API's "10 in 2022" Policy Plan

Quantification of policy impacts

Final report

Rystad Energy

November 1, 2022

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The API's "10 in 2022" policies would spur nearly $200 billion in direct investment and generate over 225 thousand jobs by 2035

API "10 in 2022" Policy impact - Reference Case versus Policy Case[1]

	2025	2035	Details	
Direct investment	*+ $12.2 billion investment*	*+ $19.8 billion investment*	• The API's "10 in 2022" policies would lead to a cumulative **$196 billion in direct investment** from 2023-2035 between oil and gas, CCUS and hydrogen	
Production	*+ 4.6 bcf/d of gas*	*+ 127 kb/d of oil* *+ 4.8 bcf/d of gas*	• Policies that enable pipeline investments and support federal leasing would lead to increased oil and gas production	
GDP	*+ $17 billion GDP*	*+ $27 billion GDP*	• The policies would support an additional $27 billion of GDP in 2035, considering direct, indirect and induced economic impacts	
Employment	*+ 142 thousand jobs*	*+ 226 thousand jobs*	• The policies would support an additional 226 thousand jobs in 2035, considering direct, indirect and induced economic impacts	
Other benefits 2023-2035	*+ $4.8 billion federal royalties, taxes and bid revenue[2]*	*More flexible infrastructure*	*+ 250 mtpa CCUS capacity*	*+ 30 mtpa Hydrogen capacity*

1: Reference Case and Policy Case are defined on slide 8
2: Only includes federal royalties, corporate income taxes and lease sale bid revenue related to federal offshore oil and gas leases
Note: GDP, employment, wages and benefits, and indirect and induced investment are provided by API using Rystad Energy's estimated direct investment under each scenario and the IMPLAN economic assessment software; dollars are in real 2022 USD
Source: Rystad Energy research and analysis; American Petroleum Institute

Table of Contents

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API's "10 in 2022" policy plan and Rystad Energy's scope of work

Background: API's "10 for 2022" policy plan

- **In June 2022, the American Petroleum Institute (API) released "10 in 2022: Ten Policies to Unleash American Energy and Fuel Recovery."**
- The API said that "Washington policymakers must confront the global mismatch between demand and supply that has driven higher fuel prices by supporting greater U.S. production. To address the growing crisis we face, Congress and the President must support energy investment, create new access and keep regulation from unnecessarily restricting energy growth."
- The policies span a wide range of topics affecting the energy industry, from federal oil and gas leasing to hydrogen credits to infrastructure permitting.

Rystad Energy's scope of work

- **Rystad Energy was commissioned by the American Petroleum Institute (API) to quantify the effects of API's "10 in 2022" policies on investment and oil and gas production.**
- Rystad provided inputs to API to estimate the effect of investment on employment and GDP using IMPLAN software. These employment and GDP effects are reflected in the report.
- Quantification draws upon Rystad's bespoke analysis, existing data and publications as well as 3rd-party sources where relevant.

About Rystad Energy

- **Rystad Energy is an independent energy consulting services and business intelligence data firm offering global databases, strategic advisory and research products for energy companies and suppliers, investors, investment banks, organizations, and governments.**
- Headquartered in Norway, Rystad Energy was established in 2004 and has ~500 employees with regional offices in London, Singapore and Houston, with additional supporting offices in Calgary, Denver, Rio de Janeiro and Sao Paulo.
- Over the last 18 years, Rystad Energy has completed over 2,500 projects for more than 500 clients, ranging from energy companies, investment banks, private equity and venture funds, service companies and governments in all regions of the world.
- In preparing the report, Rystad Energy has relied on its broad suite of proprietary research products and tools, its independent expertise and judgment as well as documents provided by the Client.

The API’s "10 in 2022" policy plan calls on policymakers to “support energy investment, create new access and keep regulation from unnecessarily restricting energy growth”

	API's "10 for 2022" policy plan	API policy details
1	Lift development restrictions on federal lands and waters	The Department of the Interior (DOI) should swiftly issue a 5-year program for the Outer Continental Shelf and hold mandated quarterly onshore lease sales with equitable terms. DOI should reinstate canceled sales and valid leases on federal lands and waters.
2	Designate critical energy infrastructure projects	Congress should authorize critical energy infrastructure projects to support the production, processing and delivery of energy. These projects would be of such concern to the national interest that they would be entitled to undergo a streamlined review and permitting process not to exceed one year.
3	Fix the NEPA permitting process	The Biden administration should revise the National Environmental Policy Act (NEPA) process by establishing agency uniformity in reviews, limiting reviews to two years, and reducing bureaucratic burdens placed on project proponents in terms of size and scope of application submissions.
4	Accelerate LNG exports and approve pending LNG applications	Congress should amend the Natural Gas Act to streamline the Department of Energy (DOE) to a single approval process for all U.S. liquefied natural gas (LNG) projects. DOE should approve pending LNG applications to enable the U.S. to deliver reliable energy to our allies abroad.
5	Unlock investment and access to capital	The Securities and Exchange Commission should reconsider its overly burdensome and ineffective climate disclosure proposal and the Biden administration should ensure open capital markets where access is based upon individual company merit free from artificial constraints based on government-preferred investment allocations.
6	Dismantle supply chain bottlenecks	President Biden should rescind steel tariffs that remain on imports from U.S. allies as steel is a critical component of energy production, transportation, and refining. The Biden administration should accelerate efforts to relieve port congestion so that equipment necessary for energy development can be delivered and installed.
7	Advance lower carbon energy tax provisions	Congress should expand and extend Section 45Q tax credits for carbon capture, utilization, and storage development and create a new tax credit for hydrogen produced from all sources.
8	Protect competition in the use of refining technologies	The Biden administration should ensure that future federal agency rulemakings continue to allow U.S. refineries to use the existing critical process technologies to produce the fuels needed for global energy markets.
9	End permitting obstruction on natural gas projects	The Federal Energy Regulatory Commission should cease efforts to overstep its permitting authority under the Natural Gas Act and should adhere to traditional considerations of public needs as well as focus on direct impacts arising from the construction and operation of natural gas projects.
10	Advance the energy workforce of the future	Congress and the Biden administration should support the training and education of a diverse workforce through increased funding of work-based learning and advancement of STEM programs to nurture the skills necessary to construct and operate oil, natural gas and other energy infrastructure.

Source: API “10 in 2022: Ten Policies to Unleash American Energy and Fuel Recovery”

For selected API “10 in 2022” policies we explicitly quantify policy impacts using a “Policy Case” vs. a “Reference Case, while for others we provide a qualitative view

API "10 for 2022" policy plan	Approach: Quantitative	Approach: Qualitative	Infrastructure
1 Lift development restrictions on federal lands and waters	✓		
2 Designate critical energy infrastructure projects	✓		✓
3 Fix the NEPA permitting process		✓	✓
4 Accelerate LNG exports and approve pending LNG applications		✓	✓
5 Unlock investment and access to capital		✓	
6 Dismantle supply chain bottlenecks		✓	
7 Advance lower carbon energy tax provisions	✓		
8 Protect competition in the use of refining technologies		✓	
9 End permitting obstruction on natural gas projects		✓	✓
10 Advance the energy workforce of the future		✓	

Methodology

For quantitative policies, we estimate the policy impact (using a "Policy Case" vs. a "Reference Case") on 1) investment; 2) oil and gas production; 3) GDP[2] and 4) employment[2].

- The **Policy Case** represents a scenario in which the proposed policy is fully implemented. The **Reference Case** represents a scenario in which the policy is *not* implemented.[1]
- We avoid double counting of impacts between scenarios.
- In some cases, some form of API policy proposal has been adopted since the proposal was released; e.g., the Inflation Reduction Act includes tax provisions for CCUS and hydrogen. In these cases, we use reference cases that assume either the policy had not been adopted or is not enacted to illustrate the policy effect.

For qualitative policies, we discuss potential policy impact but do not estimate effect on the above metrics. We avoid double counting where aspects of the policy impacts are quantified across other metrics.

- While we do not quantify the effects of these specific policies, these policies are interrelated with the quantitative policies. For instance, “advancing the energy workforce of the future” is important to achieve growth from the explicitly quantified policies.

For Infrastructure-related policies:

- Policies 2, 3, 4 and 9 each deal with infrastructure permitting and delay-related policies that are, in some ways, interrelated. We explicitly quantify the impact of API Policy #2, noting that API Policy #2 is also meant to address issues relating to the other infrastructure-related policies.

1. Note that the reference case is a custom scenario and does not necessarily correspond to a published Rystad base case.
2. As calculated and provided by API using Rystad Energy’s estimated direct capital investment under each scenario and the IMPLAN economic assessment software

Source: Rystad Energy research and analysis

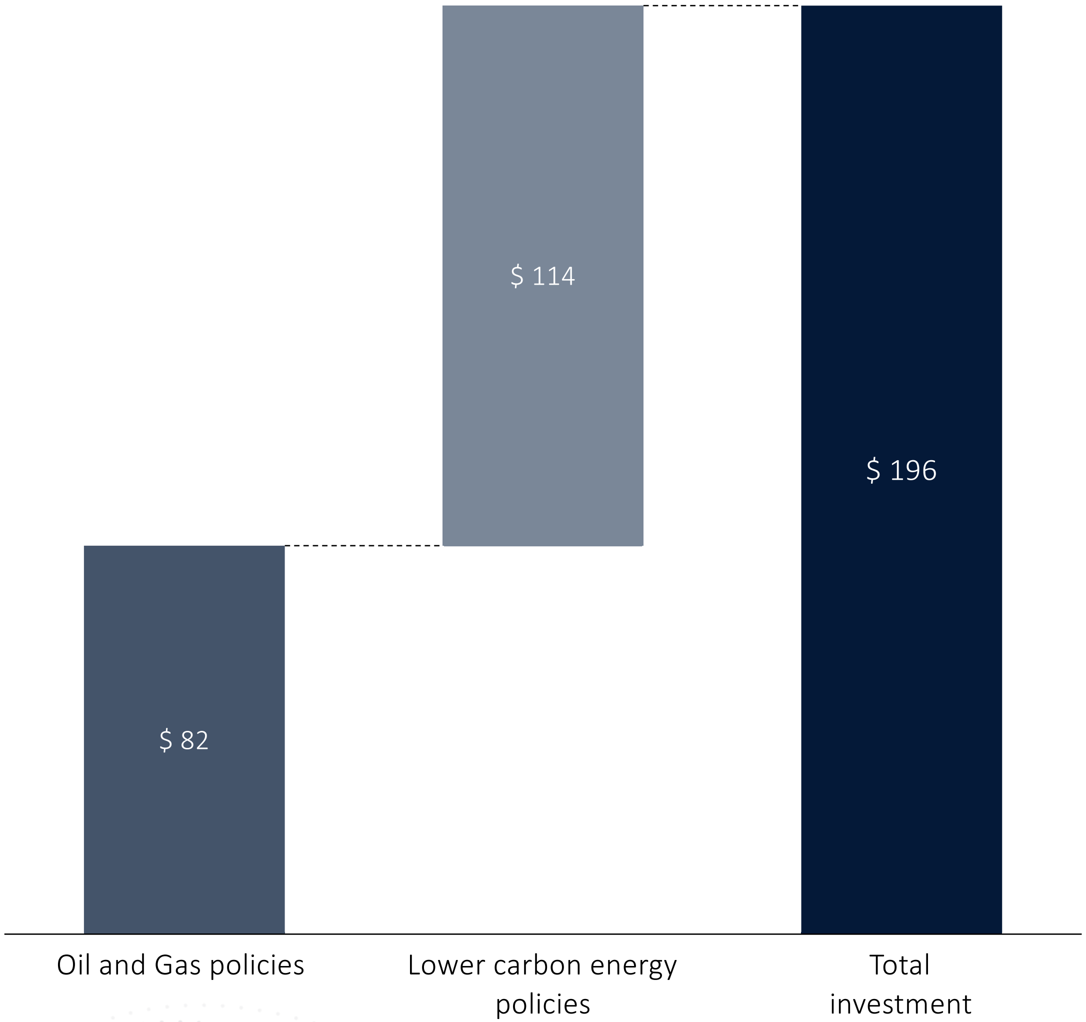
Rystad Energy has estimated the quantitative impact of API's "10 in 2022"policy plan based on the difference of policy and reference cases

API "10 for 2022" policy plan	Reference Case	Policy Case
1 Lift development restrictions on federal lands and waters	• Lease Sales 259 and 261 are not held • The 5-Year Leasing Program will be issued, but will follow the No Sale Option, where no lease sales held between 2023 and 2028. • We analyze this Reference Case as a comparison to the Policy Case, but the Reference Case does not represent Rystad Energy's Base Case.	• Lease Sales 259 and 261 are held. • 5-year plan swiftly issued, with first lease sale in 2023. We assume that the 5-year plan includes 10 Gulf of Mexico lease sales.
2 Designate critical energy infrastructure projects	• A number of future energy infrastructure projects will be cancelled due protracted and uncertain permitting process, similar to what has occurred in recent years.	• Projects that might otherwise be cancelled receive "critical energy infrastructure" designation and, due to a streamlined permitting process, are ultimately constructed.
7 Advance lower carbon energy tax provisions	• Hydrogen: The reference case presents the forecast of a scenario of where no tax credits nor funding for hydrogen-related energy infrastructure or developments. • CCUS: Continuation of the pre-IRA 45Q tax credits.	• Hydrogen: New clean hydrogen PTC is implemented based on Section 45V of the Inflation Reduction Act. • CCUS: Enhanced Section 45Q credits are implemented based on the Inflation Reduction Act.

- These reference and policy cases are the basis for the quantitative impacts – investment, production, employment and GDP – that we estimate for API's "10 in 2022" policy plan.
- While we explicitly quantify these three policies, we note that these policies are interrelated with other "10 in 2022" policy plan proposals, such as "advance the energy workforce of the future" and "dismantle supply chain bottlenecks," which could support the investment associated with the explicitly quantified policies. We avoid double counting of impacts between scenarios.

Rystad Energy estimates an incremental investment of nearly $200 billion under the“10 in 2022” policy plan – with 60 and 40 percent driven from lower carbon energy and oil & gas policies, respectively

Investment impact – Policy Case versus Reference Case
Billion USD (real 2022)



Source: Rystad Energy research and analysis

The $196 billion in direct investment brought by the Policy Case relative to the Reference Case stems from both oil and gas investment and investment in lower carbon energy.

Investment in both oil and gas and lower carbon energy polices directly and indirectly drive GDP and employment.

Oil & gas policies

- $82 billion USD in direct investment from oil and gas comes from both upstream and midstream investment. This investment is supported by the oil and gas-related policies. More specifically, investment is related to federal oil and gas leases, pipeline investment, and production that is enabled by increased pipeline capacity.

Low carbon energy policies

- $114 billion USD in direct investment for CCUS and Hydrogen stems from low carbon energy tax provisions. $77 billion USD of this comes from CCUS investment, including carbon capture, transport and storage. $37 billion USD of investment is related to hydrogen investments. The investment for CCUS related to blue hydrogen projects is captured as CCU investment.

Based on Rystad's investment estimates, the GDP and employment impact of API's "10 in 2022" plan in 2025 could be $17 Bn and 142k jobs, respectively, growing to $27 Bn and 226k jobs in 2035

Annual API "10 in 2022" policy plan impacts - Policy Case vs. Reference Case[1]

	Metric	Unit[2]	Direct 2025	Direct 2030	Direct 2035	Indirect and induced 2025	Indirect and induced 2030	Indirect and induced 2035	Annual total 2025	Annual total 2030	Annual total 2035
Oil & Gas policies	Investment	Billion USD	4.8	7.1	7.9	8.5	12.2	13.5	13.4	19.4	21.5
	GDP	Billion USD	2.4	3.7	4.1	4.5	6.6	7.3	7.0	10.2	11.4
	Employment	Thousand	22.4	29.5	31.9	40.1	58.0	64.2	62.6	87.5	96.2
	Wages and benefits	Billion USD	1.9	2.7	3.0	2.6	3.8	4.3	4.5	6.5	7.2
	Oil production	kb/d	7.0	83.0	127.0	-	-	-	7.0	83.0	127.0
	Gas production	bcf/d	4.6	4.7	4.8	-	-	-	4.6	4.7	4.8
Lower carbon energy policies	Investment	Billion USD	7.3	9.2	11.9	13.2	16.6	21.4	20.5	25.8	33.3
	GDP	Billion USD	3.1	3.9	5.0	6.8	8.5	11.0	9.8	12.4	16.0
	Employment	Thousand	22.2	28.5	37.1	56.8	71.7	92.6	79.0	100.2	129.7
	Wages and benefits	Billion USD	2.1	2.7	3.5	3.9	4.9	6.3	6.0	7.6	9.8
Total	Investment	Billion USD	12.2	16.4	19.8	21.7	28.8	35.0	33.8	45.2	54.8
	GDP	Billion USD	5.5	7.5	9.1	11.3	15.1	18.3	16.8	22.6	27.4
	Employment	Thousand	44.6	58.0	69.0	96.9	129.7	156.9	141.6	187.7	225.9
	Wages and benefits	Billion USD	4.0	5.4	6.5	6.5	8.7	10.6	10.5	14.1	17.0
	Oil production	kb/d	7.0	83.0	127.0	-	-	-	7.0	83.0	127.0
	Gas production	bcf/d	4.6	4.7	4.8	-	-	-	4.6	4.7	4.8

Economic effect definitions:

- **Direct:** The direct effects from Rystad Energy's estimated investment. Direct effects are applied to input/output multipliers to estimate the total effects.
- **Indirect:** The effect of business-to-business purchases in the supply chain taking place in the region that stem from the initial industry input purchases.
- **Induced:** The effect stemming from household spending of labor income, after removal of taxes, savings, and commuter income. The induced effects are generated by the spending of the employees within the business' supply chain.

1: GDP, employment, wages and benefits, and indirect and induced investment are provided by API using Rystad Energy's estimated direct investment under each scenario and the IMPLAN economic assessment software
2: Real 2022 dollars
Source: Rystad Energy research and analysis, American Petroleum Institute, IMPLAN

Table of Contents

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API Policy #1: Lift development restrictions on federal lands and waters

API policy	Detailed description
1 Lift development restrictions on federal lands and waters	The Department of the Interior (DOI) should swiftly issue a 5-year program for the Outer Continental Shelf and hold mandated quarterly onshore lease sales with equitable terms. DOI should reinstate canceled sales and valid leases on federal lands and waters.

Background

On *January 27, 2021*, Biden Administration issued *Executive Order on Tackling the Climate Crisis at Home and Abroad,* which paused new oil and gas leasing on public lands and offshore waters. This pause on leasing has been the subject of litigation, which is ongoing.

The BOEM cancelled Lease Sales 259 and 261. The Inflation Reduction Act later required BOEM to hold these lease sales by specified dates in 2023.

The 2023-2028 5-year leasing program has been delayed. The Proposed Program notes that the Secretary of the Interior retains the discretion to decide that no offshore lease sales are held under the 2023-2028 plan.

Reference Case

- Lease Sales 259 and 261 are *not* held.
- The 5-Year Leasing Program will be issued, but will follow the No Sale Option, where no lease sales held between 2023 and 2028.
- We analyze this Reference Case as a comparison to the Policy Case, but the Reference Case does not represent Rystad Energy's Base Case.

Policy Case

- Lease Sales 259 and 261 *are* held.
- 5-year plan swiftly issued, with first lease sale in 2023. We assume that the 5-year plan includes 10 Gulf of Mexico lease sales.

Note: We do not analyze the impact of Cook Inlet lease sales, including Lease Sale 258
Source: Rystad Energy research and analysis

The Biden Administration cancelled four offshore lease sales, only to reinstate the sales as part of the Inflation Reduction Act

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There are four major milestones in relation to the Executive Order (14008) on Tackling the Climate Crisis at Home and Abroad

1. On January 27, 2021, President Biden signed Executive Order 14008, which paused all new federal onshore and offshore lease sales
2. Remaining Lease Sales from the Five-Year Plan of 2017-2022 saw several court rulings and appeals leading to delays
3. The Executive Order led to the cancellation of Lease Sale 258, 259, and 261 due to "lack of industry interest and conflicting court rulings"
4. The IRA led to issuance of leases to high bidders in Lease Sale 257 and required DOI to hold Lease Sales 258, 259, and 261.

Key takeaways and summary of the Executive Order

Cause

- The Biden Administration issued the Executive Order on Tackling the Climate Crisis at Home and Abroad in the first days of the administration. The order put a pause on Federal oil and gas leasing pending a comprehensive review of leasing practices in light of potential climate change impacts.

Impact

- Lease sale 257 was vacated on January 27, 2022, after a federal district court in Washington D.C. found that BOEM failed to adequately consider climate impacts.
- Lease sale 258, 259, and 261 were cancelled due to "lack of industry interest" and "conflicting court rulings".
- Potential loss of government revenue from the cancelled lease sales. Furthermore, potential loss of investment and revenue for the federal government due to the delay of the new Five-Year Leasing Program.

Current status due to the IRA

- Reinstatement of Lease sale 257 that was held in November 2021. On September 14, 2022, Lease Sale 257 was officially reinstated.
- Leases 258, 259 and 261 mandated to be held. Lease 259 to occur by March 31, 2023, and Lease 261 to occur by September 30, 2023. Lease Sale 258 is proposed to be held on December 30, 2022.
- Future offshore wind lease sales are tied to oil and gas sales. The IRA prohibits the BOEM from issuing an offshore wind lease unless BOEM has both offered at least 60 million acres on the outer continental shelf for oil and gas leasing and executed an oil and gas lease in that offshore lease sale in the previous year.

Source: Rystad Energy research and analysis; Executive Order 14008

BOEM has noted that the Secretary of the Interior has discretion to issue a plan with no lease sales

No offshore lease sales option

- The 2023-2028 Proposed Program notes that the Secretary of the Interior retains the discretion to decide that no offshore lease sales are held under the 2023-2028 plan.
- The No Sales Option is a scenario included in each Five-Year Leasing Program, which analyzes the implications should there be no lease sales.
- It is unlikely the 2023-2028 Program will have zero lease sales. However, should there be no lease sales, the US would face several potential impacts. As such, we have explored the investment, production, and royalty impact of a No Sales Option, should it occur.

BOEM findings on potential impact of the No Sales Option

↓	Supply	Total domestic (and global) oil and gas supply would decrease in the long run.
↑	Price	Assuming increasing demand, may lead to increase of hydrocarbon price.
↑	Energy trade	Increase of imports, domestic onshore production, and transition to other energy sources to meet continued domestic demand for oil and natural gas products.
↑	Emissions	Carbon emissions may potentially increase due to a shift towards other oil and gas produced from higher emission intensive sources, such as onshore production.
↓	Employment	Decrease of employment and business activities in communities that have been serving goods, services, and labor to support offshore services.

Source: 2023–2028 National OCS Oil and Gas Leasing Proposed Program; Rystad Energy research and analysis

Our Policy Case assumes 12 lease sales (2 reinstated in the current BOEM program and 10 in the yet-to-be-released 5-year 2023-2028 lease program), as opposed to zero in our Reference Case

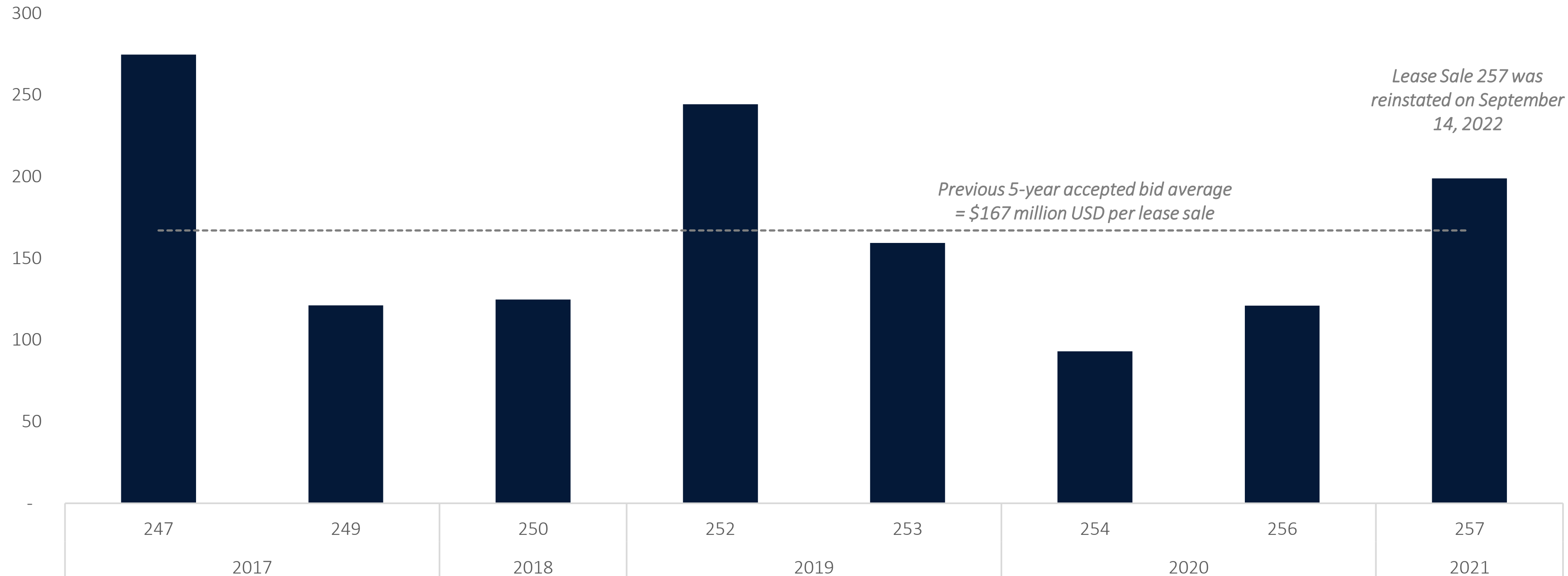
Lease Sales		Reference Case: Lease Sale Number	Reference Case: Comment	Timeline	Policy Case: Lease Sale Number	Policy Case: Comment
Lease Sales	2017-2022 Program	No Lease Sales	Continued cancellation 259 and 261	H1 2023	259	Reinstated: March 2023
				H2 2023	261	Reinstated: September 2023
	2023-2028, 5-Year Lease Program	No Lease Sales	New 5-Year Leasing Plan published by BOEM will pursue a No Sale Option, where there will be 0 lease sales between 2023-2028.	H2 2023	262	2023-2028, 5-Year Lease Plan is swiftly issued with guaranteed blocks in each Lease Sale.
				H1 2024	263	
				H2 2024	264	
				H1 2025	265	
				H2 2025	266	
				H1 2026		
				H2 2026	268	
				H1 2027	269	
				H2 2027	270	
				H1 2028	271	
				H2 2028	272	

Policy Case has an additional *12 lease sales* in the Gulf of Mexico compared to the Reference Case.

Note: Only Gulf of Mexico lease sales are shown
Source: Rystad Energy research and analysis

Total accepted bids have averaged $167 million USD in past 5 years of Gulf of Mexico leases

Total successful bids spent on winning leases, Gulf of Mexico lease sales 2017-2021
Million USD

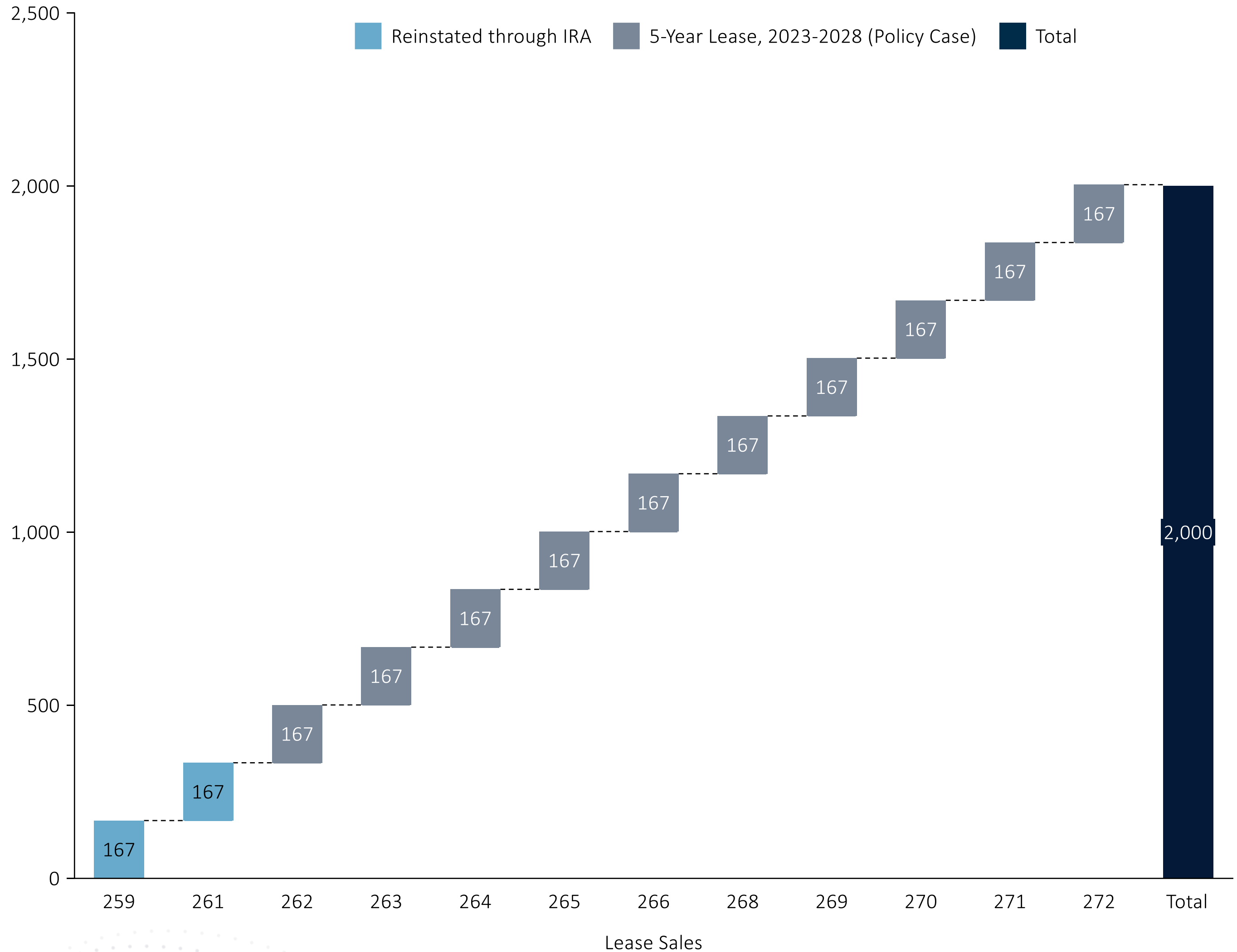


- The 5-Year Leasing Program of 2017-2022 compiled all Gulf of Mexico lease areas as “Gulf of Mexico Region”, whereas previously, it was segmented as “Central, Western, and Eastern GoM”.
- The 2017-2022 5 Year-Leasing-Program saw an average of $167 million USD per lease sale.
- On January 27, 2022, the District Court of District of Columbia ordered Lease sale 257 to be vacated due to a lack of assessment on the environmental impact of the lease. This was overturned on September 14, 2022, and Lease Sale 257 has since been reinstated.

Source: Rystad Energy research and analysis; O&G Journal

The 12 additional lease sales from the Policy Case brings an additional $2 billion from accepted bids

Total potential accepted bid gained from Policy Case vs Reference Case
Million USD



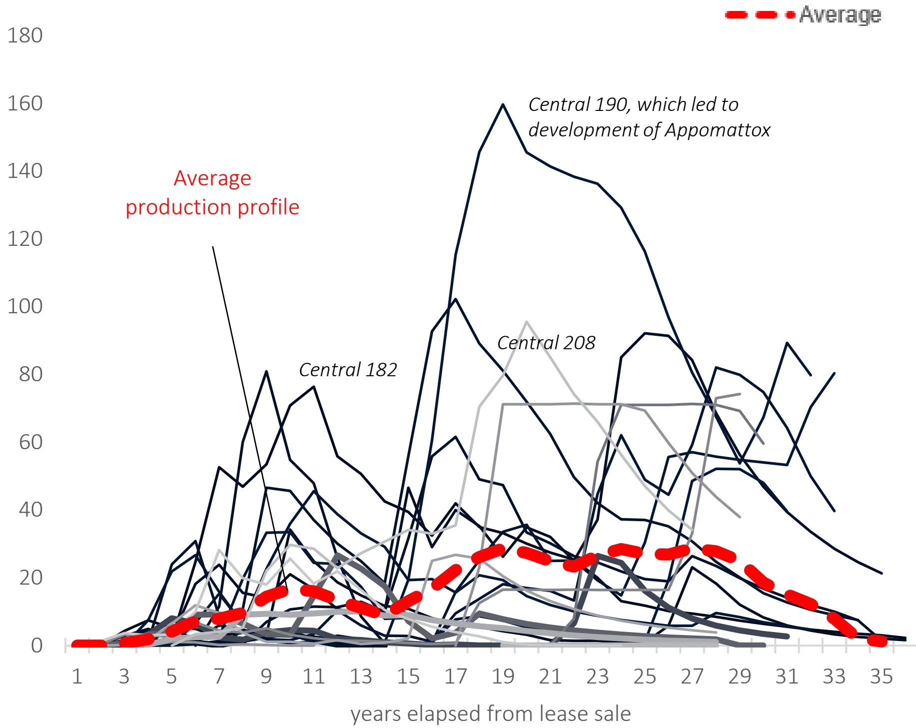
Source: Rystad Energy research and analysis

Impact of Policy Case

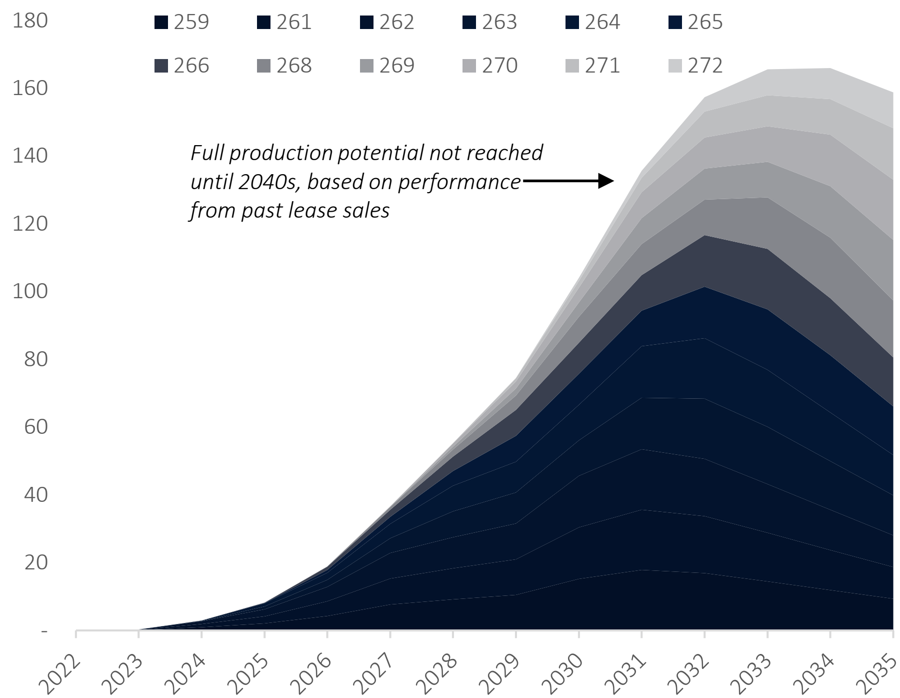
- The 12 additional Gulf of Mexico lease sales in the Policy Case versus the Reference Case could bring an additional $2 billion USD in bid revenue, based on the 2017-2021 average of $167 million USD per lease sale.

The additional lease sales could bring 395 million boe of production through 2035

Total oil and gas production per lease sale, by years elapsed [1]
Thousand boe/d (2000-2010 lease sales)



Potential production gained from Policy Case vs Reference Case
Thousand boe/d

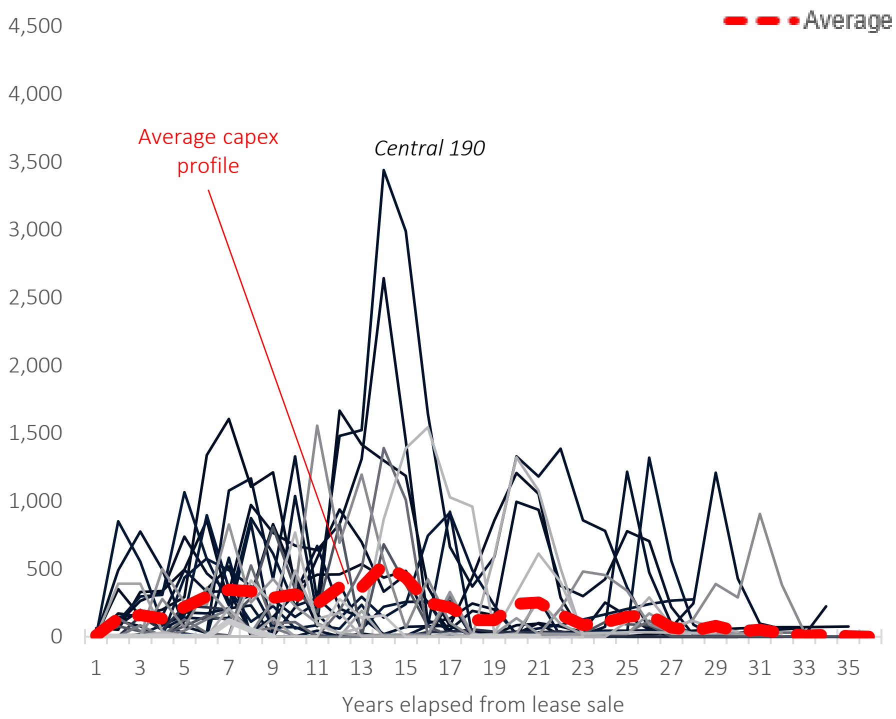


- The forecasted production with the 12 additional lease sales from the Policy Case is based on analyzing historical production from 2000-2010 lease sales.
- The reinstatement of lease sale 259 and 261 and the addition of the new 5-Year Lease Program ***(based on the Policy Case)*** could reach up to ***165 thousand boe per day by 2033***. This production ***averages 77 thousand boe per day*** over the forecast period, ***totaling 395 million boe of production***.
- Based on historical data, the production breakdown between gas and crude for future GoM Lease Sales is: **20% gas and 80% crude.**
- The production forecast does not reflect the full impact of the lease sales, as production from past leases ramps up after year 13 (or post-2035, which is after the forecast period).

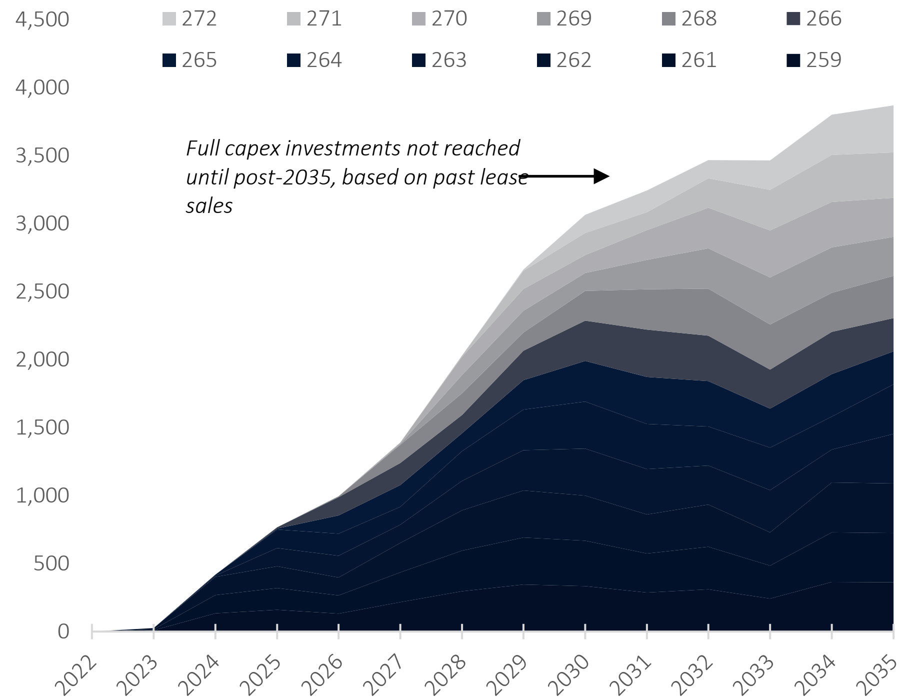
1: Each line represents a Gulf of Mexico lease sale from 2000-2010
Source: Rystad Energy research and analysis; BOEM

The additional lease sales could generate $29 billion of investment through 2035

Total upstream capex spent for developing assets under lease sales[1]
Million USD (2000-2010 lease sales)



Potential gain in capex investment from Policy Case vs Reference Case
Million USD

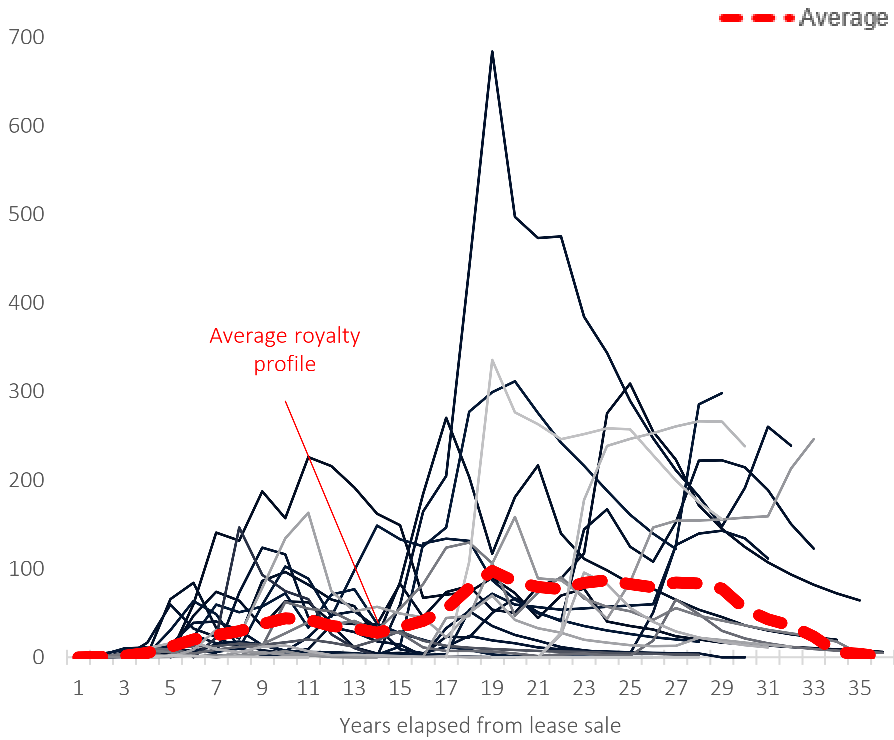


- On average, capex spend per lease sale remain below $500 million USD per year, with the **height of expenditure following between years of 13 to 15 from the closing date**. Capex highly varies depending on the assets within each lease sale and is dependent on the success of discovered resources, but capex is expected to start from year 1 in order to maximize the return on investment.
- The reinstatement of 259 and 261, with the new Five-Year Leasing Program (***based on the Policy Case)*** would generate ***$29 billion USD by 2035.*** This forecast is based on the average capex of lease sales from 2000-2010.
- Similar to the production forecast, capex is expected to further increase beyond the forecast period, as historical lease sales have shown that total capex peaks into year 15 from its closing date (post-2035 in the forecast).

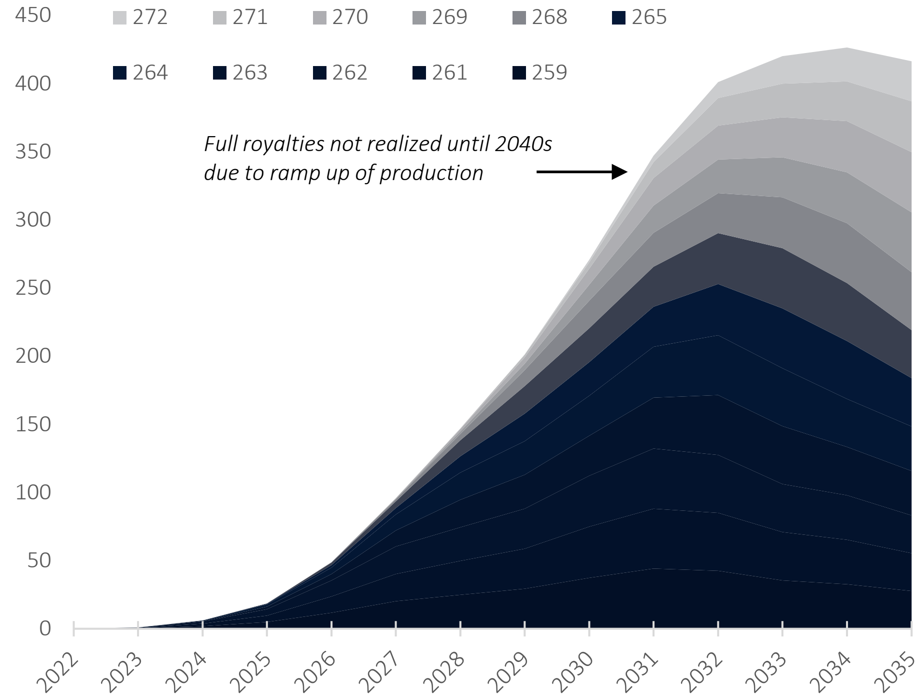
1: Each line represents a Gulf of Mexico lease sale from 2000-2010
Note: Real 2022 USD
Source: Rystad Energy research and analysis; BOEM

The additional lease sales could generate $2.8 billion in royalties and taxes through 2035

Total government royalties and taxes per lease sale[1]
Million USD (2000-2010 lease sales)



Potential royalties and taxes gained from Policy Case vs Reference Case
Million USD

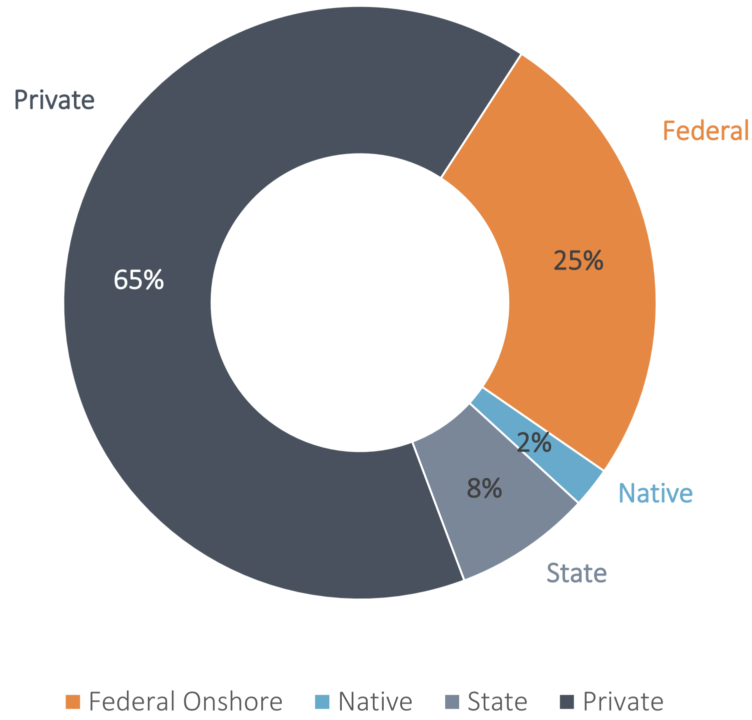


- On average, the federal government receives $22 million USD of royalty per lease sale within the first 12 to 13 years after the closing date of the lease sale bids. This further ramps up following year 13 due to the increase of production, as historically shown.
- The reinstatement of 259 and 261 with the 5-Year Leasing Program under the ***Policy Case*** could generate a revenue upwards of ***$420 million USD per year post-2030*** for the federal government.
- Annual royalty fee is expected to further increase beyond the end of the forecast period (2035), as historically, lease sales ramp up production and capex after year 13. The federal government could expect to see a sharp increase of royalty fee beyond 2035 given this forecast.

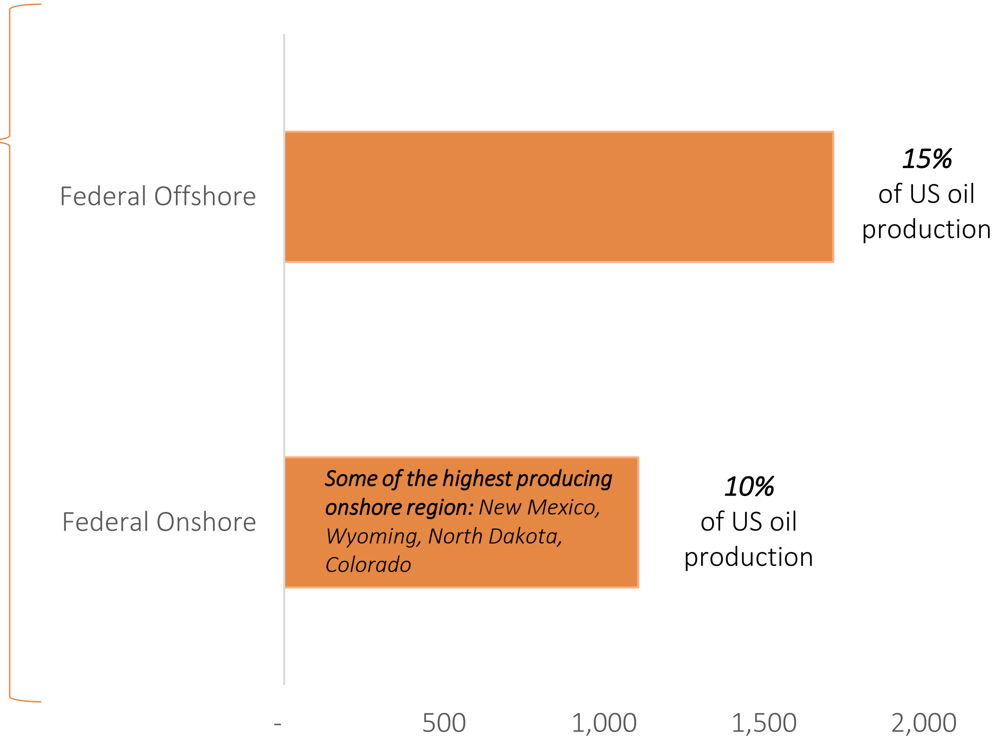
1: Each line represents a Gulf of Mexico lease sale from 2000-2010; royalties and taxes do not include potential tax on labor income
Note: Real 2022 USD
Source: Rystad Energy research and analysis; BOEM

Federal land and water contribute 25% of total US oil production; continued leasing would support production

2021 Total US oil production by land/water ownership
Percentage



Split of federal land oil production, offshore v. onshore
Thousand barrels per day



- *The Mineral Lease Act of 1920* requires that oil and gas lease sales be held for each state, where eligible lands are available. This is to occur at least quarterly or more frequently if the Secretary of the Interior determines such sales necessary.
- Federal offshore and onshore leases are ***an important contributor*** towards US oil production, as in 2021, it produced 25% of total US oil production. ***Continued federal leasing supports US oil production.***
- Federal onshore leases makes up ***10% of all US oil production.*** This makes federal onshore leases an important contributor towards total US oil production.

Source: Rystad Energy research and analysis

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Impact of API Policy #1: Lift development restrictions on federal land and waters

API policy	Policy Impacts Policy Case versus Reference Case, 2023-2035	
	Investment	Production
1 Lift development restrictions on federal lands and waters	*$29 billion USD*	*77 kboe/d average,* *up to 166 kboe/d in 2035*

Other benefits and impact Policy Case versus Reference Case, 2023-2035		
Government royalties and taxes	Bid revenue	Total additional lease sales
$2.8 billion USD	*$2 billion USD*	*12 additional lease sales in Policy Case*

Note: Real 2022 USD; royalties and taxes do not include potential tax on labor income
Source: Rystad Energy research and analysis

Table of Contents

The API's "10 in 2022" plan includes four proposals relating to infrastructure permitting

API policy		API policy details
2	Designate critical energy infrastructure projects	Congress should authorize critical energy infrastructure projects to support the production, processing and delivery of energy. These projects would be of such concern to the national interest that they would be entitled to undergo a streamlined review and permitting process not to exceed one year.
3	Fix the NEPA permitting process	The Biden administration should revise the National Environmental Policy Act (NEPA) process by establishing agency uniformity in reviews, limiting reviews to two years, and reducing bureaucratic burdens placed on project proponents in terms of size and scope of application submissions.
4	Accelerate LNG exports and approve pending LNG applications	Congress should amend the Natural Gas Act to streamline the Department of Energy (DOE) to a single approval process for all U.S. liquefied natural gas (LNG) projects. DOE should approve pending LNG applications to enable the U.S. to deliver reliable energy to our allies abroad.
9	End permitting obstruction on natural gas projects	The Federal Energy Regulatory Commission should cease efforts to overstep its permitting authority under the Natural Gas Act and should adhere to traditional considerations of public needs as well as focus on direct impacts arising from the construction and operation of natural gas projects.

- These four policy proposals focus on reducing complexity and accelerating permitting processes for energy infrastructure.
- The proposals are in many ways related. For instance, the NEPA process, which varies widely in duration and complexity, must be completed before the Department of Energy grants export permits for LNG exports to non-Free Trade Agreement countries.
- We provide background and discuss potential impacts of API Policy #3, #4 and #9.
- We explicitly quantify the impact of API Policy #2, noting that API Policy #2 is also meant to address issues relating to the other infrastructure policies.

API Policy #2: Designate critical energy infrastructure projects

Policy	Detailed description
2 Designate critical energy infrastructure projects	Congress should authorize critical energy infrastructure projects to support the production, processing and delivery of energy. These projects would be of such concern to the national interest that they would be entitled to undergo a streamlined review and permitting process not to exceed one year.

Background	Reference Case	Policy Case
• Several large energy infrastructure projects have faced extensive delays and have ultimately been cancelled due to protracted and uncertain permitting review processes. • Protracted and uncertain processes reduce investments in infrastructure, hamper US oil and gas production, and reduce the flexibility of the US energy system. • A "critical energy infrastructure" designation would reduce the risks for project developers and investors by imposing a duration limit on review and permitting processes. Ultimately, such a process could lead to increased investment, production, employment and GDP.	• Several future energy infrastructure projects will be cancelled due protracted and uncertain permitting process, similar to what has occurred in recent years.	• Projects that might otherwise be cancelled receive "critical energy infrastructure" designation and, due to a streamlined permitting process, are ultimately constructed.

Source: Rystad Energy research and analysis

In recent years, at least 10 major infrastructure projects have been cancelled or are at risk of cancellation due to protracted and uncertain permitting processes

- We have identified 10 projects that have been cancelled, stalled, or otherwise are at risk due to permitting and reviews.
- These projects have spent up to 14 years in protracted permitting and review processes. Some projects, such as the Dakota Access Pipeline Expansion, received permits which were later vacated.
- The Mountain Valley Pipeline is currently under construction but has been delayed by years of legal delays and is at risk for cancellation. Project investor NextEra has noted that "continued legal and regulatory challenges" reduce the chance that the project will be completed.

Select potential "critical energy infrastructure" projects

Project	Commodity	Operator	Status	Years elapsed proposal to cancellation[1]
Keystone XL	Crude oil	TC Energy	Cancelled	13
Portland to Montreal Pipeline Reversal	Crude oil	Suncor Energy	Cancelled	13
Dakota Access Pipeline Expansion	Crude oil	Energy Transfer	Permit vacated	3
Byhalia (Diamond to Capline)	Crude oil	Valero, Plains	Cancelled	2
Palmetto	Refined products	Kinder Morgan	Cancelled	2
Atlantic Coast	Natural gas	Dominion Energy	Cancelled	6
Constitution	Natural gas	Williams	Cancelled	8
Mountain Valley	Natural gas	Equitrans Midstream	Under construction	9
Jordan Cove Energy Project	Natural gas	Pembina	Cancelled	14
PennEast Pipeline	Natural gas	PennEast Pipeline	Cancelled	6

Crude oil · Refined products · Natural gas

1: For Mountain Valley, years elapsed represents years from proposal to current
Source: Rystad Energy research and analysis

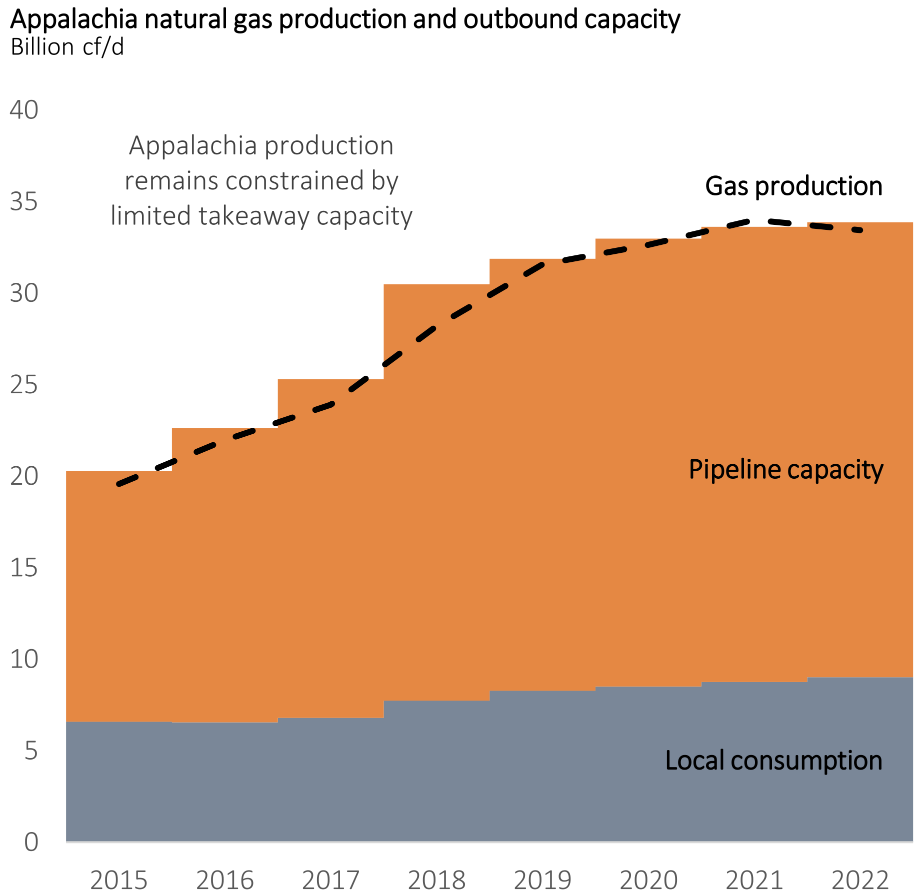
This selection of projects represents over $34 billion USD in capital expenditure

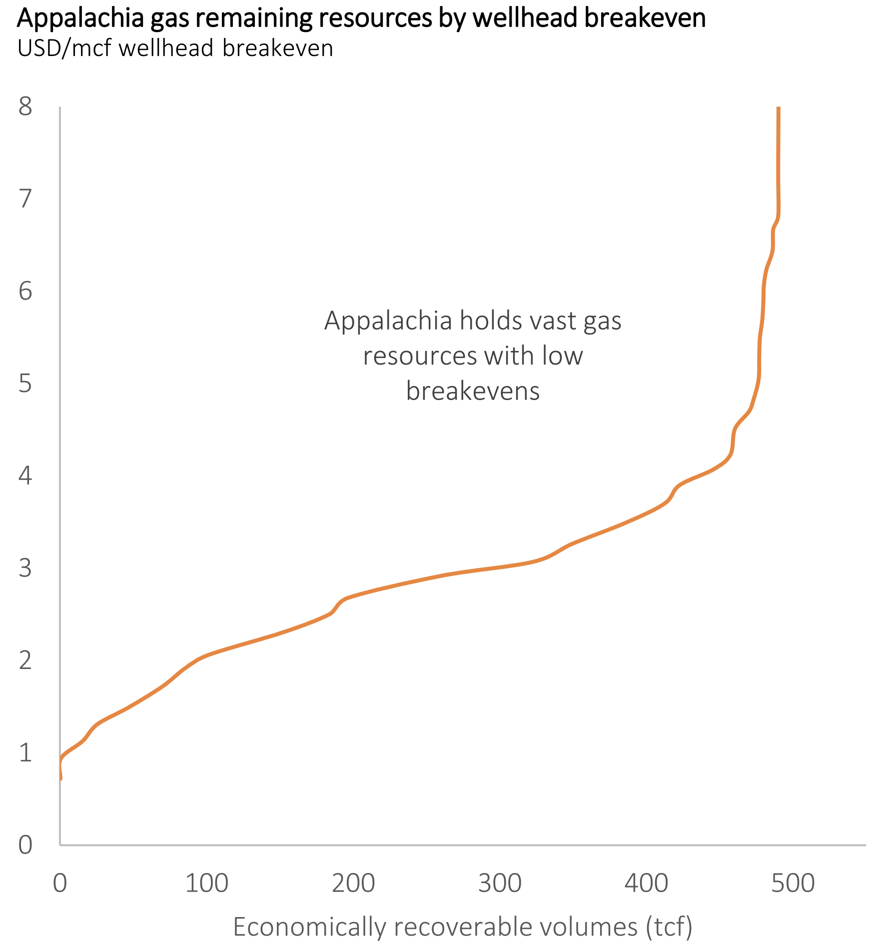
Project	Commodity	Operator	Origin	Status	CAPEX (Billion USD)[1]
Keystone XL		TC Energy	Western Canada (Hardisty, AL)	Cancelled	6.6
Portland to Montreal Pipeline Reversal		Suncor Energy	Montreal	Cancelled	0.1
Dakota Access Pipeline Expansion		Energy Transfer	Williston Basin, ND	Permit vacated	0.4
Byhalia (Diamond to Capline)		Valero, Plains	From Memphis, TN to North MS	Cancelled	0.4
Palmetto		Kinder Morgan	Belton, SC	Cancelled	1.1
Atlantic Coast		Dominion Energy	Appalachian Northeast, WV	Cancelled	8.0
Constitution		Williams	Appalachian Northeast (PA)	Cancelled	1.0
Mountain Valley		equitrans Midstream	Marcellus and Utica Shale	Under construction	6.6
PennEast Pipeline		PennEast Pipeline	Marcellus Shale	Cancelled	1.0
Jordan Cove Energy Project		Pembina	Malin, OR	Cancelled	10.0

Total capital expenditure of ***over $34 billion USD***

1: Estimated capital expenditures in the U.S. only
Source: Company reporting and Rystad Energy estimates

Pipeline capacity constrains Appalachia supply; additional capacity would enable supply growth





- Appalachian gas supply has been constrained by limited pipeline takeaway capacity in recent years. Given Appalachia's vast low-breakeven gas resources, additional pipeline capacity would enable Appalachian supply growth.

Source: Rystad Energy UCube

The Appalachia pipeline projects could support 4.6 bcf/d of production and $19 billion USD of upstream capex through 2035

Potential Appalachia "critical energy infrastructure" projects

Pipeline	Status	Capacity (bcf/d)
Atlantic Coast	Cancelled	1.5
Constitution	Cancelled	0.65
PennEast Pipeline	Cancelled	1
Mountain Valley	Under construction	2

Project impacts (2023-2035)

+4.6 bcf/d incremental supply[1]

+2,500 new wells[2]

+ $19 billion USD upstream capex[3]

With a combined 5.15 bcf/d of capacity, the Appalachia pipeline projects identified as potential "critical energy infrastructure candidates" could support 4.6 bcf/d of incremental production if built today, assuming a conservative 90% pipeline utilization.

Based on recent well performance and costs, this would amount to 2,500 wells and over $19 billion USD in upstream capex from 2023-2025.

1: Assuming 90% pipeline utilization
2: Based on 2019-2021 Appalachia type curves and well design
3: Based on 2019-2021 Appalachia well capex, real 2022 USD
Source: Rystad Energy ShaleWellCube

Impact of API Policy #2: Designate critical energy infrastructure projects

Policy	Policy Impacts Policy Case versus Reference Case, 2023-2035	
	Investment	Production
2 Designate critical energy infrastructure projects	*$53 billion USD*	*4.6 bcf/d*

Other benefits and impact
Policy Case versus Reference Case, 2023-2035

- In addition to supporting incremental investment, production, GDP and employment, implementing a critical energy infrastructure designation could increase the flexibility of the US energy system.
- With greater connectivity and flexibility, the US energy system is better able to manage the impacts of both major events, such as natural disasters or cyberattacks, and more minor events, such as cold snaps that can disrupt supply lines and cause price spikes.

Note: Real 2022 USD
Source: Rystad Energy research and analysis

API Policy #3: Fix the National Environmental Policy Act (NEPA) permitting process

API policy	Detailed description
3 Fix the NEPA permitting process	The Biden administration should revise the National Environmental Policy Act (NEPA) process by establishing agency uniformity in reviews, limiting reviews to two years, and reducing bureaucratic burdens placed on project proponents in terms of size and scope of application submissions.

Background

The NEPA process can affect most forms of energy infrastructure

- The National Environmental Policy Act requires federal agencies to determine if their actions will have significant environmental effects. This is mainly accomplished by Environmental Impact Statements (EIS).
- Nearly all aspect forms of energy infrastructure are affected by NEPA, including pipelines, LNG terminals, refineries and wind farms. Oil and gas lease sales are also affected by NEPA. A NEPA review is required for any project that requires a federal permit or receives federal funding.
- The Council on Environmental Quality (CEQ), an organization within the Executive Office of the President, oversees NEPA implementation by issuing guidance and interpreting regulations.

Source: Rystad Energy research and analysis

The average EIS takes 4.5 years and exceeds 600 pages; EIS vary widely in complexity

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Council on Environmental Quality findings on EIS timelines and lengths

The average EIS takes 4.5 years	Final EIS average 661 pages, far exceeding CEQ recommendations	EIS vary widely in complexity and other factors that influence length and timing
• The average EIS process takes 4.5 years, from notice of intent to record of decision; the median EIS takes 3.5 years. • 25% of EIS processes took over 6 years.	• Average final EIS length is 661 pages, with median length of 447 pages; final EIS appendices average 1042 page. • 25% of final EIS exceed 748 pages. • CEQ's NEPA regulations contain recommended page limits for the text of final EISs of normally less than 150 pages, or less than 300 pages for proposals of "unusual scope or complexity".	• Even within an agency, EISs may vary widely in technical complexity and other factors that influence the length and timing of the document. • EIS processes for large infrastructure projects vary considerably from those associated with rulemakings or land management planning processes that are largely within the control of the lead agency.

- The Council on Environmental Quality (CEQ) analyzed all NEPA reviews from 2010-2018 to assess typical review duration, typical EIS length and the degree of variation in processes across agencies.
- The CEQ found that the average EIS process takes 6 years; the average Final EIS significantly exceeds the CEQ's recommended page limit; and that EIS processes vary wildly in complexity.

Source: CEQ Report on Environmental Impact Statement Timelines (2010-2018); CEQ Report on Length of Environmental Impact Statements; June 2020

A 2017 study found that $157 billion USD in energy investment was waiting in the NEPA pipeline, and that a 2-year NEPA deadline could spur $67 billion USD in energy investment

Study	Key findings
Regulatory Burdens and the Supply of Infrastructure Projects American Action Forum (2017)	• In 2017, 32 energy projects with a total estimated cost of $157 billion USD were still waiting for a decision. • There could be 24 additional energy projects costing around $48.2 billion USD ready for investment if there were a 3.7-year deadline on NEPA reviews, according to the study. • Using a more-strict 2-year deadline, there would be 32 additional energy projects costing around $67.1 billion USD ready for investment. • In 2015, the RAPID Act was proposed, which would have imposed a 2-year deadline on the NEPA process with the aim of boosting investment. The RAPID Act was not passed.

Source: American Action Forum: Regulatory Burdens and the Supply of Infrastructure Projects

API Policy #4: Accelerate LNG exports and approve pending LNG applications

API policy	Detailed description
4 Accelerate LNG Exports and Approve Pending LNG Applications	Congress should amend the Natural Gas Act to streamline the Department of Energy (DOE) to a single approval process for all U.S. liquefied natural gas (LNG) projects. DOE should approve pending LNG applications to enable the U.S. to deliver reliable energy to our allies abroad.

Background

- Several LNG terminals have faced significant delays in their exports towards non free trade agreement (nFTA) countries due to long approval times for their export applications.
- Most of US's LNG importing countries having: an nFTA, extended approval times to export gas can hurt US LNG production, as well a negatively impact foreign trade and their respective energy systems, particularly in the current geopolitical environment.
- Given that most nFTA countries are close US allies, a fast-tracked approval process for LNG export applications would benefit international trade as well as bolster US production.
- According to the DOE, LNG exports can increase natural gas prices. Therefore, the DOE must regulate exports by issuing permits without modifications or delays, in order to maintain what is best for the public interest. For nFTA countries, the Natural Gas Act (NGA) will issue a rebuttable presumption *in favor* of applications to export natural gas to those countries. Opposed parties should then prove that the proposed exports are not within public interest. However, the DOE cannot act on those application unless the National Environmental Policy Act (NEPA) has completed its review.

Source: Rystad Energy research and analysis

The Natural Gas Act requires permits for exporting natural gas

Background on LNG export permits

Policy background	Detailed policy
The NGA requires permits for export of natural gas	In accordance with section 3 of the Natural Gas Act (NGA), the DOE is responsible for issuing permits for exports of natural gas, including LNG, to foreign countries. Exports have to be in accordance with the public interest in order to be authorized.
To receive a permit, exports must be in public interest	In regard to LNG exports to FTA countries, these exports "shall be deemed to be consistent with the public interest, and applications for such importation or exportation shall be granted without modification or delay."
The NGA deems FTA exports to be in public interest and requires permit issuance "without delay"	For nFTA countries, the DOE grants permits unless an opposing party proves that exports are not in the public interest. The DOE assumes that nFTA exports are in the public interest unless proven otherwise.
nFTA permits presumed in public interest unless proven otherwise, but nFTA permits face an extended timeline	Issuance of nFTA permits takes longer because applicants must wait for NEPA to review the request and allow for public comments arguing that permits are not in public interest [1]. This process delays nFTA permits. So far, no permit application has been rejected and deemed not in public interest. [2]

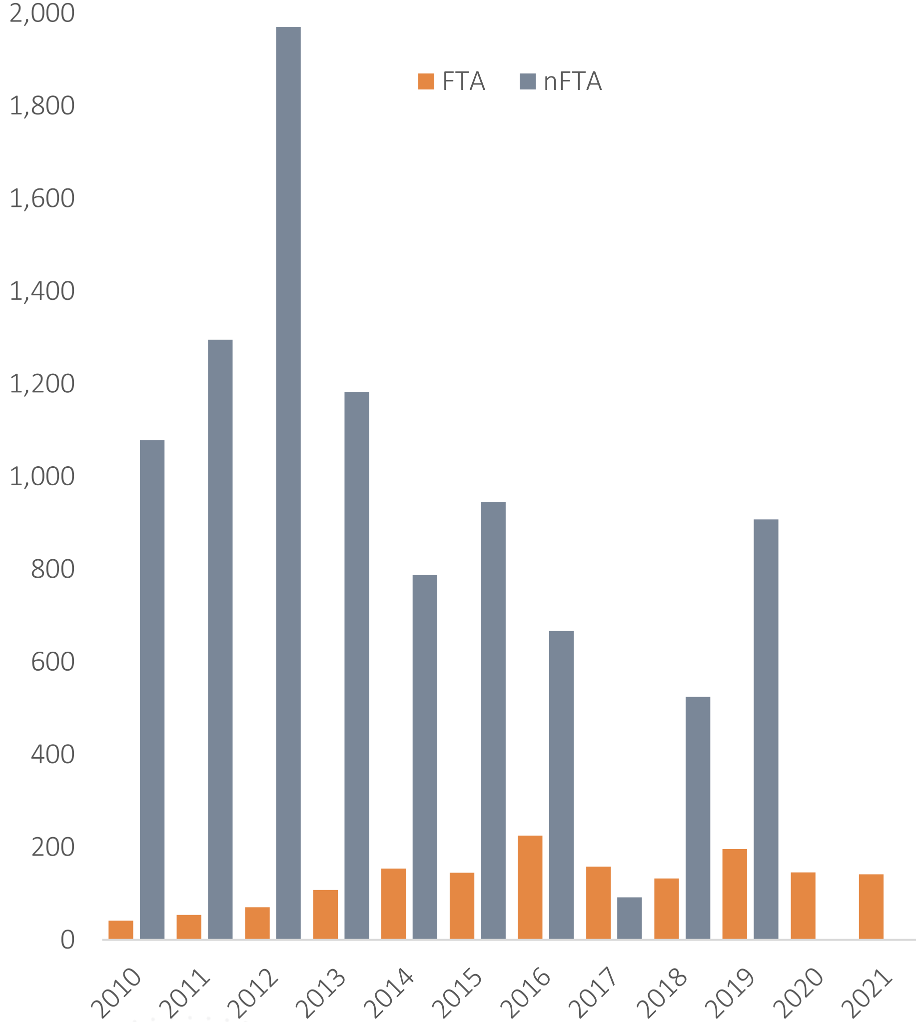
While no nFTA permits have been rejected, nFTA permits are subject to an extended process due to a required NEPA review. Afterwards, and unless deemed outside the public interest by an opposing party, the DOE should approve the permit as long as it complies with NEPA.

1: Code of Federal Regulations - The Public Health and Welfare (Title 42)
2: Department of Energy
Source: Rystad Energy research and analysis

nFTA permits take 5-to-25 times longer than FTA permits, and 22 bcf/d of non-FTA export applications are currently awaiting approval

Average number of days to approve LNG export application

Average number of days to approval, by application type and submission year



Pending LNG export applications

As of September 23, 2022 (excludes small-scale applications)

Company	Quantity pending (bcf/d)	Application status: FTA	Application status: Non-FTA
Venture Global CP2 LNG	4.0	✅	⌛
MPEH	3.2	✅	⌛
Port Arthur LNG Phase II	1.9	✅	⌛
G2 Net-Zero LNG	1.8	✅	⌛
Eos LNG	1.6	✅	⌛
Barca LNG	1.6	✅	⌛
SCT&E LNG	1.6	✅	⌛
Commonwealth LNG	1.2	✅	⌛
CE FLNG	1.1	✅	⌛
SeaOne Gulfport	1.0	⊗	⌛
Fourchon LNG	0.7	✅	⌛
Sempra Vista Pacifico	0.5	⌛	⌛
Venture Global Plaquemines LNG[1]	0.5	✅	⌛
New Fortress Energy Louisiana FLNG	0.4	✅	⌛
Freeport LNG[1]	0.2	✅	⌛
Venture Global Calcasieu Pass[1]	0.1	✅	⌛
		14 approved	1 approved

Total of 17 permits pending amounting ***24 bcf/d***

✅ Approved

⌛ Under review or pending approval

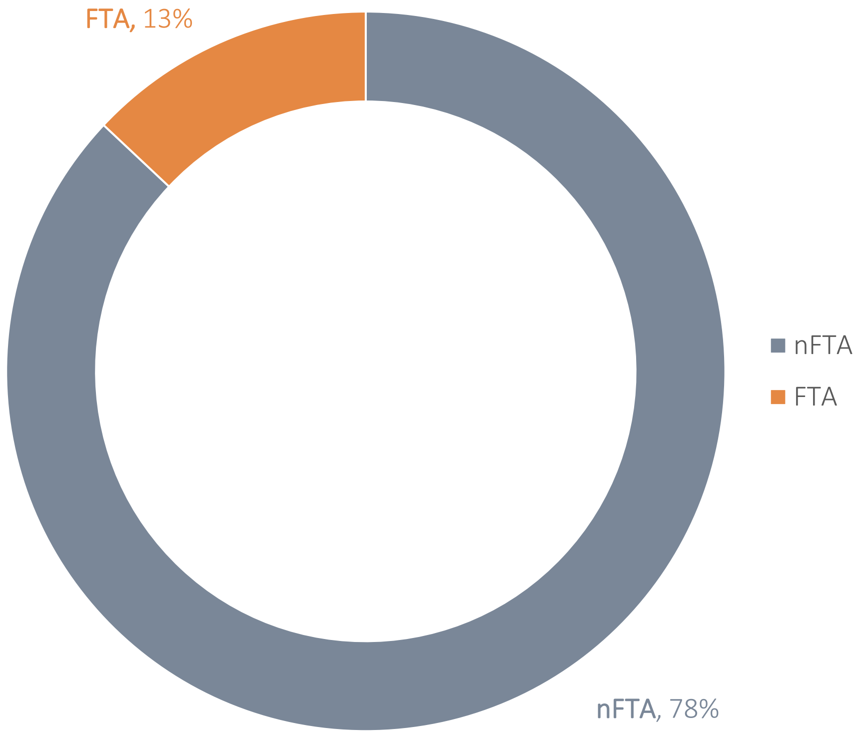
⊗ N/A

1: Design increase permits

Source: Department of Energy, ECA LNG; Rystad Energy research and analysis

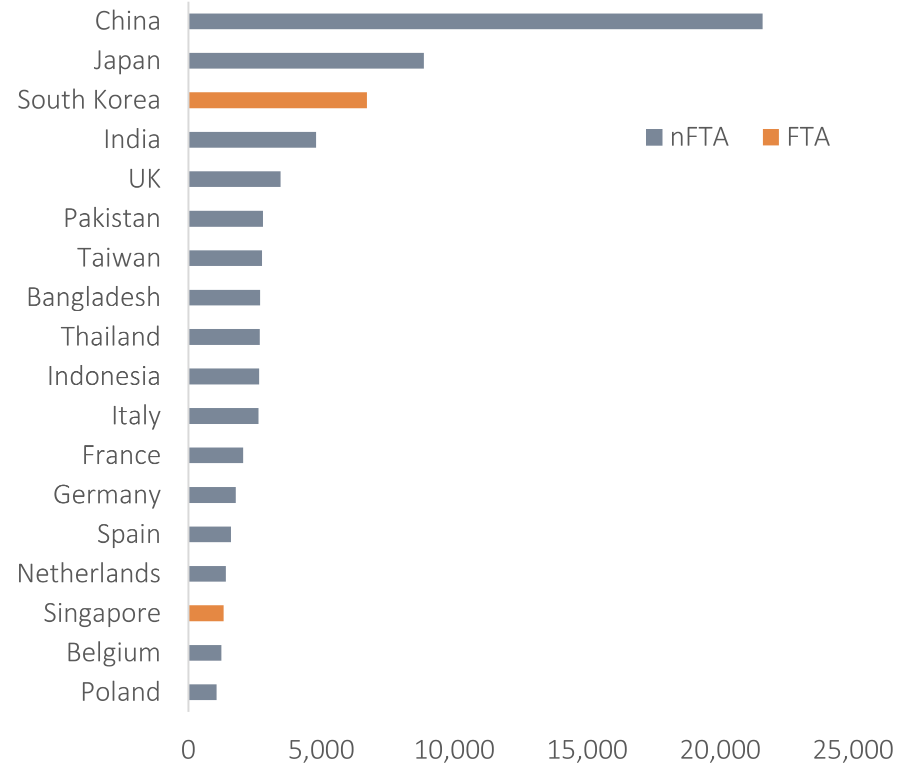
nFTA countries account for 87% of 2030 LNG demand; nFTA countries include US allies such as UK, Germany and Japan

2030 LNG demand by country trade status



Top 18 countries by LNG demand and trade status

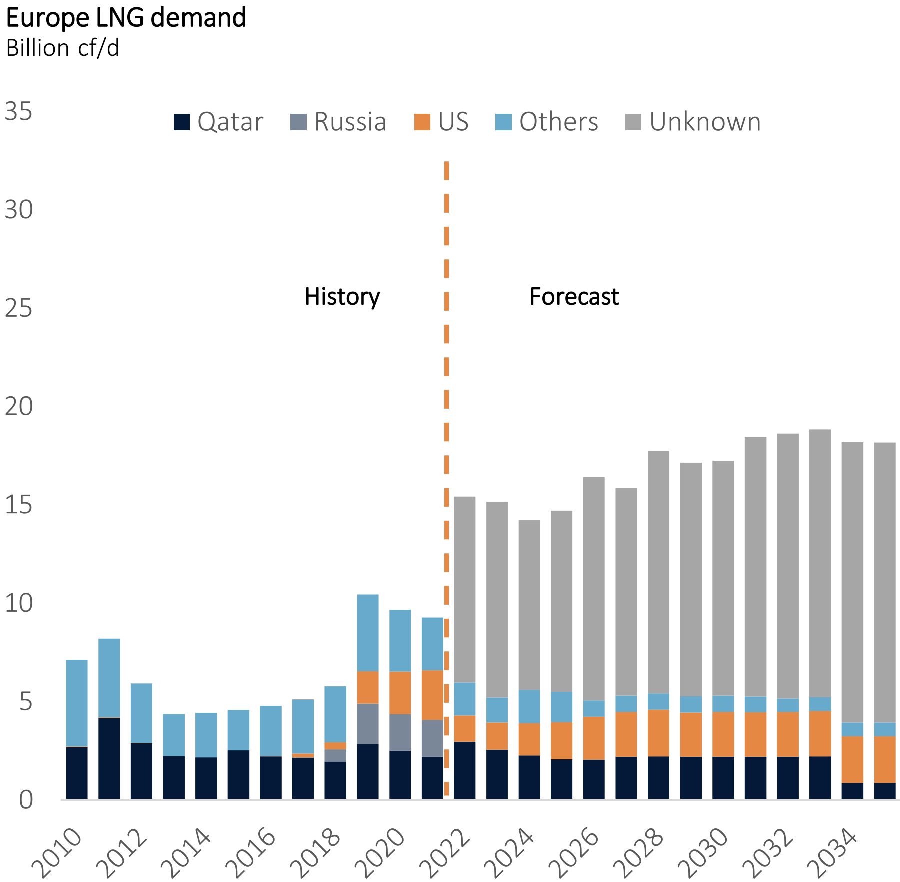
Billion cf/d

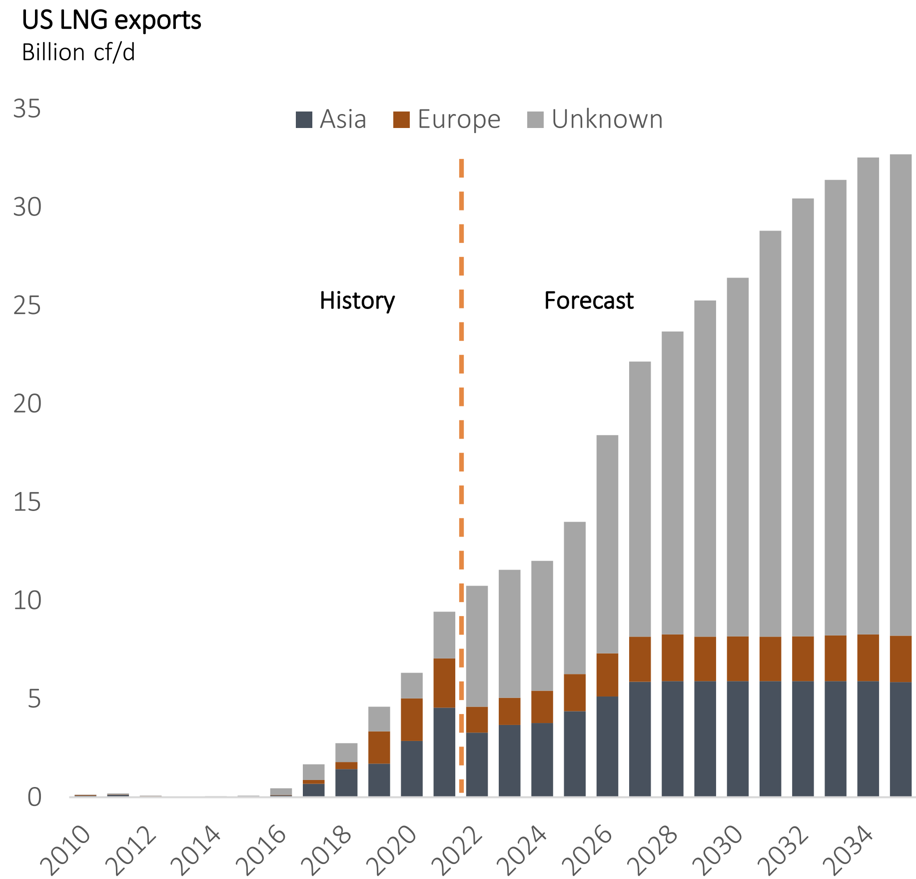


Non-FTA countries account for the majority of LNG demand, and close US allies such as the UK, Germany and Japan are among the list of non-FTA countries.

Source: Rystad Energy research of analysis

Europe LNG demand will reach 19 bcf/d – US LNG exports must grow to help meet European demand





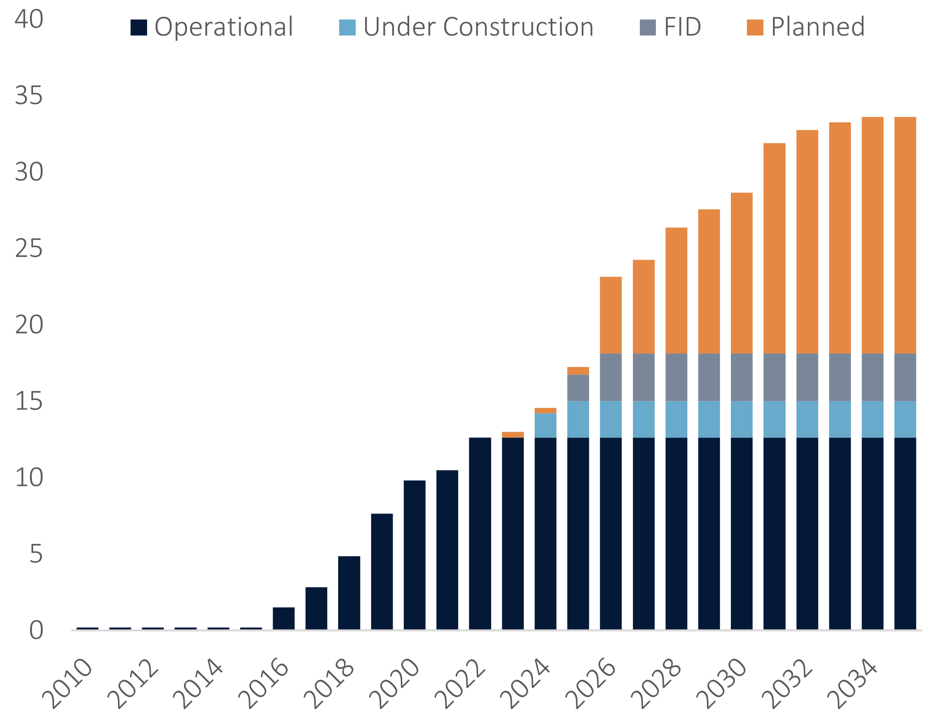
- LNG is becoming increasingly important to Europe's energy mix following Russian gas supply disruptions. We forecast that Europe will require up to 19 bcf/d of gas in coming years.
- "Unknown" LNG demand and export origins/destinations above represent demand or exports that aren't associated with long-term contracts.
- US export growth is needed to help meet Europe's growing LNG demand.

Source: Rystad Energy GasMarketCube

Most planned capacity has received export permits, but nFTA permits could be rescinded

Forecast of US liquefaction capacity

Billion cubic feet a day of LNG



Forecast of 2023-2035 LNG projects and permitting status[1]

	Project	Capacity (bcf/d)	Application status: FTA	Application status: nFTA
UC	Golden Pass LNG, T1-T3	2.4	Approved	Approved
FID	Plaquemines Phase 1[2]	1.8	Approved	Approved
FID	Corpus Christi LNG,T1-T9	1.4	Approved	Approved
Planned	CP2 Phase 1 & 2 LNG	2.8	Approved	Pending approval or under review
Planned	Driftwood Plant T1 & T2	2.2	Approved	Approved
Planned	Rio Grande LNG, T1-T3	1.8	Approved	Approved
Planned	Port Arthur LNG, T1 & T2	1.8	Approved	Approved
Planned	Delfin LNG, T1-T4	1.7	Approved	Approved
Planned	Plaquemines Phase 2[2]	1.4	Approved	Approved
Planned	Lake Charles LNG, T1 & T2	1.3	Approved	Approved
Planned	Cameron LNG, T4	0.8	Approved	Approved
Planned	Freeport LNG, T4	0.7	Approved	Pending approval or under review
Planned	Texas LNG, T1 & T2	0.5	Approved	Approved
Planned	Fast LNG 1 & 2	0.4	Approved	Pending approval or under review
Planned	Jacksonville LNG, T1-T3	0.1	Approved	Approved

Approved
Pending approval or under review

The DOE has stated its authority under the Natural Gas Act to amend or rescind nFTA export permits. Though the DOE has never rescinded a long-term nFTA export permit over the objection of the authorization order, commenters have expressed concern over this possibility.[3]

The possibility of permits being rescinded leads to uncertainty for terminal investors, developers, and offtakers.

1: This list represents the projects that Rystad Energy forecasts to start up from 2023-2035
2: Received a 3.4 bcf/d permit with an additional 0.45 bcf/d pending approval for nFTA exports
3: https://www.federalregister.gov/d/2018-13427
UC = Under construction
Source: Rystad Energy GasMarketCube; DOE

API Policy #9: End permitting obstruction on natural gas projects

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API policy	Detailed description
9 End permitting obstruction on natural gas projects	The Federal Energy Regulatory Commission should cease efforts to overstep its permitting authority under the Natural Gas Act and should adhere to traditional considerations of public needs as well as focus on direct impacts arising from the construction and operation of natural gas projects.

Background

- The Federal Energy Regulatory Commission, or FERC, is an independent agency that regulates the interstate transmission of electricity, natural gas, and oil. FERC also reviews proposals to build liquefied natural gas (LNG) terminals and interstate natural gas pipelines as well as licensing hydropower projects.
- In February 2022, FERC issued two draft policy statements that some have argued overstep the agency's permitting authority: "Certification of New Interstate Natural Gas Facilities" and "Consideration of Greenhouse Gas Emissions in Natural Gas Infrastructure Project Reviews".
- These policies would affect, among other matters, how FERC considers the GHG impact of projects and how FERC considers evidence of project need. Under the proposed policies, FERC will require any project that may emit more than 100,000 metric tons of GHGs to prepare an EIS. Additionally, FERC would consider both direct an indirect (upstream and downstream) emissions.
- Commenters, including the API, have argued that the proposed policies would reduce investment, that the policy exceeds FERC's jurisdiction, and that changes to GHG analysis are unnecessary due to frameworks like the EPA's Greenhouse Gas Reporting Program (GHGRP).

Source: FERC, Rystad Energy research and analysis

Table of Contents

API Policy #6: Dismantle supply chain bottlenecks

API policy	Detailed description
6 Dismantle supply chain bottlenecks	President Biden should rescind steel tariffs that remain on imports from U.S. allies as steel is a critical component of energy production, transportation, and refining. The Biden administration should accelerate efforts to relieve port congestion so that equipment necessary for energy development can be delivered and installed.

Background

Steel tariffs

- On March 2018, President Trump imposed a 25% tariff on steel imports. The tariffs were imposed under Section 232 of the Free Trade Expansion Act on the basis of protecting national security, on the basis that the status-quo of imports threatened US steel production capacity[1].
- Various countries have received exemptions since the tariffs were first enacted. Other countries have received tariff-rate quotas, allowing a specified quantity of goods to be imported duty-free. Importers can request exclusions in certain circumstances, but companies and members of congress have raised concerns about the intensive and time-consuming process to request exemptions.
- Steel is a critical input for oil and gas drilling, pipelines, equipment and other infrastructure. We estimate that in the US $9.5 billion USD is spent on OCTG per year, and $4.8 billion USD is spent on steel for pipelines.

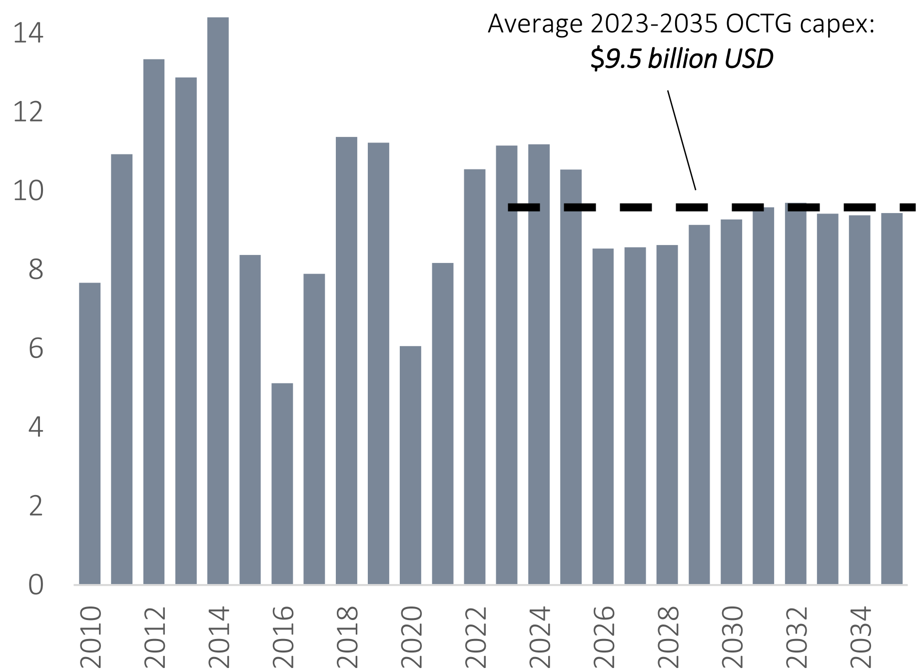
Port delays

- The Covid-19 Pandemic Lockdown caused a sharp decrease of demand and trade flow globally in 2020. The downturn led to decreased labor, supply chain backlog, and cargo constraints, as the global economy paused to adjust to the lockdown. As countries resumed consumption to pre-pandemic levels, the rapid economic contraction and expansion disrupted the global supply chain, leading to backlogs and bottlenecks at ports, delaying shipments of container goods.

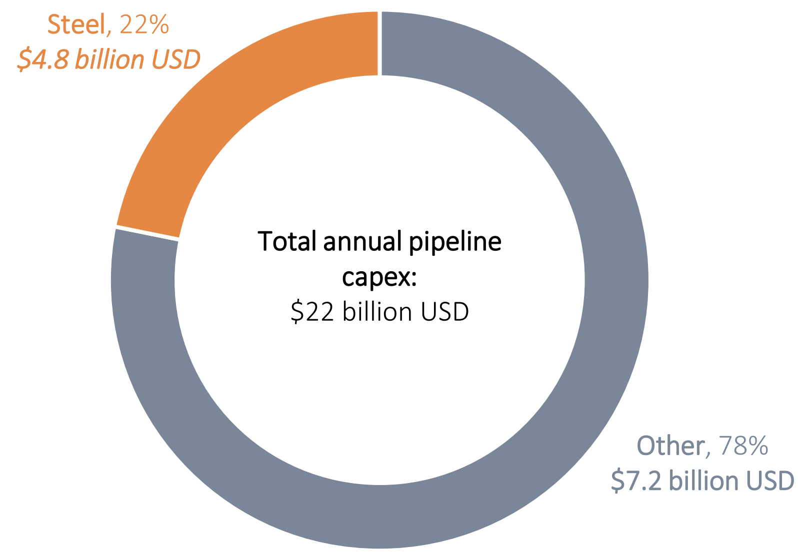
1: Proclamation 9705 of March 8, 2018
Source: Rystad Energy research and analysis

The US energy industry spends $9.5 billion USD on steel for drilling and 4.8 billion on steel for pipelines per year

US capex for OCTG (drill pipe, casing, tubing)
Billion USD



Typical annual US pipeline capex
Billion USD



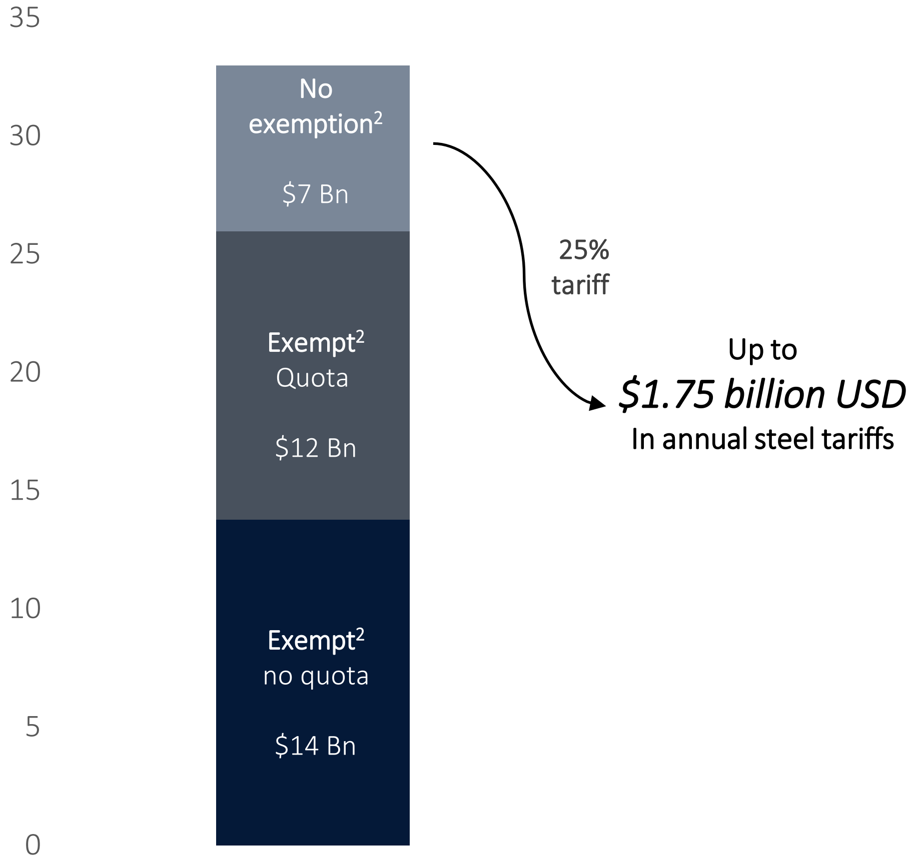
- OCTG, or "Oil Country Tubular Goods," refers to steel drill pipe, casing and tubing that is used in drilling and producing oil and gas.
- We forecast that US operators will spend an average **$9.5 billion USD per year** on OCTG from 2023-2035.
- Russia steel-pipe suppliers accounted for more than 20% of global OCTG supply in 2021 and a large portion of Russian exports went to the US. Lost supply from Russia has raised OCTG prices.

- US annual pipeline capex fluctuates but has historically averaged $22 billion USD per year.
- An estimated 22% of that total pipeline capex comes from steel imports, representing **$4.8 billion USD per year.**

Note: Real 2022 USD
Source: Rystad Energy ServiceDemandCube; "ICF, Domestic Content Requirements for Pipelines (2017)", "ICF, North America Midstream Infrastructure through 2035 (2018)".

Current tariffs affect $7 billion USD in annual steel imports, imposing up to $1.75 billion USD in tariffs per year

US imports of steel[1], by country exemption status
Billion USD, 2021



<u>Impact of tariffs</u>

- In 2021, the US imported $33 billion USD in steel and steel products that are affected by Section 232 tariffs.
    - $7 billion USD of imports from countries with no exemptions.
    - $12 billion USD of imports from companies with tariff exemptions under Tariff Rate Quotas.
- Based on $7 billion USD in steel imports from non-exempt countries, and the 25% tariff rate, importers could be subject to ***up to $1.75 billion USD in annual steel tariffs***.

<u>Quota systems</u>

- Many countries have received Tarif Rate Quotas, which allow for a specified quantity of imports without tariffs. This limits the amount of steel that can be imported without Section 232 tariffs. We do not estimate the potential tariffs on imports beyond the quotas.

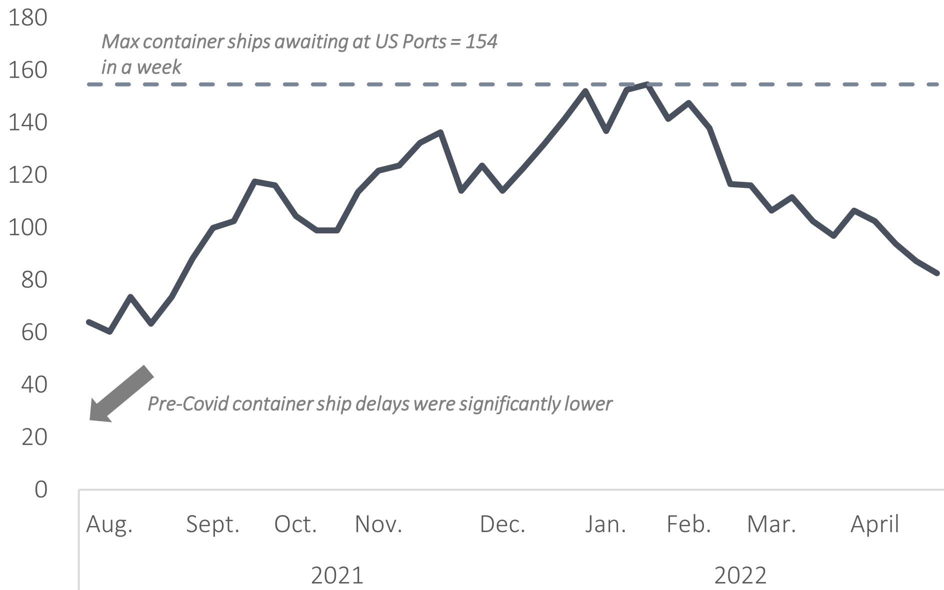
<u>Exclusion requests</u>

- Importers can request exclusions for items that are not "produced in the United States in a sufficient and reasonably available amount or of a satisfactory quality." The $1.75 billion USD tariff estimate does not account for any exclusions that may have been granted.
- Companies and members of congress have raised concerns about the intensive and time-consuming process to request exemptions. Some view the acceptance and denial of requests to be arbitrary. The exclusion process can cause project delays, increase costs, and introduce uncertainty for project stakeholders.

1: Imports for steel included under Section 232 steel tariffs; US Census Bureau
2: Exemption status based on country of origin, not accounting for product exclusion requests
Source: US Census Bureau; CRS Section 232 Investigations, Overview and Issues for Congress (2022); Rystad Energy Research and analysis

Major US ports have experienced unprecedented backlogs and congestion

Total containers at berth awaiting at US Ports
Count of Container ships



Industry Quotes on current port backlog and other supply chain constraints

In late 2021 and early 2022, the number of container ships waiting for a dock at a U.S. port more than doubled, peaking at more than 150 in early February. Levels have declined since then, but are still higher than historical levels for many ports.

-- US Department of Transportation

"It's taking 10 lanes of freeway traffic and moving them into five when the cargo gets [to the Port of LA]. We're having difficulty absorbing all of that cargo into the American supply chain."

-- Port of LA, Executive Director, Gene Seroka

"We have an expansion project and another new project in West Texas but are stymied by rig availability, electrical submersible pump and other motor availabilities, driller availability, and casing and tubing availabilities. By the time we get our first well producing in our new project, we'll probably miss the higher oil prices."

--Exploration and production firm, June 2022 Dallas Fed survey

"We are experiencing significant delays in obtaining materials and services, and costs are substantially increasing. We will shortly be ceasing investment in any new operations owing to the combination of rising costs, supply-chain slowness and our view that a recession is coming that will drop oil and natural gas prices significantly."

--Exploration and production firm, June 2022 Dallas Fed survey

Cause and impact of port delays

Cause for delays	• COVID-19 Pandemic Lockdown led to the sharp decrease of demand and trade flow globally in 2020. In 2021 and 2022, countries started to return to pre-pandemic flows, leading to a sudden return of demand. However, supply across various industries, including oil and gas, have remained lower than pre-pandemic levels due to worker shortage, raw materials (due to backlog of supply chain), and cargo constraints. This rapid economic contraction and expansion disrupted the global supply chain, leading to backlogs and bottlenecks. • In 2021, inbound cargo ships faced significant wait times at ports due to employee shortages in transportation sector and a backlog of inland heavy transport systems, among other factors.
Impact on/significance to the oil and gas industry	• Container ships wait times at US ports doubled between 2021 and 2022. • Port congestion can lead to delivery delays for essential equipment used in oil and gas developments. Steel is a critical input for the upstream and midstream investment that could be supported by other API "10 in 2022" policies.

Source: Rystad Energy research and analysis; MARAD Office of Policy and Plans; US DOT; Port of LA;

Table of Contents

API Policy #7: Advance lower carbon energy tax provisions

RystadEnergy

API policy	Detailed description
7 Advance lower carbon energy tax provisions	Congress should expand and extend Section 45Q tax credits for carbon capture, utilization, and storage development and create a new tax credit for hydrogen produced from all sources.

Background	Reference Case	Policy Case
The Inflation Reduction Act of 2022 both introduced and renewed tax credits for hydrogen and Carbon Capture, Utilization, and Sequestration (CCUS). Hydrogen: The IRA introduced a ***new production tax credit (PTC) under Section 45V*** for clean hydrogen that is produced in the US. This tax credit came at a time when clean hydrogen has gained traction in both public and private sectors due to its fungible application in the heavy transport, industrial, and power industries. CCUS: The IRA ***renewed and enhanced the 45Q tax credit for CCUS***, allowing for widened eligibility for operators and industries to receive nontaxable credits. This could lead to an uptake in CCUS projects and reducing emissions, while creating thousands of new jobs.	• Hydrogen: The reference case presents the forecast of a scenario of where *no tax credits* nor funding for hydrogen-related energy infrastructure or developments. • CCUS: Continuation of the pre-IRA 45Q tax credits. • This scenario serves as a point of comparison for the Policy Case, assuming that the Inflation Reduction Act was not passed or is not implemented. It is not the Rystad Energy base case.	• Hydrogen: New clean hydrogen PTC is implemented based on Section 45V of the Inflation Reduction Act. Producers receive up to $3.00 per kg of clean hydrogen. • CCUS: Enhanced Section 45Q credits are implemented based on the Inflation Reduction Act. CCS Project can receive up to $85 per ton stored and $60 per ton used for Enhanced Oil Recovery (EOR). Direct Air Capture (DAC) projects can receive up to $180 per ton stored and $130 per ton used for EOR.

Source: Rystad Energy research and analysis

Hydrogen: The IRA introduced a hydrogen Production Tax Credit (PTC), incentivizing investment in clean hydrogen

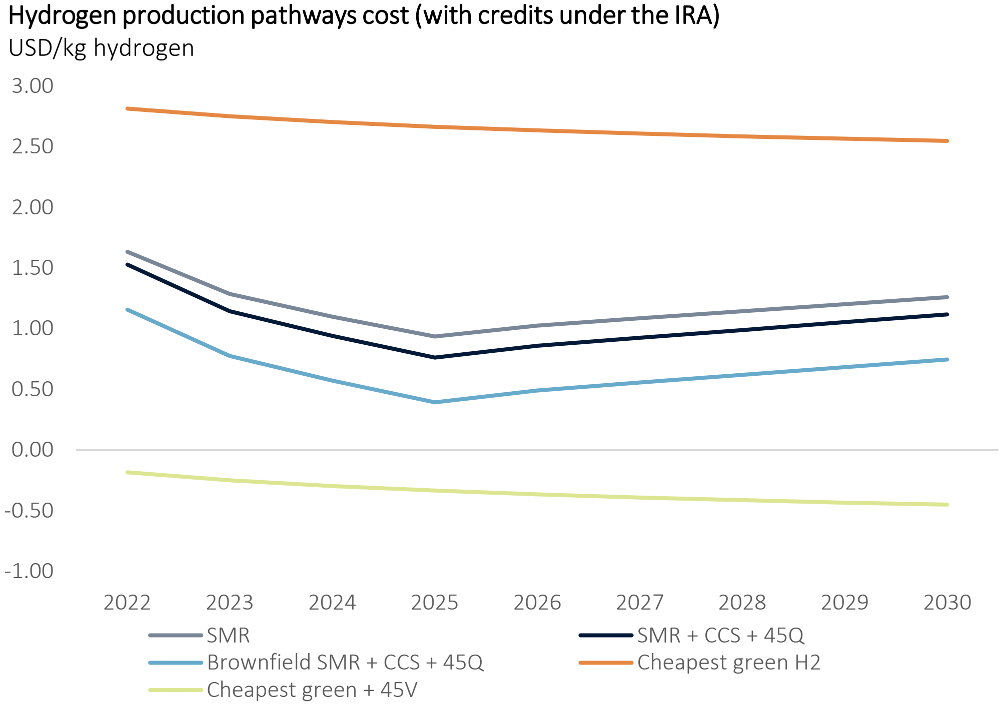
Internal Revenue Code, Section 45V: Credit for Production of Clean Hydrogen

Key Takeaways

The law	• The IRA of 2022 enacted and amended the Internal Revenue Code (IRC) to include *Section 45V, which created a clean hydrogen production tax credit (PTC).* • The IRA also gives qualified clean hydrogen production facilities the option of opting the ITC (investment tax credit). Facilities cannot take advantage of both the PTC and ITC.
Relevant date	• *January 1, 2033*: Clean Hydrogen PTC is available to facilities that begins construction before this date. • *Applies for 10-years*, starting the date that the eligible facility starts service.
Tax Incentives	• Annual credit for PTC = *Total kg of clean hydrogen produced x $0.60 x scaling adjustment ("applicable percentage").* • If the facility meets wage and apprenticeship requirements, it would be eligible for a *5 times multiplier* to its credits. • With the 5 times multiplier, total possible benefit = PTC *of up to $3.00 per kg.*
Qualification/ eligibility	• Clean hydrogen is defined as a lifecycle emission of *less than 4kg per CO2 per kg of hydrogen produced.* • Must be produced in the United States, take part in the ordinary course of trade or business of the taxpayer, and emissions must be verified by a third party.
Stackability	• Clean hydrogen facilities that take on the Clean Hydrogen PTC *under Section 45V would NOT be allowed to stack their credits onto Section 45Q (CCUS) credits*.
Impact	• Decrease cost of clean hydrogen production. Green hydrogen will benefit significantly. • Increase of potential investment for clean hydrogen.

Source: Rystad Energy research and analysis; Inflation Reduction Act of 2022; IFC International

Hydrogen: IRA's scaling adjustment gives green hydrogen highest eligibility for 45V credits



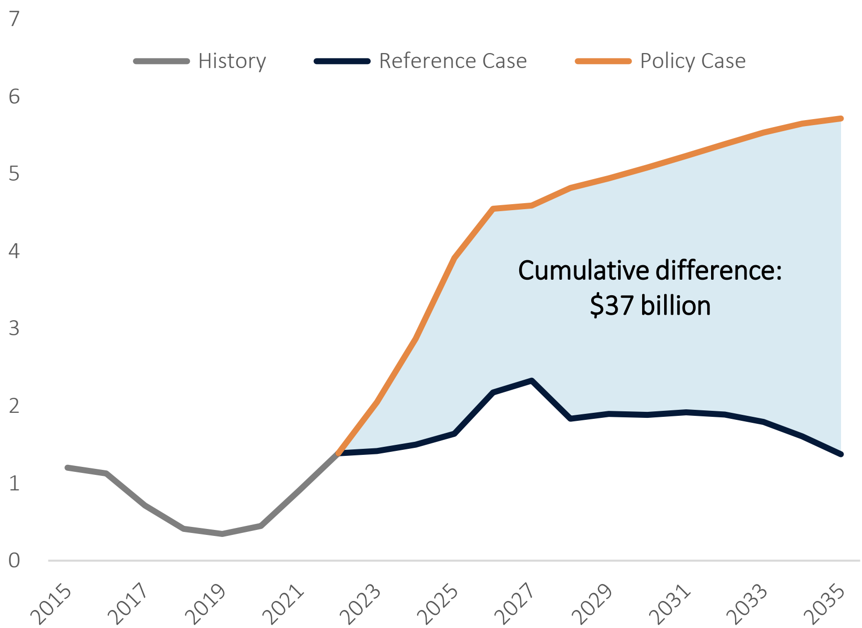
Production credits for qualified clean hydrogen [1,2]		
Life Cycle Emission, kg per CO2 equivalent per kg of hydrogen	Applicable credit percentage	Maximum credit
2.5-4 kg of CO2	20%	$0.60/kg
1.5-2.5 kg of CO2	25%	$0.75/kg
0.45-1.5 kg of CO2	33.4%	$1.00/kg
< 0.45 kg of CO2	100%	$3.00/kg

Carbon intensity of hydrogen [2]	
Hydrogen Color	Likely eligibility
Grey	*Will not qualify* for clean hydrogen credits.
Blue	Most blue hydrogen projects *will not qualify* for clean hydrogen credits, though the lowest intensity projects could qualify for 20% of the maximum credit. Those that could qualify are likely to opt for 45Q CCS credits, however.
Green	Most projects will qualify for *33.4% or 100%* of the maximum credit.

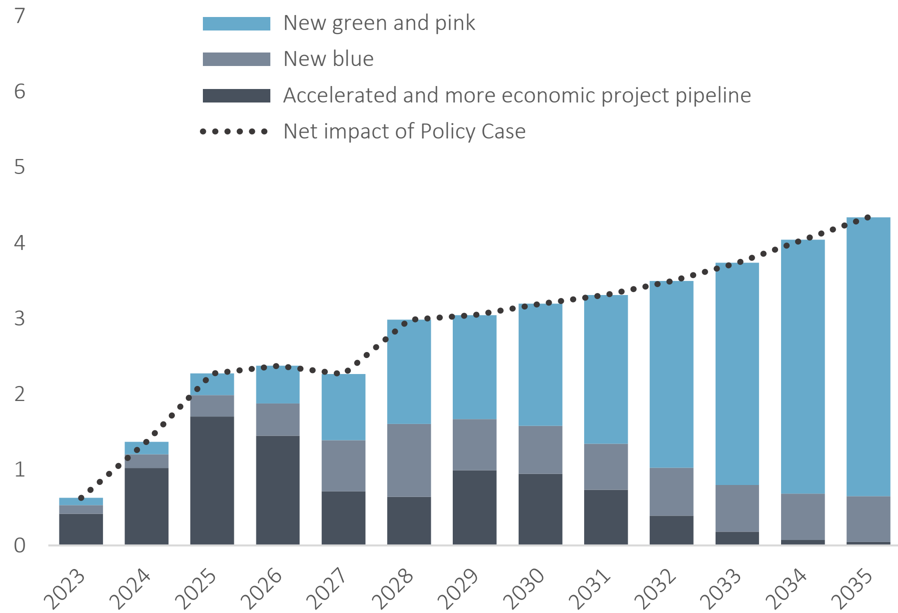
1: Maximum credit assumes that the hydrogen project qualities for 5x multiplier based on wage and apprenticeship requirements
2: A forthcoming ICF study found that, in general, hydrogen production incentives provided uniformly (per ton of greenhouse gas emissions reduced relative to grey hydrogen) result in larger, less costly emissions reductions
3: Each hydrogen type will have varying degrees of carbon intensity, depending on feedstock (i.e. coal, natural gas, renewable) and materials used to construct facilities
Source: Rystad Energy research and analysis; Rystad Energy IRA White Paper; US Senate; IEA

Hydrogen: The Policy Case brings an additional ca. $40 billion of investment capex

Net impact of Policy Case on hydrogen capex
Billion USD (2022 real)



Decomposition of Policy Case impact on hydrogen capex
Billion USD (2022 real)



Policy Case impact on hydrogen spend	*$37 billion* of additonal capex by 2035 compared to pre-IRA. $12 billion USD of this capex will go toward blue hydrogen, while $25 billion USD will go toward green hydrogen. *~30 mtpa* of incremental new hydrogen production capacity by 2035. - In the short term, there will be a balance of blue and green hydrogen developments. The long-term outlook sees greater developments and increase towards green hydrogen, due in part to higher credit value. Green ammonia will see export potential by early 2030s. - The forecast assumes continued technology improvement and cost reductions spurred by increased investment and development.
Reference case outlook	Without the enhanced support from the Inflation Reduction Act, fewer projects are announced, and fewer projects receive FID. Additionally, technology improvements are slower and hydrogen demand growth is stunted.

Note: Capex for blue hydrogen projects exclude carbon capture, transport and storage capex—this capex is included in CCUS capex in later analysis.
Source: Rystad Energy research and analysis

CCUS: Increased credit tariffs and reduced eligibility thresholds will incentivize investment

Section 45Q bonus credit tariffs
USD per tonnes

Type of capture	Captured CO_2 use	Reference Case	Policy Case
DAC[1]	Storage	50	180
	EOR	30	130
CCS[1]	Storage	50	85
	EOR	30	60

Capture threshold per credit-eligible facility
Thousand tonnes of CO_2

Type of facility	Reference Case	Policy Case
Power generation	500	18.75
Industrial	100	12.5
DAC	100	1

1: Bonus tariffs receivable when wages and apprenticeship requirements are met (non-existent in pre IRA scenario)
Source: Rystad Energy research and analysis

The Policy Case increased 45Q credits across the board:

- Policy case credits are up to 3x higher depending on the CO_2 capture methods used.
- Credits are distributed for 12-years after the start of operations.

Facilities face lower capture thresholds for credit eligibility:

- Minimum quotas decreased by up to a 100-fold depending on the type of facility.

To receive bonus credits, facilities must meet the following wage and apprenticeship requirements:

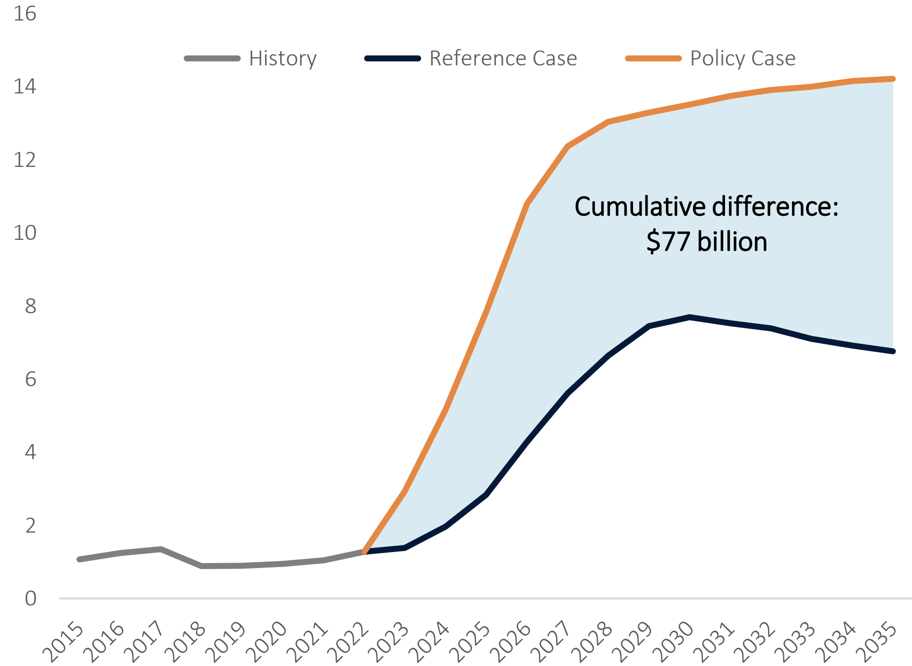
- Wages for laborer's, mechanics, contractors and subcontractors must be at prevailing rates (determined by the Secretary of Labor) during construction and for the 10 years following the start of operations.
- Construction, alteration or repair work prior to the project's start should be performed for a certain percentage (determined by the Department of Labor) by qualified apprentices. That is 10% before 2023, 15% after 2024 and 12.5% in between.

In some cases, developers are eligible for direct-cash payments:

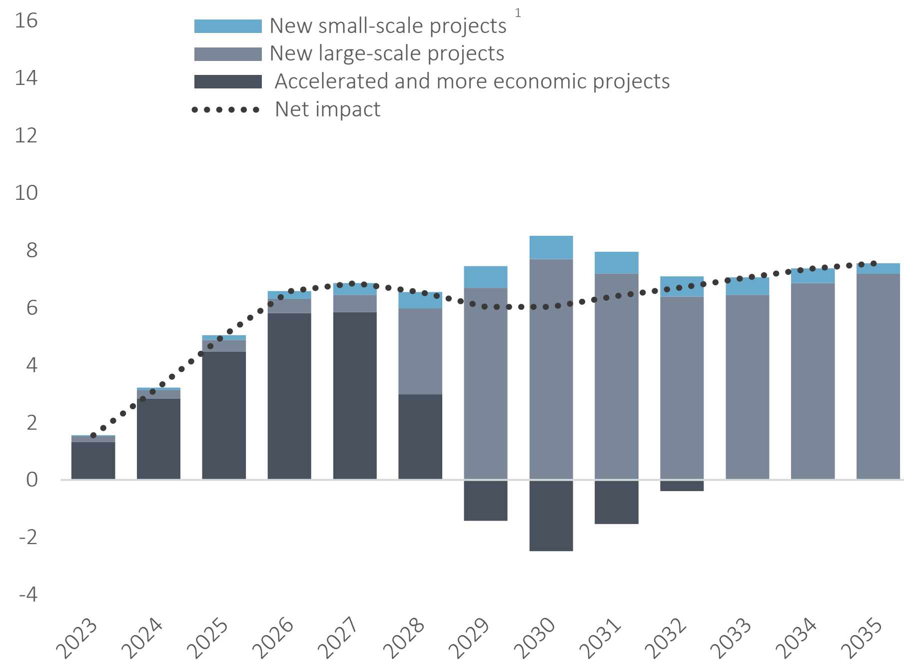
- For-profit entities can receive non-taxable direct payments for five years after operations start.
- Non-profit entities (states, municipalities or Tribes) and other cooperatives can receive non-taxable payments for the entire 12 years.

CCUS: The Policy Case significantly boosts CCUS capex by cumulative ca. $80 billion

Net impact of Policy Case on CCUS capex
Billion USD (2022 real)



Decomposition of Policy Case impact on CCUS capex
Billion USD (2022 real)



Policy Impact on CCUS spend	• *$77 billion* of additional, cumulative investment capex by 2035. This leads to approximately 250 mtpa of additional CCUS capacity. • Expected increased growth rate between 2023-2025 as increased 45Q credits accelerate final investment decisions (FIDs) for the current pipeline of projects and leads to the FID of projects that otherwise would not be economic. • CCUS capex forecasts consider the full array of project capex, including capture, transport, and storage. CCUS investment for blue hydrogen projects are also included. • The forecast assumes continued technology improvement and cost reductions spurred by increased investment and development.
Reference case outlook	• The most economic CCUS projects would have still continued with the previous 45Q, but fewer projects will reach fruition. • Learning curve would allow for a $6 to 8 billion market size by the 2030s. Investment slows slightly as the lowest-cost emissions sources are captured. • High capture thresholds would limit small-scale CCUS activity, as it would be both uneconomic and would not help producers achieve 45Q eligibility.

1: "Small-scale" refers to projects that previously did not qualify for 45Q due to size but qualify under the reduced thresholds introduced by the IRA.
Source: Rystad Energy research and analysis

Impact of API Policy #7: Advance lower carbon energy tax provisions

RystadEnergy

API policy	Policy Impacts Policy Case versus Reference Case, 2023-2035	
	Investment	
	$37 billion in hydrogen *$77 billion in CCUS* *Total: $114 billion*	
	Other benefits and impact Policy Case versus Reference Case, 2023-2035	
	Incremental carbon capture capacity	Incremental clean hydrogen capacity
7 Advance Lower Carbon Energy Tax Provisions	*250 million tonnes per annum* *by 2035*	*30 million tonnes per annum* *by 2035*

Note: Billion USD (2022 real)

Source: Rystad Energy research and analysis

Table of Contents

API Policy #5: Unlock investment and access to capital

RystadEnergy

Policy	Detailed description
5 Unlock investment and access to capital	The Securities and Exchange Commission should reconsider its overly burdensome and ineffective climate disclosure proposal and the Biden administration should ensure open capital markets where access is based upon individual company merit free from artificial constraints based on government-preferred investment allocations.

Background

- In March 2022, The Security and Exchange Commission (SEC) proposed a climate disclosure plan that would require public companies to provide certain data and disclosure related to three categories material climate impacts, greenhouse gas (GHG) emissions, and GHG targets and transition plans.
- The proposal has received over 10,000 comments during the proposal's comment period – far more than usual. Advocates of the proposal argue it will provide investors more reliable climate risk information as a basis for investment decisions. Critics have raised concerns over the compliance costs and burden of reporting requirements, and some argue reporting requirements exceed SEC's authority.
- Given the intense public interest and significant comments and feedback received regarding the proposal, the SEC extended the public comment period until June 17, 2022. The SEC will now consider whether to issue further amendments and adopt the proposal.
- Capital is required to fund the investment supported by other API "10 in 2022" policies, such as critical energy infrastructure projects, CCUS and hydrogen.

Source: Rystad Energy research and analysis; The Enhancement and Standardization of Climate-Related Disclosures for Investors; Comments for The Enhancement and Standardization of Climate-Related Disclosures for Investors; ISS Insights: SEC Climate Disclosure Comments Reveal Diversity of Views

The SEC's climate disclosure proposal would require three major categories of disclosures

Key provisions of SEC climate disclosure proposal

Material climate impacts	• Companies must disclose the climate related risks (such as fire or floods) their activities could cause, where they would happen and what share of their assets would be involved. • Therefore, a clear risk management process to manage strategic, financial, and operational risks should be established.
GHG emission	• Audited Scope 1 and Scope 2 emissions should be reported. • Scope 3 emissions should be disclosed if they are material or if the company has established an emissions target or goal. Emissions should be reported as units of GHG per revenue, as well as what specific GHG is concerned.
Targets and transition plans	• Targets around emission reduction, energy usage or revenues from low-carbon products should be disclosed. • The company should also report its strategy to achieve those goals, as well as any usage of carbon offsets or renewable-energy credits. If an internal carbon pricing is established, it should also be disclosed and how it was established.

- The SEC's proposed climate disclosure rule would require public companies to provide certain data and disclosure related to three categories:
  - Material climate impact
  - GHG emissions
  - Targets and transition plans
- This rule would be a significant departure from the current guidance. For example, the new rule would mandate companies disclose all negative and positive impacts of climate related events for each financial statement line item if the impact exceeds 1% of the line item.
- The more detailed disclosure requirements will require greater time and resources for filing companies to produce.
- Challenges in estimating GHG emissions, especially Scope 3 emissions, could lead to confusion for investors.

Source: Rystad Energy research and analysis; Securities and Exchange Commission: "The Enhancement and Standardization of Climate-Related Disclosures for Investors"

Scope 3 reporting may be difficult and costly, and calculating Scope 3 could lead to inconsistencies

GHG emission reporting requirement under SEC proposal

- Scope 3 emissions should be disclosed if they are material or if an emissions target or goal has been established by the company, according to the SEC proposal.
- The SEC notes that Scope 3 emissions would be material "if there is a substantial likelihood that a reasonable investor would consider them important when making an investment or voting decision".

Challenges and implications of Scope 3 emissions reporting

- Collecting data or making calculations on Scope 3 emissions, which are generated as a result of third parties, may be difficult and costly.
- Part of Scope 3 emissions are derived from other companies' scope 1 and 2 emissions. Several issues and inconsistencies regarding reporting can arise from this:
    - In the private sector, emissions (for all scopes) do not have to be reported. This makes reporting for public companies. burdensome and might induce some to sell off their most emitting business to private companies.
    - The same applies for companies located outside the US, where reporting is not required.
- Where Scope 3 emissions are not reported by other parties these emissions must be calculated. While methodologies for Scope 3 emission calculations must be reported, differences and methodologies could lead to inconsistent reporting across companies and challenge comparisons by investors.

Definition of emission scopes	
Scope 1	Direct GHG emissions from operations that are owned or controlled by the reporting company.
Scope 2	Indirect GHG emissions generated by the purchase or acquisition of electricity, heat, cooling, or steam that is consumed by the reporting company.
Scope 3	All indirect GHG emissions that are not part of *scope 2,* but occur in the value chain of the company, including upstream and downstream activities.

Examples of scope 3 emissions

- Emissions from use of sold products, such as oil or gas
- Processing by a third party of a company's sold products
- Upstream transportation and distribution
- Downstream transportation and distribution
- Waste generated in operations
- Business travel
- Employee commuting

Source: Rystad Energy research and analysis; Securities and Exchange Commission: "The Enhancement and Standardization of Climate-Related Disclosures for Investors"

Table of Contents

RystadEnergy

API Policy #8: Protect competition in the use of refining technologies

Policy	Detailed description
8 Protect competition in the use of refining technologies	The Biden administration should ensure that future federal agency rulemakings continue to allow U.S. refineries to use the existing critical process technologies to produce the fuels needed for global energy markets.

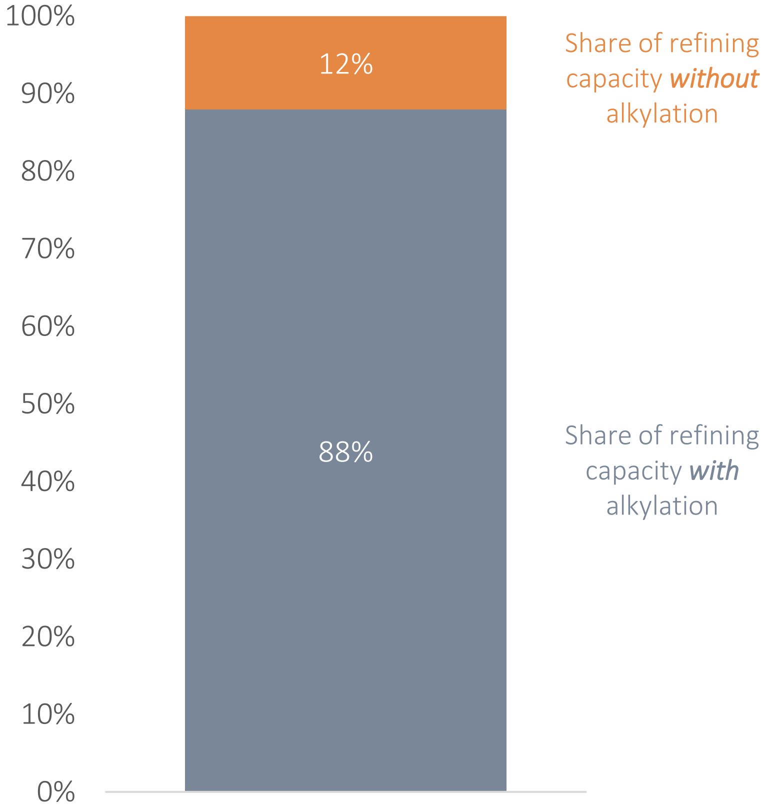
Background

- Alkylates play an important role in the production of clean-burning fuels. With a high-octane number and low sulfur content, alkylates are essential to refineries to comply with governmental fuel regulations. They are formed by reacting two light olefins together in an alkylation unit, using one of two possible catalysts, sulfuric or hydrofluoric acid (HF).
- Recently, the EPA has considered revising its Risk Management Plan (RMP) regulation, due to possible health risks associated with the use of HF. Regulators want refineries to shift towards sulfuric acid catalysts.
- Currently, 88% of refining capacity in the US is at refineries with alkylation units, with roughly 50% of them using HF as their catalyst. This represent a total of 650 thousand barrels per day of HF alkylation capacity.
- Replacing all US HF alkylation units with sulfuric acid units would cost an estimated $12-19 billion USD, averaging around $360 million USD per unit – a price tag similar to the transaction price of several recent refinery sales. The cost of replacing HF alkylation units could force some refineries to cease operations.

Source: Rystad Energy research and analysis

Alkylate is an important gasoline blendstock – 88% of US refining capacity is coupled with alkylation

Share of US refining capacity coupled with alkylation
Thousand barrels per day



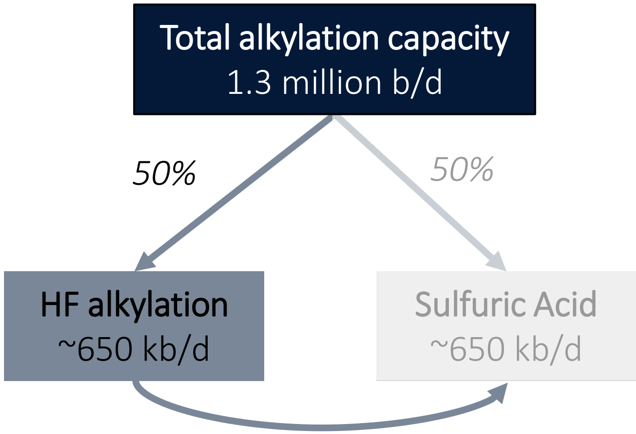
Refineries with alkylation capacity represent 88% of US refining capacity

- Total US refining capacity is 18.8 millions barrels per day split across 130 refineries (as of January 2022).
- 82 refineries, representing 88% of the overall capacity, have alkylation units. Around 50% of those alkylation units use hydrofluoric acid.[1] We therefore estimate that 44% of US overall refining capacity is coupled with HF alkylation.
- The total capacity of alkylation units at US refineries is 1.3 million barrels per day.
- Alkylate is an the best-suited gasoline blendstock due to high octane, low vapor pressure, lack of aromatic compounds, and lack of sulfur.
- Alkylate is important for refineries to meet gasoline specification, especially in California where gasoline specifications are more stringent. All alkylate specifications, such as RVP, sulfur and aromatics content, exceed gasoline specifications.

1: American Fuel & Petrochemical Manufacturers
Source: 2022 EIA refinery capacity report; Rystad Energy research and analysis

Replacing HF alkylation could cost $12-19 billion USD and would likely cause refinery closures

Total alkylate refining capacity
Thousand barrels per day



$12-19 billion USD
total replacement cost

Implied costs for US refineries

- Total US alkylation capacity amounts to 1.3 million barrels per day. Around 50% of those alkylation units, representing 650 thousand barrels per day of alkylation capacity, use hydrofluoric acid.[1]
- The estimated capex to replace hydrofluoric acid units with sulfuric acid units amounts to $17-30 million USD per thousand barrels per day of alkylation capacity, adding up to a **total replacement capex of $12-19 billion USD.**
    - Capex estimates are based on a California Energy Commission study and a recent alkylation unit investments by Valero at its St. Charles and Houston refineries.[2]
    - Other non-monetary factors can make it impractical to switch from HF to sulfuric acid operations. Sulfuric units require more space to accommodate its larger equipment; some refineries might not have the available space to accommodate a sulfuric acid catalyst.
- **No refinery has converted an HF unit to sulfuric acid**. In 2021 the Chevron Salt Lake City refinery converted an HF alkylation unit to an ionic liquid catalyst utilizing ISOALKY technology; it became the first commercial-scale application of ISOALKY technology.
- **Many refineries could be forced to shut down if faced with a $263-465 million USD alkylation unit replacement cost**, the estimated replacement cost for a typical unit. This rivals or exceeds recent transaction prices for US refineries, including Torrance at $538 million USD , Pasadena at $350 million USD, and Puget Sound at $350 million USD.
- Assuming 44% of US refining capacity is coupled with HF alkylation, **HF alkylation refineries currently support more than 447,000 jobs and contribute directly and indirectly over $119 billion USD to the US economy**.[3]

1: American Fuel & Petrochemical Manufacturers
2: California Energy Commission, Potential Transportation Fuel Supply and Price Impacts of HF Ban
3: Calculated by American Petroleum Institute using IMPLAN; real 2022 USD
Source: American Fuel and Petrochemical Manufacturers, 2017 California Energy Commission

Table of Contents

RystadEnergy

API Policy #10: Advance the energy workforce of the future

RystadEnergy

Policy	Detailed description
10 Advance the energy workforce of the future	Congress and the Biden administration should support the training and education of a diverse workforce through increased funding of work-based learning and advancement of STEM programs to nurture the skills necessary to construct and operate oil, natural gas and other energy infrastructure.

The oil and gas sector is a major employer

- At the end of 2019, the oil and gas industry directly supported over 2.5 million jobs and supported a total of over 11 million jobs throughout the economy, according to a study by PricewaterhouseCoopers. From truck drivers to pipeline welders to engineers, this multidisciplinary industry requires a broad set of skills.
- The oil and gas industry's activity is closely related to its employment. Without the proper labor force, further developments such as drilling new energy infrastructure projects or could be challenged. Education and training of a diverse workforce is required to ensure the long-term viability of the industry.

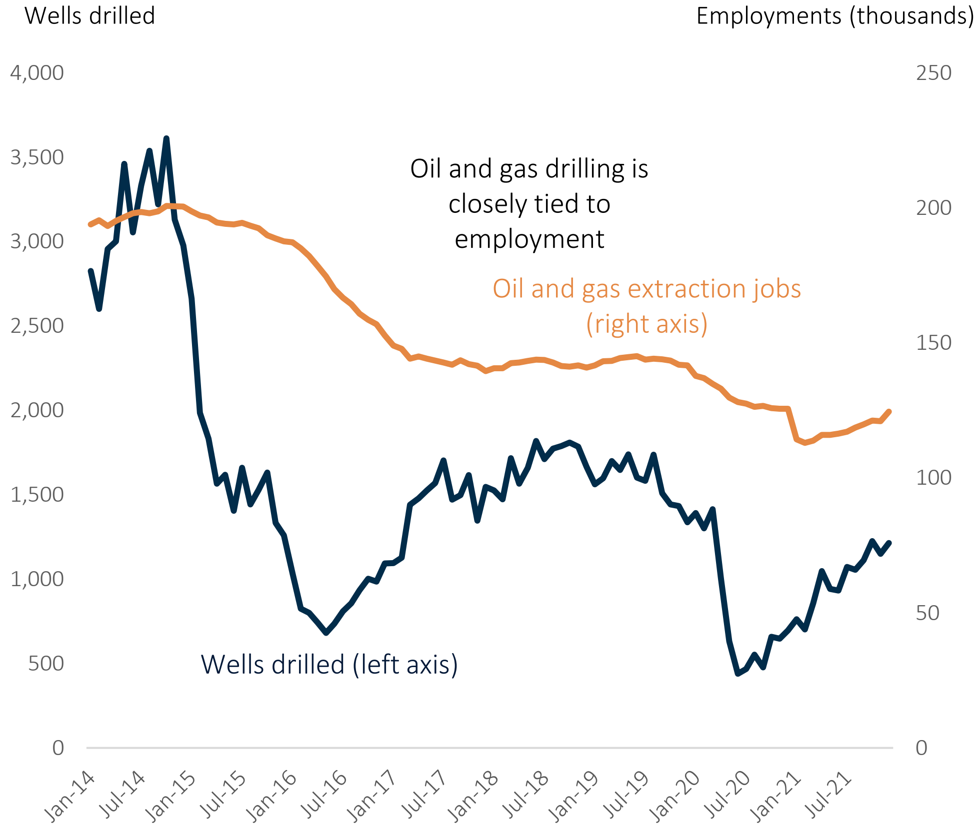
Skills training and STEM education is important to ensure a strong labor force

- With a high demand for welders, pipelayers and other field-based occupations, apprenticeship programs and postsecondary trainings for non-college degree holders can help ensure there are sufficient trained workers to meet labor needs.
- In addition to skilled craft jobs, the energy industry also depends on college-educated STEM degree holders including engineers and geologists. Efforts to support STEM education, including programs that support STEM education from a young age, can help train a new generation of energy workers.

Source: Rystad Energy research and analysis, "PWC, Impacts of Oil and Natural gas Industry on the US Economy in 2019"

Oil and gas supports over 11 million jobs; training and education is needed to support this workforce

Number of US wells drilled versus oil and gas extraction employment



Oil and gas is a multidisciplinary industry

- At the end of 2019, the oil and gas industry directly supported over 2.5 million jobs and supported a total of over 11 million jobs throughout the economy.[1]
- Highly skilled and skilled craft jobs represent a large portion of the employment opportunities. With a high demand for welders, pipelayers and other field-based occupations, apprenticeship programs and postsecondary trainings for non-college degree holders can help ensure there are sufficient trained workers to meet labor needs.
- In addition to skilled craft jobs, the energy industry also depends on college-educated STEM degree holders including engineers and geologists. Efforts to support STEM education, including programs that support STEM education from a young age, can help train a new generation of energy workers.

- The oil and gas industry accounts for over 5% of the American workforce. Employment is correlated to activity levels, and increasing drilling and production requires availability of skilled workers. A workforce shortage would negatively affect the energy industry and put a strain on the US economy.
- Supporting training for oil and gas across all educational levels can help to support a strong, sustainable industry.

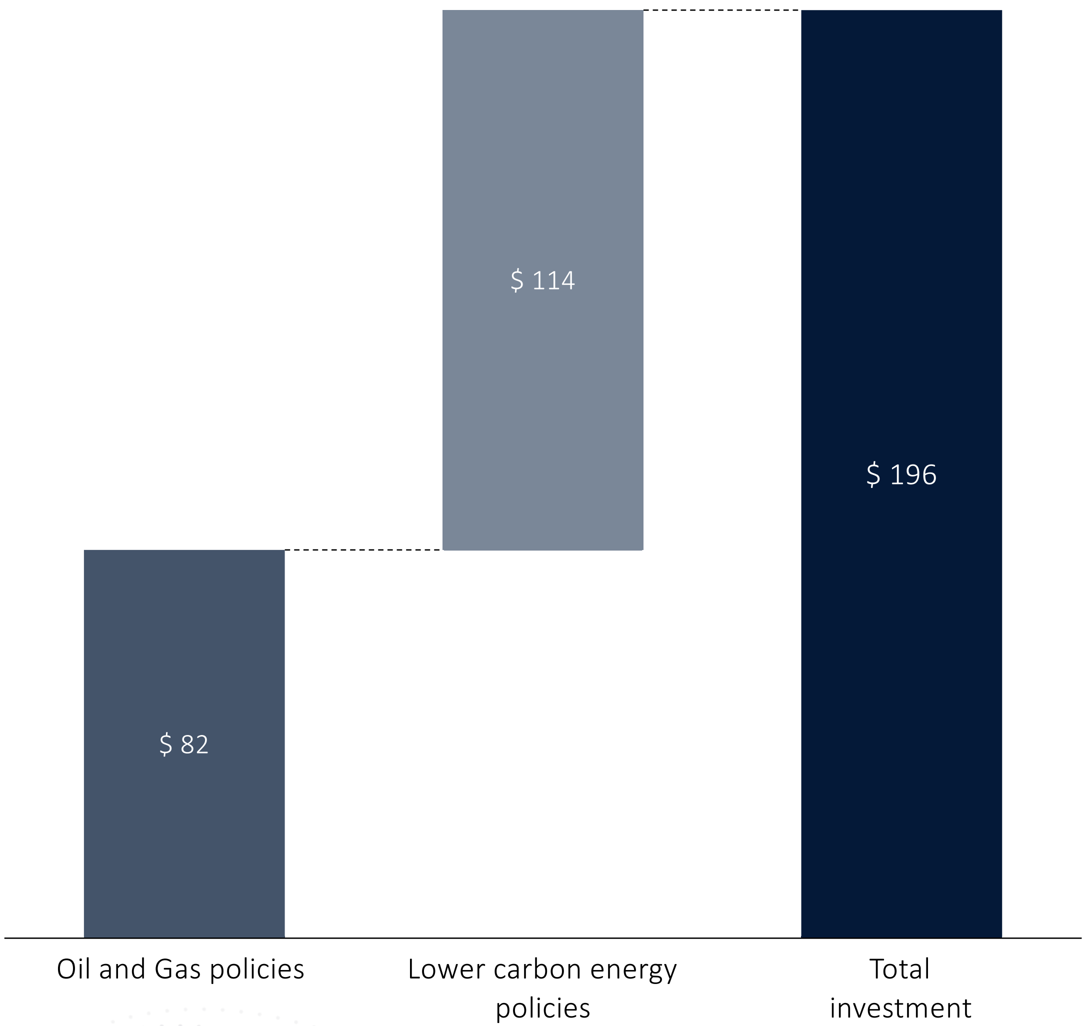
1: "PWC, Impacts of Oil and Natural gas Industry on the US Economy in 2019"
Source: Rystad Energy research and analysis, Bureau of Labor and Statistics;

Table of Contents

RystadEnergy

Rystad Energy estimates an incremental investment of nearly $200 billion under the“10 in 2022” policy plan – with 60 and 40 percent driven from lower carbon energy and oil & gas policies, respectively

Investment impact – Policy Case versus Reference Case
Billion USD (real 2022)



Source: Rystad Energy research and analysis

The $196 billion in direct investment brought by the Policy Case relative to the Reference Case stems from both oil and gas investment and investment in lower carbon energy.

Investment in both oil and gas and lower carbon energy polices directly and indirectly drive GDP and employment.

Oil & gas policies

- $82 billion USD in direct investment from oil and gas comes from both upstream and midstream investment. This investment is supported by the oil and gas-related policies. More specifically, investment is related to federal oil and gas leases, pipeline investment, and production that is enabled by increased pipeline capacity.

Low carbon energy policies

- $114 billion USD in direct investment for CCUS and Hydrogen stems from low carbon energy tax provisions. $77 billion USD of this comes from CCUS investment, including carbon capture, transport and storage. $37 billion USD of investment is related to hydrogen investments. The investment for CCUS related to blue hydrogen projects is captured as CCU investment.

Based on Rystad's investment estimates, the GDP and employment impact of API's "10 in 2022" plan in 2025 could be $17 Bn and 142k jobs, respectively, growing to $27 Bn and 226k jobs in 2035

Annual API "10 in 2022" policy plan impacts - Policy Case vs. Reference Case[1]

			Direct			Indirect and induced			Annual total		
	Metric	Unit[2]	2025	2030	2035	2025	2030	2035	2025	2030	2035
Oil & Gas policies	Investment	Billion USD	4.8	7.1	7.9	8.5	12.2	13.5	13.4	19.4	21.5
	GDP	Billion USD	2.4	3.7	4.1	4.5	6.6	7.3	7.0	10.2	11.4
	Employment	Thousand	22.4	29.5	31.9	40.1	58.0	64.2	62.6	87.5	96.2
	Wages and benefits	Billion USD	1.9	2.7	3.0	2.6	3.8	4.3	4.5	6.5	7.2
	Oil production	kb/d	7.0	83.0	127.0	-	-	-	7.0	83.0	127.0
	Gas production	bcf/d	4.6	4.7	4.8	-	-	-	4.6	4.7	4.8
Lower carbon energy policies	Investment	Billion USD	7.3	9.2	11.9	13.2	16.6	21.4	20.5	25.8	33.3
	GDP	Billion USD	3.1	3.9	5.0	6.8	8.5	11.0	9.8	12.4	16.0
	Employment	Thousand	22.2	28.5	37.1	56.8	71.7	92.6	79.0	100.2	129.7
	Wages and benefits	Billion USD	2.1	2.7	3.5	3.9	4.9	6.3	6.0	7.6	9.8
Total	Investment	Billion USD	12.2	16.4	19.8	21.7	28.8	35.0	33.8	45.2	54.8
	GDP	Billion USD	5.5	7.5	9.1	11.3	15.1	18.3	16.8	22.6	27.4
	Employment	Thousand	44.6	58.0	69.0	96.9	129.7	156.9	141.6	187.7	225.9
	Wages and benefits	Billion USD	4.0	5.4	6.5	6.5	8.7	10.6	10.5	14.1	17.0
	Oil production	kb/d	7.0	83.0	127.0	-	-	-	7.0	83.0	127.0
	Gas production	bcf/d	4.6	4.7	4.8	-	-	-	4.6	4.7	4.8

Economic effect definitions:

- **Direct:** The direct effects from Rystad Energy's estimated investment. Direct effects are applied to input/output multipliers to estimate the total effects.
- **Indirect:** The effect of business-to-business purchases in the supply chain taking place in the region that stem from the initial industry input purchases.
- **Induced:** The effect stemming from household spending of labor income, after removal of taxes, savings, and commuter income. The induced effects are generated by the spending of the employees within the business' supply chain.

1: GDP, employment, wages and benefits, and indirect and induced investment are provided by API using Rystad Energy's estimated direct investment under each scenario and the IMPLAN economic assessment software
2: Real 2022 dollars
Source: Rystad Energy research and analysis, American Petroleum Institute, IMPLAN

The API's "10 in 2022" policies would spur nearly $200 billion in direct investment and generate over 225 thousand jobs by 2035

API "10 in 2022" Policy impact - Reference Case versus Policy Case[1]

	2025	2035	Details	
Direct investment	*+ **$12.2 billion** investment*	*+ **$19.8 billion** investment*	• The API's "10 in 2022" policies would lead to a cumulative **$196 billion in direct investment** from 2023-2035 between oil and gas, CCUS and hydrogen	
Production	*+ **4.6 bcf/d** of gas*	*+ **127 kb/d** of oil* *+ **4.8 bcf/d** of gas*	• Policies that enable pipeline investments and support federal leasing would lead to increased oil and gas production	
GDP	*+ **$17 billion** GDP*	*+ **$27 billion** GDP*	• The policies would support an additional $27 billion of GDP in 2035, considering direct, indirect and induced economic impacts	
Employment	*+ **142 thousand** jobs*	*+ **226 thousand** jobs*	• The policies would support an additional 226 thousand jobs in 2035, considering direct, indirect and induced economic impacts	
Other benefits 2023-2035	*+ **$4.8 billion** federal royalties, taxes and bid revenue[2]*	*More flexible infrastructure*	*+ **250 mtpa** CCUS capacity*	*+ **30 mtpa** Hydrogen capacity*

1: Reference Case and Policy Case are defined on slide 8
2: Only includes federal royalties, corporate income taxes and lease sale bid revenue related to federal offshore oil and gas leases
Note: GDP, employment, wages and benefits, and indirect and induced investment are provided by API using Rystad Energy's estimated direct investment under each scenario and the IMPLAN economic assessment software; dollars are in real 2022 USD
Source: Rystad Energy research and analysis; American Petroleum Institute

Navigating the future of energy

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