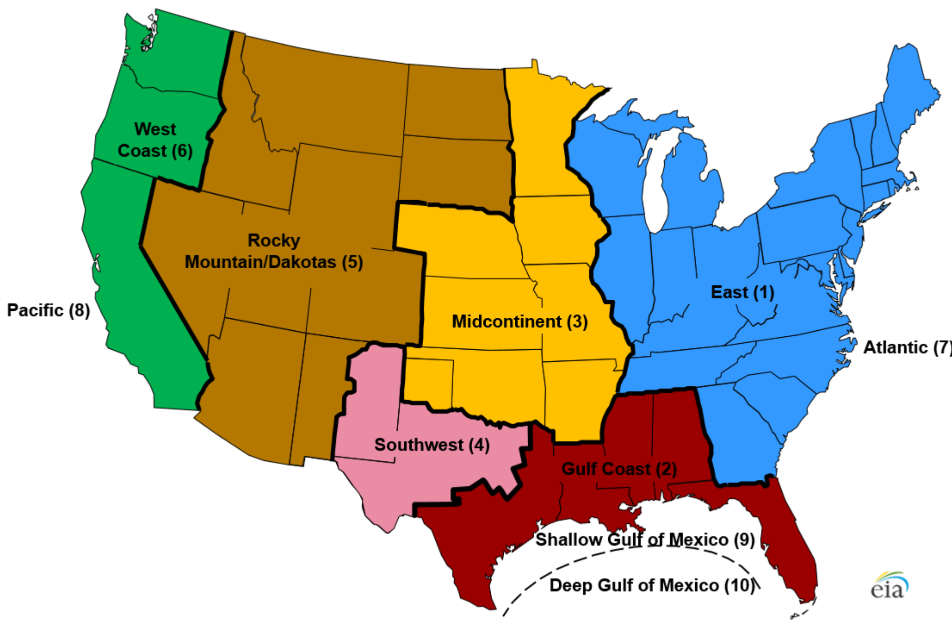
Oil and Gas Supply Module

The National Energy Modeling System (NEMS) Oil and Gas Supply Module (OGSM) constitutes a comprehensive framework used to analyze crude oil and natural gas exploration and development by region (Figure 1). The OGSM is organized into four submodules: Onshore Lower 48 Oil and Gas Supply Submodule, Offshore Oil and Gas Supply Submodule, Oil Shale Supply Submodule [1], and Alaska Oil and Gas Supply Submodule. A detailed description of the OGSM is provided in the EIA publication, *Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2017*, DOE/EIA-M063 (2017), (Washington, DC, 2017). The OGSM provides crude oil and natural gas short-term supply parameters to the Natural Gas Markets Module and to the Liquid Fuels Market Module. The OGSM simulates the activity of firms that produce oil and natural gas from domestic fields throughout the United States.

Figure 1. Oil and Gas Supply Model regions



Source: U.S. Energy Information Administration

OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil recovery includes improved oil recovery processes such as water flooding, infill drilling, and horizontal drilling, as well as enhanced oil recovery processes such as CO2 flooding, steam flooding, and polymer flooding. Recovery from highly fractured, continuous zones (e.g., Austin chalk and Bakken shale formations) is also included. Natural gas supply includes resources from low-permeability tight sand formations, shale formations, coalbed methane, and other sources.

Key assumptions

Domestic crude oil and natural gas technically recoverable resources

The outlook for domestic crude oil production is highly dependent on the production profile of individual wells over time, the cost of drilling and operating those wells, and the revenues generated by those wells. Every year, EIA re-estimates initial production (IP) rates and production decline curves, which determine estimated ultimate recovery (EUR) per well and total technically recoverable resources (TRR) [2].

A common measure of the long-term viability of U.S. domestic crude oil and natural gas as an energy source is the remaining technically recoverable resource, consisting of proved reserves [3] and unproved resources [4]. Estimates of TRR are highly uncertain, particularly in emerging plays where relatively few wells have been drilled. Early estimates tend to vary and shift significantly over time as new geological information is gained through additional drilling, as long-term productivity is clarified for existing wells, and as the productivity of new wells increases with technology improvements and better management practices. TRR estimates used by EIA for each AEO are based on the latest available well production data and on information from other federal and state governmental agencies, industry, and academia. Published estimates in Tables 1 and 2 reflect the removal of intervening reserves additions and production between the date of the latest available assessment and January 1, 2016.

Table 1. Technically recoverable U.S. crude oil resources as of January 1, 2016

billion barrels

Region	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	28.4	165.7	194.1
East	0.5	4.2	4.6
Gulf Coast	5.8	32.0	37.8
Midcontinent	2.4	14.1	16.5
Southwest	9.2	71.7	80.9
Rocky Mountain/Dakotas	8.3	39.2	47.6
West Coast	2.2	4.5	6.6
Lower 48 Offshore	4.7	49.6	54.4
Gulf (currently available)	4.3	36.6	40.9
Eastern/Central Gulf (unavailable until 2022)	0.0	3.7	3.7
Pacific	0.4	6.0	6.5
Atlantic	0.0	3.3	3.3
Alaska (Onshore and Offshore)	2.1	34.0	36.1
Total U.S.	35.2	249.3	284.6

Note: Crude oil resources include lease condensates but do not include natural gas plant liquids or kerogen (oil shale). Resources in areas where drilling is officially prohibited are not included in this table. The estimate of 7.3 billion barrels of crude oil resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic Outer Continental Shelf (OCS) is also excluded from the technically recoverable volumes because leasing is not expected in these areas.
Source: Onshore and State Offshore - U.S. Energy Information Administration; Alaska - U.S. Geological Survey (USGS); Federal (Outer Continental Shelf) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserves additions between the date the latest available assessment and January 1, 2016.

Table 2. Technically recoverable U.S. dry natural gas resources as of January 1, 2016

trillion cubic feet

	Proved Reserves	Unproved Resources	Total Technically Recoverable Resources
Lower 48 Onshore	295.5	1,611.6	1,907.1
East	94.0	613.1	707.1
Gulf Coast	53.6	370.3	423.9
Midcontinent	45.4	143.8	189.2
Southwest	43.8	194.9	238.7
Rocky Mountain/Dakotas	56.9	255.5	312.4
West Coast	1.8	34.1	35.8
Lower 48 Offshore	7.6	272.0	279.6
Gulf (currently available)	7.3	209.5	216.8
Eastern/Central Gulf (unavailable until 2022)	0.0	21.5	21.5
Pacific	0.3	9.3	9.6
Atlantic	0.0	31.7	31.7
Alaska (Onshore and Offshore)	4.6	271.1	275.6
Total U.S.	307.7	2,154.6	2,462.3

Note: Resources in other areas where drilling is officially prohibited are not included. The estimate of 32.9 trillion cubic feet of natural gas resources in the Northern Atlantic, Northern and Central Pacific, and within a 50-mile buffer off the Mid and Southern Atlantic Outer Continental Shelf (OCS) is also excluded from the technically recoverable volumes because leasing is not expected in these areas.
Source: Onshore and State Offshore - U.S. Energy Information Administration; Alaska - U.S. Geological Survey (USGS); Federal (OCS) Offshore - Bureau of Ocean Energy Management (formerly the Minerals Management Service); Proved Reserves - U.S. Energy Information Administration. Table values reflect removal of intervening reserve additions between the date the latest available assessment and January 1, 2016.

The resources presented in the tables in this document are the starting values for the model. Technology improvements in the model add to the unproved TTR, which can be converted to reserves and finally to production. In addition, the TRR is based on an assumed well spacing to calculate the number of remaining drill sites, and the model allows for closer spacing if economical even with diminishing returns per well as a result of increased well interference. The tables in this document do not include these increases in TRR, so cumulative production from 2016 through 2050 could exceed the presented TRR.

The remaining unproved TRR for a continuous-type shale gas or tight oil area is the product of (1) area with potential, (2) well spacing (wells per square mile), and (3) EUR per well. The play-level unproved technically recoverable resource assumptions for tight oil, shale gas, tight gas, and coalbed methane are summarized in Tables 3 and 4. The model uses a distribution of EUR per well in each play and often in sub-play areas. Table 5 provides an example of the distribution of EUR per well for each of the Bakken areas. The Bakken is subdivided into five areas: Central Basin, Eastern Transitional, Elm Coulee-Billings Nose, Nesson-Little Knife, and Northwest Transitional [5]. Because of the significant variation in well productivity within an area, the wells in each Bakken area are further delineated by county. This level of detail is provided for select plays in Appendix 2.C of the Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2017. The USGS periodically publishes tight and shale resource assessments that are used as a guide for selection of key parameters in the calculation of the TRR used in the AEO. The USGS seeks to assess the recoverability of shale gas and tight oil based on the wells drilled and technologies deployed at the time of the assessment. AEO2015 introduced a contour map-based approach for incorporating geology parameters into the calculation of resources recognizing that geology can vary significantly within counties. This new approach was applied only to the Marcellus play.

Table 3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2016)

Region/Basin	Play	Area with Potential[1] (mi^2)	Average Spacing (wells/mi^2)	Average EUR: Crude Oil[2] (MMb/well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (Bb)	Technically Recoverable Resources: Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (Bb)
East								
Appalachian	Bradford-Venango-Elk	16,648	8.0	0.004	0.063	0.5	8.5	0.0
Appalachian	Clinton-Medina-Tuscarora	23,878	8.0	0.002	0.051	0.4	9.7	0.0
Appalachian	Devonian	50,407	6.3	0.002	0.132	0.7	41.8	1.2
Appalachian	Marcellus Foldbelt	867	4.3	0.000	0.168	0.0	0.6	0.0
Appalachian	Marcellus Interior	21,266	4.3	0.004	3.383	0.4	309.0	14.4
Appalachian	Marcellus Western	2,510	5.5	0.001	0.264	0.0	3.7	0.3
Appalachian	Utica-Gas Zone Core	10,252	5.0	0.005	2.711	0.3	139.0	3.9
Appalachian	Utica-Gas Zone Extension	15,725	3.0	0.006	0.805	0.3	38.1	1.7
Appalachian	Utica-Oil Zone Core	1,349	5.0	0.065	0.381	0.4	2.6	0.0
Appalachian	Utica-Oil-Zone Extension	6,259	3.0	0.014	0.400	0.3	7.5	0.0
Illinois	New Albany	3,027	8.0	0.000	0.114	0.0	2.8	0.2
Michigan	Antrim Shale	13,029	8.0	0.000	0.095	0.0	9.9	0.8
Michigan	Berea Sand	6,590	8.0	0.000	0.124	0.0	6.5	0.1
Gulf Coast								
Black Warrior	Floyd-Neal/Conasauga	1,402	4.0	0.000	1.214	0.0	6.8	0.0
TX-LA-MS Salt	Cotton Valley	3,040	8.0	0.029	1.695	0.7	41.2	1.3
TX-LA-MS Salt	Haynesville-Bossier-LA	2,105	6.0	0.005	4.512	0.1	56.8	0.0
TX-LA-MS Salt	Haynesville-Bossier-TX	1,363	6.0	0.001	3.904	0.0	31.8	0.0
Western Gulf	Austin Chalk-Giddings	1,961	6.4	0.037	0.167	0.5	2.1	0.2
Western Gulf	Austin Chalk-Outlying	9,646	6.4	0.059	0.258	3.6	15.9	0.8
Western Gulf	Buda	8,654	6.4	0.057	0.541	3.2	30.0	0.6
Western Gulf	Eagle Ford-Dry Zone	3,897	6.6	0.090	1.168	2.3	30.1	2.8
Western Gulf	Eagle Ford-Oil Zone	7,977	6.4	0.136	0.133	6.9	6.8	2.0
Western Gulf	Eagle Ford-Wet Zone	2,371	8.7	0.188	0.784	3.9	16.1	2.2
Western Gulf	Olmos	5,199	4.0	0.018	1.239	0.4	25.8	0.0
Western Gulf	Pearsall	1,198	6.0	0.000	0.699	0.0	5.0	0.0
Western Gulf	Tuscaloosa	7,413	6.4	0.062	0.153	2.9	7.3	0.1
Western Gulf	Vicksburg	196	8.0	0.023	1.268	0.0	2.0	0.0
Western Gulf	Wilcox Lobo	334	8.0	0.005	0.382	0.0	1.0	0.0
Western Gulf	Woodbine	1,071	6.4	0.110	0.209	0.8	1.4	0.0
Midcontinent								
Anadarko	Cana Woodford-Dry Zone	754	4.0	0.060	2.829	0.2	8.5	0.0
Anadarko	Cana Woodford-Oil Zone	345	6.4	0.083	0.864	0.2	1.9	0.1
Anadarko	Cana Woodford-Wet Zone	1,069	4.0	0.088	1.718	0.4	7.3	0.7
Anadarko	Cherokee/Red Fork	333	4.0	0.004	0.441	0.0	0.6	0.0
Anadarko	Cleveland	453	4.3	0.044	0.256	0.1	0.5	0.0
Anadarko	Granite Wash/Atoka	2,892	4.0	0.058	0.762	0.7	8.8	0.5
Arkoma	Carney	798	4.0	0.000	0.330	0.0	1.1	0.0
Arkoma	Fayetteville-Central	1,941	8.0	0.000	2.118	0.0	32.9	0.0
Arkoma	Fayetteville-West	768	8.0	0.000	1.073	0.0	6.6	0.0
Arkoma	Woodford-Arkoma	416	8.0	0.005	1.145	0.0	3.8	0.3
Black Warrior	Chattanooga	1,696	8.0	0.000	0.121	0.0	1.6	0.0
Southwest								
Fort Worth	Barnett-Core	152	6.4	0.000	2.015	0.0	2.0	0.1
Fort Worth	Barnett-North	1,922	6.4	0.005	0.610	0.1	7.5	0.3
Fort Worth	Barnett-South	6,871	6.4	0.001	0.195	0.0	8.6	0.3

Table 3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2016) (cont.)

Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Average EUR: Crude Oil[2] (MMb/well)	Average EUR: Natural Gas (Bcf/well)	Technically Recoverable Resources: Crude Oil (Bb)	Technically Recoverable Resources: Natural Gas (Tcf)	Technically Recoverable Resources: NGPL (Bb)
Southwest								
Permian	Abo	2,426	4.0	0.058	0.215	0.6	2.1	0.1
Permian	Avalon/Bone Spring	3,866	6.4	0.160	0.389	4.0	9.6	1.3
Permian	Barnett-Woodford	5,229	4.1	0.003	0.061	0.1	1.3	0.2
Permian	Canyon	6,270	8.0	0.005	0.134	0.2	6.7	0.1
Permian	Spraberry	6,702	6.4	0.098	0.172	4.2	7.4	1.3
Permian	Wolfcamp	38,013	6.4	0.139	0.346	33.8	84.1	11.4
Rocky Mountain/Dakotas								
Denver	Denver/Jules–All plays	3,188	8.0	0.004	0.106	0.1	2.7	0.0
Denver	Niobrara	16,905	6.7	0.056	0.181	6.3	20.4	0.1
Greater Green River	Hilliard-Baxter-Mancos	4,448	8.0	0.001	0.156	0.0	5.5	0.2
Greater Green River	Tight Oil Plays	1,244	6.4	0.112	0.015	0.9	0.1	0.0
Montana Thrust Belt	Tight Oil Plays	849	6.4	0.111	0.075	0.6	0.4	0.0
North Central Montana	Bowdoin-Greenhorn	958	4.0	0.000	0.151	0.0	0.6	0.0
Paradox	Fractured Interbed	1,171	1.6	0.543	0.434	1.0	0.8	0.0
Powder River	Tight Oil Plays	9,122	6.4	0.035	0.040	2.1	2.4	0.1
San Juan	Dakota	1,807	8.0	0.002	0.460	0.0	6.7	0.0
San Juan	Lewis	1,479	5.0	0.000	2.200	0.0	16.3	0.0
San Juan	Mesaverde	454	8.0	0.002	0.425	0.0	1.5	0.0
San Juan	Pictured Cliffs	181	4.0	0.001	0.366	0.0	0.3	0.0
Southwestern Wyoming	Fort Union-Fox Hills	1,847	8.0	0.008	0.787	0.1	11.6	1.1
Southwestern Wyoming	Frontier	2,456	8.0	0.018	0.221	0.4	4.3	0.0
Southwestern Wyoming	Lance	1,896	8.0	0.040	1.109	0.6	16.8	3.0
Southwestern Wyoming	Lewis	3,606	8.0	0.014	0.322	0.4	9.3	1.7
Southwestern Wyoming	Tight Oil Plays	1,520	6.4	0.111	0.015	1.1	0.1	0.0
Uinta-Piceance	Iles-Mesaverde	4,275	8.0	0.001	0.442	0.0	15.1	0.4
Uinta-Piceance	Mancos	1,552	8.0	0.002	0.452	0.0	5.6	0.0
Uinta-Piceance	Tight Oil Plays	214	6.4	0.050	0.111	0.1	0.2	0.0
Uinta-Piceance	Wasatch-Mesaverde	1,105	8.0	0.033	0.518	0.3	4.6	0.0
Uinta-Piceance	Williams Fork	1,397	8.7	0.020	0.618	0.2	7.5	0.0
Williston	Bakken Central	3,695	4.0	0.218	0.187	3.2	2.8	0.4
Williston	Bakken Eastern Transitional	2,038	4.0	0.226	0.105	1.8	0.9	0.2
Williston	Bakken Elm Coulee-Billings Nose	3,166	3.6	0.130	0.108	1.5	1.2	0.1
Williston	Bakken Nesson-Little Knife	2,854	4.0	0.251	0.183	2.9	2.1	0.4
Williston	Bakken Northwest Transitional	2,301	4.0	0.073	0.018	0.7	0.2	0.0
Williston	Bakken Three Forks	8,142	4.5	0.163	0.145	6.0	5.3	0.6
Williston	Gammon	2,060	4.0	0.000	0.464	0.0	3.8	0.0
Williston	Judith River-Eagle	1,394	4.0	0.000	0.147	0.0	0.8	0.0
Wind River	Fort Union-Lance	568	8.0	0.068	0.596	0.3	2.7	0.1
West Coast								
Columbia	Basin Central	1,091	8.0	0.000	1.400	0.0	12.2	0.0
San Joaquin/Los Angeles	Monterey/Santos	3,141	2.4	0.028	0.065	0.2	0.5	0.0
					Total Tight/Shale	**103.8**	**1,228.1**	**58.4**

mi² = square miles; MMb = million barrels; Bcf = billion cubic feet; Bb = billion barrels; Tcf = trillion cubic feet.

EUR = estimated ultimate recovery.

NGPL = Natural Gas Plant Liquids.

[1]Area of play that is expected to have unproved technically recoverable resources remaining.

[2]Includes lease condensates.

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

Table 4. U.S. unproved technically recoverable coalbed methane resources by play (as of January 1, 2016)

Region/Basin	Play	Area with Potential[1] (mi²)	Average Spacing (wells/mi²)	Average EUR Crude Oil[2] MMb/well)	Average EUR Natural Gas (Bcf/well)	Technically Recoverable Resources Crude Oil (Bb)	Technically Recoverable Resources Natural Gas (Tcf)	Technically Recoverable Resources NGPL (Bb)
East								
Appalachian	Central Basin	1,285	8	0.000	0.176	0.0	1.8	0.0
Appalachian	North Appalachian Basin – High	359	12	0.000	0.125	0.0	0.5	0.0
Appalachian	North Appalachian Basin – Mod/Low	466	12	0.000	0.080	0.0	0.5	0.0
Illinois	Central Basin	1,277	8	0.000	0.120	0.0	1.2	0.0
Gulf Coast								
Black Warrior	Extension Area	148	8	0.000	0.080	0.0	0.1	0.0
Black Warrior	Main Area	445	12	0.000	0.206	0.0	1.1	0.0
Cahaba	Cahaba Coal Field	194	8	0.000	0.180	0.0	0.3	0.0
Midcontinent								
Arkoma	Arkoma	2,560	8	0.000	0.216	0.0	4.4	0.0
Cherokee Platform	Cherokee	3,295	8	0.000	0.065	0.0	1.7	0.0
Forest City Basin	Central Basin	23,110	8	0.022	0.172	4.0	31.8	0.0
Southwest								
Raton	Southern	1,357	8	0.000	0.376	0.0	4.1	0.0
Rocky Mountain/Dakotas								
Greater Green River	Deep	1,620	4	0.000	0.600	0.0	3.9	0.0
Greater Green River	Shallow	521	8	0.000	0.204	0.0	0.9	0.0
Piceance	Deep	1,534	4	0.000	0.600	0.0	3.7	0.0
Piceance	Divide Creek	123	8	0.000	0.179	0.0	0.2	0.0
Piceance	Shallow	1,698	4	0.000	0.300	0.0	2.0	0.0
Piceance	White River Dome	183	8	0.000	0.410	0.0	0.6	0.0
Powder River	Big George/Lower Fort Union	1,138	16	0.000	0.260	0.0	4.7	0.0
Powder River	Wasatch	173	8	0.000	0.056	0.0	0.1	0.0
Powder River	Wyodak/Upper Fort Union	5,036	20	0.000	0.136	0.0	13.7	0.0
Raton	Northern	304	8	0.000	0.350	0.0	0.9	0.0
Raton	Purgatoire River	139	8	0.000	0.311	0.0	0.3	0.0
San Juan	Fairway NM	38	4	0.000	1.144	0.0	0.2	0.0
San Juan	North Basin	1,110	4	0.000	0.280	0.0	1.2	0.0
San Juan	North Basin CO	1,503	4	0.000	1.516	0.0	9.1	0.0
San Juan	South Basin	692	4	0.000	0.199	0.0	0.6	0.0
San Juan	South Menefee NM	373	5	0.000	0.095	0.0	0.2	0.0
Uinta	Ferron	218	8	0.000	0.776	0.0	1.4	0.0
Uinta	Sego	341	4	0.000	0.306	0.0	0.4	0.0
Wind River	Mesaverde	418	2	0.000	2.051	0.0	1.7	0.0
Wyoming Thrust Belt	All Plays	5,200	2	0.000	0.454	0.0	5.4	0.0
West Coast								
Western Washington	Bellingham	441	2	0.000	2.391	0.0	2.1	0.0
Western Washington	Southern Puget Lowlands	1,102	2	0.000	0.687	0.0	1.5	0.0
Western Washington	Western Cascade Mountains	2,152	2	0.000	1.559	0.0	6.7	0.0
					Total Coalbed Methane	**4.0**	**109.0**	**0.0**

mi² = square miles; MMb = million barrels; Bcf = billion cubic feet; Bb = billion barrels; Tcf = trillion cubic feet.
EUR = estimated ultimate recovery.
NGPL = Natural Gas Plant Liquids.
[1]Area of play that is expected to have unproved technically recoverable resources remaining.
[2]Includes lease condensates.
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Table 5. Distribution of crude oil EURs in the Bakken

Play Name	State	County	Number of potential wells	EUR (Mb/well)
Bakken Central Basin	MT	Daniels	189	60
Bakken Central Basin	MT	McCone	528	60
Bakken Central Basin	MT	Richland	1,083	197
Bakken Central Basin	MT	Roosevelt	4,988	203
Bakken Central Basin	MT	Sheridan	753	57
Bakken Central Basin	ND	Divide	12	241
Bakken Central Basin	ND	Dunn	77	304
Bakken Central Basin	ND	McKenzie	3,948	268
Bakken Central Basin	ND	Williams	3,200	259
Bakken Eastern Transitional	ND	Burke	2,708	136
Bakken Eastern Transitional	ND	Divide	674	138
Bakken Eastern Transitional	ND	Dunn	1,101	330
Bakken Eastern Transitional	ND	Hettinger	7	169
Bakken Eastern Transitional	ND	McLean	250	231
Bakken Eastern Transitional	ND	Mercer	144	13
Bakken Eastern Transitional	ND	Mountrail	2,784	318
Bakken Eastern Transitional	ND	Stark	371	169
Bakken Eastern Transitional	ND	Ward	111	80
Bakken Elm Coulee-Billings Nose	MT	McCone	116	80
Bakken Elm Coulee-Billings Nose	MT	Richland	3,421	152
Bakken Elm Coulee-Billings Nose	ND	Billings	835	60
Bakken Elm Coulee-Billings Nose	ND	Golden Valley	133	173
Bakken Elm Coulee-Billings Nose	ND	McKenzie	2,450	179
Bakken Nesson-Little Knife	ND	Billings	586	92
Bakken Nesson-Little Knife	ND	Burke	682	188
Bakken Nesson-Little Knife	ND	Divide	612	165
Bakken Nesson-Little Knife	ND	Dunn	2,860	301
Bakken Nesson-Little Knife	ND	Hettinger	106	223
Bakken Nesson-Little Knife	ND	McKenzie	1,741	358
Bakken Nesson-Little Knife	ND	Mountrail	627	282
Bakken Nesson-Little Knife	ND	Slope	167	120
Bakken Nesson-Little Knife	ND	Stark	2,165	223
Bakken Nesson-Little Knife	ND	Williams	1,871	210
Bakken Northwest Transitional	MT	Daniels	2,584	82
Bakken Northwest Transitional	MT	McCone	161	82
Bakken Northwest Transitional	MT	Roosevelt	1312	82
Bakken Northwest Transitional	MT	Sheridan	2,857	47
Bakken Northwest Transitional	MT	Valley	1,005	1
Bakken Northwest Transitional	ND	Divide	608	154
Bakken Northwest Transitional	ND	Williams	678	169

Mb = thousand barrels.

EUR = estimated ultimate recovery.

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

Starting with AEO2017, new allocation factors began to be used for natural gas plant liquids (NGPL), updating both the gas-to-liquids ratios and the purity splits of the NGPL barrels. AEO2017 reflected improvements to the Appalachian and Williston basins, as well as the Eagle Ford formation. In AEO2018, allocation factors for the Permian Basin were updated. EIA will continue to update input drivers generating NGPL production going forward, focusing on plays expected to make increasing contribution to total U.S. natural gas production. The allocation factors were derived from a combination of producer public statements and filings, third-party data on production well characteristics, and analysis of EIA-collected survey data for NGPL production at the gas-plant level.

The AEO TRRs incorporate current drilling, completion, and recovery techniques, requiring adjustments to some of the assumptions used by the USGS to generate its TRR estimates, as well as the inclusion of shale gas and tight oil resources not yet assessed by the USGS. If well production data are available, EIA analyzes the decline curve of producing wells to calculate the expected EUR per well from future drilling.

The underlying resource for the AEO Reference case is uncertain, particularly as exploration and development of tight oil continues to move into areas with little to no production history. Many wells drilled in tight or shale formations using the latest technologies have less than two years of production history, so the impact of recent technological advancement on the estimate of future recovery cannot be fully ascertained. Uncertainty also extends to the areal extent of formations and the number of layers that could be drilled within formations. Alternative resource cases are discussed at the end of this document.

Lower 48 onshore

The Onshore Lower 48 Oil and Gas Supply Submodule (OLOGSS) is a play-level model used to analyze crude oil and natural gas supply from onshore Lower 48 sources. The methodology includes a comprehensive assessment method for determining the relative economics of various prospects based on financial considerations, the nature of the resource, and the available technologies. The general methodology relies on a detailed economic analysis of potential projects in known fields, enhanced oil recovery projects, and undiscovered resources. The economically viable projects are developed subject to the availability of resource development constraints that simulate the existing and expected infrastructure of the oil and natural gas industries. For crude oil projects, advanced secondary or improved oil recovery techniques (e.g., infill drilling and horizontal drilling) and enhanced oil recovery (e.g., CO2 flooding, steam flooding, and polymer flooding) processes are explicitly represented. For natural gas projects, the OLOGSS represents supply from shale formations, tight sands formations, coalbed methane, and other sources.

The OLOGSS evaluates the economics of future crude oil and natural gas exploration and development from the perspective of an operator making an investment decision. An important aspect of the economic calculation is the tax treatment. Tax provisions vary with the type of producer (major, large independent, or small independent). For AEO2018, the economics of potential projects reflect the tax treatment provided by current laws for large independent producers. Relevant tax provisions are assumed unchanged over the life of the investment. Costs are assumed constant over the investment life but vary across region, fuel, and process type. Operating losses incurred in the initial investment period are carried forward and used against revenues generated by the project in later years.

Technological improvement

The OLOGSS uses a simplified approach to modeling the impact of technology advancement on U.S. crude oil and natural gas costs and productivity to better capture a continually changing technological landscape. This approach incorporates assumptions regarding ongoing innovation in upstream technologies and reflects the average annual growth rate in natural gas and crude oil resources plus cumulative production from 1990 between AEO2000 and AEO2015.

Areas in tight oil, tight gas, and shale gas plays are divided into two productivity tiers with different assumed rates of technology change. The first tier (Tier 1) encompasses actively developing areas and the second tier (Tier 2) encompasses areas not yet being developed. Once development begins in a Tier 2 area, the rate of technological improvement doubles for wells drilling in the early development phase as producers determine how to efficiently extract the hydrocarbons and where the sweet spots are (learning by doing). This area is then converted to Tier 1, so technological improvement for continued drilling will reflect the rates assumed for Tier 1 areas. This conversion captures the effects of diminishing returns on a per-well basis from decreasing well spacing as development progresses, the rapid market penetration of technologies, and the ready application of industry practices and technologies at the time of development. The specific assumptions for the annual average rate of technological improvement are shown in Table 6.

Table 6. Onshore lower 48 technology assumptions

Crude Oil and Natural Gas Resource Type	Drilling Cost	Lease Equipment & Operating Cost	EUR-Tier 1	EUR-Tier 2	EUR-Tier 2 drilling ramp-up period
Tight oil	-1.00%	-0.50%	1.00%	3.00%	6.00%
Tight gas	-1.00%	-0.50%	1.00%	3.00%	6.00%
Shale gas	-1.00%	-0.50%	1.00%	3.00%	6.00%
All other	-0.25%	-0.25%	0.25%	NA	NA

EUR = estimated ultimate recovery

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

CO2 enhanced oil recovery

For CO2 miscible flooding, the OLOGSS incorporates both industrial and natural sources of CO2. The industrial sources of CO2 are:

- Hydrogen plants
- Ammonia plants
- Ethanol plants
- Cement plants
- Fossil fuel power plants
- Natural gas processing
- Coal/biomass to liquids (CBTL) processing

The volume and cost of CO2 available from fossil fuel power plants and CBTL are determined in the Electricity Market Module and in the Liquid Fuels Market Module, respectively. The volume and cost of CO2 from the other industrial plants are represented at the plant level (3 ammonia, 84 cement, 152 ethanol, 31 hydrogen, and 60 natural gas processing plants). The maximum CO2 available by region from the industrial and natural sources is shown in Table 7.

Table 7. Maximum volume of CO2 available

billion cubic feet

Region	Natural	Hydrogen Plants	Ammonia Plants	Ethanol Plants	Cement Plants	Natural Gas Processing
East	0	2	0	137	297	4
Gulf Coast	292	18	15	6	173	69
Midcontinent	16	6	7	298	164	23
Southwest	657	1	0	0	4	1
Rocky Mountains/Dakotas	80	5	0	47	75	28
West Coast	0	5	0	1	97	58

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

Technology and market constraints prevent the total volumes of CO2 from the other industrial sources from becoming immediately available. The development of the CO2 market is divided into two periods: (1) the development phase and (2) the market acceptance phase. During the development phase, the required capture equipment is developed, pipelines and compressors are constructed, and no CO2 is available. During the market acceptance phase, the capture technology is being widely implemented and volumes of CO2 first become available. The number of years in each development period is shown in Table 8. CO2 is available from planned Carbon Capture and Storage (CCS) power plants funded by American Recovery and Reinvestment Act of 2009 (ARRA) starting in 2016.

Table 8. CO2 availability assumptions

Source Type	Development Phase (years)	Market Acceptance Phase (years)	Ultimate Market Acceptance
Natural	1	10	100%
Hydrogen Plants	4	10	100%
Ammonia Plants	2	10	100%
Ethanol Plants	4	10	100%
Cement Plants	7	10	100%
Natural Gas Processing	2	10	100%

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

The cost of CO2 from natural sources is a function of the oil price. For industrial sources of CO2, the cost to the producer includes the cost to capture, to compress to pipeline pressure, and to transport to the project site via pipeline within the region (Table 9). Inter-regional transportation costs add $0.40 per thousand cubic feet (Mcf) for every region crossed.

Table 9. Industrial CO2 capture and transportation costs by region

$/Mcf

OGSM Region	Hydrogen Plants	Ammonia Plants	Ethanol Plants	Cement Plants	Natural Gas Processing
East	$13.80	$4.00	$3.32	$10.61	$3.01
Gulf Coast	$13.80	$4.00	$3.78	$10.61	$3.30
Midcontinent	$13.80	$3.87	$3.15	$10.61	$3.24
Southwest	$13.80	$4.00	$3.24	$10.61	$4.91
Rocky Mountains/Dakotas	$13.80	$4.00	$3.51	$10.61	$3.34
West Coast	$13.80	$4.00	$4.19	$10.61	$2.57

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

Lower 48 offshore

Most of the Lower 48 offshore crude oil and natural gas production comes from the deepwater Gulf of Mexico (GOM). Production from currently producing fields and industry-announced discoveries largely determines the near-term crude oil and natural gas production projection.

For currently producing oil fields, a 10%-15% exponential decline is assumed for production. Currently producing natural gas fields use a 30% exponential decline. Fields that began production after 2008 are assumed to remain at their peak production level for two years before declining.

The assumed field size and year of initial production of the major announced deepwater discoveries that were not brought into production by 2016 are shown in Table 10. A field that is announced as an oil field is assumed to be 100% oil, and a field that is announced as a natural gas field is assumed to be 100% natural gas. If a field is expected to produce both oil and natural gas, 70% is assumed to be oil and 30% is assumed to be natural gas.

Table 10. Assumed size and initial production year of major announced deepwater discoveries

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBOE)	Start Year of Production
Gotcha	AC865	7,844	2006	12	90	2019
Vicksburg	DC353	7,457	2009	14	357	2019
Gettysburg	DC398	5,000	2014	11	44	2024
Bushwood	GB506	2,700	2009	12	90	2019
North Platte	GB959	4,400	2012	13	176	2022
Katmai	GC040	2,100	2014	11	44	2024
Samurai	GC432	3,400	2009	12	90	2017
Stampede-Pony	GC468	3,497	2006	14	357	2018
Stampede-Knotty Head	GC512	3,557	2005	14	357	2018
Holstein Deep	GC643	4,326	2014	14	357	2017
Caesar Tonga 2	GC726	5,000	2009	12	90	2017
Anchor	GC807	5,183	2015	16	1,393	2025
Parmer	GC823	3,821	2012	11	44	2022
Heidelberg	GC903	5,271	2009	14	357	2017
Guadalupe	KC010	4,000	2014	12	90	2024
Gila	KC093	4,900	2013	13	176	2017

Table 10. Assumed size and initial production year of major announced deepwater discoveries (cont.)

Field/Project Name	Block	Water Depth (feet)	Year of Discovery	Field Size Class	Field Size (MMBOE)	Start Year of Production
Tiber	KC102	4,132	2009	15	693	2017
Buckskin	KC872	6,978	2009	13	176	2018
Kaskida	KC292	5,894	2006	15	693	2020
Leon	KC642	1,865	2014	14	357	2024
Moccasin	KC736	6,759	2011	14	357	2021
Sicily	KC814	6,716	2015	14	357	2020
Hadrian North	KC919	7,000	2010	14	357	2020
Diamond	LL370	9,975	2008	10	23	2018
Cheyenne East	LL400	9,187	2011	9	12	2020
Amethyst	MC026	1,200	2014	11	44	2017
Horn Mountain Deep	MC126	5,400	2015	12	90	2017
Mandy	MC199	2,478	2010	13	176	2020
Appomattox	MC392	7,290	2009	13	176	2017
Son Of Bluto 2	MC431	6,461	2012	11	44	2017
Rydberg	MC525	7,500	2014	12	90	2019
Fort Sumter	MC566	7,062	2016	12	90	2020
Deimos South	MC762	3,122	2010	12	90	2017
Kaikias	MC768	4,575	2014	12	90	2024
Kodiak	MC771	5,006	2008	13	176	2018
West Boreas	MC792	3,094	2009	12	90	2017
Vito	MC984	4,038	2009	13	176	2020
Phobos	SE039	8,500	2013	12	90	2018
Big Foot	WR029	5,235	2006	13	176	2018
Shenandoah	WR052	5,750	2009	15	693	2017
Yucatan North	WR095	5,860	2013	12	90	2020
Yeti	WR160	5,895	2015	13	176	2025

MMBOE = million barrels of oil equivalence.
Source: U.S. Energy Information Administration, Office of Energy Analysis.

Production is assumed to ramp up to a peak level in three years, remain at the peak level until the ratio of cumulative production to initial resource reaches 10%, and then decline at an exponential rate of 30% for natural gas fields and 25% for oil fields.

The discovery of new fields (based on the Bureau of Ocean Energy Management's (BOEM) field size distribution) is assumed to follow historical patterns. Production from these fields is assumed to follow the same profile as the announced discoveries (as described above). Advances in technology for the various activities associated with crude oil and natural gas exploration, development, and production can have a significant impact on the costs associated with these activities. The specific technology levers and values for the offshore are presented in Table 11.

Leasing is assumed to be available in 2022 in the Eastern Gulf of Mexico, in 2018 in the Mid- and South Atlantic, in 2023 in the South Pacific, and after 2035 in the North Atlantic, Florida straits, Pacific Northwest, and North and Central California.

Table 11. Offshore exploration and production technology levels

Technology Level	Total Improvement over 30 years (%)
Exploration success rates	30
Delay to commence first exploration and between exploration and development	15
Exploration and development drilling costs	30
Operating cost	30
Time to construct production facility	15
Production facility construction costs	30
Initial constant production rate	15
Decline rate	0

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

Alaska crude oil production

Projected Alaskan oil production includes both existing producing fields and undiscovered fields that are expected to exist, based on the region's geology. The existing fields category includes the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. Projected North Slope oil production also includes the initiation of oil production in the Point Thomson Field and in the fields that are part of the CD5 and Shark Tooth projects in 2016, as well as the estimated start of oil production in the fields that compose the Greater Moose's Tooth project in 2019, fields in the Pikka unit in 2021, the Umiat Field in 2022, the Quguk Field in 2024, and in the Smith Bay Field in 2026. Alaskan crude oil production from the undiscovered fields is determined by the estimates of available resources in undeveloped areas and the net present value of the cash flow calculated for these undiscovered fields based on the expected capital costs, operating costs, and projected prices.

The discovery of new Alaskan oil fields is determined by the number of new wildcat exploration wells drilled each year and by the average wildcat success rate. The North Slope and South-Central wildcat well success rates are based on the success rates reported to the Alaska Oil and Gas Conservation Commission for the period of 1977 through 2008.

New wildcat exploration drilling rates are determined differently for the North Slope and South-Central Alaska. North Slope wildcat well drilling rates were found to be reasonably well correlated with prevailing West Texas Intermediate (WTI) crude oil prices. Consequently, an ordinary least squares statistical regression was employed to develop an equation that specifies North Slope wildcat exploration well drilling rates as a function of prevailing WTI crude oil prices. In contrast, South-Central wildcat well drilling rates were found to be uncorrelated with crude oil prices or any other criterion. However, South-Central wildcat well drilling rates on average equaled slightly more than three wells per year from 1977 through 2008, so three South-Central wildcat exploration wells are assumed to be drilled every year in the future.

On the North Slope, the proportion of wildcat exploration wells drilled onshore relative to those drilled offshore is assumed to change over time. Initially, only a small proportion of all the North Slope wildcat exploration wells are drilled offshore. Over time, however, the offshore proportion increases linearly, so that after 20 years, 50% of the North Slope wildcat wells are drilled onshore and 50% are drilled offshore. The 50/50 onshore/offshore wildcat well apportionment remains constant through the remainder of the projection because offshore North Slope wells and fields are considerably more expensive to drill and develop, thereby providing an incentive to continue drilling onshore wildcat wells even though the expected onshore field size is considerably smaller than the oil fields expected to be discovered offshore.

The size of the new oil fields discovered by wildcat exploration drilling is based on the expected field sizes of the undiscovered Alaska oil resource base, as determined by the U.S. Geological Survey (USGS) for the onshore and state offshore regions of Alaska, and by the BOEM (formerly known as the U.S. Minerals Management Service) for the federal offshore regions of Alaska. The undiscovered resource assumptions for the offshore North Slope were revised in light of Shell Oil Company's disappointing results in the Chukchi Sea, the cancellation of two potential Arctic offshore lease sales scheduled under BOEM's 2012-2017 five-year leasing program, and companies relinquishing their leases in the Chukchi Sea.

EIA assumes that the largest undiscovered oil fields will be found and developed first before the small and midsize undiscovered fields. As exploration and discovery proceed and as the largest oil fields are discovered and developed, the discovery and development process proceeds to find and develop the next largest set of oil fields. This large-to-small discovery and development process is predicated on the fact that developing new infrastructure in Alaska, particularly on the North Slope, is an expensive undertaking. The largest fields enjoy economies of scale, which make them more profitable and less risky to develop than the smaller fields.

The ban on oil and natural gas exploration and production in the Arctic National Wildlife Refuge was lifted with the passage of Public Law 115-97 in December 2017. However, this law was enacted after the completion of the AEO2018 scenarios so the AEO2018 projections for Alaskan oil and natural gas production reflect the assumption that the prohibition remained in effect throughout the projection period.

Three uncertainties are associated with the Alaskan oil projections:

- The heavy oil deposits located on the North Slope, which exceed 20 billion barrels of oil-in-place, may or may not be producible in the foreseeable future at recovery rates exceeding a few percent
- The oil production potential of the North Slope shale formations is unknown
- The North Slope offshore oil resource potential, especially in the Chukchi Sea, is untested

In June 2011, Alyeska Pipeline Service Company released a report regarding potential operational problems that might occur as Trans-Alaska Pipeline System (TAPS) throughput declines from the current production levels. Although the onset of TAPS low-flow problems could begin at about 550,000 barrels per day (b/d), absent any mitigation, the severity of the TAPS operational problems is expected to increase significantly as throughput declines. If the types and severity of problems multiply, the investment required to mitigate those problems is expected to increase significantly. Because of the many and diverse operational problems expected to occur below 350,000 b/d of throughput, considerable investment might be required to keep the pipeline operational below this threshold. As a result, North Slope fields are assumed to be shut down, plugged, and abandoned when the following two conditions are simultaneously satisfied: (1) TAPS throughput at or below 350,000 b/d and (2) total North Slope oil production revenues at or below $5.0 billion per year. The remaining resources would become *stranded resources*. The owners/operators of the stranded resources would have an incentive to subsidize development of more expensive additional resources to keep TAPS operational and thus not strand their resources. The AEO2018 represents this scenario.

Legislation and regulations

The Outer Continental Shelf Deep Water Royalty Act (Public Law 104-58) gave the Secretary of the Interior the authority to suspend royalty requirements on new production from qualifying leases and required that royalty payments be waived automatically on new leases sold in the five years following its November 28, 1995, enactment. The volume of production on which no royalties were due for the five years was assumed to be 17.5 million barrels of oil equivalent (BOE) in water depths of 200 to 400 meters, 52.5 million BOE in water depths of 400 to 800 meters, and 87.5 million BOE in water depths greater than 800 meters. In any year during which the arithmetic average of the closing prices on the New York Mercantile Exchange for light sweet crude oil exceeded $28 per barrel or for natural gas exceeded $3.50 per million Btu, any production of crude oil or natural gas was subject to royalties at the lease-stipulated royalty rate. Although automatic relief expired on November 28, 2000, the act provided the Minerals Management Service (MMS) the authority to include royalty suspensions as a feature of leases sold in the future. In September 2000, the MMS issued a set of proposed rules and regulations that provide a framework for continuing deep water royalty relief on a lease-by-lease basis. The model assumed that relief will be granted at roughly the same levels as provided during the first five years of the Act.

Section 345 of the Energy Policy Act of 2005 provides royalty relief for oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico from any oil or natural gas lease sale occurring within five years after enactment. The minimum volumes of production with suspended royalty payments are:

1. 5,000,000 BOE for each lease in water depths of 400 to 800 meters
2. 9,000,000 BOE for each lease in water depths of 800 to 1,600 meters
3. 12,000,000 BOE for each lease in water depths of 1,600 to 2,000 meters
4. 16,000,000 BOE for each lease in water depths greater than 2,000 meters

The water depth categories specified in Section 345 were adjusted to be consistent with the depth categories in the Offshore Oil and Gas Supply Submodule. The suspension volumes are 5,000,000 BOE for leases in water depths of 400 to 800 meters; 9,000,000 BOE for leases in water depths of 800 to 1,600 meters; 12,000,000 BOE for leases in water depths of 1,600 to 2,400 meters; and 16,000,000 for leases in water depths greater than 2,400 meters. Examination of the resources available at 2,000 to 2,400 meters showed that the differences between the depths used in the model and those specified in the bill would not materially affect the model result.

The MMS published its final rule on the “Oil and Gas and Sulphur Operations in the Outer Continental Shelf Relief or Reduction in Royalty Rates Deep Gas Provisions” on January 26, 2004, effective March 1,

2004. The rule grants royalty relief for natural gas production from wells drilled to 15,000 feet or deeper on leases issued before January 1, 2001, in the shallow waters (less than 200 meters) of the Gulf of Mexico. Production of natural as from the completed deep well must begin before five years after the effective date of the final rule. The minimum volume of production with suspended royalty payments is 15 billion cubic feet for wells drilled to at least 15,000 feet and 25 billion cubic feet for wells drilled to more than 18,000 feet. In addition, unsuccessful wells drilled to a depth of at least 18,000 feet would receive a royalty credit for 5 billion cubic feet of natural gas. The ruling also grants royalty suspension for volumes of not less than 35 billion cubic feet from ultra-deep wells on leases issued before January 1, 2001.

Section 354 of the Energy Policy Act of 2005 established a competitive program to provide grants for cost-shared projects to enhance oil and natural gas recovery through CO2 injection, while at the same time sequestering CO2 produced from the combustion of fossil fuels in power plants and large industrial processes.

From 1982 through 2008, Congress did not appropriate funds needed by the MMS to conduct leasing activities on portions of the federal Outer Continental Shelf (OCS) and thus effectively prohibited leasing. Further, a separate executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, with the exception of the Western Gulf of Mexico and portions of the Central and Eastern Gulf of Mexico. When combined, these actions prohibited drilling in most offshore regions, including areas along the Atlantic and Pacific coasts, the eastern Gulf of Mexico, and portions of the central Gulf of Mexico. In 2006, the Gulf of Mexico Energy Security Act imposed a third ban on drilling through 2022 on tracts in the Eastern Gulf of Mexico that are within 125 miles of Florida, east of a dividing line known as the Military Mission Line, and in the Central Gulf of Mexico within 100 miles of Florida.

On July 14, 2008, President Bush lifted the executive ban and urged Congress to remove the congressional ban. On September 30, 2008, Congress allowed the congressional ban to expire. Although the ban through 2022 on areas in the Eastern and Central Gulf of Mexico remains in place, the lifting of the executive and congressional bans removed regulatory obstacles to development of the Atlantic and Pacific OCS.

On March 20, 2015, the Bureau of Land Management (BLM) released regulations applying to hydraulic fracturing on federal and Indian lands (the *Fracking Rule*). Key components of the rule include: validation of well integrity and strong cement barriers between the wellbore and water zones through which the wellbore passes; public disclosure of chemicals used in hydraulic fracturing; specific standards for interim storage of recovered waste fluids from hydraulic fracturing; and disclosure of more detailed information on the geology, depth, and location of preexisting wells to the BLM. The impact of this regulation is expected to be minimal because many of the provisions are consistent with current industry practices and state regulations. However, in June 2016, this regulation was struck down in federal court. BLM appealed the court decision but rescinded the proposed rule in December 2017.

Oil and gas supply alternative cases

Oil and Natural Gas Resource and Technology cases

Estimates of technically recoverable tight/shale crude oil and natural gas resources are particularly uncertain and change over time as new information is gained through drilling, production, and technology experimentation. Over the past decade, as more tight/shale formations have gone into production, the estimate of technically recoverable tight oil and shale gas resources has increased. However, these increases in technically recoverable resources embody many assumptions that might not prove to be true over the long term and across the entire tight/shale formation. For example, these resource estimates assume that crude oil and natural gas production rates achieved in a limited portion of the formation are representative of the entire formation, even though neighboring well production rates can vary by as much as a factor of three within the same play. Moreover, the tight/shale formation can vary significantly across the petroleum basin with respect to depth, thickness, porosity, carbon content, pore pressure, clay content, thermal maturity, and water content. Technological improvements and innovations also may allow development of crude oil and natural gas resources that are not included in the Reference case because they have not been identified yet.

The sensitivity of the AEO2018 projections to changes in assumptions regarding domestic crude oil and natural gas resources and technological progress is examined in two cases. These cases do not represent a confidence interval for future domestic oil and natural gas supply, but rather they provide a framework to examine the effects of higher and lower domestic supply on energy demand, imports, and prices. Assumptions associated with these cases are described below.

Low Oil and Gas Resource and Technology case

In the Low Oil and Gas Resource and Technology case, the estimated ultimate recovery per tight oil, tight gas, or shale gas well in the United States and the undiscovered resources in Alaska and the offshore Lower 48 states are assumed to be 50% lower than in the Reference case. Rates of technological improvement that reduce costs and increase productivity in the United States are also 50% lower than in the Reference case. These assumptions increase the per-unit cost of crude oil and natural gas development in the United States. The total unproved technically recoverable resource of crude oil is reduced to 156 billion barrels, and the natural gas resource is reduced to 1,269 trillion cubic feet (Tcf), as compared with unproved resource estimates of 249 billion barrels of crude oil and 2,155 Tcf of natural gas as of January 1, 2016, in the Reference case.

High Oil and Gas Resource and Technology case

In the High Oil and Gas Resource and Technology case, the resource assumptions are adjusted to allow a continued increase in domestic crude oil production to more than 19 million barrels per day (b/d) in 2050 compared with 11 million b/d in the Reference case. This case includes: (1) 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well; (2) additional unidentified tight oil and shale gas resources to reflect the possibility that additional layers or new areas of low-permeability zones will be identified and developed; (3) 50% higher assumed rates of technological improvement that reduce costs and increase productivity in the United States than in the Reference case; and (4) 50% higher technically recoverable undiscovered resources in Alaska and in the offshore Lower 48 states than in the Reference case. The total unproved technically recoverable resource of crude oil increases to 421 billion barrels, and the natural gas resource increases to 3,226 Tcf compared with unproved resource estimates of 249 billion barrels of crude oil and 2,155 Tcf of natural gas in the Reference case as of the start of 2016.

Arctic National Wildlife Refuge (ANWR) cases

On December 22, 2017, Public Law 115-97 was signed into law [6]. Title II, Section 20001 allows for crude oil and natural gas exploration and development in the Coastal Plain (Area 1002) of ANWR. Because this law was passed after the completion of the AEO2018 scenarios, three ANWR cases were generated after the release of the AEO2018 to address the potential impact of the development of crude oil resources in the Coastal Plain of ANWR. Based on the latest (1998) USGS resource assessment, the technically recoverable oil resource in the Coastal Plain is estimated to be between 5.7 billion and 16.0 billion barrels (95% and 5% probability range), with a mean value of 10.4 billion barrels [7]. Technically recoverable resources are assumed to be:

- 5.7 billion barrels in the Low ANWR case
- 10.4 billion barrels in the Mean ANWR case
- 16.0 billion barrels in the High ANWR case

For all three ANWR cases, the first lease sale is assumed to take place in 2021. Exploration, appraisal, permitting, and development is assumed to take nine years so first production will take place no earlier than 2031. New fields startup production every two years thereafter, if economic.

Notes and sources

[1] The current development of tight oil plays has shifted industry focus and investment away from the development of U.S. oil shale (kerogen) resources. Considerable technological development is required prior to the large-scale, in-situ production of oil shale being economically feasible. Consequently, the Oil Shale Supply Submodule assumes that large-scale, in-situ oil shale production is not commercially feasible in the Reference case prior to 2050.

[2] Technically recoverable resources are resources in accumulations producible using current recovery technology but without reference to economic profitability.

[3] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrates with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions.

[4] Unproved resources include resources that have been confirmed by exploratory drilling and undiscovered resources that are located outside oil and natural gas fields in which the presence of resources has been confirmed by exploratory drilling; they include resources from undiscovered pools within confirmed fields when they occur as unrelated accumulations controlled by distinctly separate structural features or stratigraphic conditions.

[5] The Bakken areas are consistent with the USGS Bakken formation assessment units shown in Figure 1 of Fact Sheet 2013-3013, Assessment of Undiscovered Oil Resources in the Bakken and Three Forks Formations, Williston Basin Province, Montana, North Dakota, and South Dakota, 2013 at http://pubs.usgs.gov/fs/2013/3013/fs2013-3013.pdf.

[6] To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018 (Public Law 115-97), https://congress.gov/115/bills/hr1/BILLS-115hr1enr.pdf.

[7] United States Geological Survey, Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, https://pubs.usgs.gov/fs/fs-0028-01/fs-0028-01.pdf.