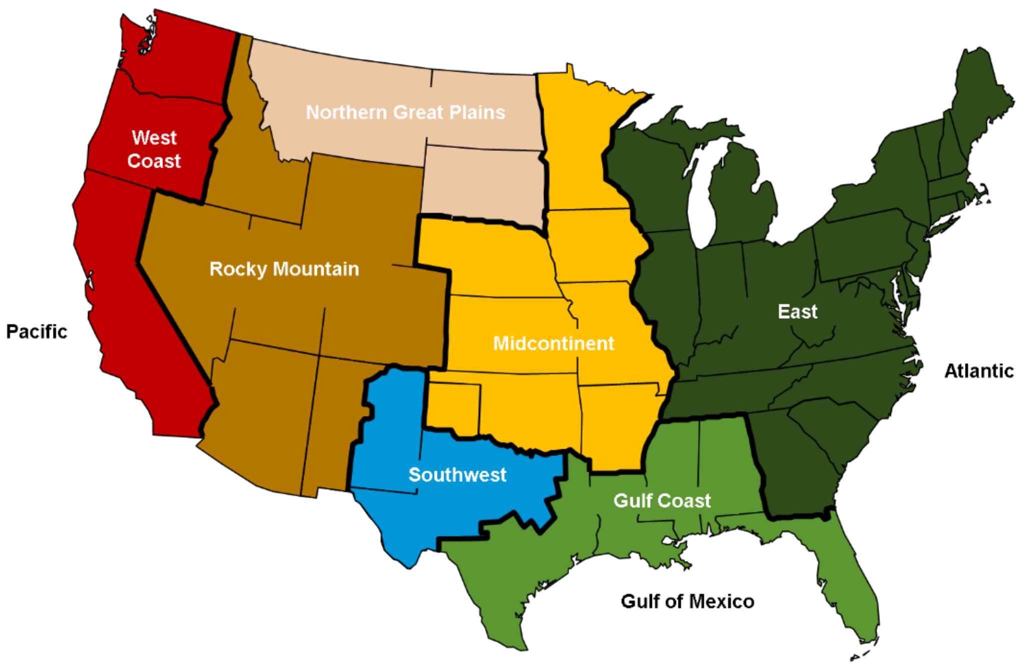
Oil and Gas Supply Module

The National Energy Modeling System (NEMS) Oil and Gas Supply Module (OGSM) is 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: the Onshore Lower 48 Oil and Gas Supply Submodule, the Offshore Oil and Gas Supply Submodule, the Oil Shale Supply Submodule [1], and the Alaska Oil and Gas Supply Submodule. The U.S. Energy Information Administration (EIA) publication, *Oil and Gas Supply Module of the National Energy Modeling System: Model Documentation 2018*, DOE/EIA-M063 (2018), (Washington, DC, 2018) provides a detailed description of this tool. 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 Module regions



OGSM encompasses domestic crude oil and natural gas supply by several recovery techniques and sources. Crude oil supply includes recovery from highly fractured, continuous zones (e.g., Austin chalk, Bakken, Eagle Ford, and Wolfcamp shale formations) primarily using horizontal drilling combined with hydraulic fracturing. In addition, crude oil supply includes improved oil recovery processes such as water flooding and infill drilling, as well as enhanced oil recovery processes such as carbon dioxide (CO_2) flooding, steam flooding, and polymer flooding. 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, which consists 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 because new geological information is gained through additional drilling, because long-term productivity is clarified for existing wells, and because the productivity of new wells increases with technology improvements and better management practices. TRR estimates used by EIA for each *Annual Energy Outlook* (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, 2018.

Table 1. Technically recoverable U.S. crude oil resources as of January 1, 2018

billion barrels

Region	Proved reserves	Unproved resources	Total technically recoverable resources
Lower 48 onshore	34.8	211.4	246.2
East	0.6	4.3	4.9
Gulf Coast	6.2	31.7	38.0
Midcontinent	2.9	10.8	13.8
Southwest	14.0	113.6	127.6
Rocky Mountain	3.1	27.3	30.5
Northern Great Plains	5.8	20.4	26.2
West Coast	2.1	3.2	5.2
Lower 48 offshore	5.2	48.8	53.9
Gulf (currently available)	4.9	36.7	41.6
Eastern/Central Gulf (unavailable until 2022)	0.0	3.7	3.7
Pacific	0.2	5.1	5.3
Atlantic	0.0	3.3	3.3
Alaska (onshore and offshore)	2.0	42.0	44.0
Total U.S.	42.0	302.1	344.1

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.
Sources: 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 of the latest available assessment and January 1, 2018.

Table 2. Technically recoverable U.S. dry natural gas resources as of January 1, 2018

trillion cubic feet

	Proved reserves	Unproved resources	Total technically recoverable resources
Lower 48 onshore	425.7	1,915.7	2,341.4
East	154.1	667.2	821.4
Gulf Coast	86.2	436.0	522.2
Midcontinent	52.6	148.3	200.9
Southwest	60.7	339.3	400.0
Rocky Mountain	61.5	266.0	327.5
Northern Great Plains	9.1	29.1	38.1
West Coast	1.5	29.9	31.4
Lower 48 offshore	6.3	233.9	240.1
Gulf (currently available)	6.2	189.5	195.7
Eastern/Central Gulf (unavailable until 2022)	0.0	3.7	3.7
Pacific	0.1	9.0	9.1
Atlantic	0.0	31.7	31.7
Alaska (onshore and offshore)	6.5	240.7	247.3
Total U.S.	438.5	2,390.3	2,828.8

Notes: 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.
Sources: 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 of the latest available assessment and January 1, 2018.

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 TRR, 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 2018 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 area with potential, well spacing (wells per square mile), and 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 five Bakken 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 2018*.

Table 3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2018)

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	Bradford-Venango-Elk	16,651	8.0	0.003	0.061	0.5	8.1	0.0
Appalachian	Burket-Geneseo	921	5.0	0.008	2.599	0.0	12.0	0.5
Appalachian	Clinton-Medina-Tuscarora	18,807	8.0	0.002	0.058	0.3	8.7	0.0
Appalachian	Devonian	28,539	5.0	0.002	0.166	0.3	23.7	0.9
Appalachian	Huron	5,713	6.4	0.000	0.068	0.0	2.5	0.0
Appalachian	Marcellus Foldbelt	867	4.3	0.000	0.018	0.0	0.1	0.0
Appalachian	Marcellus Interior	25,800	4.3	0.011	2.748	1.3	307.5	18.1
Appalachian	Marcellus Western	2,496	5.5	0.001	0.216	0.0	3.0	0.2
Appalachian	Utica-Gas Zone Core	10,124	5.0	0.007	3.810	0.3	192.9	5.7
Appalachian	Utica-Gas Zone Extension	15,595	3.0	0.005	0.988	0.2	46.3	1.9
Appalachian	Utica-Oil Zone Core	1,349	5.0	0.049	0.215	0.3	1.5	0.0
Appalachian	Utica-Oil-Zone Extension	6,277	3.0	0.014	0.439	0.3	8.3	0.0
Black Warrior	Chattanooga	1,624	8.0	0.000	0.084	0.0	1.1	0.0
Illinois	New Albany	3,023	8.0	0.000	0.099	0.0	2.4	0.2
Michigan	Antrim Shale	13,031	8.0	0.000	0.093	0.0	9.7	0.8
Michigan	Berea Sand	6,682	8.0	0.000	0.122	0.0	6.5	0.1
Gulf Coast								
Black Warrior	Chattanooga	624	8.0	0.000	0.137	0.0	0.7	0.0
Black Warrior	Floyd-Neal/Conasauga	4,485	5.0	0.000	0.601	0.0	13.5	0.0
Texas-Louisiana-Mississippi Salt	Cotton Valley	2,679	8.0	0.027	2.076	0.6	44.6	1.4
Texas-Louisiana-Mississippi Salt	Haynesville-Bossier, Louisiana	1,514	6.0	0.000	10.169	0.0	92.4	0.0
Texas-Louisiana-Mississippi Salt	Haynesville-Bossier, Texas	1,333	6.0	0.012	10.255	0.1	81.8	0.0
Western Gulf	Austin Chalk-Giddings	2,431	6.4	0.074	0.296	1.2	4.6	0.4
Western Gulf	Austin Chalk-Outlying	9,558	6.4	0.039	0.220	2.4	13.5	0.7
Western Gulf	Buda	9,421	6.4	0.037	0.125	2.2	7.5	0.2
Western Gulf	Eagle Ford-Dry Zone	3,414	6.7	0.092	1.160	2.1	26.5	2.4
Western Gulf	Eagle Ford-Oil Zone	6,682	6.4	0.155	0.116	6.6	4.9	1.6
Western Gulf	Eagle Ford-Wet Zone	2,931	8.8	0.254	0.728	6.6	18.9	2.6
Western Gulf	Olmos	4,825	4.0	0.047	1.290	0.9	24.9	0.6
Western Gulf	Pearsall	1,198	6.0	0.001	0.899	0.0	6.4	0.0
Western Gulf	Tuscaloosa	7,377	6.4	0.059	0.255	2.8	12.0	0.2
Western Gulf	Vicksburg	187	8.0	0.029	1.069	0.0	1.6	0.0
Western Gulf	Wilcox Lobo	272	8.0	0.011	0.889	0.0	1.9	0.0
Western Gulf	Woodbine	1,259	6.4	0.097	0.477	0.8	3.8	0.1
Midcontinent								
Anadarko	Cana Woodford-Dry Zone	772	4.0	0.058	2.256	0.2	7.0	0.3
Anadarko	Cana Woodford-Oil Zone	400	6.5	0.050	0.621	0.1	1.6	0.3
Anadarko	Cana Woodford-Wet Zone	1,855	4.1	0.058	1.091	0.4	8.3	1.0
Anadarko	Cherokee/Red Fork	1,087	4.0	0.027	0.477	0.1	2.1	0.2
Anadarko	Cleveland	2,849	7.8	0.034	0.300	0.8	6.6	0.9
Anadarko	Granite Wash/Atoka	5,470	4.1	0.035	0.798	0.8	18.1	1.2
Arkoma	Caney	899	4.0	0.012	0.980	0.0	3.5	0.0
Arkoma	Fayetteville-Central	1,230	8.0	0.000	3.297	0.0	32.4	0.0
Arkoma	Fayetteville-West	768	8.0	0.000	0.747	0.0	4.6	0.0
Arkoma	Woodford-Arkoma	393	8.0	0.003	0.728	0.0	2.3	0.2
Southwest								
Fort Worth	Barnett-Core	136	6.4	0.000	2.188	0.0	1.9	0.3
Fort Worth	Barnett-North	2,930	6.4	0.016	0.251	0.3	4.7	0.2
Fort Worth	Barnett-South	6,866	6.4	0.000	0.272	0.0	12.0	0.5
Fort Worth	Davis	453	4.0	0.039	1.242	0.1	2.3	0.1
Permian	Abo	3,918	4.0	0.042	0.341	0.7	5.4	0.3
Permian	Alpine High	1,914	4.0	0.004	1.132	0.0	8.7	0.2

Table 3. U.S. unproved technically recoverable tight/shale oil and gas resources by play (as of January 1, 2018) (cont.)

				Average EUR		Technically recoverable resources		
Region/basin	Play	Area with potential[1] (mi²)	Average spacing (wells/mi²)	Crude oil[2] (MMb/well)	Natural gas (Bcf/well)	Crude oil (Bb)	Natural gas (Tcf)	NGPL (Bb)
Southwest								
Permian	Avalon/Bone Spring	16,593	5.3	0.282	0.686	24.8	60.2	7.4
Permian	Barnett-Woodford	5,562	4.2	0.011	0.193	0.3	4.5	0.6
Permian	Bend	3,033	6.4	0.001	0.016	0.0	0.3	0.0
Permian	Canyon	9,500	8.0	0.004	0.079	0.3	6.0	0.1
Permian	Delaware	1,199	6.4	0.022	0.038	0.2	0.3	0.1
Permian	Glorieta-Yeso	6,470	6.4	0.045	0.005	1.9	0.2	0.0
Permian	Spraberry	8,068	6.5	0.167	0.212	8.7	11.1	1.8
Permian	Wolfcamp	46,390	6.4	0.209	0.649	62.0	192.6	25.0
Rocky Mountain/Dakotas								
Denver	Denver/Jules–All plays	13,143	8.0	0.005	0.132	0.6	13.9	0.1
Denver	Niobrara	21,850	7.0	0.082	0.301	12.5	46.1	3.6
Greater Green River	Hilliard-Baxter-Mancos	4,449	8.0	0.001	0.378	0.0	13.5	0.9
Greater Green River	Tight Oil Plays	1,244	6.4	0.112	0.015	0.9	0.1	0.0
Paradox	Fractured Interbed	288	6.4	0.543	0.434	1.0	0.8	0.0
Powder River	Tight Oil Plays	7,480	6.4	0.035	0.040	1.7	1.9	0.1
San Juan	Dakota	2,260	6.4	0.001	0.236	0.0	3.4	0.1
San Juan	Lewis	1,479	5.0	0.000	2.200	0.0	16.3	0.0
San Juan	Mesaverde	444	8.0	0.041	0.868	0.1	3.1	0.2
San Juan	Pictured Cliffs	90	6.4	0.000	0.183	0.0	0.1	0.0
Southwestern Wyoming	Fort Union-Fox Hills	1,896	8.0	0.043	1.118	0.7	16.9	0.7
Southwestern Wyoming	Frontier	1,158	8.0	0.015	0.643	0.1	6.0	0.1
Southwestern Wyoming	Lance	196	8.0	0.021	1.628	0.0	2.5	0.3
Southwestern Wyoming	Lewis	2,303	2.3	0.128	1.637	0.7	8.5	0.9
Southwestern Wyoming	Tight Oil Plays	1,520	6.4	0.111	0.015	1.1	0.1	0.0
Uinta-Piceance	Iles-Mesaverde	5,332	6.4	0.001	0.368	0.0	12.5	0.0
Uinta-Piceance	Mancos	1,538	8.0	0.012	0.504	0.1	6.2	0.2
Uinta-Piceance	Tight Oil Plays	214	6.4	0.050	0.111	0.1	0.2	0.0
Uinta-Piceance	Wasatch-Mesaverde	2,455	6.4	0.299	1.236	4.7	19.4	0.9
Uinta-Piceance	Williams Fork	1,445	8.7	0.011	0.854	0.1	10.8	0.5
Wind River	Fort Union-Lance	716	8.0	0.000	1.660	0.0	9.5	0.0
Northern Great Plains								
Montana Thrust Belt	Tight Oil Plays	849	6.4	0.111	0.075	0.6	0.4	0.0
North Central Montana	Bowdoin-Greenhorn	819	6.4	0.000	0.151	0.0	0.8	0.0
Powder River	Tight Oil Plays	3,741	3.1	0.033	0.043	0.4	0.5	0.0
Williston	Bakken Central	3,141	4.5	0.224	0.198	3.2	2.8	0.4
Williston	Bakken Eastern Transitional	1,991	4.0	0.213	0.089	1.7	0.7	0.1
Williston	Bakken Elm Coulee-Billings Nose	3,162	3.6	0.157	0.121	1.8	1.4	0.1
Williston	Bakken Nesson-Little Knife	2,620	4.0	0.288	0.182	3.0	1.9	0.4
Williston	Bakken Northwest Transitional	2,294	4.0	0.079	0.016	0.7	0.1	0.0
Williston	Bakken Three Forks	7,856	4.5	0.181	0.144	6.5	5.1	0.6
Williston	Gammon	2,060	4.0	0.000	0.465	0.0	3.8	0.0
Williston	Judith River-Eagle	1,390	4.0	0.000	0.126	0.0	0.7	0.0
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	1,929	3.8	0.024	0.045	0.2	0.3	0.0
					Total tight/shale	174.0	1611.1	89.8

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, 2018)

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	1,331	8	0.000	0.176	0.0	1.9	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	490	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	974	12	0.000	0.206	0.0	2.4	0.0
Cahaba	Cahaba Coal Field	283	8	0.000	0.179	0.0	0.4	0.0
Midcontinent								
Arkoma	Arkoma	2,779	8	0.000	0.216	0.0	4.8	0.0
Cherokee Platform	Cherokee	3,436	8	0.000	0.065	0.0	1.8	0.0
Forest City Basin	Central Basin	11,135	8	0.022	0.175	1.9	15.6	0.0
Southwest								
Raton	Southern	1,929	8	0.000	0.376	0.0	5.8	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	646	8	0.000	0.204	0.0	1.1	0.0
Piceance	Deep	1,534	4	0.000	0.600	0.0	3.7	0.0
Piceance	Divide Creek	137	8	0.000	0.179	0.0	0.2	0.0
Piceance	Shallow	1,880	4	0.000	0.299	0.0	2.3	0.0
Piceance	White River Dome	203	8	0.000	0.410	0.0	0.7	0.0
Powder River	Big George/Lower Fort Union	1,570	16	0.000	0.260	0.0	6.5	0.0
Powder River	Wasatch	206	8	0.000	0.056	0.0	0.1	0.0
Powder River	Wyodak/Upper Fort Union	6,230	20	0.000	0.136	0.0	17.0	0.0
Raton	Northern	344	8	0.000	0.350	0.0	1.0	0.0
Raton	Purgatoire River	179	8	0.000	0.311	0.0	0.4	0.0
San Juan	Fairway, New Mexico	203	4	0.000	1.142	0.0	0.9	0.0
San Juan	North Basin	1,615	4	0.000	0.280	0.0	1.8	0.0
San Juan	North Basin, Colorado	1,940	4	0.000	1.515	0.0	11.8	0.0
San Juan	South Basin	1,098	4	0.000	0.199	0.0	0.9	0.0
San Juan	South Menefee, New Mexico	373	5	0.000	0.095	0.0	0.2	0.0
Uinta	Ferron	235	8	0.000	0.776	0.0	1.5	0.0
Uinta	Sego	341	4	0.000	0.306	0.0	0.4	0.0
Wind River	Mesaverde	392	2	0.000	2.173	0.0	1.7	0.0
Wyoming Thrust Belt	All Plays	4,219	2	0.000	0.429	0.0	4.2	0.0
West Coast								
Western Washington	Bellingham	441	2	0.000	2.391	0.0	2.1	0.0
Western Washington	Southern Puget Lowlands	918	2	0.000	0.795	0.0	1.5	0.0
Western Washington	Western Cascade Mountains	1,557	2	0.000	2.009	0.0	6.3	0.0
					Total coalbed methane	1.9	104.9	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

Play name	State	County	Number of potential wells	EUR (Mb/well)
Bakken Central Basin	Montana	Daniels	189	60
Bakken Central Basin	Montana	McCone	528	60
Bakken Central Basin	Montana	Richland	1,075	245
Bakken Central Basin	Montana	Roosevelt	4,971	213
Bakken Central Basin	Montana	Sheridan	753	60
Bakken Central Basin	North Dakota	Divide	12	241
Bakken Central Basin	North Dakota	Dunn	69	236
Bakken Central Basin	North Dakota	McKenzie	3,604	287
Bakken Central Basin	North Dakota	Williams	2,914	238
Bakken Eastern Transitional	North Dakota	Burke	2,701	164
Bakken Eastern Transitional	North Dakota	Divide	658	152
Bakken Eastern Transitional	North Dakota	Dunn	1,091	382
Bakken Eastern Transitional	North Dakota	Hettinger	7	169
Bakken Eastern Transitional	North Dakota	McLean	247	303
Bakken Eastern Transitional	North Dakota	Mercer	144	13
Bakken Eastern Transitional	North Dakota	Mountrail	2,632	223
Bakken Eastern Transitional	North Dakota	Stark	371	169
Bakken Eastern Transitional	North Dakota	Ward	111	80
Bakken Elm Coulee-Billings Nose	Montana	McCone	116	80
Bakken Elm Coulee-Billings Nose	Montana	Richland	3,422	207
Bakken Elm Coulee-Billings Nose	North Dakota	Billings	821	178
Bakken Elm Coulee-Billings Nose	North Dakota	Golden Valley	132	161
Bakken Elm Coulee-Billings Nose	North Dakota	McKenzie	2,447	188
Bakken Nesson-Little Knife	North Dakota	Billings	582	130
Bakken Nesson-Little Knife	North Dakota	Burke	679	463
Bakken Nesson-Little Knife	North Dakota	Divide	597	149
Bakken Nesson-Little Knife	North Dakota	Dunn	2,561	321
Bakken Nesson-Little Knife	North Dakota	Hettinger	106	223
Bakken Nesson-Little Knife	North Dakota	McKenzie	1,390	380
Bakken Nesson-Little Knife	North Dakota	Mountrail	412	341
Bakken Nesson-Little Knife	North Dakota	Slope	167	120
Bakken Nesson-Little Knife	North Dakota	Stark	2,164	278
Bakken Nesson-Little Knife	North Dakota	Williams	1,822	220
Bakken Northwest Transitional	Montana	Daniels	2,584	82
Bakken Northwest Transitional	Montana	McCone	161	82
Bakken Northwest Transitional	Montana	Roosevelt	1,312	82
Bakken Northwest Transitional	Montana	Sheridan	2,857	70
Bakken Northwest Transitional	Montana	Valley	1,005	1
Bakken Northwest Transitional	North Dakota	Divide	601	78
Bakken Northwest Transitional	North Dakota	Williams	656	220

Mb = thousand barrels.

EUR = estimated ultimate recovery.

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

The U.S. Geological Survey (USGS) periodically publishes tight and shale resource assessments that are used as a guide for the 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.

Starting with AEO2017, new allocation factors have been 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 Basin and Williston Basin, as well as the Eagle Ford formation. Allocation factors for the Permian Basin were updated in AEO2018 and factors for the Anadarko Basin were updated in AEO2019. Going forward, EIA will continue to update input drivers generating NGPL production, focusing on plays expected to make increasing contributions 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, which require adjustments to some of the assumptions used by the USGS to generate its TRR estimates. The AEO TRRs also incorporate 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 or 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 extent of formations and the number of layers in an area 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 when resource development constraints are available to 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 processes (e.g., CO2 flooding, steam flooding, and polymer flooding) 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, which varies with the type of producer (major, large independent, or small independent). For AEO2020, the economics of potential projects reflect the tax treatment provided by current laws for large independent producers. Relevant tax provisions are assumed unchanged during the life of the investment. Costs are assumed constant during the life of the investment but vary by region, fuel, and process type. Operating losses incurred in the initial investment period are carried forward and are 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 crude oil and natural gas 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. Tier 1 encompasses actively developing areas, and Tier 2 encompasses areas not yet being developed. Once development begins in a Tier 2 area, the rate of technological improvement doubles for wells drilled in the early development phase as producers determine how to efficiently extract the hydrocarbons and to locate the high productivity areas called sweet spots (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 a result of development progression, 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 and 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 Mountain	80	1	0	6	60	25
Northern Great Plains	0	3	0	40	16	3
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 phases: development and market acceptance. 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 widely implemented and volumes of CO2 first become available. The number of years in each development period is shown in Table 8. Since 2016, CO2 has been available from planned Carbon Capture and Storage (CCS) power plants funded by the American Recovery and Reinvestment Act of 2009 (ARRA).

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 crude oil price. For industrial sources of CO2, the cost to the producer includes the cost to capture the CO2, to compress to pipeline pressure, and to transport the CO_2 to the project site via pipeline within the region. Industrial CO_2 is represented by cost curves with the following cost ranges in 2017$/million cubic feet:

- Hydrogen plants: 7.8 to 22.2
- Ammonia plants: 2.9 to 3.0
- Ethanol plants: 2.3 to 5.4
- Cement plants: 6.5 to 15.7
- Natural gas processing: 2.1 to 4.0

Interregional transportation costs add $0.40 per thousand cubic feet (Mcf) for every region crossed. The cost of CO_2 to the producer from all industrial sources reflects the impact of tax credits for CO_2 capture and sequestration, if applicable.

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, production is assumed to have a 10%–15% exponential decline. Currently producing natural gas fields are assumed to have a 30% exponential decline. Fields that began production after 2016 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 2018 are shown in Table 9. 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.

Production is assumed to ramp up to a peak level in three years, remain at peak 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.

Table 9. 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
Blacktip	AC380	6,234	2019	12	90	2029
Whale	AC772	8,799	2017	14	357	2024
Tiger	AC818	9,003	2004	11	44	2031
Gotcha	AC856	7,713	2006	11	44	2029
Trident	AC903	9,685	2001	12	90	2030
G07075	AT001	2,441	1986	9	12	2029
Cyclops	AT008	3,136	1997	8	6	2035
Vicksburg B	DC353	7,500	2008	11	44	2027
Gettysburg West	DC398	7,530	2014	11	44	2025
Raptor	DC535	8,176	2013	10	23	2038
Moccasin	GB254	1,916	1993	10	23	2031
Winter	GB605	3,399	2009	11	44	2042
North Platte	GB959	4,498	2012	14	357	2026
Navarro	GC037	2,021	1997	8	6	2032
Katmai	GC040	2,100	2014	12	90	2021
Healey	GC082	2,461	1996	7	3	2032
GC108	GC108	1,411	1987	7	3	2029
Marathon	GC153	2,461	1994	8	6	2032
GC160	GC160	2,920	1990	8	6	2031
GC162	GC162	2,802	1989	8	6	2029
Orlov	GC200	2,136	2019	10	23	2020
Sable	GC228	1,693	1985	8	6	2034
Antrim	GC364	3,110	2017	10	23	2032
Khaleesi	GC389	3,602	2017	12	90	2022
Samurai	GC432	3,363	2009	11	44	2022
GC463	GC463	4,134	1986	12	90	2033
Mormont	GC478	3,799	2017	11	44	2022
Wildling	GC520	4,117	2017	11	44	2027
Warrior	GC563	4,144	2016	11	44	2026
Caicos	GC564	4,226	2016	11	44	2026
Shenzi North	GC609	4,295	2015	11	44	2027
Constellation	GC627	4,472	2014	11	44	2019
Poseidon	GC691	4,593	1996	10	23	2033
Atlantis North	GC699	7,054	1998	12	90	2020
Calpurnia	GC727	4,596	2017	11	44	2028
Conquest	GC767	5,295	2004	10	23	2030
Anchor	GC807	5,184	2014	14	357	2024
Parmer	GC823	4,127	2003	11	44	2030
Argos Mad Dog Phase 2	GC825	5,899	2005	15	693	2022
Heidelberg Phase 2	GC859	5,869	2009	12	90	2029
Gila	KC093	4,823	2013	10	23	2045
Tiber	KC102	4,131	2009	14	357	2025
Kaskida	KC292	5,860	2006	13	176	2031
Kaskida Phase 2	KC292	5,860	2006	13	176	2034
Leon	KC642	6,119	2014	12	90	2024
Moccasin	KC736	6,759	2011	10	23	2024
Sicily	KC814	6,759	2015	12	90	2032
Buckskin	KC829	6,923	2009	12	90	2019
Buckskin Phase 2	KC829	6,923	2009	13	176	2026
Hadrian North	KC919	7,238	2010	12	90	2019

Table 9. 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
Nirvana	MC162	3,455	1994	9	12	2034
Hoffe Park	MC166	4,019	2017	11	44	2027
Macondo	MC252	4,987	2010	11	44	2040
Red Zinger	MC257	5,997	2016	9	12	2019
Nearly Headless Nick	MC387	6,480	2018	10	23	2019
Appomattox	MC392	7,398	2010	15	693	2019
Vicksburg A	MC393	7,444	2013	12	90	2019
Blue Wing Olive	MC471	5,823	2016	9	12	2019
Manuel	MC520	6,617	2018	10	23	2022
Rydberg	MC525	7,480	2014	12	90	2025
Mudbug	MC560	6,230	2016	7	3	2031
Fort Sumpter	MC566	7,060	2016	12	90	2028
Ballymore	MC607	6,562	2018	15	693	2024
Calliope	MC609	6,814	2017	10	23	2020
Dover	MC612	7,480	2018	13	176	2025
MC709	MC709	2,677	1987	9	12	2030
Thunder Horse South Phase 2	MC778	5,581	1999	13	176	2021
Gladden Deep	MC800	3,140	2019	8	6	2019
Thunder Bird	MC819	5,679	2006	10	23	2023
Ourse	MC895	3,678	2015	10	23	2021
Power Nap	MC943	4,173	2015	12	90	2022
Vito	MC984	4,091	2009	13	176	2021
Phobos	SE039	8,478	2013	12	90	2030
Stonefly	VK999	4,117	2016	9	12	2019
Big Foot	WR029	5,249	2005	13	176	2019
Shenandoah	WR052	6,037	2009	13	176	2028
Yucatan	WR095	5,784	2013	12	90	2031
Coronado	WR098	6,129	2013	12	90	2035
Yeti	WR160	5,896	2015	12	90	2030
Stones	WR508	9,573	2005	12	90	2023
Tucker	WR543	6,896	2006	10	23	2039
Julia Phase 2	WR627	7,218	2007	13	176	2031
Logan	WR969	7,533	2011	12	90	2039

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

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 assumptions for the offshore are presented in Table 10.

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

Table 10. Offshore exploration and production technology assumptions

Technology level	Total improvement over 30 years (percent)
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 include the expansion fields around the Prudhoe Bay and Alpine Fields for which companies have already announced development schedules. These announced discoveries are shown in Table 11. 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 expected capital costs, operating costs, and projected prices.

Table 11. Assumed size and initial production year of announced discoveries in Alaska

Field/project name	Year of discovery	Field size (MMb)	Start year of production
Alkaid/Phecda	2019	70	2022
Greater Mooses Tooth 2	1998	160	2022
Pikka	2013	150	2022
Pikka Expansion	2013	350	2024
Willow	2017	450	2026
Horseshoe	2017	90	2028
Putu/Stony Hill	2018	170	2028
Qugruk	2015	20	2031
Tyonek Deep	1991	30	2034
Koloa 2	2004	20	2035
Smith Bay	2016	200	2035

MMb = million barrels.

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

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 period because offshore North Slope wells and fields are considerably more expensive to drill and develop. As a result, producers have 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 USGS for the onshore and state offshore regions of Alaska and by BOEM for the federal offshore regions of Alaska. The undiscovered resource assumptions for the offshore North Slope were revised as a result of Shell Oil Company's marginal results in the Chukchi Sea in 2015, 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 are found and developed. 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 occurs because developing new infrastructure in Alaska, particularly on the North Slope, is an expensive undertaking. The largest fields enjoy economies of scale, making them more profitable and less risky to develop than the smaller fields.

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 largely 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 when throughput is less than 350,000 b/d, considerable investment might be required to keep the pipeline operational lower than this threshold. As a result, North Slope fields are assumed to be shut down (wells plugged and abandoned) when the following two conditions are simultaneously satisfied: TAPS throughput is at or lower than 350,000 b/d and total North Slope oil production revenues are at or lower than $5.0 billion per year. The remaining resources would become *stranded* (no economical options to get to market). The owners/operators of the stranded resources would have an incentive to subsidize development of more expensive additional resources to keep TAPS operational and thereby not strand their resources. AEO2020 represents this scenario.

Arctic National Wildlife Refuge

The ban on oil and natural gas exploration and production in the coastal plain (1002 Area) of the Arctic National Wildlife Refuge (ANWR) was lifted with the passage of Public Law 115-97 in December 2017 [6]. Based on the most recent (1998) USGS resource assessment, the technically recoverable oil resource in the federal, state, and native lands in the coastal plain is estimated to be between 5.7 billion barrels and 16.0 billion barrels (95% and 5% probability range), with a mean value of 10.4 billion barrels [7]. AEO2020 includes the potential of crude oil exploration and development in this area.

The exploration, discovery, and development of new oil fields in ANWR ultimately will depend on the assumed timing of development, the assumed field size distribution and production profile for each field size, and the expected profitability of development of each field size.

Potential production from ANWR fields is based on the size of the field discovered and the production profiles of other fields of the same size in Alaska with similar geological characteristics. The assumed field size distribution and resulting technically recoverable crude oil resources, shown in Table 12, are based on the mean estimates published in the 1998 USGS assessment.

Table 12. Assumed field size distribution and technically recoverable crude oil resource

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

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

Additional assumptions drive the projection of crude oil production from the coastal plain of ANWR:

- The first lease sale is assumed to take place in 2021. Congress ordered two lease sales in ANWR—the first within four years of the enactment of the law and the second within seven years. This requirement allows time for the Bureau of Land Management (BLM) to develop a leasing program, which includes approval of an Environmental Impact Statement, as well as the collection and analysis of additional seismic data.
- The first production from ANWR occurs in 2031, 10 years after the first lease sale. This 10-year timeline is needed for exploration, appraisal, permitting, and development, and it assumes no lengthy legal battle in approving the BLM's draft Environmental Impact Statement, the BLM's approval to collect seismic data, or the BLM's approval of a specific lease-development proposal.
- The largest fields are brought into production first.
- New fields are sequentially developed every two years after a previous field begins production if production costs and market conditions support their development.
- Fields are assumed to take three to four years to reach peak production, maintain peak production for three to four years, and then decline until they are no longer profitable and are abandoned.

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 the act 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 first 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 British thermal units, 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 about 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 crude oil and natural gas production in water depths greater than 400 meters in the Gulf of Mexico from any lease sale occurring within five years after enactment. The minimum volumes of production with suspended royalty payments are

1. 5 million BOE for each lease in water depths of 400 to 800 meters
2. 9 million BOE for each lease in water depths of 800 to 1,600 meters
3. 12 million BOE for each lease in water depths of 1,600 to 2,000 meters
4. 16 million 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. These suspension volumes are

1. 5 million BOE for leases in water depths of 400 to 800 meters
2. 9 million BOE for leases in water depths of 800 to 1,600 meters
3. 12 million BOE for leases in water depths of 1,600 to 2,400 meters
4. 16 million 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 significantly affect the model result.

The MMS published its final rule in 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 gas 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 CO_2 injection, while at the same time sequestering CO_2 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), effectively prohibiting leasing in those areas. Further, a separate executive ban in effect since 1990 prohibited leasing through 2012 on the OCS, except for in 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 that are 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 the development of the Atlantic and Pacific OCS.

On March 20, 2015, the BLM released regulations regarding hydraulic fracturing on federal and Indian lands, known as 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
- 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.

On December 22, 2017, Public Law 115-97 was signed into law, requiring the Secretary of the Interior to establish a program for the leasing and development of oil and natural gas from the coastal plain (1002 Area) of the Arctic National Wildlife Refuge (ANWR). Previously, ANWR was effectively under a drilling moratorium. Congress ordered two lease sales in ANWR, the first within four years of the enactment of the law and the second within seven years (Section 20001). In addition, this law includes a reduction in the federal corporate tax rate from a graduated rate structure with a top corporate rate of 35% to a flat rate of 21% (Section 13001).

The Section 45Q sequestration tax credit was amended and expanded in the Furthering Carbon Capture, Utilization, Technology, Underground Storage, and Reduced Emissions Act (FUTURE Act), which was passed as part of the Bipartisan Budget Act of 2018. The legislation intends to provide a financial incentive to industrial entities to capture and sequester CO2 that would otherwise be vented to the atmosphere. The 45Q credits provide additional value for carbon capture utilization and storage (CCUS) technologies for the first 12 years of operation for plants that start construction before January 1, 2024. These credits are available to both power and industrial sources that capture and permanently sequester CO2 in geologic storage and for use in enhanced oil recovery (EOR). Credit values are defined as follows:

- The tax credit for CO2 used for EOR starts at $12.83 per metric ton in 2017 and rises linearly to $35 per metric ton by 2026. After 2026, credits rise with inflation.
- The tax credit for CO2 that is permanently stored in saline aquifers starts at $22.66 per metric ton in 2017 and rises linearly to $50 per metric ton by 2026. After 2026, credits rise with inflation.

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. During 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 may not prove to be accurate 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 yet been identified.

The sensitivity of AEO2020 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 well for tight oil, tight gas, or shale gas 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 172 billion barrels, and the natural gas resource is reduced to 1,351 trillion cubic feet (Tcf), as compared with unproved resource estimates of 302 billion barrels of crude oil and 2,390 Tcf of natural gas as of January 1, 2018, 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 for more domestic crude oil production than in the Reference case. This case includes

- 50% higher estimated ultimate recovery per tight oil, tight gas, or shale gas well
- 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
- 50% higher assumed rates of technological improvement that reduce costs and increase productivity in the United States than in the Reference case
- 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 483 billion barrels, and the natural gas resource increases to 3,554 Tcf compared with unproved resource estimates of 302 billion barrels of crude oil and 2,390 Tcf of natural gas in the Reference case as of the start of 2018.

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 before the large-scale, in-situ production of oil shale becomes 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 before 2050.

[2] Technically recoverable resources are resources that can be produced using current recovery technology but without reference to economic profitability.

[3] Proved reserves are the estimated quantities that analysis of geological and engineering data demonstrate 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. They include undiscovered resources that are located outside oil and natural gas fields where the presence of resources has been confirmed by exploratory drilling. Unproved resources also 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.

[6] Public Law 115-97 (To provide for reconciliation pursuant to titles II and V of the concurrent resolution on the budget for fiscal year 2018).

[7] United States Geological Survey, *Arctic National Wildlife Refuge, 1002 Area, Petroleum Assessment, 1998, Including Economic Analysis*.

[8] Furthering carbon capture, Utilization, Technology, Underground storage, and Reduced Emissions Act.