



Assumptions to the Annual Energy Outlook 2026: Hydrocarbon Supply Module

April 2026

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Overview

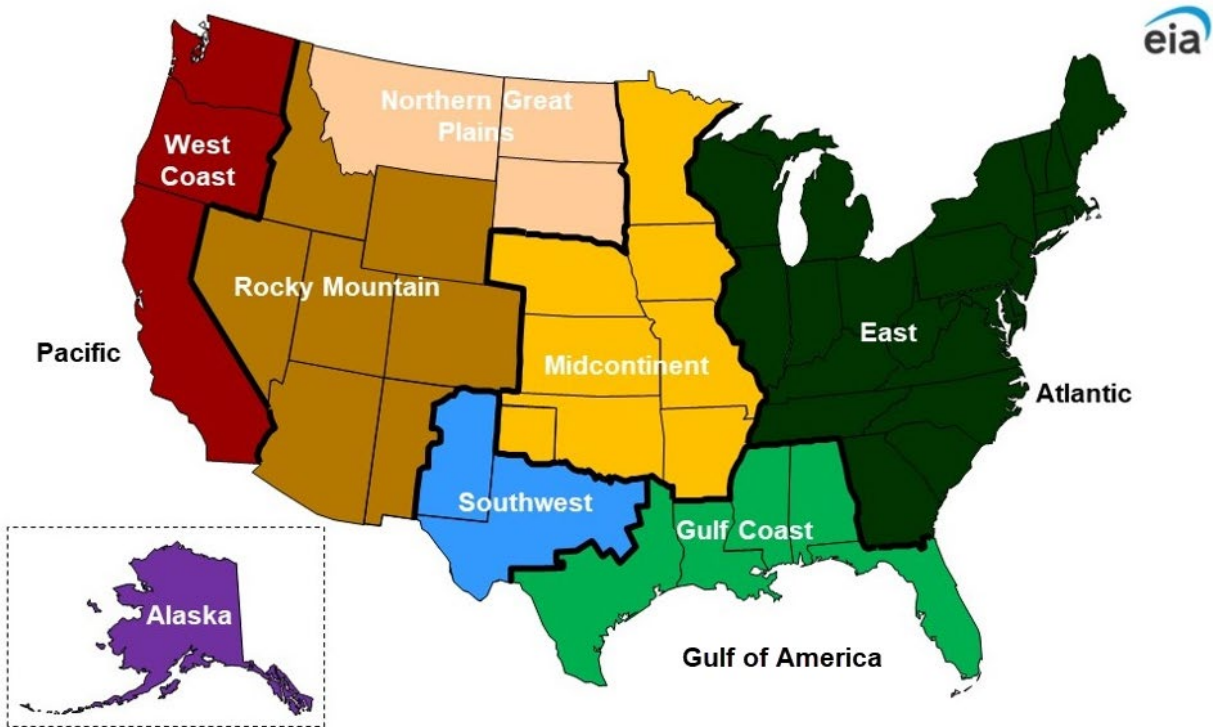
The National Energy Modeling System’s (NEMS) Hydrocarbon Supply Module (HSM) is a comprehensive framework used to analyze crude oil and natural gas exploration and development by region (Figure 1). The HSM is organized into five submodules:

- Lower 48 Onshore
- Lower 48 Offshore
- Alaska
- Canadian Natural Gas
- CO₂ Capture at Natural Gas Processing Plants

This document details key assumptions made by each submodule and includes policy updates for AEO2026. Also included is a section dedicated to detailing how HSM assumes Technically Recoverable Resources.

The HSM provides crude oil and natural gas short-term supply parameters to the Liquid Fuels Market Module (LFMM) and the Natural Gas Market Module (NGMM). The HSM simulates the activity of firms that produce oil and natural gas from fields throughout the United States.

Figure 1. Map of Hydrocarbon Supply Module regions, as of April 2026



Data Source: U.S. Energy Information Administration, Office of Energy Analysis

The HSM models domestic crude oil and natural gas production by recovery technique and source. Production modeling includes recovery from continuous formations—such as the Austin Chalk, Bakken,

Eagle Ford, and Wolfcamp shale formations. Extraction in these areas primarily relies on horizontal drilling combined with hydraulic fracturing, a process that creates additional fractures in the rock to release hydrocarbons.

The HSM also covers conventional resource extraction, which involves traditional drilling methods to access oil and gas deposits. Enhanced oil recovery (EOR) processes are included as well; these use techniques like carbon dioxide (CO₂) flooding and steam flooding to increase the amount of oil that can be produced from existing fields.

Natural gas supply sources modeled in the HSM include resources from low-permeability tight sand formations—rocks with very small pore spaces that make it difficult for gas to flow—and shale formations, which are sedimentary rocks rich in organic material. Coalbed methane, natural gas extracted from coal seams, is also modeled. HSM has a separate submodule that models non-associated natural gas from Western Canada, which is an important input for the NGMM.

Technically Recoverable Resources

This section describes the assumptions underlying domestic crude oil and natural gas technically recoverable resources (TRR) in the Hydrocarbon Supply Module (HSM). TRR is a central input to the supply outlook; it bounds the resources available for development and, together with well-level economics and decline behavior, drives production profiles in the *Annual Energy Outlook* (AEO).

What TRR is and Why It Matters

Remaining TRR is the standard long-term measure of U.S. domestic crude oil and natural gas resource potential. It is the sum of:

- **Proved reserves** — volumes that geological and engineering data demonstrate with high confidence to be recoverable under current economic and operating conditions
- **Unproved resources** — additional volumes that are considered recoverable with current or foreseeable technology but are not yet classified as reserves

The TRR values used in HSM for crude oil and natural gas are given in Table 1, by region (Lower 48 onshore, Lower 48 offshore, Alaska). These tables reflect the starting resource base for the model as of the report's reference date. Domestic crude oil production in the AEO depends on the production profile of individual wells over time, the cost of drilling and operating those wells, and the revenues they generate. Each AEO, EIA re-estimates initial production (IP) rates and production decline curves, which determine estimated ultimate recovery (EUR) per well and therefore total TRR.

Uncertainty in TRR Estimates

TRR estimates are highly uncertain, especially in emerging plays where relatively few wells have been drilled. Estimates often change over time because of:

- **New geological information** from additional drilling
- **Improved understanding of long-term productivity** as existing wells age
- **Higher productivity** from technology improvements and better management practices

The tables in this report present our best estimation as of AEO2026; revisions in future AEOs are expected as data and methods evolve.

Table 1. Technically recoverable U.S. crude oil and natural gas resources, as of January 1, 2024

Region	Total technically recoverable resources	
	Crude oil, billion barrels	Natural gas, trillion cubic feet
Lower 48 states onshore	218.5	2,735.2
East	9.2	1,210.4
Gulf Coast	27.1	467.9
Midcontinent	6.9	184.9
Southwest	128.1	584.8
Rocky Mountain	30.5	250.1
Northern Great Plains	16.7	34.7
West Coast	0.6	2.4
Lower 48 states offshore	44.1	105
Gulf	29.6	54.8
Pacific	10.2	16.1
Atlantic	4.3	34.1
Alaska (onshore and offshore)	47.4	159.6
U.S. total	310.0	2,999.8

Data source: Lower 48 states onshore and offshore—U.S. Energy Information Administration (EIA); Alaska—U.S. Geological Survey (USGS); federal (Outer Continental Shelf) offshore—Bureau of Ocean Energy Management
 Note: Table values reflect removal of intervening reserves additions between the date of the latest available assessment and January 1, 2024. Crude oil resources include lease condensates but do not include natural gas plant liquids or kerogen (oil shale).

How TRR is Sourced and Used in HSM

The TRR estimates used for each AEO are based on the latest available well production data and information from federal and state agencies, industry, and academia. Data sources by area are noted in Table 1.

The report table shows the *starting* resource for the model. Within HSM, technology improvements increase the TRR over the projection period, and that resource can be converted to production. TRR is also based on assumed well spacing used to calculate the number of remaining drill sites. The model allows closer spacing when economical, with diminishing returns per well due to well interference. The table in this report does not include these dynamic increases in TRR. As a result, cumulative production from the reference year through the end of the projection period (for example, 2024 through 2050) can exceed the TRR volumes shown in the tables.

Unproved TRR at the Play Level

For continuous-type shale gas and tight oil, **remaining unproved TRR** is computed as:

$$\text{area with potential} \times \text{well spacing (wells per square mile)} \times \text{EUR per well}$$

The module employs a distribution of EUR per well within each play, as well as within sub-play areas. Due to significant variations in well productivity across different locations, projects are further delineated by county.

Relationship to USGS

The U.S. Geological Survey (USGS) periodically publishes tight and shale resource assessments. HSM uses these as a guide to choose key parameters (for example, area, spacing, EUR) for the TRR used in the AEO. USGS assesses recoverability based on wells drilled and technologies in place at the time of the assessment. AEO TRR incorporates current drilling, completion, and recovery techniques, which can require adjustments to some USGS assumptions. AEO TRR also includes shale gas and tight oil resources not yet assessed by the USGS. Where well production data are available, EIA analyzes decline curves of producing wells to estimate EUR per well for future drilling. AEO2015 introduced a contour map-based approach to incorporate geologic variation within counties; to date, this approach has been applied to the Marcellus play.

Natural gas plant liquids (NGPL)

In the HSM, NGPL production is not estimated from a separately measured NGPL resource base. Instead, NGPL output is calculated by applying allocation factors—specific gas-to-liquids ratios and purity splits—to projected natural gas production. These allocation factors vary by region, basin, or play and serve to estimate NGPL components extracted, such as ethane, propane, butane, isobutane, and pentanes plus. This process means that rather than quantifying NGPL resources directly, the model uses factors derived from EIA research to compute NGPL production, reflecting differences in geology and plant configuration across areas.

The factors are held in preprocessed input files and can differ by area to reflect geology and plant configuration (for example, ethane rejection vs. recovery). Offshore Gulf of America (GOA) NGPL production, for example, is computed by applying an NGPL ratio to natural gas production by field/region.

The level and mix of NGPL output in the AEO therefore depend on (1) the oil and natural gas TRR and production paths (which are driven by the table above) and (2) the assumed yield of NGPLs per unit of gas (and oil) and the component mix in each area. Those yields and mixes are not reported as TRR but function as fixed or region-specific factors that tie NGPL supply to the underlying hydrocarbon TRR. EIA periodically updates allocation factors for key basins (for example, Appalachian and Willison in AEO2017, Permian in AEO2018, Anadarko in AEO2019, Denver in AEO2022) using producer filings, third-party well data, and EIA survey data at the natural gas plant level.

Lower 48 Onshore

The onshore submodule is a project-level model designed to estimate crude oil and natural gas output from onshore sources across the Lower 48 states. Projects are pre-defined by county, play, and resource type (for example, conventional, tight). The submodule prioritizes projects based on their financial viability, resource characteristics, and technological readiness, moving forward with development as permitted by infrastructure and production constraints. For crude oil, the submodule represents advanced secondary and improved recovery (for example, infill and horizontal drilling) and EOR—CO₂

flooding or steam flooding. For natural gas, it represents supply from shale, tight sands, conventional, and coalbed methane sources.

Project economics are evaluated from the perspective of an operator making an investment decision. Tax treatment in the model reflects current law for large, independent producers; we assume tax provisions and costs (by region, fuel, and process type) are unchanged over the life of the investment. Operating losses in early years are carried forward against later revenues.

Hurdle rate and cost of capital

The minimum required rate of return (hurdle rate) is the weighted average cost of capital (WACC) plus 5%. The onshore submodule applies this 5% premium to all Lower 48 onshore projects. WACC is computed as:

$$\text{WACC} = \text{DEBTRATIO} \times \text{BAA} \times (1 - \text{FEDTXR}) + (1 - \text{DEBTRATIO}) \times (\text{T10YR} + \text{OGBETA} \times \text{OGMRP})$$

where:

- DEBTRATIO = long-term debt ratio = 0.40
- BAA = Baa bond rate (from the Macroeconomic Activity Module)
- FEDTXR = federal tax rate = 0.21
- T10YR = 10-year Treasury note (from the Macroeconomic Activity Module)
- OGBETA = industry beta¹ = 1.5
- OGMRP = market risk premium = 7.5

Financial inputs (debt ratio, tax rate, beta, risk premium) are configurable via the setup and discounting input files.

Project life and abandonment

Projects cannot be abandoned until they have operated at least six years, even if net operating income (NOI) turns negative earlier. The economic limit is reached when $\text{NOI} < 0$ and the project has operated at least six years. Projects that never reach negative NOI are assigned a 30-year economic life.

Development constraints and project selection

Projects are ranked by net present value (NPV); projects with recent drilling history receive a slight sorting preference to favor continuity. Undiscovered, unconventional drilling is capped at a maximum share of available wells per year (for example, 30%). Projects are selected using the NPV ranking each model year, with several industry-wide constraints dictating how many projects can be developed, such as total capital available and rig capacity.

Constraints exist for rig count, footage, capital, and wells per rig. The constraints are built on the fundamental assumption that historical patterns between oil prices and drilling activity will

¹ Represents the sensitivity of oil and gas industry returns to the market

continue. Specifically, when oil prices rise, companies will respond by deploying more drilling rigs, drilling more footage, and increasing capital investments—but with diminishing returns at higher price levels. An OLS (Ordinary Least Squares) regression was used to analyze over a decade of historical data (2010–2024) to establish price-response relationships. These constraint equations were developed assuming drilling behavior is relatively uniform within each region.

The submodule assumes that drilling efficiency—measured as the number of wells drilled per rig—remains relatively stable over time and can be estimated from recent five-year averages.

Decline curves and production profiles

Currently producing wells are aggregated by project and, during preprocessing, production profiles are created to reflect the project’s current production level. These producing projects are declined using either the predicted decline rate as a result of decline curve analysis (DCA)² or play-specific decline rate assumptions by resource type. Future projects from continuous formations assume wells follow a pre-computed initial production and decline based on detailed DCA used to create project-specific type well profiles.³

Technological improvements

Tight oil and shale gas plays are split into two productivity tiers with different technology improvement rates. Tier 1 is actively developing area; Tier 2 is not yet developed. When development starts in a Tier 2 area, the improvement rate doubles during the early phase, defined as five years, to account for learning-by-doing and sweet-spot identification. The area then converts to Tier 1. This assumption captures diminishing returns from tighter spacing, technology diffusion, and application of best practices at the time of development. Table 2 summarizes the onshore technology assumptions by resource type.

Table 2. Onshore Lower 48 states technology assumptions

Crude oil and natural gas resource type	Drilling cost	Lease equipment and operating cost	EUR-Tier 1	EUR-Tier 2
Tight oil	-1.00%	-0.50%	1.00%	2.00%
Tight and shale gas	-1.00%	-0.50%	2.00%	3.00%
All other	-0.25%	-0.25%	0.25%	0.25%

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: EUR=estimated ultimate recovery

NA=not applicable

CO₂ enhanced oil recovery

HSM evaluates two technologies for EOR: thermal recovery and CO₂ miscible flooding. When evaluating a project for EOR via CO₂ miscible flooding, the onshore submodule computes CO₂ demand. The Carbon Capture, Allocation, Transportation, and Sequestration (CCATS) module supplies volume and cost of CO₂ from power and industrial sources. HSM uses those costs to evaluate CO₂ EOR profitability and reports

² Decline curve analysis is a method used to analyze the production histories of oil and gas wells to estimate future production rates.

³ A type well profile, as defined by SPEE (Society of Petroleum Evaluation Engineers), is a method for constructing either (1) the average well performance or (2) the average monthly performance in a developmental program over time.

back to CCATS the margin available for CO₂ purchase. CCATS considers CO₂ from both natural and industrial sources when determining the cost of CO₂ supplied to HSM. Natural-source CO₂ cost is tied to crude oil price; industrial CO₂ cost includes capture, compression, and pipeline transport to the project (modeled in CCATS; see the [CCATS Assumptions document](#)). CO₂ EOR projects are eligible within ±15 years of the legacy project’s economic life; only one EOR type per reservoir is allowed (the most profitable).

Lower 48 Offshore

HSM represents the offshore Lower 48 states upstream activity for both state-controlled waters and federal waters. There are three federal offshore regions represented: Atlantic [Outer Continental Shelf](#) (OCS), Pacific OCS, and Gulf of America (GOA) OCS.

The Atlantic OCS is subject to a drilling moratorium in the model: no fields are represented in that region, so no Atlantic offshore production is projected.

Most Lower 48 offshore crude oil and natural gas production in the model comes from the deepwater federal GOA. In AEO2026, HSM used our *Short-Term Energy Outlook (STEO) GOA model* and extended its end date through 2050. HSM continued using the offshore submodule for Pacific OCS. The assumptions below include a section on the STEO GOA model and HSM’s Lower 48 offshore submodule as it was implemented for the Pacific OCS—although this region is not expected to produce significant volumes of oil or natural gas during the projection period.

GOA model

The STEO GOA model projects crude oil and natural gas production from offshore wells in federal waters. HSM did not model production from GOA state waters for AEO2026; this is a small (<5%) portion of GOA total production. The model combines historical production data from the Bureau of Safety and Environmental Enforcement (BSEE) with well-level information from third parties to predict future production trends. The system processes data from thousands of individual wells, groups them by field and platform, and applies decline curve analysis to project production up to 25 years into the future.

Production Decline Behavior

Hyperbolic Decline Curves: The model assumes that oil production from existing wells follows a hyperbolic decline pattern. This means production decreases over time at a rate that itself decreases.

The hyperbolic decline equation for oil production from existing wells can be expressed mathematically as:

$$q_t = \frac{q_i}{(1 + b \times d_i \times t)^{\frac{1}{b}}}$$

Where:

- **q(t):** Production rate at time t
- **qi:** Initial (peak) production rate

- **b:** Hyperbolic exponent (typically around 2.0)
- **di:** Initial decline rate (starts around 0.01 to 0.7 per month)
- **t:** Time since initial production (in months or years, as specified)

Exponential Decline Transition: Wells that reach a mature stage (when the decline rate stabilizes at or below 7% per year) transition to exponential decline, which assumes a constant percentage decline rate of approximately 1% per month.

Historical Data Window

The model uses the most recent three years of production data to calculate decline parameters. Three different lookback periods are tested (12, 24, and 36 months) to capture different production trends, with the model selecting the most appropriate based on data quality and fit.

Gas-to-Oil Ratio (GOR)

The model assumes that the ratio of natural gas to crude oil production remains relatively constant for each well over the projection period. The GOR is calculated as:

- A six-month rolling average of recent production for wells producing more than 5 barrels per day
- Capped at 60,000 cubic feet per barrel to avoid unrealistic values
- Default value of 0.3 for new fields without historical data

Correction Factors

The model applies several adjustment factors to account for operational realities:

Hurricane Impacts: Production is reduced during hurricane season (June through December) based on historical patterns:

Table 3. Hurricane season reductions

Month	Production Reduction (%)
June	-0.6%
July	-0.7%
August	-2.6%
September	-9.8% (peak hurricane season)
October	-7.5%
November	-1.9%

These percentages are multiplied by a configurable hurricane correction factor to adjust for expected storm activity.

Platform Uptime Factors: Individual platforms may have specific uptime factors applied based on known operational constraints, scheduled maintenance, or infrastructure limitations. These are defined in an external configuration file and can vary by time period.

Gas Processing Constraints: A gas correction factor accounts for processing capacity limitations that may prevent all produced gas from reaching market.

New Field Development

For fields that are expected to come online during the projection period, the model assumes:

- A **ramp-up period** (typically several months) where production gradually increases to plateau levels
- A **plateau period** (typically one to three years) where production remains relatively constant
- A **decline period** following the hyperbolic decline curve after the plateau

New field production is distributed across wells based on either:

- Historical production proportions for replacement fields (fields replacing existing infrastructure)
- Equal distribution for entirely new fields with no production history

Data Quality Controls

Outlier Removal: The model identifies and removes statistical outliers in monthly production volumes using both:

- Interquartile range (IQR) method with a factor of 0.5
- Standard deviation method with a factor of 2

Data Lag: The model excludes the **most recent three months** of BSEE data by default, as these data are often incomplete or subject to revision.

Production Threshold: Wells must produce at least **5 barrels per day** to be included in decline curve calculations, filtering out marginal or intermittent production.

HSM's Lower 48 Offshore Submodule

The HSM's Lower 48 offshore submodule modeled Pacific OCS production. GOA production is modeled separately as described above and Atlantic OCS production is assumed to be zero through the projection period due to the drilling moratorium.

Producing and announced fields

Production in the Pacific is driven by currently producing fields. There have been no announced fields in the Pacific OCS since the last lease sale in 1984.

Currently producing fields. Oil fields are assumed to follow a 10%–15% exponential decline; natural gas fields a 30% exponential decline. Fields that began production after 2019 are held at peak for two years before declining.

Leasing and policy

Leasing availability in the offshore module is implemented through evaluation-unit-level parameters, which determine when undiscovered resources can be explored and developed. These assumed parameters reflect presidential memorandums and [lease timing](#). In the current configuration, Atlantic OCS units are excluded from new drilling and production, and Pacific undiscovered resources do not become available within the projection horizon, so the Counterfactual Baseline (CB) case effectively assumes no new federal leasing in the Atlantic or Pacific OCS while allowing continued production from existing Pacific federal offshore fields.

Technology parameters

Table 4 summarizes offshore technology assumptions: exploration success improvement, exploration and development delay reduction, drilling and platform cost improvement, operating cost improvement, and production facility build time and cost improvement. Annual improvement rates (for example, 1% for success, drilling cost, platform cost, operating cost; 0.5% for delays and build time) are user-definable in the input file, `off_setup.csv`. The offshore project discount rate and evaluation period (for example, 30 years), tangible cost fractions for development and capital, and the share of drilling cost tied to commodity prices are also user-defined assumptions.

Table 4. Offshore exploration and production technology assumptions

Technology level	Year-over-year improvement
Exploration success rates	1.0%
Delay to start first exploration and between exploration and development	0.5%
Exploration and development drilling costs	1.0%
Operating cost	1.0%
Time to construct production facility	0.5%
Production facility construction costs	1.0%
Initial constant production rate	0.5%

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Alaska Crude Oil Production

Alaska oil production in HSM includes producing fields and industry-announced developments. Announced projects (for example, expansion fields around Prudhoe Bay and Alpine and major discoveries with published development plans) are listed in Table 5 with discovery year, field size (million barrels [MMb]), and start year of production. The model assumes announced projects are developed on schedule and profitable after the announcement year, ensuring planned production is achieved. Undiscovered field production is determined by resource estimates in undeveloped areas and the net present value of project cash flows based on expected capital and operating costs and projected prices.

Alaska projects use a discount rate 5% higher than the Lower 48 onshore rate to reflect greater operating risk and remoteness. Capital costs are spread evenly over the first four years of development; abandonment cost is assumed to be 10% of total capital. The project evaluation period and technology improvement rate are set in Alaska setup files (for example, 30-year evaluation, 1% annual tech improvement). Royalty and severance tax rates (for example, 16.67% royalty, 15% severance on crude and natural gas) and tangible cost fractions for exploration, development, and capital are user-defined. Operating cost is modeled with coefficients that vary by production size (see `ak_opex.csv`). Alaska NGPL production is set to 10% of crude oil production, with fixed component ratios (for example, propane, butane, C5+); ethane is assumed zero.

Table 5. Assumed size and initial production year of major announced discoveries in Alaska

Field or project name	Year of discovery	Field size (MMb)	Start year of production
Nuna	2012	75	2025
Mustang	2019	20	2025
Pikka	2013	750	2026
Alkaid/Phecda	2019	95	2026
Willow (NPRA)	2017	580	2029

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: MMb=million barrels

Trans-Alaska Pipeline System (TAPS)

As throughput on the Trans-Alaska Pipeline System (TAPS) declines, operational challenges increase, raising per-barrel costs for remaining production. The model addresses TAPS-related economic constraints through project-level profitability analysis rather than explicit throughput thresholds. Each Alaska project is evaluated independently: production continues as long as net operating income (revenue minus royalties, severance taxes, operating costs, and transportation costs) remains positive. Projects are shut down, and wells are plugged and abandoned when they become uneconomical on an individual basis, typically after a minimum production period (for example, six years).

This project-level approach implicitly captures the economic pressure of declining TAPS throughput, as rising per-unit operating and transportation costs reduce project profitability. Although the model does not explicitly enforce a TAPS throughput floor or aggregate North Slope revenue threshold, the economic evaluation framework allows marginal projects to become uneconomical as infrastructure costs are spread over fewer barrels, which can lead to coordinated field shutdowns when conditions deteriorate sufficiently.

Arctic National Wildlife Refuge (ANWR)

The coastal plain (1002 Area) of the Arctic National Wildlife Refuge was opened to oil and gas leasing under Public Law 115-97 (December 2017). The model uses the 1998 USGS assessment: technically recoverable oil in the coastal plain (federal, state, and native lands) has a mean estimate of 10.4 billion

barrels (Bb) (5.7Bb–16.0 Bb at 95%–5% probability). Table 6 gives the assumed field size distribution and TRR by size class.

ANWR development assumptions:

- Lease sales occurred in 2021 and 2024 (per congressional schedule).
- First production from ANWR is assumed no earlier than 2036, allowing for exploration, appraisal, permitting, and development.
- The largest fields are developed first.
- After a field begins production, at most one new ANWR field is brought on every two years, conditional on economics; this reflects assumed regulatory and logistical pacing.
- Each field ramps to peak in three to four years, holds peak for three to four years, then declines until uneconomic and is abandoned.

For details on ANWR resource classes and production profiles, see Table 6.

Table 6. Assumed field size distribution and technically recoverable crude oil resource, ANWR

Field size (million barrels)	Number of fields	Technically recoverable crude oil resources (billion barrels)
1,370	1	1.4
700	3	2.1
360	8	2.9
180	12	2.2
90	14	1.3
45	11	0.5
23	4	0.1
12	0	0.0
Total	53	10.4

Data source: U.S. Energy Information Administration, Office of Energy Analysis

Note: ANWR=Arctic National Wildlife Refuge

Canadian Natural Gas

The Canada submodule projects natural gas production available for export to the United States from Canadian sources. The model uses baseline production data, decline curve analysis, and price-responsive drilling equations derived from the Canada Energy Regulator's [Canada's Energy Future 2023](#) report. Canadian production is divided into two main categories: non-associated (NA) natural gas from dedicated gas wells and associated-dissolved (AD) gas produced alongside crude oil.

The model tracks production by region (primarily Alberta, British Columbia, and Saskatchewan in Western Canada, plus smaller volumes from Eastern provinces) and by gas type (tight gas, shale gas, coalbed methane, conventional non-associated, and associated-dissolved gas). Each year, the model

calculates how many new wells will be drilled based on Henry Hub natural gas prices and Brent crude oil prices, applies region-specific production decline curves to estimate output from those wells over time, and aggregates total Canadian gas available for export to U.S. markets.

Price sensitivity and drilling response

New well drilling in Canada is modeled as a function of natural gas and crude oil prices. The model uses polynomial regression equations (cubic functions of Henry Hub price) calibrated to historical drilling activity in each region and gas type. When Henry Hub prices rise, more wells are drilled; when prices fall, drilling declines and can reach zero if prices are sufficiently low.

The model also adjusts drilling based on the ratio of international Brent crude prices to Canada Energy Regulator benchmark Brent prices, with different elasticity factors applied depending on whether the international price is higher or lower than the Canadian benchmark. A fixed price differential of \$0.85 per thousand cubic feet is assumed between Canadian wellhead prices and Henry Hub, reflecting transportation costs and market dynamics. This price-responsive drilling mechanism ensures that Canadian gas supply reacts realistically to market conditions, expanding when profitable and contracting when economics are unfavorable.

Key drilling assumptions:

- Drilling equations are third-order polynomials of Henry Hub price (coefficients vary by region and gas type).
- Crude oil price elasticity adjusts drilling when Brent prices diverge from Canadian benchmarks.
- Negative well counts from the polynomial equations are set to zero (no negative drilling).
- Canadian wellhead price is assumed to be Henry Hub minus \$0.85 per thousand cubic feet (fixed differential).

Production decline curves and technology improvement

Each new well drilled in the model follows a hyperbolic decline curve that determines how much gas it will produce each year over its lifetime. Decline curves are characterized by three parameters: initial production rate (IPR), decline rate (dr), and hyperbolic exponent (b). These parameters vary by region and gas type, reflecting differences in geology and well performance. For example, shale gas wells typically have steeper initial declines than conventional wells.

The model assumes that the first year of production is half the calculated annual rate (to account for mid-year startup), and subsequent years follow the full decline curve. Additionally, a technology improvement factor is applied to account for advances in drilling and completion techniques over time; this factor increases the productivity of wells drilled in later years compared with those drilled earlier, even if they are in the same region and gas type. The base technology improvement rate is 1% per year, meaning a well drilled in 2030 will be slightly more productive than an identical well drilled in 2020.

Associated-dissolved gas and oil price linkage

Associated-dissolved (AD) gas is natural gas produced as a byproduct of crude oil production. Unlike non-associated gas, AD gas production is not driven by gas prices but by oil production economics. The model uses baseline AD gas production from the Canada Energy Regulator and adjusts it based on the ratio of international Brent crude oil prices to Canadian benchmark Brent prices.

When oil prices are higher than the Canadian benchmark, AD gas production increases (because more oil wells are drilled and operated); when oil prices are lower, AD gas production decreases. The model applies different elasticity factors for high-price and low-price scenarios, recognizing that producers may respond asymmetrically to price increases versus decreases. AD gas is produced primarily in Western Canada (Alberta, British Columbia, Saskatchewan) alongside oil production, with smaller volumes from Eastern provinces and offshore areas.

Regional aggregation and export availability

The model divides Canadian production into two export regions: Western Canada (Alberta, British Columbia, Saskatchewan) and Eastern Canada (all other provinces). Western Canada accounts for most Canadian gas production and exports to the United States. The model subtracts Canadian domestic consumption (gas not available for export) from total production to determine the volume available for export. This domestic consumption is treated as a fixed input based on Canada Energy Regulator projections. The model outputs expected NA gas production, realized NA gas production (which may differ due to market constraints), and AD gas production for each region by year. These outputs feed into the broader energy system model to determine natural gas flows and prices across North America.

CO₂ Capture at Natural Gas Processing Plants

The Natural Gas Processing (NGP) submodule evaluates the economic feasibility of installing carbon capture equipment at natural gas processing facilities across the United States. Natural gas processing plants separate raw natural gas into its marketable components and often produce concentrated streams of carbon dioxide (CO₂) as a byproduct—making them attractive candidates for carbon capture and sequestration (CCS). This submodule determines which facilities will profitably install capture technology in response to CO₂ prices, tax incentives (such as the 45Q tax credit), and local electricity costs.

The model tracks both existing facilities in a database and creates representative *legacy* and *new* facilities to account for natural gas production volumes that exceed known facility capacities. Each year, the model runs a cash flow analysis for eligible retrofit projects, ranks them by profitability, and reports captured CO₂ volumes and associated costs to the broader carbon capture system.

Facility eligibility and retrofit decisions

Not all natural gas processing facilities are candidates for carbon capture retrofits. The model begins with a database of existing facilities, filtering for those marked as retrofit-eligible or already equipped with capture technology. Facilities must be younger than 60 years to remain in the model; older plants are assumed to retire. Legacy facilities (representing aggregate production not tied to specific known plants) retire at a steady rate of 2% per year to reflect natural attrition.

When modeled natural gas production exceeds the combined throughput capacity of known facilities, the model creates additional representative facilities to account for the difference. During historical years, excess production is assigned to legacy facilities; in future years, it is assigned to new representative facilities that can be evaluated for retrofits. Only facilities that have not yet been retrofitted or that have aged out of their initial evaluation period are considered for new retrofit investments each year.

These assumptions are summarized in Table 7.

Table 7. Facility lifecycle assumptions

Parameter	Value	Meaning
Maximum facility age	60 years	Facilities older than 60 years retire from the model
Legacy plant retirement rate	2% per year	Gradual retirement of aggregate legacy facilities
Retrofit evaluation period	12 years	Cash flow is evaluated over this horizon for retrofit decisions
45Q tax credit eligibility	12 years from retrofit	Projects receive enhanced CO ₂ revenue for 12 years if retrofit occurs before the 45Q cutoff year

Operating assumptions and capacity factors

Natural gas processing facilities do not operate at full design capacity year-round due to seasonal demand variation, maintenance outages, and fluctuations in upstream gas production. The model applies capacity factors (Table 8) to adjust throughput volumes and electricity consumption to realistic annual levels. For natural gas throughput, a capacity factor of 61% is applied (reflecting average utilization observed in industry data). When carbon capture equipment is installed, the model assumes the capture system will operate at a 63% capacity factor for electricity consumption (accounting for operational variability). New facilities built to meet growing gas production are assumed to operate at a 70% capacity factor, as they are expected to be better sized for actual throughput and incorporate modern design practices. These capacity factors ensure that modeled CO₂ capture volumes and electricity demands align with realistic operational performance rather than theoretical maximums.

Table 8. Capacity factor assumptions

Facility type	Capacity factor	Applied to
Existing facilities (gas throughput)	61%	Natural gas processing volumes
Carbon capture retrofits (electricity)	63%	Electricity consumption for CO ₂ separation
New representative facilities	70%	Both gas throughput and capture operations

Data source: U.S. Energy Information Administration

Economic evaluation and technology improvement

The model performs a detailed discounted cash flow analysis for each potential retrofit project, accounting for capital costs (equipment installation), operating costs (energy, maintenance), CO₂ revenue (from 45Q tax credits or market prices), and electricity costs. Capital and operating cost data

are drawn from National Energy Technology Laboratory (NETL) studies of natural gas-processing CCS retrofits, adjusted for inflation to the model year.

The model assumes that capture technology improves over time, reducing both investment costs and operating costs by 2% each year. Projects with positive net present value (NPV) are selected for retrofit. To prevent unrealistic growth surges, the model caps annual CO₂ capture expansion in each census division to twice the greater of 1 million metric tons or the previous year's capture volume. This constraint reflects real-world limits on labor, supply chains, and project development pipelines.

Policy Updates

Legislative changes affecting HSM in AEO2026

The [One Big Beautiful Bill Act](#) repealed certain sections of [Public Law 117-169](#), also known as the Inflation Reduction Act (IRA) of 2022. Additional sections of the IRA were repealed through the Congressional Review Act, a law that allows Congress to review and overrule regulations issued by government agencies. The following policy updates have been implemented in the HSM for the AEO2026 to reflect recent legislative changes. Each policy update clearly references the relevant law and section, with citations and explanations provided to clarify the purpose and implications of these changes for the HSM.

Repeal of Section 50263: Royalties on Extracted Methane

Section 50263 of Public Law 117-169, known as the Inflation Reduction Act of 2022, previously required royalties to be paid on all methane extracted from federal land and the OCS, including methane lost due to venting, flaring, or negligent releases. The repeal of this section eliminates the obligation for natural gas producers to pay royalties on gas that is consumed or lost through these processes. This legislative change is intended to reduce the financial burden on natural gas producers, thereby potentially encouraging investment and operational efficiency in federal oil and gas production. HSM has removed methane royalties on shadow revenue from venting and flaring.

Repeal of Section 50262: Minimum Oil and Gas Royalty Rate

Section 50262 of Public Law 117-169 increased the minimum royalty rate for new federal onshore and offshore fossil fuel leases. With the repeal of this section, the minimum royalty rates have been adjusted downward. Specifically, the offshore royalty rate range has been revised from 16.67%–18.75% to 12.5%–16.67%, and the onshore royalty rate has decreased from 16.67% to 12.5%. These changes are designed to make federal leasing terms more competitive and may affect the economics of future oil and gas development on federal lands and waters. HSM has adjusted royalty rates accordingly.

Repeal of Section 60113: Waste Emissions Charge

The [Waste Emissions Charge](#) (WEC) was created by the IRA via an amendment to the Clean Air Act and would have imposed an escalating fee on methane emissions. The fee would have started at \$900 per metric ton of methane in 2024 and increased to \$1,500 per ton in 2026 onward. The rule applied to facilities emitting >25,000 tons of CO₂-equivalent annually.

The final rule was disapproved by a joint resolution of Congress pursuant to the Congressional Review Act. President Trump signed the Joint Resolution of Disapproval under the Congressional Review Act on March 14, 2025. This regulation no longer has any force of law and is not in effect, and facilities will not be required to submit their WEC filings by September 2, 2025. HSM has accounted for this rule change by removing methane emissions charges from the cash flow calculation that generates project profitability.

Other Legislation and Regulation

For a comprehensive list of all legislation and regulations incorporated in the HSM, especially those from prior years, refer to the Summary of Legislation and Regulations section included in the [AEO2026 assumptions documents](#).