RYSTAD ENERGY

IDC AND TAX RATE STUDY

MODULE 1: PERMIAN BASIN IMPACT ASSESSMENT

JUNE 30, 2021

American Petroleum Institute

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Introduction

Background on this report

- US oil and gas companies have long been able to deduct their intangible drilling costs, lowering their income exposed to taxes. On the political front, several pieces of legislation seek to repeal the accounting treatment of intangible drilling costs citing the need for more climate action. The debate surrounding intangible drilling costs will continue to heat up as more legislation spotlighting the tax benefit comes up for debate in Congress.

- API engaged Rystad Energy in May 2021 to better understand the financial impact of legislation attempting to repeal the long-established accounting treatment of intangible drilling costs as well as an increase to the corporate tax rate.

- Utilizing our proprietary databases, namely ShaleWellCube (North American onshore well database) and UCube (global upstream database), in conjunction with our research and consulting experts, we will quantify the impact that the repeal of intangible drilling costs will have on future capital spending, drilling activity, production and cash flow.

- Noting API's compressed timetable, we have designed the project in modules, starting with analyzing the impact of the proposed changes outlined above on activity in the Permian.

About Rystad Energy

- Rystad Energy is an independent energy knowledge house offering consulting services, global databases, and research products. The company was established in 2004 and has ~320 employees with offices across the globe, including North America (New York, Houston, Denver, Calgary). We are highly quantitatively oriented in our consulting work due to application of in-house data, which is applied and reshaped to address the topic at hand in given consulting engagements.

- With our approach and experience, we have become one of the world's foremost energy strategy consulting firms. Since 2004m we have completed nearly 2,000 projects for over 500 clinets, ranging from energy companies, investment banks, private equity and venture funds, service companies, and governments and we are recognized by our clients as a thought leader and a trusted advisor in the rapidly evolving energy transition space.

Key findings for the Permian Basin

- A potential IDC repeal and corporate tax rate increase to 25% may reduce upstream capex in the Permian region by $30-110 billion during the 2022-2031 period (the range is determined by our low ($40/barrel), mid ($60/barrel) and high ($80/barrel) oil price scenarios).
- The proposed tax changes, and resulting capex reductions, are not the major driver in our oil production outlook – oil prices are still the most material factor in determining future production potential.
- Nevertheless, 750-1,850 thousand bpd of potential Permian oil supply in 2031 might be lost with the proposed tax changes.
- The proposed tax changes will have $3.5-16 billion negative impact on federal royalty income in 2022-2031.
- 10-year state income (sum of severance tax and state royalties) at risk is seen at $31 billion in high price scenario.
- Based on our estimated negative impact to capital investment, the proposed tax changes may reduce total employment between 30,000 and 110,000 jobs in 2031*

*As calculated and provided by API using Rystad Energy's estimated capital investment under each scenario and the IMPLAN economic assessment software

Key findings – Permian Basin

10- year cumulative amounts	Base		Delta from base		
	Scenario*	**Scenario base output**	**Repeal IDC**	**25% tax hike**	**Repeal IDC & 25% tax hike**
# Wells drilled	High	105,149	-7,421	-9,976	-17,533
Capital investment (USD billions)	High	$631	-47	-61	-108
Production (2031, thousands)	High	10,498	-752	-1,107	-1,844
Federal royalty income (USD billions)	High	$106	-5	-3	-7
State revenue (USD billions)	High	$252	-15	-26	-32
Private royalties (USD billions)	High	$412	-19	-31	-51
Employment (2031)**	High	521,300	-40,600	-70,900	-109,200
# Wells drilled	Mid	72,261	-4,816	-5,101	-10,226
Capital investment (USD billions)	Mid	$418	-29	-29	-60
Production (2031, thousands)	Mid	$7,705	-479	-588	-1,082
Federal royalty income (USD billions)	Mid	$64	-10	-7	-16
State revenue (USD billions)	Mid	$151	-8	-11	-15
Private royalties (USD billions)	Mid	$267	-11	-13	-25
Employment (2031)**	Mid	315,800	-21,400	-32,900	-51,600
# Wells drilled	Low	48,175	-3,682	-1,774	-5,916
Capital investment (USD billions)	Low	$272	-21	-10	-34
Production (2031, thousands)	Low	6,263	-435	-263	-740
Federal royalty income (USD billions)	Low	$38	-3	-1	-4
State revenue (USD billions)	Low	$83	-4	-4	-7
Private royalties (USD billions)	Low	$145	-6	-3	-11
Employment (2031)**	Low	207,000	-16,600	-13,100	-30,800

* High scenario is $80/barrel, Mid scenario is $60/barrel and Low scenario is $40/barrel **Total employment impact (direct, indirect and induced) in 2031 as calculated and provided by API using Rystad Energy's estimated capital investment under each scenario and the IMPLAN economic assessment software
Source: Rystad Energy research and analysis

Key findings – Permian Basin, by state

2031 production by state*

Scenario	State	Base	Repeal IDC	25% tax hike	Repeal IDC & 25% tax hike
High	Texas	6,604	-455	-727	-1,179
	New Mexico	3,167	-297	-380	-665
Mid	Texas	5,435	-307	-395	-713
	New Mexico	2,270	-173	-193	-269
Low	Texas	4,303	-275	-168	-472
	New Mexico	1,960	-161	-95	-269

2031 employment by state**

Scenario	State	Base	Repeal IDC	25% tax hike	Repeal IDC & 25% tax hike
High	Texas	397,500	-26,500	-51,900	-77,600
	New Mexico	123,800	-40,600	-19,000	-31,600
Mid	Texas	245,600	-15,100	-24,900	-39,800
	New Mexico	70,300	-6,300	-8,000	-11,800
Low	Texas	158,900	-11,900	-9,700	-22,500
	New Mexico	48,100	-4,700	-3,400	-8,300

10 year state revenue***

Scenario	State	Base	Repeal IDC	25% tax hike	Repeal IDC & 25% tax hike
High	Texas	157.9	-9.4	-15.1	-18
	New Mexico****	147.2	-10.4	-14.8	-21.7
Mid	Texas	94.7	-4.9	-6.2	-8.6
	New Mexico****	87.9	-5.1	-5.9	-9.9
Low	Texas	51.2	-2.7	-2.2	-3.7
	New Mexico****	51.1	-3.1	-2.1	-4.7

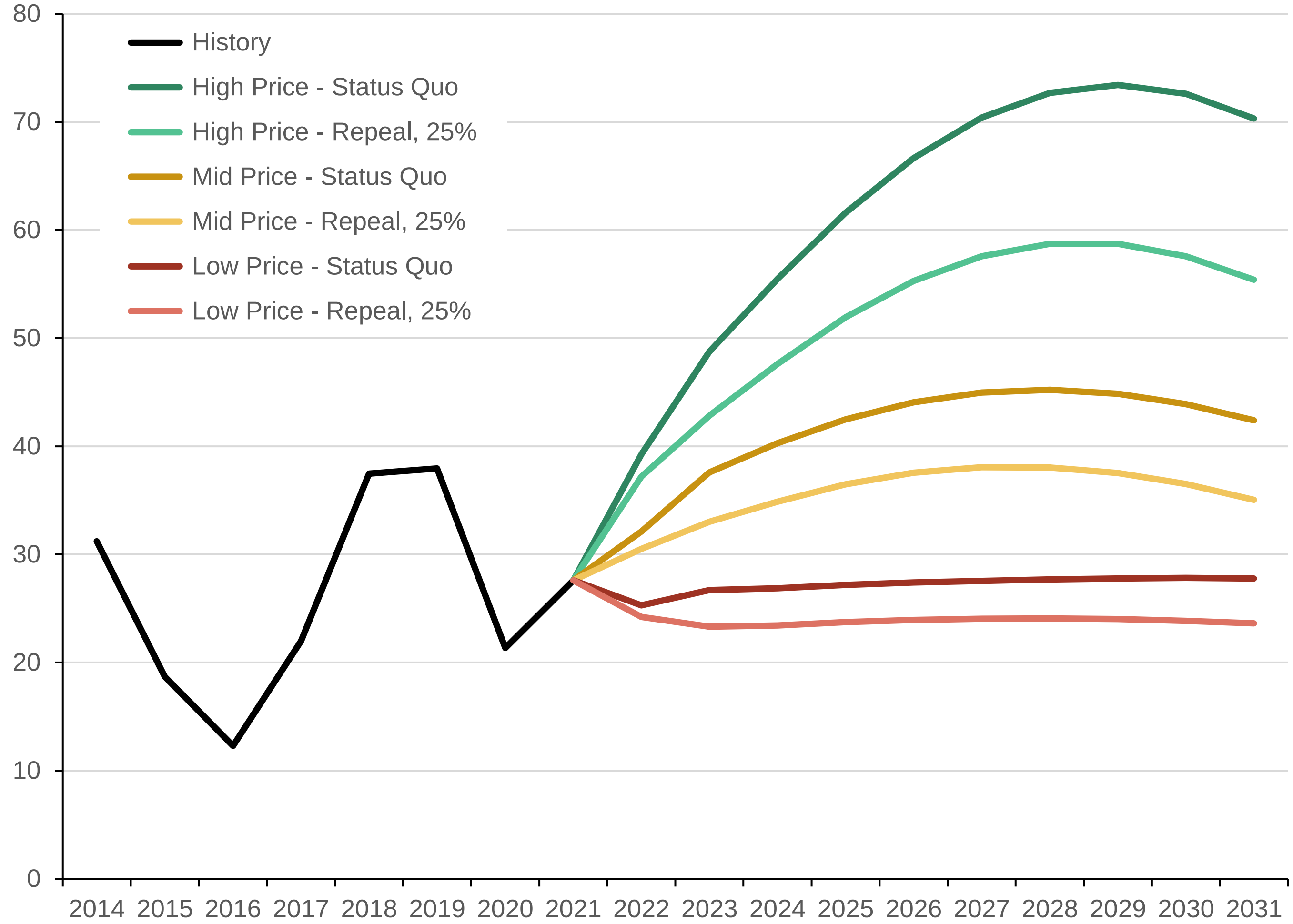
10 year private royalties***

Scenario	State	Base	Repeal IDC	25% tax hike	Repeal IDC & 25% tax hike
High	Texas	432.8	-18.7	-30.1	-49.5
	New Mexico	12.1	-0.1	-1.3	-1.7
Mid	Texas	259.5	-10.8	-12.2	-23.8
	New Mexico	7.2	-0.1	-0.5	-0.8
Low	Texas	140.4	-6.3	-3.2	-10.2
	New Mexico	4.0	-0.1	-0.2	-0.4

*In thousand barrels per day, **Total employment impact (direct, indirect and induced) in 2031 as calculated and provided by API using Rystad Energy's estimated capital investment under each scenario and the IMPLAN economic assessment software ***Billion USD ****Includes 50% of Federal royalty revenue which is shared with the states
Source: Rystad Energy research and analysis

$30-110 billion of Permian upstream capex in 2022-2031 is at risk depending on oil price

Permian, long-term drilling and completion capex scenarios
Billion USD

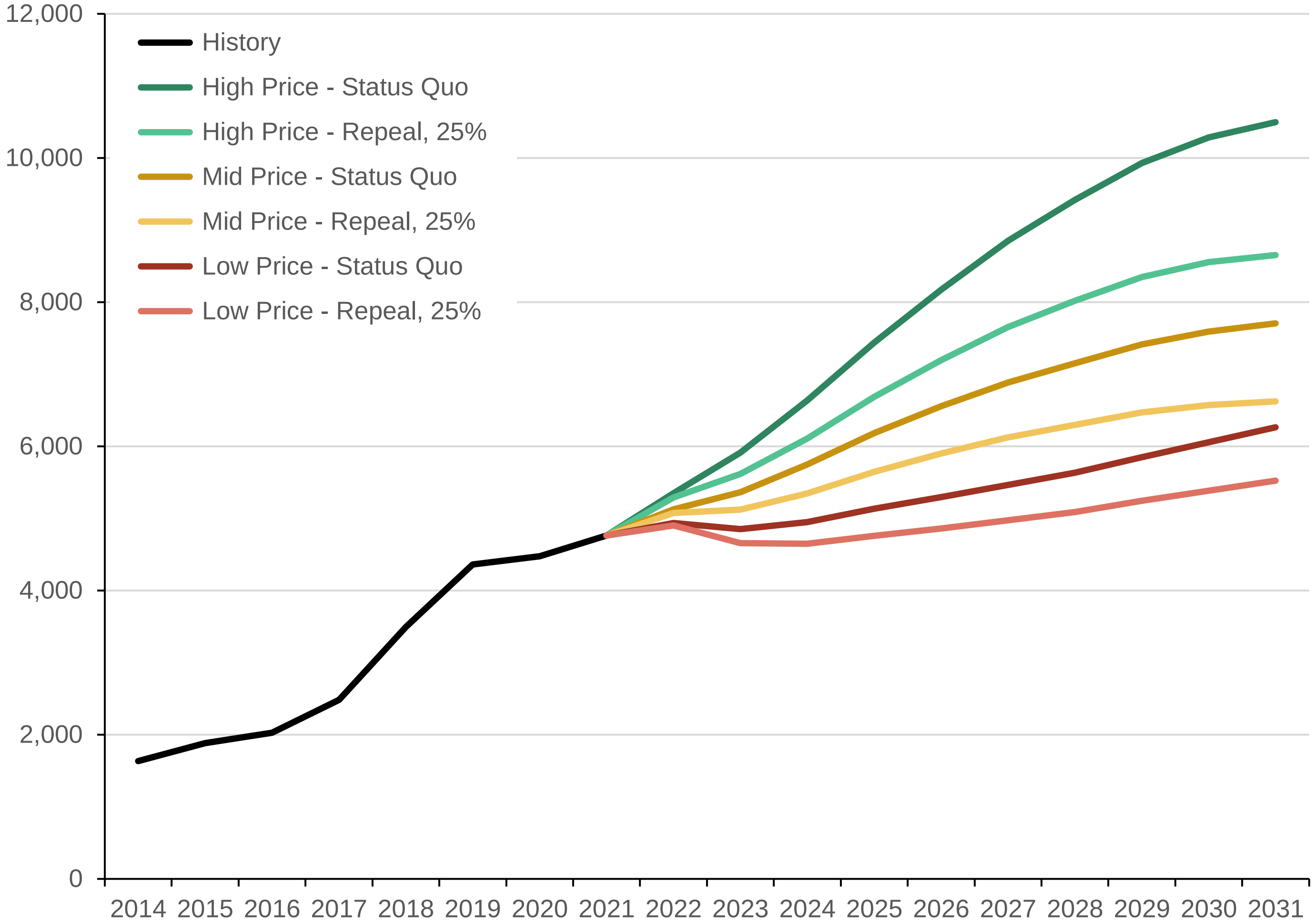


- When it comes to drilling and completion upstream capex in the Permian, the slope of the recovery curve is different from the pace of recovery for well counts in our base case.
- In the high case scenario, significant service cost inflation is triggered as soon as well activity is approaching 8,000 wells per year in 2023.
- In mid-case, capex peak at $45 billion per year in mid-20s as structural efficiency gains offset any material cost inflation.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would put $30-110 billion of expected Permian capex in 2022-2031 at risk if WTI is in $40-80 range.

Source: Rystad Energy research and analysis

In 10 years, Permian oil output might be 750-1,850 thousand bpd lower with proposed tax changes

Permian, long-term oil production scenarios
Thousand barrels per day

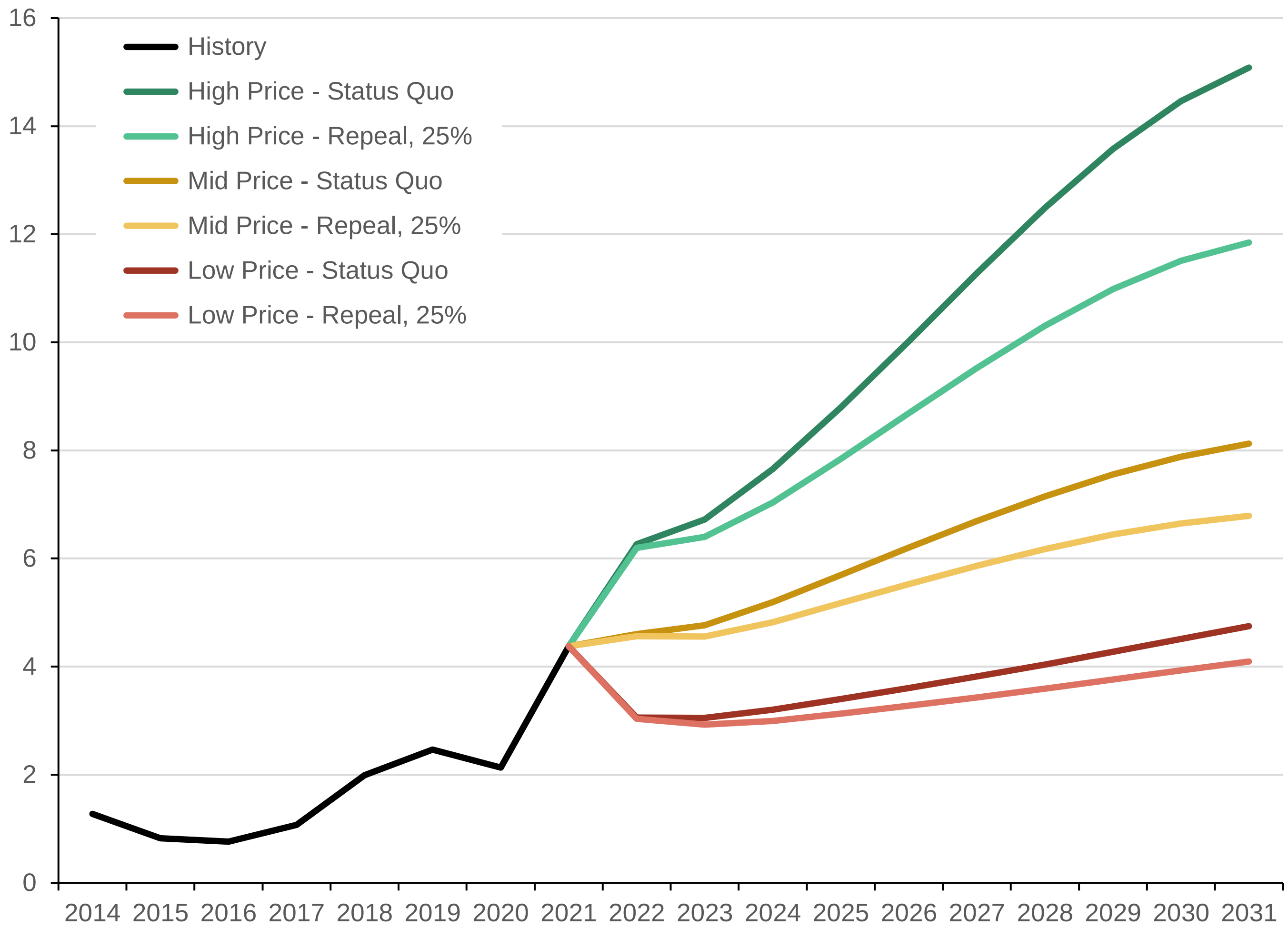


- Permian basin oil production is set to recover to pre-COVID peak of 4.9 million bpd already in early 2022 (the only US onshore oil basin on track to reach such milestone).
- Even in $40 WTI scenario we anticipate basinwide production to ultimately reach 6 million bpd (by 2030) and there is a potential to surpass 10 million bpd in $80 WTI scenario despite conservative reinvestment rates. Significant growth is set to come from private operators in the Permian.
- IDC repeal along with increase of corporate tax rate to 25% might remove 0.7 (WTI of $40) to 1.8 million bpd (WTI of $80) potential basinwide oil production in 2031.

Source: Rystad Energy research and analysis

Proposed tax changes to reduce federal royalty income in by $3.5-16 billion in the next ten years

Permian, federal royalty income scenarios
Billion USD

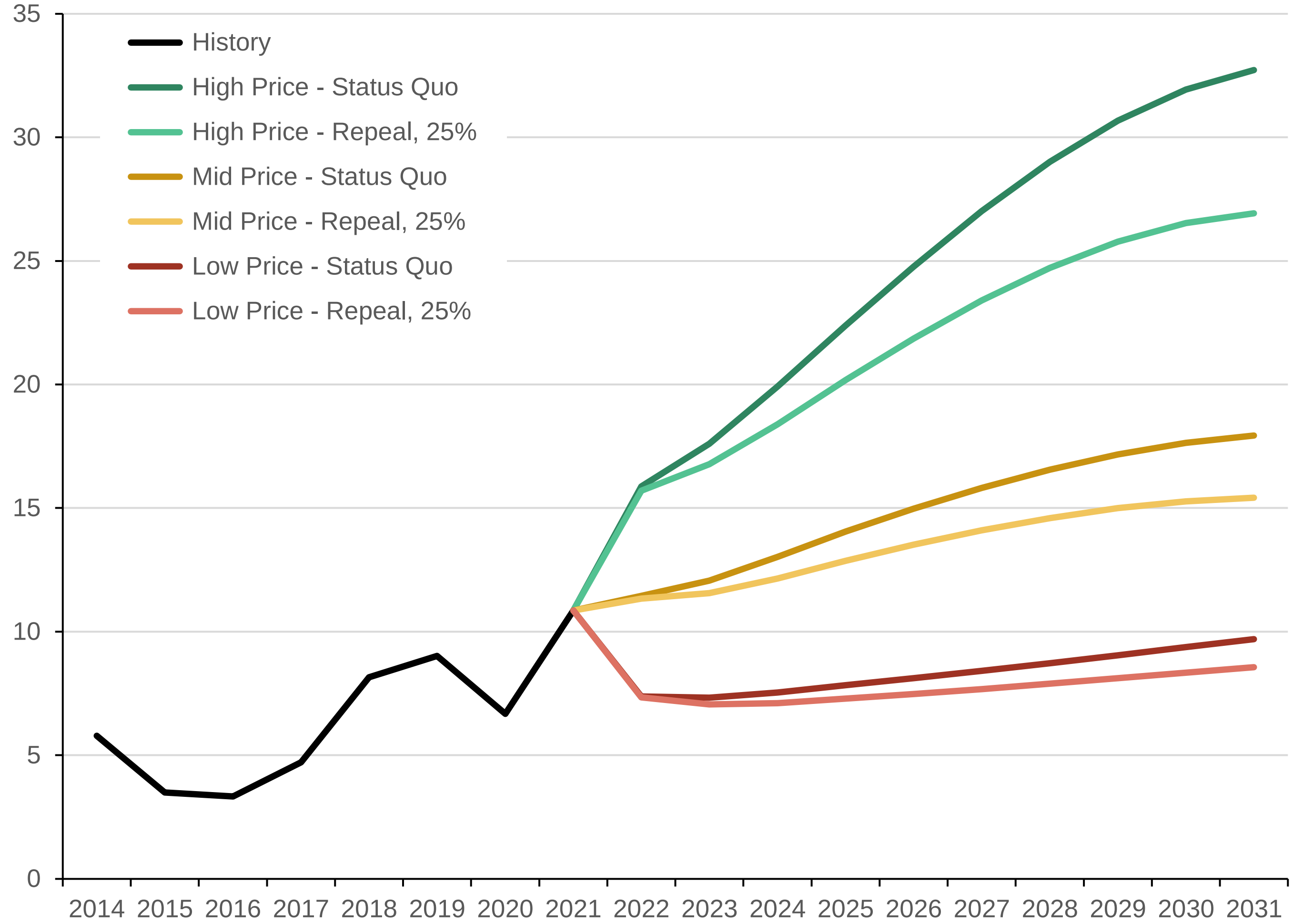


- We calculated the implied federal royalty for different price and regulation scenarios in the Permian basin.
- Federal royalty revenue is expected to reach record-high of $4.3 billion in 2021 amid improved price environment and robust production outlook for federal acreage in New Mexico.
- By 2031, this might increase further to $15 and $8 billion per year in high and mid price scenarios, respectively with status quo regulations.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would reduce federal royalty income by $3.5 billion in low price case and $16 billion in high price case (cumulative impact for 2022-2031)

Source: Rystad Energy research and analysis

Proposed tax changes to reduce state income by up to $31 billion in the next ten years

Permian, state income scenarios (royalty and severance tax combined)
Billion USD



- We calculated the implied state royalty and severance tax for different price and regulation scenarios in the Permian basin.
- State income is expected to reach record-high of $10.8 billion in 2021 amid improved price environment and general production recovery in the basin.
- By 2031, this might increase further to $32.7 and $17.9 billion per year in high and mid price scenarios, respectively with status quo regulations.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would reduce state income by $6.6 billion in low price case and $31.6 billion in high price case (cumulative impact for 2022-2031)

Source: Rystad Energy research and analysis

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Intangible drilling costs have a long legislative history

Intangible Drilling Costs

Intangible drilling costs are well known in the American oil and gas industry. Legislation dating back more than a century allows oil and gas companies in the United States to expense all intangible drilling costs associated with each well in the year in which they occur, rather than capitalize them. These costs include drilling, fuel, administrative and many other costs that have no salvage value. Integrated oil and gas companies can deduct 70% of these costs in the year in which they occur and must capitalize the other 30% over the next five years. Independent oil and gas companies may deduct 100% of these costs. A short legislative history of intangible well costs is below.

1913 – Beginnings

Oil and gas companies begin to expense their intangible drilling costs

1918 – IRS clarifies IDC regulations

Further clarification given by the IRS to oil and gas companies regardings IDCs, confirming support

1940-50s – Affirmation

Congress and the IRS continually reinforce the ability to expense intangible drilling costs

1986 – Integrated companies

IDC rule changed so that integrated companies may only expense 70% of costs and must capitalize the rest

2013/14 – IDCs targeted

Initial government budget proposes eliminating IDCs but does not pass

2021 – Renewed calls for abolishment

Several bills in Congress target intangible drilling costs citing environmental concerns

Source: Rystad Energy research and analysis

Well costs disaggregated into groups at various levels of detail

Well cost group	Well cost category	Well cost detail	Percent of well cost*
Intangible completion	Consumables	Fuel and power	4 %
		Water	7 %
	Frac	Proppant	6 %
		Stimulation	23 %
	Other completion costs	Other completion costs	18 %
Intangible drilling	Rigs and drilling	Drilling services	4 %
		Rig	6 %
	Other drilling costs	Other drilling costs	12 %
Tangible cost	Facilities	Facilities	7 %
	OCTG	OCTG	12 %

- Rystad Energy's ShaleWellCube provides high quality drilling and completion cost estimates for all drilled and completed onshore wells in the US and Canada since 2000. Four primary inputs fuel this model:
  - Type well cost benchmarks from E&P disclosures
  - Actual authorization for expenditure (AFE) for selected wells
  - Well design parameters (TVD, TMD, lateral length, etc.)
  - Service rates by basin and quarter collected from regular surveying
- Future well costs are modeled with an embedded service cost cycling assumption. This may vary with the price scenario, depending on the general activity level and supply/demand balance for equipment in each region.
- Finally, costs are split into different segments and classified as tangible or intangible, as shown to the right.

*For 2021 only
**Stimulation cost are shown net of frac sand (proppant), but include frac chemicals
***Other completion costs – sum of equipment rental, coil tubing, mud, chemicals, transportation, roustabout services, wellsite supervisor, perforation and other less cost-intensive completion services
Source: Rystad Energy research and analysis; Rystad Energy ShaleWellCube

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Rystad Energy's methodology summary

- The model is set up at operator level with the main variability among operators being achieved through long-term reinvestment rate target and the pace of convergence towards that target
- Model involves granular PDP forecast, most applicable type curves for each acreage and comprehensive economic (cost) inputs
- Each operator is assumed to make economically rational capital allocation decisions each quarter based on hydrocarbon price environment and corporate financial situation

Source: Rystad Energy research and analysis

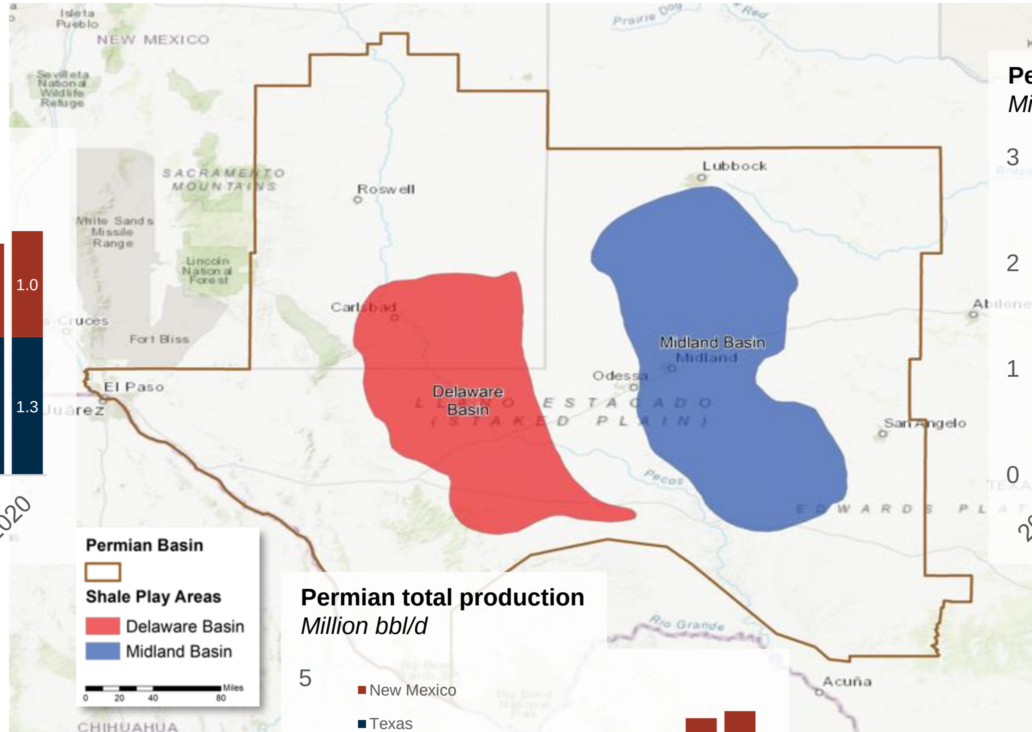
Rystad Energy's methodology: impact calculations

- Starting from 1Q22, we calculate cash from operations for each operator given upstream production profile, hydrocarbon price environment and assumed tax regulation in each scenario.
- Further, we use the expected reinvestment rate for a given operator in considered scenario to calculated allowed capex for the next quarter.
- Capex is further allocated to different assets with lower price environment resulting in increased share of capital allocated to the most commercial acreage positions.
- Once capex is allocated to individual assets, we calculate implied new well count for a given quarter. We further utilize the type curve to calculate production profile associated with new vintage of wells in each asset.
- Finally, we calculate cash from operations for the new quarter and repeat the process iteratively through 4Q31.
- Capex, well count, production and upstream EBITDA are direct outputs of the model. We further calculate the difference between each metric in a considered scenario and the same metric in status quo IDC – 21% federal income tax rate scenario.
- Federal, state and private royalty impacts are calculated at acreage level as the distribution of land ownership in each asset varies significantly across different assets in the Permian (e.g. New Mexico acreage positions tend to exhibit 60-70% of federal land exposure on average).
- Employment impact is based on Rystad's estimated detailed capital investment under each scenario, and as calculated and provided by API using the IMPLAN economic assessment software

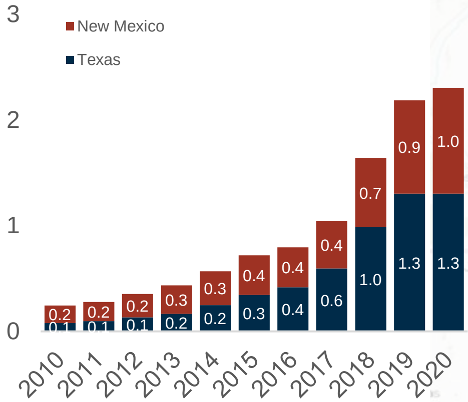
Source: Rystad Energy research and analysis

Midland and Delaware basins – key areas of Permian activity in the recent years

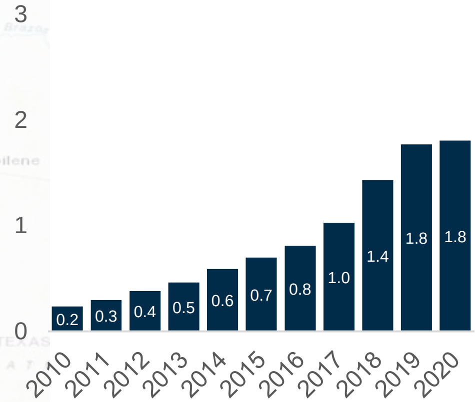
Permian Basin



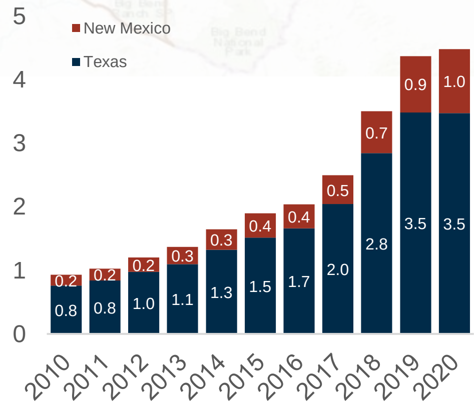
Permian Delaware production
Million bbl/d



Permian Midland production
Million bbl/d

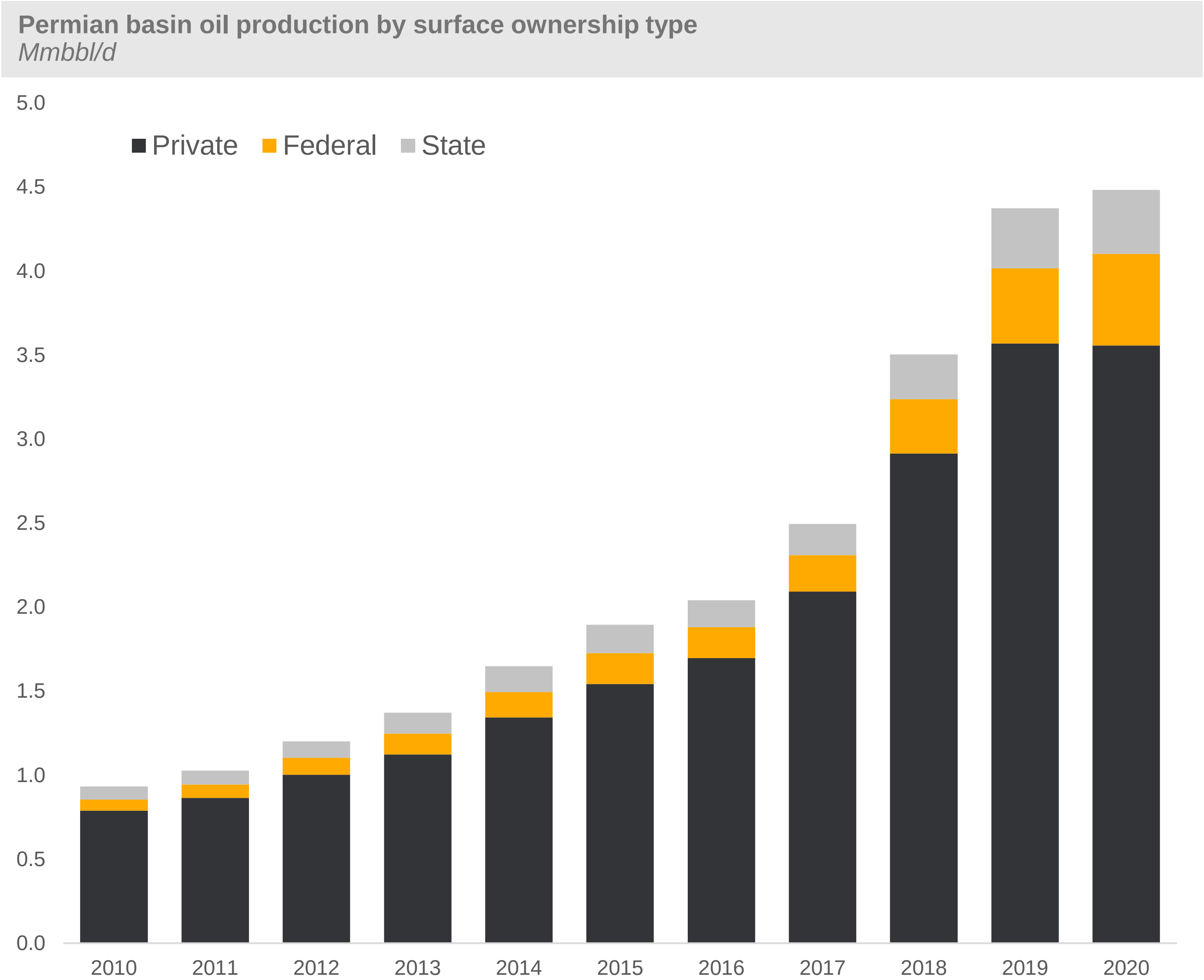


Permian total production
Million bbl/d



Source: Rystad Energy research and analysis: Rystad Energy ShaleWellCube

Privately owned land accounts for majority of Permian production

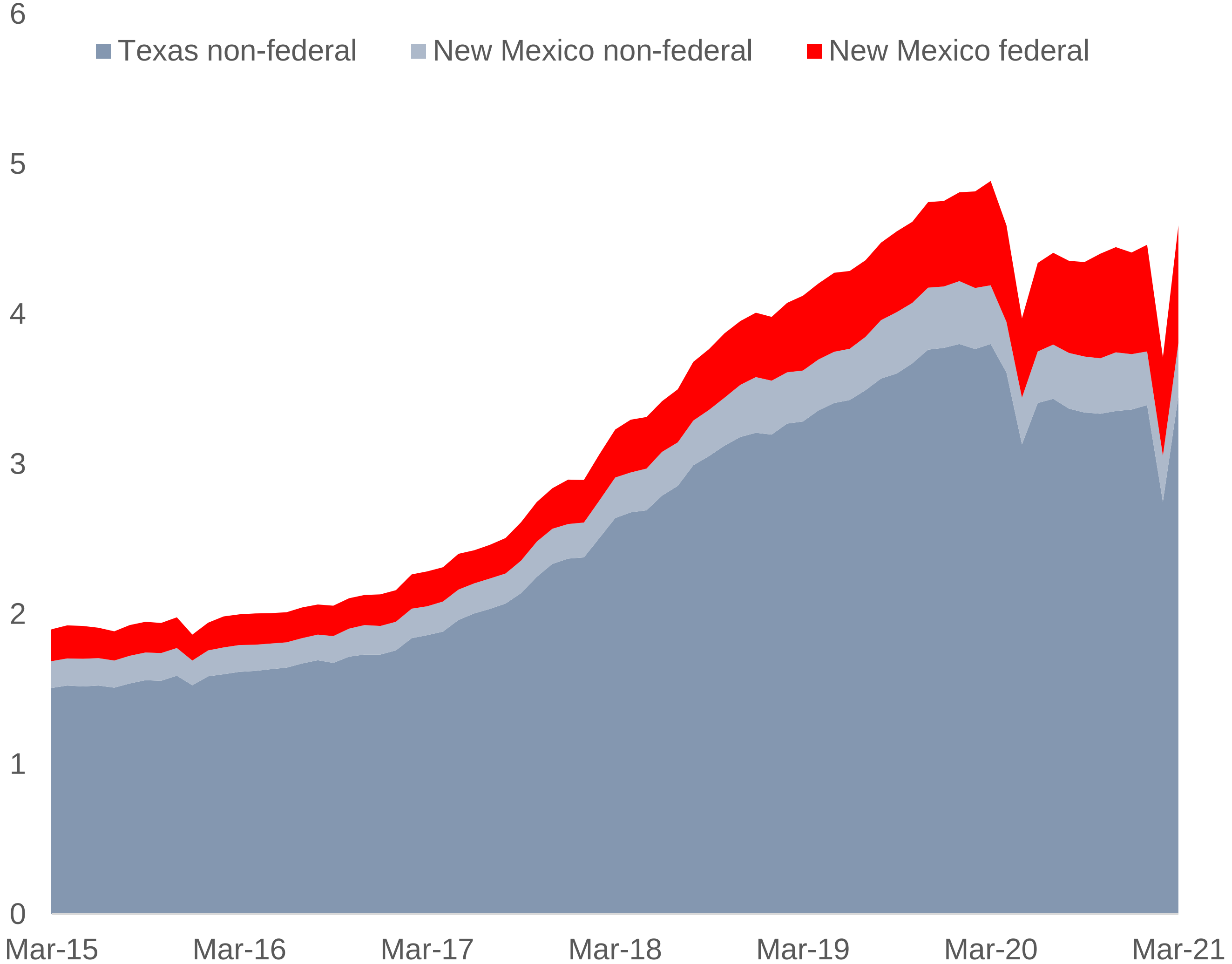


- The increase in production from the Permian basin largely comes from privately owned lands, which account for over 3.5 mmbbl/d of production in 2020.
- Recent years, however, have seen a larger amount of production come from both federal and state lands located in the Permian.

Source: Rystad Energy ShaleWellCube

Federal minerals rights are a small but increasing portion of overall Permian production

Monthly Permian basin oil production by mineral right exposure
Mmbbl/d



- When splitting the entire Permian basin by mineral right federal exposure, we see that federal mineral rights account for a small portion of overall production.
- Furthermore, these mineral rights are entirely concentrated in New Mexico, not in Texas.
- Having said that, federal acreage in New Mexico has seen the most aggressive activity expansion in relative terms since 2018.
- The contribution of federal acreage to basin wide oil production increased from ~10% in 2018 to 17-18% in 1Q21.
- The contribution of federal acreage to Permian NM oil production increased from 50% in 2014 to almost 70% in March 2021.

Source: Rystad Energy ShaleWellCube

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Impact of IDC repeal and tax hike on marginal well economics

- Before we move to our general model on future activity, capex and production scenarios for the Permian, we evaluate the impact of proposed regulations on marginal well economics.
- In this section, we assume a hypothetical model where corporate-level taxes and depreciation model are applicable to individual well/project cash flows. In addition, we allocate G&A overhead down to individual wells (treating them as part of operational expenses). Such approach allows us to get a link between individual well economics and corporate wide return on invested capital in long-term (assuming that it is driven by new drilling and completion projects only)
- We look at three half-cycle economics indicators: PV10 breakeven prices, PV10 value per well and half-cycle IRRs for different price scenarios.
- We find that corporate tax hike and IDC repeal have limited effect on well-level half-cycle breakeven prices in the Permian. Yet IDC repeal scenario has greatest impact on marginal well economics of private operators.
- The share of Permian wells not able to hit half-cycle PV10 breakeven price below $50 grows by 2% in the IDC repeal + tax hike scenario.
- In low-price scenario ($40/barrel), IDC repeal pushes significant number wells into uncommercial territory from PV10 perspective. This observation is factored in into our main model as lower price environment results in significant high-grading and shift towards the best drilling locations in all acreage positions across the basin.

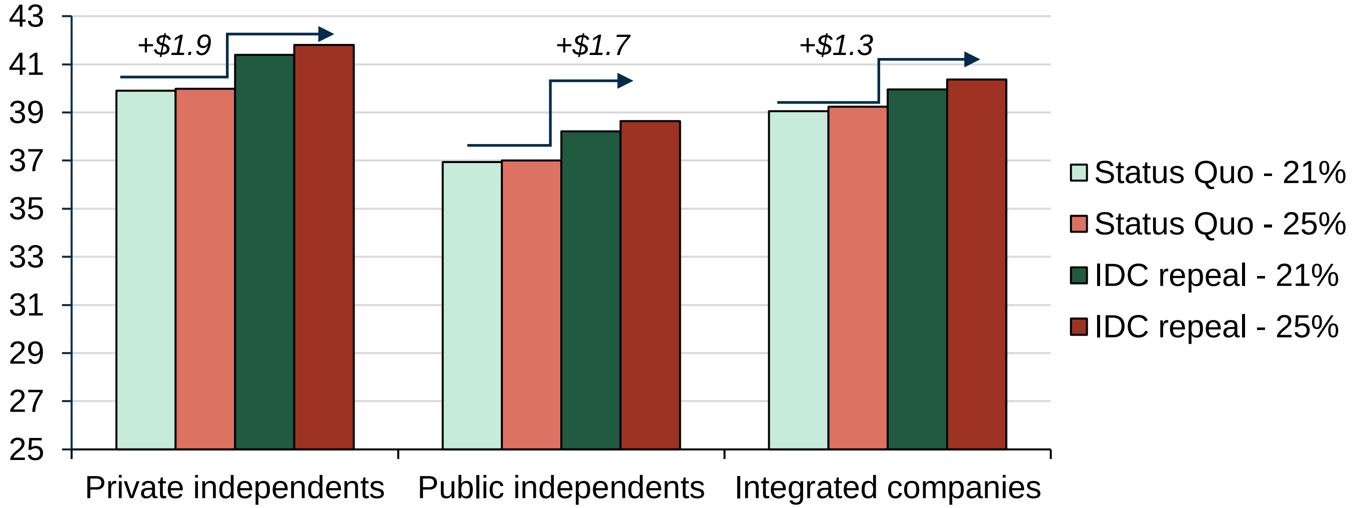
Source: Rystad Energy research and analysis

IDC repeal has greatest impact on marginal well economics of private operators

IDC repeal and tax hike increases break-even prices by $1.3 to $1.9 per barrel
Impacts are greatest for private independents

Increase in median break even price (USD)	Integrated	Public	Private
25% tax hike only	$0.2	$0.1	$0.1
IDC repealed only	$0.9	$1.3	$1.5
25% tax and IDC repealed	$1.3	$1.7	$1.9

Increase in median break even price (percent)	Integrated	Public	Private
25% tax hike only	0.5 %	0.2 %	0.2 %
IDC repealed only	2.3 %	3.4 %	3.7 %
25% tax and IDC repealed	3.4 %	4.6 %	4.8 %

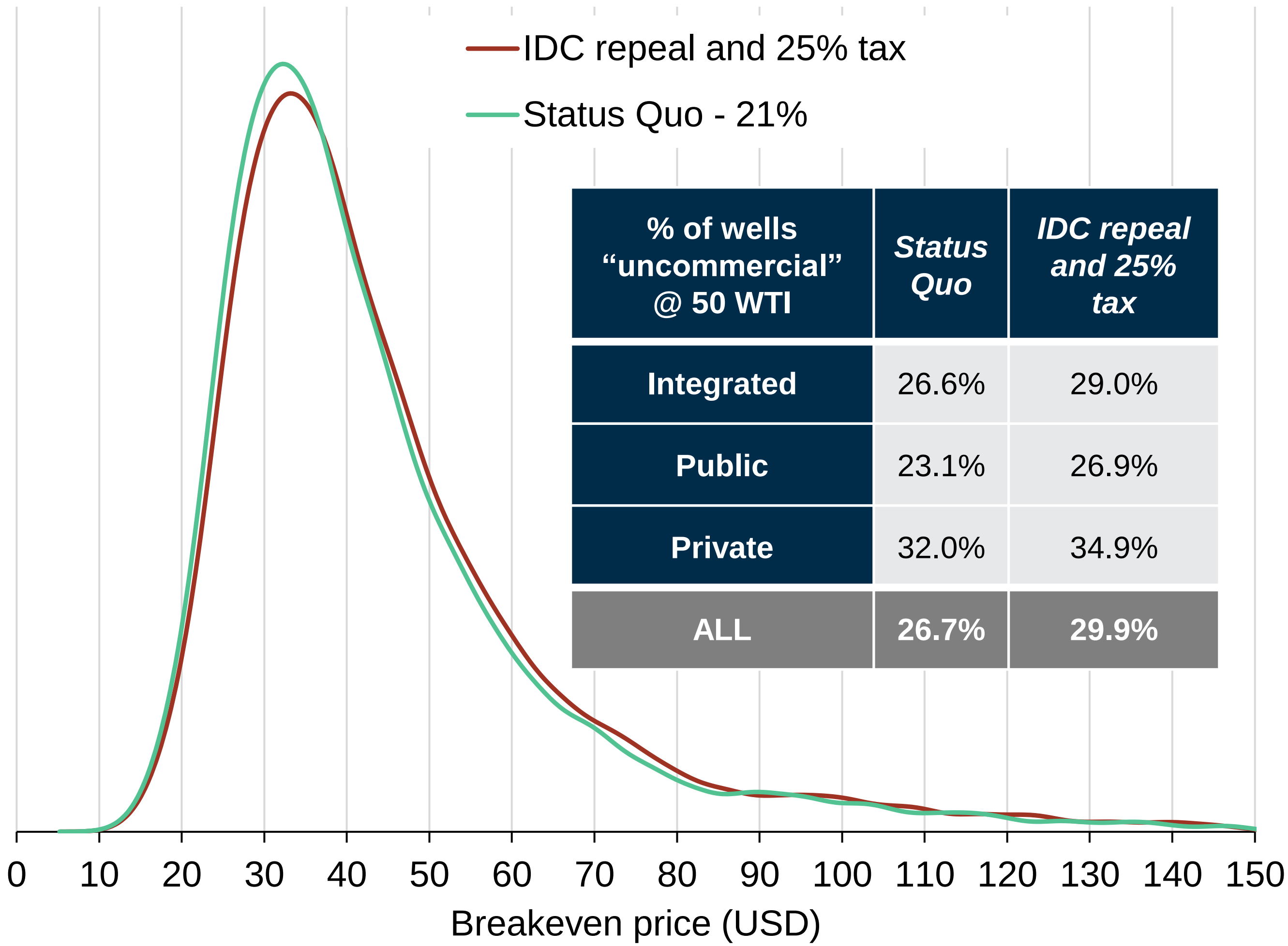


- Integrated companies already capitalize at least 30% of intangible well costs. There is therefore a lesser impact of an IDC repeal than for other operators.
- Median oil breakeven price increases the most for private companies in the case of *IDC repeal*: by $1.5 against $1.3 for public independents and $0.9 for integrated companies.
- This increases by $0.4 if a *simultaneous* tax hike to 25% is implemented.
- A simple tax hike without *IDC repeal* would have only 10 to 20 cents impact on median breakeven prices for all company types.

Source: Rystad Energy ShaleWellCube
* Permian horizontal wells put on production after 2017. Assumes 1:20 (resp. 2:5) fixed relationship between oil and gas (resp. NGL) prices

With $50 WTI, the "uncommercial" well share grows by 2% in the IDC repeal + tax hike scenario

Distribution of half-cycle oil breakeven price* by scenario



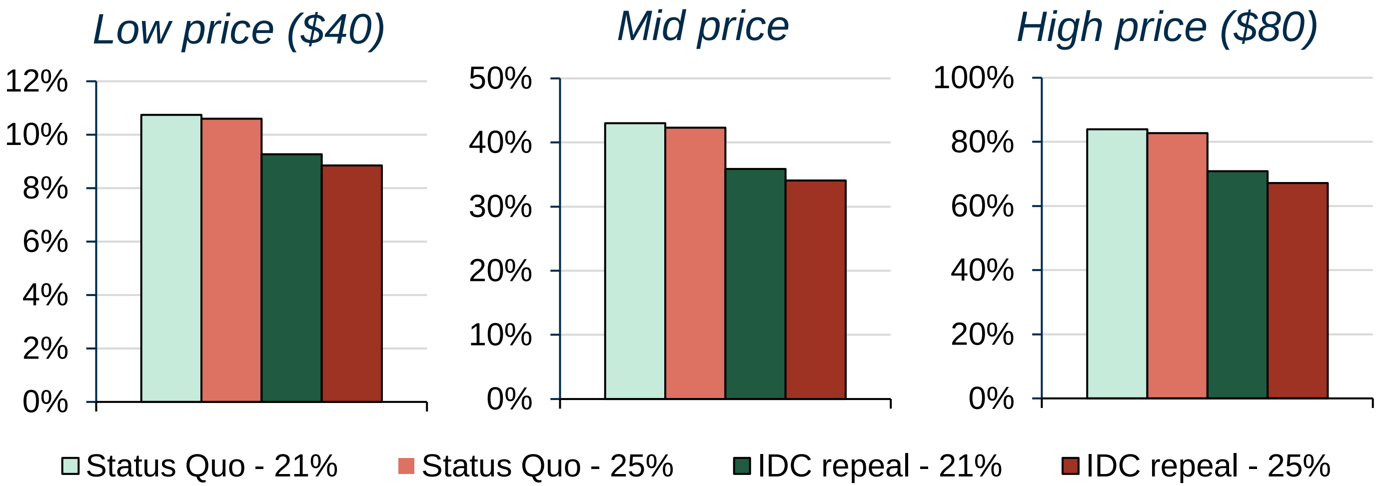
% of wells "uncommercial" @ 50 WTI	*Status Quo*	*IDC repeal and 25% tax*
Integrated	26.6%	29.0%
Public	23.1%	26.9%
Private	32.0%	34.9%
ALL	**26.7%**	**29.9%**

- In a scenario of IDC repeal and immediate tax hike to 25%, the overall shape of the distribution of breakeven prices does not change. The curve is shifted to the right, with a thicker tail.
- In a flat $50 WTI scenario, the number of wells unable to generate positive NPV at a 10% discount rate would increase by 11.8%. In other words, it would increase from 26.7% to 29.9%. This is based on the universe of wells historically put on production after 2017 and includes overhead costs allocated to individual wells.
- This share is largest among private independents, reaching nearly 35% of the well inventory.
- It should be noted that the half-cycle PV10 breakeven prices greater than $50 does not mean that operators do not pursue such drilling and completion opportunities, however, their ultimate long-term return on invested capital might be lower than 10%.

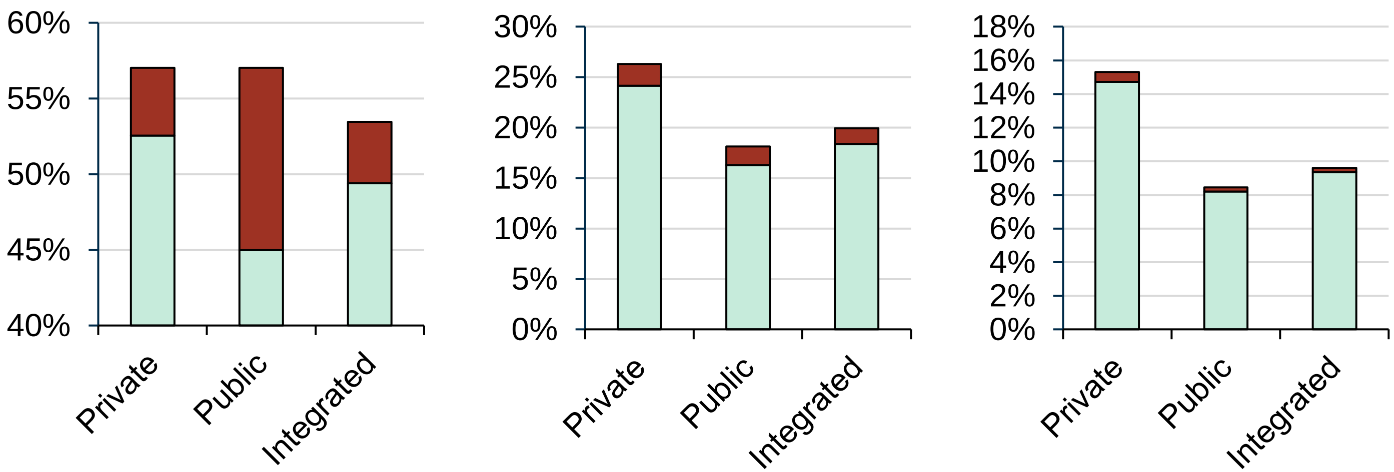
Source: Rystad Energy ShaleWellCube
* Permian horizontal wells put on production after 2017. Assumes 1:20 (resp. 2:5) fixed relationship between oil and gas (resp. NGL) prices

In low-price scenario, IDC repeal pushes many wells into uncommercial territory from PV10 perspective

Typical rate of return by price scenario*



% of uncommercial wells (IRR<10%) by price scenario



Source: Rystad Energy ShaleWellCube
* Permian horizontal POP after 2017

- In the low-price scenario, the typical internal rate of return (IRR) is 11%. A tax hike would not materially change this, but an *IDC repeal* would push the median IRR below 9%, which corresponds to a negative PV10 value.
- In other words, most projects would not be able to generate at least 10% returns on invested capital once corporate overhead costs are taken into account. For public independents, the share of such wells increases from 45% to 57%
- Yet it should be noted that even in status quo scenario, large number of Permian producers will end up with less than 10% ROIC on a large number of their projects. Hence, IDC repeal and tax rate hike are still not viewed as show stoppers for marginal drilling opportunities.
- In a high-price scenario, the consequences of an IDC repeal and immediate tax hike to 25% would trim the typical IRR from 84% to 67%.

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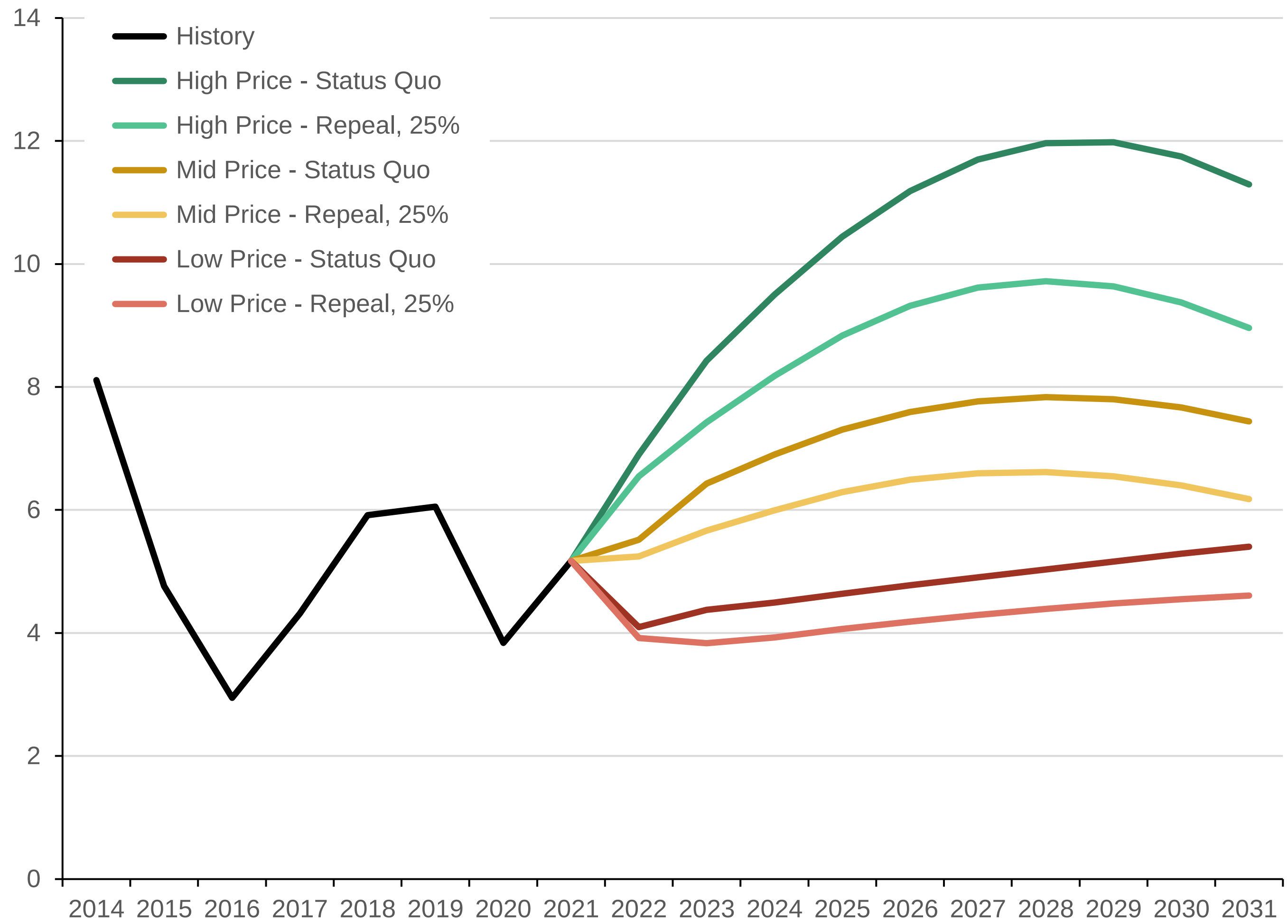
Regulatory changes might eliminate up to 17,500 Permian wells in the next ten years

Permian, long-term well activity scenarios
Number of wells put on production (thousand)



- In our base case, which assumes no changes in the existing tax regulations, Permian well activity is set to recover to pre-COVID peak and plateau at 7,800-12,000 wells per year in $60-80 WTI environment.
- In $40 low price scenario, we see the support for ~4,500-5,500 well completion per year in the basin.
- Simultaneous implementation of IDC repeal and increased tax rate to 25% does not change the direction of activity outlook in any price scenario, but it significantly affects the total number of future well completions.
- The impact of new regulations is higher in higher oil price environment (where majority of producers operate with higher EBITDA margins and more incentivized to elect larger number of accelerated depreciation incentives).
- Up to 17,500 wells (~1,750 wells per year) might be lost in 2022-2031 in $80 WTI scenario.

Source: Rystad Energy research and analysis

IDC repeal and increased tax rate have similar significance for future well activity

Permian, cumulative well count in 2022-2031 for different scenarios
Number of wells put on production in 10-year scoring window (2022-2031)

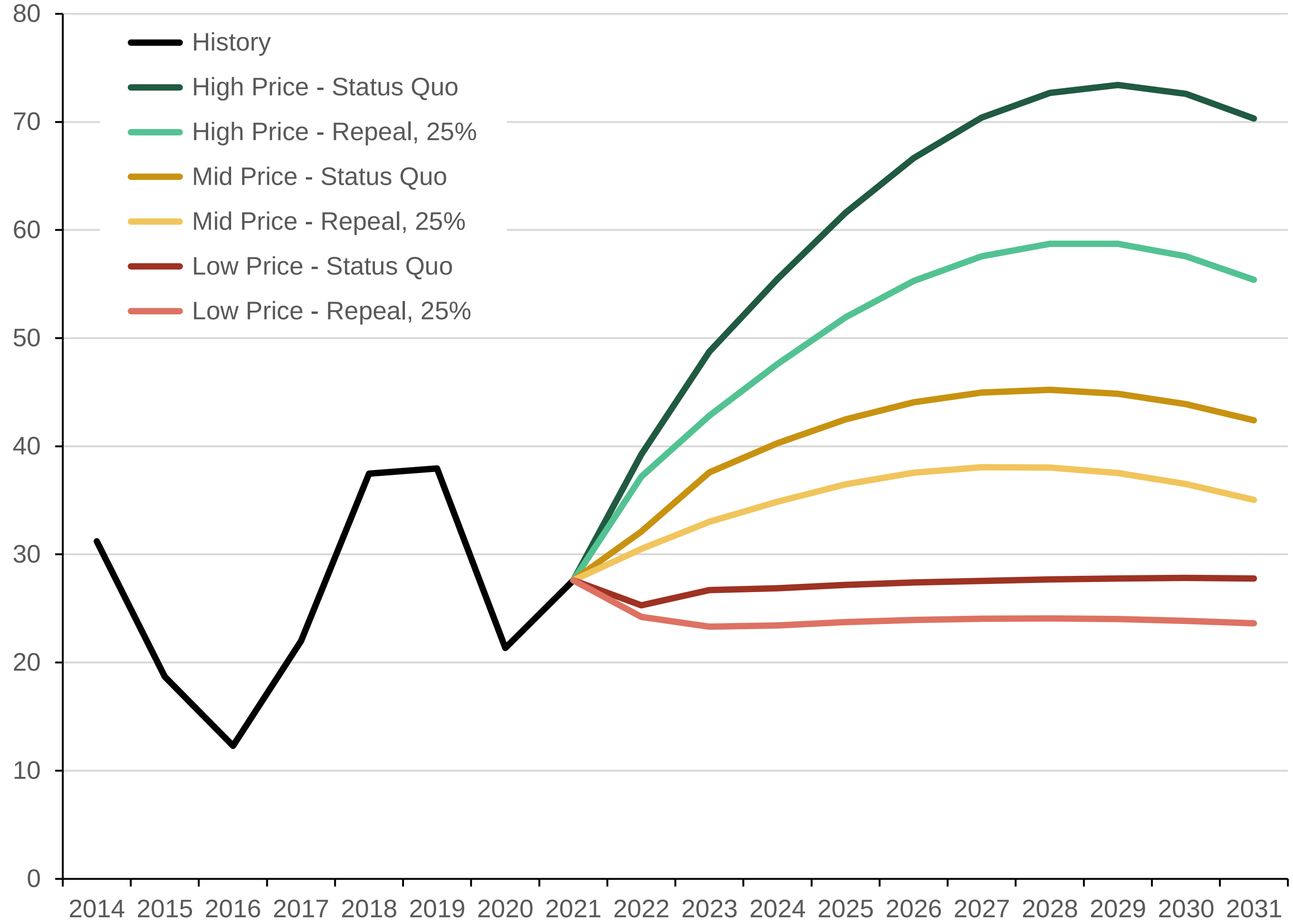
Tax Rate Scenario	IDC Scenario	High Price	Mid Price	Low Price
21%	Status Quo	105,149	72,261	48,175
	Repeal	97,728 (7,421)	67,445 (4,816)	44,493 (3,682)
25%	Status Quo	95,173 (9,976)	67,160 (5,101)	46,401 (1,744)
	Repeal	87,616 (17,533)	62,035 (10,226)	42,259 (5,916)

- The table provides more details on the impact of different scenarios on expected well activity forecast for the Permian in 2022-2031
- While the price environment is seen as the most significant driver of overall activity level, both increased tax rate and IDC repeal impose negative pressure on future cash flows and consequently the number of future well completions.
- The table reveals an important dynamics for relative significance of increased tax rate and IDC repeal.
- For high and mid price scenarios, increased tax rate from 21% to 25% is seen as more significant activity driver than IDC repeal. For low price case, IDC repeal ends up as slightly more significant than increased corporate tax rate standalone.

Source: Rystad Energy research and analysis

$30-110 billion of Permian upstream capex in 2022-2031 is at risk depending on oil price

Permian, long-term drilling and completion capex scenarios
Billion USD



- When it comes to drilling and completion upstream capex in the Permian, the slope of the recovery curve is different from the pace of recovery for well counts in our base case.
- In the high case scenario, significant service cost inflation is triggered as soon as well activity is approaching 8,000 wells per year in 2023.
- In mid-case, capex peak at $45 billion per year in mid-20s as structural efficiency gains offset any material cost inflation.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would put $30-110 billion of expected Permian capex in 2022-2031 at risk if WTI is in $40-80 range.

Source: Rystad Energy research and analysis

With only one regulatory change, capex impact for 2022-2031 is in $16-55 billion range

Permian, cumulative D&C capex in 2022-2031 for different scenarios
Billion USD for 10-year scoring window (2022-2031)

Tax Rate Scenario	IDC Scenario	High Price	Mid Price	Low Price
21%	Status Quo	$631	$418	$272
	Repeal	$584 ($47)	$389 ($29)	$251 ($21)
25%	Status Quo	$570 ($61)	$389 ($29)	$262 ($10)
	Repeal	$523 ($108)	$358 ($60)	$238 ($34)

- The table provides more details on the impact of different scenarios on expected drilling and completion capex for the Permian in 2022-2031
- While the price environment is seen as the most significant driver of overall activity level, both increased tax rate and IDC repeal impose negative pressure on future cash flows and consequently the total upstream spend.
- The table reveals an important dynamics for relative significance of increased tax rate and IDC repeal.

Source: Rystad Energy research and analysis

Independent operators to see higher impact of IDC repeal than their integrated peers

Permian, cumulative D&C capex in 2022-2031 for different scenarios and operator types
Billion USD for 10-year scoring window (2022-2031)

Operator Type	Tax Rate Scenario	IDC Scenario	High Price	Mid Price	Low Price
Independent	21%	Status Quo	420	271	182
		Repeal	384 (36)	249 (22)	165 (17)
	25%	Status Quo	379 (41)	252 (19)	175 (7)
		Repeal	342 (78)	229 (42)	157 (25)
Integrated	21%	Status Quo	211	147	91
		Repeal	201 (10)	140 (7)	85 (6)
	25%	Status Quo	192 (19)	137 (10)	87 (4)
		Repeal	181 (30)	129 (18)	81 (10)

- The table provides the breakdown of capex sensitivity to new regulations for different types of operators (independent and integrated producers).
- Comparing 21% tax rate, status quo IDC scenario to IDC repeal (with 21% tax rate), we observe 8-9% negative cumulative capex impact for 2022-2031 among independent producers in the Permian.
- As integrated operators are already required to capitalize at least 30% of their IDCs, the impact on their capex is lower (4.5-5.5% range depending on hydrocarbon price scenario).

Source: Rystad Energy research and analysis

Stronger relative impact of regulatory change in New Mexico than in Texas

Permian, cumulative D&C capex in 2022-2031 for different scenarios and state
Billion USD for 10-year scoring window (2022-2031)

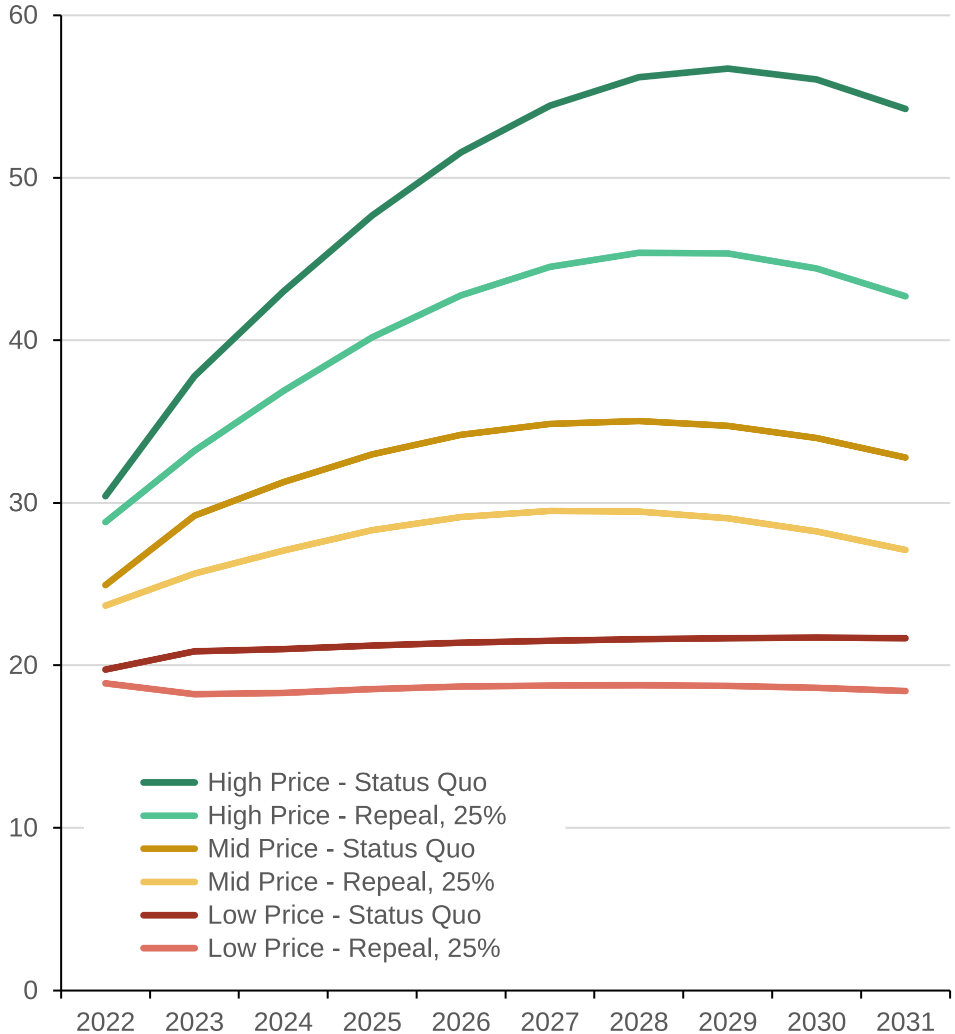
Operator Type	Tax Rate Scenario	IDC Scenario	High Price	Mid Price	Low Price
New Mexico	21%	Status Quo	166	107	73
		Repeal	151 (15)	98 (9)	67 (6)
	25%	Status Quo	148 (18)	98 (9)	70 (3)
		Repeal	133 (33)	89 (18)	63 (10)
Texas	21%	Status Quo	465	311	199
		Repeal	434 (31)	291 (20)	184 (15)
	25%	Status Quo	422 (43)	290 (21)	192 (7)
		Repeal	390 (75)	268 (43)	175 (24)

- The table provides the breakdown of capex sensitivity to new regulations for different parts of the Permian Basin (New Mexico and Texas).
- As of today, NM part of the Permian is less mature than Midland and Delaware Texas sub-basins. Significant number of operators are still positioned for aggressive production expansion in New Mexico in the next 5-10 years.
- Hence, change in regulatory environment is expected to have stronger relative impact on the outlook for Delaware New Mexico amid more material impact on high reinvestment rates.
- Comparing IDC repeal and 25% tax rate to status quo scenario, we estimate negative capex impact of 12-16% in Texas and 14%-20% in New Mexico.

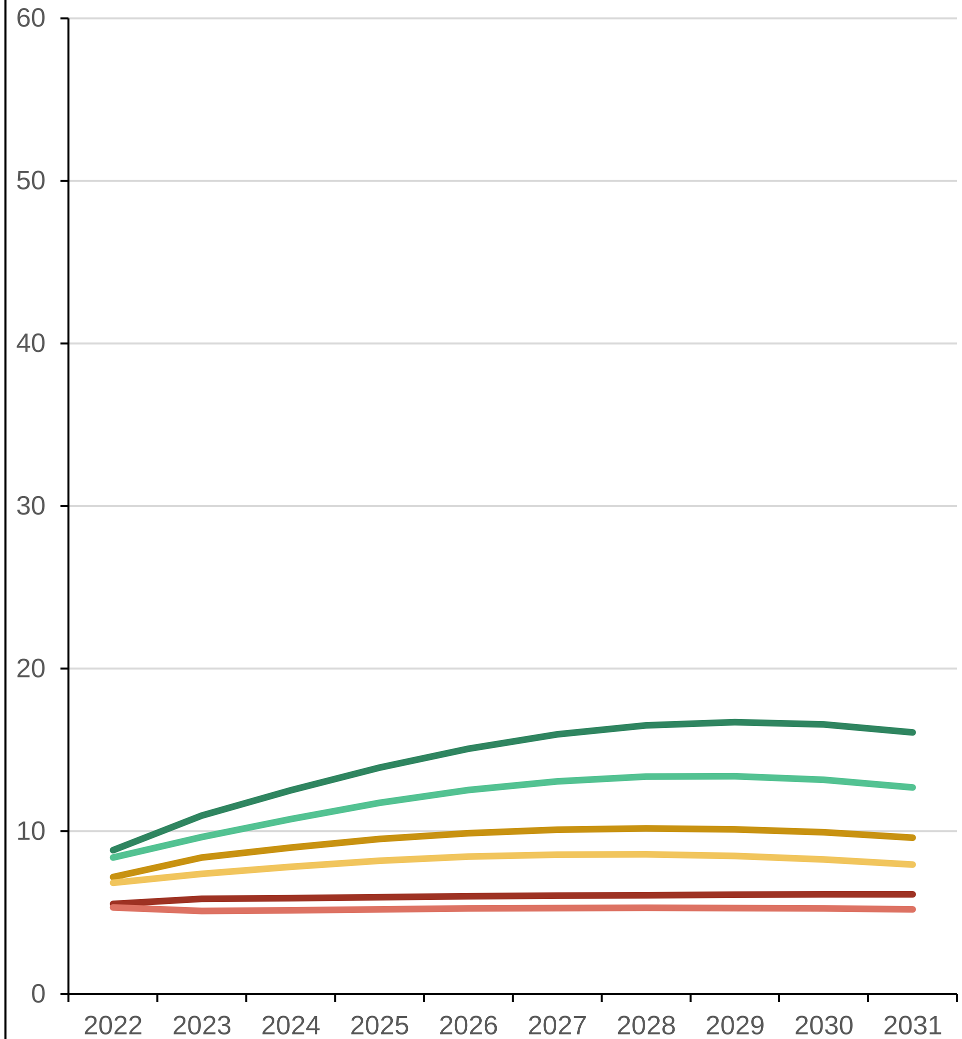
Source: Rystad Energy research and analysis

$26-84 and $7-24 billion capex impact for intangible and tangible costs, respectively

Permian, <u>intangible</u> drilling and completion capex scenarios
Billion USD



Permian, <u>tangible</u> drilling and completion capex scenarios
Billion USD



*Intangible D&C capex include both drilling and completion services
Source: Rystad Energy research and analysis

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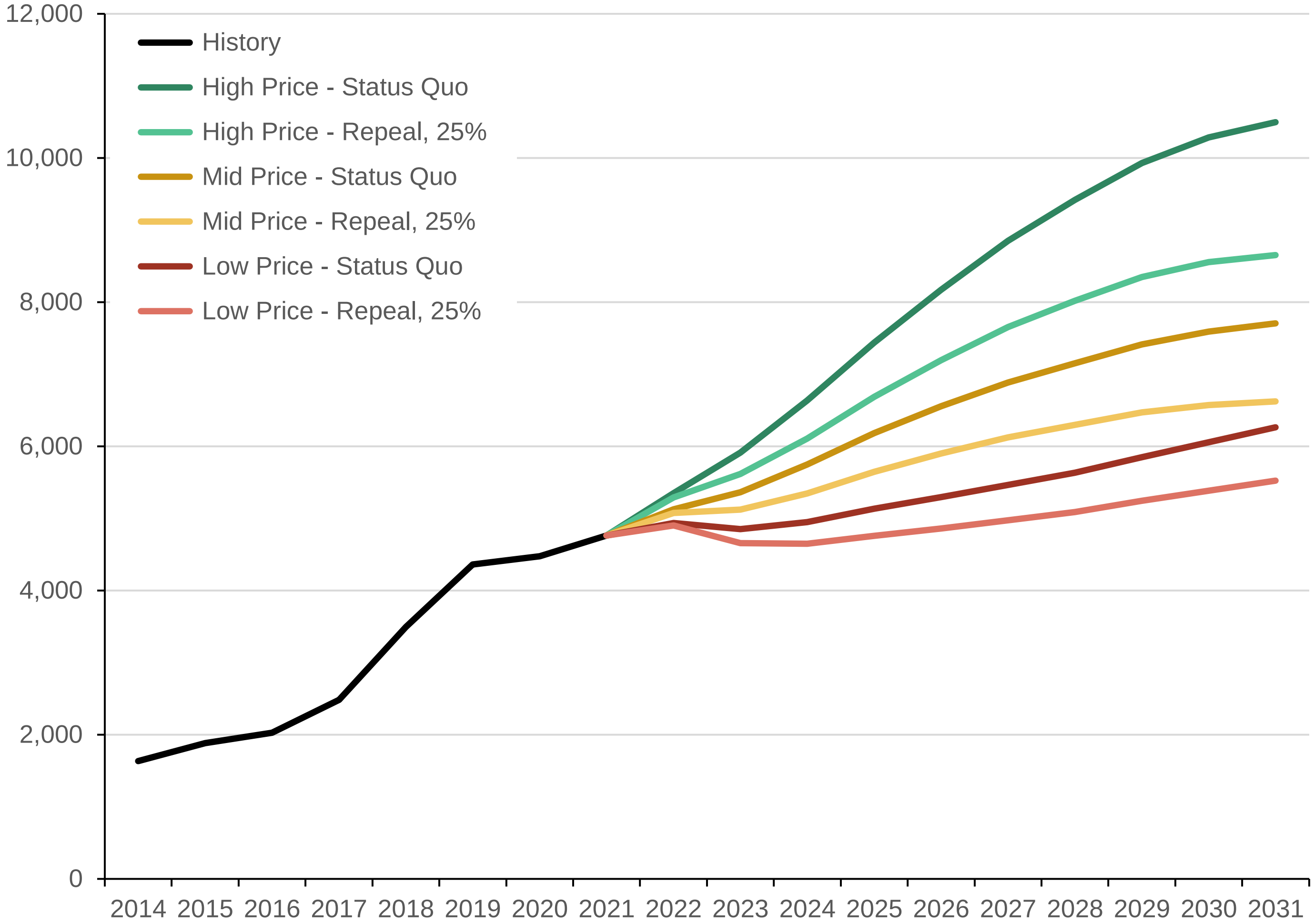
In 10 years, Permian oil output might be 740-1,840 thousand bpd lower with proposed tax changes

Permian, long-term oil production scenarios
Thousand barrels per day



- Permian basin oil production is set to recover to pre-COVID peak of 4.9 million bpd already in early 2022 (the only US onshore oil basin on track to reach such milestone).
- Even in $40 WTI scenario we anticipate basinwide production to ultimately reach 6 million bpd (by 2030) and there is a potential to surpass 10 million bpd in $80 WTI scenario despite conservative reinvestment rates. Significant growth is set to come from private operators in the Permian.
- IDC repeal along with increase of corporate tax rate to 25% might remove 0.7 (WTI of $40) to 1.8 million bpd (WTI of $80) potential basinwide oil production in 2031.

Source: Rystad Energy research and analysis

Oil production impact in 2031 might reach 740-1,840 thousand bpd

Permian, expected oil production in 2031 for different scenarios
Thousand bpd

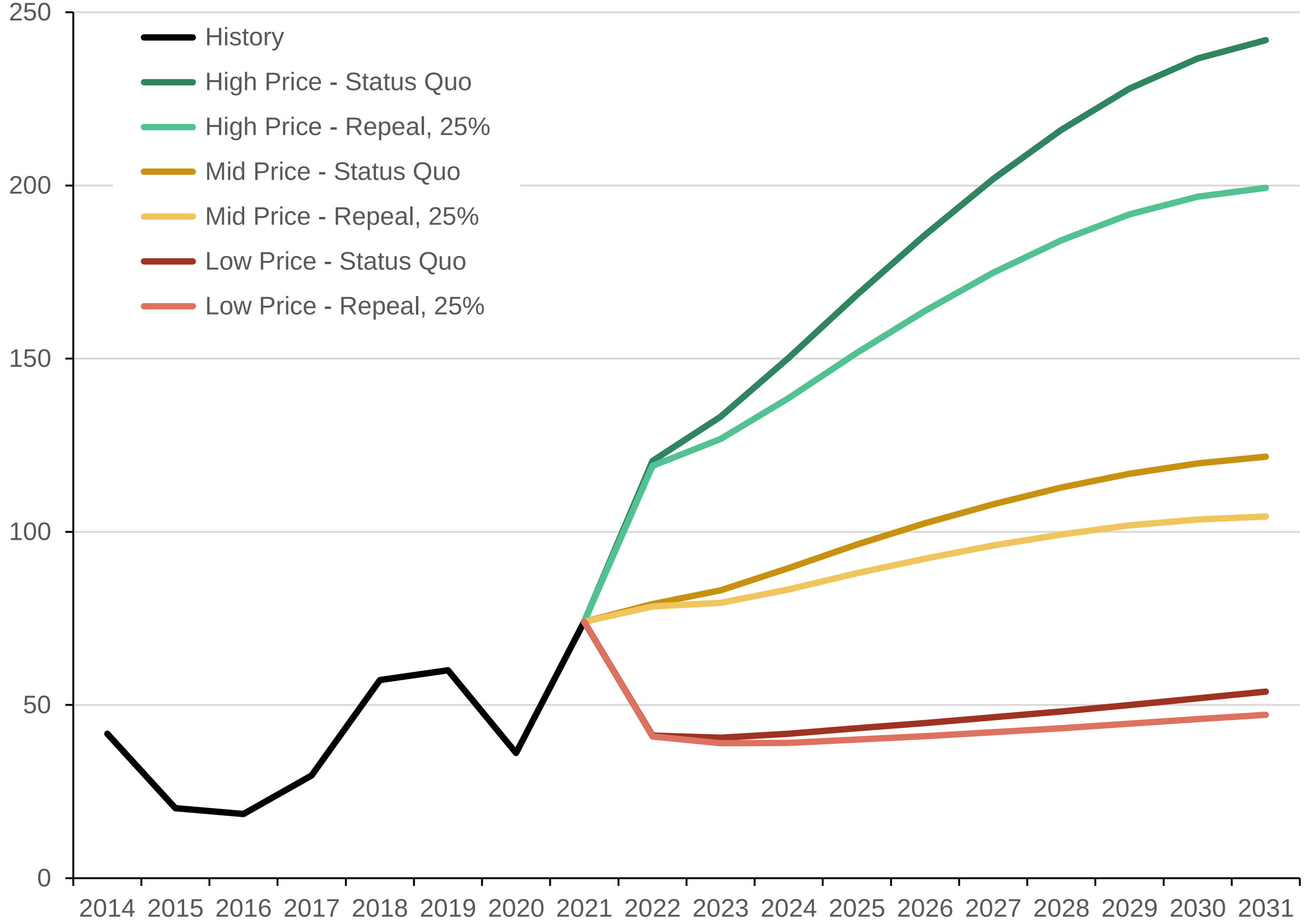
Tax Rate Scenario	IDC Scenario	High Price	Mid Price	Low Price
21%	Status Quo	10,498	7,705	6,263
	Repeal	9,746 (752)	7,226 (479)	5,827 (435)
25%	Status Quo	9,391 (1,107)	7,117 (588)	6,000 (263)
	Repeal	8,654 (1,844)	6,623 (1,082)	5,522 (741)

- The table provides more details on the impact of different scenarios on expected Permian oil production for 2031
- While the price environment is seen as the most significant driver of overall activity level, both increased tax rate and IDC repeal impose negative pressure on future cash flows and consequently lower oil production potential from new completions.
- The table reveals an important dynamics for relative significance of increased tax rate and IDC repeal.
- Simultaneous IDC repeal and increased corporate tax rate would reduce base case (status quo) expected Permian oil output by 740 thousand bpd in low price case and by ~1.8 million bpd in high price case in 2031.

Source: Rystad Energy research and analysis

$40-235 billion of Permian upstream profitability* is at risk for a 10-year scoring window

Permian, long-term upstream EBITDA scenarios
Billion USD

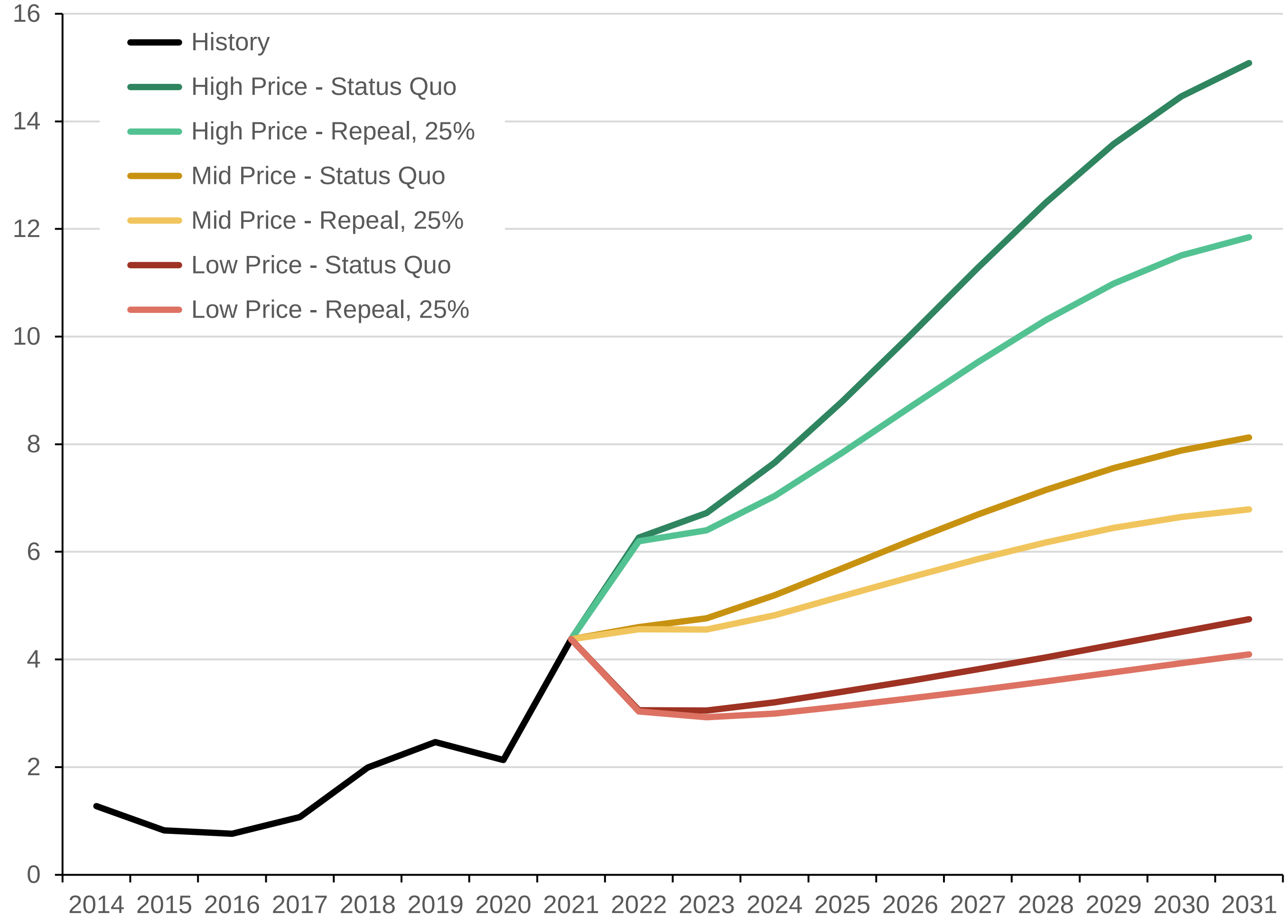


- Driven by the impact of new IDC and tax regulation on production, we anticipate negative pressure on Permian upstream EBITDA metric.
- The cumulative negative impact on EBITDA for 2022-2031 in the Permian is estimate at $40 billion in low price scenario.
- The impact is set to increase to $103 and $235 billion in mid- and high-price scenarios, respectively.

*As measured by earnings before interest, taxes, depreciation, and amortization (EBITDA)
Source: Rystad Energy research and analysis

Proposed tax changes to reduce federal royalty income in by $3.5-16 billion in the next ten years

Permian, federal royalty income scenarios
Billion USD

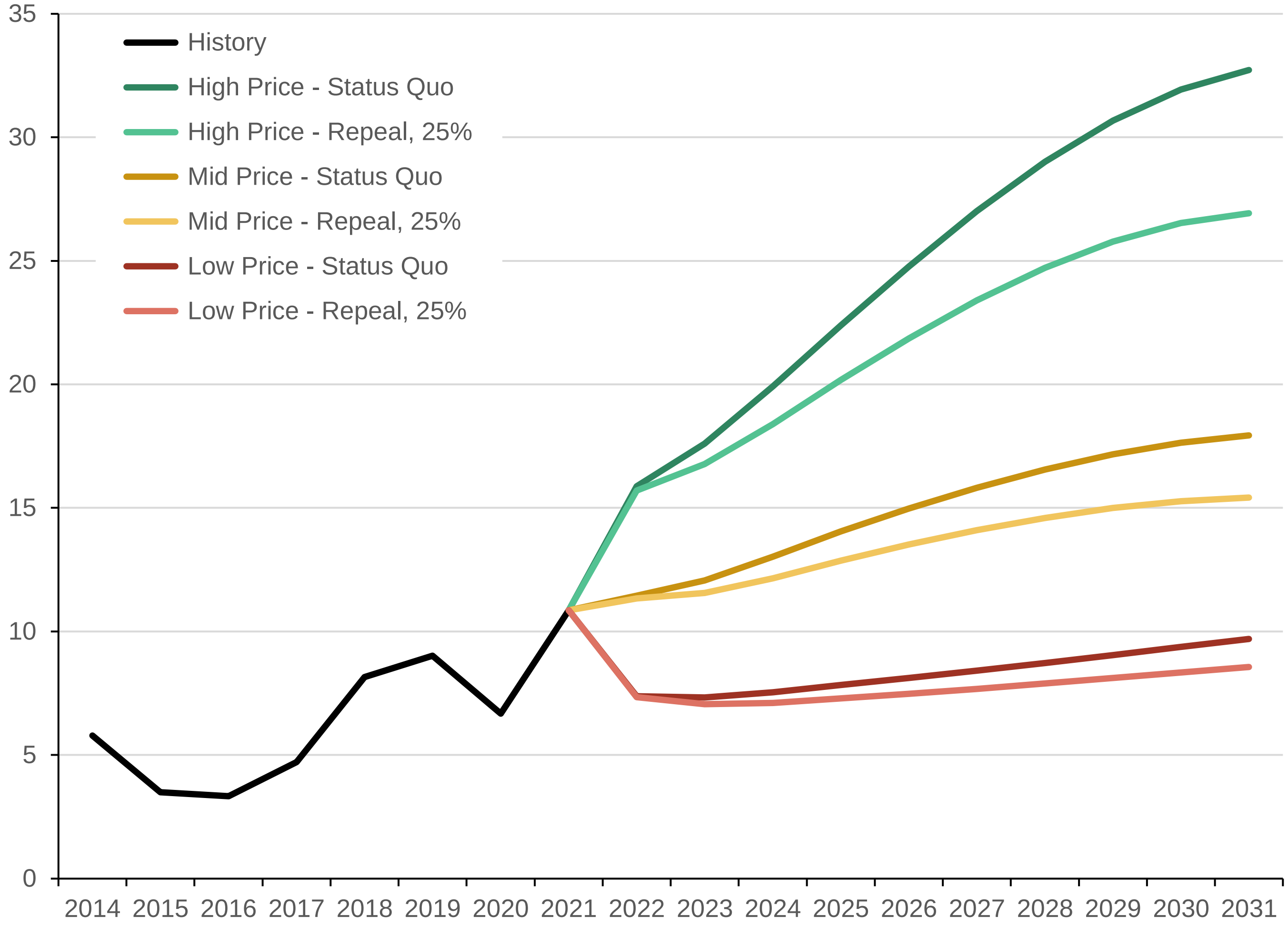


- We calculated the implied federal royalty for different price and regulation scenarios in the Permian basin.
- Federal royalty revenue is expected to reach record-high of $4.3 billion in 2021 amid improved price environment and robust production outlook for federal acreage in New Mexico.
- By 2031, this might increase further to $15 and $8 billion per year in high and mid price scenarios, respectively with status quo regulations.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would reduce federal royalty income by $3.5 billion in low price case and $16 billion in high price case (cumulative impact for 2022-2031).
- The above would also have a negative impact on New Mexico as 50% of Federal royalty revenue is shared with the state

Source: Rystad Energy research and analysis

Proposed tax changes to reduce state income by up to $31 billion in the next ten years

Permian, state income scenarios (royalty and severance tax combined)
Billion USD

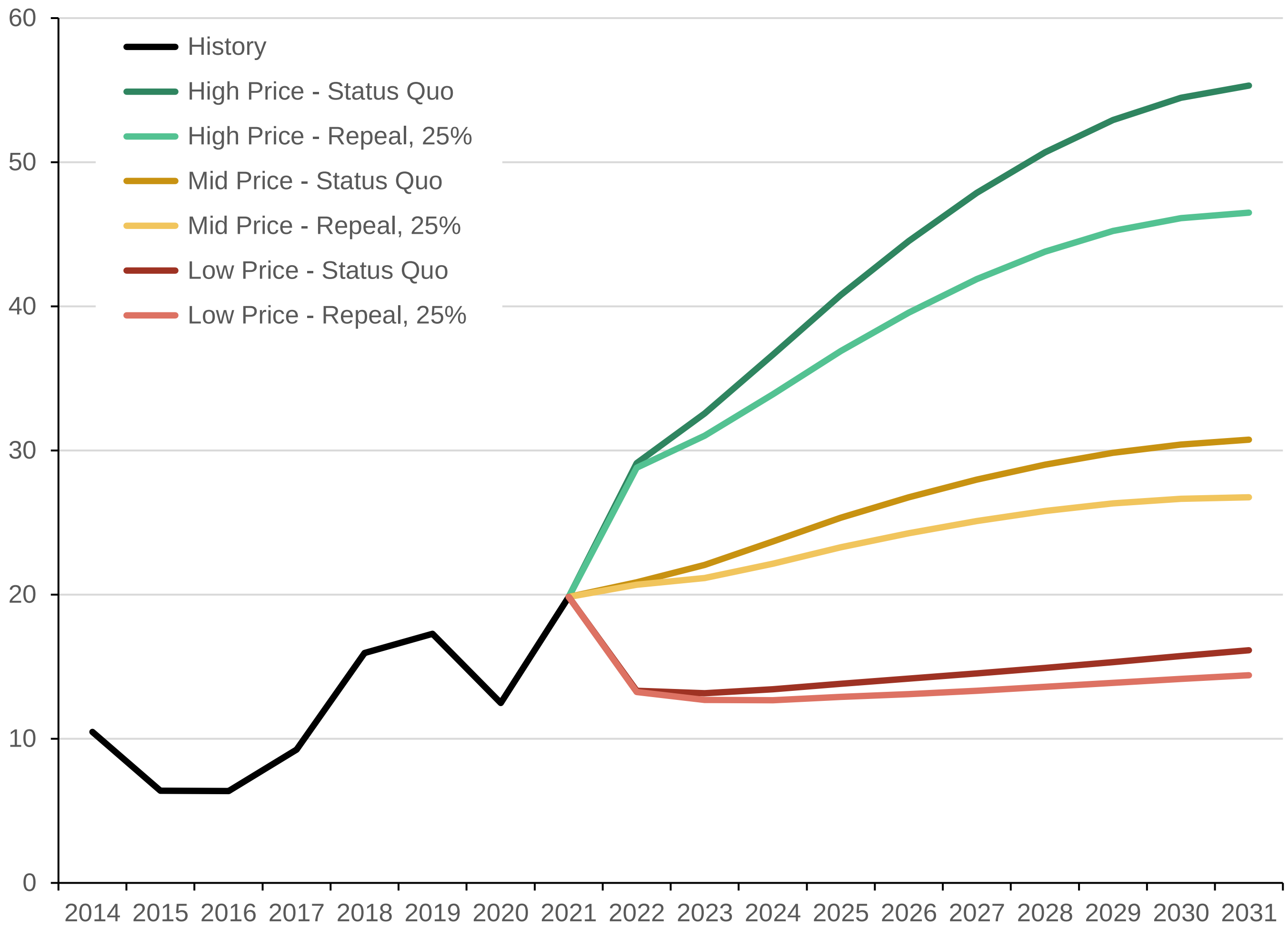


- We calculated the implied state royalty and severance tax for different price and regulation scenarios in the Permian basin.
- State income is expected to reach record-high of $10.8 billion in 2021 amid improved price environment and general production recovery in the basin.
- By 2031, this might increase further to $32.7 and $17.9 billion per year in high and mid price scenarios, respectively with status quo regulations.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would reduce state income by $6.6 billion in low price case and $31.6 billion in high price case (cumulative impact for 2022-2031)

Source: Rystad Energy research and analysis

Proposed tax changes to reduce private royalty income by up to $51 billion in the next ten years

Permian, private royalty income scenarios
Billion USD



- We calculated the implied private royalty income for different price and regulation scenarios in the Permian basin.
- Private royalty income is expected to reach record-high of $19.8 billion in 2021 amid improved price environment and general production recovery in the basin.
- By 2031, this might increase further to $55 and $30 billion per year in high and mid price scenarios, respectively with status quo regulations.
- Simultaneous removal of IDC tax incentive accompanied by corporate tax rate increase to 25% would reduce private royalty income by $10.6 billion in low price case and $51.2 billion in high price case (cumulative impact for 2022-2031)

Source: Rystad Energy research and analysis

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Model description (1/3)

High level input parameters

Parameter	Comments
1 Modeling overview	• Rystad Energy models onshore US oil and gas activity in an incredibly granular manner. • Our activity and production forecast is built bottom-up, leveraging historical well data, public company research, and primary intelligence.
2 PDP forecast	• We utilize well-level decline curve fitting. This is unconstrained for wells that have produced for more than two years. For wells with shorter production histories, we freeze b-factors or even initial decline rates. • Our forecast captures the potential impact of future workovers and interventions if they are already reflected in the empiric production data of relevant offset older wells.
3 Future activity	• In the short term, our future activity forecast is dictated by public producer guidance. • For longer forecasts timeline, we think in terms of reinvestment rate targets (either communicated by E&Ps themselves or using analogies with other more established producers and taking into account where operator is on the growth cycle). Reinvestment rates vary depending on the oil/gas price scenario. Higher price scenarios result in lower reinvestment rates in future, increased cash returns for equity investors and faster deleveraging (when relevant for a given operator).
4 Type curve	• Our type curves are based upon the combination of operator, well direction and county. • We include the last two years of well vintages for the initial decline curve modeling, but older vintages are included for modeling of mid to late-life decline rates. Gas, oil and NGL streams are modeled separately to capture important dynamics on development of GOR and GOM metrics as wells get older.
5 First oil	• Spud to first oil time is modeled based on the empiric data for the latest vintages.

Source: Rystad Energy research and analysis

Model description (2/3)

Key cost parameters

	Parameter	Comments
1	Key OPEX components	• Lease operating expense is modeled on a granular level. • Further OPEX is split into fixed LOEs, typically between $1,000/month and $4,000/month, and variable costs. The variable costs are calculated with the economic limit of each well in mind.
2	G&A expense	• For public companies, G&A along with prices and transportation are consistent with comapny 10-K and 10-Q reporting. • Analogies are made for private operators.
3	Severance taxes	• Severance taxes are consistent with state-level regulatory requirements.
4	Royalties	• Royalties modeling consists of a mix of public disclosures and assumed default values at the basin and state level.
5	Depreciation	• It is assumed that all relevant elections are made when it is optimal for corporate tax optimization.

Source: Rystad Energy research and analysis

Model description (3/3)

Model overview

Parameter	Comments
1 Model	• The Rystad Energy base case is frozen for 2Q21 - 4Q21. • The model then begins in 1Q22 using all the inputs previously outlined.
2 Reinvestment	• Cash flow from operations is calculated for each scenario from the previous quarter and put into the context of the expected reinvestment rate for a given operator. • The outcome of modeling the cash flow from operations gives the allowable capex in a given quarter.
3 Allowed CAPEX	• Capex is then allocated to individual assets i nthe portfolio of the operator. More commercial assets get higher capital allocations, which does not change if the price environment is stable. • The lower price scenario, however, results in increased share of capital allocated to the most profitable projects. similarly, the high price scenario results in a higher share of capital going to less commerical assets.
4 Final assumptions	• We then model new wells for a considered quarter in each asset based on allocated capital and expected wells costs. In general, high price scenarios result in higher well costs in each asset. • Finally, we model expected production and depreciation schedules for new vintages of wells in each asset.
5 Outputs	• The model allows us to summarize cash flows across all assets in a company's portfolio and calaculate corporate-level EBITDA, depreciation, tax, and cash flow from operations.

Source: Rystad Energy research and analysis

IDC tax incentive is not always maximized according to industry contacts

Industry insights

"Yes, it is fair to say deducting IDCs has been frequently redundant. We have generally deducted IDC in order to maximize NOLs. On occasion, we might capitalize IDC to reduce [our]Texas Margin tax loss... Several years ago [we] capitalized IDC and the capitalized portion was less than 30%."

- Tax manager, E&P company

"The immediate impact from IDC repeal on our cash position will be quite negligible, but the incentive is important from the general felxibility position. Many other industries have bonus depreciation incentives, so there is no reason to penalize oil & gas in any manner"

- Tax VP, E&P company

"If you are unable to use all of the IDCs in that year, I believe you have the ability to capitalize the IDC and utilize them over time. I suspect most independents have done this for a while, since not many companies have generated positive income until recently."

- Director of Corporate Strategy, E&P company

"There are numerous variables which drive the expense or capitalize IDC decision each year; depending on the facts and circumstances of each company, these factors would still need to be weighed, but at lower commodity prices the need to optimize current year taxes would not be driven as much by IDC deductions."

- IR director, E&P company

"We capitalized a significant portion of IDCs in recent years to delay depreciation to the years when net income becomes positive. Now with net income finally turning positive, there is increased focus on tax optimization... We think that smaller and non-op producers might see greater impact on their financials as they have lower capital availability and less financial flexibility"

- Tax VP, E&P company

"All things equal, it is certainly true that the lower the commodity prices, the less important the accelerated portion of any depletion becomes. Additionally, linear depreciation, might be more common for any midstream infrastructure investment than for the depreciation of oil and gas wells."

- IR director, E&P company

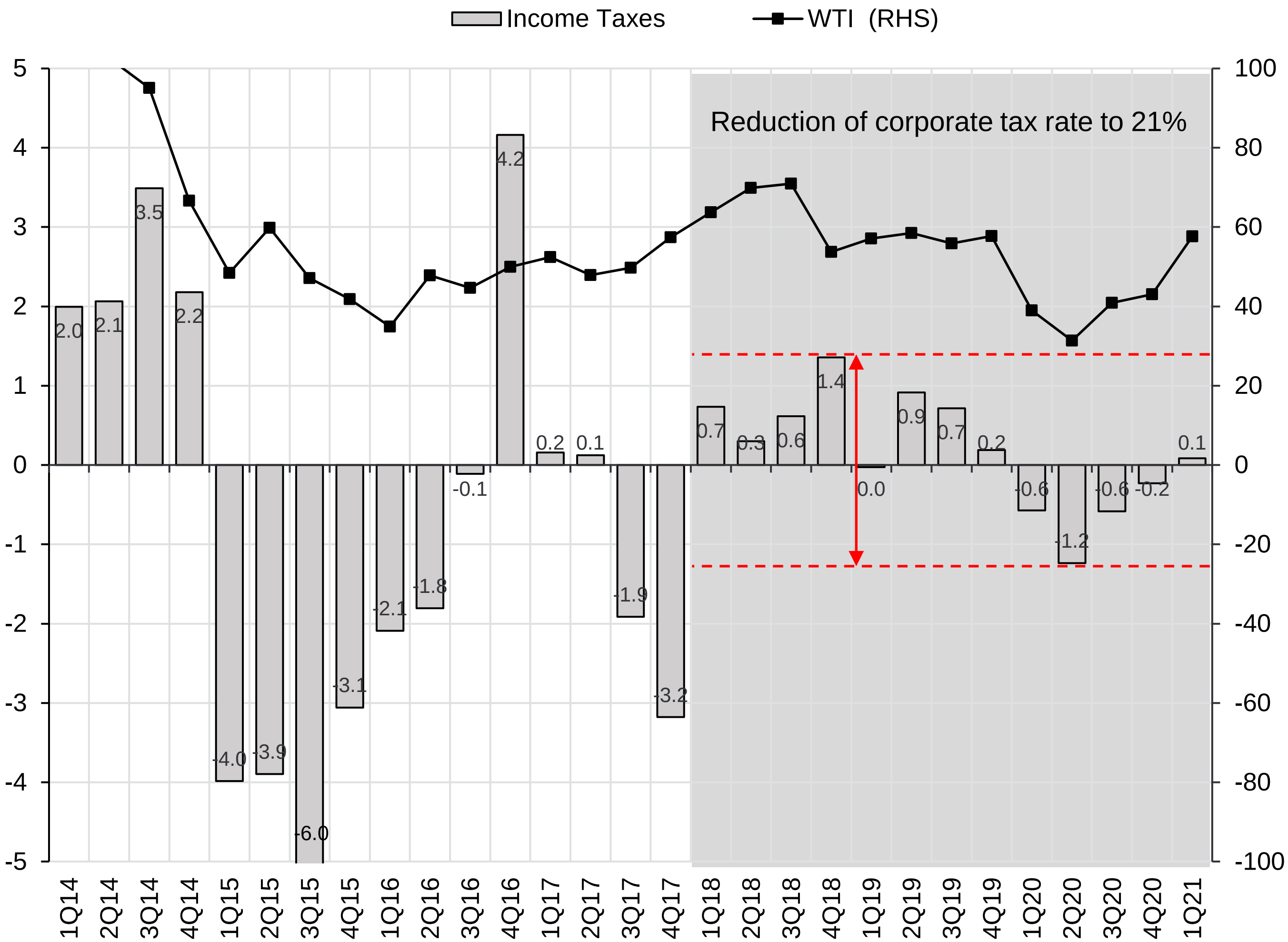
Industry best practices – IDCs

- Several E&P industry contacts attest to the fact that many operators elect to not expense their IDCs occasionally, preferring to capitalize them. A common reason cited is the failure of many operators to generate positive cash flow or low hydrocarbon price environment.
- When theoretical net income is already negative or close to zero, other tax deductions might make any form of accelerated depletion redundant, and operators might choose to capitalize a certain portion of IDCs to leverage on increased depreciation in later years.

Source: Rystad Energy research and analysis

The previous federal tax cut resulted in reduced volatility for E&P income taxes

Quarterly Income Taxes for public US tight oil producers and WTI**
Billion USD

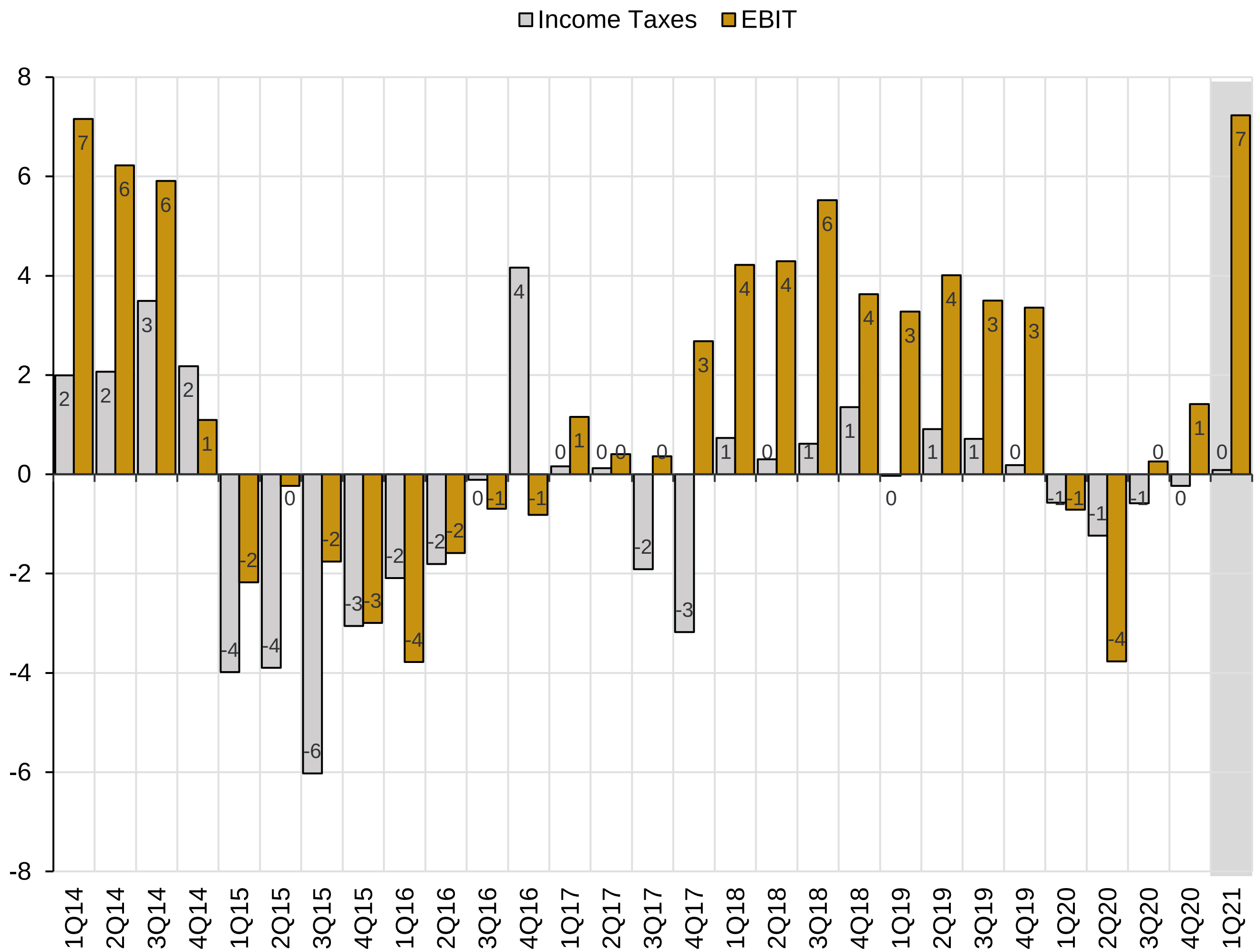


- The chart outlines income taxes for the peer group of 22 independent shale producers which account for more than 40% of US tight oil output in 2021.
- Peer group's net income and income taxes have been in recent years and exhibited certain correlation with oil prices. The topline income tax level is affected by several larger operators that had significant swings in the reported income taxes quarter over quarter.
- Overall, from 2018 onwards operators paid lower income taxes due to the decrease in corporate tax rate from 35% to 21%.
- Since 2018 the range of reported income taxes shrank to $2.6 billion from the previous $10.2 billion between 2014 and 2017.

*The peer group of 22 dedicated US tight oil companies accounts for more than 40% of expected 2021 US shale oil output
Source: Company reporting, Rystad Energy research and analysis

Record-high spread between EBIT and Income Taxes was recorded in 1Q21

Quarterly Income Taxes and EBIT for public US tight oil producers
Billion USD

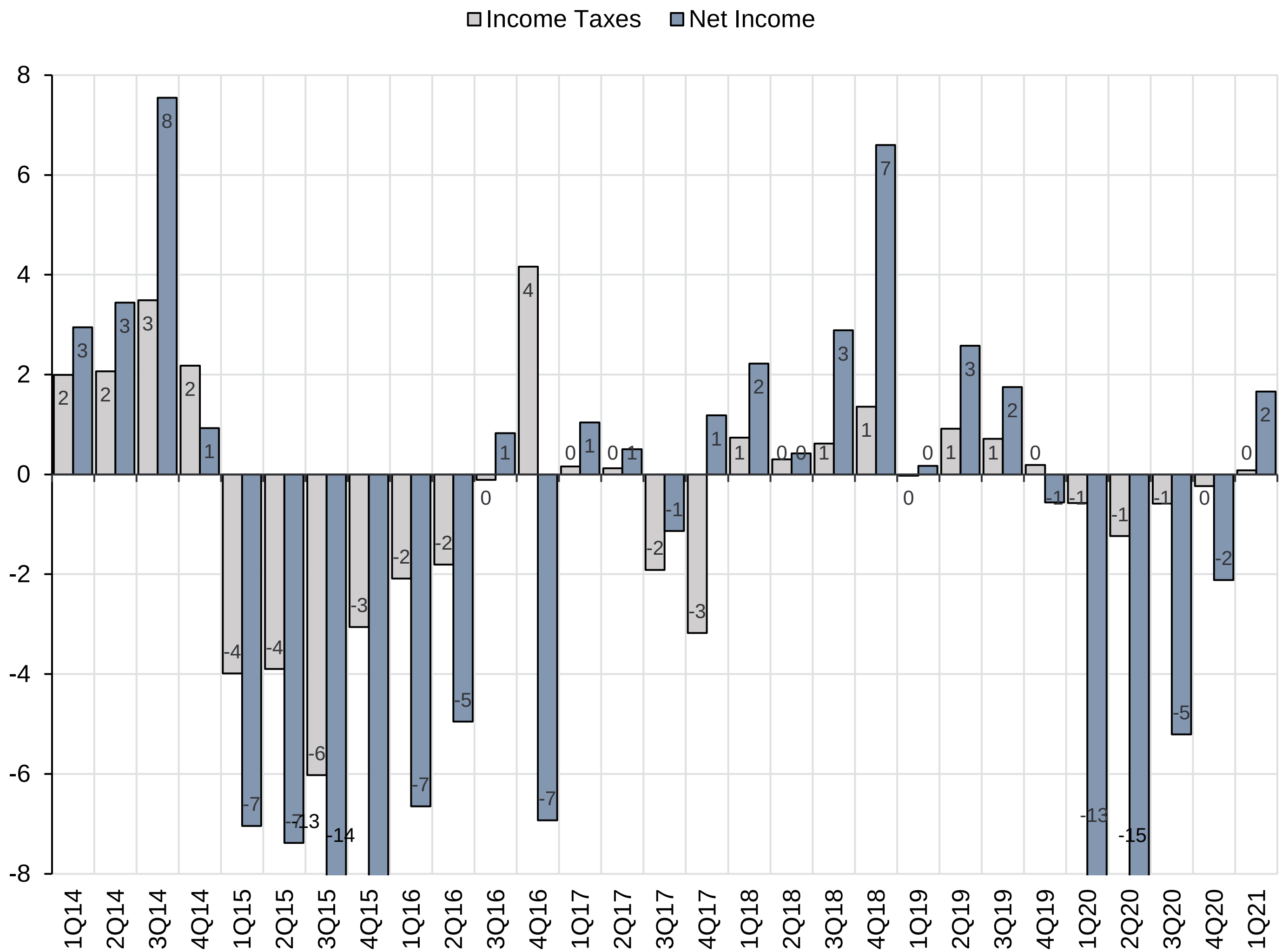


- The chart shows EBIT and income taxes quarterly for the peer group of independent US tight oil producers.
- In 1Q21, the spread between income taxes and EBIT reached $7.2 billion – historical peak, followed by 4Q17 and 1Q14.
- In 1Q21, operators reported cumulative revenue of $21.2 billion (highest since 2014) and the all-time high EBIT of $7.2 billion as WTI oil price recovered to $58 per barrel.
- At the peer group level, there is no clear correlation between EBIT and Income Taxes over time.

*The peer group of 22 dedicated US tight oil companies accounts for more than 40% of expected 2021 US shale oil output
Source: Company reporting, Rystad Energy research and analysis

Tight oil operators reported positive net income in 1Q21 despite extreme hedging losses

Quarterly Income Taxes and Net Income for public US tight oil producers
Billion USD

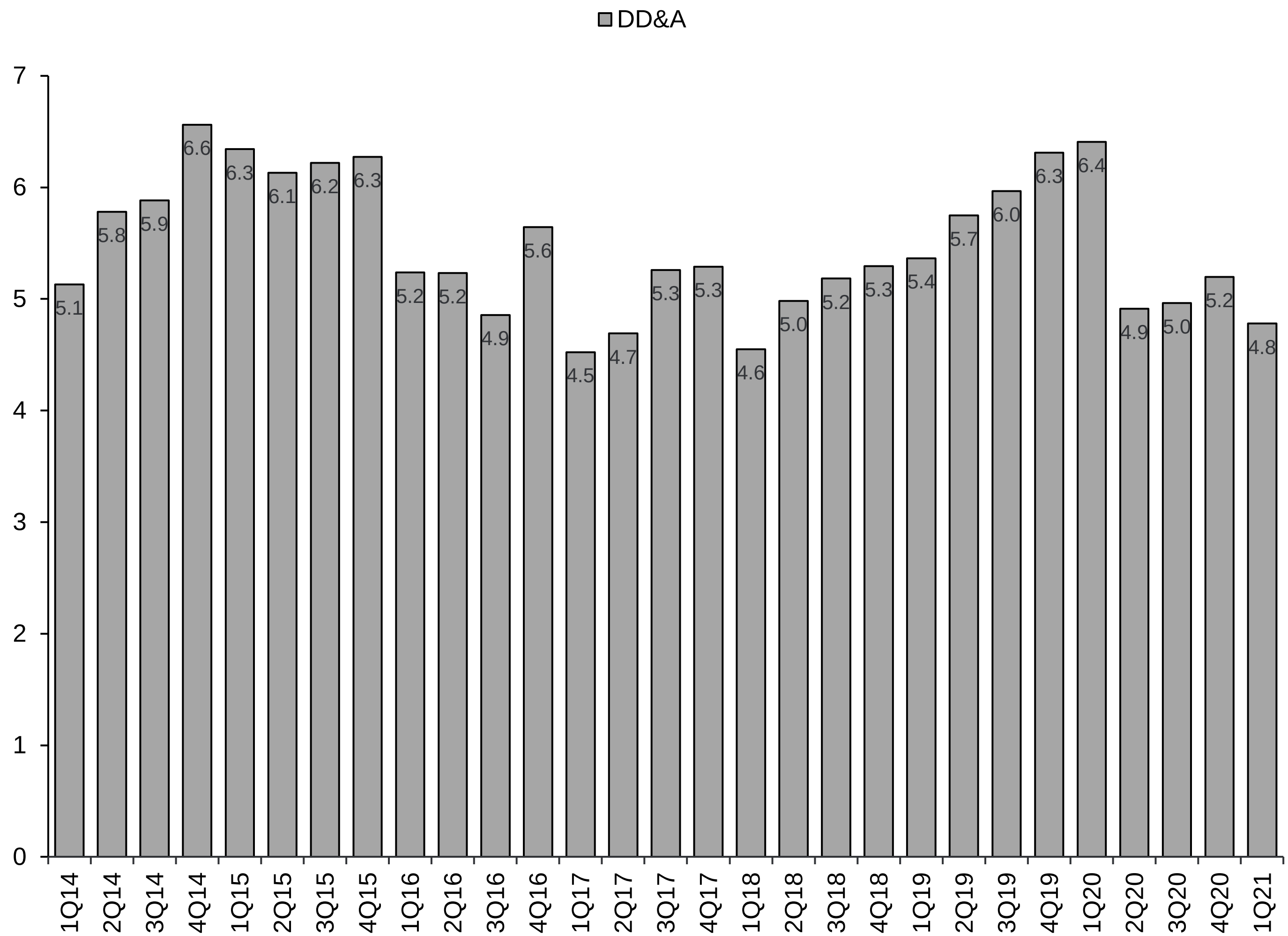


- The chart shows net income and income taxes quarterly for the peer group of independent US tight oil producers.
- In 1Q21 the industry recovered from continuous multi-quarter losses and reported $2 billion net income, level similar to the performance last seen in 3Q19.
- Most operators hedged their expected production for 2021 with the floor prices in $45-$49 WTI range limiting the upside of expected realized prices after hedging effect and overall reported income.

*The peer group of 22 dedicated US tight oil companies accounts for more than 40% of expected 2021 US shale oil output
Source: Company reporting, Rystad Energy research and analysis

Reported DD&A dropped in 2Q20, no evidence of change to accounting methods

Quarterly reported DD&A for public US tight oil producers
Billion USD

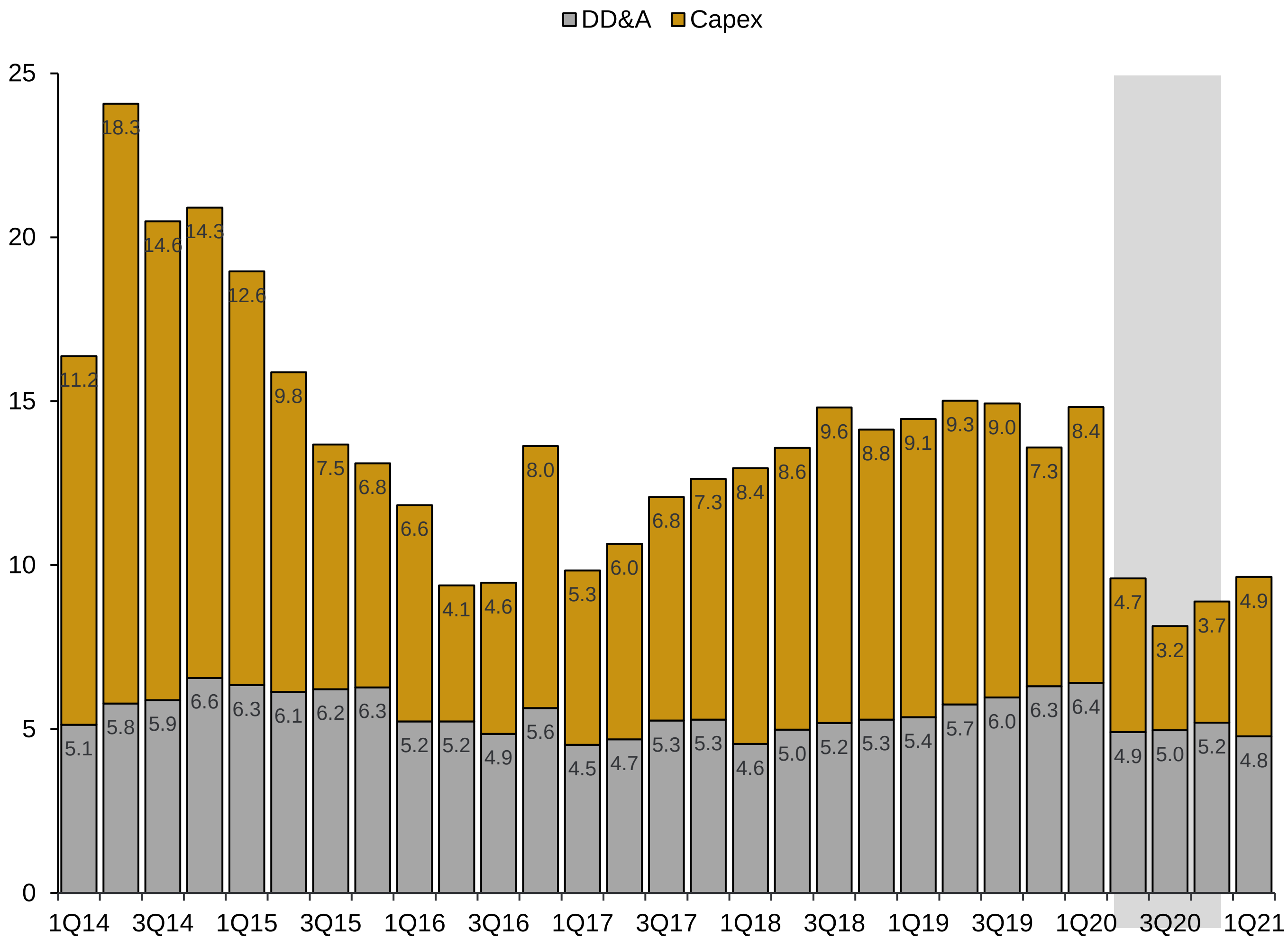


- The chart outlines reported depreciation deletion and amortization (DD&A) for the peer group of independent US shale producers.
- DD&A drop in 2Q20 is not impacted by the changes in depreciation accounting but rather by lower average unit-of-production rate in 2020
- In most cases operators are calculating DD&A using the straight-line depreciation method over the useful lives of the assets for1 10-Q/10-K reporting purposes.
- DD&A rate and expenses fluctuate from period to period depending on multiple factors including field production profiles, drilling or acquisition of new wells, abandonment of existing wells and reserve revisions including well performance, economic factors and impairments.
- According to industry contacts, IDC tax incentives are not always maximized as operators sometimes choose to capitalize a certain portion of IDCs to utilize over time.

*The peer group of 22 dedicated US tight oil companies accounts for more than 40% of expected 2021 US shale oil output
Source: Company reporting, Rystad Energy research and analysis

Capex recovered to DD&A level in 1Q21 as operators picked up drilling pace

Quarterly DD&A and Capex for public US tight oil producers
Billion USD

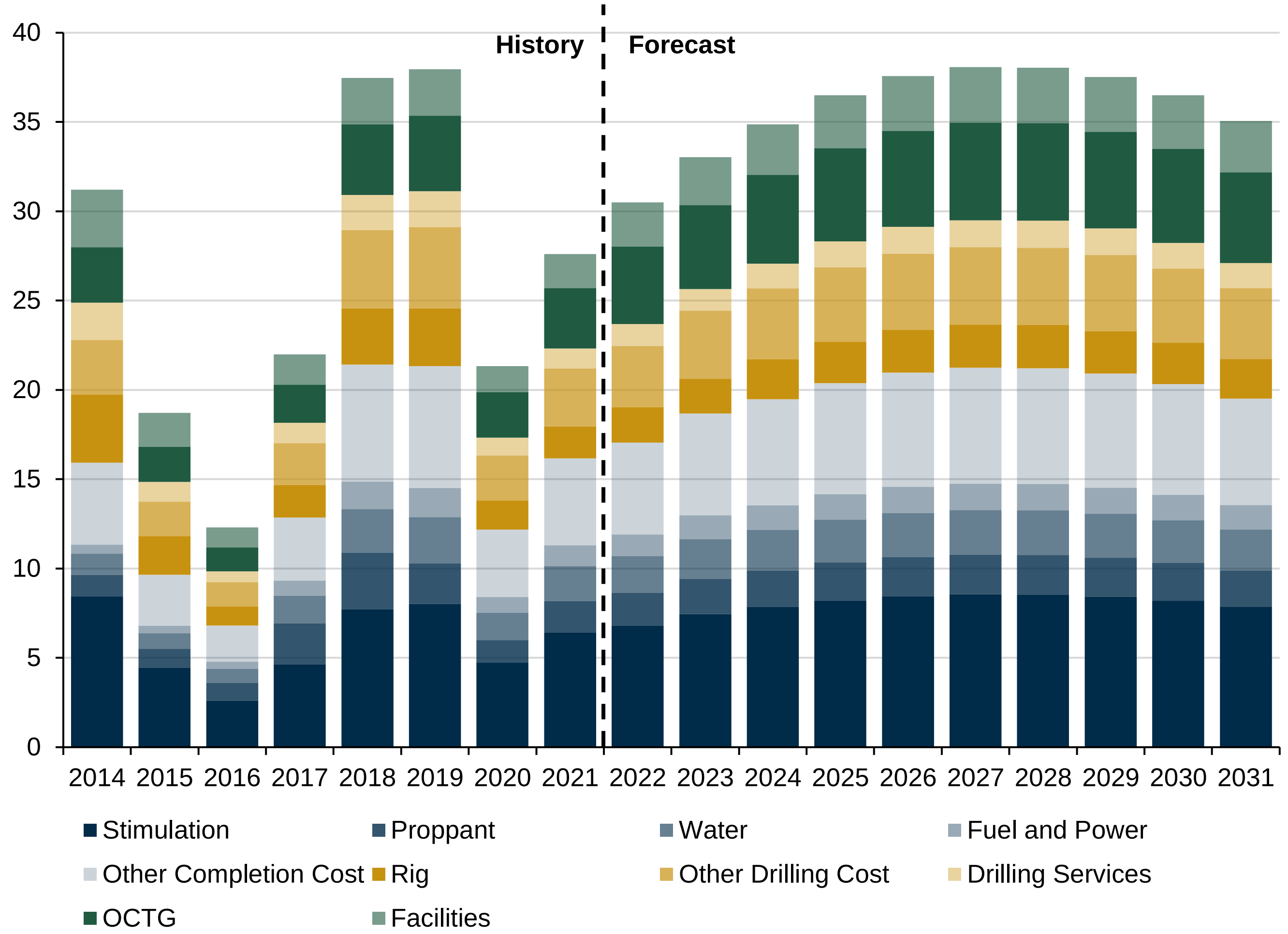


- The chart outlines depreciation depletion and amortization (DD&A) and capital expenditures (Capex) for the peer group of independent US tight oil producers.
- Noticeably three quarters of 2020 have higher reported DD&A than Capex for the same period.
- Second half of 2020 was high on reserve revisions which has also impacted DD&A for the period; while Capex dropped to all time low level.
- In 1Q21, as activity picked up, tight oil producers reported higher capex just under $5 billion leveling to DD&A for the quarter.

*The peer group of 22 dedicated US tight oil companies accounts for more than 40% of expected 2021 US shale oil output
Source: Company reporting, Rystad Energy research and analysis

Individual AFE components are set to follow general capex trend in the forecast period

Permian, long-term drilling and completion capex in mid price, IDC repeal, 25% tax rate scenario
Billion USD



- The chart shows the breakdown of historical and forecasted Permian D&C capex in mid price, IDC repeal, 25% tax rate scenario by cost item.
- Blue and yellow columns on the chart correspond to intangible costs, while green (OCTG and facilities) columns correspond to tangible costs.
- In the forecast period, we model relatively unchanged tangible and intangible cost split for the Permian.
- We anticipate the share of stimulation cost to increase by 1% between 2020 and 2024 for an average Permian well. However, this increase is partially compensated by expected 0.5% and 0.2% increase in the share of OCTG and Facility costs, respectively.
- The detailed capex impact under each scenario is used by API to calculate total employment impact in 2031 using the IMPLAN economic assessment software.

Source: Rystad Energy research and analysis

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