>18.75</td></tr>
<tr><td>New Mexico[31]</td><td>20</td><td>25</td></tr>
<tr><td>North Dakota</td><td>18.75</td><td>20</td></tr>
<tr><td>Ohio</td><td>20</td><td>20</td></tr>
<tr><td>Pennsylvania[32]</td><td>18 for oil and at least 20 for gas</td><td>20</td></tr>
<tr><td>Texas</td><td>25</td><td>25</td></tr>
<tr><td>Utah</td><td>16.67</td><td>25</td></tr>
<tr><td>West Virginia</td><td>20</td><td>20</td></tr>
<tr><td>Wyoming</td><td>16.67</td><td>18.75</td></tr>
</table>

Source: IHS Markit

SEVERANCE TAXES

A severance tax (sometimes known as production tax) is a levy applied by most, but not all, producing states on either the volume or the value of hydrocarbon production. They are most commonly applied as a percentage of the produced value of the resource after deducting transportation and processing costs. Some states tax per unit regardless of the commodity price (e.g., dollars per barrel). Pennsylvania charges an unconventional gas impact fee that depends on well age and the average natural gas price. Severance rates or per-unit amounts in the selected states do not vary depending on whether the land and/or mineral resource is Federal, state, or private (Table 2-4).

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[28] For royalties on private land, see 2018 Nov/Dec Lierle Publications on U.S. Leases.

[29] On Federal mineral estates, two royalty rates have been announced in recent lease sale notices for the National Petroleum Reserve-Alaska (NPRA)—a 12.5 percent rate applies to low potential areas versus a 16.67 percent rate for high potential areas. On state lands, the royalty rate ranges between 5 percent and 60 percent. The most common rates are 12.5 percent and 16.67 percent.

[30] There are a few reports of royalties of 35 percent, and even a report of a royalty of 50 percent on private lands in Louisiana. These were treated as outliers.

[31] Royalty rates on state lands in New Mexico are adjusted depending on the location of known production areas and likelihood of discovering oil and gas. In mid-January 2019, the newly seated New Mexico land commissioner said she would like to increase the maximum royalty on state lands to 25 percent, from 20 percent, bringing it in line with neighboring Texas, but the effort failed.

[32] In Pennsylvania, the royalty rate on state lands for natural gas is 20 percent or $0.35/Mcf, whichever is higher. On private lands, royalties must be at least 12.5 percent, but certain deductions for post-production costs can cause actual rates to be below that threshold.

Table 2-4. Severance tax rates—States/territories

Jurisdiction	Oil severance rate	Natural gas severance rate	Oil severance per-unit rate ($/bbl)	Natural gas per-unit rate ($/mcf)[33]
Alaska[34]	n/a	n/a	n/a	n/a
Canada – Yukon	n/a	n/a	n/a	n/a
Colorado*	5.0%	5.0%	n/a	n/a
Louisiana	12.5%	n/a	n/a	$0.122
Montana*	9.0%	9.0%	n/a	n/a
New Mexico	3.75%	3.75%	n/a	n/a
North Dakota	10.0%	n/a	n/a	$0.0705
Ohio	0.26%	0.26%	$0.10	$0.025
Pennsylvania	Impact fee dependent on well age and natural gas price			
Texas	4.6%	7.5%	n/a	n/a
Utah	5%	5%	n/a	n/a
West Virginia	5.0%	5.0%	n/a	n/a
Wyoming	6.0%	6.0%	n/a	n/a
Note: credits and rate reductions apply in various states				

Source: IHS Markit © 2019 IHS Markit

2.1.2.2 Income- or Profit-Based Levies

INCOME TAX

This is the most common levy and often not specific to the oil industry. Income taxes are designed for profits at a corporate level. All jurisdictions are subject to a Federal corporate income tax.

Canada: The general corporate tax rate in Canada is 38 percent. With the Federal abatement of 10 percent, this is reduced to 28 percent where a company is subject to provincial income tax. In addition, a manufacturing and processing (M&P) deduction (applicable where a corporation derives at least 10 percent of gross revenues from manufacturing and processing goods in Canada for sale or lease) or a rate reduction (available on certain qualifying income), both of which are 13 percent, can bring the Federal income tax rate up to 15 percent.

United States: In December 2017, President Trump signed the Tax Cuts and Jobs Act into law. This Act (Section 13001) changes the Federal corporate income tax rate in the U.S. from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

Tax Incentives

Incentives such as accelerated tax depreciation, depletion allowances, and tax credits are often part of the fiscal systems. Some of the following tax incentives are available in the U.S. and Canada:

[33] $/Mcf is dollars per thousand cubic feet

[34] Alaska levies a production tax that is based on profits rather than gross production value.

- **First-year bonus depreciation:** The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.
- **The Canadian Oil and Gas Property Expense (COGPE):** This is the cost of acquiring and maintaining an oil and natural gas property or lease and includes expenditure incurred for bonus and rental payment, as well as annual lease and rental payments made to maintain such rights. The cumulative COGPE is written off at the rate of 10 percent on a declining balance basis for both Federal and provincial income tax purposes.
- **Accelerated depreciation:** This incentive usually allows for a more-accelerated rate of depreciation than book or financial depreciation. In the United States, a double-declining balance method of depreciation is applied to tangible capital spent depending on the number of years of life expected from the asset or depending on the asset class category in which the capital item falls. Double-declining balance is a form of accelerated depreciation.
- **Treatment of tangible cost:** Tangible costs are depreciated and can be described as the cost of an asset that has a useful life or monetary value that exceeds one year. The U.S. applies a double-declining balance method of depreciation to tangible capital spent depending on the number of years of life expected from the asset or depending on the asset class category into which the capital item falls. According to the Internal Revenue Service, the double-declining balance method applied is called the Modified Accelerated Cost Recovery System and is used to recover the basis of most business and investment property placed in service after 1986. A half-step or half-year phase shift is applied to the annual depreciation amounts to account for midyear spending. In Canada, tangible costs related to the acquisition of assets generally located above ground are capitalized and qualify for the Capital Cost Allowance (CCA). The declining balance depreciation rates vary according to classifications provided for in Federal legislation. The legislation provides for rates of 4 percent to 100 percent. However, the applicable rate for property intended for drilling oil or natural gas wells, oil storage tanks, and oil or natural gas well equipment that is acquired for the purpose of exploring for oil or natural gas is 30 percent.
- **Treatment of intangible cost:** Intangible costs are expenditures on items that have a useful life of less than one year. Often these are services or consumables but can include much of a well's cost. These costs include exploration and intangible development drilling costs. Intangible drilling costs as a percentage of drilling costs vary widely. In the United States, intangible costs are generally expensed in the year they are incurred; however, there are some limitations that apply to certain company structures that allow intangible costs to be capitalized at the election of the taxpayer.
- **Treatment of development costs:** The Canadian Development Expense (CDE) includes costs incurred in the drilling, completion, and conversion of any development well and successful exploration well starting from 2019. Such costs are written off at rates of up to 30 percent per annum on a declining-balance basis for both Federal and provincial income tax purposes.
- **Treatment of exploration costs:** The Canadian Exploration Expense (CEE) includes several costs related to drilling oil and gas exploratory wells—the cost of successful exploratory wells is classified as CDE. CEE may be either fully written off in the year incurred or deducted to the extent that there is sufficient income, after allowing for other income tax deductions, depending on the type of company. In the United States, costs incurred in drilling a nonproductive well may be deducted by the taxpayer as an ordinary loss.

State/Territorial Income Taxes

Most states/territories have corporate income taxes, except for Ohio, Texas, and Wyoming. However, Wyoming does not have income taxes. Texas does not have income taxes either, but its franchise tax functions as a kind of corporate income tax. Ohio's corporations are subject to a gross receipts tax that is accounted for in the section on severance taxes.

Table 2.5 includes the nominal Federal and state/territorial income taxes, in which nominal (vs. effective) indicates before any deductions or carry-forward losses are considered. Note: Where the tax is graduated, the highest marginal rate is shown.

Table 2-5. Nominal income tax rates—States/territories

Jurisdiction	Nominal income tax rate	
	Federal corporate rate (%)	State/territorial corporate rate (%)
Alaska	21	9.4
Canada – Yukon	28	12
Colorado	21	4.63
Louisiana		8.0
Montana		6.75
New Mexico		5.9
North Dakota		4.31
Ohio[35]		n/a
Pennsylvania		9.99
Texas[36]		n/a
Utah		4.95
West Virginia		6.5
Wyoming		n/a

Source: IHS Markit

FRANCHISE TAX

Texas and Louisiana have a variant of a corporate income tax called a franchise tax. The franchise rate in Texas is 0.525 percent. Louisiana's top rate is 0.3 percent for every $1,000 of capital used in Louisiana above $300,000.[37] The franchise tax in Louisiana is in addition to its corporate income tax.

ALASKA PETROLEUM PRODUCTION TAX

Companies that derive income from the production of oil and gas in Alaska are subject to an additional state income tax known as Alaska's Oil and Gas Production Tax (AOGPT).[38] All oil and gas produced in Alaska, except for the state and Federal royalty share, is subject to taxation (i.e., constitutes "Taxable Oil and Gas"). This is in lieu of a severance tax; however, unlike severance taxes, it is not based on gross production value, but rather on profits from oil and gas production.

[35] Ohio's corporations are subject to a gross receipts tax that is accounted for in the section on severance taxes.
[36] Texas does not impose income tax; however, it does levy a franchise tax.
[37] Louisiana Department of Revenue, "Corporate income & franchise taxes."
[38] *Oil and Gas Production Taxes and Oil Surcharge, Alaska Statutes Title 43 Chapter 55 (AS 43.55).*

2.1.2.3 Other Fiscal and Quasi-Fiscal Instruments

Governments capture revenue from oil and gas through various other fiscal and quasi-fiscal instruments. Additional levies observed in this comparative analysis include the following:

CARBON TAX

Canada has adopted taxes and policies that target greenhouse gas emissions. The Canadian government introduced the Pan-Canadian Framework on Clean Growth and Climate Change, which requires all provinces to have carbon pricing initiatives by 2018. In the Yukon, it will start on July 1, 2019 by covering industrial facilities emitting 50,000 metric tons of carbon dioxide equivalent (CO_2e) per year.[39] There will be a charge applied to fossil fuels, often paid by registered distributors, but aviation fuel will not be subject to tax. There will also be fuel charge relief for diesel-fired electricity.

In the United States, a few scattered carbon taxes are levied by localities. For instance, the city of Boulder, Colorado has had a Climate Action Plan tax since 2007.[40] It is levied on residents and businesses depending on the amount of electricity they consume.

BONUSES

Each jurisdiction awards acreage upon payment of a cash bonus. For state and Federal mineral estate bonuses are determined by the market at auction. Minimum amounts are set for parcels on sale and acreage is granted through sealed bids or ascending open bids. More information on bonuses payable is included in Section 2.2, Acreage Award Criteria, of this report.

RENTAL

Annual rental payments typically apply in the jurisdictions surveyed and are owed as long as a lease is held, but is not yet under production. In general, rentals are relatively minor when compared with the other fiscal terms. Rentals for Federal leases are \$1.50/acre/year for the first five years and \$2.00/acre/year for the remaining years. Rentals on state and private leases are generally higher with \$10/acre/year or less being the norm.

AD VALOREM

Ad valorem taxes are assessed at the county and municipal level. The majority of the states reviewed for this study impose ad valorem property taxes on the oil and gas industry. The most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as the oil rig. Table 2-6 shows effective ad valorem levies in the respective jurisdictions.

Table 2-6. Effective ad valorem rates—States/territories

Jurisdiction	Effective ad valorem rate on equipment	Effective ad valorem rate on produced value
Alaska	2%	2%
Canada – Yukon	n/a	n/a
Colorado	2%	6.1%
Louisiana	0.7%	n/a
Montana	0.9%	n/a

[39] Government of Canada, "Yukon and pollution pricing."
[40] Boulder, Colorado, "Climate action tax."

Jurisdiction	Effective ad valorem rate on equipment	Effective ad valorem rate on produced value
New Mexico	3.3%	5%
North Dakota	n/a	n/a
Ohio	2.3%	1%
Pennsylvania	n/a	n/a
Texas	2.18%	2.18%
Utah	0.7%	2%
West Virginia	0.83%	0.83%
Wyoming	1.6%	6.9%

Source: IHS Markit

2.2 Acreage Award Criteria

Governments in the United States and Canada typically authorize oil and gas E&P rights through a competitive bidding process. Competitive bidding is a transparent process with clearly defined award criteria.

More specifically, auctions or lease sales are usually used for BLM lands and state lands. In this system, acreage is awarded to qualified bidders on the basis of competitive bids. A set of fixed and variable bid criteria are established in advance, with the award going to the highest bid. Negotiations for bonuses on private lands occur between investors and owners of mineral rights.

Generally, Federal and state lands are auctioned on regular predetermined schedules. BLM leasing generally occurs quarterly, while states tend to either have quarterly or monthly lease sales. Alaska has annual Federal and state land lease sales. However, there is some sporadic leasing on BLM or state mineral estates in certain jurisdictions. Private leasing occurs on an *ad hoc* basis.

2.2.1 Cash Bonus Bidding

Cash bonuses are considered for the award of oil and gas rights onshore for the Federal, state and often private mineral estate. The range of bonuses payable varies widely among the jurisdictions surveyed, as well as within the areas offered in each jurisdiction. Acreage on state land tends to generate higher bonuses on a $/acre basis. The difference in average bonus amounts on a $/acre basis between state and Federal mineral estates could be attributed to the access restrictions and often greater regulatory burden imposed on the Federal mineral estate. The lowest amount of the three groups—Federal, state, and private—are generated on private land. This is attributed to two factors: a) the mineral estate is split into small interests; and b) the acreage is not granted on a competitive bid process, but rather through *ad hoc* negotiation. Table 2-7 includes bonus information for each jurisdiction.

Table 2-7. Recent bonus payments—Selected states

Jurisdiction	Bonus ($/acre)					
	Private lands[41]		State lands		Federal mineral estate	
	Range	Average	Range	Average	Range	Average
Alaska	n/a	n/a	27–586	122	6–19	9

[41] A lot of the data is from 2018 Nov/Dec Issue. Lierle Publications on US Leases. For Colorado, Montana, New Mexico, Texas, Utah, and Wyoming, figures shown are the median values of the low, high, and most common bonus payments listed in the counties with conventional oil and gas. In other states, that method is used for all counties.

Jurisdiction	Bonus ($/acre)					
	Private lands[41]		State lands		Federal mineral estate	
	Range	Average	Range	Average	Range	Average
Canada – Yukon[42]	n/a	n/a	n/a	n/a	n/a	n/a
Colorado	1–450	16	34–501	76	2–100	13
Louisiana	39–525	200	500–910	797	201[43]	201
Montana	1.5–86	5	2–130	17	2–306	53
New Mexico	20–3,800	325	78–40,410	4,801	2–35,003	399
North Dakota	1–350	10	97–1,509	273	3–2,501	19
Ohio	1–5,800	3	n/a	n/a	201[44]	201
Pennsylvania	17.5–500	150	2,700[45]	n/a	n/a	n/a
Texas	35–3,800	325	100–25,511	5,823	101–6,001	1,488
Utah	2–1,600	30	2–3,720	120	2-66	20
West Virginia	1–9,000	10	3,017–7,201	4,887	n/a	n/a
Wyoming	1–1,475	19	4–3,786	223	2–6,001	165

Note: Data for each jurisdiction corresponds to 2018, except for Yukon which dates back to 2010, the last year a permit was granted in Yukon.

Source: IHS Markit

2.2.2 Work and Financial Obligation

Exploration obligations are the criteria on which the award of bids is based in the Canadian territory of Yukon. The permit holders are required to drill at least one exploratory or delineation well before the expiration of the initial term. The commitment to drill is associated with an expenditure commitment, backed by a deposit of 25 percent of the expenditure bid. The financial commitment for the Northern Cross parcel in 2010 is approximately $448,350.[46]

2.3 E&P Terms

2.3.1 Parcel Size

A factor in determining the pace of E&P activity is the size of acreage offered to individual investors. Companies generally prefer large leases because they can implement more-robust development plans, without having to deal with pooling and unitization of oil and gas deposits. Especially when drilling for unconventional resources, companies need considerable contiguous acreage to go forward with development. An analysis by IHS Markit of the pace of development in the Permian Basin shows faster drilling and development of the resource when the mineral rights held by the same operator are in contiguous leases, versus scattered checker-box lease holdings. In general, average BLM leases are somewhat larger than average state lands leases. Table 2-8 includes information on average parcel sizes in each jurisdiction during 2014–18.

[42] No meaningful leasing activity has occurred since 2014.
[43] Only one parcel was sold at the BLM Eastern States Federal Lease Sale, June 21, 2018.
[44] Two parcels were sold with this bonus at the BLM Eastern States Federal Lease Sale, December 13, 2018. However, Federal mineral estate in Ohio has not been analyzed in this study.
[45] *The Sentinel,* "Pennsylvania Game Commission Briefs," February 22, 2019.
[46] 2010 was the latest year an oil and gas permit was granted in Yukon.

Table 2-8. Average size of parcels 2014-2018—Federal and state/territory mineral estate

Jurisdiction	Average lease size (acres)	
	Federal mineral estate	State lands
Alaska	8,026	1,814
Canada – Yukon	n/a	35,636
Colorado	698	472
Louisiana	658	164
Montana	444	447
New Mexico	403	236
North Dakota	277	88
Ohio	63	n/a
Pennsylvania	866	724
Texas	562	525
Utah	1,193	631
West Virginia	n/a	n/a
Wyoming	971	345
Yukon acreage represents the average of all active licenses and permits in the territory. There has been no acreage disposition since 2010 in the territory.		

Source: IHS Markit

2.3.2 Lease Term

The oil and gas lease under Federal, state, and private mineral estate is granted for a specific primary term, and as long thereafter as oil and gas is produced in paying quantities. There are other circumstances under which a lease can extend beyond the primary term. Such circumstances usually include: drilling operations being under way at the end of the primary term; payment of shut-in royalties for natural gas or condensate wells to allow the lessee to defer production from a well capable of producing, but shut in for lack of a satisfactory market; and continuation of the lease in effect, when the lessee is entitled to receive an allocation from an off-lease well. The lease extension provisions are not uniform among the various mineral estates and have not been included in this analysis.

PRIVATE LANDS

In multiple jurisdictions, the primary lease term is 3–5 years for private mineral estates. There are private leases in some states with less standard terms, varying by individual lease. Table 2-9 provides information on the primary term of private oil and gas leases.

Table 2-9. Primary lease term—Private lands

Jurisdiction	Primary term (years)
Alaska	n/a
Canada – Yukon	n/a
Colorado	3–5
Louisiana	3–5
Montana	3–5
New Mexico	Varies
North Dakota	3–5
Ohio	Varies, sometimes 10
Pennsylvania	5–6

Jurisdiction	Primary term (years)
Texas	3–5
Utah	Varies
West Virginia	Varies
Wyoming	Varies

Source: IHS Markit © 2019 IHS Markit

STATE/TERRITORIAL LANDS

Primary lease terms vary by jurisdiction, but many them fall into a range of 5–10 years. Only Texas and occasionally Louisiana tend to have shorter terms. Table 2-10 shows the duration of the primary term on state land.

Table 2-10. Primary lease term—State/territory lands

Jurisdiction	Primary term (years)	Additional detail
Alaska	7–10	
Canada – Yukon	Up to 10	
Colorado	5	The standard exploratory period on state lands is 5 years and then for as long as oil and gas are produced in paying quantities.
Louisiana	3 or more	The primary term is usually 3 years or less with a 2-year extension. Ultra-deep wells (> 22,000ft true vertical depth [TVD]) or approved secondary or tertiary recovery projects may have longer terms.
Montana	10	
New Mexico	5–10	LH exploratory leases are for 10-year terms. VA exploratory leases are for 5 years, as are V0 discovery leases.
North Dakota	5+	
Ohio	n/a	Given previous effective moratorium and lack of recent state land leasing.
Pennsylvania	10	The standard primary term on state lands is 10 years. However, the operator must drill the first well in first 5 years of the lease.
Texas	3	
Utah	5–10	
West Virginia	5	
Wyoming	5+	

Source: IHS Markit © 2019 IHS Markit

FEDERAL MINERAL ESTATE

Federal oil and gas leases are granted for a primary term of 10 years. Similar to private and state oil and gas leases, the lease continues beyond the primary term for as long as oil and gas are produced in paying quantities.

2.3.3 Decommissioning and Abandonment Requirements

2.3.3.1 Regulatory Requirements

STATE REQUIREMENTS

Jurisdictions have relatively similar requirements for decommissioning and abandonment on state lands. Typically, a notice must be given to a state regulator with certain information and the operator must follow state guidelines for plugging and abandonment. In some states, wells that have not been producing for a specified amount of time (often one year) must be at least plugged. Table 6-11 provides a high-level description of requirements at the state level.

Table 2-11. State decommissioning and abandonment requirements

Jurisdiction	Overview
Alaska	Upon abandonment or expiration of a lease, all facilities must be removed, and the sites rehabilitated.
Canada – Yukon	Licensees are responsible for wells that will not be completed or have not been produced or used as an injector for 12 months. Surface abandonment should be completed within 12 months of subsurface abandonment.
Colorado	Prior to plugging and abandoning any oil and gas well, operators must submit a Notice of Intention to abandon a well and follow guidelines regarding how this must be achieved.
Louisiana	The lessee is obliged to plug and abandon all wells no longer necessary for operations or production on the lease and to remove all related structures and facilities.
Montana	Prior to plugging and abandoning any oil and gas well, operators must submit a Notice of Intention to abandon a well and follow guidelines regarding how this must be achieved.
New Mexico	Wells must be plugged or given a status of "temporary abandonment" within 90 days of certain events (60-day period after suspension of drilling operations; determination well is no longer useable for beneficial purpose; or a period of one year of continuous non-activity).
North Dakota	A well can be placed in "abandoned-well" status if it has not produced oil or natural gas in paying quantities for one year.
Ohio	When any oil and gas well will be abandoned, it must first be plugged in accordance with regulations.
Pennsylvania	There are provisions on well site restoration including the restoration of surface land, as well as the filling of pits within a certain amount of time. Specific plugging obligations include obligations to notify of intent to plug and abandon and specific procedures to be followed in doing so.
Texas	Inactive wells (wells that have been spudded, equipped with cemented casing, and have had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months) must be plugged and a plugging report must be filed.
Utah	Utah Administrative Code sets out rules on plugging and abandonment of wells. Notice of the intent to abandon must be submitted with specific information.
West Virginia	An operator can plug a well as soon as it receives verbal permission, but it then needs to file the plugging affidavit. There is an Abandoned Well Act that documents the processes needed to lawfully abandon wells.
Wyoming	Prior to any abandonment work commencing on a well, a Notice of Intent to Abandon must be submitted and approval received for such work to begin. Any approval given is valid for one year.

Source: IHS Markit

FEDERAL MINERAL ESTATE

Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[47] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[47] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

3 E&P Activity Overview

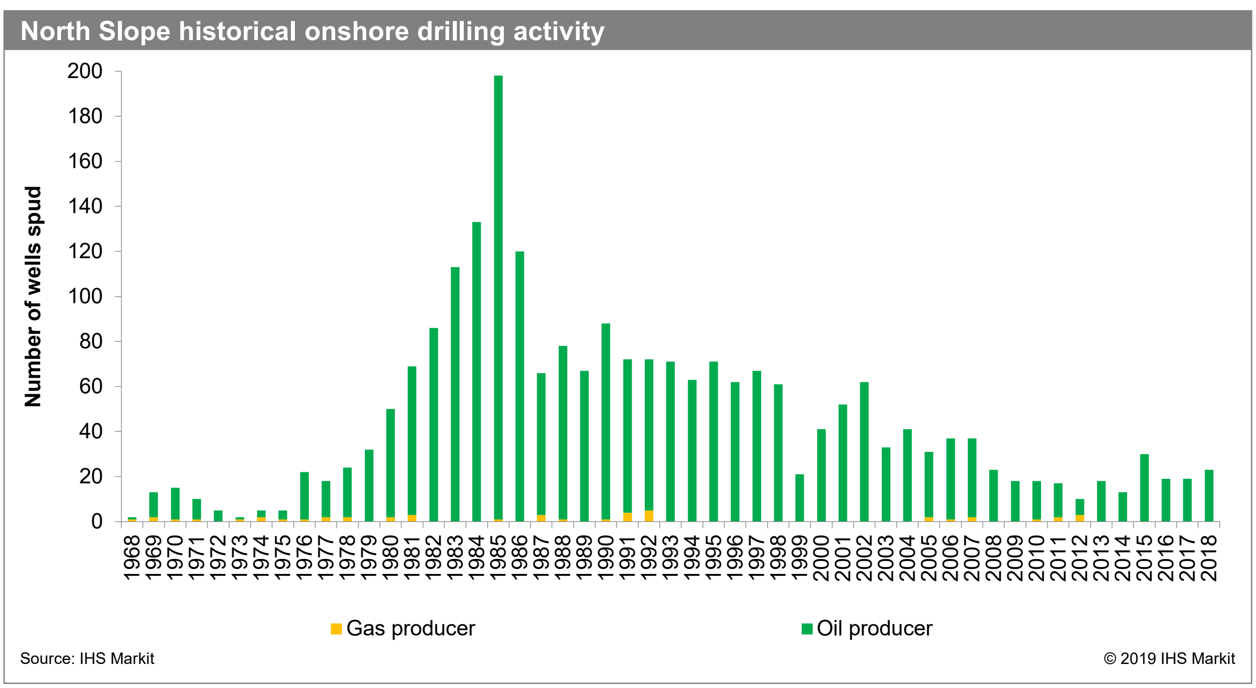
3.1 Exploration and Development Activity

Unconventional resource exploration activity has been booming in the United States since 2006 in driving a shift towards decreasing U.S. energy imports and increasing U.S. energy exports. Unconventional resource exploration and development is different from conventional resource exploration and development, as it takes place in less-permeable formations where operators have been able to recover increasing volumes of oil and gas that result from improvements in horizontal, vertical, and directional drilling technology and practices, mobile, multi-pad drilling platforms, as well as enhanced recovery and well completion techniques. The drilling of new wells, the pace of completions, and the available trend recognition are critical to understand the maturity of an unconventional play and its future potential. Conventional exploration in the U.S. takes place in largely more mature and more permeable formations.

3.1.1 Alaska Onshore Exploration and Development Activity

Alaska onshore oil and gas exploration activity is centered around the North Slope Basin. Prime activity onshore Alaska peaked in the mid-1980s and has been adversely affected by drilling restrictions. However, the 2017 opening of the Coastal Plain region of the Alaska Wildlife National Reserve (AWNR) and the intensification of the development programs in the NPR-A is expected to re-energize exploration drilling in the North Slope Basin. The importance of the North Slope Basin emerged in the 1980s and lasted until 1998 (Figure 3-1). The variances in drilling activity levels in the North Slope Basin are not due to play exhaustion, but rather to changes in commodity prices impacting operator returns. Capital expenditures are higher in North Slope as compared to equivalent onshore projects in the U.S. main land because of remoteness and arctic conditions that trigger operational delays, thus affecting project profitability.

Figure 3-1. North Slope historical drilling activity



ANS onshore drilling activity has almost been at a standstill since 2014, with 41 wells spudded during the five-year period—containing only four oil producers and one gas producer. After reaching its lowest level in 2016 (over 2014–18 period), exploratory well drilling started to recover: eight exploratory wells were spudded in the North Slope Basin in 2018, as compared to three in 2016 (Figure 3-2). In early April 2019, ConocoPhillips reported spudding two new oil wells in the Nanushuk formation of the Tinmiaq lease. The Nanushuk formation was the target of 39 percent of the exploration wells drilled between 2014 and 2018 (Figure 3-3). It is especially promising in fields such as Willow or Alpine and is expected to yield more discoveries.

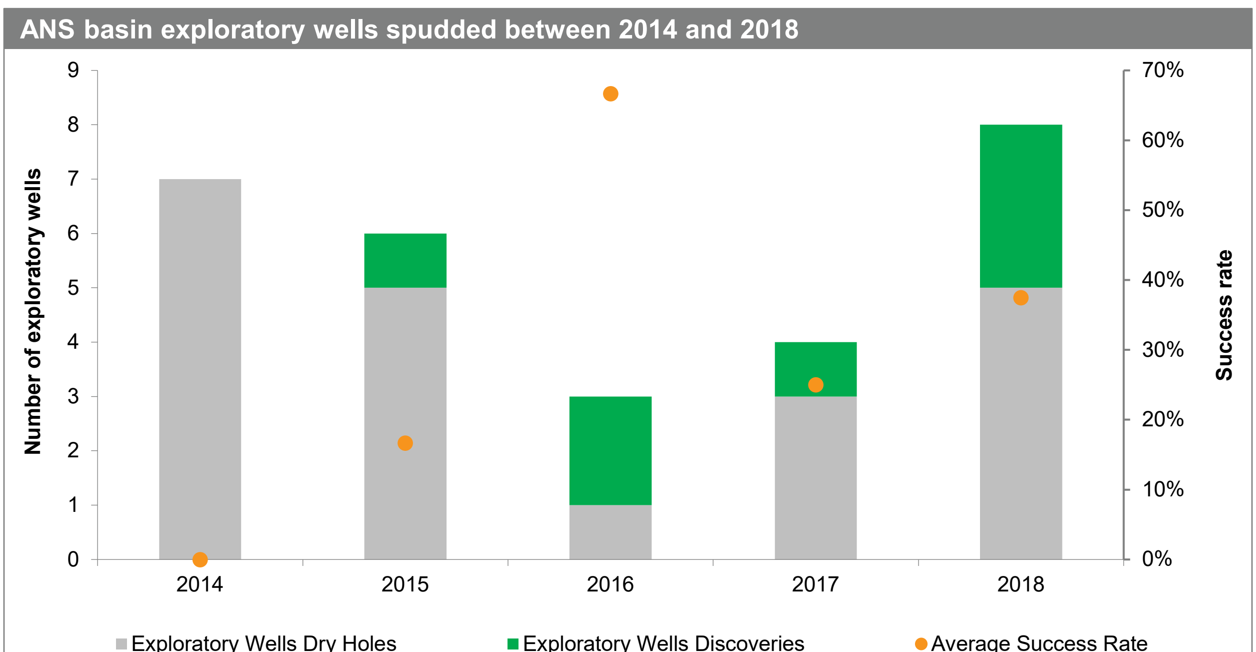
There was no exploratory drilling activity in Yukon between 2014 and 2018. The last exploratory well drilled in the Eagle Plain Basin was spudded in 2013. Most of the exploratory drilling activity in Yukon happened between 1963 and 1973. Out of the 28 exploratory wells drilled during this period, only three were discoveries—resulting in a 10 percent success rate.

Table 3-1. Alaska onshore peer group exploratory well drilling, 2014–18

Region	Primary production	Number of exploratory wells spudded 2014–18
ANS	Oil	28
Alaska Cook Inlet	Gas	4
Canada Yukon	Oil	0

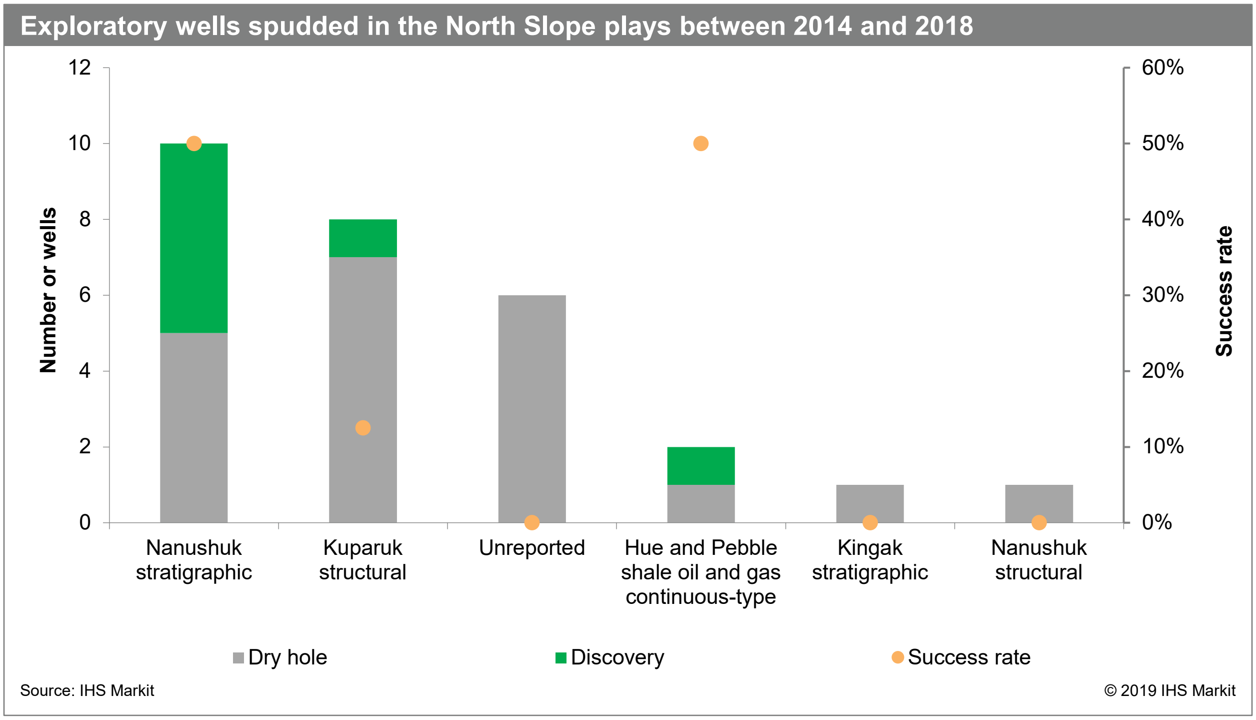
Source: IHS Markit

Figure 3-2. General exploratory well drilling in the North Slope between 2014 and 2016



Source: IHS Markit

Figure 3-3. North Slope exploratory wells spudded by play between 2014 and 2018



3.1.2 Conventional Exploration and Development Activity

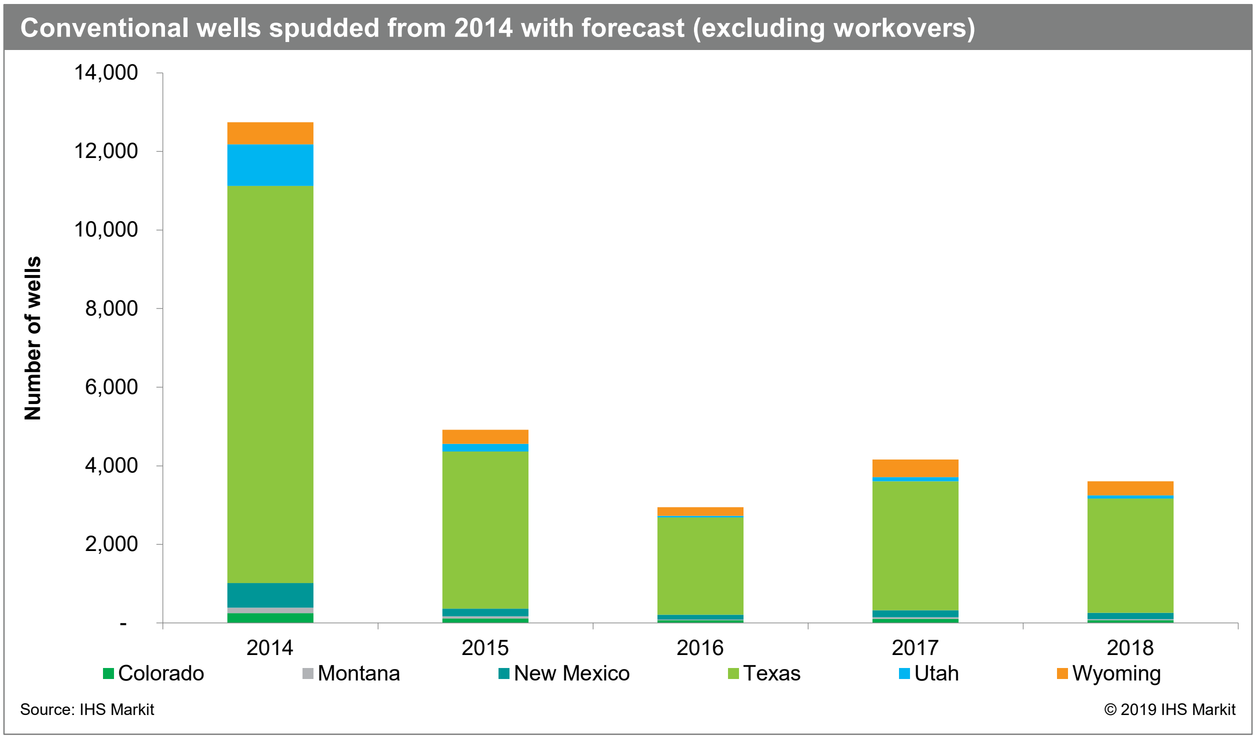
The count of new conventional wells spudded for oil and gas production decreased between 2014 and 2016 and flattened in 2018. In our conventional peer group during 2018, 81 percent of the conventional wells were spudded in Texas, more specifically, in the Gulf Coast Basin and the Permian Basin. This can be explained by the lack of competitiveness of the conventional fields against the unconventional developments, with break-even prices significantly below $40 for the core areas. The effect has been more severe for conventional gas fields as U.S. gas markets have tightened over the past five years. Table 3-2 shows the number of conventional wells spudded in the Lower-48 peer group. The table also includes the workovers, injection, and dry holes to get a better picture of the intensity of capital investment in each jurisdiction.

Table 3-2. Conventional vertical wells producers spudded between 2014 and 2018

Jurisdiction	Primary production	Number of wells spudded 2014–18	Including workovers, injection, dry holes
Colorado	Oil and gas	110	783
Montana	Oil and gas	57	360
New Mexico	Oil and gas	416	2,005
Texas	Oil and gas	156	982
Utah	Oil and gas	299	1,399
Wyoming	Oil and gas	**335**	2,234

Source: IHS Markit
@ 2019 IHS Markit

Figure 3-4. Lower-48 conventional peer group—Conventional wells spudded, 2014–17



Development activity in the conventional arena decreased almost four-fold between 2014 and 2016. Since then, activity has recovered, but at a level well below the 2014 level. The reality is that most of the U.S. onshore conventional formations have reached their maturity, leading to a flattening of the new wells spudded between 2017 and 2018 (Figure 3-4). In addition, conventional projects are generally at a disadvantage while competing for capital as compared to unconventional projects. The pools of investors are much different and so is the capital spent. Investors in the smaller onshore conventional assets usually are smaller private companies, or even private non-incorporated land owners such as farmers and ranchers. This investor group does not have the overhead that medium and large oil and gas companies have and therefore can maintain investing in smaller assets. They also tend to be a bit less reactive to market conditions as their costs are usually much lower.

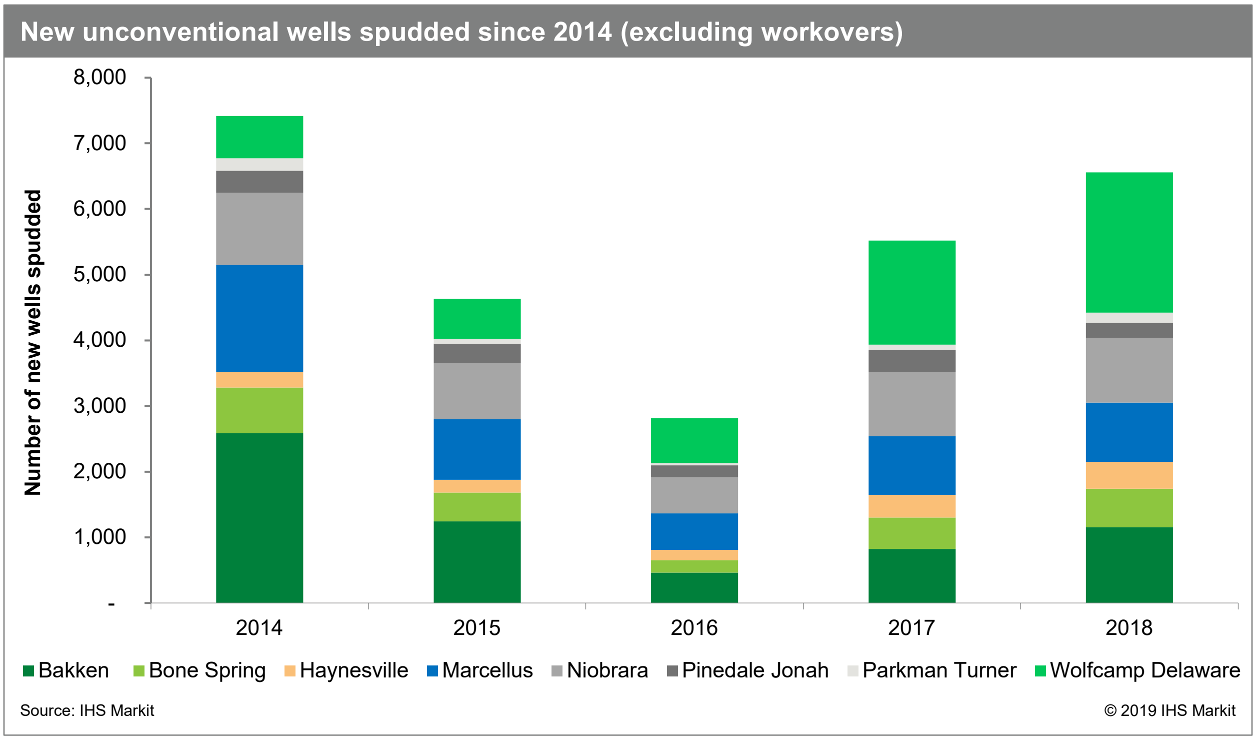
3.1.3 Unconventional Exploration and Development Activity

Hydrocarbon exploration and development activity have a strong correlation to market conditions, especially for the short-cycle barrels from unconventional reservoirs.[48] The number of new wells spudded in the selected jurisdictions between 2014 and 2018 has followed the fluctuations of the oil markets. In 2014, at the onset of the last downturn, all plays except the Wolfcamp Delaware were at their highest levels. The year 2016 saw the lowest levels of activity in all selected plays except in the Wolfcamp Delaware, which bottomed in 2015; however, all eight of the selected unconventional jurisdictions have seen a recovery in activity since the bottom of the crisis in 2016. Figure 3-5 captures the number of wells spudded,

[48] Short-cycle barrels are projects that can generate profit within one to two years of development, or, in the case of new entrants, projects that progress to final investment decision (FID) in less than three years.

excluding workovers, between 2014 and 2018, in the unconventional plays included in this study. The largest increase in activity has been in the Permian Basin in the Wolfcamp Delaware play, although the legacy plays of the Bakken and Niobrara have also seen a revival of activity. These legacy plays have benefitted from a strong oil price (as well as service-sector cost reductions), allowing them to restart production growth. Another consequence of additional drilling activity is a mismatch in service-sector capability. For example, during the recovery, Permian drilling rigs were more plentiful than completion crews, leading to the creation of drilled-but-uncompleted (DUC) wells in the basin. Thus, when reviewing annual spuds and new wells, quantities will see a timing shift due to the rapid resurgence of activity.

Figure 3-5. Unconventional peer group: Unconventional wells spudded between 2014 and 2018



The difference between the producers and the total number of wells spudded is driven by the number of wells reaching target formation, but not being completed. This difference usually increases when prices see large swings—when prices collapse, operators prefer waiting for a recovery rather than using hedges on new production. When prices rise, there is a mismatch in service-sector capabilities. This is particularly evident in plays such as Bakken, where 300 DUCs were created during 2018. Table 3-3 indicates the number of wells spudded excluding workovers.

The most active plays of the peer group during this period are Bakken, Wolfcamp Delaware, Marcellus, and Niobrara. The Wolfcamp Delaware is a key area of growth activity, with 4,067 wells spudded between 2014 and 2018, and 958 wells spudded in 2018 alone. There is also high growth in the Bakken and the Niobrara, with 569 and 566 wells spudded in 2018, respectively.

Table 3-3. Unconventional wells spudded classified as producers, 2014–18

Jurisdiction	Primary production	Number of wells spudded 2014–18	Number of wells spudded 2018
Bakken	Oil	5,231	569

Jurisdiction	Primary production	Number of wells spudded 2014–18	Number of wells spudded 2018
Bone Spring	Oil	2,056	363
Haynesville	Gas	1,038	204
Marcellus	Gas	4,031	350
Niobrara	Oil	3,813	566
Parkman/Turner/Shannon Sands	Oil	434	88
Pinedale Jonah	Gas	1,281	216
Wolfcamp Delaware	Oil	4,067	958

Source: IHS Markit @ 2019 IHS Markit

3.1.4 Conventional Oil and Gas Production Outlook

This section describes IHS Markit's 20-year production outlook for the peer groups. This forecast considers both the liquid plays' contribution to the gas outlook and the gas states' contribution to the oil outlook. The forecasts are expressed in average daily production as well as a total volume yield for the 20-year forecast period.

Alaska crude oil production is expected to grow through the North Slope Basin's reemergence. In the North Slope Basin, new projects such as Qugruk, Willow, Horseshoe, and Umiat will contribute to raising production, which is expected to peak at 724 MMbbl/d in late 2020. The U.S. Cook Inlet contribution to the Alaskan oil output is expected to remain very limited, as this basin mostly delivers gas.

Table 3-4. Conventional oil production outlook for Alaska

Jurisdiction	Primary production	Average daily oil production 2014–18 MMbbl/d	Average daily oil production 2019–38 MMbbl/d
Alaska	Oil	491	629

Source: IHS Markit @ 2019 IHS Markit

Most of the U.S. conventional oil and gas production comes from the state of Texas. In Texas, the Permian Basin and the Gulf Coast Basin drive current conventional oil and gas production and are expected to drive the next 20 years of conventional production. Public information was used to derive the Lower-48 conventional peer group oil and gas production forecasts. Overall, conventional oil and gas production in the selected U.S. jurisdictions is expected to follow its natural decline as operators continue shying away toward shorter-cycle barrels. The outlook referenced herein is therefore built on a decline-curve basis.

Table 3-5. Conventional jurisdictions production outlook, 2019–38

Conventional jurisdiction	Primary production	Average conventional oil production MMbbl/d	Average conventional gas production Bcf/d	Total oil estimated MMbbl	Total gas estimated Tcf
Colorado	Oil and gas	20.1	0.10	147	0.7
Montana	Oil and gas	1.9	0.08	14	0.6
New Mexico - Permian	Oil and gas	105.0	0.26	766	1.9
Texas - Permian	Oil and gas	525.0	1.33	3,895	1.3
Utah	Oil and gas	7.4	0.20	54	2.6
Wyoming	Oil and gas	25.9	0.02	189	0.1

Source: IHS Markit

3.1.5 Unconventional Plays Production Outlook

This section describes IHS Markit's 20-year production outlook for the peer groups. This forecast considers both the liquid plays' contribution to the gas outlook and the gas plays' contribution to the oil outlook. The forecasts are expressed in average daily production as well as a total volume yield for the 20-year forecast period.

Wolfcamp Delaware, Bakken, and Bone Spring outputs are expected to represent 88 percent of the peer group oil production forecast between 2019 and 2038 (Figure 3-6). This also represents 43 percent of the total expected[49] U.S. oil production in 2040. Marcellus, Wolfcamp Delaware, and Haynesville are expected to represent 80 percent of the gas peer group production forecast. With an average daily production of 3.1 MMbbl/d of oil and 10.78 Bcf/d of gas for the next 20 years, Wolfcamp Delaware represents a strategic component in the U.S. oil and gas production playbook. In the next 20 years, 64 percent of the future oil production of the selected peer group will come from the Wolfcamp Delaware and the Bone Spring plays, while 61 percent of the future gas production of our peer group will come from the Marcellus and Haynesville plays (Figure 3-6). Wolfcamp Delaware and the Bone Spring wells spudded are expected to increase in the next 20 years. During the same time frame, a contraction of the spudding activity is expected in the Marcellus play.

[49] IHS Markit's total expected U.S. oil production in 2040 is 15,955 thousand barrels of oil per day.

Figure 3-6. Oil and gas unconventional daily production forecast, 2019–38

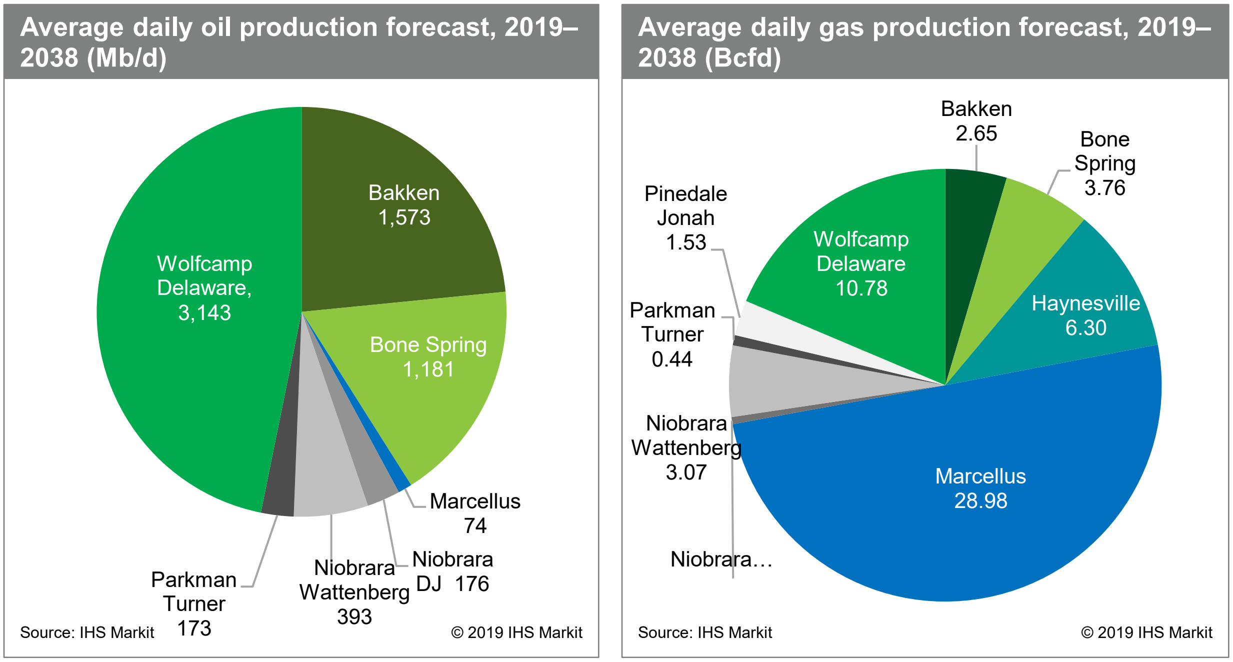


Table 3-6. Unconventional production outlook, 2019–38

Jurisdiction	Primary production	Oil production MMbbl/d	Gas production Bcf/d	Total oil estimate MMbbl	Total gas estimate Tcf
Bakken	Oil	1.57	1.01	11,485	19.366
Bone Spring	Oil	1.81	3.76	8,621	27,483
Haynesville	Gas	0.00	6.30	0	45,984
Marcellus	Gas	0.07	28.98	543	211,565
Niobrara DJ	Oil	0.18	0.31	1,290	2,247
Niobrara Wattenberg	Oil	0.39	3.07	1,871	22,438
Parkman/Turner/Shannon Sands	Oil	0.17	0.44	1,261	3,237
Pinedale Jonah	Gas	0.00	1.53	0	11,146
Wolfcamp Delaware	Oil	3.14	10.78	22,242	78,659

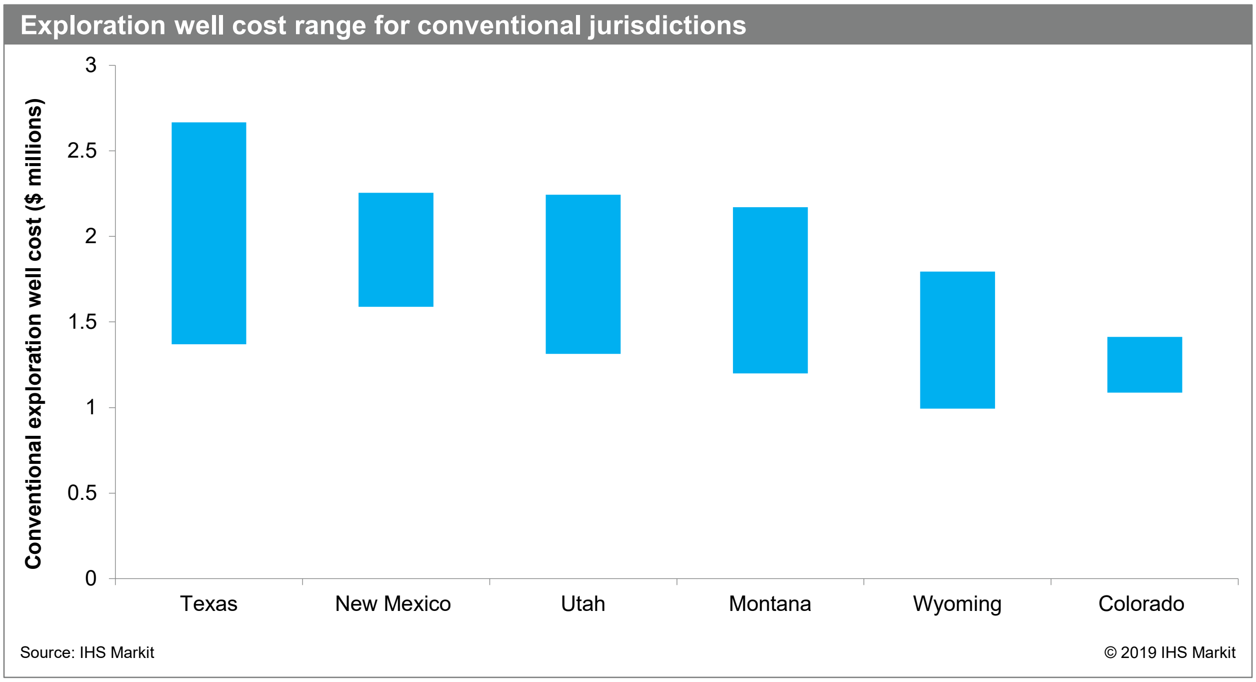
Source: IHS Markit
@ 2019 IHS Markit

3.2 Exploration and Development Costs

In the North Slope Basin, onshore conditions are extreme and the drilling window small. This helps to cause North Slope onshore exploratory well costs to range from $9 million to $15 million. The range is driven by both well direction and completion types.

There are fewer variances in conventional exploration well costs for our selected conventional jurisdictions, as they all draw hydrocarbons vertically from shallower formations (Figure 3-7).

Figure 3-7. Exploration well cost range for conventional jurisdictions



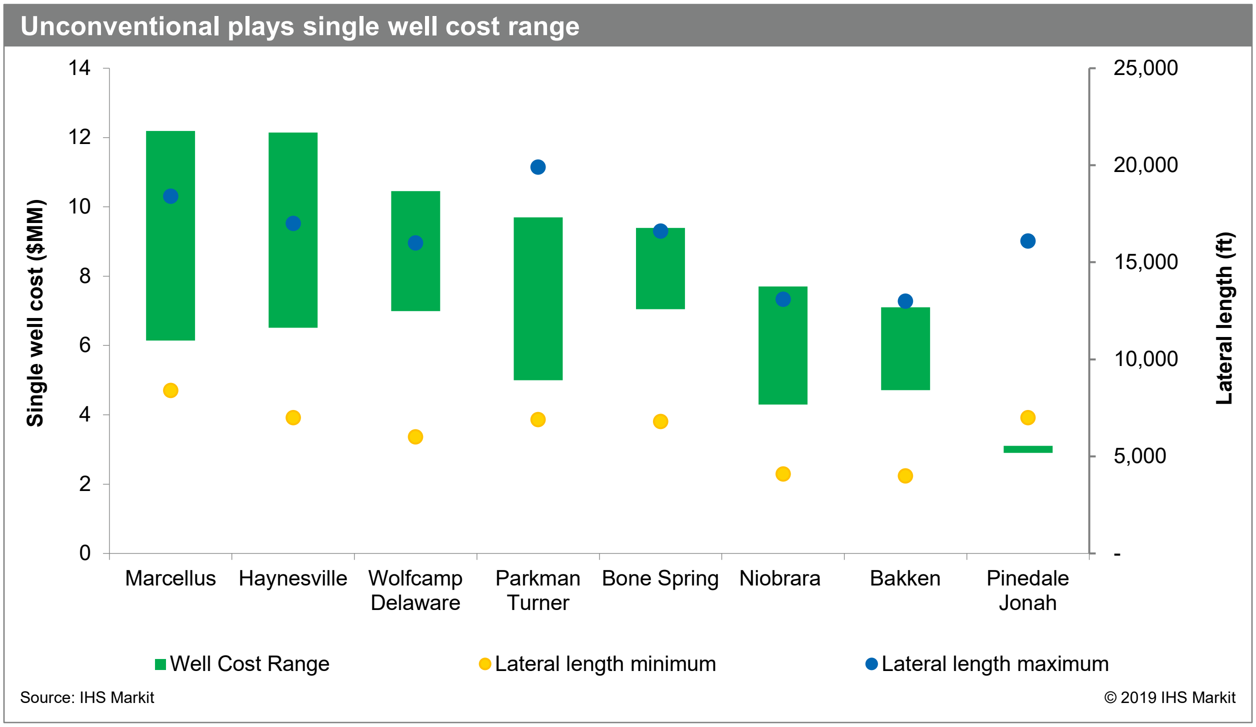
As explained in section 3.1, unconventional exploration is expected to occur in drilling multiple wells to delineate the targeted formations. Understanding a typical unconventional well cost range makes sense, as the pilot[50] usually ends up in the higher spectrum of the cost range.

Figure 3-8 describes the single-well cost ranges for typical wells in the unconventional jurisdictions selected for this study. This cost is viewed in parallel with ranges of lateral length completed for the same typical wells in the same jurisdictions.

The highest well cost is in the Marcellus play ($12 million), as the reservoirs holding the gas are deep and the lateral length ranges between 8,400 ft. and 10,000 ft. Pinedale Jonah has the lowest well cost ($3 million), as it is shallower and still mainly developed with vertical wells. Outside of Pinedale Jonah, the median well costs for our peer group jurisdictions vary between $5.8 million and $9.8 million. Key drivers of well costs are the vertical depth, the lateral length, and the fracking job intensity. The frack job intensity is characterized by the amount of pressurized proppant injected into the formation to frac the rocks, the amount of water, and the quantity of other additives involved. Fracturing costs vary widely, even within the same play, as they depend on the competencies and preferences of the operators, rather than the sole geology and the geochemistry of the rocks.

[50] A pilot well is a well testing production for an unconventional project. A pilot program usually counts multiple unconventional wells.

Figure 3-8. Range of single-well costs for the unconventional plays



4 Trends in Fiscal Terms since 2014

4.1 Changes in Fiscal Terms

The question of what constitutes a "fair return" for Federal oil and gas resources is often debated with the discourse centering on the issue of fairness. What share of the oil and gas development revenue is appropriate for companies to retain in exchange for its investments and the activities undertaken to develop the resources? What share of the revenue is appropriate for a government to retain for the public? And finally, how can a resource manager, like the BLM, use the fiscal terms at its disposal (like royalties, rentals, and other fees) to ensure that its resources are competitive with other jurisdictions.

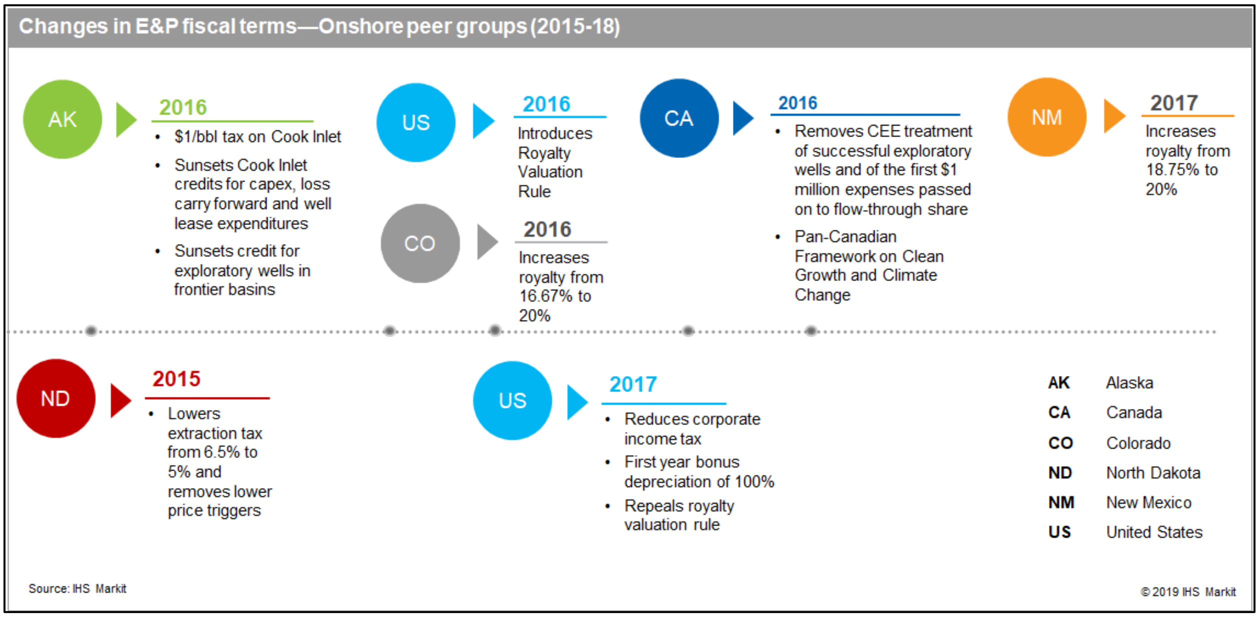
During periods when energy prices are high, and governments may question whether they are receiving a fair share of the revenue that oil and gas companies receive from operation on their lands. The study commissioned by the DOI, *2011 Comparative Assessment of the Federal Oil and Gas Fiscal System,*[51] observed the reactions of governments and industry engaged in a "race to the top" as commodity prices skyrocketed to $147/bbl in 2008. While current market conditions are dramatically different from those of the 2011 study, calls for state governments or the Federal government to review the oil and gas fiscal system periodically emerge. The ability of the fiscal system to strike a proper balance between the need for investments and the desire to generate a fair return to the public often also comes under scrutiny when commodity prices decline, and public finances are in distress. Short-term needs sometimes outweigh long-term goals of resource development.

Traditionally, state oil and gas fiscal systems in the United States have been fairly stable, in that many of them have not undergone significant changes for decades.[52] The budget shortfalls resulting from the drop in commodity prices during 2014–16 put a lot of pressure on legislatures of various oil-producing states to increase oil and gas taxes, fees, and/or royalties to make up for decreased revenue. Various initiatives were introduced at the state level in Alaska, Colorado, Montana, North Dakota, Ohio, New Mexico, West Virginia, etc., some of which were still being debated at the time of this report. Legislative proposals, on occasion, led to public discourse about the role of the oil and gas industry in the economy of various states and what the appropriate government take should be. For the most part, legislative initiatives to increase the government take in oil and gas-producing states were voted down, with very few changes actually passing through the legislative process. Figure 4-1 provides a snapshot of the key measures that took place in North America since 2014. In this report, IHS Markit examines these changes and the economic drivers behind each initiative, as well as industry reaction to such changes.

[51]Agalliu I, supra note 11.

[52] Louisiana severance tax for natural gas has not changed since 1990 when annual indexation was introduced. In Montana, the production tax has not been subject to change since its introduction in 1996. Wyoming severance tax for oil and gas was last modified in 1995.

Figure 4-1. Changes in E&P fiscal terms: Onshore peer groups (2015–18)

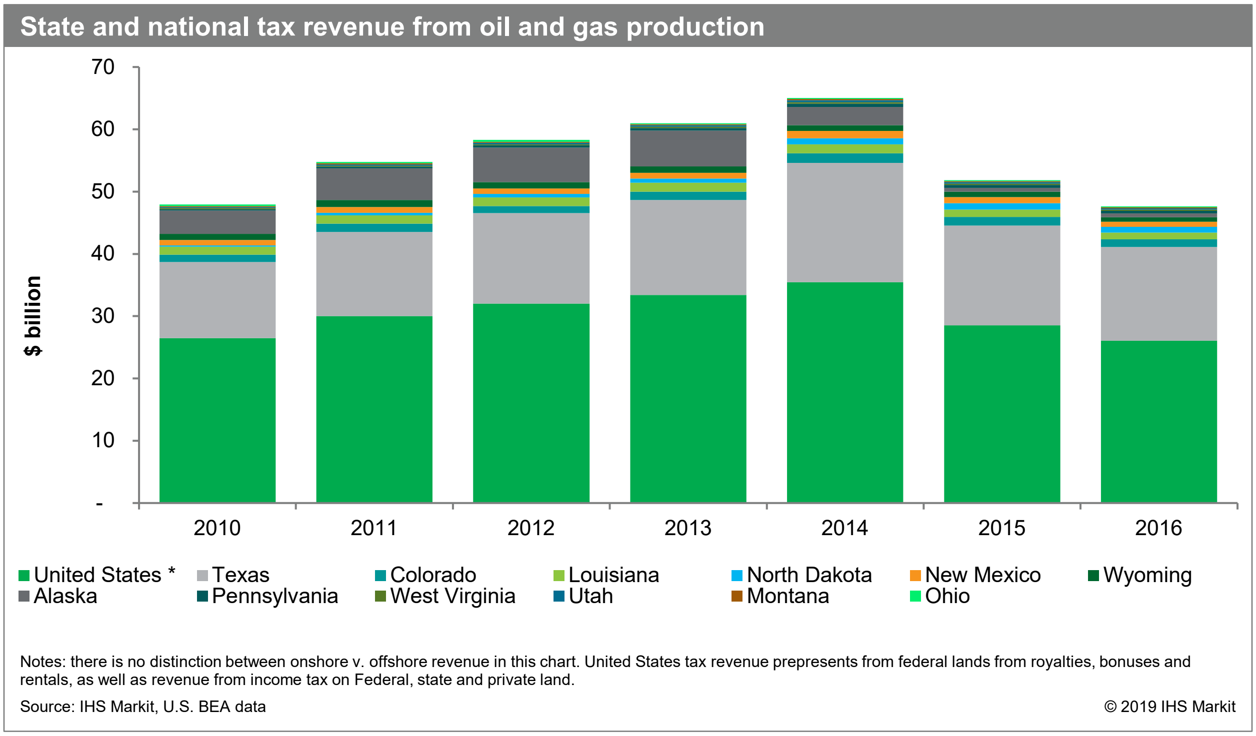


4.2 Key Policy Initiatives and Main Drivers Behind Each Policy

The main driver behind the recent calls to examine the way that states tax and administer revenue from oil and gas resources has been oil price volatility and the resulting fiscal pressures on oil and gas-producing states.[53] It is worth noting that up until 2013, the main beneficiaries of the oil boom among the jurisdictions included in this study were the Federal government, the state of Texas, and the state of Alaska. That, however, changed with the 2014 oil price collapse. While revenue from oil and gas production dropped for every state in this study, including the Federal government, the impact of the oil price collapse was not uniform among states. When looking at the aggregated oil and gas tax revenue at the state and Federal level, a loss of about $17.5 billion is observed in 2016 compared to 2014, representing a 27 percent decline in combined tax revenue (Figure 4-2). However, not all states suffered equally.

[53] Maciag M, "How energy states could better weather the boom-and-bust cycle," Governing the States and Localities, April 2016.

Figure 4-2. State and national tax revenue from oil and gas production

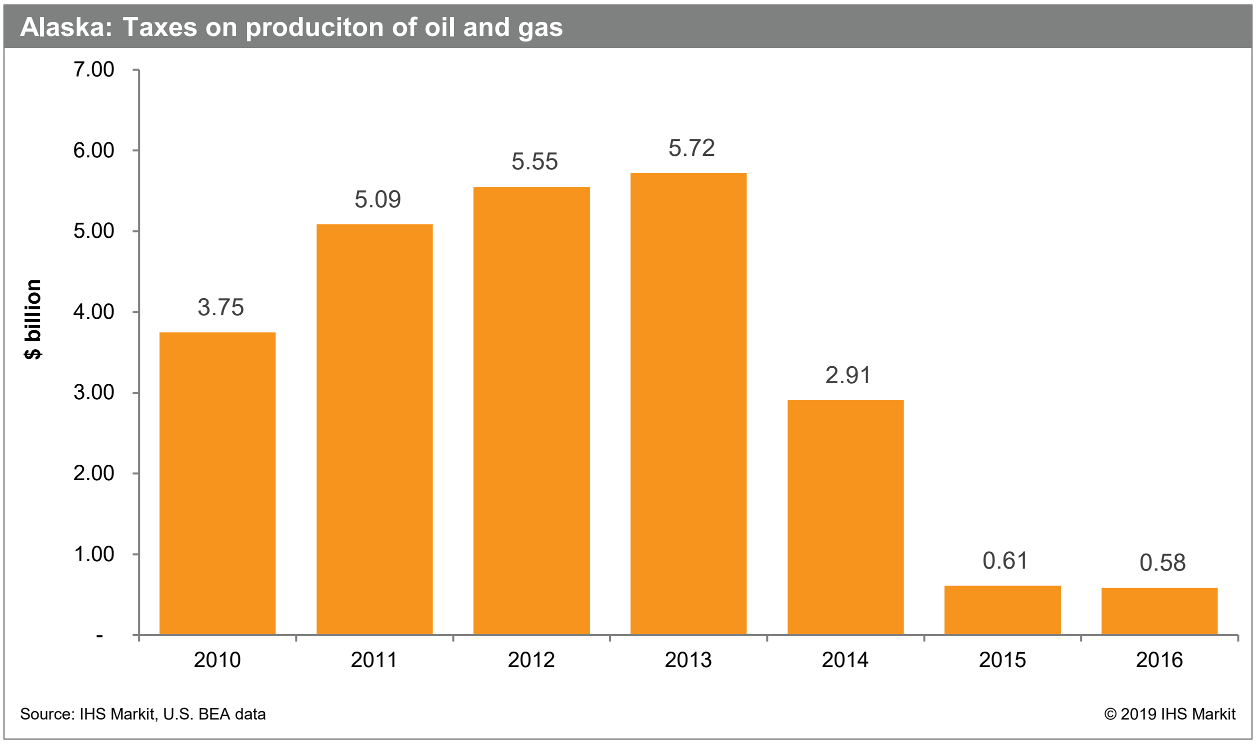


4.2.1 Alaska's Financial Distress—Feeling the Brunt of the Resource Curse

The state of Alaska was hit the hardest by this oil price cycle, which wiped out $5 billion in tax revenue in 2016 versus 2013, representing a 90 percent drop in tax revenue from oil and gas production in the state (Figure 4-3). The heavy reliance on revenues from the oil and gas sector made it harder for the state to cope with the downturn. In 2013, the tax revenue from the oil and gas industry accounted for 70 percent of tax collection on all industries in Alaska. That share had dropped to 19 percent by 2016.[54]

[54] Department of Commerce, Bureau of Economic Analysis, Regional Economic Accounts, 2017.

Figure 4-3. Alaska tax revenue from oil and gas production



The market downturn pushed Alaska into a three-year recession, the longest in the history of the state.[55] The Alaskan economy is estimated to have lost 12,000 jobs since 2015, with 5,000 of those in the oil and gas sector.[56] While other major oil and gas-producing states saw their oil and gas revenues decline as a result of the oil price collapse, none of them are as dependent on oil revenue to pay for government services as is Alaska. In the past, oil revenues have funded 90 percent of Alaska's unrestricted annual budget.[57] Other major producing states with more diversified economies either avoided recession altogether or came out of it relatively quickly. Table 4-1 shows oil and gas revenue as a percentage of GDP during the 2010–16 period.[58] The commodity price collapse has resulted in a lower share of the states' GDP from oil and gas production revenue. The latest data (from 2016) indicate that the oil and gas sector accounts for 0–8 percent of GDP in those states included in this study, with the highest dependence observed in Alaska, at 8 percent of GDP. In other major producing states such as Texas, Wyoming, and New Mexico, oil and gas revenues account for 4–5 percent of their GDP. This is a significant decline from 2014, when ite accounted for 10–11 percent in Texas and Wyoming and 18 percent in Alaska.

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[55] Brehmer E, "Economists say Alaska recession likely to end in 2019," *Anchorage Daily News*, January 2017.
[56] Ibid.
[57] Hobson M.K, "For nation's most oil dependent state, the bottom is deep," *E&E News*, November 2016.
[58] 2016 is the last year data was available by U.S. BEA.

Table 4-1. Oil revenue share of GDP of North American jurisdictions

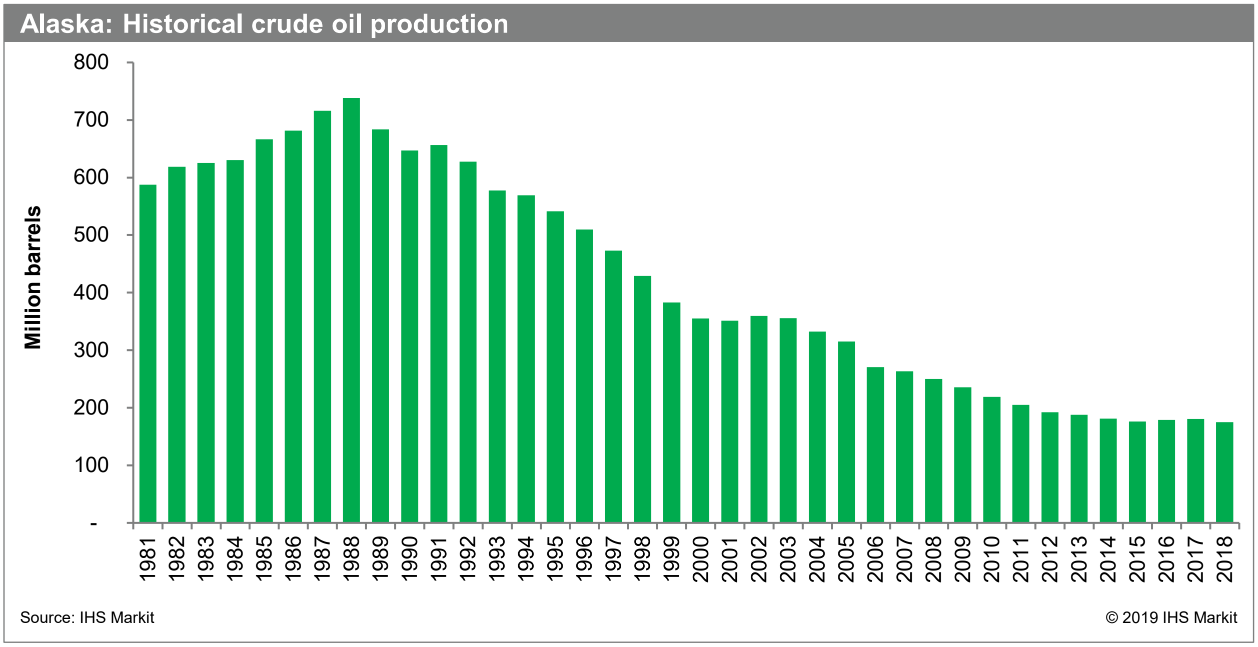
Jurisdiction	Oil and gas revenue as a percent of GDP (%)						
	2010	2011	2012	2013	2014	2015	2016
Alaska	23	25	25	22	18	9	8
Colorado	3	3	3	3	4	2	2
Louisiana	6	6	5	5	4	2	2
Montana	1	2	2	2	2	1	1
New Mexico	7	7	6	7	8	4	4
North Dakota	3	4	5	7	6	4	3
Ohio	0	0	0	0	1	1	1
Pennsylvania	0	1	1	1	2	1	1
Texas	8	9	9	10	10	5	5
Utah	1	1	1	1	1	0	0
West Virginia	1	1	2	3	5	3	3
Wyoming	15	13	9	10	11	6	5
U.S.	1	1	1	2	2	1	1

Source: IHS Markit, U.S. BEA data

Since 1976, Alaska has set money aside for future generations in a permanent fund, currently funded at about $52.8 billion. The state has, however, been unable to diversify its economy and is currently finding that its various pockets of savings are depleting fast.[59] Alaska's budgetary problems are compounded by the fact that oil production in the state peaked in 1988 and has been gradually declining ever since (Figure 4-4). While the resurgence of activity in the Permian Basin has helped states such as Texas and New Mexico to weather the storm, depressed commodity prices do not favor E&P activity in Alaska's arctic environment. There are expectations that, with price recovery, the oil and gas industry will resume activity in the state—however, the uncertainty associated with today's depressed and unstable commodity prices could tip the balance towards lower-cost developments in the Lower 48.

[59] Brooks J, "Alaska Senate votes to spend Permanent Fund to balance portion of state deficit," *Juneau Empire*, April 2018.

Figure 4-4. Alaska historical crude oil production



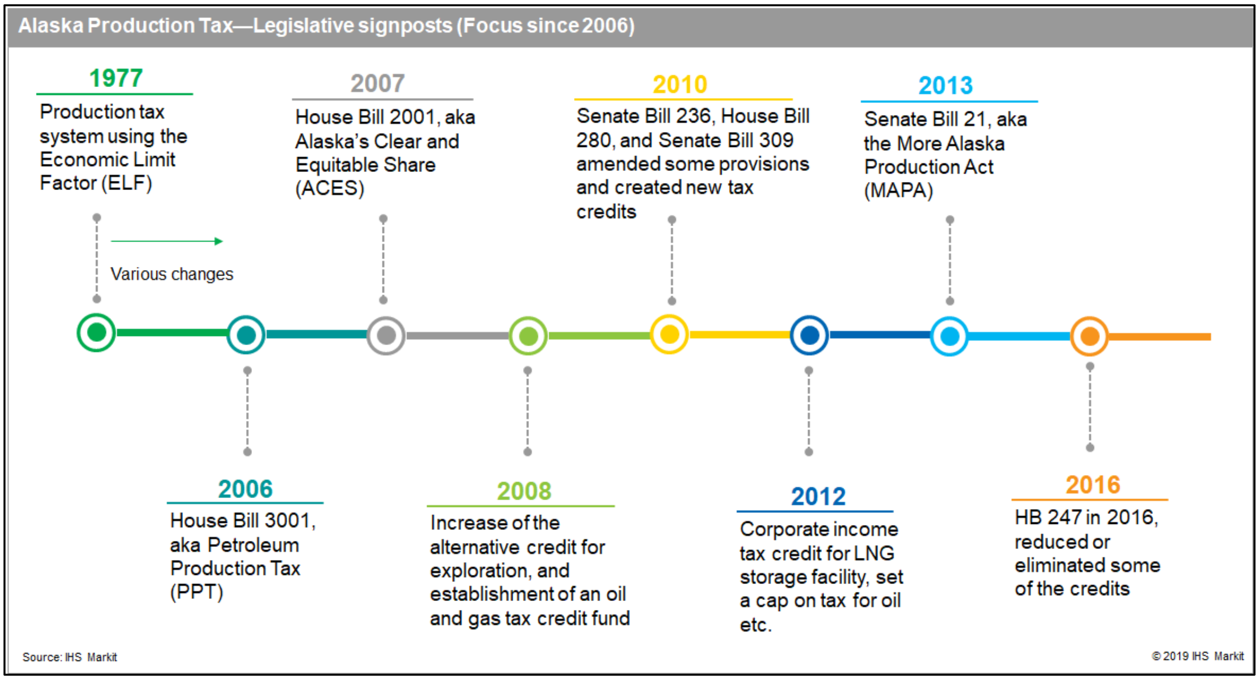
It is against this backdrop that the governor of Alaska and the state legislature took measures to phase out the credits applicable against petroleum production tax for exploration and appraisal wells in the U.S. Cook Inlet. HB 247 passed in the 29th Legislature's fourth special session in 2016 and became effective on January 1, 2017. Among the measures introduced by HB 247 the most notable ones include:

- Imposition of a $1 per barrel tax on Cook Inlet oil,
- The expiration of Cook Inlet credits for qualified capex, carried-forward annual loss, and well lease expenditures by December 31, 2017, and
- Expiration of the credit for exploration wells drilled in the Frontier Basin in 2017.

Alaska Production Tax History

Since 2006, Alaska's production tax has undergone a series of changes that have contributed to a perception of unstable fiscal regime. The changes introduced reflect the state government's challenge in balancing the objective of receiving a fair return for Alaskans and the need to attract oil and gas investments. The production tax that was first introduced in 1977 was levied as the greater of a percentage of the production value (12.25 percent for new leases) or a cents-per-barrel fee ($0.60), multiplied by an economic limit factor (ELF). In 2006, as oil prices were rising to unprecedented levels, the state of Alaska overhauled the oil and gas production tax by repealing ELF, introducing a net profit tax system on oil and gas production (22.5 percent), and providing various credits for certain qualifying expenditures. The tax also had a progressive component that applied when oil prices increased above $40/bbl. The new tax was called the Petroleum Production Tax (PPT) (Figure 4-5).

Figure 4-5. Alaska Production Tax—Legislative signposts (focus since 2006)



However, this measure was short lived. Less than four months after the PPT took effect the government embarked on a campaign to introduce another profits tax to capture a greater share of the revenue from high oil prices. The tax was called Alaska Clear and Equitable Share (ACES). Despite warnings of the unsustainability of these oil prices and the risks to investment through fiscal instability, the legislation was passed in November 2007 with very little opposition. ACES introduced a base rate of 25 percent that increased gradually by 0.4 percent for every dollar the production value exceeded $30/bbl. For production tax values greater than $92.50 per barrel, the progressivity rate changed to 0.1 percent for every additional dollar of production tax value.[60]

The oil and gas industry reacted to the introduction of the PPT and ACES: licensing activity in Alaska during 2007–09 period plummeted 74 percent versus 2006 levels. The decline in licensing activity, despite the rising oil prices until July 2008, is a clear indication that such decline was related to the changes to the oil and gas production tax.[61]

During 2008–12, various amendments were introduced to ACES, such as an increase of the exploration credit, establishment of an oil and gas tax credit fund, credits introduced for exploration wells using jack-up rigs in Cook Inlet, credit for well lease expenditures, corporate income tax credit for liquefied natural gas storage facility, etc. While state revenue undoubtedly increased under ACES, the decline in production continued. Indeed, ACES was perceived to disincentivize oil and gas investments in the state.

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[60] Agalliu I, supra note 11.
[61] Ibid.

In 2013, the oil and gas production tax undergoes yet another significant overhaul. A new tax known as the More Alaska Production Act (MAPA) increased the base of the tax from 25 percent to 35 percent, eliminated the progressive element that existed in ACES, and amended various incentives and credits associated with the tax. The measure was intended to "put in place a system for the taxation of oil and gas that is fair, stable, predictable, durable, balanced, and free from complexity across a wide range of oil prices."[62]

Impact of Changes Introduced in 2016

While the current oil and gas production tax in Alaska may be more predictable than ACES, the system is still very complex compared to the severance taxes used by the oil and gas-producing states in the Lower 48. As the latest oil crisis proved, the Alaska oil and gas production tax, which is no longer a production-based levy but rather a net revenue tax, is not a very reliable source of revenue for the government when commodity prices are low and profit margins are tight.

The 2016 removal of some of the incentives under Alaska's production tax has exacerbated the instability and undermined the reliability of the state's fiscal system and may have hurt small producers in Cook Inlet. However, the 2016 change is not the major contributor to the decline in drilling activity since 2014—the low oil price environment is the reason. Given the high per-unit cost, Alaskan projects are very sensitive to oil price changes. As prices have recovered somewhat from the low levels of 2015–16, some of the companies operating in Alaska have announced plans to go ahead with drilling. Nevertheless, E&P activity there remains challenged by the competition from the lower-cost and shorter-cycle sources of supply, such as tight oil plays in the Lower 48.

4.2.2 North Dakota—Reacting to Oil Prices

North Dakota, while no stranger to the oil and gas industry, was a relatively minor producer prior to the onset of the "unconventional revolution" in the United States. The rise of the Bakken as one of the major tight oil plays increased North Dakota's annual crude oil production more than seven-fold within a decade, leading the state to surpass Alaska as the second-largest producer of crude oil in the United States.[63] This rapid increase in crude oil and gas production was associated with an unprecedented boom. The state saw revenue from oil and gas production rise from $63 million in 2005 to over $1 billion in 2015 (Figure 4-6).

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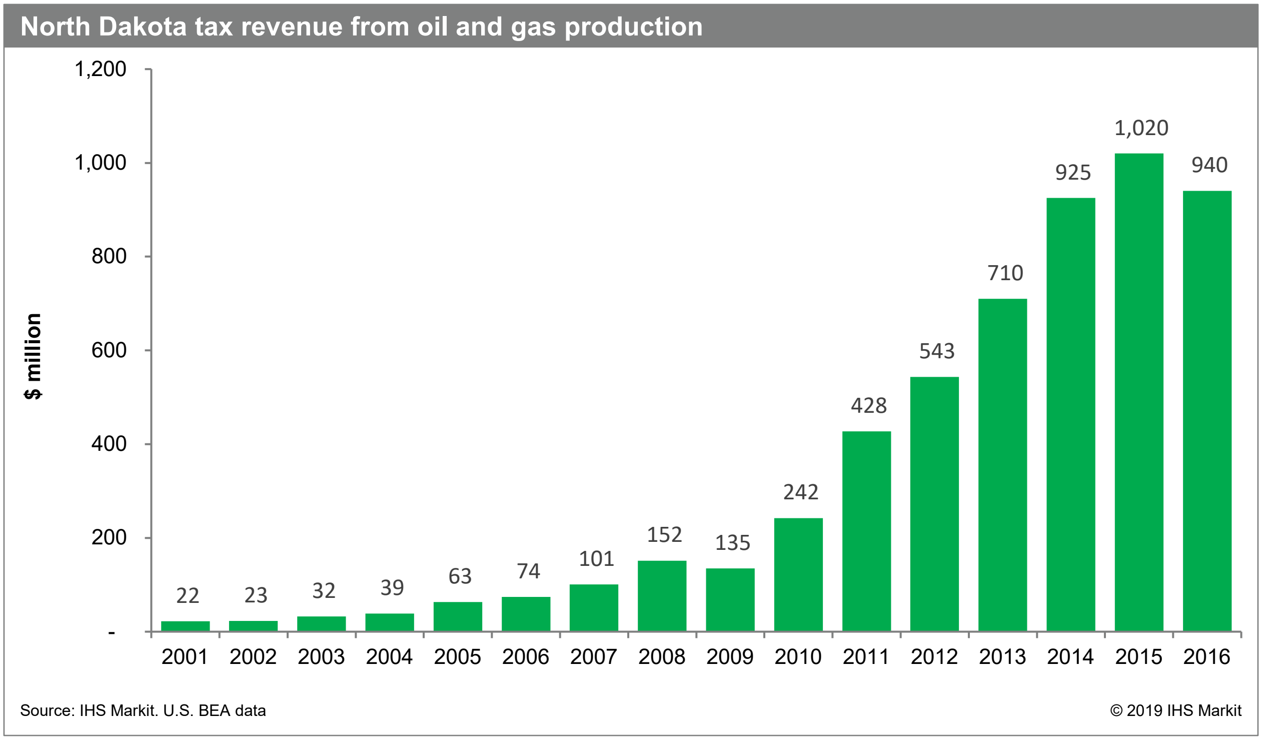
[62] *Alaska Senate Journal*, 28th leg., 1st sess. 441 (February 28, 2013).
[63] North Dakota's crude oil production rose from 62MMbbl in 2008 to 460MMbbl in 2018.

Figure 4-6. North Dakota state tax revenue from oil and gas production



When commodity prices dropped in 2014, North Dakota sought to protect its revenue stream, while ensuring investments there were competitive with those in other regions. North Dakota levies a production tax and an extraction tax in lieu of property taxes. At the time, the combined maximum rate was 11.5 percent (i.e., 5 percent production tax and 6.5 percent extraction tax). The 11.5 percent rate was not always guaranteed. The extraction tax had built-in price thresholds that would lower the tax rate when commodity prices were low. Concerned about the impact of dramatically lower commodity prices on state revenue and investments in the Bakken, the legislature passed HB 1476 in 2015, which lowered the extraction tax from 6.5 percent to 5.0 percent and eliminated the low oil price thresholds. However, the bill also introduced a new price trigger that would return the extraction tax rate to 6.5 percent when crude oil prices were $90/bbl or higher.[64]

It was argued at the time that this measure was intended to provide stability and predictability for both industry and the state. According to Tax Commissioner Rauschenberger, the state would have lost $942 million in tax revenue from January 2016 to January 2019 had the measure not been passed into law. The commissioner argues that the industry would have paid an average 6 percent tax rate during most of the period, versus the 10 percent flat under the 2015 tax measure.[65] It is possible that the measure did in fact protect state revenue in the face of declining production and drilling activity—state revenue from oil and

[64] While the combined extraction and production tax in North Dakota is higher than severance and property taxes combined in most states, North Dakota's taxes are lower than Louisiana's severance tax of 13 percent and about the same as Montana when severance and property taxes are combined.
[65] Dalrymple A, "Bills seek to restore North Dakota oil extraction tax to 6.5 percent," *Bismarck Tribune*, January 2019.

gas production was 8 percent lower in 2016 compared to 2015, despite a 12 percent production decline in the same period.

At the time the measure was introduced, the Bakken along with the other unconventional plays were experiencing a significant decline in drilling activity (Chapter 3). The number of wells spudded in the Bakken hit bottom at 462 in 2016, versus 1,263 in 2015 and 2,591 in 2014. Since then, drilling activity has recovered, reaching 1,155 wells spudded in 2018. There is no indication that the tax measure had any impact on E&P activity in the state. The decline and subsequent recovery in drilling activity mirrors the oil price movement.

4.2.3 U.S. Federal Government—Mixed Approaches

The actions taken by the Federal government during the period in review are more a reflection of different policy directions resulting in a change in administration rather than conditioned by the changes in the oil and gas markets. While natural gas production of the Federal mineral estate has seen a slight decline, the production of crude oil has increased 127 percent in the last decade (Figures 4-7 and 4-8). While the drop of commodity prices in 2014 may have affected the revenue accruing to the Federal government, it did not deter production on the Federal mineral estate. In fact, the Federal government has incurred a 44 percent increase in crude oil production since 2014, which is similar to the rate of production increase observed in the state of Texas during the same period. More than half of the 2014–18 production increase occurred in 2018. This could be attributed, in part, to recent initiatives taken by the Federal government to streamline and expedite processing of applications for permit to drill. While price recovery may have had a role to play, such a significant jump in oil production from the Federal mineral estate was not observed during the 2010–12 price recovery that followed the 2008–09 drop in commodity prices.

Figure 4-7. Oil production on Federal mineral estate onshore

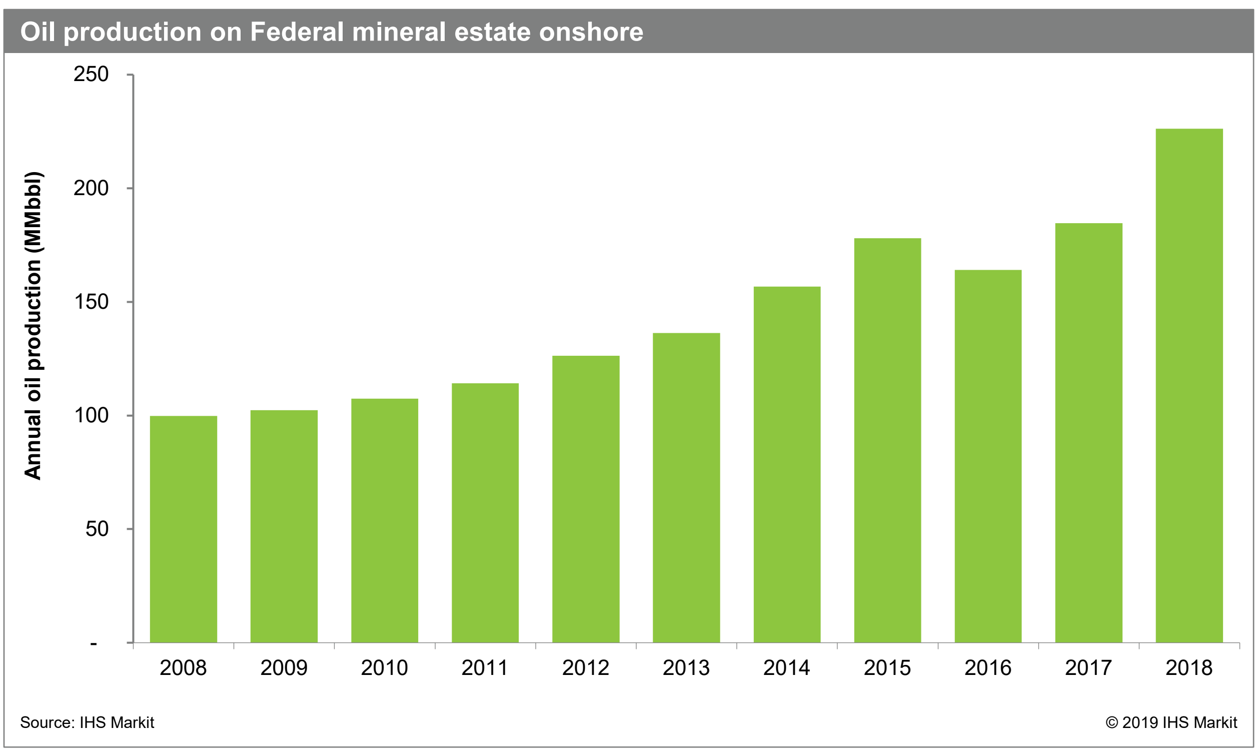
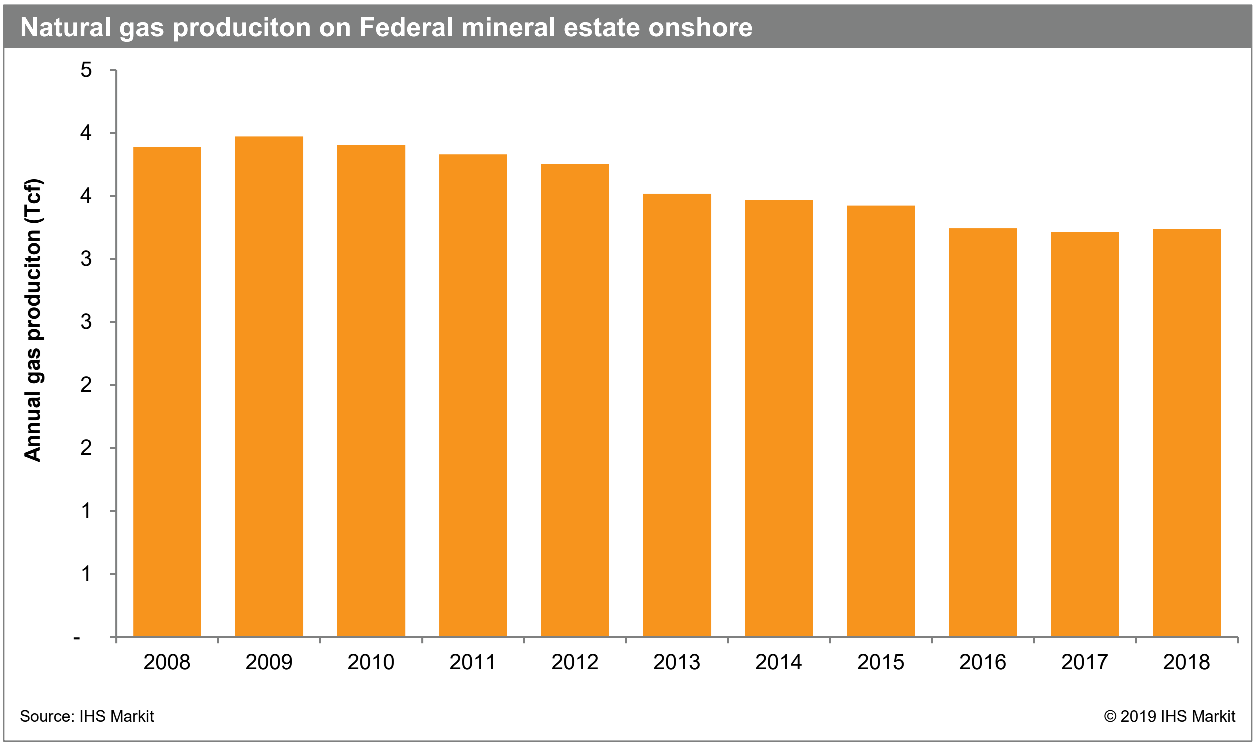


Figure 4-8. Natural gas production on Federal mineral estate onshore



The following key legislative and administrative measures have affected the onshore Federal fiscal system since the market downturn in 2014.

Changes to royalty valuation rule: In August 2017, the DOI repealed a royalty valuation rule issued by the previous administration in 2016. The 2016 rule sought, among other things, to reform the approach to valuation of oil and gas royalty by eliminating transportation and processing allowances. The rule faced opposition and litigation challenges prior to its effective date of January 1, 2017. The DOI repealed the rule on the following grounds:

- The rule had "a number of defects that make certain provisions challenging to comply with, implement, or enforce." Such defects would, among other things, compromise the Office of Natural Resources Revenue's (ONRR) mission to collect and account for royalties and would "impose a costly and unnecessary burden on the Federal and Indian lessees."
- The rule would "unnecessarily burden the development of Federal oil and gas…beyond the degree necessary to protect the public interest or otherwise comply with the law."

Reduction of the corporate income tax: The most significant recent change that has affected U.S. oil and gas producers was the passage of the Tax Cuts and Jobs Act in December 2017. This Act (Section 13001) changes the corporate income tax rate in the U.S. from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-year bonus depreciation: The Tax Cuts and Jobs Act increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified properties that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent.

The Tax Cuts and Jobs Act provides for a five-year phase down of the 100 percent depreciation starting on January 1, 2023.

Elimination of loss carry back: The Tax Cuts and Jobs Act also amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years. Section 13302 of the Tax Cuts and Jobs Act amended the statute to allow a deduction for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carry backs to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 U.S.C. Section 172. Such loss can be carried forward indefinitely, but there is no longer a carry back option.

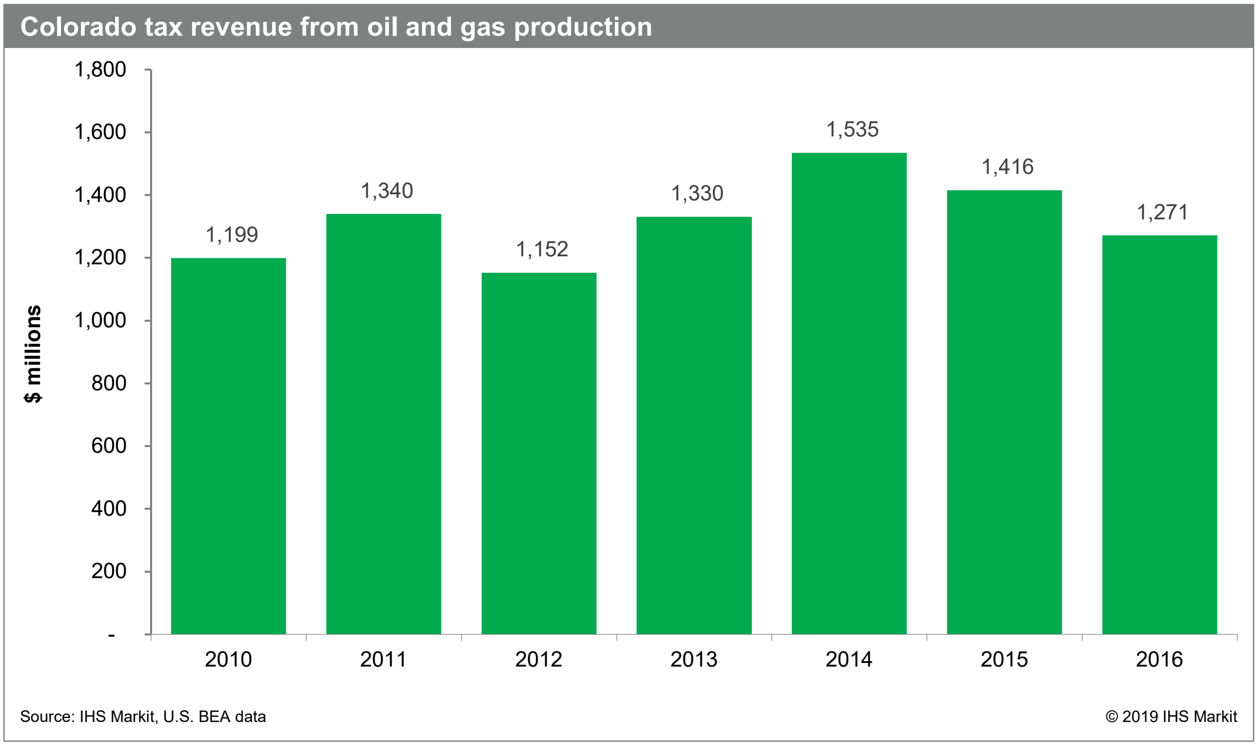
4.2.4 Canada—New Government Keeps Election Promise

The changes to the Canadian Exploration Expenditure (CEE) that were introduced in the 2017 budget make good on a promise made by the current administration during the 2015 election platform. Prior to the 2017 Federal budget, expenses related to the drilling and completion of a discovery well were classified as CEE and were written off (100 percent deduction) in the year incurred. The 2017 Federal budget reclassifies such expenditure as Canadian Development Expense (CDE), which are capitalized and deducted at 30 percent per year on a declining-balance basis. Only the expenses related to the drilling of dry holes can be classified as CEE and be eligible for 100 percent deduction.

4.2.5 Colorado and New Mexico—Catching Up with Other States

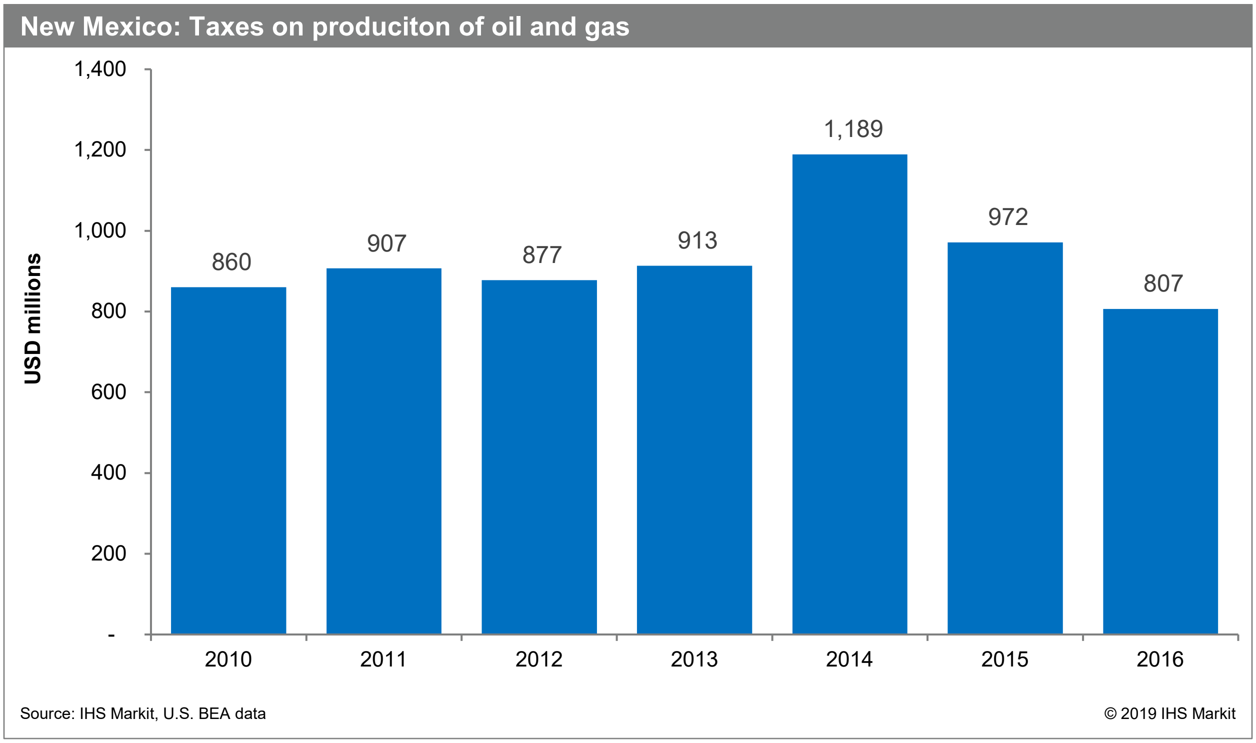
In February 2016, Colorado increased royalties applicable on state land from 16.67 percent to 20 percent. The move, which went largely unnoticed, could have been introduced in an effort to catch up with royalty rates imposed by other states. It is difficult to categorize the change as driven by financial challenges. A look at oil and gas production revenue shows Colorado was less affected by the downturn than other major producing oil and gas states (Figure 4-8). Yet, the measure went through without any reporting. Given the contractual nature of royalties in the United States, i.e., royalty rates are established in the oil and gas lease, such measures are less likely to draw attention. Royalty rate increases often are administrative measures and do not require the involvement of the legislature.

Figure 4-9. Colorado tax revenue from oil and gas production



Similar steps were taken in March 2017 by New Mexico, which resulted in an increase of the royalty rate for high potential areas such as the Permian Basin from 18.75 percent to 20 percent. This measure too was not publicized, largely due to the administrative nature of the measure. The royalty rate increase was included in the lease sale notices that were issued since March 2017. Like Colorado, this measure appears to be motivated more by a desire to receive a greater share of the revenue for the state, rather than as a response to the drop in oil and gas revenue resulting from the downturn in commodity prices in 2014. Like all oil and gas-producing states, New Mexico was affected by the 2014 crash of commodity prices, which resulted in about a $300-million drop in oil and gas tax revenue in 2016 compared to 2014 (Figure 4-10). If the royalty increase was driven by financial constraints, an increase in oil and gas severance taxes would have been able to generate more revenue since it affects the Federal and the private mineral estates, in addition to the state mineral estate, and hence a larger portion of the oil and gas investments in the state.

Figure 4-10. New Mexico tax revenue from oil and gas production



In 2019, the New Mexico legislature attempted to increase the royalty rate cap to 25% to match that of the state of Texas. The initiative, however, failed to receive approval within the House Commerce and Economic Development Committee.[66]

4.3 Industry Response

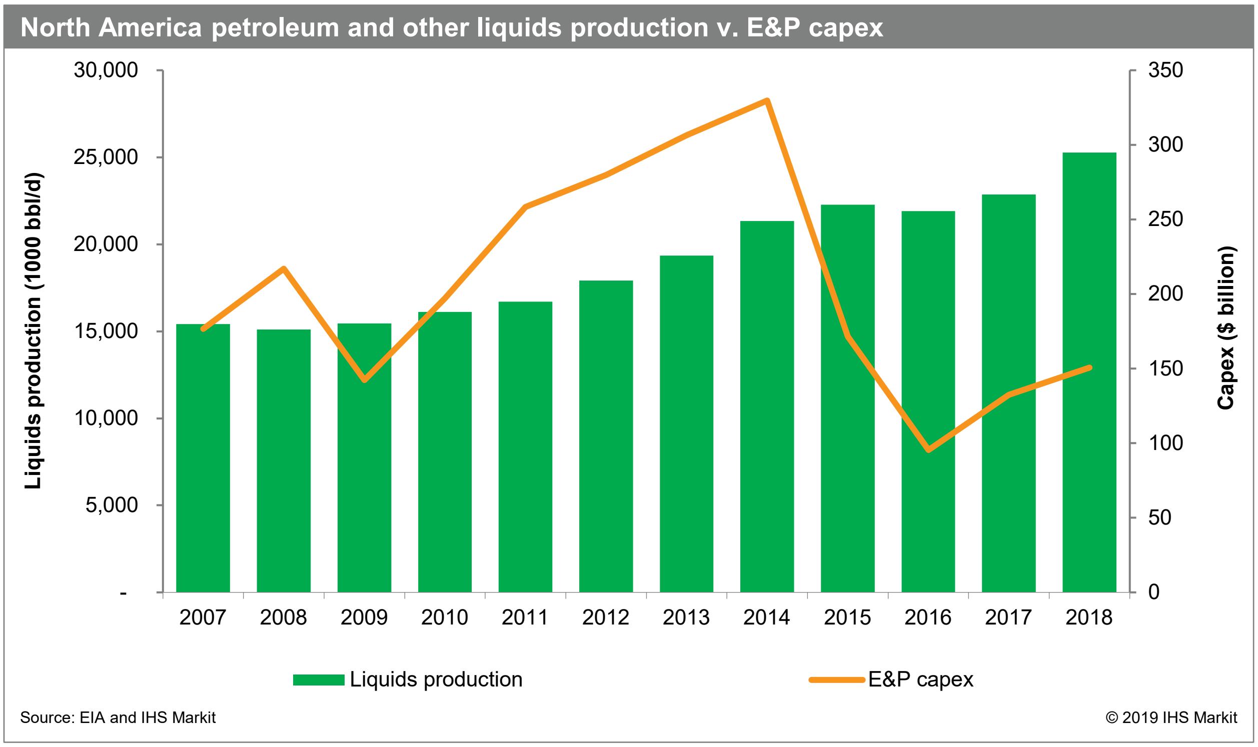
The "unconventional revolution" that brought about an abundance of oil and gas supply and transformed completely the market landscape in the United States is largely responsible for the commodity price collapse in 2014. While crude oil prices were in the $90–100/bbl range, companies were testing the productive potential and limits of plays across the country, thus fueling the "unconventional revolution" by maintaining activity in smaller plays with less favorable economics.[67] The oil price collapse of 2014 pushed operators to the highest productivity and most economical acreage as they fought for survival. During the price drop, typical U.S. unconventional companies lost more than 40 percent of their share price and more than 100 went bankrupt.[68]

The price downturn forced spending discipline and focus on the major liquids plays in the Eagle Ford, the Bakken, and the shales of the Permian Basin. North American onshore drilling and well services capex decreased 54 percent from 2014 to 2018, as E&P operators focused on controlling spending in line with

[66] Mckay D. "Proposal to boost oil, gas royalty rates is tabled" Albuquerque Journal, February 15, 2019.
[67] Olmstead R, "Where is fiscal discipline taking us? Finding the limits of U.S. supply," IHS Markit, September 2018.
[68] Ibid.

declining oil prices.[69] Liquid production, on the other hand, grew 18 percent in the same period, according to EIA data (Figure 4-11).[70] The United States now imports 12 percent of its total oil, compared with 60 percent a little more than a decade ago. The natural gas trade balance also shifted markedly: imports accounted for about one-sixth of domestic consumption a decade ago, but the United States is now a net gas exporter and headed to be a much larger one. The United States is poised to become one of the world's biggest exporters of liquefied natural gas and a net petroleum exporter by the early 2020s.[71]

Figure 4-11. North America petroleum and other liquids production vs. E&P capex



At the state level, IHS Markit observes operators moving into the most highly productive and most economical plays. As a result, Texas, North Dakota, New Mexico, Colorado, and to a lesser extent Wyoming are among the states that have seen increased oil production despite challenges presented by depressed commodity prices (Figure 4-12).

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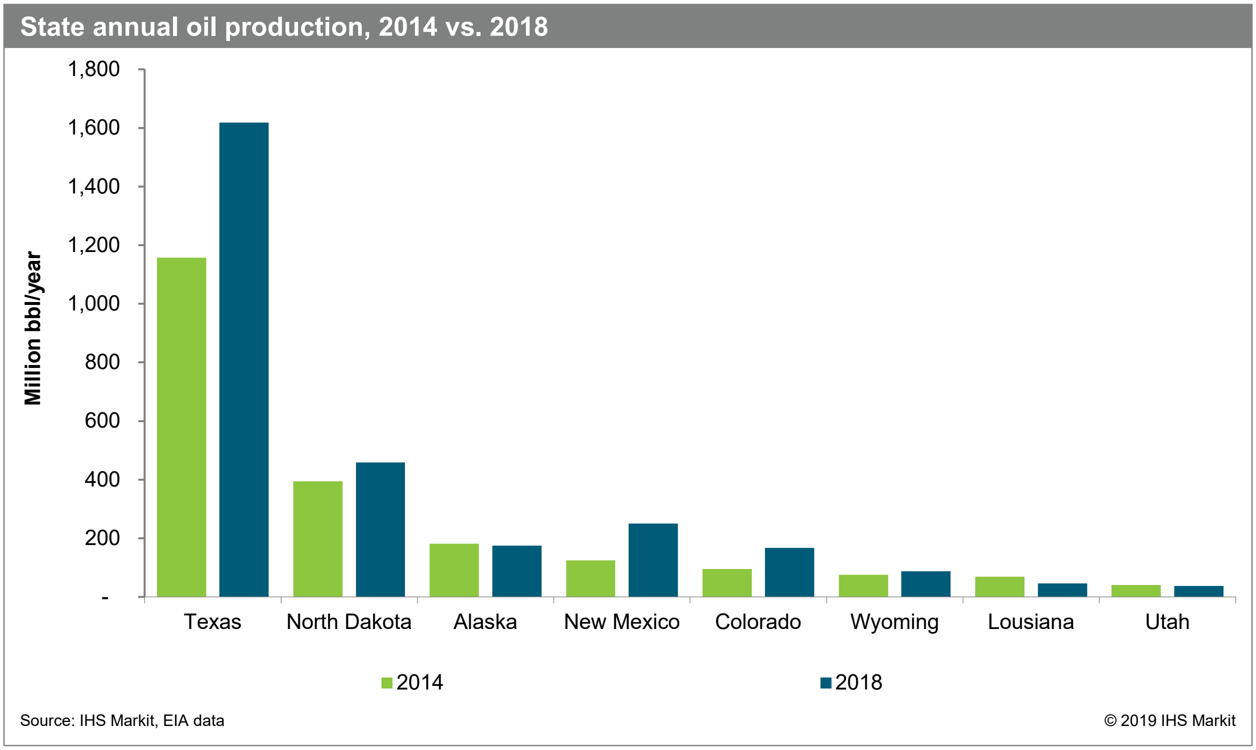
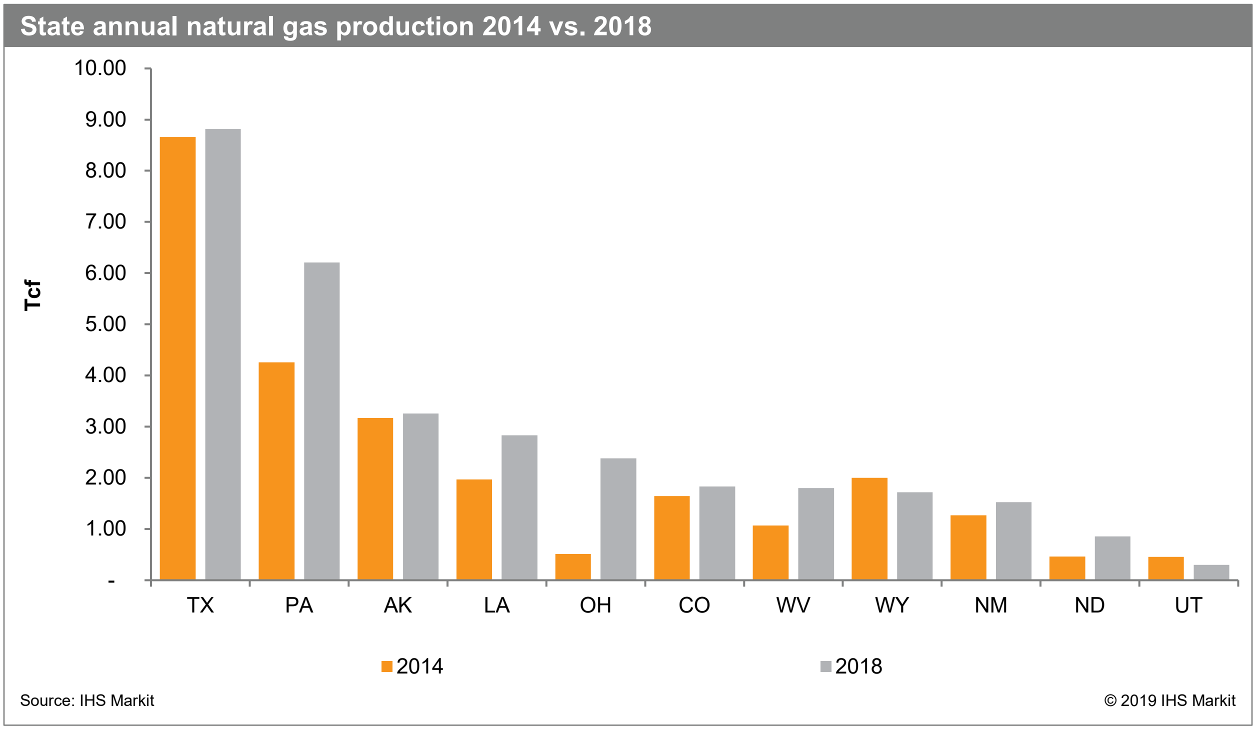
[69] Patel P, Moore S, and Ashcroft K, "Upstream Costs Service—First Quarter Update," IHS Markit, May 2019.
[70] EIA, International Energy Statistics, 2019.
[71] IHS Markit outlook.

Figure 4-12. State annual oil production, 2014 vs. 2018



Among the states in this peer group, Pennsylvania, Louisiana, Ohio, West Virginia, and New Mexico are the ones with more marked increases in their natural gas production levels in 2018 versus 2014 (Figure 4-13).

Figure 4-13. State annual natural gas production, 2014 vs. 2018



Overall drilling activity in the Lower 48 during the downturn has focused on identification of major liquid plays. Going forward, U.S. production is becoming more dependent on one play. The Permian basin, with its tens of thousands of remaining drilling locations, large inventory of drilled-but-uncompleted wells, and strong economics will dominate the E&P growth in the United States through 2020. There are about 105,000 drilling locations in the Permian Basin, with 22,000 having been drilled to date.[72] It will be difficult for other plays to grow beyond the mid-2020s because of sweet-spot exhaustion.[73]

[72] The drilling location assessment assumes 4 wells per section in the Delaware basin and 5 wells per section in the Midland and Central Basin Platform of the Permian.
[73] Olmstead R, supra note 67.

5 Comparison and Ranking of the Federal Fiscal System

This study compares the oil and gas fiscal systems by relying on measures used by investors to assess global investment opportunities and make investment decisions, such as IRR and NPV/boe, as well as EMV. The study also uses the government take as a measure often relied upon by governments to assess their relative take with that of other jurisdictions. To assess the competitiveness of prospective investments in the respective jurisdictions under a wide range of commodity prices, the study examines the results of the above metrics under three different oil and gas price scenarios: base case, high case, and low case. For more information on price assumptions and selection of models, see Chapter 1. All metrics, prices, and costs are modeled in real terms using 2018 U.S. dollars.

IHS Markit models assume a 10% real discount rate, reflecting a high-level consensus on minimum project return expectations for oil and gas operators. This hurdle rate can be dissected into the weighted average cost of capital (WACC) of these operators plus a discretionary premium. The WACC is the sum of the operator's cost of equity and cost of debt. Both the cost of equity and cost of debt depend on inflation, as their calculations imply the use of a risk-free rate that is derived from inflation. An inflation rate of 2 percent is generally assumed.

The study relies on a total of 155 economic models representing 9 economic models for the Alaska peer group consisting of 3 fiscal systems, 102 conventional oil and gas field models for the Lower 48 representing 17 fiscal systems, and 44 economic models for unconventional resources representing 22 fiscal systems. This results in a total of 465 cases being analyzed when all three price scenarios are applied. The costs and production are customized for each jurisdiction, but are uniform across the fiscal systems within the same jurisdiction (Table 5-1). Regarding fiscal terms, taxes vary by jurisdiction while royalty rates and bonus amounts differ by fiscal system within the same jurisdiction. The development timeline for both conventional and unconventional resources accounts for differences in time to first drill in each fiscal system (mineral estate).

Table 5-1. Variance of costs and economic models at the jurisdiction and fiscal system level

Category level	Exploration & development cost models			Economic model		
	By field or subplay[74]					
	Costs	Production	Time to first drill	Taxes[75]	Royalty rate	Bonus amounts
Jurisdiction	X	X		X		
Fiscal system			X		X	X
Note: Jurisdiction refers to state or territory. Fiscal system refers to Federal, state, or private mineral estate for the Lower 48. For the Alaska peer group, fiscal system refers to Federal, state, or territorial mineral estate.						

Source: IHS Markit

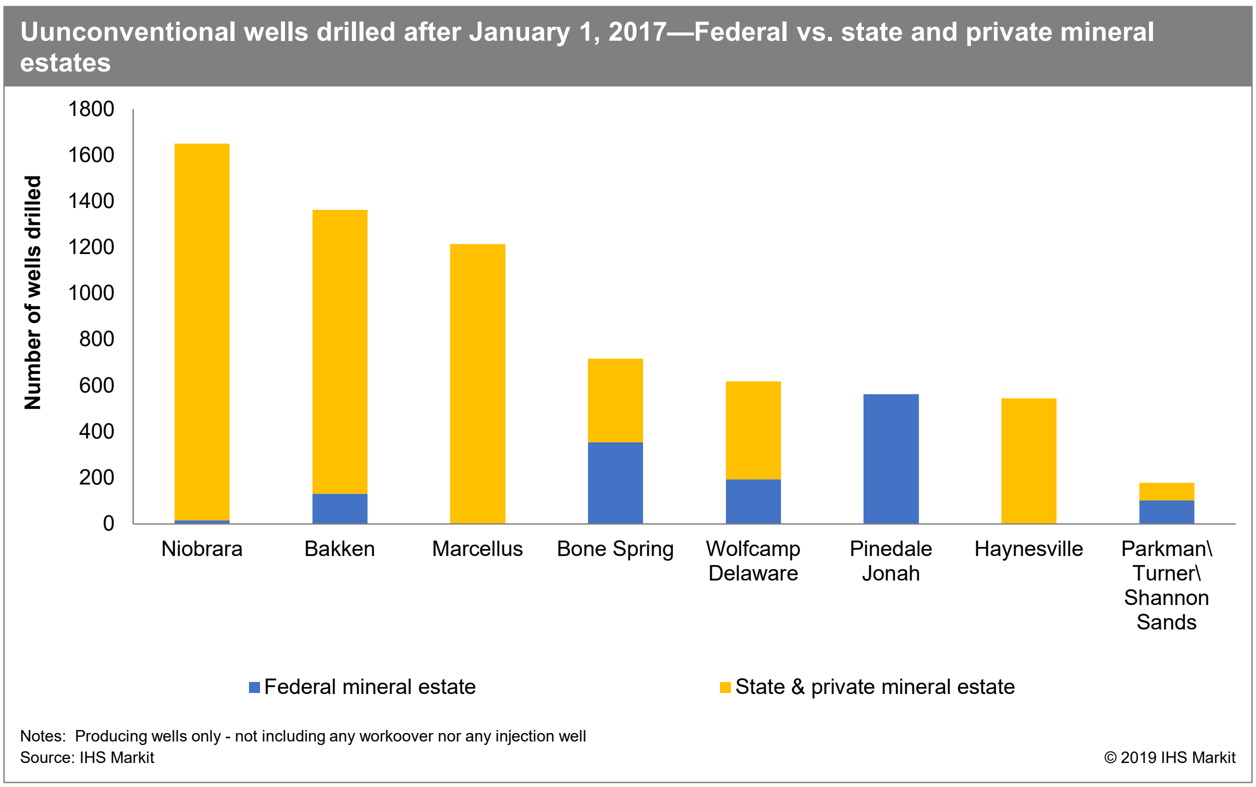
In order to capture recent trends in drilling and completion costs and well performance, the wells drilled between 2017 and 2018 were considered for each unconventional subplay. Type curves at the subplay level were developed for wells in the top three quintiles in terms of expected ultimate recovery (EUR) per well. Based on the number of wells drilled and the distribution of wells between the Federal and the state and private mineral estates in each play, a decision was made to adopt uniform type curves at the subplay level—i.e., no distinction between Federal, state or private mineral estate. Only three plays were considered to have a sufficient number of wells drilled during the 2017–18 period in the separate mineral estates to justify

[74] The cost and production profiles vary by field size for conventional and by subplay for unconventional resources.

[75] Taxes include income, severance, and ad valorem.

development of two separate-type curves distinguishing between the Federal and the state and private mineral estates: the Bakken, Bone Spring, and Wolfcamp Delaware (Figure 5-1). No distinction is made in this study between the state and private mineral estates regarding type curves. Given that Parkman/Turner/Shannon Sands consists of three subplays, and that the relatively low number of wells drilled in the play during 2017–18 compared to other jurisdictions—149 wells, versus 545–1,651 wells in other plays—a decision was made not to distinguish between the Federal and the state and private mineral estates since there were no sufficient data points to establish with confidence six different type curves. The Federal–state/private split of the wells drilled in Niobrara, Haynesville, Marcellus, and Pinedale Jonah during the 2017–18 period is dominant in one mineral estate versus the others, so that it does not warrant development of separate type curves for this study (Figure 5-1). The analysis in this chapter focuses on the economic results generated from uniform type curves at the subplay level. The analysis of the distinct Federal mineral estate type curves generated for the Bakken, Bone Spring, and Wolfcamp Delaware plays is incorporated in Chapter 6, together with the analysis of alternative fiscal systems.

Figure 5-1. Unconventional wells drilled after January 1, 2017—Federal vs. state and private mineral estates



There is a wide variance regarding bonus amounts in all jurisdictions. Reporting of bonuses often does not distinguish between conventional and unconventional resources. IHS Markit estimated the average bonus per acre for each resource based on the ratio of conventional versus unconventional activity in each state and the location of the areas with high bonus payments on a per-acre basis.

The time to first drill is driven by factors other than the application for permit to drill (APD) approval process. Quite often operators wait for months or even a year from the time the APD is approved until they execute the option to drill. In fact, the APDs in most states are valid for at least a couple of years. Such behavior is influenced by a number of factors, such as commodity prices at the time the APD is approved, other competing opportunities to invest, rig availability, ongoing efforts to consolidate acreage for a robust development program, etc. For the purpose of this study, investor behavior is not factored into the stand-alone field models. Instead, the models take into account the approval timelines for APDs on state and private mineral estates versus the Federal mineral estate. Thus, an assumption of 1–2 months is used for state and private mineral estates in the respective jurisdictions, versus 10 months for the Federal mineral estate. While the BLM has recently taken steps to shorten the APD processing timelines, the study assumes a 10-month delay, the maximum observed over a 10-year period.[76] The APD timelines varied by BLM regional office and the level of activity in the region. According to the Wyoming Oil and Gas Conservation Commission, APD approval on Federal mineral estate in the state ranged between six months to two years.[77] The 10-month delay assumed for this study is intended to measure the maximum impact the APD approval process could have on project economics in the Lower 48, based on reported averages published by BLM.

5.1 Economic Metrics

Internal rate of return (IRR): Investor IRR expresses the discount rate that would generate an NPV of zero when applied to the investor's net cash flow after all levies and taxes. The investor IRR is the rate at which the sum of the project's discounted cash outflows equals the sum of its discounted inflows. Companies usually set internal IRR target rates, or thresholds, for investment decisions. Projects with an IRR lower than the target rate, or threshold rate, are not typically pursued. IRR thresholds are unique to each company and tend to be greater for higher-risk exploration versus lower-risk development projects.

The IRR, however, has some limitations and, as a result, is never referenced and utilized as the sole evaluation criterion.[78] One of the main limitations is its inability to help evaluate incremental investments. It assumes reinvestment of interim cash flows in projects with equal rates of return. When a project's interim cash flows are reinvested at a rate lower than the calculated IRR, the IRR approach overstates the annual equivalent rate of return. Another issue with the IRR indicator is that a single project can have more than one rate of return when cash flow switches from positive to negative and turns positive again. While the IRR is easy to understand as a metric, it could lead one to believe that a smaller project with a shorter lifecycle is preferable to a larger project that will eventually generate more revenue. To avoid this downfall, oil and gas companies use various economic indicators (including those described in this section) to compare and evaluate opportunities.

Net present value per barrel of oil equivalent (NPV/boe): NPV/boe shows the amount of value in today's terms that each boe of entitlement production will generate for the operator on a full-cycle basis, including dry holes, appraisal, development, and abandonment.[79] The NPV/boe enables comparisons between different projects across a larger spectrum of investments. One main limitation of the NPV/boe is that it does not allow one to understand the initial size of the investment or its embedded risk. An NPV of $5/boe could be generated by either a project requiring billions of dollars of investment or a smaller project

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[76] In 2011, the APD processing timeline averaged at 10 months, while the 2017 average was 9 months. Efforts are being made to bring the BLM APD permitting timeline closer to the state process. In 2017, permits that used the new version 2 of the Automated Fluid Minerals Support System (AFMSS) only required 122 days (approximately 4 months).

[77] WOGCC, Watson M, Oil and Gas Supervisor, Mineral Development and State Primacy, Joint Minerals and Economic Development Interim Committee, June 30, 2017.

[78] Mian M.A, *Project economics and decision analysis, volume 1: deterministic models*, 2002.

[79] Entitlement production is all equity production to the operator net of royalty volumes for concession contracts. In PSCs, entitlement production is the sum of cost oil, cost gas, profit oil, and profit gas net to the operator.

requiring several hundreds of millions of dollars invested. Therefore, NPV analysis is often done in parallel with the EMV analysis.

The NPV is the difference between an operator's discounted cash inflows and its discounted cash outflows. For a project, NPV is calculated on a full-cycle basis and discounted back to the period of first expenditure on a midyear basis, which is 2019 in the IHS Markit models. [80] The NPV is also referred to as "present worth," as it looks at the present value of the project's economic streams. The calculation below is used to determine NPV:

$$\boldsymbol{NPV = \sum_{t=1}^{n} \frac{net\ cash\ flow\ at\ t}{(1 + discount\ rate)\hat{}t}}$$

Where t is the time period and n is the project life in years.

The discount rate used in the NPV calculation is often described as the "hurdle rate" or the "minimum acceptable rate of return." When making investment decisions, different companies use different discount rates, depending on their average cost of capital and the risk assessment inherent to the investment opportunity. Usually, an investment project will be approved if its NPV is positive. Any project or field with a negative NPV after taxes is considered sub-economic.

The NPV per boe is the ratio of the NPV, as defined in the equation above, divided by the total hydrocarbon production corresponding to the same period in barrels of oil equivalent.

$$\boldsymbol{NPV\ per\ boe = \frac{1}{P} \sum_{t=1}^{n} \frac{net\ cash\ flow\ at\ t}{(1 + discount\ rate)\hat{}t}}$$

Where P is the total hydrocarbon production over the same period expressed in barrels of oil equivalent.

In this study, IHS Markit uses a real 10 percent discount rate for all cases and all jurisdictions. The discount rate used for this study represents the cost of capital and does not account for political risk, or any other aboveground risks. The cost of capital varies among companies—smaller companies tend to have a greater than 10 percent cost of capital due to their financial capability and the riskier nature of projects they tend to pursue.[81] Comparative analysis studies of this nature use the same discount rate across all jurisdictions and all projects for the sake of consistency.[82] This approach is also consistent with the U.S. Securities and Exchange Commission (SEC). The SEC requires public companies to use a 10 percent discount for their filings, no matter where their investments are located.[83]

Expected monetary value (EMV): The EMV represents the weighted average of possible monetary streams multiplied by their respective probability of occurrence. This metric is used as a proxy for the investor decision to drill an exploration well since it attempts to include the risk involved in making an investment, while also providing a value in absolute terms.

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[80] All cash inflows and outflows are allocated to the middle of the year to approximate even spending and discounting throughout a year.
[81] "Alberta at a Crossroads," Royalty Review Advisory Panel Report, 2016.
[82] The same approach was used in comparative analysis conducted for the government of Alberta, Newfoundland and Labrador, Ireland, and others.
[83] See Campbell R.G, "Valuing oil and gas assets in the courtroom," presented at the American Institute of Business Law in conjunction with the Oklahoma Bar Review and the Conference on Consumer Finance Law, February 7-8, 2002.

The calculation below is used to determine EMV:

$$\boldsymbol{EMV\ project = P(success) * NPV(success) + \left(1 - P\ (success)\right) * NPV\ failure}$$

When making investment decisions, operators will select the projects with the highest EMV. The EMV adds another dimension to the NPV because it introduces the cost of failure events (dry holes), and therefore provides a fuller cash exposure than the simple NPV.

The main weakness of the EMV is that it addresses averages rather than ranges. Nonetheless, EMV is a very useful metric for decision makers. The EMV analysis is important for this study as it incorporates the probability of success based on exploration success rates achieved in their respective jurisdictions, thus giving a fuller appreciation of the prospectivity challenges associated with each jurisdiction.

Note that only Alaska onshore and Lower 48 conventional will have EMVs with an exploration program. The unconventional analysis will not have an EMV because there is no exploration program or probability of success.

Government take: This metric is often used by host governments when comparing their fiscal system against those of other nations. Government take is a general term used to describe the share of revenues that accrues to the government (or governments) over the life of an E&P project. The calculation of government take in this study includes the share of revenues accruing through royalties, taxes, and other fiscal and quasi-fiscal levies such as regulatory fees. Government take in this report is defined as the government's (or governments') percentage of pretax project net cash flow on an undiscounted basis. The calculation below is used to determine government take, which includes Federal, state, and private take:

$$\boldsymbol{Government\ take = 1 - \left(\frac{Investor\ Cash\ Flow}{Investor\ Gross\ Revenue - Investor\ OPEX - Investor\ CAPEX}\right) \times 100}$$

In addition to government take, this study also looks at discounted "share of the barrel," which shows how one barrel of oil is split between the government and investors in each jurisdiction. This analysis shows in percentage terms what portion of revenues are spent in discounted capital and operating costs, versus the discounted revenue accruing to the government and investor separately. Table 5-2 shows the advantages and disadvantages of each economic metric used for this study.

Table 5-2. Economic metrics advantages and limitations

Economic metric	Advantages	Disadvantages
IRR	Easy to calculate and use measure of profitability	• Does not account for the project size • Does not distinguish between a significant investment and a well workover that yields a high IRR • Does not work when cash flows are all positive or all negative • Does not work when cash flows have multiple inflection points (multiple incremental investments after the initial phase) • Assumes the cashflows are reinvested at the same rate as the IRR, which is often unrealistic

Economic metric	Advantages	Disadvantages
NPV/boe	• Normalized to enable project comparison on the same basis • Flexible enough to enable use of various discount rates in various time periods • NPVs are additive and suitable for the stochastic analysis deriving in EMV	• Does not reflect the size of the project • Does not reflect project risk
EMV	• Useful decision indicator for committing initial or incremental investment • Addresses risk via scenarios and sensitivities • Enables to understand outcome given a certain cost of failure	• Addresses averages rather than ranges
Government take	• Academics and consultants often use it to compare fiscal systems, in particular to compare changes resulting from a recent or proposed change in taxation	• Although the cash flow is generated on an annual basis, the government take statistic per se does not reveal the timing of revenue and the sharing of risk between the investor and the government • A high government take statistic does not always mean high revenues or realization of that particular statistic

5.2 Alaska Conventional Resources Comparative Analysis

For Alaska onshore, three jurisdictions are compared for conventional resources: Alaska Federal mineral estate, Alaska state mineral estate in the North Slope Basin, and the Yukon in Canada's Eagle Plain Basin. For each fiscal system, three field sizes are analyzed: 50MMBoe, 100 MMboe, and 200 MMboe. Gas is assumed to be reinjected or exported to Prudhoe Bay for power and injection, thus only oil fields are compared. Tie-back development is assumed, as the fields are not large enough for economic stand-alone projects.

5.2.1 Alaska Conventional Resources—IRR

In North America, companies usually apply a lower discount rate for onshore oil and gas development versus offshore. A 10 percent discount rate is generally acceptable onshore. That means most projects that meet a 10 percent IRR would go forward. The investor IRR for the Alaskan fiscal systems is above the 10 percent threshold for the high and base case scenarios except for the 50 MMboe field, where the Federal fiscal system falls short of the 10 percent IRR threshold. Overall, the Federal fiscal system outperforms both the state and the Yukon investments for similar size fields (Table 5-3).

Table 5-3. IRR: Alaska conventional onshore peer group across field sizes and prices

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	200	100	50	200	100	50	200	100	50
Alaska State	39	30	19	26	17	7	8	0	0
Alaska Federal	40	31	20	28	19	9	10	1	0
Yukon	28	21	14	18	12	4	7	2	0

Source: IHS Markit

IRR: Box and whisker chart

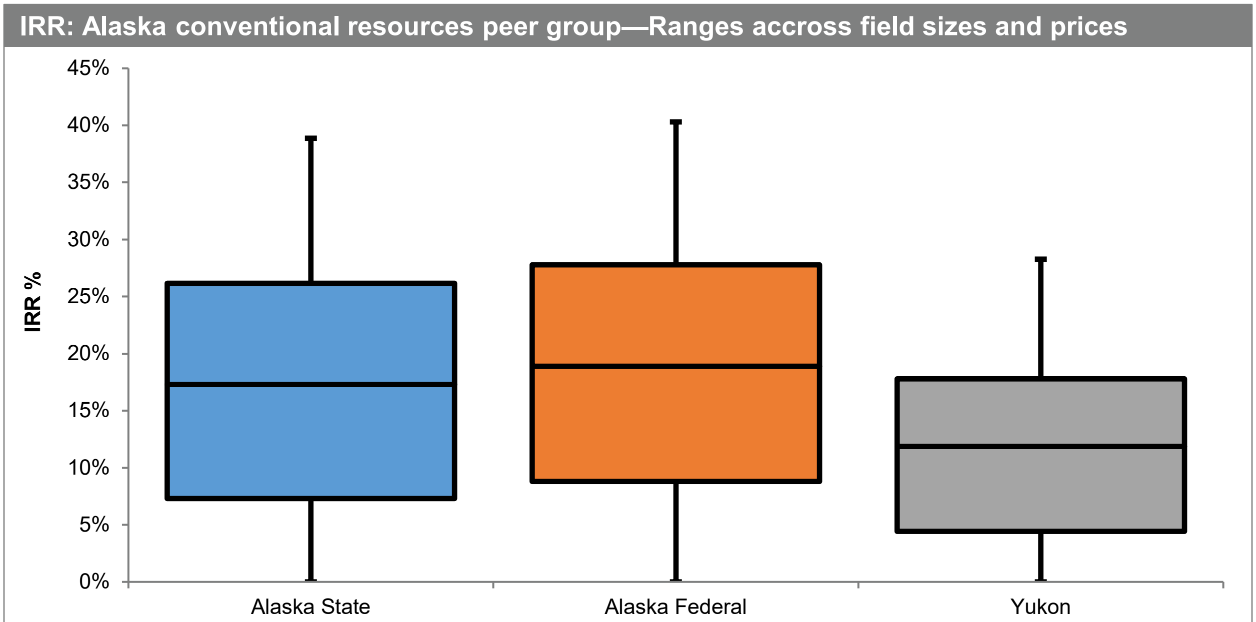
Each box represents a particular fiscal system's distribution of all cases (low, base and high price scenarios for all three field sizes).

- The ends of the box represent the upper and lower quartiles.
- The horizontal line inside the box represents the median value.
- The whiskers, the two vertical lines outside the box, show the extreme ranges of the minimum and maximum values.

When the results of all fields are considered under the three price scenarios, the Federal fiscal system in Alaska yields a median IRR of 19 percent, versus 17 percent for the state fiscal system and 12 percent for Yukon. The median IRR suggests that Alaskan projects, while very sensitive to crude oil prices, can withstand relatively short cycles of low commodity prices. However, this presumes that there will be cycles of high prices during the life of the field to offset the low price cycles. When the median IRR of the all the fields under low and base cases is taken into account, the IRR for the Federal fiscal system drops from 19 percent to 9 percent.

Figure 5-2 shows the distribution of IRR values for all field sizes under the low, base and high price cases. The IRR for the lower quartile under the Federal fiscal system in Alaska is 9 percent—just under the 10 percent investment threshold. The values for the Alaska state and Yukon are considerably lower, 7 percent and 4 percent, respectively. This indicates that investments in Alaska state and Yukon are more sensitive to oil prices.

Figure 5-2. IRR: Alaska conventional resources peer group—Ranges across field sizes and prices



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median.
Source: IHS Markit

The Alaskan projects have lower per-unit capital costs than equivalent field sizes in Yukon. This contributes to significantly lower rates of return in the Canadian territory versus fields in Alaska. The lower range of IRR for Yukon fields reflects the investment reality in the jurisdiction—low levels of E&P activity and investor interest.

5.2.2 Alaska Conventional Resources—NPV/boe

The majority of projects on the Federal mineral estate in Alaska generally yield better value per barrel than their peers when all three prices are taken into account. The Alaskan projects on the Federal mineral estate yield a positive NPV/boe under the base and high price scenarios except for the 50 MMboe field size. Based on the distribution of recent fields in Alaska, the 50 MMboe and 100 MMboe oil fields are more probable than the 200 MMboe field, with respective P90, P50, and P20 probabilities[84] Under the base price scenario, the Alaska Federal fiscal system yields better value per boe than its peers (Figure 5-3). The Alaska state mineral estate and Yukon projects are more sensitive to the low oil price environment than projects on the Federal mineral estate (Table 5-4). They present with values that are 30 percent to 100 percent lower than the ones for the Alaska Federal fiscal system. The higher royalty rates applicable in the Alaska state and Yukon fiscal systems—16.67 percent and 22.4 percent, respectively, versus 12.5 percent in the Federal fiscal system—contribute to the steeper value erosion under the low price, environment for projects in these jurisdictions.

[84] P20 means that 20 percent of the estimates exceed the P20 estimate of 200MMboe or that the P20 estimate is greater than 80 percent of the estimates, consequently the P90 estimate of 50 MMboe is greater than 10 percent of the estimates. P50 estimate of 100 MMboe represents the median.

Figure 5-3 displays the range of NPV/boe for the projects in the Alaska peer group under the base price scenario. The lighter green bar represents the P10 values. The border between the lighter and darker green bars represents the P50 values, whereas the darker green bars represent the P90 values.

Figure 5-3. NPV/boe: Alaska peer group—Base case

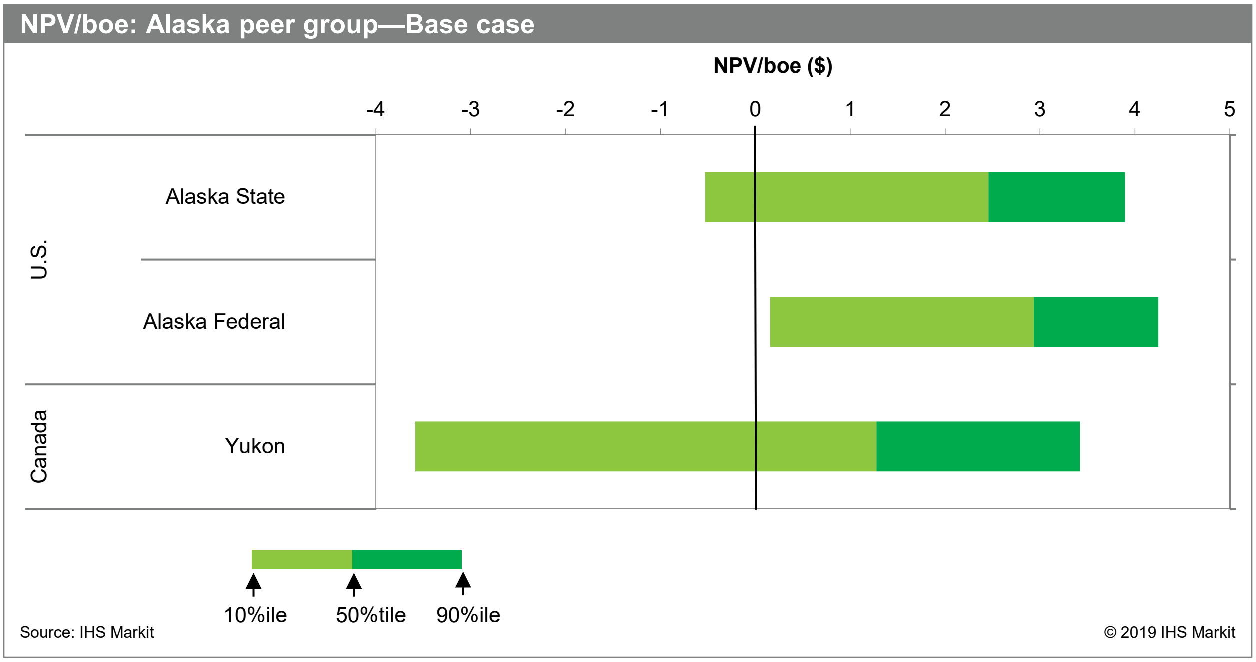


Table 5-4. NPV/boe: Alaska conventional onshore peer group across field sizes and prices

Jurisdiction	NPV/boe ($)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	200	100	50	200	100	50	200	100	50
Alaska State	9.3	8.0	4.7	4.3	2.5	-1.3	-0.4	-3.0	-9.1
Alaska Federal	9.6	8.4	5.3	4.6	2.9	-0.5	0.0	-2.3	-7.7
Yukon	11.2	9.6	4.1	4.0	1.3	-4.8	-1.1	-5.0	-13.9

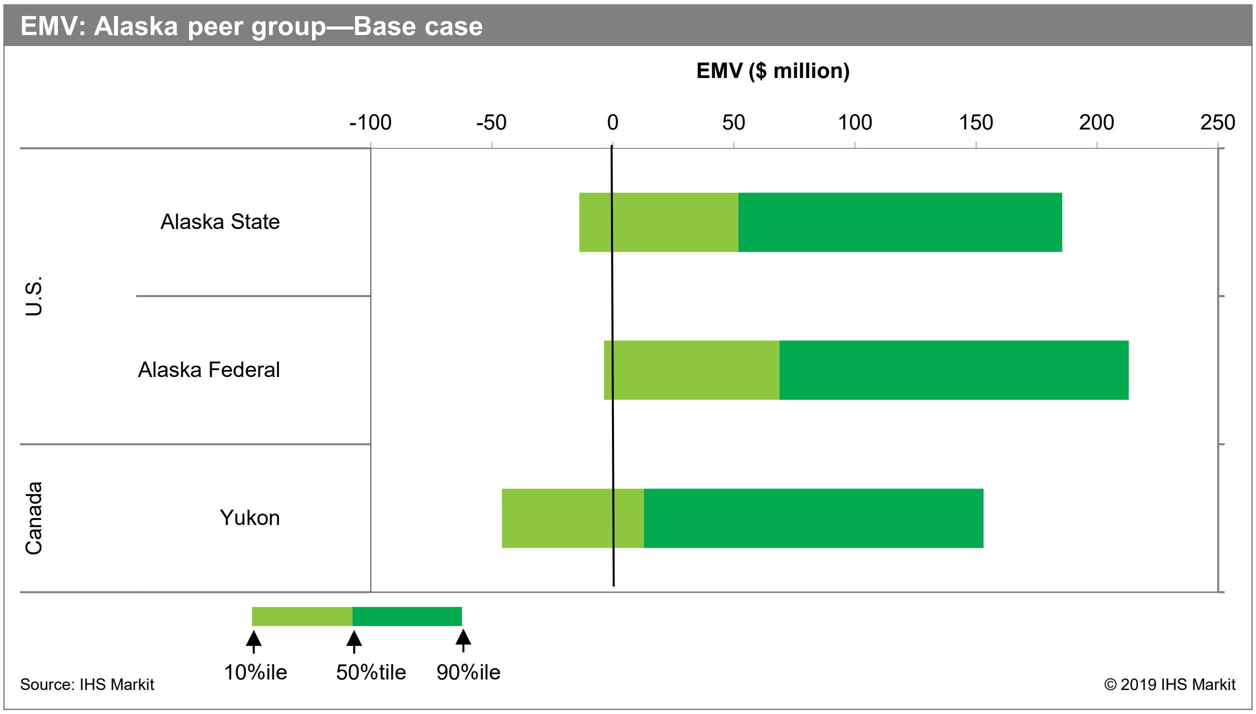
Source: IHS Markit

Figure 5-4 displays the NPV/boe for the low, base, and high cases. All fields perform better under the Federal fiscal system than the Alaska state and Yukon fiscal systems when all three price scenarios are taken into account. This is attributed to the lower degree of regressively of the Federal fiscal system relative to its peers.

5.2.3 Alaska Conventional Resources—EMV

The expected value per exploration well drilled under the Federal mineral estate in Alaska is higher than that of both the state of Alaska and Yukon for similar-sized fields. The Federal fiscal system for Alaska conventional resources offers robust monetary value per exploratory well drilled under the high and base price scenarios, except for the 50 MMboe oil field that presents with a negative EMV in the base case, as it does for other fiscal systems in this peer group (Figure 5-4). In the high price scenario, projects on the Federal mineral estate yield EMVs ranging from $61 million to $539 million (Table 5-5). In the base case, the medium and large size fields yield EMVs of $69 million and $249 million, respectively. Table 5-5 displays the EMVs for the low, base, and high cases.

Figure 5-4. EMV: Alaska peer group—Base case



The high cost associated with oil and gas investments in Alaska and Yukon is prohibitive for development of oil fields in the low oil price environment. The EMVs for all projects in this peer group range from minus $15 million to minus $128 million in this environment. (Table 5-5). Negative EMVs suggest that the cost of a failed well outweighs the successful development case on a probability-weighted basis. This analysis mirrors the results of the E&P activity in Alaska during 2015–16, when not a single exploratory well was drilled as the oil price was looming in the $40–50/bbl range—the low case in this study averages at $40/bbl through 2040.

Table 5-5. EMV: Alaska conventional onshore peer group across field sizes and prices

Jurisdiction	EMV ($ million)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	200	100	50	200	100	50	200	100	50
Alaska State	498	206	50	219	52	-30	-37	-86	-106
Alaska Federal	539	227	61	249	69	-22	-15	-73	-99
Yukon	561	191	28	188	13	-60	-67	-108	-128

Source: IHS Markit

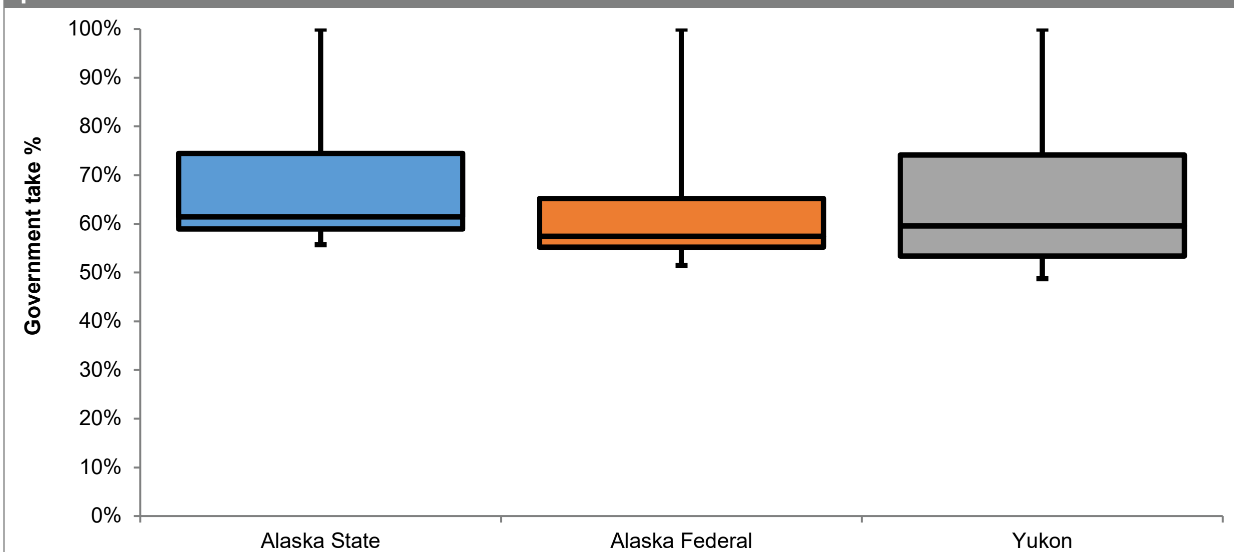
On a stand-alone basis, most of the fields in both jurisdictions (Alaska and Yukon) would not be viable under the base case. However, development of discoveries near fields that can tie in to the infrastructure and facilities already in place in Alaska's North Slope are economically feasible under the base case.

5.2.4 Alaska—Government Take

Both the range and median government take for Federal mineral estate in Alaska are somewhat lower than its peers—57 percent median government take under the Federal fiscal system, versus 60 percent in Yukon and 61 percent in Alaska state (Figure 5-5). The narrower range of the government take for the Federal versus state mineral estates in Alaska is indicative of a lower degree of regressivity for the Federal fiscal system—the higher the share of revenue received upfront by the government, the more regressive the fiscal system. There is an inverse relationship between government take and project profitability. When costs are higher, and thus profitability goes down, the government take in fiscal systems that deploy royalties as a means of generating revenue for the government(s) tends to go in the opposite direction—i.e., it increases as profitability declines.

Figure 5-5. Government take: Alaska conventional resource peer group—Ranges across field sizes and prices

Government take: Alaska conventional resource peergroup—Range across field sizes and prices



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median.

Source: IHS Markit

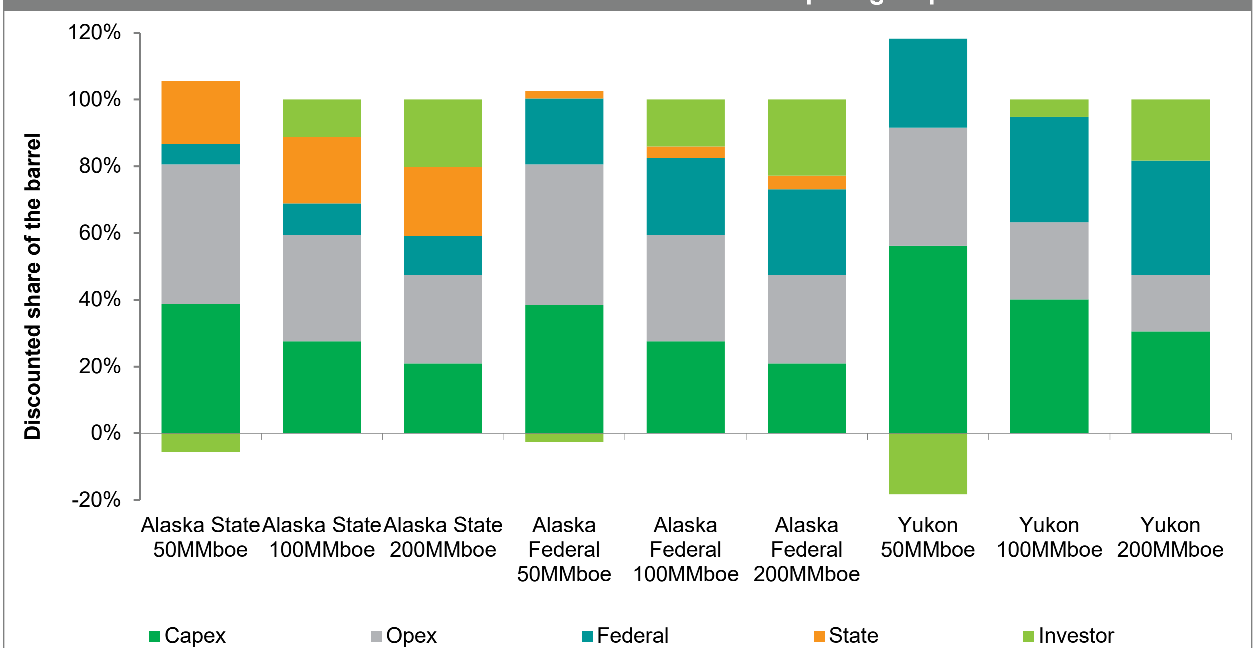
Discounted share of the barrel

The graphic shows, the components of the discounted cash flow as a percentage of a barrel of oil equivalent. The total in each column adds up to 100 percent. In the case of negative NPV projects, the company share will appear negative and other components, such as operating expenses (opex) and taxes at state and federal levels, will add up to greater than 100 percent.

When the discounted share of the barrel accruing to investors for all fields under the base price scenario is taken into account, the Federal fiscal system outperforms its peers—i.e., investors get a higher discounted share of the barrel under the Federal fiscal system (Figure 5-6).

The economics of the Alaska peer group are somewhat similar, with Yukon presenting greater challenges due to the higher per-unit development cost. The high cost of finding and development in Yukon has contributed to the relatively higher government take under the base and low price, scenarios in this jurisdiction. In the high price scenario, Yukon's government take is lower than that of Alaska Federal and Alaska state fiscal systems, which indicates a more regressive fiscal system than the Alaskan systems reviewed in this study (Appendix D).

Figure 5-6. Discounted share of the barrel: Alaska conventional resources peer group—Base case



Source: IHS Markit

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Yukon's much higher royalty rate, 22.4 percent, versus 16.67 percent levied by the state of Alaska and 12.5 percent by Federal government, is the primary reason for the more regressive nature of the Canadian fiscal system. Within the peer group, capital and operating costs range between 47 percent and 92 percent of the share of the barrel on a discounted basis, with Yukon having a higher per-unit cost than Alaska (Figure 5-6). The results of the hypothetical field analysis mirror the E&P activity on the ground, with the territory of Yukon being considered a frontier area—i.e., higher geological risk involved.

5.3 Lower-48 Conventional Resources Comparative Analysis

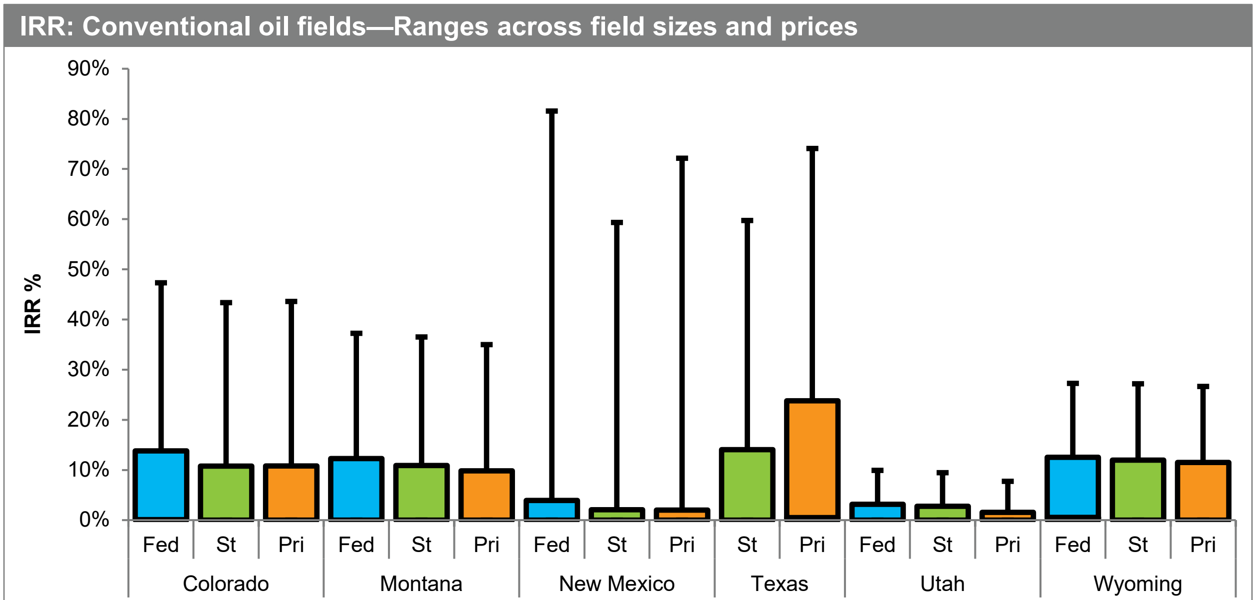
For conventional resources, six states are analyzed: Colorado, Montana, New Mexico, Texas, Utah, and Wyoming. Each state has three fiscal systems—Federal, state, and private—except for Texas, which includes only state and private fiscal systems. In the case of private mineral estate, royalties payable to private owners of mineral rights are considered government take in the sense that they represents a share of the revenue that does not go to investors. This is the case only when it comes to calculation of the government take percentage; however, the discounted share of the barrel analysis identifies private landowner share separately. For each jurisdiction, three field sizes are considered: 1 MMboe, 2 MMboe, and 5 MMboe, which represent the expected field sizes for conventional oil and gas developments in the Lower 48 based on recent drilling, with more frequency in the smaller 1 MMboe and 2 MMboe fields. Conventional resources are reaching maturity in the United States, with a diminishing amount of larger field sizes remaining to be discovered.

5.3.1 Lower-48 Conventional Resources—IRR

From an investor perspective, the return on investment for oil fields is very robust in the 5 MMboe base and high cases, and to some extent the 2 MMboe-field high case (Table 5-3). The majority of the cases, however, are uneconomic, resulting in a zero percent median IRR for all fiscal systems in this peer group (Figure 5-7 and Table 5-3). For the top quartile of the results, investor IRR on the Federal mineral estate is above the 10 percent threshold in Colorado, Montana, and Wyoming. While the return to investors in New Mexico is among the highest in the 5 MMboe-field high and base cases, the 2 MMboe oil fields are not economic under any of the price scenarios for this study in the state. The oil fields in Utah do not yield optimum rates of return under any price scenario (Table 5-3). That is reflective of the lower resource potential and lower well productivity compared to other states.[85]

[85] Johnston D, "Wyoming—legal and fiscal frameworks: best practices," November 2018.

Figure 5-7. IRR: Conventional oil fields—Ranges across field sizes and prices



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. In this case, the median and lower quartile are at 0 percent IRR. Fed is Federal, St is state, Pri is private.
Source: IHS Markit

Generally, the investor IRR is one to three percentage points higher on the Federal mineral estate than on the respective state land, except for New Mexico, where the difference is more prominent—13 percentage points. The range for bonuses for state lands in New Mexico is much higher than that for the Federal mineral estate, assuming $4,500/acre for state lands, $400/acre for private lands, and $300/acre for Federal . This upfront-cost results in the gap in the IRR between the Federal mineral estate and state lands. The IRR analysis further highlights the unattractive economics associated with discovery and development of the 2 MMboe and 1 MMboe oil fields across all jurisdictions and fiscal systems (Table 5-6). Current market prices, which were below the base price assumption as of July 2019, do not favor the development of such fields.

Table 5-6. IRR: Conventional oil fields across field sizes and prices

Jurisdiction		IRR (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	31	47	14	13	0	0	0	0	0
	State	28	43	10	11	0	0	0	0	0
	Private	28	44	10	11	0	0	0	0	0
Montana	Federal	37	15	2	12	0	0	0	0	0
	State	37	15	1	11	0	0	0	0	0
	Private	35	14	1	10	0	0	0	0	0
New Mexico	Federal	82	4	0	36	0	0	0	0	0
	State	59	2	0	23	0	0	0	0	0
	Private	72	2	0	27	0	0	0	0	0
Texas	State	60	14	0	27	0	0	0	0	0
	Private	74	24	1	34	0	0	1	0	0

Jurisdiction		IRR (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Utah	Federal	9	10	0	3	2	0	0	0	0
	State	9	9	0	3	1	0	0	0	0
	Private	8	8	0	2	0	0	0	0	0
Wyoming	Federal	27	13	0	13	1	0	1	0	0
	State	27	13	0	12	0	0	0	0	0
	Private	27	12	0	11	0	0	0	0	0

Source: IHS Markit

For natural gas fields, the range in the IRR is narrower—the upper, median, and lower quartiles are at zero percent IRR, with 87 percent of the cases generating no return. For the high case 5 MMboe gas fields, the hurdle rates for investment decisions are surpassed in four out of the six states reviewed for this study. In the base case scenario, the 10 percent IRR threshold is surpassed only in New Mexico on Federal, state, and private land (Table 5-7). Conventional gas field development in the Lower 48 is challenged by the marginal size of discoveries and the prevailing commodity prices.

Table 5-7. IRR: Conventional gas fields across field sizes and prices

Jurisdiction		IRR (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	**2**	**1**	**5**	**2**	**1**	**5**	**2**	**1**
Colorado	Federal	23	2	0	0	0	0	0	0	0
	State	20	0	0	0	0	0	0	0	0
	Private	20	0	0	0	0	0	0	0	0
Montana	Federal	0	0	0	0	0	0	0	0	0
	State	0	0	0	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0	0
New Mexico	Federal	72	0	0	40	0	0	0	0	0
	State	56	0	0	25	0	0	0	0	0
	Private	64	0	0	28	0	0	0	0	0
Texas	State	15	0	0	0	0	0	0	0	0
	Private	19	0	0	2	0	0	0	0	0
Utah	Federal	2	0	0	0	0	0	0	0	0
	State	1	0	0	0	0	0	0	0	0
	Private	0	0	0	0	0	0	0	0	0
Wyoming	Federal	20	3	0	0	0	0	0	0	0
	State	18	1	0	0	0	0	0	0	0
	Private	17	0	0	0	0	0	0	0	0

Source: IHS Markit

5.3.2 Lower 48 Conventional Resources—NPV/boe

When crude oil prices are at current levels or higher (base and high cases), the 5 MMboe oil fields are viable in the majority of jurisdictions in this peer group, i.e., they yield a positive NPV/boe. Development of 2 MMboe oil fields is even more challenging—they are viable only in four out of six states in the high case scenario (Table 5-8). The P90 results for the NPV/boe are positive only in the case of Texas private and state land, and the Federal fiscal systems in New Mexico and Colorado (Figure5-8).

Figure 5-8. NPV/boe: Lower-48 conventional oil field—Base case

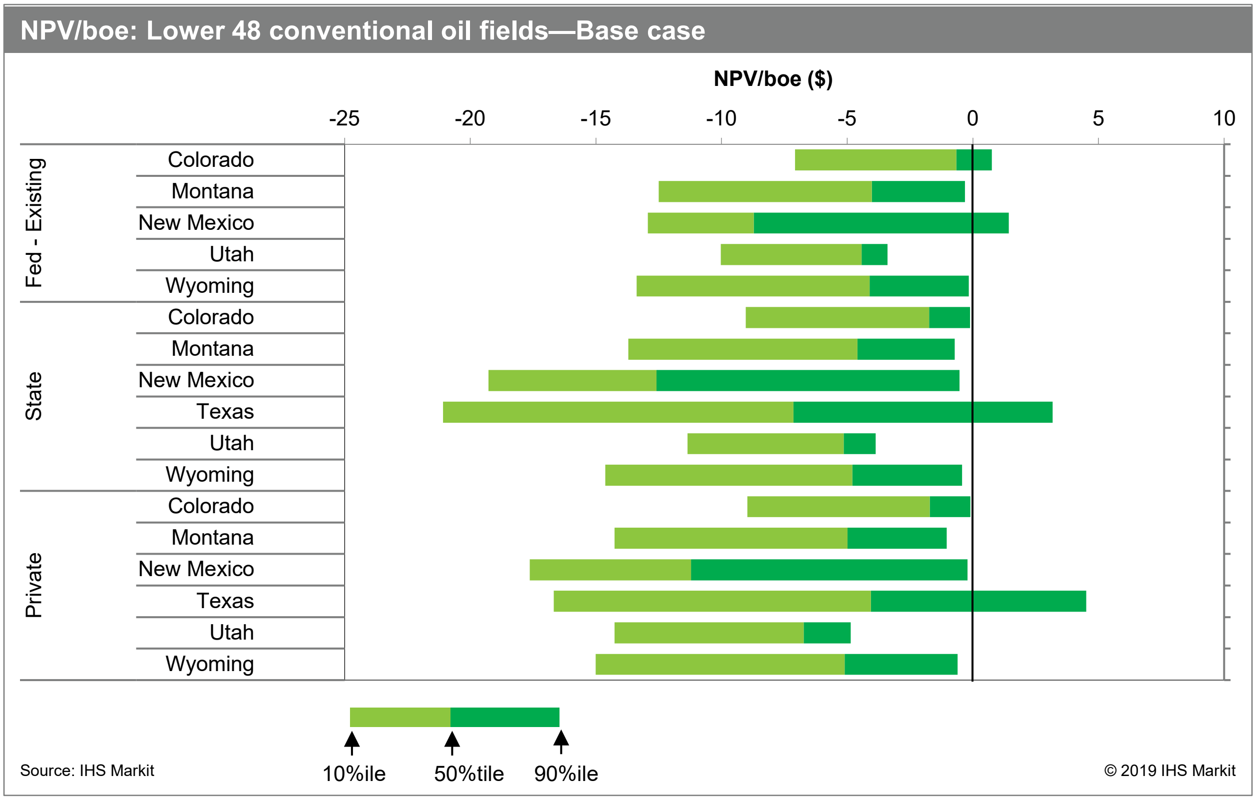


Table 5-8. NPV/boe: Conventional oil fields across field sizes and prices

Jurisdiction		NPV/boe ($)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	7.4	8.7	1.6	1.1	-0.7	-8.7	-3.0	-6.9	-15.6
	State	7.0	7.9	0.1	0.3	-1.7	-10.9	-4.1	-8.8	-18.3
	Private	7.0	7.9	0.2	0.3	-1.7	-10.8	-4.1	-8.8	-18.2
Montana	Federal	7.9	2.6	-11.2	0.6	-4.0	-14.6	-4.3	-8.5	-16.8
	State	8.1	2.5	-12.4	0.3	-4.6	-16.0	-5.0	-9.4	-18.3
	Private	7.8	2.2	-13.0	0.0	-5.0	-16.6	-5.3	-9.8	-18.9
New Mexico	Federal	13.1	-5.4	-3.9	4.0	-8.7	-14.0	-2.1	-10.9	-20.9
	State	12.3	-9.1	-10.0	2.5	-12.6	-21.0	-4.2	-15.0	-29.0
	Private	12.3	-7.7	-8.3	2.5	-11.2	-19.2	-4.1	-13.6	-27.0
Texas	State	18.9	2.1	-21.7	5.8	-7.1	-24.6	-3.0	-13.4	-26.6
	Private	19.8	5.1	-16.9	6.7	-4.1	-19.8	-2.1	-10.3	-21.8
Utah	Federal	-0.4	-0.1	-2.9	-3.1	-4.4	-11.4	-4.9	-7.3	-17.2
	State	-0.7	-0.5	-3.7	-3.5	-5.1	-12.9	-5.5	-8.2	-19.1
	Private	-1.5	-2.1	-6.9	-4.4	-6.7	-16.1	-6.4	-9.8	-22.3
Wyoming	Federal	5.8	2.2	-11.4	0.8	-4.1	-15.7	-2.5	-8.5	-18.6
	State	6.0	2.0	-12.5	0.7	-4.8	-17.1	-2.9	-9.4	-20.2
	Private	5.8	1.7	-12.9	0.5	-5.1	-17.5	-3.0	-9.8	-20.6

Source: IHS Markit

The value per boe of production from gas fields is lower than that of the oil fields due to the lower commodity prices on an energy-equivalent basis. Similar to the IRR analysis, 5 MMboe gas fields are attractive to investors only under the high price scenario, except for New Mexico, which presents a positive NPV/boe under the base case for 5 MMboe gas fields (Table 5-9). The 2 MMboe and 1 MMboe gas fields are uneconomic under all three price scenarios.

Table 5-9. NPV/boe: Conventional gas fields across field sizes and prices

Jurisdiction		NPV/boe ($)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	1.9	-1.8	-16.1	-1.5	-4.7	-18.4	-4.2	-6.6	-20.0
	State	1.5	-3.0	-18.6	-2.2	-6.2	-21.1	-5.1	-8.3	-22.9
	Private	1.5	-3.0	-18.5	-2.2	-6.2	-21.1	-5.1	-8.3	-22.9
Montana	Federal	-4.4	-8.2	-14.3	-6.0	-10.4	-17.7	-7.0	-12.3	-20.3
	State	-5.0	-8.9	-15.5	-6.6	-11.4	-19.3	-7.8	-13.4	-22.2
	Private	-5.2	-9.3	-16.1	-6.8	-11.8	-19.9	-8.0	-13.8	-22.8
New Mexico	Federal	9.2	-6.2	-12.5	3.5	-8.2	-17.1	-0.6	-9.6	-20.5
	State	8.3	-9.1	-19.1	2.1	-11.2	-24.6	-2.2	-12.9	-29.2
	Private	8.1	-8.4	-16.7	1.9	-10.6	-21.9	-2.3	-12.2	-26.2
Texas	State	1.8	-10.0	-19.7	-3.0	-12.8	-22.4	-6.3	-14.8	-24.2
	Private	2.8	-7.6	-14.5	-2.0	-10.3	-17.2	-5.2	-12.3	-18.9
Utah	Federal	-3.2	-8.4	-15.2	-5.4	-10.7	-18.0	-6.9	-12.3	-20.0
	State	-3.8	-9.4	-16.9	-6.2	-11.8	-20.0	-7.9	-13.7	-22.2
	Private	-5.0	-11.1	-19.7	-7.4	-13.6	-22.9	-9.1	-15.5	-25.1
Wyoming	Federal	2.3	-2.3	-12.9	-1.6	-6.2	-18.0	-4.2	-8.8	-22.1
	State	1.9	-3.1	-14.6	-2.2	-7.2	-20.1	-5.0	-10.1	-24.6
	Private	1.7	-3.4	-15.2	-2.5	-7.6	-20.7	-5.2	-10.4	-25.2

Source: IHS Markit

5.3.3 Lower-48 Conventional Resources—EMV

In the case of oil fields, about 22 percent of the cases analyzed for the Federal mineral estate—10 out of 45 cases—yield a positive value per exploration well drilled (Table 5-10). That is aligned with the overall peer group ratio of cases with a positive NPV—only 33 cases out of a total of 153 analyzed for this study.

Table 5-10. EMV: Conventional oil fields across field sizes and prices

Jurisdiction		EMV ($ millions)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	11.2	5.1	-0.3	1.0	-1.2	-3.0	-5.7	-5.1	-4.8
	State	10.0	4.5	-0.4	0.0	-1.4	-3.0	-6.6	-5.5	-4.7
	Private	10.0	4.5	-0.3	0.1	-1.4	-2.9	-6.5	-5.4	-4.7

Jurisdiction		EMV ($ millions)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Montana	Federal	11.0	0.7	-4.2	0.0	-3.2	-5.2	-7.4	-5.9	-5.9
	State	11.2	1.1	-3.9	-0.1	-3.0	-4.9	-7.6	-5.7	-5.6
	Private	10.5	0.8	-4.0	-0.5	-3.1	-5.0	-7.9	-5.8	-5.7
New Mexico	Federal	15.6	-3.6	-2.1	3.9	-5.1	-4.7	-3.7	-6.1	-6.5
	State	11.5	-6.7	-5.2	0.0	-8.1	-7.8	-7.4	-9.1	-9.6
	Private	12.8	-3.6	-2.4	2.1	-5.0	-4.9	-4.8	-5.9	-6.5
Texas	State	23.6	-2.6	-9.7	4.7	-6.6	-10.5	-7.7	-9.2	-11.1
	Private	27.8	1.7	-5.4	8.9	-2.3	-6.2	-3.5	-5.0	-6.8
Utah	Federal	-1.3	-0.7	-1.5	-4.2	-3.1	-3.5	-6.1	-4.7	-4.8
	State	-1.1	-0.6	-1.2	-4.0	-3.0	-3.3	-6.0	-4.6	-4.7
	Private	-1.8	-1.2	-1.7	-4.4	-3.4	-3.6	-6.2	-4.8	-4.8
Wyoming	Federal	7.0	0.6	-3.6	0.3	-3.4	-4.7	-4.2	-6.2	-5.4
	State	7.2	0.8	-3.3	0.4	-3.4	-4.4	-4.2	-6.1	-5.2
	Private	6.9	0.6	-3.2	0.3	-3.4	-4.3	-4.1	-6.1	-5.0

Source: IHS Markit

The EMV analysis for conventional gas fields in the Lower 48 mirrors the results of the IRR and NPV/boe. Only 8 percent of the cases run are viable under the EMV analysis, i.e., the 5 MMboe for Colorado, New Mexico, and Wyoming in the high case, and in New Mexico in the base case. The 2 MMboe and 1 MMboe gas fields are not economic under any price scenarios (Table 5-11). Development of new sources of conventional natural gas in the Lower 48 is not viable in the current market.

Table 5-11. EMV: Conventional gas fields across field sizes and prices

Jurisdiction		EMV ($ millions)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	2.4	-1.9	-4.7	-3.2	-3.8	-5.3	-6.5	-5.0	-5.6
	State	1.8	-2.2	-4.6	-3.7	-4.0	-5.1	-6.9	-5.3	-5.5
	Private	1.8	-2.1	-4.6	-3.6	-4.0	-5.1	-6.8	-5.2	-5.5
Montana	Federal	-4.7	-4.8	-4.9	-6.1	-5.9	-5.7	-7.0	-6.7	-6.4
	State	-4.5	-4.5	-4.5	-5.9	-5.7	-5.4	-6.8	-6.5	-6.1
	Private	-4.6	-4.6	-4.6	-5.9	-5.7	-5.4	-6.9	-6.5	-6.2
New Mexico	Federal	14.3	-5.3	-4.0	4.5	-6.8	-5.0	-2.1	-7.7	-5.7
	State	9.8	-8.6	-6.9	0.2	-10.0	-7.9	-5.9	-10.9	-8.7
	Private	11.0	-5.6	-3.9	2.0	-6.9	-4.9	-3.6	-7.8	-5.6
Texas	State	-1.3	-9.1	-8.5	-7.3	-10.6	-9.2	-11.1	-11.7	-9.7
	Private	2.9	-4.8	-4.2	-3.0	-6.3	-4.9	-6.9	-7.4	-5.4
Utah	Federal	-4.2	-5.0	-5.4	-6.6	-6.1	-6.2	-8.2	-6.9	-6.8
	State	-4.2	-4.9	-5.3	-6.7	-6.0	-6.1	-8.3	-6.8	-6.7
	Private	-4.9	-5.1	-5.5	-7.1	-6.1	-6.2	-8.6	-6.9	-6.7
Wyoming	Federal	2.9	-2.9	-4.4	-3.4	-6.2	-5.7	-7.7	-8.5	-6.5
	State	2.5	-3.1	-4.3	-3.9	-6.5	-5.7	-8.1	-8.8	-6.4
	Private	2.2	-3.2	-4.2	-4.0	-6.5	-5.6	-8.2	-8.7	-6.3

Source: IHS Markit

5.3.4 Lower-48 Conventional Resources—Government Take

Conventional oil fields in the Lower 48 generally present challenging economics under the price scenarios analyzed in this study. This is reflected in the rather high government take percentages for all fiscal systems analyzed (Table 5-12). The median government take for all fiscal systems in this study is 100 percent, which indicates the majority of the projects are uneconomic and would not go forward under the base and low price scenarios. The government take on Federal mineral estate is lower than the take on state and private lands in each of the jurisdictions reviewed in this study. Generally, the highest government take is observed on private lands for the respective jurisdiction due to the higher royalty rate, except for Texas, where state land bonuses are higher, and Colorado, where the royalty rate between private and state lands is identical.

Table 5-12. Government take: Conventional oil fields across field sizes and prices

Jurisdiction		Government take (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	52	76	100	63	100	100	99	100	100
	State	59	86	100	71	100	100	100	100	100
	Private	59	86	100	71	100	100	100	100	100
Montana	Federal	54	64	80	70	100	100	100	100	100
	State	58	68	89	75	100	100	100	100	100
	Private	60	70	92	78	100	100	100	100	100
New Mexico	Federal	58	73	100	76	100	100	100	100	100
	State	65	85	100	88	100	100	100	100	100
	Private	70	89	100	90	100	100	100	100	100
Texas	State	56	80	100	67	100	100	100	100	100
	Private	56	78	94	66	100	100	99	100	100
Utah	Federal	52	59	100	70	91	100	100	100	100
	State	56	64	100	76	98	100	100	100	100
	Private	64	74	100	87	100	100	100	100	100
Wyoming	Federal	49	60	100	58	98	100	96	100	100
	State	52	65	100	62	100	100	100	100	100
	Private	54	67	100	64	100	100	100	100	100

Source: IHS Markit

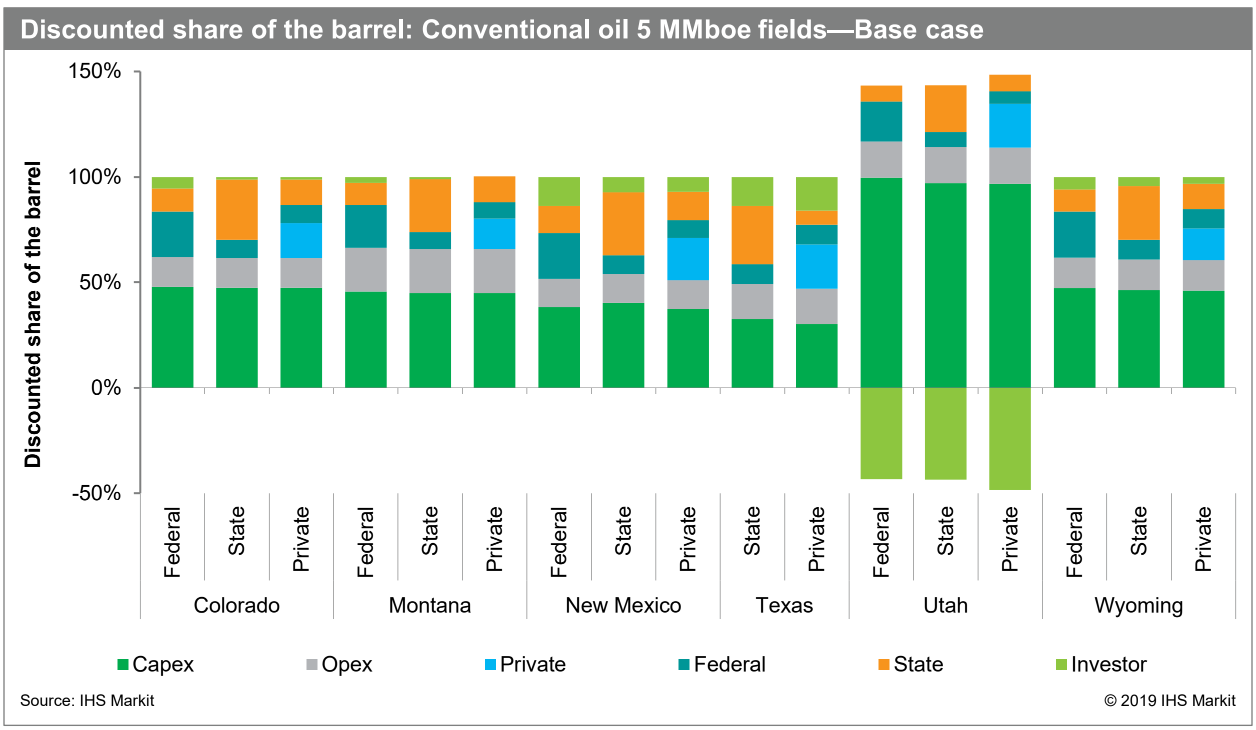
The rather high government take range (80–100 percent) for 1 MMboe under the high price scenario indicates that such fields may not be economic under any price scenario. At the base price, only the largest field size of 5 MMboe has less than 100 percent government take under all fiscal systems (Table 5-9).

The discounted share of the barrel shows what percentage of the revenue goes to each part of the cash flow, and is compared among the state and jurisdictions for each oil field size. For states that have the same royalty rate for state and private lands, the investor share of the barrel will be the same, except that state cash flow for the private fiscal system will be split between the private cash flow and state cash flow.

Under the base case, the Federal government receives, on average, 7 percent of the discounted barrel on state and private land and 20 percent on the Federal mineral estate. The share of the barrel accruing to the Federal government has a parallel relationship with project profitability. As project profitability increases, the share of the barrel accruing to the Federal government increases—it averages around 6 percent, 7 percent, and 8 percent on state and private land for 1MMBoe, 2MMBoe, and 5 MMboe oil fields, respectively; and 19 percent, 20 percent, and 21 percent on Federal mineral estate for the 1 MMboe, 2 MMboe, and 5 MMboe oil fields, respectively (Appendix D). From an investor perspective, the states of Texas and New Mexico offer more reasonable splits of the discounted barrel for the 5 MMboe oil field under the base case. This is attributed to the lower cost per unit observed in these jurisdictions. The discounted share of the barrel offered to investors in Texas private lands is by far the highest, at 16 percent, followed by New Mexico Federal mineral estate at 14 percent (Figure 5-8). While the shares of the barrel accruing to investors in Colorado, Montana, and Wyoming for the 5 MMboe oil field are positive (i.e., they pass the 10 percent hurdle rate) in the base case, the cost structure for new conventional oil fields in Utah is prohibitive. The shares accruing to investors are negative under all three fiscal systems for the state. The 2 MMboe and 1 MMboe oil fields are uneconomic under the base case in all states, thus resulting in negative investor shares of the discounted barrel (Figure 5-9).

For 5 MMboe oil fields, Colorado, Montana, and Wyoming have marginal economics with slightly positive company share percentages. New Mexico and Texas have stronger economics, while still maintaining a similar percentage share of the barrel for Federal cash flow—around 20 percent in the Federal jurisdictions. Utah fields have higher capital requirements; the capex share uses up the revenue at greater than or equal to a 100 percent share of the barrel.

Figure 5-9. Discounted share of the barrel: Conventional oil 5 MMboe fields—Base case



Similar to oil fields, conventional natural gas fields' economics are challenged by commodity prices and the rather marginal nature of discoveries. When all 153 cases analyzed for this peer group are taken into account, only 21 cases result in less than 100 percent government take (Table 5-13).

Table 5-13. Government take: Conventional gas fields across field sizes and prices

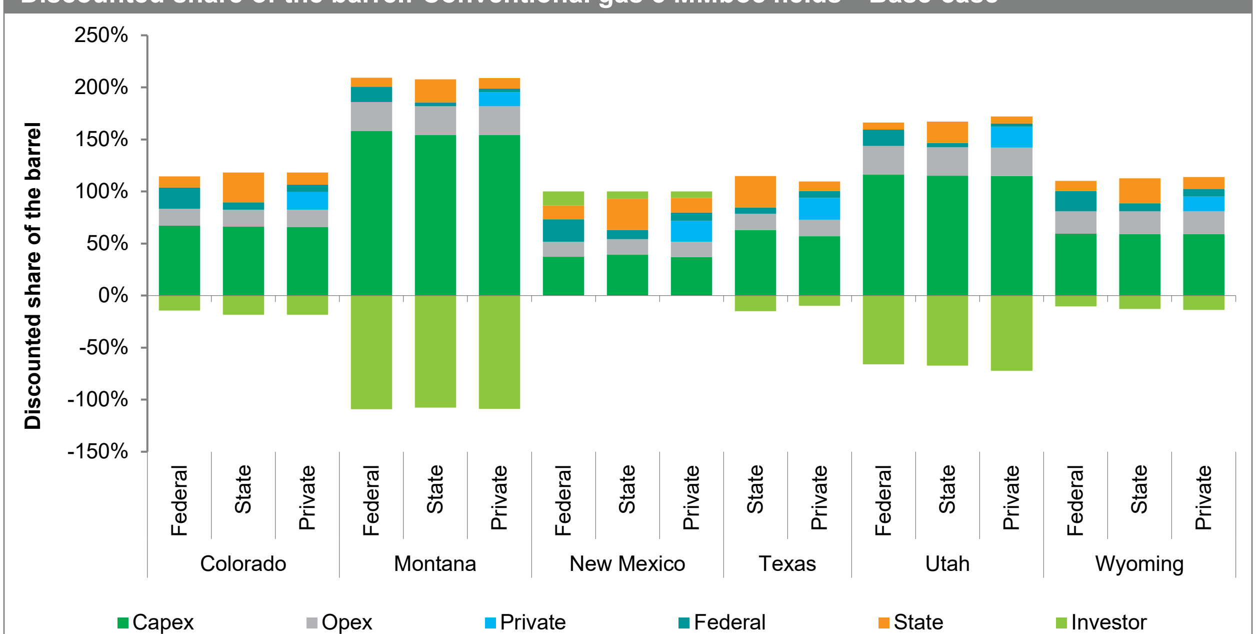
Jurisdiction		Government take (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
Colorado	Federal	72	99	100	100	100	100	100	100	100

Jurisdiction		Government take (%)								
		High case			Base case			Low case		
		Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
		5	2	1	5	2	1	5	2	1
	State	82	100	100	100	100	100	100	100	100
	Private	82	100	100	100	100	100	100	100	100
Montana	Federal	100	100	100	100	100	100	100	100	100
	State	100	100	100	100	100	100	100	100	100
	Private	100	100	100	100	100	100	100	100	100
New Mexico	Federal	64	100	100	75	100	100	100	100	100
	State	73	100	100	87	100	100	100	100	100
	Private	78	100	100	91	100	100	100	100	100
Texas	State	72	100	100	100	100	100	100	100	100
	Private	71	100	100	96	100	100	100	100	100
Utah	Federal	84	100	100	100	100	100	100	100	100
	State	94	100	100	100	100	100	100	100	100
	Private	100	100	100	100	100	100	100	100	100
Wyoming	Federal	68	88	100	100	100	100	100	100	100
	State	73	95	100	100	100	100	100	100	100
	Private	76	99	100	100	100	100	100	100	100

Source: IHS Markit

When the discounted share of the barrel is taken into account, only the 5 MMboe gas fields in New Mexico have positive investor share under the base case (Figure 5-10). Both 2 MMboe and 1 MMboe gas fields have rather negative company cash flows (Appendix D).

Figure 5-10. Discounted share of the barrel: Conventional gas 5 MMboe fields—Base case



Source: IHS Markit

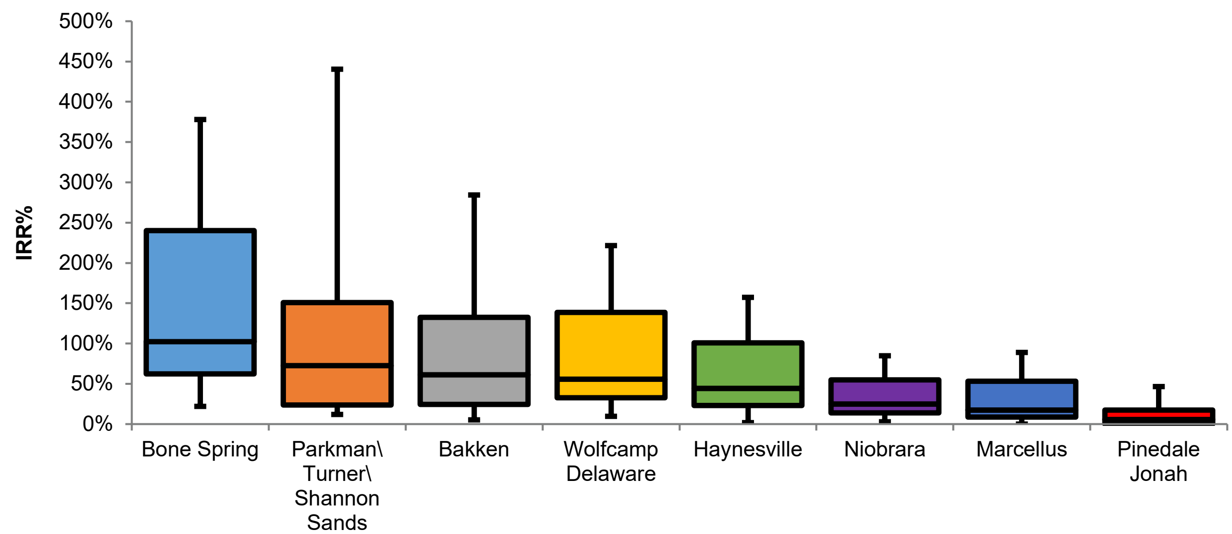
5.4 Unconventional Resources Comparative Analysis

5.4.1 Unconventional Resources—IRR

Overall, unconventional plays offer robust rates of returns to investors across all jurisdictions and fiscal systems, with Bone Spring outperforming the other plays with regard to the median, as well as the range of IRR (Figure 5-11). The Federal fiscal systems generally outperform the state and private fiscal systems except in Marcellus and Niobrara, as the Federal mineral estate is in the subplays with higher costs per boe. The median IRR across all the plays and jurisdictions averages to 40 percent, ranging from 5 percent in Jonah Pinedale to 108 percent in Bone Spring (Figure 5-12).

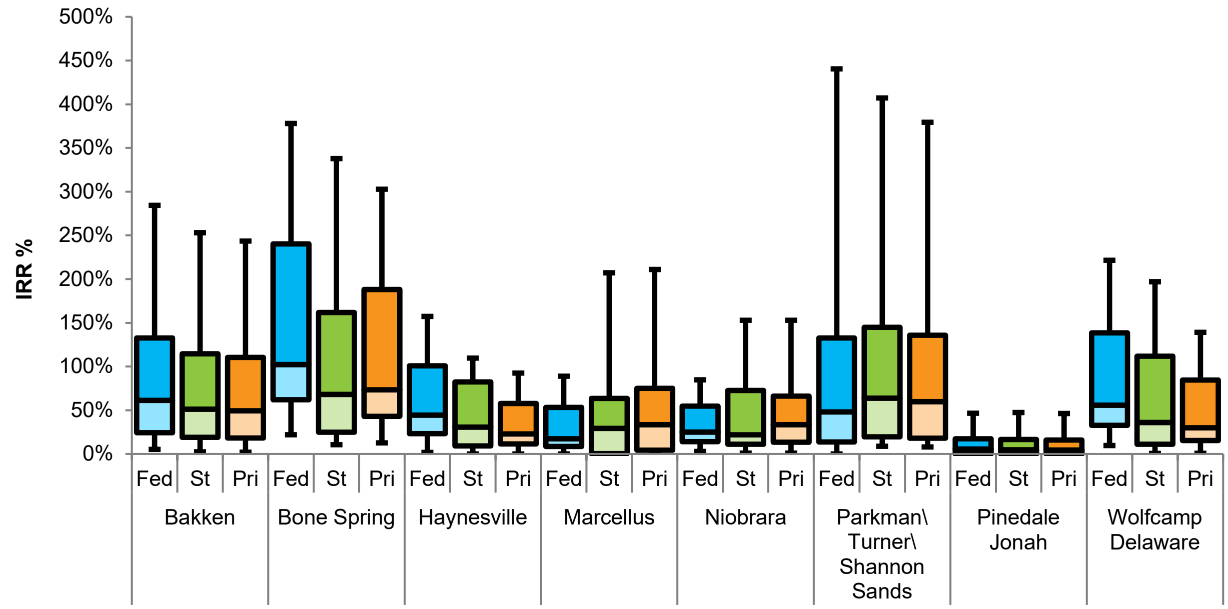
Figure 5-11. IRR: Ranking of Federal mineral estate unconventional plays—Ranges across subplays and prices

IRR: Ranking of Federal mineral estate for unconventional plays—Ranges accross subplays and prices



Notes: Rank ordered by median IRR. The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median.
Source: IHS Markit

Figure 5-12. IRR: Unconventional resources—Ranges across subplays and prices



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. Fed is Federal, St is state, and Pri is private.

Source: IHS Markit

While the Jonah subplay is the only subplay that is not viable under the base case, the majority of plays/subplays are not viable under the low price scenario. Only 30 percent of the cases run in the low price scenarios meet the 10 percent investment threshold. The differences in well productivity, depth, and cost among the subplays within a particular play yield different results within the same fiscal system. While the Federal fiscal system in North Dakota yields robust rates of return of 19 percent in the New Fairway under the low case, the rates of return in Parshall under the same price scenario are sub-optimal—14 percentage points lower than those of the New Fairway (Table 5-14)

Table 5-14. IRR: Unconventional resources across subplays and prices

Jurisdiction		IRR (%)		
		High case	Base case	Low case
Bakken	New Fairway (ND)-Federal	284	81	19
	New Fairway (ND)-State	253	68	14
	New Fairway (ND)-Private	244	66	13
	Parshall (ND)-Federal	150	41	5
	Parshall (ND)-State	130	34	2
	Parshall (ND)-Private	125	33	2
	Elm Coulee (MT)-State	166	47	8
Bone Spring	New Mexico Deep (NM)-Federal	378	102	22
	New Mexico Deep (NM)-State	338	82	15
	New Mexico Deep (NM)-Private	303	73	13
	Texas Deep (TX)-State	188	54	11
Haynesville	Haynesville Core (LA)-Federal	157	44	2
	Haynesville Core (LA)-State	110	29	0
	Haynesville Core (LA)-Private	93	23	0
	Shelby Trough (TX)-State	99	33	3

Jurisdiction		IRR (%)		
		High case	Base case	Low case
Marcellus	Marcellus Super Core (PA)-State	207	51	1
	Marcellus Super Core (WV)-State	181	44	0
	Marcellus Super Core (PA)-Private	211	52	1
	Marcellus Southwest Core (WV)-Federal	89	17	0
	Marcellus Southwest Core (PA)-State	82	15	0
	Marcellus Southwest Core (PA)-Private	83	15	0
	Marcellus Periphery (OH)-State	57	12	0
Niobrara	Niobrara DJ (WY)-Federal	85	25	3
	Niobrara DJ (WY)-State	79	22	1
	Niobrara DJ (CO)-State	73	20	1
	Niobrara DJ (CO)-Private	73	20	1
	Niobrara Wattenberg (CO)-State	153	47	11
	Niobrara Wattenberg (CO)-Private	153	47	11
Parkman\ Turner\ Shannon Sands	Parkman (WY)-Federal	440	97	16
	Parkman (WY)-State	407	85	12
	Parkman (WY)-Private	379	80	11
	Turner Sands (WY)-Federal	169	48	12
	Turner Sands (WY)-State	165	42	9
	Turner Sands (WY)-Private	154	40	8
Pinedale Jonah	Pinedale (WY)-Federal	47	11	0
	Pinedale (WY)-State	47	10	0
	Pinedale (WY)-Private	46	9	0
	Jonah (WY)-Federal	19	0	0
	Jonah (WY)-State	19	0	0
	Jonah (WY)-Private	18	0	0
Wolfcamp Delaware	Middle Hotspot (NM)-Federal	222	56	10
	Middle Hotspot (NM)-State	197	43	5
	Southern Liquids (TX)-State	135	29	1
	Southern Liquids (TX)-Private	139	30	1

Source: IHS Markit

5.4.2 Unconventional Resources—NPV/boe

The NPV/boe analysis largely mirrors the IRR analysis, with the majority of the subplays failing to yield a positive NPV/boe under the low price scenario. All the tight oil plays yield a positive NPV/boe under the base price scenario, with the P10 results being greater than $4/boe under all three mineral estates (Figure 5-12). The majority of the plays and subplays fail to yield positive values per boe under the low price scenario. (Table 5-15).

Figure 5-13. NPV/boe: Unconventional oil plays—Base case

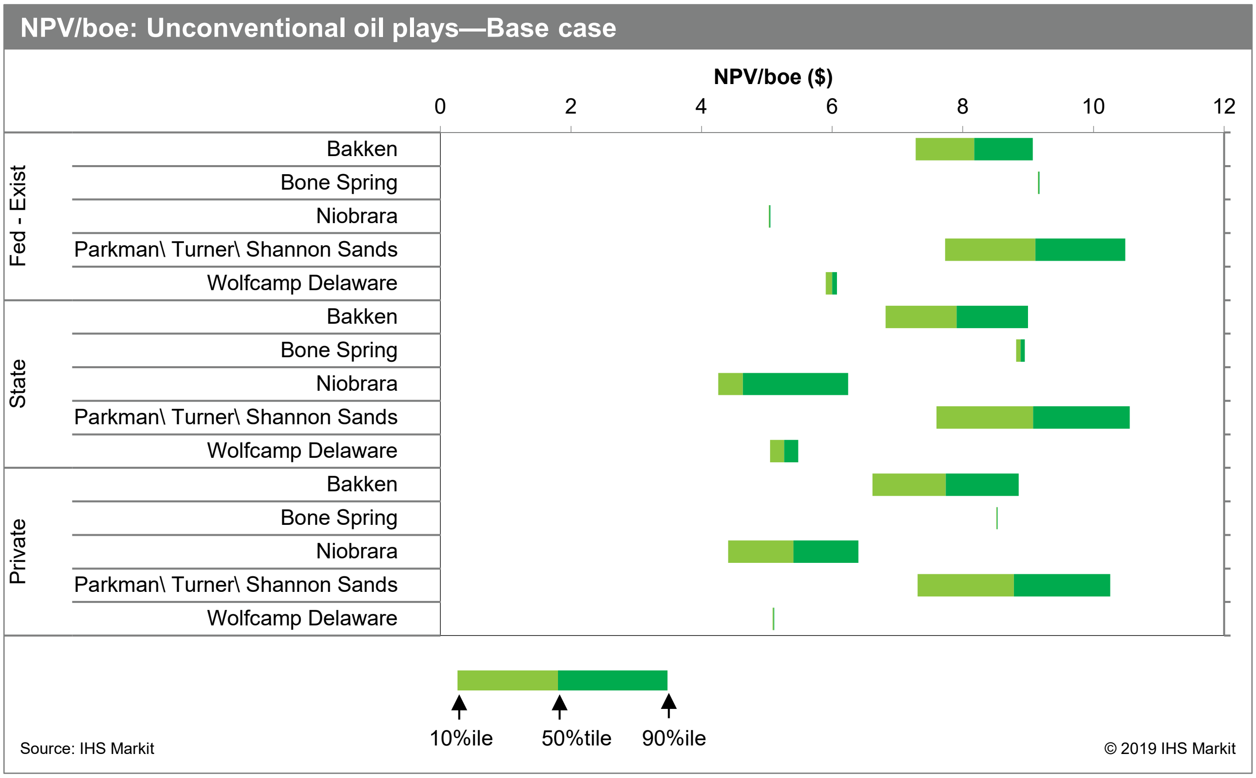


Table 5-15. NPV/boe: Unconventional resources across subplays and prices

Jurisdiction		NPV/boe ($)		
		High case	Base case	Low case
Bakken	New Fairway (ND)-Federal	20.1	9.3	1.9
	New Fairway (ND)-State	21.2	9.3	1.0
	New Fairway (ND)-Private	21.1	9.1	0.9
	Parshall (ND)-Federal	19.3	7.1	-1.6
	Parshall (ND)-State	20.0	6.5	-3.1
	Parshall (ND)-Private	19.8	6.3	-3.3
	Elm Coulee (MT)-State	21.4	8.3	-0.7
Bone Spring	New Mexico Deep (NM)-Federal	19.9	9.2	2.0
	New Mexico Deep (NM)-State	20.7	9.0	1.1
	New Mexico Deep (NM)-Private	20.3	8.5	0.6
	Texas Deep (TX)-State	21.6	8.8	0.2
Haynesville	Haynesville Core (LA)-Federal	8.3	2.9	-0.9
	Haynesville Core (LA)-State	7.9	2.1	-2.2
	Haynesville Core (LA)-Private	7.5	1.6	-2.9
	Shelby Trough (TX)-State	8.1	2.7	-1.0
Marcellus	Marcellus Super Core (PA)-State	7.0	2.4	-0.8
	Marcellus Super Core (WV)-State	6.6	2.1	-1.0
	Marcellus Super Core (PA)-Private	7.0	2.4	-0.7
	Marcellus Southwest Core (WV)-Federal	4.8	0.7	-2.6
	Marcellus Southwest Core (PA)-State	5.0	0.5	-3.3
	Marcellus Southwest Core (PA)-Private	5.0	0.5	-3.2
	Marcellus Periphery (OH)-State	8.8	0.8	-5.2

Jurisdiction		NPV/boe ($)		
		High case	Base case	Low case
Niobrara	Niobrara DJ (WY)-Federal	17.1	5.1	-3.4
	Niobrara DJ (WY)-State	17.7	4.6	-4.7
	Niobrara DJ (CO)-State	16.9	4.2	-5.1
	Niobrara DJ (CO)-Private	16.9	4.2	-5.1
	Niobrara Wattenberg (CO)-State	16.0	6.6	0.3
	Niobrara Wattenberg (CO)-Private	16.0	6.6	0.3
Parkman\ Turner\ Shannon Sands	Parkman (WY)-Federal	25.3	10.8	1.2
	Parkman (WY)-State	26.5	10.9	0.5
	Parkman (WY)-Private	26.2	10.6	0.2
	Turner Sands (WY)-Federal	17.5	7.4	0.6
	Turner Sands (WY)-State	18.5	7.2	-0.4
	Turner Sands (WY)-Private	18.2	6.9	-0.7
Pinedale Jonah	Pinedale (WY)-Federal	4.5	0.2	-3.0
	Pinedale (WY)-State	4.8	-0.1	-3.7
	Pinedale (WY)-Private	4.7	-0.2	-3.9
	Jonah (WY)-Federal	1.9	-2.7	-6.6
	Jonah (WY)-State	1.9	-3.4	-7.8
	Jonah (WY)-Private	1.8	-3.5	-8.1
Wolfcamp Delaware	Middle Hotspot (NM)-Federal	15.1	6.1	-0.1
	Middle Hotspot (NM)-State	15.7	5.5	-1.5
	Southern Liquids (TX)-State	17.8	5.0	-4.1
	Southern Liquids (TX)-Private	18.0	5.1	-4.0

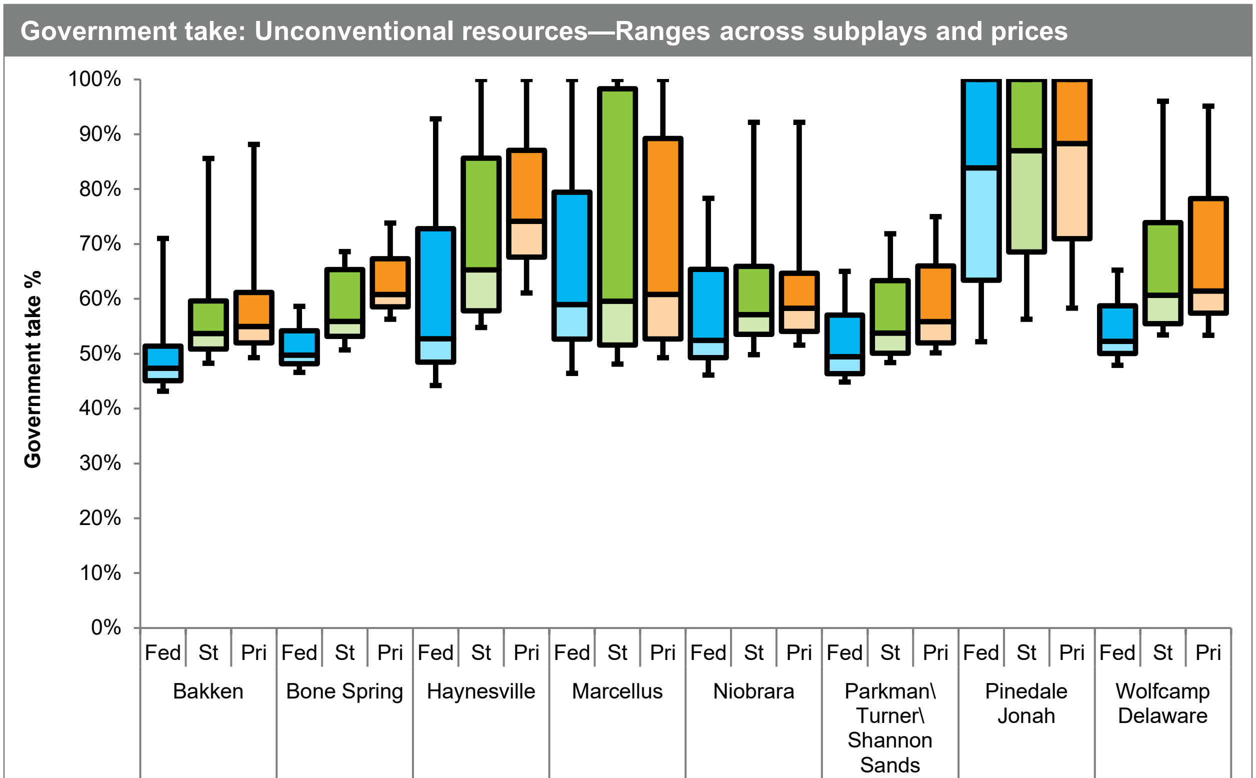
Source: IHS Markit

The values per boe for shale gas play are generally lower than those for tight oil formations. Not all unconventional gas plays yield a positive NPV/boe under the base price. Pinedale Jonah has a negative a NPV/boe under all fiscal systems, except the Federal fiscal system in the Pinedale sublay. The lower royalty rates applicable under the Federal fiscal system give that system a slight edge over the state and private mineral estates in the Pinedale formation.

5.4.3 Unconventional Resources—Government Take

The Federal fiscal systems generate the lowest government take in each play, both in terms of the range as well as the median take, compared to state and private lands. This is a result of the lower royalty rates applicable on Federal mineral estate. The government take percentage on the Federal mineral estate ranges from the mid-40s to the mid-50s in established unconventional oil plays such as the Bakken, Bone Spring, and Wolfcamp Delaware. The range, however, widens considerably for shale gas plays such as Marcellus and Haynesville, as well as emerging tight oil plays such as Pinedale Jonah—from the mid-50s to the upper 80s, and even 100 percent. The high government take for the shale gas and emerging oil plays reflects the challenges such plays face under the low price scenario. Figure 5-14 shows the range and median government take for the Federal mineral estate, state lands, and private lands in each of the eight plays selected for this study. The government take for states in Figure 5-14 represents the combined data for the states in the particular play, e.g., Montana and North Dakota in the case of Bakken. Table 5-16 provides the government take data for Federal, state, and private lands and their respective jurisdictions.

Figure 5-14. Government take: Unconventional resources—Ranges across subplays and prices



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. Fed is Federal, St is state, and Pri is private.

Source: IHS Markit

Table 5-16. Government take: Unconventional resources across subplays and prices

Play	Fiscal System	Government take (%)		
		High case	Base case	Low case
Bakken	New Fairway (ND)-Fed	43	45	52
	New Fairway (ND)-St	48	51	61
	New Fairway (ND)-Pri	49	52	62
	Parshall (ND)-Fed	45	49	71
	Parshall (ND)-St	51	56	86
	Parshall (ND)-Pri	52	58	88
	Elm Coulee (MT)-St	47	52	67
Bone Spring	New Mexico Deep (NM)-Fed	47	50	59
	New Mexico Deep (NM)-St	52	57	68
	New Mexico Deep (NM)-Pri	56	61	74
	Texas Deep (TX)-St	51	55	69
Haynesville	Haynesville Core (LA)-Fed	44	53	93
	Haynesville Core (LA)-St	56	68	100
	Haynesville Core (LA)-Pri	61	74	100
	Shelby Trough (TX)-St	55	63	92

Play	Fiscal System	Government take (%)		
		High case	Base case	Low case
Marcellus	Marcellus Super Core (PA)-St	49	56	98
	Marcellus Super Core (WV)-St	52	60	100
	Marcellus Super Core (PA)-Pri	49	56	97
	Marcellus Southwest Core (WV)-Fed	46	59	100
	Marcellus Southwest Core (PA)-St	52	66	100
	Marcellus Southwest Core (PA)-Pri	52	66	100
	Marcellus Periphery (OH)-St	48	59	100
Niobrara	Niobrara DJ (WY)-Fed	46	52	78
	Niobrara DJ (WY)-St	50	57	88
	Niobrara DJ (CO)-St	54	61	92
	Niobrara DJ (CO)-Pri	54	61	92
	Niobrara Wattenberg (CO)-St	52	56	66
	Niobrara Wattenberg (CO)-Pri	52	56	66
Parkman\Turner\Shannon Sands	Parkman (WY)-Fed	45	49	65
	Parkman (WY)-St	48	54	72
	Parkman (WY)-Pri	50	56	75
	Turner Sands (WY)-Fed	45	49	60
	Turner Sands (WY)-St	49	54	66
	Turner Sands (WY)-Pri	51	56	69
Pinedale Jonah	Pinedale (WY)-Fed	52	68	100
	Pinedale (WY)-St	56	74	100
	Pinedale (WY)-Pri	58	77	100
	Jonah (WY)-Fed	62	100	100
Wolfcamp Delaware	Jonah (WY)-St	67	100	100
	Jonah (WY)-Pri	69	100	100
	Middle Hotspot (NM)-Fed	48	52	65
	Middle Hotspot (NM)-St	54	60	78
	Southern Liquids (TX)-St	53	62	96
	Southern Liquids (TX)-Pri	53	61	95

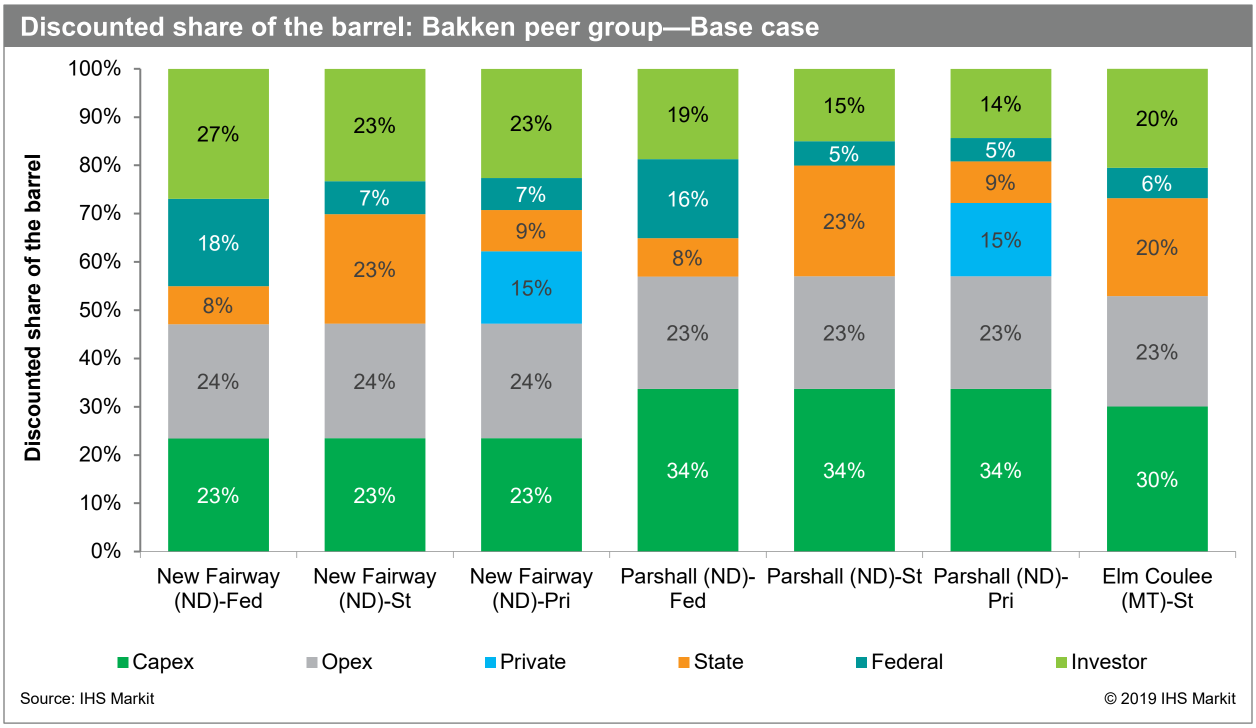
Source: IHS Markit

The individual components of government take, and Federal, state, and private cash flow are examined more closely in the discounted share of the barrel outputs. Each play's peer group is compared by state, jurisdiction, and subplay combination.

5.4.3.1 Bakken Peer Group—Discounted Share of the Barrel

Three subplays have been analyzed for this study of the Bakken to represent key areas of Federal, state, and private lands. Generally, the play offers attractive shares of the discounted barrels to investors (14–27 percent), with the New Fairway subplay being the most attractive from an investor point of view. This is largely due to the higher per-unit capital cost in Parshall and Elm Coulee (Figure 5-15).

Figure 5-15. Discounted share of the barrel: Bakken peer group—Base case

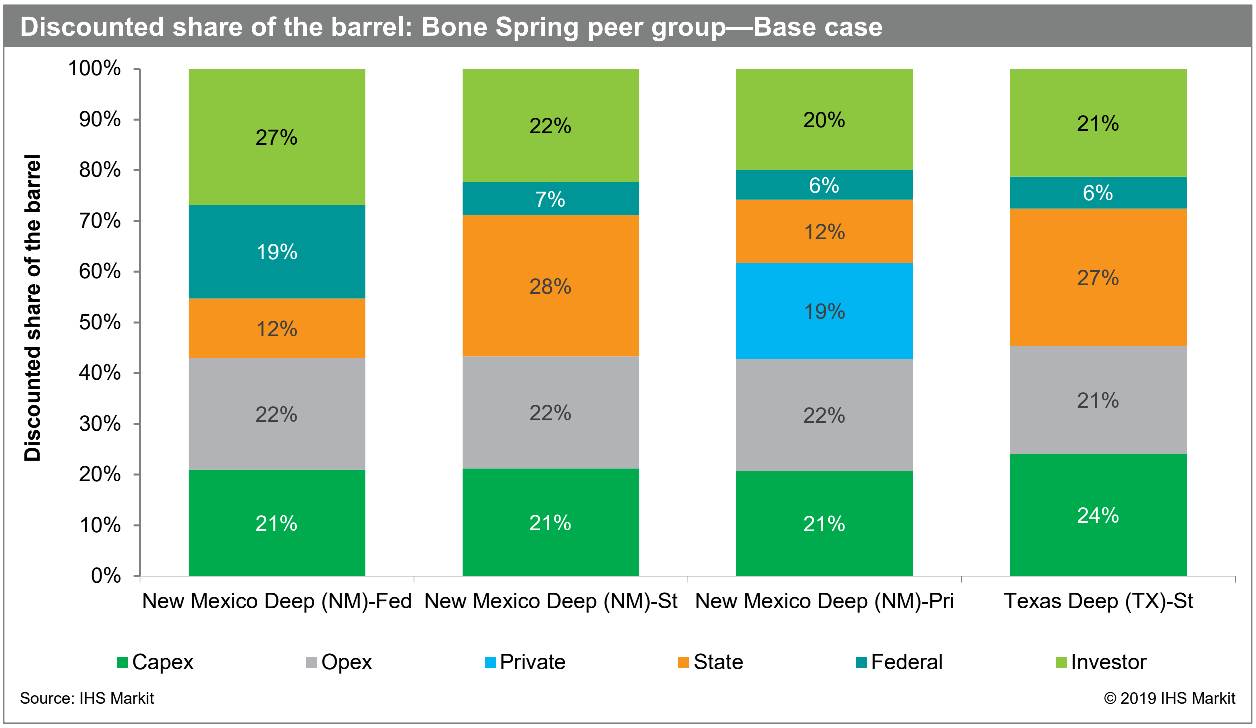


The share of the barrel accruing to the Federal government across the play is 16–18 percent on the Federal mineral estate and 5–7 percent on state and private lands. The combined state and Federal shares of the discounted barrel in the Bakken ranges from 16 percent on private land to 30 percent on Federal mineral estate.

5.4.3.2 Bone Spring Peer Group—Discounted Share of the Barrel

The discounted share of the barrel results for the Bone Spring subplays of New Mexico Deep and Texas Deep are somewhat more uniform on state and private lands—with investor shares of 20–22 percent. This is primarily due to the uniform per-unit cost structure in both subplays (Figure 5-16).

Figure 5-16. Discounted share of the barrel: Bone Spring peer group—Base case

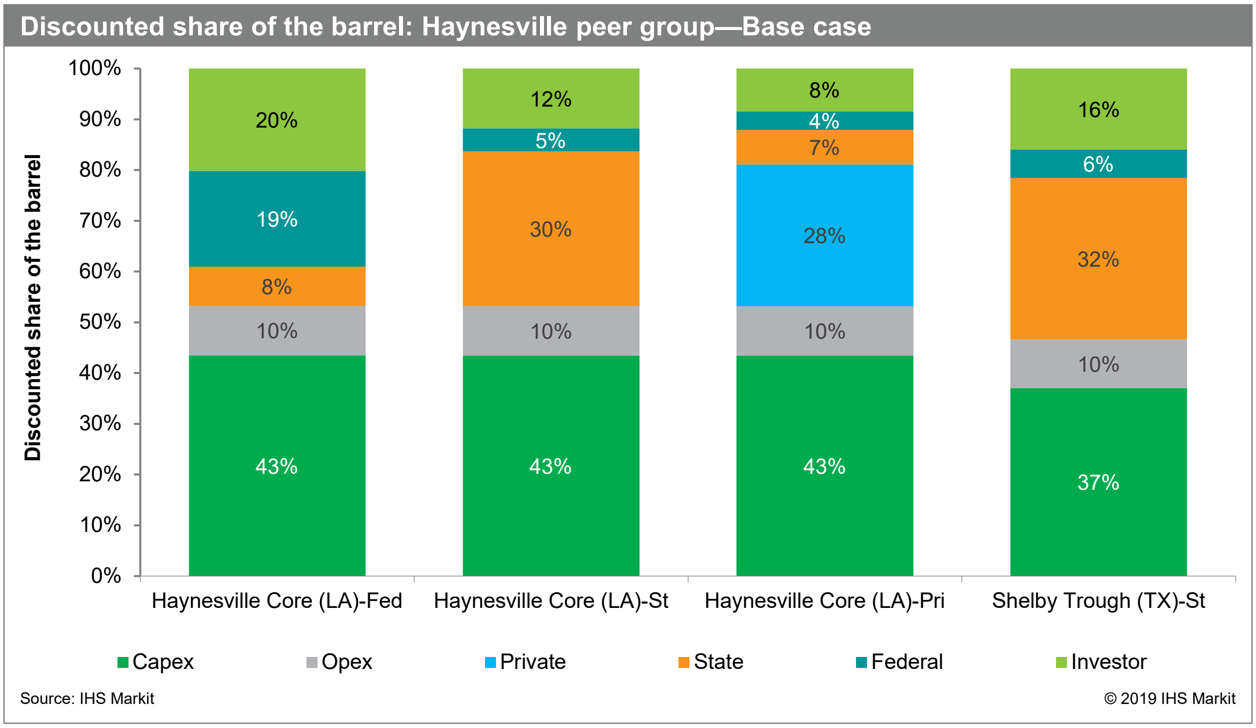


The investor share of the discounted barrel on the Federal mineral estate in New Mexico is 27 percent, while the share accruing to the Federal government is 19 percent. The Federal fiscal system is more attractive to investors than the state fiscal systems in Texas and New Mexico, as well as New Mexico private land.

5.4.3.3 Haynesville Peer Group—Discounted Share of the Barrel

From an investor point of view, the Federal mineral estate in Louisiana offers a greater share of the barrel than state and private land. The lower cost per unit on the Shelby Trough results in a greater share of the barrel accruing to investors on Texas state land versus Louisiana state land (Figure 5-17). While the investor share on Federal mineral estate in Haynesville is not as high as in Bone Spring (20 percent versus 27 percent), the share of the barrel accruing to the Federal government is 19 percent in both plays.

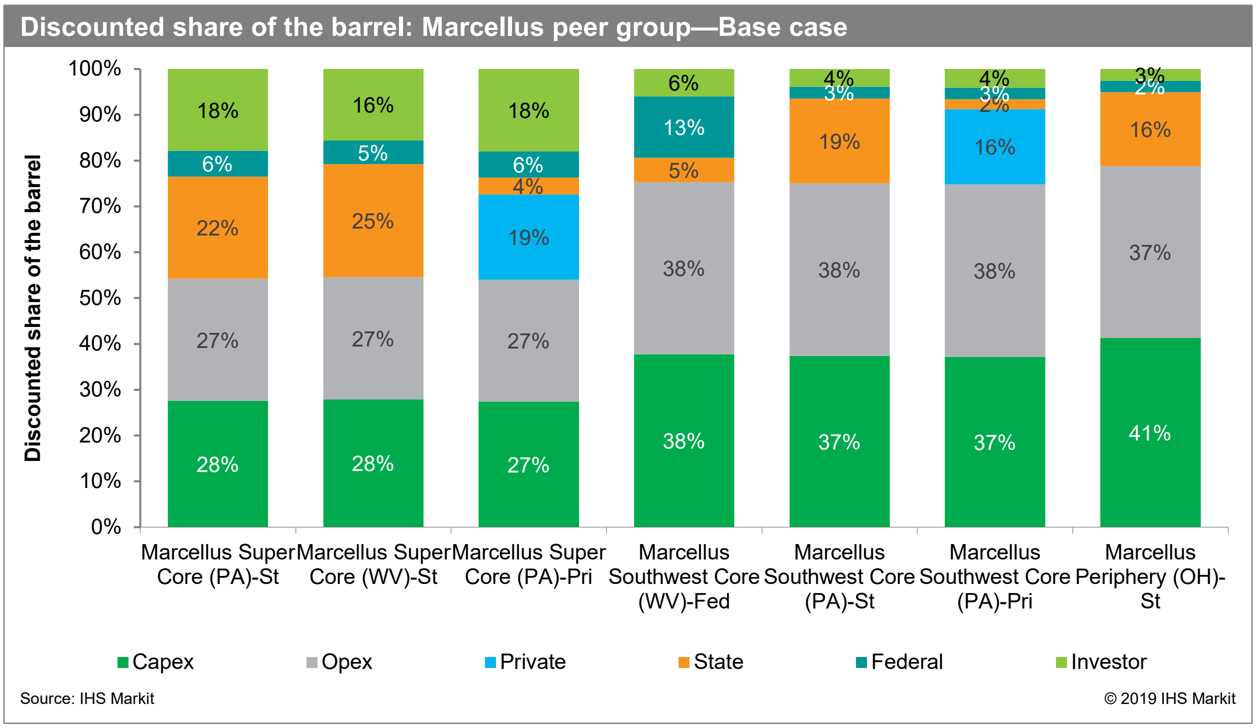
Figure 5-17. Discounted share of the barrel: Haynesville peer group—Base case



5.4.3.4 Marcellus Peer Group—Discounted Share of the Barrel

Moving from Marcellus Super Core subplay to Marcellus Southwest Core and Marcellus Periphery, the share of the discounted barrel accruing to investors tumbles from 18 percent to 2 percent (Figure 5-18). The cost per unit is substantially higher in the Southwest Core and Periphery subplays. The lower profitability of the Southwest Core subplay results in a significantly reduced share of the discounted barrel accruing to the Federal government on the Federal mineral estate in Marcellus than in Haynesville or any of the established unconventional oil plays—13 percent in Marcellus versus 19 percent in Haynesville. The share of the discounted barrel to the Federal government shrinks significantly on state and private land in the Southwest Core and periphery subplays, 2–3 percent versus 5–6 percent in the Super Core subplay.

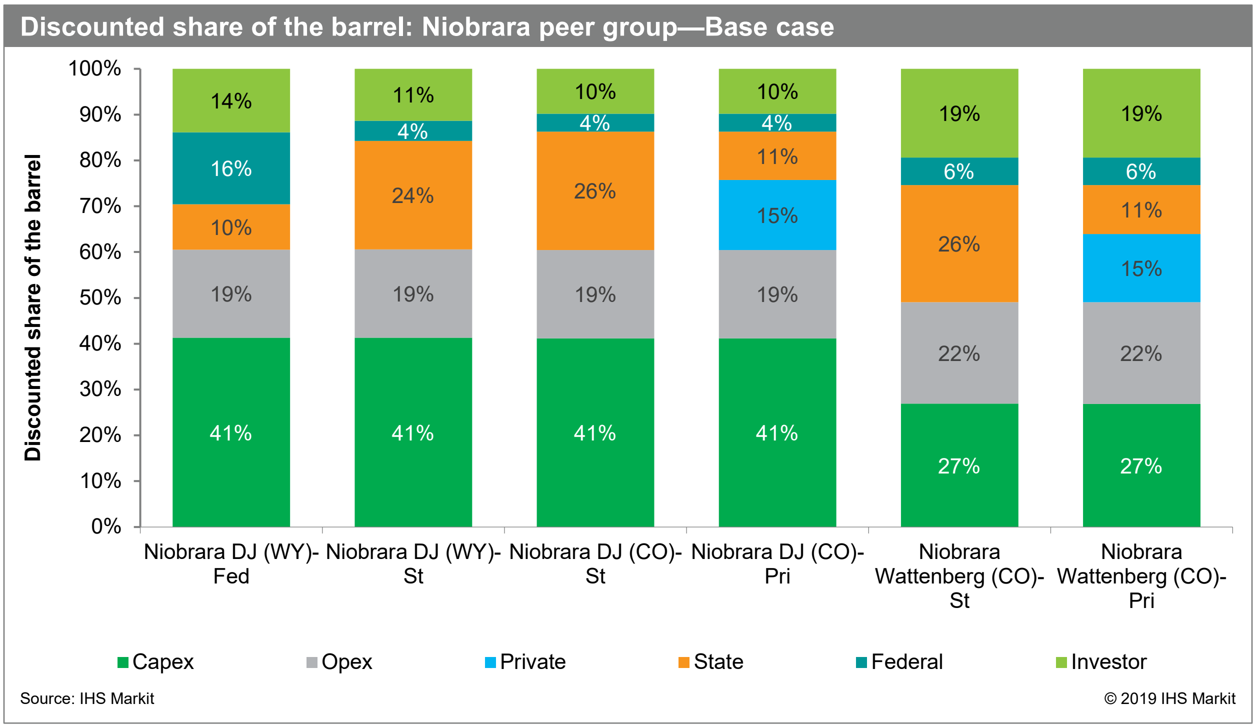
Figure 5-18. Discounted share of the barrel: Marcellus peer group—Base case



5.4.3.5 Niobrara Peer Group—Discounted Share of the Barrel

Despite having the lowest royalty rate in the peer group, the Federal fiscal system in Niobrara does not result in the highest share of the discounted barrel to investors (Figure 5-19). The significantly higher capital cost per unit in the DJ subplay results in a lower investor share of the barrel on the Federal mineral estate in Wyoming, versus state and private lands in Colorado in the Wattenberg subplay.

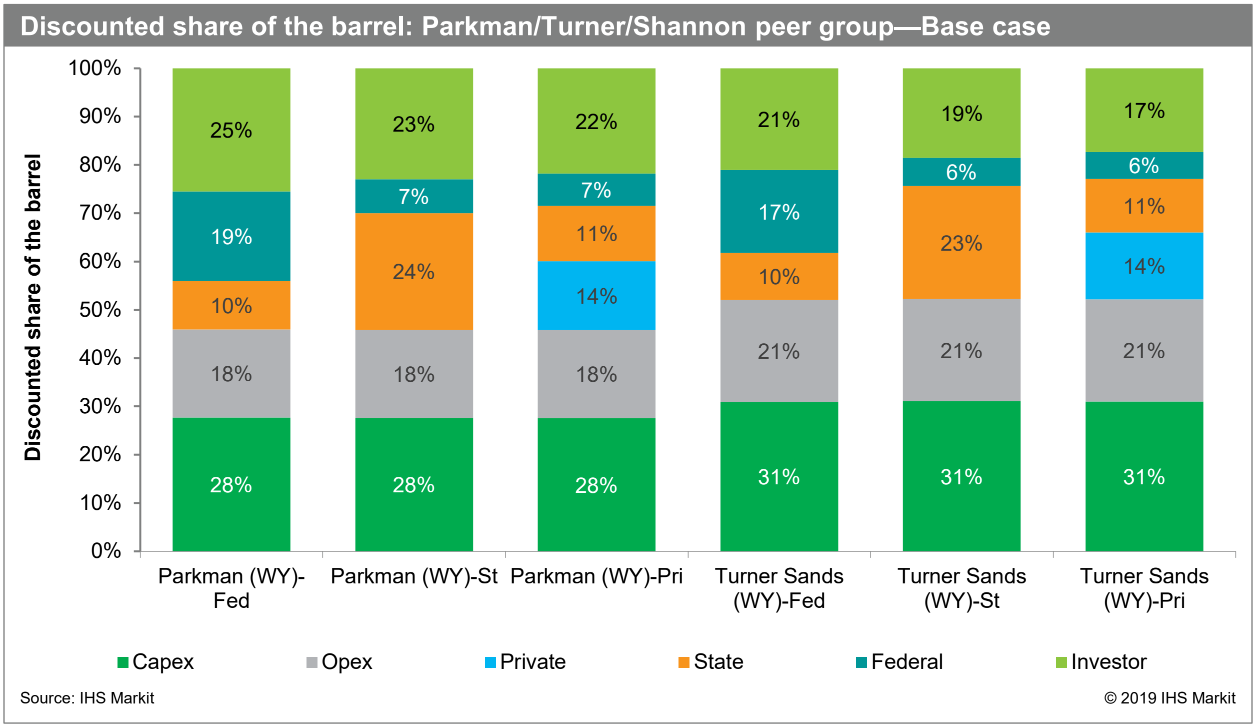
Figure 5-19. Discounted share of the barrel: Niobrara peer group—Base case



5.4.3.6 Parkman/Turner/Shannon Peer Group—Discounted Share of the Barrel

In both the Parkman and Turner Sands subplays, there is a 2–3 percent difference in company shares between Federal and state lands—with the Federal fiscal system being more favorable to investors (Figure 5-20). While both subplays offer attractive shares of the discounted barrel to investors, the Parkman subplay is more attractive from an investor point of view due to the lower per-unit cost. The share of the Federal government in this subplay appears to be similar to that of the more established tight oil plays, such as the Bakken and Bone Spring.

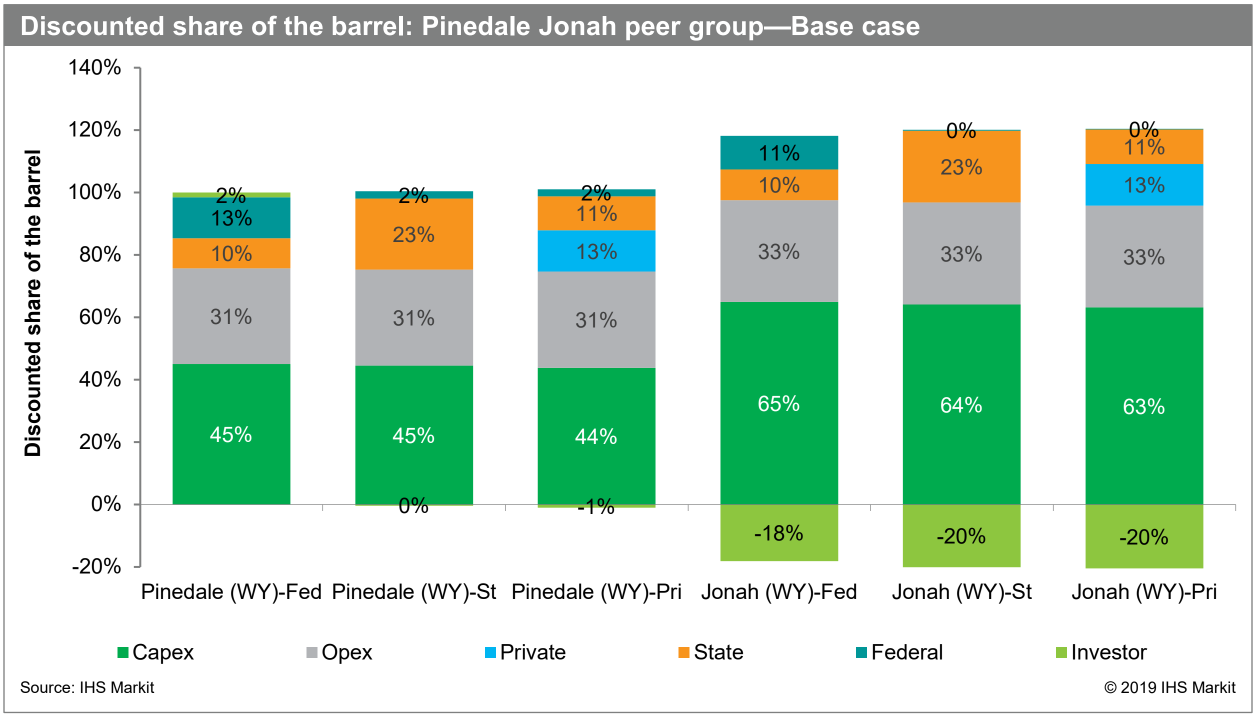
Figure 5-20. Discounted share of the barrel: Parkman/Turner/Shannon peer group—Base case



5.4.3.7 Pinedale Jonah Peer Group—Discounted Share of the Barrel

Of all the unconventional plays analyzed in this study, the Pinedale Jonah is the only one where investor shares of the discounted barrel are negative. While investors break even in Pinedale Federal and state lands, the Jonah subplay is not economic in the base case. The costs per unit in this play range between 75 percent and 95 percent of the discounted barrel in the base case (Figure 5-21). When royalties are applied on Federal, state and private mineral estates, the overall tax and cost burden on investors exceeds 100 percent, leading to negative investor returns in the Jonah subplay under the base case.

Figure 5-21. Discounted share of the barrel: Pinedale Jonah peer group—Base case

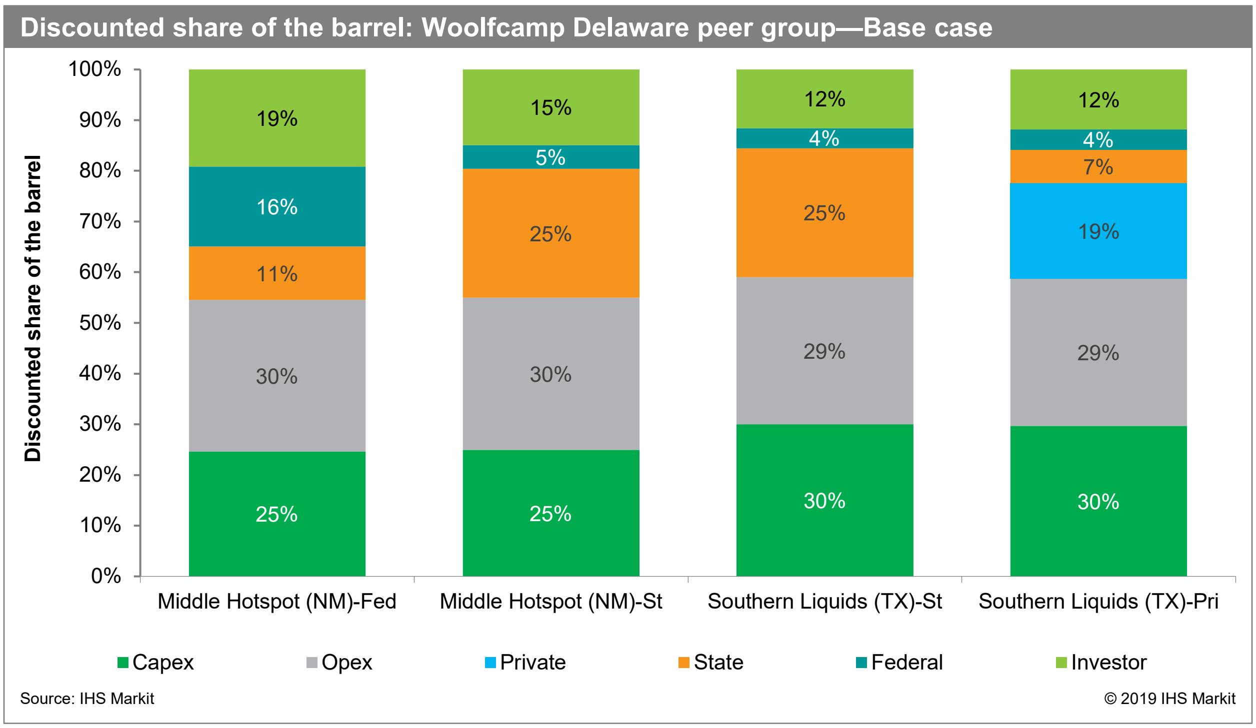


The application of royalties, severance, and ad valorem property taxes on gross revenues, irrespective of project profitability, hurts the bottom line in such investments as those displayed for the Jonah subplay in Figure 5-21. This is a characteristic of all fiscal systems in the United States, not just the Federal fiscal system. Given the lower royalty rates applicable on the Federal mineral estate, the negative impact on investor cash flow in this instance is slightly lower than that of the state and private mineral estates.

5.4.3.8 Wolfcamp Delaware Peer Group—Discounted Share of the Barrel

The Federal fiscal system in New Mexico is by far the most attractive one in the peer group from an investor point of view. The lower royalty rate on the Federal mineral estate results in a four-percentage-point difference between investor shares on Federal versus state lands in New Mexico. The contrast between Federal and state lands is bigger when compared to the Southern Liquids subplay in Texas, which has a higher capital cost per unit (Figure 5-22).

Figure 5-22. Discounted share of the barrel: Wolfcamp Delaware peer group—Base case



6 Fiscal System Alternatives

6.1 Non-discretionary Fiscal System Alternatives

The fiscal system alternatives analyzed in this section were requested by BLM. They do not necessarily represent plans or policy decisions at the time of the study. They are more theoretical and are applied to understand to what extent, if any, such alternatives could impact investment decision and affect the competitiveness of the Federal mineral estate.

6.1.1 Alaska Fiscal System Alternatives

Royalty rates on the Federal mineral estate in Alaska are announced in the lease sale notices. The latest lease sale notices for the NPR-A have prescribed royalties at 12.50 percent for low-potential areas and 16.67 percent for high-potential areas. This study has considered the 12.50 percent royalty rate as the statutory minimum applicable on the Federal mineral estate. The alternative rate considered in this chapter is 16.67 percent. Table 6-1 describes the existing and alternative rates analyzed in this study.

Table 6-1. Alaska alternative royalty rates

	Existing Federal fiscal system	State fiscal system	Alternative fiscal system
Royalty rate	12.50%	16.67%	16.67%

6.1.2 Lower-48 Conventional Resources Fiscal System Alternatives

In the case of conventional resources in the Lower 48, this chapter considers the royalty rates applicable on state land as alternative rates for each respective Federal fiscal system. This study evaluates the Federal fiscal system when the Federal royalty rate is increased to match the applicable state royalty rates. Table 6-2 describes the alternative Federal royalty rates by state.

Table 6-2. Lower-48 conventional alternative royalty rates

State	Statutory minimum Federal royalty rate (%)	State land (%)	Private land (%)	Alternative royalty rate (%)
Colorado	12.50	20.00	20.00	20.00
New Mexico	12.50	20.00	25.00	20.00
Texas	n/a	25.00	25.00	n/a
Montana	12.50	16.67	18.75	16.67
Wyoming	12.50	16.67	18.75	16.67
Utah	12.50	16.67	25.00	16.67

Source: IHS Markit

6.1.3 Unconventional Resources Fiscal System Alternatives

In the case of unconventional resources, this chapter considers the royalty rates applicable on state land as alternative rates for each respective Federal fiscal system (again, where the Federal royalty rate is increased to match the applicable state royalty rates). Where the play extends across state boundaries, the royalty rate of the state with the highest level of activity has been selected as alternative royalty. States that do not have significant Federal mineral estate are not evaluated at alternative royalty rates (see Chapter 1 for selection of jurisdictions and fiscal systems). Table 6-3 describes the alternative royalty rates by play.

Table 6-3. Unconventional alternative royalty rates

Play	States	Existing Federal royalty rate (%)	State land royalty rate (%)	Alternative royalty rate (%)
Bakken	Montana	n/a	16.67	n/a
	North Dakota	12.50	18.75	18.75
Bone Spring	New Mexico	12.50	20.00	20.00
	Texas	n/a	25.00	n/a
Haynesville	Louisiana	12.50	25.00	20.00
	Texas	n/a	25.00	n/a
Marcellus	Ohio	n/a	20.00	n/a
	Pennsylvania	n/a	20.00	n/a
	West Virginia	12.50	20.00	20.00
Niobrara	Colorado	12.50	20.00	n/a
	Wyoming	12.50	16.67	16.67
Parkman\Turner\Shannon Sands	Wyoming	12.50	16.67	16.67
Pinedale Jonah	Wyoming	12.50	16.67	16.67
Wolfcamp Delaware	New Mexico	12.50	20.00	20.00
	Texas	n/a	25.00	n/a

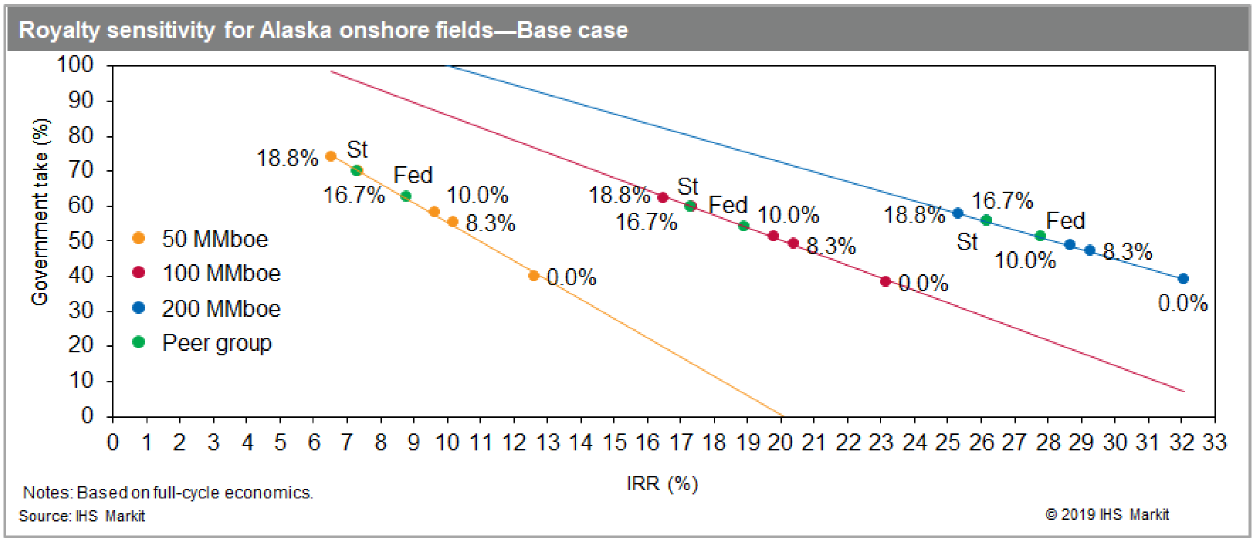
Source: IHS Markit

6.2 Comparative Analysis of Alternative Fiscal Systems

6.2.1 Alaska Fiscal System Alternative

Sensitivities performed on a wide range of royalty rates on the Federal mineral estate in Alaska produce a range of investor rates of return, between 8 percent and 19 percent under the base case for all three field sizes. In Figure 6-1, which displays results of the sensitivity analysis, each trend line represents a field size. The data points illustrate the impact of royalty rates to the investor IRR and government take as the royalty rate changes from 12.50 percent to 18.8 percent and zero percent. The trend lines indicate how sensitive a particular field is to royalty rate changes; a more-horizontal trend line has a higher response to the change in the royalty rate, while a more-vertical line indicates less elasticity. The lines are indicative only, and may be inaccurate beyond the data points. This analysis uses the statutory minimum royalty rate of 12.50 percent as a starting point. Any increase in the royalty rate to match the 16.67 percent royalty rate applicable on state land will undoubtedly have an impact on the government take, IRR, and NPV/boe. The impact is more significant in the case of smaller field sizes, both in terms of the degree of change in IRR, as well as in terms of the economic viability of such fields.

Figure 6-1. Royalty sensitivity for Alaska onshore fields—Base case



Overall, the returns to investors under a royalty alternative of 16.67 percent drop by one or two percentage points across the three price cases for this study. The Federal fiscal system under the alternative royalty rate would lose the advantage it had against investments in the peer group and becomes very sensitive to commodity price changes. In particular cases where the IRR was at 9 percent or 10 percent, onshore fields are now pushed further into uneconomic territory. While larger field sizes such as the 200 MMboe field were viable under the low price environment, they are no longer economic under the royalty alternative. Also, the development of small fields, i.e., 50 MMboe oil fields under the base price environment, could be affected by the 16.67 percent alternative. The IRR in that instance drops from 9 percent to 7 percent in the base case (Table 6-4).

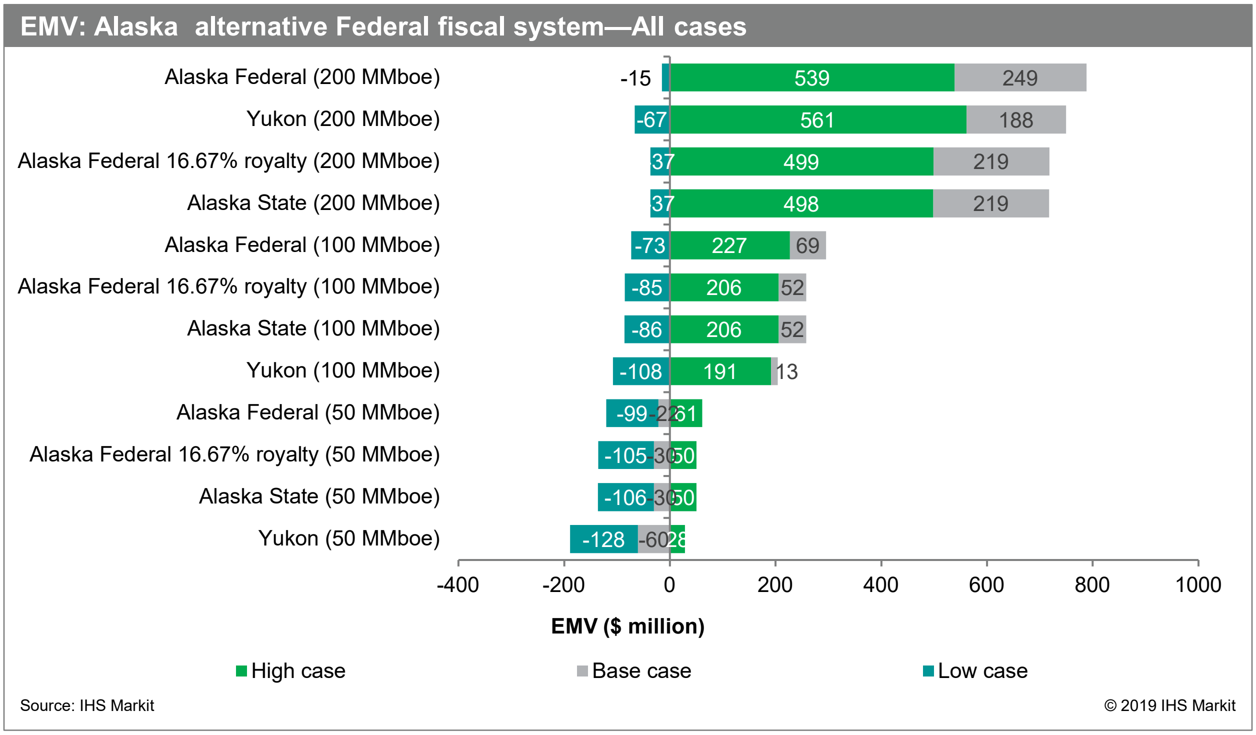
Table 6-4. IRR: Alaska Federal fiscal system alternative

Jurisdiction	IRR (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	200	100	50	200	100	50	200	100	50
Alaska State	39	30	19	26	17	7	8	0	0
Alaska Federal	40	31	20	28	19	9	10	1	0
Yukon	28	21	14	18	12	4	7	2	0
Federal 16.67% royalty	39	30	19	26	17	7	8	0	0

Source: IHS Markit

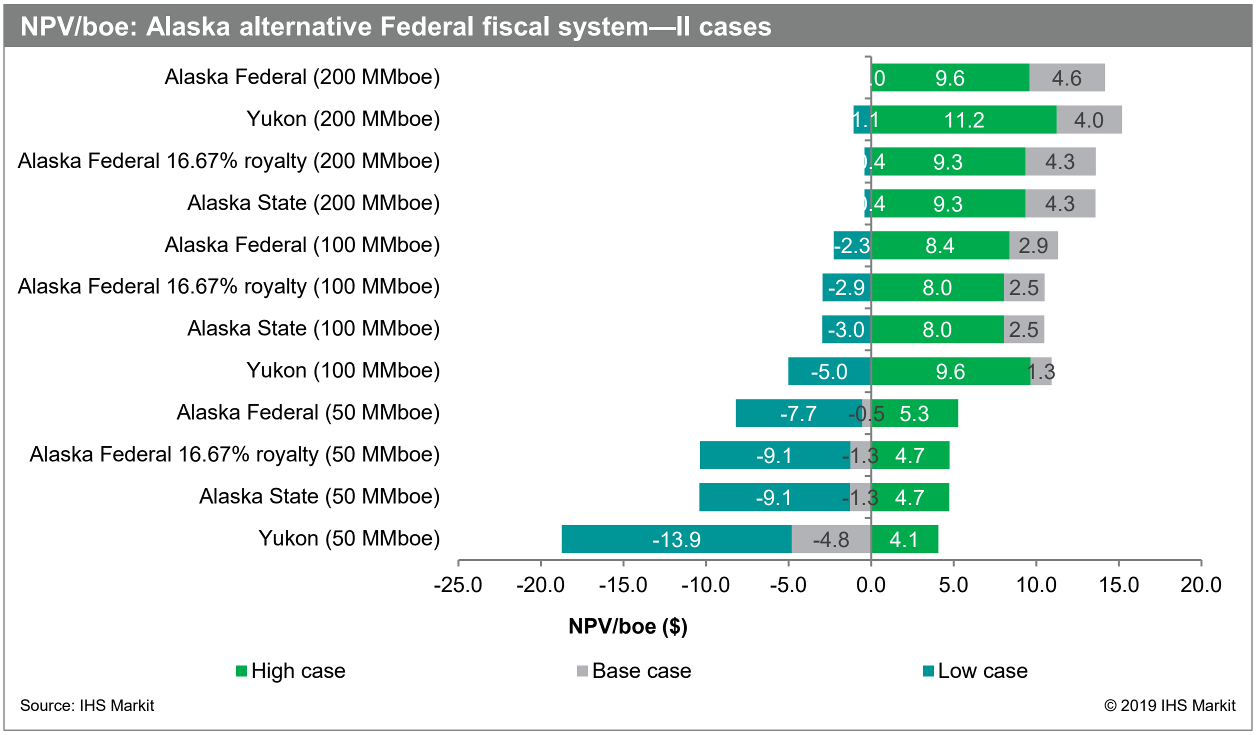
The Alaska alternative Federal fiscal system performs about the same as the state fiscal system when the royalty rate is increased to 16.67 percent to match that of the state (Figure 6-2). The results are still robust for the large and medium sized fields under the high and base price scenarios; however, the value lost per exploratory well for the medium sized field—likely to be representative of most investments in Alaska onshore—is 24 percent in the base case. After the 2014 drop in commodity prices, most companies use prices well below those of the base case scenario in this study to make investment decisions. Therefore, ability of investments to withstand cycles of low commodity prices is important.

Figure 6-2. EMV: Alaska alternative Federal fiscal system—All cases



The NPV/boe analysis yields similar results to the EMV analysis, showing the Federal fiscal system with the same result as the Alaska state. The differences in bonuses and rentals is not significant enough to result in measurable differences between the two fiscal systems (Figure 6-3)

Figure 6-3: Alaska alternative Federal fiscal system—All cases



From a government take perspective, the 16.67 percent royalty aligns the government take on the Federal mineral estate with that on state land. This results in an increase of the government take by three percentage points in the high case to five percentage points in the base case and nine percentage points in the low case (Table 6-5). Considered separately, the shift in government take does not really shed light on the impact such measures may have on investment decisions. Therefore, an analysis of the economic indicators such as IRR or NPV/boe is necessary.

Table 6-5. Government take: Alaska Federal fiscal system alternative

Jurisdiction	Government take (%)								
	High case			Base case			Low case		
	Reserve size (MMboe)			Reserve size (MMboe)			Reserve size (MMboe)		
	200	100	50	200	100	50	200	100	50
Alaska State	58	59	61	56	60	70	74	100	100
Alaska Federal	55	56	57	51	54	63	65	93	100
Yukon	49	51	57	53	60	74	66	85	100
Federal 16.67 % royalty	58	59	61	56	60	70	74	100	100

Source: IHS Markit

6.2.2 Lower-48 Conventional Resources Fiscal System Alternatives

In the case of conventional resources, where economics results are marginal at best, the application of alternative fiscal systems that result in an increase of the share accruing to the Federal government could negatively affect the ability of such projects to attract investors. Given the maturity of the conventional formations in the United States and the competitive disadvantage that conventional drilling has over unconventional drilling in the Lower 48—unconventional wells have significantly lower break-even costs than conventional resources—an increase of the royalty rate could affect investment decisions for the small- and medium-sized fields (Appendix D).

While at a first glance both the percentage decline in the IRR and the $/bbl value loss to investors in relation to the NPV/boe may not appear substantial, Lower-48 conventional resources with marginal economics are more sensitive to price fluctuations, and thus more vulnerable to any change in the status quo.

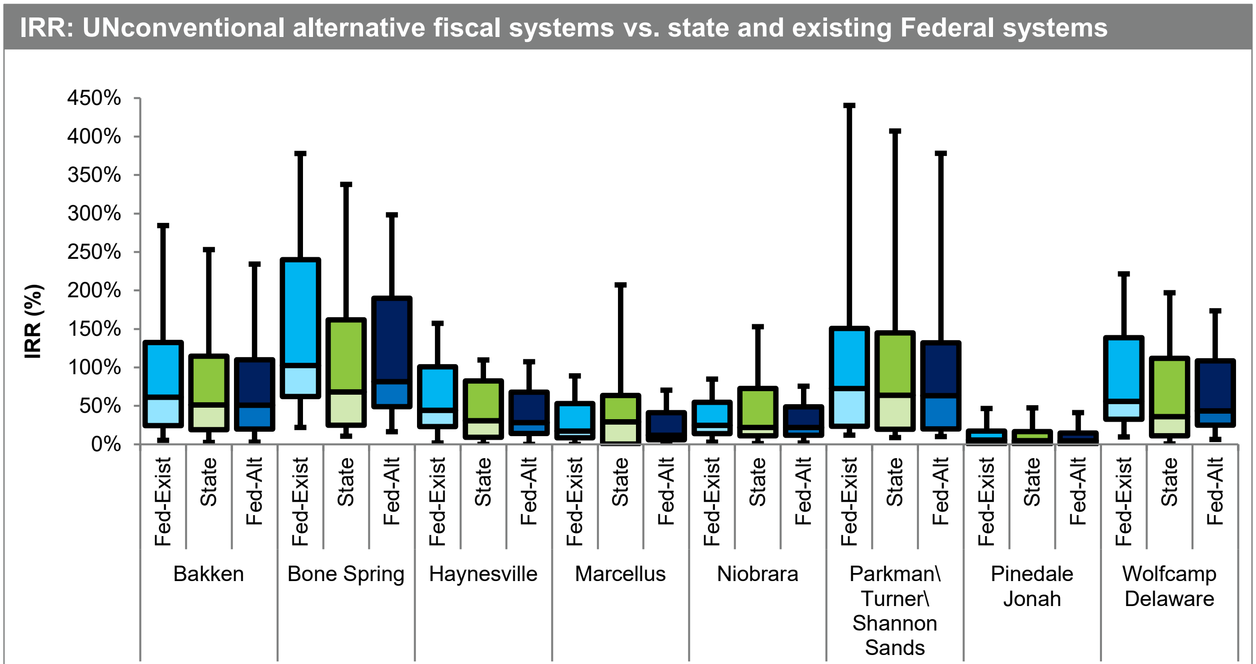
The application of alternative fiscal systems on the Federal mineral estate generally aligns the government take on the Federal mineral estate with that on state land (Appendix D). The alternative fiscal systems result in an increase by five to seven percentage points of the average government take for 5 MMboe oil fields in the high and base price scenarios and six percentage points for the 2 MMboe oil fields in the high price scenario. As expected, the introduction of alternative fiscal systems aligned with the respective state fiscal systems does not change the status quo of natural gas conventional projects. The overwhelming majority of the cases are uneconomic, resulting in a 100 percent government take.

6.2.3 Unconventional Resources Fiscal System Alternatives

The economic analysis for unconventional resources in Chapter 5 assumes a uniform type curve per subplay among all fiscal systems in the respective jurisdictions. While it is not within the scope of this study to assess the differences in type curves for the Federal mineral estate versus state and private mineral estates in the future, wells drilled during the 2017–18 period in the Bakken, Bone Spring, and Wolfcamp Delaware were segregated into a Federal versus state and private mineral estate category to establish separate-type curves for the Federal mineral estate. See the introduction to Chapter 5 for more-detailed information on the approach for cost and economic models. The separate type curves on the Federal mineral estate represent the current state of wells drilled in the three plays mentioned above in the 2017–18 period, and are not intended to represent a trend or relationship for drilling on Federal versus state and private mineral estates.

While the impact of royalty rate alternatives on the Federal mineral estate varies by play and subplay, overall, the median IRR drops from 45 percent to 38 percent on the Federal mineral estate across all plays, bringing it somewhat lower to the IRR investors would expect in the mineral estates of the respective states—the median IRR for all the states is 38 percent across all plays (Figure 6-4). There are variances in each jurisdiction, depending on the differences among mineral estates with regards to signature bonuses payable and time to first drill. Figure 6-4 shows the distribution range of the IRR results for all subplays within a particular play under all three price scenarios for the existing Federal fiscal system, the alternative Federal fiscal system, and the state fiscal systems. The state IRR distribution in each play displays the combined results for the mineral estates of the states that are part of the play or subplay. For example, the box and whisker for the state fiscal system in the Bakken represents the distribution of the IRRs generated for the states of North Dakota and Montana analyzed for that play. The intent is to focus on how the alternative Federal fiscal system compares with the existing Federal fiscal system and the state fiscal systems for the respective plays.

Figure 6-4. IRR: Unconventional alternative fiscal systems vs. state and existing Federal systems



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the IRR in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. Fed-Exist is the existing Federal system and Fed-Alt is the alternative Federal system.

Source: IHS Markit

Overall, the unconventional plays yield robust rates of return to investors under the high and base price scenarios—that is true of the returns on the Federal mineral estate. Some of the subplays—such as New Fairway in the Bakken, New Mexico and Texas Deep in Bone Spring, Niobrara Wattenberg, and Parkman—yield acceptable rates of return even under the low oil price scenario. While there are instances where the IRR under alternative fiscal systems is lower than that of the respective state fiscal system, overall the alternative Federal fiscal systems generally do not appear to push the IRR of viable cases below 10 percent, except in the case of Jonah Pinedale under the base case (Table 6-6).

Table 6-6. IRR: Unconventional resources fiscal system alternatives

Play	Jurisdiction	IRR (%)		
		High case	Base case	Low case
Bakken	New Fairway (ND)-Federal	284	81	19
	New Fairway (ND)-Federal-Alt	234	68	15
	New Fairway (ND)-State	253	68	14
	New Fairway (ND)-Private	244	66	13
	Parshall (ND)-Federal	150	41	5
	Parshall (ND)-Federal-Alt	124	34	3
	Parshall (ND)-State	130	34	2
	Parshall (ND)-Private	125	33	2
	Elm Coulee (MT)-State	166	47	8
Bone Spring	New Mexico Deep (NM)-Federal	378	102	22
	New Mexico Deep (NM)-Federal-Alt	298	81	16
	New Mexico Deep (NM)-State	338	82	15
	New Mexico Deep (NM)-Private	303	73	13
	Texas Deep (TX)-State	188	54	11

Play	Jurisdiction	IRR (%)		
		High case	Base case	Low case
Haynesville	Haynesville Core (LA)-Federal	157	44	2
	Haynesville Core (LA)-Federal-Alt	107	28	0
	Haynesville Core (LA)-State	110	29	0
	Haynesville Core (LA)-Private	93	23	0
	Shelby Trough (TX)-State	99	33	3
Marcellus	Marcellus Super Core (PA)-State	207	51	1
	Marcellus Super Core (WV)-State	181	44	0
	Marcellus Super Core (PA)-Private	211	52	1
	Marcellus Southwest Core (WV)-Federal	89	17	0
	Marcellus Southwest Core (WV)-Federal-Alt	70	12	0
	Marcellus Southwest Core (PA)-State	82	15	0
	Marcellus Southwest Core (PA)-Private	83	15	0
	Marcellus Periphery (OH)-State	57	12	0
Niobrara	Niobrara DJ (WY)-Federal	85	25	3
	Niobrara DJ (WY)-Federal-Alt	76	22	2
	Niobrara DJ (WY)-State	79	22	1
	Niobrara DJ (CO)-State	73	20	1
	Niobrara DJ (CO)-Private	73	20	1
	Niobrara Wattenberg (CO)-State	153	47	11
	Niobrara Wattenberg (CO)-Private	153	47	11
Parkman\ Turner\ Shannon Sands	Parkman (WY)-Federal	440	97	16
	Parkman (WY)-Federal-Alt	378	84	13
	Parkman (WY)-State	407	85	12
	Parkman (WY)-Private	379	80	11
	Turner Sands (WY)-Federal	169	48	12
	Turner Sands (WY)-Federal-Alt	148	42	10
	Turner Sands (WY)-State	165	42	9
	Turner Sands (WY)-Private	154	40	8
Pinedale Jonah	Pinedale (WY)-Federal	47	11	0
	Pinedale (WY)-Federal-Alt	41	9	0
	Pinedale (WY)-State	47	10	0
	Pinedale (WY)-Private	46	9	0
	Jonah (WY)-Federal	19	0	0
	Jonah (WY)-Federal-Alt	17	0	0
	Jonah (WY)-State	19	0	0
	Jonah (WY)-Private	18	0	0
Wolfcamp Delaware	Middle Hotspot (NM)-Federal	222	56	10
	Middle Hotspot (NM)-Federal-Alt	174	43	6
	Middle Hotspot (NM)-State	197	43	5
	Southern Liquids (TX)-State	135	29	1
	Southern Liquids (TX)-Private	139	30	1

Source: IHS Markit

The values per boe generated for the unconventional plays included in this study are generally very reasonable under the high and base scenarios for the majority of the plays. In six out of eight plays, the alternative Federal fiscal systems fail to deliver a positive NPV/boe under the low price scenario, as do the respective state and private fiscal systems in the same peer group. Figures 6-5 to 6-8 display the NPV/boe for the low, base and high cases on stacked horizontal bars. The sum of the three cases yields an aggregate value that is used to determine rank order from the largest to the smallest value.

Figure 6-5. NPV/boe: Bakken and Bone Spring plays

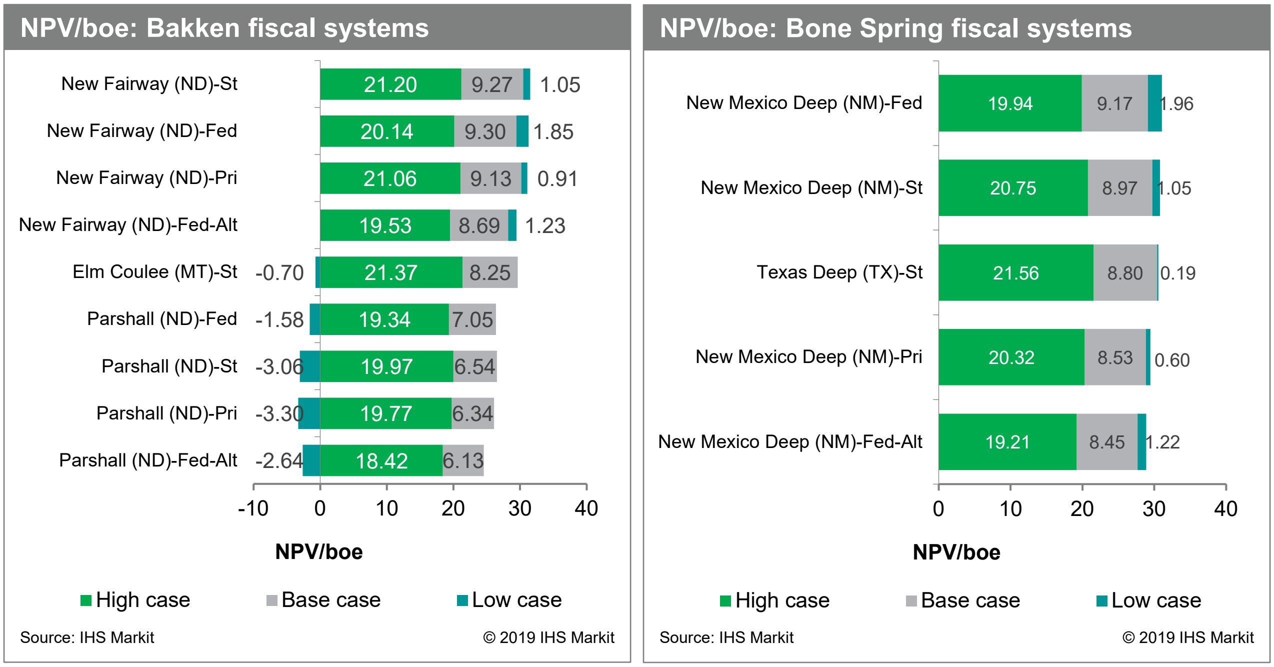


Figure 6-6. NPV/boe: Haynesville and Marcellus plays

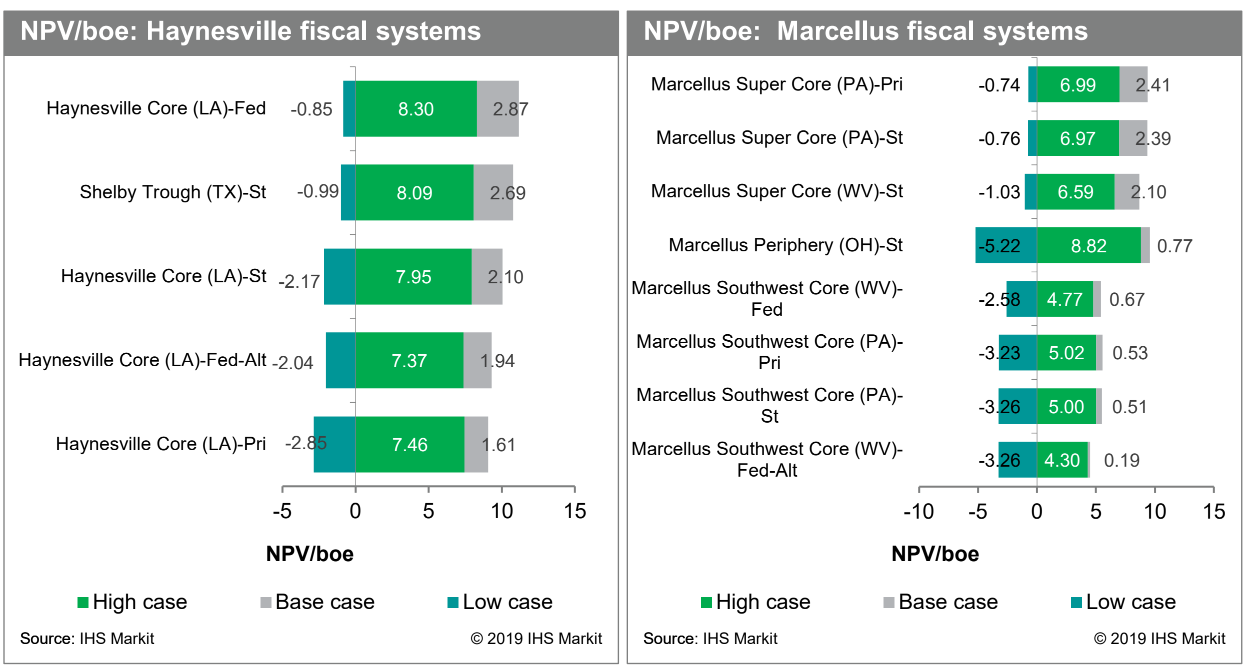


Figure 6-7. NPV/boe: Niobrara and Parkman\Turner\Shannon Sands plays

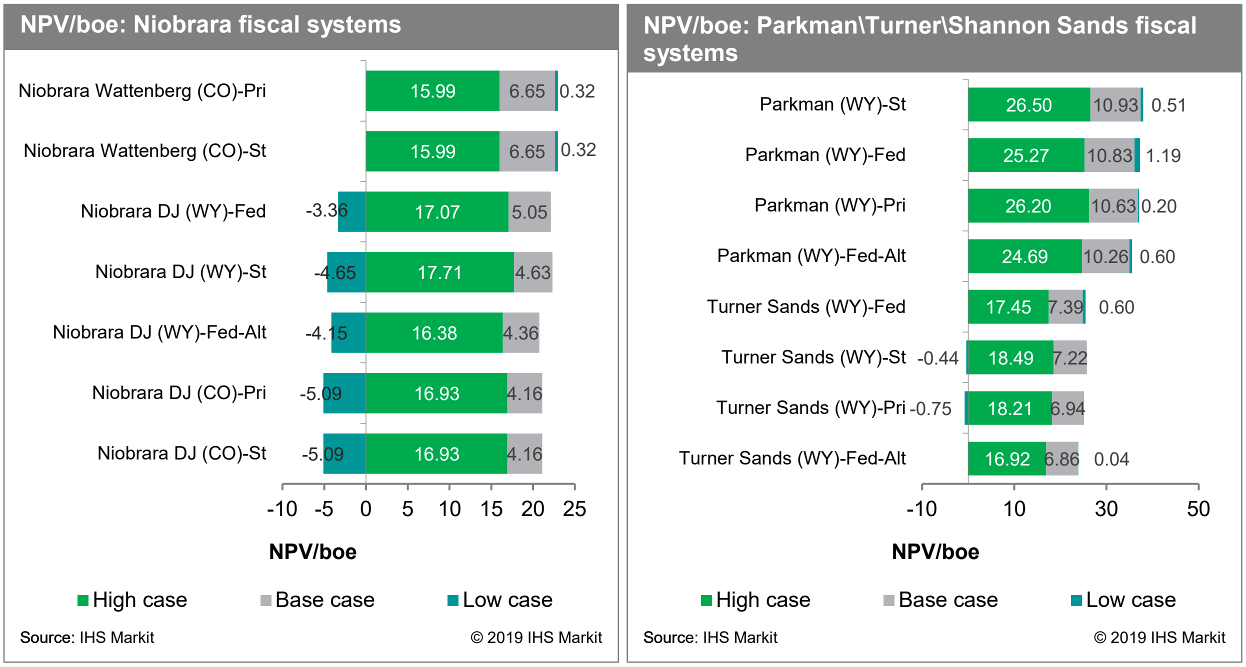
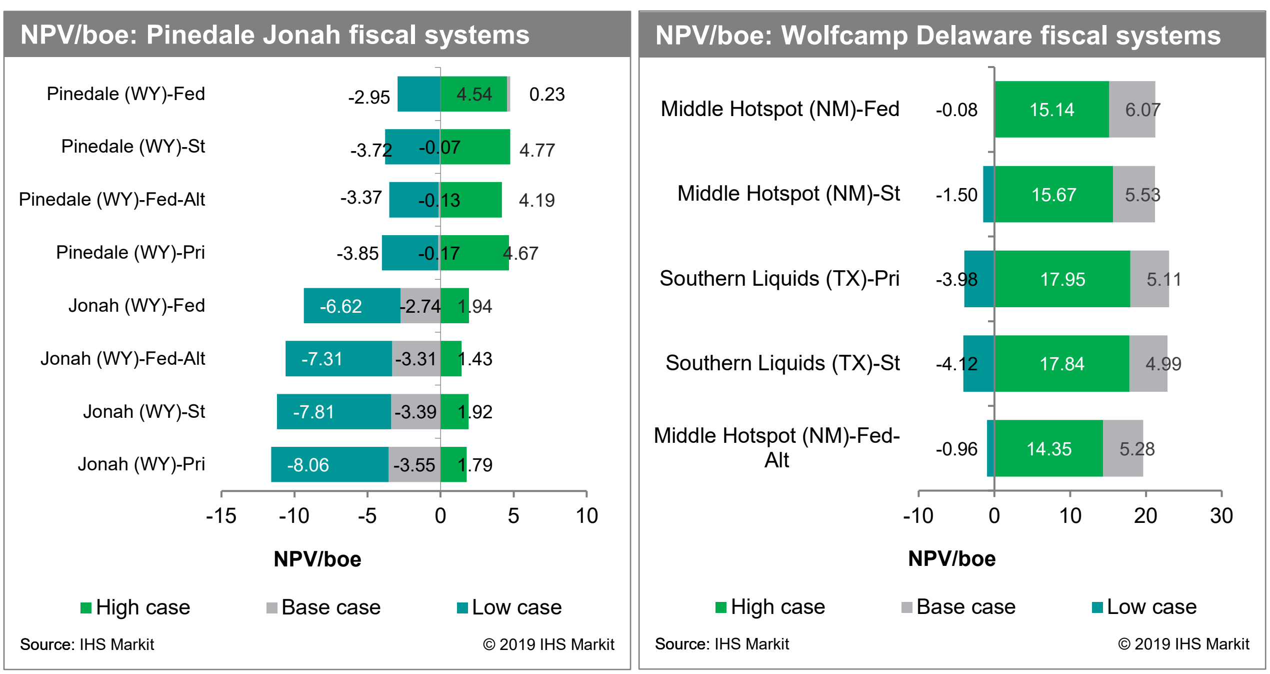


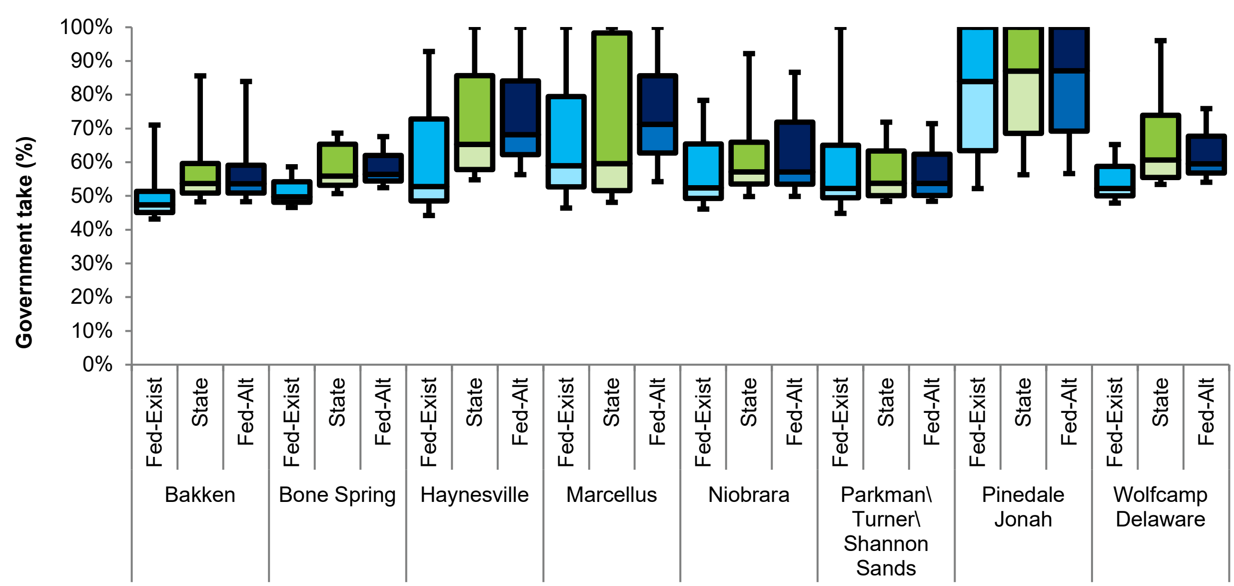
Figure 6-8. NPV/boe: Pinedale Jonah and Wolfcamp Delaware plays



The alternative Federal fiscal systems for unconventional plays increase the median government take by seven percentage points, on average, and widen the range of such takes in the respective plays. The increase in the median government take varies by play and ranges from three percentage points in the case of Parkman\Turner\Shannon Sands to 15 percentage points in the case of Haynesville (Figure 6-9). The widening of the range of the government take is a result of a higher degree of regressivity in the alternative fiscal systems.

Figure 6-9. Government take: Unconventional alternative fiscal systems vs. state and existing Federal systems

Government take: Unconventional alternative fiscal systems vs. state and existing Federal systems



Notes: The distribution of values from all cases are represented here. The boxes show the upper and lower quartile ranges of the government take in the respective jurisdictions. The whiskers show the extreme ranges. The lines in the middle represent the median. Fed-Exist is the existing Federal system and Fed-Alt is the alternative Federal system.

Source: IHS Markit

Table 6-7. Government take: Unconventional resources fiscal system alternatives

Play	Fiscal system by subplay	Government take (%)		
		High case	Base case	Low case
Bakken	New Fairway (ND)-Fed	43%	45%	52%
	New Fairway (ND)-Fed-Alt	48%	51%	60%
	New Fairway (ND)-St	48%	51%	61%
	New Fairway (ND)-Pri	49%	52%	62%
	Parshall (ND)-Fed	45%	49%	71%
	Parshall (ND)-Fed-Alt	51%	56%	84%
	Parshall (ND)-St	51%	56%	86%
	Parshall (ND)-Pri	52%	58%	88%
	Elm Coulee (MT)-St	47%	52%	67%
Bone Spring	New Mexico Deep (NM)-Fed	47%	50%	59%
	New Mexico Deep (NM)-Fed-Alt	52%	56%	68%
	New Mexico Deep (NM)-St	52%	57%	68%
	New Mexico Deep (NM)-Pri	56%	61%	74%
	Texas Deep (TX)-St	51%	55%	69%

Play	Fiscal system by subplay	Government take (%)		
		High case	Base case	Low case
Haynesville	Haynesville Core (LA)-Fed	44%	53%	93%
	Haynesville Core (LA)-Fed-Alt	56%	68%	100%
	Haynesville Core (LA)-St	56%	68%	100%
	Haynesville Core (LA)-Pri	61%	74%	100%
	Shelby Trough (TX)-St	55%	63%	92%
Marcellus	Marcellus Super Core (PA)-St	49%	56%	98%
	Marcellus Super Core (WV)-St	52%	60%	100%
	Marcellus Super Core (PA)-Pri	49%	56%	97%
	Marcellus Southwest Core (WV)-Fed	46%	59%	100%
	Marcellus Southwest Core (WV)-Fed-Alt	54%	71%	100%
	Marcellus Southwest Core (PA)-St	52%	66%	100%
	Marcellus Southwest Core (PA)-Pri	52%	66%	100%
	Marcellus Periphery (OH)-St	48%	59%	100%
Niobrara	Niobrara DJ (WY)-Fed	46%	52%	78%
	Niobrara DJ (WY)-Fed-Alt	50%	57%	87%
	Niobrara DJ (WY)-St	50%	57%	88%
	Niobrara DJ (CO)-St	54%	61%	92%
	Niobrara DJ (CO)-Pri	54%	61%	92%
	Niobrara Wattenberg (CO)-St	52%	56%	66%
	Niobrara Wattenberg (CO)-Pri	52%	56%	66%
Parkman\Turner\Shannon Sands	Parkman (WY)-Fed	45%	49%	65%
	Parkman (WY)-Fed-Alt	48%	54%	71%
	Parkman (WY)-St	48%	54%	72%
	Parkman (WY)-Pri	50%	56%	75%
	Turner Sands (WY)-Fed	45%	49%	60%
	Turner Sands (WY)-Fed-Alt	49%	54%	65%
	Turner Sands (WY)-St	49%	54%	66%
	Turner Sands (WY)-Pri	51%	56%	69%
Pinedale Jonah	Pinedale (WY)-Fed	52%	68%	100%
	Pinedale (WY)-Fed-Alt	57%	74%	100%
	Pinedale (WY)-St	56%	74%	100%
	Pinedale (WY)-Pri	58%	77%	100%
	Jonah (WY)-Fed	62%	100%	100%
	Jonah (WY)-Fed-Alt	68%	100%	100%
	Jonah (WY)-St	67%	100%	100%
	Jonah (WY)-Pri	69%	100%	100%
Wolfcamp Delaware	Middle Hotspot (NM)-Fed	48%	52%	65%
	Middle Hotspot (NM)-Fed-Alt	54%	60%	76%
	Middle Hotspot (NM)-St	54%	60%	78%
	Southern Liquids (TX)-St	53%	62%	96%
	Southern Liquids (TX)-Pri	53%	61%	95%

Source: IHS Markit

6.2.3.1 Analysis of Separate Federal Mineral Estate Type Curves

Each subplay assumes a uniform type curve for all jurisdictions. Not enough production data are available to create distinct type curves to differentiate by mineral estate. However, three plays that have a mixed ratio of Federal, state, and private drilled wells, specific type curves for the Federal mineral estate are introduced to see how competitive the Federal mineral estate would be when accounting for geological differences.

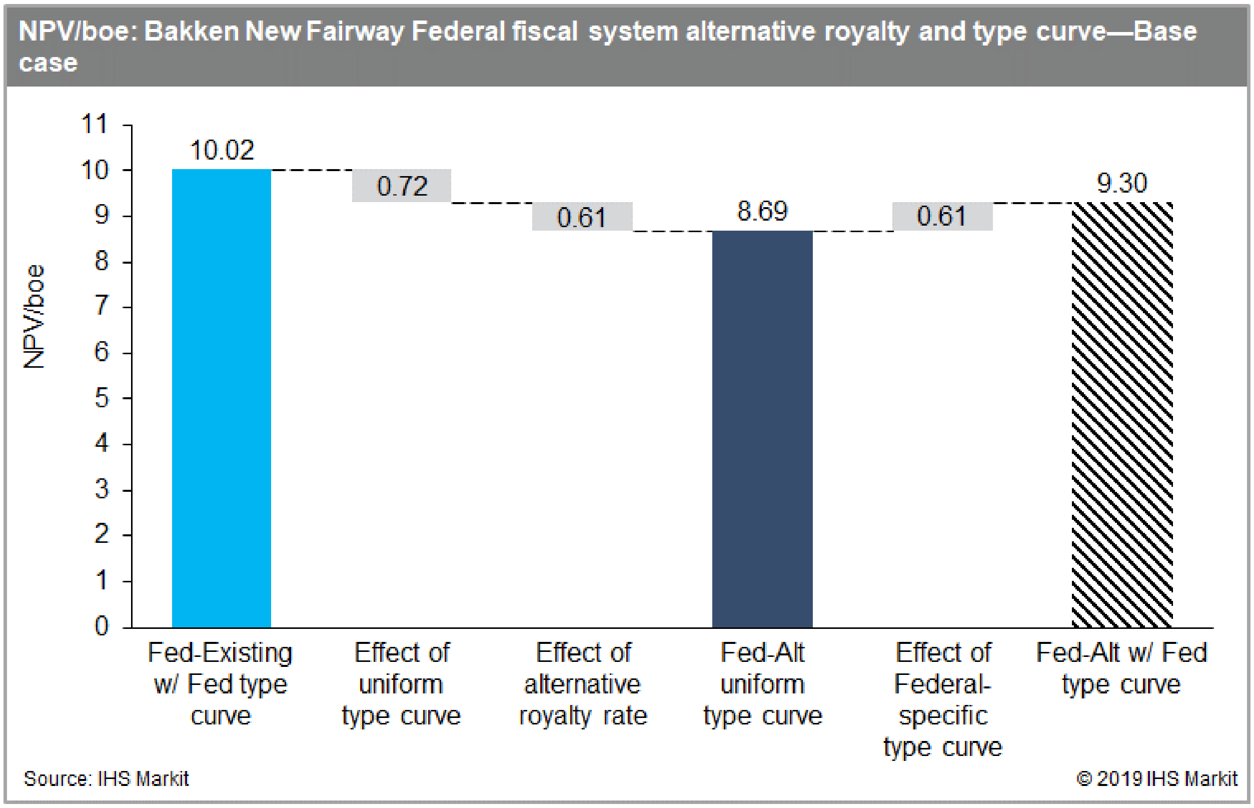
> **Federal jurisdiction with alternative royalty rate and specific type curve chart:**
>
> Each stacked column represents a model combination: Federal existing, Federal alternative, and a new output Federal alternative with specific type curve. The floating bars in between each model case show the difference between each case while changing one variable at a time.

The plays with mixed drilling across mineral estates are the Bakken, Bone Spring, and Wolfcamp Delaware. For further explanation about the approach and selection of plays for separate type curves see Chapter 5. The type curves are generated at the subplay level using wells in the Federal mineral estate. Wells drilled earlier than 2017 use older completion technology and shorter lateral lengths, which would result in outdated productivity that does not reflect today's drilling. The subplays with Federal mineral estate-type curves are New Fairway and Parshall (Bakken), New Mexico Deep (Bone Spring), and Middle Hotspot (Wolfcamp Delaware).

Wells in the Bakken New Fairway's Federal mineral estate perform slightly better than the uniform type curve and could compete with the state at the alternative royalty rate. The decrease in investor NPV/boe with the higher royalty rate is compensated by the more productive type curve in the Federal mineral estate by almost the same amount of $0.61 per barrel oil equivalent. Figure 6-10 displays the following NPV/boe alternatives:

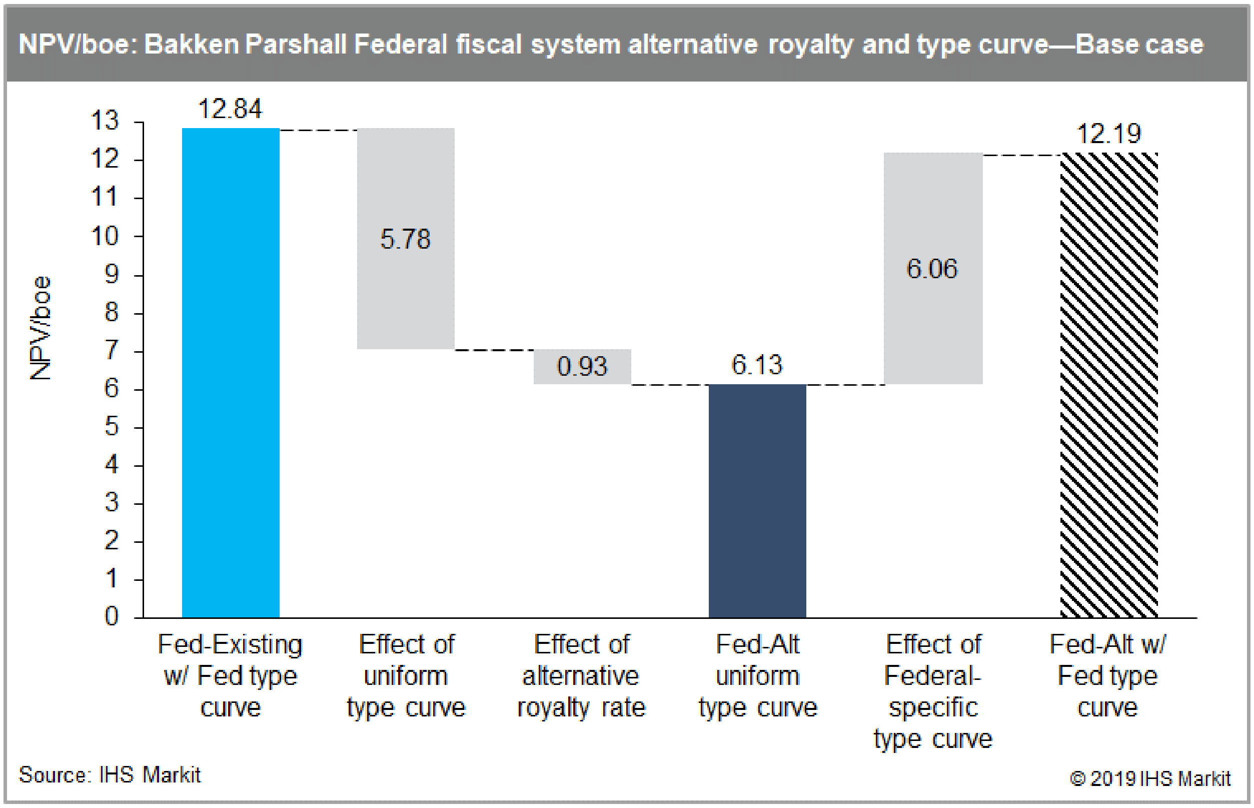
- the NPV/boe under the current Federal fiscal system using the uniform type curve for the subplay,
- the difference between the NPV/boe of the existing Federal fiscal system and the alternative Federal fiscal system resulting from application of the alternative royalty rate,
- the resulting NPV/boe for the alternative Federal fiscal system,
- the difference between the NPV/boe of the alternative Federal fiscal system rand the application of the Federal mineral estate type curve, and
- the resulting NPV/boe for the alternative Federal fiscal system using the Federal mineral estate type curve.

Figure 6-10. NPV/boe: Bakken New Fairway Federal fiscal system alternative royalty and type curve—Base case



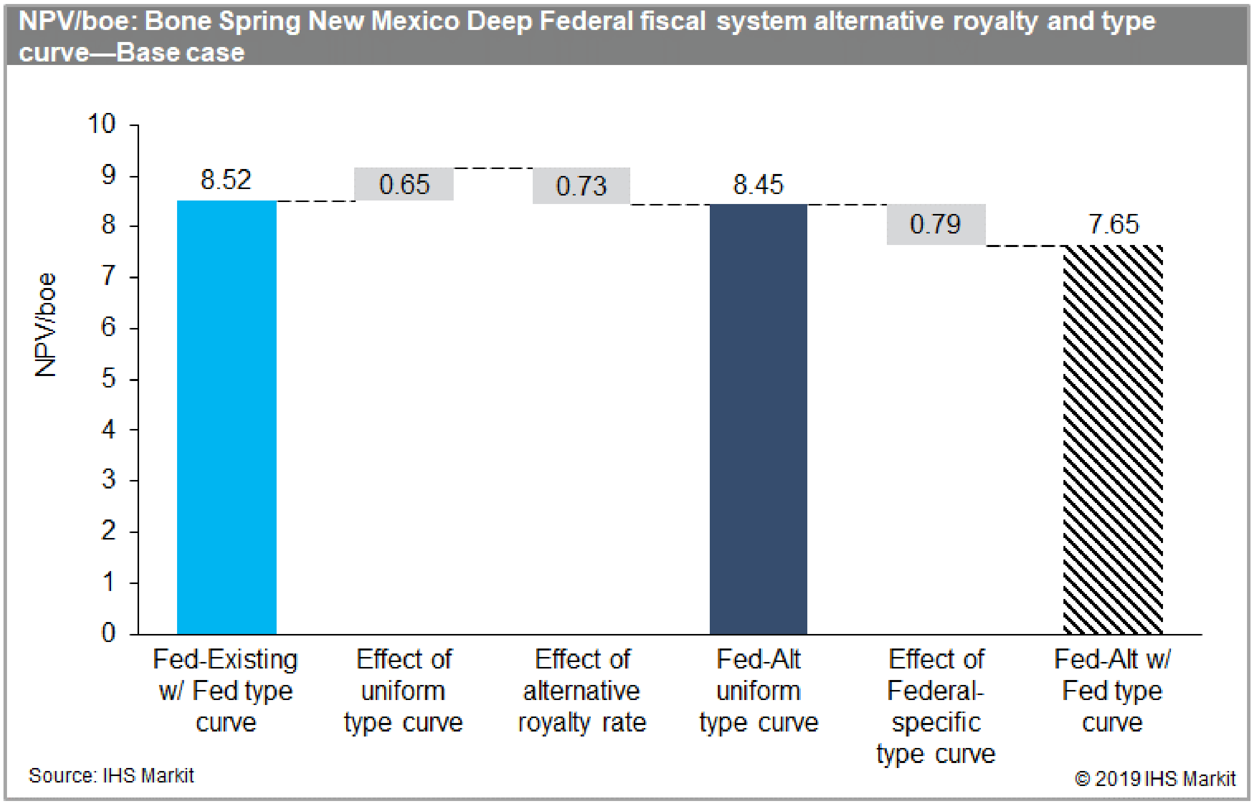
Under the existing Federal mineral estate using the uniform type curve, the Bakken Parshall subplay shows an NPV/boe of $7.05 while the New Fairway is $9.30, suggesting that New Fairway is a more productive and attractive investment area. However, the Federal mineral estate in the Bakken's Parshall subplay lie in the core area of drilling and reflects a much higher type curve than the uniform type curve. The history of bonus bids in North Dakota confirms the superior geology, with a higher range for the Federal mineral estate than state and private lands. In the Bakken Parshall, raising the royalty rate to the state level decreases the NPV/boe by almost a dollar, but with the Federal mineral estate type curve, the NPV/boe almost doubles from $6.13 to $12.19 (Figure 6-11).

Figure 6-11. NPV/boe: Bakken Parshall Federal fiscal system alternative royalty and type curve—Base case



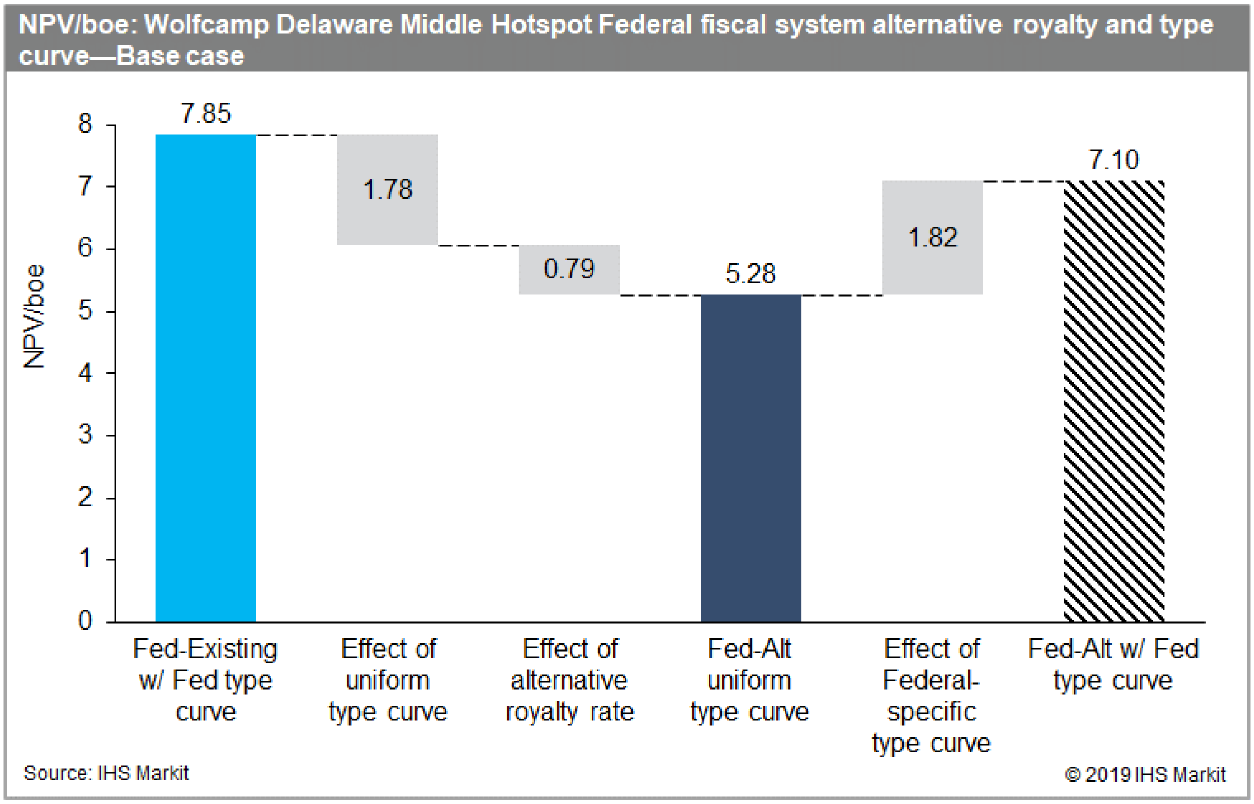
In the Bone Spring, the Federal mineral estate spans only one subplay, the New Mexico Deep. The Bone Spring's Federal mineral estate underperforms against the uniform type curve, making the Federal jurisdiction less competitive with the state. After using the alternative royalty rate, the NPV per barrel oil equivalent decreases by $0.73. When assuming the Federal mineral estate type curve, the loss in NPV/boe is around the same magnitude of impact from changing the royalty rate (Figure 6-12).

Figure 6-12. NPV/boe: Bone Spring New Mexico Deep Federal fiscal system alternative royalty and type curve—Base case



Wells in the Wolfcamp Delaware's Federal mineral estate outperform the uniform type curve, indicating stronger competition with the state. The NPV per barrel oil equivalent decreases by $0.79 after changing to the alternative royalty rate, but then increases by $1.82 when assuming the Federal mineral estate type curve (Figure 6-13).

Figure 6-13. NPV/boe: Bone Spring New Mexico Deep Federal fiscal system alternative royalty and type curve—Base case



6.3 Discretionary Royalty Relief

IHS Markit was asked to analyze a discretionary royalty relief alternative for producing leases that are approaching the economic limit, i.e., have earnings that cannot sustain production under existing royalty rates and relief would likely result in additional production. The analysis assumes that investors continue production as long as it is economic to do so. Economic production is measured by positive operating profit (revenue less operating costs, royalties, and taxes) on a cumulative basis (i.e., production ceases after reaching the highest point of cumulative operating profit); continuing beyond that point would create only negative value. To extend the production life, end-of-life incentives for Lower-48 conventional production would have to be executed on a per-well basis—onshore developments and permitting is done on a per-well basis. The end-of-life sensitivity conducted for this study is defined by two main variables:

1. Average daily production rate threshold, and
2. Royalty rate reduction.

IHS Markit applied a reduced royalty rate whenever daily production from a well fell below the average daily production rate threshold for at least 12 months in a row. To follow the IRS definition of a stripper well, the average daily production rate threshold was set to 15 boe/d.

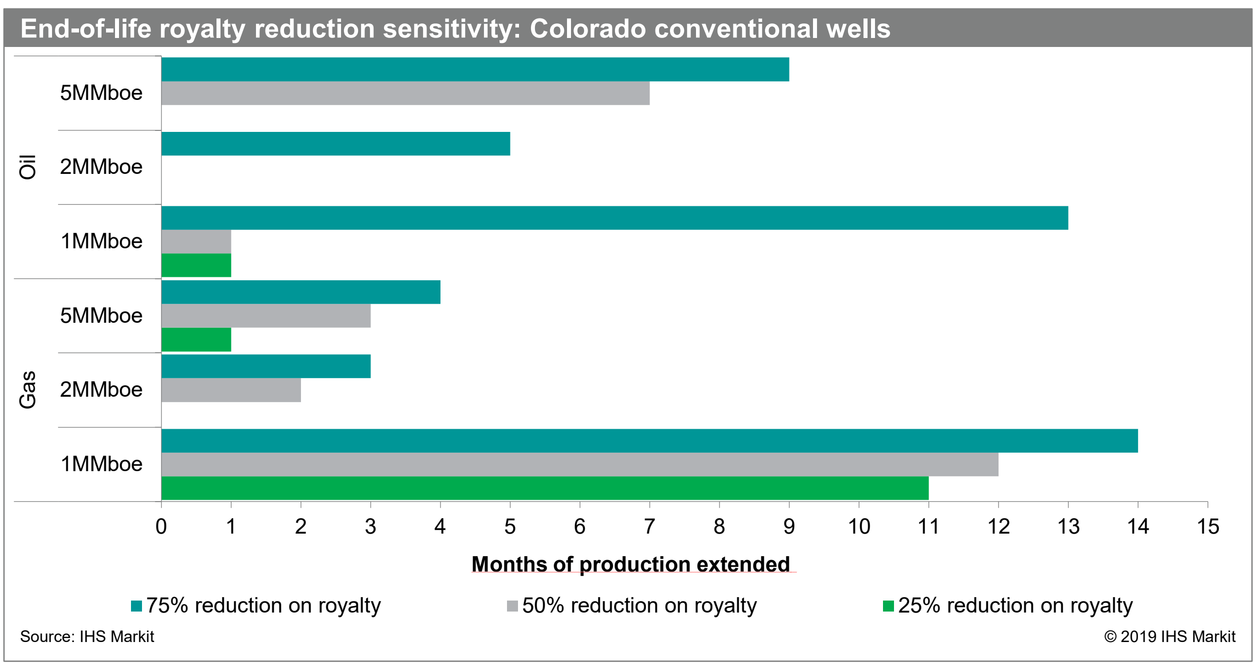
For each state with a Federal jurisdiction, IHS Markit tested three tiers of royalty rate reduction: 25 percent, 50 percent, and 75 percent, where 75 percent has the greatest reduction in royalty rate. The study measures the incremental months of production resulting from the end-of-life incentive to assess the impact of the incentive. Observations include:

- Greater benefit occurs for uneconomical projects that previously reached an economic limit;
- Some fields resulted in no well life extension until 75 percent royalty reduction was applied;
- The degree of impact varies among the cases without a clear pattern since it depends on when the well reached its economic limit originally; and
- Wells with oil as the primary product tend to have more months of production extended than wells with primary gas production—on average, gas wells extend from one to three months while oil wells extend from three to nine months.

As Figures 6-14 to 6-18 suggest, the benefits of such a scheme, i.e., the extent to which the life of the well is extended and how much relief it requires, vary among wells and type of primary production. Hence, this is an alternative that can be applied only on a discretionary basis upon consideration of the economic life of each well.

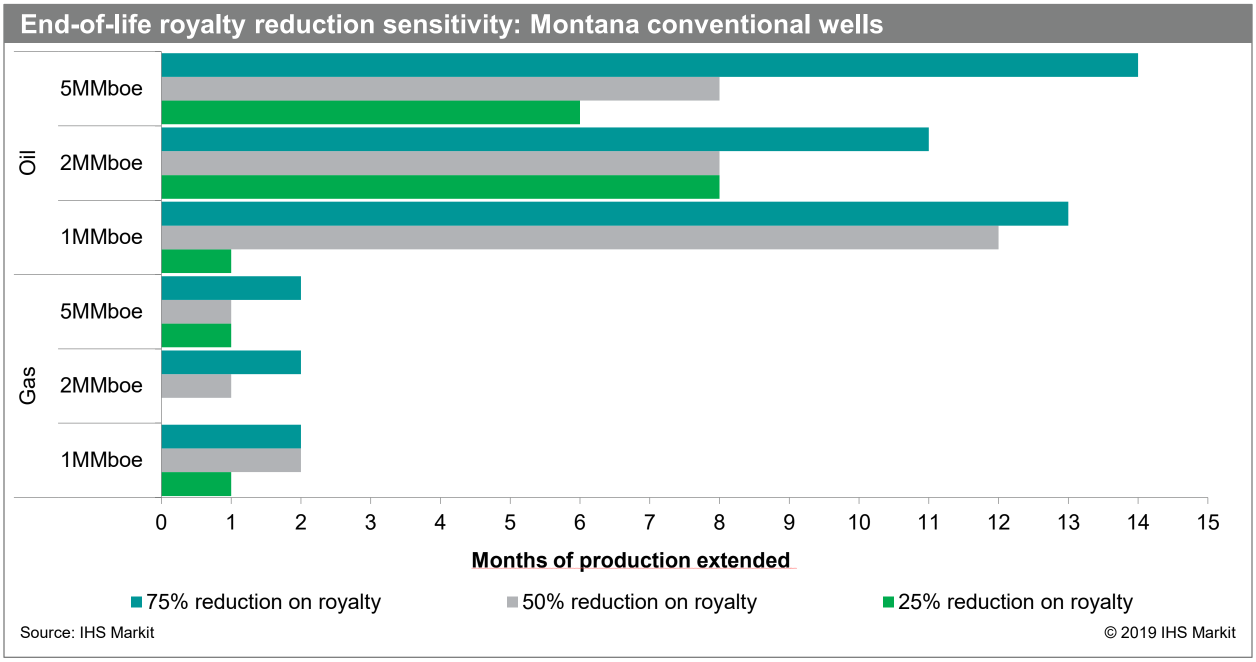
Colorado oil wells need at least 50–75 percent royalty reduction for an impact, whereas the gas wells are more sensitive—the 1 MMboe gas case increases by 11 months with a 25 percent royalty reduction.

Figure 6-14. End-of-life royalty reduction sensitivity: Colorado conventional wells



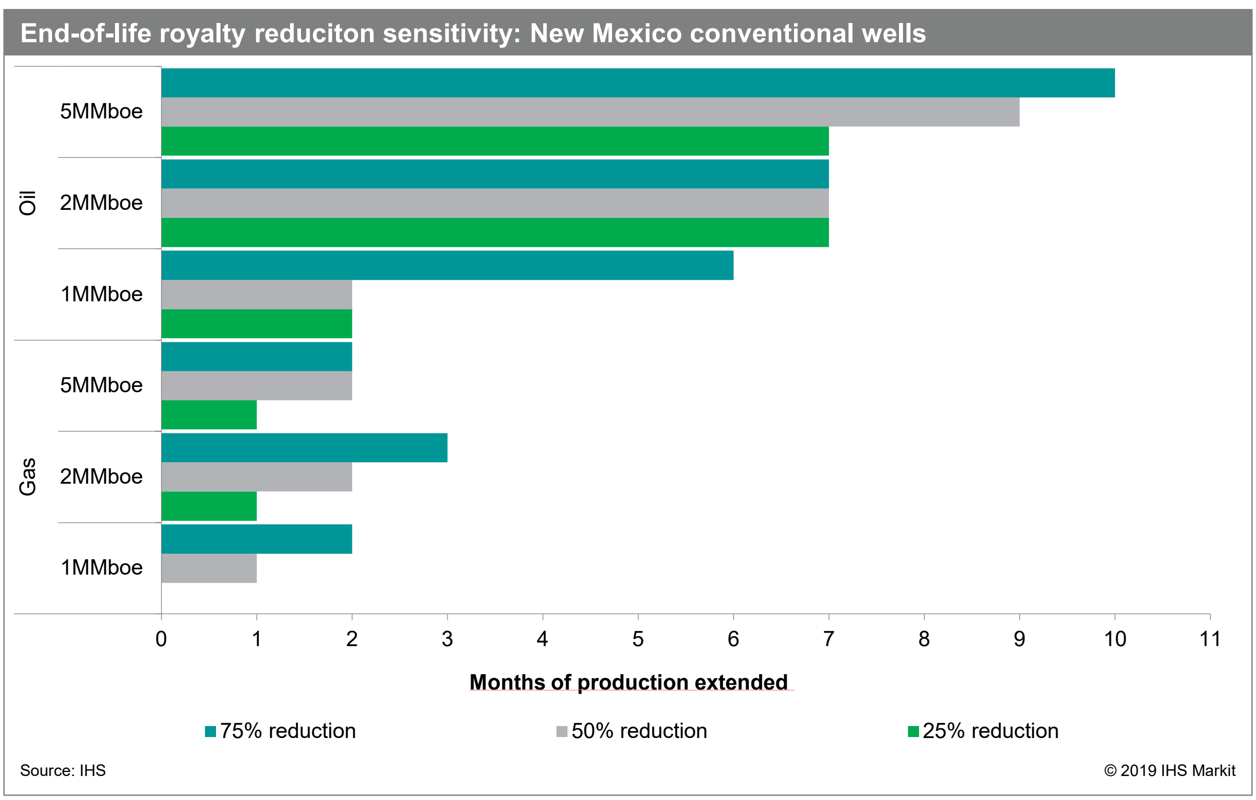
Montana gas fields are less responsive, resulting in 1–2 additional months, while the oil fields increase by up to 14 months of additional production.

Figure 6-15. End-of-life royalty reduction sensitivity: Montana conventional wells



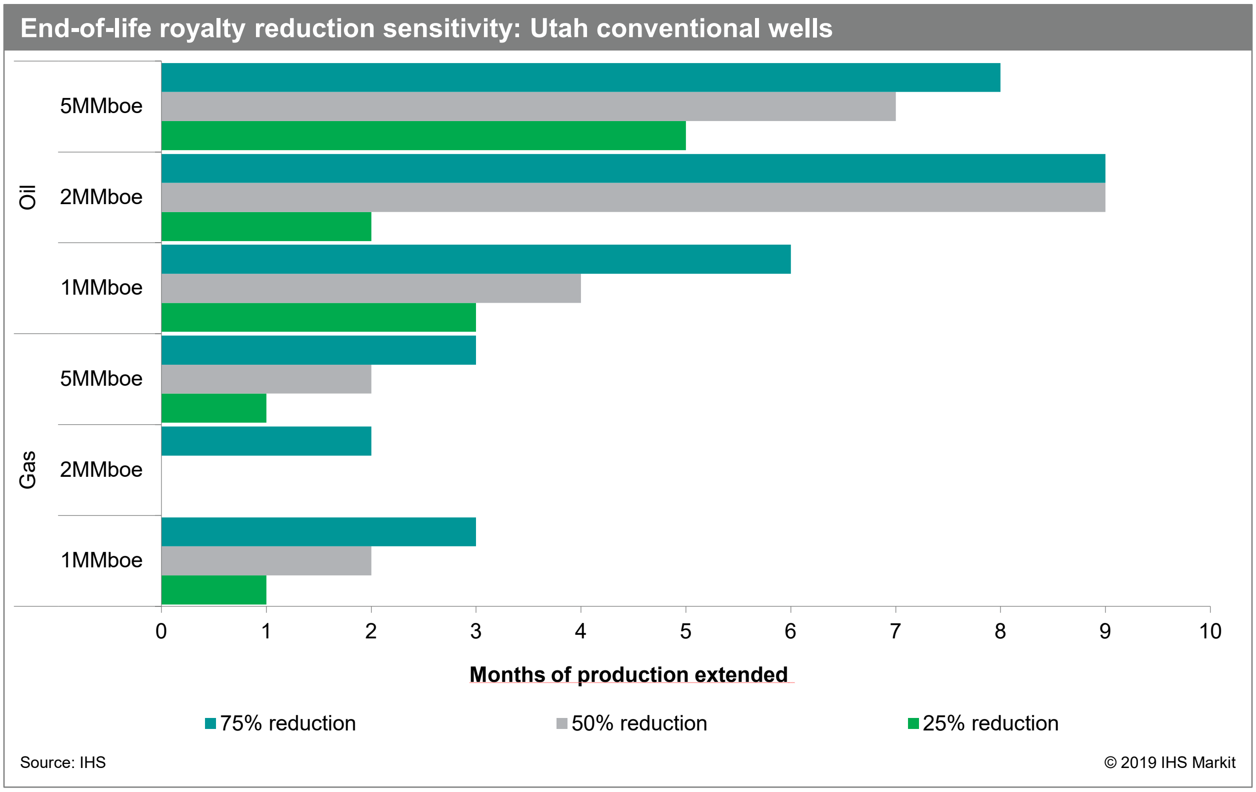
New Mexico is similar to Montana in that the oil wells are more responsive to royalty reduction than the gas wells. The larger field sizes benefit from a lengthier extension of the field life.

Figure 6-16. End-of-life royalty reduction sensitivity: New Mexico conventional wells



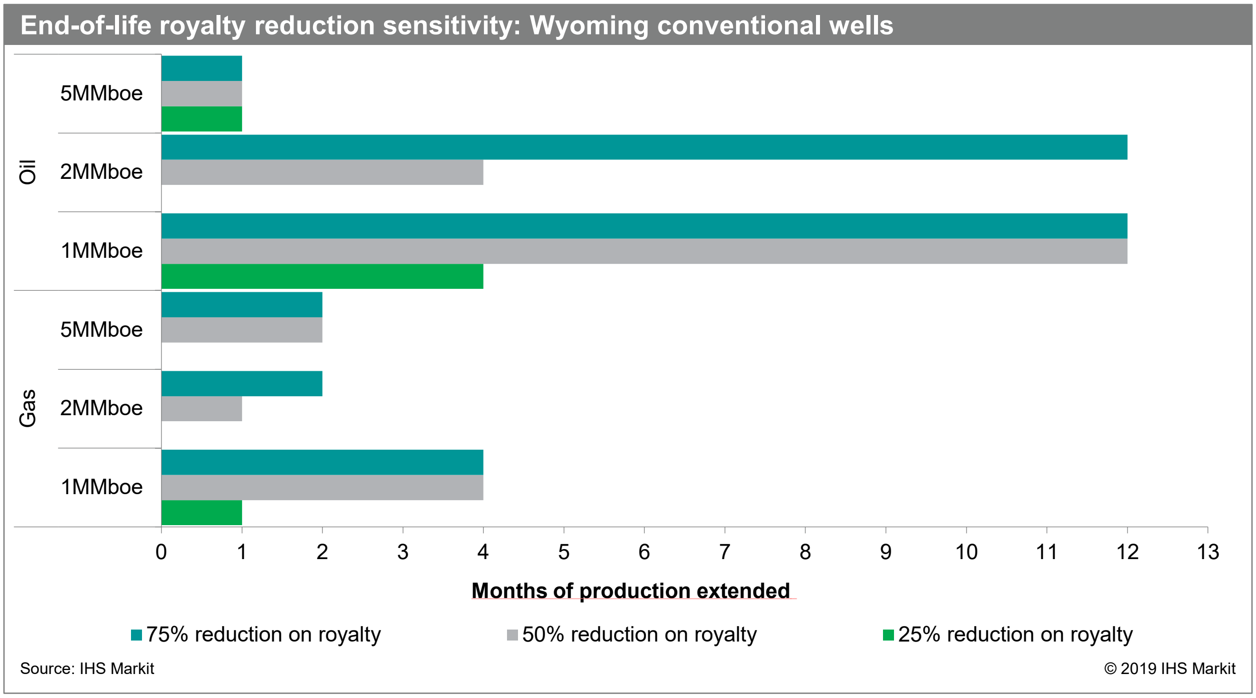
Utah shows a smaller response in extension for a 25 percent royalty reduction. The 2 MMboe gas case has no change unless there is a 75 percent reduction in the royalty rate.

Figure 6-17. End-of-life royalty reduction sensitivity: Utah conventional wells



Wyoming's small 1 MMboe and 2 MMboe cases benefit considerably more from the end-of-life royalty reduction than the 5 MMboe case. This suggests that the 5 MMboe oil case is already economic and producing to its full production potential.

Figure 6-18. End-of-life royalty reduction sensitivity: Wyoming conventional wells



6.4 Application for Permit to Drill Processing Time Impact

The pace of activities on state and private land differs from that on the Federal mineral estate. This is especially the case when it comes to processing APDs. A longer APD process is likely to impact the economics of a lease since it delays the start of generating revenue. It can decrease investor risk tolerance because operators are less confident in the availability and cost of services once drilling can begin, as well as the price of hydrocarbons when production can begin. Finally, a longer timeframe for APD approval is often correlated with greater range around when the approval can occur, which may interfere with strategic planning and allocation of capital when developing a field or starting an unconventional drilling program.

An analysis of the APD approval times on private and state mineral estates relative to the Federal mineral estate shows that APD approval timelines are generally vastly shorter for the state and private mineral estates than they are for the Federal mineral estate.

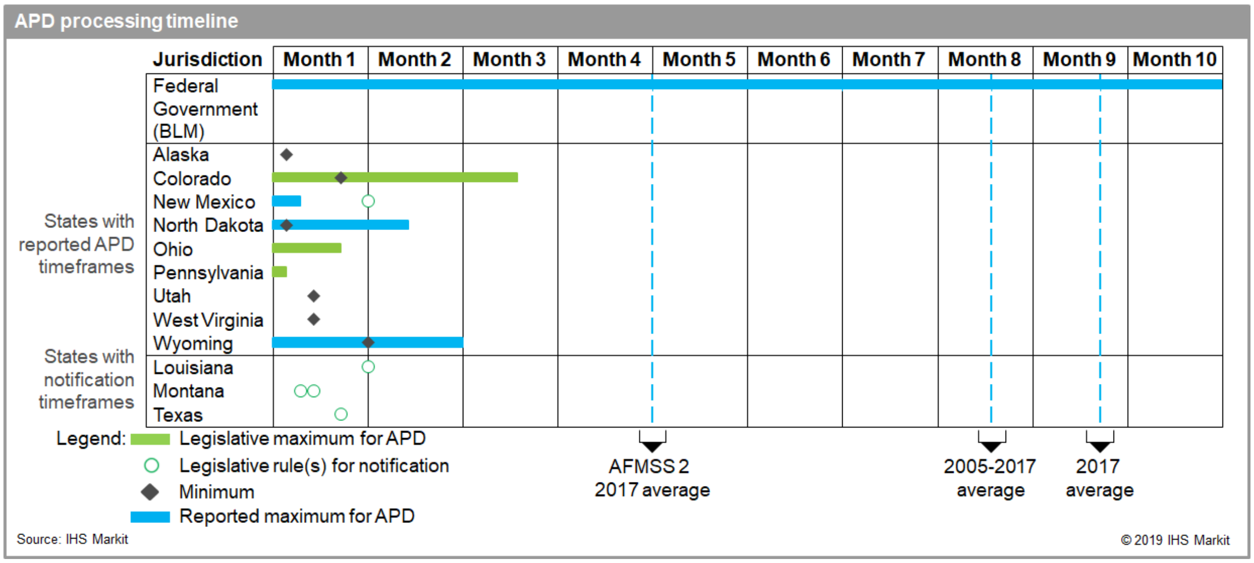
The Federal mineral estate is subject to the National Environmental Policy Act (NEPA) process and Endangered Species Act (ESA), with public input and more environmental review, when compared to state and private lands.[86] The longest an operator is likely to wait in nearly any state is 2–3 months for an APD approval, assuming no significant errors or legal challenges. Meanwhile, the average APD approval for BLM lands in 216 and 2017 is nearly 9 months.[87] There has been some variation from year to year, with a

[86] Congressional Research Service Report R42432, "U.S. Crude Oil and Natural Gas Production in Federal and Nonfederal Areas," October 23, 2018.
[87] BLM "Table 12 Time to Complete an Application for Permit to Drill (APD) Federal and Indian."

low of 154 days (approximately 5 months) in 2005 and a high of 307 days (approximately 10 months) in 2011. Still, these figures are much greater than the time that states report.

A summary of the APD and notification timelines on Federal and state lands is visualized in Figure 6-19. Green indicates timelines mandated by legislation. Blue indicates reported information from sources such as the state's oil and gas commission or the state's independent petroleum industry group, which may be biased toward shorter time frames. Bars represent the maximum duration, while markers indicate the minimum number of days. Note that individual reports of Utah's 7- to 10-month backlog are not represented in the chart due to the short-term situation of recent retirements.

Figure 6-19: Comparison of APD processing time across jurisdictions



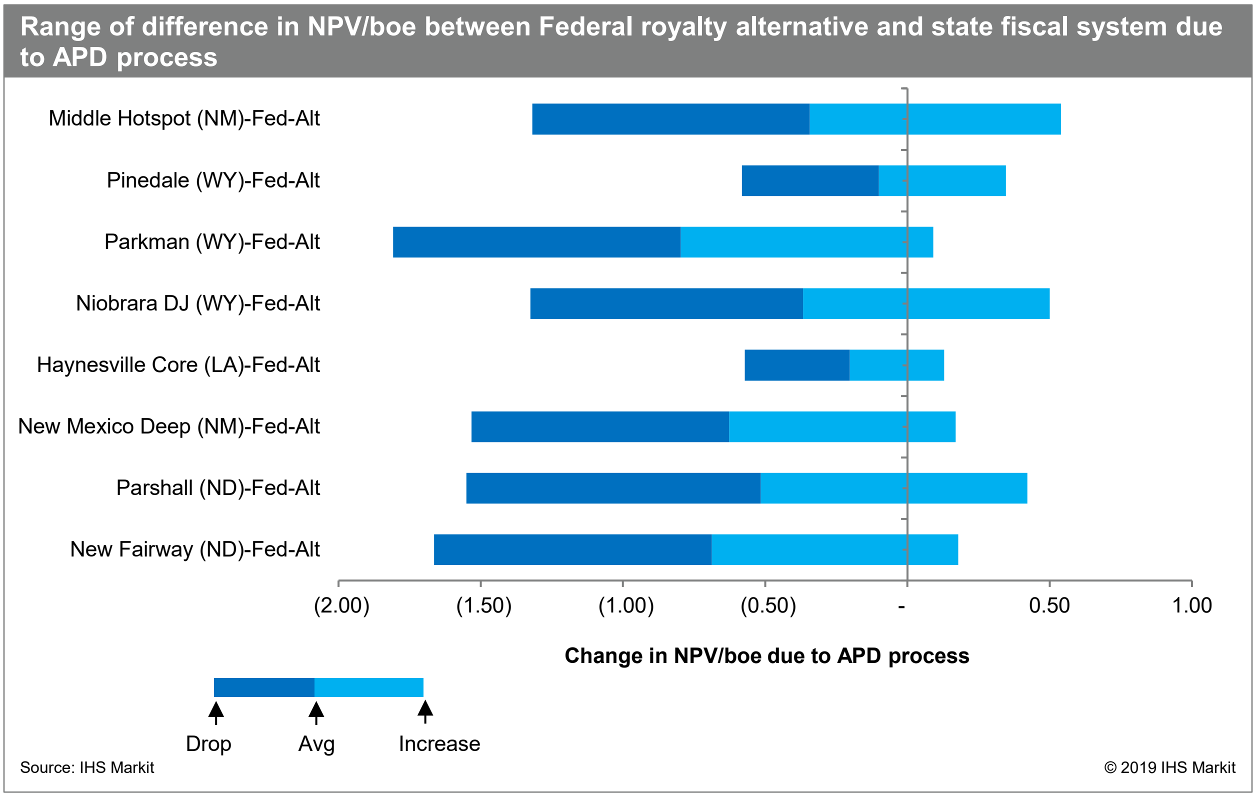
The economic analysis conducted for this study shows that differences in the APD approval time lines between the BLM and state mineral estate have a relatively minimal impact on project economics. While the BLM has recently taken steps to shorten the APD processing time lines, the study assumes a 10-month delay, the maximum observed over a 10-year period.[88] The APD time lines varied by BLM regional office and the level of activity in the region. According to the Wyoming Oil and Gas Conservation Commission, APD approval on Federal mineral estate in the state ranged between six months to two years.[89] The 10-month delay assumed for this study is intended to measure the maximum impact the APD approval process could have on project economics in the Lower 48 based on reported averages published by BLM. If the Federal royalty rate is increased to match the respective state royalty rate, the highest impact of the APD process would be observed in the most profitable projects, i.e., unconventional resources in the high and base price scenarios and the 5 MMboe oil fields in the high price scenario. As project profitability goes down, under the low price scenario, the delay of capital spent tends to have the opposite effect—i.e., it results in a higher NPV/boe than the state fiscal system. In the high price scenario, the NPV/boe is likely

[88] In 2011, the APD processing time line averaged 10 months, while the 2017 average was 9 months. Efforts are being made to bring the BLM APD permitting time line closer to the state process. In 2017, permits that used the new version 2 of the Automated Fluid Minerals Support System (AFMSS) only required 122 days (approximately 4 months).

[89] WOGCC, Watson M, Oil and Gas Supervisor, Mineral Development and State Primacy, Joint Minerals and Economic Development Interim Committee, June 30, 2017.

to drop on average by $1.29/boe compared to the state mineral estate under the uniform type curve, which assumes the same EUR per well for the Federal mineral estate and state and private mineral estates in each subplay. In the low price scenario, on average, the NPV/boe would likely increase by $0.30/boe compared to the state fiscal system. Overall, the impact of the APD process on unconventional plays across all three price scenarios is likely to result in $0.47/boe average drop in the NPV/boe (Figure 6-20). The average impact for conventional resources in the Lower 48 is likely to be $0.4/boe drop in the NPV/boe across all fields and commodity prices.

Figure 6-20. Range of difference in NPV/boe between Federal royalty alternative and state fiscal system due to APD process



BLM has taken steps to reduce APD processing time "by prioritizing permitting, modernizing its databases, and shifting resources across the BLM offices," resulting in the average APD processing time dropping to approximately six months, including time to determine an application to be administratively complete.[90] Given the efforts by BLM during 2017–19 to clear the backlog of APDs and shorten the APD approval process, the impact on project economics is likely to be even less significant than the one observed in this study. While the tangible benefits of an expeditious APD approval process are not substantial on an NPV/boe basis, the intangible benefit relates to the ability to plan and proceed with drilling programs that involve sufficient contiguous acreage to enable multiple wells per drilling pad, with long laterals required

[90] U.S. DOI, Examining the Policies and Priorities of the Bureau of Land Management, the U.S. Forest Service, and the Power Marketing Administrations, Statement of Michael Nedd Deputy Director, Operations, BLM, House Committee on Natural Resources Subcommittee on Energy and Mineral Resources, March 12, 2019.

for tight and shale formations. Improved APD approval time lines offer companies the necessary clarity and certainty required to develop drilling programs and engage service providers for the executions of such programs. Where the acreage positions include state and/or private and Federal mineral estates, any potential APD processing delays on the Federal mineral estate are likely to impact the timing of the combined drilling program on state and private lands. The shortening of the APD processing time lines, however, does not come without risks. Such timelines need to be sufficient to account for the environmental impact of drilling on Federal lands. Striking the right balance between an expeditious process and environmental protection is key to an optimum APD approval process. A recent federal court ruling that temporarily blocked drilling on roughly 300,000 acres of Federal land in the state of Wyoming for failure to sufficiently consider climate change highlights the challenges associated with striking the right balance between shorter APD processing time lines and review of environmental impact.[91]

[91] Corbett E. Federal Judge Blocks Trump Administration from Drilling on Federal Land, Fortune, March 20, 2019.

7 Conclusion

Oil and gas drilling activity has a strong correlation to market conditions, especially for the short-cycle barrels from unconventional reservoirs. The number of new wells spudded in the selected jurisdictions between 2014 and 2018 is positively correlated to the fluctuations of the oil markets. Among the three peer groups analyzed in this study, unconventional oil and gas developments are the most competitive and are attracting most of the capital among U.S. onshore resources.

Most of the U.S. onshore conventional formations in the Lower 48 have reached their maturity. The poor economics associated with the small size of conventional discoveries puts conventional oil and gas investment at a significant disadvantage when competing for capital with unconventional projects. Both the pools of investors and the amount of capital spent are very different.

Most unconventional plays offer robust rates of returns to investors across all jurisdictions and fiscal systems, with Bone Spring outperforming the other plays with regard to the median, as well as the range of the investor IRR**.** Federal fiscal systems generally outperform state and private fiscal systems except in Marcellus and Niobrara—where the Federal mineral estate is in the subplays with a higher cost per boe. The median IRR across all the plays, prices, and mineral estates averages 40 percent—with the average for the Federal mineral estate at 45 percent. In the majority of the plays, the Federal mineral estate generates healthy rates of return under the high and base price scenarios used for this study.

Investors would generally expect slightly lower returns compared to the mineral estates of the respective states if the BLM were to raise the Federal royalty rates to match those of the state fiscal systems. While an increase in royalty rates results in lower rates of return and places the Federal fiscal systems at a slight comparative disadvantage when compared to the state fiscal systems, the higher EUR per well observed on the Federal mineral estate in certain tight-oil plays offsets any comparative disadvantage resulting from the increase in royalty rates. Such a measure would not necessarily make the Federal mineral estate less attractive, on average, in comparison to investment opportunities on state and private mineral estates.

Competitiveness of the Federal fiscal system varies by play—depending on the expected ultimate recovery from wells drilled on the Federal mineral estate. Investment on the Federal mineral estate in the Wolfcamp Delaware and the Bakken plays outperforms investments on state land when the EUR per well on the Federal mineral estate is taken into account. The opposite is true for Bone Spring, where investments on the Federal mineral estate underperform those on state land. However, the rates of return are still very robust under all three price scenarios

The Alaskan Federal fiscal system for conventional resources is more attractive to investors than the state of Alaska and Yukon fiscal systems, as the expected value per exploration well drilled under the Federal mineral estate in Alaska is higher than that of the state of Alaska and Yukon for similar-sized fields.

The Federal fiscal system however, is subject to instability caused by frequent changes to the oil and gas production tax levied at the state level. Decisions made by the state of Alaska with regard to its share of revenue from oil and gas investments in the state apply to the state and Federal mineral estates.

While the Federal fiscal system in Alaska yields robust rates of return for oil fields ranging between 100 MMboe and200 MMboe under the alternative royalty rate, the Federal fiscal system is likely to lose the advantage it had against investments in the peer group and becomes very sensitive to commodity price changes. After the 2014 drop in commodity prices, most companies use prices well below the base price used in this study to make investment decisions. Therefore, the ability of investments to withstand cycles of low commodity prices is important. Currently, neither the state nor the Federal fiscal system is attractive under the low oil price environment.

The conventional oil and gas fields in the Lower 48 are the most economically challenged of the three peer groups, reflecting the maturity of the resource. The Federal fiscal system for oil is competitive with its peers, but it tends to only offer attractive returns for fields of 5 MMboe or larger reserve size in the high and base price scenarios—in some states not even the 5 MMboe fields are able to reach the 10 percent IRR investment threshold. As the basins continue to mature, the share of conventional fields with 5 MMboe declines, thus limiting opportunities for investment in conventional resources in the Lower 48. Fields with reserves of 1–2 MMboe, which make up the majority of the potential new discoveries in the Lower 48, are not economic across all jurisdictions under the base and low price scenarios.

Conventional natural gas fields in most plays and basins struggle to remain economic at current and forecasted natural gas prices in the United States. Conventional gas resources are highly mature in the Lower 48. New fields tend to be small and with marginal economics, at best. It is extremely challenging for the conventional gas fields to compete with wells in the most prolific unconventional gas plays that have kept commodity prices for natural gas persistently low in North America. A change to the Federal royalty rate would affect the conventional resources in the Lower 48 the hardest, making already uneconomic prospects even more challenging and less desirable.

Differences in the application for permit to drill (APD) approval timelines between the BLM and state mineral estates have a relatively minimal impact on project economics. If the Federal royalty rate is increased to match the respective state royalty rate, the highest impact of the APD process would be observed in the most profitable projects, i.e., unconventional resources in the high and base price scenarios and the 5MMboe oil fields in the high price scenario. As project profitability goes down, under the low price scenario, the delay of capital spent tends to have the opposite effect—i.e., it results in a higher NPV/boe than the state fiscal system. BLM has taken steps to reduce APD processing time "by prioritizing permitting, modernizing its databases, and shifting resources across the BLM offices," resulting in the average APD processing time dropping to approximately six months, including time to determine an application to be administratively complete. While the tangible benefits of an expeditious APD approval process are not substantial on an NPV/boe basis, the intangible benefit relates to ability to plan and proceed with drilling programs that involve sufficient contiguous acreage to enable multiple wells per drilling pad, with long laterals required for tight and shale formations. The shortening of the APD processing time lines, however, does not come without risks. Such time lines need to be sufficient to account for the environmental impact of drilling on Federal lands.

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Appendix A—Fiscal System Information

A.1 Alaska North Slope (ANS)

The terms used for this study relate to the latest applicable terms as of February 2019.

A.1.1 Fiscal and Contractual Terms

Bonuses

State lands: The November 2018 auction garnered an average bid of $122/acre, with bids as high as $586/acre.[92] Cash bonuses are payable for the issue of an oil and gas lease or gas only lease in a lease sale. However, no bonus is payable when an exploration license is converted to an oil and gas lease or gas only lease.

The minimum amounts of cash bonuses are stated in notices of lease sale and they range between $10 and $25 per acre depending on the potential of the area on offer. For modeling purposes, IHS Markit assumes a bonus of $100/acre for conventional assets on state lands.

Federal mineral estate: In the December 2018 lease sale for the National Petroleum Reserve in Alaska (NPR-A), the average bid was $9/acre, with a range from $5/acre to $19/acre.[93] For modeling purposes, IHS Markit assumes a bonus of $10/acre for conventional assets on Federal mineral estate.

Table A-1.1 describes minimum bid amounts in Federal mineral estate and state lands from 2018 lease sales.

Table A-1.1. Minimum bonus bids

Area potential	Minimum bid amount ($/acre)	
	Federal mineral estate	State lands
High potential	25	25
Low potential	5	10

Source: IHS Markit

Rental Payments

State lands: The rates on state lands may be varied for a lease which is re-offered after receiving no bids in an earlier sale. A rate of $3 per acre applies if an exploration lease is converted to an oil and gas lease.

The commissioner may raise the rental rate above $3 per acre for an oil and gas lease once production commences.

If the holder of a gas only lease demonstrates that the potential resources underlying the lease are reasonably estimated to be only unconventional gas, rental will be reduced to $1 per acre until the lease expires or paying quantities of conventional oil or gas are discovered in the lease area. Rental rates are set as follows:

Table A-1.2. Rental payments: ANS—State lands

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[92] Alaska Department of Natural Resources, "Preliminary sale summary, North Slope Areawide 2018W," January 3, 2019.

[93] Bureau of Land Management, "Alaska NPR-A oil & gas lease December 12, 2018 sale summary."

Type of right	Rental rate ($/acre)
Exploration License	none
Oil and gas lease or gas only lease—year 1	1.00
Oil and gas lease or gas only lease—year 2	1.50
Oil and gas lease or gas only lease—year 3	2.00
Oil and gas lease or gas only lease—year 4	2.50
Oil and gas lease or gas only lease—from year 5 onwards	3.00

Source: IHS Markit © 2019 IHS Markit

Federal mineral estate: Annual rentals are payable in advance. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[94] Rental rates are set as follows:

Table A-1.3. Rental payments: Alaska NPRA—Federal mineral estate

Area potential	Rental rate ($/acre)
High potential	5
Low potential	3

Source: IHS Markit © 2019 IHS Markit

Royalties

State lands: The royalty rate ranges between 5 percent and 60 percent. The most common rates are 12.50 percent and 16.67 percent. A sliding-scale royalty ranging between 16.67 percent and 33.33 percent was implemented for some North Slope leases sold in 1996 and 2002. Where a lessee under a gas only lease demonstrates that the potential resources underlying the lease are reasonably estimated to be nonconventional gas, then the royalty may be reduced to 6.25 percent.

Royalty is levied on gross wellhead revenue (referred to as the "field price" in the 2003 model lease). If the oil, gas, or associated substance is sold off the leased premises, the field price is calculated as the price realized less the actual and reasonable transportation costs. Note: this is highly significant for North Slope fields paying a Trans-Alaska Pipeline System (TAPS) tariff of $4.67 per barrel.

Federal mineral estate: Royalties are due and are collected by ONRR on behalf of the Federal government. Two royalty rates have been announced in recent lease sale notices for NPRA—a 12.50 percent rate applies to low potential areas, versus a 16.67 percent rate for high-potential areas. Some older or reinstated leases have different royalties.

Income Taxes

Lease holders in Alaska are subject to both state and Federal income tax regardless of whether the production is from state, Federal, or private lands.

[94] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR) Sec 3108.2-1; See also BLM Form 3100-11, Standard Lease Terms, Section 1.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[95]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year; or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: The state of Alaska imposes a state income tax on income derived from sources in Alaska.[96] Alaska has adopted the U.S. Code for establishing deductions and depreciation in determination of taxable income, with some exceptions:[97]

- Taxes based on or measured by net income that are deducted in the determination of the Federal taxable income shall be added back (except for Alaska's Oil and Gas Production Tax and State Conservation Surcharges on Oil).

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[95] U.S. Code title 26 § 164 provides that State, local and foreign, taxes which are paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212, are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

[96] Alaska Net Income Tax Act, Alaska Statutes Title 43 Chapter 20 (AS 43.20).

[97] Alaska Net Income Tax Act, Alaska Statutes Title 43 Chapter 20 (AS 43.20.021; AS 43.20.144(b)).

- Intangible drilling and development costs that are deducted as expenses in the determination of the Federal taxable income shall be capitalized and depreciated.
- Percentage depletion shall be recomputed and deducted on the cost depletion basis (i.e., depreciation method on a unit of production basis).
- Depreciation shall be computed on the basis of *26 USC Sec 167*[98] as that section read on June 30, 1981.

Multistate corporations apportion income on a water's edge basis using the standard apportionment formula of property, payroll, and sales. Oil and gas corporations use a modified apportionment formula applied to worldwide income.[99]

Tax rates are graduated from 0 percent to 9.4 percent in increments of either $24,000 or $25,000 of taxable income. The 0 percent rate applies to taxable income of $25,000 and below, while the 9.4 percent rate applies to taxable income of $222,000 and over.

For simplification, it is assumed that state income tax is levied on gross revenue less royalty, conservation oil surcharges, property tax, Petroleum Production Tax, operating costs, first-year bonus depreciation allowance for qualified tangible costs, and depreciation of all other capital costs on a unit of production basis with losses carried forward indefinitely, subject to a ceiling equal to 80 percent of taxable income before application of loss carry forward allowance.

<u>Ad Valorem Taxes</u>

Alaska imposes the oil and gas property tax,[100] which is assessed at the rate of 20 mils (1,000th of a dollar), or 2 percent of the value of taxable exploration production and pipeline transportation property located within the state.

<u>Severance Taxes</u>

Companies that derive income from the production of oil and gas in Alaska are subject to an additional state tax known as Alaska's Oil and Gas Production Tax (AOGPT).[101] All oil and gas produced in Alaska, except for the state and Federal royalty, is subject to taxation (i.e., constitutes "Taxable Oil and Gas").

Different tax rates and rules for determining the tax base apply before and after 1 January 2022, as described below.

Petroleum Production Tax on Oil and, Before January 1, 2022, on Gas

Effective January 1, 2014, AOGPT is levied on the "Production Tax Value" of the Taxable Oil and Gas at a flat rate of 35 percent as calculated below:

$$AOGPT\ Liability = (Production\ Tax\ Value\ \times 35\%) - Credits$$

Production Tax Value = Gross Value at the Point of Production—Gross Revenue Exclusion—Lease Expenditure

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[98] U.S. Internal Revenue Code 167 – Depreciation.
[99] Alaska Department of Revenue–Tax Division, Corporate Income Tax (http://tax.alaska.gov).
[100] Oil and Gas Exploration, Production and Pipeline Transportation Property Taxes Act, Alaska Statutes Title 43 Chapter 56 (AS 43.56).
[101] Oil and Gas Production Taxes and Oil Surcharge, Alaska Statutes Title 43 Chapter 55 (AS 43.55).

Taxable Oil and Gas = Gross Revenue—Royalty

Gross Value at the Point of Production = Taxable Oil and Gas—Transportation Costs

Lease Expenditure = Opex + Capex

Gross Revenue Exclusion

Oil and gas production in the North Slope (but not gas produced before 2022 and used within the state or any gas produced on or after January 1, 2022) qualifies for "Gross Revenue Exclusion," which is a deduction of 20 percent of the Gross Value at the Point of Production in the calculation of the Production Tax Value.

However, for oil and gas produced after 2016, this deduction expires ("sunsets") after three years, consecutive or nonconsecutive, during which the average annual oil price exceeded $70/bbl or after seven years from the commencement of commercial production, whichever occurs first.

ANS crude oil for sale on the U.S. West Coast. For the modeling purposes, price triggers for gas fields are modeled on equivalence basis using 6,000 cubic ft of gas = 1 boe.

The Gross Revenue Exclusion may be increased by an additional 10 percent for leases that are subject to royalty rate in excess of 12.5 percent. This additional 10 percent exclusion is subject to the same "sunset" provisions as the 20 percent exclusion. Since a 12.5 percent royalty rate is assumed here, the additional Gross Revenue Exclusion is not modelled.

Lease Expenditure

Producer's "Lease Expenditure" (i.e., operating and capital costs, except for signature bonuses) are expensed and deducted from the Gross Value at the Point of Production of Taxable Petroleum to arrive to the Production Tax Value that forms the basis of the tax liability calculation. Production Tax Value may not be less than zero but, effective 2018, losses can be carried forward and included in the lease expenditure of the future year(s).

The amount of losses that can be carried forward is to be decreased annually by 10 percent of the value of accumulated losses as of the end of the preceding year, commencing on the 11th anniversary of the losses incurred with regards to pre-production costs and on the 8th anniversary with regards to post-production costs. For the modeling purposes, the reduction of loss amount to be carried forward is assumed to start from the 8th anniversary of commencement of the loss carry.

AOGPT Credits under AS 43.55 applicable to ANS[102]

- AS 43.55.025 (i)—Fixed per Barrel Credit—If the 20 percent and/or 10 percent Gross Revenue Exclusion applies, the taxpayer qualifies for a credit of $5 per barrel of Taxable Oil. This credit cannot reduce PPT liability below zero. Unused barrel credits cannot be carried forward.
- AS 43.55.025 (j)—Sliding Scale per Barrel Credit—If the 20 percent and/or 10 percent Gross Revenue Exclusion does not apply, the taxpayer qualifies for a credit as outlined in Table A-1.4

[102] Table of Tax Credits under Alaska Statutes Title 43 Chapter 55 (AS 43.55), http://tax.alaska.gov/programs/documentviewer/viewer.aspx?1399r

below. This credit cannot reduce the PPT liability below the amount of the minimum tax. Unused barrel credits cannot be carried forward.

- AS 43.55.019—Education Credit—For cash donations to qualified educational institutes or foundations. Maximum of $5 million.

Table A-1.4. Sliding scale per barrel credit for AOGPT

Average gross value at the point of production (oil price $/bbl)	PPT credit ($/bbl of taxable oil)
< 80	8
80—90	7
90—100	6
100—110	5
110—120	4
120—130	3
130—140	2
140—150	1
>= 150	0

Source: IHS Markit

Minimum AOGPT

Notwithstanding all the above, taxable oil and gas produced in the North Slope are subject to a minimum production tax levied on the gross value at the point of production on a sliding scale tied to the average price of ANS crude for sale on the U.S. West Coast as follows:

Table A-1.5. AOGPT minimum production tax

Oil price ($/bbl)	Minimum PPT rate (%)
<= 15.00	0.0
15.00 < price <= 17.50	1.0
17.50 < price <= 20.00	2.0
< price <= 25.00	3.0
> 25.00	4.0

Source: IHS Markit

Petroleum Production Tax on Gas from January 1, 2022

Note that AOGPT levied on Gas from January 1, 2022 onwards is calculated in a slightly different manner (see below), while AOGPT Liability for oil is determined in the same way as described previously.

Effective January 1, 2022, AOGPT is levied on the gross value at the point of production of the taxable gas at a flat rate of 13 percent, i.e., gross revenue exclusion is not applicable and capital and operating costs are no longer deductible for the AOGPT purposes. Minimum tax provisions will no longer be applicable to AOGPPT on gas.

$$Gas\ AOGPT\ Liability = Gross\ Value\ at\ the\ Point\ of\ Produciton\ \times 13\%$$

Taxable Gas = Gross Revenue—Royalty on Gas

Gross Value at the Point of Production = Taxable Gas—Transportation Costs

Gas AOGPT Liability = (Gross Value at the Point of Production x 13%)

A.1.2 Acreage Award Criteria

State lands: Petroleum rights are granted by the commissioner of the Alaska Department of Natural Resources (DNR) for state lands. The method of bidding is at the discretion of this commissioner. There are seven types of bid that can be utilized, with different combinations of cash bonuses, royalties, and net profit shares.[103] Four of the seven options involve fixed cash bonuses, rather than bids.

After an apparent high bidder is found, the lease is awarded after a lease-adjudication process. This process involves a comprehensive evaluation of land status, ownership and survey information, and a final determination on what lands, if any, are available for oil and gas or gas only leasing. All bidders must qualify with the Department of Oil and Gas, largely in terms of citizenship or equivalent, or through a company authorized to operate in Alaska.

Federal mineral estate: Federal mineral estate is awarded through a competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[104]

A.1.3 E&P Terms

Parcel Sizes

State lands: The size of tracts on state lands in the North Slope averaged 1,682 acres in the most recent sale in November 2018.[105]

Federal mineral estate: Tracts of Federal mineral estate tend to be larger that tracts on state lands. The maximum lease size outside of the NPRA is 5,760 acres. Acreage within NPRA range between 1,280 acres and 19,000 acres, with an average of 11,188 acres in the most recent December 2018 offering.[106]

Lease Term

State lands: An oil and gas lease or gas only lease has generally been granted for initial periods of five to 10 years, as specified when offered for bidding. The exploration period will be extended indefinitely if oil or gas is being produced in paying quantities from the leased area.

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[103] The Alaska Legal Resource Center, "Sec. 38.05.180. Oil and gas and gas only leasing."
[104] 30 U.S. Code (30 USC) Sec 226.
[105] Alaska Department of Natural Resources, "Preliminary sale summary, North Slope Areawide 2018W," January 3, 2019.
[106] Bureau of Land Management, "Alaska NPR-A oil & gas lease December 12, 2018 sale summary."

Federal mineral estate: Leases expire at the end of the primary term, which is 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

<u>Relinquishment Obligations</u>

There is no interim relinquishment requirement for state lands, or for Federal mineral estate.

<u>Domestic Market Obligations</u>

There are no domestic market obligations for the state of Alaska.

<u>Abandonment Requirements</u>

State lands: Upon abandonment or expiration of a lease, all facilities must be removed, and the sites rehabilitated to the satisfaction of the Alaska Department of Fish and Game and the Oil and Gas Conservation Commission.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[107] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[107] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.2 Canada—Yukon

The terms used for this study relate to the latest applicable terms as of February 2019. While the provincial government handles onshore leasing, the federal Canadian government is the resource owner.

A.2.1 Fiscal and Contractual Terms

Bonuses

Cash bonuses are required for bidding. Any location requires a minimum bid of Canadian dollar (CAD) 400,000 (USD303,720).[108] 2010 was the last year an oil and gas permit was granted in Yukon. For modeling purposes, IHS Markit assumes a bonus of $3/acre for conventional assets on provincial and Canadian Federal lands in U.S. dollars.

Rental Payments

Annual rentals of CAD5 (USD3.80) per hectare payable during the second phase of the exploration permit.

Royalties

Territorial: For oil and gas, there are different royalty rates for the "initial period" compared with latter periods. For oil, this initial period is the period of months ending with the production month when the cumulative total of volumes of crude oil reaches 30,000 cubic meters (188,694 barrels).[109] For natural gas, the triggering cumulative volume is 2,000,000 gigajoules (1,894,173 million Btu).

During the initial period, royalty rates for both oil and gas are 2.5 percent. After the initial period, they are subject to a maximum of 25 percent and a minimum of 10 percent, determined by the following equation:

Royalty = (10*Select Price) + (30*(Par Price—Select Price)) / Par Price

The Select Price is determined from "time to time" and the Par Price is determined each month. According to this equation, a higher Par Price leads to a higher royalty rate, but a higher Select Price leads to a lower royalty rate. The math is such that the maximum royalty of 25 percent is demanded when the Par Price is 4 times or more the Select Price (e.g., a Par Price of $16/cubic meter and a Select Price of $4/cubic meter, or a Par Price of $8/gigajoule and a Select Price of $2/gigajoule in U.S. dollars), and the minimum royalty of 10 percent is demanded when the Select Price is greater or equal to the Par Price.

There can be some crude oil royalty allowances. When natural gas is utilized or flared within Yukon, it is often exempt from royalty. It can also receive injection credits for use at a gas injection facility.

There are no initial rates for condensate, which immediately faces royalty rates of 10–25 percent.

Income Taxes

Territorial: The provincial income tax rate in Yukon for business income and investment income is 12 percent. The deductions and depreciation are the same as for crown corporate income tax.

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[108] Yukon Government Energy, Mines and Resources, "Yukon oil and gas rights disposition process," Exchange rate of 0.7593 applicable on February 20, 2018 was applied for conversion of CAD to USD.
[109] Oil and Gas Act (OGA) 2008. Conversion rates: 1 cubic meter = 6.28981 barrels, and 1 gigajoule = 0.9470863 million Btu.

Allowances for Income Tax

The same income tax allowances and deductions apply for Federal and territorial income tax. Deductions include the following:

- Exploration costs (The Canadian Exploration Expense—CEE)
  - Any expense incurred by the taxpayer (other than an expense incurred in drilling or completing an oil or gas well or in building a temporary access road to, or preparing a site in respect of, any such well) for the purpose of determining the existence, location, extent, or quality of an accumulation of petroleum or natural gas in Canada, including such an expense that is a geological, geophysical, and geochemical expense or an expense for environmental studies or community consultations (including studies or consultations that are undertaken to obtain a right, license, or privilege in order to search for oil or gas).
  - Any expense incurred for the purpose of bringing a natural accumulation of oil or gas in Canada into production and incurred prior to such production in reasonable commercial quantities form such accumulation, including (i) clearing, removing overburden, and stripping, and (ii) sinking a shaft or constructing an underground entry
- Operating and lifting costs
  - Includes overhead administrative costs
  - Includes abandonment costs, but the money deposited in the abandonment fund levy for the final abandonment of the field is classified for accounting purposes as money for future work and is not deductible
- A capital cost allowance (in the case of acquisitions)
- Oil and gas property expenses
  - Up to a certain percentage of the depreciated costs
- Interest expenses
- General and administrative expenses
- Royalties

The following costs are capitalized and depreciated:

- Development costs
  - This Canadian Development Expense (CDE) includes costs incurred in the drilling, completion, and conversion of any development well, written off at rates of up to 30 percent per annum on a declining-balance basis.
  - It is worth noting that the definition of CEE was amended pursuant to the 2017 Federal budget, often expanding the scope of CDE, thus reducing the cost items that can be expensed under CEE. These include drilling and completing a (new discovery) oil or gas well, and preparing the well site and building temporary access roads thereto. However, the change occurs in 2021 if the expense is incurred in connection with an obligation that was committed to in writing by the taxpayer before March 22, 2017, or 2019 otherwise.
- Oil and gas property expense
  - This is the cost of acquiring and maintaining an oil and natural gas property or lease (including oil sands rights acquired after March 21, 2011). It is written off at the rate of 10 percent on a declining-balance basis.
- Tangible costs related to the acquisition of assets generally located above ground
  - These are capitalized and qualify for the Capital Cost Allowance (CCA). The declining-balance depreciation rates vary according to classifications provided for in Federal legislation. The legislation provides for rates of 4 percent to 100 percent.
  - The rate for oil storage tanks and oil or natural gas well equipment is 30 percent. In the case of oil and natural gas pipelines with a life expectancy of less than 15 years, the

depreciation rate is 4 percent per annum. Tangible development drilling and tangible facilities have rates of 25 percent.[110]

Losses (noncapital losses) may be carried back for three years and forward for twenty years. Net capital losses may be carried back for three years and carried forward indefinitely.

Federal: The general corporate tax rate is 38 percent. With the Federal abatement of 10 percent (*Note: Where a company is subject to provincial income tax, the Federal income tax rate is reduced by 10 percent)* this is reduced to 28 percent. In addition, a manufacturing and processing (M&P) deduction (applicable where a corporation derives at least 10 percent of gross revenues from manufacturing and processing goods in Canada for sale or lease) or a rate reduction (available on certain qualifying income) both 13 percent, can bring the Federal income tax rate to 15 percent.

Ad Valorem Taxes

Property taxes in Whitehorse, the capital of Yukon, is approximately 1.1–1.2 percent.[111]

Severance Taxes

There are no severance taxes in Yukon.

Carbon Tax

Canada is implementing a revenue-neutral carbon tax that will begin to apply in Yukon on July 1, 2019.[112] The price will start at CAD20 (USD15.19) per metric ton of CO_2e.[113] It will increase at a rate of CAD10 (USD7.59) per year until reaching a level of CAD50 (USD37.97) per metric ton of CO_2e in 2022.

The tax will start by covering industrial facilities emitting 50,000 metric tons of CO_2e per year.[114] There will be a charge applied to fossil fuels, often paid by registered distributors, but aviation fuel will not be subject to tax. There will also be fuel charge relief for diesel-fired electricity.

Revenues will be returned to taxpayers and other specific entities. In Yukon, each resident will receive a check for CAD43 (USD32.65) in October 2019.[115] Those in rural communities will receive 10 percent more. Rebates will increase as the carbon tax rates and collections increase. Businesses, First Nations governments, and municipalities will also receive annual rebates. Business rebates will begin in 2020, and they can receive greater rebates and additional tax credits for green technology investments.

A.2.2 Acreage Award Criteria

Cash bonuses are required for bidding, but award of bids is also based on the criteria of exploration obligations. The permit holders are required to drill at least one exploratory or delineation well before the expiration of the initial term. The commitment to drill is associated with an expenditure commitment, backed by a deposit of 25 percent of the expenditure bid.

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[110] IHS Markit, Koakoak, Vantage, 2018.
[111] City of Whitehorse, "Base rate calculator for the city of Whitehorse."
[112] Government of Canada, "How we're putting a price on carbon pollution."
[113] *The Guardian,* "Canada passed a carbon tax that will give most Canadians more money."
[114] Government of Canada, "Yukon and pollution pricing,"
[115] *Canadian Broadcasting Company,* "Yukoners to get first carbon tax rebates this fall–for $43 per person."

Successful bidders must deposit 25 percent of the work commitment when submitting their bids.[116]

In general, Canada's work commitment bids cover nine years, so long as a well is drilled within the first five years.[117]

A.2.3 E&P Terms

Parcel Sizes

The maximum size of a lease is 500 square kilometers.[118] This is the equivalent of 2 grid areas or 160 sections.

Grid areas are 15' of longitude by 10' of latitude, and they are identified by the Lat/Long of the northeast corner.[119] The average lease size is 35,636 acres.

Lease Term

There is a maximum 10-year exploration duration.[120] When oil and / or gas is discovered, a significant discovery license may be applied for when the market conditions may not warrant immediate development of the discovery. This type of right is intended to encourage exploration in remote areas where there are no prospects of immediate commercial development. Such licenses are granted for an indefinite duration until the discovery becomes commercially viable and a production license is issued to that effect. There is a 10-year production lease that can be renewed for additional terms of five years each.

Relinquishment Obligations

In general, Canada does not have relinquishment provisions.[121]

Domestic Market Obligations

In general, there is no domestic supply obligation for crude oil.[122]

Abandonment Requirements

Licensees are responsible for wells that will not be completed or have not been produced or been used as an injector for 12 months.[123] A Well Operation Approval (WOA) for suspension or abandonment can be initially made orally and then later issued in writing. A WOA must both include enough information to evaluate the effectiveness of the proposed suspension or abandonment program and, when required, provide a formation flow test summary for the well and a copy of the logs run in the well with proper geological interpretation. Surface abandonment should be completed within 12 months of subsurface abandonment.

[116] Yukon Government Energy, Mines and Resources, "Pre-disposition."
[117] National Petroleum Council Arctic Subgroup of the Resource & Supply Task Group, "Arctic oil and gas."
[118] IHS Markit, "Summary of Yukon territory annual bid process 2016 through 2018, Global Exploration & Production Service (GEPS), 2017.
[119] Yukon Government Energy, Mines and Resources, "Oil and gas division system."
[120] IHS Markit, "Regulatory framework for Yukon, GEPS, 2017.
[121] IHS Markit, Alberta, Petroleum Economics and Policy Solutions (PEPS), 2018.
[122] Ibid.
[123] OGA 2004, "Drilling and production regulations."

Casings must be cut and steel plates must be welded over the top of each casing string so that the wellbore and the annuli between casing strings are completely closed off.

A.3 Colorado

The terms used for this study relate to the latest applicable terms as of April 1, 2019.

A.3.1 Fiscal and Contractual Terms

<u>**Bonuses**</u>

Private lands: Generally, an operator pays a bonus payment to the mineral owner upon execution of the oil and gas lease. In November and December of 2018, median bonuses for counties with oil and gas resources ranged from $1/acre to $450/acre, with the median being $16/acre.[124] For modeling purposes, IHS Markit assumes a bonus of $16/acre for conventional resources and $200/acre for unconventional resources.

State lands: The bonus payment is paid by the highest bidder for the opportunity to explore and produce on state lands. Bid amounts vary widely. The February 2019 auction garnered an average bid of $76/acre, with bids as high as $501/acre.[125] For modeling purposes, IHS Markit assumes a bonus of $76/acre for conventional resources and $250/acre for unconventional resources.

Federal mineral estate: The average bids per acre have varied over the years from $3.86/acre in March 2017 sale to $13.15/acre in March 2019 lease sale, with a range from $2/acre to $100/acre.[126] For modeling purposes, IHS Markit assumes a bonus of $13/acre for conventional resources and $75/acre for unconventional resources.

<u>**Rental Payments**</u>

Private lands: Payment timing and amount is negotiable within the lease. In the last two months of 2018, rentals were $1/acre/year across the state.[127]

State lands: Annual rentals are payable in advance. Rental is computed at the rate of $2.50 per acre, or fraction thereof, per year.[128] The rental may be increased by the lessor at the end of the primary term extended) provided the increase is not more than two times the initial rental rate.

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre (or a fraction thereof) each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[129]

[124] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[125] Colorado State Lands Board Lease Sale, February 21, 2019.
[126] BLM Colorado Federal Lease Sale, December 13, 2018.
[127] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[128] Colorado state lands Form Oil and Gas Lease (Form Lease).
[129] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR) Sec 3108.2-1; See also BLM Form 3100-11, Standard Lease Terms, Section 1.

Royalties

Private lands: Royalties are payable to the mineral rights owner and are determined by the terms in the lease agreement. Newer horizontal wells typically receive a royalty of 20 percent.[130]

State lands: Royalties are payable to the Colorado State Lands Board (State Lands Board). Royalties on state lands are 20 percent.[131]

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in Colorado are subject to both state and Federal income taxes regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[132]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

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[130] Greg Avery, "Wattenberg Field oil and gas could be worth $179 billion, royalty owners say," Denver Business Journal, June 13, 2018, This rate was further confirmed by 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.

[131] Form Lease.

[132] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: Colorado's corporate state income tax rate is 4.63 percent. This applies to the share of Federal taxable income attributable to Colorado (though exceptions apply to interstate corporations).

The state offers largely the same income tax deductions as are included in the Federal Income Tax Code. Colorado adopts a "rolling conformity" stance as regards the Federal Income Tax Code.

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of “property” is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY 2016 are available for the state.[133] Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below.

Table A-3.1. Effective ad valorem rates: Colorado

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
2%	6.1%

Source: IHS Markit

Severance Taxes

Severance tax is a levy applied by most (but not all) producing states on either the volume or the value of hydrocarbon production. Colorado levies severance tax against actual oil and gas production.[134] The state assesses severance tax depending on gross income. The current severance tax rates for oil and gas are as follows:

- Up to 15 barrels per day (oil) or 90,000 cubic ft per producing day (gas) are exempt
- Under $25,000 = 2 percent of gross income
- $25,000–99,999 = 3 percent of the excess over $24,999

[133] 2018. New Mexico Legislative Finance Committee.
[134] Code of Colorado Regulations (1 CCR 201-10, et. seq.)

- $100,000–299,999 = 4 percent of the excess over $99,999
- $300,000 and over = 5 percent of the excess over $299,999

Deductions are allowable for transportation, manufacturing and processing done prior to sale. Very importantly, Colorado provides an ad valorem tax credit that allows producers of oil and gas to deduct from their severance tax bills an amount equal to 87.5 percent of ad valorem taxes paid to reduce the burden of multiple taxation.

A.3.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor.

State lands: The Colorado State Lands Board (State Lands Board or SLB) acts as the licensing authority and leases are offered through competitive bidding.[135] Lease applications are made to the State Lands Board, and the system is cash bonus bidding. The Colorado State Lands Board (SLB) issues oil and gas leases through quarterly competitive live online auctions serviced by EnergyNet. Payment of the bid amount, and a lease-processing fee of $100, is required for issue of the lease.

Federal mineral estate: The Federal mineral estate is awarded through a competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[136]

A.3.3 E&P Terms

Parcel Sizes

Private lands: There are no restrictions as regards mineral lease area.

State lands: IHS Markit has not found an authority which states the maximum lease size in Colorado. In the February 2019 auction, lease acreages ranged from 40 acres to 640 acres, with an average of 434 acres.[137]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[138] In the December 2018 auction, lease acreages ranged from 1.49 acres to 1,372 acres, with an average of 392 acres.[139]

[135] Colorado Constitution, Art. IX.
[136] 30 U.S. Code (30 USC) Sec 226.
[137] Colorado State Lands Board Lease Sale, February 21, 2019.
[138] Title 30 U.S. Code (30 USC) Sec 184
[139] BLM Colorado Federal Lease Sale, December 13, 2018.

Lease Term

Private lands: The duration of the primary term, and any extensions, varies on private leases. Standard exploratory terms are 3–5 years, but may extend into perpetuity if the lessee completes an oil and gas well producing in paying quantities prior to the end of the primary term.

State lands: The standard primary term on state lands is five years and then for so long as oil and gas are produced in paying quantities. Extensions of the primary terms may also occur in other limited circumstances (e.g., where there is no production in paying quantities but the lessor applies in writing or where a well is shut in due to a mechanical condition or the lack of a suitable market for produced oil and gas).[140]

Federal mineral estate: Leases expire at the end of the primary term, which is 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Colorado.

Abandonment Requirements

Private and state lands: Prior to plugging and abandoning any oil and gas well, or any other well under the jurisdiction of the Division of Oil Gas and Geothermal Resources (DOGGR), operators must submit a Notice of Intention to abandon a well and follow DOGGR guidelines as regards to how this must be achieved (specific rules can be viewed on the DOGGR website).

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[141] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[140] Form Lease Sec 14.
[141] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.4 Louisiana

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.4.1 Fiscal and Contractual Terms

Bonuses

Private lands: Bonuses on private lands are negotiable and determined by the terms of the lease. Bonuses vary by hydrocarbon type and lands location. Haynesville bonuses ranged from $5,000/acre to $25,000/acre in 2009–12. Tuscaloosa Marine Shale bonuses from 2015 were $300–350/acre. For modeling purposes, IHS Markit assumes a bonus of $200/acre for unconventional resources.

State lands: Bonuses on state lands are upfront payments determined by the Department of Natural Resources (DNR) sealed bid sale. An operator's bid amount represents the cash payment, or bonus payment, to the state. The February 2019 auction garnered an average bid of $797/acre, with a range of bids from $500/acre to $910/acre.[142] For modeling purposes, IHS Markit assumes a bonus of $800/acre for unconventional resources.

Federal mineral estate: An auction in June 2018 leased a parcel for $201/acre.[143] For modeling purposes, IHS Markit assumes a bonus of $200/acre for unconventional resources.

Rental Payments

Private lands: Land owners maintain the right to receive rentals. Payment timing and amount is negotiable within the lease agreement.

State lands: The bonus serves as the rental payment in the first year.[144] Separate rental payments begin in the second year if drilling or mining operations have not yet begun. Payment of rentals ends once sufficient production begins to meet a minimum royalty payment.[145]

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[146]

Royalties

Private lands: Lease holders are liable to pay royalty on production. Royalty rates on private lands are negotiable and determined by the terms of the lease agreement. While rates vary, Louisiana has some of the highest royalty rates. IHS Markit assumes 30 percent for modeling purposes.[147]

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[142] Louisiana Department of Natural Resources, Tract Sheets.
[143] BLM Eastern States Federal Lease Sale, June 21, 2018.
[144] Form Lease, Art 1.
[145] If at the end of the primary term there are not drilling or mining operations, a lessee can pay a guaranteed payment equal to a minimum royalty payment.
[146] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).
[147] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.

State lands: The Notice of Publication specifies the royalty rate on state lands. The minimum royalty cannot be less than 12.5 percent. School Board lands leases require a minimum one-sixth royalty. However, minimum royalty rates are often exceeded, and the royalty rates are usually closer to private royalty rates than the minimum. Royalties are payable in cash or in kind, at the discretion of the state. IHS Markit assumes 25 percent for modeling purposes.

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in Louisiana are subject to both state and Federal income tax regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[148]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

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[148] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: State corporate income tax in Louisiana is 8 percent (lower rate if taxable income is less than $200,000). Louisiana also levies a corporate franchise tax applied to all capital employed in Louisiana. The current rate of tax is $1.50 for each $1,000 or major fraction thereof up to $300,000 of capital employed in Louisiana. It is $3 for each $1,000 or major fraction thereof in excess of $300,000 of capital employed in Louisiana.

The state offers largely the same income tax deductions as are included in the Federal Income Tax Code. Louisiana adopts a "rolling conformity" stance as regards the Federal Income Tax Code.[149]

The carry forward of losses is allowed in Louisiana for 20 years but that the net operating loss (NOL) carry forward is limited to 72 percent of the aggregate NOL carryover amount.[150]

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry in Louisiana, there are taxes on oil and gas equipment, such as an oil rig. There is no "property" tax on the produced value of oil and gas in Louisiana, as the constitution exempts oil and gas production from the ad valorem tax.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY 2016 are available for the state.[151] Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) at 0.7 percent on equipment.

Severance Taxes

In Louisiana, the state levies severance tax on oil and gas production at the time of severance at the following rates:

- Oil and condensate = 12.5 percent
- Gas = 12.2 cents per MCF

Lower severance rates are available for stripper or reclaimed wells, which are out of the modeling scope.

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[149] Louisiana Administrative Code (LAC) §1114 et seq. detail corporate tax provisions including the deduction of Federal taxes paid from taxable income in the state and modifications to the Federal rules on calculating gross income, when calculating gross income in state.

[150] The carry-forward rules were amended in 2015 to that as described above by virtue of House Bills 218, 624, 629, and 805, which also removed a provision allowing carry back of NOLs. Louisiana Administrative Code (LAC) §1124.

[151] 2018. New Mexico Legislative Finance Committee.

A.4.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor. Cash offers on a dollar per acre basis and royalty rates are usually negotiable variables.

State lands: The Office of Mineral Resources of the Department of Natural Resources (DNR) conducts mineral leasing on behalf of the State Mineral and Energy Board (Energy Board). DNR conducts lease sales once a month through a sealed bid process. The Energy Board has authority to accept the bid most advantageous to the state, and the Energy Board may lease upon whatever terms it considers proper.[152] Cash bonus bids are common.

Federal mineral estate: The Federal mineral estate is awarded through a cash bonus bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder. This must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[153]

A.4.3 E&P Terms

<u>Parcel Sizes</u>

Private lands: There are no restrictions as regards to the mineral lease area.

State lands: In the February 2019 auction, lease acreages ranged from 26 acres to 2,188 acres, with an average of 1,231 acres.[154]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[155] In the June 2018 auction, the lease auctioned was 5.56 acres.[156]

<u>Lease Term</u>

Private lands: Parties negotiate terms of the servitude through individual lease agreements. Primary terms for leases in the Haynesville and Tuscaloosa Marine shales were typically 3–5 years. The Louisiana Mineral Code extinguishes mineral servitudes after the expiration of 10 years without use.[157] The servitude may extend into perpetuity based on well productivity in the leased area.

Once the operator develops the lease and the leased area is producing, the lease typically continues into perpetuity so long as operations continue without cessation for more than a reasonable time. An operator may negotiate a shut-in royalty fee payable to the landowner for not operating a well capable of producing in paying quantities.

[152] Louisiana Revised Statutes (LA Rev Stat) § 30:127 (2016)).
[153] 30 U.S. Code (30 USC) Sec 226.
[154] Louisiana Department of Natural Resources, Tract Sheets.
[155] Title 30 U.S. Code (30 USC) Sec 184.
[156] BLM Eastern States Federal Lease Sale, June 21, 2018.
[157] Louisiana Revised Statutes (LA Rev) § 31:27-28 (2016)).

State lands: The duration of the primary term and any extensions is determined based on the terms of the lease sale—for inland tracts, the primary term is usually three years or less with a two-year extension. Ultra-deep wells (> 22,000ft TVD) or approved secondary or tertiary recovery projects may have longer terms.[158]

Once a well is producing, a lease shall continue in force so long as such operations are being conducted in good faith without lapse of more than 90 days between cessation of operations and their recommencement.[159]

Federal mineral estate: Leases expire at the end of the primary term, which is usually 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Louisiana.

Abandonment Requirements

Private lands: Leases should include abandonment and decommissioning obligations, and even in the absence thereof general obligations as set out by the Office of Conservation or the Louisiana Department of Environmental Quality or as codified in Statute would apply.[160]

State lands: The Form Lease provides that the lessee is obliged to plug and abandon all wells no longer necessary for operations or production on the lease and to remove all related structures and facilities. Where the lessee does not do this in a timely fashion, the state will do so and the lessee will be charged accordingly. The lessee is also, prior to the date of first production from the site, is obliged to establish a Trust Account which IHS Markit understands ensures funds are available for decommissioning and abandonment as required.[161]

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[162] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

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[158] Form Lease Art 1.
[159] Form Lease Art 4.
[160] Louisiana Revised Statutes (LA Rev Stat) § 30:4 provide for the Office of Conservation to make such rules as necessary to require the plugging and abandoning of wells.
[161] Form Lease Art 12.
[162] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.5 Montana

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.5.1 Fiscal and Contractual Terms

Bonuses

Private lands: In November and December of 2018, median bonuses for counties with oil and gas resources ranged from $1.50/acre to $86/acre, with the median being $5/acre.[163] For modeling purposes, IHS Markit assumes a bonus of $5/acre for conventional resources.

State lands: The bonus payment is paid by the highest bidder for the opportunity to explore and produce on state lands. The March 2019 auction garnered an average bid of $17/acre, with a range from $2/acre to $130/acre.[164] For modeling purposes, IHS Markit assumes a bonus of $17/acre for conventional resources and $100/acre for unconventional resources.

Federal mineral estate: The average bid in the December 2018 auction was $53/acre, with a range from $2/acre to $306/acre.[165] For modeling purposes, IHS Markit assumes a bonus of $53/acre for conventional resources.

Rental Payments

Private lands: Payment timing and amount is negotiable. In the last two months of 2018, rentals were $1/acre/year across the state.[166]

State lands: Rentals must be at least $1.50/acre/year, so long as the total annual rental payment is at least $100.[167] The amount of the rental often appears in a sale notice.

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[168]

Royalties

Private lands: Royalties are payable to the mineral rights owner and are determined by the terms of the lease. IHS Markit assumes 18.75 percent for modeling purposes.[169]

State lands: Royalties are levied at 16.67 percent.[170]

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[163] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[164] State of Montana, "Oil & Gas Lease Sale-March 5, 2019 Lease Sale Results."
[165] BLM Montana Federal Lease Sale, December 11, 2018.
[166] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[167] "State of Montana Oil and Gas Lease; State of Montana Department of Natural Resources and Conservation. "Statues and Rules Governing the Leasing and Issuance of Oil and Gas Leases on State Land," 2015.
[168] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).
[169] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[170] "State of Montana Oil and Gas Lease."

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in Montana are subject to both state and Federal income tax regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[171]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

[171] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

State income tax: Montana's corporate state income tax rate is 6.75 percent. This applies to the share of Federal taxable income attributable to Montana (though exceptions apply to interstate corporations).

The state offers largely the same income tax deductions as are included in the Federal Income Tax Code. Montana adopts a "rolling conformity" stance as regards the Federal Income Tax Code.

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry in Montana, there are taxes on oil and gas equipment, such as an oil rig. There is no "property" tax on the produced value of oil and gas in Montana.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY 2016 are available for the state.[172] The effective ad valorem rate on equipment is 0.9 percent.

Severance Taxes

Montana levies a severance tax of 9.0 percent on oil and gas. However, the first 18 months of production from horizontal wells are only taxed at a rate of 0.8 percent. For conventional wells, the severance tax is 0.8 percent for the primary recovery production during the first 12 months.

A.5.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor. Usually a dollar per acre payment and royalty rates are part of the negotiation.

State lands: Leases are offered through competitive bidding.[173] There is oral competitive bidding for acreage.

Federal mineral estate: The Federal mineral estate is awarded through competitive cash bonus bidding. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[174]

A.5.3 E&P Terms

Parcel Sizes

Private lands: There are no restrictions as regards mineral lease area.

[172] 2018. New Mexico Legislative Finance Committee.
[173] State of Montana, "Oil & Gas Lease Sale-March 5, 2019 Lease Sale Results."
[174] 30 U.S. Code (30 USC) Sec 226.

State lands: IHS Markit has not found an authority that states the maximum lease size in Montana. In the March 2019 auction, lease acreages ranged from 4 acres to 691 acres, with an average of 385 acres.[175]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[176] In the December 2018 auction, lease acreages ranged from 4 acres to 1,463 acres, with an average of 471 acres.[177]

Lease Term

Private lands: The duration of the primary term, and any extensions, varies on private leases. Standard exploratory terms are 3–5 years, but may extend into perpetuity if the lessee completes an oil and gas well producing in paying quantities prior to the end of the primary term.

State lands: The standard primary term on state lands is 10 years.[178] The lease is then extended for so long as oil and gas is produced in paying quantities.

Federal mineral estate: Leases are awarded for a primary term of 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Montana.

Abandonment Requirements

Private and state lands: Prior to plugging and abandoning any oil and gas well, or any other well under the jurisdiction of the Department of Natural Resources and Conservation (MDNRC), operators must submit a Notice of Intention to abandon a well and follow MDNRC guidelines as regards how this must be achieved.[179]

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[180] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

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[175] State of Montana, "Oil & Gas Lease Sale-March 5, 2019 Lease Sale Results."
[176] Title 30 U.S. Code (30 USC) Sec 184.
[177] BLM Montana Federal Lease Sale, December 11, 2018.
[178] "State of Montana Oil and Gas Lease."
[179] Rule Subchapter 36.22.13, "Abandonment, Plugging, and Restoration."
[180] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.6 New Mexico

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.6.1 Fiscal and Contractual Terms

Bonuses

Private lands: Bonus payment is made upon execution of the lease agreement with the mineral owners.

Bonuses on private lands are negotiable and determined by the terms in the lease. Bonuses vary by mineral type and lands location. In November and December of 2018, median bonuses for counties with oil and gas resources ranged from $20/acre to $3,800/acre, with the median being $325/acre.[181] For modeling purposes, IHS Markit assumes a bonus of $300/acre for conventional resources and $3,000/acre for unconventional resources.

State lands: Bonuses are determined in bidding process. The February 2019 auction garnered an average bid of $4,801/acre, with a range from $78/acre to $40,410/acre.[182] For modeling purposes, IHS Markit assumes a bonus of $4,500/acre for conventional resources and $35,000/acre for unconventional resources.

Federal mineral estate: The average bid in the December 2018 auction was $399/acre, with a range from $2/acre to $35,003/acre.[183] For modeling purposes, IHS Markit assumes a bonus of $400/acre for conventional resources and $20,000/acre for unconventional resources.

Rental Payments

Private lands: In November and December of 2018, median bonuses for counties with oil and gas resources were generally $1–2/acre/year, and the assumed rental rate for the state is $1.13/acre /year.[184]

State lands: Rentals are determined as part of oral/sealed bid process. Minimal rentals of $0.25/acre apply. January–-February 2016 rentals ranged from $79.17/acre to $10,000/acre, with an average of $230–350/acre. Published bid amounts do not distinguish between bonuses and rental.

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[185]

Royalties

Private lands: Private lands are assumed to have a royalty rate of 25 percent.[186] The amount of the royalty is negotiable, and is determined by the terms of the lease.

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[181] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[182] New Mexico State Lands Board Lease Sale, February 19, 2019.
[183] BLM New Mexico Federal Lease Sale, December 5 and 6, 2018.
[184] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[185] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).
[186] Ibid.

State lands: State lands has a maximum royalty rate of 20 percent. Royalty rates on state lands are adjusted depending on the location of known production areas and likelihood of discovering oil and gas. A proposal to increase the maximum royalty to 25 percent on state lands failed in February 2019.[187]

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

<u>**Income Taxes**</u>

Lease holders in New Mexico are subject to both state and Federal income tax regardless of whether the production is from state, Federal or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[188]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to

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[187] Associated Press, "New Mexico shuns proposal to raise royalty rates on oil, February 15, 2019.
[188] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry back option.

State income tax: New Mexico's corporate state income tax rates are as follows:

- 4.8 percent for taxable income < $500,000
- $24,000 + 5.9 percent for taxable income > $500,000

The state offers largely the same income tax deductions as are included in the Federal Income Tax Code. New Mexico adopts a "rolling conformity" stance as regards the Federal Income Tax Code.

In addition, certain credits/deductions are available in New Mexico that are specific to corporate tax payers in the energy industry. Examples include the following:

- A deduction for the expenses incurred in an arm's-length, non-affiliated transaction for transporting the product (i.e., the oil / gas)
- A processing deduction when the amount received from the sale of natural gas has associated processing-related costs (this deduction equals the natural gas processing expenses incurred in an arm's-length, non-affiliated transaction)
- An Intergovernmental Production Tax Credit is applied against the four New Mexico taxes imposed on the production of oil and gas (the oil and gas severance tax, the oil and gas conservation tax, the oil and gas emergency school tax, and the oil and gas ad valorem production tax). This applies only to a "qualifying well," drilling of which commenced on or after July 1, 1995 on Indian Tribal lands. The legislation also provides an "Intergovernmental Equipment Tax Credit" to be applied against the oil and gas production equipment ad valorem tax.

A franchise tax is also payable for corporations in New Mexico of approximately $50 per year.

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY 2016 are available for the state.[189] Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below.

Table A-6.1. Effective ad valorem rates: New Mexico

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
3.3%	5.0%

Source: IHS Markit

[189] 2018. New Mexico Legislative Finance Committee.

Severance Taxes

New Mexico imposes an oil and gas severance tax on the taxable value of all oil, natural gas, or liquid hydrocarbons and CO_2 severed from the soil and sold.[190] The standard rate is 3.75 percent. There are reduced rates for oil and gas from well workover projects if West Texas Intermediate (WTI) <$24/barrel and for stripper wells if gas is <$1.35/mcf or oil is <$18/bbl.

A.6.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor. Usually a dollar per acre payment and royalty rates are part of the negotiation.

State lands: The Oil, Gas and Minerals Division of the New Mexico State Lands Office (SLO) issues all mineral leases for the state.[191] The SLO offers tracts for oil and gas leasing on the third Tuesday of every month. Tracts are leased through a competitive sealed or oral bid process, with cash bonus bids being the only variable.

Federal mineral estate: The Federal mineral estate is awarded through competitive cash bonus bidding. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[192]

A.6.3 E&P Terms

Parcel Sizes

Private lands: There are no restrictions regarding mineral lease area.

State lands: The maximum size offered is two sections of lands. (One section is 640 acres). In the February 2019 auction, lease acreages ranged from 40 acres to 320 acres, with an average of 223 acres.[193]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[194] In the December 2018 auction, lease acreages ranged from 40 acres to 2,560 acres, with an average of 923 acres.[195]

Lease Term

Private lands: The duration of the primary term is negotiated in each individual lease agreement.

State lands: Duration is dependent on the type of lease.[196]

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[190] New Mexico Annotated Statutes (NMAS) Chapter 7, Article 29.
[191] IHS Markit understands that the Commissioner of Public lands executes and issues oil and gas leases covering common school and institutional trust lands.
[192] 30 U.S. Code (30 USC) Sec 226.
[193] New Mexico State Lands Board Lease Sale, February 19, 2019.
[194] Title 30 U.S. Code (30 USC) Sec 184.
[195] BLM New Mexico Federal Lease Sale, December 5 and 6, 2018.
[196] The primary term can be extended if the lease has been maintained in accordance with its provisions and, at the expiration of the primary term, oil or gas is not being produced but the lessee is engaged in drilling or reworking

- LH exploratory leases are for 10-year terms for exploration outside the Restricted Area (as determined by the state).
- VA exploratory leases are for five-year terms for exploration in the Restricted Area.
- V0 discovery leases are for five-year terms for drilling in the Restricted Area.

Federal mineral estate: Leases are awarded for a primary term of 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

<u>Relinquishment Obligations</u>

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

<u>Domestic Market Obligations</u>

There are no domestic market obligations for the state of New Mexico.

<u>Abandonment Requirements</u>

Private and state lands: Wells must be plugged or given a status of "temporary abandonment" within 90 days of certain events (60-day period after suspension of drilling operations; determination well is no longer useable for beneficial purpose; or a period of one year continuous non activity).[197]

Notice must be given be an operator of intention to permanently plug a well, plugging must be completed before the well can be abandoned. The Oil and Gas Conservation Division will not approve the record of plugging or release a bond until the operator has filed necessary reports and the division has inspected and approved the location. Specific provisions exist as regards approval for temporary abandonments, permits are required and mechanical integrity of the well must be demonstrated.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[198] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

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operations. In these cases, the lease shall remain in full force and effect so long as such operations are diligently prosecuted and, if they result in the production of oil or gas, so long thereafter as oil and/or gas in paying quantities is produced. Provided that such operations are approved by the lessor and a report of the status of all such operations shall be made by the lessee to the lessor every 30 days. A cessation of such operations for more than 20 consecutive days shall be considered as an abandonment of such operations and the lease shall terminate.

[197] New Mexico Annotated Statutes Sec 19.15.25 provide rules on plugging and abandonment.

[198] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.7 North Dakota

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.7.1 Fiscal and Contractual Terms

Bonuses[199]

Private lands: Bonus payment is made upon execution of the lease agreement with the mineral owners. Bonuses on private lands are negotiable and determined by the terms in the lease. In November and December 2018, median bonuses for counties with any oil and gas resources, both conventional and unconventional, ranged from $1/acre to $350/acre, with the median across all counties of $10/acre.[200] For modeling purposes, IHS Markit assumes a bonus of $300/acre for unconventional resources.

State lands: A bonus of not less than $ 1.00 per acre is required.[201] Lease terms specify actual values of rental and bonus payments. The February 2019 auction garnered an average bid of $273/acre, with a range from $97/acre to $1,509/acre.[202] Prior lease sales included bonuses ranging from $8/acre to $7,000/acre depending on county and perceived land value.[203] For modeling purposes, IHS Markit assumes a bonus of $1,500/acre for unconventional resources.

Federal mineral estate: The average bid in the September 2018 auction was $19/acre, with a range from $3/acre to $2,501/acre.[204] For modeling purposes, IHS Markit assumes a bonus of $2,000/acre for unconventional resources.

Rental Payments

Private lands: Rental payments on private lands are determined by the terms of the lease. Rentals are typically $1/acre/year.[205]

State lands: Before a lease is issued the successful bidder pays one year's rental; payment of such yearly rental will continue until royalties are being paid on the lease.[206] Rental rates are often approximately $4/acre/year.[207]

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[208]

[199] IHS Markit, United States: North Dakota, PEPS, 2018.
[200] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[201] North Dakota Administrative Code (NDAC) Title 85, Article 06, Chapter 06, Section 05.
[202] North Dakota State Lands Board Lease Sale, February 5, 2019.
[203] Sample state lands Lease Article 1.
[204] BLM North Dakota and South Dakota Federal Lease Sale, September 11, 2018.
[205] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[206] The North Dakota Administrative Code (NDAC) and the Sample state lands Lease Article 1.
[207] North Dakota Department of Trust landslands, “Lease auctions by county.”
[208] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).

Royalties

Private lands: Royalties on private lands are negotiable and determined by the terms in the lease. Typically, a royalty of 12.5 percent is standard—but Bakken royalties range from 20 percent to 22 percent.

State lands: Royalty rates are specified in sale terms. The lease shall provide for a 1/6 (16.67 percent) royalty of all oil and gas produced from the leased premises in all counties except Billings, Divide, Dunn, Golden Valley, McKenzie, Mountrail, and Williams counties, which will be set at 3/16 (18.75 percent).[209] Ten-year exploratory lease (issued from 1981 onwards) outside of a restricted area or a five-year exploratory lease (issued from 1984 onwards) within a restricted area demands royalties of 1/8 (12.5 percent).

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in North Dakota are subject to both state and Federal income tax regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[210]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase down of the 100 percent depreciation starting on January 1, 2023.

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[209] The Sample state lands Lease doesn't specify a royalty rate. These are specified by the North Dakota Administrative Code (NDAC) Title 85 Article 06 Chapter 06 Section 05.

[210] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: The state corporate income tax rate is 4.31 percent.

The state offers largely the same income tax deductions as are included in the Federal Income Tax Code. North Dakota adopts a "rolling conformity" stance as regards the Federal Income Tax Code.

Ad Valorem Taxes

North Dakota charges a Gross Production Tax in lieu of ad valorem tax and property tax.[211] North Dakota levies a gross production tax of 5 percent to the gross value at the well of all oil produced. For gas, the gross production tax rate on gas is (4 cents) * (the gas base rate adjustment for the fiscal year). The base rate adjustment is a fraction and is subject to a price index change on July 1 each year.[212] The rate through June 30, 2019 is $.0705 per MCF.[213]

Severance Taxes

North Dakota levies an extraction tax of 5 percent on the value of oil and gas produced. If the trigger price of $90 is exceeded for three consecutive months, the oil extraction tax rate increases to 6 percent and will revert back to 5 percent after the trigger price is below $90 for three consecutive months. The oil extraction tax is lower for qualified production from wells completed outside the Bakken and Three Forks formations, as well as for stripper wells.

A.7.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor. Usually a dollar per acre payment and royalty rates are part of the negotiation.

State lands: Acreage is awarded through competitive cash bonus bidding. Winning bidders may take all or a portion of the tract won, and rejected tracts are re-offered for bid immediately. The Department of Trust Lands conducts live auctions, and bidding is on the bonus price per mineral acre.[214] The bonus amount, to be paid up front, is the winning bid.

[211] North Dakota Century Code (NDCC) Title 57, Chapter 51, Section 01.
[212] The calculation is set out in the North Dakota Century Code (NDCC) Title 57, Chapter 57, Section 51.
[213] ND Tax, FAQ Articles.
[214] North Dakota Administrative Code (NDAC) Title 85, Article 06, Chapter 06, Section 14.

Federal mineral estate: The Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[215]

A.7.3 E&P Terms

<u>**Parcel Sizes**</u>

Private lands: There are no restrictions regarding mineral lease area.

State lands: Recent lease sales have included leases of as little as 0.16 acres and as much as 4,895 acres. In the February 2019 auction, lease acreages ranged from 5 acres to 160 acres, with an average of 103 acres.[216]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[217] In the September 2018 auction, lease acreages ranged from 5 to 1,076 acres, with an average of 472 acres.[218]

<u>**Lease Term**</u>

Private lands: Standard primary terms are 3–5 years, but may extend into perpetuity if the lessee completes an oil and gas well producing in paying quantities prior to the end of the primary term. Once the well is producing in paying quantities, the lease continues indefinitely for the leased area.[219]

State lands: The standard primary terms on state lands may not be less than five years from the effective date. The sample state lands lease provides for a five-year primary period.[220]

The lease continues so long as oil and/or gas are produced in paying quantities, and there is no lapse in operations.

Federal mineral estate: Leases are awarded for a primary term of 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

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[215] 30 U.S. Code (30 USC) Sec 226.
[216] North Dakota State Lands Board Lease Sale, February 5, 2019.
[217] Title 30 U.S. Code (30 USC) Sec 184.
[218] BLM North Dakota and South Dakota Federal Lease Sale, September 11, 2018.
[219] As decided by the case Fleck v. Missouri River Royalty Corp. (2015 ND 287, 872 N.W.2d 329), the North Dakota Supreme Court adopted the Texas rule for production in paying quantities to satisfy the habendum clause that can define how long the lease will extend. Production now means "production in paying quantities," which can be summarized as a lease can be deemed to be not producing in paying quantities when it has not yielded a profit over operating costs over a reasonable period of time and where a reasonable and prudent operator would not continue to operate a well in the manner in which the well was operated under the relevant facts and circumstances.
[220] state lands Lease Art 1.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of North Dakota.

Abandonment Requirements

Private and state lands: The North Dakota Industrial Commission (NDIC) has the responsibility of enforcing the provisions of the North Dakota Century Code (NDCC) and has also produced Guidelines on Temporary Abandonment.[221]

Included in the provisions of NDCC Title 38 are rules that ensure that oil and gas resources are not wasted. Pursuant thereto, the NDIC has the power to place a well in "abandoned-well" status where it has not produced oil or natural gas in paying quantities for one year. At least one of the following steps must be taken for a well in abandoned-well status:

- Promptly returned to production in paying quantities,
- Approved by the commission for temporarily abandoned status, or
- Plugged and reclaimed within six months.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[222] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

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[221] North Dakota Century Code (NDCC) Title 38, Chapter 08 deals with the control of oil and gas resources and covers areas such as the plugging and abandonment of wells and liability, such as civil and criminal penalties for noncompliance with rules.
[222] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.8 Ohio

The terms used for this study relate to the latest applicable terms as of March 1, 2019. The terms described relate to the top Federal mineral estate given lack of activity on state lands.

Between 2011 and 2017, there was essentially a six-year moratorium on hydraulic fracturing on state lands and parks because there were not sufficient appointments to the Oil & Gas Commission.[223] After the last appointments were filled in, March 2018 was the first meeting of the Oil & Gas Commission.[224]

A.8.1 Fiscal and Contractual Terms

Bonuses

Private lands: In November and December of 2018, median bonuses for counties with any oil and gas resources, both conventional and unconventional, ranged from $1/acre to $5,800/acre, but the median across all counties was only $3/acre.[225] For modeling purposes, IHS Markit assumes a bonus of $4,000/acre for unconventional resources.

State lands: Not active for over five years. However, For modeling purposes, IHS Markit assumes a bonus of $1,000/acre for unconventional resources.

Federal mineral estate: The most recent significant BLM lease in Ohio occurred in December 2017. That auction yielded an average bid of $2,725/acre, with a range from $2,002/acre to $6,502/acre.[226] Another BLM auction in December 2018 resulted in two leases with bids of $201/acre each.[227]

RENTAL PAYMENTS

Private lands: As an example, certain private rentals have been reported at $5/acre/year.[228]

State lands: Not active for over five years.

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[229]

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[223] Stewart J, Energy in Depth, “Ohio mineral owners win huge six-year-long standoff over fracking under state lands, August 28, 2017.
[224] The Ohio House of Representatives, “As state takes first step to frack public lands, Leland pushes for commonsense protections.”
[225] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[226] BLM Eastern States Federal Lease Sale, December 14, 2017.
[227] BLM Eastern States Federal Lease Sale, December 13, 2018.
[228] Tassone C, “How long will perpetual leases last in Ohio oil and gas law.”
[229] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).

Royalties

Private lands: Royalties are payable to the mineral rights owner and are determined by the terms of the lease agreement. Newer horizontal wells have received royalties of 20 percent.[230]

State lands: Royalties are close to private lands at around 20 percent. Royalties must be at least 12.5 percent.[231]

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in Ohio are only subject to state and Federal income taxes.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[232]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net

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[230] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[231] Chapter 1509: Division of Oil and Gas Resources Management–oil and gas.
[232] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State Tax: Ohio levies a Commercial Activity Tax, which is a "gross receipts tax" on taxable gross receipts, net of certain costs. It applies for businesses with over $150,000 in taxable gross receipts.[233] The Commercial Activity Tax rate is 0.26 percent.[234] For businesses grossing between $150,000 and $1,000,000, there is an annual minimum tax of $150.[235]

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below.

Table A-8.1. Effective ad valorem rates: Ohio

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
2.3%	1%

Source: IHS Markit

Severance Taxes

There is a severance tax of $0.10 per barrel of oil and $0.025 per mcf of natural gas.[236] Natural gas liquids have no traditional severance tax.[237]

Previous governor John Kasich proposed raising[238] the severance tax, but his successor Mike DeWine is not proposing any increase in his first budget.[239]

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[233] Ohio Department of Taxation, "Commercial Activity Tax (CAT) – general information."
[234] Walczak J, Tax Foundation, "Ohio's Commercial Activity Tax: a reappraisal."
[235] Ohio Department of Taxation, "Commercial Activity Tax (CAT) – general information."
[236] Ohio Department of Taxation, "Severance Tax."
[237] Downing B, "Ohio severance tax on natural gas, oil produced windfall of $21.3 million in in 2014-2015, total likely to top $30 million in 2015-2016," *Akron Beacon Journal,* January 31, 2016.
[238] Patton W, Policy Matters Ohio, "Low oil and gas severance tax costs Ohio millions, April 20, 2017.
[239] Pelzer J, "Rotunda Rumblings," Cleveland.com, March 11, 2019.

A.8.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor.

State lands: The Ohio Oil & Gas Leasing Commission is responsible for issuing drilling licenses for state lands. The first recent documented meeting of the commission occurred in March 2018.[240] As of March 2019, no state lands had been leased, and it is unclear if, when, and how state lands may eventually be leased.[241] It remains uncertain if it will issue and manage state leases, as no state lands have been leased in more than five years.

Federal mineral estate: Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[242]

A.8.3 E&P Terms

Parcel Sizes

Private lands: As far as IHS Markit is aware there are no restrictions as regards mineral lease area.

State lands: IHS Markit has not found an authority which states the maximum lease size in Ohio.

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[243] In the December 2017 BLM auction, lease acreages ranged from 40 to 115 acres, with an average of 70 acres.[244]

Lease Term

Private lands: Leases in Ohio vary in length, but there are reports of 10-year leases on private lands.[245] The leases often extend indefinitely as long as oil or natural gas is produced in paying quantities.

State lands: There is no established lease term, given the effective moratorium on hydraulic fracturing that recently ended.

Federal mineral estate: Leases expire at the end of the primary term, which is usually 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

[240] Ohio Department of Natural Resources, "Oil and gas leasing commission to hold meeting," February 27, 2018.
[241] Personal communication with Mike Angle, Chairman of Ohio Oil & Gas Leasing Commission, March 12, 2019.
[242] 30 U.S. Code (30 USC) Sec 226.
[243] Title 30 U.S. Code (30 USC) Sec 184.
[244] BLM Eastern States Federal Lease Sale, December 14, 2017.
[245] Tassone C, "How long will perpetual leases last in Ohio oil and gas law."

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Ohio.

Abandonment Requirements

Private and state lands: When any oil and gas well will be abandoned, it must first be plugged in accordance with regulations.[246] The abandonment report must be submitted no longer than 30 days after abandonment and include information such as how the well was plugged.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[247] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[246] Chapter 1509: Division of Oil and Gas Resources Management – oil and gas.
[247] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.9 Pennsylvania

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.9.1 Fiscal and Contractual Terms

Bonuses

Private lands: Lessees and mineral rights holders negotiate bonus amount based on perceived quality of the resource. Bonus estimates range from $2,500/acre to$7,500/acre. For modeling purposes, IHS Markit assumes a bonus of $500/acre for unconventional resources.

State lands: Bonuses on state lands are up-front payments determined by the lease sale results. As an example of bonus rates, the Pennsylvania Game Commission leased lands for approximately $3,000/acre in April 2018[248] and then approximately $2,700 in February 2019.[249] For modeling purposes, IHS Markit assumes a bonus of $2,700/acre for unconventional resources.

Federal mineral estate: While there is Federal mineral estate in the state of Pennsylvania, there has not been a BLM auction for at least the last five years.

Rental Payments

Private lands: Rental payments are paid through the primary term before development. In the last two months of 2018, most rentals were between $1/acre/year or $5/acre/year.[250]

State lands: Oil and gas leases have an annual rental rate calculated as follows:[251]

- Year 1: negotiated in lease agreement
- Years 2–4: $20/acre/year
- Subsequent years: $35/acre/year

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[252]

Royalties

Private lands: The minimum royalty on production paid to oil and gas lessors in Pennsylvania is set by law at 1/8 (12.5 percent) of the value of the produced oil or gas. Although the lessor may seek greater royalty amounts, the lessee is not required by law to pay more. 20 percent is indicative.

State lands: Royalties on state land, state mineral-controlled, leases are as follows:[253]

[248] FOX43, "Game commission OK's semiautomatic shotguns," April 25, 2018.
[249] *The Sentinel,* "Pennsylvania Game Commission briefs," February 22, 2019.
[250] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[251] Form Lease Art 3. It is of course possible that different rental rates could be applied for leases of unconventionals (as is the case in leases on Federal mineral estates).
[252] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).
[253] Form Lease Art 4, 5.

- Oil: 18 percent of marketable value
- Gas: Greater of $0.35/mcf or 20 percent of marketable value[254]

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in Pennsylvania are subject to both state and Federal income tax regardless of whether the production is from state, Federal or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[255]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

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[254] For gas, see Marie Cusick, "Pa. owed 'hundreds of thousands of dollars' in royalties from forest drilling," *StateImpact Pennsylvania,* February 26, 2017.

[255] U.S. Code title 26 § 164 provides that state, local and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: The state corporate income tax rate is 9.99 percent.

Pennsylvania is a no conformity state in terms of the Federal tax code.[256] The 9.99 percent corporate tax rate is levied on "Federal taxable income, without the Federal net operating loss deduction and special deductions" and modified by certain additions and subtractions.[257]

According to Pennsylvania Code Sec 153.13, Federal tax credits cannot be used to reduce the taxable income, although Section 153.14 does list items that will be allowed as special deductions, including a deduction where application of depreciation rules set out in the Federal Tax Code (Sec 1250) have been applied and resulted in accelerated depreciation falling below straight-line depreciation. It is also apparent that a Research and Development Credit is available, which may be relevant to oil and gas companies.

Ad Valorem Taxes

Pennsylvania does not have ad valorem taxes for oil and gas.

Severance Taxes

Pennsylvania has an impact fee for unconventional wells that depends on well age and the natural gas price. Impact fee income is distributed to the state and counties in much the same way as severance taxes are distributed in other states.

The Unconventional Gas Impact Fee is charged for the first 15 years of the life of the well. Rates for horizontal wells in 2018 ranged from $20,300 to $50,700, depending on the age of the well. [258] Vertical wells are charged 20 percent of these values for 10 years.

These were the rates given average natural gas prices between $3/Mcf and $4.99/Mcf in 2017. Had natural gas prices been less than $3/Mcf, some horizontal wells could have been charged as little as $5,000/year.[259] Meanwhile, had natural gas prices been higher, the newest wells could have been charged as much as $60,900/year. Each year, these rates can increase in line with the Consumer Price Index if the number of unconventional wells spudded in that year increased from the previous year.

The Pennsylvania Public Utility Commission (PUC) administers the collection and disbursement of the fee.

A.9.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor.

[256] Kaeding N, “Does your state’s individual income tax code conform with the Federal tax code?” Tax Foundation, December 13, 2017.
[257] Pennsylvania Code Sec 153.11.
[258] Pennsylvania Independent Fiscal Office, “2018 impact fee estimate,” Research Brief 2019-January 1, 2019.
[259] Marcellus Shale Coalition, “Pennsylvania’s impact fee.”

State lands: The Pennsylvania Department of Conservation and Natural Resources (DCNR) Bureau of Forestry, Minerals Section and the Pennsylvania Game Commission (PGC) (not part of the DCNR) hold most state lands with connected mineral rights in trust and makes acreage available for mineral exploration and development. They have the ability to grant leases for mineral rights. The Department of General Services (DGS) is the third state body that can issue oil and gas rights.

Typically, industry personnel nominate tracts for lease sale—subject to state approval. However, there is currently a moratorium on DCNR-controlled land, and the DCNR is therefore unable to issue any leases. More specifically, in 2015, an executive order placed a moratorium on any new oil and gas leases in Pennsylvania State Forest lands. This excludes forest lands where the mineral interests have been severed and are held privately.

The PGC maintains a formalized process of entertaining a "sole-source" proposal from operators that have a legitimate claim to offer the PGC the best possible lands development scenario. Or, in the event several operators have a legitimate claim to develop acreage with similarly minimal impacts, a bid package for those acreages impacts the decision to award acreage. Presumably, where lease terms have been established in a bidding situation, then the highest bid will win.

At least in the case of the DGS, interested parties can nominate properties for oil and gas leasing. The DGS has the authority to issue leases and specifies that the lease shall be awarded to the highest and best bidder after a competitive bid situation (the requirement for competitive bidding can be waived in limited circumstances, notably where the state owns a fractional interest in the relevant mineral).[260]

Federal mineral estate: The Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[261]

A.9.3 E&P Terms

Parcel Sizes

Private lands: There are no apparent restrictions regarding mineral lease area.

State lands: There are no clear restrictions regarding lease size area. However, the form lease (as issued by the Department of Conservation of Natural Resources) is for a tract of 7,441 acres. As an example of acreage, the Pennsylvania Game Commission leased 724 acres in April 2018[262] and then approximately 24 acres in February 2019.[263]

[260] Indigenous Mineral Resources Development Act 2012 Sec 3.
[261] 30 U.S. Code (30 USC) Sec 226.
[262] FOX43, "Game commission OK's semiautomatic shotguns," April 25, 2018,
[263] *The Sentinel,* "Pennsylvania Game Commission briefs," February 22, 2019.

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[264]

Lease Term

Private lands: Standard primary terms are 5–6 years, but may extend up to 20 years. The lease continues in perpetuity as long as production in paying quantities is maintained.[265]

State lands: The standard primary term on state lands is 10 years. However, the operator must drill the first well in first five years of the lease. The lease continues in perpetuity as long as production in paying quantities is maintained. [266]

Federal mineral estate: Leases expire at the end of the primary term, which is usually 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Pennsylvania.

Abandonment Requirements

Private lands: Leases should include abandonment and decommissioning obligations and, even in the absence thereof, general obligations as set out by the Department of Environmental Protection (DEP), Bureau of Oil and Gas Management would apply. The provisions of the Oil and Gas Act will also have applicability.[267]

For state lands as well, an Abandoned and Orphan Well program is in existence in the state and is managed by the DEP. An Orphan Well Plugging Fund also exists and a surcharge (initially set at $100, but which is subject to revision) is added to each well permit application to be placed in that fund.

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[264] Title 30 U.S. Code (30 USC) Sec 184.

[265] The Pennsylvania Supreme Court announced, in 2012, the standard for producing in paying quantities (T.W. Phillips Gas and Oil Co. and PC Exploration, Inc v. Ann Jedlicka) stating that a profit over operating expenses is generally enough. However, where such profit has been sporadic, then the court must consider efforts to re-establish profitability and the time taken to do so.

[266] Form Lease Art 1.02.

[267] For example, the Sec 601.206 details required well site restoration, including the restoration of surface lands as well as the filling of pits, within a certain amount of time. Restoration activities must also comply with the terms of specific environmental laws such as the Clean Stream Law. Specific plugging obligations are contained in Sec 601.210 of the Oil and Gas Act and include obligations to notify of intent to plug and abandon and specific procedures to be followed in doing so including erecting a marker over a plugged well.

State lands: There are provisions on well site restoration including the restoration of surface land, as well as the filling of pits within a certain amount of time.[268] Restoration activities must also comply with the terms of specific environmental laws such as the Clean Stream Law. Specific plugging obligations include obligations to notify of intent to plug and abandon and specific procedures to be followed in doing so.[269] The Form Lease also contains plugging requirements that largely mimic those contained in the legislation and defer to the Department of Environmental Protection (DEP), Bureau of Oil and Gas Management.[270]

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[271] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[268] Oil and Gas Act Sec 601.206.
[269] Oil and Gas Act Sec 601.210.
[270] Form Lease Art 33.
[271] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.10 Texas

The terms used for this study relate to the latest applicable terms as of March 1, 2019. The majority of leases are on private and state lands with a small percentage on Federal mineral estate.

A.10.1 Fiscal and Contractual Terms

Bonuses

Private lands: Bonuses on private lands are negotiable and determined by the terms in the lease agreement. Bonuses vary by mineral type and lands location. In November and December of 2018, median bonuses for counties with conventional oil and gas resources ranged from \$35/acre to \$3,800/acre, with the median being \$325/acre.[272] For modeling purposes, IHS Markit assumes a bonus of \$325/acre for conventional resources and \$3,000/acre for unconventional resources.

State lands: To obtain a lease for state owned minerals under state owned land, operators make an upfront bid, or bonus, payments to the Texas General Land Office (GLO) as determined through a competitive lease sale bidding process. The October 2018 auction garnered an average bid of \$5,823/acre, with a range of bids from \$100/acre to \$25,511/acre.[273] For modeling purposes, IHS Markit assumes a bonus of \$5,800/acre for conventional resources and \$20,000/acre for unconventional resources.

For leases of state owned minerals under privately owned surface lands, on lands subject to the Relinquishment Lands Act, the bonus amount is agreed between the surface owner (acting as agent for the state) and the lessee. A lease requires approval by the state; however, bonus amounts should be akin to those achieved for state owned minerals under state owned lands. The bonus payment in this case, however, is paid one-half to the surface owner and one-half to the state, which is the mineral rights owner.

Federal mineral estate: The average bid in the December 2018 auction was \$1,488/acre, with a range from \$101/acre to \$6,001/acre.[274] For modeling purposes, IHS Markit assumes a bonus of \$1,500/acre for conventional resources and \$5,000/acre for unconventional resources.

Rental Payments

Private lands: In November and December of 2018, median bonuses for counties with oil and gas resources ranged from \$1–20/acre/year, and the assumed rental rate for the state is \$3.67/acre/year.[275]

State lands: The Form Lease provides that if a rental is not specified therein then the payment shall be \$1/acre. For lands subject to the Relinquishment Lands Act, the rental is paid in equal amounts to the surface owner and the state. Rental amounts are determined on a case-by-case basis.

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are \$1.50 per acre (or fraction thereof) in the first five years and \$2 per acre each year thereafter. If a lease does not have a

[272] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[273] Texas State Lands Board Lease Sale, October 2, 2018.
[274] BLM New Mexico Federal Lease Sale, December 13, 2018.
[275] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.

producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[276]

Royalties

Private lands: The amount of the royalty is negotiable, and is determined by the terms of the lease. Royalty rates of 25 percent are indicative.[277]

State lands: State lands has royalty rates up to 25 percent.[278] The rate can be reduced to:

- 20 percent if production, in paying quantities, is established, brought onstream, and sales thereof are commenced within the initial 18 months of the primary term of the lease.
- 22.5 percent if production, in paying quantities, is established, brought onstream, and sales thereof are commenced between the 19th and 24th month of the primary term of the lease.

If the initial well drilled is a dry hole, the lessee may receive the lower royalty rate as follows:

- 20 percent if a second well is commenced and production, in paying quantities, can be established, brought onstream, and sales thereof are commenced by the end of the 21st month, as provided for in the lease.
- 22.5 percent if a second well is commenced and production, in paying quantities, can be established, brought onstream, and sales thereof are commenced by the end of the 27th month, as provided for in the lease.

For this study, IHS Markit has used the standard 25 percent royalty rate.

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

There is no state corporate or income tax in Texas. Lease holders are still subject to Federal income tax regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[279]

[276] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).
[277] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[278] Section 22, Chapter 52 Natural Resources Code, specifies that the Board shall set the royalty rate which shall be at least 1/8th (12.5 percent).
[279] U.S. Code title 26 § 164 provides that State, local and foreign, taxes which are paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212, are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for

In December 2017, the resident signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018, remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY 2016 are available for the state.[280] Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below.

In Texas, the property tax rate is set at the county level.

Table A-10.1. Effective ad valorem rates: Texas

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
2.18%	2.18%

Source: IHS Markit

(1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

[280] 2018. New Mexico Legislative Finance Committee.

Severance Taxes

In Texas, severance rates are 4.6 percent on oil and 7.5 percent on natural gas. The 7.5 percent rate for natural gas also includes “liquid hydrocarbons” such as NGLs.

OTHER TAXES

Texas imposes a franchise tax, also known as margin tax, on entities with more than $1,130,000 total revenues at rate of 0.75 percent or 0.375 percent for entities primarily engaged in retail or wholesale trade. This is applied on the lesser of 70 percent of total revenues or 100 percent of gross receipts after deductions for either compensation or cost of goods sold. An equivalent rate would be 0.525 percent of total revenue (70 percent x 0.75 percent).

A.10.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor. Usually a dollar per acre payment and royalty rates are part of the negotiation.

State lands: The GLO leases mineral holdings of the state for oil and gas development. The GLO conducts lease sales through a sealed bid process. Oil and gas leases, upon state lands where the state owns the mineral and the surface lands, are issued to the highest and best bidder after competitive offers by sealed bids. Lands may also be nominated for lease by interested parties.

Tie bids being treated as follows: If the highest bid for an area is made by more than one applicant, all applications shall be rejected and the board shall set a date for lease of the area that cannot be later than the 15th of the following month. The area will be subject to lease in the same manner as it was originally. No bids for a lease shall be considered if the price is less than the highest bid offered in the original application.

The mineral rights are owned by the state but the surface lands are owned by another party and is subject to the Relinquishment Lands Act then the GLO issues the leases through the surface owner who acts as its agent. Where the minerals being leased are under lands covered by the Relinquishment Lands Act, there is no bid process and leases are agreed through direct negotiation. If the board approves the application, the commissioner shall issue a lease to the applicant.[281]

Federal mineral estate: Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[282]

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[281] Section 52.190 Natural Resources Code. It is also expressly stated that the lease will be the only agreement entered into between the surface owner and the lessee, no collateral agreements may be executed and "top leasing" is also prohibited (i.e., the surface owner cannot enter into a new lease when the prior lease is in effect).

[282] 30 U.S. Code (30 USC) Sec 226.

A.10.3 E&P Terms

Parcel Sizes

Private lands: There are no restrictions regarding mineral lease area.

State lands: In the October 2018 auction, lease acreages ranged from 0.3 acres to 640 acres, with an average of 162 acres.[283]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[284] In the December 2018 auction, lease acreages ranged from 71 acres to 1,270 acres, with an average of 424 acres.[285]

Lease Term

Private lands: Standard exploratory terms are 3–5 years, but may extend into perpetuity based on lease terms and well productivity in the leased area. Mineral owners grant the exclusive right to produce from the leased area—subject to the terms of the lease agreement and common law covenants.

State lands: Leases issued under the terms of the Natural Resources Code, Title 2, Chapter 52 (i.e., leases for state-owned minerals under state owned land) shall be for a primary term not to exceed 10 years (per Section 21) and for as long after that time as oil or gas is produced from the leased area.

A typical primary period on state lands is 1–3 years with operators being obliged to drill a well within the first three years or the lease expires. Extension of the primary lease term is possible.[286]

Leases issued on Relinquishment Lands Act can be issued for a negotiable primary term. The Rules on Leasing on the GLO website state as such but also state that options to extend the primary term are prohibited.[287]

Federal mineral estate: Leases expire at the end of the primary term, which is usually 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Texas.

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283 Texas State Lands Board Lease Sale, October 2, 2018.
284 Title 30 U.S. Code (30 USC) Sec 184.
285 BLM New Mexico Federal Lease Sale, December 13, 2018.
286 Natural Resources Code, Title 2, Chapter 52, Sec 31.
287 Form Lease Clause 2.

Abandonment Requirements

Private and state lands: Plugging and abandonment obligations should be included in leases and that these will refer to specific Texas Railroad Commission (TRC) rules.[288] The rules can be summarized as follows: Inactive wells (wells that have been spudded equipped with cemented casing and that have had no reported production, disposal, injection, or other permitted activity for a period of greater than 12 months) must be plugged and a plugging report must be filed with the TRC. More specific provisions as to time limits for plugging, how it must be done, and standards to be met are provided by the TRC.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[289] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[288] Texas Administrative Code Title 16, Part 1 Chapter 3.
[289] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.11 Utah

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.11.1 Fiscal and Contractual Terms

Bonuses

Private lands: In November and December of 2018, median bonuses for counties with oil and gas resources ranged from \$2/acre to \$1,600/acre, with the median being \$30/acre.[290] For modeling purposes, IHS Markit assumes a bonus of \$30/acre for conventional resources.

State lands: Payment of the winning bid amount is required up front where a lease is won from the Utah School and Institutional Trust Lands Administration (SITLA) or the Utah Division of Forestry, Fire and State lands (FFSL) at competitive auction. SITLA manages lands owned by trusts, including an oil and gas leasing and development program. FFSL manages and grants state mineral estates on non-SITLA lands.

The January 2019 SITLA auction garnered an average bid of \$120/acre, but bids were as low as \$2/acre.[291] For modeling purposes, IHS Markit assumes a bonus of \$120/acre for conventional resources.

Federal mineral estate: The average bid in the December 2018 auction was \$20/acre, with a range from \$2/acre to \$66/acre.[292] For modeling purposes, IHS Markit assumes a bonus of \$20/acre for conventional resources.

Rental Payments

Private lands: In November and December of 2018, median bonuses for counties with oil and gas resources were generally \$1–5/acre/year, and the assumed rental rate for the state is \$1.67/acre/year.[293]

State lands: A recent lease offering by FFSL declares that the minimum bid acts as the first year's rental and the annual rental will be a minimum of \$1.10/acre or \$20/acre, whichever is higher.[294]

It appears that rental payments will cease under SITLA leases when production commences and royalty is being paid. However, this is not specifically set out in the lease terms. This does not appear to be the case for FFSL leases.

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are \$1.50 per acre (or fraction thereof) in the first five years and \$2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[295]

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290 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
291 Utah State Lands Board Lease Sale, January 25, 2019.
292 BLM Utah Federal Lease Sale, December 11, 2018.
293 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
294 Rule 652-20-1000 Utah Administrative Code sets out the same rule as regards rental.
295 Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).

Royalties

Private lands: Royalties on private lands are negotiable and determined by the terms in the lease agreement. Royalties of 25 percent are indicative.[296]

State lands: Royalty is payable on production from leases issued by SITLA and FFSL. State Trust Lands Sample Lease Art 4 details royalty rates of 12.5 percent for oil and 12.5 percent for gas, but a rate of 16.67 percent is also standard in many leases. Some FFSL royalty rates are 12.5 percent for oil or gas.[297] IHS Markit assumes 16.67 percent for modeling purposes.

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

Income Taxes

Lease holders in Utah are subject to both state and Federal income tax regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[298]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018, remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

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[296] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[297] Rule 652-20-1000 Utah Administrative Code.
[298] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: The state income tax rate is 4.95 percent.

The state offers largely the same income tax deductions as are included in the Federal Income Tax Code. Utah adopts a "rolling conformity" stance as regards the Federal Income Tax Code.

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY 2016 are available for the state.[299] Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below. The actual tax rate is established by each respective county, and thus varies by county.[300]

Table A-11.1. Effective ad valorem rates: Utah

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
0.7%	2%

Source: IHS Markit

Severance Taxes

Severance tax (sometimes known as production tax) is a levy applied by most (but not all) producing states on either the volume or the value of hydrocarbon production.

In Utah, severance rates for both oil and gas are 5 percent, as long as prices are at least $13/bbl and $1.50/Mcf, respectively. Otherwise, rates would be 3 percent. Rates are 4 percent for NGLs.

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[299] 2018. New Mexico Legislative Finance Committee.
[300] Rule 59-2-201 Utah Administrative Code. Also see Rule 884-24P-10 of the Utah Administrative Code pursuant to Utah Code Title 59, Ch 2.

A.11.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor.

State lands: For trust lands managed by SITLA, bids are conducted through a sealed bid process.[301] Auctions are typically conducted through the online site EnergyNet. SITLA typically accepts the highest bid. State lands managed by FFSL also typically accept the highest bid.

For SITLA land, there is also an alternative approach to a competitive bid situation. Lands may be offered for noncompetitive leasing by over-the-counter application, provided those lands have been offered in a competitive offering and have received no bids. Designated lands may be offered for a period of three months from the date of the opening of bids in the competitive bid situation. The minimum acceptable offer for over-the-counter applications cannot be less than $1 per acre, or fractional acre thereof. However, it does not appear as though FFSL also has a process by which lands can be offered by way of an over-the-counter application.

Prior to parcels being offered for lease by SITLA, parties can seek the inclusion of a particular parcel in a lease sale. A parcel of lands is nominated by a company for an auction by notifying the administration of its interest, in writing. Only Pennsylvania and Texas also have nomination processes.

Another process which allows special leasing or development proposals is referred to as Other Business Arrangements (OBAs). The OBA process can be used for special consideration of certain lands (to bring them into production under a predetermined plan that suits the short- and long-term interests of the beneficiaries).

Federal mineral estate: Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[302]

A.11.3 E&P Terms

<u>**Parcel Sizes**</u>

Private lands: There are no restrictions regarding mineral lease area.

State lands: SITLA and FFSL leases shall (unless good cause is shown) be issued for no less than a quarter-quarter section or surveyed lot (except where the lands owned by the state within any quarter-quarter section

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[301] Rule 850-21-300, Utah Administrative Code sets out the full procedure for oil and gas lease applications on SITLA lands. The rules specify (i) the information which must be given in a notice of offering (ii) how long an offering must run for (at least 15 days) (iii) the process by which bids are received and opened; (iv) how applications can be withdrawn.

[302] 30 U.S. Code (30 USC) Sec 226.

or surveyed lot is less than the whole thereof, in which case the lease will be issued only on the entire area owned and available for lease by the state therein).[303] Further, leases are limited to no more than 2,560 acres or four sections. In the January 2019 SITLA auction, lease acreages ranged from 30 acres to 722 acres, with an average of 504 acres.[304]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[305] In the December 2018 auction, lease acreages ranged from 40 acres to 2,438 acres, with an average of 1,449 acres.[306]

Lease Term

Private lands: The primary term may be any period of time mutually agreed to by the lessor and the lessee. Leases continue for so long as oil and gas are produced from the leased lands in paying quantities.

State lands: Leases issued by SITLA shall have a primary term of no more than 10 years.[307] However, it appears, per the terms of the State Trust Lands Sample Lease, that the initial duration could be as short as five years. The lease can extend beyond the primary term, as the lease can be extended indefinitely when production occurs.

The most recent offering from FFSL provides for leases with a primary 10-year term.

Leases can be extended, provided that either a SITLA or an FFSL lease is part of a unit plan or cooperative agreement. In those cases, the lease will be extended automatically for the term of such plan or agreement.[308]

Federal mineral estate: Leases are granted for a primary term of 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Utah.

Abandonment Requirements

303 Rule 850-21-400 and Rule 652-20-800 Utah Administrative Code, respectively.
304 Utah State Lands Board Lease Sale, January 25, 2019.
305 Title 30 U.S. Code (30 USC) Sec 184.
306 BLM Utah Federal Lease Sale, December 11, 2018.
307 Rule 850-21-500 Utah Administrative Code.
308 Rule 652-20-2700 Utah Administrative Code and Rule 850-21-500 Utah Administrative Code.

Private and state lands: Rule 649-3-24 Utah Administrative Code sets out rules on plugging and abandonment of wells. Notice of the intent to abandon must be submitted to the Division of Oil Gas and Mining (DOGM) and must contain information including, but not limited to the following:

- The location of the well described by section, township, range, and county
- The status of the well, whether drilling, producing, injecting, or inactive
- A description of the well-bore configuration indicating depth, casing strings, cement tops if known, and hole size
- The tops of known geologic markers or formations
- The plugging program approved by the appropriate Federal agency if the well is located on Federal or Indian lands
- An indication of when plugging operations will commence.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[309] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[309] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.12 West Virginia

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.12.1 Fiscal and Contractual Terms

Bonuses

Private lands: Generally, an operator pays a bonus payment to the mineral owner upon execution of the lease agreement. In November and December of 2018, median bonuses for counties with oil and gas resources ranged from $1/acre to $9,000/acre, with the median being $10/acre.[310] For modeling purposes, IHS Markit assumes a bonus of $7,500/acre for unconventional resources.

State lands: The bonus payment is paid by the highest bidder for the opportunity to explore and produce on state lands. Bid amounts vary widely. Among leases in 2018, acreage received an average bid of $4,887/acre, with a range from $3,017/acre to $7,201/acre.[311] In January 2015, acreage garnered a similar average bid of $4,848/acre, but the bids had a wider range from $857/acre to $14,851/acre.[312] For modeling purposes, IHS Markit assumes a bonus of $7,000/acre for unconventional resources.

Federal mineral estate: There has not been a recent BLM Federal auction in West Virginia. For modeling purposes, IHS Markit assumes a bonus of $5,000/acre for unconventional resources.

Rental Payments

Private lands: Payment timing and amount is negotiable within the lease agreement. In the last two months of 2018, the most common rentals were $1/acre/year or $5/acre/year across the state, although there were a couple of outliers with rates over $100/acre/year.[313]

State lands: There are no annual rentals payable.[314]

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[315]

Royalties

Private lands: Royalties are payable to the mineral rights owner and are determined by the terms in the lease agreement. For horizontal wells, royalties are as high as 20 percent.[316]

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[310] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[311] Personal communication with Joe Scarberry, Office of Lands and Streams, WV Department of Natural Resources, March 12, 2019.
[312] Mattise J, "Companies bid millions to drill under state lands in W.Va.," *Associated Press,* January 26, 2015, Additional information can be found at West Virginia Department of Commerce, "Mineral development properties."
[313] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[314] Personal communication with Joe Scarberry, Office of Lands and Streams, WV Department of Natural Resources, March 12, 2019.
[315] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).
[316] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.

State lands: The state requires a royalty of 20 percent.[317]

Federal mineral estate: The Federal government collects a royalty on production of 12.5 percent for both competitive and non-competitive leases.

Income Taxes

Lease holders in West Virginia are subject to both state and Federal income tax regardless of whether the production is from state, Federal, or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[318]

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed

[317] West Virginia Department of Commerce, "Procedure to enter into lease."

[318] U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: West Virginia's corporate state income tax rate is 6.5 percent. This applies to the share of Federal taxable income attributable to West Virginia (though exceptions apply to interstate corporations). West Virginia adopts a "static conformity" stance regarding the Federal Income Tax Code, so there may be some differences between current Federal and state deductions.[319]

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below.

Table A-12.1. Effective ad valorem rates: West Virginia

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
0.83%	0.83%

Source: IHS Markit © 2019 IHS Markit

Severance Taxes

West Virginia levies a severance tax of 5 percent on oil and gas.[320]

A.12.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor.

State lands: The West Virginia Department of Commerce and the Division of Natural Resources are involved with acreage awards.[321] The system is one of competitive bidding. The process follows the following steps:

- At first, an interested bidder notifies the Division of Natural Resources of its interest by submitting a Lease Nomination Form
- The Division of Natural Resources seeks written approval to lease from the Office of the Governor
- The Director of the Division of Natural Resources seeks competitive sealed bids
- An advertisement is placed once per week for two weeks in the leading newspaper of the county in which minerals are located

[319] Kaeding N, "Does your state's individual income tax code conform with Federal tax code?" Tax Foundation, December 13, 2017.
[320] West Virginia State Tax Department, "Severance taxes – tax data, fiscal years 2015-2018."
[321] West Virginia Department of Commerce, "Procedure to enter into lease."

- Once that two-week period has ended, bids are evaluated, and the "highest responsible bid" will win the lease

Federal mineral estate: Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre). The lessees for a competitive lease must pay the bonus, first-year rental, and processing fee of $165.[322]

A.12.3 E&P Terms

Parcel Sizes

Private lands: As far as IHS Markit is aware there are no restrictions as regards mineral lease area.

State lands: In leases granted in 2018, lease acreages ranged from 22 to 301 acres, with an average of 123 acres.[323] In the leases granted in January 2015, lease acreages ranged from 134 acres to 1,400 acres, with an average of 599 acres.[324] There is no maximum acreage requirement.

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[325]

Lease Term

Private lands: The duration of the primary term, and any extensions, varies on private lease terms.

State lands: Until 2019, leases on state lands lasted for four years.[326] They will now last for five years.[327] The leases then continue for so long as oil and gas is produced.

Federal mineral estate: Leases expire at the end of the primary term, which is usually 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

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322 30 U.S. Code (30 USC) Sec 226.
323 Personal communication with Joe Scarberry, Office of Lands and Streams, WV Department of Natural Resources, March 12, 2019.
324 Mattise J, "Companies bid millions to drill under state lands in W.Va.," *Associated Press,* January 26, 2015.
325 Title 30 U.S. Code (30 USC) Sec 184.
326 West Virginia Mineral Development, "The state of West Virginia oil and gas lease – no surface use (4 year paid-up lease)."
327 Personal communication with Joe Scarberry, Office of Lands and Streams, WV Department of Natural Resources, March 12, 2019.

Domestic Market Obligations

There are no domestic market obligations for the state of West Virginia.

Abandonment Requirements

Private and state lands: An operator can plug a well as soon as it receives verbal permission, but it then needs to file the plugging affidavit.[328] There is an Abandoned Well Act that documents the processes needed to lawfully abandon wells.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[329] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

[328] West Virginia Legislature, Chapter 22. Environmental Resources, Articles 6 and 10.
[329] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

A.13 Wyoming

The terms used for this study relate to the latest applicable terms as of March 1, 2019.

A.13.1 Fiscal and Contractual Terms

Bonuses

Private lands: In November and December of 2018, median bonuses for counties with conventional oil and gas resources ranged from $1/acre to $1,475/acre, with the median being $19/acre.[330] For modeling purposes, IHS Markit assumes a bonus of $19/acre for conventional resources and $1,000/acre for unconventional resources.

Bonus payment is made upon execution of the lease agreement with the mineral owners. Bonuses on private lands are negotiable and determined by the terms in the lease agreement. Bonuses vary by mineral type and lands location.

State lands: Bonus payment is made upon execution of the lease agreement with mineral owner. The November 2018 auction garnered an average bid of $223/acre, with a range of bids from $4acre to as high as $3,786/acre.[331] For modeling purposes, IHS Markit assumes a bonus of $223/acre for conventional resources and $3,500/acre for unconventional resources.

Federal mineral estate: The average bid in the February/March 2019 auction was $165/acre, with a range from $2/acre to $6,001/acre.[332] For modeling purposes, IHS Markit assumes a bonus of $165/acre for conventional resources and $5,000/acre for unconventional resources.

Rental Payments

Private lands: In November and December of 2018, median bonuses for counties with conventional oil and gas resources were generally $1–2/acre/year, and the assumed rental rate for the state is $1.50/acre /year.[333]

State lands: The state lands Sample Lease Sec 1(c) provides for a rental of $1 for the period of time prior to the discovery of oil or gas in paying quantities and then a payment of $2 per acre annually thereafter. (This $2 payment is also referred to as a minimum annual royalty.)

Federal mineral estate: Annual rentals are payable in advance. Annual rental rates are $1.50 per acre (or fraction thereof) in the first five years and $2 per acre each year thereafter. If a lease does not have a producible well, or a producible well attributed to the lease, the lease will automatically terminate without payment of an annual rental in full and on time.[334]

Royalties

[330] 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
[331] Wyoming State Lands Board Lease Sale, November 14, 2018.
[332] BLM Wyoming Federal Lease Sale, February 25-March 1, 2019.
[333] Ibid.
[334] Title 30 U.S. Code (30 USC); Title 43 Code of Federal Regulations (43 CFR).

Private lands: IHS Markit assumes a royalty rate of 18.75 percent.[335]

Mineral owners maintain the right to receive royalty payments. Royalties on private lands are negotiable and determined by the terms of the lease agreement. Typically, a royalty of 12.5 percent was considered standard. However, royalties above 12.5 percent and even as high as 25 percent are increasingly more common based on mineral type and the perceived value of the lands.

State lands: The royalty rate on state lands paid to the state of Wyoming is typically 16.67 percent.[336]

Per the terms of the state lands Sample Lease Sec 1(e), the lessor can opt to take the royalties in kind or take cash payment.

However, The Board of lands Commissions Rules and Regulations Wyoming Administrative Rules Ch 18 (as applied to the Office of State lands and Investments [OSLI]) specifically state that the Board can also do the following:

- Offer a tract, which received no bids at a competitive lease sale, for a royalty rate of 12.5 percent at a subsequent lease sale and then, if no bids are received at that sale, offer the leases at 12.5 percent royalty in a noncompetitive "over the counter" application process
- In order to stimulate exploration on nonproducing primary term leases: offer a drilling window of up to two years with a royalty rate of 10 percent where production in paying quantities is established during a window from a wildcat well (this reduced royalty is limited to times where the price for oil and gas received by the lessee is below set amounts
- Reduce the royalty rate when a lease has become an operating lease if necessary for it to continue to operate. A reduction to a 5 percent royalty rate is possible.[337]

Federal mineral estate: Royalties are due and are collected ONRR on behalf of the Federal government. ONRR collects a royalty on production of 12.5 percent for both competitive and noncompetitive leases, although some older leases have a different royalty and some reinstated leases have a higher royalty.

<u>**Income Taxes**</u>

There are no state corporate or personal income taxes in Wyoming. Lease holders in Wyoming still are subject to Federal income tax regardless of whether the production is from state, Federal or private lands.

Federal income tax: Federal income tax is levied on operations on all lands. The current Federal corporate income tax rate is 21 percent.

The taxable base for Federal income tax is revenue less royalty, operating costs, dry hole costs, intangible development costs, depreciation of bonuses, and geological and geophysical (G&G) costs on a unit of production (UOP) basis and depreciation of tangible development costs over seven years (switching to straight-line depreciation in later years).

Property taxes and ad valorem and severance taxes are deductible for income tax.[338]

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335 2018 Nov / Dec Issue. Lierhle Publications on U.S. Leases.
336 State lands Sample Lease Sec 1(d).
337 Wyoming Administrative Rules Ch 18.
338 U.S. Code title 26 § 164 provides that state, local, and foreign taxes paid or accrued within the taxable year in carrying on a trade or business or an activity described in U.S. Code Title 26 § 212 are deductible. That section

In December 2017, the president signed the Tax Cuts and Jobs Act into law. This act (Section 13001) changes the corporate income tax rate in the United States from a maximum of 35 percent to a flat rate of 21 percent, effective January 1, 2018.

First-Year Bonus Depreciation

The new law increases the bonus depreciation percentage from 50 percent to 100 percent for qualified property acquired and placed in service after September 27, 2017 and before January 1, 2023. The bonus depreciation percentage for qualified property that a taxpayer acquired before September 28, 2017 and placed in service before January 1, 2018 remains at 50 percent. The Tax Cuts and Jobs Act provides for a five-year phase-down of the 100 percent depreciation starting on January 1, 2023.

Elimination of Loss Carry Back

The Tax Cuts and Jobs Act, enacted December 2017, has amended the longstanding provisions on income tax loss carry forward and back. The Federal Income Tax Act (26 USC) provided that 100 percent of net operating losses could be carried back for a maximum of two taxable years and forward for a maximum of 20 taxable years.

Section 13302 of the Tax Cuts and Jobs Act amends the rules so that they provide that a deduction shall be allowed for the taxable year equal to the lesser of (1) the aggregate of the net operating loss carryovers to such year, plus the net operating loss carrybacks to such year, or (2) 80 percent of taxable income computed without regard to the deduction allowable under 26 USC Sec 172. Such loss can be carried forward indefinitely, but there is no longer a carry-back option.

State income tax: There is no state income tax.

Ad Valorem Taxes

Ad valorem taxes are assessed at the county and municipal level. For the purposes of the oil and gas industry, the most important form of "property" is the produced value of oil and gas. There are also taxes on oil and gas equipment, such as an oil rig.

Calculating the effective rate of ad valorem taxes by state is performed on an aggregate basis due to the breadth of local entities and various rates. Ad valorem revenues for FY2016 are available for the state.[339] Additional secondary research helps approximate effective tax rates (mill levy * assessment rate) shown in the table below.

In Wyoming, ad valorem rates vary by county.

Table A-13.1. Effective ad valorem rates: Wyoming

Effective ad valorem rate on equipment (%)	Effective ad valorem rate on produced value (%)
1.6%	6.9%

allows, as a deduction, all the ordinary and necessary expenses paid or incurred during the taxable year for (1) the production or collection of income; and (2) the management, conservation, or maintenance of property held for the production of income.

339 2018. New Mexico Legislative Finance Committee.

Severance Taxes

Severance tax (sometimes known as production tax) is a levy applied by most (but not all) producing states on either the volume or the value of hydrocarbon production.

In Wyoming, severance taxes are 6 percent on oil and natural gas. There are lower rates for tertiary recovery and CO_2 for tertiary recovery.

Regulatory Fees

Wyoming has an Oil and Gas Conservation Tax of 0.05 percent.[340]

Table A-13.2. Regulatory fees details: Wyoming

State	Oil severance rate (%)	Natural gas severance rate (%)	Oil severance per-unit rate ($/bbl)	Natural gas per-unit rate ($/mcf)
Wyoming	0.05%	0.05%	n/a	n/a

A.13.2 Acreage Award Criteria

Private lands: Acquisition of rights on private lands occurs through *ad hoc* negotiation between the owner of mineral rights and potential investor.

State lands: Leases are available by competitive bid (mainly done via OSLI's Oil and Gas lease auction) or by way of a process known as "over the counter."

The auction bid amount, or bonus payment, is paid by the highest bidder for the opportunity to explore and produce on state lands. In the latter case, parties can apply directly for leases which have been offered at auction twice and have not been bid on.

Auctions are conducted through the online site EnergyNet.

Federal mineral estate: The Federal mineral estate is awarded through competitive bidding process. Tracts that do not receive bids may then be awarded through noncompetitive leasing, and no bonus is collected on noncompetitive leases. The BLM awards a competitive lease to the highest bidder.

Payment of the bid amount for a competitive lease is required for issue of the lease. The highest bid is accepted and this must be equal to or greater than the national minimum acceptable bid (that is set at $2/acre).[341]

Note that on March 20, 2019, a Federal judge temporarily blocked drilling on roughly 300,000 acres of the Federal mineral estate in Wyoming after he ruled that the Interior Department failed to account for the climate impact of oil and gas leasing in the state.[342] Analysis for hundreds of projects would have to be done again.

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[340] Bureau of Land Management, "Wyoming oil and gas state taxes, January 25, 2018.
[341] 30 U.S. Code (30 USC) Sec 226.
[342] Eilperin J and Dennis B, "Federal judge casts doubt on Trump's drilling plans across the U.S. because they ignore climate change," *Washington Post,* March 20, 2019.

A.13.3 E&P Terms

Parcel Sizes

Private lands: As far as IHS Markit is aware there are no restrictions regarding mineral lease area.

State lands: As far as IHS Markit is aware there is no standard lease size or minimum / maximum size which can be offered for lease. In the February 2019 auction, lease acreages ranged from 40 acres to 640 acres, with an average of 368 acres.[343]

Federal mineral estate: Federal competitive oil and gas leases cannot exceed 2,560 acres.[344] In the February/March 2019 auction, lease acreages ranged from 77 acres to 2,560 acres, with an average of 1,205 acres.[345]

Lease Term

Private lands: The duration of the primary term is negotiated in each individual lease agreement. The duration for production is indefinite as production rights may be retained so long as there is production of oil and gas in commercial quantities.

State lands: The standard primary term on state lands may not be less than five years from the effective date. Approval from the Board of Lands Commissioners is the only way to retain a lease beyond its primary term in a nonproducing status.[346]

The lease continues so long as oil and/or gas are produced in paying quantities. This can go on indefinitely.

Federal mineral estate: Leases expire at the end of the primary term, which is usually 10 years. However, the BLM may extend a lease, or a lease may continue under its own terms if the following occur:

- Qualifying drilling operations are in progress;
- The lease contains a well capable of producing in paying quantities; or
- The lease is entitled to receive an allocation of production from an off-lease well.

An alternative way leases can continue is where compensatory royalty is paid.

Relinquishment Obligations

There is no interim relinquishment requirement for private or state lands, or for Federal mineral estate.

Domestic Market Obligations

There are no domestic market obligations for the state of Wyoming.

Abandonment Requirements

Private and state lands: Prior to any abandonment work commencing on a well, a Notice of Intent to Abandon must be submitted to the Wyoming Oil and Gas Conservation Commission and approval received

343 Wyoming State Lands Board Lease Sale, November 14, 2018.
344 Title 30 U.S. Code (30 USC) Sec 184.
345 BLM Wyoming Federal Lease Sale, February 25-March 1, 2019.
346 State lands Sample Lease Section 2.

for such work to begin. The notice must show the reason for abandonment and must give a detailed statement of proposed work including such information as kind, location, and length of plugs (by depths), and plans for mudding, cementing, shooting, testing, and removing casing, as well as any other pertinent information. Any approval given is valid for one year. After that time expires, a new Notice of Intent to Abandon must be submitted.

Federal mineral estate: Each operator shall promptly plug and abandon each newly completed or recompleted well in which oil or gas is not encountered in paying quantities or which, after being completed as a producing well, is demonstrated to the satisfaction of the authorized officer to be no longer capable of producing oil or gas in paying quantities.[347] This plugging and abandonment is undertaken in accordance with a plan first approved in writing or prescribed by the "authorized officer." Additional requirements relate to the temporary abandonment of wells and the potential conversion of wells to water wells.

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[347] Title 43 of the Code of Federal Regulations (43 CFR) Sec 3162.3; 43 CFR Sec 3162.

Appendix B—Cost Modeling Assumptions

B.1 Alaska Onshore

B.1.1 Alaska Onshore

Table B-1. Alaska onshore oil

State	Reserves case (MMboe)	Development plan			Parameters	
		Development concept	Gas export method	Oil export method	True vertical depth (m)	GOR (scf/bbl)
Alaska	200	Tie-in to existing field and facilities	Reinjected	Tie-in to pipeline system	2,270	735
	100	Tie-in to existing field and facilities	Reinjected	Tie- in to pipeline system	2,270	735
	50	Tie-in to existing field and facilities	Reinjected	Tie-in to pipeline system	2,270	735

Source: IHS Markit

B.1.2 Canada Yukon

Table B-2. Canada Yukon onshore oil

Country	Reserves case (MMboe)	Development plan			Parameters	
		Development concept	Gas export method	Oil export method	True vertical depth (m)	GOR (scf/bbl)
Canada	200	Well group to main production facility	Reinjected	Transport through onsite terminal	1,620	1,210
	100	Well group to main production facility	Reinjected	Transport through onsite terminal	1,620	1,210
	50	Well group to main production facility	Reinjected	Transport through onsite terminal	1,620	1,210

Source: IHS Markit

B.2 Lower-48 U.S. Conventional

Table B-3. Conventional cost parameters

State	Primary product	Parameters	
		True vertical depth range (ft)	Regional gas hubs for export
Colorado	Oil	4,000-7,600	Cheyenne, Opal, CIG
	Gas	4,700-7,600	
Montana	Oil	5,100-9,200	Cheyenne, Opal, CIG
	Gas	1,300-3,300	
New Mexico	Oil	9,000-11,600	Permian, San Juan, Waha
	Gas	6,500-13,800	
Texas	Oil	5,500-12,800	Katy, East Texas, South Texas, HSC
	Gas	6,700-13,800	
Utah	Oil	5,700-7,300	Cheyenne, Opal, CIG
	Gas	5,500-8,400	
Wyoming	Oil	2,500-7,500	Cheyenne, Opal, CIG
	Gas	8,200-12,000	

Notes: The average differential among regional hubs is applied to Henry Hub. CIG is Colorado Interstate Gas pipeline, and HSC is Houston Ship Channel pipeline.

Source: IHS Markit

B.3 Lower-48 U.S. Unconventional

Table B-4. Unconventional cost parameters

Play	Subplay	Parameters			
		True vertical depth (ft)	Measured depth (ft)	Number of stages	Regional gas hubs
Bakken	New Fairway	10,200	20,930	48	Cheyenne, Opal, CIG
	Parshall	10,109	21,085	47	
	Elm Coulee	10,200	20,930	48	
Bone Spring	New Mexico Deep	9,900	17,640	42	Permian, San Juan, Waha
	Texas Deep	10,180	17,100	34	Katy, East Texas, South Texas, HSC
Haynesville	Haynesville Core	11,800	20,710	65	Katy, East Texas, South Texas, HSC
	Shelby Trough	10,850	17,160	52	
Marcellus	Marcellus Super Core	6,900	14,400	30	Columbia Gas Appalachia, Dominion South Point, Tennessee Z4 313/Marcellus
	Marcellus Southwest Core	7,400	17,000	44	
	Marcellus Periphery	7,500	15,600	53	
Niobrara	Niobrara DJ	6,418	14,418	47	Cheyenne, Opal, CIG
	Niobrara Wattenberg	7,200	15,270	34	
Parkman\Turner\Shannon Sands	Parkman	9,780	18,000	32	Cheyenne, Opal, CIG
	Turner Sands	11,730	18,230	36	
Pinedale Jonah	Pinedale	13,775	13,775	18	Cheyenne, Opal, CIG
	Jonah	11,930	11,930	11	
Wolfcamp Delaware	Middle Hotspot	9,730	16,210	40	Permian, San Juan, Waha
	Southern Liquids	10,400	17,100	35	Katy, East Texas, South Texas, HSC
Notes: The average differential among regional hubs is applied to Henry Hub. CIG is Colorado Interstate Gas pipeline, and HSC is Houston Ship Channel pipeline.					

Source: IHS Markit

Appendix C—Commercial Assumptions

C.1 Oil Price Forecast

Table C-1. Annual global WTI oil price assumptions, $/bbl in 2018 real terms

Case	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
High	98.73	104.92	100.23	98.31	97.49	97.73	100.22	101.50	101.97	104.02	107.93	109.82	109.78	109.76	109.74	109.73	109.69	109.67	109.66	109.65	109.61	109.60
Base	61.71	65.58	62.65	61.45	60.93	61.08	62.64	63.44	63.73	65.01	67.46	68.63	68.61	68.60	68.59	68.58	68.55	68.54	68.54	68.53	68.51	68.50
Low	37.02	39.35	37.59	36.87	36.56	36.65	37.58	38.06	38.24	39.01	40.48	41.18	41.17	41.16	41.15	41.15	41.13	41.13	41.12	41.12	41.10	41.10

Source: IHS Markit

C.2 Gas Sales Price

For Alaska onshore, all gas is assumed to be flared or reinjected. Gas and associated gas sales for conventional and unconventional varied by state and assigned to the regional gas hubs (Table C-2). The average differential among the various gas hubs is applied to the Henry Hub gas outlook (Table C-3).

Table C-2. Gas hub assignments

U.S. region	Gas hubs	State jurisdictions
Appalachia	Columbia Gas Appalachia, Dominion South Point, Tennessee Z4 313/Marcellus	OH, PA, WV
Desert Southwest	Permian, San Juan, Waha	NM
Gulf Coast	Katy, East Texas, South Texas, HSC	LA, TX
Rocky Mountains	Cheyenne, Opal, CIG	CO, MT, ND, UT, WY

Source: IHS Markit

Table C-3. Annual Henry Hub gas sales price assumptions, $/MMBtu in 2018 real terms

Case	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
High	3.94	3.6	3.79	4.54	5.22	5.86	6.18	6.37	6.22	6.05	6.37	6.91	7.06	7.28	7.5	7.6	7.09	6.98	7.22	7.62	7.97	8.05
Base	2.46	2.25	2.37	2.84	3.26	3.66	3.86	3.98	3.89	3.78	3.98	4.32	4.41	4.55	4.69	4.75	4.43	4.36	4.51	4.76	4.98	5.03
Low	1.48	1.35	1.42	1.70	1.96	2.2	2.32	2.39	2.33	2.27	2.39	2.59	2.65	2.73	2.81	2.85	2.66	2.62	2.71	2.86	2.99	3.02

Source: IHS Markit

C.3 Cost Escalation

The following tables show the real annual fluctuations in cost levels. These are representative of the IHSM Upstream Capital Cost Index and Operating Cost Index for the IHSM macroeconomic scenario called Rivalry.

The Rivalry scenario assumes intense competition among energy sources and evolutionary social change. Gas loosens oil's grip on transport demand, while renewables become increasingly competitive with gas, coal, and nuclear power. The world transitions from concentrated political and economic power to a broader distribution of wealth and influence. Expansion of international trade and investment continues, but is hobbled at times by domestic politics and misaligned interest among large global players. Inter-fuel competition is driven by four factors: price differentials, environmental concerns, technology improvements, and efforts to enhance national competitiveness. Social and political opposition to local pollution grows in many countries, leading to incremental environmental improvements and moderation in greenhouse gas-emissions growth. Technological progress and cultural change regarding public opinion on climate, pollution, and emissions continue to advance at an evolutionary pace, resulting in steady change over time, but with no fundamental or revolutionary shocks to energy demand or supply.

Table C-4. Annual real cost escalation for onshore drilling by U.S. region, year-on-year percentage change

U.S. region	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
North	0.0	-0.8	-3.2	-0.9	-0.1	-0.3	-2.1	-0.5	-1.0	-1.7	-1.3	-1.5	-1.9	-1.9	-2.5	-3.9	-1.8	-1.3	-1.2	-1.1	-1.2	-1.2
Northeast	0.0	-0.9	-2.4	-0.7	-0.5	-0.6	-0.7	-0.8	-0.6	-0.6	-0.5	-0.7	-0.8	-0.8	-0.8	-0.9	-0.8	-0.8	-0.8	-0.8	-0.9	-0.8
South	0.0	-0.9	-2.4	-1.6	-0.7	-0.6	-2.2	-3.1	-2.8	-3.8	-1.7	-1.1	-1.0	-1.4	-1.5	-1.4	-1.2	-1.2	-1.8	-2.1	-1.5	-2.3
West	0.0	-1.0	-4.9	-0.9	-0.5	-0.6	-0.8	-0.8	-0.6	-0.6	-0.5	-0.7	-0.8	-0.8	-0.8	-0.9	-0.8	-0.8	-0.8	-0.8	-0.9	-0.8
Alaska & Canada	0.0	3.2	1.5	2.0	2.0	1.6	1.1	0.9	0.8	1.1	1.1	0.9	0.5	0.4	0.5	0.7	0.4	0.5	0.5	0.7	0.7	0.6

Source: IHS Markit

Table C-5. Annual real operating cost escalation for onshore by U.S. region, year-on-year percentage change

U.S. region	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038	2039	2040
North	0.0	-0.4	-1.0	-0.3	0.4	0.1	-1.2	0.0	-0.4	-1.0	-0.9	-1.1	-1.4	-1.4	-2.0	-3.4	-1.3	-0.9	-0.8	-0.7	-0.7	-0.7
Northeast	0.0	0.0	0.5	0.2	0.8	0.7	1.1	1.1	1.3	1.3	1.2	0.2	0.0	-0.1	-0.4	-0.3	0.2	0.2	0.0	0.8	0.8	0.0
South	0.0	2.1	0.5	-1.0	-0.2	0.0	-1.3	-2.7	-2.3	-3.1	-1.3	-0.7	-0.5	-0.9	-1.1	-0.9	-0.6	-0.8	-1.3	-1.7	-1.0	-1.8
West	0.0	0.0	0.3	0.4	0.9	0.6	1.2	0.4	0.9	1.2	0.9	0.6	0.9	0.7	0.5	0.6	0.8	0.6	0.6	0.7	0.7	0.7
Alaska & Canada	0.0	-2.2	4.0	-2.1	0.7	0.4	0.2	0.5	-0.3	-0.1	0.3	0.1	-0.4	-0.3	0.0	0.0	0.0	0.1	0.0	0.0	0.1	0.0

Source: IHS Markit

Appendix D—Results of Economic Analysis

Figures in the main body of the report without a corresponding table are shown in this section. Government take figures have been represented as 100 percent for projects with no profit. For models that produced no return, IRR figures have been represented as 0 percent. Depth assumptions between reserve size cases in a country may not correlate positively with the reserve size, making results for a smaller case possibly better than one with greater reserves.

D.1 Discounted Share of the Barrel

D.1.1 Alaska Onshore

Table D-1. Discounted share of the barrel: Alaska onshore field jurisdiction comparisons by size and case

Jurisdiction	Land owner	Field size (MMboe)	Discounted share of the barrel (%)														
			High case					Base case					Low case				
			Inv	Fed	St	Opex	Capex	Inv	Fed	St	Opex	Capex	Inv	Fed	St	Opex	Capex
Alaska	St	50	14	15	20	27	24	-6	6	19	42	39	-59	4	17	67	71
		100	23	19	21	20	17	11	9	20	32	28	-21	4	18	52	47
		200	28	22	21	17	13	20	12	21	27	21	-3	6	18	44	35
	Fed	50	16	29	4	27	24	-3	20	2	42	39	-55	17	0	68	70
		100	25	33	4	20	17	14	23	3	32	28	-18	17	1	52	48
		200	30	36	5	17	13	23	26	4	27	21	0	19	2	44	35
Yukon		50	10	33	0	23	34	-18	27	0	35	56	-81	24	0	56	101
		100	25	36	0	14	25	5	32	0	23	40	-31	25	0	36	70
		200	32	38	0	11	19	18	34	0	17	30	-8	29	0	28	51
Notes: “Inv” is investor, “Fed” is federal, and “St” is state.																	

Source: IHS Markit

D.1.2 Conventional Resources

Table D-2. Discounted share of the barrel: Conventional resources oil 5 MMboe fields by case

Jurisdiction	Land owner	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Colorado	Fed	24	24	12	0	9	31	6	22	11	0	14	48	-23	18	10	0	22	74
	St	20	11	30	0	9	31	1	9	28	0	14	48	-27	6	27	0	22	73
	Pri	20	11	13	17	9	31	1	9	12	17	14	47	-27	6	11	16	22	73
Montana	Fed	23	23	12	0	13	29	3	20	10	0	21	46	-33	15	9	0	34	75
	St	21	11	27	0	13	28	1	8	25	0	21	45	-34	4	22	0	34	74
	Pri	20	10	13	15	13	28	0	8	12	14	21	45	-36	4	10	14	34	74
New Mexico	Fed	29	24	14	0	9	25	14	22	13	0	14	38	-11	18	11	0	21	60
	St	23	11	31	0	9	26	7	9	30	0	14	40	-18	6	28	0	21	64
	Pri	22	10	14	21	9	24	7	8	14	20	13	38	-17	6	12	19	21	60
Texas	St	29	11	29	0	11	21	14	9	28	0	17	33	-11	6	26	0	27	53
	Pri	30	11	7	22	11	19	16	9	7	21	17	30	-8	6	6	20	27	49
Utah	Fed	-4	22	8	0	11	62	-43	19	8	0	17	100	-112	14	6	0	28	164
	St	-5	10	24	0	11	61	-43	7	22	0	17	97	-111	3	19	0	28	160
	Pri	-10	8	9	22	11	61	-49	6	8	21	17	97	-116	2	7	19	28	159
Wyoming	Fed	26	24	11	0	9	30	6	22	11	0	14	47	-30	18	10	0	24	79
	St	24	12	26	0	9	29	4	10	25	0	14	46	-31	6	24	0	24	77
	Pri	23	11	12	16	9	29	3	9	12	15	14	46	-32	6	11	14	24	76
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

Table D-3. Discounted share of the barrel: Conventional resources oil 2 MMboe fields by case

Jurisdiction	Land owner	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Colorado	Fed	19	23	12	0	10	36	-2	21	11	0	15	56	-36	17	9	0	22	87
	St	15	10	30	0	10	35	-5	8	28	0	14	54	-39	5	26	0	23	86
	Pri	15	10	13	17	10	35	-5	8	12	17	14	54	-39	5	10	16	23	86
Montana	Fed	9	23	11	0	11	46	-22	20	10	0	18	74	-76	15	8	0	30	123
	St	8	10	26	0	11	45	-22	8	25	0	18	72	-74	3	22	0	30	119
	Pri	6	10	13	15	11	45	-23	7	12	14	18	72	-76	3	10	14	30	119
New Mexico	Fed	-37	20	13	0	9	95	-92	18	12	0	14	148	-182	15	11	0	23	234
	St	-52	7	30	0	9	106	-113	5	29	0	14	165	-213	2	27	0	23	261
	Pri	-42	7	14	21	9	91	-95	5	13	20	14	143	-181	2	12	19	23	226
Texas	St	5	9	29	0	12	46	-26	6	28	0	19	73	-80	2	26	0	31	122
	Pri	12	10	7	22	12	38	-15	7	7	21	19	62	-62	3	6	19	31	103
Utah	Fed	0	23	9	0	12	56	-27	21	8	0	18	80	-61	18	7	0	25	111
	St	-2	11	24	0	13	55	-28	9	22	0	18	78	-62	7	21	0	25	109
	Pri	-7	9	9	21	13	55	-33	8	8	21	18	78	-67	5	7	20	25	109
Wyoming	Fed	8	23	11	0	13	46	-23	19	11	0	20	74	-80	14	10	0	33	123
	St	6	10	26	0	13	45	-24	7	25	0	20	72	-80	3	24	0	33	120
	Pri	5	10	12	16	13	45	-25	7	12	15	20	72	-81	3	11	14	33	119
Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.																			

Source: IHS Markit

Table D-4. Discounted share of the barrel: Conventional resources oil 1 MMboe fields by case

Jurisdiction	Land owner	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Colorado	Fed	3	23	12	0	8	54	-30	20	11	0	12	86	-89	15	9	0	21	144
	St	0	10	30	0	8	52	-32	7	28	0	12	84	-90	3	26	0	21	140
	Pri	0	10	13	17	8	52	-32	7	12	17	12	84	-89	3	10	16	21	140
Montana	Fed	-63	22	11	0	13	116	-120	19	10	0	20	171	-197	15	9	0	28	244
	St	-62	9	26	0	14	113	-117	7	25	0	20	166	-191	4	23	0	28	236
	Pri	-63	9	13	15	14	113	-118	6	12	14	20	166	-193	4	10	14	28	236
New Mexico	Fed	-8	21	13	0	12	63	-45	17	12	0	18	99	-110	12	10	0	29	159
	St	-18	7	30	0	12	69	-58	3	28	0	18	108	-130	0	26	0	30	175
	Pri	-14	7	14	21	12	61	-50	4	12	20	18	96	-114	0	11	19	30	155
Texas	St	-156	7	29	0	12	207	-280	5	28	0	19	328	-493	1	27	0	31	534
	Pri	-122	8	7	22	12	172	-226	6	7	21	19	273	-405	2	7	20	31	445
Utah	Fed	-7	22	8	0	12	65	-39	19	8	0	17	95	-85	15	6	0	25	139
	St	-8	10	23	0	12	63	-39	7	22	0	17	93	-85	4	20	0	25	136
	Pri	-13	8	9	21	12	63	-44	6	8	20	17	93	-90	3	7	19	25	136
Wyoming	Fed	-59	22	11	0	9	116	-129	20	11	0	15	184	-250	15	10	0	24	300
	St	-58	10	26	0	9	112	-125	7	25	0	15	178	-242	4	24	0	24	290
	Pri	-58	10	12	16	9	111	-125	7	12	15	15	176	-241	4	11	14	24	287

Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.

Source: IHS Markit

Table D-5. Discounted share of the barrel: Conventional resources gas 5 MMboe fields by case

Jurisdiction	Land owner	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Colorado	Fed	12	23	12	0	10	43	-15	20	11	0	16	67	-57	16	9	0	24	108
	St	8	10	30	0	10	42	-18	7	29	0	16	66	-61	4	27	0	24	106
	Pri	8	10	13	17	10	42	-18	7	12	17	16	66	-60	4	10	16	24	106
Montana	Fed	-55	19	10	0	19	108	-109	15	8	0	28	158	-187	11	7	0	40	229
	St	-55	7	24	0	19	105	-108	4	22	0	28	154	-184	1	20	0	40	224
	Pri	-56	6	12	14	19	105	-109	3	10	14	28	154	-186	0	8	13	40	224
New Mexico	Fed	26	23	14	0	10	26	13	22	13	0	14	37	-3	19	12	0	20	52
	St	20	10	31	0	11	28	7	9	30	0	15	40	-10	7	29	0	19	55
	Pri	18	9	15	21	11	26	6	8	14	20	15	37	-10	6	13	19	19	51
Texas	St	6	9	31	0	11	43	-15	6	30	0	16	63	-44	3	29	0	22	89
	Pri	10	9	9	21	11	39	-10	7	9	21	16	57	-36	4	9	20	22	81
Utah	Fed	-27	19	8	0	19	81	-66	16	7	0	27	117	-119	12	5	0	38	164
	St	-28	7	22	0	19	80	-67	4	21	0	27	115	-121	1	19	0	39	162
	Pri	-34	6	8	21	19	80	-72	3	7	20	27	115	-126	0	6	19	39	162
Wyoming	Fed	10	22	10	0	15	42	-10	19	10	0	22	59	-37	16	9	0	30	82
	St	8	10	25	0	15	42	-13	8	24	0	22	59	-39	5	23	0	30	82
	Pri	7	9	12	15	15	42	-14	7	11	14	22	59	-40	4	11	13	30	81

Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.

Source: IHS Markit

Table D-6. Discounted share of the barrel: Conventional resources gas 2 MMboe fields by case

Jurisdiction	Land owner	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Colorado	Fed	-8	21	11	0	13	63	-28	20	10	0	16	82	-49	18	10	0	20	102
	St	-12	8	29	0	13	62	-32	7	28	0	17	81	-54	5	27	0	21	102
	Pri	-12	8	12	17	13	62	-32	7	11	17	17	81	-54	5	11	16	21	102
Montana	Fed	-83	17	9	0	17	140	-168	12	8	0	26	221	-323	10	7	0	43	362
	St	-80	5	24	0	17	135	-163	1	22	0	26	214	-314	0	20	0	43	351
	Pri	-82	4	11	15	17	135	-164	1	9	14	26	214	-315	0	8	13	43	350
New Mexico	Fed	-55	19	13	0	16	108	-106	16	12	0	23	156	-177	12	10	0	33	223
	St	-70	5	30	0	16	118	-125	2	29	0	23	171	-205	0	27	0	33	245
	Pri	-61	5	14	21	16	105	-110	2	13	20	23	153	-182	0	12	19	33	218
Texas	St	-78	5	31	0	10	132	-159	2	31	0	15	211	-304	0	30	0	26	348
	Pri	-59	5	9	22	10	113	-129	3	9	22	15	180	-253	0	9	21	26	297
Utah	Fed	-80	16	7	0	19	138	-151	13	6	0	28	205	-256	10	5	0	40	300
	St	-80	4	22	0	19	135	-149	1	20	0	28	201	-254	0	18	0	41	295
	Pri	-85	3	7	21	19	135	-155	1	6	20	28	200	-259	0	6	18	41	294
Wyoming	Fed	-10	20	10	0	17	63	-39	17	10	0	24	88	-75	13	9	0	33	120
	St	-12	8	25	0	17	62	-41	5	24	0	24	88	-78	2	23	0	34	120
	Pri	-13	7	12	15	17	62	-42	5	11	14	24	87	-79	1	11	13	34	120

Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.

Source: IHS Markit

Table D-7. Discounted share of the barrel: Conventional resources gas 1 MMboe fields by case

Jurisdiction	Land owner	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Colorado	Fed	-132	17	10	0	15	190	-216	14	9	0	21	272	-324	12	8	0	29	374
	St	-132	4	28	0	15	186	-215	2	27	0	21	265	-322	0	26	0	29	367
	Pri	-132	4	11	17	15	185	-214	2	10	17	21	264	-321	0	9	16	29	366
Montana	Fed	-102	15	9	0	16	162	-200	12	8	0	26	255	-373	10	7	0	42	414
	St	-99	3	23	0	16	156	-193	0	22	0	26	246	-362	0	20	0	42	400
	Pri	-100	3	10	15	16	156	-195	0	9	14	26	246	-363	0	8	13	42	400
New Mexico	Fed	-48	18	13	0	12	105	-93	14	11	0	17	151	-158	11	10	0	24	212
	St	-62	3	30	0	12	117	-116	0	28	0	17	170	-197	0	27	0	25	246
	Pri	-50	4	14	21	12	100	-96	1	12	20	17	146	-166	0	12	19	25	211
Texas	St	-91	5	31	0	11	144	-133	3	31	0	15	184	-176	2	31	0	18	226
	Pri	-67	6	10	22	11	119	-102	4	10	21	15	152	-138	3	10	21	18	186
Utah	Fed	-110	15	7	0	20	169	-183	12	6	0	28	238	-278	10	5	0	38	324
	St	-109	3	21	0	20	165	-182	1	20	0	28	234	-278	0	18	0	39	321
	Pri	-114	2	7	21	20	165	-188	1	6	20	28	233	-283	0	6	19	39	320
Wyoming	Fed	-46	17	10	0	18	101	-91	13	10	0	25	143	-151	10	9	0	34	197
	St	-46	5	25	0	18	99	-91	1	24	0	25	141	-153	0	22	0	35	195
	Pri	-47	5	12	15	18	98	-92	1	11	14	25	140	-153	0	11	13	35	194

Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.

Source: IHS Markit

D.1.3 Unconventional Resources

This analysis assumes a uniform type curve across all jurisdictions. In the following subsection, D.1.4 Unconventional Resources with Federal Specific Type Curve, specific type curves for the Federal mineral estate are introduced to see how competitive the Federal mineral estate would be when accounting for geological differences. This was done for three plays that have a mixed ratio of Federal, state and private drilled wells.

Table D-8. Discounted share of the barrel: Bakken play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
New Fairway	Fed (ND)	38	22	10	0	15	15	27	18	8	0	24	23	8	13	6	0	37	36
	St (ND)	34	10	25	0	15	15	23	7	23	0	24	23	4	3	19	0	37	37
	Pri (ND)	34	9	10	16	15	15	23	7	9	15	24	23	4	2	7	13	37	37
Parshall	Fed (ND)	33	21	10	0	15	22	19	16	8	0	23	34	-7	10	6	0	37	53
	St (ND)	29	8	26	0	15	22	15	5	23	0	23	34	-11	0	19	0	37	54
	Pri (ND)	29	8	11	16	15	22	14	5	9	15	23	34	-12	0	7	13	37	54
Elm Coulee	St (MT)	34	10	23	0	15	19	20	6	20	0	23	30	-3	2	17	0	37	48
Notes: “Inv” is investor, “Fed” is federal, “St” is state, “Pri” is private, “Opx” is opex, and cpx is capex.																			

Source: IHS Markit

Table D-9. Discounted share of the barrel: Bone Spring play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
New Mexico Deep	Fed (NM)	38	22	13	0	14	14	27	19	12	0	22	21	9	13	10	0	35	33
	St (NM)	33	9	30	0	14	14	22	7	28	0	22	21	4	2	24	0	35	34
	Pri (NM)	30	8	14	20	14	13	20	6	12	19	22	21	2	2	10	17	35	33
Texas Deep	St (TX)	33	9	28	0	14	15	21	6	27	0	21	24	1	2	25	0	34	39
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

Table D-10. Discounted share of the barrel: Haynesville play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Haynesville Core	Fed (LA)	37	23	7	0	6	27	20	19	8	0	10	43	-10	13	8	0	16	73
	St (LA)	28	8	31	0	6	27	12	5	30	0	10	43	-20	0	31	0	16	73
	Pri (LA)	24	7	6	29	6	27	8	4	7	28	10	43	-24	0	9	26	16	73
Shelby Trough	St (TX)	30	9	32	0	6	23	16	6	32	0	10	37	-10	1	31	0	16	62
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

Table D-11. Discounted share of the barrel: Marcellus play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Marcellus Super Core	St (PA)	32	9	24	0	17	17	18	6	22	0	27	28	-9	0	19	0	44	46
	St (WV)	31	9	27	0	17	17	16	5	25	0	27	28	-13	0	22	0	44	46
	Pri (PA)	33	9	5	19	17	17	18	6	4	19	27	27	-9	0	1	18	44	46
Marcellus Southwest Core	Fed (WV)	27	19	7	0	24	24	6	13	5	0	38	38	-38	9	4	0	63	63
	St (PA)	24	7	22	0	24	23	4	3	19	0	38	37	-40	0	15	0	63	63
	Pri (PA)	24	7	4	18	24	23	4	3	2	16	38	37	-40	0	1	14	63	62
Marcellus Periphery	St (OH)	21	6	18	0	26	29	3	2	16	0	37	41	-25	0	14	0	53	58

Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.

Source: IHS Markit

Table D-12. Discounted share of the barrel: Niobrara play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Niobrara DJ	Fed (WY)	30	20	10	0	12	27	14	16	10	0	19	41	-14	10	9	0	30	65
	St (WY)	28	8	25	0	12	27	11	4	24	0	19	41	-18	0	21	0	31	66
	St (CO)	26	8	28	0	12	26	10	4	26	0	19	41	-19	0	23	0	31	66
	Pri (CO)	26	8	12	16	12	26	10	4	11	15	19	41	-19	0	9	14	31	66
Niobrara Wattenberg	St (CO)	31	9	28	0	15	18	19	6	26	0	22	27	1	2	22	0	34	41
	Pri (CO)	31	9	12	16	15	18	19	6	11	15	22	27	1	2	9	13	34	41
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

Table D-13. Discounted share of the barrel: Parkman\Turner\Shannon play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Parkman	Fed (WY)	38	22	11	0	12	18	25	19	10	0	18	28	4	13	9	0	29	44
	St (WY)	35	10	25	0	12	18	23	7	24	0	18	28	2	2	22	0	29	45
	Pri (WY)	34	10	12	15	12	18	22	7	11	14	18	28	1	2	11	13	29	45
Turner Sands	Fed (WY)	34	21	10	0	14	21	21	17	10	0	21	31	3	12	9	0	31	45
	St (WY)	32	9	25	0	14	21	19	6	23	0	21	31	-2	2	21	0	32	47
	Pri (WY)	30	9	12	15	14	21	17	6	11	14	21	31	-3	2	10	13	32	47
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

Table D-14. Discounted share of the barrel: Pinedale Jonah play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Pinedale	Fed (WY)	21	18	10	0	21	30	2	13	10	0	31	45	-30	9	9	0	45	66
	St (WY)	19	7	24	0	20	29	0	2	23	0	31	45	-34	0	20	0	47	67
	Pri (WY)	18	6	12	14	20	29	-1	2	11	13	31	44	-35	0	10	12	47	66
Jonah	Fed (WY)	9	16	10	0	22	44	-18	11	10	0	33	65	-63	9	9	0	48	97
	St (WY)	7	4	24	0	22	42	-20	0	23	0	33	64	-68	0	21	0	50	98
	Pri (WY)	7	4	12	14	22	42	-20	0	11	13	33	63	-68	0	10	12	50	97
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

Table D-15. Discounted share of the barrel: Wolfcamp Delaware play jurisdiction comparisons by case

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Middle Hotspot	Fed (NM)	32	20	12	0	20	16	19	16	11	0	30	25	0	10	8	0	45	37
	St (NM)	28	8	28	0	20	16	15	5	25	0	30	25	-6	1	21	0	46	38
Southern Liquids	Fed (TX)	27	8	27	0	19	19	12	4	25	0	29	30	-15	0	22	0	45	47
	St (TX)	27	8	7	20	19	19	12	4	7	19	29	30	-14	0	6	16	45	46
Notes: "Inv" is investor, "Fed" is federal, "St" is state, and "Pri" is private.																			

Source: IHS Markit

D.1.4 Unconventional Resources with Federal Specific Type Curve

Federal specific type curves are available for only three plays, given production data availability.

Table D-16. Discounted share of the barrel: Bakken play jurisdiction comparisons by case with Federal specific type curve

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opx	Cpx	Inv	Fed	St	Pri	Opx	Cpx	Inv	Fed	St	Pri	Opx	Cpx
New Fairway	Fed (ND)	37	21	10	0	15	16	26	18	8	0	23	25	6	12	6	0	36	39
	St (ND)	34	10	25	0	15	15	23	7	23	0	24	23	4	3	19	0	37	37
	Pri (ND)	34	9	10	16	15	15	23	7	9	15	24	23	4	2	7	13	37	37
Parshall	Fed (ND)	41	22	11	0	13	13	31	19	9	0	21	21	13	14	7	0	33	33
	St (ND)	29	8	26	0	15	22	15	5	23	0	23	34	-11	0	19	0	37	54
	Pri (ND)	29	8	11	16	15	22	14	5	9	15	23	34	-12	0	7	13	37	54
Elm Coulee	St (MT)	34	10	23	0	15	19	20	6	20	0	23	30	-3	2	17	0	37	48

Notes: “Inv” is investor, “Fed” is federal, “St” is state, “Pri” is private, “Opx” is opex, and cpx is capex.

Source: IHS Markit

Table D-17. Discounted share of the barrel: Bone Spring play jurisdiction comparisons by case with Federal specific type curve

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
New Mexico Deep	Fed (NM)	36	21	13	0	14	16	24	18	12	0	22	25	4	12	9	0	35	39
	St (NM)	33	9	30	0	14	14	22	7	28	0	22	21	4	2	24	0	35	34
	Pri (NM)	30	8	14	20	14	13	20	6	12	19	22	21	2	2	10	17	35	33
Texas Deep	St (TX)	33	9	28	0	14	15	21	6	27	0	21	24	1	2	25	0	34	39
Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.																			

Source: IHS Markit

Table D-18. Discounted share of the barrel: Wolfcamp Delaware play jurisdiction comparisons by case with Federal specific type curve

Subplay	Land owner (St)	Discounted share of the barrel (%)																	
		High case						Base case						Low case					
		Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex	Inv	Fed	St	Pri	Opex	Capex
Middle Hotspot	Fed (NM)	35	21	12	0	18	13	23	17	11	0	28	21	4	11	9	0	44	32
	St (NM)	28	8	28	0	20	16	15	5	25	0	30	25	-6	1	21	0	46	38
Southern Liquids	Fed (TX)	27	8	27	0	19	19	12	4	25	0	29	30	-15	0	22	0	45	47
	St (TX)	27	8	7	20	19	19	12	4	7	19	29	30	-14	0	6	16	45	46
Notes: “Inv” is investor, “Fed” is federal, “St” is state, and “Pri” is private.																			

Source: IHS Markit

D.2 Fiscal System Alternatives

D.2.1 Alaska Onshore

Table D-19. Alaska onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner (field size MMboe)	Royalty rate	Royalty sensitivity								
		High case			Base case			Low case		
		IRR	Government take	NPV/boe	IRR	Government take	NPV/boe	IRR	Government take	NPV/boe
Federal (50)	12.5%	20%	57%	5.26	9%	63%	-0.54	0%	-281%	-7.66
	0.0%	23%	46%	6.56	13%	40%	1.12	0%	-83%	-4.91
	8.3%	21%	54%	5.74	10%	55%	0.08	0%	-211%	-6.74
	10.0%	20%	55%	5.55	10%	59%	-0.15	0%	-239%	-7.10
	16.7%	19%	61%	4.74	7%	70%	-1.26	0%	-287%	-9.12
	18.8%	18%	63%	4.46	7%	74%	-1.65	0%	-316%	-9.68
Federal (100)	12.5%	31%	56%	8.38	20%	54%	2.93	1%	93%	-2.26
	0.0%	34%	46%	8.32	23%	39%	4.03	7%	46%	-0.81
	8.3%	32%	53%	7.83	20%	49%	2.95	3%	77%	-1.74
	10.0%	32%	54%	7.72	20%	51%	3.15	2%	83%	-1.94
	16.7%	30%	59%	7.24	17%	60%	2.46	0%	110%	-2.95
	18.8%	29%	60%	7.08	16%	62%	2.21	0%	120%	-3.31
Federal (200)	12.5%	40%	55%	8.69	28%	51%	4.58	10%	65%	-0.01
	0.0%	44%	46%	9.27	32%	39%	5.32	15%	38%	0.96
	8.3%	42%	52%	8.90	29%	47%	4.85	12%	56%	0.35
	10.0%	41%	53%	8.82	29%	49%	4.74	11%	60%	0.21
	16.7%	39%	58%	8.46	26%	56%	4.26	8%	74%	-0.41
	18.8%	38%	60%	8.32	25%	58%	4.07	7%	78%	-0.66
State (50)	16.7%	19%	61%	4.73	7%	70%	-1.27	0%	-289%	(9.14)
State (100)	16.7%	30%	59%	8.04	17%	60%	2.45	-1%	110%	(2.96)
State (200)	16.7%	39%	58%	9.34	26%	56%	4.26	8%	74%	(0.42)

Source: IHS Markit

D.2.2 Conventional Resources

Table D-20. Colorado oil conventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner	Field size (MMboe)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Private	1 MMboe	20%	0%	100%	-10.80
	2 MMboe		0%	100%	-1.72
	5 MMboe		11%	71%	0.31
State	1 MMboe		0%	100%	-10.86
	2 MMboe		0%	100%	-1.74
	5 MMboe		11%	71%	0.30
Federal	1 MMboe	12.5%	0%	100%	-8.68
	2 MMboe		0%	100%	-0.66
	5 MMboe		13%	63%	1.11
	2 MMboe	0.0%	21%	100%	1.39
		8.3%	12%	100%	0.09
		10.0%	0%	100%	-0.20
		16.7%	0%	100%	-1.18
		18.8%	0%	100%	-1.64
		20.0%	0%	100%	-1.93
		25.0%	0%	100%	-3.12
		30.0%	0%	100%	-4.54
	5 MMboe	0.0%	18%	48%	2.34
		8.3%	15%	58%	1.56
		10.0%	14%	60%	1.38
		16.7%	12%	68%	0.61
		18.8%	11%	70%	0.35
		20.0%	10%	72%	0.18
		25.0%	9%	77%	-0.54
		30.0%	7%	83%	-1.37

Source: IHS Markit

Table D-21. Montana oil conventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner	Field size	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Private	1 MMboe	18.8%	0%	100%	-16.58
	2 MMboe		0%	100%	-4.99
	5 MMboe		10%	78%	-0.05
State	1 MMboe	16.7%	0%	100%	-16.00
	2 MMboe		0%	100%	-4.60
	5 MMboe		11%	75%	0.25
Federal	1 MMboe	12.5%	0%	100%	-14.62
	2 MMboe		0%	100%	-4.01
	5 MMboe		12%	70%	0.60
	2 MMboe	0.0%	4%	84%	-2.25
		8.3%	0%	100%	-3.37
		10.0%	0%	100%	-3.62
		16.7%	0%	100%	-4.72
		18.8%	0%	100%	-5.10
		20.0%	0%	100%	-5.34
		25.0%	0%	100%	-6.37
		30.0%	0%	100%	-7.55
	5 MMboe	0.0%	18%	53%	1.94
		8.3%	14%	64%	1.09
		10.0%	13%	67%	0.90
		16.7%	10%	76%	0.07
		18.8%	9%	78%	-0.22
		20.0%	9%	80%	-0.40
		25.0%	6%	87%	-1.18
		30.0%	3%	94%	-2.08

Source: IHS Markit

Table D-22. New Mexico and Texas oil conventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner (St)	Field size	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Private (NM)	1 MMboe	25%	0%	100%	-19.24
	2 MMboe		0%	100%	-11.22
	5 MMboe		27%	90%	2.54
State (NM)	1 MMboe		0%	100%	-20.95
	2 MMboe		0%	100%	-12.60
	5 MMboe		23%	88%	2.49
Private (TX)	1 MMboe	20%	0%	100%	-19.83
	2 MMboe		0%	100%	-4.06
	5 MMboe		34%	66%	6.66
State (TX)	1 MMboe	25%	0%	100%	-24.57
	2 MMboe		0%	100%	-7.14
	5 MMboe		27%	67%	5.76
Federal (NM)	1 MMboe	12.5%	0%	100%	-13.99
	2 MMboe		0%	100%	-8.72
	5 MMboe		36%	76%	3.96
	2 MMboe	0.0%	0%	100%	-6.96
		8.3%	0%	100%	-8.08
		10.0%	0%	100%	-8.33
		16.7%	0%	100%	-9.42
		18.8%	0%	100%	-9.80
		20.0%	0%	100%	-10.04
		25.0%	0%	100%	-11.07
		30.0%	0%	100%	-12.25
	5 MMboe	0.0%	46%	59%	5.35
		8.3%	39%	71%	4.47
		10.0%	38%	73%	4.27
		16.7%	32%	82%	3.41
		18.8%	30%	85%	3.11
		20.0%	29%	86%	2.92
		25.0%	24%	90%	2.17
		30.0%	19%	97%	1.23

Source: IHS Markit

Table D-23. New Mexico and Texas gas conventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner (St)	Field size	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Private (NM)	1 MMboe	25%	0%	100%	-19.24
	2 MMboe		0%	100%	-11.22
	5 MMboe		27%	90%	2.54
State (NM)	1 MMboe		0%	100%	-20.95
	2 MMboe		0%	100%	-12.60
	5 MMboe		23%	88%	2.49
Private (TX)	1 MMboe	20%	0%	100%	-19.83
	2 MMboe		0%	100%	-4.06
	5 MMboe		34%	66%	6.66
State (TX)	1 MMboe	25%	0%	100%	-24.57
	2 MMboe		0%	100%	-7.14
	5 MMboe		27%	67%	5.76
Federal (NM)	1 MMboe	12.5%	0%	100%	-13.99
	2 MMboe		0%	100%	-8.72
	5 MMboe		36%	76%	3.96
	2 MMboe	0.0%	0%	100%	-6.96
		8.3%	0%	100%	-8.08
		10.0%	0%	100%	-8.33
		16.7%	0%	100%	-9.42
		18.8%	0%	100%	-9.80
		20.0%	0%	100%	-10.04
		25.0%	0%	100%	-11.07
		30.0%	0%	100%	-12.25
	5 MMboe	0.0%	46%	59%	5.35
		8.3%	39%	71%	4.47
		10.0%	38%	73%	4.27
		16.7%	32%	82%	3.41
		18.8%	30%	85%	3.11
		20.0%	29%	86%	2.92
		25.0%	24%	90%	2.17
		30.0%	19%	97%	1.23

Source: IHS Markit

Table D-24. Utah oil conventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner	Field size	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Private	1 MMboe	25%	0%	100%	-16.14
	2 MMboe		0%	100%	-6.73
	5 MMboe		2%	87%	-4.40
State	1 MMboe	16.7%	0%	100%	-12.92
	2 MMboe		1%	98%	-5.14
	5 MMboe		3%	76%	-3.54
Federal	1 MMboe	12.5%	0%	100%	-11.43
	2 MMboe		2%	91%	-4.43
	5 MMboe		3%	70%	-3.13
	2 MMboe	0.0%	5%	67%	-2.74
		8.3%	3%	83%	-3.82
		10.0%	3%	86%	-4.05
		16.7%	0%	98%	-5.10
		18.8%	0%	100%	-5.47
		20.0%	0%	100%	-5.69
		25.0%	0%	100%	-6.68
		30.0%	0%	100%	-7.80
	5 MMboe	0.0%	5%	52%	-2.24
		8.3%	4%	64%	-2.81
		10.0%	3%	67%	-2.93
		16.7%	3%	76%	-3.49
		18.8%	2%	79%	-3.69
		20.0%	2%	81%	-3.81
		25.0%	1%	88%	-4.33
		30.0%	1%	95%	-4.94

Source: IHS Markit

Table D-25. Wyoming oil conventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Land owner	Field size	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Private	1 MMboe	18.8%	0%	100%	-17.49
	2 MMboe		0%	100%	-5.10
	5 MMboe		11%	64%	0.51
State	1 MMboe	16.7%	0%	100%	-17.08
	2 MMboe		0%	100%	-4.79
	5 MMboe		12%	62%	0.67
Federal	1 MMboe	12.5%	0%	100%	-15.70
	2 MMboe		1%	98%	-4.11
	5 MMboe		13%	58%	0.82
	2 MMboe	0.0%	5%	73%	-2.37
		8.3%	2%	90%	-3.48
		10.0%	2%	93%	-3.72
		16.7%	0%	100%	-4.81
		18.8%	0%	100%	-5.19
		20.0%	0%	100%	-5.43
		25.0%	0%	100%	-6.45
		30.0%	0%	100%	-7.63
	5 MMboe	0.0%	16%	44%	1.69
		8.3%	14%	53%	1.14
		10.0%	13%	55%	1.02
		16.7%	11%	62%	0.48
		18.8%	11%	65%	0.29
		20.0%	10%	66%	0.17
		25.0%	9%	71%	-0.33
		30.0%	8%	77%	-0.91

Source: IHS Markit

Table D-26. Colorado end of life royalty reduction sensitivity—Months extended

Primary Product	Field size	End of life royalty sensitivity		
		Base case		
		25 percent reduction	50 percent reduction	75 percent reduction
Gas	1 MMboe	11	12	14
	2 MMboe	0	2	3
	5 MMboe	1	3	4
Oil	1 MMboe	1	1	13
	2 MMboe	0	0	5
	5 MMboe	0	7	9

Source: IHS Markit

Table D-27. Montana end of life royalty reduction sensitivity—Months extended

Primary Product	Field size	End of life royalty sensitivity		
		Base case		
		25 percent reduction	50 percent reduction	75 percent reduction
Gas	1 MMboe	1	2	2
	2 MMboe	0	1	2
	5 MMboe	1	1	2
Oil	1 MMboe	1	12	13
	2 MMboe	8	8	11
	5 MMboe	6	8	14

Source: IHS Markit

Table D-28. New Mexico end of life royalty reduction sensitivity—Months extended

Primary Product	Field size	End of life royalty sensitivity		
		Base case		
		25 percent reduction	50 percent reduction	75 percent reduction
Gas	1 MMboe	0	1	2
	2 MMboe	1	2	3
	5 MMboe	1	2	2
Oil	1 MMboe	2	2	6
	2 MMboe	7	7	7
	5 MMboe	7	9	10

Source: IHS Markit

Table D-29. Utah end of life royalty reduction sensitivity—Months extended

Primary Product	Field size	End of life royalty sensitivity		
		Base case		
		25 percent reduction	50 percent reduction	75 percent reduction
Gas	1 MMboe	1	2	3
	2 MMboe	0	0	2
	5 MMboe	1	2	3
Oil	1 MMboe	3	4	6
	2 MMboe	2	9	9
	5 MMboe	5	7	8

Source: IHS Markit

Table D-30. Wyoming end of life royalty reduction sensitivity—Months extended

Primary Product	Field size	End of life royalty sensitivity		
		Base case		
		25 percent reduction	50 percent reduction	75 percent reduction
Gas	1 MMboe	1	4	4
	2 MMboe	0	1	2
	5 MMboe	0	2	2
Oil	1 MMboe	4	12	12
	2 MMboe	0	4	12
	5 MMboe	1	1	1

Source: IHS Markit

D.2.3 Unconventional Resources

This analysis assumes a uniform type curve across all jurisdictions. In subsection, D.1.4., Unconventional Resources with Federal Specific Type Curve, three plays that have a mixed ratio of Federal, state and private wells drilled, specific type curves for the Federal mineral estate are introduced to see how competitive the Federal mineral estate would be when accounting for geological differences.

Table D-31. Bakken unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
New Fairway	Fed (ND)	12.5%	81%	45%	9.30
	St (ND)	18.8%	68%	51%	9.27
	Pri (ND)	20.0%	66%	52%	9.13
Parshall	Fed (ND)	12.5%	41%	49%	7.05
	St (ND)	18.8%	34%	56%	6.54
	Pri (ND)	20.0%	33%	58%	6.34
Elm Coulee	St (MT)	16.7%	47%	52%	8.25
New Fairway	Fed (ND)	0.0%	112%	33%	10.28
		8.3%	91%	41%	9.66
		10.0%	87%	43%	9.52
		16.7%	72%	49%	8.90
		18.8%	68%	51%	8.69
		20.0%	65%	52%	8.56
		25.0%	56%	57%	7.98
		30.0%	47%	62%	7.33
Parshall	Fed (ND)	0.0%	58%	36%	8.55
		8.3%	47%	45%	7.60
		10.0%	45%	47%	7.39
		16.7%	36%	54%	6.45
		18.8%	34%	56%	6.13
		20.0%	33%	58%	5.93
		25.0%	27%	63%	5.05
		30.0%	22%	69%	4.04
Notes: "Fed" is Federal, "St" is state, and "Pri" is private.					

Source: IHS Markit

Table D-32. Bone Spring unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
New Mexico Deep	Fed (NM)	12.5%	102%	50%	9.17
	St (NM)	20.0%	82%	57%	8.97
	Pri (NM)	25.0%	73%	61%	8.53
Texas Deep	St (TX)	25.0%	54%	55%	8.80
New Mexico Deep	Fed (NM)	0.0%	143%	39%	10.14
		8.3%	115%	46%	9.52
		10.0%	110%	48%	9.39
		16.7%	90%	53%	8.78
		18.8%	85%	55%	8.58
		20.0%	81%	56%	8.45
		25.0%	69%	61%	7.88
		30.0%	58%	65%	7.24
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-33. Haynesville unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Haynesville Core	Fed (LA)	12.5%	44%	53%	2.87
	St (LA)	25.0%	29%	68%	2.10
	Pri (LA)	30.0%	23%	74%	1.61
Shelby Trough	St (TX)	25.0%	33%	63%	2.69
Haynesville Core	Fed (LA)	0.0%	63%	37%	3.56
		8.3%	50%	48%	3.12
		10.0%	48%	50%	3.02
		16.7%	39%	58%	2.59
		18.8%	36%	60%	2.44
		20.0%	34%	62%	2.34
		25.0%	28%	68%	1.94
		30.0%	23%	74%	1.47
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-34. Marcellus unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Marcellus Southwest Core	Fed (WV)	12.5%	17%	59%	0.67
	St (PA)	20.0%	15%	66%	0.51
	Pri (PA)	20.0%	15%	66%	0.53
Marcellus Super Core	St (PA)	20.0%	51%	56%	2.39
	St (WV)	20.0%	44%	60%	2.10
	Pri (PA)	20.0%	52%	56%	2.41
Marcellus Periphery	St (OH)	20.0%	12%	59%	0.77
Marcellus Southwest Core	Fed (WV)	0.0%	28%	38%	1.29
		8.3%	21%	52%	0.90
		10.0%	19%	55%	0.81
		16.7%	14%	66%	0.42
		18.8%	13%	69%	0.28
		20.0%	12%	71%	0.19
		25.0%	8%	79%	-0.18
		30.0%	5%	88%	-0.63
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-35. Niobrara unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Niobrara DJ	Fed (WY)	12.5%	25%	52%	5.05
	St (WY)	16.7%	22%	57%	4.63
	St (CO)	20.0%	20%	61%	4.16
	Pri (CO)	20.0%	20%	61%	4.16
Niobrara Wattenberg	St (CO)	20.0%	47%	56%	6.65
	Pri (CO)	20.0%	47%	56%	6.65
Niobrara DJ	Fed (WY)	0.0%	35%	38%	6.79
		8.3%	28%	48%	5.69
		10.0%	27%	50%	5.44
		16.7%	22%	57%	4.36
		18.8%	20%	59%	3.98
		20.0%	20%	61%	3.74
		25.0%	16%	66%	2.72
		30.0%	13%	72%	1.54
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-36. Parkman\Turner\Shannon Sands unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Parkman	Fed (WY)	12.5%	97%	49%	10.83
	St (WY)	16.7%	85%	54%	10.93
	Pri (WY)	18.8%	80%	56%	10.63
Turner Sands	Fed (WY)	12.5%	48%	49%	7.39
	St (WY)	16.7%	42%	54%	7.22
	Pri (WY)	18.8%	40%	56%	6.94
Parkman	Fed (WY)	0.0%	142%	37%	12.28
		8.3%	111%	45%	11.36
		10.0%	105%	47%	11.15
		16.7%	84%	54%	10.26
		18.8%	78%	56%	9.94
		20.0%	75%	57%	9.75
		25.0%	62%	62%	8.91
		30.0%	50%	67%	7.94
Turner Sands	Fed (WY)	0.0%	68%	37%	8.71
		8.3%	54%	45%	7.87
		10.0%	52%	47%	7.68
		16.7%	42%	54%	6.86
		18.8%	40%	56%	6.57
		20.0%	38%	57%	6.39
		25.0%	32%	62%	5.62
		30.0%	26%	67%	4.73
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-37. Pinedale Jonah unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Pinedale	Fed (WY)	12.5%	11%	68%	0.23
	St (WY)	16.7%	10%	74%	-0.07
	Pri (WY)	18.8%	9%	77%	-0.17
Jonah	Fed (WY)	12.5%	0%	100%	-2.74
	St (WY)	16.7%	0%	100%	-3.39
	Pri (WY)	18.8%	0%	100%	-3.55
Pinedale	Fed (WY)	0.0%	18%	49%	1.11
		8.3%	14%	61%	0.55
		10.0%	13%	64%	0.42
		16.7%	9%	74%	-0.13
		18.8%	8%	77%	-0.33
		20.0%	7%	79%	-0.45
		25.0%	5%	87%	-0.99
		30.0%	2%	95%	-1.62
Jonah	Fed (WY)	0.0%	3%	79%	-1.37
		8.3%	0%	100%	-2.24
		10.0%	0%	100%	-2.43
		16.7%	0%	100%	-3.31
		18.8%	0%	100%	-3.62
		20.0%	0%	100%	-3.81
		25.0%	0%	100%	-4.68
		30.0%	0%	100%	-5.72
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-38. Wolfcamp Delaware unconventional fields onshore royalty sensitivity: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Middle Hotspot	Fed (NM)	12.5%	56%	52%	6.07
	St (NM)	20.0%	43%	60%	5.53
Southern Liquids	Fed (TX)	25.0%	30%	61%	5.11
	St (TX)	25.0%	29%	62%	4.99
Middle Hotspot	Fed (NM)	0.0%	80%	40%	7.13
		8.3%	63%	48%	6.46
		10.0%	60%	50%	6.31
		16.7%	49%	56%	5.65
		18.8%	45%	58%	5.42
		20.0%	43%	60%	5.28
		25.0%	36%	64%	4.66
		30.0%	30%	69%	3.95
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

D.2.4 Unconventional Resources with Federal Specific Type Curve

Federal specific type curves are available for only three plays, given production data availability.

Table D-39. Bakken unconventional fields onshore royalty sensitivity with Federal specific type curve: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
New Fairway	Fed (ND)	0.0%	100%	34%	11.19
		8.3%	100%	42%	10.45
		10.0%	100%	44%	10.28
		16.7%	82%	51%	9.55
		18.8%	76%	53%	9.30
		20.0%	73%	54%	9.14
		25.0%	62%	59%	8.46
		30.0%	52%	64%	7.68
Parshall	Fed (ND)	0.0%	100%	34%	13.89
		8.3%	100%	42%	13.22
		10.0%	100%	43%	13.07
		16.7%	100%	50%	12.41
		18.8%	100%	51%	12.19
		20.0%	100%	53%	12.04
		25.0%	100%	57%	11.43
		30.0%	98%	62%	10.72

Notes: “Fed” is Federal, “St” is state, and “Pri” is private.

Source: IHS Markit

Table D-40. Bone Spring unconventional fields onshore royalty sensitivity with Federal specific type curve: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
New Mexico Deep	Fed (NM)	0.0%	100%	40%	9.68
		8.3%	100%	48%	8.95
		10.0%	97%	49%	8.78
		16.7%	78%	56%	8.06
		18.8%	73%	58%	7.81
		20.0%	70%	59%	7.65
		25.0%	58%	64%	6.97
		30.0%	47%	68%	6.20
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

Table D-41. Wolfcamp Delaware unconventional fields onshore royalty sensitivity with Federal specific type curve: Government take vs. IRR and NPV/boe

Subplay	Land owner (St)	Royalty rate	Royalty sensitivity		
			Base case		
			IRR	Government take	NPV/boe
Middle Hotspot	Fed (NM)	0.0%	100%	39%	8.85
		8.3%	96%	47%	8.21
		10.0%	91%	48%	8.07
		16.7%	74%	54%	7.45
		18.8%	69%	56%	7.24
		20.0%	66%	57%	7.10
		25.0%	55%	62%	6.52
		30.0%	45%	67%	5.86
Notes: “Fed” is Federal, “St” is state, and “Pri” is private.					

Source: IHS Markit

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